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**General Electric, Hydrogen for power generation experience, requirements, and
implications for use in gas turbines (March 2022)**

Hydrogen for power generation

Experience, requirements, and
implications for use in gas turbines

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Building a world that works

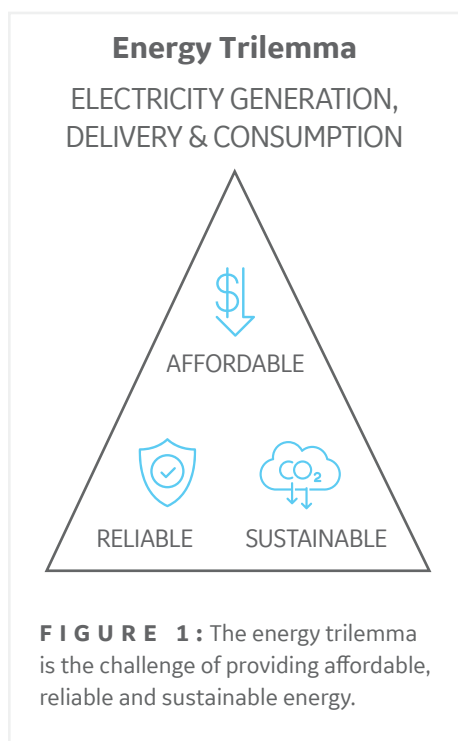
Introduction

In order to combat man-made climate change, there is a global need for decarbonization,* and all sectors that produce carbon dioxide (CO₂) must play a role.

In 2019, global CO₂ emissions from fossil fuels amounted to 33 gigatons, with 41 percent of that coming from the power generation sector, and the remainder from the transportation and industrial sectors. There is a lot of work to be done and time is against us. According to the IPCC's 2018 special report "Global Warming of 1.5 °C," we had 580 gigatons of CO₂ in our remaining carbon budget if the globe were to have a 50–50 chance of keeping global warming to 1.5 °C compared to pre-industrial levels. Bring that forward from 2018 to 2020, and if we continue on our current path of emissions, we have only 15 years left before the budget runs out. The good news is that there are solutions available today to enable the power sector's rapid reduction in carbon intensity and allow the world to buy more time.

The power sector's journey to lower carbon, often referred to as the *Energy Transition*, is characterized by rapid deployment of renewable energy resources and a rapid reduction in coal, the most carbon-intensive power generation source.

As governments, countries, and companies establish their charters for achieving carbon reduction goals, they will all grapple with the Energy Trilemma: the need to balance affordable energy, maintain reliable power supply, and improve sustainability. See Figure 1. Each country is at a different point in its decarbonization journey and will prioritize the elements of the trilemma differently, but the most effective way is a mix of generation resources that complement one another.



Based on our extensive analysis and experience across the breadth of the global power industry, GE believes that the accelerated and strategic deployment of renewables and gas power can change the near-term trajectory for climate change, enabling substantive reductions in emissions quickly, while in parallel continuing to advance the technologies for near zero-carbon power generation.

*Decarbonization in this paper is intended to mean the reduction of carbon emissions on a kilogram per megawatt hour basis.

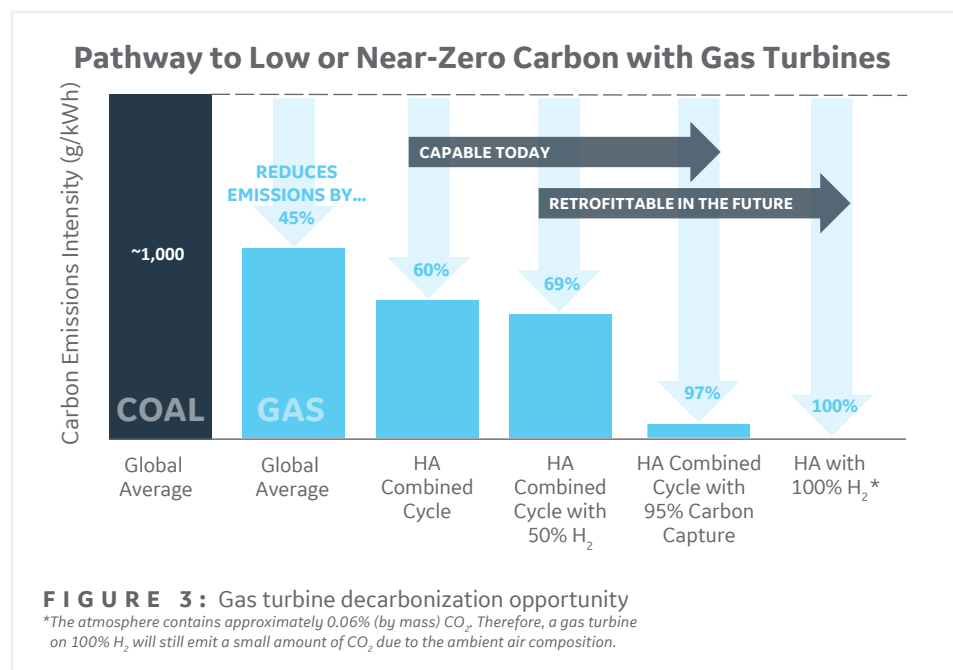
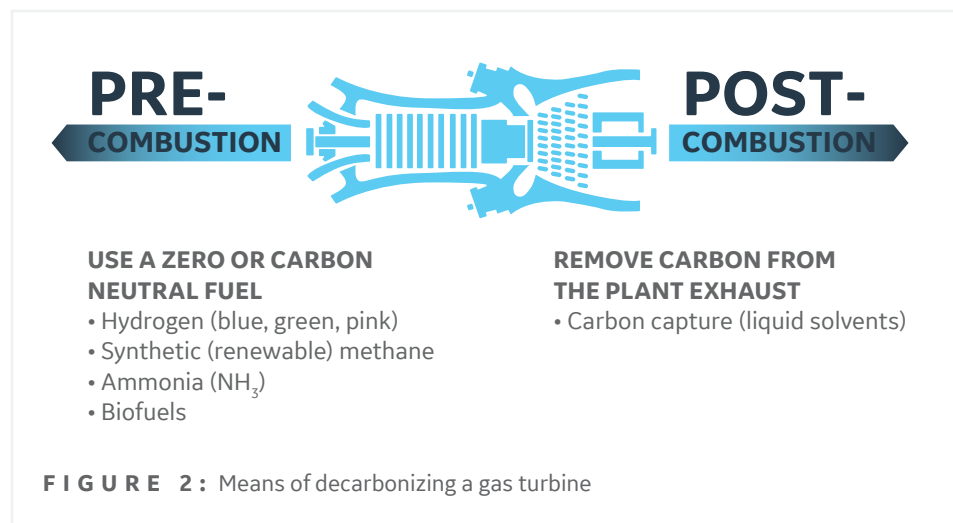
GE believes that the accelerated and strategic deployment of renewables and gas power can change the trajectory for climate change



Introduction

As of 2020 there were ~1.6 TW of gas turbines installed globally, and despite the effects of COVID-19 on power demand gas generation accounted for ~22 percent of generation globally. There are two ways to systematically approach the task of turning high efficiency gas generation into a zero or near zero-carbon resource: pre and post-combustion. See Figure 2. Pre-combustion refers to the systems and processes upstream of the gas turbine. The most common approach today to tackle pre-combustion decarbonization is simple: change the fuel. The vast majority of gas turbines burn natural gas, or methane (CH_4), to release energy which ultimately produces the electricity we use at home and for industry. An advantage of gas turbines is that they are able to operate on many other fuels besides natural gas. Some of these fuels, such as hydrogen (H_2), do not contain carbon in the first place, and will therefore not emit CO_2 when combusted. Furthermore, H_2 can be introduced to new gas turbines and existing gas turbines alike, reinforcing the concept that solutions are available today to decarbonize assets already in the field and those waiting to be installed. The possibility of burning hydrogen in a gas turbine avoids the potential “lock-in” of CO_2 emissions for the entire life of the power plant.

On the other side of the gas turbine, or post-combustion, there is a tool chest of different technologies that can remove CO_2 from the flue gases in a process that is commonly referred to as carbon capture. The general concept of carbon capture involves introducing into the plant exhaust stack a specialized chemical which has an engineered affinity to carbon. Once the CO_2 and the agent bond, the CO_2 and specialized chemical are processed, the CO_2 is separated, and taken to a compression tank as pure CO_2 . This CO_2 is then transported to either a geologic formation deep underground for permanent sequestration, or re-used in industrial process, thus completing the process of Carbon Capture and Utilization or



Sequestration (CCUS). Similar to introducing hydrogen to a plant, CCUS can be applied to both new and existing gas power plants, again avoiding lock-in of CO_2 emissions for the life of the power plant.

GE believes that in order for the power sector to rapidly decarbonize while maintaining high levels of reliability, both

pre and post-combustion decarbonization options for gas turbines are viable tools available today. Both hydrogen and CCUS have their own merits and ideal areas of application. This paper will discuss the merits and limitations specific to hydrogen as a fuel. See Figure 3.

HYDROGEN INFRASTRUCTURE – PRODUCTION, TRANSPORT, AND STORAGE

Hydrogen is the most abundant element in the universe. However, despite the plentiful nature of hydrogen, it does not exist on earth as a standalone molecule. In other words, hydrogen likes to bond with other molecules. Therefore in order to yield pure hydrogen on earth, it must be intentionally separated from its paired molecules, which mostly commonly take the form of water (H_2O), or hydrocarbons (e.g., CH_4). The various production processes and feedstocks supply the current world demand for hydrogen (H_2) of ~70 million tonnes per year.¹ Approximately 90% of this is produced using natural gas or coal as a feedstock, typically in a reforming process. Steam methane reforming (SMR) is a common method, using natural gas and steam in a reaction to form hydrogen, but there are alternatives such as auto thermal reforming (ATR). Both of these processes generate CO_2 ; for each kg H_2 produced using an SMR, ~9.5 kilograms of CO_2 are generated. Today, most if not all of this CO_2 is vented to the atmosphere. There are other methods of generating hydrogen including electrolysis of water. Additional details on blue and green hydrogen production methods can be found in GE's 2019 Hydrogen for Power white paper, GEA33861.²

A color-based convention is being used internationally to describe and differentiate hydrogen production methods:

- **Grey (or black):** Gasification of coal or reforming of natural gas without carbon capture
- **Blue:** Reforming of methane (SMR or ATR) with carbon capture and storage
- **Green:** Electrolysis of water using renewable power
- **Pink (Red):** Electrolysis of water using nuclear power
- **Turquoise:** Pyrolysis of methane which produces hydrogen and solid carbon as a by-product
- **White:** Gasification or other process using 100% biomass as a feedstock

From a power generation perspective, the production method is not critical as the gas turbine only sees hydrogen.

TRANSPORTATION & STORAGE

Once produced, hydrogen will most likely have to be transported and/or stored. This can be done as a gas or a liquid. When stored as a gas, tanks are typically kept at pressures in excess of 5000 psi (34.5 MPa). Compressing hydrogen from 20 bar (~290 psi) to 350 bar (~5000 psi, ~35 MPa) requires at least 1.05 kWh/kg; compression energies of 1.7–6.4 kWh/kg (~2630–9900 BTU/lb) may be more representative of requirements for real systems with losses and other inefficiencies.³ For comparison, according to the US Energy Information Administration, the average US residential home uses ~29 kWh of electricity per day.

Hydrogen gas can be condensed to the liquid phase, but this requires a temperature of -423.6 °F (-252.9 °C) which is ~36 °F (~20 °C) above absolute zero. The process of liquefying hydrogen is highly energy intensive, requiring ~10–13.3 kWh of energy per kg of liquid hydrogen,³ which is ~30% of the lower heating value per kg of hydrogen. Once liquefied, storage tanks are typically are double-walled and heavily insulated to maintain cryogenic conditions. The world's largest liquid hydrogen tank is located at Kennedy Space Center. It can hold 858,000 gallons of liquid hydrogen; this is equivalent to ~97 million cubic feet when expanded to a

gas. If used to fully fuel a 7HA.03 (~430 MW) gas turbine, it would provide ~8 hours of fuel; if used to fuel a TM2500 (~35 MW) it would provide about 80 hours of operation.

An alternative being considered is geological storage, including the use of salt caverns, aquifers, depleted gas wells, and hard rock caverns.^{4,5} Storing gas in underground caves is not new; the US has been storing natural gas in underground systems for decades.⁶ Figure 4 shows the volume of natural gas underground storage in the US since 1975.⁷ The base gas data shows the total amount of natural gas stored underground, where the working gas volume data shows the maximum amount of natural gas that was stored. Due to the nature of underground storage, not all of the gas stored can be removed; some gas must be retained in the cave to keep the system pressurized. This is called the “cushion,” and the percentage of the base gas that must remain as cushion depends on the type of underground geology being utilized.

To help accelerate the development of a hydrogen supply-chain, the government of Japan commissioned the world's first liquid hydrogen (LH_2) carrier ship.⁸ This ship will be able to transport 1,250 m³ in a single tank, which is a relatively small amount compared to the 125,000–175,000 m³ transported by

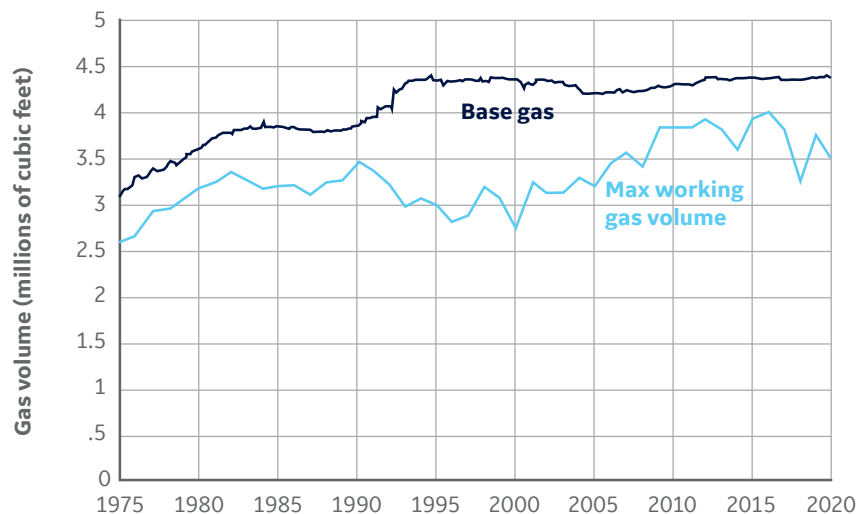


FIGURE 4: Volume of US natural gas storage 1973–2020⁷

typical LNG carrier ships. From a transported energy standpoint, the LH₂ tanker is capable of shipping only ~1% percent of the energy in a typical LNG tanker. Although this ship will transport hydrogen, its engines run on diesel fuel.

Another transportation alternative is to transform the hydrogen into more stable compounds, such as ammonia (NH₃). An advantage for ammonia is that it can be stored as liquid at -28 °F (-33.3 °C) which is hundreds of degrees warmer than the conditions required to liquefy hydrogen. Ammonia could be transported in multi-cargo gas carrier ships which are capable of carrying LPG (liquefied petroleum gas)⁹; this is aided by the fact that the boiling point of propane is -43.6 °F (-42 °C) is approximately 15.6 °F (8.7 °C) cooler than ammonia’s boiling point.

Another option being considered is the use of organic liquids, such as methylcyclohexane (MCH), which would function as a liquid organic hydrogen carrier (LOHC).^{10,11} In this concept hydrogen is combined with toluene (C₇H₈) to form MCH (C₇H₁₄) which has a boiling point of ~214 °F (~101 °C), meaning that it can be transported as a liquid at room temperature without need for any special cryogenic or pressurized tanks.

CARBON EMISSION
REDUCTION
WITH HYDROGEN

Since hydrogen (H₂) does not contain any carbon, it does not produce any carbon when burned in a gas turbine. In a complete and balanced combustion reaction, hydrogen only produces water: $H_2 + \frac{1}{2} O_2 \rightarrow H_2O$

Using 100% hydrogen as fuel for a gas turbine will lead to elimination of essentially all CO₂ emissions relative to operation on natural gas or other hydrocarbon fuels. CO₂ emissions attributed to the fuel will be zero, although the plant will still emit a very small amount of CO₂ as there is approximately 0.04% (by volume) CO₂ in the air that will be emitted with the products of combustion. For example, a gas turbine operating on 100% (by volume) H₂ fuel will see a CO₂ reduction of more than 99% relative to the CO₂ emission on 100% methane.

There are also cases where H₂ blending with natural gas is being considered to reduce CO₂ emissions as a near-term alternative to operating on 100% natural gas. In these cases, the amount of CO₂ reduction will be a function of the percentage of H₂ in the fuel. The amount or percent H₂ in the fuel can be measured on a volume, mass, or heat input basis. There is a significant difference in the H₂ flows based on these methods due to the difference between hydrogen’s energy density on a mass and volume basis as shown in Table 1.



Operation of a gas turbine on 100% hydrogen results in zero fuel-based CO₂ emissions

TABLE 1: Comparisons of lower heating values (LHV)

PROPERTY	UNITS	METHANE	GAS POWER
Formula		CH ₄	H ₂
LHV (per volume)	MJ/Nm ³	35.8	10.8
	BTU/scf	911.6	274.7
LHV (per mass)	MJ/kg	50	120
	BTU/lb	21,515	51,593

Typically, flows into a gas turbine are quoted on a volumetric basis, as this is easier to measure than heat content but the key factor in determining emissions for a fuel blend is the relative heat input from the fuel constituents, especially as methane and hydrogen have very different energy densities. This is an important distinction as adding small amounts of hydrogen to the fuel (on a volumetric basis) will have a smaller impact on carbon dioxide emission reduction. Using this information, the relationship between the amount of H_2 in the fuel (by volume) and CO_2 emission reduction can be defined (See Figure 5). Due to the non-linear nature of this curve, attaining a 50% reduction in CO_2 emissions requires a blend that is ~75% (by volume) hydrogen.

If instead, the hydrogen content in the fuel is defined as a percentage of the turbine heat input, the relationship between H_2 and CO_2 reduction is linear as shown in Figure 6. To attain a 50% reduction in CO_2 emissions requires a blend that is 50% hydrogen and 50% methane (by heat content).

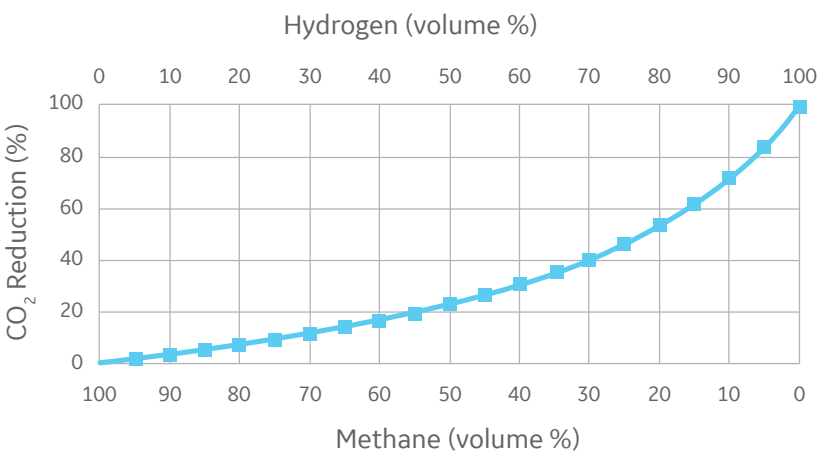


FIGURE 5: Relationship between CO_2 emissions and hydrogen/methane fuel blends (volume %)

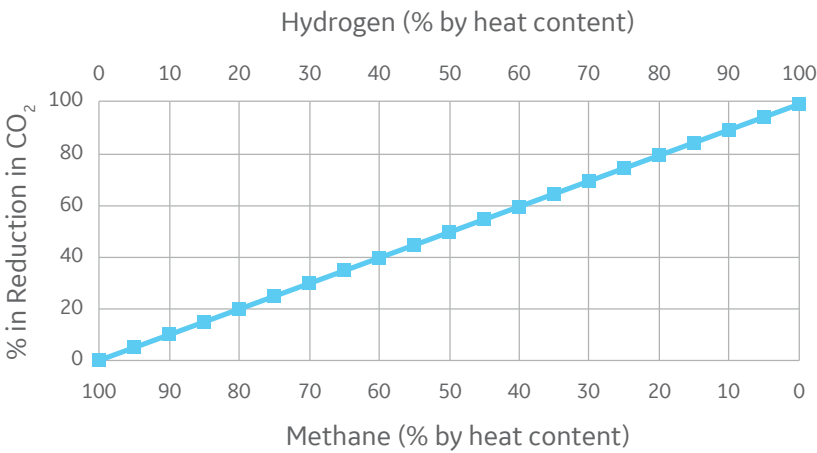


FIGURE 6: Relationship between CO_2 emissions and hydrogen/methane fuel blends (% heat input)



In addition to a simple percent reduction, the carbon intensity of a system can be used as a gage to assess carbon emissions. In the case of a power plant, this ratio is the mass of CO₂ emitted divided by the electrical power output. This is typically listed as gram per kilowatt-hour (g/kWh) which normalizes the CO₂ emissions to the energy produced by the power plant. A modern combined cycle power plant operating on 100% natural gas will have a carbon emission intensity of ~305–380 g/kWh, depending on the efficiency of the gas turbine. Gas turbines with higher efficiencies will consume less fuel to generate the same amount of electricity and therefore have lower carbon intensities. A gas turbine operating on 100% hydrogen will have a carbon emission intensity of ~0 g/kWh.* Gas turbines operating on a blend of hydrogen and natural gas will have a carbon intensity profile that is a function of the hydrogen content in the fuel. Figure 7 shows the carbon intensity for a 9H.02 gas turbine gas turbine in a combined cycle configuration.

In some parts of the world, environmental regulations have been put into place to reduce carbon emissions using carbon taxes. The World Bank’s Carbon Pricing Dashboard** provides details on many of the

world’s carbon taxes and emissions trading systems (ETS). Another pathway being used to reduce new carbon emissions is by setting a carbon emission intensity as a criterion for power plant project financing. For example, the European Investment Bank (EIB) has set an Emissions Performance Standard of 250 g of CO₂ per kWh (g/kWh) for any new project it will finance.¹² This replaces the older EIB standard of 550 g/kWh. Using Figure 7 as an example, a gas turbine operating on 100% natural gas would have satisfied the older 550 g/kWh requirement. However, a 9HA.02 combined cycle power plant, which is the most efficient CCGT in operation today, would not meet the standard. This combined cycle plant would have to be operated on a fuel with at least ~49% (by volume) hydrogen to meet the 250 g/kWh requirement.

New carbon policies are being evaluated globally, which could drive more interest in hydrogen and other zero carbon fuels, as well as renewable and low-carbon fuels.

*The atmosphere contains approximately 0.04% carbon dioxide. Therefore, a gas turbine that is operating on a fuel without any carbon will still emit a small amount of carbon dioxide due to the ambient air composition.
**<https://carbonpricingdashboard.worldbank.org>

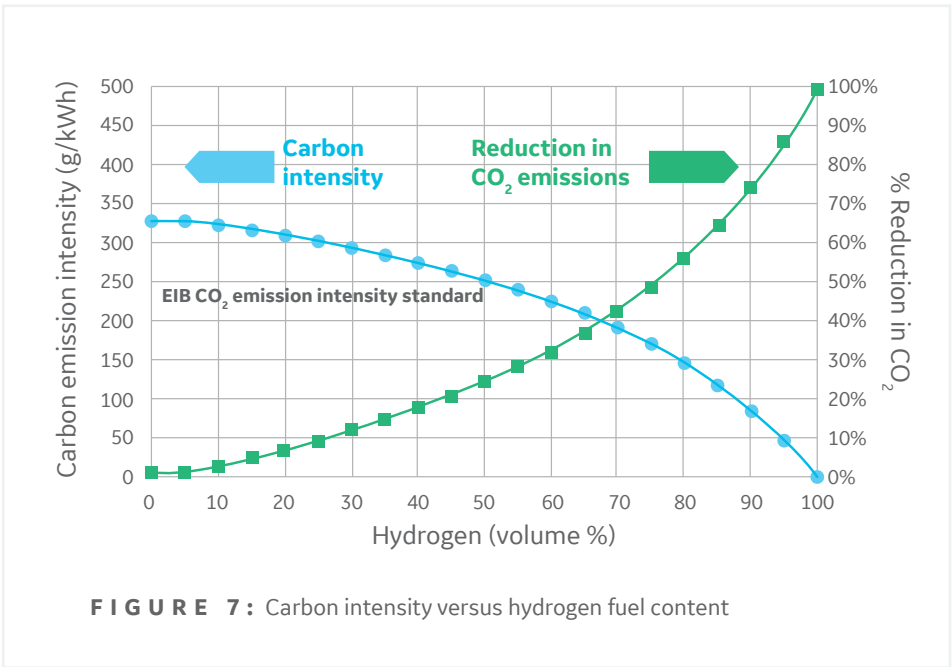


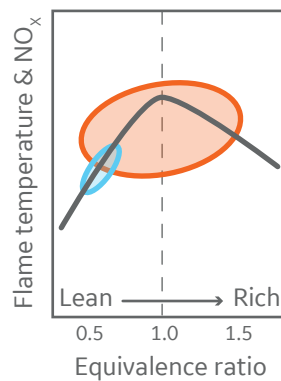
FIGURE 7: Carbon intensity versus hydrogen fuel content



GAS TURBINE COMBUSTION TECHNOLOGY

The ability of gas turbine to operate on a high hydrogen fuel requires a combustion system that can deal with the specific nature of this fuel. Combustion systems are typically categorized into one of two categories: diffusion or lean premixed.

Diffusion combustion systems operate at or near stoichiometric conditions. (This occurs when the fuel and air are in balanced proportion and there isn't excess fuel or air. In terms of combustion chemistry, a balanced combustion reaction happens at an equivalence ratio of one.) This leads to very high flame temperatures as well as high NO_x emissions, as illustrated in Figure 8. These combustion systems typically use a diluent such as water, steam, or nitrogen injected into the combustor to reduce NO_x emissions. GE has diffusion combustion systems in-service for both Aeroderivative and Heavy-Duty gas turbines that are capable of burning hydrogen. These include the single annular combustor (SAC) for Aeroderivative gas turbines and the single nozzle or multi-nozzle quiet combustor (MNQC) for Heavy-Duty gas turbines as shown in Figure 9 on the following page.



DIFFUSION FLAME

Flame characteristics

- Highly stable
- High peak flame temperature
- NO_x : ~200 to ~600 ppm



LEAN PREMIXED FLAME

Flame characteristics

- Low NO_x without diluent
- Susceptible to flashback and combustion dynamics
- NO_x : single digit ppm



FIGURE 8: Diffusion versus lean premixed combustion

GE has proven combustion technology that can operate on blends of hydrogen and natural gas



Lean premixed combustion systems operate with aerodynamically stabilized flames in the lean region of the chart shown in Figure 6. In this regime, flame temperature is reduced, which lowers NO_x emissions. GE's dry low emissions (DLE) and dry low NO_x (DLN) combustion systems operate in this regime. Most DLE and DLN combustion systems are limited in the amount of hydrogen they can utilize due to risks of flashback and flame holding as discussed in the Plant Impact section below. Some newer combustion systems, like GE's DLN 2.6e combustor (See Figure 9), have newer fuel injection configurations and can handle increased levels of hydrogen.

These combustion systems are detailed in the next sections.

SINGLE ANNULAR COMBUSTOR (SAC)

GE's Aeroderivative gas turbines can be configured with a single annular combustor (SAC), which can operate on a variety of fuels, including process fuels and fuel blends with hydrogen. There are over 2,600 gas turbines configured with this combustion system; these units have accumulated more than 100 million fired hours on a variety of fuels. Depending on the specific Aeroderivative gas turbine model, SAC combustors can handle hydrogen concentrations from 30% (by volume) up to 85% (by volume).

Single Nozzle and Multi Nozzle combustors GE's Heavy-Duty gas turbines have two combustor configurations capable of operating on fuels with high H_2 content. The Single Nozzle (SN) or standard combustor is available on B and E-class turbines. The Multi-Nozzle Quiet Combustor (MNQC) is available for multiple E and F-class gas turbines. Combined, these combustion systems have been installed on more than 1,700 gas turbines, and have accumulated more than 3.5 million fired hours on a variety of low calorific value fuels, including syngas, steel mill gases, refinery gases, etc.

During the 1990's GE evaluated the use of the MNQC combustor to operate on high hydrogen fuels.¹³ The hydrogen concentration of the fuels examined ranged from ~44% (by volume) up to ~90% (by volume); the remaining constituents in the fuel were inert gases, i.e., nitrogen and water vapor. The program evaluated the impact on NO_x emissions, combustion dynamics and combustion metal temperatures. The test results demonstrated the feasibility of burning hydrogen as the only combustible (up to 90% by volume of the total fuel) in GE's MNQC combustion system.

Today, GE is able to quote hydrogen levels up to ~90–100% (by volume) for applications with the MNQC combustor or single nozzle combustor.*

DLE AND DLN COMBUSTORS

DLE and DLN combustion systems are capable of operating with varying amounts of hydrogen in the fuel. The DLE combustor, which is found on GE's Aeroderivative gas turbines is limited to 35% (by volume) hydrogen. The DLN1 combustion system, which is available on GE's 6B, 7E, and 9E gas turbines is capable of operating with up to ~33% (by volume) hydrogen when blended with natural gas. GE's DLN 2.6+ combustors are capable of operating on hydrogen levels as high as ~18% (by volume).^{*} The standard fuel systems for these combustors are typically only configured for a maximum of 5% (by volume) hydrogen and would require upgrading to safely operate at higher hydrogen concentrations.

The GT26 configured with the Environmental Burner (EV) and Sequential Environmental Burner (SEV) combustion system is also capable of operating on blends of hydrogen and natural gas. Based on previous combustion studies and testing, the capability of the current combustion system is estimated to be ~40* percent (by vol) hydrogen.³⁴

*Hydrogen limits for a given project will be a function of gas turbine model, ambient conditions, composition of natural gas if blending, emissions requirements, and other site-specific requirements.

AERO GAS TURBINES



HEAVY-DUTY GAS TURBINES



FIGURE 9: High hydrogen combustion systems



FIGURE 10: A: multi-tube mixer concept hardware, B: combustor test of multi-tube mixers on a H_2/N_2 fuel blend, and C: commercial configuration of the DLN 2.6e combustor

NEXT GENERATION HIGH H_2 COMBUSTION SYSTEM

As part of the US Department of Energy's Advanced IGCC/Hydrogen Gas Turbine program which ran from 2005–2015, GE developed a low NO_x hydrogen combustion system.* This new combustion system was based on the operating principle of small-scale jet-in-crossflow mixing of the fuel and air streams.¹⁴ The miniaturized tubes (see Figure 10A) function as “fast” mixers enabling premixed combustion for gaseous fuels with higher reactivity (ethane, propane, hydrogen, etc.)

During this program, multiple pre-mixing configurations were tested at GE's Global Research Center in a single nozzle test facility as well as at GE's Gas Turbine Technology Lab in Greenville, South Carolina. (Information on the Greenville combustion facility is available in Reference¹⁵). Figure 10B shows a combustor chamber with multi-tube mixers operating on a H_2/N_2 fuel blend.

Due to the advanced premixing capability of this technology, it became an element of GE's DLN 2.6e combustion system.¹⁶ Based on interest in low-carbon power for future power plants, the hydrogen capability of the

DLN 2.6e combustion system was evaluated. Results of preliminary testing indicated that this combustion system has entitlement to operate on fuels containing up to 50% (by volume) hydrogen.

This combustion technology is now available on GE's 9HA.01, 9HA.02, and 7HA.03 gas turbines. The first turbine configured with this combustion system is a 9HA.02 that entered commercial operation in early 2021.

*This effort was sponsored by the US Department of Energy under Cooperative Agreement DE-FC26-05NT42564.

GAS TURBINE EXPERIENCE WITH HYDROGEN

Once hydrogen has been generated it can be utilized as a power generation fuel. Gas turbines have the capability to operate on hydrogen, supporting a variety of industrial applications, including steel mills, refineries, and petrochemical plants. GE is a world leader in gas turbine fuel flexibility, including more than 100 gas turbines that have (or continue to) operate on fuels that contain hydrogen. This fleet has accumulated more

GE has more than 100 gas turbines that have operated with hydrogen blends as a fuel. These gas turbines have accumulated more than 8 million operating hours.

than 8 million operating hours and over 530 Terawatt-hours of power generation. This fleet also includes a set of more than 30 gas turbines that have operated on fuels with at least 50% (by volume) hydrogen; these units have accumulated more than 2.5 million operating hours. Figure 10 highlights some of the projects that have used fuels with varying concentrations of hydrogen over the last 50 years. The following sections provide more details on some of these projects.^{17, 18, 19}

Timeline of GE Experience with H₂ and Associated Fuels

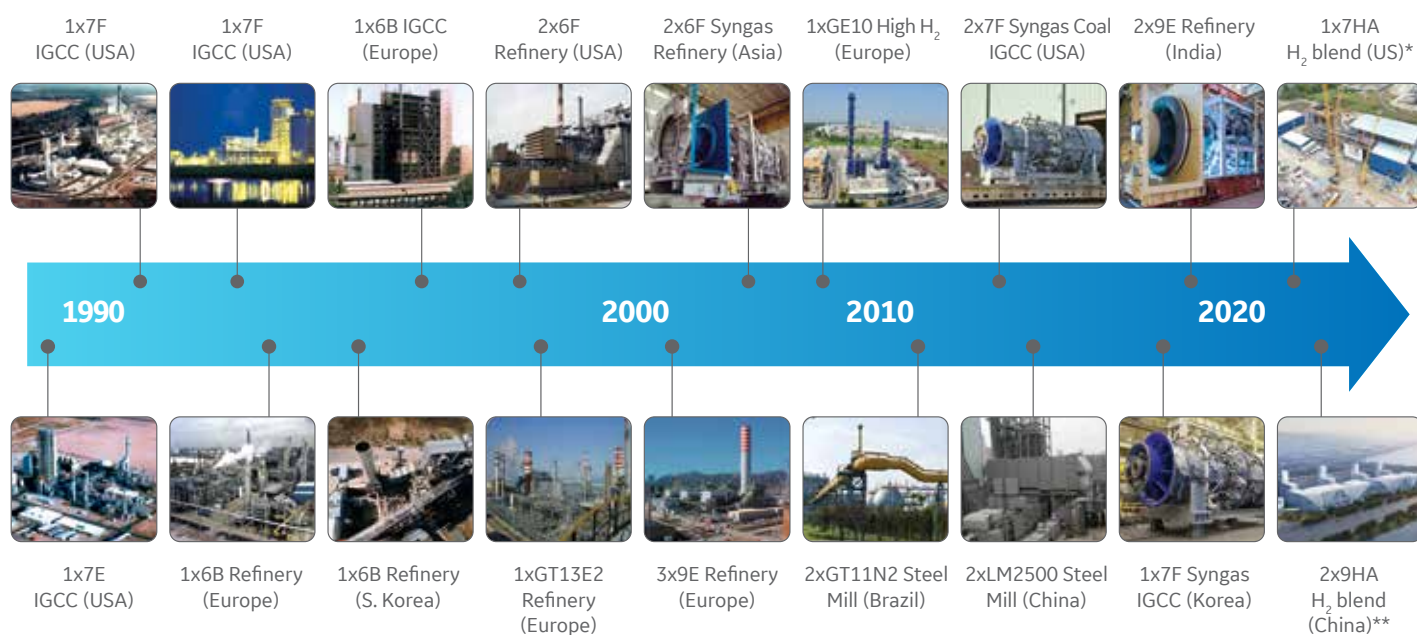


FIGURE 11: Timeline of selected projects with hydrogen fuels

*Expected H₂ operation in 2022. **Expected H₂ operation in 2023.

HYDROGEN FUEL BLENDING

There are circumstances when hydrogen is available as a by-product of an industrial or petrochemical process. But in some situations, there may not be enough hydrogen to fully load a gas turbine, so a blend of hydrogen and natural gas is used; in these cases, traditional DLE and DLN combustion systems can be utilized. One example of this fuel blending application was at the Dow Plaquemine plant in the USA.²⁰ At this site, hydrogen was injected into natural gas to create a 5%/95% (by volume) blend of hydrogen and natural gas. Figure 12 shows the blending system; after blending, the fuel gas was fed to four GE 7FA gas turbines configured with DLN 2.6 combustion systems; operation on the blended fuel started in 2010.

A second example of hydrogen fuel blending is at the Gibraltar-San Roque refinery owned by Compañía Española de Petróleos (CEPSA), one of Spain's leading petrochemical companies. At this site a 6B.03 gas turbine is operating on a refinery fuel gas (RFG) that contains a varying amount of hydrogen. If the hydrogen level exceeds ~32% (by volume) the RFG is blended with natural gas. As of 2015, this gas turbine had operated more than 9,000 hours on this fuel.²¹

LOW CALORIFIC VALUE FUELS: STEEL MILL GASES

Steel mills produce a variety of low calorific value by-product gases, i.e., blast furnace gas (BFG) and coke oven gas (COG), that have varying amounts of hydrogen. GE has multiple heavy-duty gas turbines operating on these fuels. Examples include multiple steel mills in Asia using COG/BFG fuel blends in GE 9E.03 gas turbines;^{22, 23} Figure 13A is an example of a steel mill configured with a GE gas turbine. GE's Aeroderivatives can also operate on coke oven gas.²⁴ An example of the latter case is a set of LM2500+ turbines operating on a coke oven gas (COG) with approximately 60% (by volume) hydrogen; see Figure 13B. These units were commissioned in 2011 and have accumulated over 100,000 hours on COG. Combined, GE's aero and heavy-duty gas turbines have accumulated more than 1.5 million fired hours with steel mill gases.

LOW CALORIFIC VALUE FUELS: SYNTHESIS GASES (SYNGAS)

The gasification of coal or refinery residuals creates a fuel known as synthesis gas (syngas) that contains a variety of gases, including hydrogen. The H₂ content in these fuels can range from 20% to ~50% (by volume) depending on the feedstock (i.e., coal, refinery bottoms) and the gasification process. Multiple IGCC (integrated gasification combined cycle) plants utilizing E-class and F-class gas turbines are in commercial operation globally. Plants with GE gas turbines burning syngas have accumulated more than 1.9 million operating hours. This includes the Tampa Electric Polk Power Station, Duke Edwardsport IGCC plant, and the Korea Western Power (KOWEPO) TaeAn IGCC plant.

HIGH HYDROGEN

Typically, when H₂ is available in large volumes it is used in hydrotreating crude oil or in the production of other commercial products, such as fertilizers. However, there are instances where a large volume of high concentration hydrogen is available from a process where there are no other available off-takers.

GE's fleet of gas turbines installed for operation on high hydrogen fuels includes more than a dozen Frame 5 gas turbines and more than twenty 6B.03 gas turbines. Many of these turbines operated on fuels with hydrogen concentrations ranging from 50% (by volume) to 80% (by volume). One example of a gas turbine operating on a high hydrogen fuel is a 6B.03 operating at a refinery in South Korea. This unit (Figure 14) has operated on a fuel that contains more than 70% (by volume) hydrogen for over 20 years with max H₂ levels greater than 90%.^{25, 26} To date the unit has accumulated more than 180,000 hours on the high hydrogen fuel. A second example of a high hydrogen turbine is at Enel's Fusina, Italy facility. This plant, which was inaugurated in 2010, used a GE-10 gas turbine to produce ~11.4 MW of net electrical power operating on a fuel that was ~97.5% (by volume) hydrogen.^{27, 28, 29}



FIGURE 12: Hydrogen/natural gas blending system

A



B



FIGURE 13: A: Frame 9E.03 operating on steel mill gases at a plant in China; B: LM2500+ operating on high H₂ coke oven gas



FIGURE 14: High hydrogen fueled 6B.03 gas turbine

PLANT IMPACT

One of the many advantages of gas turbines is that they can be re-configured for operation on new fuels, including fuels with increased levels of hydrogen. Due to differences in the physical and chemical properties of hydrogen (see Table 2), adding hydrogen to a gas turbine may require changes to the gas turbine, gas turbine accessories and/or the balance of plant as illustrated in Figure 15. The magnitude of the required changes is a function of the amount of hydrogen in the fuel. This section

will highlight the potential impacts to power plant systems when using hydrogen.

FUEL ACCESSORY SYSTEMS

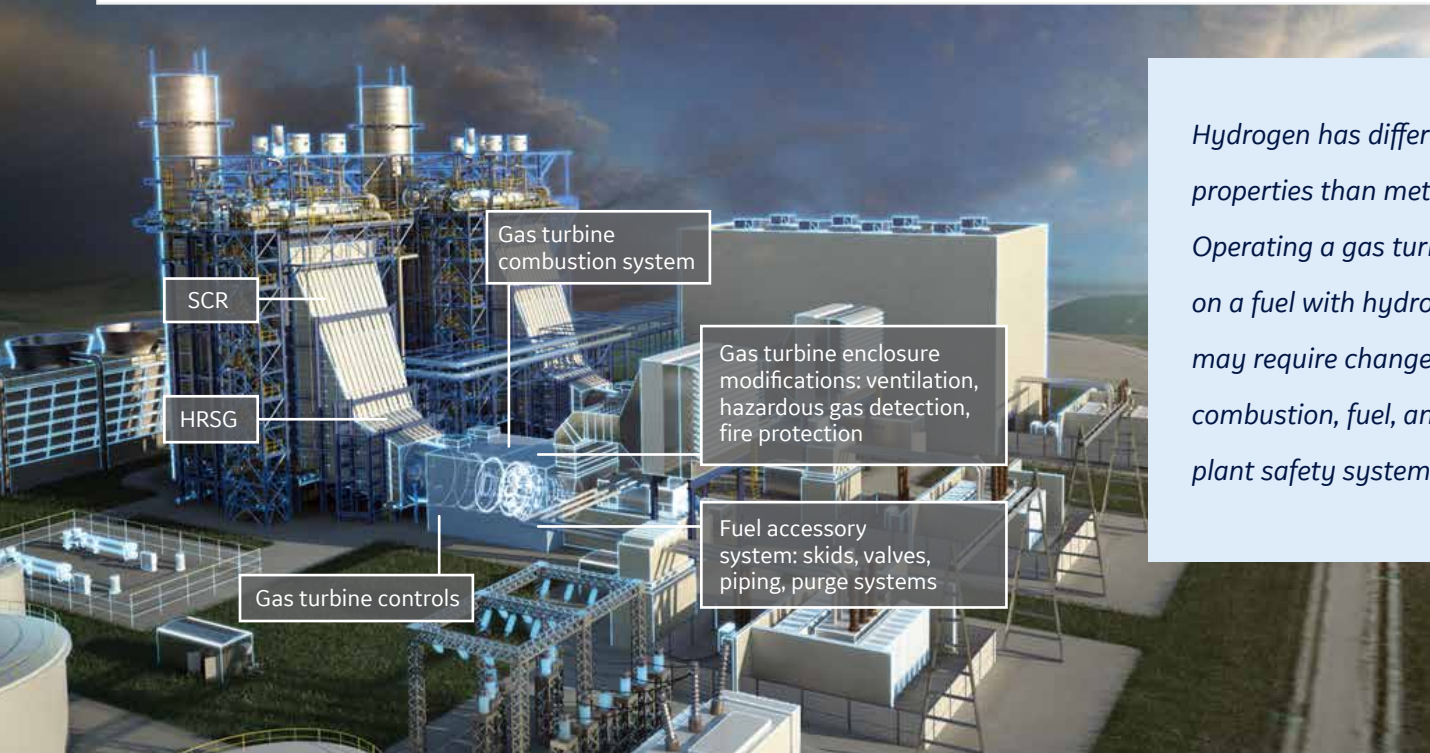
There are two fundamental operational scenarios with hydrogen: operating on a blend of hydrogen and natural gas, and operation on 100% hydrogen. If hydrogen is to be blended into an existing natural gas power plant, and the hydrogen is transported to the plant separately from natural gas, a fuel blending system will be required. This will ensure proper mixing of the hydrogen into the existing fuel system. This also allows proper control of the mix to ensure safe

operation of the power plant. Regardless of how the hydrogen is transported to the plant, there will be changes required to the fuel blending system.

As hydrogen's volumetric heating value is 1/3 that of methane (as shown in Table 2), it takes 3X more volume flow of hydrogen to provide the same heat (energy) input as methane. Therefore, if a fuel blend is to be used, the existing piping system might be acceptable, if using a small concentration of hydrogen. If planning to operate on high levels of hydrogen, a fuel accessory system configured for the required flow rates is required.

TABLE 2: Hydrogen and methane properties

CHARACTERISTIC	UNITS	METHANE	HYDROGEN
Formula		CH ₄	H ₂
Molecular weight	grams/mol	16	2
Molecular size	Picometers, 10 ⁻¹² meters	380	289
Lower/Upper flammability limits	%	4.4/17	4/75
Flame speed	cm/sec	~30–40	~200–300
Adiabatic flame temperature	° F (° C)	~3565 (~1963)	~4000 (~2204)
Lower Heating value	MJ/Nm ³ (BTU/scf)	35.8 (911.6)	10.8 (274.7)
Lower Heating value	MJ/kg (BTU/lb)	50 (21,515)	120 (51,593)



Hydrogen has different properties than methane. Operating a gas turbine on a fuel with hydrogen may require changes to combustion, fuel, and plant safety systems.

FIGURE 15: Potential impact of hydrogen fuel conversion on gas turbine systems

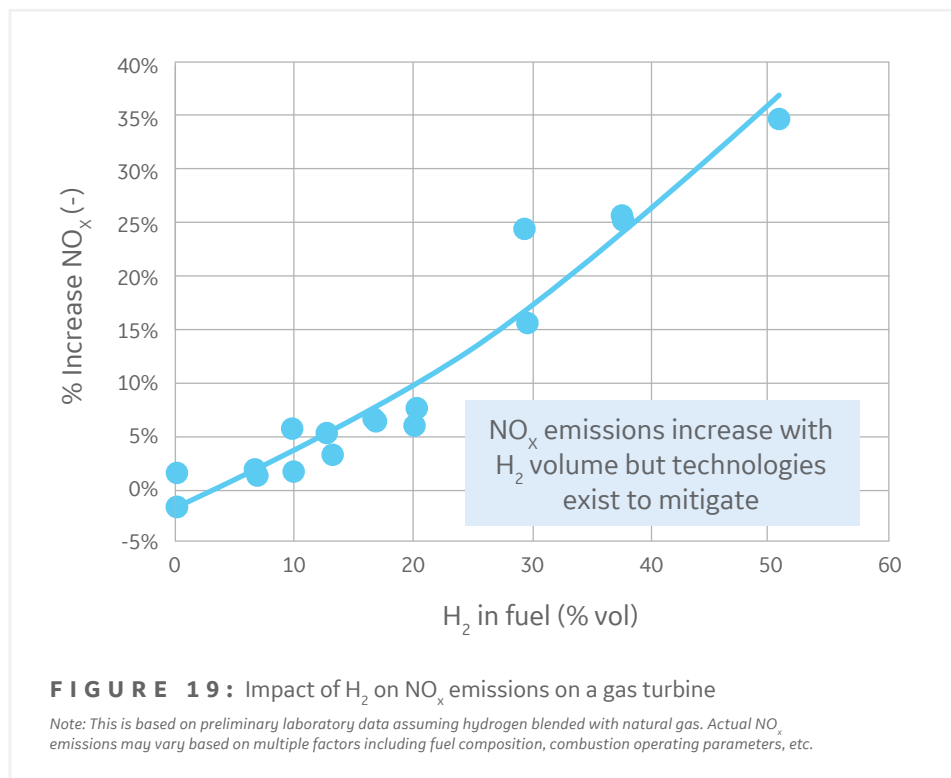
There are also likely to be increased NO_x emissions due to the increased flame temperature of hydrogen. The magnitude of the increase in NO_x emissions will depend on the percentage of hydrogen in the fuel, and the specific combustion system and gas turbine operating conditions. Figure 19 shows the percent increase in gas turbine NO_x emissions as a function of the percent hydrogen in the fuel. The overall trend shows that at lower percentages of hydrogen the increase in NO_x emissions are minimal, but at 50% hydrogen (by volume), NO_x emissions could increase by as much as 35%. Extrapolating this data, gas turbine NO_x emissions could potentially double if operating at or near 100% hydrogen.

For power plants currently in development, one potential mitigation for increased NO_x emissions is a larger or more efficient SCR (selective catalytic reduction) system. For existing power plants, there may be some ability to accept some increases in NO_x emissions based on existing NO_x emissions, existing SCR capabilities (if installed), and the plant's air permit limits. Other mitigations could include derating the power plant to maintain operation within the existing air permit's NO_x emission limits.

SAFETY

There are additional operational challenges with hydrogen that relate to overall plant safety. Hydrogen is more flammable than methane. The lower explosion limit for methane (in air) is ~5%, while for hydrogen it is ~4%.³² In addition, hydrogen's upper explosion limit is 75% compared to methane at 15%. Therefore, hydrogen leaks could create increased safety risks requiring changes to plant procedures, safety/ exclusions zones, etc. In addition, there may be other plant level safety issues that merit review.³³

Typical hazardous gas detection systems in power plants are targeted at hydrocarbon fuels. Increased levels of hydrogen can reduce the sensitivity of these instruments requiring new systems capable of detecting the presence of hydrogen. In addition, hydrogen flames have lower luminosity than hydrocarbon flames and are therefore hard to detect visually as shown in Figure 20.



This requires flame detection systems specifically configured for hydrogen flames. Therefore, the use of hydrogen may require the installation of sensors and instrumentation specifically configured for fuels containing hydrogen.

OTHER IMPACTS

The addition of hydrogen can impact other plant elements. For example, existing plants with duct or supplemental burners in the HRSG may need to upgrade this component as the current hardware might not be capable of operating with hydrogen in a safe and/or reliable manner. There may be a requirement (or desire) to store some amount of hydrogen at site, depending on where the hydrogen is generated and potential interruptions in supply. This in turn could impact the overall plant configuration due to safety regulations regarding safety zones around hydrogen storage tanks. There could also be changes to exclusion zones as well as classification of electrical systems based on the presence of hydrogen.

Before formalizing any plan to blend hydrogen into natural gas for an existing plant, a full audit of plant systems should be performed with a goal of developing a plan for safe operation.



In addition to the increases in flow, hydrogen can impact materials and systems differently than other gases. For example, hydrogen is a smaller molecule than methane and may diffuse through seals that might be considered airtight or impermeable to other gases. Therefore, traditional sealing systems used with natural gas may need to be replaced with welded connections or with upgraded seals.

Another challenge when using hydrogen is its ability to diffuse into some solid materials, including some steel alloys. This process, known as hydrogen embrittlement, may lead to degradation of material strength properties. In this process, hydrogen diffuses into the grain boundaries in the alloys and interacts with the carbon forming microscopic methane bubbles.³⁰ The result is a disruption in the microscopic structures that provide the strength of the alloy. Figures 16 and 17 show examples of embrittlement-based fatigue. Some stainless steel alloys, including 316L, offer increased embrittlement resistance.

COMBUSTION SYSTEM

The ability of a combustion system to operate safely and reliably on a fuel depends on many factors, some of which are defined by the fuel's fundamental properties. For example, a flame will try to propagate upstream into the unburned fuel, at a velocity defined as flame speed. As shown in Table 2, hydrogen has a flame speed that is an order of magnitude faster than methane. In fact, hydrogen's flame speed is higher than most common hydrocarbon fuels, as shown in Table 3.

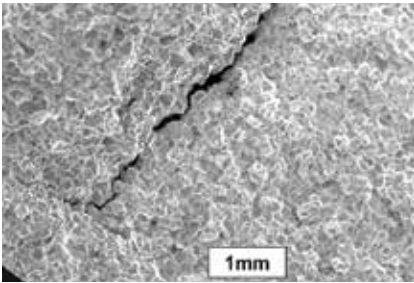


FIGURE 16: Example of a field failure due to hydrogen embrittlement

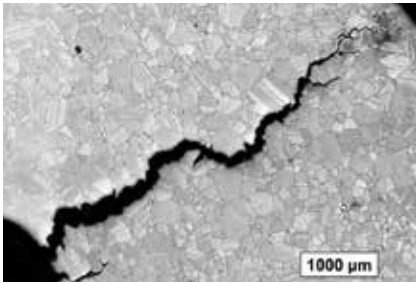


FIGURE 17: Cracked induced by hydrogen embrittlement

TABLE 3: Laminar flame speed of common fuels³¹

FUEL	FORMULA	LAMINAR FLAME SPEED
Hydrogen	H ₂	170
Methane	CH ₄	38.3
Ethane	C ₂ H ₆	40.6
Propane	C ₃ H ₈	42.3
Carbon monoxide	CO	58.8

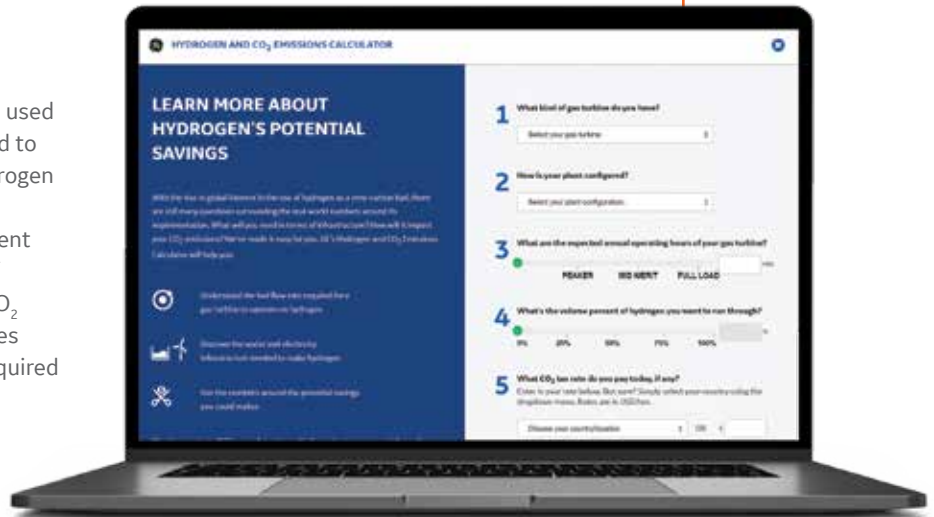


HOW MUCH HYDROGEN IS REQUIRED?

GE Gas Power has an online tool that can be used to determine how much hydrogen is required to support a specific gas turbine at a given hydrogen percentage. Using three simple inputs (gas turbine model, plant configuration, and percent hydrogen) the tool computes an estimate of the required hydrogen flow, as well as the CO₂ emissions reduction. The tool also determines the infrastructure needed to produce the required amount of blue or green hydrogen.

This tool is available online at:
www.gepower.com/hydrogen

A tutorial is available online at:
<https://tinyurl.com/yxkl8zd8>



Using fuels with higher flame speeds increases the risk that the flame could propagate upstream into the pre-mixer. If the flame enters the pre-mixer, is not able to stabilize, and then is pushed back into the main combustion zone, this is known as flashback. Flame holding occurs when the flame is able to anchor itself and stays within the pre-mixer. Both situations can lead to combustion hardware distress and even fuel nozzle damage. Figure 18 illustrates an example of damage caused by a flame holding event on a dry low NO_x (DLN) fuel nozzle.

Typically, combustion systems are configured to operate on a set of fuels that have a defined range of flame speeds. Due to the significant difference in the flame speeds of methane and hydrogen, combustion systems configured for operating on methane (or natural gas) may not be suitable for operating on a high hydrogen fuel. Therefore, there are defined ranges for hydrogen on DLN and DLE combustion systems to avoid this issue. Mitigating this risk may require upgrading to a combustor specifically configured for operation on hydrogen and similar more reactive fuels.

Operating on a fuel with increased levels of hydrogen could also impact combustion system operability, including combustion dynamics (also known as combustion acoustics). Therefore, there could be changes in gas turbine controls, start-up and shutdown sequences.

Pairing the correct combustion system for the target hydrogen percentage is critical to ensure reliable gas turbine operation

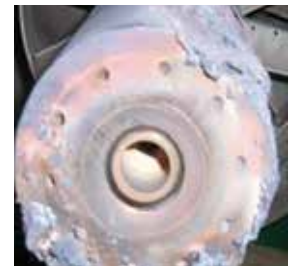
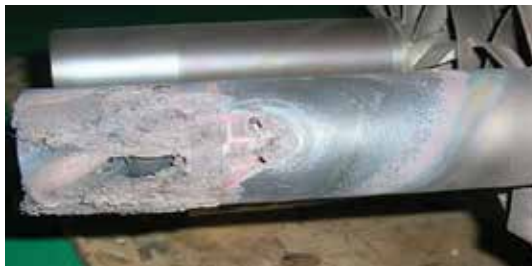


FIGURE 18: Gas turbine fuel nozzle damage from a flame holding event



Conclusion

Supporting the global need for deep decarbonization, there are multiple pathways to achieve low or near zero carbon emissions with gas turbines.

These are typically categorized as pre or post-combustion methods. One pre-combustion option is the use of 100% hydrogen or a blend of hydrogen and natural gas. This could be blue hydrogen, green hydrogen, or hydrogen produced from an alternative low or zero carbon emission production process. Regardless of the source of hydrogen, gas turbines operating on blends of hydrogen and natural gas, or on 100% hydrogen will see reductions in CO₂ emissions.

It is possible to operate new units and upgrade existing units for operation on these fuels with appropriate consideration to the combustion system, fuel accessories, emissions, and plant systems. For existing units, these upgrades can be scheduled with planned outages to minimize the time the plant is not generating power, and for new units these capabilities can be part of the initial plant configuration or phased in over time as hydrogen becomes available. Given GE's experience in the industry, with over eight million operating hours on hydrogen blends as a fuel, many of the technical questions on the viability of this fuel for power generation applications have been answered.

Having both pre or post-combustion technologies can prevent future lock-in of CO₂ emissions, and so existing gas turbine power plants should be considered a key element of any future energy ecosystem focused on reducing carbon emissions.

Addressing climate change is an urgent global priority and one that we think we can do a better job of accelerating progress on—starting now—not decades from now. We believe there are critical and meaningful roles for both gas power and renewable sources of energy to play, advancing global progress faster today with coal-to-gas switching while continuing to develop multiple pathways for low-to-zero carbon gas technologies in the future.

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NOMENCLATURE

ATR	Auto thermal reforming
BTU	British thermal units
CH ₄	Methane
CO ₂	Carbon dioxide
DLE	Dry low emissions
DLN	Dry low NO _x
ft ³	Cubic feet
H ₂	Hydrogen
H ₂ O	Water
HRSG	Heat recovery steam generator
kg	Kilogram
kWh	Kilowatt hour
lb	Pound (mass)
LHV	Lower heating value
m ³	Cubic meters
MJ	Megajoule
MMBTU	Million BTU
MPa	Megapascal
MW	Megawatt
Nm ³	Normal cubic meters
O ₂	Oxygen
psi	pounds per square inch
scf	Standard cubic feet
SMR	Steam methane reforming

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