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PREREQUISITES FOR THE USE OF LOW-CARBON ALTERNATIVE FUELS IN GAS TURBINE POWER GENERATION

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ABSTRACT

As the world shifts towards mitigating climate change, gas turbine (GT) manufacturers are focusing on enabling low-carbon fuel flexibility in GTs. This comprehensive review examines the current status and prerequisites of alternative fuels (excluding hydrogen) for use in GT power generation with the aim to identify the most promising low-carbon solutions.

The review critically compares the thermophysical and chemical properties of non-traditional fuels such as ammonia, biomass or waste-derived fuels, and alcohol-derived fuels with standard GT fuels. The viability of these alternative fuels for power generation is evaluated, considering advantages, challenges, and potential barriers such as availability, fuel composition, and lifecycle greenhouse gas emissions. The maturity of each alternative fuel in the market is assessed, considering production methods and generation potential.

Based on the detailed comparison, the study proposes economically, technologically, and environmentally viable alternative fuels, along with knowledge and experience gaps that need to be addressed. This review can serve as a guide for the GT industry in advancing research and development efforts for alternative fuels to support the global energy transition and decarbonization goals.

NOMENCLATURE

ASTM	American Society for Testing and Materials
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
EU	European Union
FAME	Fatty Acid Methyl Ester
GHG	Greenhouse Gas
GT	Gas Turbine
HEFA	Hydrotreated Esters and Fatty Acids
HVO	Hydrotreated Vegetable Oil
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
ISCC	International Sustainability & Carbon Certification
LHV	Lower Heating Value
NG	Natural Gas
NZE	Net Zero Emissions
OCGT	Open Cycle Gas Turbine
OEM	Original Equipment Manufacturer
RED	Renewable Energy Directive
RFNBO	Renewable Fuel of Non-Biological Origin

INTRODUCTION

Gas turbines (GTs) are expected to provide a fundamental contribution to the net-zero energy transition, by providing secure and reliable power generation. In order to play such an important role in the near future, enabling fuel flexibility of GTs has become a key aspect for the turbomachinery sector. GT original equipment manufacturers (OEMs) are already working to enable the low-carbon fuel flexibility of commercially available GTs fleet. Though the ability of industrial GTs to operate with a variety of gaseous and liquid fossil fuels has already been demonstrated (General Electric, 2009, General Electric, 2011, General Electric, 2018, Kliemke and Johnke, 2012, Saxena et al., 2021), the need to shift towards renewable and sustainable alternative fuels is becoming more compelling to allow GTs to contribute in the future low-carbon energy system. Table 1 provides examples of commercial or field testing conducted with alternative fuels and a variety of GT types.

As shown in Table 1, there is a range of options to choose from among existing alternative fuels, however, not all the choices are equal and several aspects must be taken into account when this selection is made. For instance, many non-conventional fuels are produced by processing biomass or waste and understanding if there is enough sustainable feedstock to satisfy the fuel demand is essential. In addition, according to the production process and the supply chain, alternative fuels may vary in terms of lifecycle greenhouse gas (GHG) emissions compared with existing fossil fuels.

Table 1. *Alternative fuel GT commercial operations and testing*

Fuel	Country	Operator (T = Test / C = Commercial)	GT OEM	GT	GT Output (MWe)	Year
Methanol	UK	RWG/Siemens (T)	Siemens	SGT-A20	15	2023
	Israel	Israel Electric Corporation (C)	P&W	FT4C	50	2014
	USA	Southern Calinfornia Edison (T)	P&W	FT4C	26	1979
	USA	Florida Power Corporation (T)	P&W	FT4C	24	1974
Ethanol	USA	LPP Combustion (T)	Capstone	C30	0.03	2014
	Brazil	Petrobras (C)	GE	LM6000PC	87	2010
	India	Reliance Energy (T)	GE	6B	48	2008
Biogas	Taiwan	Taipei Public Works Department (C)	Capstone	C30	0.03	2016
	Norway	Risavika Gas Centre (T)	Turbec	T100	0.1	2013
Biodiesel (FAME)	Switzerland	Groupe E (T)	GE	6B	36	2007
Biodiesel (HVO)	UK	Uniper (T)	Rolls-Royce	Olympus	17.5	2022
	Germany	Uniper (T)	KWU/Siemens	V93.1	63	2022
	Sweden	Göteborg Energi (T)	Siemens	SGT-800	45	2021
	Sweden	Uniper (T)	KWU/Siemens	V93.0	63	2021
Ammonia	Japan	AIST (T)	Toyota	TPC-50	0.05	2015
	USA	International Harvester Company (T)	Solar	T-350	250 hp	1966

In addition, fuel composition and quality may vary significantly between alternative fuel options and even within the same fuel when produced following different technological pathways. Therefore, it is essential to verify if the fuel composition is in line with the requirements specified by the OEMs for the safe, reliable use of fuels and, if not, which potential issues may arise that can impact on fuel storage and handling, compromise the combustion process, or damage hot gas path components.

Table 2 reports the density and the mass-specific lower heating value (LHV) of the alternative fuels considered in this work and compares them with the same properties of their conventional fossil-based substitutes. In some cases, alternative fuels are able to achieve values close to the fuel they intend to replace (such as HVO and FAME compared to diesel). The same holds for biomethane that in most cases is a product very similar to NG, in terms of composition, density and LHV. Conversely, methanol and ammonia are characterised by a significantly lower LHV if compared to NG and diesel. This means that a higher volume of fuel is required to provide the same heating rate.

Table 2. *Density and LHV of conventional and alternative fuels considered in this study.*

Fuel	Density at 20°C	LHV [MJ/kg]
Natural gas	0.67 kg/m^3	49.5
Diesel	0.83 kg/l	43.1
Biogas	1.2 kg/m^3	13-23
Biomethane	0.67 kg/m^3	45-49.5
Ethanol	0.79 kg/l	26.7
Methanol	0.79 kg/l	19.7
FAME	0.88 kg/l	37.1
HVO	0.78 kg/l	44.4
Ammonia*	0.61 kg/l	18.6

*Density at saturation pressure (~8.6 bar)

This work analyses different non-conventional fuel alternatives for GT-based power generation such as biomass or waste-derived fuels (e.g., biomethane and biodiesel), alcohol-derived fuels (e.g., methanol and ethanol) and hydrogen-derived (e.g. ammonia) with the aim of identifying the necessary prerequisites for use and establishing a common framework to compare these fuels to identify the most promising alternative fuel for GTs, taking into account all the above mentioned aspects. Thus, the framework in which the work will be developed includes fuels that are established global commodities, excluding hydrogen which has already been covered extensively elsewhere (ETN Global 2020, 2022a, 2022b).

The work is organised as follows: 1) the future demand and the potential availability of alternative fuels for power generation is investigated, 2) an overview of the current production capabilities and the future estimates for each of the alternative fuels analysed is given, 3) the GHG reduction achievable through low-carbon fuels use is assessed and compared with the current requirements set out by the European regulatory framework, and 4) finally the presence of impurities in fuel composition potentially harmful for the GTs components is discussed.

AVAILABILITY OF ALTERNATIVE FUELS

An important initial step in assessing the feasibility of decarbonizing GTs with alternative fuels is to accurately quantify the potential demand for these fuels in the gas-based power generation sector. According to the Ten-Year Network Development Plan (TYNDP) scenario report (ENTSOG and ENTSO-E, 2022) the yearly natural gas (NG) consumption for the EU27 NG-based power generation is currently equal to 1109 TWh (corresponding approximately to 4 EJ) and will go down to 253 TWh in 2050, according to the Global Ambition scenario. Assuming no addition of new generation capacity (i.e., only retrofit or replacement of the current capacity) and to decarbonize only a fraction (e.g., 10-20%) of the existing generators through alternative fuel use, the estimated demand for alternative fuels ranges between 0.4 and 0.8 EJ for the EU27. If the same estimate is repeated considering the world NG consumption (6521 TWh (IEA, 2022)) this results in a global alternative fuel demand equal to 2.3 EJ and 4.7 EJ for 10% and 20% capacity retrofit, respectively.

The second aspect pertains to the availability of the alternative fuels in question. Since most of these fuels are derived from biomass or waste-based feedstocks, it is legitimate to investigate if the potential feedstock would be enough in the future to sustain the production and supply of such alternative fuel quantities. Estimates on the feedstock potential availability vary widely at a regional and a global level and many studies report different values according to the methodology considered (IRENA, 2022, IRENA, 2016).

According to IRENA estimates (IRENA, 2022), the sustainable biomass potential in 2030 ranges from 97 EJ to 147 EJ per year, most of which derives from agricultural residue and waste (37-66 EJ), forest products and residues (24–43 EJ) and energy crops (33–39 EJ). A prudent assumption is to consider the maximum sustainable potential available in 2050 to be constrained to 100 EJ, a value close to lower bounds reported by most of the studies on biomass potential (IRENA, 2022, IRENA 2016). Moreover, this assumption is coherent with the level of bioenergy use assessed by IEA in their Net Zero Emissions (NZE) scenario (IEA, 2021a). The IEA NZE scenario analysis (IEA, 2021a) clearly states that in 2050 the global demand for bioenergy will be well-below the assessed sustainable potential: starting from the available potential (100 EJ) and taking into account conversion losses, still 85 EJ of bioenergy supply will be available. Then, following the IEA projection, half of them will be directly employed by solid bioenergy for heat and power generation while the remaining half (40-45 EJ) will be equally divided into gaseous and liquid biofuels. This means that, assuming an alternative fuels demand corresponding to a 20% GT fleet decarbonization in 2050, this would lead to a bioenergy supply exploitation limited to 10% of the market (4.7 EJ out of 45 EJ) in 2050. Even considering all the potential competing applications for biomass and waste-derived fuels in 2050 devised by the IEA NZE scenario, the actual demand for alternative fuels requires to replace part of the gas-based power generation is indeed contained if compared to the overall available potential.

Biofuels

Global biofuel production capacity reached 159.2 billion litres (corresponding to 4.1 EJ) in 2021 (REN21, 2022). The main biofuels in terms of production volume are ethanol, produced mostly from corn, sugar cane and other crops, and biodiesel (fatty acid methyl ester, or FAME), produced from vegetable oils and fats, including wastes such as used cooking oil. In recent years, the production capacity has increased for other diesel substitute fuels, made by treating animal and vegetable oils and fats with hydrogen, such as hydrotreated vegetable oil (HVO) and hydrotreated esters and fatty acids (HEFA). In 2019, ethanol accounted for 59% (in energy terms) of overall biofuel production, FAME biodiesel for 35% and HVO/HEFA for the remaining 6%. Other biofuels included biomethane and a range of advanced biofuels, but their production volumes remained low, representing less than 1% of the total biofuels market (REN21, 2022).

To produce such liquid biofuels several production pathways are available which are already mature and have a high TRL (i.e., 8-9) (IRENA, 2016): ethanol is mainly produced via fermentation of sugars, FAME from transesterification while HVO and HEFA are derived from the hydroprocessing of oils and fats.

In IEA NZE scenario (IEA, 2021a), the biofuels market will reach 15 EJ by 2030 and this number is expected to double in 2050, according to IRENA's long-term forecast for biofuel demand (IRENA, 2022). Such increase is largely due to the development of advanced biofuels based on waste-derived feedstocks like renewable diesel (HVO/HEFA) while the role of biodiesel and conventional (i.e. crop-based) ethanol will be more limited in the future. Moreover, different biofuels such as FAME biodiesel and renewable diesel compete for the same feedstock, further complicating relative growth between the two biofuels.

Regarding potential applications for liquid biofuel, they are expected to provide a significant contribution to road transport initially, but their market share will be more limited in future, as electricity will play, progressively, a growing role in this sector (IEA, 2021a). Therefore, biofuel use shifts to shipping and aviation in 2050 and even if not directly accounted for within the NZE scenario, a share of the biofuel market dedicated to power generation may be put in place to replace the phase-out of other biofuel applications.

Methanol

The interest towards the use of methanol as fuel either by itself, as a blend with gasoline to produce biodiesel, or in other forms has increased in the last years since the methanol production has grown significantly for the production of polyethylene and polypropylene in particular. Hence, methanol is a key intermediate product in the chemical industry, used not only in fuel blending but to also produce formaldehyde, acetic acid and plastics. Current methanol production is around 98 million tonnes, nearly all produced from natural gas or coal, bio-methanol accounting for less than 0.2 million tonnes (IRENA, 2021). Though the current production volumes of bio-methanol are low, the available potential is remarkable: IRENA estimated that up to 1,100 million tonnes of production potential could be made available globally, exploiting all the range of (unused) feedstocks suitable for methanol production (IRENA, 2021). Even if this number already accounted for other biomass uses, it can be considered only a rough estimate for the bio-methanol production potential.

Production processes for bio-methanol starting from the gasification of biomass feedstocks have been demonstrated at scale, however the production cost is still not competitive from a market perspective, even when low-cost feedstocks are used. Given the lack of current production capacity and the higher costs of bio-based methanol, production volumes are unlikely to increase in the absence of support measures that encourage production and offset the cost differential.

Nonetheless, the production cost is likely to reduce in the future, unlocking the methanol production potential: according to IRENA's Transforming Energy Scenario, methanol demand is projected to achieve 500 million tonnes in 2050, 135 of which will derive from bio-methanol.

Biogas and biomethane

Today, 3 billion cubic meters (bcm) of biomethane and 15 bcm of biogas are produced in the EU-27 (Alberici et al. 2022). The European Commission set a target of 35 bcm of annual biomethane production by 2030 in its recent REPowerEU plan (European Commission, 2022). According to a recent study by Gas for Climate (Alberici at al. 2022), enough sustainable feedstocks are available in the EU-27 to meet the REPowerEU 2030 target. In this report, by applying a unified methodology for each EU Member State (plus Norway, Switzerland and the UK) and considering strict sustainability criteria for feedstocks selection (waste and residues are priorities taking into account sustainable removal rates and existing uses, only sequential crops are included), they assessed up to 41 bcm of biomethane production potential that could be unlocked by 2030. This number potentially grows to 151 bcm in 2050, representing more than one-third of the 2020 EU NG consumption (400 bcm). Most of the production capacity will be derived from anaerobic digestion (38 bcm in 2030, 91 bcm in 2050), which currently is the most mature production process, while the remaining will come from biomass gasification.

Besides Europe, the role of biomethane will be certainly more contained worldwide, particularly in those countries where a large gas infrastructure has not been developed. In NZE scenario biomethane will contribute to global bioenergy supply by 3% and 8% in 2030 and 2050, respectively.

Low-carbon Ammonia

Ammonia has the potential to be used as a low-emission energy carrier in a variety of applications, including power generation. It is produced starting from hydrogen as raw feedstock, but in contrast to pure hydrogen, has a higher volumetric energy density and a higher liquefaction temperature, which make ammonia more suitable to transport and storage. Ammonia has a variety of applications in the chemical sector, therefore can rely on an already established market: in 2020, 185 million tons (Mt) of ammonia were produced and around 20 Mt of it was globally traded (IEA, 2021b). In comparison to hydrogen, ammonia has a well-established infrastructure and established practices for safe and reliable storage, distribution, and export, making it a promising alternative fuel for gas turbines. Subsequently, once transported to the desired location, ammonia can be even cracked to yield pure hydrogen for use in GTs or co-fired with NG in existing power plants. For these reasons, ammonia is gaining attention for its potential role in reducing emissions, particularly in power generation and in the maritime sector.

In the IEA Sustainable Development Scenario (IEA, 2021b), the use of ammonia for co-firing in coal power stations climbs to 60 Mt per year and 140 TWh of electricity generation by 2050, up from a handful of pilot and demonstration scale projects today. Despite providing only around 0.2% of global electricity generation in 2050, this application accounts for around a third of the consumption of ammonia for purposes other than its existing uses today.

However, almost all ammonia traded today has fossil origin and decarbonised ammonia production and use on a large scale will be limited until the production of low-carbon hydrogen is scaled up.

GREENHOUSE GAS (GHG) REDUCTION

One of the key considerations for the use of alternative, low-carbon fuels in GTs is the associated lifecycle GHG reduction attributed to that fuel in comparison with its fossil fuel equivalent. In Europe, minimum requirements for GHG reduction as well as default lifecycle GHG emission factors for certain bio-derived fuels and renewable fuels of non-biological origin (RFNBOs) are set out in prevailing legislation, namely the Renewable Energy Direction (RED II) (European Commission, 2018) and two recently proposed delegated acts related to the use of renewable hydrogen in the production of RFNBOs (European Commission, 2023a).

For biofuels and RFNBOs, GHG emissions attributed to the fuel are considered on a lifecycle basis, including the extraction and cultivation of raw materials, processing, transport and distribution, and end use. For fuels used in electricity, heat, or cooling applications, these GHGs are expressed in RED II in terms of grams of CO_2eq per MJ of final energy commodity of heat or electricity. For example, for energy installations that deliver only electricity from these fuels, such as open cycle GTs (OCGTs) and combined cycle GTs (CCGTs), the GHG emissions (EC_{el}) are expressed as given in Equation 1.

$$EC_{el} = \frac{E}{\eta_{el}} \tag{1}$$

where E is the GHG emission expressed in grams of CO_2eq per MJ of renewable fuel before end conversion, and η_{el} is the electrical efficiency defined as the annual electricity produced divided by the annual energy input, based on net fuel energy content. Combined heat and power (CHP) applications producing useful heat in addition to electricity require a modified version of Equation 1 to be applied for GHG emissions calculation. It should be noted that CO_2eq is used in RED II to account for equivalent contributions from the following GHGs: CO_2, CH_4, and N_2O.

One important difference between biofuels/bioliquids and RFNBOs is the lifecycle CO_2eq accounting for the end use of the fuel. According to RED II (European Commission, 2018), emissions of the fuel in use should be zero for biofuels and bioliquids since it can be assumed that their combustion releases only biogenic CO_2. Therefore, the biofuel GHG emissions are associated with cultivation, processing, transport and distribution. However, the proposed delegated act for RFNBOs requires that emissions from fuel combustion are included in the overall lifecycle CO_2eq calculation (European Commission, 2023b).

Article 29 of RED II (European Commission, 2018) sets out the minimum required GHG savings from the use of biomass to produce electricity, heating, and cooling, and these are assumed here to be the same for other biofuels including biogases and bioliquids. Minimum GHG savings are stipulated to be 70% until 31 December 2025 and 80% from 1 January 2026 onwards. To calculate the GHG savings according to RED II (European Commission, 2023) for a given renewable bioliquid used in the production of electricity, the GHG emissions for the fuel ($EC_{B(h\&c,el)} = EC_{el}$) are compared to a fixed fossil fuel comparator, $EC_{F(h\&c,el)}$, as shown in Equation 2, where $EC_{F(h\&c,el)}$ is 183 $gCO2_{eq}/MJ$ for electricity production. Note that 183 $gCO2_{eq}/MJ$ is also referred to in the proposed RFNBO delegated act as equivalent to the carbon intensity of grid electricity (European Commission, 2023b). This grid carbon intensity value is assumed to be indicative of an average EU fossil electricity mix.

$$GHG\ Savings = \frac{(EC_{F(h\&c,el)} - EC_{B(h\&c,el)})}{EC_{F(h\&c,el)}} \qquad (2)$$

Combining Equations 1 and 2 with the minimum RED II GHG savings targets, the following biofuel or RFNBO maximum lifecycle GHG emissions can be calculated for fuels used in electricity production until the end of 2025 (i.e., 70% GHG savings) in Equation 3 and from 2026 (i.e., 80% GHG savings) onwards in Equation 4

$$E_{max} = \eta_{el}(54.9\, gCO_2eq/MJ) \qquad (3)$$

$$E_{max} = \eta_{el}(36.6\, gCO_2eq/MJ) \qquad (4)$$

Figure 1 plots the maximum allowable lifecycle biofuel GHG emissions to maintain compliance with RED II GHG savings targets (E_{max}) as a function of GT electrical efficiency (η_{el}) alongside the maximum and minimum default lifecycle GHG emission factors (E) given in RED II (European Commission, 2018) for biomethane, methanol, ethanol, FAME, and HVO. RFNBOs produced using recycle carbon are proposed to have a minimum GHG savings of 70% (European Commission, 2023c), and this is assumed to be when compared with a default transport emissions intensity of 94 gCO_2eq/MJ, thus yielding a maximum allowable lifecycle GHG emissions intensity for RFNBOs of 28.2 gCO_2eq/MJ, also plotted in Figure 1. Note that the negative emissions scale has been changed for clarity to account for the minimum default GHG emissions value of -100 gCO_2eq/MJ for biomethane.

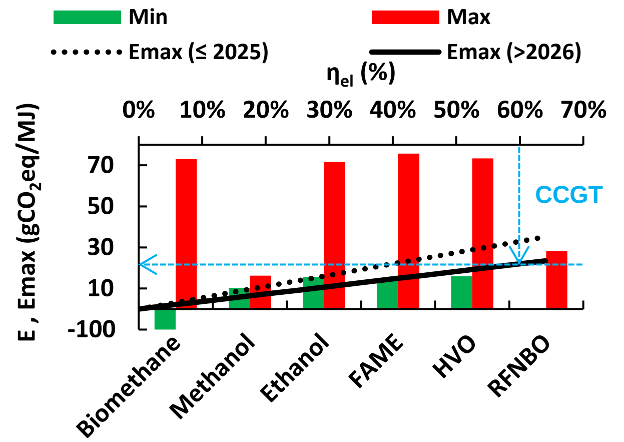

Figure 1. *Default maximum and minimum GHG emissions from RED II and maximum allowable GHG emissions from biofuels to achieve RED II GHG reduction targets.*

Figure 1 highlights an important point of consideration for the use of alternative fuels in GT power generation. The default GHG emissions factors for biofuels can vary widely (e.g., -100 gCO_2eq/MJ to 73 gCO_2eq/MJ for biomethane) as a result of the feedstock and production process. The default minimum values given in RED II are not necessarily the lowest lifecycle GHG emissions that can be achieved for each biofuel, but are used here as indicative and for comparison between biofuels. Also, by comparing the maximum and minimum default values with the maximum allowable GHG value to achieve the required GHG savings from electricity generation, limits for each biofuel can be identified.

As shown in Figure 1, for a CCGT power generation application to meet the RED II GHG savings target from 2026 onwards, the certified lifecycle GHG emissions of the biofuel or RFNBO should not exceed 22 $gCO2_{eq}/MJ$, if the annual electrical efficiency is assumed to be 60%. In this example, all biofuels would be suitable as long as the production method and feedstock were equivalent to the minimum default GHG emissions factor in RED II. To use an RFNBO in this application, it would need to achieve around 77% GHG savings with respect to the transport fuel comparator.

For an OCGT application with an electrical efficiency of 30%, the lifecycle GHG emissions of that fuel should not exceed 11 $gCO2_{eq}/MJ$ if the RED II GHG savings target from 2026 onwards is to be met. Based on the minimum default GHG values given in RED II, only specific types of biomethane or methanol could be used in this application. However, given the RED II default values are not indicative of a biofuel's absolute minimum lifecycle GHG, other biofuels may also satisfy this requirement. To use an RFNBO in this application, it would need to achieve over

88% GHG savings with respect to the transport fuel comparator.

In both examples, it is essential that the lifecycle GHG emissions of the biofuel or RFNBO are certified by the producer and the supplier with transparency throughout the supply chain with organisations such as International Sustainability and Carbon Certification (ISCC) providing the necessary supply chain governance to give certainty to GT users that RED II requirements can be met. Note that ammonia has not been included in Figure 1 as it is not currently considered in RED II or the recently proposed delegated acts. However, to aid in the comparison herein, lifecycle GHG emissions factors of 20.8 gCO_2eq/MJ (blue ammonia) and 1.4 gCO_2eq/MJ (green ammonia) can be used from the work done by the Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping (2022), with fuel combustion CO_2eq set to zero. Given the relatively nascent stage of ammonia use in GTs, more work will be necessary to determine if the lifecycle GHG emissions factors should also include contributions from N_2O produced from fuel combustion.

EU TAXONOMY

In addition to the GHG reduction targets set out in RED II, the EU Complementary Climate Delegated Act (European Commission, 2022) sets out strict carbon intensity conditions for specific NG energy activities covered by the EU taxonomy. For construction or operation of electricity generation facilities using fossil gaseous fuels, the lifecycle GHG emissions using fossil gaseous fuels should be lower than 100 $gCO_2eq/kWhe$, or for sites built before the end of 2030, the GHG emissions should be less than 270 $gCO_2eq/kWhe$ with a pathway to full renewable or low-carbon gas by 2035. Using default lifecycle GHG values for fossil and fossil-derived fuels given in the Annex of the proposed RFNBO delegated act (European Commission, 2023b) and the maximum and minimum default lifecycle GHG values for HVO given in RED II, Figure 2 shows that an H-class CCGT with 64% efficiency would exceed the 2030 EU taxonomy limit in all cases except the HVO produced from a feedstock yielding its lowest default carbon intensity value in RED II (16 gCO_{2eq}/MJ). Using HVO produced from feedstock yielding the highest default carbon intensity value in RED II (73.3 gCO_{2eq}/MJ) would not meet the EU taxonomy limit for installations by 2030. Note that HVO is only selected here to highlight the importance of alternative fuel feedstock impact on lifecycle carbon intensity, and that not all fuels within the same category (i.e., HVO) will carry the same carbon intensity. Other alternative fuels would meet the 2030 EU taxonomy limit in this CCGT application based on their default values in RED II. In fact, any alternative fuel would need to achieve lower than 48 gCO_{2eq}/MJ carbon intensity to meet the 270$gCO_{2eq}/kWhe$ limit or lower than 18 gCO_{2eq}/MJ to meet the 100$gCO_{2eq}/kWhe$ limit in this particular application (i.e., H-class CCGT with 64% efficiency). An OCGT activity with 30% efficiency would approximately double the values plotted in Figure 2.

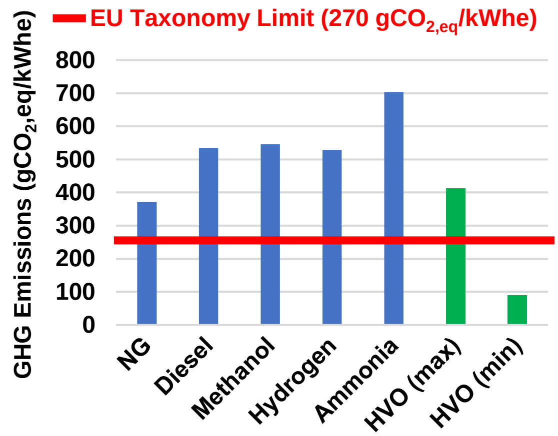

Figure 2*. GHG emissions from an H-class CCGT for fossil, fossil-derived, and HVO fuels compared with the 2030 EU taxonomy limit.*

Designated electricity generation activities which blend fossil gaseous fuels with gaseous or liquid biofuels to reduce lifecycle GHG emissions would appear to be permitted under the EU taxonomy as long as sustainability criteria for the feedstock is compliant with RED II (European Commission, 2022). The EU taxonomy includes GHG emissions limit criteria for electricity generation activities from pure gaseous and liquid fuels from RFNBOs and RFNBO-biofuel blends (< 100 gCO_2eq/kWh) and pure biofuels (>80% GHG reduction as set out in RED II). Additional criteria are also set for the use of biofuels based on the thermal input of the installation. For example, for electricity generation installations with greater than 100 MWth input, the activity must either achieve η_{el} >36%, or apply CHP, or use carbon capture and storage technology.

ALTERNATIVE FUEL COMPOSITION

Currently, many of the proposed alternatives to NG and diesel are not primarily produced for use as fuel in gas turbines. Hence, the level of impurities present from the production process is not analyzed following the standard for GT fuels (ASTM D2880). ASTM D2880 sets the maximum level acceptable of impurities that could potentially be harmful for the GTs components, shown in Table 3 in terms of chemical elements that could increase the degradation of blades' material, such as V, Na, K, Ca, Pb and so on. Some of the chemical compounds are produced and analyzed considering different standards, such as ASTM D4806-21a for ethanol or D6751-20a for biodiesel. These standards do provide instructions for the use of such compounds as a fuel for spark engine (ASTM D4806) and as blended fuel (ASTM D6751).

Table 3. *Limits of trace metals entering GT combustors for natural gas (adapted from ASTM D2880).*

Designation[1]	Trace Metal Limits mg/kg			
	V	Na+K	Ca	Pb
0-GT	0.5	0.5	0.5	0.5
1-GT	0.5	0.5	0.5	0.5
2-GT	0.5	0.5	0.5	0.5
3-GT	0.5	0.5	0.5	0.5
4-GT	Consult Turbine Manufacturer			

[1] No. 0-GT includes naphtha, Jet B fuel and other volatile hydrocarbon liquids. No. 1-GT corresponds in general to specification D396 Grade No. 1 fuel and D975 Grade 1-D diesel fuel in physical properties. No. 2-GT corresponds in general to Specification D396 No. 2 fuel and D975 Grade 2-D diesel fuel in physical properties. No. 3-GT and No. 4-GT viscosity range brackets specification D396 Grades No. 4, Grade No. 4-D diesel fuel in physical properties

Most of the standards though, do not provide guidelines on the level of the contaminants (impurities) of interest for GT fuels. Therefore, in order to gather relevant information for gas turbine (GT) applications, it is necessary to consult various sources, including research papers, manufacturer guidelines, and studies such as the one by Amri et al. (2021), in order to obtain comprehensive and up-to-date insights. Amri et al. (2021) compared the values of different impurities found in biodiesel, with the requirements set by ASTM D2880 and the GE-HD guidelines. Selected results of the study are summarised in Figure 3 and Table 4. Figure 3 shows a comparison between the measured value in biodiesel and the accepted values of ASTM D2880 and GE-HD (manufacturer). As it can be seen, the ASTM standard does set strict standards, and the biodiesel could meet the standard for Pb and V. These two metals are quite detrimental when present in the exhaust stream. In fact, V can form vanadate, which is responsible for corrosion damage (Ozgurluk Y et al., 2018).

Table 4. *Impurities levels for Biodiesel, adapted from (Amri et al, Journal of Physics: Conference Series, 2021 for biodiesel).*

Parameters	Units	Methods	SNI 7182	EN14214	GE-HD
Phosporus	wt%	ASTM D4951	4	4	-
Ca+Mg	mg/kg	ASTM D7111	-	5	2
V		ASTM D7111	-		0.5
Pb		ASTM D7111	-		1
Na+K		ASTM D7111	-	5	1

In terms of other impurities, the analysis reveals that biodiesel contains approximately three times the amount of Ca+Mg compared to the standard, and twice the amount of Na+K as per the standard. However, these levels are lower or similar to the specifications set by GE-HD. Ca+Mg is responsible for the CMAS type of attack in GTs; while Na+K can react with S contained in the exhaust stream (S could come from the fuel or air as impurities) and form $(Na,K)SO_4$ which can attack the alloys of the blades. The alloys with low Cr content as alloying elements are quite prone to the attack of S containing molecules, especially at lower temperature, around 700°C (Mori et al., 2022).

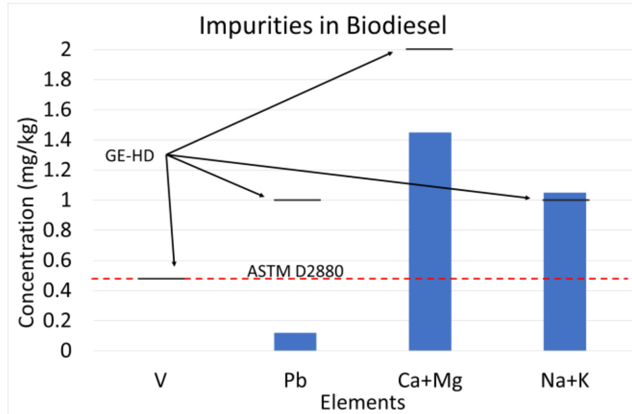

Figure 3. *Measured impurities in Biodiesel (blue columns) and standard for Natural Gas: ASTM D2880 (red line) and GE-HD (black lines). Data are from Amri et al. (2021).*

Looking at ammonia the situation appears to be less definitive or conclusive. There are no established standards for the utilization of ammonia as a fuel. Presently, ammonia is commercially available in various grades in the market (Atchison J, 2020):

- Premium or Metallurgical (Met-grade) ammonia at 99.995% purity;
- Refrigeration (R-grade) ammonia at 99.98% purity;
- Commercial or Agricultural (C-grade) ammonia at 99.5% purity.

It is believed that ammonia to be used as fuel would sit at a C-grade or below C-grade (Atchison J, 2020), thus lower than 99.5% purity. This could pose several problems, as the exact composition of the C-grade ammonia is not well specified, and a correct quantification of impurities such as V, Pb, Na, K, Ca, S is needed for application as fuel for GT. This presents an opportunity for further experimental investigations involving the interaction of exhaust gases from the combustion or use of ammonia with alloys that are expected to be used as blade materials.

Some works assessing the corrosiveness of ammonia in different types of applications already exists. Valera-Medina et al. (2018) assessed the impact of ammonia for combustion. The study concluded that the high temperature cycling could induce nitridation of the alloy, but further studies are needed to also assess the impact of the flow rate. In the same study (Valera-Medina et al., 2018), it is reported that ammonia is particularly corrosive when mixed with water. In fact, ammonia causes the rapid increase of pH (up to 11.6), causing problems for several materials, especially alloys such as copper, brass and zinc. The compatibility of different materials with ammonia is reported in Table 5.

From what can be seen in Table 5, different types of materials could suffer severe degradation when in contact with ammonia, not just metals, but also polymer. This effect could pose problems even in the storage and distribution of ammonia, especially when stored at high pressure. This is because the increase in pressure could increase the diffusivity of the NH_3 molecules inside the materials, with the possibility of causing leakages and damage.

Table 5*. Compatibility of different materials with ammonia, where A= Excellent; B= Good (but some effect); C=moderate effect (continuous use not recommended); D= Severe. Adapted from Valera-Medina et al. (2018).*

ABS plastic	D	CPVC	A	Polycarbonate	D
Acetal (Delrin ®)	D	EPDM	A	PEEK	A
Aluminium	A	Epoxy	A	Polypropylene	A
Brass	D	Fluorocarbon (FKM)	D	Polyurethane	D
Bronze	D	Hastelloy-C ®	B	PPS (Ryton ®)	A
Buna N (Nitrile)	B	Hypalon ®	D	PTFE	A
Carbon graphite	A	Hytrel ®	D	PVC	A
Carbon Steel	B	Kalrez	A	PVDF (Kynar ®)	A
Carpenter 20	A	Kel-F ®	A	Silicone	C
Cast iron	A	LDPE	B	Stainless Steel 304	A
Ceramic Al2O3	N/A	Natural Rubber	D	Stainless Steel 316	A
Ceramic magnet	N/A	Neoprene	A	Titanium	C
ChemRaz (FFKM)	B	NORYL ®	B	Tygon ®	A
Copper	D	Nylon	A	Viton ®	D

All the information collected during this review does show a variegated picture. The different alternative fuels could potentially contain different contaminants/impurities, that when combusted could form compounds potentially harmful to the turbines' components (in particular blades). It would be crucial to correctly choose the operating parameters (such as pressure and temperatures). Other thermal power plants faced a similar challenge in the past. For example, some solid-fuels fired power plants switched from coal to biomass, but to achieve the same lifetime for heat-exchanges, they were forced to run at lower temperatures (Montgomery et al, 2011). This was due to the difference in composition between coal and biomass (especially the difference in Cl and S content) that resulted in a different post combustion environment (Mori et al., 2021, 2022 and 2023). A similar scenario may be anticipated for GTs, but caution is necessary when extrapolating lessons from other industrial sectors. Further studies should be conducted to comprehensively understand the potential composition of the exhaust stream, and based on these findings, formulate a focused experimental plan for GTs.

CONCLUSIONS

The current study reviews the alternative fuels that are already deployed and that can substitute natural gas or fossil diesel in industrial gas turbines. Hydrogen has been widely covered in other studies and reports, and therefore, the efforts have been focused on: HVO, FAME, ethanol, methanol, biogas/biomethane, and low-carbon ammonia. The aim of this study is to provide a comprehensive review of the existing alternative fuels and derive the best indicative parameters to assess the potential of each to be used in industrial gas turbines.

The study looks at three important prerequisites when adopting an alternative fuel:

- availability and potential to be widely deployed for industrial gas turbines,
- GHG reduction and EU taxonomy to meet the Renewable Energy Directive and the EU Complimentary Climate Delegate Act, and
- how the alternative fuel composition of these alternative fuels can impact the life expectancy of gas turbine components.

The estimated potential of alternative fuels for the EU27, when retrofitting 10% and 20% of the NG gas turbine fleet to use these fuels, ranges from 0.4 EJ to 0.8 EJ. On a global scale, this estimate increases to 2.3 EJ to 4.3 EJ. Biofuel technology is well-established with a high TRL, but its primary role is expected to be in road transportation, with HVO showing particular promise as a drop-in diesel replacement. Bio-methanol production, on the other hand, has a lower TRL and production costs that are currently not competitive. Biomethane production is likely to be limited to regions with well-developed gas infrastructure, while low-carbon ammonia is seen as a potential energy carrier for decarbonizing the power generation sector. However, most of the ammonia production today relies on fossil fuels.

Each of these fuels can play an essential role to meet the GHG reduction criterion imposed by the RED II as well as the EU taxonomy delegated act. However, it is of utmost importance to consider that not all alternative fuels might meet the criterion. In the case of a CCGT with an electrical efficiency of 60%, all alternative fuels considered could meet the RED II criterion, but in the case of an OCGT with an efficiency of 30% only some alternative fuels might be considered to comply with RED II. Traceability and certification of biofuel or RFNBO GHG reduction will be essential to enable their use in GTs.

Finally, the absence of established standards for alternative fuels which cover the GT application is a significant obstacle to the progress and widespread adoption of the technology in gas turbines. Current standards do not address the limitations of certain impurities, and there is no standard for the use of ammonia as fuel. Consequently, further fuel standard development is required.

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