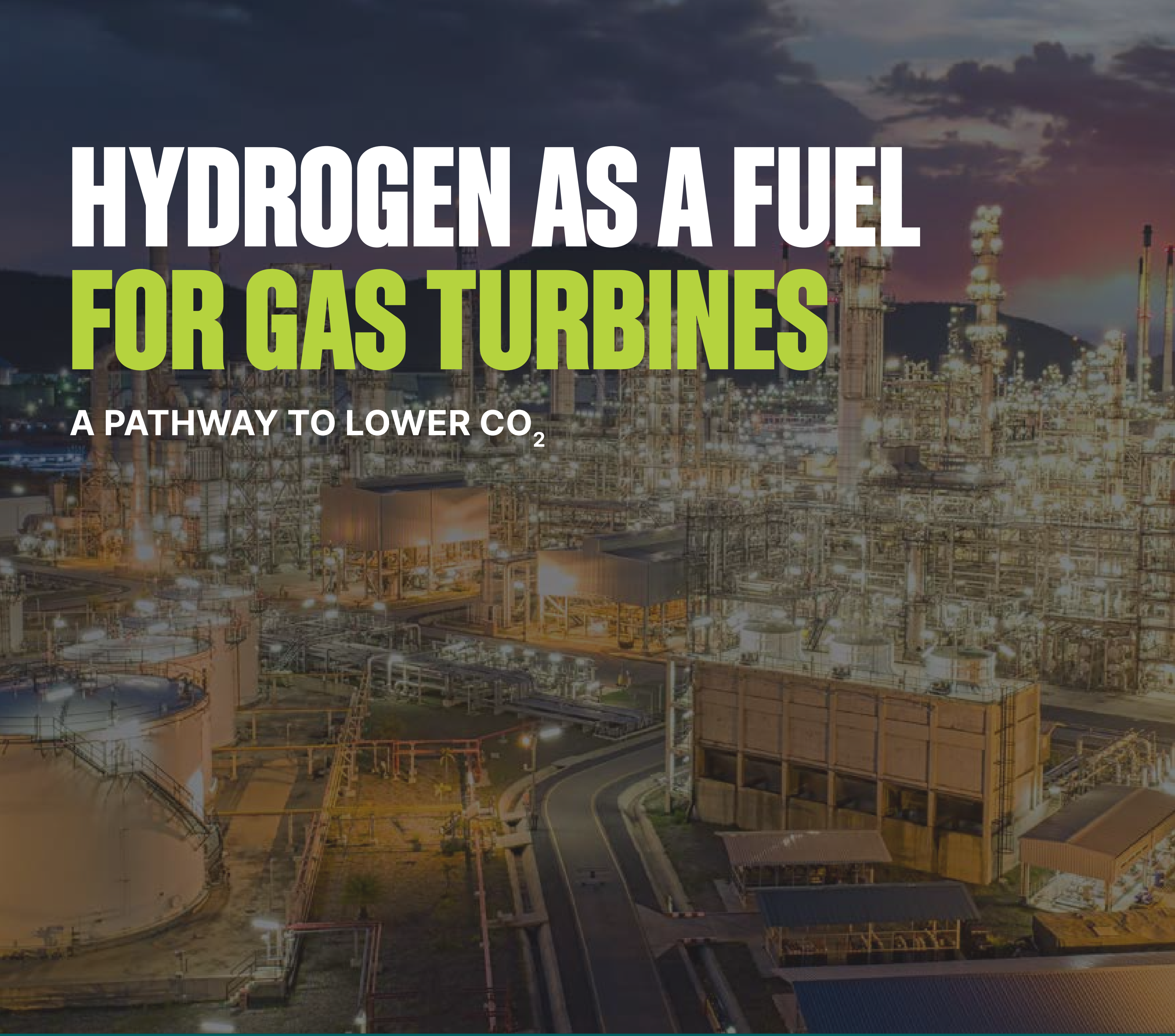
HYDROGEN AS A FUEL FOR GAS TURBINES

A PATHWAY TO LOWER CO_2



GE VERNOVA

EXECUTIVE SUMMARY

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.

The power sector's journey to decarbonize, 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. Based on our extensive analysis and experience across the breadth of the global power industry, GE Vernova 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. Part of this deployment of gas power may involve the use of hydrogen as a fuel in order to reduce CO_2 emissions.

As of 2020 there were ~1,600 GW of gas turbines installed globally, and gas power accounted for ~22 percent of global electricity generated. 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, schools, factories, in the community and for industry.
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. Pre-combustion refers to the systems and processes upstream of the gas turbine and post-combustion refers to systems and processes downstream of the gas turbine. The most common approach today to tackle pre-combustion decarbonization is simple: to change the fuel, and the most talked about fuel for decarbonization of the power sector is hydrogen.

GE Vernova 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 than 8 million operating hours and produced more than 530 Terawatt-hours of electricity. It includes a group 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, giving GE Vernova a unique perspective on the challenges of using hydrogen as a gas turbine fuel.

GE Vernova is continuing to advance the capability of its gas turbine fleet to burn hydrogen through internally funded R&D programs and through US Department of Energy funded programs. The goals of these efforts are to ensure that ever higher levels of hydrogen can be burned safely and reliably in GE Vernova's gas turbines for decades to come.

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

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

INTRODUCTION

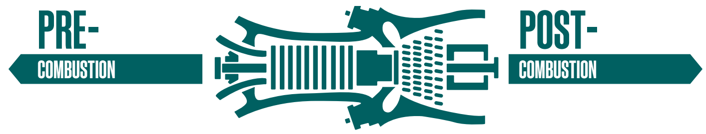
Figure 1 depicts the two methods for decarbonizing a gas turbine: pre and post-combustion. For pre-combustion decarbonization a fuel such as hydrogen containing no carbon or a carbon neutral fuel such as biogas is burned in the gas turbine. GE Vernova gas turbines have a long history of burning fuels ranging from hydrogen, to natural gas and high molecular weight hydrocarbons, to diesel fuel, to crude oil. Each fuel has unique challenges.

For post-combustion decarbonization, there is a tool chest of different technologies that can remove CO_2 from the flue gases with the most common being in a process referred to as carbon capture. The general concept of carbon capture involves introducing a specialized chemical which has an affinity to carbon into the plant exhaust stack.
Once the CO_2 and the chemical bond, the compound is taken to a separate vessel and separated into its constituents. The resulting pure CO_2 is taken to a compression tank and is ready for transportation. This CO_2 is then transported to either a geologic formation deep underground for permanent storage, or re-used in industrial processes, thus completing the process of Carbon Capture and Utilization or Sequestration (CCUS).

It's important to note that pre and post-combustion decarbonization approaches can be employed on existing installed gas turbines as a retrofit or included in the design of a new power plant, avoiding the potential "lock-in" of CO_2 emissions for the entire life of the power plant.

HYDROGEN INFRASTRUCTURE – PRODUCTION, TRANSPORT, AND STORAGE

Hydrogen is the most abundant element in the universe, but despite its plentiful nature it does not exist on earth as a standalone molecule. In other words, hydrogen likes to bond with other molecules. In order to yield pure hydrogen, it must be separated from its paired molecules, usually found in the form of water (H_2O), or hydrocarbons (e.g., CH_4). More than 90% of the hydrogen produced globally today uses natural gas or coal as a feedstock, typically in a process called steam methane reforming (SMR). The SMR process produces CO_2 as a by-product and most of this CO_2 is released to the atmosphere. An alternative method of producing hydrogen is through electrolysis in which a water molecule is broken into its hydrogen and oxygen constituents by passing electricity through the water. No CO_2 is produced directly by the electrolysis process, but depending on the fuel source of the electricity, CO_2 could be produced.



USE A ZERO OR CARBON NEUTRAL FUEL

- Hydrogen (blue, green, pink)
- Synthetic (renewable) methane
- Ammonia (NH_3)
- Biofuels

REMOVE CARBON FROM THE PLANT EXHAUST

- Carbon capture (liquid solvents)

Figure 1: Means of decarbonizing a gas turbine

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) 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

The cost of hydrogen produced by these different methods can vary widely, with grey (or black) typically being the least expensive. The price for hydrogen produced using the electrolytic processes (i.e., green, pink, red) depends primarily on the cost of the electricity used in the process and the utilization rate, or capacity factor of the electrolyzers.

A higher capacity factor tends to result in lower hydrogen costs, all other factors being equal. Gas turbines are capable of operating on hydrogen from any of the previously described sources.

Transporting and storing hydrogen requires special considerations due to its property of attacking and embrittling certain materials and the extreme pressures and temperatures needed to compress and liquefy it. Hydrogen embrittlement occurs when hydrogen atoms diffuse into a base material and disrupt the microscopic structure of the material that provides its strength. Some stainless steels offer increased hydrogen embrittlement resistance, but at a higher cost than the carbon steels typically used for transporting natural gas.

Hydrogen is typically compressed to between 35 to 150 bar (~500 to ~2,200 psi) for pipeline transmission whereas the distribution system that provides gas to many end users typically operates at pressures less than ~7 bar (~100 psi). For storage, hydrogen is typically compressed to more than 350 bar (~5,000 psi. Hydrogen storage and transmission systems may require specialized high-pressure equipment and will require a significant amount of energy for compression. Liquefying hydrogen is even more of a challenge because it condenses from a gas into a liquid at less than -250º C (~-420º F), requiring a significant amount of energy for cooling the gas to this temperature, and special double-walled cryogenic tanks for storage. The largest tank of this kind in the world is located at NASA's Kennedy Space Center and stores approximately 3.2 million litres (~850,000 gallons) of liquid hydrogen. This amount of fuel would be consumed in a GE 7HA.03 gas turbine rated at 430 MW in about 8 hours.

CONSIDERATIONS FOR USING HYDROGEN AS A GAS TURBINE FUEL

The basic configuration of a gas turbine capable of burning natural gas would remain unchanged for burning hydrogen. Specific areas that need to be addressed within the gas turbine, its accessory systems, and the plant itself include: 1) fuel delivery piping and components, 2) gas turbine combustion system and controls, 3) gas turbine enclosure, and 4) the heat recovery steam generator (HRSG) and selective catalytic reduction (SCR) system for NO_x removal. Control of NO_x is important because in most jurisdictions it is a regulated pollutant that if unabated contributes to smog, acid rain, and ozone depletion.

Hydrogen has a heating value that is approximately one-third of natural gas. This means that for a given volume of flow, hydrogen delivers less energy. It is also a smaller molecule than natural gas, meaning that it can leak through seals that would be leak-free in a natural gas system. If a hydrogen/natural gas fuel blend with a relatively low concentration of hydrogen is used, the existing fuel delivery system may be adequate, but at higher concentrations of hydrogen, larger fuel delivery system components with materials not susceptible to hydrogen embrittlement, and welded seals may be required.

The flame speed of hydrogen is an order of magnitude faster than natural gas. This is an important consideration for the safe and reliable operation of the combustion system. A higher flame speed could result in the flame in the combustor propagating upstream too far, resulting in a condition called flashback that can cause combustion hardware damage. Combustor configuration changes and associated turbine control system changes may be needed to operate with high concentrations of hydrogen fuel.

Hydrogen is more flammable than natural gas and special considerations are needed for the safe operation of a gas turbine with a natural gas/hydrogen fuel blend. The gas turbine enclosure and ventilation system need to be designed to ensure the concentration of hydrogen is maintained outside of its upper and lower explosive limits. Hazardous gas and flame detection systems configured for typical hydrocarbon fuels may need to be supplemented with systems capable of detecting hydrogen.

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.

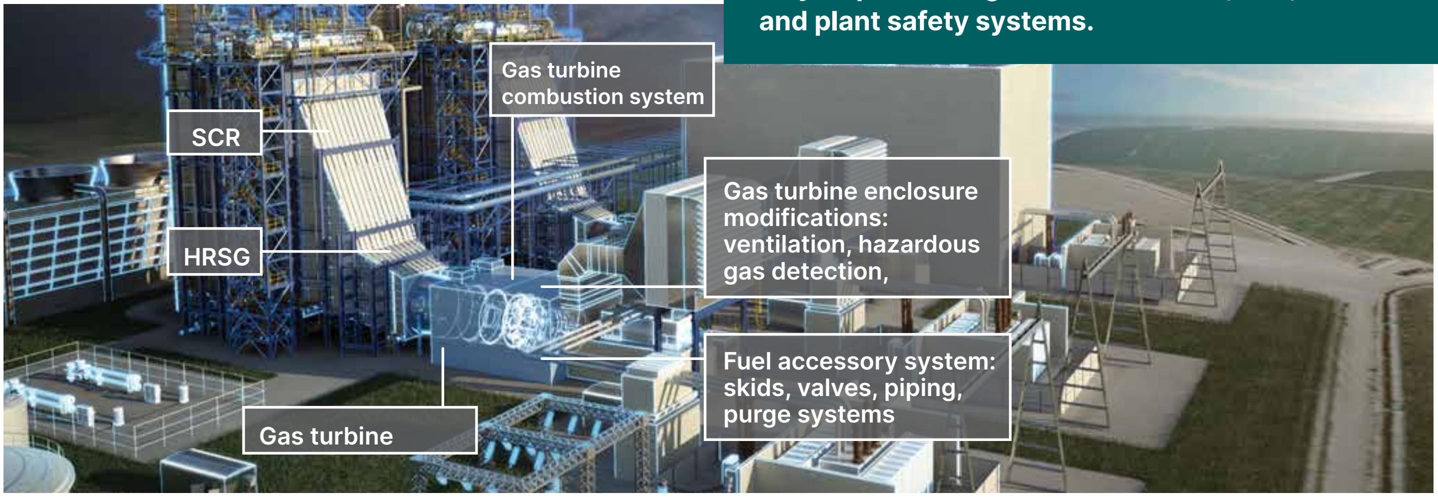


FIGURE 15: Potential impact of hydrogen fuel conversion on gas turbine systems

The flame temperature of hydrogen is higher than natural gas. This could result in an increase in NO_x emissions depending on the concentration of hydrogen in the fuel and the specific combustion system in the gas turbine. GE Vernova combustion studies indicate a 50/50 mixture by volume of hydrogen/natural gas could increase the concentration of NO_x in the gas turbine exhaust by 35 percent. For a plant under development this may require a larger or more efficient SCR system. For existing power plants, there may be some ability to accept increases in NO_x emissions based on existing SCR capabilities (if installed), and the plant's air permit limits. Another mitigant could be to derate the power plant to maintain operation within the existing air permit's NO_x emission limits.

One additional consideration when blending hydrogen with natural gas as a fuel for gas turbines is that there is not a 1:1 relationship between the volume of hydrogen in the fuel and the CO_2 emissions reduction achieved. Figure 3 shows this non-linear relationship., and as an example, attaining a 50 percent reduction in CO_2 emissions requires a blend that is ~75 percent (by volume) hydrogen.

Before finalizing any plan to blend hydrogen into natural gas for a power plant, a full audit of all plant systems should be performed with the goal of ensuring safe and reliable operation.

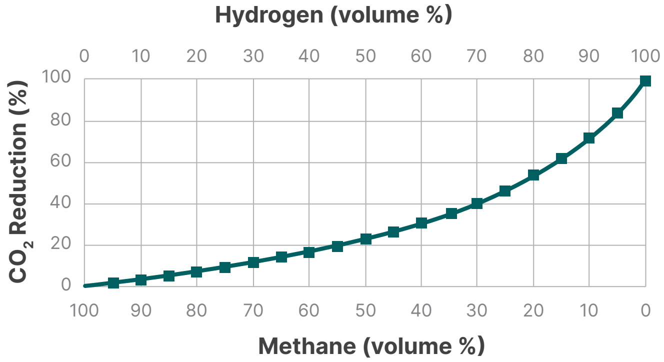


FIGURE 3: Relationship between CO2 emissions and hydrogen/methane fuel blends (volume %)

Hydrogen fuel capability for a gas turbine can be planned into a new power plant project or retrofit into an existing plant

GE VERNOVA'S EXPERIENCE WITH HYDROGEN IN GAS TURBINES

GE Vernova gas turbines have been operating with hydrogen fuel blends in 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 operated (or continue to) on fuels that contain hydrogen. This fleet has accumulated more than 8 million operating hours and over 530 Terawatt-hours of power generation. It includes a group of more than 30 gas turbines that have operated on fuels with at least 50 percent (by volume) hydrogen. These units have accumulated more than 2.5 million operating hours. Figure 4 below highlights some of the projects that have used fuels with varying concentrations of hydrogen over the last 35+ years.

GE Vernova has decades of experience burning hydrogen and similar fuels in its gas turbines. This experience provides a unique perspective on how to use hydrogen as a fuel while ensuring safe and reliable operation.

Timeline of GE Vernova Experience with H_2 and Associated Fuels

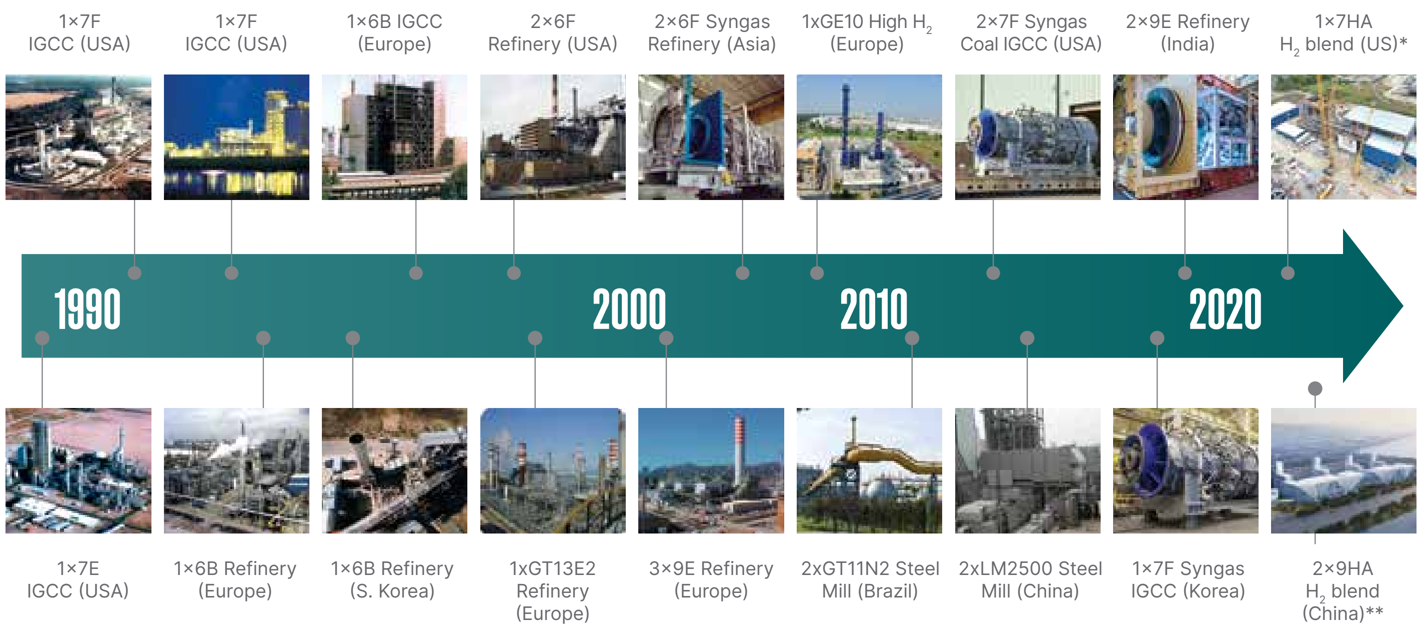


FIGURE 4: Timeline of selected projects with hydrogen fuels

*Expected H2 Operation in 2022 **Expected H2 Operation in 2023

All GE Vernova gas turbines have the ability to burn hydrogen fuel to some degree. The specific amount that can be burned in any particular gas turbine model depends on several factors, but most importantly on the combustion system.

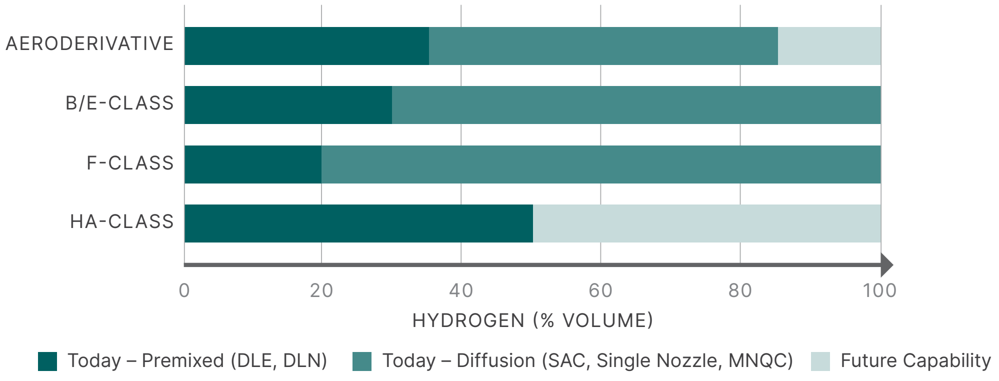
Combustion systems are usually classified as either diffusion systems or lean premix systems. Diffusion systems usually have very high flame temperatures as well as high NO_x emissions, and typically use a diluent such as water, steam, or nitrogen injected into the combustor to reduce the NO_x emissions level.

Lean premix combustion systems operate with a lower flame temperature compared to a diffusion combustion system, resulting in lower NO_x emissions. GE Vernova's dry low emissions (DLE) and dry low NO_x (DLN) are lean premix combustion systems. 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 previously.

Development of GE Vernova's DLN 2.6e combustor system began as part of the US Department of Energy's (DOE) Advanced IGCC/Hydrogen Gas Turbine program. During this program, multiple pre-mixing configurations were tested at GE Vernova's Global Research Center in a single nozzle test facility as well as at GE Vernova's Gas Turbine Technology Lab in Greenville, South Carolina. The DLN 2.6e combustion system is capable of a 50/50 hydrogen/natural gas blend by volume and it is currently offered on GE Vernova's 9HA and 7HA.03 gas turbines. The first gas turbine with the DLN 2.6e combustion system entered commercial service at the end of 2020.

GE Vernova is continuing to develop increased hydrogen capability for its gas turbines through in-house R&D and testing as well as participating in US DOE hydrogen fuel programs.

GE Vernova Gas Turbine Hydrogen Capability



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 CO_2 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 Vernova'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 an prevent future lock-in of CO_2 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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Note: This paper was updated to reflect GE Vernova H2 statistics as of September 2021 – inclusive of both heavy-duty and aero-derivative gas turbines and to update the hydrogen capability of GE Vernova's gas turbines (Figure 5)

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