DECARBONIZING: THE FUTURE OF HYDROGEN FIRING

Presenting Author
Marc E. Lemmons
Supervisor, Customer Advisor
Koch Engineered Solutions

ABSTRACT

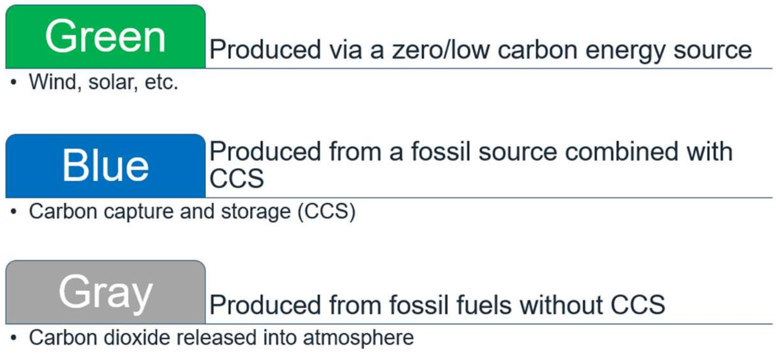
Historically, firing hydrogen fuel was only economical in certain applications outside of the power industry. Unlike other fossil fuels, hydrogen does not naturally exist as H_2 and is commonly produced in hydrogen reformers and considered an energy carrier and not an energy source. Steam-methane reforming (SMR) accounts for approximately 95% of the hydrogen fuel produced in the United States (U.S.) due to lower natural gas costs, lower energy demand from production and relatively low quantity of heavy residuals. Interests in hydrogen firing continues to grow on a global scale, particularly in the power and refinery industry, as a viable CO_2 emissions reduction approach. The U.S. Department of Energy has developed concepts called H_2@Scale and H_2Hubs which focus on wide-spread production and utilization. With large corporations formally announcing their ambitions for net zero greenhouse gases by 2050 or sooner, hydrogen firing has become an attractive solution.

Increased hydrogen firing on an existing combustion system will have unique challenges and require important design considerations when compared to other fuels. These unique challenges include a higher flame temperature, higher flame speed, lower heating value on a volume basis and a reduction in combustion air requirements. This presentation will explore the industries interests in hydrogen firing, an overview of hydrogen as a fuel, impacts to balance of plant equipment, impacts to burner and boiler components, and emission considerations. Since hydrogen has a small molecular weight and higher flame speed, safety considerations will also be presented. We will also explore recent research and development to improve approaches in NOx reduction.

1. INTRODUCTION

Unlike other fossil fuels, hydrogen does not naturally exist as H_2 and is commonly produced in hydrogen reformers which is considered an energy carrier and not an energy source. Hydrogen fuel is defined into three categories; green, blue and gray (refer to Figure 1 below). Green hydrogen is produced using renewable energy, such as wind or solar. Hydrogen produced from a fossil fuel may be called gray or brown hydrogen if derived from coal or natural gas, respectively. Gray hydrogen, when combined with carbon capture and storage/sequestration might be referred to as blue hydrogen.

Figure 1. Categorizing Hydrogen Fuel



Although there are several methods to produce hydrogen as a fuel, emission intensive SMR currently accounts for approximately 95% of the hydrogen fuel produced in the U.S. The remaining hydrogen production is mostly a by-product e.g., the formation of naphtha into gasoline produces some hydrogen as a by-product. For this reason, it is critical for the industry to develop low carbon hydrogen production. The two main low-carbon production routes use fossil fuels coupled with carbon capture, utilization and storage (CCUS) or water electrolysis. The U.S. Department of Energy is investing significant amounts of resources in CCUS while major U.S. utility companies[1] are investigating the use of nuclear power as an electricity source for water electrolysis.

Interests in hydrogen firing continues to grow on a global scale, particularly in the power and refinery industry, as a viable CO_2 emissions reduction approach when using either green or blue hydrogen. The U.S. Department of Energy developed concepts called H_2@Scale and H_2Hubs which focuses on its wide-spread production and the industry approach in utilization. These opportunities may be worth up to $8B[2] for the U.S. to invest in its utilization. With large corporations formally announcing their ambitions for net zero greenhouse gases in the near future, hydrogen firing is becoming a solution to achieving these ambitions.

1.1 Hydrogen Infrastructure

National policy and other initiatives across the world are working to accelerate hydrogen hubs. Depending on infrastructure and production capacity, regions may be positioned to consume and/or consume higher rates of hydrogen. Currently, Houston/Gulf Coast region is the world's leading hydrogen system which mainly supports the refining and petrochemical industries. which services local demand such as oil refining and petrochemical industries. The Houston/Gulf regions currently produces about one-third of the United States hydrogen. This region accounts for forty-eight (48) hydrogen production plants and nearly 1,000 miles of hydrogen pipeline infrastructure. In comparison, the Midwest only has approximately 15 miles of dedicated hydrogen pipelines.

[1] https://www.powermag.com/partner-content/xcel-energy-pioneering-bridge-between-nuclear-and-the-hydrogen-economy/
[2] https://www.energy.gov/articles/doe-launches-bipartisan-infrastructure-laws-8-billion-program-clean-hydrogen-hubs-across

Figure 2. Houston Hydrogen Infrastructure (https://www.centerforhoustonsfuture.org/h2houstonhub)

Alberta is another region in North America posed for large production and consumption of hydrogen and plans to become a major blue hydrogen hub due to its low cost of production. Canada has invested significantly in carbon capture technologies and began trial hydrogen blending projects through its existing natural gas infrastructure.

In other parts of the world, countries may either be positioned to produce hydrogen on a large scale with little consumption or be large consumers due to limited capabilities, such as Japan.

This paper provides a general approach and assessment of firing higher amounts of hydrogen in a boiler. We present an approach to assess the projects' technical feasibility, impact on emissions, balance-of-plant considerations, emissions control equipment and safety.

2. TECHNICAL CONSIDERATIONS

2.1 Estimated Boiler Performance and Expected Plant Performance

Firing hydrogen will impact combustion-zone radiation rates and convection heat transfer surfaces. Achieving design steam temperatures and full boiler output will be challenging for a boiler originally designed to different fuel. Furnace exit gas temperatures are expected to be higher due to its higher adiabatic flame temperature which may increase tube-metal temperatures and may require tube material changes. In other cases, steam temperature derates may be seen since hydrogen firing requires a significant reduction in combustion air when compared to other fuels, i.e., coal or natural gas, which reduces the flue gas flow rate and rate of heat transfer.

Radiation heat transfer is also expected to be impacted when firing higher amounts of hydrogen. Although hydrogen has a higher adiabatic temperature and dependent on the fourth power of absolute temperature, soot radiation will be eliminated which provides significant amount of radiation heat transfer with other hydrocarbon fuels. Therefore, it is recommended to perform a boiler thermal analysis to determine the effects of burning hydrogen in an existing boiler.

Blending or switching to 100% hydrogen fuel will decreases boiler efficiency since during combustion hydrogen is converted to water. Evaporating this water uses a portion of the flue gas energy, thus, lowering boiler efficiency. Auxiliary power demand is reduced with hydrogen firing due to the significant reduction in required combustion air, which would impact the FD and ID fans. If switching from coal, pulverizers, primary air (PA) fans, precipitators, coal and ash handling systems, sootblowers, and other equipment are no longer required.

Net Plant Heat Rate (NPHR) will change due to the changes in boiler efficiency, power output limitation, and auxiliary power usage. More accurate NPHR estimates can be calculated based on unit-specific design, operating parameters and the current fuel being fired.

2.2 Hydrogen Combustion

Increased hydrogen firing on an existing combustion system will have unique challenges and require important design considerations when compared to other fuels. These unique challenges include lower heating value on a volume basis, higher flame speed, higher adiabatic flame temperature, and a reduction in combustion air requirements. These major differences are discussed below.

Table 1. Key Fuel Properties

Fuel and Combustion Properties	Hydrogen (H_2)	Methane (CH_4)	Propane (C_3H_8)
LHV, Btu/lb	51,625	21,495	19,937
LHV, Btu/scf	275	912	2,385
Flame speed, ft/s	9.91	1.37	1.41
Ignition temperature, deg-F	1,062	1,170	919
Adiabatic flame temperature, deg-F	3,807	3,542	3,610
Combustion air, scf/mmbtu	8,667	10,439	9,979
Flue gas, scf/mmbtu	10,488	11,535	10,818
Wobbe index, WI	1,228	1,361	2,101

2.2.1 Heating Value

Hydrogen has a higher heating value than most fuels but has a one of the lowest heating values on a volume basis due to its low molecular weight (refer to Table 1). Having a lower volumetric heating value will contribute to higher volumetric flow rates which needs to be considered if existing fuel infrastructures are used for higher amounts of hydrogen i.e., higher pressure drop and velocities.

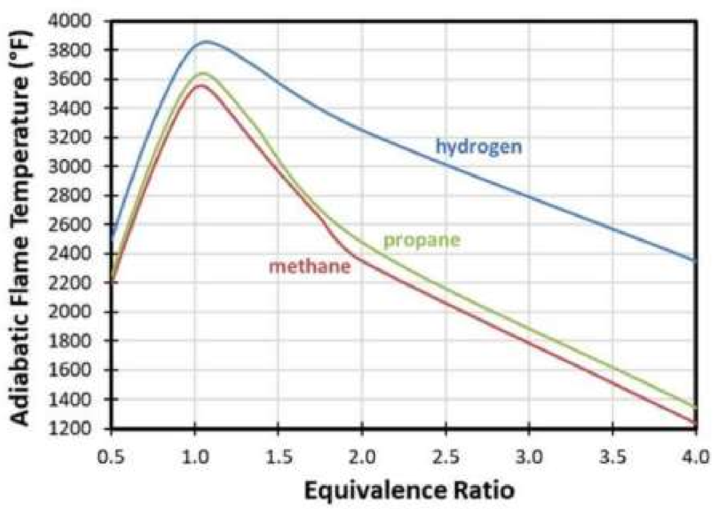
2.2.2 Flame Speed

Hydrogen's flame speed is approximately 7 times faster than natural gas, which is a concern for premix burners due to flashback. Flashback occurs when gas velocity existing the burner is slower than the flame speed, which will cause burner component damage.

2.2.3 Adiabatic Flame Temperature

Figure 3 highlights the change in adiabatic equilibrium flame temperature with varying stochiometric conditions, with the peak temperature near an equivalence ratio of 1.0. The adiabatic flame temperature for hydrogen is higher when compared to other gaseous fuels.

Figure 3. Adiabatic Equilibrium Flame Temperature vs. Equivalence Ratio for Gaseous Fuels (air and fuel at 77 deg-F)



2.2.4 Combustion Air and Flue Gas Flowrate Impacts

Combustion air and flue gas flowrates are expected reduce significantly (refer to Table 1 above). The stoichiometric air requirements for hydrogen is approximately 20% less than when compared to natural gas. Energy savings is expected from reduced capacity needed on the FD and ID fans.

2.3 Code Requirements

All hydrogen system piping from the property fence line to the boiler burners fronts are in accordance with applicable requirements of:

- ASME B31.1, Power Piping and ASME B31.12, Hydrogen Piping and Pipelines
- NFPA 2, 70, 497, 85

Due to its low molecular weight, hydrogen is more likely to leak compared to other fuels. Additional leak detection or the use of welded components are a couple of approaches to monitor and minimize leaks.

Under conditions of elevated temperature, pressure, or applied stress, hydrogen embrittlement of metals can be a problem and should be evaluated on each case to determine appropriate materials of construction for the fuel delivery system. As discussed earlier, hydrogens lower volumetric heating value will contribute to higher volumetric flow rates which will increase pressure drop and velocities if used in existing natural gas balance of plant systems. In cases where varying mixtures of hydrogen will be used, a Wobbe Index meter is recommended to help monitor the varying fuel compositions and allows the combustion control system to properly adjust air to fuel ratios.

2.4 Burner Technologies

2.4.1 Low-NO_X Natural Gas Burners

Low-NO_X burners (LNBs) limit NO_X formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced peak flame temperature, and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower NO_X emissions during the combustion process. These burners are not a concern when firing higher amounts of hydrogen since air and fuel isn't mixed prior to combustion. In addition, most LNBs are designed with higher alloy materials near the burner tips which may be suitable for higher flame temperature when firing hydrogen but needs to be evaluated. Since most igniters are considered small premix burners, flashback becomes a concern. Modifications or redesign of the igniters are likely required for high percentages of hydrogen, such as a new hydrogen igniter or using a NFPA 85 Class 3 special igniter.

2.4.2 Duct Burners

Firing higher amounts of hydrogen in existing duct burners will likely require modifications which may include changes to the element size and existing gas tips due to higher volume flowrates. Changes in the duct burner metallurgy may be require due to higher flame temperatures.

2.4.3 Flame Detection

A hydrogen flame has a wavelength of approximately 300 nm, which is typically in the range for most UV/IR flame scanners. Although flame scanner tuning may be required, recent testing concluded no major issues with flame detection when firing either 100% natural gas or 100% hydrogen. Another flame detection technology is flame rods. Flame rods may have challenges since hydrogen produces a weaker flame signal which will impact flame signal and inconsistencies with burner operation.

2.5 Emission Control Equipment

Firing hydrogen instead of hydrocarbon fuels eliminates soot, carbon monoxide, carbon dioxide, and unburned hydrocarbon emissions since there is no carbon in hydrogen. Although most emissions are drastically eliminated or reduced, NOx emissions are expected to increase significantly when firing higher amounts of hydrogen.

2.5.1 NO_X Control

The formation of NO_X is determined by the interaction of chemical and physical processes occurring within the boiler. There are two primary forms of NO_X: *thermal* NO_X and *fuel* NO_X.

Since hydrogen has no nitrogen content, NO_X formation through the fuel NO_X mechanism is nonexistent. Therefore, the principal mechanism of NO_X formation in hydrogen combustion is thermal NO_X, which results from the oxidation of nitrogen in the combustion air contained in the inlet gas in the high-temperature, post-flame region of the combustion zone.

The major factors influencing thermal NO_X formation are temperature, the concentration of oxygen in the inlet air, and residence time within the combustion zone. LNB technology can affect thermal NO_X formation by regulating the distribution and mixing of the fuel and air to reduce flame temperatures and residence times at peak temperatures.

Several methods are available to effectively limit NO_X formation during combustion, as summarized below.

- Increase the size of the furnace
- Control peak flame temperatures below 2800°F
- Add flue gas recirculation to the combustion air to lower flame temperature
- Reduce excess air

2.5.1.1 Flue Gas Recirculation

Flue gas recirculation (FGR) controls NO_X by recycling a portion of the flue gas from the economizer outlet and back into the primary combustion zone in the windbox. The recycled air lowers NO_X emissions by (1) lowering the combustion temperature; and (2) reducing the O_2 content in the primary flame zone.

Our experience also suggests that the mixed flue gas/combustion air flow supplied to the windbox should be not lower than approximately 16% O_2 because lower O_2 content impacts flame stability.

An FGR system may also increase heat absorption in the convection pass, resulting in increased boiler tube temperatures and attemperation rates. Increased flue gas flow rates would be a concern regarding boiler tube-metal temperatures; however, lower excess combustion air with natural gas firing will tend to reduce the overall flue gas flow increase. In most cases, steam temperatures and attemperation feedwater flows assist in maintaining design steam temperatures.

Existing attemperators, valves, and piping often include design margins allowing these components to work on a gas-converted boiler without modification.

NFPA 85 requires that an FGR system be provided with either the ratio of flue gas to air or to the oxygen content of the mixture. Oxygen analyzers typically are supplied downstream of the FGR mixing area in the windbox since duct space is limited for a flow measurement system. These analyzers will monitor the oxygen content of combustion air and alert the operator if oxygen is being overly diluted, which may cause the flames to become unstable.

2.5.1.2 Selective Catalytic Reduction

In the event that NO_X cannot be adequately controlled with an LNB and FGR, it may be necessary to use a selective catalytic reduction (SCR) system. SCR is a process in which ammonia reacts with NO_X in the presence of a catalyst to reduce the NO_X to nitrogen and water. The catalyst enhances the reactions between NO_X and ammonia, according to the following reactions:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

$$4\ NO_2 + 8\ NH_3 + 2\ O_2 \rightarrow 6\ N_2 + 12\ H_2O$$

The location for this process is normally downstream of the economizer and upstream of the air heater. Static mixers typically are not installed in gas units, as high ammonia slip of 5-10 ppm can be tolerated. An injection grid can be used to distribute reagent uniformly across the entire flue gas path.

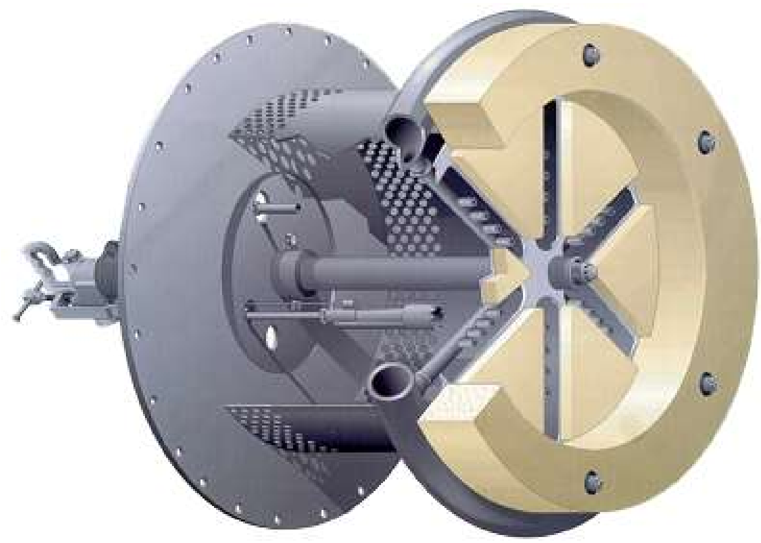
We find that most existing SCR systems on gas-fired boilers can be reused when firing higher amounts of hydrogen but should be evaluated before doing so.

3. CASE STUDY

Our QLN burner was tested on high amounts of hydrogen in 2021 as part a large burner order for an international project. This burner technology is also used heavily in Canada where the QLN technology has >90% market share. As discussed earlier in this paper, the Canadian market has expressed interest in increasing hydrogen capacity and usage.

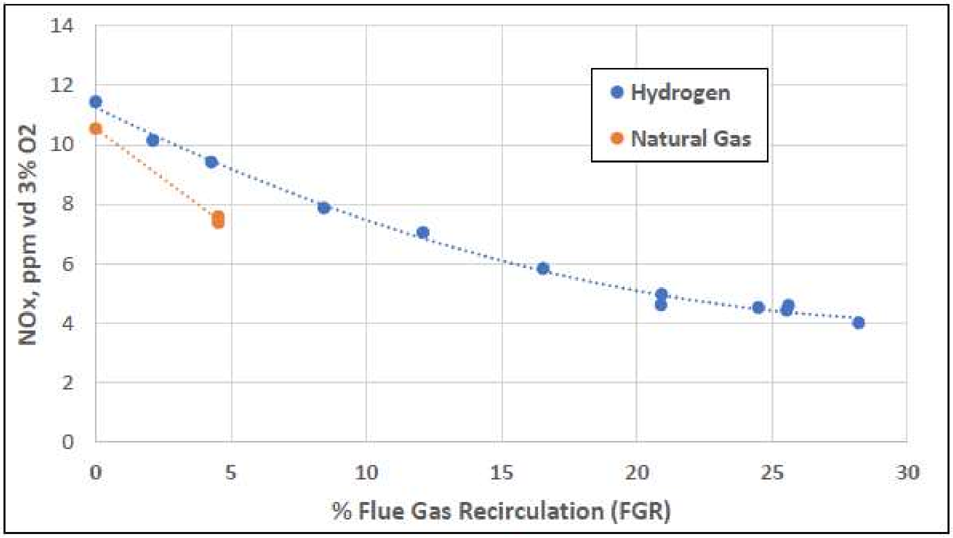
Hydrogen in the QLN burner was found to produce very reliable and stable combustion. Due to the wide flammability of the fuel, the burner technology could be adjusted to maximize fuel staging to greatly offset the NOx impact of higher flame temperature from the hydrogen fuel. NOx emissions with pure hydrogen matched closely with the emissions achieved on natural gas. Field data is required to finalize NOx predictions for hydrogen applications, but the data provides confidence that the current prediction methods used in design tools offer a conservative lower-risk prediction for evaluating new opportunities.

Figure 4. Isometric View of QLN Burner



Additional tests were conducted utilizing FGR to evaluate the effect on NOx reduction. Due to lack of a strong recirculation zone and swirl, the QLN burner is generally not considered as technology that is compatible with FGR, however, since the flammability range with hydrogen is much wider, it was thought high levels of FGR could still be utilized with this fuel. As expected from previous experience, natural gas performance was limited to ~5%FGR. Operation became unreliable if FGR flow was increased further. For hydrogen firing, the predicted increase in burner stability was valid; very high levels of FGR could be utilized. The maximum test point used nearly 30% FGR to make 4ppm stack NOx. The NOx performance at 17MMBH (LHV) with natural gas and hydrogen with varying levels of FGR can be found in Figure 5.

Figure 5. NOx Performance with Varying FGR Flowrates



Generally, the NOx predictions utilizing our NOx model provided accurate predictions within ±10%. A surprising test result was the optimum NOx achieved with Hydrogen fuel matched the NOx achieved with natural gas. Higher NOx was expected, both due to the NOx model from the increase in adiabatic flame temperature as well as the trend found from the test burner data.

This NOx data could be optimistically utilized to predict emissions currently achieved for QLN burner applications with natural gas and retrofitted for hydrogen firing.

4. CONCLUSION

Interests in hydrogen firing continues to grow on a global scale, particularly in the power and refinery industry, as a viable CO_2 emissions reduction approach when using either green or blue hydrogen. National policy and other initiatives across the world are working to accelerate hydrogen hubs. Depending on infrastructure and production capacity, regions may be positioned to consume and/or consume higher rates of hydrogen. Increased hydrogen firing on an existing combustion system will have unique challenges and required important design considerations when compared to other fuels. These unique challenges include a higher flame temperature, higher flame speed, lower heating value on a volume basis and a reduction in combustion air requirements. With these challenges, it is recommended to perform a boiler thermal analysis to determine the effects of burning hydrogen in existing boiler.