Examination of carbon-neutral fuels for utility-scale power generation

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Abstract

The increased focus worldwide on reducing carbon emissions from power generation assets has led to remarkable rates of renewables installation. As these energy sources make up a growing portion of the landscape, challenges arise in balancing the electrical grid given the intermittent nature of renewables and their lack of storage capability. To reduce strain on systems, gas turbine units are ready now provide reliable, dispatchable power to the grid in a dense footprint and deliver low or zero-carbon electricity. By leveraging alternative fuels that generate less or no carbon emissions from combustion, such as synthetic methane, renewable (bio) fuels, and hydrogen (H_2), gas turbines serve a critical role in the power transformation currently underway. New units and the existing installed base can run on a variety of fuel blends, with 100% H_2 fuels resulting in carbon-free operation. This paper outlines the global drivers, challenges, and opportunities for hydrogen-based fuels in power generation and how GE's turbine technology and unparalleled fuel expertise provides a clear framework for implementation in a decarbonized energy future.

Introduction

Ensuring that power remains secure and stable is critical for public safety and economic growth. Although renewables have seen tremendous growth across the globe, some countries have had significant fluctuations on the grid, stressing both the infrastructure and power producers alike. Sweden nearly experienced outages

in the winter of 2019 after replacing baseload nuclear plants with wind turbines [1].

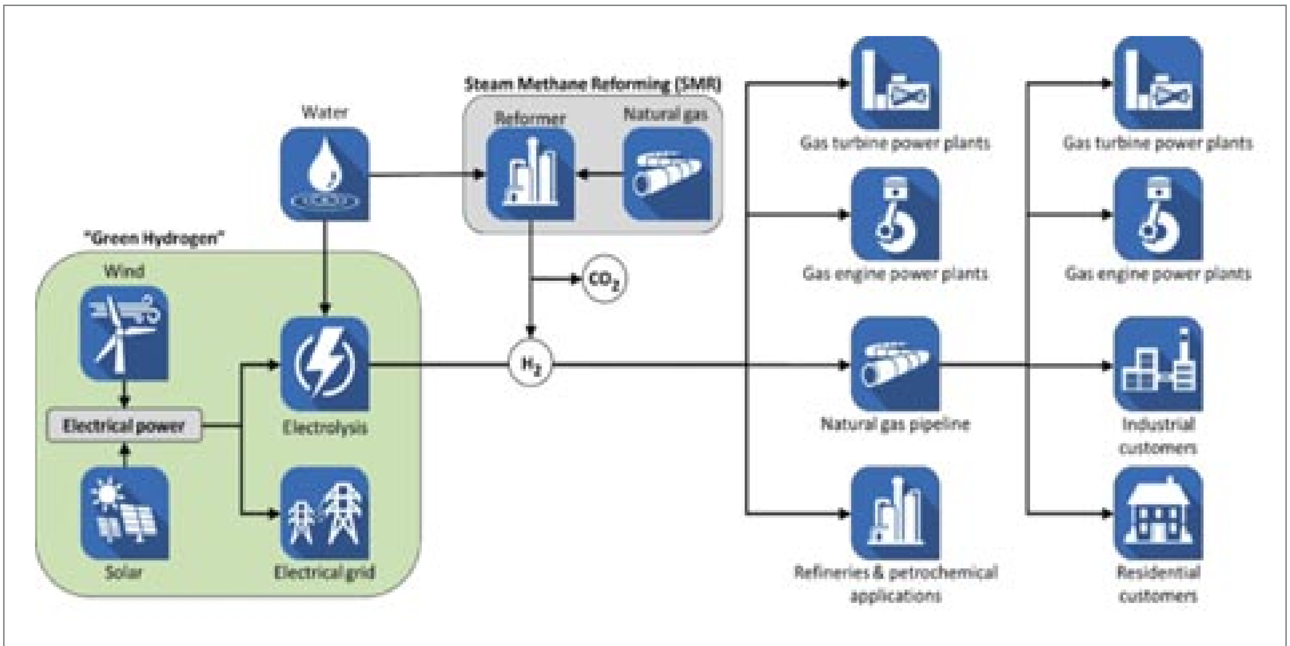


Figure 1: Hydrogen energy ecosystem concept

Hydrogen serves as an energy carrier and has been referenced by the International Energy Agency (IEA) as a means of time-shifting energy. Once produced at a large enough scale and properly stored, it can provide near-term, seasonal, and/or reserve contingency energy [2]. The complementary use of gas turbine power plants to dispatch large blocks of power during peak demand is a proven means of ensuring a balanced grid. As the world becomes more focused on transitioning to a carbon-free energy landscape, they can continue to serve critical baseload or grid-firming functions while using low-carbon or carbon-free fuels, including hydrogen.

Today's gas turbine technology can burn a wide range of H_2 fuel concentrations, and many commercial power plants in operation today have done so for decades. GE's experience and capability provides a blueprint which can help power producers better understand the economics, implementation, and equipment required to leverage this carbon-free fuel. Steam methane reforming (SMR), electrolysis, and industrial processes currently serve as the primary methods of production with the technology available in the market, but there are limitations. SMR is currently the most widespread industrial method, however, it generates CO_2 and thus requires carbon capture technologies to reduce the actual footprint. Electrolysis of water requires a large amount of energy and water to produce appreciable volumes of H_2. Excess power from renewables to generate "green hydrogen" for use in power plants, referred to as "power-to-gas", may be more widespread in the future but could substantially increase the resulting LCOE.

Independent of the evolving economic and supply chain factors surrounding hydrogen, GE's gas turbine technology is ready now to generate reliable power for customers, serving as a dispatchable, decarbonized solution. Although a plant's overall maximum H_2 blending quantity is largely dependent upon configuration, GE combustion technology can operate on fuels up to nearly 100% hydrogen. In addition to industry-leading equipment, GE has and experience across a broad spectrum of fuels and its fleet of gas turbines running on H_2 have accumulated decades of operational hours. This paper will examine the concept of hydrogen fuel use in new and existing gas turbines.

Power to Gas Global Drivers

Carbon emission reduction targets were brought into the spotlight at the 2015 Paris Agreement. Since then, many nations, states, and local governments have taken increased action to set and achieve their carbon goals through more stringent policies, research, and investment. This paradigm shift highlights hydrogen's role as a carbon-free energy carrier in the energy ecosystem. In 2017, Japan was the first country to release a hydrogen- focused strategy and many other nations have followed suit [3]. Japan's published hydrogen strategy aims to develop commercial-scale supply chains by around 2030 to procure 300.000 tons of hydrogen annually [4]. In

2018, its government sponsored the first international ministerial meeting focused on a hydrogen-powered society, resulting in a Memorandum of Cooperation between the Japanese Minister of Economy, Trade and Industry (METI) and the New Zealand Minister of Business, Innovation and Employment (MBIE). This serves as a hydrogen-centric framework for the two nations to collaborate across government, private sector, and research bodies [5, 6].

In parallel there are developments and small-scale projects running to better understand the technical and economic feasibility of building and scaling power to hydrogen systems. The US National Renewable Energy Lab is demonstrating feasibility with an integration of wind turbines, photovoltaic arrays, and an electrolyzer system to generate hydrogen [7]. ITM Power has multiple small-scale installations in Europe that are already providing hydrogen for power from renewable energy sources; in one case the hydrogen is injected into the local gas distribution network, and in the other it is stored and used with fuel cells to provide back-up power [8,9] In addition, the Australian Renewable Energy Agency (ARENA) is planning a trial of a new electrolysis system in the city of Adelaide; the hydrogen generated from the electrolyzers will be injected into the cities gas distribution network [10]. Long-term goals are to use renewables power for electrolysis to generate hydrogen for export [11]. As hydrogen investment gains momentum, power producers are seeking to better understand the many future implications, spanning supply chains to impact on levelized cost of electricity (LCOE).

Hydrogen Production Methods

Hydrogen can be generated from a variety of feedstocks and chemical processes, as shown in Figure 1. Although many processes produce hydrogen, steam methane reforming and electrolysis have been identified as the most promising pathways for power generation.

Steam methane reforming

Steam methane reforming is the most popular methods of generating H_2 today, with petrochemical and ammonia production processes requiring large quantities. A two-step reaction involving methane, water, a catalyst, and heat produces H_2 and CO_2

[12,13]. For each mole of methane used, one mole of CO_2 and four moles of H_2 are produced. In terms of mass, one kg of methane yields ½ kilogram of H_2 and 2.75 kilograms of CO_2 (each kilogram of H_2 produced from this method generates 5.5 kilograms of CO_2). Given this ratio, a single 6B.03 gas turbine operating 8,000 hours per year would consume approximately 33 million kg of H_2 (per year) producing~178.000 metric tonnes of CO_2 per year if fuel was generated using SMR. Table 1 shows the rates of CO2 production from SMR based upon various gas turbine hydrogen consumption.

Although generating hydrogen via SMR creates carbon dioxide, there are several projects that are considering this pathway to generating hydrogen by combining it with carbon capture and sequestration (CCS). Examples of projects considering generating hydrogen with SMR are the H21 Leeds City Gate and Magnum Vattenfall projects. The City of Leeds project [14] estimates 2.4 billion m3 of hydrogen would be produced annually to provide heat and electricity to roughly 660,000 people. A 90% carbon capture system is being considered which will capture approximately 1.5 million tonnes of CO_2 annually. The Magnum Vattenfall project in the Netherlands has proposed to upgrade an existing gas turbine to operate on 100% hydrogen [15,16], with hydrogen generated from natural gas and resulting CO_2 to be captured and stored in underground bunkers. Open questions remain on transporting and storing the hydrogen at the power plant. The challenge of these projects is the goal of creating carbon free power using technology that requires large scale sequestration of CO_2. Alternative H_2 generation methods without yielding CO_2 are available.

Electrolysis of water

The electrolysis of water is the process of splitting a water molecule (H_2O) into its components of H_2 and ½ O_2 using electricity to drive the reaction [17]. For each mole of water used, one mole of hydrogen and one-half mole of oxygen are generated; consequently, each gram of water used yields 0.11g of hydrogen and 0.89g of oxygen. Using this proportionality, the generation of one kg of hydrogen requires nine kg of water if no losses in the process are assumed. Table 2 shows the resulting calculations from this rationale, with the volumes required to support the power to

Table 1: Steam methane reforming requirements supporting 100% hydrogen operation

Gas turbine	Output1	Heat input1	100% H_2 flow rate	CO_2 generated	
	MW	GJ/hour (MMBTU/hour)	kg/hour	kg/hour	Metric tons/year
GE-10	11.2	129 (122)	~1,140	~6,250	~50,000
TM2500	34.3	350 (332)	~3,120	~16,950	~135,600
6B.03	44.0	473 (448)	~4,170	~22,300	~178,000
6F.03	87	857 (813)	~7,550	~41,500	~332,000
9F.04	288	2,677 (2,537)	~23,600	~130,000	~1,040,900
9HA.02	557	4,560 (4,322)	~40,200	221,000	~1,800,000

Note: ISO conditions operating on natural gas

Table 2: Electrolysis requirements supporting 100% hydrogen operation

Gas turbine	Output1	Heat input1	100% H_2 flow rate	Water required to generate H_2	Electrolysis power required2
	MW	GJ/hour (MMBTU/hour)	m^3/hour (ft^3/hour)	m3/hour (gallons hour)	GWh
GE-10	11.2	129 (122)	~11,700 (~446,000)	~10 (~3,700)	~500
TM2500	34.3	350 (332)	~31,800 (~1,210,800)	~27 (~7,300)	~1,500
6B.03	44.0	473 (448)	~ 43,000 (~1,635,900)	~37 (~9,900)	~2,000
6F.03	87	857 (813)	~78,000 (2,970,000)	~68 (~17,950)	~3,600
7F.05	243	2,197 (2,083)	~200,000 (~7,600,000)	~174 (~46,000)	~9,400
9F.04	288	2,677 (2,537)	~243,500 (~9,266,900)	~212 (~56,000)	~11,400
9HA.02	557	4,560 (4,322)	~415,000 (~15,786,400)	~361 (~95,500)	~19,500

(1) ISO conditions operating on natural gas
(2) Power required for electrolysis to supply H_2 flow; gas turbine to operating with 100% H_2 for 8000 hours

hydrogen concept in generating enough hydrogen to operate different gas turbines on 100% hydrogen. For reference, an Olympic size swimming pool contains 2,500 m^3 of water. An electrolyzer generating hydrogen for a GE-10 turbine would consume this volume in approximately 250 hours (just over 10 days); a 9F.04 would use an Olympic pool of water every twelve hours.

The higher heating value (HHV) of hydrogen is 12,756.2 kJ/Nm^3 or 39.39 kWh/kg. Electrolyzers require power to split water and the amount required is defined by the HHV divided by electrolyzer system efficiency [18]. The average efficiency of commercially available equipment is 65%, which equates to approximately 60.61 kWh/kg H_2 demand. As Table 2 shows, all listed GE gas turbines require considerable electrolysis power to generate enough hydrogen to run. Electrolysis efficiency improvement will reduce needed volume, as would operating the gas turbine on a hydrogen and natural gas blend. Operating a gas turbine on a hydrogen/natural gas blend below 100% hydrogen reduces the hydrogen flow needed as well as the amount of water required to generate the hydrogen. Operating a 9F.04 gas turbine on a blend of 5% (by volume) hydrogen with natural gas would require ~840 gallons/hour of water.

Direct water electrolysis currently makes up only 1% of hydrogen produced, however, the IEA predicts that capacity could nearly triple from 2017-2020 if all planned projects are completed [19]. The United States budget in 2018 had notable increases in hydrogen technologies and globally there were many announcements of electrolysis projects up to 100MW with most planned for Europe [20]. Ultimately, electrolysis requires large amounts of power and water to adequately create a hydrogen ecosystem using electrolysis of water. The next section examines the availability of renewable power to support this concept.

Renewables to Hydrogen

Electrolysis using renewable power, also known as power to hydrogen, requires large amounts of carbon free power. Fortunately, the amount of power from and share of renewables are both on the rise. This surge is evident in Europe, where electricity from renewables increase from ~12.6 terawatt hours (TWh) in 1990 to more than 570 TWh in 2016. From 2004-2017, EU countries saw the share of renewables rise from 8.5% to 17.5% [21]. This growth in Europe continued in 2018 as 11.7 GW of wind power was added, raising the total to an estimated 189GW or approximately 18% of the EUs total installed capacity [22]. A key to using renewable sources to generate hydrogen is having excess power, above and beyond grid electrical demand. This surplus can be gauged by the quantity of curtailed renewable sources, as shown in Table 3 for four EU countries between 2012 and 2016; data was not available for all countries in all years.

Table 3: Curtailed wind power (GWh) [21]

Country	2012	2013	2014	2015	2016
Germany	410	358	480	3,743	4,722
Ireland	103	171	236		
Italy	164	106	119		
UK	45	380	659	1,277	

Table 4: Comparison of Hydrogen fuel price forecasts

Report & forecast period	Forecast period	Forecasted cost range ($USD/MMBTU)
Hydrogen for Australia's future [23]	2018	30.4 - 46.8
2018 IEA World Energy Outlook [19]	2018	35.2 - 52.8
METI Basic Hydrogen Strategy [4]	2030	27.2 (30 Yen/Nm3)
METI Basic Hydrogen Strategy [4]	Beyond 2030	18.2 (20 Yen/Nm3)
Hydrogen for Australia's future [23]	2050	14.6 – 19.6

Given the significant growth in the use of renewable power sources, there exists the potential to use excess amounts to support a power to hydrogen system. Currently, the power required for electrolysis to supply hydrogen for a F or HA-class gas turbine (Table 2) is larger than curtailed renewable power shown in Table 3. An energy ecosystem that generates adequate volumes of hydrogen for use in power generation will require much larger amounts of renewable power. The resulting price of hydrogen resulting from production via electrolysis and renewables has been evaluated by multiple studies. Table 4 is a comparison summary of those published price forecasts on a $USD/MMBTU basis.

Landed LNG prices throughout the world in April 2019 as per the U.S. Federal Energy Regulatory Commission (FERC) were reported as follows: $2.48/MMBTU in the United States, $4.61/MMBTU - $4.99/MMBTU in Europe, and $5.00/MMBTU in Asia [24]. Comparing these values to hydrogen cost ranges in Table 4 an order of magnitude difference in fuel price between hydrogen and LNG is observed. Operating a power plant on a fuel costing three to ten times the current price of natural gas will undoubtedly have an impact on the levelized cost of electricity (LCoE) and is an important consideration in a power to hydrogen system.

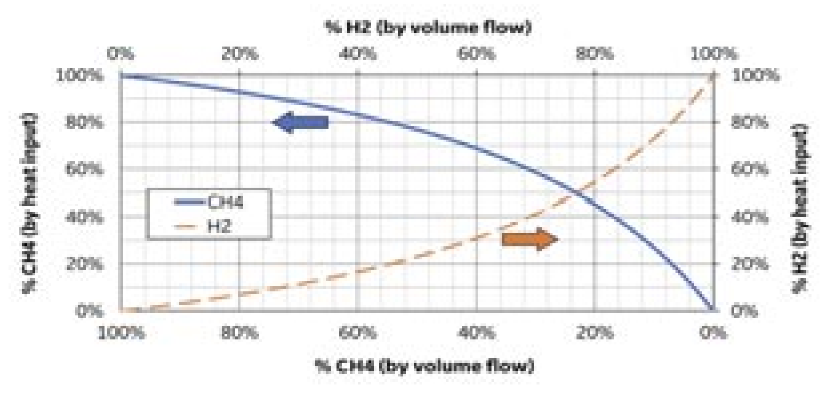
Carbon Dioxide emissions reduction with Hydrogen

As a carbon-free fuel, Hydrogen (H_2) gas combustion in a complete and balanced system does not result in any net Carbon Dioxide (CO_2) emissions into the atmosphere; the combustion of 100% (by volume) H_2 fuel results in water (H_2O). For gas turbines within a power plant, CO_2 emissions are equal to just the CO_2 of intake, approximately 0.04% by volume, since the system draws in atmospheric air for combustion. When compared to a turbine operating on 100% methane, a relative CO_2 reduction of ~99% is observed. This substantial decrease clearly highlights the benefit to using hydrogen as a gas turbine fuel.

Methane (the primary component of natural gas) and hydrogen can both be used in a gas turbine, however, there are key differences to note between the two compounds. Table 5 shows the differences in molecular weight and heating values, per mass and volume. The difference between hydrogen's energy density on a mass and volume basis is critical to understanding the implications of the fuel used. Hydrogen is twice more energy dense that methane by mass, however, it has one third of methane's energy density by volume. Flows into a gas turbine are quoted on a volumetric basis. As a result, it takes three times more volume flow of hydrogen to provide the same heat (energy) input as methane. Thus, operating a gas turbine on 100% hydrogen requires a fuel accessory system configured for the increased required flow rates.

The amount of H_2 in the fuel can be measured on a volume, mass, or heat input basis. The key factor in determining emissions for a fuel blend is the relative heat input from the fuel constituents; the amount of CO_2 reduction is a function of the proportion of H_2 in the fuel blend. Adding small amounts of hydrogen to the fuel (on a volumetric basis) will have a smaller impact on carbon dioxide emission reduction. Gas turbines require constant heat input and since H_2 has a lower volumetric energy density, a blend on a heat input basis contains less hydrogen (relative to a blend on a volumetric basis). Using this information, to attain a 50% reduction in CO_2 emissions requires a blend that is 50% hydrogen and 50% methane by heat content. Figure 2 illustrates the relationship between volumetric flow and heat input (mass flow) for a system for blends blend of methane and hydrogen. To attain a 50% reduction in CO_2 emissions a blend that is ~75% (by volume) hydrogen would be required.

Figure 2: Relationship between mass flow (heat input) and volumetric flow for a methane/hydrogen fuel mix



There are cases where H_2 blending with natural gas is being considered to reduce CO_2 emissions as a near-term alternative to operating on 100% natural gas. Understanding the magnitude of CO_2 emission reduction relative to H_2 content in the fuel is a key step in evaluating the value of a potential power to hydrogen system. However, one must also understand the technical challenges that accompany the use of hydrogen.

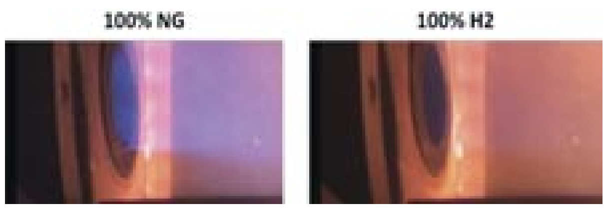
Table 5: Comparisons of fuel properties

Property	Units	Methane	Hydrogen
Molecular Formula		CH_4	H_2
Molecular weight	gram/mol	16	2
LHV (per volume)	MJ/Nm3	35.8	10.8
	BTU/scf	911.6	274.7
LHV (per mass)	MJ/kg	50	120
	BTU/lb	21,515	51,593
Laminar flame speed at stoichiometric conditions [25]	cm/sec	38.3	170

Technical Challenges

Given the differences from methane, hydrogen combustion poses several challenges that must be addressed. This section provides a summary of some key topics to understand given the differences between hydrogen and many traditional hydrocarbon fuels. In a combustion reaction, the flame velocity or flame speed is the velocity at which the unburned gases propagate into the flame. As stated in Table 5, the flame speed of hydrogen is an order of magnitude faster than methane. Flame speed is an important property used in determining if a turbine combustor may have issues with the flame propagating upstream from the combustion zone into the premixing zone (near the fuel nozzles). Combustion systems are configured to operate on fuels within a defined range of flame speeds. Some natural gas combustion systems may not be suitable for operating on a high hydrogen fuel and in many cases may require a combustor specifically configured for the different conditions. There are additional operational challenges with hydrogen that relate to overall safety. First, a hydrogen flame has low luminosity and is therefore hard to see visually as shown in Figure 3.

Figure 3: Comparison of natural gas and hydrogen flames



Flame detection systems specifically configured for hydrogen flames may be required. Hydrogen also can diffuse through seals that might be considered airtight or impermeable to other gases, potentially rendering traditional sealing systems in need of be replacement by welded connections or other appropriate components. The increased flammability of hydrogen is an additional concern (the lower flammability limit for methane in air is 5%, while for hydrogen it is 4%) [26]. 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 [27]. Hydrogen embrittlement results from hydrogen dissolving into metals and impacting their properties. This can occur when hydrogen atoms are absorbed by carbon steel alloys. Once diffusion into the metal occurs, bubbles are formed at metal grain boundaries

Figure 4: GE combustion test stand

which ultimately exert pressure. The weakened grain boundaries reduce ductility and strength of the metal. One possible solution is to use 316

Stainless Steel, which has been identified by Sandia National Lab as highly resistant to absorption [28]. This is an important consideration in considering overall plant compatibility with high-hydrogen fuels.

Combustion Technology Development

As more customers turn to alternative fuels for power generation, GE is supporting this trend by developing gas turbines that can deliver high efficiency and increased reliability while operating on a wide range of alternative fuels. The combustion testing capabilities at GE's Greenville facility enables the company to develop fuel flexible combustion technologies. This facility contains five independent test cells housing 10 full-scale test stands capable of supporting full-scale and full-flow combustion development and validation tests. A typical test stand is shown in Figure 4. This facility supports a full range of fuel composition testing, which means the fuel flexibility of combustor can be evaluated using a wide range of alternative gases and liquid fuels prior to on site deployment. Precision data acquisition systems yield actionable, high-quality information that can in turn be used by the company's engineering teams to improve existing combustors and develop next generation combustors and technologies for advanced technology gas turbines [29].

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. GE offers combustion systems for both Aeroderivative and Heavy-Duty gas turbines that can operate with

Figure 5: High-Hydrogen Combustion Systems

increased levels of H_2, ranging from 5% (by volume) to 100% (by volume). Figure 5 shows the various combustion systems capable of handling higher concentrations of H_2. It is important to note that hydrogen limits for a given gas turbine model may vary based on available combustion systems, fuel composition, ambient conditions, emissions requirements, and other site-specific requirements.

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 fuel blends with hydrogen with concentrations ranging from 30%-95% by volume. Over 2,600 GE gas turbines have this combustion system and have accumulated more than 100 million fired hours on a variety of fuels.

Single Nozzle and Multi Nozzle combustors

GE's Heavy-Duty gas turbines have two combustor configurations capable of operating on fuels with higher H_2 content. The Single Nozzle (SN) or standard combustor is available on B and E-class turbines and 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 MQNC combustor to operate on high hydrogen fuels [30]. Test results demonstrated the feasibility of burning hydrogen as the only combustible up to 90% by volume in GE's MNQC combustion system. Today, GE can quote hydrogen levels up to ~90-100% (by volume) for applications with this technology.

Dry low emission (DLE) and dry low NOx (DLN) combustors

DLE and DLN combustion systems can operate with limited amounts of hydrogen in the fuel. The DLE combustor, installed on GE's Aeroderivative gas turbines is limited to 5% (by volume) hydrogen. The DLN1 combustion system, which is available on GE's 6B, 7E, and 9E gas turbines can operate with up to 33% (by volume) hydrogen when blended with natural gas and GE's DLN 2.6+ combustors can operate on hydrogen levels as high as ~15-18% (by volume). The associated fuel systems for these combustors would require upgrading to safely operate at hydrogen concentrations over 5% H_2.

Next generation high H_2 combustion system

As part of a cooperative agreement with the US Department of Energy's Advanced IGCC/Hydrogen Gas Turbine program, GE developed a low NOx 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 [31]. During this program, multiple pre-mixing configurations were tested at the GE Global Research Center in a single nozzle test facility as well as at GE's Gas Turbine Technology Lab.

Table 6: Examples of GE Gas Turbines with H2 Fuels

Plant	Fuel	Turbine
Dow Plaquemine plant [36]	Blended: 5% H2/ 95% natural gas	4 x 7FA
CESPA Gibraltar-San Roque refinery [37]	Refinery fuel gas (RFG): blended with natural gas when >32% H_2	6B.03
Daesan refinery, South Korea [38, 39]	Fuel >70% H2 & can exceed 90% H_2	6B.03
Enel Fusina [40-42]	~97.5% H_2	GE-10

Figure 6: Potential impact of hydrogen fuel conversion on gas turbine systems

Due to the advanced premixing capability of this technology, it became an element of GE's DLN 2.6e combustion system, which is available on the 9HA gas turbine [32]. Due to interest in low-carbon power for future power plants, the hydrogen capability of the DLN 2.6e combustion system was evaluated with preliminary indication that it has entitlement to operate on fuels containing up to 50% (by volume) hydrogen.

Gas Turbine experience with Hydrogen

GE is a world leader in gas turbine fuel flexibility, including more than 70 gas turbines that have operated (or continue to operate) on H_2 fuels. The cumulative 4.5 million operating hours of these turbines have generated 300 TW of power. 25 units within this group have operated on fuels with at least 50% (by volume) hydrogen for a total of over one million operating hours. [33, 34, 35].

Hydrogen Fuel Blending

Hydrogen may be available as a by-product of an industrial or petrochemical process but not at volumes to fully load a gas turbine. A blend of hydrogen and natural gas is generated and, in these cases, traditional dry low NOx (DLN) combustion systems can be utilized.

Low Calorific Value Fuels: Steel Mill Gases & Synthesis Gas (syngas)

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 and gas turbines operating on these fuels. Examples include steel mills in Asia using COG / BFG fuel blends in GE 9E.03 gas turbines [43]. GE's aeroderivative gas turbines can also operate on coke oven gas (COG), such as a set of LM2500+ turbines with approximately 60% (by volume) hydrogen commissioned in 2011 with over 100.000 hours [44]. GE gas turbines have accumulated more than one million fired hours with steel mill gases.

The use of gasification creates a fuel known as synthesis gas (syngas) that contains a variety of gases, including hydrogen. The H_2 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 have accumulated more than 1.5 million operating hours.

High-hydrogen applications

Typically, when H_2 is available in large volumes it is used in an industrial process, not for power generation. However, there are instances where a large volume of high concentration hydrogen is available when there are no other available off-takers. GE's fleet of gas turbines installed for operation on high hydrogen fuels includes more than one dozen Frame 5 gas turbines and more than 20 6B.03 gas turbines. Many of these turbines operated on fuels with hydrogen concentrations ranging from 50% (by volume) to 80% (by volume). Table 6 highlights the Daesan refinery and Enel's Fusina power project as proof of power generation using very high levels of hydrogen fuel.

Plant Considerations

An advantage to gas turbines is that they can be re-configured for operation on new fuels. Changes may be required for the turbine, accessories and/or the balance of plant; the scope and magnitude is a function of the amount of hydrogen in the fuel and must be evaluated on a case-by-case basis. If the new fuel will be a blend of hydrogen in natural gas, the required changes might be limited to controls updates and new combustor fuel nozzles. If the conversion is to a high hydrogen fuel, the scope could include changes to numerous gas turbine systems, as shown in Figure 6. A fuel conversion may necessitate switching to a new combustion system, requiring new fuel accessory piping and valves. Fuel skid, enclosure and ventilation system modifications may also be necessary. Safety measures may include upgrading to flame detectors capable of detecting H_2 flames and upgrading gas sensors to detect gases with reduced levels of hydrocarbons. Gas turbine control modifications might impact turbine performance in terms of output and heat rate. Changes in the fuel may also impact the larger balance of plant scope. For example, increasing the concentration of hydrogen in the fuel may lead to significant increases in NOx emissions. There could also be a change in the exhaust energy from the gas turbine necessitating a review of HRSG limits.

Power plants are substantial long-term investments. If future fuel upgrades are anticipated during the planning stages a new power plant, other considerations should include plant layout space for new and/or modified fuel modules, as well as impact to major capital items, i.e. HRSG and SCR. Site emission limits, fuel storage, and local safety regulations should all be included in the planning process. On-site storage may be needed to mitigate interruptions in supply, another factor that could impact the overall plant configuration regarding safety zones around hydrogen tanks.

Conclusion/ Summary

Gas turbines are ready now to deliver reliable power in a decarbonized energy landscape. The technical implementation of reduced carbon or carbon-free fuels such as hydrogen have been proven for decades as part of GE's solutions across many different implementations. The reliable performance provided by gas turbines on this wide variety of fuels, including blends with low, moderate, and high levels of hydrogen serve as a blueprint for the future. The currently available technology in existing and new gas turbine power plants can be leveraged to ensure a balanced grid and should be considered in any future power to hydrogen ecosystem to deliver dispatchable, robust power in a decarbonized future. ■

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