Emissions and Performance Implications of Hydrogen Fuel in Heavy Duty Gas Turbines

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Executive Summary

Decarbonized gas turbines can serve a significant role in achieving goals for climate-change mitigation. Recognizing that hydrogen can be a pathway for achieving zero carbon emissions, original equipment manufacturers (OEMs) are focused on enhancing the capability to operate gas turbines on fuels with high hydrogen content. For OEMs to remain competitive, turbines designed to operate on hydrogen as their primary fuel must maintain or even improve their performance with respect to emissions, heat rate, stability, and operational stability and flexibility relative to natural-gas-fueled turbines. The ultimate goal of these development efforts is turbine technology having ability to operate up to 100% hydrogen. When fueled with 100% "Green Hydrogen",[1] turbines can be classified as "Green" power sources. While diffusion flame combustors are already 100% hydrogen-capable, their performance with respect to emissions of nitrogen oxides (NOx is limited to applications where inert diluent is available. Therefore, OEMs are expanding the hydrogen capability of current, premixed dry low NOx combustors while also introducing turbines with new combustor concepts.

Current commercial offerings by the major turbine OEMs are advertised as having capability to operate on 30%–65% ratios of hydrogen/natural gas (by volume). Achieving the capability to operate on higher hydrogen ratios expands the scope of required development from combustion technology to improvements in hot gas path thermal management and materials in order to provide the performance and operational flexibility to deal with variable grid demand and hydrogen availability. Prior experience with hydrogen from integrated gasification combined cycle (IGCC), refinery, and process plants, together with developments from the U.S. Department of Energy's (DOE's) Advanced Turbines Program, are essential to inform current technology approaches to hydrogen-rich fuels. This paper surveys recent technology developments with respect to hydrogen use in heavy-duty (i.e., utility-scale) gas turbines and identifies challenges, potential solutions and potential pathways for OEMs to achieve 100% hydrogen capability, with special attention to NOx emissions and performance.

[1] "Green" hydrogen is that produced solely by the energy from renewable sources such as by electrolysis.

Key conclusions of this analysis:

- Firing gas turbines with hydrogen above *de minimus* levels presents many challenges. These challenges include NOx emissions, flashback, stability, and ramping and load-change impacts—all of which vary with the level of hydrogen in turbine fuel (throughout this discussion, references to 30% hydrogen" means fuel supply of 30% hydrogen and 70% natural gas, by volume).[2] Hydrogen will affect a variety of gas turbine systems including the combustor and hot gas path as well as fuel management and control strategies. NOx mitigation will have to be achieved in the context of other performance challenges when designing gas turbines to burn hydrogen.
- Based on thermodynamic fundamentals, hydrogen combustion in gas turbines is expected to have no detrimental impact on output, as typically measured in megawatts (MW) of generating capacity, or heat rate (overall efficiency), although considerable engineering, analysis, testing, and real-world validation at full scale will be required to achieve commercial deployment of high-hydrogen heavy-duty gas turbines.
- With dry low NOx combustors, "F-class" combined cycle gas turbines burning natural gas can achieve NOx emissions below 9 parts per million (ppm) by volume (dry basis, adjusted to 15% oxygen) and in the low single digits (ppm) with selective catalytic reduction (SCR). Without mitigation, hydrogen combustion has the potential to increases NOx formation due to high adiabatic flame temperatures. However, hydrogen's combustion characteristics (e.g., flammability at low (lean) equivalence ratios) can be exploited for effective NOx control.
- NOx emissions from gas turbines burning up to 100% hydrogen can be managed effectively with diffusion flame combustors. The turbine OEMs have considerable experience with these systems. Diffusion combustors rely on an inert diluent for NOx control, (generally either nitrogen gas, or water/steam). Nitrogen availability is limited to IGCC and chemical plants having air separation plants. Steam/water abatement incurs high water consumption and demand on limited resources. Diffusion combustion is a limited option for high-hydrogen turbines.
- Turbine manufacturers are adapting natural gas dry low-NOx (DLN) and dry low-emission (DLE) combustor technology to take advantage of hydrogen's beneficial combustion characteristics. With current combustors and increased hydrogen to natural gas ratios, OEMs are targeting maintaining NOx emissions the same as their natural gas DLN combustors. The latest versions of these combustors can accommodate fuels with as much as 20%–30% hydrogen by volume (vol.) with some OEMs claiming capability to operate on 65% hydrogen with advanced combustor designs.
- By the end of this decade, OEMs are aiming to achieve NOx emissions performance similar to or better than natural gas while firing fuel with high (up to 100%) hydrogen. OEMs have the resources, technologies, tools, experience and qualification processes, as well as the development facilities necessary to solve combustion, thermal management and materials issues associated with hydrogen and the increased moisture in its combustion products. Backup and startup procedures will likely require 100% natural gas, distillate, or other low-reactive fuel, so that a dual-fuel control system and combustor configuration will be necessary as have been employed for synthetic gas/natural gas-fueled IGCC turbines The key questions are when and how these solutions will be commercially available, and how much operational complexity and restrictions will be necessary
- The commercialization timelines for high hydrogen turbines will depend on the availability of hydrogen to validate turbines at full scale and their ability to meet performance, emissions and operability requirements. Lack of adequate hydrogen supply will extend these timelines.
- The large installed base of existing gas turbines provides an opportunity for turbine OEMs to increase their role in significant global decarbonization by providing retrofit solutions for hydrogen fuels. OEMs are beginning to look beyond their new and advanced machines optimized for hydrogen fuels towards developing economically viable solutions for the installed base. While retrofit solutions are likely to be limited to modest hydrogen capability, conversion options for the installed base should be evaluated for its role in global decarbonization.

Projecting forward to a future hydrogen economy when high quantity supply and distribution infrastructure are established, hydrogen can replace Natural Gas as a primary gas turbine fuel. This would relieve gas turbine designers from having to incorporate complex combustor, fuel control system and operational design as currently required for firing hydrogen over wide concentration ranges. Simplified combustor designs optimized for single, pure Hydrogen fuel will be possible. For example, micromixer technology has been demonstrated at prototypic turbine operating conditions to achieve single digit NOx for fuels having 95% to 100% hydrogen.

[2] Depending on combustor design, hydrogen may be delivered to the combustor either pre-blended, separately, or as streams at different hydrogen concentrations. Hydrogen to natural gas ratios are on a volumetric basis and as delivered to the fuel control system regardless of disposition to the combustor.

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SECTION 1

Background

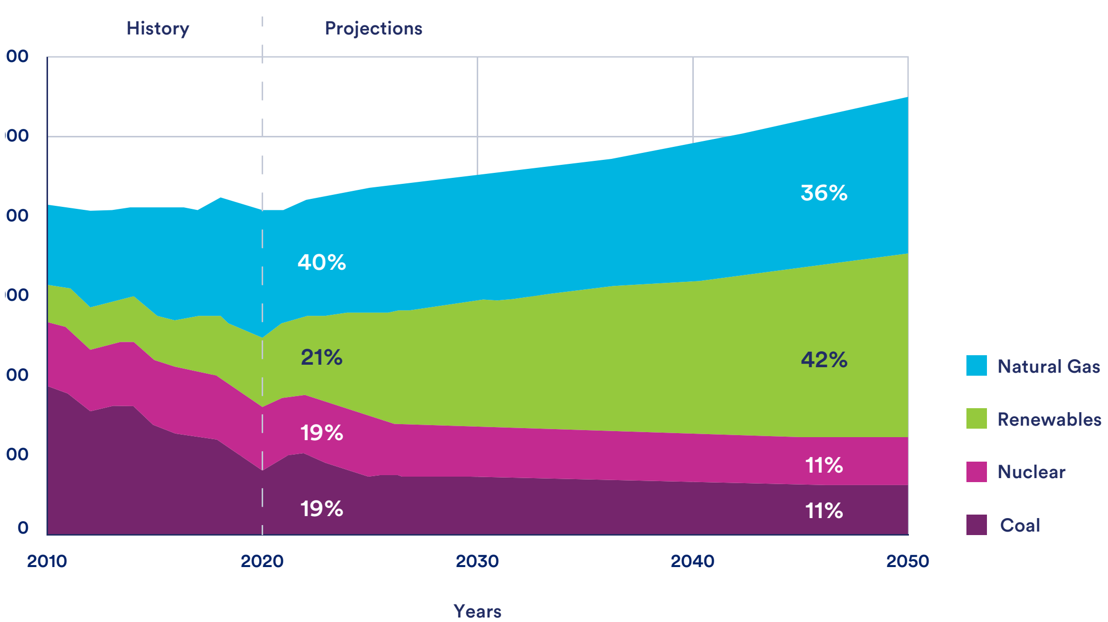
Gas turbines are already playing a key role in decarbonizing the U.S. economy. They provide reliable and flexible power that enables deeper penetration of renewable resources into electric systems. As a replacement for retiring higher-carbon-emitting coal plants, turbines have further reduced the electric power sector's carbon footprint. Despite these benefits and their low—but not zero—carbon emissions, natural-gas-fueled turbines are still classified as fossil energy. In past decades, turbine manufacturers focused on improving efficiency towards the objectives of reducing reduce fuel consumption and pant variable cost. The new driver for turbine improvement is carbon dioxide (CO_2) footprint. Hydrogen is well suited to reduce CO_2 emissions below the levels achievable through efficiency improvements.

Ultimately, and when fueled with "Green Hydrogen", hydrogen has the potential to reduce CO_2 emissions to zero. Due to hydrogen's high reactivity and adiabatic flame temperature, its potential to produce high levels of NOx emissions is often raised as an argument for excluding gas turbines as a component of a "Green" economy. In response, turbine OEMs recognize that they must, in addition to low or near-zero CO_2 emissions, also reduce criteria pollutant emissions to levels that are at least as low as those of current state-of-the-art turbines operating on natural gas.[3]

Over the past decade the share of natural gas generation in the U.S. power sector has increased to approximately 40% (Figure 1) (US Energy Information Agency, 2021).

Figure 1: Share of US Electrical Generation by Fuel Type

Source: Annual Energy Outlook Narrative, US Energy Information Agency, 2021 (US Energy Information Agency, 2021)



[3] Current federal New Source Performance Standards (NSPS) limit NOx emissions from new natural gas turbines to 15 ppm for turbines larger than 250 MW capacity and 25 ppm for turbines smaller than 250 MW (EPA, 2006). These criteria should be treated as minimum performance requirements that are frequently lowered in a facility permitting process. Typically, permitted gas turbine combined cycle plants achieve NOx emissions below 9 ppm (at 15% oxygen) without post-combustion (i.e., SCR) treatment.

Over the next three decades, according to the reference case scenario in the U.S. Energy Information Agency's (EIA's) *2021 Annual Energy Outlook*, natural gas power generation is projected to increase by 47% (Richard Dennis, US DOE, 2019) and maintain a share of about one-third of total U.S. electricity production. In large part, this estimate reflects continued retirement of coal plants and limited switching from coal to natural gas (GE Power, 2020). Also, according to the EIA, capacity additions to meet increasing electricity demand will be shared between natural gas and renewables. This will lead to increased CO_2 emissions from natural gas use in the power sector (Figure 2) (GE Power, 2020), mostly from gas turbines. In a policy environment that is targeting carbon reductions, natural-gas-fueled gas turbines will increasingly be in the crosshairs of environmental attention and, potentially, CO_2 regulation. As coal's contribution to U.S. CO_2 emissions fades, the electricity industry's defense of continued natural gas use, based on the lower carbon intensity of natural gas compared to coal, will also fade in potency. This presents both a challenge and an opportunity to utilize hydrogen as a way to flatten—and then turn downward—the curve of CO_2 emissions from gas turbines.

The properties of hydrogen that distinguish it from natural gas and that affect turbine and combustion performance are summarized in Table 1 (below) (Data sources in Table). Due to a combination of high flame speed, wide flammability limits, and low ignition energy, hydrogen in the turbine fuel can cause the flame to migrate upstream (flashback) to the head-end, where the flame will hold tight and cause significant damage (Figure 3) (Jeffrey Goldmeer - GE Gas Power, 2018).

Figure 2: US CO_2 Emissions by Fuel

Source: Accelerated Growth of Renewables and Gas Power Can Rapidly Change the Trajectory on Climate Change, GEA34578, GE Power December 2020. (GE Power, 2020)

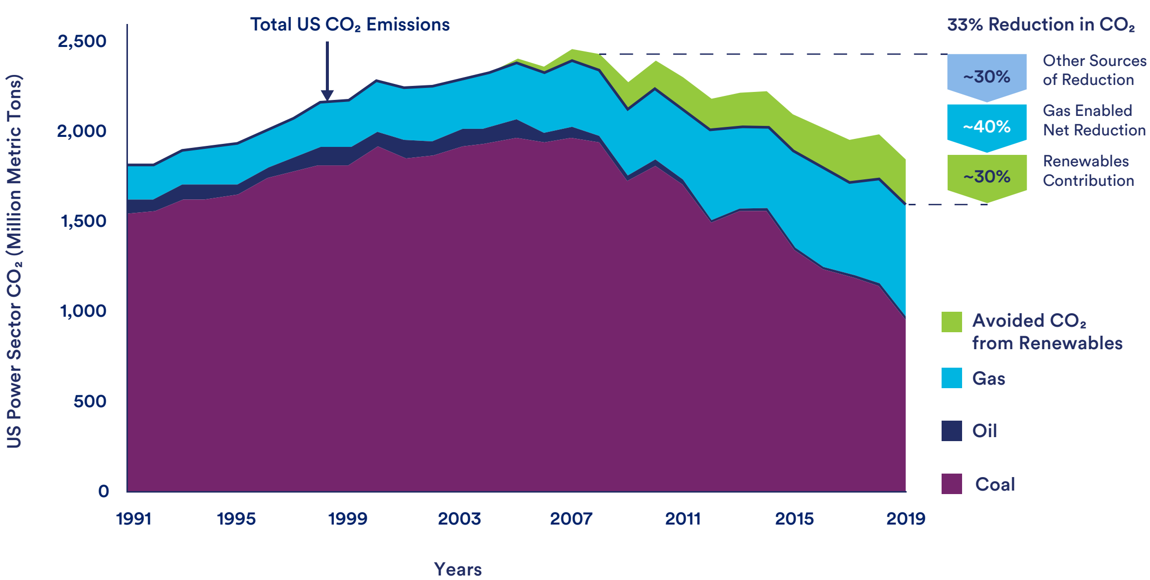


Table 1: Comparison of Hydrogen and Methane (CH_4) Properties

Property	Units	Hydrogen	Natural Gas (as CH_4)
Volume specific energy density[1] (LHV@stp)	kJ/Nm3	10	36
Mass specific energy density[1] (LHV@stp)	MJ/kg	120.00	55.00
Density[2] (@stp)	kg/Nm3	0.09	0.72
Exhaust H_2O[3]	% Vol	16.94	8.3
Adiabatic flame temperature[1]	Deg C	2,254	1,963
Lower flammability limit[4] (LFL) at STP	%Vol fuel/air	4%	5%
Upper flammability limit (UFL)[4] at STP	%Vol fuel/air	74%	15%
Flame speed[1]	cm/sec (@stp)	300	40
Minimum ignition energy[4] (E_i)	mJ	0.018	0.033
Wobbe Index[2] at (25°C)	btu/(sg DegF^$^{0.5}$)	45	53
Expansion coefficient k[3] (Cp/Cv @ 77°F)	Dimensionless	1.404	1.307
Stochiometric concentration[4] (C_S)	% Vol	29.6	9.6
Diffusivity[1]	cm^2/sec	0.756	0.21

1 "*The Challenges of Hydrogen Combustion*", Diesel & Gas Turbine Worldwide: Hydrogen Realities - challenges and opportunities of wide-scale adoption of green hydrogen as a fuel source (public webinar) Presentation by Dr. Jaqueline O'Connor, February 25, 2021

2 *Calculated*

3 "Gas Tables: Thermodynamic Properties of Air, Products of Combustion and Components Gases", Joseph H. Keenan & Joseph Kaye. 11th printing 1966, John Wiley and Sons

4 "*Hydrogen Fueled Gas Turbines*", Michelle Moliere, 2nd CAME GT Conference, Bled Slovenia, April 29-30, 2004 Michelle Moliere

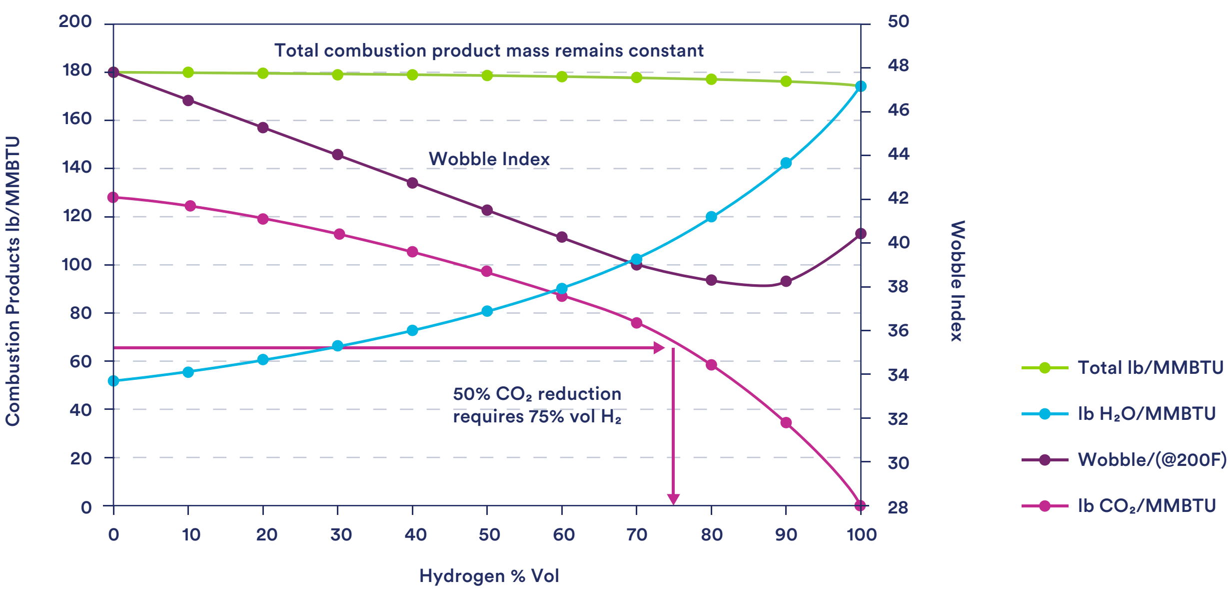
5 "*DOE-EPRI Workshop on Hydrogen Combustion in Gas Turbines*", Roger Schonewald, Willy Ziminsky, Pittsburgh PA, March 2007

Figure 3: Combustor Damage from Flame Flashback

Source: Fuel Flexible Gas Turbines as Enablers for a Low or Reduced Power Ecosystem, J. Goldmeer - GE Gas Power, Electrify Europe Conference, Vienna Austria, 2018 (Jeffrey Goldmeer - GE Gas Power, 2018)

OEMs have begun to offer combustor and fuel system modifications that allow for fuel blends with as much as 30% hydrogen by volume. Achieving substantial (i.e., 50% or greater) reductions in CO_2 emissions, however, requires much higher levels of hydrogen (above 75%) (Figure 4). The impacts of running a turbine on hydrogen fuel are not limited to the combustor and its fuel supply system. At high levels of hydrogen, turbine aero-thermal effects and impact on materials and performance must also be considered. Therefore, OEMs are focusing development efforts on all aspects of increasing the hydrogen capability of their turbines. The challenge they face is to achieve compatibility with hydrogen as a fuel component without compromising performance, emissions, reliability, operability, and fuel flexibility in ways that would disqualify turbines as a viable generation technology in a future "fully Green" economy.

Figure 4: Combustion Products of H_2/NG Blends



SECTION 2

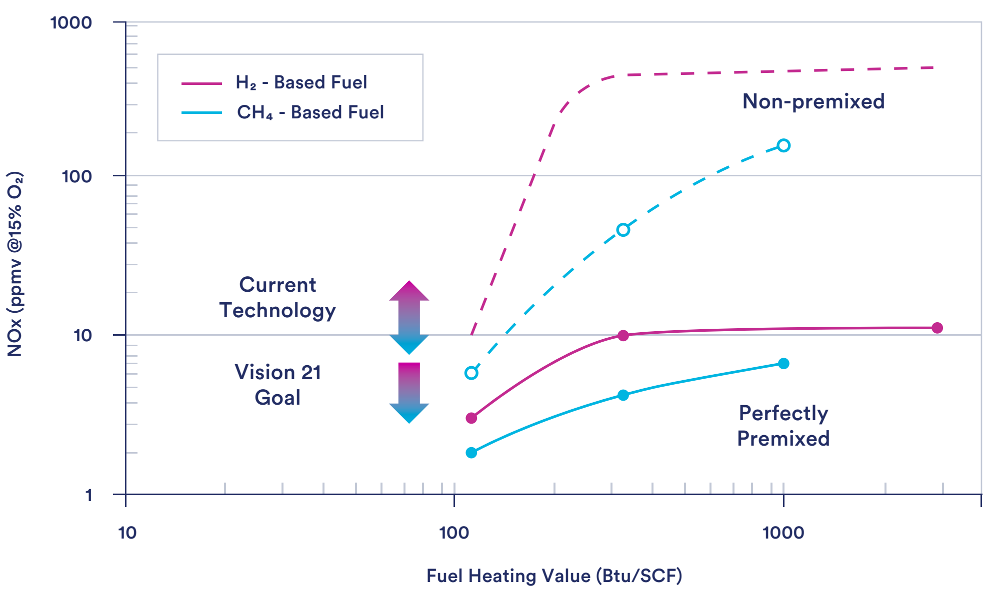
Fundamental Performance Expectations with Hydrogen

This section summarizes the impact on gas turbine performance if hydrogen could be used in current gas turbines as a "plug-in" substitute for natural gas without degradation of performance. Turbine performance in this scenario can be described as the potential performance of turbines that can obtain from hydrogen—assuming other engineering challenges with respect to emissions, hot gas path (HGP), and operational flexibility can be resolved so as to allow for direct substitution of natural gas by hydrogen. (Some of these specific engineering challenges and their impact on turbine performance, along with potential design solutions, are discussed in more detail later.)

NOx: Entitlement NO_x emissions for a gas turbine operating on hydrogen are set by the performance of a "perfect" combustor, where a perfect combustor is defined as a well-stirred reactor at equivalence ratios (ratio of actual fuel/air to stoichiometric fuel/air) that achieve required turbine firing temperatures.[4] With perfect premixing of 100% hydrogen with air, NO_x emissions in the single-digit parts per million can be achieved (Figure 5) (GE Jon Ebacher, 2003) for specific heating values below 300 British thermal units per standard cubic foot (BTU/scf).

Figure 5: NOx Versus Fuel Heating Value

Source: Hydrogen in the Power Generation World, Jon Ebacher – GE, Presentation to the WP-6 Working Party on Regulatory and Standardization Policies, Geneva, Switzerland, 2003 (GE Jon Ebacher, 2003)



[4] Firing temperature (T_{fire}) is defined here as total temperature in the plane between first-stage nozzles and buckets.

Due to hydrogen's low ignition energy, and lower flame limit (Table 1), it is possible to maintain combustion at even lower specific heat (i.e., approximately 100 BTU/scf). This allows for high levels of dilution with either air or inert gases to achieve stable combustion with zero carbon monoxide (CO) emissions. The strategies manufacturers are using to approach this level of performance are discussed in more detail later. Low single-digit ppm NO_x emissions have been achieved with high (90%+) hydrogen/natural gas blends at laboratory scale and in prototype combustor testing. *However, the challenge will be to accommodate real-world operating requirements and conditions, which include load swings, wide and even on-the-fly changes of hydrogen-to-natural-gas fuel blend ratios, and safe startup/shutdown procedures.*

CO_2 footprint: The primary reason to use hydrogen in gas turbines is to reduce CO_2 emissions. For heavy-duty gas turbines, hydrogen to natural gas ratios will be limited to low concentrations until hydrogen price and availability justify high concentrations.[5] OEMs quote the hydrogen capability of their turbine offerings in terms of percent hydrogen by volume. This can be misleading. Due to its low molecular weight (specific mass volume), a given volume of hydrogen provides only 30% of the specific volumetric heating value (BTU/scf or kJ/Nm³) of an equivalent volume of natural gas. For example, compared to natural gas, a 30%/70% hydrogen/natural gas ratio (by volume) reduces net CO_2 emissions by only 9%. (Table 2 as CO_2/MMBTU) Achieving a 50% CO_2 reduction requires approximately 75% hydrogen by volume (Figure 4).[6] *Increasing attention to CO_2 emissions for environmental reasons is the driver for current OEM interest in accelerating development of hydrogen capability in gas turbines beyond 30% hydrogen.*

Table 2: Properties of Combustion Products for H_2/NG Blends

H_2 vol%	Wobbe (@200F)	LHV BTU/lb	LHV BTU/scf	lb H_2O/ MMBTU	lb CO_2/ MMBTU	Total lb / MMBTU	Product %Vol H_2O	Product %Vol CO_2	Product scf/lb
0	47.7	21,552	910.8	52	128	180	50%	50%	12.24
10	46.4	21,965	847.1	56	123	180	53%	47%	12.56
20	45.1	22,465	783.3	61	119	179	56%	44%	12.89
30	43.8	23,083	719.6	66	113	179	59%	41%	13.25
40	42.6	23,867	655.9	73	106	179	63%	37%	13.74
50	41.3	24,867	592.1	81	98	178	67%	33%	14.27
60	40.1	26,301	528.4	90	88	178	71%	29%	14.86
70	39.0	28,342	464.7	103	75	178	77%	23%	15.82
80	38.3	31,569	400.9	120	58	177	84%	16%	17.12
90	38.2	37,445	337.2	142	34	176	91%	9%	18.66
100	40.4	51,549	273.5	175	0	175	100%	0%	21.05

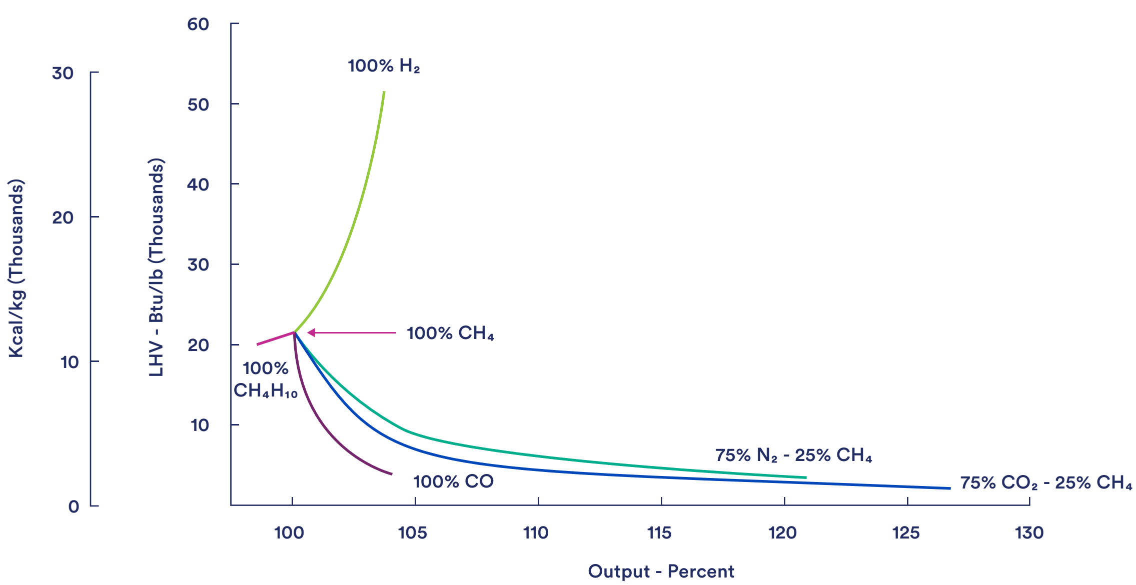
5 For perspective, a single GE 207HA.03 combined cycle turbine would consume 65 tons of hydrogen per hour—about 5% of total U.S. hydrogen production (2019).

6 For this purpose, turbine output (MW), heat rate (BTU/kW/hr), and fuel heat input rate (BTU/hr) are not expected to change significantly with hydrogen. As a result, the relative carbon content of the fuel (lb CO_2/MMBTU) provides a relative comparison of net turbine CO_2 emissions (lb/kWh).

Output: Without major changes to key turbine parameters (e.g., compressor pressure ratio (PR), T_{fire}, fuel BTU/hr), the output (MW) of a simple-cycle turbine is proportional to the total mass flow through the turbine expansion stages.[7] The total mass flow into the turbine firing plane equals the compressor mass discharge flow[8] plus combustion products. To maintain the same output, a turbine requires about the same fuel heat input (BTU/hr) with either hydrogen or natural gas. Due to its high mass-specific heat (Table 1), the required mass flow for hydrogen is less than half that of natural gas. Despite the lower mass flow from hydrogen in a blend, the mass flow of net combustion products (CO_2+H_2O) and the implied output are relatively constant (Figure 4).[9] Figure 6 (Frank Brooks, GE Power Systems, 2000) shows the effect of heating value, higher specific heat (C_p) of water vapor, and compressor performance on output from E-class turbines for various fuels (compared to natural gas). *The figure indicates an increase in output of approximately 3% with 100% hydrogen fuel. It is expected that output with hydrogen will range from no loss to higher compared to natural gas. More precise estimate requires further refinement with machine-specific details and OEM "real" cycle performance decks that include the effect of water vapor on hot gas components and the effect of back pressure on compressor performance.*

Figure 6: Turbine Output for Various Fuels

Source: Gas Turbine Performance Characteristics; Frank Brooks – GE Power Systems, GER-3567H 2000 (Frank Brooks, GE Power Systems, 2000)



[7] Turbine axial compressors are effectively constant volume machines. The mass-flow effect on output is further demonstrated by the need to correct expected turbine output for altitude to account for lower air density at higher elevations.

[8] A portion of compressor flow is extracted from various compressor stages to be admitted back to various hot gas path components (nozzles, buckets, shrouds) that require cooling. Depending on their position in the HGP, these flow additions are classified as chargeable to fuel consumption and efficiency.

[9] To put this in perspective, combusting 1 pound (lb) of hydrogen produces 9 lbs of water (H_2O), while combusting 1 lb of natural gas produces less than 4 lbs of CO_2 and H_2O.

Heat rate: An estimate of how hydrogen fuel affects heat rate can be derived from the efficiency of an ideal Brayton cycle. For a Brayton cycle, gas turbine efficiency is solely a function of the turbine expansion pressure ratio and the gas specific heat ratio: k (C_p/C_v) (Jones & Hawkins, 1963).[10] With no expected degradation in compressor performance (efficiency, capacity and surge margin) due to hydrogen combustor pressure drop and HGP back pressure, little change in heat rate is expected. For example, a factorial analysis of hydrogen vs. natural gas performance for a GE 6B turbine (GE Energy; Michelle Moliere, 2004) predicts that hydrogen increases both turbine net efficiency and output relative to natural gas, assuming constant heat input.[11] *Heat rate is expected to range from no worse to better than natural gas. These results require further refinement with machine-specific and OEM "real" cycle performance decks that include the effect of water vapor on hot gas components and the effect of back pressure from combustor and HGP on compressor performance.*

The devil is in machine-specific details. These conclusions assume that OEMs will be able to address the challenges that hydrogen poses to turbine hardware (hot gas path, combustor) and auxiliary systems for fuel management and control. The next sections discuss these challenges and review current and potential future options for mitigating them.

10 The efficiency of an ideal Brayton cycle with pressure ratio (PR) is $1\text{-}1/(PR^{(k\text{-}1/k)})$. For a real-world Brayton cycle, firing temperature increases both output and efficiency.

11 The analysis in this reference did not account for cycle modifications (e.g., modifications to T_{fire}, chargeable cooling air, etc.) as would be required for NO_x control.

SECTION 3

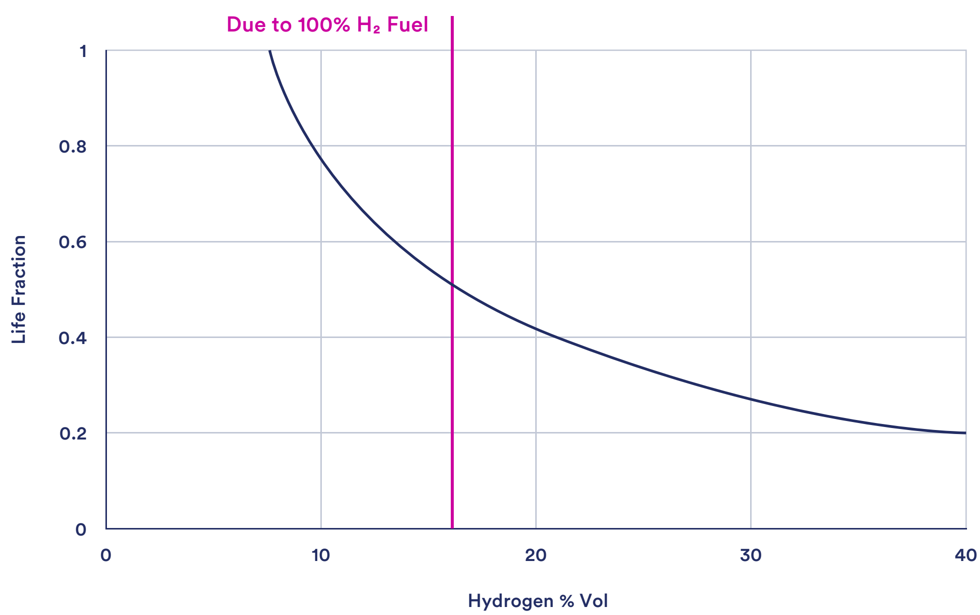
Hydrogen's Challenges

As discussed later, hydrogen's unique characteristics impact combustor design. Hydrogen also presents ancillary challenges to gas turbines that designers need to address.

Thermal management: Hydrogen will increase water vapor in combustion products. The moisture content of combustion products over a range of hydrogen/natural gas blends is shown in Figure 4. Due to its thermal transport properties, water vapor will increase heat transfer to HGP components—primarily nozzles and buckets—that have strength parameters that are highly sensitive to temperature. Materials concerns include the potential for "creep" (stress/rupture), which can result in shroud/bucket contact, rupture with blade liberation, thermal-mechanical fatigue (TMF), and oxidation/corrosion Moisture diffusion can cause thermal barrier coatings (TBCs) to spall and cause accelerated corrosion or oxidation in base alloys. This will require either derating the firing temperature; modifying the cooling flow, for example by using steam or cooled air; and/or increasing cooling effectiveness for hot gas components. Without increased cooling effectiveness, moisture will raise tradeoffs between component life and performance. As an example, for 100% hydrogen, moisture content in the flue gas doubles from 8.3% (vol.) with natural gas, to 16.9%. (Schonewald & Ziminsky, 2007). The impact of moisture and increased heat transfer is reflected in the component life factor (Figure 7) (GE Jon Ebacher, 2003) as compared to a turbine designed for natural gas use with original components that have not been upgraded for hydrogen.

Figure 7: Turbine HGP Component Life Factor Versus Hydrogen Content

Source: Hydrogen in the Power Generation World, Jon Ebacher – GE, Presentation to the WP-6 Working Party on Regulatory and Standardization Policies, Geneva, Switzerland, 2003 (GE Jon Ebacher, 2003)Regulatory and Standardization Policies, Geneva, Switzerland, 2003 (GE Jon Ebacher, 2003)



Designing and choosing materials for turbine HGP components is an integrated process that incorporates combustor development and thermal/heat transfer analysis of the turbine hot gas path. Combustors with high hydrogen capability will differ from the combustors currently used for natural gas. While the primary goals of combustor development are to achieve low emissions and maintain firing temperature, consideration must also be given to the combustor's direct impact on downstream components. Hot streaks from the combustor exit that continue into the turbine must be minimized. The velocity/temperature profile at the combustor exit plane, (pattern factor), as measured in combustor testing and the impact of peak temperatures evaluated with three-dimensional computational fluid dynamics (3D-CFD) to determine its impact on nozzles and blades.

Several strategies are available for mitigating hydrogen's thermal impacts:

- Firing temperature reduction
- Increased or modified coolant
- Increased airfoil cooling effectiveness
- Materials and coatings of HGP components with higher strength and corrosion resistant properties

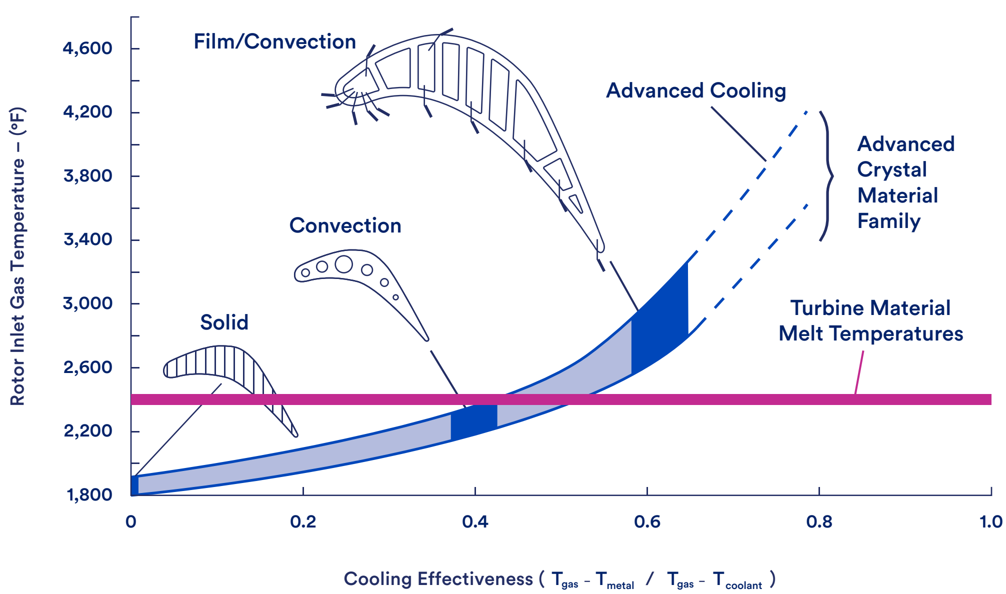
Each has different impacts, as briefly summarized below

Firing temperature: A reduction in firing temperature can be easily implemented through turbine fuel control modifications, but this approach will degrade turbine output and efficiency.[12] In combined cycle plants a reduction in firing temperature will reduce exhaust temperatures, which will further reduce bottoming cycle output and efficiency. For high-cost fuels such as hydrogen, maintaining high efficiency is important to competitiveness. *Due to negative performance impacts, OEMs are likely to consider this approach a last resort.*

Airfoil cooling: With the high firing temperatures of advanced turbines, hot-section component cooling has become both increasingly important and challenging. Historically, OEM's have pushed efficiencies higher through increased cycle firing temperatures and compressor pressure ratios. This has been primarily accomplished through advances in component cooling and new materials (Figure 8) (Koff, 2016) designed for firing temperatures that exceed metal melting points. Approximately 20%–25% of the total air flow through a gas turbine bypasses the combustor and is used to cool turbine airfoils, disks, and other turbine

Figure 8: Cooling Effectiveness Has Increased Firing Temperature

Source: Producing the World's Finest Heat Engine, Bernard L. Koff; ASME Power Journal, 2016-59103, V001T02A001, 2016 (Koff, 2016)

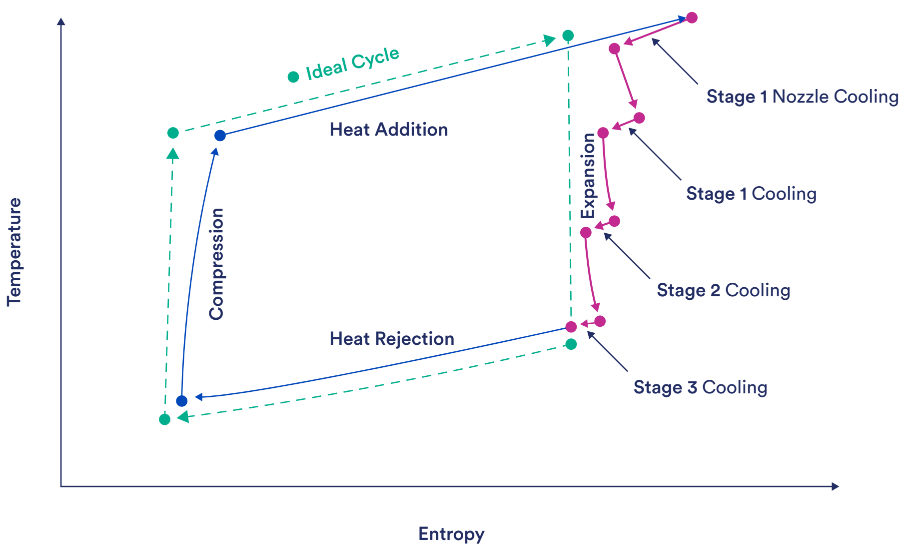


12 For IGCC applications, firing temperature is reduced to compensate for the higher mass flow of low-BTU syngas and its diluent. However, increased mass flow provides higher output that offsets the temperature reduction.

components (Michael Barringer, 2014). Cooling air is extracted from various stages of the compressor with different pathways to HGP stages. As firing temperatures and pressure ratios have increased, the extracted cooling air has become hotter. Increasing cooling flow inflicts a cost in performance since most of this flow is chargeable to cycle performance.[13] Increasing the amount of air used for cooling decreases the thermal efficiency of the turbine. As a rule-of-thumb, 1% additional chargeable cooling air increases the heat rate by approximately 1%. An illustration of the thermodynamic effect of cooling on a Brayton cycle is shown in Figure 9. The option to separate and cool extraction air from the compressor depends on the physical configuration of turbine pathways from compressor to HGP.[14] The first H-class machines substituted steam for air (Frank Brooks, GE Power Systems, 2000), which provided high cooling effectiveness without film cooling for a 200°F increase in T_{fire}. However, steam had to be supplied from the bottoming cycle, which required an extended startup time while waiting for the generation of steam. Despite improvement in the combined cycle heat rate and output, the need for cycling operation to accommodate increased power grid demand variability reduces the viability of this approach. *Responding to market demand for machines that can start and change load quickly, OEM attention has focused on increasing on turbine cooling effectiveness using air (with film cooling) through airfoil design.*

Turbine airfoils are complex miniature heat exchangers, industrial gas turbines having benefitted from technology flow-down from aircraft engines. Along with thermal barrier coatings, high cooling effectiveness[15] for nozzles and buckets is necessary to maintain component life.

Figure 9: Effect of Film Cooling Flow on Simple Cycle Performance



13 Cooling air entering the flow-path is classified as chargeable when there is no work extracted from it downstream of its injection point. For example, the cooling air for a first-stage nozzle would not be chargeable, while that for first-stage buckets and later-stage buckets and nozzles are classified as chargeable.

14 Mitsubishi Heavy Industries (MHI) has adopted cooling in its G and J class machines, which has allowed the use of directionally solidified nozzles and vanes to avoid the high cost and low yield of single crystal blades.

15 Cooling effectiveness is defined as $(T_{gas}-T_{metal})/(T_{gas}-T_{coolant})$ (Razak, 2007). Effectiveness data is generally held as proprietary by OEMs.

Advanced airfoils require internal cooling with enhancements and external film for shielding from hot gas (Figure 10) (Joseph Weber, Lindsay Kebler; GE Power, 2018) (Figure 11) (Jens Dickhoff, 2016). Several schemes are used:

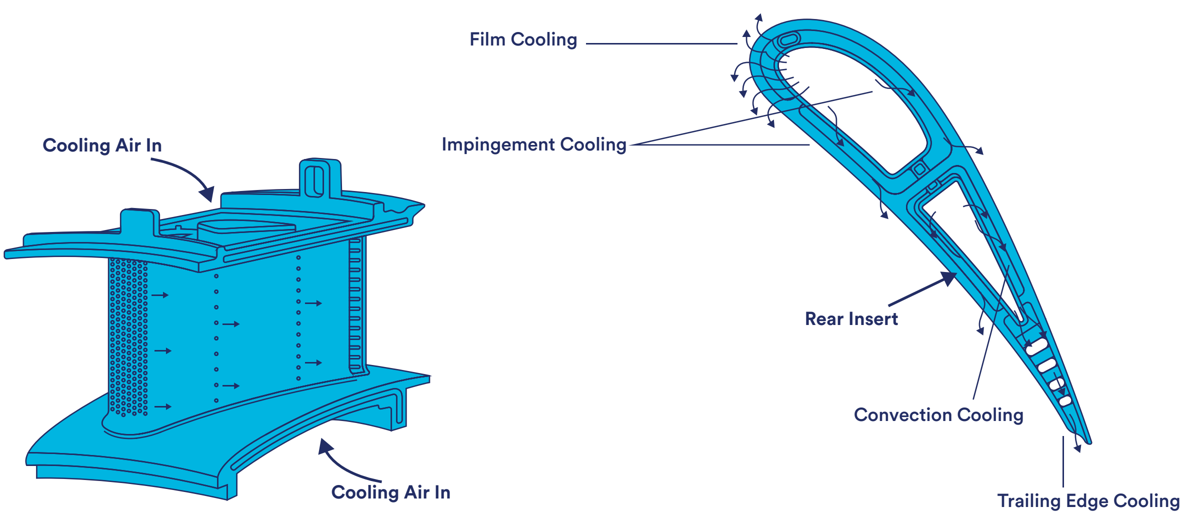
- **Internal**
  - Enhanced convection (e.g., turbulators)
  - Impingement cooling
  - Pin fin cooling (airfoil trailing edge)
  - Multi-pass serpentine cooling
- **External**
  - Film cooling
  - Shower-head cooling

OEMs employ different combinations of these options for their cooling strategy. Refining these approaches as required for hydrogen will increase complexity and bring associated challenges with respect to (1) manufacturability and (2) testing procedures and (3) modalities to verify that all internal features meet specification requirements.

Research on blade cooling is brisk and the literature is increasingly voluminous.[16] Additive manufacturing is allowing OEMs to rapidly produce prototype realistic three-dimensional airfoils for flow and thermal testing (Figure 12) (John Marra, Siemens Energy, Inc., 2015). Processes such as electron beam melting (EBM), direct metal laser melting (DMLM), and tomolithography will accelerate prototyping and actual hardware manufacture to realize even more advanced cooling concepts for combustors and hot gas components that could not be manufactured with conventional processes. As an example, Siemens was able to produce an advanced, cooled row-1 turbine blade incorporating a monolithic, one-piece core made by the Mikrosystem's Tomolithographic process. This produced significant improvements in blade thermal efficiency (John Marra, Siemens Energy, Inc., 2015).

Figure 10: Nozzle Cooling Example

Source: High Temperature Additive Architectures for 65% Efficiency: Joseph Weber, Lindsay Kebler – GE Power, Presentation given at 2018 DOE UTSR Project Review Meeting, PDOE-FE0031611, Daytona Beach FL (Joseph Weber, Lindsay Kebler; GE Power, 2018)



16 An extensive discussion on advanced cooling concepts is given by Siemens in (John Marra, Siemens Energy, Inc., 2015).

Figure 11: CFD Simulation of Gas Turbine Blade Cooling Showing A) Blade Cutaway View B) Cooling Air Pathway and Streamlines C) Blade Surface Temperature

Source: Improving cooling effectiveness of gas turbines through design exploration; Jens Dickhoff, Masahide Kazari and Ryozo Tanaka, Power Engineering International, November 2016 (Jens Dickhoff, 2016)

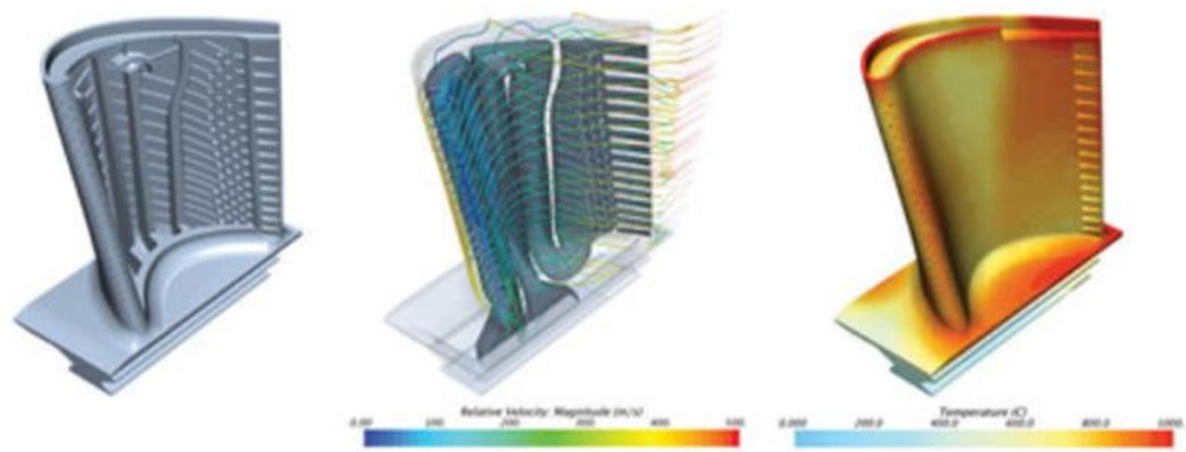
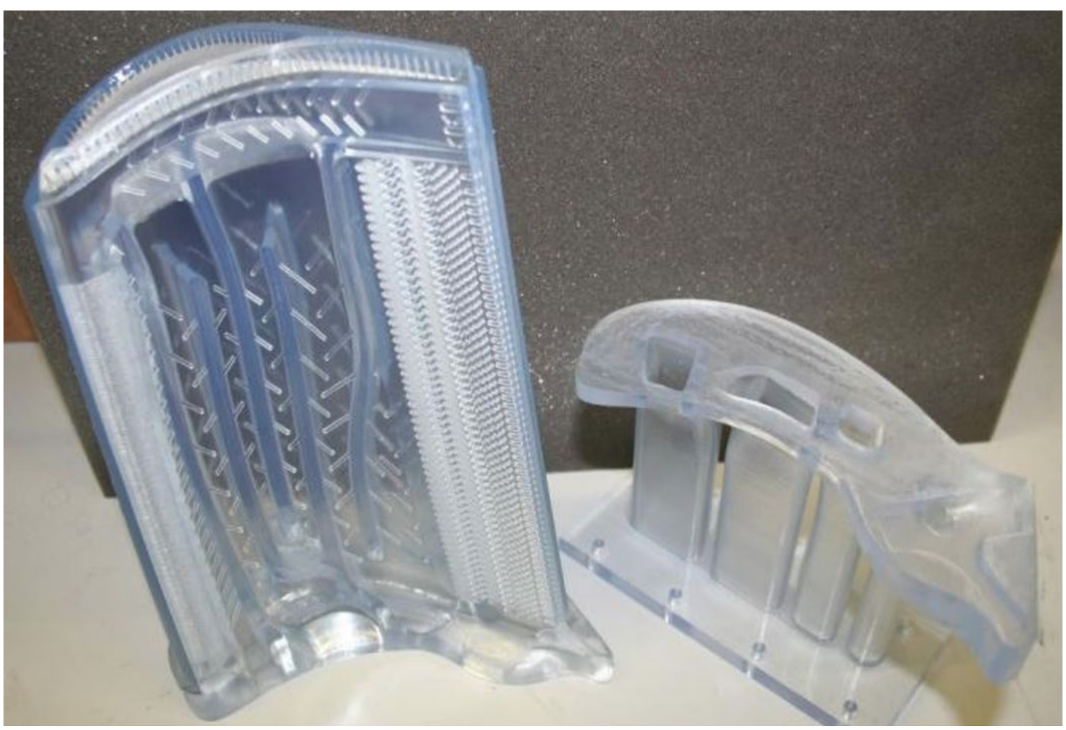


Figure 12: Three Dimensional Airfoils Produced for Aerodynamic Testing

Source: Advanced Hydrogen Development; Final Technical Report Number: DOE-SEI-42644, Marra, Siemens Energy, 2015 (John Marra, Siemens Energy, Inc., 2015)



HGP materials: In addition to its heat transfer properties, water vapor causes hot corrosion and oxidation on gas turbine coatings and base materials. (Tang, 2018). By exposing HGP components to increased water vapor, the use of high hydrogen fuel presents a risk for the life of both base alloys and TBCs due to moisture degradation. The corrosion/oxidation vulnerability of advanced alloys has increased with temperature capability (Figure 13) (Koff, 2016). TBCs and environmental barrier coatings (EBCs) are the first line of defense against base material corrosion and erosion.

Figure 13: Oxidation/Corrosion Susceptibility of Turbine Alloys

Source: Producing the World's Finest Heat Engine, Bernard L. Koff; ASME Power Journal, 2016-59103, V001T02A001, 2016 (Koff, 2016)

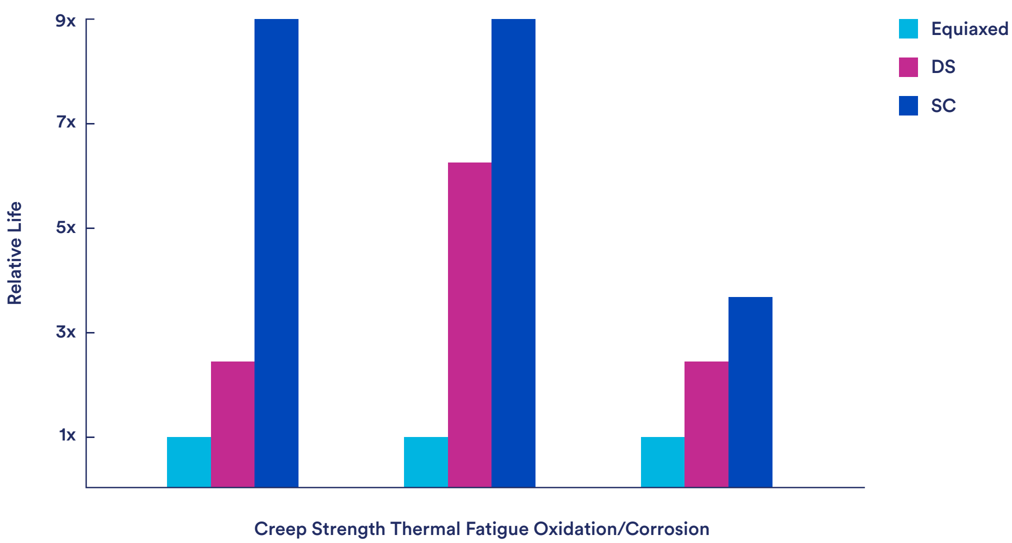
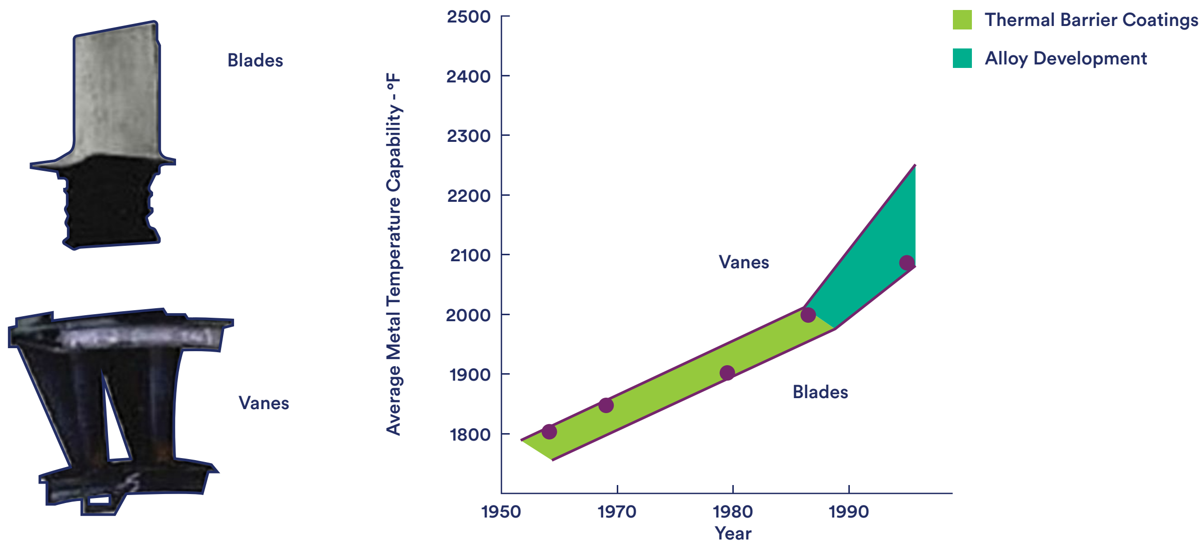


Figure 14: Impact of TBCs on HGP Components

Source: Producing the World's Finest Heat Engine, Bernard L. Koff; ASME Power Journal, 2016-59103, V001T02A001, 2016 (Koff, 2016)



TBCs with low thermal conductivity have made a major contribution to enabling higher firing temperatures (Figure 14) (Koff, 2016).
In addition to static high-temperature testing, validation testing must include thermal gradients, cooling, and heating phases during startup, shutdown and load changes as contributors to TBC spalling and delamination. Prior OEM experience with the development of TBCs having resistance to the corrosive components (e.g. moisture, sulfur, alkalis) in synthesis gas from gasification is relevant to hydrogen combustion. Under DOE's Advanced Turbine Program, both Siemens (John Marra, Siemens Energy, Inc., 2015) and GE (William York et.al, GE Energy, 2016) successfully developed TBCs specific to advanced hydrogen turbine conditions (Figure 15)

Figure 15: TBC Thermal Shock and Temperature Gradient Testing

Source: GE Perspectives – Advanced IGCC/Hydrogen Gas Turbine Development; Reed Anderson, Presentation for 2010 US-DOE UTSR Meeting, Schenectady, NY (Reed Anderson - GE Energy, 2010)

(Reed Anderson - GE Energy, 2010).[17] It is likely that OEMs will vigorously pursue TBC development and field validation in operating units for high hydrogen fuels. Merely increasing TBC thickness may affect performance by increasing airfoil throat blockage and airfoil trailing edge thickness, which increases vane and nozzle wake span (A.J. Fredmonski,Bob Hoskin, Joe Weber - GE Power, 2019). Research is currently underway to combine the functions of TBCs and EBCs in a single protective coating (Quan Li, 2018).

Through their participation in DOE's Hydrogen Turbine program, both GE and Siemens performed extensive testing of candidate alloys for deployment in next-generation hydrogen turbines. Ceramic matrix composites (CMCs) have shown promise for use in extreme temperatures (greater than 3100°F/1,700°C), but have lower resistance to moisture damage than alloys (Tang, 2018) and require further EBC development for use in high moisture environments for HGP components such as non-rotating first-stage nozzles (John Delvaux - GE Energy, 2019) and the transition piece from the combustor to the turbine inlet (Jay Morrison - Siemens, 2017).

Thermal management is critical to maintaining the high firing temperatures and high efficiency needed to make turbines economic when operating on high-cost hydrogen fuel. OEMs have the technologies, tools, experience, and qualification processes required to address the thermal management and materials issues associated with hydrogen fuel and its combustion moisture.

Other components: In addition to the combustor and HGP, other turbine components that can potentially be affected by hydrogen are the compressor and fuel system; in addition, there can be aeromechanical effects on last-stage airfoils:

Compressor: For constant fuel heat input, total turbine mass flow is relatively unchanged.[18] The lower specific energy density (BTU/scf) of hydrogen will increase fuel volumetric flow through the combustor and, in combination with the higher velocities needed to avoid flashback, will tend to increase combustor

17 For example, a low thermal conductivity TBC with excellent moisture resistance for high hydrogen applications was qualified for commercial application in (GE Power and Water, 2015)

18 Oxygen in stoichiometric quantities as required for hydrogen combustion with air exceed that for natural gas.

pressure drop. Water vapor in combustion products will also increase volumetric flow through the turbine (moderated by the equivalence ratio).[19] Increased volume through the turbine may increase turbine expander back pressure and increase turbine stage Mach numbers. Due to these potential effects, OEMs must consider the compressor and its matching to the turbine, which is normally optimized for natural gas (MacDonald, 2006). Higher fuel volumetric flow may also increase combustor pressure drop.[20] Higher back pressure will move the compressor toward its surge margin and away from its peak efficiency point.[21] Additionally, the addition of axial fuel staging to both conventional swirl flow combustors and micromixers will also increase combustor pressure drop. *At a minimum, the control schedule for positioning compressor inlet guide vanes (IGVs) with load changes and combustor fuel sequencing will require modification. In an extreme case of additional back pressure, it may be necessary to modify the compressor flow path or even add stages (John Marra, Siemens Energy, Inc., 2015).*

Fuel control and the Wobbe Index: The Wobbe Index[22] (WI) provides a measure of the thermal energy flow for fuel in a given fuel system. It is a commonly used parameter for specifying the acceptability of a gaseous fuel in a combustion system. For a given set of fuel supply and combustor conditions (nozzle sizes, temperature, and pressure) and control valve settings, two gases with different compositions, but with the same Wobbe Index, will deliver the same rate of energy input to the combustion system. Compared to natural gas, hydrogen has a lower Wobbe Index. Turbines need flexibility to accommodate a wide range of hydrogen/natural gas blends and Wobbe Indexes. OEMS generally provide allowable index ranges in their fuel specifications. For example, GE's fuel specification GEI-41040i (GE Energy, 2005) allows a plus or minus 5% range for a given gaseous fuel with conventional DLN combustors. The greater the change in Wobbe Index, the greater the required flexibility of the combustor and fuel control system.

The Wobbe Index over a range of hydrogen/natural gas blends (Figure 4) is 20%, which will, theoretically, require specific modifications, each limited to a specific range of blends. Fuel heating is an effective approach for Wobbe control.[23] *Backup and startup procedures will likely require 100% natural gas or another low-reactive fuel,[24] thus necessitating a dual-fuel control system and combustor configuration, as are already employed for syngas/natural gas-fueled IGCC turbines.*

Aeromechanics: Volume change will also change inter-stage velocity matching and Mach numbers, with consequences for stage aeromechanical performance. Depending on specific OEM evaluations of impact, potential mitigation options include opening of turbine nozzle flow areas, compressor bleed, IGV control, or addition of compressor stages. *Due to their longer length and low solidity, and the potential for damaging flutter and vibration, special attention should be given to the materials and design of last-stage turbine buckets.*

19 For E-class turbines, velocities and the hot gas path for 100% hydrogen will be approximately 6% higher than with natural gas.

20 In its testing of micromixer combustors, GE obtained pressure drops that were roughly equivalent to swirl combustors (GE Power and Water, 2015). However, axial staged combustion will increase pressure drop.

21 Turbine manufacturers generally treat their turbine compressor maps as proprietary information.

22 The index in this report is the Modified Wobbe Index (MWI) as based on fuel lower heating value (LHV).

23 For example, increasing the temperature of natural gas from 100°C to 240°C will reduce the Wobbe index to that of hydrogen

24 Fuels low autoignition temperatures such as Naptha are not acceptable for sartup.

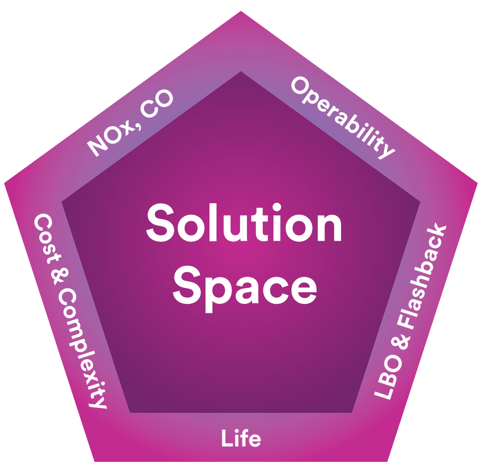
SECTION 4

Combustion

The primary combustion challenge for gas turbines operating on hydrogen is NOx emissions. Key performance criteria for combustors are emissions, operability over a wide range of loads, resistance to flashback, lean blowout (LBO), life, and cost (Figure 16) (Norman Z Shilling GE Power Systems, 2006). Gas turbine OEMs must also deal with the higher temperatures of hydrogen combustion through design, materials capability, and thermal management over wide mixture ranges and load variability.

Figure 16: Combustor Design Criteria

Source: IGCC: On the Roadmap to Zero Emissions; N.Z. Shilling, VGB Congress: Power Plants, Dresden Germany, 2006 (Norman Z Shilling GE Power Systems, 2006)



Hydrogen burns hotter and faster and is more easily ignited than natural gas. Due to its mass specific energy (BTU/lb) being more than two times that of natural gas and its low molecular weight, hydrogen's adiabatic stoichiometric flame temperature (AFT) is approximately 300°C higher than natural gas.

Flame temperature is a strong (exponential) driver of NOx emissions. NOx formation takes place at combustion temperatures above 1500°C, where the oxygen (O_2) molecules dissociate and the resulting oxygen radicals act on the nitrogen molecules to form nitrogen oxides. Most (95%) of this oxidation results in nitric oxide (NO) formation with nitrogen dioxide (NO_2) and nitrous oxide (N_2O) making up the balance (MacDonald, 2006).

The fundamental challenge in combustor design is to achieve capability for fuels having widely different flame speeds. Hydrogen requires high velocities within the combustor to prevent flashback. For natural gas, high velocities can result in flame blowout and insufficient carbon burnout. In the interim before hydrogen sufficient for full firing is available, OEM's are striving to develop combustor designs that provide operational flexibility.

The maximum flame temperature for hydrogen is its adiabatic flame temperature (AFT). Figure 17 (below) shows AFTs for hydrogen and other fuels with predicted NOx emissions derived by correlation from the utilization of a high hydrogen fuel (up to 95% vol.) in a GE 6B turbine in a refinery application (GE Energy; Michelle Moliere, 2004). For 100% hydrogen, NOx emissions exceed 500 ppm. Unmitigated NOx emissions for F-class turbine (GE 6FA) firing temperatures are shown in Figure 18 (below) (GE Jon Ebacher, 2003). Without mitigation, high hydrogen fuels will increase NOx emissions to levels that will be challenging to control—even with post-combustion selective catalytic reduction (SCR).

At high combustion temperatures (e.g., 1600°C) (Figures 19, 20, below) (Siemens A.G., April, 2020) hydrogen's laminar flame speed[25] is 2.8 times higher and ignition delay time is 80% lower, with minimum ignition energy

[25] Flame speed is measured as the velocity at which a flame will propagate upstream into unburned fuel from standard air interface.

Figure 17: NOx Emissions Versus Adiabatic Flame Temperature

Source: Hydrogen-Fueled Gas Turbines - Status and Prospects, Michelle Moliere – GE Energy, Proceedings of the 2nd CAME-GT Conference, Bled Slovenia, 2004 (GE Energy; Michelle Moliere, 2004)

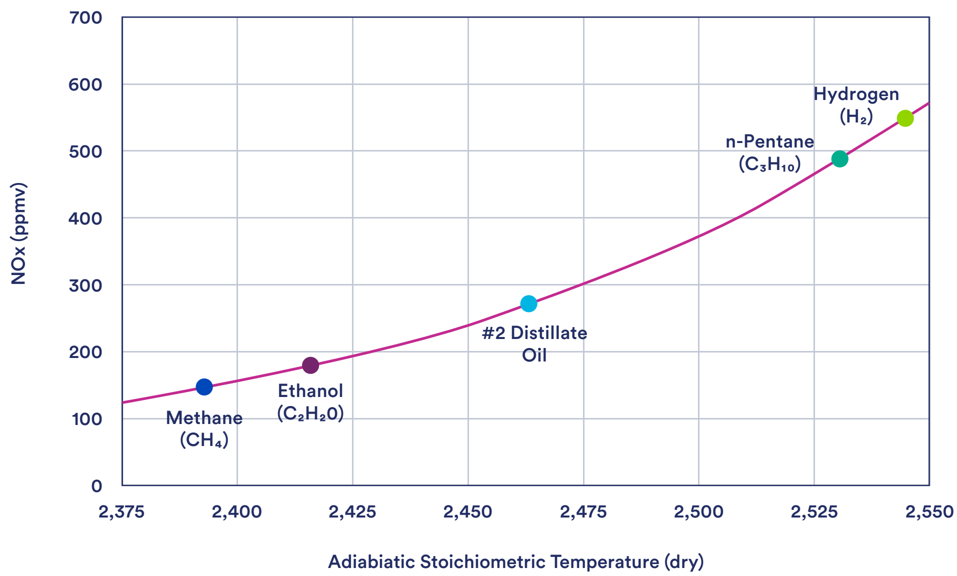


Figure 18: NOx Levels Without Mitigation for 6FA Firing Conditions

Source: Hydrogen in the Power Generation World, Jon Ebacher – GE, Presentation to the WP-6 Working Party on Regulatory and Standardization Policies, Geneva, Switzerland, 2003 (GE Jon Ebacher, 2003)

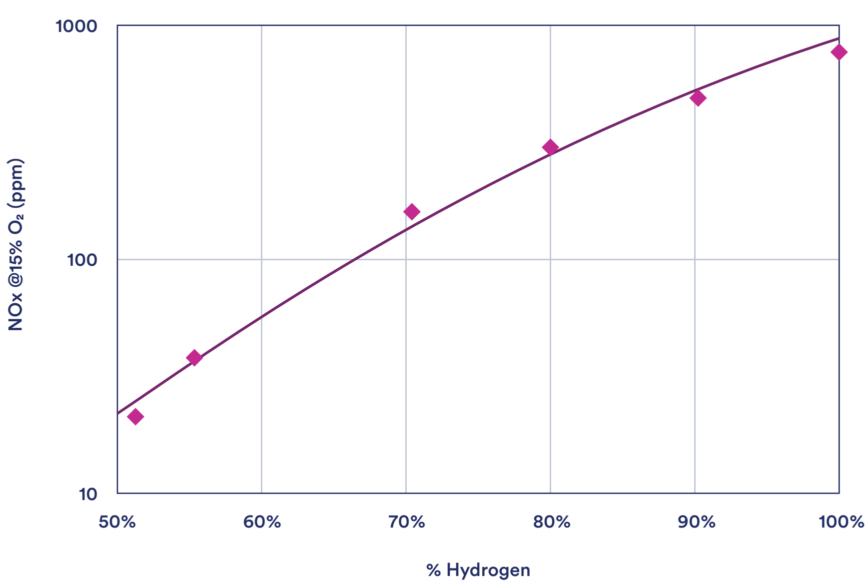


Figure 19: Laminar Flame Speeds for H2/Methane Mixtures

Source: Hydrogen Power with Siemens Gas Turbines; Article - Siemens Gas and Power GmbH & Co. KG, Erlangen Germany, April 2020 (Siemens A.G., April, 2020)

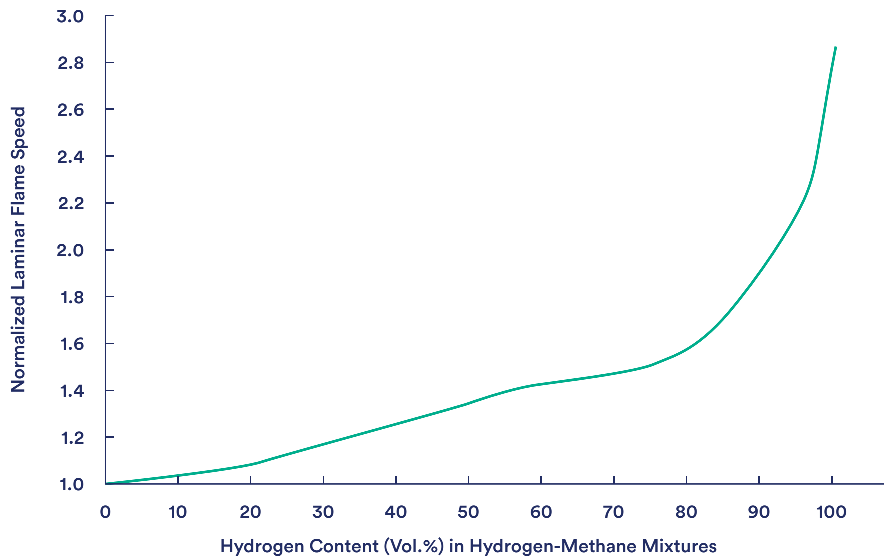
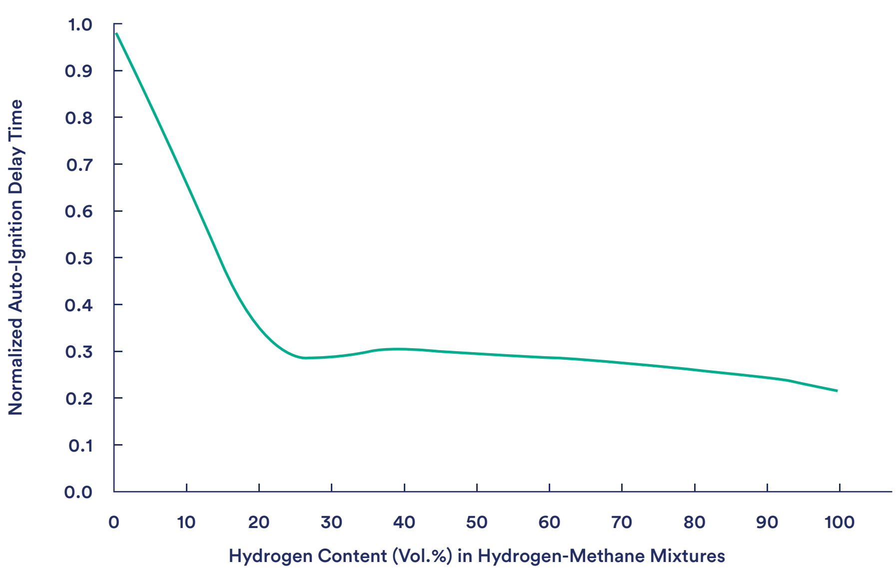


Figure 20: Hydrogen/Methane Mixture Autoignition Delay

Source: Hydrogen Power with Siemens Gas Turbines; Article - Siemens Gas and Power GmbH & Co. KG, Erlangen Germany, April 2020 (Siemens A.G., April, 2020)



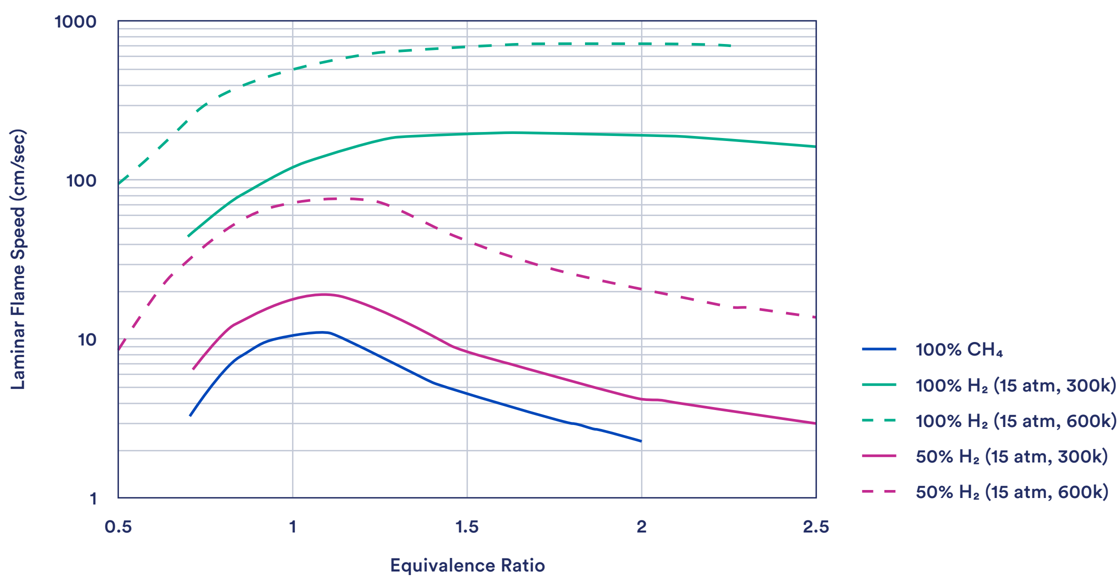
half that of natural gas (Table 1). The primary challenge then is to produce stable combustion over a range of turbine loads while maintaining low levels of NOx emissions (e.g., less than 9 ppm vol% at 15% O_2). Flame control to avoid damage to the combustor is a formidable challenge for combustor design. (Kathleen Bohan, 2020) (GE Norman Shilling, 2004). At low (lean) fuel-to-air equivalence ratios, the ratio of hydrogen to methane flame speed remains fairly constant (at approximately 10 to 1). Figure 19 shows how, beginning at 75% hydrogen concentration, flame speed increases exponentially, making flame control even more difficult. Laminar flame speeds for hydrogen, methane, and various hydrogen/methane blends are shown in Figure 21 (Goldmeer, 2020) as a function of equivalence ratio.

The two major classes of combustors are non-premixed (diffusion) and premixed dry low NOx (DLN).[26] Configuration and combustion characteristics for each of these classes of systems are shown in Figure 22 (EPRI, 2017). Each differs in its approach to NOx control.

Diffusion combustion: From the earliest uses of gas turbines for power generation, diffusion combustors have been the mainstay technology for hydrogen and hydrogen bearing fuels. Diffusion combustion results from the direct admission of fuel into an oxidizing medium (air), which produces a flame front at the fuel/air interface. The temperature at the flame front in diffusion combustion is extremely high—approaching that obtained by burning the fuel under near-stochiometric conditions. Admission of combustion air is balanced between the head-end and by later addition of air from the combustor shroud and even from the transition piece between the combustor and the first-stage nozzle so as to complete the burnout of hydrocarbons.[27] Diffusion combustor designs have grown in sophistication such that they can now burn a wide variety of fuels in extreme environments of temperature and pressure (H.E. Miller GE Power Systems, 1988) with a primary focus on NOx control. Diffusion combustors operating with high (greater than 90%) hydrogen have been successfully demonstrated in many commercial projects (GE Energy; Michelle Moliere, 2004), (Balestri, 2008) (Siemens A.G., April, 2020).

Figure 21: Laminar Flame Speed as a Function of Equivalence Ratio

Source: Hydrogen Combustion - Solving the Challenge of Lean Premix Combustion with Highly Reactive Fuels; J. Goldmeer, Turbomachinery International, Nov/Dec 2020 (Goldmeer, 2020)

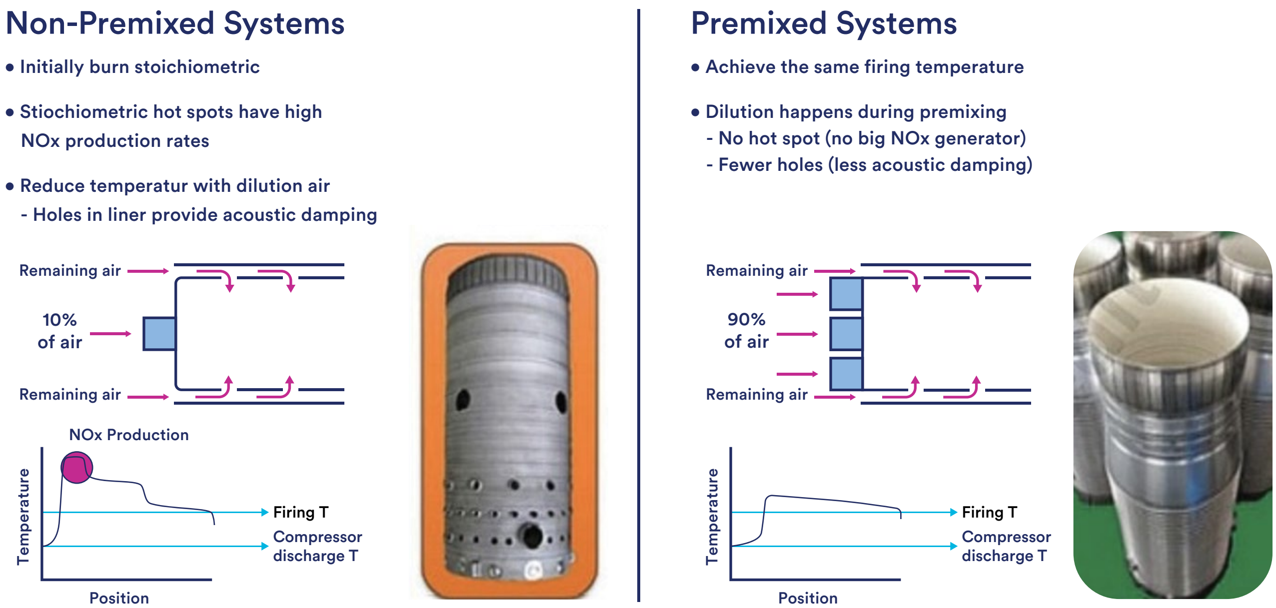


[26] The acronyms DLE and DLN are used interchangeably

[27] The use of hydrogen fuel reduces hydrocarbon (i.e., carbon monoxide (CO)) emissions due to hydrogen's effect on flame temperature and its wide flammability range. However, customer demands for complete fuel flexibility so that turbines can operate on natural gas or other fuel as a backup or primary energy source tightens the design space for combustor design.

Figure 22: Schematics of Diffusion and Premixed Combustors

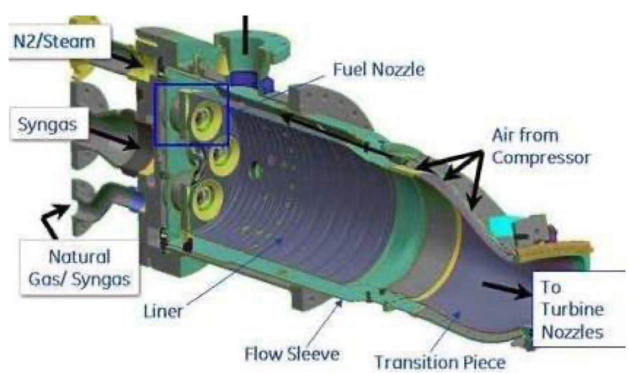
Source: Combustion Dynamics Reference Guide, EPRI- Ref: 3002010505 Palo-Alto CA, 2017 (EPRI, 2017)



Reduction of flame temperature for purposes of NOx mitigation can be achieved by pre-diluting the fuel with an inert gas (generally nitrogen) to lower the fuel specific heating value (BTU/scf). As an example, the GE MNQC syngas combustor uses this approach (Figure 23) (Joseph Citeno GE Power, 2011) to burn hydrogen-rich synthesis gas produced from gasification. The MNQC combustor employs co-located injection nozzles to deliver diluent and fuel prior to the combustion zone[28,29] (Figure 24, below) (Jeffrey Goldmeer, Keith White - GE Energy, October, 2009), with the diluent consisting of inert gases such as nitrogen, carbon dioxide, or water (Figure 25, below) (Robert M. Jones, 2005). There is an extensive history of experience with these combustors in integrated gas combined cycle (IGCC) and integrated reformer combined cycle (IRCC) applications. The hydrogen content of synthesis gases in these applications has ranged from 11% to 50% (MacDonald, 2006) with NOx levels generally between 15 to 25 ppm vol %.

Figure 23: GE MNQC Syngas Diffusion Combustor

Source: The IGCC Solution for CCS; Joseph Citeno – GE Power, IGTI PowerExpo, Vancouver, Canada 2011 (Joseph Citeno GE Power, 2011)



28 For diffusion combustion, reducing the turbine's overall firing temperature does not prevent the formation of localized high temperature zones in the combustor; these zones are responsible for the largest share of NOx production.

29 High amounts of diluent volumetric flow can change the matching between a compressor and a turbine that has been optimized for natural gas. Loss of surge margins may require turbine or compressor modifications such as opening the turbine stage 1 nozzle throat area and changing the compressor IGV schedule.

Figure 24: MNQC Fuel Nozzle for High Hydrogen Syngas

Source: Development of the 7F Syngas Heavy-Duty Gas Turbine, Jeffrey Goldmeer, Keith White, GE Gas Turbine Technology Symposium Greenville, SC, October 2009 (Jeffrey Goldmeer, Keith White - GE Energy, October, 2009)

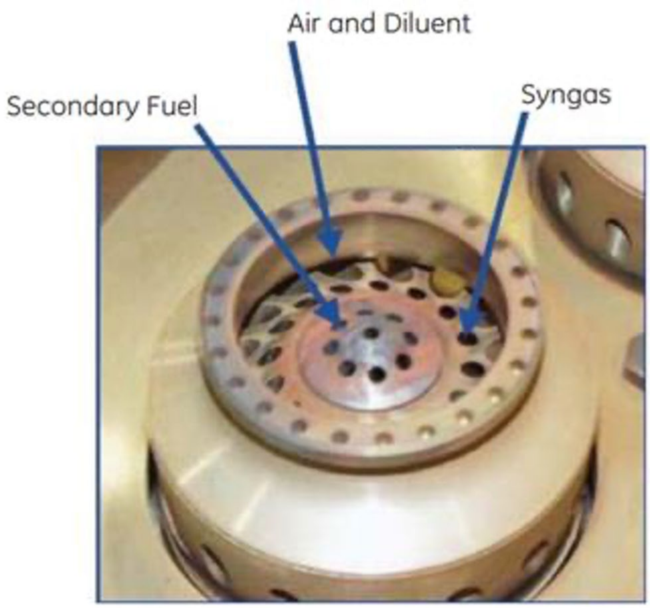
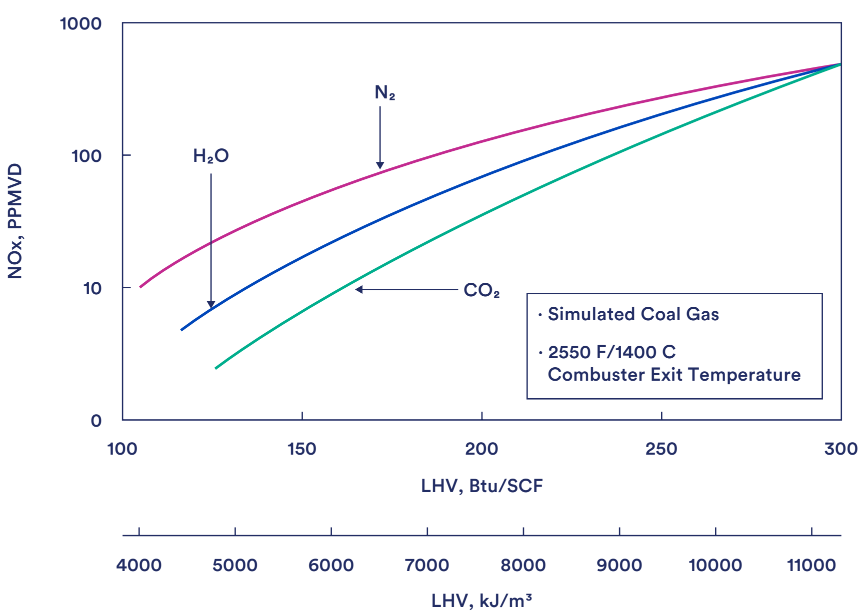


Figure 25: Effectiveness of Diluents on NOx for Simulated Gases

Source: The Impact of Gas Turbine Fuel Flexibility on IGCC Growth; Robert M. Jones, Shilling, N.Z. – GE Energy; IChemE 6th European Gasification Conference Paper 31 Track CO2, 2005 (Norman Z Shilling, Jones, Robert M. GE Power Systems, 2003)



Several OEMs claim 100% hydrogen capability for their diffusion combustors. The caveat is that, to reduce NOx emissions, hydrogen must be pre-diluted with 50%–60% inert gas to a specific heating value typical of syngas. Nitrogen is not readily available except in certain process power applications, such as IGCC with an air separation plant that produces nitrogen as a byproduct. However, neither nitrogen nor carbon dioxide are available as diluents for stand-alone combined cycle plants. Adding moisture to reduce maximum temperature using steam and water injection and/or fuel humidification is highly effective, but as discussed previously, additional moisture has required reductions in firing temperature to maintain component life.

However, the addition of hydrogen to natural gas or other carbonaceous fuels can provide benefits that combustor designers can use to advantage:

- **Lean blow out (LBO):** The lower limit to achieving NOx reductions via dilution occurs when the flammability of the fuel has been reduced to the point where stable combustion cannot be sustained and flameout (LBO) occurs. An additional limiting factor for strategies that rely on reductions in fuel heating value is that lower temperatures result in incomplete combustion of hydrocarbons, which in turn drives carbon monoxide (CO) emissions to unacceptable levels. Due to its high flammability, the addition of hydrogen to diluted fuel is beneficial in terms of avoiding LBO, as shown in Figure 26 (Norman Z Shilling, Jones, Robert M. GE Power Systems, 2003).
- **Carbon monoxide–NOx tradeoff:** For natural gas and other fuels with carbon content, combustor designers have had to deal with a tradeoff between NOx and CO emissions. CO increases with decreasing residence time, while NOx decreases. Combustor designers seek the minimum residence time to achieve acceptable CO levels. The addition of hydrogen with its fast kinetics essentially eliminates this tradeoff. As an example, Figure 27 (Timothy Bullard, Alexander Steinbrenner, Peter Stuttaford, Ansaldo Energia, 2018) shows the ability to operate below 2 ppm NOx and 9 ppm CO with the addition of hydrogen (at 18% by volume) for a current commercial offering, the Ansaldo Flamesheettm diffusion combustor.

Figure 26: Hydrogen Effect on Diffusion Combustion

Source: The Impact of Fuel Flexible Gas Turbine Control Systems on Integrated Gasification Combined Cycle Performance; Norman Z Shilling, Jones, R.M. – GE Power Systems, ASME/IGTI Turbo Expo Paper GT2003-38791, Atlanta, GA 2003 (Norman Z Shilling, Jones, Robert M. GE Power Systems, 2003)

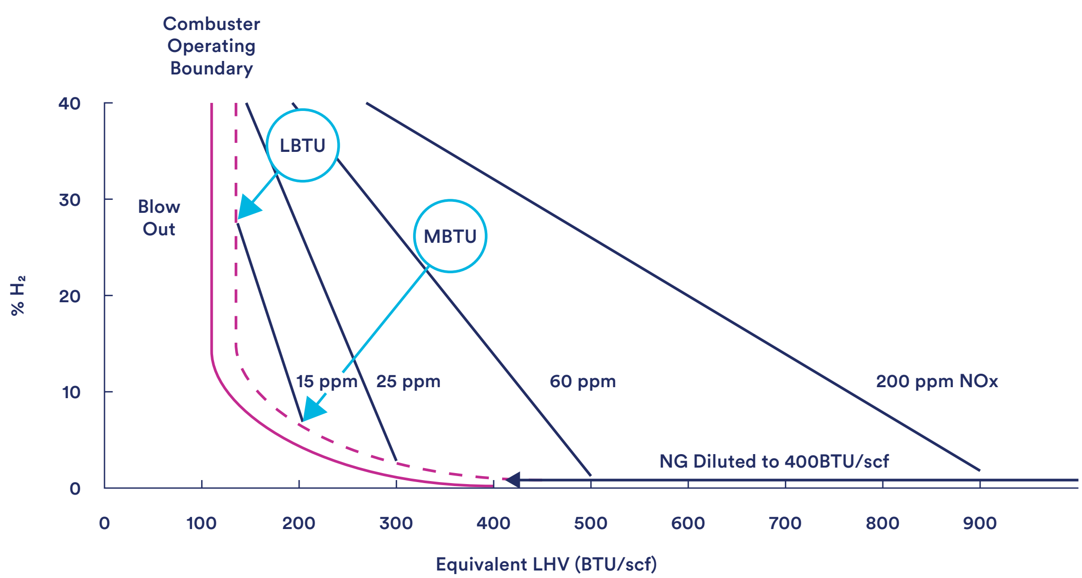
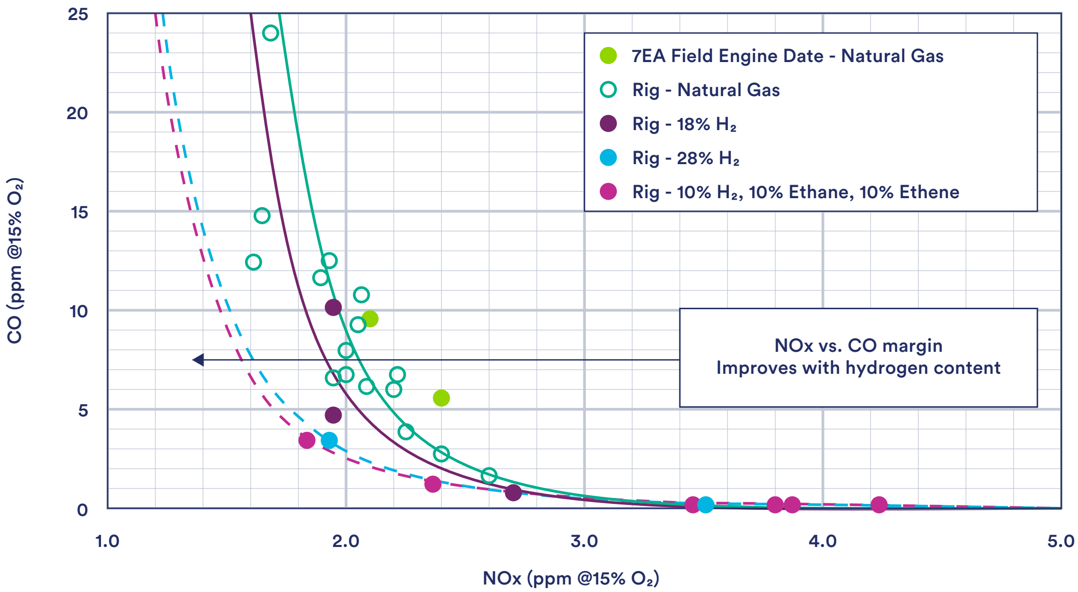


Figure 27: CO-NOx Tradeoff for an Ansaldo (PSM) FlameSheet™ Combustor

Source: Improvement of premixed gas turbine combustion system fuel flexibility with Increased Hydrogen Consumption in a Renewable Market Place; Timothy Bullard, Alexander Steinbrenner, Peter Stuttaford, Ansaldo Energia: Proceedings of ASME Turbo Expo 2018 / GT2018 Paper GT2018-75553 (Timothy Bullard, Alexander Steinbrenner, Peter Stuttaford, Ansaldo Energia, 2018)



Premixed combustion: Premix combustors classified as either DLE or DLN have been widely employed for use with natural gas and distillate fuels. Today, most turbines fueled with natural gas are equipped with DLN combustors. NOx mitigation is achieved by diluting fuel with air before it is admitted to the combustion zone. In order to prevent thermal damage, the combustion flame must remain detached from the fuel nozzles located at the combustor's head-end. For early DLN combustors that were primarily designed for natural gas, the level of hydrogen content (relative to natural gas) had to be kept low (e.g., 5%–15%). Recently, OEM specifications for allowable levels of hydrogen in current heavy-duty turbines with DLE combustors have been expanded to 20% (GE Power System) up to 30%, by volume (Mitsubishi Power, 2020) (Siemens A.G., April, 2020). In these more recent DLN combustor designs, staged combustion is being used for NOx control. This is accomplished by, using an initial low lean) equivalence ratio at the combustor head end while maintaining temperature sufficient to promote auto-ignition for downstream fuel injection and achieve required final turbine firing temperatures.

Due to flashback potential, Hydrogen has several effects on air/premix combustion:

- **Flashback and flame holding:** Air premixing immediately delivers a highly combustible mixture to the combustion zone. The challenge for combustor design is to keep the combustion zone quarantined well downstream of the fuel injection nozzles. In simple terms, the combustible mixture needs to "run faster" than the flame that is chasing it. The flame speed of hydrogen is more than seven times that of natural gas (Table 1) and twice that of a 50% hydrogen/natural gas mixture (Goldmeer, 2020). For DLN combustors, this means that 100% hydrogen fuel needs to exit the nozzles at a velocity that is an order of magnitude higher than for natural gas. Hydrogen's combination of high flame speed and low ignition energy means that the flame front can move rapidly from the combustion chamber back to the fuel injectors (Figure 28) (University of Michigan, 2014). In that case, subsequent flame-holding to the combustor head-end will cause severe damage. This can happen very quickly (milliseconds) so that monitoring thermocouples and flame detectors must have fast response times to detect and prevent damage with immediate turbine trip. Even with this protection, very frequent trips will be unacceptable.
- **Heat release:** A hydrogen flame front will be compact and release concentrated heat close to the combustor head (Figure 29) (Siemens A.G., April, 2020). When combined with the higher emissivity of H_2O in the combustion products and the absence of CO and CO_2,

local heat transfer at the combustor head-end shroud will increase (GE Energy; Michelle Moliere, 2004). This will require attention in combustor thermal management testing and design.[30]

- **Combustor dynamics:** Combustion dynamics can cause pressure oscillations at or near the natural acoustic frequencies of the combustion chamber. In extreme cases, these dynamics can cause catastrophic damage to the combustor (Figure 30) (European Turbine Network, 2020). Compared to natural gas, hydrogen's combination of high flame speed, low ignition energy, shortened ignition delay, and wide flammability limits is expected to increase combustion dynamics. This has not been an issue for diffusion combustors operating with high levels of hydrogen but can be expected to increase with premix dry low NOx (DLN) combustors, especially at the high firing temperatures of advanced turbines. Mitigation has proceeded through sophisticated measurement and characterization, and by an improved understanding of hydrogen combustion mechanisms at full temperature, pressure, and scale (European Turbine Network, 2020).
- **Accelerated Development:** Additive manufacturing will accelerate the process of producing and testing prototype combustor design variations. For example, in 2019 and 2020, Siemens was rapidly able to test 30 burner concepts for its SGT-800 gas turbine and 18 burners for its SGT-600 using three-dimensional printed components.

Figure 28: Flashback and Flameholding (Source University of Michigan at the 2014 OSTI/DOE UTSR Meeting

Source: Hydrogen combustion characteristics; University of Michigan. DOE/OSTI UTSR Workshop, 2014 (University of Michigan, 2014)

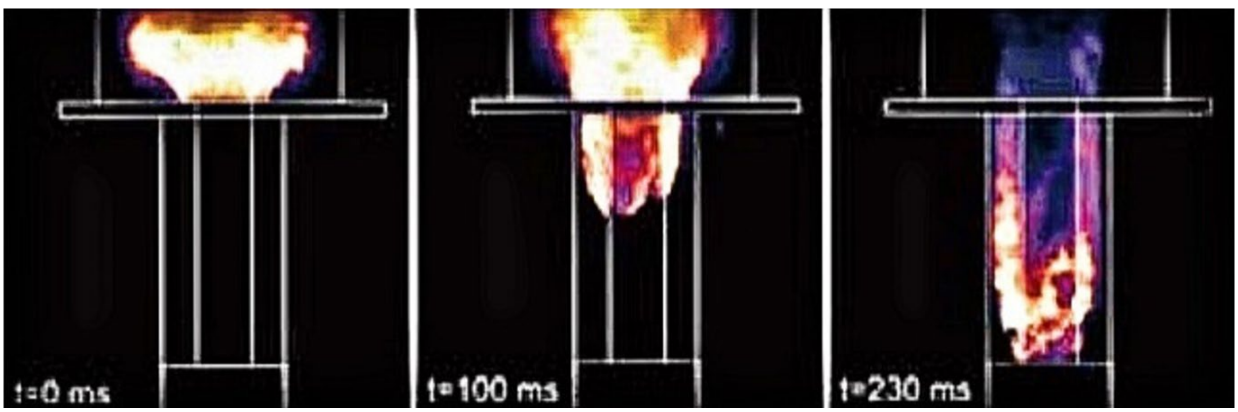
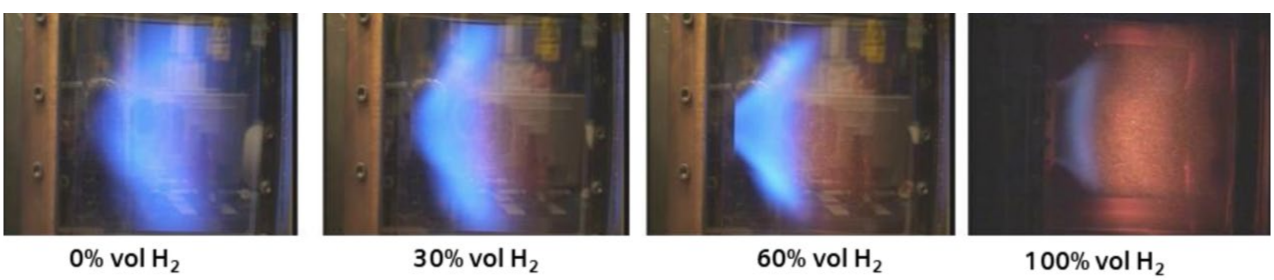


Figure 29: Flame Front Moves Forward and Becomes More Compact with Hydrogen

Source: Hydrogen Power with Siemens Gas Turbines; Siemens Gas and Power GmbH & Co. KG, Erlangen Germany 2020 (Siemens A.G., April, 2020)



[30] In recognition of hydrogen flame compactness, which limits combustion to a portion of the combustor, OEMs have taken advantage of fuel staging (i.e., splitting fuel between the head-end and downstream) as an effective approach to reduce peak flame temperatures and NOx production. This strategy is discussed further in the next section on OEM solutions

Figure 30: Combustor Damage Due to High Frequency Thermo-Acoustic Instabilities

Source: Hydrogen Gas Turbines; European Gas Turbine Network (ETN), ETN Global a.i.s.b.l, Grussels, Belgium, 2020 (European Turbine Network, 2020)

SECTION 5

Current and Potential Future OEM Solutions

With diffusion combustion limited by the fact that it requires an inert diluent, OEMs are proceeding with efforts to develop high hydrogen capability for pre-mixed (DLN) combustion. Their approaches proceed from different starting points based on existing DLN technology and IGCC experience. Current DLN combustors from different OEMs share common configurations and features. Due to scalability across frame sizes (where frame size is based on combustor can count) and the ability to test individual combustors at full flow, temperature, and pressure conditions, turbine OEMs have universally adopted can-annular combustors for heavy-duty industrial and utility turbines.

Mitsubishi-Hitachi Power Systems (MHPS): Since 1970, MHPS has gas turbine units fired with hydrogen content ranging between 30% and 90% in tests that have spanned over 3.5 million operating hours (Patel, High-Volume Hydrogen Gas Turbines Take Shape, 2019). MHPS has also sought to reduce the risk of combustion oscillation and "flashback" in higher hydrogen mixes and with premix combustion. In 2018, MHPS announced that it had successful demonstrated up to 30% hydrogen co-firing capability with the state-of-the art DLN combustion system used in its advanced G and J class gas turbines. In this combustor, air supplied from the compressor to the inside of the combustor passes through a swirler. Fuel is supplied from a small hole on the swirler's wing surface and is mixed rapidly with the surrounding air due to the swirling flow effect. Combustion tests were performed successfully with a 30% (vol.) hydrogen mix in natural gas and showed a 10% reduction in CO_2 emissions compared to a natural-gas-fired power plant. The tests were performed at the firing conditions of J-Series gas turbines. All the new G and J machines MHPS ships will have the capability to operate on 30% hydrogen (Mitsubishi Power Systems Renewable Fuels, 2020). Projects recently announced by Mitsubishi Heavy Industries (MHI) will initially have 30% hydrogen capability; they include the Intermountain Power Project (two M501JAC turbines) (Danskammer Energy Center, LLC, 2020) and the Danskammer Energy Upgrade Project (one M501JAC turbine). The combustors used in the first phase of these projects (with 30% hydrogen)[31] will be modified DLE combustors (Mitsubishi Power, 2020) and will have increased swirl centerline velocity to minimize flashback potential (Figure 31).

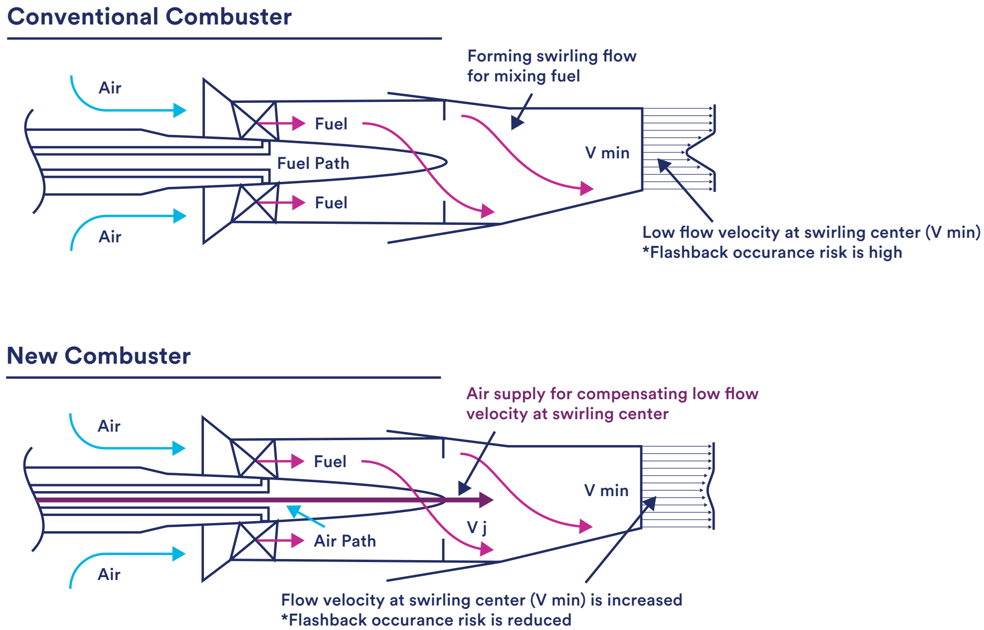
Outlook: MHI Power Systems has issued a comprehensive and integrated development and commercialization roadmap (MHI Tanimura, Satoshi, April 24, 2019) to achieve 100% hydrogen capability. MHI Americas Power Systems CEO Paul Browning has stated that this goal will likely be reached within the next decade (Patel, High-Volume Hydrogen Gas Turbines Take Shape, 2019). MHI's plan includes a demonstration of the feasibility of large scale 100% hydrogen on a M701F turbine at the Vattenfall Magnum power plant[32] and within the NOx envelope of natural gas machines (Patel, High-Volume Hydrogen Gas Turbines Take Shape, 2019) A key component of MHI's strategic plan is to couple hydrogen-capable turbines with hydrogen production facilities. MHI's development effort is focused on expanding and validating its multi-cluster combustor technology which is basically diffusion combustion. It reduces conventional diffusion combustion down to a small scale at which multiple discrete flame fronts can avoid the large-eddy turbulent stochastics of fuel mixing at large scale for conventional diffusion combustors. MHI's concept uses coaxial mixing of air and fuel directly at the combustor head end

31 Pending development, hydrogen capability will be 30% to 70% in phase 2, and 60% to 100% in phase 3.

32 It is unclear as to what combustion technology MHI will employ at Vattenfall. MHI has reported that NOx control at 100% hydrogen will not require steam or water abatement. (Patel, High-Volume Hydrogen Gas Turbines Take Shape, 2019). However, MHI's development roadmap (MHI Tanimura, Satoshi, April 24, 2019) shows a diffusion combustor for the Vattenfall demonstration. This may be multi-cluster technology that, by strict definition, is diffusion combustion.

Figure 31: MHI Flashback Resistant DLE Combustion

Source: Hydrogen Power Generation Handbook: Mitsubishi Power MP43-00GT02E1-A-0, 2020 (Mitsubishi Power, 2020)



(Figure 32) (Mitsubishi Power , 2020; Tomohiro Asai, 2016). The company projects completion of its development efforts for 100% hydrogen capability by 2025 (Mitsubishi Power Systems Renewable Fuels, 2020). The challenge to MHI's designers will be maintain sufficient air-to-fuel mixing at small scale for compliant NOx emissions without excessive combustor pressure drop.

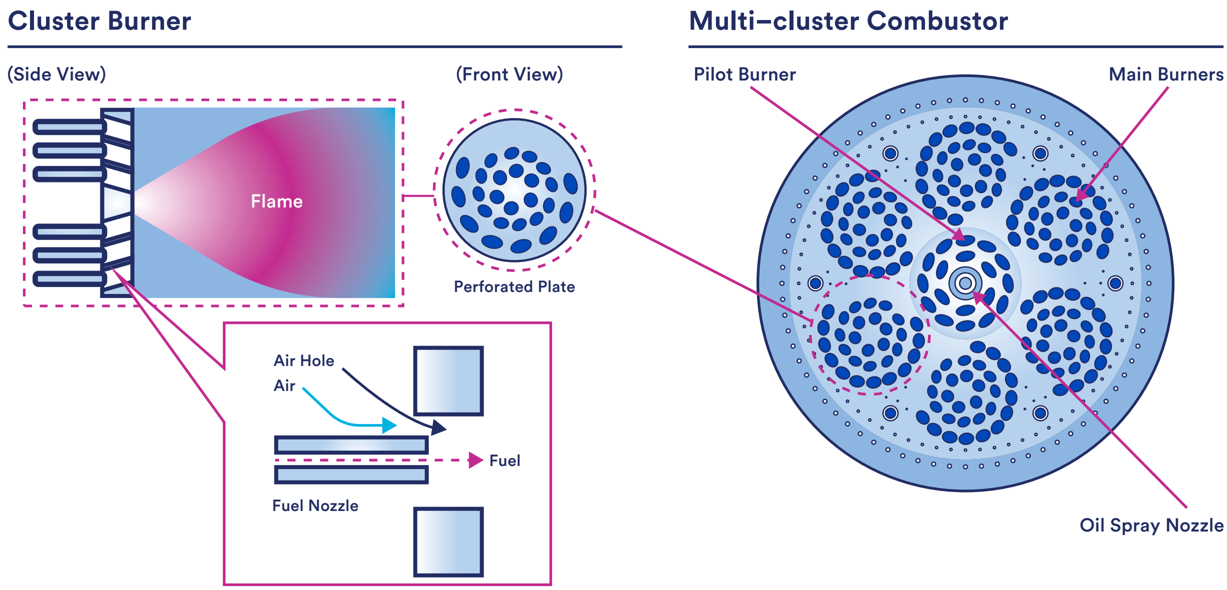
Siemens: Siemens has extensive experience with high hydrogen content fuels, with more than 55 units around the world that have amassed 2.5 million operating hours since the 1960s. These high hydrogen gas turbines have found applications in a variety of industries and span the power range of the Siemens gas turbine portfolio (Siemens A.G., April, 2020). Siemens offers diffusion, wet low emissions (WLE)[33] for industrial turbines, and DLE combustors for its heavy-duty turbines (SGT5 and SGT6 classes) having NOx performance of <=9ppm for 60HZ and <=15ppm for 50HZ. Its heavy-duty gas turbines are capable of handling up to a maximum of 30% hydrogen as achieved through axial fuel staging with Siemens's distributed combustion system (DCS). Two Siemens heavy-duty gas turbines, SGT5/6-2000E and SGT5/6-4000F, use the HR3 burner design. The HR3 has a central pilot swirler and a concentric diagonal swirler with gas injection through the swirler vanes. The SGT6-5000F and SGT5/6-8000H use the Ultra-Low NOx Platform Combustion System (ULN/PCS), which integrates sequential fuel injection (SFI) technology in a combustor with a premixed pilot and concentrically arranged main swirlers. Recently Siemens will be providing a 2000E utility-scale gas turbine with a modified DLE combustor to a customer in the petrochemical industry with the requirement that the turbine will run on up to 27% (vol.) hydrogen starting in 2020 (Patel, Siemen's Roadmap to 100% Hydrogen Gas Turbines, 2020).

Siemens' industrial gas turbines (SGT-600, 700, and 800) currently use third-generation DLE technology with a cylindrical duct downstream of a conical swirler for optimal premixing. Rig testing has validated 60% (vol.)

[33] Achieving WLE (wet low emissions) requires water injection for NOx control (below 25ppm), but adoption is limited by the need for large quantities of high-quality water and impact on parts life.

Figure 32: MHI Multicluster Combustor

Source: (Tomohiro Asai, 2016)



hydrogen on the SGT-600, 55% (vol.) on the SGT-700, and 50% (vol.) on the SGT-800. These hydrogen levels are now listed in Siemen's product brochures. For its existing 2000E and 4000F turbines, an upgrade package for higher hydrogen content, "H2DeCarb", is available. The 2000E upgraded with this package can operate with up to 30% (vol.) hydrogen. For the 4000F, an upgrade to operate on as much as 15% (vol.) hydrogen is possible (European Turbine Network, 2020). However, I have not yet found NOx with hydrogen containing fuels in the current specification sheets for Siemens' turbines.

Outlook: Over the last decade, further development and testing has steadily improved the hydrogen capability of Siemens commercial offerings. As a member of the EU Turbines industry group, Siemens has pledged to achieve 100% hydrogen capability in all its turbine models by 2030 (Nils Lindstrand Siemens, 2020). The company's roadmap to 100%-hydrogen-capable low NOx gas turbines begins with full pressure testing, followed by 100% hydrogen capability in aero-derivatives, then industrial gas turbines, and lastly heavy-duty gas turbines (Noble, Wu, Emerson, Shephard, & Lieuwen, 2020). While Siemens achieved a goal of 2 ppm NOx emissions in its turbine development efforts as part of the DOE Advanced Turbine Program, (John Marra, Siemens Energy, Inc., 2015), these emissions were defined as "at the stack" assuming a 95% efficient SCR. The actual NOx for its turbine combustor was 40 ppm. As the result of recent research (Andrew North - Siemens Energy, Inc., 2019) Siemens has identified a promising solution for combustion NOx reduction using reburning mechanism that is significantly different than those being pursued by other OEMs.   Siemen's combustor configuration extends conventional axial fuel staging to two downstream stages - the first stage having standard residence followed by a second hydrogen-rich, ultra-low residence time stage. A further design enhancement incorporating these mechanisms within separate co-axial modules Siemens expects will help to accelerate commercial adoption.[34] For this advanced combustion technology, Siemens estimates <25ppm combustion-only NOx at turbine inlet firing temperature (3,100 Deg F) as required to achieve

[34] An additional advantage from the further break-down of can-annular combustors into sub-components such as co-axial modules can provide relief from current hydrogen supply constraints and enable validation at full prototypic conditions and for longer time spans.

DOE's 65% turbine thermal efficiency goal. It must be recognized that significantly lower NOx levels should be obtainable at the lower firing temperatures of current F, G and even H class machines. Pending commercialization of this technology, Siemens has not yet disclosed hydrogen capability nor NOx performance.

Ansaldo Energia: Ansaldo currently offers two types of DLN combustor technologies for its heavy-duty gas turbines. Both utilize staged combustion in which the combustor head is first fired at low equivalence ratios to keep the combustion front away from the head-end and thereby prevent flashback while still achieving auto-ignition temperature. Additional fuel is then injected downstream where it auto-ignites to achieve required turbine firing temperature. This approach stabilizes the head-end flame position and eliminates the hot regions that generate high NOx emissions[35] (Figure 33) (Ansaldo Energia, 2020). New Ansaldo GT26 and GT36 heavy-duty turbines are equipped with axially staged DLE combustors. The GT26 is capable of operating on 30% hydrogen blends (or up to 45% (vol.) hydrogen in natural gas, depending on the respective GT26 F-class engine rating, and up to 25% (vol.) hydrogen in natural gas for the AE94.3A F-class engine) (European Turbine Network, 2020). To control NOx emissions, the GT26 utilizes sequential combustion after the first-stage nozzle (Ansaldo Energia: Andrea Ciani, Mirko R. Bothien, Birute Bunkute, John P. Wood, Gerhard Früchtel , 2019).

The Ansaldo's GT36 H-class is advertised as having capability to burn up to 50% hydrogen/natural gas blends. As in the GT26, it has a can-annular combustor that eliminates the need for a high-pressure turbine stage separating primary and secondary combustion. The approach used in the Ansaldo system is called constant pressure sequential combustion (CPSC). No efficiency or power penalty is incurred when the temperature differential between the sequential combustion stages is increased. The GT36 is currently offered for commercial use with fuel blends that have up to 50% (vol.) hydrogen content.

Figure 33: Ansaldo Combustion Solutions for Hydrogen

Source: https://www.ansaldoenergia.com/business-lines/hydrogen-technology

Ansaldo Energia Solutions for Burning Hydrogen

Technology	Application in Gas Turbine *(No hardware modification on gas turbines)*	H_2 Capability any blend between to max [vol %]	NOx Emissions [ppmv @15% O_2 dry gases] *(No additional device for flue gas treatment)*	GT Load Range [%]
Sequential Combustion	GT 36 New and Service	50	15	25-100
Sequential Combustion	GT 26 New and Service	30	15	20-100
Single Stage Combustion	AE94.3A New and Service*	25	25	45-100
Single Stage Combustion	AE94.2 New and Service*	25	25	45-100

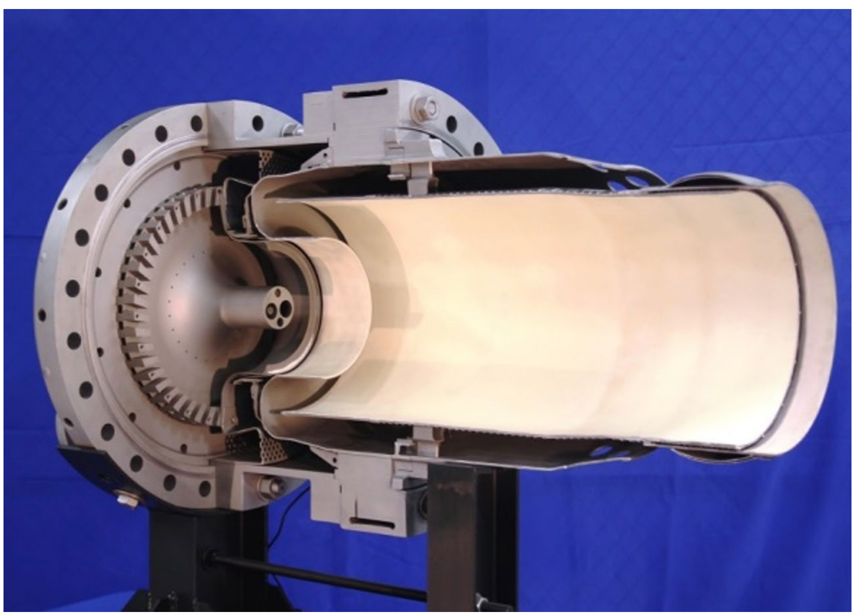
35 Auto-ignition for sequential fuel injection will also require a hydrogen-containing gaseous fuel. This will make SFI difficult for liquid fuels.

For the retrofit market, Ansaldo's PSM affiliate offers its Flameheet™ combustor as a drop-in solution to increase hydrogen capability for a wide range of existing GE, MHI, and Siemens E- and F-class machines (Figure 34) (PSM Ansaldo Energia Group, 2020). The FlameSheet™ combustor has been rig tested for F-class conditions at full pressure and full temperature for up to 80% hydrogen (vol.) blends without emissions excursions (Team CCJ, 2021).[36] Designed as a "combustor within a combustor," the FlameSheet™ incorporates a method for injecting the fuel–air mixture as a continuous uninterrupted sheet into the reaction zone of the combustor whereupon an aerodynamically generated trapped vortex anchors and stabilizes the flame (Peter Stuttaford, 2016). The combustor incorporates two aerodynamic stages and four fuel stages. The two aerodynamic stages consist of a pilot along the axis of the combustor and a main stage surrounding the pilot. The pilot and main stages are effectively two independent combustors with their own flame stabilization mechanisms for operational flexibility.[37] The stages are designed for specific operational requirements such as transient loading and extended turndown operation. Each of the two combustors can be operated independently of the other.

Outlook: As a member of EU Turbines, Ansaldo has pledged to achieve 100% hydrogen capability. The company's development efforts have continued to focus on extending DLN hydrogen capability past 30% using staged combustion for its heavy-duty gas turbines (Bothien M. R., 2019). Ansaldo is also likely to improve the hydrogen capability of its single-staged combustor. With sequential combustion, the combustor exit temperature can be maintained for hydrogen blends up to 70% while also fulfilling all combustor requirements, such as NOx emissions

Figure 34: PSM Flamesheet™ Cutaway View

Source: https://psm.com/project/flamesheet/



[36] A GE 9E in the Netherlands has operated with Flamesheet's predecessor LEC-III combustor on 9%–25% hydrogen over four years without problems.

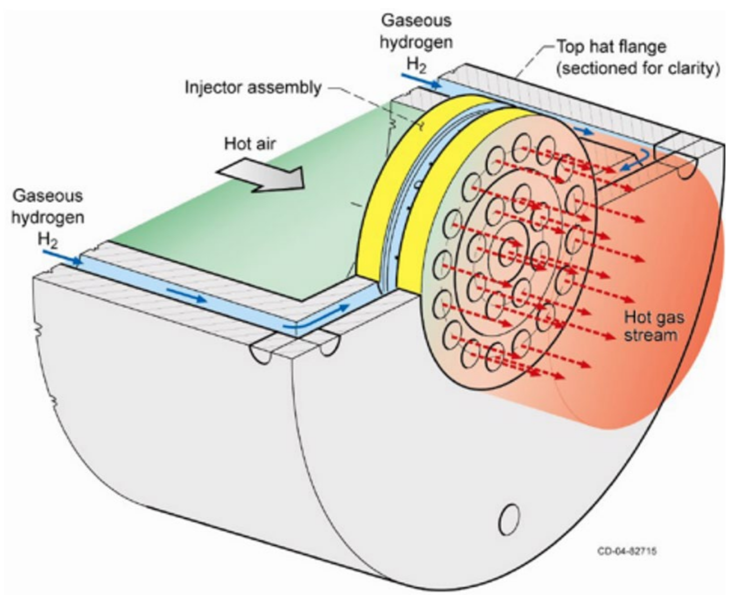
[37] Commercial development of a Flamesheet™ combustor for a blend of refinery gas and natural gas with up to 40% hydrogen content is currently underway (confidential client).

below 15 ppm, low dynamics, and no degradation of useful life. This is achieved by steadily decreasing the first-stage fuel flow to compensate for higher fuel reactivity with increasing hydrogen content. Efforts to develop solutions for fuel blends with more than 70% hydrogen are ongoing. Additionally, Ansaldo's PSM affiliate is participating in a program to develop its FlameSheet™ combustor as a "platform" for turbines that can fire up to 100% hydrogen; this program is being subsidized by the Dutch government.

General Electric: GE has been developing turbine technology for use with high hydrogen fuels for more than 15 years. The company's experience in this area spans 75 gas turbines and 6 million total operating hours; it includes diffusion combustors burning hydrogen/natural gas blends up to 95% hydrogen and DLE combustors burning approximately 5% hydrogen blends (Jeffrey Goldmeer GE Gas Power, 2020). GE has extended hydrogen capability to 33% hydrogen blends for its DLN-1 turbines (B, E classes) and to approximately 18% blends for its DLN 2.6+ turbines (F, H classes) (EPRI Innovation Scouts, 2019). Axial fuel staging (AFS) is incorporated within its DLN 2.6+ combustor for increased turndown and lower emissions. When applied to hydrogen/natural gas blends, AFS allows leaner head-end fuel introduction, reduced NOx production, liner thermal input, and reduced flashback risk (Christian Vandervort, David Leach and Marcus Scholz, 2016). GE also offers its DLN 2.6+ FLEX combustion system with AFS as an upgrade for its F-class turbines, for hydrogen/natural gas blends up to 10% (GE Gas Power, n.d.).

Figure 35: Low Emissions LDI (Micromixer) Hydrogen Combustor Assembly

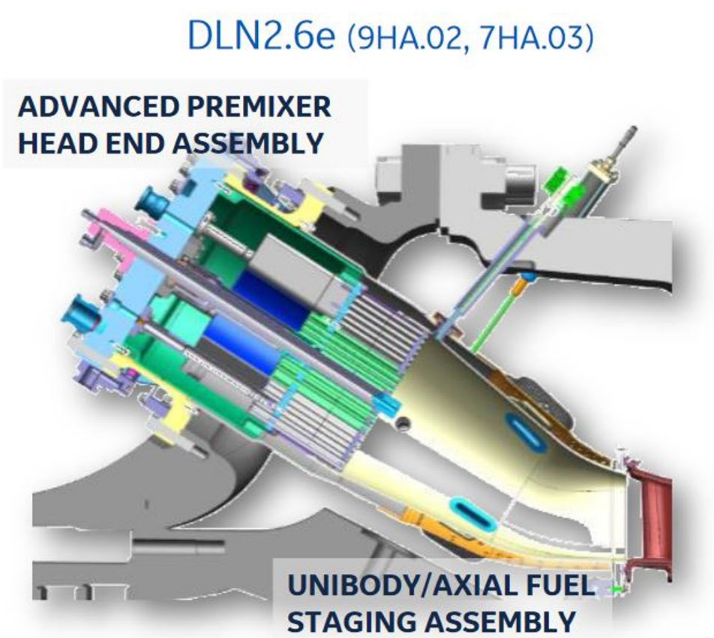
Source: Hydrogen Combustion – Solving the Challenge of Lean Premix Combustion with Highly Reactive Fuels (Goldmeer, 2020)



Outlook: It can be expected that GE is pursuing micromixer technology as a core for its future hydrogen combustors.[38] Micromixer combustion utilizes direct cross-flow injection and pre-mixing of hydrogen into air flow in small diameter tubes prior to injection into the combustor head-end. (Figure 35) The diameter, number and volumetric flow of these micromixers is chosen so that the combined microtube exit velocity exceeds the fuel flame speed. The scale of the individual tubes is smaller than the fuel flame quench distance to prevent flashback back into the pre-mixer tubes. The DLN 2.6e (Figure 36) (Michael J Hughes, Jonathon D. Berry GE Power, 2019) combines micromixing with AFS for high (approximately 50%) hydrogen fuel. GE is currently offering its DLN 2.6e combustor for commercial use in its 7HA.03 and 9HA.02 turbines. The micromixer substitutes swirl in a conventional DLN with axial velocity at equivalent pressure drop. GE estimates hydrogen capability (based on preliminary testing) at up to 50% blends (Jeffrey Goldmeer GE Gas Power, 2019), with NOx comparable to conventional natural gas DLN combustors. For future higher hydrogen/natural gas blends, GE is pursuing the potential to integrate combustor, AFS, and stage-1 nozzles in a single unibody structure (John Delvaux - GE Energy, 2019).

Figure 36: GE 2.6+e Combustor with Micromixers and AFS

Source: Advanced Multi-Tube Mixer Combustion for 65% Efficiency; Michael J Hughes, Jonathon D. Berry GE Power, Presentation - 2019 DOE UTSR Workshop, Orlando FL, November 5, 2019 (Michael J Hughes, Jonathon D. Berry GE Power, 2019)



[38] While the appearance of GE's micromixer combustor head-end resembles that of MHI's multi-cluster combustor, its combustion mechanism is fundamentally different. MHI's multi-cluster uses diffusion combustion (coaxial air/fuel injection) at miniature scale whereas GE's micro-mixers pre-mixes air and fuel prior to combustion.

SECTION 6

Operational Considerations

Factors that define operational flexibility for a gas turbine are (1) fuel flexibility; (2) responsiveness to normal changes in operating load; (3) stable, rapid, and trip-free startup/shutdown (SUSD); and (4) rapid and safe response should turbine trips occur.

Fuel flexibility: Fuel flexibility denotes capability of the turbine and its fuel system to co-fire a range of hydrogen/natural gas blends. While details of fuel management design are not publicly available from the OEMs, a simple approach that has been employed for low (5%) hydrogen blends is pre-blending the hydrogen and natural gas before it enters the turbine fuel control system (Figure 37) (Jeffrey Goldmeer GE Gas Power, 2020). Similarly, MHI has disclosed its proposed fuel system for hydrogen/natural gas blends that includes a pre-blender (Mitsubishi Power Systems Renewable Fuels, 2020). The function of the fuel control system is to distribute blended fuel and combustion air to the various combustor components at the rates, compositions and pressures necessary to respond to load variations with stable and compliant emissions. Examples are fuel and air splits between the various nozzles or sub-sections of a micro-cluster or micromixer combustor. When combined with AFS, additional fuel and air splits will be necessary between the combustor head end (primary) and secondary or tertiary axial fuel injection stages. In the short term, it will also be necessary to accommodate day-to-day or even hour-to-hour variability in hydrogen availability, with resulting changes in Wobbe Index. Over a longer time and as combustion technology development

Figure 37: Hydrogen/NG Blending Systems for 4 GE 7F Turbines for 5% Hydrogen

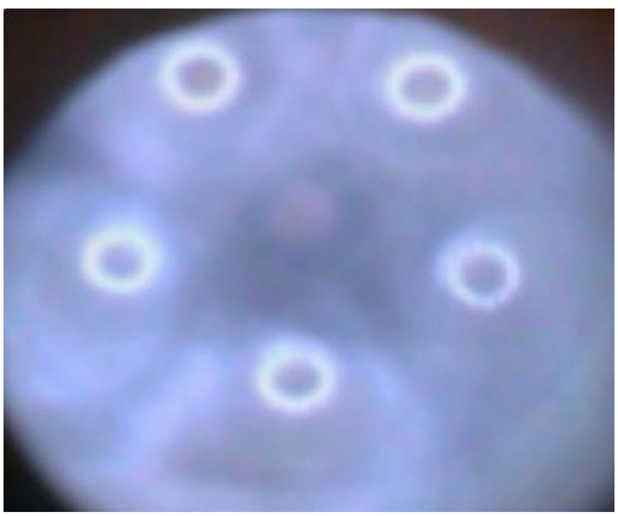
Source: Hydrogen Technology; Jeffrey Goldmeer - GE Gas Power, Bank of America/Merrill Lynch future of Hydrogen Energy Economy Seminar, December 17. 2020 (Goldmeer, 2020)

and hydrogen availability allow, there will be large changes in both the maximum and minimum allowable co-firing range requiring reconfiguration of both combustor and fuel control systems. For example, MHI is implementing a phased approach to increase hydrogen capability in its early installations, as warranted by combustion development and expected changes in available hydrogen supply (Mitsubishi Power Systems Renewable Fuels, 2020). The three phases encompass hydrogen blends of 0%–30%, 30%–70%, and 60%–100% hydrogen. The Wobbe Index range (relative to the mean) for 0%–100% hydrogen is 13%—beyond the capability of a single fuel system, whereas the Wobbe Index range for each of the individual phases can be within the capability of a specific fuel control system. This means that OEMs need to avoid lock-in to a specific blend range after an upgrade.[39] Capability to operate on 100% natural gas or other non-reactive fuels as a backup (in the case of a hydrogen-supply interruption), as part of SUSD procedures, and potentially under low-load conditions to qualify as rolling reserve, will be necessary. Figure 38 (Goldmeer, 2020), which shows natural gas flame patterns for the GE micromixer combustor using a nozzle set separate from the larger micromixer array, points to measures being taken at the micromixer head to allow for operation on 100% natural gas.

Load flexibility: Conventional natural gas DLN combustors are equipped with multiple nozzles that are activated in different sequences and combinations depending on turbine load. For example, the GE DLN2.6 is equipped with six nozzles that fire in a particular sequence and quantity according to the turbine's mode of ignition and load (Figure 39) (L.B. Davis, S.H. Black - GE Power, 2000). GE has mimicked its conventional DLN nozzle configuration with five clusters of micromixers for its hydrogen-capable

Figure 38: GE Micromixer Combustor Flame Pattern for 100% NG

Source: Hydrogen Technology; Jeffrey Goldmeer - GE Gas Power, Bank of America/Merrill Lynch future of Hydrogen Energy Economy Seminar, December 17. 2020 (Goldmeer, 2020)



[39] Micromixer combustors that were tested in Reference (GE Power and Water , 2015) were shown to have wider Wobbe Index range capability than conventional DLE combustors so that Wobbe limitations will be of concern only for the fuel control system.

Figure 39: GE DLN2.6 Nozzle Firing Modes

Source: Dry Low NOx Combustion Systems for GE Heavy Duty Gas Turbines Ref: GER3568G; L.B. Davis, S.H. Black - GE Power Systems, 2020 (L.B. Davis, S.H. Black - GE Power, 2000)

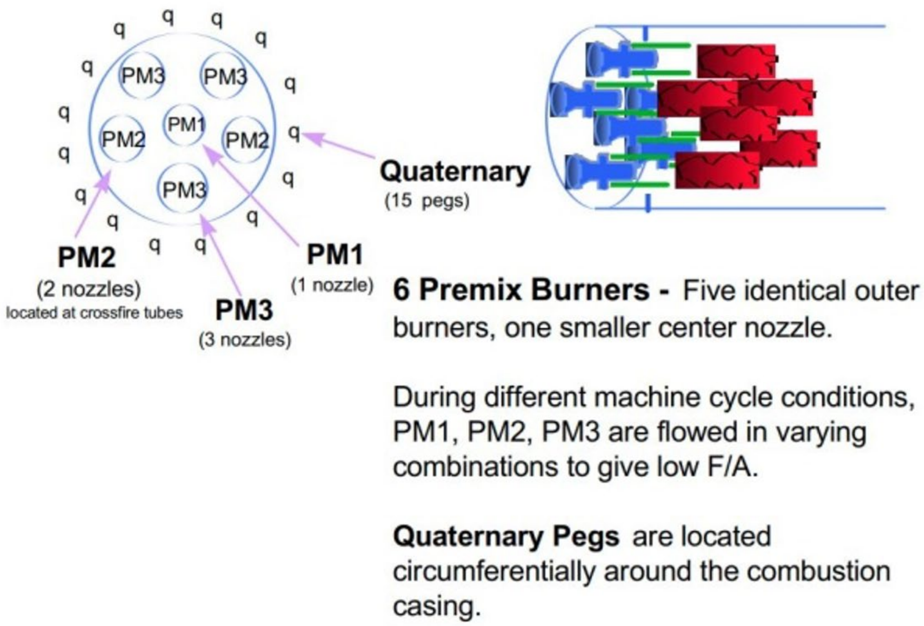


Figure 40: GE DLN 2.6e+ Micromixer Combustor

Source: Hydrogen Combustion - Solving the Challenge of Lean Premix Combustion with Highly Reactive Fuels; Goldmeer, Jeffrey, Turbomachinery International, November/December 2020 (Goldmeer, 2020)

DLN2.6e combustor (Figure 40) (Goldmeer, 2020), which is undergoing validation testing at a site in Asia. MHI has adopted a similar configuration for its multi-cluster combustor (Figure 32). This suggests that the load-following strategy for micromixer multi-cluster combustors will continue to be to sequence individual sections, similar to conventional DLN nozzles, using a similar fuel control system. Multimixer and multi-cluster combustors require sufficient fuel volume and exit velocities to ensure flame detachment. Due to hydrogen's low volumetric heating value (BTU/scf), the specific volume (scf/MMBtu) of hydrogen/natural gas blends increases with hydrogen content. As an example, for the same turbine heat input, the fuel flow volume for 100% hydrogen has to be more than 300% higher than the fuel flow volume for 100% natural gas. Higher fuel flow volume helps to naturally compensate for increased flame speed in maintaining separation of the flame from the combustor head. A disadvantage that needs to be considered in terms of fuel system design—including compressor matching—and overall performance is that there will be an increase in combustor pressure drop.

Startup/shutdown: Emissions during turbine startup and shutdown can be significant in the context of total annual emissions and facility permit restrictions. Due to the increasing variability of grid demand, startup emissions are an important consideration in OEM combustion system development. Given the current state of development for hydrogen combustion technologies, OEMs have not yet disclosed the details of their SUSD procedures. First-of-a-kind introductions of commercial hydrogen-capable combustion systems will include efforts to test and validate startup procedures in real-world situations that are difficult to fully simulate in rig testing. The startup procedure for the blending system will govern the composition of the fuel delivered to the fuel control system. A blending strategy that starts with 100% natural gas followed by measured increases in hydrogen to target levels is likely and will require coordination with the fuel control system to deliver fuel to proper combustor stages.

Trips: Turbine trips are a normal (but infrequent) event in turbine operation. Generally, trips can occur on startup (if ignition is not achieved) or when turbine exhaust temperature patterns indicate a problem with a particular combustor or turbine stage, or abnormal rotor vibration. When the turbine trips, the fuel control system immediately stops supplying fuel, but it does not stop the flow of residual fuel contained within supply manifolds. Normally, turbine rotor spin-down and the air provided by the spinning compressor are sufficient for adequate purge. With the low flammability limit of high hydrogen fuel, additional purge times may be necessary. Hydrogen's low specific density and buoyancy may result in fuel "hideout"—especially in the upper regions of combined-cycle heat recovery steam generators. But whatever purge procedures OEMs prescribe (e.g., extended shaft roll prior to re-ignition), these procedures will extend outage time and reduce turbine availability.

The bottom line is that within OEM development organizations, there must be constant (sometimes intense) interaction between combustor development and control engineering to arrive at workable and commercially acceptable solutions.

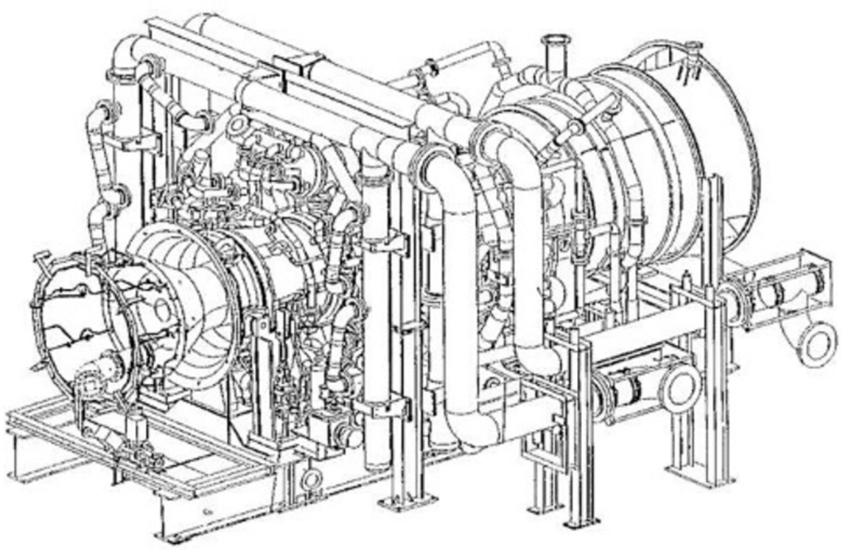
SECTION 7

Auxiliary Turbine Systems

Fuel System: New fuel control systems will be needed for hydrogen. Resizing and changes to the manifolding material between the control system and turbine will also be necessary. Because its volumetric specific heat (BTU/scf) is approximately 25% that of natural gas, hydrogen requires larger supply manifolding.[40] As an example, Figure 41 (Norman Z Shilling, Jones, Robert M. GE Power Systems, 2003) shows the fuel manifold arrangement for a GE 6FA turbine for low-BTU syngas. A consideration for manifold sizing is the residual energy of any gas that is stored in manifolds when there is a turbine trip. For a trip caused by a failure to maintain ignition, such as may occur during a failed startup, the residual gas in the manifold will continue to be combusted to spin up the rotor. High speed can cause damage through centrifugal rubs between airfoils and shrouds and even potential liberation. For dual-fuel (natural gas and hydrogen) systems, the filling of larger manifolds with natural gas during startup and backup operations will increase spin-up. For safety reasons, it is therefore likely that 100% natural gas or other fuel used for backup and SUSD will require separate and smaller manifolds, similar to those used in IGCC dual-fuel turbines. In addition, the combustor will need to be configured separately for 100% natural gas. Another event can be caused by instantaneous load rejection due to a generator breaker being open. As typically occurs with hydrogen-rich syngas from IGCC, the fuel system immediately transfers to backup fuel and holds the turbine at full-speed, no-load until resynchronization.

Figure 41: Example - 6FA Manifolding for Low BTU Syngas

Source: The Impact of Fuel Flexible Gas Turbine Control Systems on Integrated Gasification Combined Cycle Performance; Norman Z Shilling, Jones, Robert M. GE Power Systems, ASME/IGTI Turbo Expo Paper GT2003-38791, Atlanta GA, 2003 (Norman Z Shilling, Jones, Robert M. GE Power Systems, 2003)



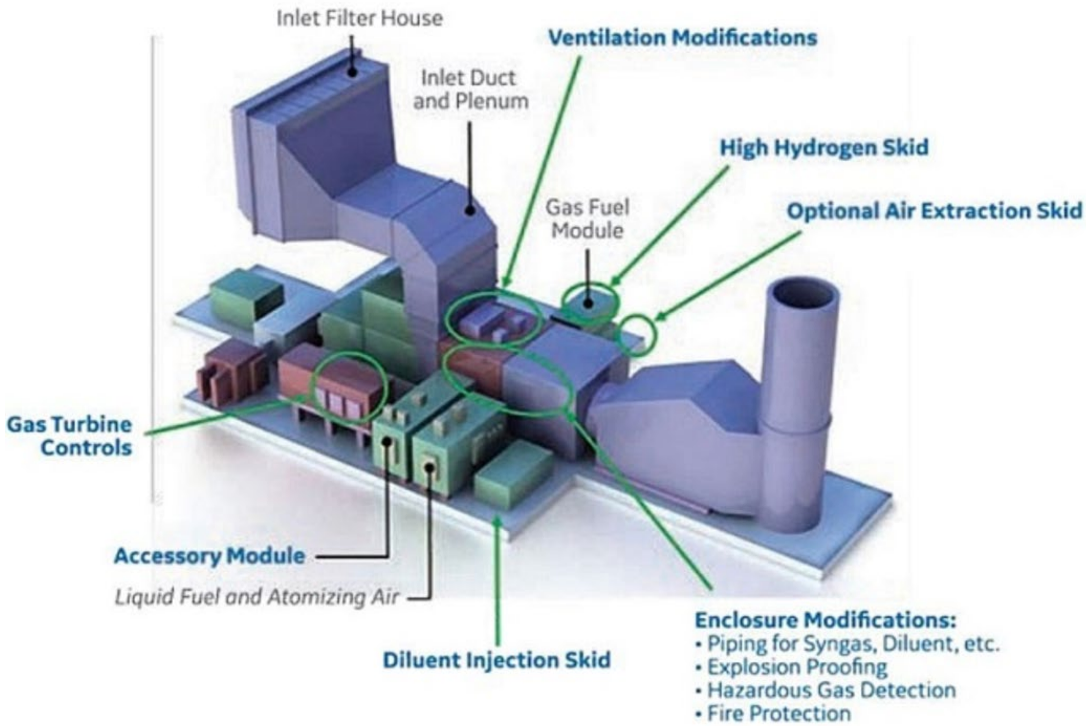
[40] As an alternative to increasing manifold sizes, supply pressure can be increased by three to four times to offset the lower volumetric specific heat of 100% hydrogen. Due to safety considerations and higher potential for material embrittlement, however, this is an unlikely approach.

The staged combustion designs employed by most OEMs entail additional complexity for fuel control systems. Partitioning fuel between the lean (lean initial low equivalence ratio) head-end combustor and downstream additions of hydrogen-rich fuel requires modifying existing fuel control systems beyond the adjustments needed to enable dual-fuel capability. The need to optimize fuel splits for NOx mitigation and performance maintenance over a range of operating conditions requires "tuning", testing, and modifying control algorithms to arrive at final NOx reduction solutions.

Safety: The safety-related characteristics of hydrogen, and options for mitigating safety risks, are summarized in Table 3;[41] Figure 42 (Jeffrey Goldmeer - GE Gas Power, 2018) illustrates these mitigation options. Enclosed spaces that have the potential to create hazardous conditions include the fuel control skid enclosure and the gas turbine compartment, which has the potential to expose personnel to hazardous gases (W.I Rosen, GE Company, 1990). Due to its non-luminous flame, hydrogen also requires additional fire detection measures.

Figure 42: Sample Gas Turbine Modifications for Hydrogen Fuels

Source: Fuel Flexible Gas Turbines as Enablers for a Low or Reduced Power Ecosystem; Jeffrey Goldmeer - GE Gas Power, Electrify Europe Conference, Vienna, Austria, 2018 (Jeffrey Goldmeer - GE Gas Power, 2018)



[41] This summary should not be interpreted as, or used as, a comprehensive listing of safety requirements.

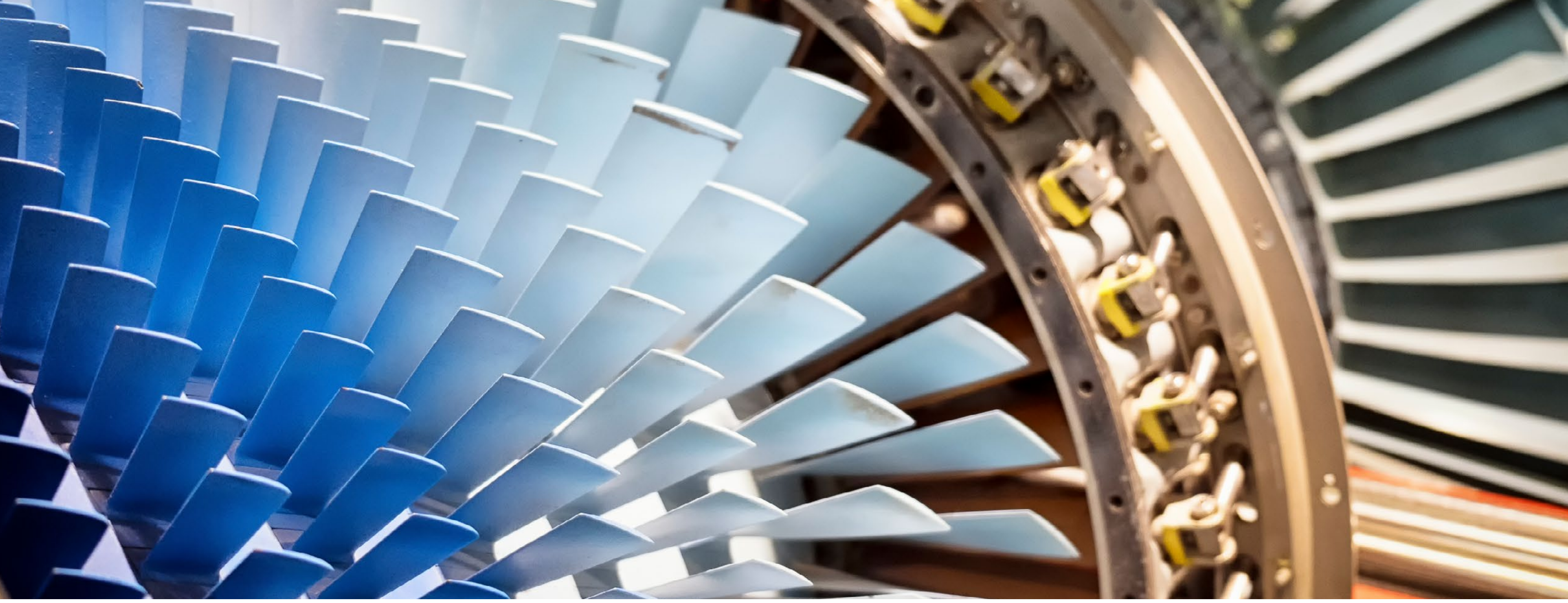
The presence of high-pressure hydrogen means that the power block and fuel system should be subject to project safety management (PSM) requirements established by the Occupational Safety and Health Administration (OSHA)[42] that provide for the prevention of and response to accidental releases within the confines of the process facility that have the potential to threaten workers within the facility.

Materials: Components in the fuel control system (e.g., piping, valves, etc.), as well as in the combustor (e.g., end cover, nozzles, etc.), that come into contact with high concentrations of hydrogen need to be designed to avoid embrittlement. This can be accomplished via the selection of appropriate materials and by controlling environmental conditions. To provide guidance on these issues, the National Association of Corrosion Engineers (NACE) has developed several standards that set forth materials requirements, including MR0175, MR0177, and MR0284. Components exposed to high concentrations of hydrogen generally utilize materials that are resistant to hydrogen embrittlement, including austenitic steels and superalloys, which are also selected for resistance to corrosion. Fuels are typically dried and kept at temperatures sufficiently above dewpoints to prevent condensation that can promote corrosion and embrittlement. *Experience from refinery and IGCC applications suggests that fuel control systems can perform adequately over the desired range of operating conditions, as there are many examples of gas turbines operating successfully on high hydrogen fuels over long periods of time.*

Table 3: Safety Related Aspects for Hydrogen

Safety Related Characteristic	Safety Concern	Where	Mitigation
Non-luminous flame	Not visually detectable Personnel compartment entry	Turbine enclosure Fuel skid compartment	Additional UV and Hazgas Detectors
Broad flammability range	Explosion	Turbine enclosure, fuel skid compartment	Compartment explosion proofing Increased compartment ventilation
	Turbine trips Combustor flameouts	Turbine casing, HRSG and exhaust ducting	Combustor flame detection Rapid fuel shutoff Lengthened evacuation
Low specific volumetric energy density	Larger gas supply manifolds	Turbine enclosure	Increased inert purge capacity and purge times
Low MW	Leakage across seals and gaskets	Piping and manifolding	Welded construction wherever possible
Bouyancy	Trips, combustor flameouts and hideout at high points	HRSG	Increased length of air purge
Toxicity	Personnel exposure	Turbine enclosure, fuel skid compartment	CO detectors Increased compartment ventilation

42 Occupational Health and Safety Administration (OSHA), Process Safety Management (PSM) Regulation, Title 29, Code of Federal Regulations, § 1910.119 (29 CFR 1910.119).



SECTION 8

Summary and Conclusions

The major gas turbine OEMs are preparing for a zero-carbon future in which hydrogen turbines play a key role. Indeed, several of these companies are mounting "all-in" efforts to adopt hydrogen as a solution. There is little doubt that they will resolve the challenges described here. The key questions are when and how. Several OEMs have projected that they will achieve 100% hydrogen capability by the end of the current decade. This may be optimistic. While laboratory testing can be used to qualify individual components, the more pertinent question now is when will turbines be available that are fully validated to operate on fuels with high (greater than 50%) hydrogen content. From the perspective of commercial readiness, this requires proving all components operating as an integrated system in a real-world, day-to-day environment. Contractual obligations may be satisfied with performance testing. Absent sufficient hydrogen supply to complete acceptance testing, it will be difficult to move forward with the next phases of technology development for higher hydrogen blends. Project developers are reluctant to own a first-of-a-kind technology. To finance their projects, they rely on demonstrated prior experience with full-scale OEM testing to reduce risk. While all major OEMs have full-scale, full-load test facilities, procuring enough hydrogen to complete full-scale validation will be challenging. High-pressure hydrogen cylinders are adequate to complete combustor tests, but they allow only a few minutes of full turbine testing. The problem of hydrogen availability also applies to pilot projects. Thus, the "when" depends on OEMs' ability to achieve full-scale validation when sufficient hydrogen supply is available to meet contractual performance requirements.[43] It also depends on governments, utilities, or large industrial users (e.g., integrated oil companies) being willing to accept the financial risk for large-scale, early-adoption projects.

[43] One solution to gain acceptance, from a contractual performance standpoint, for the phased introduction of hydrogen-capable full-scale pilot projects is to develop local facilities that can store hydrogen produced from low-capacity resources. For example, a joint effort by Magnum and MHI, the Advanced Clean Energy Storage (ACES) project in Utah (Berkshire Hathaway Business Wire, 2019), includes utility-scale underground hydrogen storage.

An assessment of the state of gas turbine technology identifies no fundamental roadblocks to achieving 100% hydrogen capability. Given the high cost of hydrogen fuel, high turbine efficiency to offset fuel cost is important to be competitive with renewable resources. For retrofits of existing turbines, a primary consideration will be to maintain NOx and CO emissions so as to not compromise existing permits. Over the past two decades, OEMs have gained a deeper understanding of the fundamentals of hydrogen combustion. While hydrogen presents challenges, it also has advantages that OEMs are learning to use to advantage. For example, hydrogen's low flammability limit allows for lean mixtures that reduce combustion temperature and thereby limit NOx formation. Its low auto-ignition energy and latency enables staged combustion to achieve required firing temperatures. With combustor modifications to current DLE fuel systems, moderate hydrogen blends with natural gas have been successfully used in commercial projects. However, implementation hurdles remain on the path to proving high hydrogen capability because the impact of higher hydrogen blends extends beyond the combustor and into the hot gas path. As already noted, OEMs have the resources to test and qualify individual components for hydrogen but currently lack access to the hydrogen supply needed to perform normal, full validation on a complete turbine power block and OEM supplied auxiliary systems. Such validation, using highly instrumented testing, is necessary to iron out any wrinkles in the performance of an integrated system under real-world operating conditions. Appropriately, OEMs are adopting a strategy of phased commercial introduction of full-scale turbine systems that have moderate hydrogen capability. Absent sufficient hydrogen supply, initial operation of these systems on natural gas will provide only limited information. Full system validation will proceed as the hydrogen supply issue is addressed.[44] Therefore, OEM timelines for fully validated, high-hydrogen-capable turbines that can meet stringent NOx limits should be considered uncertain until the industry can work through the current hydrogen availability challenge.

44 The US DOE's NETL defines a Technical Readiness Level (TRL) of 8 as the end of development and readiness for commercial deployment. It requires that an actual system is completed and qualified through test and demonstration including proven operational procedures.

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