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Review

The Fuel Flexibility of Gas Turbines: A Review and Retrospective Outlook

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Abstract: Land-based gas turbines (GTs) are continuous-flow engines that run with permanent flames once started and at stationary pressure, temperature, and flows at stabilized load. Combustors operate without any moving parts and their substantial air excess enables complete combustion. These features provide significant space for designing efficient and versatile combustion systems. In particular, as heavy-duty gas turbines have moderate compression ratios and ample stall margins, they can burn not only high- and medium-BTU fuels but also low-BTU ones. As a result, these machines have gained remarkable fuel flexibility. Dry Low Emissions combustors, which were initially confined to burning standard natural gas, have been gradually adapted to an increasing number of alternative gaseous fuels. The paper first delivers essential technical considerations that underlie this important fuel portfolio. It then reviews the spectrum of alternative GT fuels which currently extends from lean gases (coal bed, coke oven, blast furnace gases …) to rich refinery streams (LPG, olefins) and from volatile liquids (naphtha) to heavy hydrocarbons. This "fuel diet" also includes biogenic products (biogas, biodiesel, and ethanol) and especially blended and pure hydrogen, the fuel of the future. The paper also outlines how, historically, land-based GTs have gradually gained new fuel territories thanks to continuous engineering work, lab testing, experience extrapolation, and validation on the field.

Keywords: gas turbine; fuel flexibility; alternative fuels; combustion; low emissions; hydrogen; fossil fuels; biofuels

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1. Introduction

The current decade will see disruptive changes in the energy scene as a dramatic abatement of GHG emissions, especially those of CO_2, has become a global, inescapable necessity [1]. However, as pointed out by the IEA [2], the thermal power segment will survive, initially, in order to deliver the massive power additions that will be required by the upcoming electrification of the economies, particularly, that of the transportation sector. Then, the thermal sector will continue to play a critical role since electrical grids will need dispatchable units and "spinning reserves" to support the grids and offset the intermittency of renewables. Currently, among thermal power facilities, land-based gas turbines are serious candidates to support the energy transition as they meet all the requisites, including efficiency, reliability, controlled emissions, and peak shaving capability, with fast start and ramp-up ability [3]. The irreplaceable role played by gas turbines in the reliability of power grids and their potential contribution to a decarbonized economy in conjunction with the advent of hydrogen as an energy vector has been discussed elsewhere [4,5].

In addition, gas turbines have the additional advantage of being highly fuel flexible, a key asset in addressing the volatile and uncertain fuel market of the future. Indeed, they have managed to build a wide fuel portfolio, starting from natural gas and light distillate—which are their historical fuels—and now encompassing a large variety of alternative gases and liquids.

This paper aims to review the vast fuel territories that have been successfully explored and occupied by land-based gas turbines over the years, drawing in particular on the author's own experience. To better understand the reasons for this success, it will first set out some key aspects that pertain to the technology of these machines. It will also highlight some interesting milestones in this fuel flex expansion process.

2. Essential Technical Considerations

2.1. The Value of Fuel Flex in the Power Generation Market

Generically, fuel flexibility is the ability not only to accommodate a plurality of fuels but also to achieve reliable fuel changeovers. In modern power plants, these must be performed either automatically or upon simple "push-button" orders. The simplest and most common case of fuel flex is dual fuel capability, which usually involves natural gas (NG) and light distillate oil (LD) for gas turbines [6]. However, two cases should be distinguished because the expectations from a prime mover depend on to the type of service it provides:

- Peak-shaving service is characterized by few operation hours but a constraint of permanent "dispatchability", which is the ability to respond to changes in power demand over time, and which requires faultless startups and fast access to the targeted load; here, the plant operator's attention is essentially focused on maintenance costs;
- Base-load or "semi-base-load" service implies longer operation periods, during which the operator focuses on fuel cost which represents up to 60% of his O&M expenses.

Figure 1 shows the "pyramid of merits" of gas turbines intended for peak-shaving and base-load service, respectively. In both cases, the objective is to maximize the gain per kWh generated and the load factor of the unit.

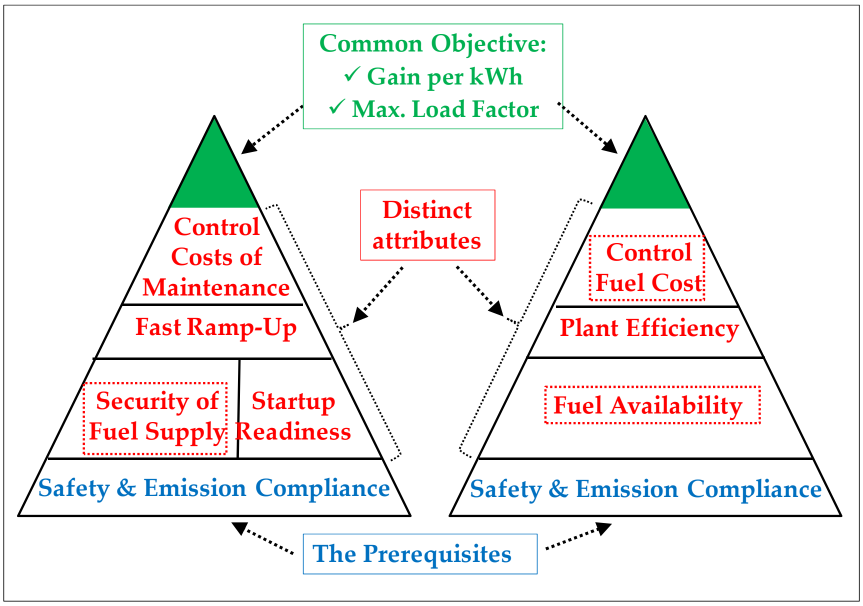


Figure 1. The "pyramid of merits" for peak-shaving and base-load gas turbines.

For a peak-shaving service, the required qualities are: (i) startup readiness, with, at best, a black-start capability; (ii) secured access to fuel, implying a backup fuel; (iii) fast ramp-up time; and (iv) containment of maintenance costs since operating in peak-shaving mode considerably increases the "maintenance factor" due to multiple startups/shutdowns, fast load changes, and peak-load excursions. Here, a dual fuel capability represents an additional security as it will avoid the financial losses potentially caused by failures to start upon a requisition from the dispatch center. For a GT normally burning NG, which represents most cases, the second fuel can simply be a light distillate, which will be rarely used. However, in some areas lacking natural gas and light distillate (e.g., in some remote islands), the possibility to start with an alternative fuel, such as a liquefied petroleum gas, is highly desirable. However, efficiency remains an important consideration.

For a base-load or a semi-base-load service, fuel availability is also essential, but the focus is more on securing an uninterrupted supply of large fuel volumes and on minimizing fuel cost. Indeed, GTs serving large industrial plants such as refineries, petrochemical plants, or ironworks, usually operate for long periods of time, sometimes non-stop for an entire year. It is where the access to an alternative but also economic fuel acquires its full value.

The purpose of this paper is therefore to explore fuel flexibility in all its forms by highlighting the gains it can bring to many industrial sectors, especially when this quality is combined with efficient energy conversion methods, including cogeneration and combined cycles, and smart uses of residual or low-grade secondary energies [7].

2.2. Inherent Strengths of Gas Turbines Favoring Fuel Flex

Contemporary gas turbines operate according to the Brayton cycle, in which the heat addition step is made by combusting a fuel in a continuous flow of air [8]. For several reasons, this cycle is very propitious for fuel flexibility. At first, the three cycle steps (compression; combustion; expansion) are performed sequentially and in separate sections of the machines. Once the targeted load is reached, both air and fuel enter the combustors at constant flow, temperatures, and pressure, creating stationary aerodynamic and thermal patterns that greatly aid flame stability. These stable conditions and the absence of any moving part in the combustors provide a fairly large amount of room to conceive versatile combustion systems capable of matching a plurality of objectives, the most important being complete combustion, low NOx emissions, and multifuel capability, which is the focus of this article. In addition, a large portion of the combustion testing activity can be made on single combustor assemblies, separately from the rest of the machine, which enables accelerated developments of new combustion concepts or designs [9,10].

Boilers also feature continuous flow and permanent flames [11] and are greatly fuel flexible. However, a main difference is that GTs operate under pressure (up to 30 bars) and use hot combustion air, resulting in faster and more complete combustion kinetics, even when dealing with difficult fuels. The flames are therefore shorter, so the combustion chambers are of much smaller size. Moreover, the combustion heat is directly converted into mechanical power as the combustion gases themselves act as the driving fluid that rotates the machine shaft. On the contrary, the energy conversion in boilers proceeds through several heat exchanges that require very large surface areas, entailing strong thermal inertia and large transient expansions/contractions, imposing much slower temperature changes, i.e., slower load changes. These differences are also important because the much smaller hot parts of GTs can be fabricated using advanced materials, such as single crystal superalloys that are internally cooled and coated with thermal barriers [12–17]. The small, sophisticated turbine blades and vanes can withstand much higher mechanical strains and temperatures than boiler tubes, as well as steeper thermal transients, opening the way to (i) elevated cycle pressures/temperatures and hence high efficiencies that are essential for base-load operation; and (ii) fast starts/load changes that are key for peak-load service [18,19]. Finally, the compactness and modularity of gas turbine units are additional advantages that explain their high power-to-weight ratio and their short fabrication and erection times [20].

Turning to reciprocating engines, their combustion process is intermittent with alternations of several strokes and intermediate ignition events [21]. Due to the need of repetitive ignitions, those engines are specialized for certain classes of fuels with specific ignition properties. While spark-ignited (gasoline and gas) engines require fuels that are resistant to auto-ignition (i.e., with high octane indices) to avoid knocking [22,23], diesel engines need autoignitable fuels (i.e., fuels with high cetane indices) to avoid difficult startups and smoke emissions [24–26]. Gas turbines are free of these constraints as they operate with permanent flames and with large air excesses. Consequently, they emit no smoke and virtually no CO/UHC—even when they burn difficult liquid fuels—thanks to their air atomization systems. The PM content at the exhaust of gas-fired GTs is very low and has even been found to be lower than in ambient air, owing to the air filters at the compressor inlet [27]. While the rotary movement of reciprocating engines is created by pistons whose rings rub against cylinder walls, GT shafts rotate on hydrodynamic, friction-free journal bearings [28]. Another difference is that GT combustion liners are air-film cooled, which largely prevents flame quenching effects on their walls [29]. Although internal combustion engines boast interesting efficiencies as stand-alone machines [30,31], they release exhaust gases at medium temperature levels, which allows for only moderately or weakly efficient heat recoveries [32]. In contrast, gas turbines of the heavy-duty family ("HDGT") that are designed with moderate compression ratios have relatively high exhaust temperatures (550–620 °C). Therefore, they can drive "topping" cycles and discharge their combustion gas into heat recovery boilers to deliver heat to "bottoming" steam cycles or cogeneration units, resulting in high overall efficiencies [33,34]. However, a definitive advantage of reciprocating engines is that their fuel does not need to have been compressed before injection in the engine.

Finally, the low fuel/air ratios and the large stall margins of HDGTs allow them to accommodate large fuel flowrates, thus enabling the combustion of low-BTU fuels in addition to medium- and high-BTU fuels [35,36]. All these design factors that favor the fuel flexibility of gas turbines represent the basic capital on which it has been possible, historically, to build a large fuel portfolio [37], thanks to continuous efforts made over years in designing and testing. As a result, these machines have gained wide fuel flexibility and have been sometimes nicknamed the "omnivorous" prime movers [38].

2.3. Technologies and Designs Underlying Fuel Flex

Validating the use of an alternative fuel in a gas turbine requires a somewhat holistic approach as one must address multiple and often interrelated design and operational aspects. Figure 2 sketches a gas turbine unit with its main fuel accessories and lists the essential operational functions to perform [39].

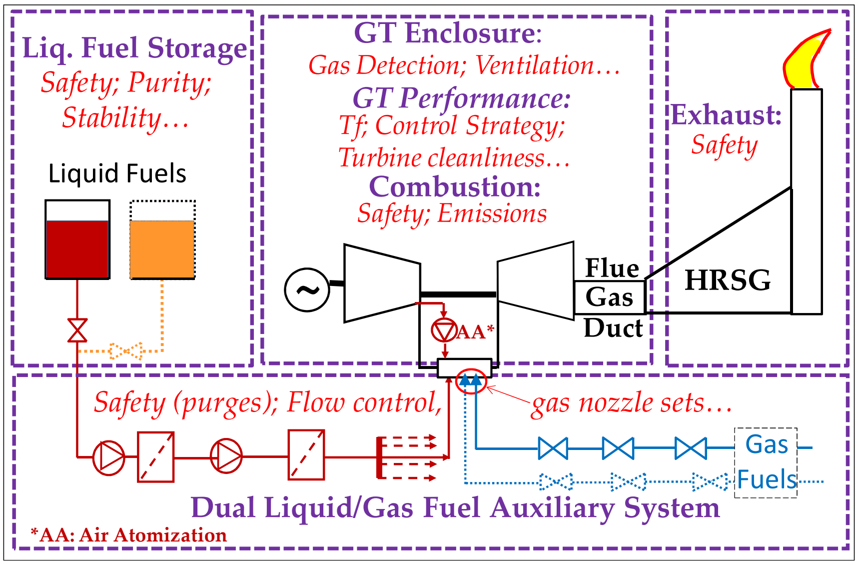


Figure 2. Sketch of a dual fuel GT unit (two gases; two liquids or one gas and one liquid).

Adding a second fuel needs not only a dual fuel system [6] but must also meet additional requirements, which are (i) performing successful fuel changeovers [40]; (ii) keeping operation safe; (iii) protecting machine integrity; and (iv) staying emission compliant. All these four aspects deserve specific considerations.

2.3.1. Reliable Operation with Dual Fuel Systems

Gas turbines are generally qualified as "dual gas" when they burn two gases and "dual fuel" when they burn one gas and one liquid. However, "dual fuel" is also a generic terminology to designate the capability to burn two fuels, regardless of their physical states.

- Dual Gas Systems

An essential datapoint for the reliable and safe combustion of any gaseous fuel is its "Wobbe Index", and more precisely, its "Modified Wobbe Index", which governs the sizing of the gas fuel system [41] and more generally the interchangeability of gas fuels in industrial and domestic applications [42]. These indices are defined as follows:

$$\mathrm{WI} = \mathrm{LHV}/\mathrm{SG}^{0.5} \tag{1}$$

$$\mathrm{MWI} = \mathrm{LHV}/(\mathrm{SG}^{0.5} \times \mathrm{T_g}^{0.5}), \tag{2}$$

where SG is the specific gravity of the fuel (a dimensionless property, independent of the temperature) and T_g its absolute temperature (Kelvin). The MWI decreases when the temperature increases.

The MWI is a key datapoint to properly manage the use of different fuel gases in a given piece of combustion equipment. Indeed, the calorific power being transported by the gas, which determines the power output of the GT, is a function of (i) its MWI; (ii) the nozzle pressure drop (i.e., essentially the gas feed pressure); and (iii) the total section area of the set of orifices of the gas nozzles (i.e., the diameter and number of these orifices).

Since the gas feed pressure is limited in a certain range, and the geometry of the nozzle orifices is fixed for a defined hardware, if the MWI of the alternative gas differs too much from that of the first gas, there is a need to add secondary nozzle caps with suitable orifice diameters. Incidentally, the combustor plates of gas turbines are large enough to allow for such additions, which is an advantage of GT construction. More specifically, a sound engineering practice recommends limiting the MWI variations to ±5% for a given set of gas nozzles as a measure to avoid any damage of combustor subcomponents [43,44]. Indeed, the nozzle pressure drop is proportional to the kinetic energy of the injected gas; thus, for a given nozzle set, setting the MWI around a defined value and controlling the gas pressure keeps the flame at a suitable distance from (i) the gas nozzle tip and (ii) the end portion of the combustion chamber, namely, the transition pieces. The MWI also conditions both the aerothermal patterns and the heat release process; it consequently affects flame stability and thermoacoustic activity [45,46].

When the MWI numbers of two gas fuels differ by slightly more than 5%, it is possible to reduce this difference by heating the higher calorific gas. If, for example, the MWI gap is 6%, the necessary temperature increase, ΔT_g, given by Equation (2), will equal:

$$\Delta T_g = 2 \times T_g \times \Delta(\mathrm{MWI})/\mathrm{MWI} \approx 2 \times 300 \times 0.06 = 36\ \mathrm{K}.$$

More generally, one will use a dual-gas system, which consists of a set of double-gas nozzles and possibly two gas manifolds and two sets of gas valves (Figure 3) [47].

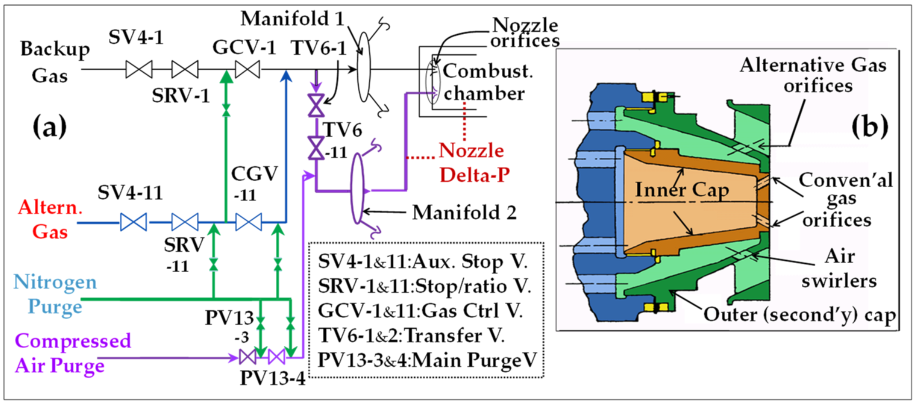


Figure 3. (**a**) Typical dual gas system; (**b**) double set of gas nozzles [47].

- Liquid Fuel (LF) Systems [39]

The high-pressure portion of the LF circuit is fed by a low-pressure forwarding circuit. It comprises a positive displacement HP pump, the flow rate of which is adjusted by recirculation through a by-pass valve. In some designs, a mechanical device called "flow divider" is used to distribute equal fuel flows to all combustors; they can be of the linear type, as represented in Figure 4, or circular.

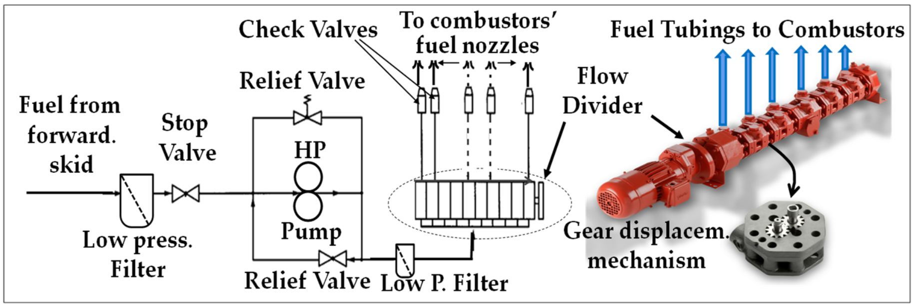


Figure 4. Simplified diagram of liquid fuel line.

Some atomization air is bled from the GT compressor and boosted by an auxiliary compressor to have the liquid fuel finely sprayed into the combustor and to suppress soot formation [48].

Virtually all liquid fuels, including biodiesel but excepting alcohols, have relatively close heating values; this dispenses from changing the fuel accessories and the fuel injectors when passing, for instance, from a naphtha to a No.2 distillate fuel.

Viscous LFs can be heated (in the upstream low-pressure section) to reduce their viscosity and enable their proper atomization into the combustors, thus preventing smoke emissions [39]. However, the heating temperature must not exceed the incipient pyrolyzing temperature of the fuel, which depends on its composition, the usual maximum being 130–140 °C [43].

Conversely, some light liquids (naphtha, alcohols) are low-viscosity fuels and have poor "lubricity", a property which is evaluated via the "HFRR test" [49,50]. If it is insufficiently "lubricious", dosing a lubricity improving additive may prove necessary.

2.3.2. Ensuring Operation Safety

- Essential safety measures

As indicated in Figure 2, GT enclosures must be equipped with adequate ventilation and fuel leak detection systems, as well as CO_2 inerting systems in emergency case.

The essential safety data for fuels are (i) the lower and upper explosion limits (LEL-UEL), the LEL being the critical datum; (ii) the autoignition temperature (AIT); (iii) the minimum ignition energy (MIE); and, for liquids, (iv) the boiling point and (v) the vapor pressure (measured at e.g., 38 °C) [51]. The LEL of gas or vapor mixtures can be estimated by Le Chatelier's law in the absence of inert compounds [52] and based on empirical models in presence of inerts [53]. It is mandatory to verify that the installed gas detectors fit with the vapors of the fuel being burned [54,55]. The prediction of the AITs of gas mixtures in GT conditions, i.e., at elevated temperatures and pressures, is a complex subject on which interesting progress is nevertheless being made thanks to Artificial Intelligence [56].

In the case of a dual gas machine, a gas changeover is preceded by a purge of the fuel circuit using compressed air extracted at the GT compressor discharge. Since this compressed air is hot, nitrogen is used instead for purging if the gas has a low AIT or MIE. This point will be revisited when dealing with hydrogen applications. Similarly, before transferring from a volatile liquid to a gaseous backup fuel, and vice versa, a purge of the liquid fuel line by a light distillate is performed to avoid uncontrolled flash vaporization of the volatile liquid. In case of leaks, LPGs (butane/propane) and volatile fuels (naphtha/NGL) can generate hazardous liquid pools and vapor clouds that are denser than air and may stagnate at low points [57], requiring highly sensitive vapor detectors [55].

As far as product and operational safety is concerned, an international safety standard (ISO 21789:2022) has been developed at the initiative of the UK HSE and implemented in the late 2000s to facilitate the integration of some recent EU regulations in GT designs, especially the Explosive Atmosphere (ATEX) and Pressure Equipment (PED) Directives. This ISO standard has been updated in 2022 [58].

- Safe Fuel temperature range

If the alternative fuel is a volatile liquid, it is a sound engineering practice to keep its temperature at about 56 °C below its bubble point to prevent vapor locks and the associated risk of pump cavitation, which is conducive to uncontrolled or hazardous operation. It is the case with naphtha, gas condensates (GC), or "natural gas liquids" (NGL) [59]. This measure is illustrated by Figure 5.

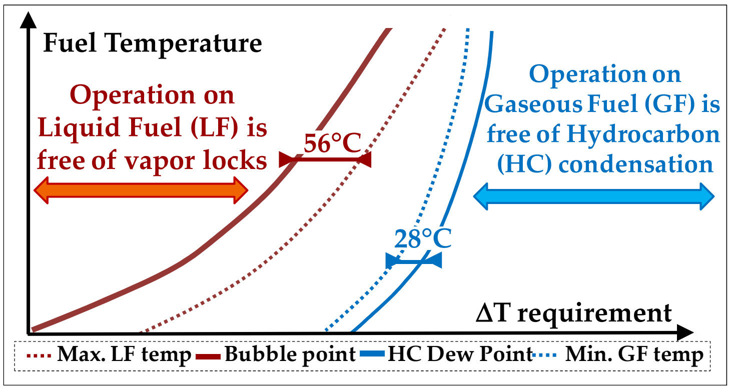


Figure 5. Safe temperature ranges for volatile liquids and condensable gases.

Conversely, if it is a partly condensable gas, then its temperature must be brought to about 28 °C above its dew point [43] to prevent the occurrence of a "blowpipe effect" that would devastate the combustors and possibly some turbine parts. This would occur if one were to burn incompletely vaporized LPG or a C_{3+} rich natural gas.

2.3.3. Staying Emission Compliant

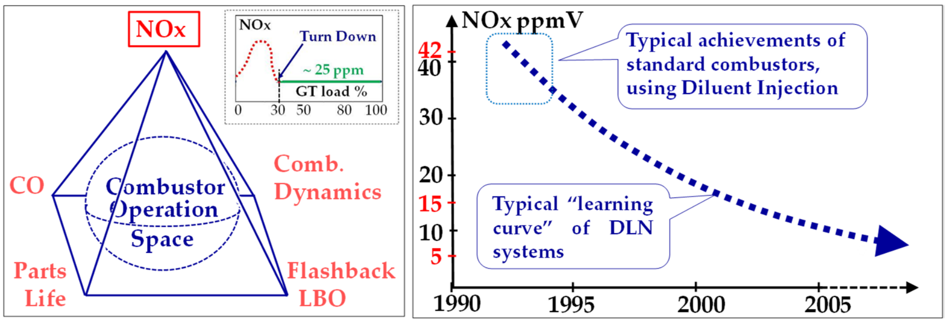
Emission compliance is now mandatory worldwide, whatever the fuel burned.

SOx emissions and "organic" NOx emissions (generated by the fuel-bound nitrogen) are directly related to the sulfur and nitrogen contents of the fuel, respectively; these must be kept below appropriate levels. Flue gas desulfurization or "DeSOx" post-combustion technologies exist [60,61], but they are expensive and reserved in practice for boilers as they entail elevated pressure drops at equipment exhaust and GT performance penalties.

As pointed out above, gas turbines release minute CO, UHC, and smoke emissions, even with difficult fuels, including highly aromatic by-products, which will be discussed later.

Due to the firing temperature and pressure developed in their combustors, GTs tend, however, to generate high thermal NOx when they operate with diffusion flames, which is the historical combustion mode of these machines; each fuel has an own NOx index that depends on its composition and is approximately an exponential function of its (adiabatic) stoichiometric combustion temperature, "$T_{ad,st}$" [62]. This must be carefully considered when envisaging an alternative fuel [63,64].

To reduce the NOx emission, up until the late 1980s, OEMs applied a "wet control", which consisted in injecting a diluent (most often liquid water or steam) in the combustors to reduce the temperature peak ($T_{ad,st}$) in the flame. However, major developments conducted in the 1980s–90s in combustion laboratories led to the design of inherently-low-NOx systems that prevent GT users from injecting any diluent or installing expensive post-combustion DeNOx systems when burning natural gas. The solution, referred to as "Dry Low NOx" (DLN) (or "Dry Low Emissions", DLE) technologies, is based on the combustion of premixed gas/air mixtures [65–68]. Successful DLN designs must overcome a set of complex difficulties, namely, (i) avoiding lean blowouts (LBO) and flashbacks; (ii) containing CO emissions; and (iii) controlling combustion dynamics [69] while (iv) keeping hardware durability (Figure 6a).



(**a**) (**b**)

Figure 6. (**a**) Operation boundaries of DLN systems; (**b**) typical historical progress in NOx emissions on natural gas.

Flame flashbacks possibly occur according to different mechanisms: by autoignition in the premixed zone due to a too-low AIT of the fuel or combustion instabilities (combustion dynamics); and by retro-propagation in the core flow or through boundary layers [70]. Combustion dynamics are due to an interaction between unsteady aerodynamics and heat release fluctuation processes causing pressure oscillations that can resonate in the combustor cavities and cause mechanical wear/damage [71]. Since premixed flames have, by design, a narrow lean richness range, they are more sensitive to dynamics than diffusion flames that have broad richness ranges with lower risks of simultaneous extinction of all points of the flame front.

A typical evolution of NOx control is outlined in Figure 6b. Ongoing efforts are being made with success to improve the operability of DLN systems, namely, in two directions: (i) expanding the range of emission compliance to lower GT loads, the so-called "Minimum Emissions Compliance Load" (MECL) or, more simply, the "Turn Down" (see inset in Figure 6a); and, as regards fuel flexibility, (ii) extending the capability of those systems to non-NG fuels by improving the aerothermal patterns of the combustors to counteract the adverse combustion effects described above [72].

Regarding low NOx systems for liquid fuels, it must be noted that C_{5+} hydrocarbons have low AIT data as compared, e.g., to methane. Therefore, "Dry Oil NOx" systems are very challenging to design for trouble-free operation. For some alternative fuels, the sole option is therefore to inject a diluent (most often liquid water or steam) in the combustors to reduce the temperature peak in the flame and correlatively the emission of NOx.

2.3.4. Ensuring Machine Integrity

The design and operational measures covered in Sections 2.3.1 and 2.3.2 enable the avoidance of defective combustion and associated component damages in dual fuel configurations. However, many alternative fuels contain impurities. Some of them (e.g., coke oven and blast furnace gases: COG; BFG) contain inorganic particles that must be removed by proper filtration as they can inflict severe erosion to turbine parts [43]. Some others contain sulfur (e.g., sour natural gases) leading to polluting SOx emissions. Finally, some liquid fuels (crude and residual oils) contain both sulfur and traces of alkaline metals (Na, K) and vanadium (V), leading to corrosive, low-melting point salts or oxides (mainly sodium sulfate: Na_2SO_4; and vanadium pentoxide: V_2O_5) [73]. Reference [41] gives a comprehensive review of the adverse effects of fuel impurities on turbine parts and the corrective pretreatments, including filtration, desalination, and corrosion inhibition.

2.3.5. Measures Specific to the Operation on Hydrogen-Rich Gases

Additional measures relating to the combustion of hydrogen taken to suppress the risk of hot parts overheating and material embrittlement will be addressed in Section 4.

3. Creation and Growth of the Fuel Portfolio

3.1. General Overview

Since the 1960s, land-based gas turbines have gradually occupied a wide space of alternative fuels [37,38,74–78]. Figure 7 gives a synoptic view of the current extension of that fuel portfolio.

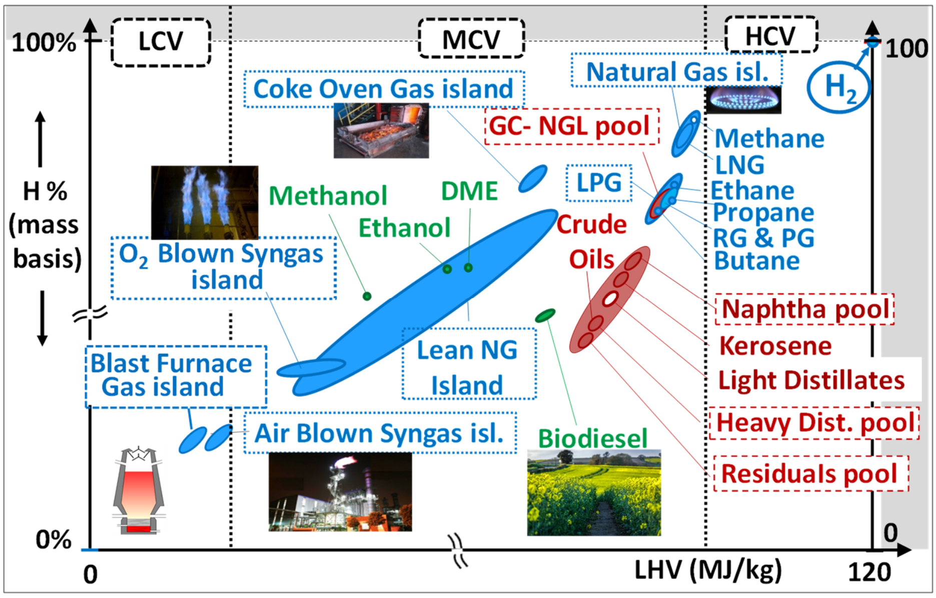


Figure 7. Current extension of the gas turbine fuel map.

To be able to bring together both gaseous and liquid fuels in a same chart, the chosen ordinate is the mass percentage of hydrogen, the abscissa being the mass LHV. Since the dihydrogen molecule has both the highest mass LHV (120 MJ/kg) and contains, by definition, 100% elemental hydrogen, it occupies the top right corner of that chart.

Table 1 lists most of these fuels along with the following data: (i) their origins; (ii) the acronyms used in this paper; (iii) their gaseous/liquid state; and (iv) their level of purity, namely, their ash-free or ash-forming character. This table also includes the two conventional fuels (natural gas and light distillate).

Historically, the acquisition of this portfolio started from pipeline NG and LD and has been a gradual process that took place over several decades. The additions of the different fuels generally were/are in response to specific demands from industrial actors. The most frequent opportunities are related to by-products of industrial processes available in substantial volumes. These come from multiple economy branches: the oil and gas, petrochemical, and metallurgical sectors; the processing and gasification of coal, of biomass or even municipal solid wastes.

The plants in demand typically generate streams of combustible by-products that have valuable energetic potentials but were previously either wasted—e.g., by flaring—or used in few profitable applications, until more cost-effective usages became feasible [79]. Conversion to heat and power is one of them: thermal power is generally used to cover domestic needs (chemical, petrochemical, or food processes), while the electric power is intended for self-consumption and sometimes for export.

Table 1. List of alternative GT fuels, along with conventional NG and LD [78].

Economy Branches	Origin Process	Fuel Name	Acronym	State (L/G)	Main Features	Ash-Less or Ash-Forming
	Extraction	Crude oil				
		Liq. Petr. Gas				
		Naphtha				
		Kerosene				
Oil Production & refining	Distillation	Light Distil'te	CO	L	Light to Heavy	AL
		Heavy Dist'te				
		Heavy Oil	LPG	L/G[1]	HCV[2]	AL
	Catalytic Cracking		-	L	Volatile	AL
		Light Cycle oil	-	L	Ultra Pure	AL
		Ref Fuel Gas	LD	L	Conventional	AL
			-	L	Liq.	Slight. AF
			HFO	L	Viscous	Strong. AF
					Impurities	
			LCO	L		AL
			RFG	G	Aromatic	AL
					H_2 & C_n	
Gas Exploration & processing	NG extraction	Natural Gas				
		Gas Cond'sate	NG	G	Rich/weak/Soft/sour	AL
	NG reforming	Nat. Gas Liq	GC	L	Light to heavy	AL
		Hydrogen	NGL	L	Low viscosity	AL
			H_2	G	Highly flamm.	AL
	Coal mining					
Coal Mining & Processing	Coal gasification	Coalbed gas	CBG	G	LCV[3]	Slight. AF
		Syngas	SG	G	MCV[4]/LCV	AF
		Substitute NG	SNG	G	MCV/LCV	AL
		Methanol	MeOH	G	Highly volatile	AL
		Hydrogen	H_2	G	Highly flamm.	AL
	Coal pyrolysis					
Metallurgy	Metal oxide reduction	Coke Oven Gas	COG	G	MCV	AF
		Blast Furnace Gas	BFG	G	LCV	AF
	Naphtha Cracking					
Petrochemistry	Aromatisation	Olefin-rich Pet. Gas	PNG	G	Var. olefin %	AL
	Butadiene unit		PNG	G	Var. H_2 content	AL
		H_2 Pet Net G.				
			PNG	G	Var. C_3 & C4%	AL
		C_3/C_4 Pet Net G				
Farming	Aerobic fermentation	Biogas	BG	G	Var. N_2-CO_2%	AL/sligh AF
			BD			
Biomass	Vegetables processing	Biodiesel	EtOH	L	Analog. to LD	AL
		Bioethanol	DME	L	Analog. to naph	AL
		Dimethyl Ether		L	Analog. to LPG	AL

Historically, the beneficiation options involved the combustion of these by-products in utility boilers, but more efficient GT-driven cogeneration units gradually displaced these boilers. This displacement began around the 1970s in the USA, where GT started their brisk development (with efficiencies reaching then exceeding 25%), then roughly in the 1980s in Europe and during the 1990 s in Asia. It was accelerated by emerging regulations encouraging cogeneration as a virtuous tool for improving energy effectiveness [80].

Recently, gaseous and liquid biofuels, resulting from the processing of a wide variety of biomass feedstocks, have emerged as potential GT fuels. The reference [81] offers a thorough technical coverage of the raw materials and processing technologies that are currently involved in the production of biofuels.

Before a given candidate becomes "entitled" as an actual alternative GT fuel, it must pass rigorous analyses and lab combustion tests, but subsequent pilot field tests are also highly advisable. These tests became increasingly focused on emission compliance due to the rise of environmental regulations worldwide. In the 1970s, the first USEPA recommendations—the so-called Clean Air Act—began setting a NOx emission limit of 75 ppm to fight against the episodes of "smogs" in big cities and enforced more stringent limits (42 or 25 ppm) in critical "non-attainment areas" (California, Texas) [82]. Since DLN technologies were industrially available only in the early 1990s (see Section 2.3.3), DeNOx was formerly achieved in GTs by steam injection. To that end, medium-pressure steam was extracted from the heat recovery steam generators. Resorting to the SCR (Selective Catalytic Reduction) technology was necessary to reach the lowest NOx codes [83].

When the pilot tests of an alternative fuel candidate prove successful, they result in "win–win" opportunities for both the requesting industrial partner and the GT OEM. Sometimes, it becomes the starting point for a closer relationship. For instance, the power generator Groupe E (formerly ENSA), which has its headquarters in Neuchatel (Switzerland), has greatly contributed to the successful testing of several alternative fuels [84–86].

3.2. The Gas Fuel Portfolio

Figure 8 illustrates the way the map of gaseous GT fuels has been extending over the years. The MWI Index (Equation (2)) has been taken as ordinate and the mass LHV as abscissa. In this new representation, hydrogen has the highest mass LHV and lies on the right borderline while butane has the highest MWI and marks the higher boundary.

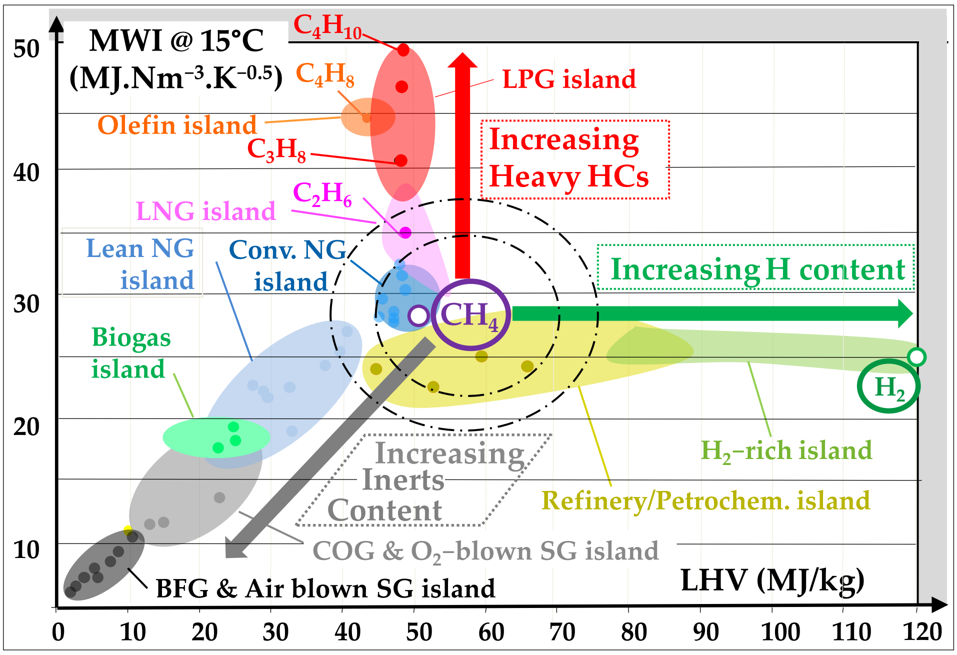


Figure 8. Expansion of the gas fuel map towards miscellaneous by-product gases.

Fuel gases can be classified as HCV fuels (having LHV ranging from 50 to 120 MJ/Nm^3), MCV (11 to 50 MJ/Nm^3) and LCV ones (below 11 and possibly down to 3 MJ/Nm^3). It is worth mentioning that this classification is not an absolute one as some GT OEMs use different scales.

In addition, this classification would change if one would consider mass-based LHVs instead of volume-based ones: for instance, hydrogen would pass from the LCV to the HCV category since its LHV is 120 MJ per kg but hardly 11.7 MJ per Nm^3.

Since the 1960s, the sphere of gaseous GT fuels has been expanding, starting from the historic "island" of natural gas, which consists essentially in methane and traces of C_{2+} hydrocarbons. It currently embraces HCV, MCV, and LCV gases. The backup fuel is generally a light distillate.

The expansion of this gas portfolio has occurred in three directions: towards higher and lower calorific fuels and higher hydrogen contents.

- Expansion towards high-calorific fuels:

  This family includes the following products:

  - Commercial LPGs (propane, butane, and mixtures thereof) mainly come from the processing of NG and the atmospheric distillation of crudes. They are generally burned after vaporization. Their combustion in variable amounts in GTs is interesting as it allows matching the offer to the demand of LPGs namely in summer [87];
  - Refinery fuel gases (RFG) [88] as well as petrochemical net gases (PNG) [87–90] mainly contain C_2 to C_4 alkanes and/or olefins, in addition to variable amounts of H_2; they stem from fluid catalytic cracking (FCC) or steam catalytic cracking (SCC) units. They are produced continuously and yield high GT performances.

- Expansion towards low-calorific fuels:

This family involves gaseous streams in which the combustible species (mainly CH_4, CO, and H_2) are diluted by elevated amounts of N_2, H_2O, and/or CO_2. Their main representatives are the following:

  - "Lean natural gases" stem from some NG wells or coal mines and contain CH_4, N_2, and CO_2 [37]; they are medium- or low-BTU fuels; their combustion after compression is interesting if the sale of the kWhs exceeds the cost of compression that is only partly compensated by the extra power produced by the expansion in the turbine;
  - Biogases are produced in breeding farms or in landfills; they can be cleaned (H_2S removal) and burned in microturbines to cover power self-consumption; recently, they have been transported and injected in natural gas networks [91–94];
  - Coke oven gases (COG) come from the pyrolysis of coal for the preparation of metallurgical coke and contain H_2, CH_4, CO, CO_2, and H_2O. They contain dusts that must be filtered and tars that must be removed by condensation/water scrubbing [95–97].
  - Air-blown syngases (SG) are very lean gases which contain mainly CO, N_2, H_2O, and H_2 and come from the gasification of coal/lignite [98–102], or biomass [103–105], or even solid municipal wastes [106–108]; oxygen-blow gasification is applied to very difficult solids (HFOs and bituminous coals) and yield syngases with higher LHVs [101]. Syngases from coals and HFOs must undergo drastic clean-up processes to remove particles, sulfur, nitrogen, and heavy metals;
  - Blast furnace gases (BFG) are also lean fuels and are loaded with high concentrations of CO_2 and H_2O; due to their high level of dust, they also need very efficient clean-up facilities before injection in GTs [109–111].

- Expansion towards higher H_2 contents:

Both steam cracking and aromatization units in petrochemical and refineries release gaseous byproducts that contain variable amounts of hydrocarbons and hydrogen. These streams are gathered in a gas network and are called "fuel gas" or "net gas"; they are used as secondary energies in the plant utilities equipped with gas turbines. The amount of H_2 can reach 70% or even 95%: this point is important and will be brought up again when dealing with the development of the hydrogen economy.

3.3. The Liquid Fuel Portfolio

Figure 9 shows a map of most popular alternative liquids, which can be split into fossil and biogenic products. The (non-linear) ordinate of this chart is the hydrogen content. Biofuels have, in general, lower calorific value and do not have higher hydrogen contents than fossil fuels, both points being due to the presence of oxygen atoms in their molecules.

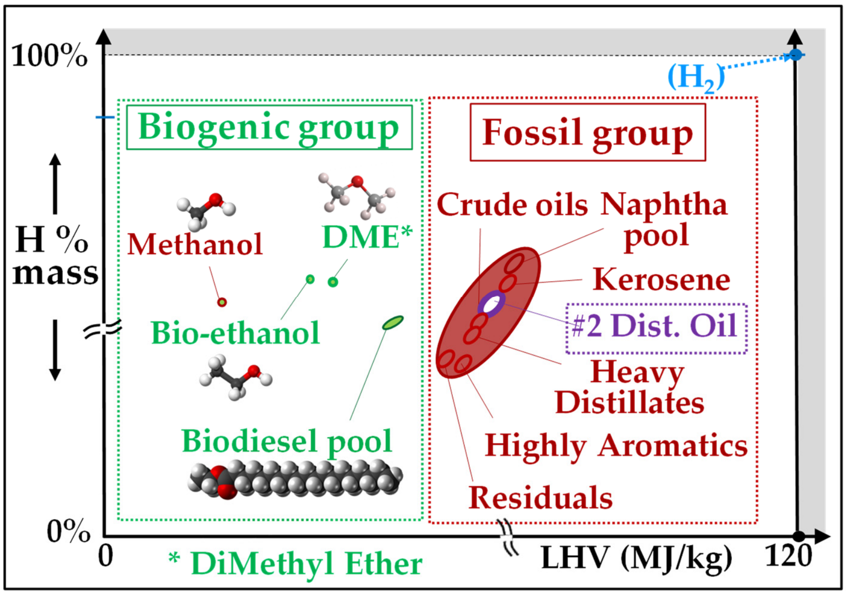


Figure 9. Map of fossil and biogenic liquid fuels.

3.3.1. Fossil Liquids

The overwhelming majority of fossil liquids stem from O&G production, oil refineries, and, to a lesser extent, from petrochemical plants. A sketch of a typical natural gas chain is given in Figure 10 and a diagram of a modern refinery in Figure 11.

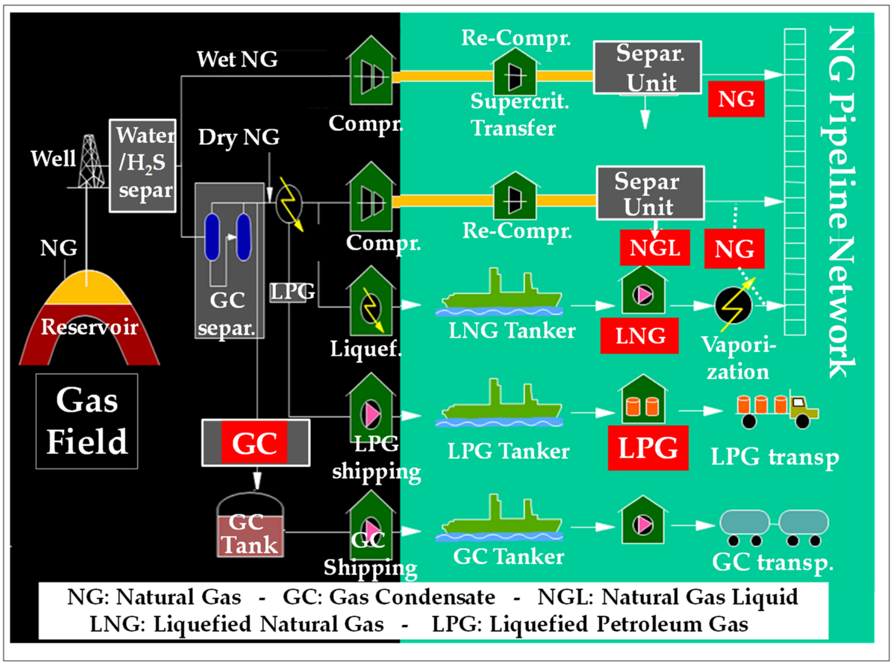


Figure 10. Sketch of a natural gas chain involving NG, LNG, NGL, and LPG products.

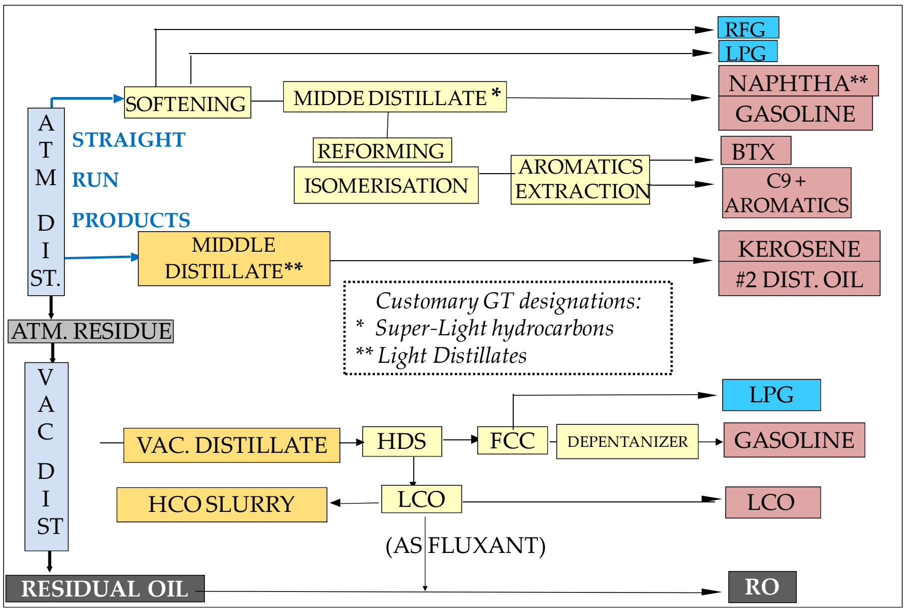


Figure 11. Typical oil refining diagram (gases are in blue; liquids in brown and black).

Fossil liquids can be categorized according to their volatility and aromatic character:

- “Super-Light Distillates” (SLHCs) include three main products:
    - Naphtha’s that stem from the distillation of crude in refineries;
    - Gas condensates (GC) that come directly from gas fields (Figure 10);
    - Natural gas liquids (NGL) that originate from the stripping of raw NGs [112].

  Naphtha and NGLs are high-grade, clean fuels and belong to the same refining pool as gasoline; they yield GT performances similar to those of #2 distillate oils. GCs are raw products that are mainly constituted by light hydrocarbons but can contain some heavy ends, such as light crudes. All require specific safety precautions, due to their high volatility, and the dosage of a “superlubricant” additive to make up for their low lubricity (see Section 2.3.1) [113]. Startups and shutdowns are made using a No. 2 distillate.

  Naphtha has been largely used as GT fuel in India and Pakistan, where there are surpluses of gasoline and shortages of NG. More generally, SLHCs are “bridging fuels” to natural gas or to LNG in regions with high development potential but a lack of NG resources or immature pipeline networks. Incidentally, we should note that naphtha is not named a “super light hydrocarbon” in the in the oil business but is instead categorized as a light distillate, like gasoline (Figure 11).

- Light distillates (LDs) are classified as “middle distillates” by the oil business. They consist of kerosene and #2 distillate oil; their use in GTs does not require the additives package that is necessary for aircraft and diesel cars. Kerosene’s and No. 2 distillate oils are “straight-run” refinery products that originate from the atmospheric distillation of crudes (Figure 11); they are prime-quality, expensive GT fuels. While No. 2 distillate is the conventional liquid fuel for heavy-duty GTs, kerosene is the preferred one for aeroderivatives in consideration of its still-higher purity. However, the expensive kerosene is generally used only on some rare islands where No. 2 diesel is not demanded as car fuel. Finally, another refinery cut called “light cycle oils” (LCOs) can be integrated in this group although it is of much lower grade; LCOs are not straight-run products as they come from the cracking of vacuum distillates (Figure 11) and are rich in aromatics and polyaromatics. Their possible use in gas turbines is described below in the paragraph devoted to aromatic fuels;
- Heavy distillate Oils originate from the vacuum distillation of crudes [87]. They are available from refineries that do not have “deep conversion” units; they must be burned after heating to reduce their viscosity for proper atomization;

- Crude oils are the raw hydrocarbons extracted from oil fields where they may be associated with C_1-C_4 gases (LPGs) or C_{5+} condensable gases (gas condensates). Their composition is variable as they can contain heavy hydrocarbon ends. Heavy crudes, especially those extracted in remote areas, do not interest refiners as they do not yield light cuts; they can be cleanly burned in GTs on the spots, using—if necessary—a combustion catalyst additive, e.g., cerium derivatives [114], to avoid a slight smoking trend;
- Residual oils (RO) are very-low-grade refinery cuts. These ash-forming fuels can no longer be distilled and represent the "bottom of the barrel". Due to their high SOx, NOx, and PM emissions, they are disappearing from the market, being converted into "pet-cokes" or gasified in oxygen-blown gasifiers to produce syngases (SG). Nevertheless, the combustion of HFOs in GT combined cycles generates significantly fewer polluting emissions than if using diesel engines. As mentioned in Section 2.3.4, both crudes and ROs need to be cleaned before combustion. Some low-sulfur waxy residual fuels, called "LSWR", have been used in the Far East (Japan, Korea, Singapore . . .) for power generation. Efforts have also been made to alleviate the adverse effects of smoke and ash deposition on the performances of gas turbines [114,115];
- Aromatic fuels belong either to the group of super light hydrocarbons ("BTX" and "C_{9+} aromatics") or to that of light distillates (Light Cycle Oil or "LCO"):
    - BTXs (Benzene–Toluene–Xylene) are C_6–C_8 mono-aromatics. Huge volumes are also used as petrochemical feedstock for the synthesis of a large variety of commodities, including polymers, paints, and solvents. They have also been used, along with "C_{9+} aromatics", as RON improvers for gasoline's, owing to the high AITs of aromatics. However, due to the ban of aromatics in automotive fuels, they may be produced in surpluses in refineries deprived of petrochemical units; moreover, the exportation of such sensitive cuts represents a financial burden and creates EHS difficulties that can lead refiners to envisage other usages. This is where on-site power generation becomes an interesting option. A stream of such aromatic hydrocarbons, called BHC (for "Benzene Heart Cut"), with a BTX composition, have been successfully tested in a 40 MWe heavy-duty GT [84]. Subsequently, based on this successful test, a C_{9+} aromatic cut found an industrial application in Korea [116];
    - LCO (light cycle oil) tends to be produced in increasing amounts in modern refineries. Indeed, fluid catalytic crackers ("FCC") crack heavy distillate feedstocks into lighter ones, thereby helping convert the original crude to more middle distillates and gasolines with higher RON indices. LCOs contain up to 70% aromatics (essentially in the form of di-aromatics). Their very poor cetane number and high smoking propensity strongly limits the proportion that can be added to diesel fuels and to domestic heating oil. In contrast, the combustion of LCO has been successfully tested, also in a 40 MW heavy-duty GT [84,85].

3.3.2. Liquid Biofuels

Liquid biofuels represent a prolific and promising family. Figure 12 summarizes the different production processes starting from vegetable biomass. The most popular liquid biofuels belong to three main groups: alcohols (bio-ethanol); vegetable oils (VO), and biodiesels.

The combustion of liquid biofuels in gas turbines is not a new topic but its interest has been renewed in the late 2000s, as energy decarbonation became an increasing concern [117–124]. However, both bioethanol and biodiesel are currently produced from edible substances: the former comes from sugars, corn, or wheat starches and the latter from oil seeds. This "food versus fuel" competition has raised a legitimate debate [125].

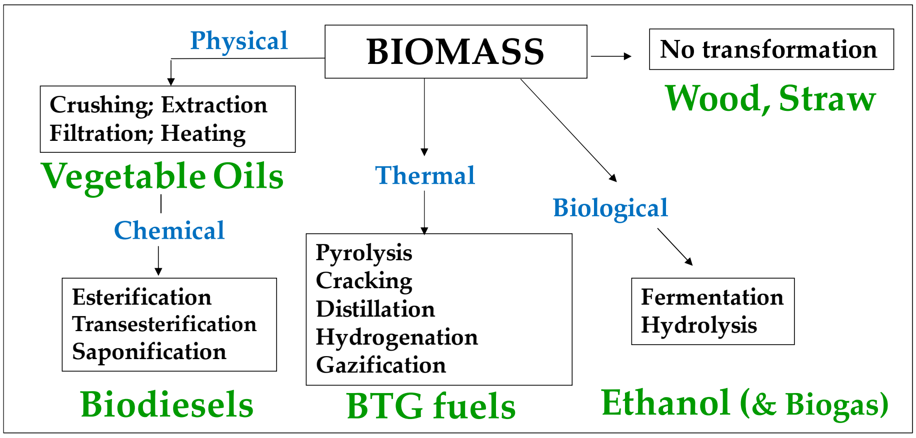


Figure 12. Simplified sketch of the various processes of biofuel production from biomass.

Since biodiesel and bioethanol are already used as blenders of diesel and gasoline car fuels, respectively, it looks reasonable to consider that their use for power generation, which consumes large volumes, should be reserved for small units.

- Bioethanol comes from the anaerobic fermentation of natural sugars (grape, sugar beet, sugar cane, etc.) (Figure 12) and are often produced in surplus in some agricultural sectors and some countries. Dehydrated ethanol is fully miscible with gasoline; this property has been exploited in a bioethanol combustion test that was carried out on a 20 MW GT in India and in which naphtha was used as starting fuel and gradually blended with increasing proportions of bioethanol, up to 95% [126]. This field test demonstrated that ethanol can be burned without any trouble with NOx emissions lower than those of LD and close to those of NG (Figure 13). Bioethanol from sugar cane has also been recently burned in a 40 MW GT at Saint Pierre de La Réunion (a French ultramarine territory), although this experience is not well documented [127].

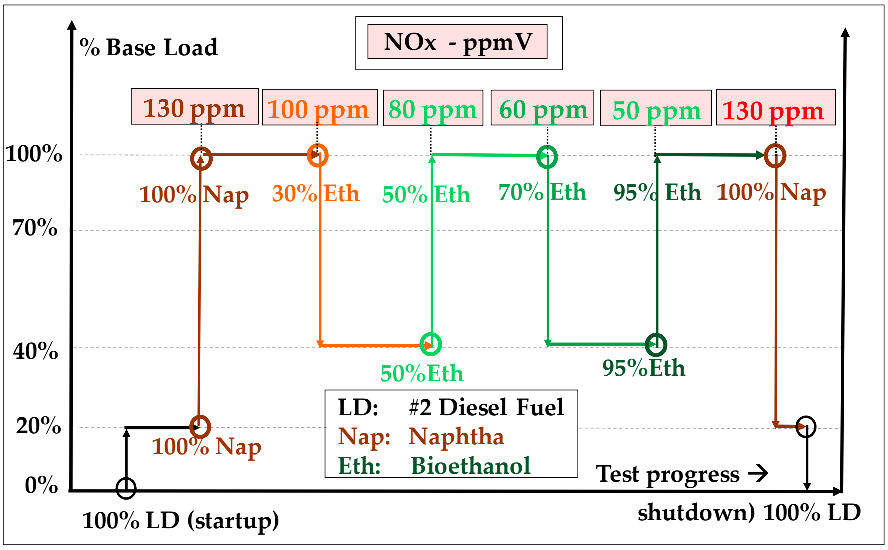


Figure 13. Summary of an Ethanol field test: ethanol/naphtha mixtures were used [126].

Brazil is the world leader for the production of bioethanol. The "first-generation" bioethanol is prepared from sugar harvested from cane fields ("first crop"). It is largely consumed as automotive fuel in Brazil, where the fleet of flex-fuel cars can accept up to E100 fuel (i.e., 0% gasoline). However, the "food versus fuel debate" has prompted the use of a "second crop" source of ethanol, which will exploit the lignocellulose contained in bagasse as raw matter [128]. Bagasse is the fibrous substance left after the juice of the sugarcane plant has been harvested; it will be processed in “ethanolic biorefineries” that will produce “second-generation biofuels” [129].

- Methanol was formerly prepared by the distillation/carbonization of wood (charcoal industry) and was named “wood alcohol”. However, currently, 98% of methanol comes from the reforming of methane and has thus a non-bio, fossil origin. It can also be produced through the coal-to-liquid or biomass-to-liquid (CTL/BTL) routes. It is a feedstock to produce FAME biodiesel, as discussed below. Kinetics simulations show that it could be burned in GTs [130]. However, its high vapor pressure (13 kPa at 20 °C) and acute toxicity are major obstacles for this application.
- Dimethyl-Ether

DME also originates from the CTL/BTL routes. It is gaseous at room temperature, with a vapor pressure of 5.10 bars at 20 °C. It has as some analogy with LPG as a potential fuel, as set out below, and has been used as domestic fuel in China. Kinetics simulations are also available [130] and a successful field test by British Petroleum on a 120 MW GT has been performed [131].

- Biodiesels

Biodiesels are “Fatty Acid Alkyl Esters” obtained by trans-esterification of vegetable oils (VOs) using methanol (FAME: fatty acid methyl esters) or, more rarely, ethanol (FAEE: fatty acid ethyl esters). VOs are sourced from a large variety of seeds (soybean, rapeseed, palm, coco (copra), corn, sunflower, cotton, peanut, sugarcane (bagasse), canola, etc.), depending on the world regions [132]. They have variable chain lengths and double bond numbers. This VO source is often complemented by triglycerides: “yellow greases” coming from recycled food wastes or even by animal fats (“tallow”).

Various biodiesel field tests were performed, namely, in 2007 in Switzerland on an E-class GT [86], in 2009 at Duke Energy Carolinas on an F-class G, and in 2021 at Göteborg Energi [133]. These field tests have demonstrated the excellent behavior of FAME biodiesels, including during “cold” and “hot” startups performed with 100% biodiesel, as shown in Figure 14. The inset in that figure sketches a typical molecule of FAME biodiesel with a single double bond.

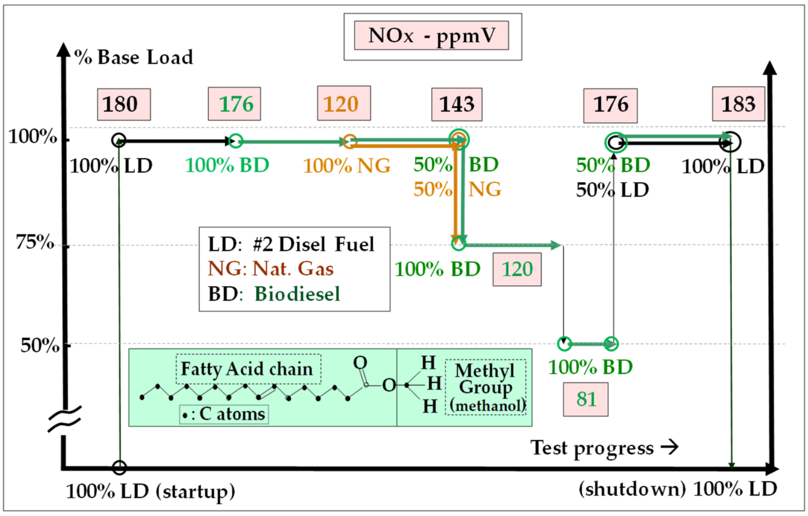


Figure 14. Summary of a biodiesel field test (inset: a typical biodiesel molecule) [86].

A question arose as to whether the thermal NOx indices of biodiesels, i.e., their combustion temperature “$T_{ad,st}$“ (see Section 2.3.3), are lower or higher than those of No. 2 distillates. Both field test results and detailed kinetic simulations showed that the values of $T_{ad,st}$ are always slightly lower for FAMEs than for hydrocarbons with the same degree of insaturation (alkanes, alkenes, trienes, alkylaromatics), irrespective of the chain length (Figure 15) [134]. This point is interesting as it contrasts with the results obtained for some diesel engines, in which another physical process prevails, which is the higher compressibility bulk modulus of biodiesel that alters the ignition time and tends to increase NOx [135].

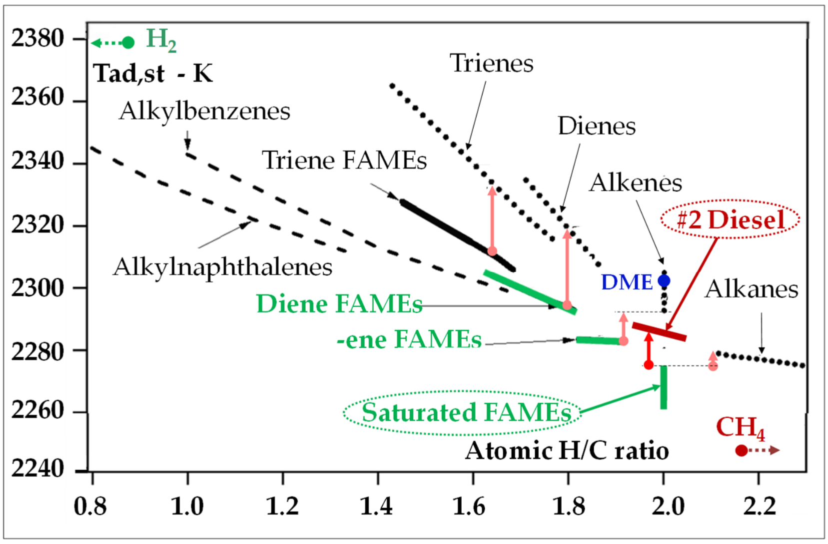


Figure 15. Flame temperatures of some organic molecules in function of the H/C ratio.

- Vegetable Oils

So far, VOs have not been entitled as GT fuels, the main reasons being (i) their high viscosity and the risk of chemical degradation by pyrolysis when heating them to make them more fluid; and (ii) their content of metallic contaminants (K and Ca) that often exceed GT fuel specifications (Section 2.3.4) and cannot be completely extracted by water-washing as they are partly oil-soluble, which makes their removal difficult.

3.3.3. Similarities between Biofuels and Fossils

As regards gas turbine applications, there are some interesting commonalities between biogenic and fossil fuels (Table 2).

For instance:

- Bioethanol versus naphtha: Anhydrous ethanol is fully miscible with naphtha, i.e., with gasoline. This is interesting in countries such as India where naphtha is often used as base-load GT fuel due to the scarcity of natural gas and distillate fuels and, on another hand, the fact that bioethanol is available through the fermentation of discarded cotton [136];
- Biodiesel versus light distillate: Biodiesel is fully miscible with light distillate oils, i.e., with diesel fuels. It is more lubricious than diesel fuels but, due to its higher power as solvent, it can be aggressive against certain elastomeric seals used in fuel circuits;
- Vegetable oils versus crude oils: VOs are partly miscible with crude oils [137] and have several similarities with them: both are unprocessed liquids that contain long molecules with many chemical functions and are contaminated with metals. However, there are important differences. Indeed, contrary to crude oils, vegetable oils contain no heavy metals (vanadium, nickel) and very little sulfur and nitrogen; their metallic contaminants are partly oil-soluble and, when they are heated, they do not distil but tend to degrade more rapidly than petroleum cuts by pyrolysis. For these reasons, VOs are not currently used as a GT fuel; they can be burned in boilers with some precautions due to the generation of corrosive low-melting point salts (potassium and calcium chlorides).

Table 2. Similarities between biogenic and fossil fuels.

Biofuel	Similar Fossil Fuel	Commonalities	Differences (Bio Versus Fossil)
		GASES	
Biogas (raw)	Weak Natural Gas (raw)	- Comparable values of %C1 & WI	- Higher CO_2 & H_2S contents - siloxane contaminants
		LIQUIDS	
DiMethyl-Ether (DME)	LPG	- High Vapor pressure - High vapor density	- Narrower distillation range - burned as liquid (LPG as gas)
Bioethanol-(biomethanol)	Naphtha - Gasoline	- Intermiscible - Good purity - Highly volatile - Poor lubricity	- Narrower distillation range - Lower NOx emission
Biodiesel	Light Distillate Fuel (#2 DF)	- Intermiscible - Good to fair purity - limited volatility	- Better lubricity - Aggressive to gaskets
Vegetable Oil (VO) *	Crude oils	- Wide distillation range - Partly intermiscible - Metallic impurities - Highly viscous	- No light hydrocarbon - No aromatic species - Less heat resistant - oil soluble contaminants

* Not considered a GT fuel.

4. The Contribution of Gas Turbines to the Hydrogen Energy Move

Hydrogen is an energy carrier and not a primary energy as there are very scarce natural sources thereof; the rare reservoirs of hydrogen originate from chemical reactions inside the earth crust and are sometimes referred to as "natural H_2"or "white H_2" [138].

4.1. The "Hydrogen Rainbow"

The main supply of hydrogen is currently from fossil fuels via two main routes which are (i) the steam reforming of natural gas that yields "grey" or "blue" H_2, depending on whether the resultant CO_2 is captured or not; and (ii) the gasification of coal which leads to "black" (or "brown") H_2. These processes are very energy intensive. However, an increasing number of projects are conducted or planned to produce H_2 by the electrolytic splitting of water into H_2 and O_2, using either solar power ("yellow" H_2), wind/hydro power ("green" H_2), or nuclear power generated during off-peak hours ("pink" or "purple" H_2). There are in fact numerous approaches under investigation to produce hydrogen, resulting in the so-called "H_2 rainbow" (Figure 16) [139].

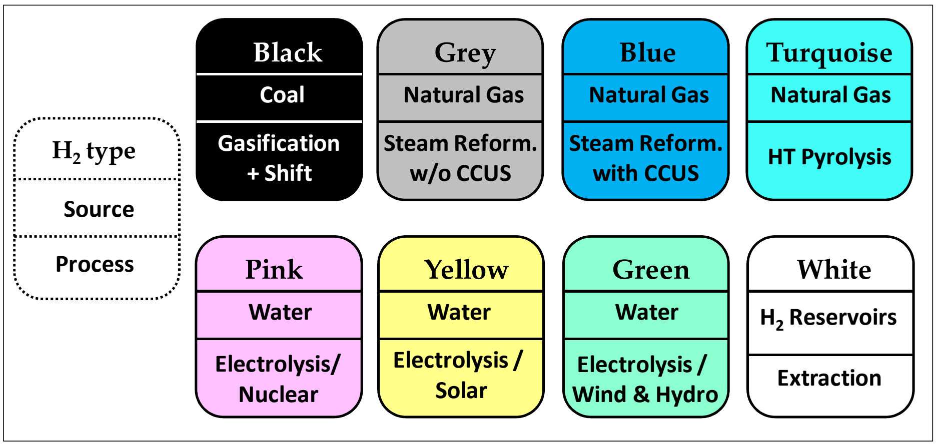


Figure 16. The "H_2 rainbow": the various types and production routes of dihydrogen.

The development of hydrogen as an energy vector must deal not only with its production, but also with the delicate development of all the infrastructures that are required for its storage and transportation, as well as its conversion into power or its adaptation to cars. This vast theme, along with the associated feasibility and safety aspects, fall by far beyond the scope of the present paper. This set of topics generates an exponential number of publications. Extensive information is available from different sources, namely, from the EU commission [140], the USDOE [141], or the UK government [142].

The advent of hydrogen of the green, yellow, or pink type as a universal substitute for fossil fuels would procure a dramatic solution to some critical environmental problems. Indeed, it would provide not only the sought route towards carbon-neutral economies but also a radical solution to endemic urban pollutions by suppressing all emissions of VOCs, CO, SOx, O_3, PAH, and soot particles.

However, the development of the "hydrogen economy" must overcome several technology challenges since, apart from high R&D investment needs, hydrogen has critical physical and chemical properties which impact the safety of its entire application chain, i.e., its production, storage, transportation, and end usages. With regard to the performance and the safety of combustion, hydrogen features a set of challenging properties, which are as follows: a wide flammability range; a high diffusivity with metallurgical impacts on materials; and a very-high flame speed and low ignition energy. In this respect, Table 3 shows a comparison between hydrogen and methane [143,144].

Table 3. Compared combustion properties of hydrogen and methane.

DATA – FUEL	**No of Molecules of Combustion Products**	**LHV Mass MJ/kg**	**LHV Volume MJ/Nm^3**	**Diffusion Coefficient 1 atm; 25 °C – 10^{-6} m^{2}s^{-1}**	**LFL – UFL Low/Up. Flam. Lim. – % vol**	**Lamin. Flame Speed – cm.s^{-1}**	**Min. Ignition Energy – mJ**
H_2	1 (H_2O)	120	10.7	7.9	4.0 - 75	265	0.018
CH_4	3 (CO_2 + 2 H_2O)	50	35.8	0.2	5.0 - 15	33	0.033

4.2. The Possible Role of Gas Turbines

As discussed below, gas turbines can burn both pure and blended hydrogen and, as discussed above, they boast high energy effectiveness in combined cycles as well as fast installation. Therefore, these machines are placed in the front of the energy scene, as they are in position to boost the deployment of hydrogen energy in the power generation sector. Figure 17 shows a possible energy system involving gas turbines: green, yellow, or pink hydrogen is produced in electrolysis "power-to-gas" units fed by wind, PV, and nuclear plants; it is partly used as an automotive fuel and partly mixed with NG (and possibly with some carbon-neutral biogas streams) in gas networks which, in turn, feed "gas-to-power" GTCC nodes (or large Fuel Cell units) [145].

Energy wise, H_2 is also a very singular fuel since; on one hand, it has a weak volume LHV (10.7 MJ/Nm^3) that would place it in the category of LCV gases; however, on the other hand, it boasts the highest mass LHV (120 MJ/kg) of all fuels [146].

Moreover, NOx emissions pose a serious challenge due to the addition of two effects:

- Hydrogen flames are very hot (Figure 18a) [147]. Indeed, one molecule of H_2 generates three times less molecules of combustion products than does CH_4 (Table 3); therefore, its stoichiometric combustion temperature (at the flame front) is much higher (2120 °C versus 1950 °C, in E-class GT conditions) since its combustion heat is transferred to one molecule instead of three. This is why hydrogen generates much higher NOx in diffusion flames than methane;
- Conventional Dry Low NOx systems based on the current fuel/air premix devices are defeated due to the very fast flame speed (Figure 18b) [148] that results in very short flames (Figure 18a) but causes very difficult flashback issues (see Section 2.3.3).

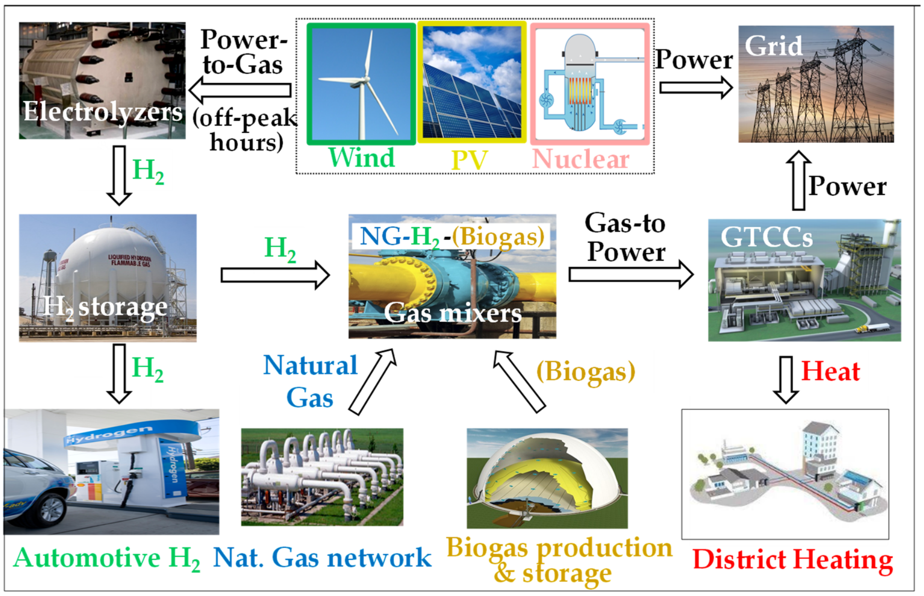


Figure 17. Projection of a possible integration of gas and power systems.

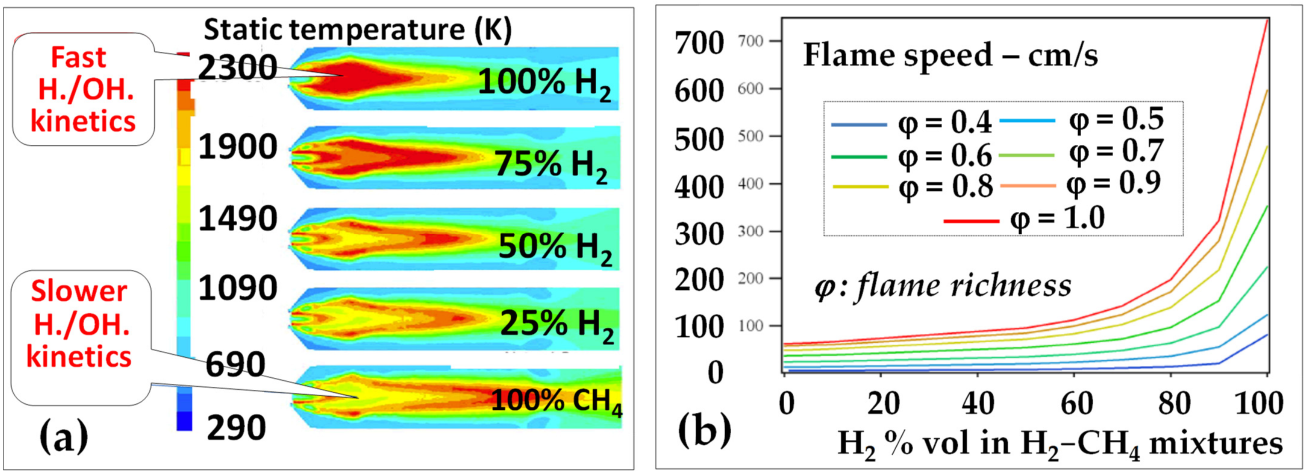


Figure 18. (**a**): Flame front temperatures and (**b**) laminar flame speeds of H_2-CH_4 mixtures.

Therefore, the combustion of hydrogen in GTs requires innovative approaches to design appropriate DLN systems likely to avoid flashbacks and secure proper flame holding.

It should be noted that the combustion of ammonia (NH_3) as a potential substitute of dihydrogen is not feasible as it would generate huge amounts of organic NOx (Section 2.3.3). Consequently, an intense activity has been deployed for several years to develop “hydrogen-capable” low-NOx combustors. To prevent flashbacks, current designs focus on multiple small H_2/air jets passing at high velocity through small injection orifices and become intimately mixed with corresponding air jets. Such devices, based on “micromix” injectors, are very promising; they enable the fine control of the spatial distribution of the fuel richness, down to the sub-millimetric scale, and minimize the risks of both core-flow and boundary-layer flashbacks (see Section 2.3.3). Figure 19 shows such a device that has been successfully lab tested [149,150]. Other similar designs exist [151,152].

Another important specificity of hydrogen resides in the fact that due the intrinsically high thermal conductivity of gaseous H_2O at high temperature, there are intense convective heat exchanges between the H_2O-rich combustion gases and the hot parts of the expansion turbine; this tends to increase metal skin temperatures and requires the reinforcing of the cooling of the hot parts to avoid premature creep and thermal fatigue effects.

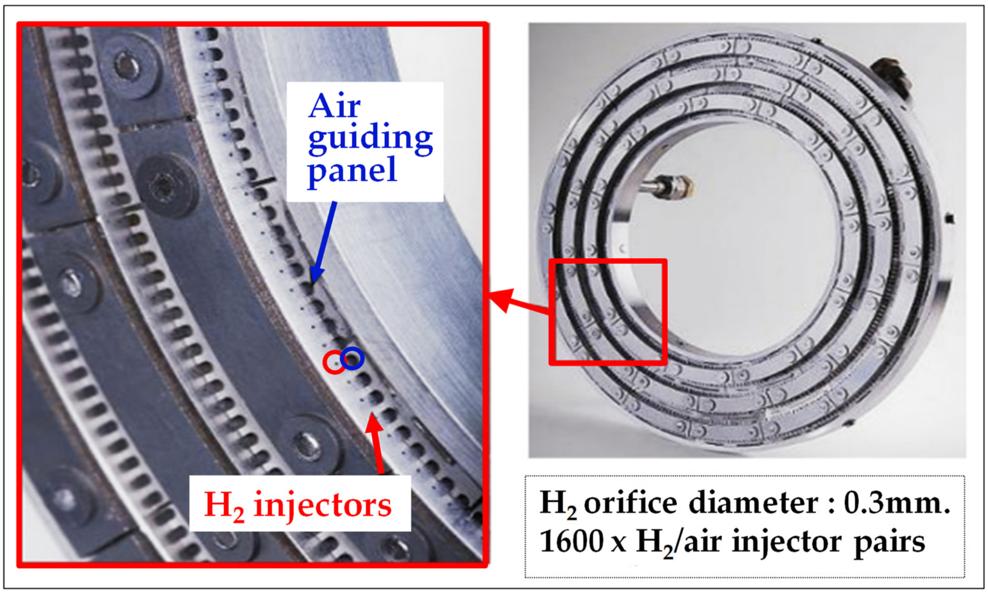


Figure 19. Sketch of a GT micromix burner: a pair of H_2/air orifices is circled [149] (with permission and minor changes).

Finally, hydrogen can cause the embrittlement of some metallic alloys, depending on pressure and temperature, so compatibility testing is required [153].

4.3. Exploiting the Experience Gained with H_2-rich fuels

From a historical perspective, the ability of gas turbines to handle industrially H_2-rich gases and eventually pure hydrogen is demonstrated by the wide experience that has been gained over the years in tens of refining and petrochemical plants burning by-process gases worldwide, as discussed in Section 3.2.

For instance, Spanish, UK, Korean, and Chinese refiners/petrochemists have managed major revamping programs of their utilities in the 1990s and 2000s, replacing aging refinery boilers with CHP units driven by 40 MW-class and sometimes 100 MW-class gas turbines that can burn up to 70% H_2 rich gases [87–89].

However, the "hydrogen fleet leader" is a 40 MWe gas turbine installed at the Daesan Petrochemical Plant in Korea (Figure 20) [154]. In the 1970s, this site hosted a first petrochemical unit (marked as #1 Pet-Chem Unit in that figure) equipped with a naphtha cracker along with a 25 MWe gas turbine (#1 GT), which began to burn a C_3-rich "petrochemical net gas" (PNG) coming from that cracker. Thereafter, the petrochemical company (Samsung General Chemicals at that time) installed an aromatization reactor that generated a net gas highly rich in H_2 (H_2-rich PNG) and was associated with a 40 MWe gas turbine (#2 GT) that drove an additional power unit (marked as #2 Pet-Chem Unit). Since 1997, this second GT has been reliably running for hundreds of thousands of hours on that H_2-rich PNG with hydrogen contents up to 90–95%. Although this machine operates with conventional diffusion flames and is equipped with DeNOx steam injection, this experience has amply demonstrated, with a hindsight of six years at present, the feasibility of operating a GT with nearly 100% hydrogen from both safety and reliability standpoints.

This plant also illustrates the multifaceted fuel flex and the high integration potential of heavy-duty gas turbines since (i) the two GTs use a C_4-LPG as startup fuel; and (ii) the first one burns a C_3-rich gas stream produced by the naphtha cracker and its flue gas serves as hot fluid to heat the same cracking reactor.

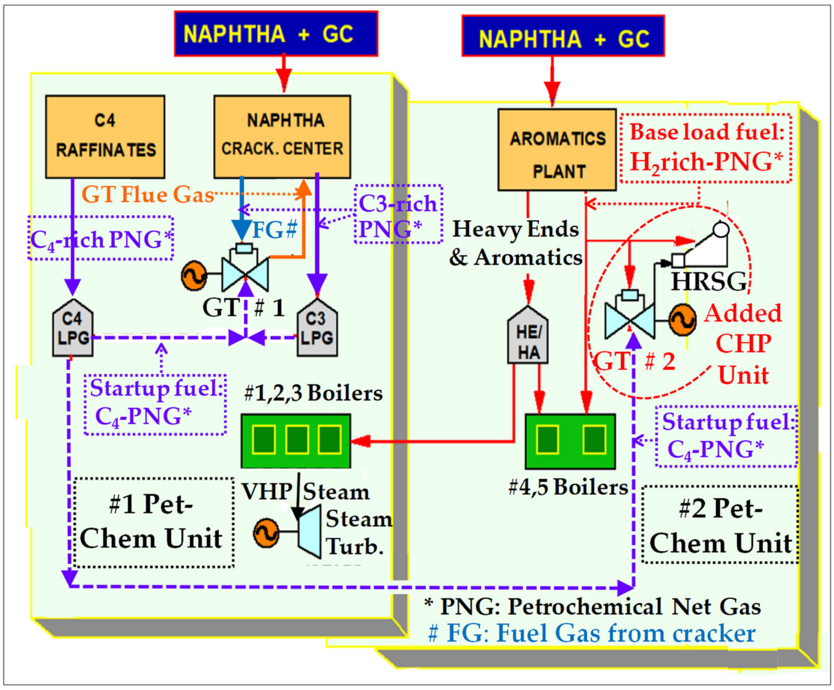


Figure 20. Sketch of the Daesan plant with the addition of the H_2-rich PNG.

5. Conclusions

This paper aimed to offer an extensive view on the wide fuel flexibility acquired by land-based gas turbines in the power generation sector.

First, it has provided essential technical keys by which to understand the reasons for this distinctive capability. To highlight the value of fuel flex in modern electrical grids, this quality has been put in perspective with the set of duties expected from modern power generators. Furthermore, to understand how gas turbines can accept multiple fuels, basic aspects of the Brayton cycles and GT combustion systems have been set out.

Then, this paper reviewed the various classes of products that make up the GT fuel portfolio, as well as the corresponding applications, outlining how this fuel portfolio has been expanding over years. The resulting range of alternative GT fuels cuts across many sectors of the economy worldwide, overlapping with most industrial and farming activities where gaseous or liquid combustible streams have been made available.

This outcome relies on the great adaptability of the gas turbine product but has been made possible by intense engineering work, experience accumulation and extrapolation, lab testing, and validation on the field. It has also been favored by market opportunities and fostered by the vivid development of cogeneration and combined cycles as effective energy conversion systems.

In the future, the development of new energies, especially hydrogen and second-generation bio-sourced fuels, is expected to preserve the assets of land-based gas turbines in the power generation sector and reinforce their role in the energy transition. This is despite the irresistible but indispensable rise in power of renewable energy alternatives, which tend to displace thermal generation.

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