The Future of Gas Turbine Technology
9th International Gas Turbine Conference
10-11 October 2018, Brussels, Belgium

Paper ID Number: 53-IGTC18

"FUTURE-PROOFING" TODAY'S INDUSTRIAL GAS TURBINES : COMBUSTION SYSTEM FUEL FLEXIBILITY IMPROVEMENTS FOR HYDROGEN CONSUMPTION IN A RENEWABLE DOMINATED MARKETPLACE

Hany Rizkalla, Fred Hernandez, Tim Bullard, Jeff Benoit – PSM - Ansaldo Energia Group
1440 W. Indiantown Road, Jupiter Florida, USA
+1.561.262.5211
Jeffrey.benoit@psm.ansaldoenergia.com

Peter Stuttaford – Ansaldo Thomassen B.V., Ansaldo Energia Group, Rheden, Netherlands
Dennis Jansen, Theo de Bruijne – AES Eurasia SBU, Amsterdam, Netherlands

ABSTRACT

Renewable energy has disrupted the energy market place. Fuel is free for renewables, and coupled typically with "must run" governmental requirements, they are the first to be dispatched on the power grid. Wind and solar are a function of the weather and can experience rapid swings in load. The result of this type of highly variable power demand is that gas turbine power plants must effectively respond to the load swings and capture periods of profitability. It's called "chasing renewables" and is highlighting operational limitations of the installed base of gas turbine power plants in a time where reducing maintenance cost are more critical to maintain profitability.

Alternative fuel combustion offers the potential of a low cost energy source for power generation. Some of these fuels, such as those produced as by-products at petrochemical plants and refineries, can be readily available, and absent the ability to 'flare this gas', it awaits the implementation of robust gas turbine combustion systems to harness their energy in a meaningful way. Additionally, Hydrogen also has the ability to be a 'battery fuel' as excess energy produced by wind and solar can be used to produce hydrogen through electrolysis.

Pertaining to gas turbine combustion, hydrogen is a highly reactive fuel and presents challenges for industry standard dry low NOx combustors to switch between natural gas and hydrogen fuel blends while remaining stable and with NOx emissions always below stringent emission limits. Significant concerns regarding emissions compliance, combustion dynamics and stability must be addressed prior to operation on these fuels.

This paper will highlight successful retrofit solutions for both E-class and F-class combustion turbines that are in commercial operation today, offering significant benefit to the operators and the environment.

INTRODUCTION

The gas turbine power generation market continues to face changing market conditions due to fluctuations in gas prices, electricity demand, natural gas inventory, economic and political conditions. Additionally, the global investment in renewable energy continues to increase according to AWEA (2015) [2] and pose additional challenges to power generation markets in the form of volatility in the electricity market due to the fluctuation of the energy supply to the grid as discussed by Stuttaford et al, 2016 [1]. As such, achieving the lowest possible in-emissions compliance turndown during hours of low demand, while remaining online and available, allows a gas turbine power plant to follow market pricing, and can significantly impact power plant profitability by being able to quickly ramp up in load and capture profits when electricity demand and prices are favorable. An example illustrating this using actual real time market information in the ERCOT power generating region within the U.S.A., in May 2014 is referenced in paper by Stuttaford et al (2016) [1]. Due to the potential profitability advantages discussed, industrial gas turbine manufacturers have invested heavily to optimize combustion systems to enable emissions compliant turn down techniques.

NOMENCLATURE

LHV = gas lower heating value (BTU/ft^3)
SG = Specific gravity of fuel gas relative to air
T = Fuel gas absolute temperature (^{o}R)

THE FRACKING DILEMMA

Increased shale gas production has been credited for reduced NG (natural gas) prices in the U.S.A, but has also posed a challenge to the gas turbine power generation market due to variations in gas composition and heating value.

A normalized measure of fuel flexibility can be represented using the Modified Wobbe Index (MWI) which accounts for variation in fuel heating value and density, and is defined as follows:

$$\mathrm{MWI} = \frac{LHV}{\sqrt{(SG \times T)}}$$

The Modified Wobbe Index is affected by both fuel gas temperature and heating value of the fuel. It is possible to offset the effect of one of these parameters with the other to maintain the MWI within an acceptable range.

According to the IEA (2015) [3], shale gas composition varies substantially from one shale gas region to another across the U.S.A. Calculated MWI variation based on the compositions can be as high as 78%. As such, a combustion system capable of operating with large fuel MWI variation is an asset to gas turbine power plants.

THE VALUE OF HYDROGEN TO THE CLIMATE ENVIRONMENT

Burning hydrogen in a combustion process such as in an industrial gas turbine, allows the generation of energy without the creation of carbon dioxide, one of the major contributors to climate change. Consider the curve in Figure 1: If 25% of Hydrogen by volume could be mixed with natural gas and combusted in a gas turbine, approximately 9% of the gas turbine's CO2 created would be eliminated. As an example, consider a 120 MW Frame 9E gas turbine operating in simple cycle. If one was able to do this type of blending of hydrogen with natural gas, and the unit was operated about 8000 hours a year, it would result in a CO_2 reduction of 54,160 metric tons, equivalent to taking 11,600 gas powered vehicles off the road per calculations from the United States EPA [4].

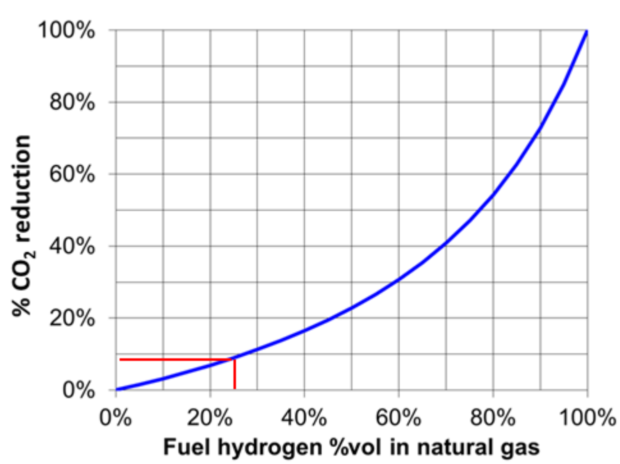


Figure 1 : CO2 generation reduction as a fraction of the amount of hydrogen blended by with natural gas fuel if used in a combustion process

RETROFIT SOLUTION #1 - LEC-III® COMBUSTION SYSTEM

The LEC-III® (**L**ow **E**mission **C**ombustor 3rd generation) combustor technology was first incorporated into GE Frame 7E gas turbines in 1998 by PSM. This can-annular, reverse-flow combustion system, shown in 2, was designed to be a direct replacement into an existing gas turbine outfitted with the Original Equipment Manufacturer (OEM) DLN-1 system. This lean premixed system includes fuel nozzle assemblies, transition pieces, flow sleeves and combustion liners which were initially designed to achieve less than 25ppm NOx (corrected to 15% O2) at baseload conditions. To date, the PSM fleet of LEC systems has over 1,000,000 hours of operation. See Benoit et al. (2011) [11] for a full description of this system installed on multiple machines at a mature power plant.

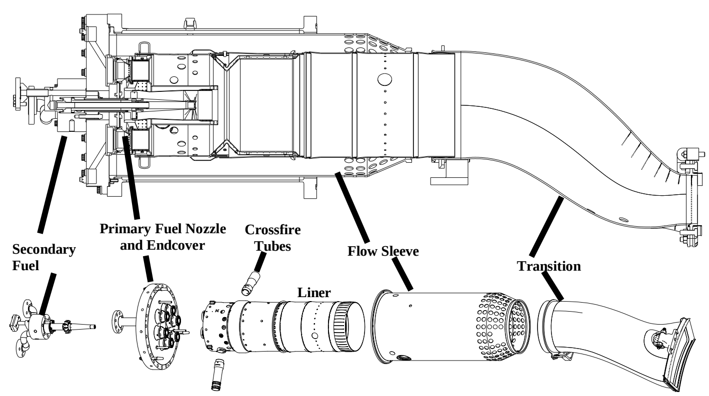


Figure 2: PSM's LEC-III® Combustion System Cross Section

There are a number of key technology advances made over the previous state of the art in the LEC-III® system that enables it to perform as discussed and shown in Figure 3. The operation of this type of dual stage lean premixed combustion system is described by Davis & Black (2007) 0.

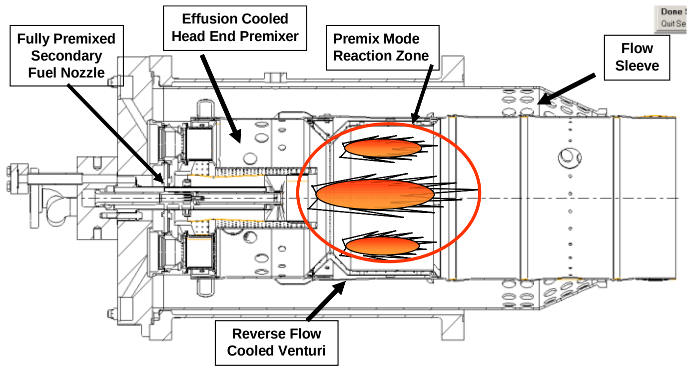


Figure 3: Combustion System Description

The key mixing features of the LEC-III® include a cooled venturi, increased dilution air to the head-end premixer enabled by the enhanced cooling efficiency of effusion cooling, and a fully-premixed "Fin Mixer" secondary fuel nozzle (SFN).

The secondary fuel nozzle is a key contributor to the demonstrated stability of the 7E/EA OEM DLN-1 combustion system. The secondary fuel nozzle sets up a central 'pilot' zone of reaction and recirculation that acts as the continual ignition source for the surrounding reaction zones of premixed primary fuel. By design, this secondary reaction zone is a richer mixture, burning hotter to provide excellent combustion stability. In the conventional DLN-1 system of the 7EA, this secondary fuel flow is actually channeled through two separate circuits. The majority of the fuel is discharged from 'pegs' near the nozzle's mid-section. This fuel premixes with air as it travels along the length of the nozzle, and it goes thru swirler vanes for final premixing prior to discharge into the reaction zone. The second circuit within the nozzle has a small amount of fuel discharging at the tip (extreme aft end), which is not premixed at all. It burns in a 'diffusion' mode of combustion. As discussed, this region has some areas of reaction temperatures above 3500F (1930C) and associated NOx formation is significant. It is only a small amount of the total fuel flow, but its contribution to the system's total NOx formation can be significant. Elimination of this 'diffusion' burning aspect of the conventional nozzle has been the focus of the LEC-III®'s secondary fuel nozzle design evolution. A significant amount of rig and engine development testing has been conducted in development of this nozzle design by Oumejjoud et al (2005) 0. As a result, PSM's fully evolved, current production SFN offering is known as the "Fin Mixer" SFN, which has demonstrated in engine verification and validation the ability to significantly reduce NOx. This improvement is simple in concept and implementation, and it provides a step change in emission reduction in an already low emission combustion system. 4a illustrates the discussed variations of SFN fuel distribution designs, and 4b shows the Fin Mixer SFN undergoing high pressure combustion tests.

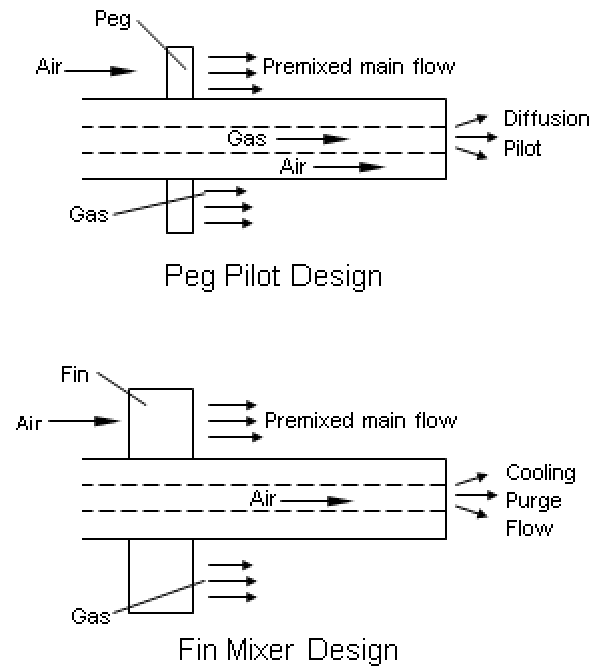
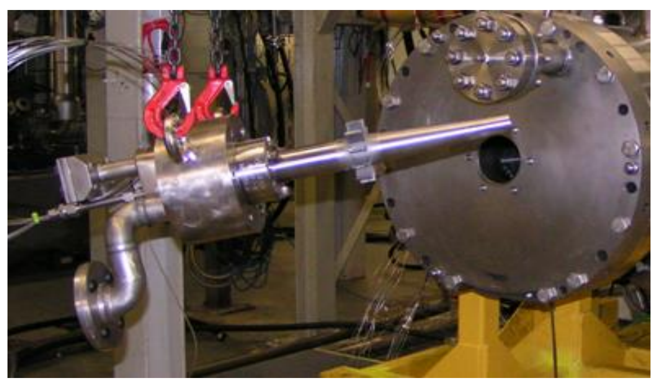


Figure 4a: Secondary Fuel Nozzle (SFN) Differences



4b: Fin Mixer in High Hydrogen Test

HIGH PRESSURE COMBUSTION TEST FACILITY

The results discussed in this work were obtained from engine field installations and the PSM high pressure combustion test rig. The full scale test rig (shown in Figure below) is capable of delivering full F-class base load operating conditions, with the following maximum operating conditions:

Air flow = 60 #/sec (27 kg/sec)
Pressure = 350psia (2.4MPa)
Inlet Air temp = 1200F (650C)
Exhaust temp 3500F (1930C)

The test rig provides optical access to the flame as well as allowing measurement of emissions, combustion dynamics, pressures and temperatures. Various fuel gases are provided to the combustion system being evaluated through the facility alternative fuels infrastructure.

As shown in 5, air is provided to the test section in two locations from a single air feed pipe (blue arrows). A series of baffles are installed within the test section to simulate the engine air flow pattern to the combustor, as well as the engine equivalent acoustic plenum. The latter is an important consideration to correctly duplicate field engine combustion dynamics within the test rig. Rig to field engine qualification is further discussed in Oumejjoud and Stuttaford, (2007) 0. The combustor is exhausted through a slave transition duct to properly simulate the engine acoustic boundary condition of the first stage vane (red arrows). The hot gases then travel through the water cooled exhaust duct (red arrows). A quartz window is located in the exhaust on the combustor centerline for observation of the flame (sample flame views shown in Figure). The exhaust turns 90 degrees around the quartz window before entering a back pressure valve (not shown) which is used to properly modulate combustion system pressure-drop. Results of the rig test benchmarking can be found in the paper by Bullard and Steinbrenner, (2018) [8].

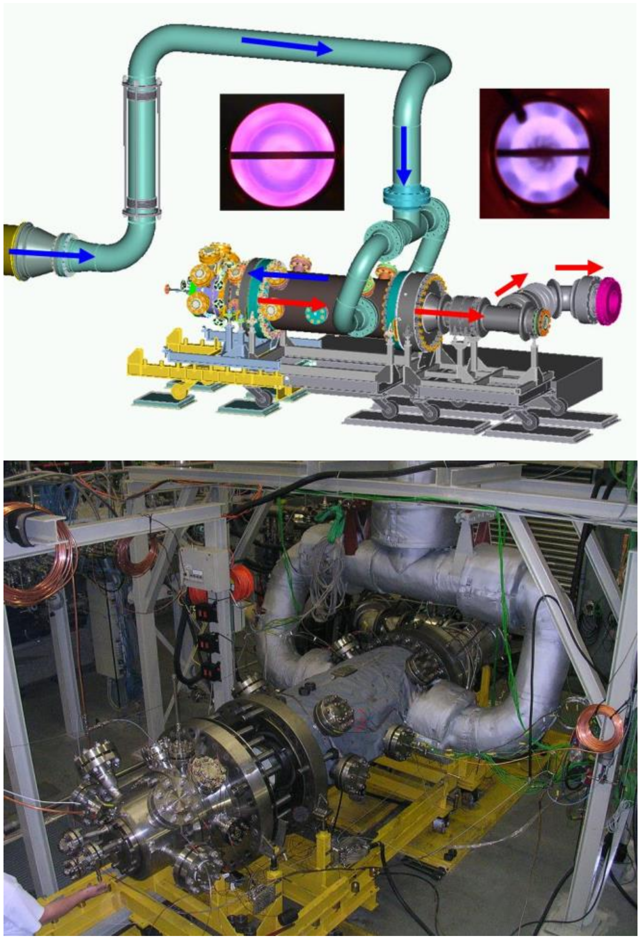


Figure 5: PSM full scale combustion test rig

AN OPERATOR'S PERSPECTIVE – FRAME 9E

Consider the following Frame 9E retrofit example in the Netherlands. The Cogeneration Facility, already in commercial service for 19 years, has held reliability and availability as the most important Key Performance Indicators (KPI's) during operations. In the engineering and construction phase of the facility these KPI's were taken into account. The gas turbines were originally equipped with dual fuel technology allowing use of fuel gas or liquid fuel as primary fuels. The liquid fuel system was never commissioned and was removed after one year of operation while at the same time changing from low to high calorific fuel gas. A secondary fuel stream called 'sitegas', which is a mixture of methane and hydrogen, is used. This gas stream is supplied by a neighbouring factory which produces sitegas. Natural gas and sitegas streams are mixed via a valve mixing station. This system was tested and commissioned by the gas turbine OEM and the machines were guaranteed for a maximum of 10% hydrogen by volume in the fuel gas.

The background of the dual fuel-gas system was directly related to the KPI's: reduce the risk depending on one fuel type. After switching from low to high calorific gas, two different sources of primary fuel were available, namely low and high caloric gas. During the following years, confidence in one primary fuel type became greater and the focus of the facility changed to more flexibility, higher efficiency and to adapt to the changing energy market. Increasing gas prices and lower spark spreads changed the plant's operation, while trying to safeguard the availability and reliability of the facility.

The allowable minimum load of the facility was decreased in two different ways, by reducing the minimum load of the gas turbines form 55% to 45% load/55MW and by operating two gas turbines instead of three. The increased efficiency was delivered mainly by modifications and by operational improvements at the steam side of the process. The operator of the Cogeneration facility discovered the market for equipment which enables the gas turbines to burn more hydrogen resulting in higher fuel flexibility. Additional advantages like reduced emissions and the opportunity to use sitegas as a primary fuel source were taken into account. These aspects all together improve, beside the KPI's availability and reliability, the facility's position in the market, through a high efficiency, fuel flexibility and competitive fuel costs.

In 2011, PSM presented the opportunities to burn more hydrogen by replacing the Secondary Fuel Nozzles (SFN's). At that time the Cogeneration facility already operated the PSM LEC-III® combustion equipment on all three gas turbines, using the ring type SFN's instead of the now proposed fin mixer type SFN's. PSM indicated that an increase of the maximum hydrogen content to a maximum of 25% hydrogen by volume should be possible.

GAS TURBINE CONTROL & OPERATION

With the use of significant levels of hydrogen in the gas fuel, special consideration is made for flashback within the gas turbine control system. Premixed gas fuel presents challenges with regard to flashback, a phenomenon in which the flame can propagate upstream to areas of the combustor which are not designed for elevated temperature as mentioned by Stuttaford (2011) 0. Hydrogen has a higher flame speed than natural gas and thus combustors burning higher proportions of hydrogen will be at higher risk of flashback than when running on conventional natural gas mixtures.

The LEC-III® combustor operates in multiple combustion modes. These combustion modes consist of flame in either a primary zone (premixer), secondary zone (reaction zone), or both. During the premixed combustion mode, when flame exists in the secondary zone only flame temperature is high enough that a flame in the primary zone would be undesirable. Additionally, a flame within close proximity of the secondary nozzle fuel fins would be particularly detrimental at any time. With the use of elevated levels of hydrogen, a control sequence was developed to mitigate the risk of flashback during initial testing and long term operation of the gas turbine.

Test experience with this combustor indicates that when a flashback does occur, it will occur to the primary zone prior to the secondary fuel nozzle. This allows use of existing instrumentation to monitor and prevent flashback to the secondary nozzle. The sequence begins when the primary flame detector signal is activated while operating in premix mode above a threshold of hydrogen percentage. Once initiated, the sequence consists of a rapid change in fuel staging as well as a fast load dump, quickly reducing the load of the gas turbine. The fuel is entirely diverted from the secondary nozzles to the primary nozzles, thus extinguishing the flame in the secondary zone. At the same time, the ignition system is activated to establish flame in the primary combustion zone. The generator load is then reduced to approximately one third of maximum load, a level that is sustainable given the change in combustion mode. After a brief settling period, the gas turbine is automatically loaded into the premix combustion mode. The entire sequence requires less than three minutes.

For the machine test campaign, the control sequence was tested with success. Changes to fuel staging were accomplished in less than 1 second while maintaining stable combustion and generator load was reduced to the target load in less than 3 seconds. Further optimizations were made for combined cycle stability and auxiliary systems.

The entire test campaign with hydrogen did not yield a flashback event, indicating sufficient margin exists for the installed hardware. The flashback system remains in service to mitigate the risk of elevated hydrogen in the gas fuel.

FUEL FLEXIBILITY – COMMERCIAL TEST RESULTS

In order to validate a new long term plant maximum of 25% hydrogen content in the fuel gas, a test program was developed with the goal of checking the combustion performance at levels beyond the expected maximum operating limit. Hydrogen targets of +5% (30% maximum) at base load and +10% (35% maximum) at 48% load were used. The level of hydrogen in the fuel gas was controlled with a gas valve mixing station, in which the percentage of hydrogen constituent in the fuel gas is measured with two redundant hydrogen analysers.

The test procedure included checking the emissions and combustion dynamics levels at varying loads and levels of hydrogen in the fuel gas. Emissions constituents measured were Nitrous oxide (NOx), carbon monoxide (CO), and oxygen percentage. Emissions data were collected via the plant continuous emissions monitoring system (CEMS). The sample probe for the CEMS is located in the stack. No exhaust conditioning systems (i.e. duct burner) were in use for the duration of the test. Combustion dynamic pressure data were collected for each chamber with a transducer mounted to the chamber casing. The location of the pressure probe is flush with the combustion liner.

Figure 6 is a plot of NOx emissions versus fuel gas hydrogen content. Two curves, one for base load and one for minimum load are shown. Base load represents maximum gas turbine load seen during typical operation. 48% load represents the lowest demand load (55MW) during automated grid control given the ambient condition of the test day. The minimum load is also slightly above the point at which the combustor will transfer out of premix combustion mode. Assuming fuel schedule is unchanged from the tested condition, the full realm of emissions data across the load range are bounded by these two curves.

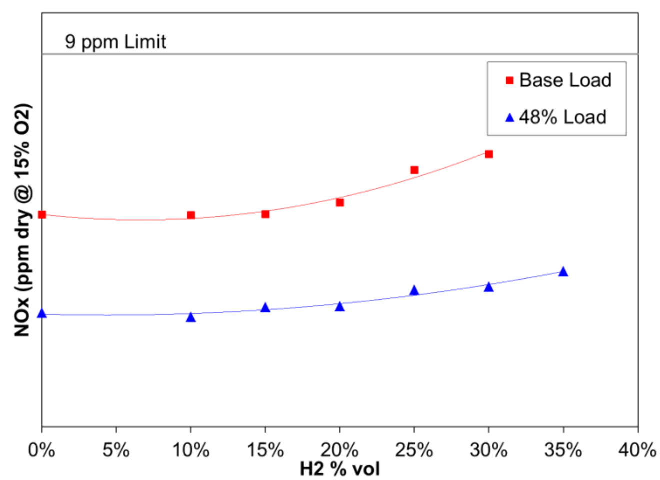


Figure 6: NOx Emissions versus fuel gas hydrogen content

Additionally in Figure 6, NOx emissions are relatively unaffected by addition of hydrogen until surpassing a level of at least 15% by volume. The effect is somewhat lower at 48% load. At higher levels of hydrogen, NOx increases. Overall NOx performance with hydrogen is as expected according to prior experience from Oumejjoud et al (2005) [10] and Benoit et al (2011) [11]. The maximum levels of NOx emissions seen during testing are also favourable compared to the typical limits for the combustor. Additionally, there is enough room within the limit to allow use of duct burners which add to the NOx emissions in the exhaust gas.

The result obtained with NOx emissions is to be expected due to the combination of two competing phenomena. On the one hand, hydrogen has a higher flame temperature and flame speed than methane which will move the flame upstream and change the flame geometry. The higher temperature along with greater localized fuel/air ratio serves to increase NOx formation. On the other hand, with the gas turbine operating at constant load, the higher temperature results in a reduction of total fuel flow by mass. The gas turbine control system is automatically adjusting fuel mass flow in response to the change in fuel constituent. The change in mass flow serves to reduce the effect of the higher flame temperature on NOx formation.

Figure 7 is a plot of CO emissions versus fuel gas hydrogen content. As previous, one curve is shown for each of base load and 48% load. As would be expected, CO emissions at base load are essentially zero. This is typical for most modern low emissions gas turbine combustion systems. The CO at base load is thus not affected by changes in hydrogen content. Conversely, at 48% load there is a substantial effect due to the addition of hydrogen. At a level of 10% hydrogen, the CO emissions were already in exceedance of the typical combustor limit. Elevated CO at low load is common amongst dry low NOx combustors due to the reduced localized flame temperature (high premix quality) of the combustion zone. Increasing hydrogen to 15% and higher brings the CO emissions significantly below the limit. A separate data point indicating 51% load shows the required load to reach sub 25 ppm using 0% hydrogen with the current hardware.

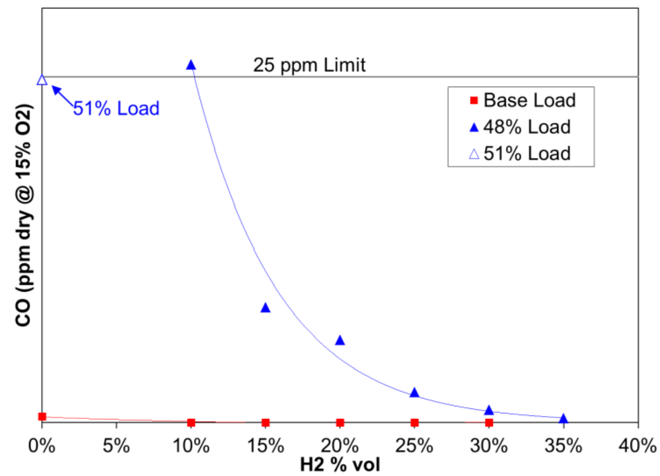


Figure 7: CO Emissions versus fuel gas hydrogen content

The result obtained with CO emissions is to be expected since with higher temperature the fuel will tend to be burned more to completion, consuming available CO. Additionally, with increased proportion of hydrogen in the supply, the availability of carbon compounds for CO formation is reduced.

Figure 8 is a plot of maximum combustion dynamic amplitude versus fuel gas hydrogen content. Again, separate curves for base load and 48% load are shown. Base load combustion dynamics were already quiet, and addition of hydrogen did not exacerbate the levels observed. In fact, at higher concentrations of hydrogen, a reduction of dynamic amplitudes and a widening of the tuning window were found. This result was similar to that observed during rig testing. At 48% load dynamic amplitudes were higher than base load. From a stability standpoint the combustor is certainly closer to its stability limits when running at minimum load. This is a condition that is farther off the combustor design point. Similarly at 48% load the combustion dynamics were quieted when hydrogen concentration exceeded 20%.

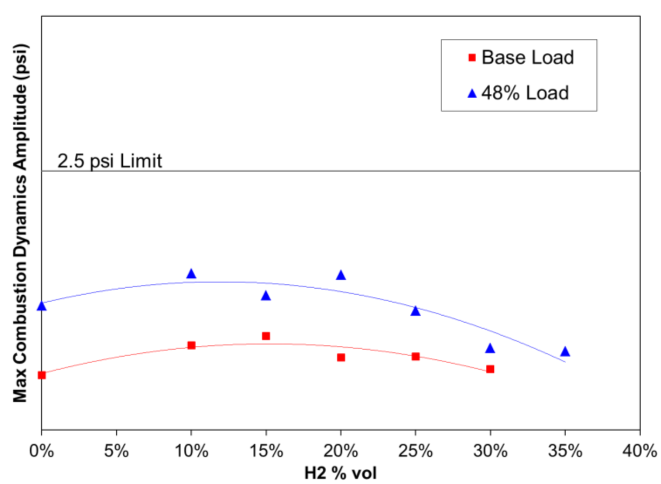


Figure 8: Maximum combustion dynamics amplitude versus fuel gas hydrogen content

The result obtained with combustion dynamics is expected to be burner specific in that the flame dynamics are moving away from hardware dynamic resonance modes. This may not be the trend if the hardware geometry is changed. Combustion dynamics play a strong role in ensuring the hardware will reach its target maintenance intervals. As shown in figure 8, a favourable margin to the typical limit exists at both base load and 48% load.

RETROFIT SOLUTION #2 - FLAMESHEET™ COMBUSTOR

Invented at PSM in 2002, the FlameSheet™ combustion system has been designed to offer extended operational and fuel flexibility ranges to ensure maximum operating capacity and reduced fuel costs. The combustion system is designed to:

- Provide extended fuel flexibility to allow simultaneous operation on natural gas, liquefied natural gas, refinery off-gas, high hydrogen content syngas, and low carbon content syngas
- Extend turndown capability by an additional 20% load whilst maintaining emissions compliance.
- Operate below 9ppm of NOx and below 9ppm of CO across the load range, from extended turndown to baseload and overfired operating conditions.
- Allow increased firing temperature of at least 50^{o}F (28^{o}C), improving cycle performance while maintaining emissions targets
- Achieve all targets without the addition of any diluent such as water/steam/nitrogen
- Provide durability to allow continuous operation without inspection for at least 24,000 hours or 900 starts, with a view to 32,000 hours
- Be easily retrofitted into existing F and E-class gas turbine platforms.

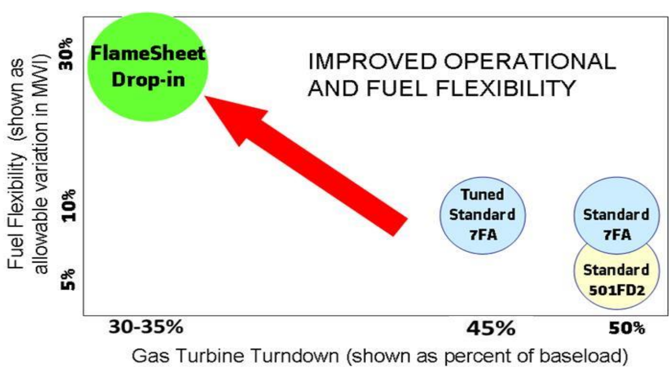


Figure 9: FlameSheet™ operational and fuel flexibility in comparison to other standard F-class combustors

Operating Principle

Please refer to Stuttaford et al (2016) [1] & Rizkalla et al (20180 [12] for a thorough description of the FlameSheet™ combustor. The FlameSheet™ system is a combustor within a combustor, each of which can be operated independently of the other. The system consists of two aerodynamic stages and four fuel stages. The stages are designed for specific operational aspects such as transient loading and extended turndown operation. 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 robust flame stabilization mechanisms. This allows either combustor to be operated with the other combustor OFF, providing significant operational flexibility.

Figure 10 illustrates the overall structure of the FlameSheet™ system. The pilot and main stages are fed from the compressor discharge plenum. Pilot air passes through the radially outermost circuit to the head end of the combustor where it enters a radial inflow swirler. Fuel is mixed into the air stream through a row of vanes. The fuel-air mixture then enters the combustor and a flame is swirl stabilized behind a bluff body on the centreline of the combustor as outlined by Oumejjoud et al (2005) [10]. The main stage air flows along the backside of the combustion liner and then through a main fuel injector. The fuel-air mixture is then turned 180 degrees and flows into the combustor. As the flow enters the combustor it separates off the combustion liner and forms a strong recirculation region, or aerodynamically trapped vortex which stabilizes the flame.

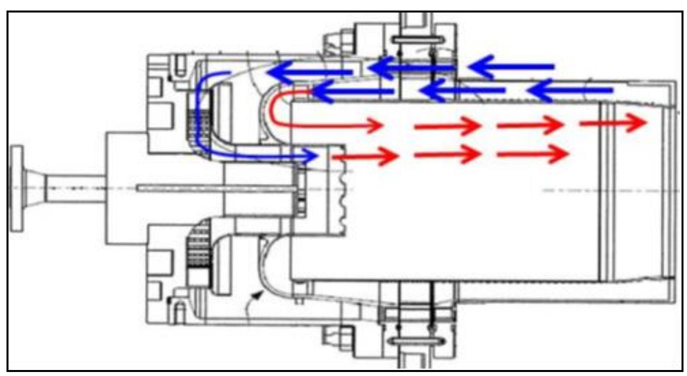


Figure 10: Overall flow design of FlameSheet™ system, Stuttaford et al (2005) [13]

The pilot and main stages hence form two independent flame stabilization zones resulting in a "combustor within a combustor" configuration, which is key to enhancing operational flexibility.

Mechanical Description

The FlameSheet^{TM} combustor is designed to be mechanically "drop-in", allowing the combustor to be installed with no impact to the mating envelope. The design is also uniquely modular, allowing the system to be cross platform compatible for various E and F class engine platforms. Figure 11 illustrates an exploded view of the 7FA FlameSheet^{TM} Combustor.

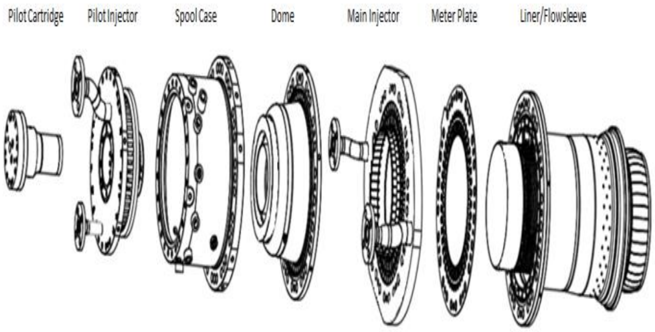


Figure 11: 7FA FlameSheet^{TM} combustion system components

INITIAL AND EXTENDED MACHINE VALIDATION

In the spring and fall of 2015, the FlameSheet™ combustor was installed on two commercially operating "unflared" 7FA heavy duty gas turbine engines. This section focuses on the initial as well as extended FlameSheet^{TM} combustor engine validation results, beginning with the installation, engine emissions performance at the min load (LOL), baseload and overfired conditions. The section will also illustrate performance results, including ambient effects on tuning emissions margin after two years of engine operation as well as a durability assessment after 16,600 hours of continuous operation on the said unflared 7FA Gas turbine engine. Effects on Hot Gas Path will also be evaluated.

A. MECHANICAL INSTALLATION

The FlameSheet™ combustor installation on the General Electric 7FA heavy duty gas turbines was demonstrated to take approximately one week, half the duration of a standard Combustor Inspection (CI). During the installation, the 7FA combustors and fuel flex lines were replaced, minimal changes were required to the fuel skid, and the existing four fuel feed ring manifolds on the engine were utilized. Customer and mechanics' feedback from the installation efforts was positive due mainly to the FlameSheet^{TM} smaller footprint relative to that of the OEM DLN2.6 combustion system, see Figures 12, 13 &14 below.

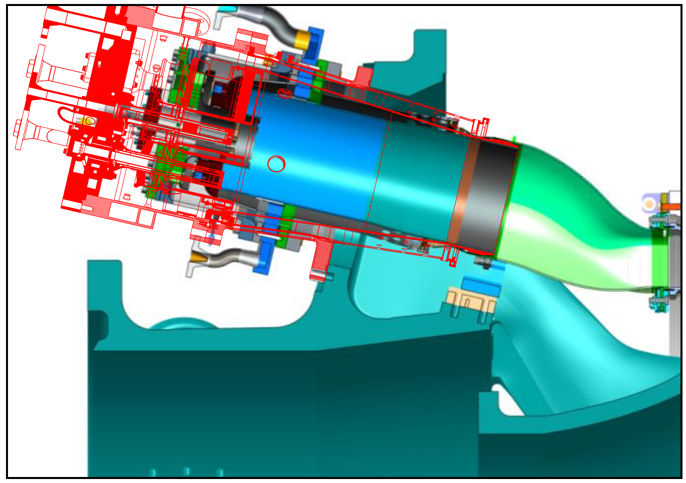


Figure 12: FlameSheet^{TM} smaller foot print to that of a DLN2.6 (red wireframe) combustion system on a 7FA gas turbine

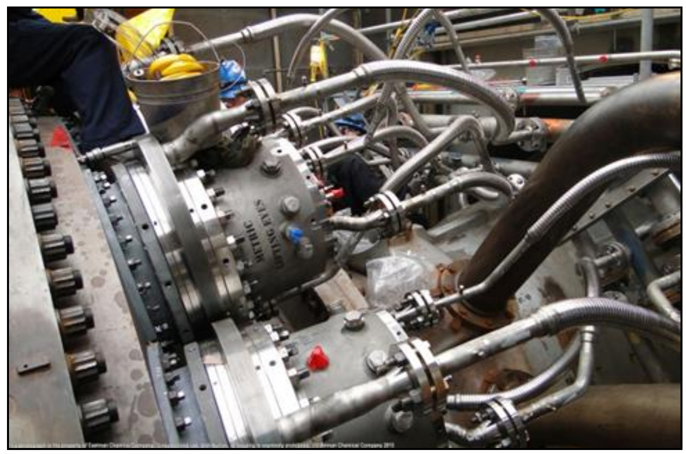


Figure 13: FlameSheet^{TM} combustion system installation on a 7FA heavy duty gas turbine in 2015

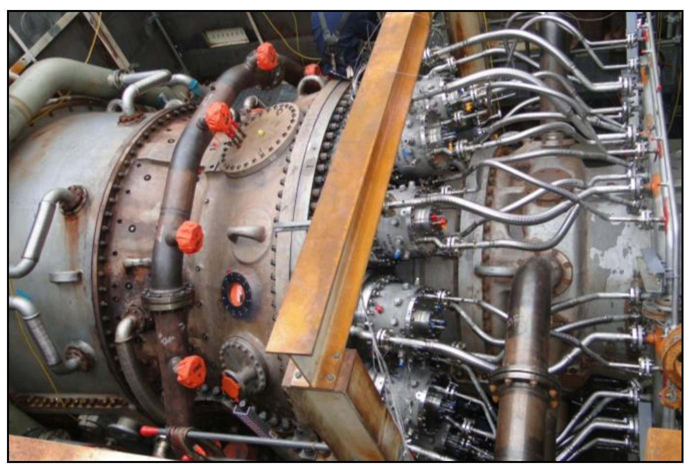


Figure 14: FlameSheet^{TM} combustion system installation on a 7FA heavy duty gas turbine in 2015

B. FLAMESHEET™ MACHINE PERFORMANCE

This section focuses on the operating performance of the FlameSheet™ combustor during its first interval of commercial operation in a 7FA gas turbine. As discussed, the FlameSheet™ was installed on two commercial engines at the same site. The second installed set of FlameSheet™ was removed at the 16,600 hour mark to accommodate the customer's major outage schedule, which afforded the opportunity to evaluate the performance characteristics and inspection results over time. This section focuses on the performance of this second set of hardware, with comparison of emissions, dynamics and turndown throughout the entire interval, from initial commissioning to the last seasonal tuning prior to combustor removal.

C. RECENT NEW FLAMESHEET™ INSTALLATIONS

In 2018, two (2) additional advanced FlameSheet™ combustion systems were installed at one of Long Term Service Agreement (LTSA) customers shown in figure 15. Included with this design were additions of a low delta pressure drop (Low DP) combustion system adaption which effectively removes flow restrictions, allowing higher pressure air to reach the combustor and thus improving the turbine power output and efficiency. Additional to this, results confirmed emission performance below 7ppm NOx across the normal operating range and ambient conditions including in an 'overfired' condition of +50deg C, confirming the upgrade potential of this system when additional turbine technology is added for improved performance needs.

Figure 15. FlameSheet™ combustor configuration (before fuel delivery piping installation) of latest fleet additions

FLAMESHEET™ HYDROGEN CAPABILITY

With the FlameSheet™ combustion system operating now since 2015 with confirmed durability to meet 32k fired hours inspection intervals and noting the tremendous potential of the design's combustor within a combustor layout to provide high airflow speeds allowing for increased resistance to flashback with the introduction of hydrogen, testing was conducted at the test rig facility as shown in Figure 4.

Noting the strong desire to reduce the carbon intensity in the European Union, and some renewable infrastructure to generate and transportation systems to delivery hydrogen, it becomes feasible to consider development of larger gas turbine focused solutions to consume hydrogen. While the economics of generation of hydrogen are not addressed in this paper, there is a consideration with the rise of renewably-generated electricity that 'stranded' wind/solar power could be used to generate "green hydrogen" via a hydrolysis process.

Figure 16 shows the results from the test rig at F-class conditions. What was confirmed with the existing system operating in the 7F fleets today is that the up to 65% blended hydrogen by volume with natural gas can be consumed safely without risk of flashback. Additionally, recent atmospheric pressure testing where minor geometric changes were made strongly suggests that upwards of 80% blended hydrogen is achievable, without the need for diluent such as nitrogen and without a performance impact. The solution would be easily adapted to OEM Frame 9F and 701F gas turbine machines to address opportunities in 50hz markets.

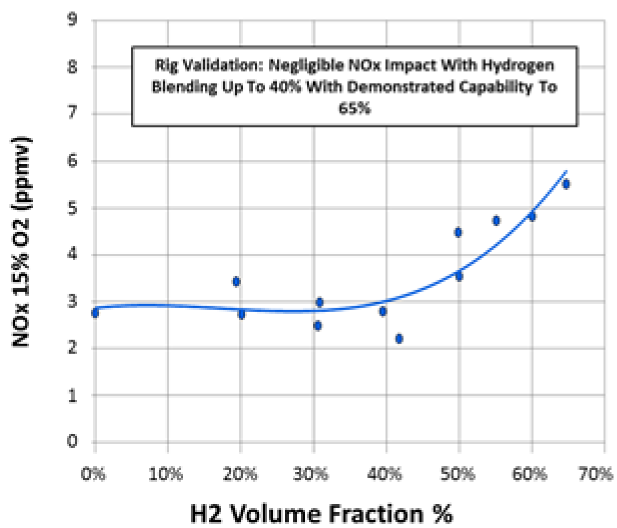


Figure 16 : Full pressure test rig results with FlameSheet™

NEXT STEPS TO 100% HYDROGEN

Recent focused efforts conducted at PSM have identified a path forward to leverage the FlameSheet™ combustion system design to consume 100% Hydrogen safely. This involves the benchmarking analytically the current test results with 100% hydrogen, then conducting atmospheric rig tests to confirm the designed path from 80% to 100%. From here, high pressure at full scale conditions would be used to verify the robustness of the solution, followed by a full machine demonstration, including fuel switch fully from 100% natural gas to 100% hydrogen.

CONCLUSIONS

The retrofit solution identified for B and E-class can-annular combustion gas turbine is achieved with innovative fuel injection redesign leveraging CFD tools and benchmarked to full pressure rig testing. This design methodology has allowed a simple retrofit to be available for all OEM Frame 7E and 9E gas turbines with the LEC-III® solution. Demonstrated results show that at least 25% hydrogen by volume can be blended with natural gas with margin and is providing operators today with a sound financial proposition including the benefit of reducing their carbon intensity at this plant by 9% per machine. This has the same carbon intensity impact as taking almost 11,600 gas fueled vehicles off the road.

The FlameSheet™ combustion system is a novel combustion system utilizing a combustor within a combustor concept. The combustion system was installed on two GE 7FA industrial gas turbine engines in 2015 and low emissions and superior turndown performance were demonstrated for over 36,600 hours of combined operation on both units with no tuning margin or turndown performance degradation. The combustion hardware was removed, inspected and found in good condition after ~16,600 hours of operation on unit-2 and exceeds expectations. The combustion system continues to operate successfully meeting all performance guarantees and is expected to expand to other heavy gas turbine platform applications in the near future.

Additionally, the FlameSheet™ combustion system, due to its inherently novel design allows unraveled quantities of hydrogen to be used as a fuel source, currently up to 65% by volume today with the defined roadmap to burn 100% hydrogen, without diluent and with low emissions, dynamics and unprecedented turndown capabilities.

Both of these simple and straightforward retrofits allow the operators a sound financial and low risk option to “future-proof” their existing assets in a rapidly evolving and dynamic power generation marketplace.

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