WHITE PAPER

HYDROGEN AS A GAS TURBINE FUEL

FEASIBILITY & CONSIDERATIONS

By JASON NEVILLE
Senior Consulting Engineer
Turbine Generator Advisers, Inc. an
ENTRUST Solutions Group Company

ENTRUST SOLUTIONS GROUP

TABLE OF CONTENTS

ABSTRACT

While natural gas is the cleanest large scale combustion fuel in use today, utilizing it as a fuel for power generation purposes is responsible for approximately 15% of all CO2 emissions in the US. Gas turbines are responsible for a large fraction of these emissions. Renewable energy sources are continuing to make inroads into the global energy ecosystem, but gas turbines remain a key piece of the ecosystem as their flexibility complements renewables and their fluctuations in output well. Hydrogen, and its derivatives, are receiving much attention as a possible fuel to displace natural gas and provide CO2 free combustion in gas turbines and beyond.

Hydrogen is the most abundant element on earth but does not naturally occur on its own and is therefore known as an energy carrier rather than an energy source. It needs to be extracted from other compounds which poses production and scalability challenges. Additionally, hydrogen's physical properties differ greatly from those of methane or natural gas, creating unique challenges to storage, transportation, and combustion.

There is much momentum for technology programs that are working to overcome these challenges, including the use of hydrogen as a fuel in gas turbines. Hydrogen gas is being considered as a fuel in turbines both blended with natural gas and on its own. According to numerous industry publications, blends with low percentage hydrogen by volume (~20% or less) can be used safely in many gas turbines today with minimal or no modifications. For blends with larger percentages of hydrogen, turbine modification is necessary. These modifications largely focus on the turbine combustion system with additional controls and plant level considerations. Combustion system type and design drive a turbine's hydrogen burning ability and emission levels (NO_x, CO_2), which results in varying hydrogen capabilities across engines and OEMs.

Original equipment manufacturers (OEMs) including Ansaldo Energia, General Electric, Mitsubishi Hitachi Power Systems, Siemens, and others have multiple offerings with hydrogen burning capabilities. Offerings using diffusion type combustors can burn larger percent hydrogen by volume blends but require significant dilution to manage NO_x at the expense of plant efficiency and output. The OEMs recognize that lean premixed combustors (dry low emissions combustors) will continue to be the combustors of the future due to their ability to manage emissions and maintain high efficiency levels. They have dedicated considerable resources to designing hydrogen enabled combustors, many of which are currently being tested in lab environments and are just starting to be put to work in fielded engine demonstrations.

INTRODUCTION

Burning natural gas in turbines is the cleanest large-scale fossil-based energy production source on the planet today. According to the US Energy Information Administration (EIA), natural gas produces approximately half of the carbon dioxide (CO_2) emissions as compared to coal at 116 pounds per million Btu versus 211 pounds per million Btu (U.S. Energy Information Administration). In 2021, natural gas accounted for 32% of all US power generation and 40% of the power generation CO_2 emissions (U.S. Energy Information Administration). This equates to just under 15% of all the CO_2 emissions in the US.

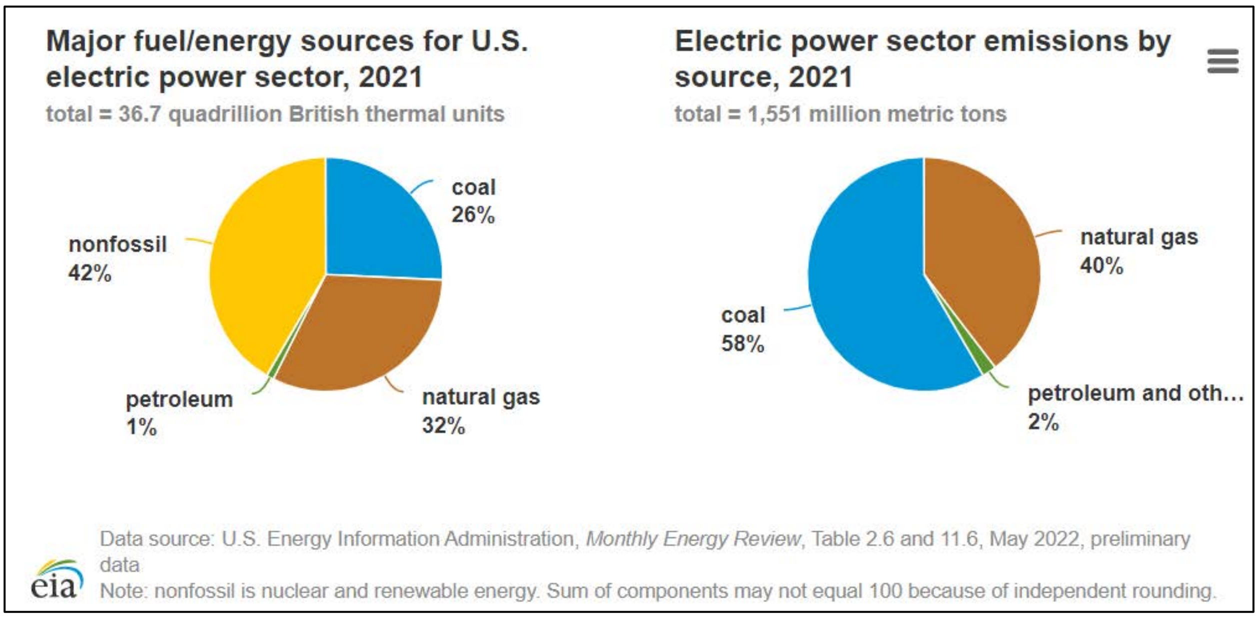


Figure 1: Power Sector Fuel and Emission Sources (U.S. Energy Information Administration)

As the demand for green energy has continued to grow and carbon reduction efforts have gained momentum, gas turbines remain a major part of both the US and international power grids. A major driver for this is a gas turbines' ability to quickly respond to intermittent and fluctuating energy production levels from renewable sources, such as wind and solar, and to stabilize the energy grid. Assuming the continued build-out of variable intermittent renewable resources on the electricity grid, it is a good assumption that moving forward gas turbines will continue to be prevalent. Addressing their CO_2 emissions will be an important step towards achieving a carbon-free energy network.

CO_2 reduction in gas turbines can be addressed through both a front-end approach, using carbon free fuels, and a back-end approach, with carbon capture. While carbon capture will have its role in the carbon-free effort, this paper will focus on fuels with carbon free byproducts, specifically hydrogen. The main byproduct of combusting hydrogen is H_2O, or water, making it a truly CO_2 emission free fuel. Over the past couple years, hydrogen has received a lot of attention and funding from US based and international organizations, including national governments, to tackle production and infrastructure challenges. Additionally, large gas turbine OEM such as GE, Siemens, Mitsubishi Hitachi Power Systems (MHPS), and others are actively working to build out hydrogen fuel capability and are betting on hydrogen being a major piece of their businesses moving forward.

HYDROGEN BASICS

Hydrogen does not naturally exist on its own and must be produced from compounds that contain it. Therefore, it is known as an energy carrier rather than an energy source (Office of Energy Efficiency & Renewable Energy). Hydrogen is produced by extracting it from fossil fuels, biomass, or water. There are numerous different hydrogen production technologies used today in varying technology readiness levels. Three of the most well-known technologies are steam methane reforming, coal gasification, and electrolysis. Steam methane reforming and coal gasification are thermochemical processes, while electrolysis is an electrolytic process. The chemical reactions associated with steam methane reforming and electrolysis are good illustrations of the differences between a thermochemical and an electrolytic process.

The steam methane reforming process utilizes methane or natural gas and combines it with steam and a catalyst to create a reaction that separates hydrogen from the methane. Byproducts from steam methane reforming (SMR) are carbon monoxide and smaller amounts of carbon dioxide.

$$CH_4 + H_2O + heat \rightarrow CO + 3H_2$$

Figure 2: Basic Steam Methane Reforming Equation

A follow up water-gas shift reaction takes place to convert the CO to CO_2 and complete the reforming process. This reaction generates one extra hydrogen molecule.

$$CO + H_2O \rightarrow CO_2 + H_2 + heat$$

Figure 3: Water Gas Shift Reaction Used with SMR Reaction

Electrolysis utilizes electricity in an electrolyzer to split water into hydrogen and oxygen. Since the process requires electricity its contributions to carbon emissions are dependent on the origin of the utilized electricity.

$$2H_2O \rightarrow 2H_2 + O_2$$

Figure 4: Basic Electrolysis Equation

Color Types

Hydrogen is referred to throughout the industry by different color types which indicate with what or how it was produced. The most common color types are listed below, but the list is not exhaustive as different colors are frequently being assigned.

- Grey: Hydrogen reformed from natural gas that does not utilize carbon capture.
- Black/Brown: Hydrogen created through gasification of coal.
- Blue: Typically, grey hydrogen that uses carbon capture and storage (CCS) or carbon capture and utilization (CCU).
- Green: Hydrogen produced through electrolysis using renewable energy.
- Pink: Electrolysis using nuclear power.
- Turquoise: Hydrogen from low emission methane pyrolysis (splitting of methane into hydrogen and solid carbon).
- White: Biomass gasification or similar process.
- Yellow: Hydrogen produced using the photolytic process (light energy used to split water). Also, has been used for grid-based electrolysis.

Comparison to Natural Gas

The long-term goal is to be able to burn 100% green hydrogen in gas turbines, replacing natural gas and driving CO_2 emissions to near zero. In the shorter term, hydrogen can be blended with natural gas and burned in gas turbines for a fractional reduction of CO_2 emissions. The figure below shows the percentage emissions reduction versus the percentage of hydrogen blending. Note that the relationship between hydrogen percent by volume and CO_2 reduction is not linear due to methane's volumetric energy density is close to 3x that of hydrogen. Near a 75% blend of hydrogen is required to reduce CO_2 emissions by 50%.

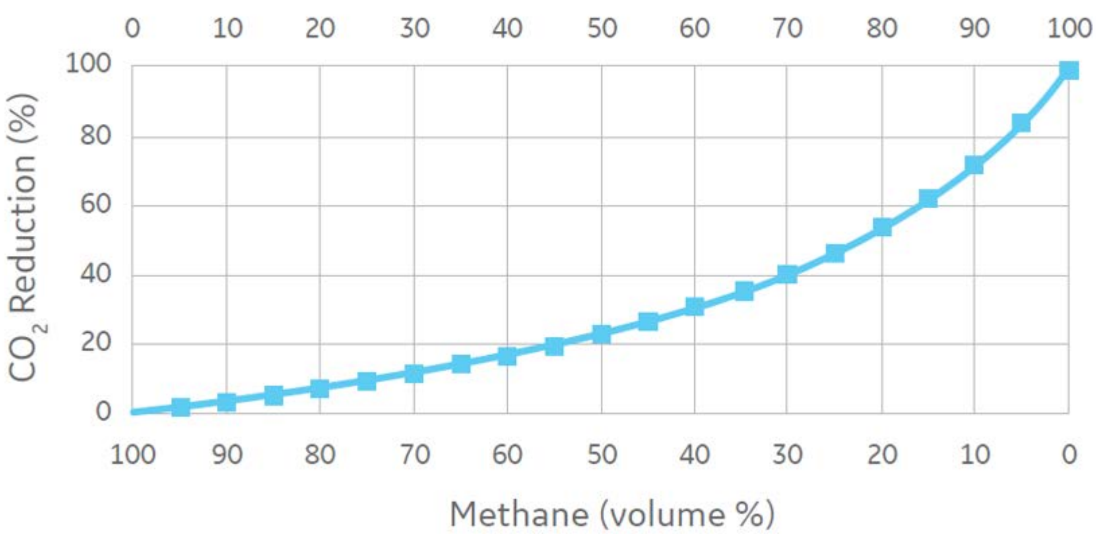


Figure 5: CO_2 Emissions vs. Volume Percentage of Hydrogen Blended with Natural Gas (General Electric Gas-Power)

A 100% hydrogen blend requires 208% of additional volumetric flow, or roughly three times the volumetric flow, as compared to methane.

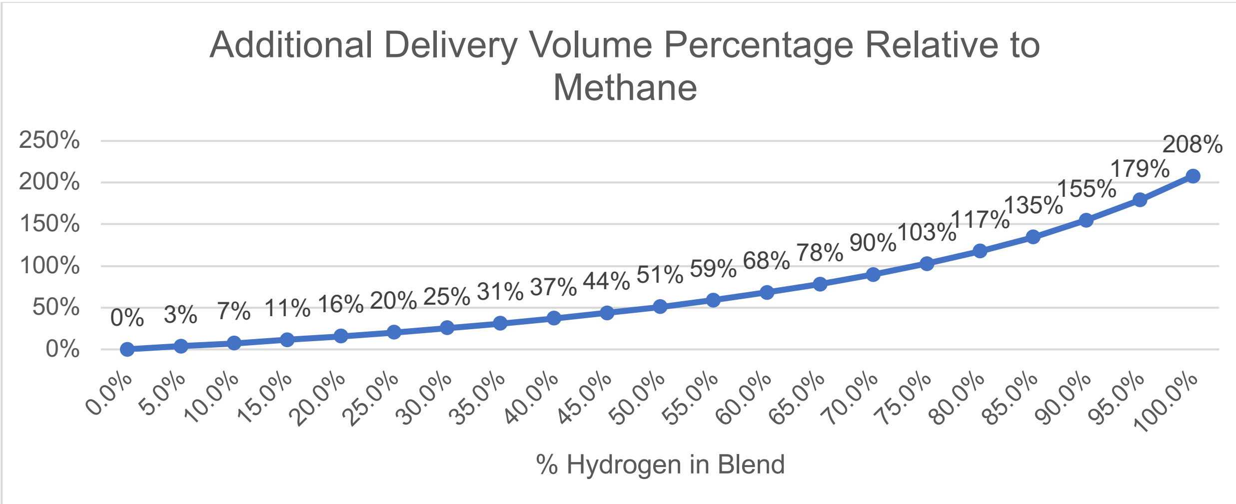


Figure 6: Additional Required Volumetric Flow vs. Methane

With the knowledge that hydrogen is intended to be used in conjunction with natural gas or as a full replacement, it is important to understand how the two fuels differ. It is their differences that makes immediate plug and play use of hydrogen in gas turbines difficult. The table below summarizes many of the physical differences between hydrogen and natural gas.

Table 1: Comparison of Natural Gas and Hydrogen

	Natural Gas	Hydrogen
Composition	90% CH_4 (methane), C2H6 (ethane), C3H8 (propane), C4H10 (butane), CO2, O_2, N_2 (nitrogen), H_2S (hydrogen sulfide)	H_2
Main Byproduct(s)	CO2, NO_x (Nitrogen Oxide)	H_2O, NO_x (nitrogen oxide)
Vapor Density at STP (lbm/ft^3)	0.05	0.0056
Kinetic Diameter (pm)	380	289
Lower Heating Value (Btu/ft^3)	983	290
Flammability Limit (% LL/UL)	7/20	4/75
Autoignition Temperature (°F)	1003	1085
Adiabatic Flame Temperature (°F, 1 atm pressure)	3565	4009

Flame Speed (ft/s)	1.0-1.3	6.6-9.8
Main Production Method(s)	Drilling (natural gas wells)	Steam Methane Reforming (SMR), Gasification, Electrolysis
Compressed Liquid Temp (°F)	-163	-423
Cost (2022, $/MMBtu)	9.00	15.00-52.50

References: (Engineering ToolBox), (Wikipedia), (U.S. Energy Information Administration), (Escola Europea)

Supply & Infrastructure

As touched upon previously, there are numerous ways to produce hydrogen, many of which do so with no or low emissions. However, these low emission methods have not yet been scaled. As of 2021, 98% of the worlds hydrogen was produced using fossil fuels with no emissions control, with methane being the overwhelming source at 76%, followed by coal at 22% (Columbia Center of Global Energy Policy). The total hydrogen demand in 2020 was 90 megatons and is expected to nearly triple in the next thirty years (International Energy Agency). The International Energy Agency predicts that to support net zero emissions by 2050, the hydrogen production would have to grow to an excess of 500 megatons, of which approximately one-fifth would be consumed by the power industry (International Energy Agency). To meet this demand, production will have to scale significantly.

In addition to scaling production, infrastructure for transportation of hydrogen will have to be built out. Hydrogen can be transported in three different forms: gas, liquid, or in a carrier such as ammonia or a liquid organic hydrogen carrier (LOHC). To transport hydrogen in gas form, a dedicated pipeline would have to be established. This would require building of a new pipeline or retrofitting existing natural gas pipelines. Modern pipelines today made from polyethylene or fiber-reinforced polymers are generally considered compatible for low level blends of hydrogen. However, pipeline valve, seal, and compressor upgrades are likely required to deal with the smaller hydrogen molecules that have a propensity to leak, and to provide more compression capability required for the lower density and energy content of hydrogen. Numerous research programs and consortia are actively investigating the maximum percentage of hydrogen (blended with natural gas) that existing infrastructure can transport with minimal modifications.

Like natural gas, hydrogen can be cooled and transported in liquid form. It does require specifically designed transport vehicles (trucks, ships) and supporting equipment. For example, storage insulation requirements are greater for hydrogen since the liquid hydrogen temperature is about 250°F cooler than that of liquid natural gas.

Attaching hydrogen with a carrier such as ammonia or a LOHC can allow the hydrogen to be transported with a greater density per volume than on its own. However, this does require a chemical conversion to separate out the hydrogen once the usage point is reached. In the case of the LOHC, either a bidirectional pipeline or a second pipeline to return the dehydrogenated organic carrier is required. The graphic below is a good illustration of the main production, transportation, and consumption methods of hydrogen in use today. In the near term, a good option to avoiding transportation challenges and costs is to collocate production and consumption facilities, such as power plants.

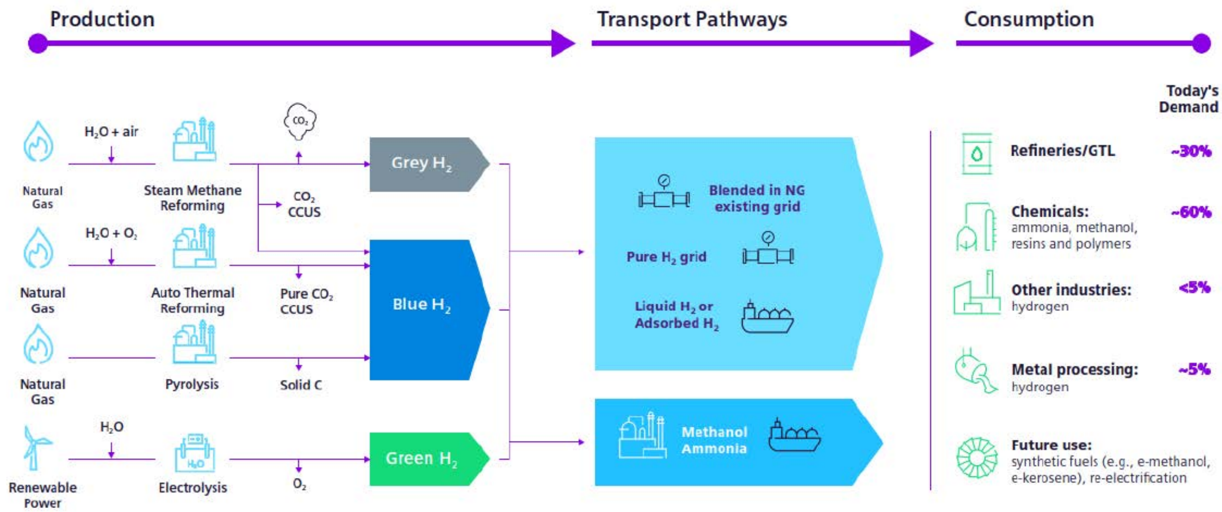


Figure 7: Production, Transportation, and Consumption of Hydrogen (Siemens Energy)

CONSIDERATIONS FOR HYDROGEN IN GAS TURBINES

It is important to recognize that all gas turbines are not created equal. There can be large differences between industrial gas turbines (IGT) and smaller aeroderivative engines, as well as across equipment manufacturers. The point is that every gas turbine design needs to be evaluated on an individual basis to determine its hydrogen burning ability and what level of retrofit or design change is required to improve this ability.

Required design changes can be highly dependent on the percent volume of hydrogen desired to be burned. Reviewing literature published by the gas turbine OEMs, hydrogen burning can be segmented into low, medium, and high percentage blend groups. A turbine operating on a low percentage blend of hydrogen (5-10%) may not require any design or material changes as the fuel burn characteristics are generally similar to a 100% natural gas fuel stream. For medium percentage blends (10-50%), design changes to existing equipment are necessary. For example, modifications will be made to combustor materials, fuel nozzles, and control systems. However, the scope of the changes will be on a medium level and the combustor and overall turbine architecture will be mostly unchanged. For higher blends of hydrogen, more than 50%, more major modifications must be made to the turbines. Complete retrofit of the combustion system is likely required. Many of the OEMs are currently working on new combustion systems to be able to handle high hydrogen blend levels.

Again, it should be stressed that the percent ranges used above, as well as the rough modification scope for the applicable high, medium, and low blend ranges, are very much dependent on the turbine design. The following sections will discuss turbine considerations to help provide an understanding of why this is so. These sections will look at the gas turbine from the enclosure on in and discuss challenges, potential design changes, and impacts of burning hydrogen.

Enclosure Considerations

The gas turbine enclosure is the packaging or housing that encloses the gas turbine for safety purposes and operating environment control. It contains piping for fuels and diluents, safety systems for gas detection and fire protection, and a ventilation system. Additionally, enclosures are typically explosion proof.

Fuel system piping and valves in the enclosure that are intended to flow hydrogen must be made compatible with it. Hydrogens' small molecules are able to permeate materials and cause embrittlement, as well as escape through seals, where almost all other gases cannot due to larger molecule size. These concerns are the same for transportation piping and the fuel system outside of the enclosure. This means materials need to be selected to function in a hydrogen environment and engineering safety factors must be included into the design. Moreover, hydrogen-tight seals need to be capable of containing the small hydrogen gas molecules. Piping and valves may have to be enlarged to handle the higher volumetric flow that hydrogen requires depending on the intended blending percentage to be used (see Figure 5).

Safety systems for gas detection and fire protection will have to be modified too. Gas detection specifically for hydrogen will have to be installed. Fire protection systems will also have to be made capable of suppressing fires started with the more volatile hydrogen fuel. Similarly, explosion proofing will have to be made capable of containing larger explosions. Along with these systems, ventilation will have to be considered. Ventilation is setup to help keep enclosure internal temperature cool and to keep the enclosure free of any gas that may be leaking into the air. There is a balance, to ensure the enclosure is properly vented, but also not over vented. Over venting of the enclosure can lead to cold casing temperatures that may cause the casing to pinch the rotor, resulting in hard rubbing.

Combustion Considerations

A turbine's ability to burn hydrogen is almost solely dependent on the combustion system. The larger the hydrogen percentage in the fuel, the more challenged an unmodified combustion system becomes. To add to the difficulties, for the foreseeable future, combustion systems will have to maintain fuel flexibility and the ability to burn natural gas. The combustion system is challenged by the following factors:

- Hydrogen is 1/9th the density of natural gas and is the smallest known molecule, which creates transportation and sealing challenges. Fuel tight sealing joints that prevent natural gas from leaking, for example, may not be suitable for hydrogen. Smaller molecules also allow for hydrogen to permeate certain materials and cause embrittlement.
- Hydrogen's heating value is 1/3rd of natural gas', which means that three times as much hydrogen fuel flow is needed to produce the same amount of power as compared to natural gas.
- The flammability range of hydrogen is much larger than that of natural gas creating elevated environmental, health, and safety concerns for both transporting and burning hydrogen. This is less of a concern for low percentage hydrogen blends and a greater concern for pure hydrogen. The plot below shows how the upper explosive or flammability limit changes with increasing hydrogen volume in hydrogen-methane blends.

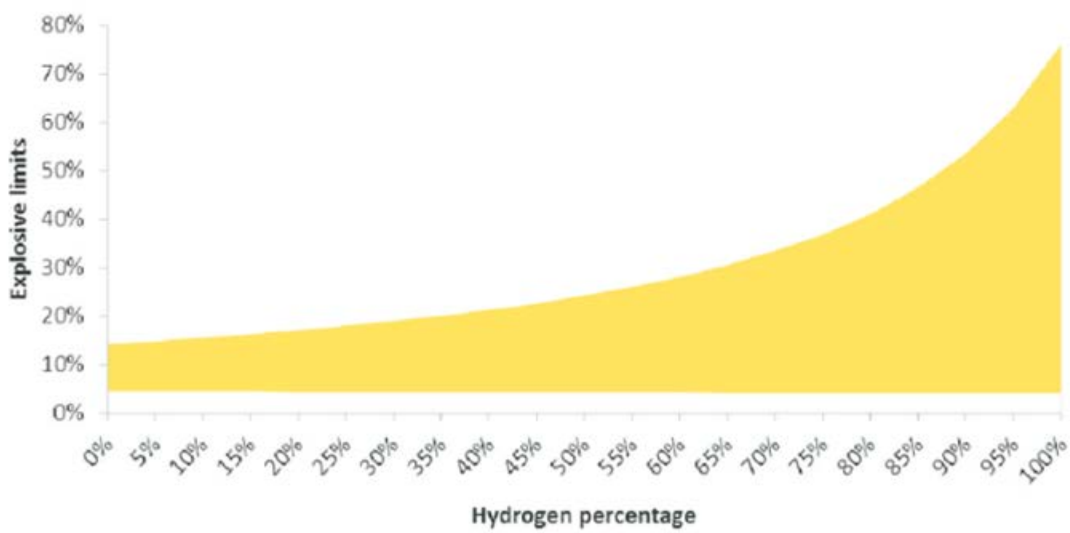


Figure 8: Upper Explosive/Flammability Limit of Hydrogen-Methane Blends (Blacharski, Janusz and Kaliski)

- Hydrogen burns hotter and has a faster flame speed than natural gas. This creates combustion stability difficulties and increases potential for flame out and flashback.
- Hydrogen flames are much less visible than natural gas flames, making flame detection difficult.

Hydrogen embrittlement occurs as soon as hydrogen is introduced into a system and cannot be undone. As previously stated, the small hydrogen molecules can diffuse into metals and cause embrittlement. Embrittlement lowers the material's yield stress which reduces the material's fatigue capability, particularly for low cycle fatigue. Temperature, pressure, and stress level can influence the rate or magnitude of embrittlement. However, not all materials are equally prone to hydrogen embrittlement. Both stainless steels and nickel alloys, commonly used in gas turbine combustion systems, experience increased levels of embrittlement at elevated temperatures. This makes combustion material selections for hardware, weld joints, and braze joints difficult.

There are several main combustion system types used throughout IGTs and the challenges described above will impact the systems differently. The two main combustion system types used in today's industrial gas turbines are Diffusions Systems and Lean Premixed Systems (DLE Combustor).

DIFFUSION COMBUSTION SYSTEMS

In diffusion flame, or conventional, combustion systems fuel is directly injected into the reaction zone with no intentional premixing with the combustion air. A diffusion, or non-premixed, flame burns at the flame surface while fuel on the interior of the flame remains unburned. Diffusion flames generate higher gas temperatures as compared to premixed because the fuel burns close to the stoichiometric ratio (Greenwood). The stoichiometric ratio is the ratio between gas and air where complete combustion occurs. High gas temperature results in lower CO levels, but higher NO_x levels, as illustrated in Figure 9.

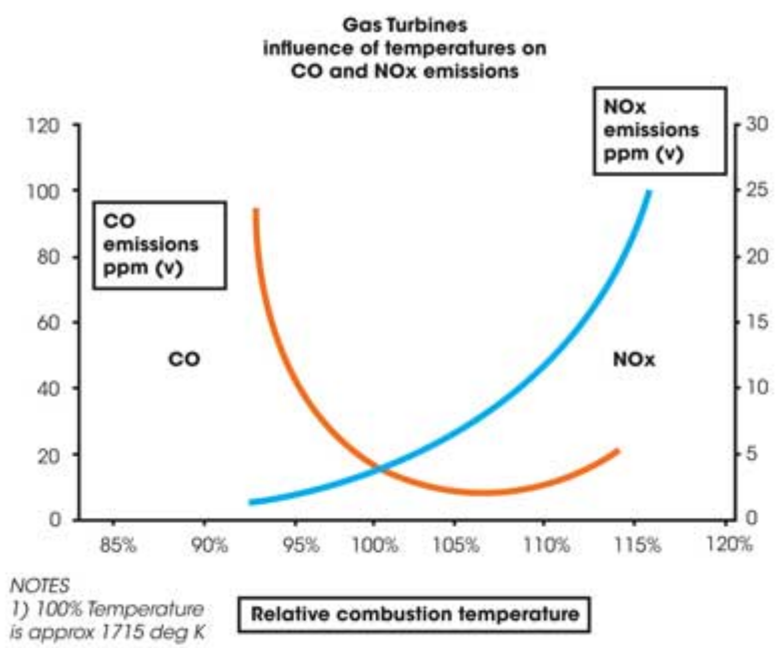


Figure 9: Relationship Between NO_x and CO (Power Engineering International)

The figure below shows an example of an annular diffusion combustor. In the primary zone, fuel is injected and burned. Fuel and air mixing is less than ideal and incomplete combustion of the fuel occurs. A secondary zone, where additional air is added to the combustor, is required to complete full combustion of the fuel. The gas temperatures aft of the primary and secondary zones are too high for downstream turbine component health, thus a dilution zone is used to inject additional air and to drop the gas temperature to an acceptable level.

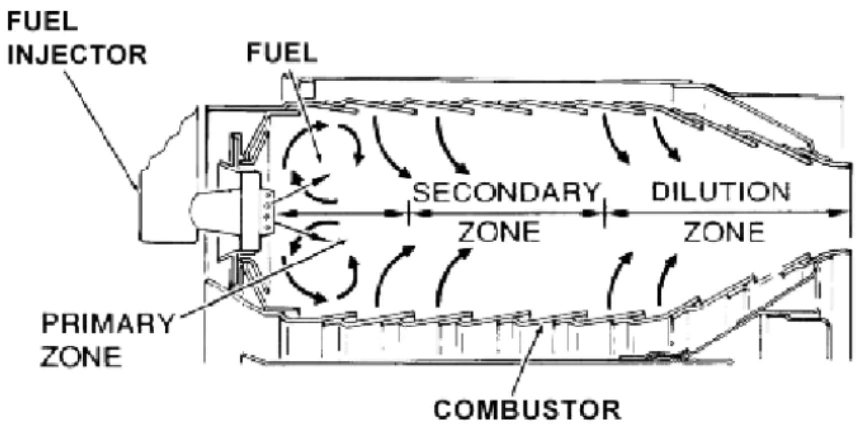


Figure 10: Example of a Standard Combustor (Greenwood)

Injecting a diluent such as steam, water, or nitrogen into the primary combustion zone can also be used to decrease flame temperature and NO_x levels.

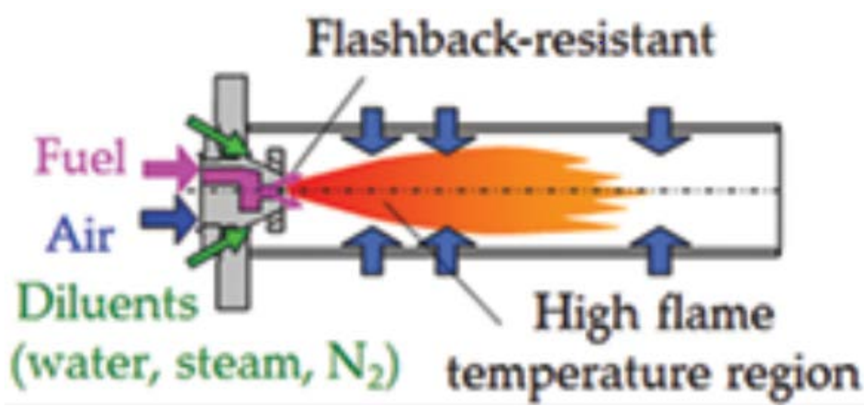


Figure 11: Representative Diffusion Combustor Using Diluents (Asai, Akiyama and Dodo)

Diffusion combustors offer greater flame stability over a wider range of flame temperatures and fuel compositions, including hydrogen, as compared to lean premixed systems. Because the flame burns close to the stoichiometric ratio it is less prone to lean blow out during operation, and due to higher gas velocities, it is less likely to flashback. With more flame stability, combustion dynamics remain within acceptable limits. Some diffusion combustors can burn 100% hydrogen today, but elevated NO_x emissions are expected and will require more dilution at the fuel injection zone. It should be noted that diluent systems add complexity to plants, requiring water or steam injection systems, and can alter the mass flow rates between the compressor and turbine sections, potentially reducing surge margin. Alternatives to increased dilution would be output reduction, which is typically not favorable, or application of a post emissions control system such as selective catalytic reduction (SCR), which also increases plant complexity.

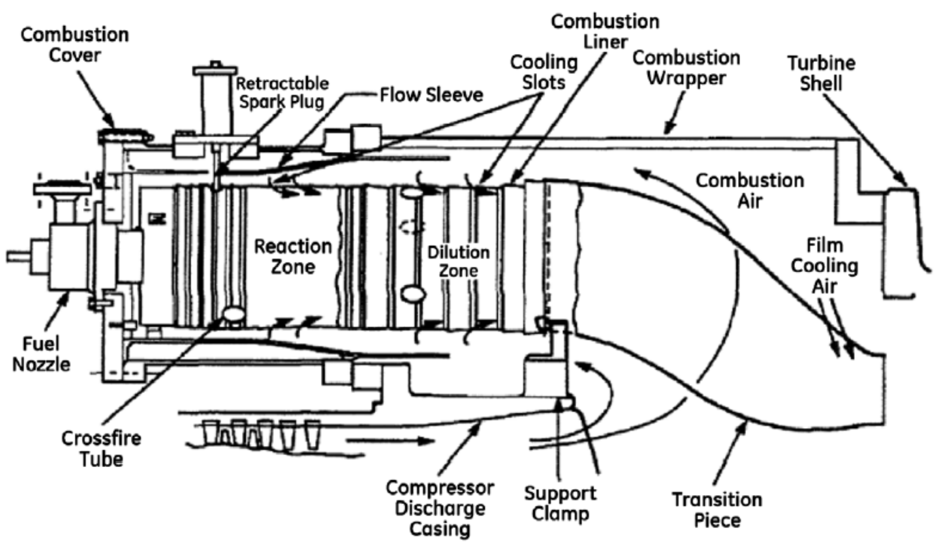


Figure 12: Example of a Can-Annular GE 7E Standard Combustor (GE Energy)

LEAN PREMIXED COMBUSTORS (DLE AND DLN COMBUSTORS)

Due to the NO_x challenges in diffusion combustors, many of today's new gas turbine designs are equipped with lean premixed combustors also known as dry low emissions (DLE) and dry low NO_x (DLN) combustors. The word "dry" indicates that no diluents are being used for emissions control. While diffusion combustors are currently more capable of burning hydrogen, the gas turbine industry recognizes that lean premixed combustors, with superior emissions control, will continue to be the dominant combustion system for new designs, even with hydrogen.

The main difference between the lean premix and diffusion combustors is that the fuel and air is mixed prior to injection into the combustion chamber in a lean premix system. The homogeneous mixture of air and fuel allows for a uniform and lower temperature flame, reducing NO_x emissions without the use of dilution and the associated efficiency penalty. Most lean premixed combustors also use fuel staging with lean fuel-air ratios to help further control emissions. Lean premixed systems can look vastly different between OEMs and even turbine designs. DLE technology has been continuously evolving as there has been a constant push for higher efficiencies and lower emissions. The wide variety of designs translates to a large range of hydrogen burning capabilities across turbines. But today, in almost all cases, lean premixed combustors can handle lower volume percentages of hydrogen when compared to diffusion combustors.

Figure 13 offers a simple comparison between a diffusion (top) and a lean premixed (bottom) combustor. The lean premixed cross section shows an inner and outer fuel circuit. The outer fuel circuit uses over 85% of the gas fuel and swirls it with air before injecting it out into the combustor. A smaller center fuel circuit is used for non-mixed pilot fuel that burns rich. In most cases, the center pilot fuel nozzle is shutoff at steady state natural gas operation. The mixed air allows for a lower flame temperature, but the lower temperature flame is much closer to the lean limit and isn't as stable when compared to a diffusion flame. Additionally, the center pilot nozzle surrounded by air and fuel on its perimeter creates a dead zone, or slow-moving air zone, in the center of the nozzle. This region is prone to flame instability and poses an increased risk to flashback. Note that this a general example and is not inclusive of all DLE designs and technologies.

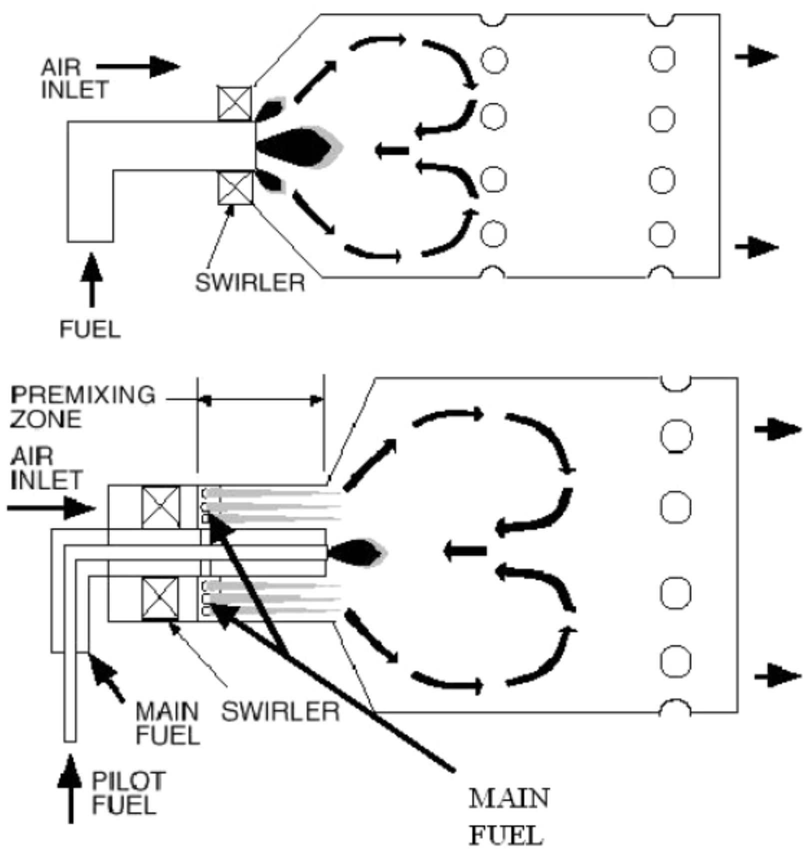


Figure 13: Simple Comparison Between Diffusion and Lean Premixed Combustion Systems

When considering hydrogen in DLE and DLN systems, similar challenges that exist for diffusion combustors are magnified. First, hydrogen's higher flame speed as compared to natural gas (>3x) and the slower moving flame center in the above DLE system increases the flashback risk. Figure 14 shows an illustrated example of flashback.

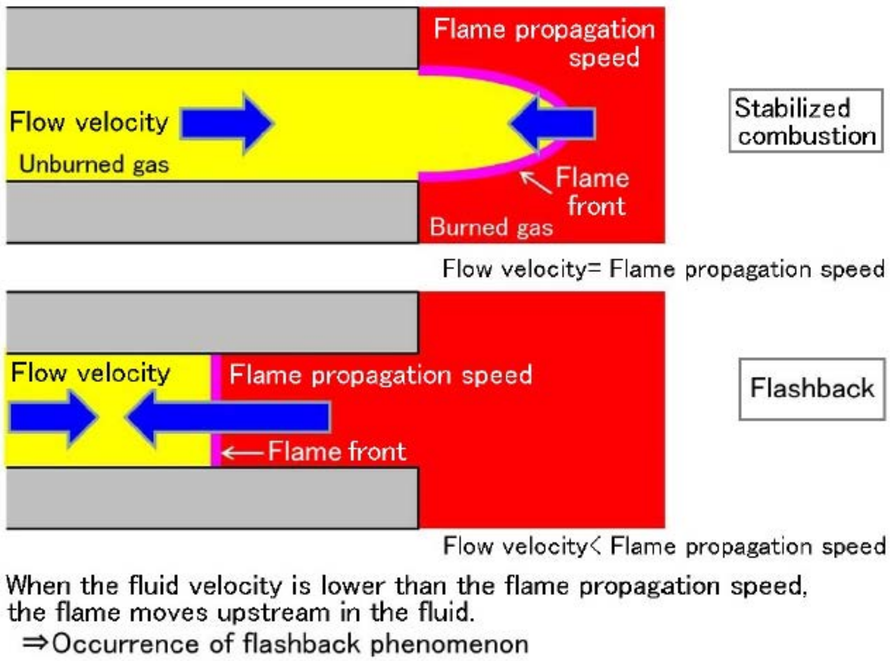


Figure 14: Illustration and Description of Flashback (Inoue, Miyamoto and Domen)

Next, the higher flammability range of hydrogen increases the risk of fuel ignition inside the mixing passages. Combustion dynamics are also altered with hydrogen usage. Elevated dynamics amplitudes over a larger range are expected for hydrogen since flame stability is reduced. During transient operation, like startup and shutdown, dynamics are of greatest concern and for the foreseeable future a "safe fuel", such as natural gas, will be required for non-steady operation (startup, shutdown, part-load). In summary, the stable operability window for most lean premixed combustors is narrower as compared to diffusion combustors, which translates to premixed combustors only being capable of lower percent blends of hydrogen. There are ongoing efforts from the gas turbine OEMs to overcome the challenges associated with hydrogen and lean premixed combustors. Lean premixed combustors are critical to enabling hydrogen burning in gas turbines with acceptable emissions levels.

Compressor Considerations

Since all the combustion takes place downstream of the compressor, the combustion of hydrogen does not have direct impact on the compressor. There are a few indirect impacts that are notable and pertain to NO_x abatement. Two possible ways to minimize NO_x emissions are through unit derate or dilution (standard combustor). If unit derate is chosen to reduce NO_x, the off-design point selected needs to be acceptable for the compressor performance and health. If additional dilution in standard combustors is chosen to abate NO_x, surge margin may be adversely impacted by the change in mass flow of the turbine section relative to the compressor section.

Hot Gas Path Considerations

Hydrogen's higher burning temperature driving up turbine firing temperature is the largest concern to the hot gas path components. It should also be expected that the gas temperature profile leaving the combustor will be hotter and look different when firing hydrogen versus natural gas. For example, the gas temperature profile exiting a diffusion combustor will likely look more peaky (highest temperature in center of combustor) when burning hydrogen if no additional changes are made. Firing temperature increase and combustion profile shape change will drive modifications to the component cooling and coating designs to avoid part life reduction.

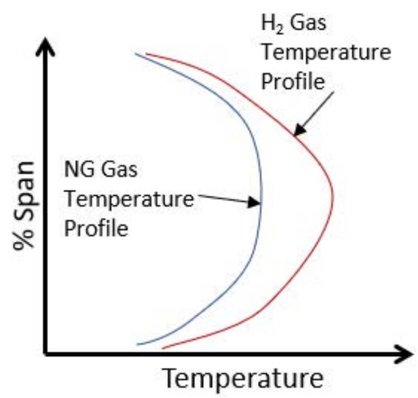


Figure 15: Example of Possible Gas Temperature Profiles of Hydrogen vs. Natural Gas

Additionally, there has been some noted concern about additional moisture content in combustion gas (water is a byproduct of burning hydrogen) causing higher heat transfer to hot gas path components (Mulder). Based on the expectation that combustion gas temperatures will be high, any moisture content will be in the vapor phase. Water and steam, including superheated or vaporous, both have a higher specific heat (cp) than air. This will translate to more heat being transferred to the turbine components. Work will be required to determine the impact, if any, on the downstream turbine components.

CURRENT OEM EXPERIENCE

There are numerous companies that produce a range of industrial, aeroderivative, and even aviation gas turbines that are exploring hydrogen usage in varying capacities. This section focuses on the hydrogen experience and ongoing developments of the main original equipment manufacturers in the industrial and large aeroderivative gas turbine spaces. It is a thorough review but is not intended to be inclusive of all companies and all hydrogen work being completed in the industrial turbine space today.

Ansaldo Energia

The Italian based turbine manufacturer offers E, F, and H class gas turbines capable of 80MW and greater. Ansaldo claims more than 15 years of hydrogen burning experience and capabilities ranging from 25-80% hydrogen blends depending on turbine model (Ansaldo Energia). They target 100% hydrogen burning capability across all frames by 2030.

Table 2: Ansaldo Energia's Main Gas Turbine Offerings

MODEL	ISO POWER [MW]	FREQUENCY [Hz]
GT36-S5	538	50
GT36-S6	369	60
GT26	370	50
AE94.3A	340	50
AE94.2	190	50
AE64.3A	80	50/60

Of the above offerings, Ansaldo claims all can burn hydrogen in some capacity, except for the AE64, with no required hardware modification.

Table 3: Ansaldo Energia Hydrogen Capability by Engine

Ansaldo Energia solutions for burning hydrogen			
Technology	Application in Gas Turbine (No hardware modification on gas turbine)	H_2 Capability: any blend between 0 up to max [vol %]	NOx Emissions [ppmv @15%O_2, dry gases] (No additional device for flue gas treatment)
Sequential Combustion	GT36 New and service	50	15
Sequential Combustion	GT26 New and service	30	15
Single Stage Combustion	AE94.3A New and service*	25	25
Single Stage Combustion	AE94.2 New and service*	25	25

including V94.3A/V94.2 technology

The AE94 engines uses Ansaldo's tried and true single stage combustors. The AE94.2 uses silo style combustors with DLN burners and the AE94.3 uses an annular combustor again with DLN burners. In 2006 two AE94.3A were commissioned to burn 15% hydrogen by volume, which has since been increased to 25%. Combined, these two engines have over 200,000 EOH.

Figure 16: Ansaldo Energia AE94.2 and AE94.3A Engines

Ansaldo's GT26 and GT36 engines take advantage of Ansaldo's latest and greatest combustion model, the sequential combustor. These engines are advertised as capable of burning up to 50% hydrogen by volume.

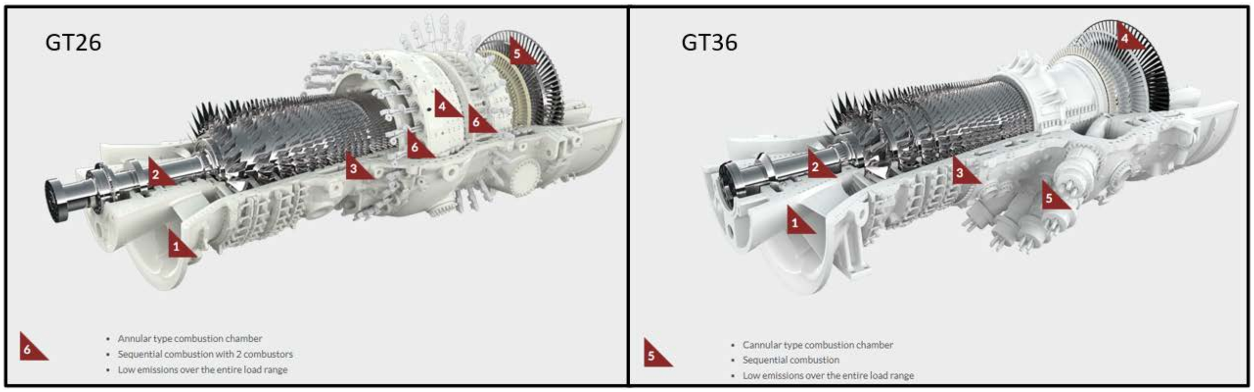


Figure 17: Ansaldo Energia GT26 and GT36 Engines

What makes this possible is Ansaldo's sequential combustor that utilizes two combustion stages. By splitting fuel between the first and second combustion stages, the conventional first stage can maintain flame location at a lower temperature. The lower temperature gas travels to the second stage which uses auto-ignition to maintain flame stability even at a higher fuel flow. These combustors with hydrogen use have been validated in lab conditions (not full engine). Ansaldo is working to further validate these combustors and to increase the hydrogen burning capability up to 70% by volume.

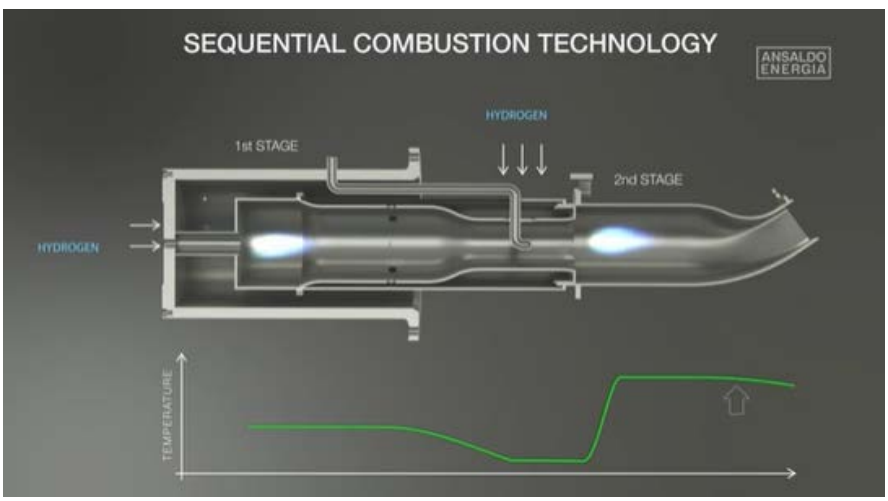


Figure 18: Ansaldo Energia Sequential Combustor

It should be noted that Ansaldo through PSM also offers combustion system upgrades, such as the FlameSheet combustor which is retrofittable to GE, MHI, and Siemens E and F class engines. The combustor can currently burn up to 60% hydrogen and has demonstrated up to 80% in a lab setting (Power Systems Mfg, LLC).

General Electric

General Electric claims to be the leader in gas turbine fuel flexibility and hydrogen with more than 100 turbines that operate fuels with some level of hydrogen, which have accumulated 8 million operating hours, and more than 30 turbines that have operated with fuels of at least 50% hydrogen (General Electric Gas-Power). Most of GE's experience with hydrogen has occurred at industrial facilities or at IGCC plants (integrated coal gasification combined cycle) where the hydrogen or fuel source is collocated with the power plant.

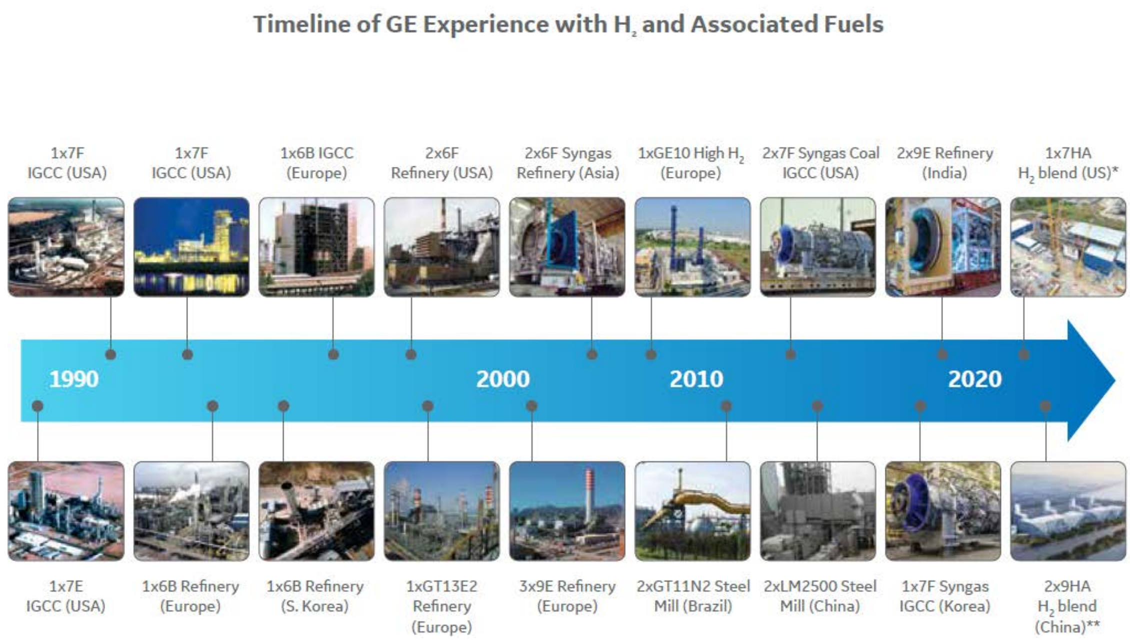


Figure 19: GE Experience with Hydrogen Gas Turbines (General Electric Gas-Power)

GE summarizes their hydrogen burning capability by engine frame in a bar chart that differentiates between capability with lean premixed combustors and diffusion combustors. This highlights the significant differences in these technologies and the required progress that lean premixed combustors must make to enable high hydrogen blend fuels.

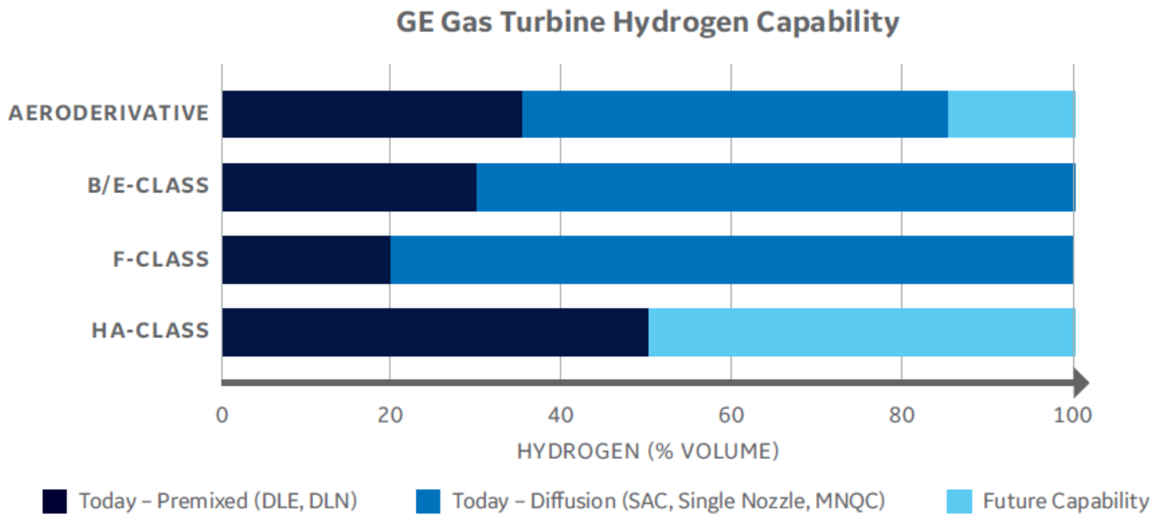


Figure 20: GE Gas Turbine Hydrogen Capability by Frame (General Electric Gas-Power)

GE is committed to continued development of hydrogen combustors and gas turbines. GE industrial gas turbines, except for some of the legacy Alstom offerings, have historically had can-annular combustion systems. These can-annular systems have evolved from a single nozzle diffusion combustor to a multi-nozzle quiet combustor, and then to a DLN combustor design. GE was the original leader in DLN and DLE technologies. Their latest HA turbines are equipped with DLN 2.6e combustion systems that can burn up to 50% hydrogen by volume when paired with an HA engine (Goldmeer). The DLN 2.6e, instead of using the typical 5-6 fuel nozzles with swirlers, uses hundreds of smaller nozzles to help promote even mixing of air and gas without the air dead or slow zones that were described in the combustion section of this paper.

Figure 21: GE's Combustor Evolution (Goldmeer)

GE has a handful of commercial hydrogen demonstration projects underway or in the works. Their latest 7HA and 9HA engines are being equipped with the DLN2.6e combustors. Most recently, the Long Ridge Energy Plant (Ohio) in early 2022 completed execution of a demonstration that burned a 5% hydrogen blend with natural gas in GE's 60 Hz 7HA.02.

Figure 22: GE's Planned Commercial Hydrogen Demonstrations (GE Power)

Mitsubishi Hitachi Power Systems (MHPS)

MHPS is actively pursuing increasing their hydrogen burning capability. Like other OEMs, they do have experience burning hydrogen-rich fuels such as syngas and off gas.

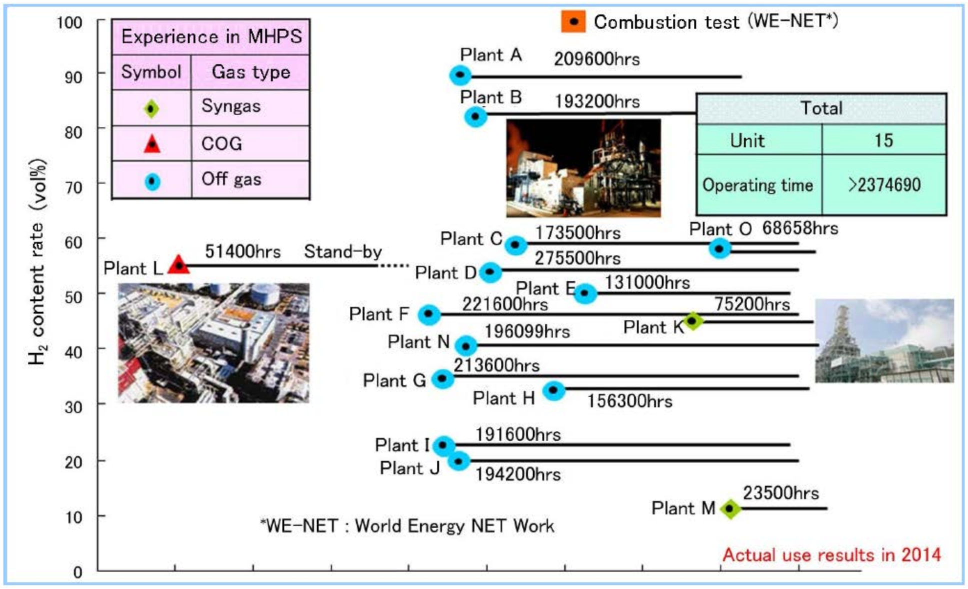


Figure 23: MHPS Experience with Hydrogen Rich Fuels (Inoue, Miyamoto and Domen)

MHPS has three combustor technologies with varying hydrogen capabilities: diffusion combustor, DLE multi-nozzle combustor, DLE multi-cluster combustor.

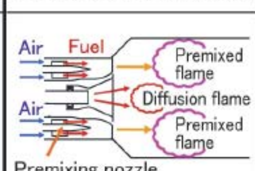
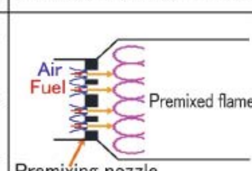
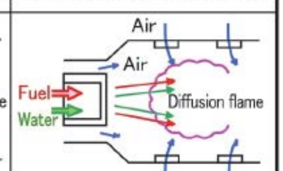
Combustor	Multi-nozzle combustor	Multi-cluster combustor	Diffusion combustor
Combustion method	Premixed flame combustion	Premixed flame combustion	Diffusion flame combustion
Structure			
NOx	Low NOx due to flame temperature uniformed by premixing nozzle	Low NOx due to flame temperature uniformed by small premixing nozzle	Fuel is injected in to air. There is a high-flame temperature region and the NOx is high
Flashback	High flashback risk in the case of hydrogen mono-firing because of the large flame propagating area	Low flashback risk due to the narrow flame propagating area	No flashback risk because of diffusion flame
Cycle efficiency	No efficiency drop due to no steam or water injection	No efficiency drop due to no steam or water injection	Efficiency drop occurs because steam or water are injected to reduce NOx
Hydrogen co-firing ratio	Up to 30 vol%	Up to 100 vol% (under development)	Up to 100 vol%

Figure 24: Comparison of MHPS Hydrogen Enabled Combustors (Nose, Kawakami and Araki)

MHPS has made strides with both of their DLE combustor types to enable hydrogen burning. Their typical DLE design uses 8 premixing nozzles where only gas is injected at the center of the nozzle and air and gas are injected and mixed on the perimeter of the nozzle. This fuel nozzle configuration with an absence of air at the nozzle center, creates a low velocity air zone at the center. The low velocity zone can lead to flashback when using hydrogen due to the higher hydrogen flame speed as compared to natural gas. To overcome this concern, MHPS has added air injection to the nozzle center.

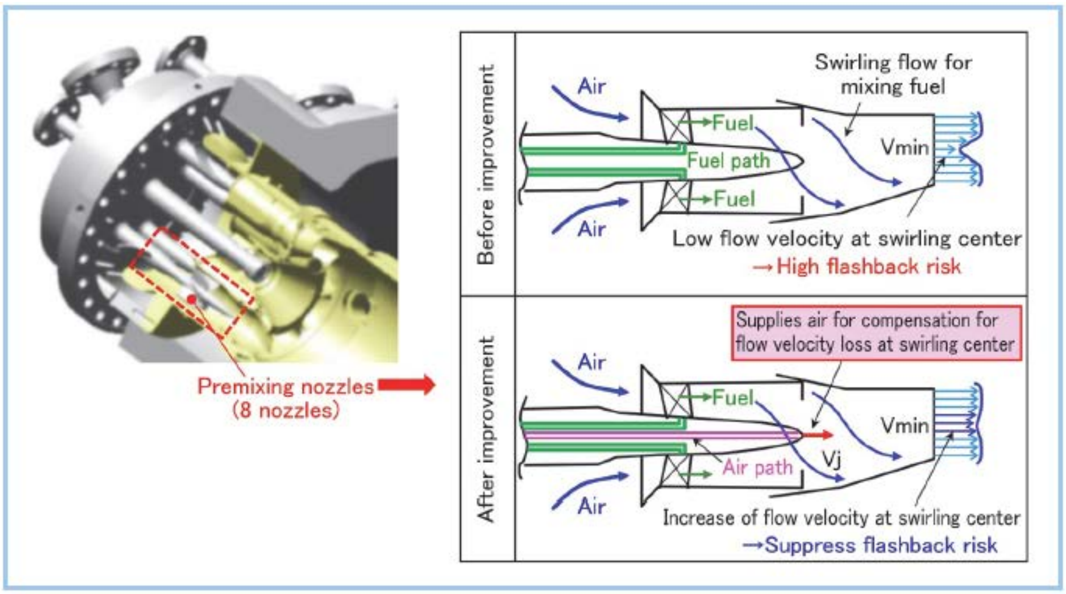


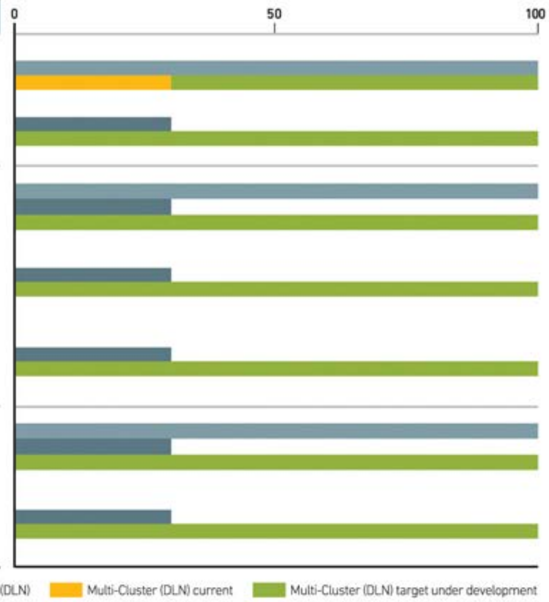
Figure 25: MHPS Latest DLE Fuel Nozzle Design (Nose, Kawakami and Araki)

The DLE multi-cluster combustor is MHPS' latest technology and believed enabler for achieving burning of 100% hydrogen by volume. Like GE's DLN2.6e, the combustor uses many smaller fuel nozzles to disperse the fuel and combustion flame creating more stable combustion that minimizes the risk of flashback. The combustor is currently under continued development.

Figure 26: MHPS Multi-Cluster Nozzle (Nose, Kawakami and Araki)

The below figure shows the latest hydrogen gas turbine development status per MHPS.

GT Model		Combustor Type	H_2 (vol%)
H-25	60/50Hz	Diffusion Multi-Cluster (DLN*)	100 30→100 (target)
H-100	60/50Hz	Pre-Mix (DLN) Multi-Cluster (DLN)	30 100 (target)
M501F	60Hz	Diffusion Pre-Mix (DLN) Multi-Cluster (DLN)	100 30 100 (target)
M501GAC	60Hz	Pre-Mix (DLN) Multi-Cluster (DLN)	30 100 (target)
M501J M501JAC	60Hz	Pre-Mix (DLN) Multi-Cluster (DLN)	30 100 (target)
M701F	50Hz	Diffusion Pre-Mix (DLN) Multi-Cluster (DLN)	100 30 100 (target)
M701J M701JAC	50Hz	Pre-Mix (DLN) Multi-Cluster (DLN)	30 100 (target)



• DLN: Dry Low NOx

Figure 27: MHPS Hydrogen Development Status by Gas Turbine (Mitsubishi Heavy Industries)

Siemens

Siemens claims extensive experience with high hydrogen content fuels in greater than 55 units with over 2.5 million cumulative engine operating hours since the 1960s (Siemens Gas and Power). This experience spans across multiple industries, geographies, and engine frames with varying output levels. The vast majority of this experience is with high hydrogen content synfuels.

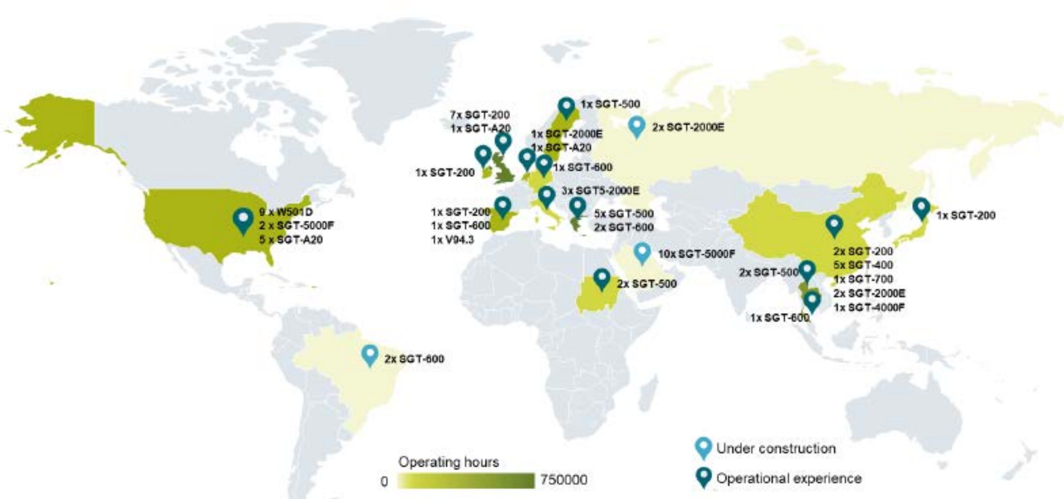


Figure 28: Siemens Energy Hydrogen Experience by Turbine and Location (Siemens Gas and Power)

Siemens has three primary combustion system types: DLE, wet low emissions (WLE), and diffusion. These systems are both annular and can-annular depending on the turbine model.

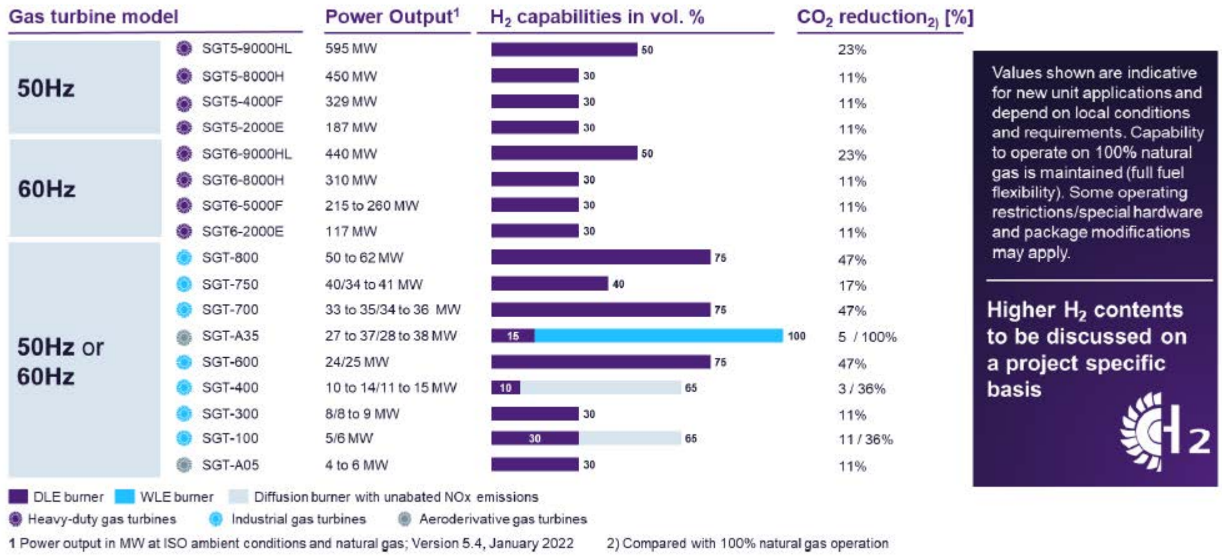


Figure 29: Siemens Gas Turbine Hydrogen Capability by Model (Siemens Energy)

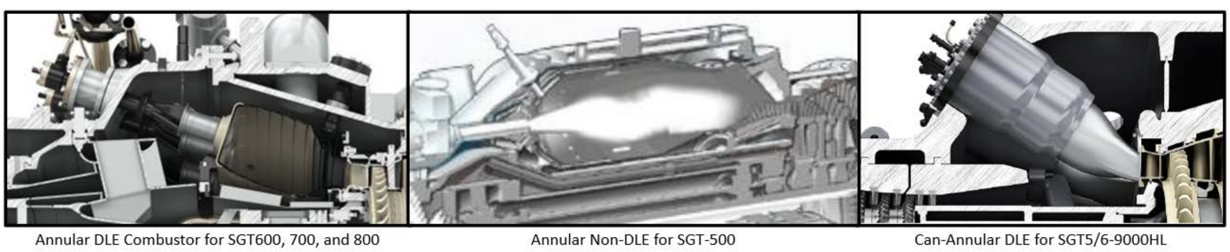


Figure 30: Siemens Combustor Design Examples (Siemens Gas and Power)

Siemens has several DLE technologies with which they are equipping their latest turbines. They are:

- HR3 burners for annular combustors in SGT5/6-2000E and SGT5/6-4000F
- Ultra-low NO_x Platform Combustion System (ULN/PCS) in the SGT6-5000F and SGT5/6-8000H
- Advanced Combustion for Efficiency System (ACE) in SGT5/6-9000HL

Each of these systems has the capability of burning 30-50% hydrogen by volume with a target of 100% by 2030.

SUMMARY

Gas turbines will continue to be an important part of the World's energy network as they complement renewable energy sources well and have a large existing installed base. Through use of pure hydrogen fuel, there is opportunity to drastically reduce CO_2 emissions generated as a byproduct of burning traditional fuels. There are many technologies that exist and that are under development that will help make hydrogen prevalent in the future energy economy. Many of these technologies are very promising, but the major challenge will be scaling them and making hydrogen generation, distribution, and usage economically viable and truly green.

Many of the World's largest energy companies and gas turbine OEMs are betting that these challenges can be overcome. Gas turbine OEMs are committing significant resources to designing hydrogen burning technology into their new engines and to creating modification packages for existing engines. The focus of these design efforts is mainly on the turbine combustion systems, while the remainder of the engine and overall engine architecture remains mostly unchanged. Through continued aggressive goal setting and funding, it is expected that hydrogen usage in gas turbines will fully be enabled in existing and new assets within the next one to two decades.

References

Ansaldo Energia. *Hydrogen for the Energy Transition*. 2022. Web Page . 8 August 2022.

Asai, Tomohiro, Yasuhiro Akiyama and Satoschi Dodo. *Recent Advances in Carbon Capture and Storage*. Intech open, 2017.

Blacharski, Tomasz, et al. "The Effect of Hydrogen Transported Through Gas Pipelines on the Performance of Natural Gas." 2016.

Columbia Center of Global Energy Policy. *Hydrogen Fact Sheet: Production of Low-Carbon Hydrogen*. Fact Sheet. New York: Columbia University, 2021. Document.

Engineering ToolBox. *The Engineering ToolBox*. n.d. Web Site. 20 July 2022. <https://www.engineeringtoolbox.com/>.

Escola Europea. *From LNG to Hydrogen? Pitdalls and Possibilities*. 14 August 2018. Article. 26 July 2022. <https://escolaeuropea.eu/news/environmental-news/from-lng-to-hydrogen-pitfalls-and-possibilities/#:~:text=There%20are%20other%20dissimilarities%20between,kept%20at%20%2D253%C2%B0C.>.

GE Energy. *Uprate Options for the MS7001 Heavy Duty Gas Turbine*. Technical Report. Atlanta: General Electric Company, 2006. Document.

GE Power. "Hydrogen Fueled Gas Turbines." February 2022. *GE.* Document. 10 August 2022.

General Electric Gas-Power. "Hydrogen as a Fuel for Gas Turbines." 2022.

Goldmeer, Jeffrey. "Power to Gas: Hydrogen for Power Generation (GEA33861)." Technical Report. 2019. Document.

Greenwood, Stuart A. *Low Emissions Combustion Technology for Stationary Gas Turbine Engines*. Technical Report. San Diego: Solar Turbine Inc., 2002. Document.

Inoue, KEI, et al. "Development of Hydrogen and Natural Gas Co-firing Gas Turbine." Technical Report. 2018. Document.

International Energy Agency. "Global Hydrogen Review 2021." 2021. Document.

Mitsubishi Heavy Industries. *Creating a Sustainable Future Through Hydrogen Generation*. 2022. web page. 10 August 2022.

Mulder, Sebastiaan. "Ready for the Energy Transition: Hydrogen Considerations for Combined Cycle Power Plant." *Power* (2021): 2. Magazine. <https://www.powermag.com/ready-for-the-energy-transition-hydrogen-considerations-for-combined-cycle-power-plants/>.

Nose, Masakazu, et al. "Hydrogen-Fired Fas Turbine Targeting Realization of CO2 Free Society." Technical Report. 2018. Document.

Office of Energy Efficiency & Renewable Energy. *Hydrogen: A Clean, Flexible, Energy Carrier*. 21 February 2017. Article. 20 July 2022. <https://www.energy.gov/eere/articles/hydrogen-clean-flexible-energy-carrier>.

Power Engineering International. *Hitting the Gas*. 21 October 2014. Online Article. 5 August 2022. <https://www.powerengineeringint.com/coal-fired/equipment-coal-fired/hitting-the-gas/>.

Power Systems Mfg, LLC. "PSM." 2020. *FlameSheet.* Document. 10 August 2022.

Siemens Energy. *Hydrogen Power and Heat with Siemens Energy Gas Turbines*. Report. Erlangen: Siemens Energy Global GmbH & Co. KG, 2022. Document.

Siemens Gas and Power. "Hydrogen Power with Siemens Gas Turbines." 2020. Document.

U.S. Energy Information Administration. *Carbon Dioxide Emissions Coefficientes*. 19 November 2021. Table. 20 July 2022. <https://www.eia.gov/environment/emissions/co2_vol_mass.php>.

—. *Energy and the Environment Explained*. 24 June 2022. Article. 20 July 2022. <https://www.eia.gov/energyexplained/energy-and-the-environment/where-greenhouse-gases-come-from.php#:~:text=In%202021%2C%20petroleum%20accounted%20for,energy%2Drelated%20CO2%20emissions.>.

—. *Natural Gas Prices*. 8 July 2022. Table. 7 July 2022. <https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm>.

Wikipedia. *Kinetic Diameter*. 21 June 2022. Web Site. 7 July 2022. <https://en.wikipedia.org/wiki/Kinetic_diameter>.