Net Zero Technology Centre

Technology Driving Transition

Fuel of the Future: An e-Methanol Study

ETF Alternative Fuels for Gas Turbines

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Abbreviations & Key Terms

AFGT ... Alternative Fuel Gas Turbines
BOE/D ... Barrels of Oil Equivalent per Day
CNS ... Central North Sea
CO_2 ... Carbon Dioxide
CO ... Carbon Monoxide
DAC ... Direct Air Capture
DME ... Dimethyl ether
eMeOH ... e-Methanol
ETF ... Energy Transition Fund
FPSO ... Floating Production Storage and Offloading
INTOG ... Innovation and Targeted Oil and Gas
LC50 96 ... Lethal Concentration that will kill 50% of life in a 96-hour test period
LNG ... Liquified Natural Gas
LPG ... Liquified Petroleum Gas
MeOH ... Methanol
MSW ... Municipal Solid Waste
NH_3 ... Ammonia
NNS ... Northern North Sea
NOx ... Nitrogen Oxides
NSTA ... North Sea Transition Authority
NZTC ... Net Zero Technology Centre
OEM ... Original Equipment Manufacturers
OSV ... Offshore Support Vessel
PM ... Particulate Matter
RED II ... Renewable Energy Directive
SI ... Spark Ignition
SNS ... Southern North Sea
Solar PV ... Solar Photovoltaics
SOx ... Sulphur Oxides

Synthetic Fuel

In broadest definition, a liquid or gaseous fuel that is not derived from naturally occurring crude oil is a synthetic fuel. Fuels produced from a combination of hydrogen and carbon to generate synthesis gas are all correctly labelled as synthetic fuels. The hydrogen and carbon feedstock can be derived from a multitude of sources including natural gas and renewable sources.

e-Methanol

A form of renewable methanol derived from the combination of carbon dioxide and hydrogen produced from renewable electricity (green hydrogen). For the product to be classified as green, the CO2 used in the process must either be captured directly from the atmosphere, from a biogenic source or recycled from industrial point-source emissions.

Bio-methanol

Bio-methanol is produced from biomass. Key sustainable feedstocks include forestry and agricultural waste and by-products, biogas from landfill, sewage, municipal solid waste (MSW) and black liquor from the pulp and paper industry.

e-Kerosene

Much like e-methanol, e-kerosene is created using the combination of carbon dioxide from direct air capture (DAC), biogenic sources or recycled carbon and green hydrogen. e-Kerosene can utilise both CO and CO2 to produce synthetic crude oil in-turn to produce e-Kerosene.

Green Ammonia

Ammonia is a carbon-free fuel derived from the combination of nitrogen and hydrogen predominantly produced via natural gas. The medium becomes green when the hydrogen is produced via the electrolysis of water powered by renewable energy and the nitrogen feedstock is extracted from the atmosphere.

Executive Summary

The North Sea Transition Deal (NSTD) set out significant emissions reduction targets for the offshore energy industry. As we near those targets, it is well understood that decommissioning activities and a reduction in the number of operational assets will not solely meet the NSTD targets.

Electrification from shore has been a hot topic for some time with the scale of offshore wind developments continuously increasing. To meet that scale-up, the National Grid is currently completing the holistic network design to support and deliver the Government's ambitious target of 50GW integrated offshore wind by 2030 – but 2030 is too late to meet the NSTD targets. Additionally, through the work performed by the NZTC, it is well understood that around only 50% of the current ScotWind licenses are accounted within this plan.

The industry can achieve significant progress to reach the targets through the adoption of alternative fuels for power generation whilst fuel production facilities mature from the use of recycled industry sources of carbon (non-renewable) to renewable sources such as direct air capture or biogenic. This report identifies the key strengths associated with renewable methanol and proposes how the industry may benefit from its deployment in an offshore environment.

UK AMBITION TO BECOME A EUROPEAN LEADER IN CLEAN HYDROGEN PRODUCTION AND EXPORTS

Renewables targets:

- **70 GW** SOLAR (2035)
- **50 GW** OFFSHORE WIND (2030)
- **10 GW** LOW-CARBON HYDROGEN CAPACITY (2030)

TARGET OF 4 LOW-CARBON INDUSTRIAL CLUSTERS BY 2030, AND A NET ZERO INDUSTRIAL CLUSTER BY 2040

Emissions reduction targets from O&G production:

- **10%** BY 2025
- **25%** BY 2027
- **50%** BY 2030
- **NET ZERO** BY 2050

68% EMISSIONS REDUCTION GOAL BY 2030, AND NET ZERO BY 2050

1. The adoption of e-methanol as a fuel over natural gas would provide an emissions reduction of approximately 74% - based on e-methanol production from renewable electricity and captured CO_2 from a coal power plant.

It should be made clear, such adoption would still allow for gas to be produced and subsequently used as a fuel in domestic markets.

2. Methanol can provide a significant near-term transition in terms of technology availability due to the large number of OEM's offering methanol compatible gas turbines.

Coupled alongside the significant growth in renewable methanol production plants located in the countries that surround the perimeter of the North Sea.

3. The environmental impact of methanol, in the event of a spill, is significantly less than those of conventional fuels, in that 15,400mg/l of methanol creates a lethal concentration that could kill half of the affected marine life over a 96-hour period – compared to 3.4mg/l of ammonia and 21mg/l of diesel.

4. The Renewable Energy Directive now allows for the combustion emissions of fuels created from recycled carbon as the feedstock to typically be discounted thus allowing for the waste streams of carbon intense industries such as the steel or cement industry to be re-purposed for a second life.

It should be noted this is only applicable until 2035 to allow for the continued investment in direct air capture technology.

5. Based on the North Sea Transition Authorities Emissions Monitoring Report 2022, 11.3MtCO_2e of emissions was associated with the offshore energy sector in 2021.

65% of this can be attributed to power generation. If alternative fuels for offshore power generation was adopted by a modest 30% of the industry, an overall emissions reduction of 3.39Mt of CO_2e per year could be recognised.

For context, it would take 85 years for the UK's largest carbon capture facility - which can remove a maximum of 40kt per year – to capture the same amount of carbon.

Introduction

One of the key challenges to delivering a net-zero UK is reducing the emissions associated with the offshore energy industry. It is well understood that 65% of those emissions come from power generation, as installations rely on their own produced gas as the fuel that is then combusted in a gas turbine to produce electricity[1].

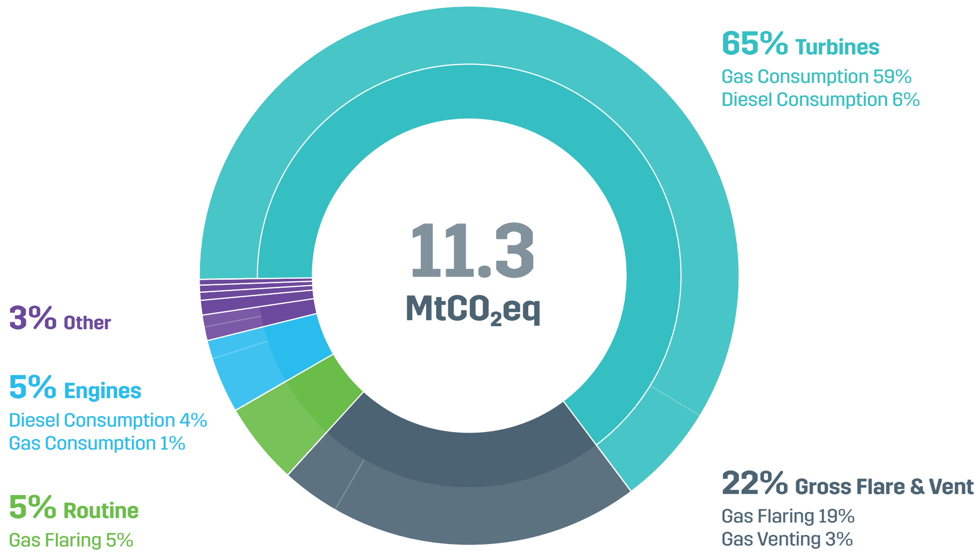


Figure 1: Facility emissions by source and category, 2021[1]

We have gained a comprehensive understanding of the varying challenges associated with the broader decarbonisation of offshore installations. It is a key objective of the report to demonstrate the bigger picture to decarbonisation and disseminate that knowledge. All the while, not offering a bias towards a particular solution but presenting an array of options subject to the asset specifics and strategic direction of their operators.

As part of the Net Zero Technology Centre's review, the following report has been constructed to ensure that the organization has a comprehensive understanding of the alternative fuel landscape, to develop appreciation on the applicability of each fuel subject to the environment said fuel will be utilised in and additionally illustrate how e-methanol may be utilised in an offshore environment.

When the Alternative Fuel Gas Turbine Energy Transition Fund (ETF) project was initially scoped in mid-2020, the focus was entirely on ammonia as the chosen 'Alternative Fuel'. Two years have now passed since the original business case was written and there has been a marked evolution in the pathways to the decarbonisation of offshore power generation, supply, and distribution.

Siemens Energy is an industry leader and key stakeholder in the project. Their current position is that renewable/green e-methanol and/or traditionally produced 'black' methanol (MeOH) is "the most likely transition fuel" for aero-derivative gas turbines. Simply put, because it can provide a real-term power generation decarbonisation 'win' much sooner (i.e., no fundamental technical barriers to mid-2020's deployment) than H_2/H_2-NH_3 or partial and full electrification schemes[2].

What is an alternative fuel?

As defined within The Alternative Fuel Labelling and Greenhouse Gas Emissions Regulations 2019[3], alternative fuels are "fuels or power sources that serve, at least partly, as a substitute for fossil oil sources in the energy supply to transport and which have the potential to contribute to its decarbonisation and enhance the environmental performance of the transport sector".

Introduction to e-fuels

e-Fuels are synthetic fuels produced from hydrogen and carbon dioxide. The hydrogen that is used as a feedstock for e-fuel production is generated from a renewable source (green hydrogen). Green hydrogen is obtained from the electrolysis of water, where the electricity comes from a renewable method of energy production, such as wind or solar. The CO_2 obtained for the process can be via direct air capture or from recycled point source emissions. There are a variety of processes that can take place with green hydrogen and carbon dioxide to convert them into synthetic fuels.

E-fuels come in many forms such as ethanol, methanol, and kerosene but the starting point is always the combination of green hydrogen and carbon dioxide. When forming an e-fuel, the process involves taking hydrogen fuel and converting it into a liquid. This removes one of the largest challenges of hydrogen as a fuel for offshore installations – its low volumetric energy density.

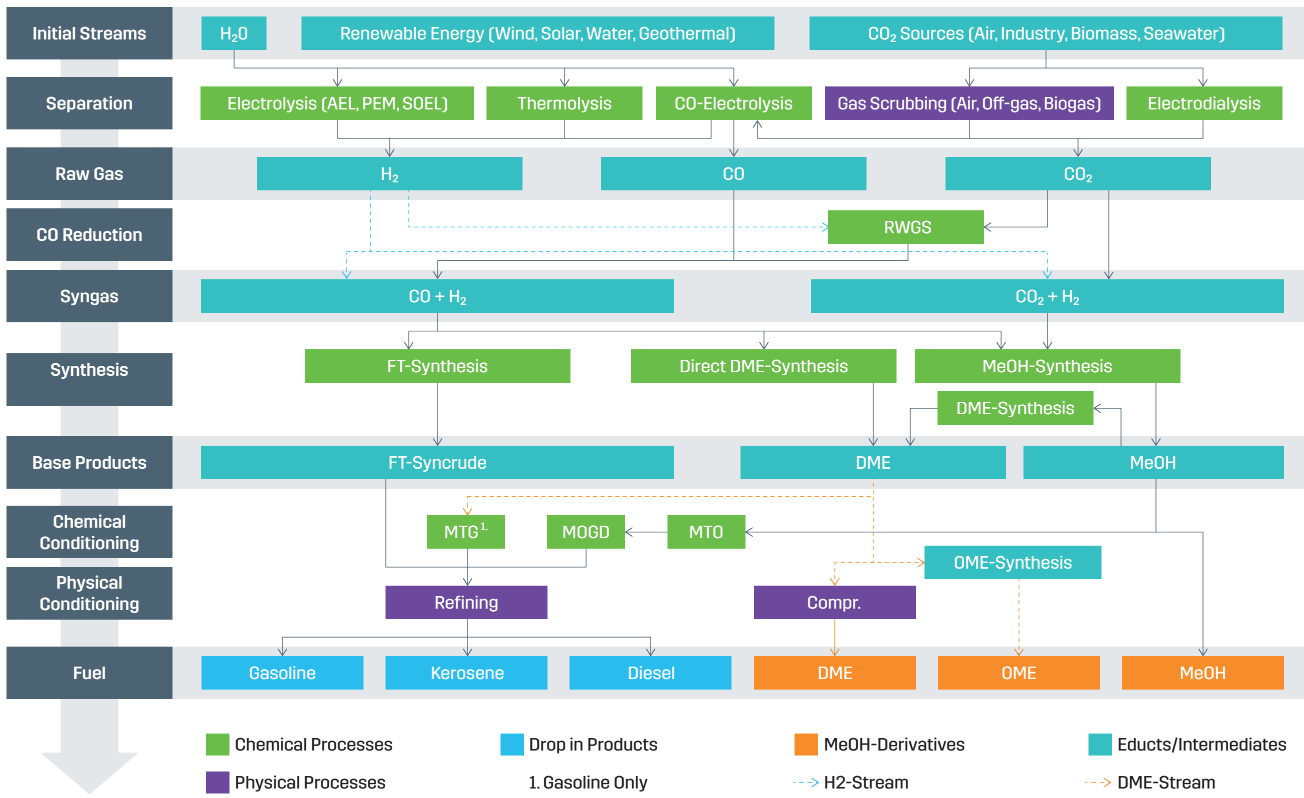


Figure 2: Diversity of pathways for electrofuel production[59]

e-Methanol

Properties

Methanol is the simplest member of the organic chemical group called alcohols. Liquid in a state when at ambient temperature and pressure, the chemical is used heavily in the creation of formaldehyde. More recently, however, methanol has been identified as an attractive alternative fuel source within the marine and energy sectors due to the chemical's environmental and economic advantages[4].

The prefixed 'e' from e-methanol can be adopted when hydrogen is produced via electrolysis of water which is powered by renewable energy, also referred to as green hydrogen. e-Methanol classification remains open to interpretation. However, the current EU draft directive (RED II) states that provided the CO_2 feedstock is from either direct air capture, biogenic resources or carbon recycling from industrial waste streams that would have occurred anyway, the medium can be classed as green.

In simple terms, the characteristics, and properties of the final product, whether it is grey, blue or green/ e-methanol, are identical. All feedstocks and all energy used to produce methanol must be of a renewable origin to be defined as green methanol, with carbon recycling being the only exception[5].

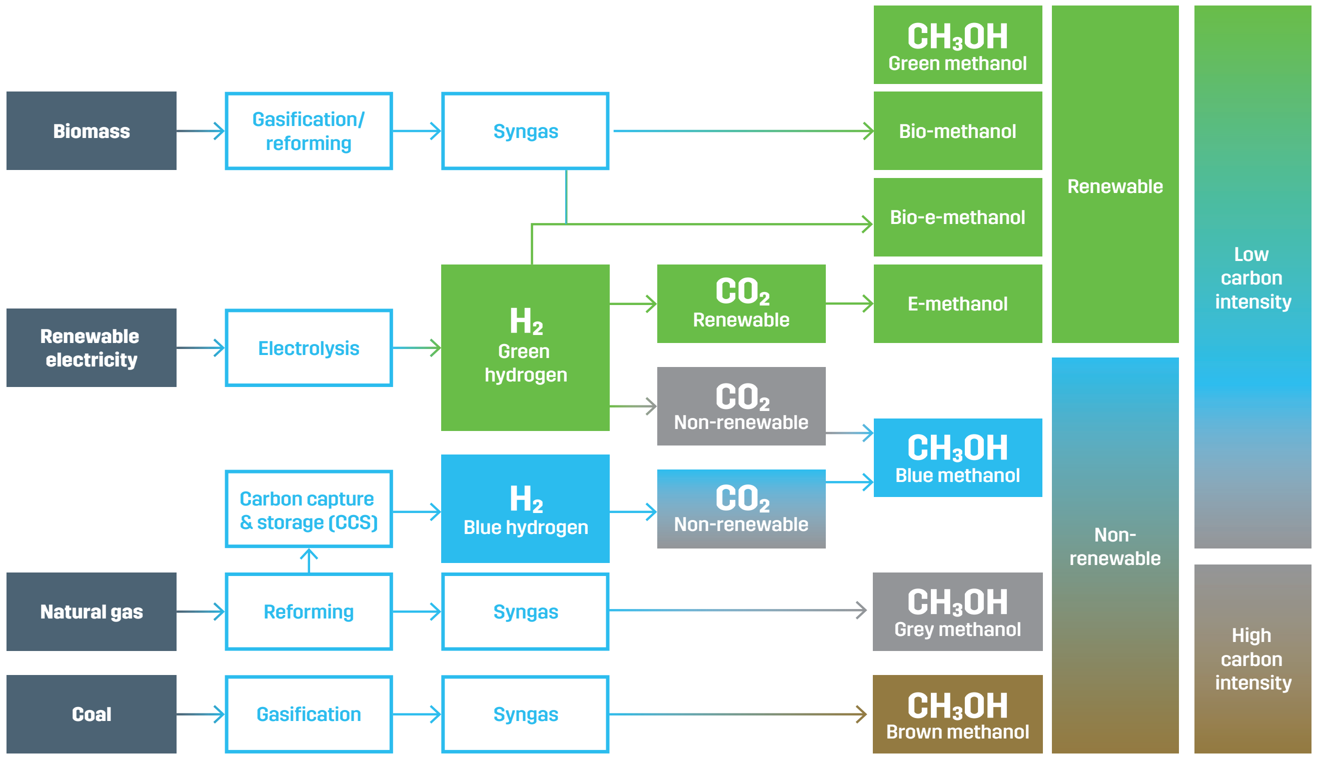


Figure 3: Proposed classification of methanol production [4]

For clarity, whilst this report is focused on e-methanol, contrasts have often been made against conventional grey methanol due to the data available and the identical properties of the end products.

Emissions Impact

Based on the previous work performed by the NZTC, the table below summarizes the life cycle emissions of each fuel – a key comparison among others that need to be considered when discussing alternative fuels.

Fuel Type	Energy Content (MJ/kg)	Energy Density (MJ/L)	Octane Rating	Cetane Rating	CO_2 Combustion Emissions (kg/L)	Flammability Range LEL-UEL (%VOL)	Life Cycle CO_2 Emissions (kg/L)
Petrol	42.6	32	95	-	2.32	1 - 7.6	2.31
Diesel	44.3	37.7	-	51	2.61	0.6 - 7.5	2.70
LPG	46.1	22.6	112	-	1.53	1.81 - 8.86	1.52
LNG	49	22	-	0	-	4.2 - 16.0	-
Biodiesel	37.8	32.9	-	46 - 60	2.48	-	2.59
Ethanol	24.8	19.6	113	-	1.50	3 - 19	0.5 - 0.7
Methanol [6,7]	19.9	15.8	109	3	1.08	6 - 36.5	0.2 - 1.6[1]

1e methanol: 0.2, fossil-based methanol: 1.6

The work conducted by O. Siddiqui and I. Dincer's 'A comparative life cycle assessment of clean aviation fuels'[8] provides a great insight into the adoption of various fuels and their resulting emissions. The study assumes a net aircraft weight of 234 tons. for each fuel and a functional unit of tonne-km. This functional unit denotes aircraft travel of one kilometer with a load of goods equivalent to one ton.

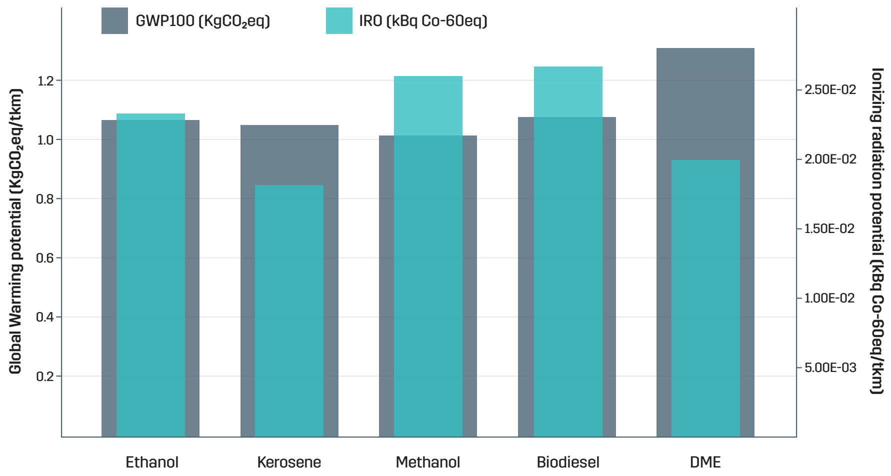


Figure 4: Comparison of Life Cycle Global Warming Potential [8]

Conventional methanol has a comparable GWP against the four alternative fuels being compared by O. Siddiqui et al. Whilst this is the case for methanol made from natural gas, renewable sources of CO_2 that are used in e-methanol can be measured in a vastly different manner.

It is imperative that we properly understand the difference between fossil and biogenic CO_2 emissions. Simply put, burning fossil fuels adds carbon to the biosphere-atmosphere that has been in the ground for millions of years, whilst biomass combustion emits carbon that is already part of the biogenic carbon cycle i.e., carbon that was absorbed as plants grew[9]. Biomass carbon can be seen as nature's very own direct air capture unit. Therefore, in the instance of methanol via biomass carbon, the end-of-life carbon combustion emissions are typically not considered or reported. Whilst this justifies the attraction to bio-methanol, their contribution towards renewable energy targets is limited due to the indirect land-use change. These are fuels that are produced from food and feed crops that have a considerable adoption of land with high carbon stock.

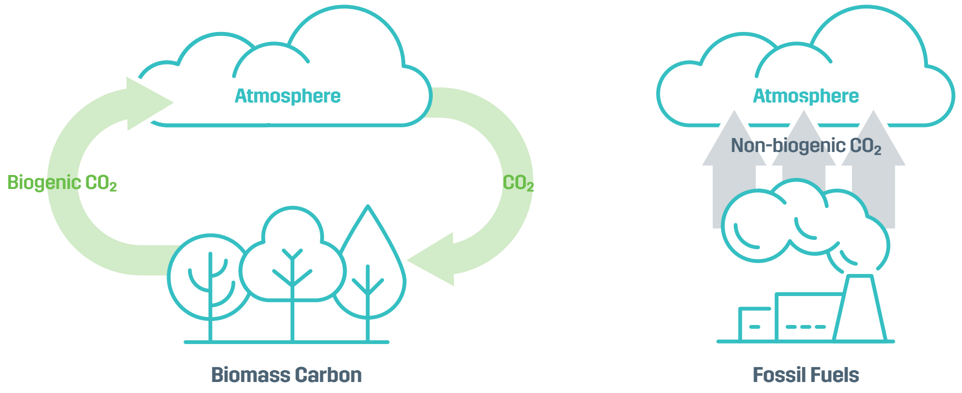


Figure 5: IEA Bioenergy fossil vs biogenic CO_2 emissions[9]

Adoption of e-methanol can contribute in a similar manner as bio-methanol without implications for food and feed crops. The anthropogenic carbon cycle for e-methanol can be viewed in the same way as the biogenic carbon cycle. Carbon is removed from the atmosphere via direct air capture technology. This carbon is then used as a feedstock for the fuel production and resultantly released back into the atmosphere when the fuel is combusted. Figure 6 Emissions of each production step of e-methanol highlights the carbon credit gained during the initial production phase against the various emitting factors along the entire life cycle of the fuel[10].

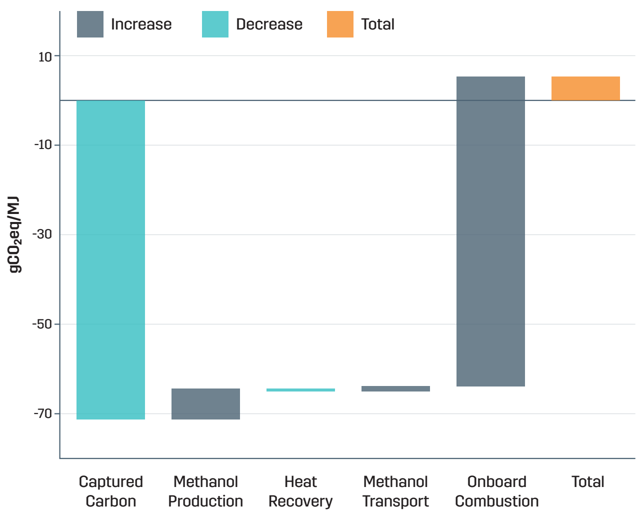


Figure 6: Emissions of each production step of e-methanol[10]

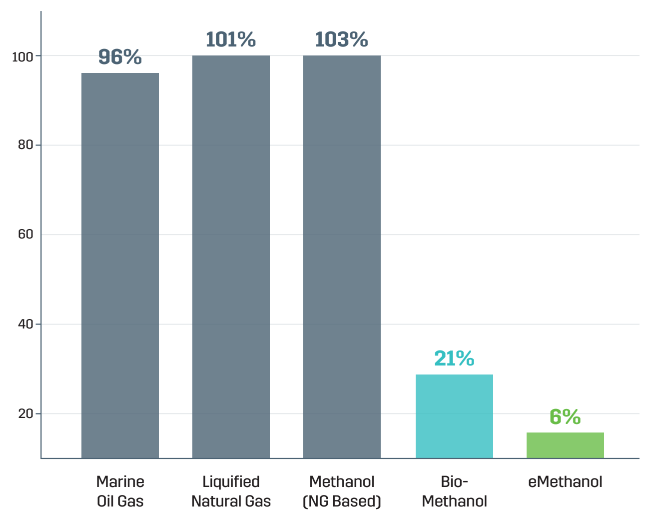


Figure 7: Greenhouse gas of marine fuels compared to low sulphur oil[10]

Figure 7: Greenhouse gas of marine fuels compared to low sulphur oil is demonstrated on the previous page, where low sulphur oil is represented as 100% with the GHG deltas illustrated for comparison.

Recycled Carbon Fuels

There have been significant developments in the adoption of carbon recycling whereby the emissions from industrial sources are directly utilised as feedstocks for e-methanol production. Such feedstocks are abundantly available and lower the overall cost of e-methanol production. This is particularly important to allow renewable methodologies to mature.

When recycled carbon is utilised for e-fuel production, the end-use carbon combustion emissions are cancelled out by the carbon emissions from the input feedstock that would have otherwise been unavoidably released. The equation below demonstrates the emissions calculation approach set out by the EU Renewable Energy II Directive.

The delegated act has been created to introduce new provisions for the promotion of renewable fuels of non-biological and recycled origin by establishing common principles and rules to remove barriers, stimulate investment and aid in the cost reduction of renewable energy technologies[11].

$$E = -e_{(ex\text{-}use)} + e_p + e_{td} + e_u$$

Where all inputs are in gCO_2/MJ of fuel and:

eex-use = Emissions from exiting use or fate i.e., the CO_2 recycled from the point source.

ep = Emissions from processing including the electricity source footprint.

etd = Emissions from the transport and distribution.

eu = Emissions from the end-use combustion.

The emissions recycled from the CO_2 point source will be equal to those emissions that are combusted latterly, thus making eex-use and eu cancel each other out. This leaves the emissions from the fuel production and transportation to be the only remaining factors.

The total of the emissions pertaining to the renewable fuel is then compared against the full life-cycle emissions of the fossil fuel, which is set to Ef = $94gCO_2e/MJ$, as per the RED II Directive. This includes the production/processing, transport, and combustion of the fuel. The net savings are then calculated as[11]:

$$=(E_f - E)/E_f$$

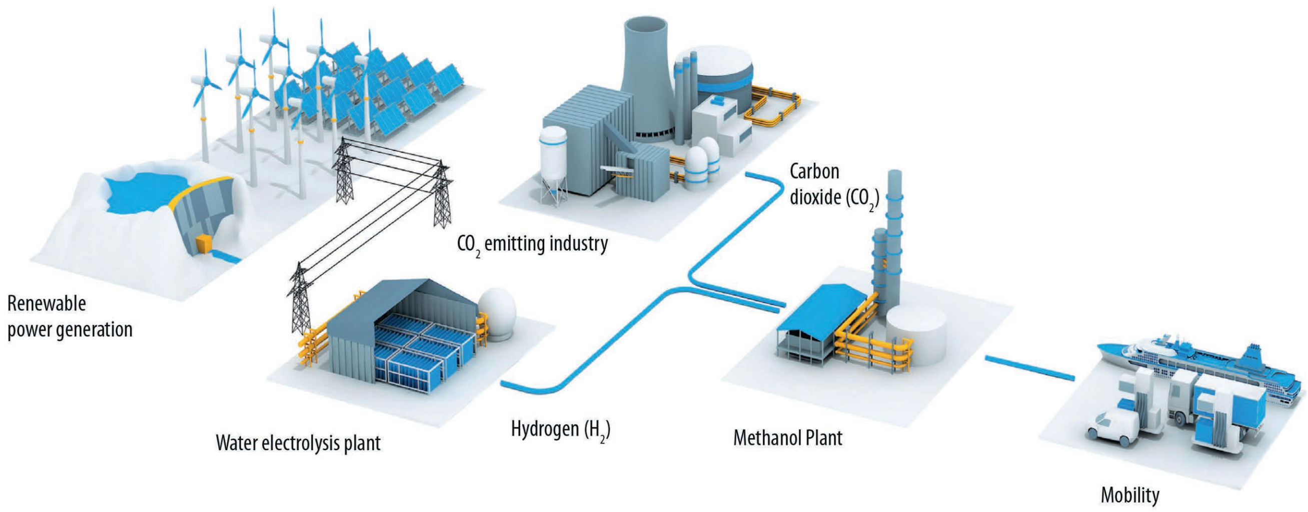


Figure 8: Thyssenkrupp's concept of using renewable energy and waste CO_2 to make e-methanol [18]

In the short term, whilst the use of recycled carbon is encouraged to begin the decarbonisation of industry, the use of carbon from non-sustainable practices requires the continued use of non-sustainable fuels and their respective emissions. As such, per the latest RED II Draft Directive, the use of carbon recycling will be phased out through to 2035. After which, the carbon used for e-fuel production will have to be of renewable sources to be considered green - hence the need to continue investment in sustainable technologies such as direct air capture.

Whilst methanol from non-renewable sources will yield decarbonisation of industrial machinery/processes, we mustn't treat that as the answer to the problem, but as a steppingstone. Investment in technology to lower the cost of green hydrogen and hence e-fuel production whilst scaling up is, of course, essential.

Current Power Generation Emissions

Natural gas is often favoured due to the fuel being available by association. Offshore oil and gas facilities are therefore capable of utilising a portion of the gas recovered from the reservoirs to supply their turbines for power generation – evading the need for concern over fuel supply and delivery.

There are several arguments surrounding the principle of utilising natural gas for power generation. One could argue that the gas would be better off being sold to consumers in the UK or for export to foreign markets. A study performed by the Net Zero Technology Centre found that 12% of the UK's current gas resource is utilised as fuel for offshore installations.

Furthermore, the global warming potential (GWP) of various alternative fuels has been evaluated above, drawing on the work performed by O. Saddiqui et al. However, the comparison between e-methanol and natural gas is equally as important to analyse.

The North Sea Transition Authorities (NSTA) Emissions Report 2021[13] denotes an average emission intensity for associated gas fuelled power generation as 460kgCO_2e per MWh - once converted can be expressed as 128gCO_2e per MJ. For diesel, 167.2 gCO_2e per MJ should be used based on a 602kgCO_2e per MWh for typical offshore diesel engine.

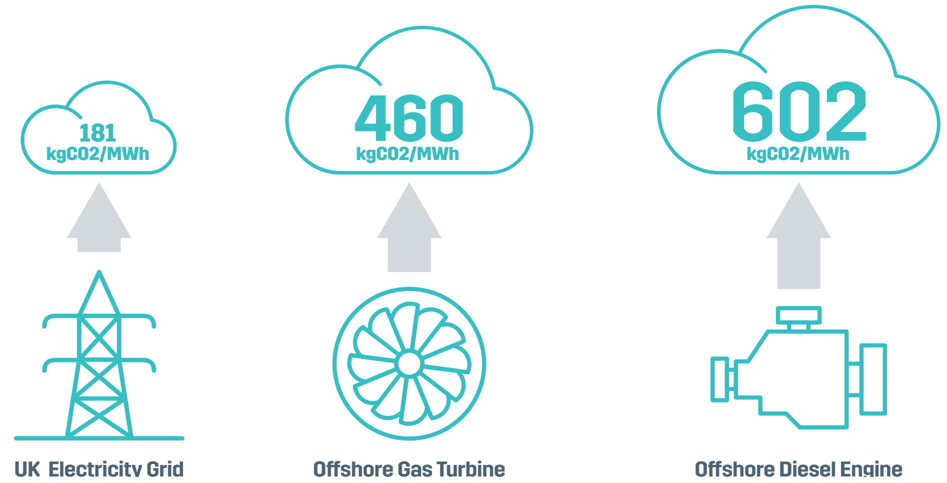


Figure 9: Emission intensity (kgCO_2/MWh) of power sources (2020 average) [12]

The two main variables to the emissions intensity of e-methanol are the source of captured carbon and the source of electricity used to produce green hydrogen. Firstly, if we look at the emissions intensity based on the electricity source, e-methanol produced from wind – the most likely renewable source to be used in Scotland - has a full life cycle emissions factor of 6gCO_2e per MJ [13].

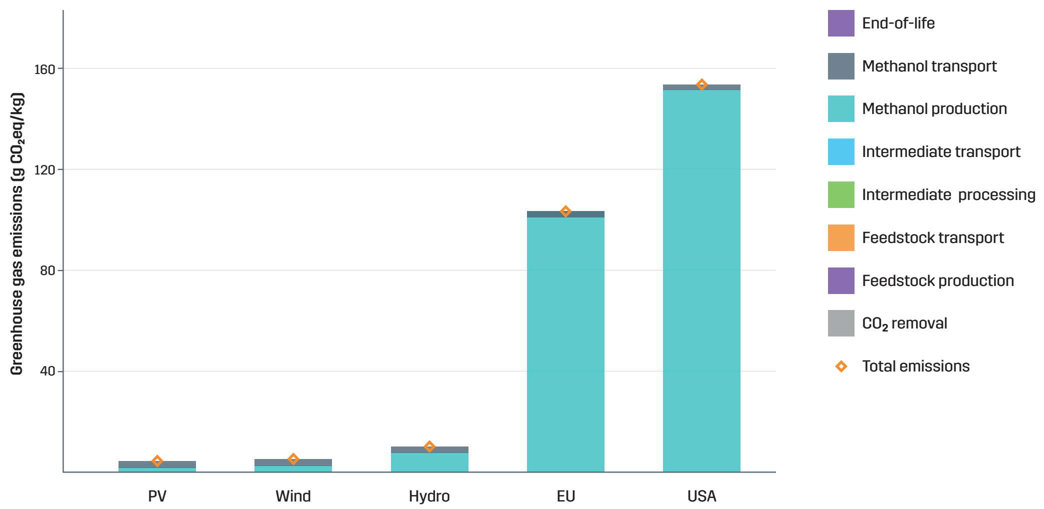


Figure 10: e-Methanol emissions subject to source of electricity [13]

If we look at the emissions intensity based on the recycled/captured CO_2 source, there is a variety in the overall life cycle emissions figure. In the instance where CO_2 is captured from a coal power plant, e-methanol can have a total life cycle emissions intensity of up to 33.1gCO_2e/MJ. It should be noted that the default REDII value of 2gCO_2e/MJ for transportation and distribution for eMeOH should be added.

Feedstock	Original system boundaries	Raw material to final use GHG emitted in g Co_2eq/MJ*	Source
Renewable electricity, flu gas from biomass plant	(B)	3.23	Buddenberg et al., 2016
Renewable electricity, CO_2 from ethanol plant	(A)	13	Matzen and Demirel, 2016
Renewable electricity, CO_2 from biogas process	(B)	0.5	Hoppe et al., 2018
Renewable electricity, CO_2 from ethanol plant	(D)	21.3	Kajaste et al., 2018
Renewable electricity, CO_2 captured from coal power plant	(D)	33.1	Kajaste et al., 2018
Renewable electricity, fluegas bracket geothermal energy plants	(A)	12.1	CRI, 2020
Renewable electricity, fluegas from biomass plant	(A)	1.74	Chaplin, 2013

* Raw material to final use GHGs in g CO_2-eq/ MJ calculated from the original system boundary:

(A) From raw material extraction until use phase; no correction needed

(B) From raw material extraction until methanol production gate; add the RED II default value of 2.0g CO_2-eq/MJ for transport and distribution of MeOH

(C) From raw material extraction until methanol production gate; add the RED I default value of 2.0g CO_2-eg/MJfortransportand distribution and the combustion emission of MeOH of 69g CO_2-eq/MJ

(D) From raw material extraction until methanol production gate; corrected for CO_2 emitted during methanol use 69g CO_2-eg/MJ; add the RED II default value of 2.0g CO_2-eq/MJ for transport and distribution of MeOH

Figure 11: GHG emissions of methanol from various sources[5]

This means that the adoption of e-methanol as a fuel over natural gas would provide an emissions reduction of approximately 74% - based on e-methanol production from renewable electricity and captured CO_2 from a coal power plant.

It should be made clear, such adoption would still allow for gas to be produced and subsequently used as a fuel in domestic markets, moving the emissions from scope 1 of the offshore asset to scope 3 of the end user. That said, the energy industry is driven to deliver energy with as small a scope 1 footprint as possible therefore such a reduction in scope 1 emissions can therefore only be viewed as positive.

Ecotoxicological Values LC50 (96-Hour Period)

The primary purpose to the adoption of alternative fuels is to reduce the environmental implications imposed by current fossil fuels. A significant focus is placed on the emissions characteristics of each fuel candidate, but there is also a need to explore the environmental implications should the fuel be spilt during the production, transportation, and utilisation phases.

The figure shown here demonstrates the lethal concentration in water in which half the population died over a 96-hour test period. To produce the graphic, the ecotoxicological information in terms of aquatic toxicity was studied, looking at the short-term toxicity to fish. The smaller the circle, the less dose amount needed to be deemed as a lethal concentration [14, 15, 16, 17].

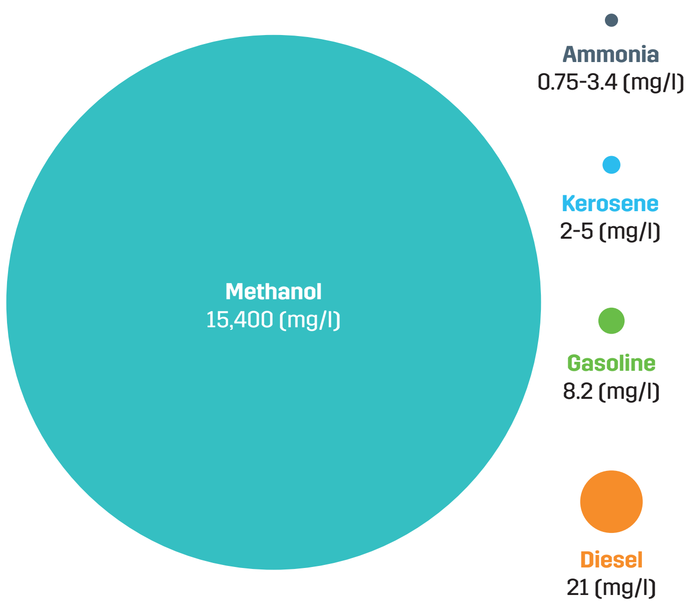


Figure 12: Ecotoxicological values LC50 for various alternative fuels - Ammonia is 4,529 times more toxic to the marine environment than Methanol

Current Manufacture

Methanol is conventionally produced via steam methane reforming with natural gas being the most prominent feedstock. There was previously also a significant dependency on coal as a feedstock too, particularly in the Asian markets. The CO, CO_2, H_2O, and H_2 by products are then partially oxidized during the catalytic synthesis from the synthesis gas, combining CO_2 with H_2 to produce methanol.

Renewable methanol can be produced from a varied range of feedstocks available worldwide. The five most popular feedstocks are:

- Municipal Solid Waste (MSW).
- Agricultural Waste.
- Forestry Residues.
- Captured Atmospheric CO_2 or Recycled Industrial sources of CO_2.
- Renewable/Green Hydrogen.

Our primary focus will be on the creation of methanol from captured CO_2 and green hydrogen as shown in *Figure 13: Renewable methanol production processes from different feedstocks*[18].

Technology development in recent years allows for carbon emitted from industrial exhaust streams such as power plants, steel, cement factories, and distilleries to be captured and re-utilised as one of the feedstocks to produce methanol. Additionally, direct air capture of carbon from the atmosphere can also be adapted to provide the renewable feedstock needed.

A great example of this is Carbon Recycling International. The Icelandic company can produce 4,000 metric tons of renewable methanol from 5,500 metric tons of recycled carbon dioxide each year supplied in the form of emissions from a neighbouring geothermal power plant[19].

The second aspect of methanol production is the hydrogen feedstock. Focus has been driven into the development of renewable hydrogen production, or 'green hydrogen', whereby electrolysis of water is used to extract hydrogen whilst being powered by a renewable source such as wind, solar PV, or hydropower.

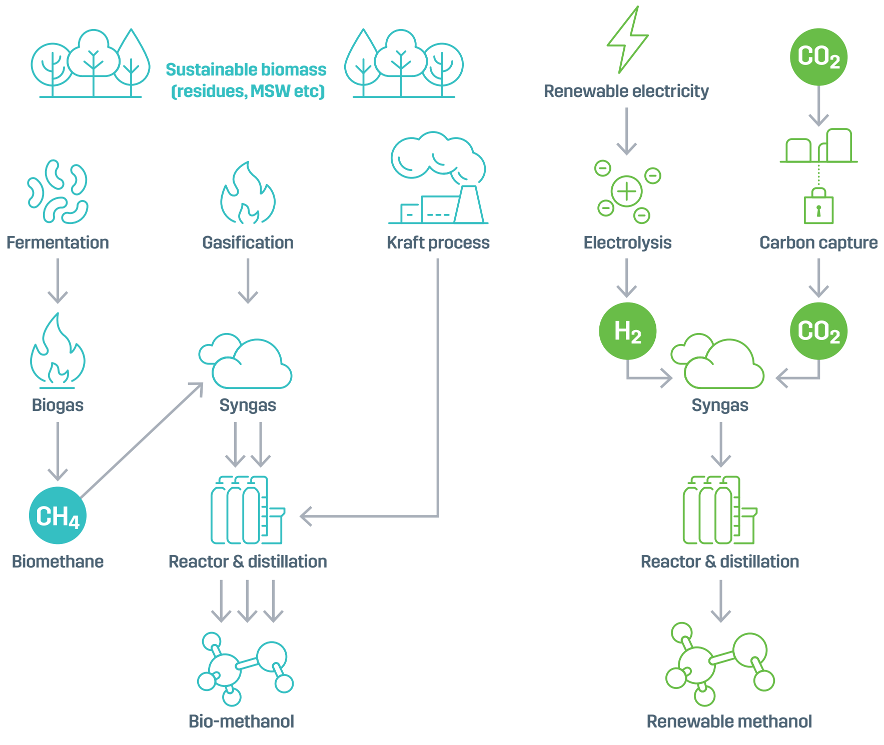


Figure 13: Renewable methanol production processes from different feedstocks 18]

Applications

Several notable examples can be utilised to highlight the appeal of methanol as an alternative fuel. The earliest example of methanol adoption into the maritime sector is the Stena Germanica. Converted in 2015, the passenger/freight ferry running on the Gothenburg – Keil route utilised methanol as the primary fuel with backup marine gas fuel capability. As a result, Stena reported a sulphur oxide emission reduction of 99%, nitrogen oxide reduction by 60%, particulates by 95%, and carbon dioxide emission reduction by 25%.

Since then, Wartsila the engine supplier for the Germanica has commercialized the Wartsila '32' model to be available for new build or retrofitting[20].

The Green Pilot project is another similar example, converting a pilot boat to operate on renewable methanol fuel and subsequently reporting the improvements to the environmental performance[21].

From a gas turbine perspective, methanol conversions of existing turbine models are already well established and understood by many original equipment manufacturers (OEMs) today. Siemens and GE are some of the world's leading developers in power generating equipment, including aero-derivative gas turbines. Both GE and Siemens publicly offer literature on methanol compatibility or conversion requirements for their turbines. Figure 14 SGT-A35 G62 Emissions Comparison highlights the work done to date by Siemens energy and the significant impact green methanol has on the turbine operating footprint.

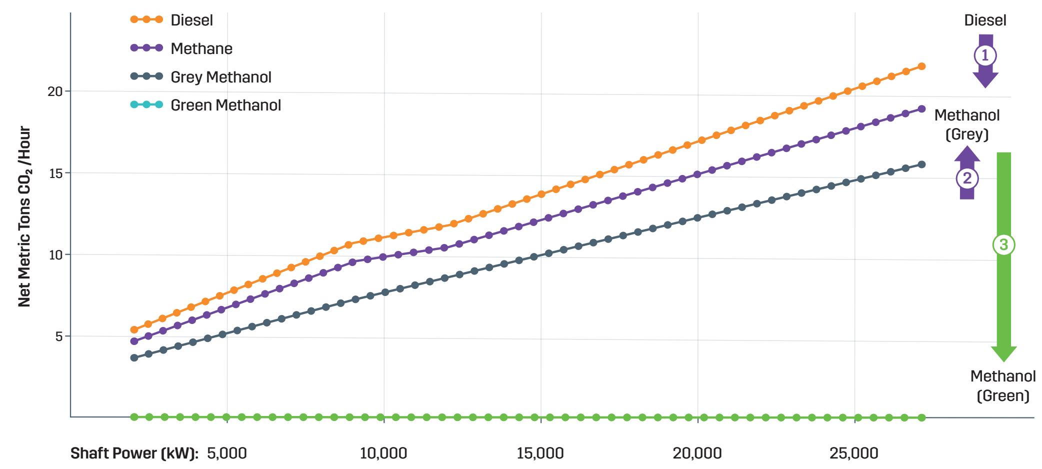


Figure 14: SGT-A35 G62 Emissions Comparison[22]

Based on the information available in Siemens 'Decarbonisation AGT Product Guide,'[22] the following scope is needed to convert their SGT-A05, SGT-A20, and SGT-A35 turbines to run on 100% methanol.

- Higher capacity burners.
- Liquid fuel capacity upgrade.
- Assess package fire & gas detection and ventilation systems.
- Control system update.

Similarly, GE produced the white paper 'The Fuel Flexibility of GE Power's Aeroderivative Gas Turbines' which identifies a variety of fuels against their current product range[23].

	Gaseous Fuels				Liquid Fuels			
Fuels	High BTU: ethane, propane, butane, LPG, isopentane	Natural Gas & LNG	Medium BTU: lean methane	Low BTU: syngas, steel mill, landfill	Light Distillates diesel, kerosene, jet fuel (A, A1, naptha)	Biodiesel	Ethanol	Methanol
Heating Value	>1,200 BTU/scf	~900 BTU/scf	>300-700 BTU/scf	>300 BTU/scf	~18,000-19,000 BTU/lbm	~16,500-18,000 BTU/lbm	~11,500-BTU/lbm	~8,500 BTU/lbm
	>44,900 kJ/Nm³	>35,800 kJ/Nm³	~11,200-26,000 kJ/Nm³	>11,200 kJ/Nm³	~42,000-44,000 kJ/kg	~39,500-18,000 kJ/kg	~26,850 kJ/kg	~19,850 kJ/kg
Gas Turbine								
LM/TM2500	•	•	•	•	•	•	•	•
LM6000	•	•	•		•	•	•	•
LM9000	•	•	•		•	•		
LMS100	•	•	•		•	•	•	•

Figure 15: GE Fuel Flexibility 23

Combustion Characteristics and Attributes

A summary of the combustion characteristics, specific to gas turbine generators, is outlined below to highlight the key advantages methanol holds over conventional fossil-based fuels such as gasoline[24].

Attribute	Relevance
Lower nitrogen oxides (NOx) and particulate matter (PM)	NOx is a component of ozone air pollution which can produce harmful health effects; PM is an air pollutant that is classified as a known human carcinogen by the World Health Organization (WHO).
Lower combustion temperature	Results in lower NOx.
Lower lean flammability limit	Lean mixture application and, consequently, better fuel economy and lower emissions of NOx, and carbon monoxide (CO).
High octane	For fuel production, reduce process energy consumption; for plant manufacturers, cleaner fuel combustion, better vaporisation, and reduced engine knock.
Vapour pressure	Vapour pressure is not a problem for high blends of methanol; for low blends, it can easily be handled by adjusting the before oxygenating blending at the refinery.
Comparable distillation characteristics to gasoline.	Distillation characteristics of hydrocarbons have an important effect on their safety and performance, especially in the case of fuels and solvents. The boiling range gives information on the composition, properties, and the visor of fuels during storage and use. Volatility is the major determinant of the tendency of a hydrocarbon mixture to produce potentially explosive vapours. Distillation affects starting warm-up and the tendency to vapour-lock at high operating temperatures or high altitude, or both. The presence of high boiling components in these and other fuels can significantly affect the degree of formation of solid combustion deposits.

Transport, Logistics and Storage

Methanol is used widely in oil and gas production as a preventative to hydrate formation, thus making the industry well versed with the transportation and logistical practices of handling methanol. There are several stakeholders responsible for the safe transfer of bulk methanol to offshore locations including the supplier, transporter, and user of the product. For this section, the technical documentation available concerning the transportation of bulk methanol via offshore support vessels has been evaluated exclusively.

Methanol is well developed in terms of the regulatory framework, particularly for the handling of the medium. The documents detailed on the following page provide some further guidance and information on the handling practices of methanol in an offshore environment.

- The Carriage of Methanol in Bulk Onboard Offshore Vessels, Marine Safety Forum, and Oil Companies International Marine Forum.
- Guidelines for the Transport and Handling of Limited Amounts of Hazardous and Noxious Liquid Substances in Bulk on Offshore Support Vessels (OSV Chemical Code IMO).
- International Code for the Construction and Equipment of Ships Carrying Dangerous Chemicals in Bulk (IBC Code IMO).
- International Convention for the Prevention of Pollution from Ships (MARPOL).
- International Safety Guide for Oil Tankers and Terminals.

Although offshore installations are not directly regulated by the International Maritime Organization, it is worth noting that methanol was approved as a fuel by the IMO in November 2020.

The lower and upper flammability limits (L/UFL), expressed as a percentage of the volume of flammable vapour in the air, is the range in which fuel is in a flammable state. When a vapour and air composition is combusted, gas is rapidly expanded which, if constricted in a confined space such as a tank, will result in the pressure within the space to rise to the point of explosive rupture. As a means of mitigation, the ullage space of the tank is filled with an inert gas, commonly nitrogen, to reduce the oxygen content levels past the lower flammability limit of the fuel, effectively making the mixture too lean to support combustion.

Substance	LFL/LFE % by Volume of Air	UFL/UEL % by Volume of Air	Flashpoint (°C)
Methyl Alcohol (Methanol)	6.0 to 6.7	36	11

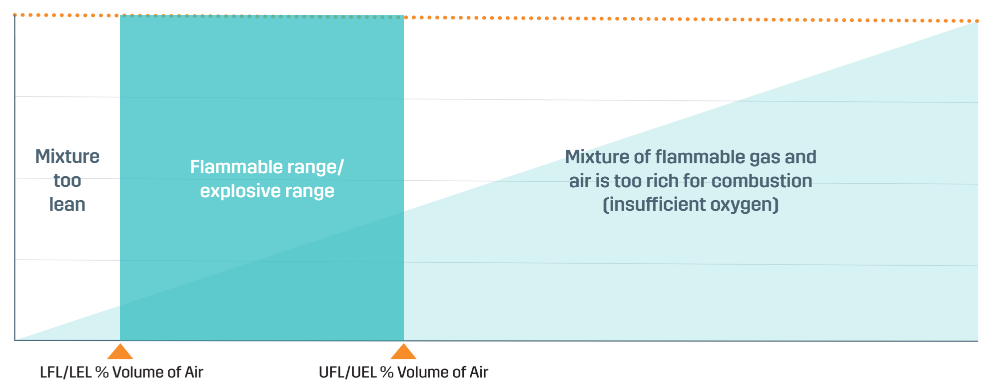


Figure 16: LFL & UFL of Methanol[25]

Whilst on board offshore support vessels, the carriage of bulk methanol should be maintained in an inert condition in alignment with the IMO OSV Chemical Code. The code dictates that the substance should maintain an oxygen content of 8% or less with clear areas surrounding the pressure/vacuum relief valves and manifolds. Additionally, the assigned product tanks should be protected by cofferdams containing water or nitrogen[25].

Whilst methanol handling and transportation is well understood by the oil and gas industry, the scale of methanol volumes utilised would dramatically increase. Such an increase leads to the question on storage capacities. FPSOs are best placed to address this issue due to the existing storage tanks, already sized at the capacities needed but for fixed assets, systems like the NOV Subsea Energy Storage System can also address the issue.

If we take the NOV example [26] and modify it for methanol, the system potential can be effectively demonstrated:

A fixed platform with five 5,000m3 storage units, gives a total storage volume of 25,000m3. Energy storage with methanol, given the density of methanol, gives 19,800 tons of fuel. Each ton of methanol gives 1.66 MWh of energy if it is used as a direct fuel and the turbines used are capable of a 30% open cycle efficiency. This gives a total power of 32,868 MWh, which will fuel a medium 30 MW platform for 45.65 days, before re-filling is needed.

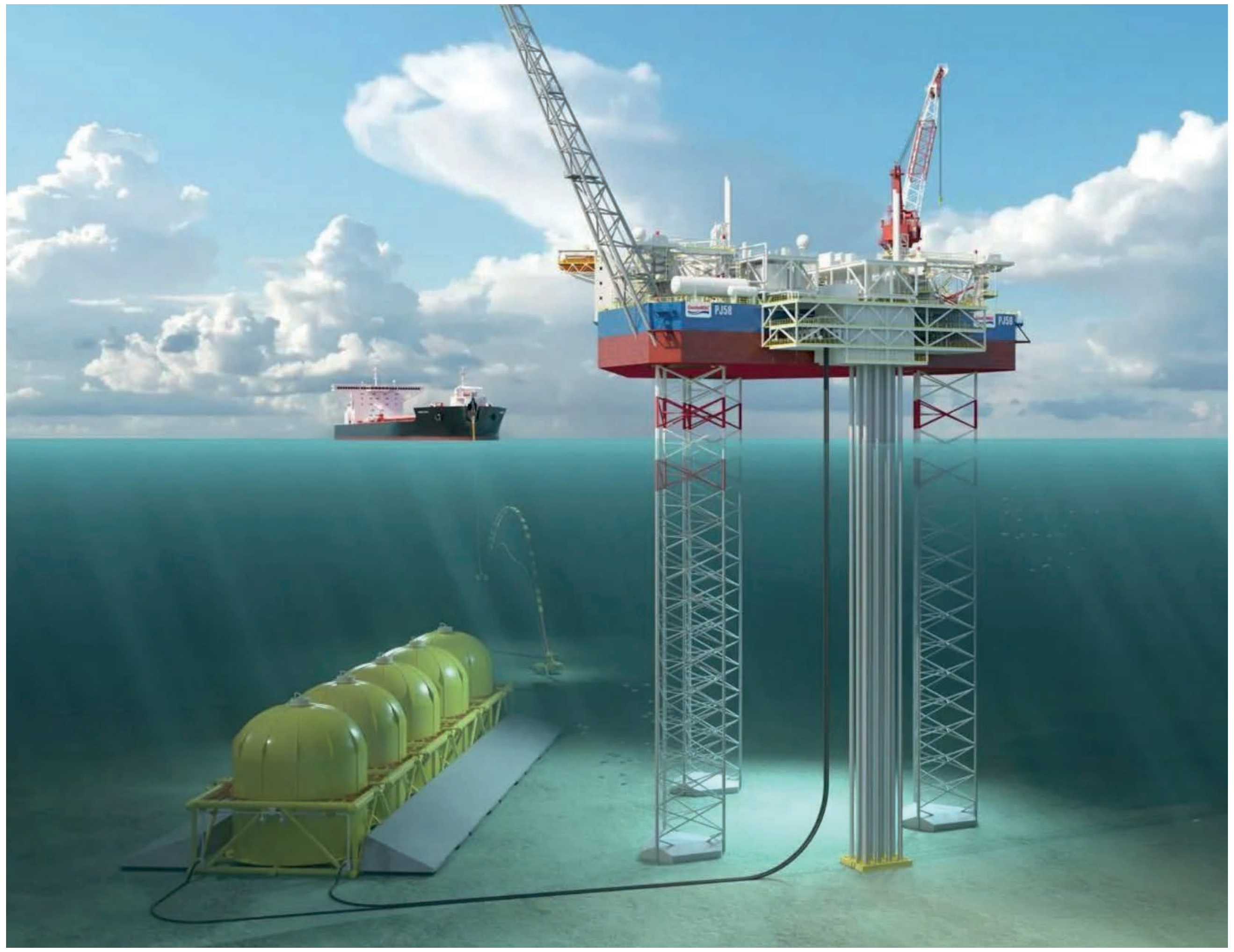


Figure 17: NOV Subsea Energy Storage System [26]

e-Kerosene Comparison

Properties

(e)-Kerosene has a lot of similarities with methanol, due to the fundamental construction of kerosene requiring the same feedstocks as methanol – hydrogen combined with carbon. Kerosene like methanol is also a liquid at ambient pressure and temperature. The differentiator is the synthesis and refining treatment that occurs once both feedstocks are received to produce the fuel. Whilst methanol utilises methanol synthesis, kerosene adopts the Fischer-Tropsch method (FT), using direct CO input. It should be noted that industry experience with CO_2-based feed gases is limited, resulting in current synthetic fuel manufacturing facilities relying on co-electrolysis to separate carbon monoxide from carbon dioxide before the Fischer-Tropsch synthesis can occur [27].

Fuel Type	Energy Content (MJ/kg)	Energy Density (MJ/L)	Octane Rating	Cetane Rating	CO_2 Combustion Emissions (kg/L)	Flammability Range	Life Cycle CO_2 Emissions (kg/L)
Kerosene [28,29]	43.5	34.7	38-48	70 - 80	-	0.7 - 5	3.1
Methanol	19.9	15.8	109	3	1.08	6 - 36.5	0.2 - 1.6[1]

Emissions Impact

Reference to O. Siddiqui et. Al's work has been made on numerous occasions to allow for consistent comparisons to be made across the various fuels being considered. The process considered for methanol comprises of production of syngas from natural gas via steam methane reforming. The fuels identified below are all conventional in construction due to the limited data on their green alternative production routes [8].

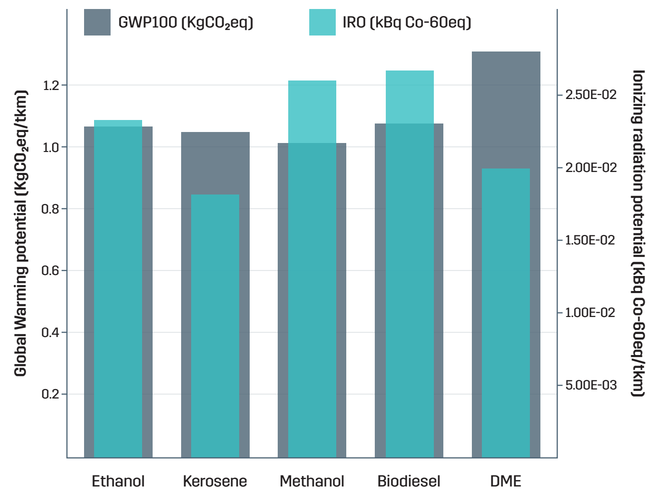


Figure 18: Comparison of life cycle Global warming potential [8]

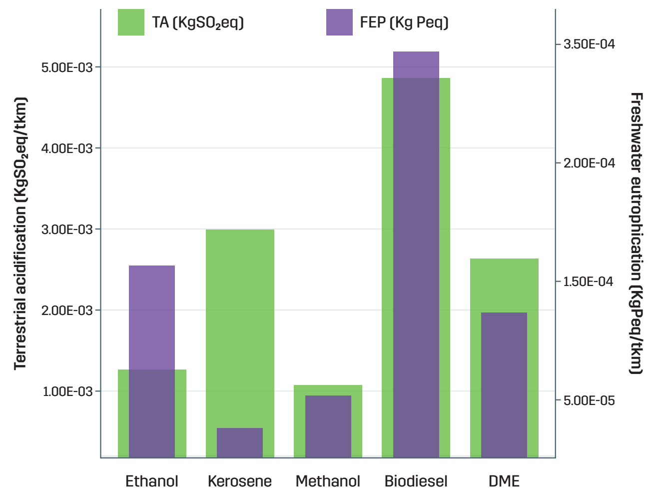


Figure 19: Terrestrial Acidification and Freshwater Eutrophication [8]

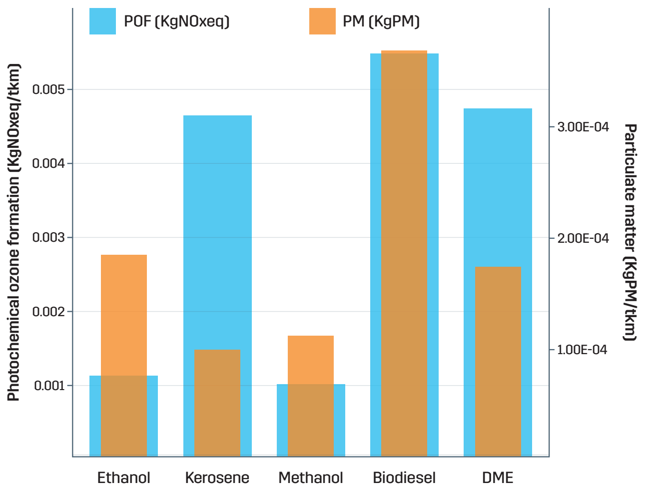


Figure 20: Photochemical Ozone Formation and Particulate Matter [8]

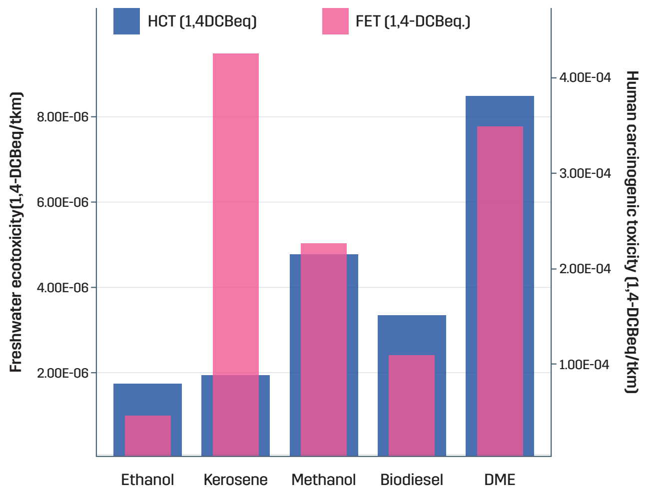


Figure 21: Freshwater Ecotoxicity and Human Carcinogenic Toxicity [8]

Fuel Comparison

Current Industry Adoption

In terms of synthetic e-kerosene, adoption has already been vastly integrated into the aviation industry. However, due to current aviation standards, a maximum of 50% synthetic fuel can be used at one time whilst mixed with conventional jet fuels. Trials have been successfully performed when a world-first Boeing 737 flight from Amsterdam to Madrid departed with 500L of synthetic e-kerosene mixed with regular jet fuel in January 2021 [30].

Parallels can be drawn from the aviation industries' adoption of e-kerosene and relate these to synthetic fuel use in power generation at offshore installations. Such parallels are available due to the turbine similarities and the aero-derivative models that are used today on various offshore installations.

Environmental Implications

Kerosene being more energy-dense than methanol with the addition of its high flammability makes the fuel the ideal choice for use in aviation. However, such physical properties come with a cost to the environment as displayed above, with kerosene having a greater GWP than methanol. The focus should also be given to the greenhouse gas emissions related to the combustion of kerosene over methanol which is highlighted in the figures formerly.

Additionally, kerosene can cause some of the most detrimental effects to marine life out of all the fuels being compared in this study. In the event of a release whilst the fuel is being bunkered or stored offshore, the medium only requires 2-5mg/l to establish lethal concentration levels. Further details of the ecotoxicological values of each fuel can be found above.

Feedstock Scale

Both methanol and kerosene are very similar in terms of quantities of hydrogen and carbon dioxide needed to produce the fuels. For 1 MJ of energy out, the following calculations can be done:

$$1\text{kg Kerosene } (3.10\text{kg } CO_2 + 0.439\text{kg } H_2) = 43.5\text{MJ} \therefore 1\text{MJ Kerosene} = 0.07\text{kg } CO_2 + 0.01\text{kg } H_2$$

$$1\text{kg Methanol } (1.37\text{kg } CO_2 + 0.189\text{kg } H_2) = 19.9\text{MJ} \therefore 1\text{MJ Methanol} = 0.068\text{kg } CO_2 + 0.009\text{kg } H_2$$

Closing Statement

The aviation industry's adoption of synthetic fuel provides great insight into the key drivers and considerations, particularly due to the concentration of both the aviation and offshore energy industry. Based on the work presented by Shell in 'Decarbonizing Aviation: Cleared for Take-off,' it was found that the top two engine manufacturers account for around 75% of the market, much like the offshore gas turbine sector. Additionally, the top twenty-five airlines account for almost half of the global volume which again draws parallels to the operator diversity within the North Sea [31].

Whilst Kerosene does offer nearly double the energy content of methanol, the GWP delta of the two fuels can be deemed as significant if the CO_2 used to produce methanol is from biogenic, atmospheric, or recycled sources. The aviation industry needs a medium such as kerosene to deliver the high energy content with constraints against the total weight of fuel. Such constraints do not have the same criticality on-board an offshore installation. Furthermore, the ecotoxicological profiles of the two fuels give clear direction on which fuel is best suited in a marine environment.

Ammonia Comparison

Properties

Ammonia is the carbon-free product of combining one (1) mole of nitrogen with three (3) moles of hydrogen, hence its chemical formula NH_3. Green ammonia proposes to be a promising alternative fuel due to the feedstock availability and the low feedstock volume requirements. Although the process is different from other electro fuels, the reaction scheme is simple - using the Haber-Bosch process whereby the nitrogen and hydrogen feedstocks react over a metallic catalyst. The notable differentiator between ammonia and methanol is the storage conditions. Methanol is a liquid at ambient pressure and temperature whereas ammonia needs to be either refrigerated past its boiling point of around -33°C or pressurized (16-18 bar) to remain in a liquid state. This makes the substance more challenging to handle, although there is extensive experience in the onshore handling and transportation of ammonia via its use in the fertilizer industry [32].

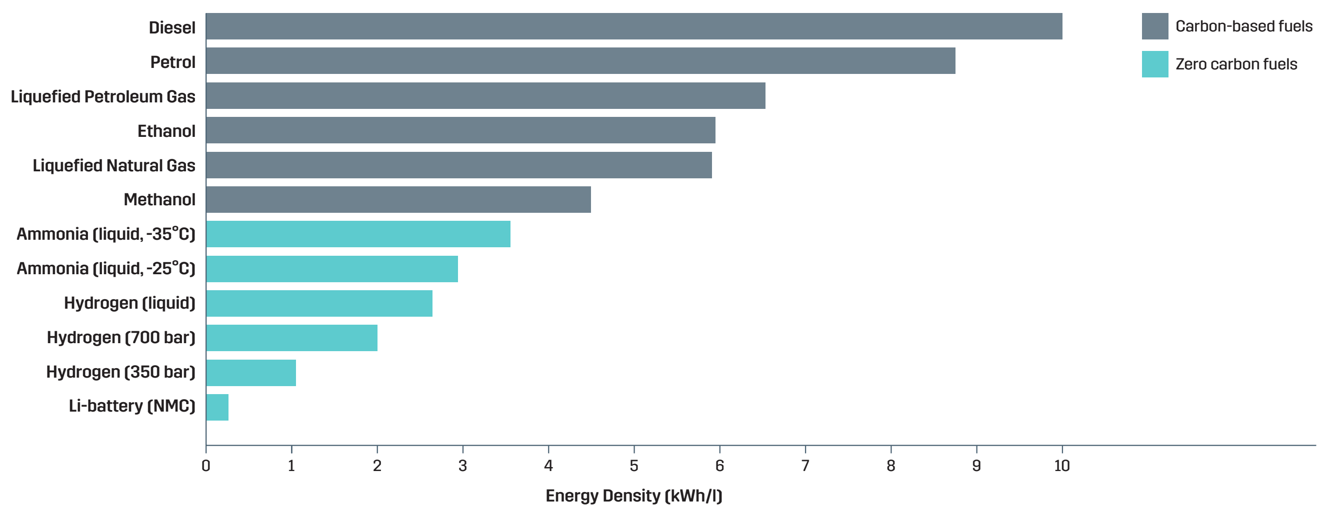


Figure 22: Energy density of a range of fuel options [35]

Fuel Type	Energy Content (MJ/kg)	Energy Density (MJ/L)	Octane Rating	Cetane Rating	CO_2 Combustion Emissions (kg/L)	Flammability Range	Life Cycle CO_2 Emissions (kg/L)
Ammonia	18.6	11.5	120	-	N/A	16-25	0.53-0.97 [2,3]
Methanol	19.9	15.8	109	3	1.08	6-36.5	0.2-1.6 [1]

[1] e-Methanol: 0.2, fossil-based methanol: 1.6
[2] Source units are $kgCO_2/MJ$ and subsequently converted
[3] Ammonia from wind: 0.53, ammonia from natural gas: 0.97

Emissions Impact

O. Siddiqui et. Al [8] identified not only the emissions characteristics of ammonia but also derived each characteristic, subject to the ammonia manufacturing methodology. The results of that study are displayed from Figure 23 through to Figure 26. In comparison, conventional ammonia produced three times more NOx and SOx emissions during the fuel life cycle than conventional methanol when used as an aviation fuel. It should be noted that the production route considered in the conventional ammonia study includes the use of steam methane reforming as 85% of the production, with the remaining 15% considered to be derived from partial heavy oil oxidization.

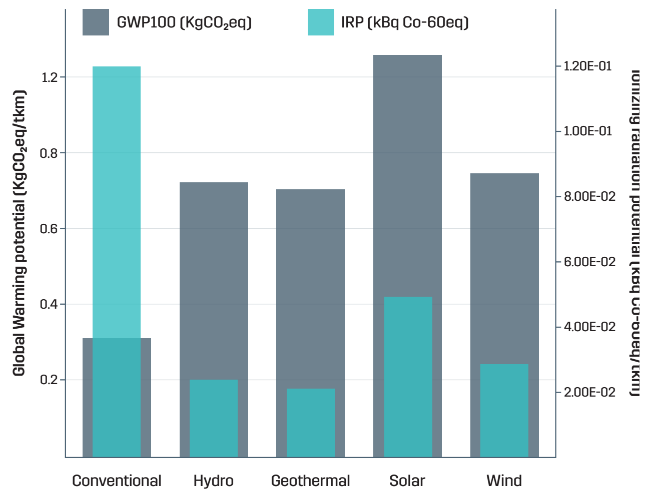


Figure 23: Global Warming Potential and Ionizing Radiation Potential of Ammonia [8]

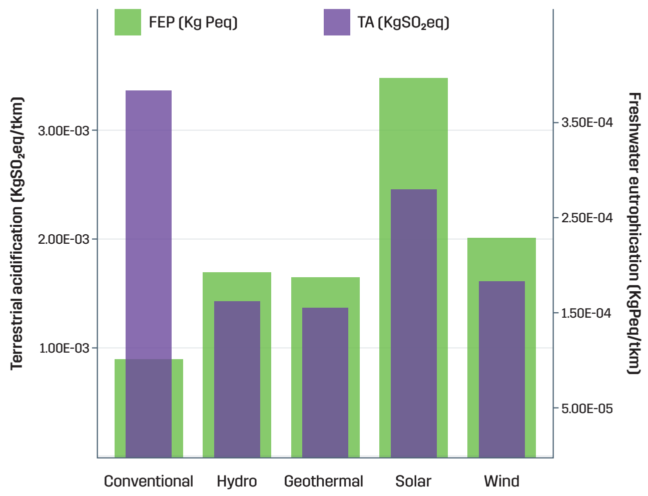


Figure 24: Terrestrial Acidification and Freshwater Eutrophication for Ammonia [8]

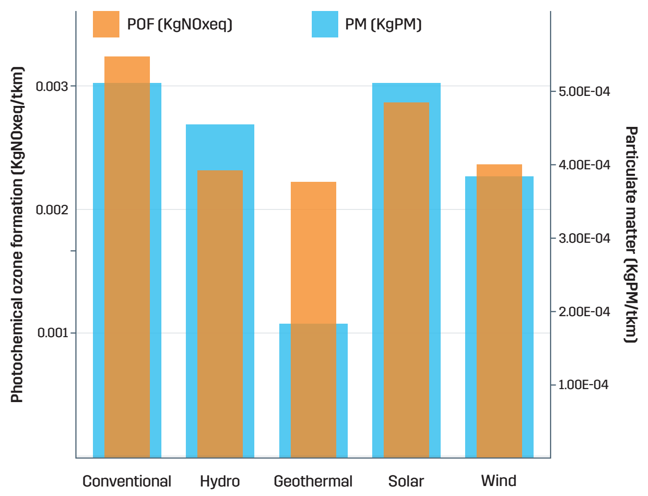


Figure 25: Photochemical Ozone Formation and Particulate Matter for Ammonia [8]

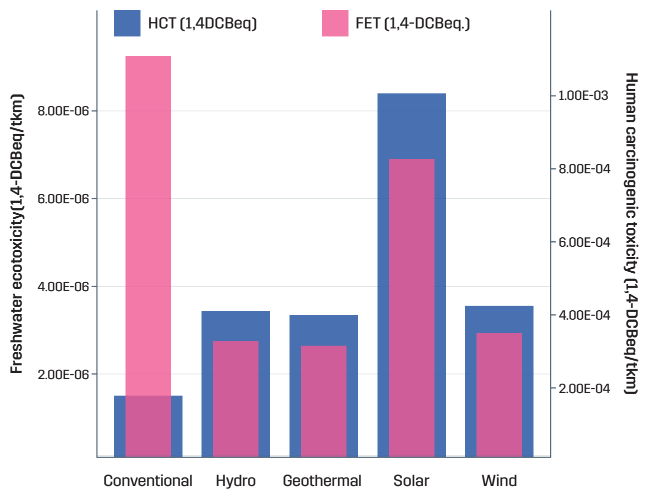


Figure 26: Freshwater Ecotoxicity and Human Carcinogenic Toxicity for Ammonia [8]

Whilst ammonia is a completely carbon-free fuel, in comparison to carbon-neutral methanol, ammonia is significantly more damaging to the environment on NOx, SOx, and PM GHG levels. Whilst these GHGs have a shorter life-expectancy in the atmosphere, in comparison to CO_2, their GWP over a twenty-year period can be up to three-hundred times more potent. With the effects of climate change being felt now, and predicted to worsen over the coming decades, comparisons on all relevant GHGs within a twenty-year period merit the same amount of consideration.

Two graphs have been produced to summarize the GHG impacts of both ammonia via natural gas versus methanol, alongside ammonia produced with green hydrogen via wind against methanol via natural gas. There is limited data on the GHG emissions of e-methanol – hence the use of conventional methanol – although one can assume with a high degree of certainty that the associated production emissions would be lower for the green variant.

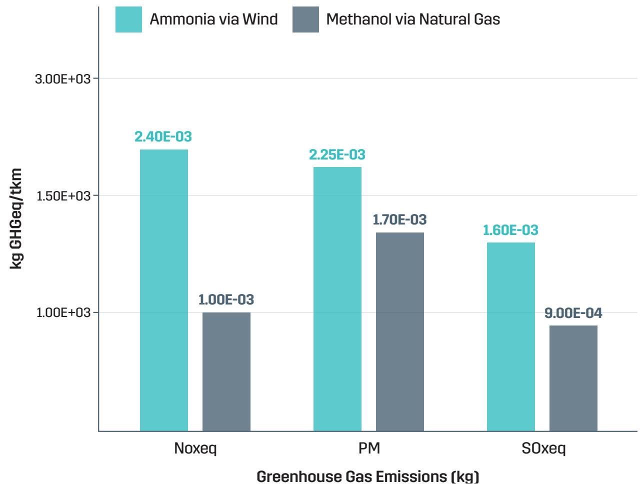


Figure 27: Green Ammonia (via Wind) vs Conventional Methanol (via Natural Gas SMR) excluding CO_2e

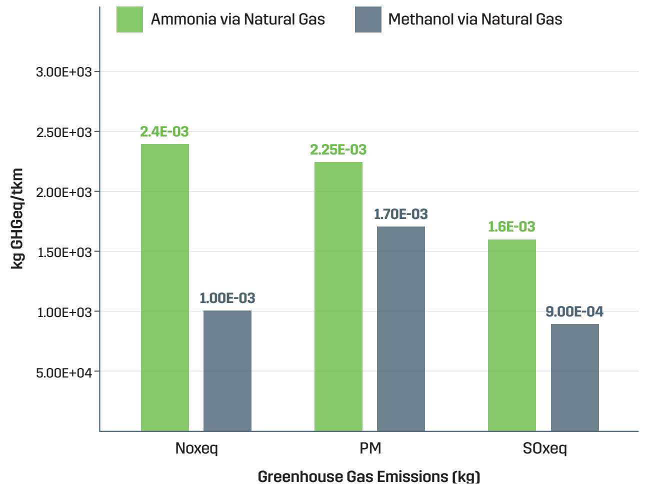


Figure 28: Conventional Ammonia vs Conventional Methanol GHG Emissions excluding CO_2e

Transportation and Logistics

One of the key differentiators between methanol and ammonia is the maturity of the handling practices of both mediums within the offshore energy industry. There is a well-established logistics capability for the handling of liquid methanol - ammonia is more challenging to handle. Apart from being moderately explosive when mixed with air, ammonia is toxic [34]. Ammonia at ambient pressure and temperature is a gas. The fuel becomes liquid in state by means of refrigeration whereby the medium is cooled past its boiling point of -33°C. Quantities greater than 5kt of ammonia are typically transported in this manner. On a smaller scale - quantities less than 1.5kt - ammonia is liquified under pressure at around 16-18bar and ambient temperatures [32].

Fuel Comparison

Current Industry Adoption

Industry adoption of ammonia has been slow to kick-off, largely due to the combustion challenges associated with the fuel. Ammonia combustion presents significantly more NOx emissions than any other fuel but there are several well-established methods to control these emissions. In addition to the emissions challenges, there are further challenges associated with the combustion compatibility of ammonia.

Firstly, whilst ammonia does not directly provoke carbon steel, ammonia is corrosive to copper. Therefore, ammonia is also corrosive to alloys that contain copper. System upgrades and part replacement would be required to ready the use of the fuel in an offshore environment. Secondly, when used as a fuel in gas turbines, ammonia can present a series of problems due to the slow kinetics and high ignition energy requirements. Additionally, ammonia must be in a vapour state to provide stable combustion, thus there is a need to develop onboard vaporising and cracking systems to increase the flame speed and combustion ratios [35].

	Methane (CH_4)	Hydrogen (H_2)	Methanol (CH_3OH)	Ammonia (NH_3)
Density (kg/m³)	0.66 [244]	0.08 [244]	786 [244]	0.73 [244]
Dynamic viscosity x 10^{-5} (P)	11.0 [245]	8.8 [245]	594 [245]	9.90 [245]
Low heating value (Mj/kg)	50.05 [246]	120.00 [246]	19.92 [246]	18.80 [25]
Laminar burning velocity (m/s) - close to stoich.	0.38 [247]	3.51 [203]	0.36 [247]	0.07 [248]
Minimum ignition energy (mJ)	0.280 [249]	0.011 [249]	0.140 [249]	8.000 [212]
Auto-ignition temperature (K)	859 [10]	773-850 [250]	712 [251]	930 [10]
Octane number	120 [252]	-	119 [253]	130 [10]
Adiabatic flame temperature (with air) (K)	2223	2483	1910	1850 [10]
Heat capacity ratio, *y*	1.32 [244]	1.41 [244]	1.20 [244]	1.32 [244]
Gravimetric Hydrogen denisty (wt%)	25.0	100.0	12.5	17.8

Figure 29: Progress in Energy and Combustion Science: Ammonia for Power [36]

Environmental Implications

Whilst ammonia presents itself to be a promising carbon-free alternative, there needs to be increased focus on the NOx emissions that are released during combustion. Although the NOx emissions are comparatively small when evaluated against the CO_2 combustion emissions of methanol, the GWP of NOx over one hundred years is 310 times higher than CO_2. Selective catalytic reduction (SCR) systems have been utilised in various fossil fuel-fired combustion applications for decades to control harmful emission levels. The ammonia-based reagent is combined with the nitrogen oxide combustion flue gas to produce the harmless nitrogen and water vapour byproduct [37]. Aftertreatment systems such as SCRs would need to be incorporated into the operating plant to help control the emissions related to ammonia combustion.

Similarly, to kerosene, ammonia causes the most detrimental effects to marine life out of all the fuels being compared in this study. In the event of a release whilst the fuel is being bunkered or stored offshore, the medium only requires 0.75-3.4mg/l to establish lethal concentration levels. Further details of the ecotoxicological values of each fuel can be found above.

Feedstock Scale

Green ammonia production is largely dependent on the availability and cost of green hydrogen. Nitrogen is readily available in our atmosphere and can be easily extrapolated from air to supply the second feedstock. Based on green hydrogen alone, for 1MJ of energy out, the following calculations can be done:

1kg Ammonia (0.822kg N_2+0.178kg H_2)=18.6MJ ∴ 1MJ Ammonia=0.044kg N_2+0.009kg H_2

1kg Methanol (1.37kg CO_2+0.189kg H_2)=19.9MJ ∴ 1MJ Methanol=0.068kg CO_2+0.009kg H_2

Closing Statement - e-Methanol, the Road to Ammonia?

'Ammonia for Power', produced by a consortium of ammonia energy experts from the University of Cardiff, University of Oxford, the UK Science and Technology Facilities Council, and Tsinghua University, China, is an extensive literature review that has over 300 citations of past and present research into the use of ammonia in engines, gas turbines and fuel cells [36].

Despite this, with regard to fuel for gas turbines, the discourse relating to ammonia remains an immature field of study with limited publications supporting the adoption of alternatives.

Ammonia blending is one of the more frequently discussed alternatives. The discourse relating to this approach involves a secondary fuel such as natural gas or hydrogen, which is used to assist with the high input energy required to ignite ammonia. There are several examples of this method detailed in the paper by A. Valera-Medina et al. The findings from the paper demonstrate improvements in flame stability when hydrogen is introduced into an ammonia fuel blend whilst mitigating further NOx production.

The leading turbine manufacturers have all produced papers or slide packs detailing the significant changes required to the entire plant systems to accept ammonia. GE Gas power highlighted some of these impacts in their slide deck 'Ammonia as a gas turbine fuel' [38]. Research is continuing to be announced as the demand for emissions reduction gains greater momentum. GE and IHI signed an agreement in June 2021 to pursue joint research and feasibility studies focusing on the possible approaches to carbon-free ammonia as a viable fuel option for gas turbines [39].

Mitsubishi Power have also demonstrated an attraction towards ammonia as a decarbonisation medium whilst the company begins its research into a 40MW 100% ammonia-capable gas turbine. Commercialization of the turbine is expected around 2025 [40].

In terms of ammonia from a decarbonisation outlook, the alternative fuel is extremely attractive, but the lack of carbon does not compensate for the extremely high NOx and unburned ammonia emissions emitted at the present stage. Further development of turbine systems is needed to address these issues. Furthermore, although ammonia is already transported as cargo, standards are yet to be developed to qualify the medium as an alternative fuel accounting for the toxicity and flammability risks associated with ammonia [41].

During the course of literature review and research in general, we found that alternative fuels are often seen as being in competition with each other rather than complimentary to each other. Whilst said technological developments continue to evolve, e-Methanol implementation, development and experience will provide tangible learning to the implementation of green ammonia. General challenges such as fuel availability and security of supply of methanol will continuously become more reliable and efficient whilst the green ammonia production industry develops - ensuring that said associated challenges are rectified before green ammonia is adopted.

Likewise, policy recommendations that are proposed for green ammonia are the same policies that need to be addressed for any decarbonisation medium, again compounding the development of e-methanol as a tangible benefit to the implementation of green ammonia.

Opportunity

Transition Fuel – Short Term Prospect

With greater focus on security of supply as highlighted through the UK Energy Security Strategy goals [42], reliance on local energy sources is at an all-time high. For the UK, oil and gas exploration and production are at the very forefront with the dependency on fossil fuel resources remaining strong. Such dependency does not mean that the industry cannot optimize. In fact, the very sense that reliance on fossil fuels will continue for many more decades to come puts all the greater focus on decarbonizing the industry, especially when the consortium of operators within the North Sea has agreed to reduce 50% of its emissions by 2030.

The use of natural gas for power generation leads to greater scrutiny by climate activists as ultimately it is still a fossil fuel. Although a cleaner alternative to the diesel methods used today, gas can provide a readily available on-site source of power to aid in the decarbonisation of the sector. However, Shell and Siemens set-out uncomfortable truths on the use of natural gas for decarbonisation, stating that the UK is currently producing less than 50% of the gas needed in a net-zero pathway [43].

An estimated two-thirds of the carbon footprint of an offshore asset is from power generation, particularly when diesel generators are utilised, making it the ideal medium for change. Electrification of offshore assets has been the hot topic for some time now, but many have already disclosed the scale of challenges to overcome for electrification to work. The economics of electrification can often be the biggest deterrent for operators. Additionally, the timeline to achieve electrification could be more extensive than the timeline for the adoption of an alternative fuel. Thus, the reduction in emissions could be realized sooner with the use of alternative fuels.

Based on the North Sea Transition Authorities Emissions Monitoring Report 2022, 11.3Mt CO_2e of emissions was associated with the offshore energy sector in 2021. 65% of this can be attributed to power generation. If alternative fuels for offshore power generation was adopted by a modest 30% of the industry, an overall emissions reduction of 3.39Mt of CO_2e per year could be recognised. For context, it would take 85 years for the UK's largest carbon capture facility - which can remove a maximum of 40kt per year – to capture the same amount of carbon.

Transition Fuel – Long Term Prospect

Integration of alternative fuels into the energy industry is a rare opportunity. The need to decarbonise creates a demand for the medium. That demand will increase investment in the supply chain and continuously require it to scale as interest in green methanol increases. The locality of the fuel production is particularly important. We know that fuel production and distribution are the biggest contributors for a full life cycle perspective of green methanol. Reducing the distribution distance of said fuel will undoubtedly reduce the overall life cycle emissions. Additionally, having feedstocks from local sources, whether that be nearby green hydrogen production facilities or direct air capture plants, reduces the emissions relative to the fuel production.

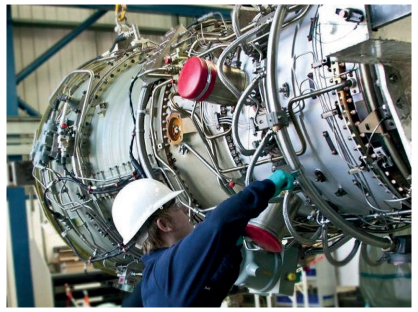
Local renewable feedstock sources create a massive opportunity for alternative fuel export. Countries which do not have the same geographical advantages for sources of renewable energy have to decarbonise in a different fashion, which is likely to be heavily dependent on the use of alternative fuels. The UK is expertly placed to export alternative fuels into European or global markets.

Technology and techniques developed for the alternative fuel industry can also be exported whilst other countries begin to invest further.

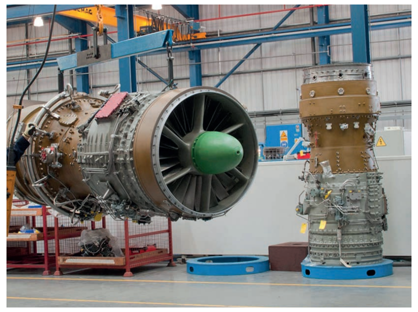
Northeast Scotland – Local Content

Gas Turbine Maintenance and Repair

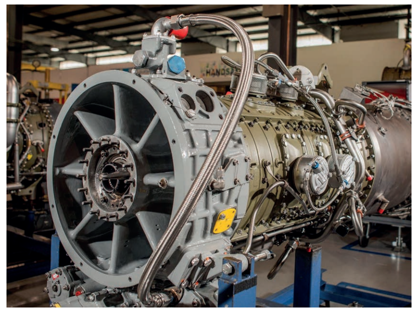
There is a well-established network of turbine repair, overhaul, and maintenance service providers within the North-East of Scotland, all with significant exposure to the turbine manufacturers that are employed massively offshore. In fact, many of the turbine manufacturers have dedicated service centres located in the North-East of Scotland. That knowledge base is only going to grow through the adoption of e-methanol as fuel for aero-derivative turbines, particularly if existing turbines require modification whilst new models are introduced into circulation. Adoption of the renewable alternative fuel could help prevent the decommissioning of ageing infrastructure in the North Sea, helping to maintain the overall number of operational turbines and consequently maintaining demand for turbine overhaul services. That demand, upon estimation, could prevent the loss of over five-hundred local jobs [44].



SGT-A35 (Industrial RB211)
SGT-A35 gas generator maintenance, repair and overhaul



SGT-A20 (Industrial Avon)
SGT-A20 gas generator maintenance, repair and overhaul



SGT-A05 (Industrial 501)
SGT-A05 gas generator maintenance, repair and overhaul

Figure 30: RWG Aeroderivative Gas Turbine Product Support [44]

Alternative Fuel Production

Scotland has a massive geographical advantage providing vast volumes of wind capacity as a vital component in the net-zero transition[45] Already established as a critical contributor to Scotland's electricity network, wind power was accountable for 22.1% of all electricity generated in the country in 2021[46].

Utilising renewable electricity for green hydrogen production is a rapidly growing market in Scotland. There have been a vast number of 'world first' developments based in Scotland with the world's first hydrogen production system from tidal energy (Surf 'n' Turf) and the world's first hydrogen-fuelled double-decker fleet based in Aberdeen operating daily.

Such projects continue to provide Scotland with indigenous knowledge in renewable energy integration. That growing knowledge has highlighted not only the strengths but some of the key challenges associated with offshore wind, particularly integrating the large volumes of variable wind power into the grid which may require further development into energy storage/grid infrastructure. These changes can strengthen the case for alternative fuel production, utilising the excess renewable energy into something constructive whilst reducing the dependency on fossil fuels.

As for carbon sourcing, connections to the Acorn CCUS project would be one of the obvious tangents to draw. The project is set to utilise various local sources of carbon with the majority in 2026 coming from direct air capture (GGR) and greenhouse gas emissions relating to the St. Fergus gas terminal, both of these located in Peterhead.

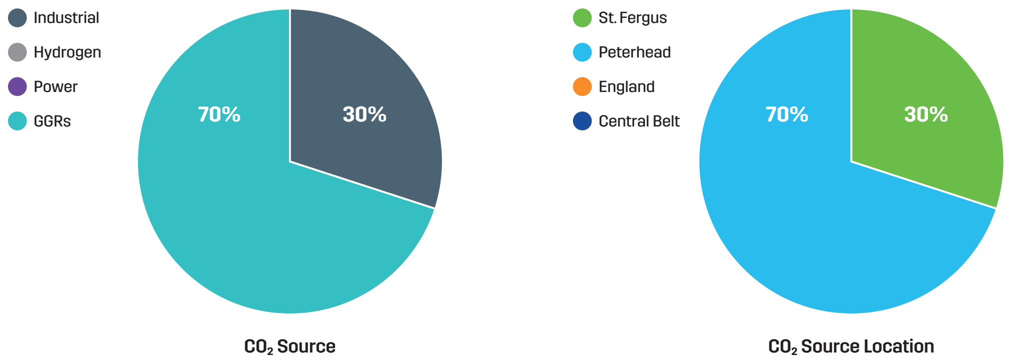


Figure 31: 2026 Annual CO_2 Split for The Scottish Cluster

The first e-methanol production facility has been announced, located in Nigg, Scotland. A partnership between Global Energy Group and Swiss-based integrated energy company Proman has been agreed to develop a renewable power for methanol plant at the Nigg Oil Terminal. Utilising local sources of industrial carbon and green hydrogen, the facility will generate e-methanol to be exported by bulk carrier vessels at the repurposed jetty already on site[47].

Figure 32 highlights a conceptual circle economy of alternative fuel production. Although the illustration is a concept, the theory and location of various infrastructures are all based on existing or proposed developments, many of which are discussed earlier in this section, to provide the highest level of realism to the local outlook possible.

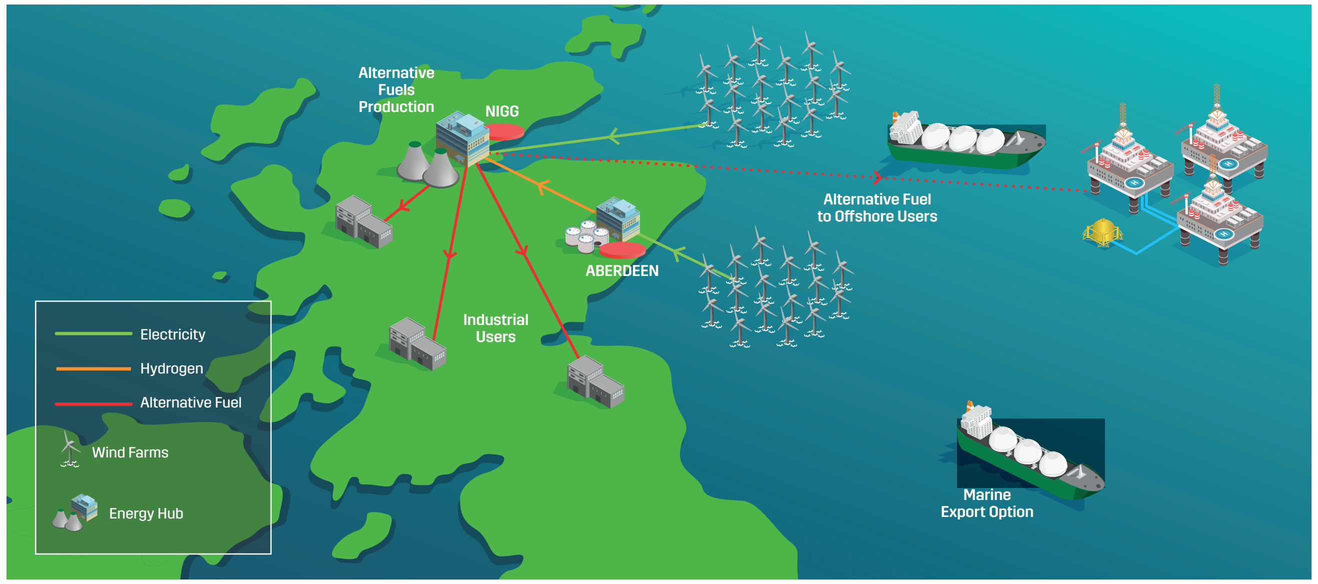


Figure 32: Alternative Fuel Production Local Lifecycle

Sustainable Manufacture

A recent poll conducted during a DNV webinar 'Alternative ship fuels – status and outlook'[48] found that the largest concern with the adoption of alternative fuels was the availability of fuels. Methanol is an attractive option based on such concerns with the supercharged influx of production facility investment.

The graphic shown here demonstrates the e-methanol and bio-methanol production facilities either operational or planned alongside all the offshore assets within the UKCS.

The representation is key to understanding the clusters of platforms within the North Sea and how said clusters would be supplied from the various production facilities. Details of each facility are listed on the following page.

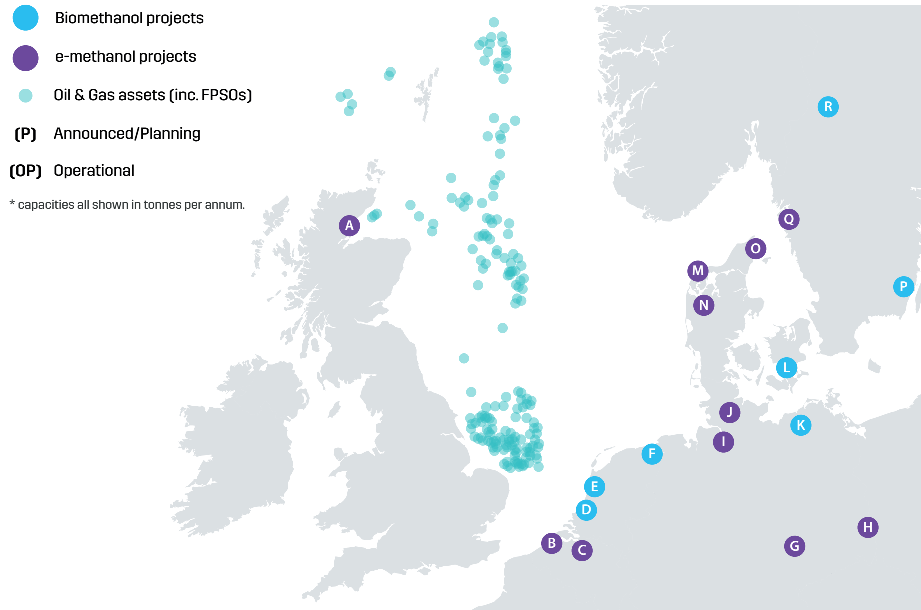


Figure 33: Renewable methanol production surrounding the North Sea

	Company	Start-Up Year	Capacity (kt/y)	Product	Feedstock
A	GEG & Proman, Scotland	2026	20	e-Methanol	Recycled CO_2 + Green Hydrogen
B	North C Methanol, Belgium	2024	44	e-Methanol	Recycled CO_2 + Green Hydrogen
C	Port of Antwerp, Belgium	2023	8	e-Methanol	Recycled CO_2 + Green Hydrogen
D	Lowlands Methanol, Netherlands	2023	120	Bio-e-Methanol	MSW/Waste Wood + Green Hydrogen
E	Advanced Methanol Amsterdam, Netherlands	2023	87.5	Bio-Methanol	MSW
F	BioMCN, Netherlands	Oper-ation-al	60	Bio-Methanol	Biogas
G	Total Energies Leuna, Germany	2022	u/k	e-Methanol	Recycled CO_2 + Green Hydrogen
H	Hy2Gen, Germany	2025	61	e-Methanol	Recycled CO_2 + Green Hydrogen
I	Dow, Germany	2027	200	e-Methanol	Recycled CO_2 + Green Hydrogen
J	Westkuste 100, Germany	u/k	u/k	e-Methanol	Recycled CO_2 + Green Hydrogen
K	Sun2Gas, East Energy, Germany	2027	8	e-Methanol	CO_2 from Biogas + Green Hydrogen
L	Vordingborg Biofuel, Denmark	2024	300	Bio-Methanol	Biogas
M	European En-ergy, Denmark	2025	32	e-Methanol	CO_2 from Biogas + Green Hydrogen
N	ReIntegrate, Denmark	2023	10	e-Methanol	CO_2 from Biogas + Green Hydrogen
O	European Energy, Denmark	2027	32	e-Methanol	u/k
P	Sodra, Sweden	Oper-ation-al	5.25	Bio-Methanol	Wood Chips
Q	Perstorp, Sweden	2025	200	e-Methanol	CO_2 via DAC + Green Hydrogen
R	Varmlands Metanol, Sweden	2027	100	Bio-Methanol	Biomass

BioMCN Bio-Methanol, Netherlands

Based in Delfzijl in the north-eastern part of the Netherlands, BioMCN produces renewable methanol via biogas from various sources including municipal solid waste landfills and anaerobic digestion plants. In 2017 the company produced 60,000 tons of renewable methanol which were primarily sold to the European transportation sector as a biofuel. More than half of all the biogas produced in the Netherlands is consumed by BioMCN with the expectation that the share will only grow, decreasing the reliance on conventional natural gas.

Carbon Recycling International e-Methanol, Iceland

Carbon Recycling International is the global leader in e-methanol production, operating at scale since 2012. The George Olah renewable methanol plant in Svartsengi, Iceland, can produce four thousand tons of e-methanol, which in turn recycles 5500 tons of carbon dioxide emissions via flue gas released by an adjacent geothermal power plant. Hydrogen is created via the electrolysis of water and combined with the captured CO_2 to produce synthesis gas that is catalytically reacted to form methanol.

Reintegrate e-Methanol, Denmark

Like BioMCN, REintegrate – a subsidy of European Energy has announced the drive to produce 10,000 tonnes per annum of bio-e-methanol from their facility in Port of Aalborg, whilst construction on the large-scale demonstration plant in Skive continues. Renewable electricity needed for the power-to-methanol production will be sourced via a solar farm in Kasso, Southern Denmark whilst CO_2 is fed via the emissions from biogas plants.

Maersk has shown particular interest in the development, signing a partnership agreement for REintegrate to supply methanol to Maersk as part of their net-zero operating ambitions. Henriette Hallberg Thygesen, CEO of Fleet and Strategic Brands, A.P Moller – Maersk said, "This agreement with European Energy/REintegrate brings us on track to deliver our ambition to have the world's first container vessel operated on carbon-neutral methanol on the water by 2023".

Liquid Wind e-Methanol, Sweden

Liquid Wind is an operating company that manages commercial-scale facilities to convert carbon dioxide emissions into green electro-fuel. The first commercial-scale facility FlagshipONE, located adjacent to the Horneborgsverket biofuel-based combined heat and powerplant, will utilise CO_2 emitted from the CHP and capture it as a feedstock for e-methanol. It is predicted that each flagship facility will upcycle circa 70,000 tons of carbon dioxide per year.

The second feedstock, hydrogen, will be provided by the electrolysis of water. Siemens Energy is providing the electrolyser technology which will require up to 470 GWh of renewable electricity per year to run. Renewable methanol will be the output of the facility, produced at a rate of 140 tons per day. Tangentially, oxygen is also produced as a by-product which can be captured and supplied to local industry.

FReSMe Valve-Added Steel Manufacturing On-Site Methanol Production, Sweden

Regarding scalability, all four manufacturing cases have similarities – the feedstock. This can be down to several factors, but the main rationale is the increase in the green hydrogen market. Additionally, the previous examples highlight the utilisation of recycled and renewable CO_2 sources as the second feedstock but what consideration is there for on-site methanol production?

The FReSMe project can provide a fitting example of on-site production without the need for a separate dedicated production facility. Carbon Recycling International's modular system was incorporated into the Swerea MEFOS facility in Lulea, Sweden –capturing both CO_2 and hydrogen from by-products streams thus eliminating the need for water electrolysis in the process, subsequently converting the synthesis gas into methanol. 50kg. hr. of methanol was produced and provided to the Stena Germanica - as mentioned above - highlighting the full lifecycle potential of methanol as an emission-reducing medium[49,50].

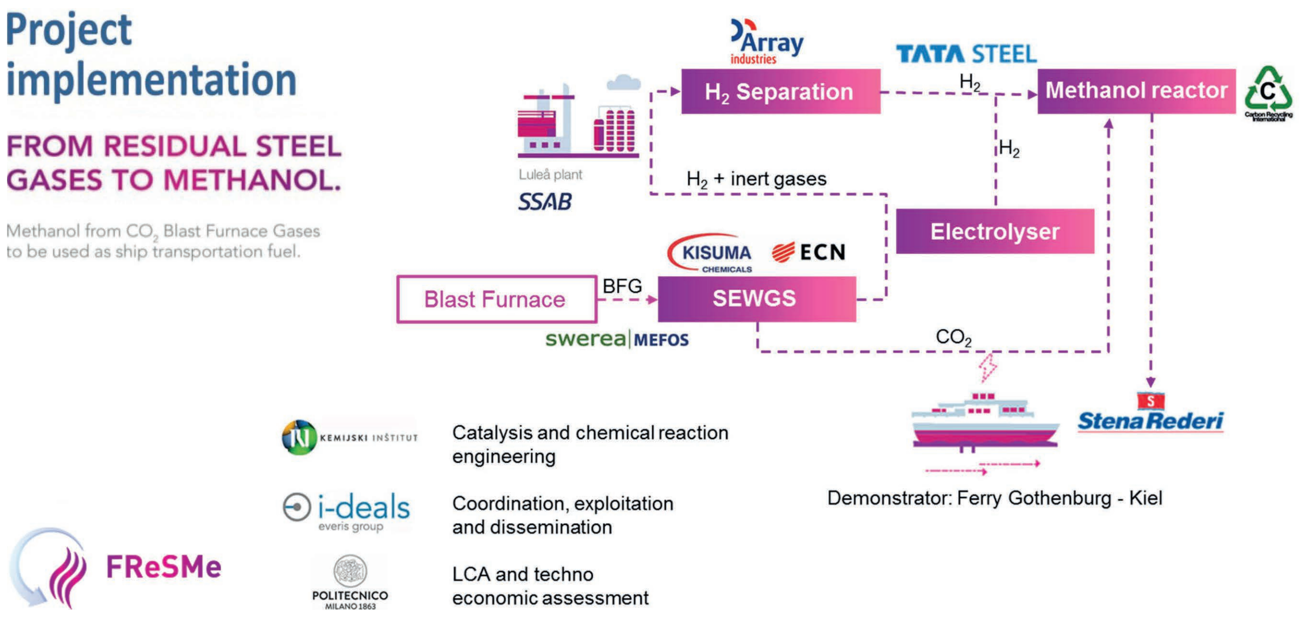


Figure 34: FReSMe Project Implementation

Politecnico Di Milano, part of the Department of Energy within Milan has since published 'Techno-economic assessment of the FReSMe technology for CO_2 emissions mitigation and methanol production from steel plants' concluding that the FReSME system represents an attractive solution for the steel industry in decarbonisation, particularly when evaluated alongside the anticipated rise in carbon tax rates.

Additionally, Politecnico Di Milano produced a second paper 'From residual steel gases to methanol: The FReSMe project,'[51] evaluating the carbon emissions related to methanol production via natural gas versus the FReSMe project principles. The figures on the following page highlight the energy balance and CO_2 emissions for both routes considering the methanol-related CO_2 emissions to be negative due to their repurpose as a fuel.

	Specific Consumption	Specific Energy Demand	Specific CO2 Emission
Natural Gas	0.65 t NG/t MeOH	30.40 GJ/t MeOH	1759.9 kgCO2/t MeOH
Electricity	275.3 kWh/t MeOH	2.48 GJ/t MeOH*	126.6 kgCO2/t MeOH
Pure MeOH (purity)	994.5 kg/t MeOH	-19.83 GJ/t MeOH	-1371.6 kgCO2/t MeOH
Net per tonne MeOH		13.05 GJ/tMeOH	515.0 kgCO2/t MeOH

Figure 35: Summary of energy balance and CO_2 emissions for the plant fed with natural gas[50]

	Specific Consumption	Specific Energy Demand	Specific CO2 Emission
Natural Gas	0.08 t NG/t MeOH	3.61 GJ/t MeOH	209.2 kgCO2/t MeOH
Electricity	242.8 kWh/t MeOH	2.19 GJ/t MeOH*	111.7 kgCO2/t MeOH
Electricity for the electrolyzer	10229.4 kWh/t MeOH	36.83 GJ/t MeOH	0 kgCO2/t MeOH
Pure MeOH (purity)	994.1 kg/t MeOH	-19.83 GJ/t MeOH	-1371.6 kgCO2/t MeOH
Net per tonne MeOH		22.79 GJ/tMeOH	-1050.7 kgCO2/t MeOH

Figure 36: Summary of energy balance and CO_2 emissions for the plant fed with the FReSMe proposal[50]

Supply and Demand in an Offshore Power Generation Model

There has been a colossal amount of low carbon, bio, and e-methanol production facilities announced in the past three years with many prospects due to come online in the coming few years. The map on the following page has been created by the Net Zero Technology Centre to highlight those facilities and announcements that surround the North Sea. The landscape is continuously changing as more details of facilities are announced. It should be highlighted that these are only the facilities that surround the North Sea. Renewable methanol transportation in bulk is also more than possible, especially if we consider the volume potential of the work being done by CRI in northern Norway.

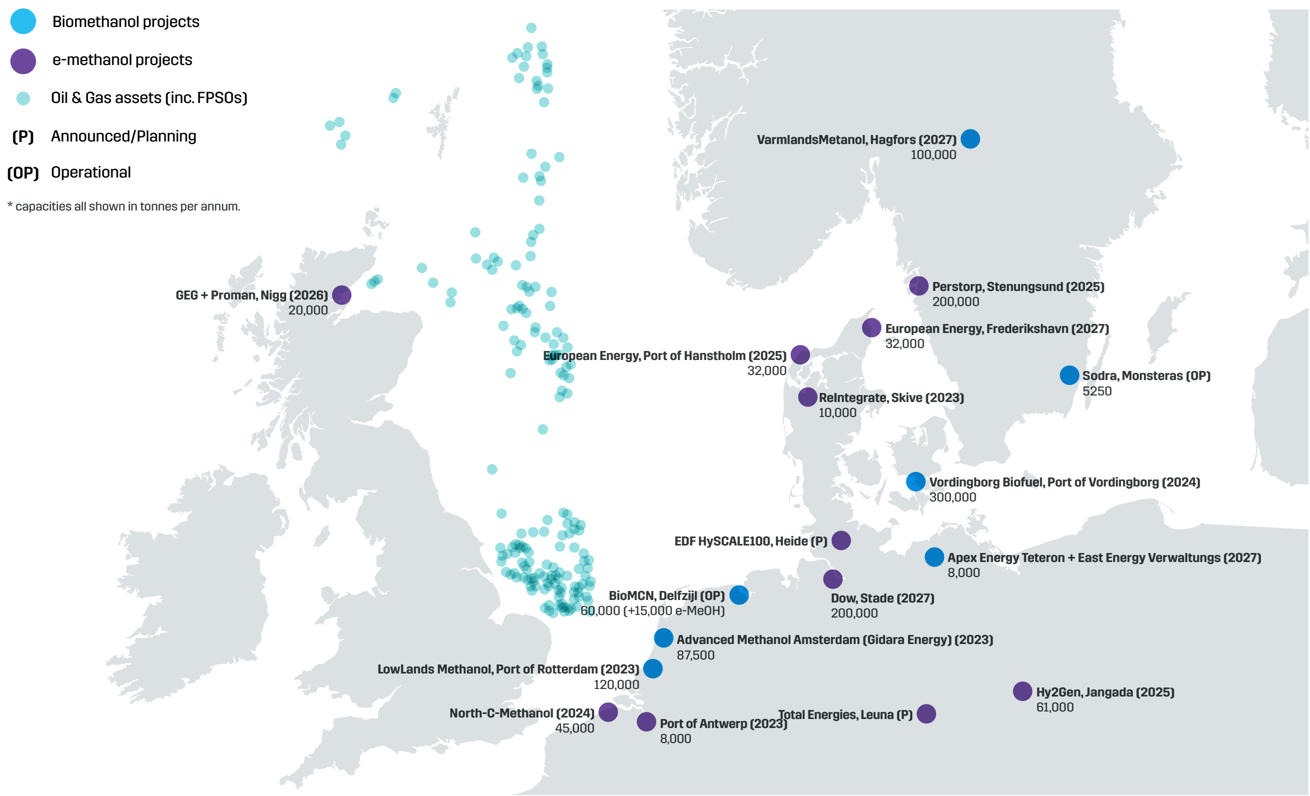


Figure 37: Methanol location map

Based on the calculation in the Transport and Logistics sub-section, we can demonstrate that one 30MWh out platform with 30% turbine efficiency needs 158,313.25 tonnes of methanol per year. The graph below has been created to highlight how that calculation correlates in terms of supply.

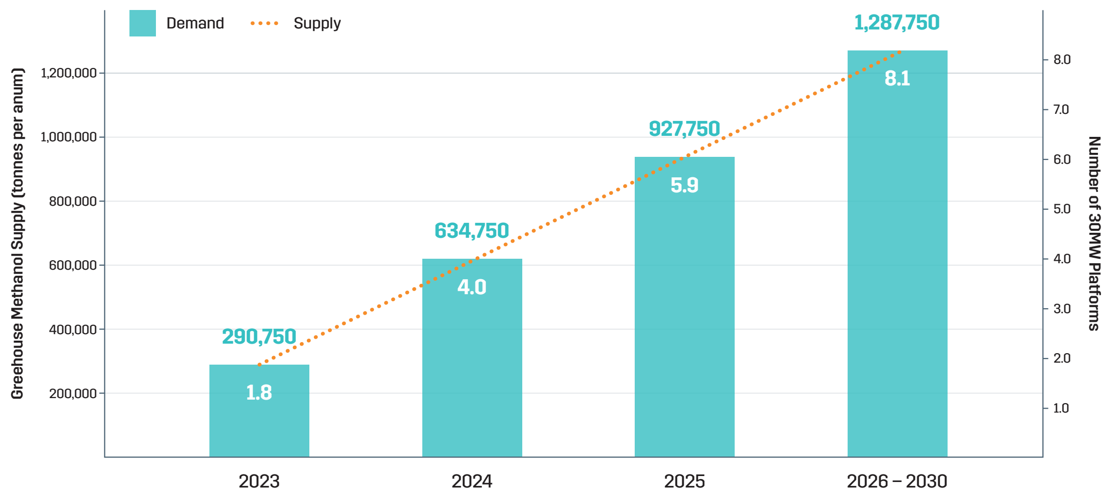


Figure 38: Green Methanol Supply x Demand

Timeline

Remaining life in O&G Platforms: Late-Life Economics and Decom Timescales

As part of the e-methanol study, data gathering of all the assets in UKCS excluding, the Irish Sea and Southern North-Sea, was performed to understand the potential candidates for an alternative fuel conversion – in this case, converting to e-methanol. Additionally, existing asset data that has previously been gathered by the Net Zero Technology Centre for electrification studies has been utilised. There are three main considerations as part of the candidate study:

Considerations

1. Planned COP date, it is assumed that assets with a COP before 2030 would not approve of the CAPEX investment needed for a methanol conversion.
2. Asset type, fixed or FPSO? Both instances require consideration to fuel storage whether that is in the form of the already available storage in an FPSO being re-certified for an alternative fuel or a retrofit solution being required for fixed platforms like the NOV system highlighted previously.
3. The power demand and equipment used for that power generation to better understand the scale of fuel needed and the extent of modifications needed to make the plant compatible.

Based on the criteria above, it was found that twenty-two assets all had a COP before 2030. Out of those twenty-two assets, eleven have already been decommissioned or submitted decommissioning plans for removal in the coming years.

Five assets from the forty-six were found to be using diesel generators for power which does not necessarily remove these assets as candidates but certainly increases the overall CAPEX requirements to change out these systems for methanol compatible turbines. Forty-one assets remain available for conversion, of which nine are FPSOs and thirty-two are fixed platforms.

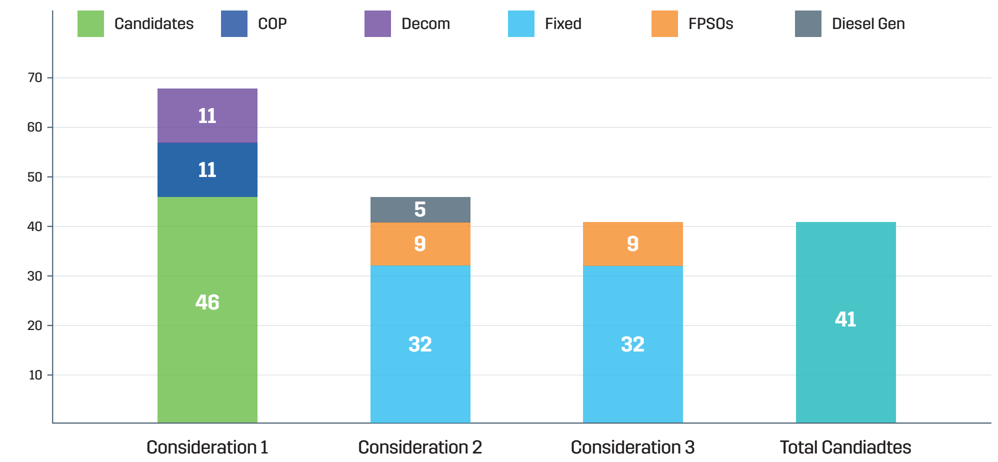


Figure 39: Alternative Fuels for Gas Turbines Candidates

The Innovation and Targeted Oil and Gas (INTOG)

Electrification of assets has been the hot topic for some time now with many believing that full platform electrification from shore is the solution. Although this remains a potential solution - especially with areas Eb and WoSB shown below - there is a greater understanding of the barriers to that solution and what impacts electrification from shore has from an economic and environmental viewpoint.

In support of that challenge, Crown Estate Scotland has launched The Innovation and Targeted Oil and Gas (INTOG) leasing round, specifically targeted to developers aiming to construct offshore wind farms as a low carbon electrical power source for oil and gas installations. In addition, the leasing round allows small-scale innovation projects to apply, including alternative outputs such as hydrogen[52].

The results of the INTOG leasing round will provide great data on the cluster of assets that have been identified for electrification and what developments are planned to achieve such objectives.

However, fresh reports are surfacing daily by operators, disclosing the challenges identified within their asset electrification feasibility studies regardless of the source of power. These assets play perfectly into the hands of alternative fuels.

As a low carbon power solution, alternative fuels can provide the answer to assets that would have been omitted from electrification and undoubtedly been the main target of regulators during the asset's late-life due to their higher emissions profile in comparison to others.

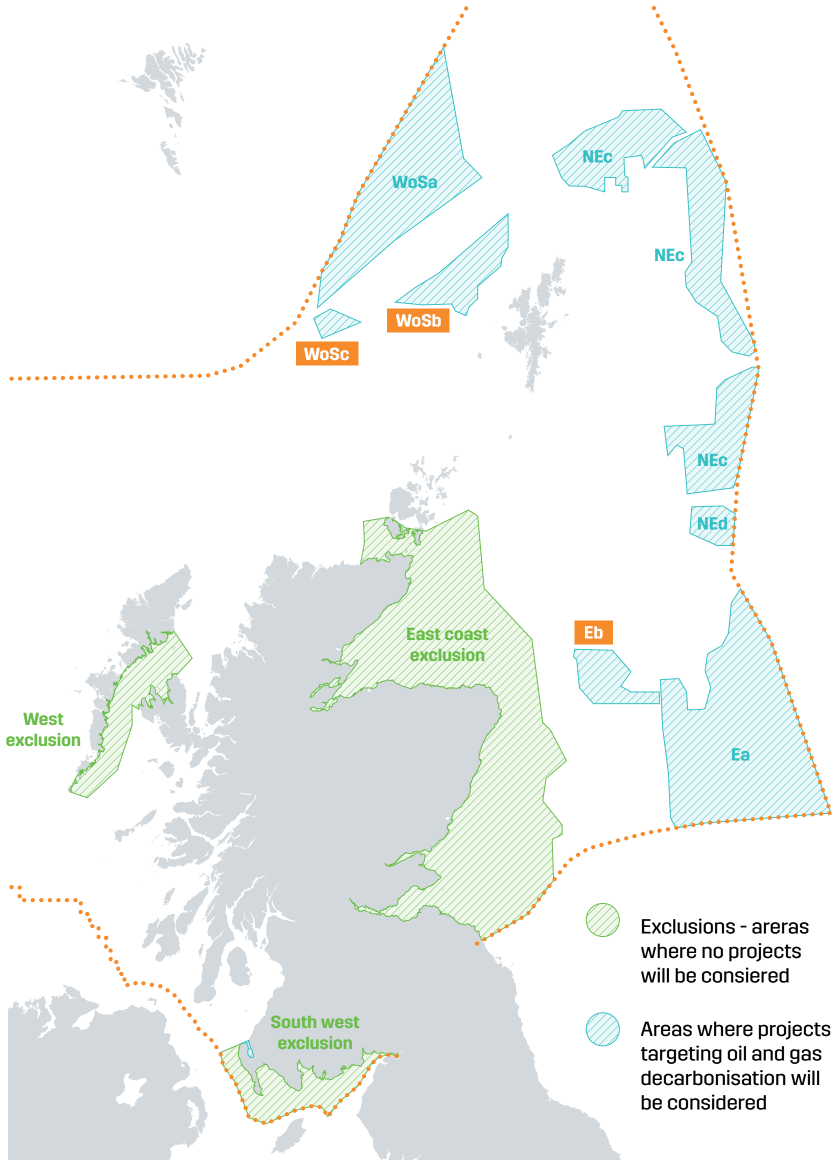


Figure 40: INTOG Areas of Consideration[52]

New Order FPSO and Existing Asset Re-Deployment

Another factor that has meaningful relevance to the adoption of alternative fuels is the type of assets that will be prominent within the UKCS in the coming years. Based on the decommissioning difficulties mentioned in the previous section, many operators are looking to FPSOs as the solution to field development, with an increase in both new build orders and existing assets being selected for re-deployment. Such an approach relies on operators to incorporate emission-conscious designs - or brownfield modifications to existing assets - to ensure prospects anticipated to last in the range of 30 years will also remain within the stringent emissions regulations that are currently set out.

Global Data produced a report in February 2022/2023 on the 'FPSO Market Analysis and Forecast, 2022-2027'. The report presented insight into the recent uptake of FPSO orders, detailing the fields associated with each order. Details of each field have been presented below to highlight the scale of the developments[53].

FPSO Name	Operator	Status	Participants	Associated Field
Rosebank	Equinor UK	Announced	Equinor ASA (40.00%); Siccar Point Energy Ltd (20.00%); Suncor Energy Inc (40.00%)	Rosebank
Penguins	Shell UK	Planned	Exxon Mobil Corp (50.00%); Royal Dutch Shell Plc (50.00%)	Penguins Redevelopment
Marigold	Anasuria Hibiscus UK	Announced	Aban Offshore Ltd (50.00%); Hibiscus Petroleum Bhd (50.00%)	Marigold, Sunflower
Cambo	Siccar Point Energy E&P	Announced	Royal Dutch Shell Plc (30.00%); Siccar Point Energy Ltd (70.00%)	Cambo
Bentley	Whalsay Energy	Announced	Whalsay Energy Ltd (100.00%)	Bentley

Figure 41: Global Data UKCS FPSO Developments as of 27th August 2020[53]

FPSOs favour themselves toward the use of liquid fuels like e-methanol as they can accommodate the large storage capacities required. Verification would need to be performed to ensure the storage tank coatings were suitable for methanol as per the IGF Code. The location of the listed developments above is also of significance, with many of the developments West of Shetland where deeper water depths are making the prospect of electrification more challenging to achieve.

Ironically, the associated fields have been subject to enormous amounts of opposition and scrutiny from environmental campaign groups which compounds the need for zero-emissions power generation.

EnQuest Bressay and Bentley

The EnQuest Producer FPSO is currently warm stacked at the Nigg Oil Terminal, Scotland after coming off the Alma and Galia field in 2020. A decision is still yet to be made on the FPSOs fate. Whether that be in the form of re-use, a sale or recycling is undetermined, but EnQuest has signalled strong consideration for the re-deployment of the Producer on the Bressay and Bentley fields. Located eighty-five miles southeast of Shetland, the 250 million barrels of oil equivalent fields are expected to have a final field development plan announced later this year.

Alternatively, the Kraken FPSO which is currently on station may be utilised as the tie-back host. Such a decision also plays well into the hands of alternative fuel adoption. EnQuest released a statement on 30th June 2022 claiming the Kraken FPSO is "almost impossible to electrify", highlighting that FPSOs, in general, are exceedingly difficult to electrify due to the swivel configuration [54].

Shell Penguins

The Penguins field, located northeast of Shetland was first developed in 2002 and tied directly back to Brent Charlie within the nearby Brent field. After operating for over forty years, Shell decided in 2017 to begin the decommissioning process, with the Brent Charlie being the only topside remaining in the field. A final investment decision was subsequently made to redevelop the Penguins field with the introduction of a brand new FPSO that would take the place of the Brent Charlie platform. The field is expected to produce 45,000 boe/d [55].

Equinor Rosebank

Discovered in 2004, the Rosebank field lies 140km west of the Shetland Islands in a water depth of around 1,110m. Siccar Point Energy estimates that the field could provide over three hundred million barrels of recoverable oil. The latest market reporting suggests EnQuest has signed a contract with Altera Infrastructure to use the Knarr FPSO for the field. Such re-deployment of assets with increasing scrutiny on the carbon footprint of the field plays perfectly into the hands of alternative fuel integration [56].

Siccar Point Energy Cambo

One of the sixteen developments proposed in the UK continental shelf to form part of the country's energy security strategy through the energy transition, Cambo is poised to deliver up to 170 million barrels of oil equivalent during its 25-year operational life. The development will utilise Sevan SSP, of Norway, for the construction of the FPSO [57].

Concluding Remarks

Perspective

Hydrogen will play a crucial role as an energy source. and further research and development will identify its benefits and limitations. One of the key challenges of hydrogen gas is its low energy density, making it far more attractive in liquid form. Several solutions are identified, including utilising a liquid hydrogen carrier such as ammonia or an alternative fuel that contains hydrogen as a feedstock.

Significant research is currently being undertaken to understand the compatibility of new, low-carbon fuels with existing aero derived turbine systems. Ammonia's lack of carbon molecules makes it a prime candidate as an alternative fuel, and its compatibility with turbine systems is now being explored extensively. Leading turbine manufacturers are working to understand the operating parameters and required modifications to make ammonia work as a fuel.

However, the large CAPEX investments required to implement ammonia as a fuel for gas turbines will likely discourage operators from switching to it as an alternative fuel. Further work is needed to prepare the power generating equipment and associated systems for ammonia, but operators should still consider it. Provided that the correct regulations are established to ensure handling in a marine environment does not adversely impact marine life, ammonia presents a vast opportunity for emissions reduction – especially being a carbon free-fuel. Unfortunately, the development of ammonia compatible systems will take considerable investment and time to become a reality.

Methanol as a fuel is more mature and can offer short-term decarbonisation achievements for operators due to its compatibility with existing power generating systems and the continual increase in fuel availability. Within the past two years, a colossal amount of e-methanol and bio-methanol production facilities have either been announced or commenced production. Such uptake has indicated a push towards low carbon power solutions that can be implemented much sooner than technology that requires further development and maturity.

In parallel, the importance of the security of supply and the source of supply has increased due to various world affairs. Such factors have established the oil and gas industry as a key deliverable for the UK economy and a source of the country's energy requirements, validating the claim that the UK will need oil and gas production for many more years.

The North Sea Transition Deal has outlined industry targets to create a net-zero basin by 2050. During this point, the industry will continue to reduce greenhouse gas emissions with an absolute 10% reduction in 2025, 25% in 2027, and 50% in 2030 as part of the pathway. Such targets drive industry change, with power generation of assets being the most significant component to change.

On that basis, the electrification of assets has been evaluated and continuously developed to understand which assets can be electrified and the effect of doing so. Emissions implications, integration to current energy systems, and source of supply are all topics under scrutiny whilst operators release their electrification prospects.

The INTOG leasing round will provide a great insight into the appetite and uptake of electrification, specifically the electrification of assets via offshore wind. However, operators are already highlighting the electrification challenges and which assets are known to be unattainable for the solution – FPSOs seem to have a regular appearance in such headlines due to the fundamentals of the asset design.

Alternative fuels can meet the decarbonisation need for such assets which are not technically or economically suited to partial/full electrification. With the vast amount of research done to date on methanol as a fuel for gas turbines, the industry can achieve a significant win through the adoption of methanol for power generation whilst alternative fuel production facilities mature from the use of recycled industry sources of carbon (non-renewable) to renewable sources such as direct air capture or biogenic. In parallel, ammonia compatibility will continue to develop, ensuring turbine manufacturers remain technology leaders in the fuel flexibility required for a net-zero future.

Potential of e-Methanol as a Fuel

Decarbonisation will be achieved via multiple options, with each option highly dependent on the integration feasibility of the associated installation. On this basis, the following route has been suggested as the most logical pathway for an asset owner to create a decarbonisation road map:

1. If electrification is possible and achievable within the emissions reduction timeframes set by the North Sea Transition Authority, electrify!
2. If you have pipelines which are available for re-purpose to hydrogen and a green hydrogen supply from shore is available, use hydrogen.
3. If neither of the solutions above are feasible, alternative fuels can be the solution to such shortfall.

In regards to this approach, there are several clean alternative fuel options available, with existing knowledge relating to their performance and compatibility with current systems. There is also a steadily growing supply chain of fuel production to address the concerns associated with fuel availability. Each alternative fuel brings unique decarbonisation advantages, which must be evaluated against their impact on the local environment. For example, e-kerosene and e-methanol have very similar feedstock scales, production routes, compatibility with existing plant and end combustion emissions. The significant difference in ecotoxicological values which leads us to encourage the adoption of e-methanol when being used in an offshore environment.

Alternative Fuel Summary Table

Medium	Challenge	Solution
Methanol	1. Utilising a fuel that emits carbon upon combustion.	1. Adoption of green methanol to ensure the carbon feedstock needed to manufacture the fuel is from DAC, biogenic sources, or carbon recycling.
Kerosene	1. Highly toxic to a marine environment. 2. Produces more NOx, and SOx emissions in comparison to methanol. 3. Limited sources of supply based on publicly announced production development plans.	1. Regulations need to be established to address the use of kerosene in an offshore environment. 2. Continuous development of sustainable manufacturing practices can help to reduce the overall life-cycle emissions of the medium. 3. Further investment into e-kerosene production facilities is needed for the supply quantities to meet demand.
Ammonia	1. Current turbine OEMs cannot get ammonia to combust without several changes to the plant design. 2. Highly toxic to a marine environment. 3. Combustion presents high levels of NOx emissions. 3. Corrosive to copper and/or copper containing alloys.	1. Further research and development projects are needed to fully verify ammonia as a potential gas turbine fuel. 2. Regulations need to be established to address the use of ammonia in an offshore environment. 3. Adoption of SCR systems must be implemented when combusting ammonia for power generation. 3. Modification and replacement of existing fuel delivery systems and associated pipework will be required.

Recommended direction of the ETF Alt Fuels Project

The green hydrogen market is growing steadily, with countries recognising its value potential, but the compatibility of green hydrogen and end-use cases is still being understood. Utilising green hydrogen as a feedstock for an alternative fuel will create substantial demand, especially when the timescale of e-methanol implementation is far closer in than that of green hydrogen alone.

The research in this report, validates the increased interest in green methanol production and the growing adoption of green methanol within the maritime industry. This report presents a greater understanding of the limitations of hydrogen combustion and ammonia compatibility with gas turbines. Although the solution isn't zero carbon in composition, if bio-methanol or e-methanol is utilised, the fuel can be classed as carbon neutral at the end-use site.

During the OEUK MODU meeting held on 1st June 2022, the question was raised as to what was believed to be the biggest hurdle to the adoption of alternative fuels. The results are demonstrated below with maturity of the technology and availability of fuels being the biggest concerns.

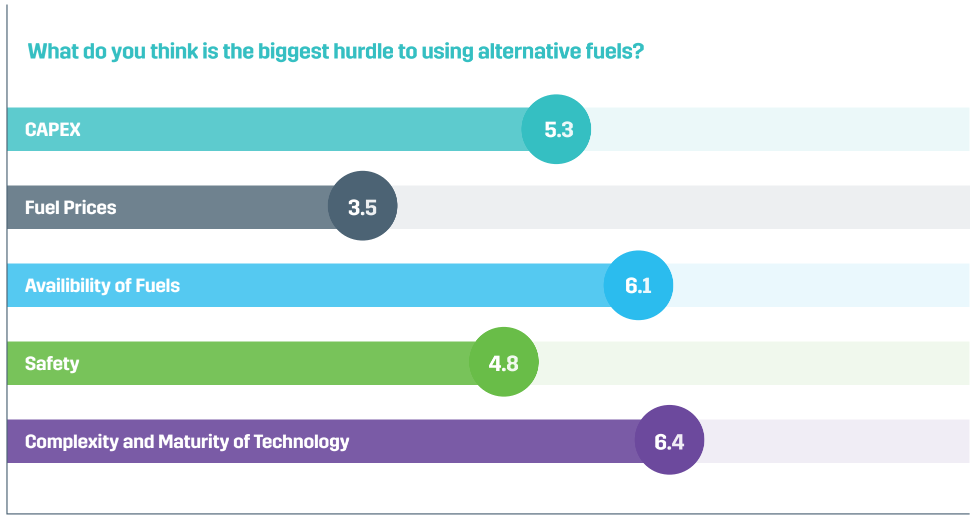


Figure 42: OEUK Modu Menti Results (8 participants)

An onshore trial of a gas turbine(s) powered by e-methanol will be conducted in conjunction with Siemens Energy, with the trial results returned to the Net Zero Technology Centre for appropriate dissemination to industry, settling the concern on the complexity of the technology. The trial will allow operators of assets to witness the turbine operating on e-methanol and engage with the relevant subject matter experts to discuss potential adoption.

Validation of this concept should be further substantiated via a pilot project which is likely to take place at Sullom Voe Terminal. The primary objective of this pilot is to prove that alternative fuels can reduce emissions from existing turbines and thus prevent their decommissioning. A thorough review of North Sea assets has been conducted, and a list of potential candidates has been identified. Engagement with these candidates will occur as soon as the project has advanced enough and demonstrated its maturity. This pilot project holds significant value as it has the potential to demonstrate a successful application of alternative fuels on operational assets and could be of interest to other operators.

Power generation accounts for a significant amount of the emissions of an offshore asset and thus the adoption of e-methanol has the potential for vast scope 1 emission reductions. As an example, a site that currently uses fuel gas for power generation would become net zero through the adoption of e-methanol based on the latest guidance from the EU RED II Directive. It is likely that the North Sea Transition Deal emissions reduction targets will be achieved through a combination of asset decommissioning and alternative fuels as opposed to changes in working practices. With the increase in vessel demand, for the installation of offshore wind farms and decommissioning of assets, operators may have to look to extend the late-life timeframe of their infrastructure [58]. That driver will influence operators to evaluate the efficiencies of the assets. Whilst ceasing production is the primary driver for decommissioning decision-making, an increase in operating efficiency with a decrease in environmental footprint may incentivise operators to extend the life of the asset further.

We must be mindful that fuel suggestions are transition fuels. Yes, e-methanol is a carbon-containing fuel, but through sustainable manufacture, appropriate carbon management policies and improved turbine efficiencies, e-methanol is a significant step towards decarbonising the offshore energy industry.

Whilst we recognise that sustainable, renewable sources of energy need to replace fossil fuel, we still require fossil fuels to meet our current energy demands. Adopting alternative fuels will help reduce emissions from fossil fuel production until clean energy can take its place.

The journey to net zero is a transition involving multiple stages. The industry must adopt alternative fuels while entirely carbon-free solutions are developed, and every offshore operator should be a leading participant in achieving this goal.

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