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Impact of Hydrogen/Natural Gas Blends on Partially Premixed Combustion Equipment: NO_x Emission and Operational Performance

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Abstract: Several North American utilities are planning to blend hydrogen into gas grids, as a short-term way of addressing the scalable demand for hydrogen and as a long-term decarbonization strategy for 'difficult-to-electrify' end uses. This study documents the impact of 0–30% hydrogen blends by volume on the performance, emissions, and safety of unadjusted equipment in a simulated use environment, focusing on prevalent partially premixed combustion designs. Following a thorough literature review, the authors describe three sets of results: operating standard and "ultra-low NO_x" burners from common heating equipment in "simulators" with hydrogen/methane blends up to 30% by volume, in situ testing of the same heating equipment, and field sampling of a wider range of equipment with 0–10% hydrogen/natural gas blends at a utility-owned training facility. The equipment was successfully operated with up to 30% hydrogen-blended fuels, with limited visual changes to flames, and key trends emerged: (a) a decrease in the input rate from 0 to 30% H_2 up to 11%, often in excess of the Wobbe Index-based predictions; (b) NO_x and CO emissions are flat or decline (air-free or energy-adjusted basis) with increasing hydrogen blending; and (c) a minor decrease (1.2%) or increase (0.9%) in efficiency from 0 to 30% hydrogen blends for standard versus ultra-low NO_x-type water heaters, respectively.

Keywords: hydrogen; natural gas; combustion; partially premixed; water heater; furnace; appliances; NO_x emissions; hythane; hydrogen-blended gas

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1. Introduction

The interest in hydrogen in North America on the part of the energy industry is growing rapidly, as a means of supporting climate change mitigation goals with this flexible low-carbon energy carrier. As an energy vector, not unlike electricity, low-carbon hydrogen can be generated in multiple ways, as a means of storing renewable energy ("green" H_2) or decarbonizing fossil natural gas with integrated carbon capture ("blue", "turquoise" H_2). This flexibility has driven a rapid scale up in investment and interest, from numerous utilities initiating programs to inject hydrogen into natural gas networks to Canada's national hydrogen strategy and the U.S. Dept. of Energy's Earthshot program to reach a goal of USD 1/kg H_2 [1,2].

The scale of the decarbonization challenge is not trivial, with a combined U.S./Canadian natural gas network of 5.4 million km serving 85 million homes and businesses, where natural gas combustion in U.S. and Canadian buildings and industry are responsible for a combined 1077 Mt CO_2e/year [3–6]. However, with significant potential as a decarbonized energy vector, blending hydrogen into gas grids serving buildings and industry can serve as both an important short-term way of addressing the scalable demand for hydrogen, driving down costs of generation, storage, and distribution and an important long-term strategy to decarbonize 'difficult-to-electrify' end uses, including those with significant thermal demands, in older buildings, and in cold climates [7–9].

Hydrogen utilization represents one of several important and emerging shifts in the energy industry towards broad decarbonization. While this concept is not new, with North American development of the "green hydrogen" concept going back to the 1970s [10], only recently are multiple large-scale pilots and demonstrations underway, as summarized in Table 1. These efforts build on a prior coordinated shift from one piped gas to another, the transition from manufactured gas to natural gas in the early 20th century. This prior transition is covered well by Tarr in a comprehensive historical account, highlighting that industry-wide, the full transition took 30 to 40 years to accomplish, with the greatest effort concerning the conversion of end-use equipment [11].

Table 1. Selected North American hydrogen/natural gas blending demonstrations.

Location	Details of Demonstration *
Canada—Alberta [12]	ATCO Gas will inject 5% of H_2 by volume starting in late 2022, in a section of its customer network serving approximately 2000 customers.
Canada—Ontario [13]	Enbridge Gas will inject 2% H_2 by volume in a network serving approximately 3600 customers in the Toronto metropolitan area in 2022.
US—California [14]	A joint effort of San Diego Gas & Electric and SoCalGas to perform multiple demonstrations of blending initially from 1 to 5% H_2 by volume up to 20%, in multiple portions of their networks, from 2021 to 2026.
US—Utah [15]	Beginning with 5% H_2 injection at a training facility in the Salt Lake City region, Dominion Energy may expand to customer networks starting in 2022.
US—Oregon [16]	Testing at training facility at 5% H_2 blended, NW Natural may also expand into customer networks into 2022–2023.
US—Hawaii [17]	Not a blending demonstration per se, but Hawaii Gas has long operated a distribution network on Oahu delivering a manufactured gas containing 10–15% H_2 by volume serving approximately 30,000 customers.

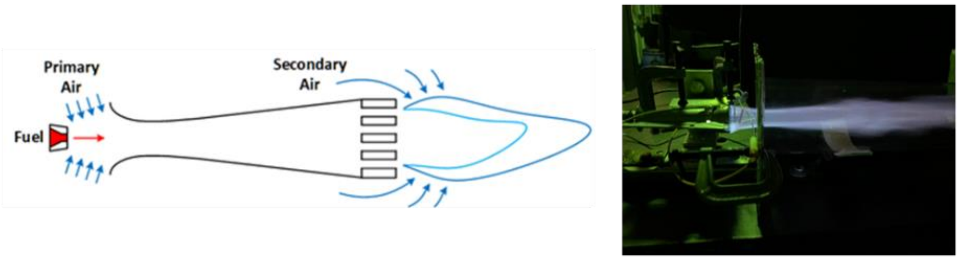
* Information current as of 2021.

Concerning these risks of blending hydrogen into the existing natural gas networks in the U.S., several excellent overviews were performed with focus on infrastructure concerns, including a National Renewable Energy Laboratory (NREL) and Gas Technology Institute (GTI) technical review focused on pipeline distribution concerns [18], followed by two comprehensive industry reviews, prepared jointly for the American and Canadian Gas Associations and the Pipeline Research Council International, respectively. Additionally, the heating, ventilation, air-conditioning, and refrigeration (HVAC/R) industry commissioned its own review with a focus on end use equipment [19]. Studies largely point to the European "NaturalHy" Project [20], from 2004 to 2009 that concluded that minor adjustments to equipment in Europe could accommodate fuel blends with up to 20% hydrogen by volume, though given variations in equipment in the U.S. versus Europe, the 2013 study pointed to 5–15% as a range that would "appear to be feasible with very few modifications to existing pipeline systems and end-use appliances" [18]. More recent industry reviews agreed that up to a 20% limit was generally suitable, though the HVAC/R industry's detailed failure analysis approach concluded that only currently (as of 2021) produced equipment should be safe to operate with up to a 20% hydrogen blend, provided that no adjustments are made regarding the reduction in heating capacity, a conclusion largely based on an attempt to certify one piece of North American equipment in Europe [13]. Citing the efficiency benefit of newer products, the study also recommended that existing equipment be replaced and did not specify a hydrogen blend tolerance for equipment currently in operation [19].

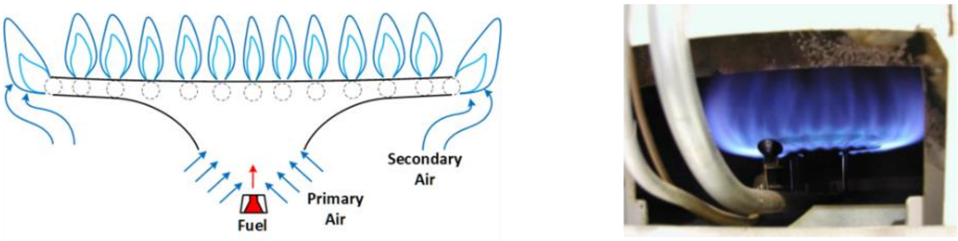
Up until recently, most investigations of blended hydrogen's impacts on building equipment, including the highly cited "NaturalHy" project [20], were performed in Europe, and the equipment evaluated differed from that in use in the U.S. and Canada. However, with the growing interest in hydrogen's role as a low-carbon energy carrier, in addition to the continued research in Europe [21], there is a renewed interest in North America, with recent laboratory investigations by UC Irvine [22] and Appliance Engineering [23], in addition to the work described in this paper.

Using a laboratory and field-based approach, the authors investigated the impact of hydrogen-blended natural gas on conventional unadjusted fuel-fired equipment frequently found in North American buildings, specifically the impact on this equipment's performance, emissions, and safety in a simulated use environment. In these buildings, where natural gas (>95% methane) remains the predominant fuel for heating, this study focuses on space and water heating equipment, which consumes 95–97% of natural gas in these applications [24,25], with simplified diagrams of these burners shown in Figure 1. Miscellaneous appliances such as hearth products and cooking equipment, in addition to water heaters and furnaces, were also examined in a field environment, focusing on partially premixed equipment and the resulting NO_x emissions. While residential-sized equipment is evaluated in this study, note that the designs examined are often simply scaled-up in size for commercial building applications, where variants of burners shown in Figure 1 are applied in residential-sized and commercial-sized equipment alike.

"In-Shot" Warm-air Furnace Burner (< 40 ng NOx/J)



Standard NOx Water Heater Burner (< 40 ng NOx/J)



Ultra-Low NOx Water Heater Burner (< 10 ng NOx/J)

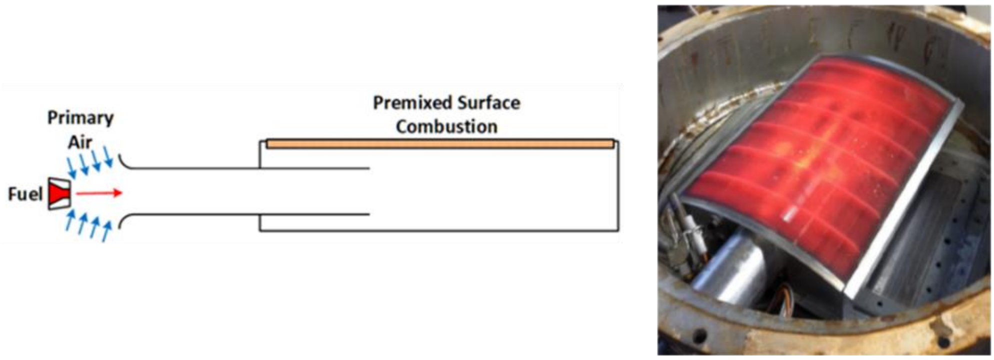


Figure 1. Primary burner types investigated.

With a focus on the U.S. and Canadian context, the goal of this study is to (a) perform a thorough review of the current state of knowledge concerning the performance and emissions impacts of hydrogen-blended natural gas on typical combustion equipment in homes and businesses, (b) expand these datasets with laboratory and field-based sampling of partially premixed type burners and combustion equipment operating with up to 30% hydrogen blends, with a focus on operational performance and NO_x emission impacts, and (c) draw distinctions between common variations, including natural versus induced draft, high versus standard efficiency, and standard versus "ultra-low NO_x" designs.

2. Background

For combustion equipment designed to operate with standard gaseous fuels (natural gas, liquified propane, and manufactured gas), hydrogen presents numerous challenges as a fuel when blended, including its faster flame speed, increased flame temperature, reduced volumetric density, wider flammability range, reduced flame luminosity, and other factors [21–23]. Appendix A provides an overview of the fuel gas quality impacts of blending hydrogen into natural gas.

As apparent in the aforementioned reviews, predicting the tolerance of blended hydrogen in the wide array of combustion-based end-use equipment is challenging, in large part due to the limited datasets available. For earlier studies, hydrogen tolerance of existing end use equipment was based largely on a small number of older European studies [18], while more recent assessments analyzed an expanded dataset for residential and commercial-sized equipment; however, they remain limited (<30 pieces of equipment) [19]. This presents a challenge to utilities when considering the injection of hydrogen into existing natural gas networks, as the short-term and long-term impacts on the wide diversity of combustion equipment downstream remain uncertain.

$$\text{Combustion Air Requirement} = \frac{(\text{Air to Fuel Ratio})_{\text{stoichiometric}}}{\sqrt{\text{SG}_{\text{fuel}}}}$$

2.1. Equipment Testing Data

Despite noted challenges with predicting equipment impacts on gas quality alone, for fuel-fired heating and cooking equipment in North America considered in this study, general trends do apply to the major combustion system types with hydrogen blending. As with this study, the following applies to "moderate" levels of hydrogen blending into natural gas at or less than 30% by volume, though equipment-specific impacts can vary:

1. All unadjusted equipment will see reductions in heating output with increased hydrogen added. For steady-state (i.e., on/off) equipment, manual adjustments are possible, but may not be necessary. For equipment meeting a thermal demand, equipment may be manually or automatically adjusted to compensate, and unadjusted equipment will compensate with longer runtimes.
2. Partially premixed combustion systems will likely see an increase in primary aeration, resulting in the potential for concerns with flame stability and temperature, leading to flashback and increased thermal NO_x emissions, respectively. However, the available test data show that for moderate ranges of blending (<30%), flame stability is generally not an issue and NO_x emissions are stable or decline [22,23], as will also be shown later in this paper. As a class, these are the most common combustion system types in North America, due to low cost and high reliability, including most furnaces, water heaters, boilers, cooking equipment, and hearth products.
3. Premixed combustion system impacts will vary by the control of fuel/air mixing, as the impact of hydrogen addition varies accordingly. For common pneumatically controlled fuel/air mixing, the air flow remains approximately constant as hydrogen is added, and thus combustion shifts to being leaner (λ increases), which can counteract the impact hydrogen has on flame temperature, speed, and stability. For electronically (or "digitally") controlled fuel/air mixing, often a constant-λ approach is employed, the equipment automatically compensates for the change in fuel properties with added hydrogen, requiring additional compensation to avoid flame stability issues. Premixed systems are commonly used in high-efficiency equipment where the precise control

and modulation can be valued, and pressurization of the combustion chamber(s) is needed to overcome heat exchanger pressure losses. Examples of common equipment classes that utilize premixed combustion include tankless water heaters, combi boilers, fuel-fired heat pumps, micro-combined heat and power, and equipment required to meet ultra-low emission requirements (<14 ng NO_x/J).

4. Non-premixed (diffusion) combustion systems have a greater tendency towards flame lift, though these have been observed to be minor in practice at moderate ranges of blending (up to 30%). While there are many examples of non-premixed combustion in daily life, from candle flames to wood fires, these are not common with gaseous fuels due to the poor combustion control. Examples are limited to decorative flames (e.g., gas lights), log lighters, and individual pilot lights.

While published datasets of equipment testing are scarce, an excellent review provided additional insights, largely based on the testing of European-style premixed combustion systems (e.g., hot water domestic boilers) [21]. Broadly, with increasing hydrogen blending, efficiency impacts are generally small (<2%) or within measurement error. Flame ionization sensors showed measurable declines in the control signal requiring further investigation; however, this impact did not warrant overall safety concerns. Similarly, an impact on ignition was not observed for hydrogen addition. The impact on flame temperature was mixed, though generally studies showing the region near the flame did increase in temperature but combustion chamber temperatures declined due to the increase in excess air levels. Regarding emissions, generally CO and NO_x emissions are shown to decrease or remain the same with added hydrogen. Regarding flame stability issues such as flashback, this is observed in some studies with higher hydrogen blend ratios, at or above 20% for fuel-rich combustion and at or above 40–50% for standard combustion. These stability issues are not well characterized in the literature, some appearing to be random, and cannot be explained by hydrogen addition alone [21].

For the North American context, these findings do not always translate to the prevalent partially premixed combustion-type water heaters, furnaces, and cooking equipment. Two recent datasets provide insights on North American appliances, though studies differed in the equipment tested, the operating conditions, the test method and instrumentation employed, and the analytical approaches. Additionally, one study included the operation of all equipment at 5 and 15% hydrogen blended with methane, while the second study varied the blending ratio into natural gas by appliance, depending on observations and experimental limitations. With these disclaimers noted, the following consistent results between datasets concerning furnaces, boilers, and water heaters that primarily use partially premixed combustion system designs can be observed [22,23,26–28]:

1. Equipment de-rating was a consistent result, wherein hydrogen blending decreases the input rate of equipment that the shift in Wobbe Index generally underpredicts, where more than a 3.5% de-rate is observed at 15% H_2 in most instances.
2. The impact on CO and NO_x emissions from unadjusted equipment with hydrogen blending is inherently complex and it is a common misconception, particularly for NO_x, that hydrogen blending rates are proportional to rates of emissions. In principle, unadjusted partially premixed equipment will experience competing factors towards CO and NO_x emission increases owing to the shifts in the gas quality and availability and distribution of combustion air. In most cases, for the furnaces, boilers, and water heaters, the 15% H_2 case had CO emissions within ±10 ppm air-free (AF) from baseline and NO_x emissions ±5 ppm AF from baseline, though some boilers saw significant decreases from the baseline of both. In all cases, the overall fuel/air ratio shifted lower as predicted, as observed with stack O_2 and CO_2 measured.

The current study seeks to both (a) expand the dataset for a broader range of equipment types, with variation within categories (high vs. low efficiency) and (b) quantify these impacts through steady and dynamic experiments, simulated use and extreme scenarios, from 0 to 30% hydrogen blends.

2.2. Partially Premixed Burner Typologies

Figure 2 schematically illustrates the three types of burners tested in the laboratory as part of this study. These burners belong to a broader category of "self-aspirating" or "inspirating" burners, whereby some or all the air required for combustion is entrained into the burner body by an expanding fuel gas jet through momentum transfer. Most commonly, these types of burners are implemented as "partially premixed" burners, where less than 100% of the air required for complete combustion is injected as "primary air". "Secondary air" is then required to complete combustion outside the burner body. Flames from these types of burners exhibit a distinct "double flame" structure, where a bright inner-cone of a rich-premixed flame is visible, surrounded by a duller outer cone diffusion flame. Gas manifold pressures of 3.5–12 mbar are commonly used with these types of burners to inject gas into the body of the burner. Both the "pancake" water heater and the "in-shot" burners illustrated in Figure 2a,b are examples of partial premix systems. Other types of appliances where these styles of burners are common include gas ranges, clothes dryers, decorative fireplaces, space heaters, older boilers, grills, commercial ovens and fryers, among others.

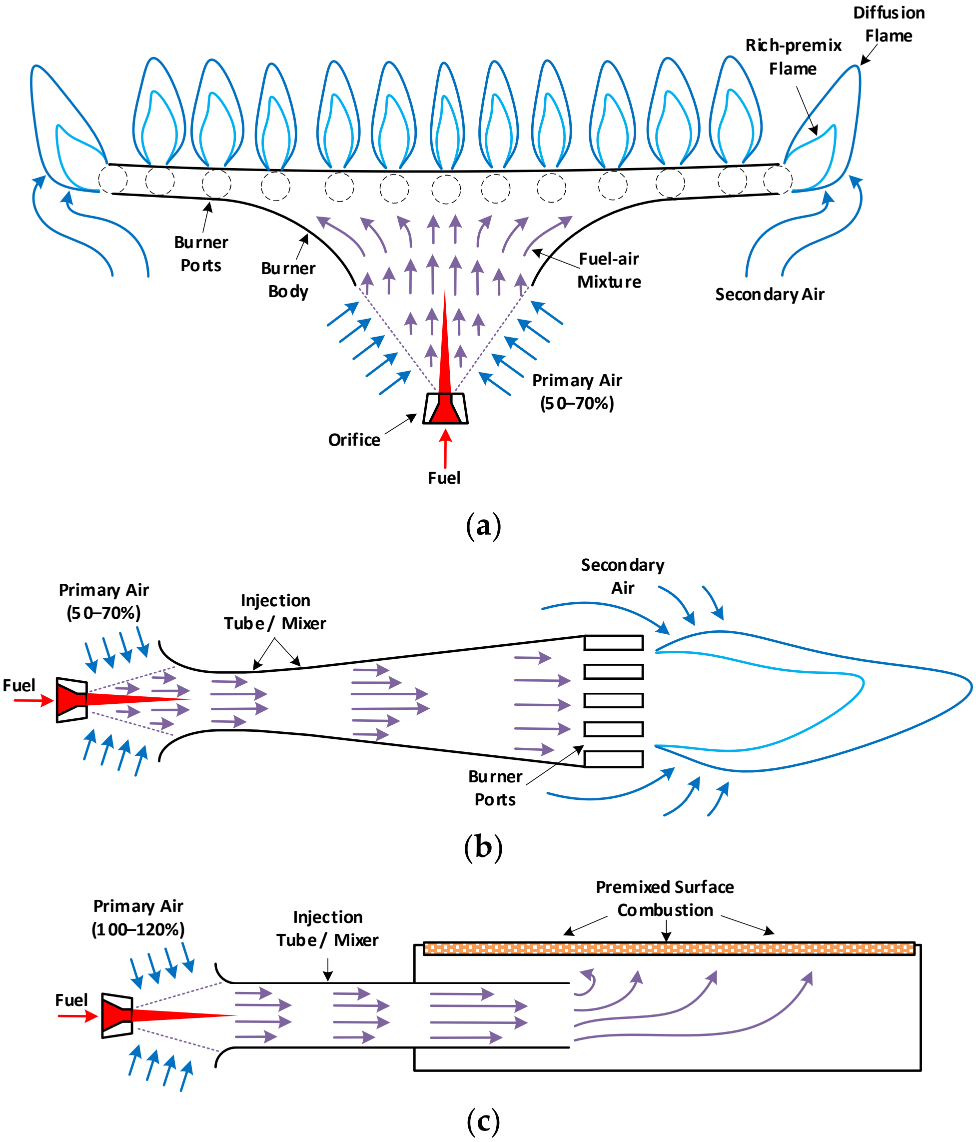


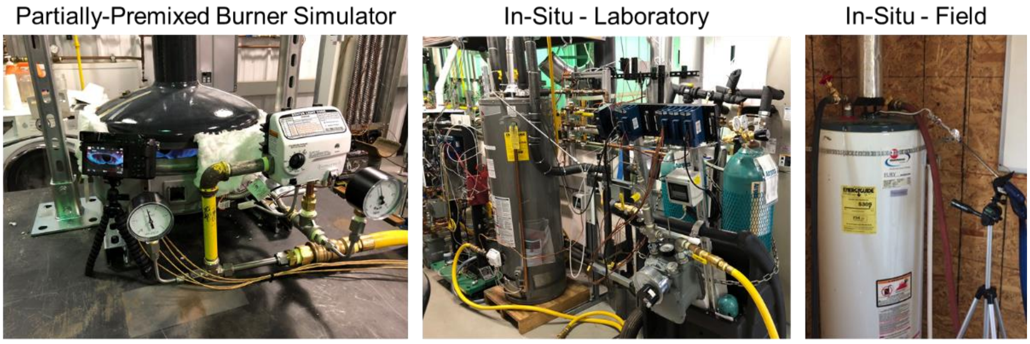
Figure 2. Schematic illustrations of typical North American atmospheric burners, including: (**a**) a "pancake" partially premixed burner from a storage water heater; (**b**) an "in-shot" partially premixed burner from a modern residential furnace; (**c**) an premixed ultra-low NO_x burner from a storage water heater.

The prevalence of partially premixed burners in North America can be in the large part attributed to their low cost (often stamped steel or cast iron), simplicity (can be unpowered), as well as stable and efficient operation [29]. The amount of primary air injected is typically 50–70% [30], leading to a rich-premix flame with a laminar speed of less than 50% of the maximum [31]. The reduced flame speed makes the burner more resistant to flashback, while consuming most of the fuel. To complete combustion, secondary air is entrained into a diffusion flame either through a naturally induced draft (pancake) or a forced draft (in-shot). In the latter case, induced draft is required to allow the burner to operate in a horizontal orientation without allowing the flame to impinge on the heat exchanger (common in North American furnaces).

Additionally illustrated in Figure 2c is a unique fully premixed self-aspirating burner. In North America, these types of burners are used for ultra-low NO_x water heaters, as required by local laws in both California and Utah. To achieve ultra-low NO_x levels of emissions, these burners rely on a radiant screen (metal wire, perforated plate, or ceramic) to absorb some of the heat of combustion and radiate it back out along the surface. This phenomenon has the effect of reducing the gaseous flame temperature and stabilizes the flame near the surface with an overall smaller reaction volume [29,30]. This in turn reduces the formation of NO_x [32]. What makes the burner in Figure 2c unique is how it achieves fully premixed operation. Instead of using a blower and a pressurized combustion system, the burner in Figure 2c relies on self-aspiration to inject nearly 100% of the air required for complete combustion (by means of a large port area [30]). To get up to 115–120% of stoichiometric air for complete combustion, this burner relies on a natural draft established inside the water heater flue to draw additional air through the burner inlet, which is positioned outside the combustion chamber (i.e., the burner outlet is at a negative pressure relative to the burner inlet). Regardless of whether they are partially or fully premixed, the types of burners depicted Figure 2 have operating characteristics (firing rate, fraction primary air, and port loading) that are sensitive to the geometry, operating conditions, as well as the gas properties. While a self-aspirating burner can be designed to operate using any type of gaseous fuel [30], if the fuel properties suddenly change, the same burner may become susceptible to flashback, flame lift, or other instabilities.

3. Methods

In this study, a comprehensive approach was used to characterize the impacts of hydrogen blended with natural gas on common North American fuel-fired equipment. First, the authors built and operated two partially premixed combustion system "simulators" to represent a storage-type water heater and warm-air furnace combustion chambers. These simulators were used to evaluate common burners and their controls, while permitting imaging and direct observation of qualitative impacts on flame appearance, stability, and other factors. Second, the authors identified and acquired five appliances, including conventional (standard NO_x) and ultra-low-NO_x versions, and designed flexible test stands to evaluate each appliance with natural gas mixtures with increasing hydrogen content, with a focus on mass-market products. For these laboratory tests, the burners and equipment were operated with pipeline natural gas and mixtures of methane/hydrogen ranging from 0 to 30% hydrogen by volume. Finally, the authors travelled to a North American utility-owned training facility, consisting of a collection of small buildings, to perform field sampling of emissions from fifteen (15) appliances that included water heaters, furnaces, ranges, ovens, dryers, and a fireplace. In the field, emission measurements were taken for all appliances operated with 100% natural gas and a blend of approximately 5% hydrogen and 95% natural gas, with one water heater also tested at a 10% hydrogen blend. While many aspects of equipment operation were examined, the primary focus concerned the measured emissions of NO_x. Figure 3 below highlights this progression of testing for water heaters, from the simulator, to in situ testing in the laboratory, and then the field.


Partially-Premixed Burner Simulator
In-Situ - Laboratory
In-Situ - Field

(**a**) (**b**) (**c**)

Figure 3. Example of approach with: (**a**) water heater simulator testing; (**b**) laboratory testing; (**c**) field testing.

3.1. Laboratory Testing

Two sets of tests were performed with a focus on the two primary categories of equipment in North American homes, the fuel-fired storage-type water heater and the warm-air furnace, one or both used in more than half of North American homes [24]. Custom fueling rigs were built for open air and in situ testing, which fed the experimental equipment with natural gas, 100% methane, and hydrogen/methane mixtures from 5 to 30% hydrogen with increments of 5%. An upper limit of 30% was selected a priori due to the anticipated suitability with most equipment, based on the literature review and discussions with manufacturers; however, this is not suggestive as an upper limit of hydrogen tolerance for any equipment tested. Fuel mixtures were supplied from cylinders with a simplified process, and the instrumentation diagram of the fueling rig is shown in Figure 4, while the instrumentation, analyzers, and other equipment used are listed in Table 2 below. The semi-portable fueling rig comprised a cylinder cart and an instrumentation cart which allowed the rig to be easily moved around to various test locations. No filters were used with either the gas from the cylinder or from the building supply. The gas supply from the high-pressure cylinders was allowed to expand naturally, resulting in a ~6 °C degree drop in some instances. An improvement for the future will be to better control the gas supply temperature, which varied in the present study by 5–6 °C.

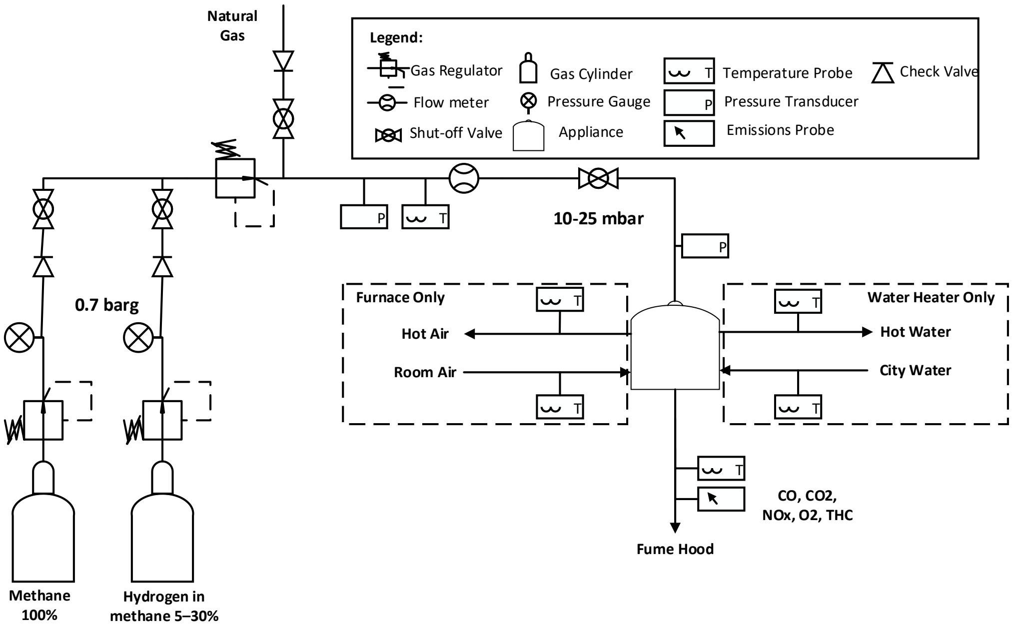


Figure 4. Simplified Process and Instrumentation Diagram (P&ID) of experimental fueling rig.

Table 2. Summary of instrumentation used in simulator and in situ laboratory testing.

Measurement	Instrument/Analyzer Used	Calibration Range/ Instrument Accuracy
Total Hydrocarbons (THC)	Rosemount Analytical 400A	800 ppm
NO_x (NO and NO_2)	Ecophysics CLD 700EL	80 ppm NO
O_2	Rosemount Analytical X-Stream	8% O_2
CO/CO_2	Rosemount Analytical X-Stream	400 ppm CO, 18% CO_2
Fuel Pressure	Dwyer ISDP-008	±31.1 Pa
Fuel Flow	Elster DTM-200A Gas Meter	±1% of reading (prec.: 17.7 pulses per L)
Gas/Air Temperatures	T-type/K-type thermocouples	±0.75% of reading
Atmospheric Pressure	Traceable Excursion-Trac Barometer	±406 Pa
Water pressure	Ashcroft G2 (0–6.9 bar)	±1.0% full scale
Water Temperatures	Omega P-M-1/10-1/8-6-0-P-3 RTDs	1/10 DIN (less than ± 0.08 °C at 60 °C, less than ± 0.04 °F at 10 °C)
Supply Water Flow	Dwyer MFS2-3	±1% of reading

Regarding the natural gas supplied during testing, house gas analysis of the natural gas supply to the lab showed it to contain 93.5% methane by volume and have a higher heating value of 38.8 MJ/m^3 (1042.4 Btu/scf). For the water heater burners, the ignition process was controlled and the fuel supplied, using an unmodified storage water heater gas valve in simulator testing with a 10.0 mbar manifold pressure. Supply pressure was kept at or slightly above 17.0 mbar. For the furnace simulator, the "high" and "low" firing rates were controlled by manifold pressures of 8.7 and 3.7 mbar, respectively. All in situ testing was initially calibrated to manufacturer requirements with pipeline natural gas conditions and then held constant for methane and hydrogen/methane blends. All tests were performed at an altitude of 196 m above sea level.

3.1.1. Simulator Testing Details

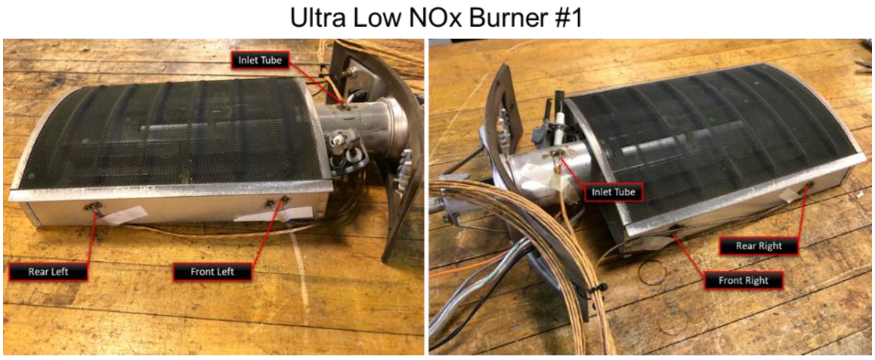
The primary goal with testing using "simulators" of water heaters and furnaces was to gather quantitative and qualitative data on the short-term operation of the appliance burners alone, while providing physical and visual access not afforded by testing equipment (burners in situ). Representing most installed gas-fired water heaters, both the standard and ultra-low NO_x type, and warm-air furnaces in North America, four burners were evaluated using simulators. Burners were removed from appliances, installed in simulated operating environments, and operated with standard controls and boundary conditions (e.g., fuel pressure). Exhaust properties were measured, including temperature and composition, in addition to fuel inlet conditions (temperature, pressure, and flow) and burner surface temperatures at multiple locations. Visually, photography and video were used to capture the dynamic impacts of hydrogen addition on flame ignition, start-up, and steady operation, provided that successful start-up was demonstrated, using a digital single-lens reflex (DSLR) camera.

Test durations were up to 10 min, until loss of flame, or until flame instability and/or an unsafe combustion condition was observed (e.g., >400 ppm CO air-free). If the measured surface temperatures were observed to climb for the duration of the 10 min test period, then the test period was extended such that no appreciable trend of increasing burner surface temperatures was observed for at least 5 min. The purpose of these tests was to observe and record the ignition process, and to determine whether stable combustion was achieved and could be maintained afterwards.

Each burner was first tested with natural gas, then 100% methane, followed by hydrogen–methane mixtures from 5 to 30% hydrogen by volume in increments of 5%. Natural gas served as the baseline for the burner operation and adjustments, with properties such as gas pressures, orifice sizes, and simulator controls held constant for subsequent fuels. Both “cold” and “hot” starts were performed, where the latter represented cycling, operating the burner after a loss of flame/re-light operation. As the blended hydrogen fraction increased, the original objective was to terminate the test at a hydrogen level where instabilities or inconsistent operation were observed. However, in all cases, tests were performed up to the a priori limit of 30%. The following issues of concern were monitored with increasing hydrogen blending:

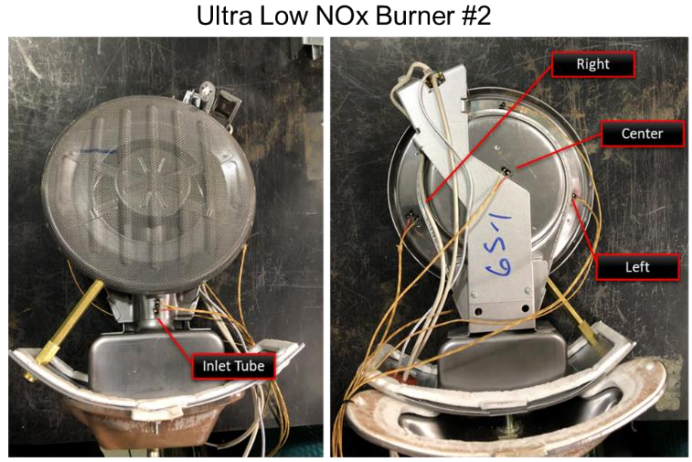
1. Uneven flame distribution and hot spots: particularly for ultra-low NO_x burners. These burners have a larger burner port/flame holder surface area to decrease the flame temperature for NOx control.
2. Overheating of burner material: this could occur in any of the burners, but most readily in the “pancake” and “in-shot” burners because of the higher port loading compared to the other burners.
3. Flashback and/or formation of a diffusion flame at the burner orifice: The higher flame speed and wider flammability range of hydrogen makes it possible for a flame to occur where it would otherwise not be possible with methane or natural gas. The simple flow-through design of the “in-shot” furnace burners makes them particularly susceptible to this.

The water heater simulator (Figure 3) approximated the operating environment of a water heater while providing ease of visual access to the burners. The simulator was based on a combustion chamber and flue segments from an unassembled water heater. The burners were tested in the bottom portion of a water heater combustion chamber, and a storage water heater flue piece was suspended above the combustion chamber with a ~2.5 cm gap between the top of the combustion chamber and the flue section. The gap between the bottom portion of the combustion chamber and the fuel input assembly was partially covered with ceramic fiber insulation to minimize flue gas dilution and to establish a draft for the burners. A small opening was left to serve as an observation port and to allow for ease of recording unobstructed videos of the ignition and combustion process. In addition to measuring fuel properties (temperature, pressure) and exhaust gas analysis, burner surface temperatures were measured during simulator testing. The diagrams in Figure 5 show the location and naming of welded surface thermocouples for the ultra-low NO_x (ULN) burner designs #1 and #2. Given the similarities in geometry, the circular Standard NO_x “pancake burner” (Figure 1) had similar locations and identical naming to those thermocouples shown for ULN burner #2.



(**a**)

Figure 5. *Cont.*



(**b**)

Figure 5. Ultra-low NO_x water heater burners with positions of thermocouples: (**a**) #1 and; (**b**) #2.

The induced draft warm-air furnace simulator was constructed to approximate the operating environment and for visual access to the “in-shot” burner, with an example pictured in Figure 6. As the typical furnace flame is a “loose” flame, flame stability and structure were a key component of the testing, and unique methodologies of qualifying these were provided using the simulator. The simulator comprised a solid steel metal U-pip with a burner and borosilicate glass tube at the inlet, a water-cooled heat exchange loop, and an induced-draft blower at the outlet. The system was completely sealed outside of the inlet and outlet portions with insulation provided on the body of the loop, as shown in Figure 6, covered with fiberglass insulation for safety.

(**a**) (**b**)

Figure 6. Photos of furnace simulator: (**a**) flow path; (**b**) placement of camera.

The “in-shot” burner used was a typical design found in residential forced-air furnaces, made of stamped sheet metal and carry-over flamelets on either side of the main burner outlet for ignition propagation, with an orifice size 2.08 mm providing the fuel. The burner was situated 3.2 cm from an inlet plate that has an inlet hole 3.2 cm in diameter with the burner being concentric with the inlet hole—the placement and dimensions were taken from a non-condensing residential furnace on site later used for in situ testing.

During tests, the visible flame resided within the borosilicate glass tube, immediately after the inlet plate, and the glass tube was 46 cm long, 9 cm in diameter, and 0.3 cm thick. The upstream end of the tube was compressed into glass fiber insulation that covers the inlet plate, and the downstream end of the tube was inserted 5 cm into the metal framing of the simulator body, with insulation compressed radially at the interface of the glass and body. The “U”-shaped steel flow path downstream of the glass and viewing tube and temperature measurement point contained water-cooled copper tubing loops. An inducer fan was installed at the outlet of the U-tube, modulated by a custom-built controller providing a pulse width modulation signal with digital tachometer output. Measurements included flue gas composition and the following temperatures: (1) that of a thermocouple welded to the burner body itself, approximately 1 cm from the burner face, (2) that of a thermocouple placed 20 cm downstream of the glass tube-to-metal housing transition, with the bead in the centerline, recessed 0.6 cm into the body of a shielding tube to limit radiant heat from the flame, and (3) that of a thermocouple placed 10 cm upstream of inducer blower in order to prevent damage to the impeller. Emission measurements were performed 15 cm upstream of the inducer, immediately after the copper cooling coils.

Two firing rates were used based on a common two-stage reference residential furnace, with a 5.9 kW “High” fire and a 4.1 kW “Low” fire, set with natural gas as a reference fuel based on manifold pressures noted previously. The inducer blower speed was adjusted such that that the horizontal flame did not impinge on the glass observation tube and to minimize exhaust temperatures to protect the inducer. The nominal stack O_2 concentration was 14% by volume (dry), set with natural gas. The inducer speed was then kept constant for the remaining tests. For ignition control, a standard control module was used with a self-grounding spark ignitor and separate flame sense rod. The spark ignitor was placed 1 cm downstream from the burner face and the flame sense rod placed 1.3 cm from the burner face, both placed in the center of the primary burner face. The fuel flow was controlled via an unmodified gas valve which in turn was controlled via a signal from the ignition module, operated with a manual switch.

3.1.2. In Situ Testing Details

In situ equipment testing was performed with three water heaters and two furnaces. The appliances were operated with simulated loads, with imposed draws on the water heater and simulated thermostat calls for the furnace. Each appliance was first adjusted using natural gas (supply pressure and flue installation) and then tested with hydrogen blended with methane in the 0–30% range by volume, in 5% increments. The appliances were installed and operated in a manner consistent with manufacturer requirements (aside from fuel mixture). The three water heaters selected used the three open air burners as shipped, the standard NO_x “pancake” burner, ULN burner #1, and ULN burner #2, respectively. As is common in industry, the furnaces both used variations on the “in-shot” burner design. While four manufacturers were represented amongst the five products selected, where the “pancake” burner and ULN #1 burner-type water heaters were from the same OEM, an important note is that *results should not be viewed as manufacturer-specific, but reflecting the authors’ operation of these appliances as per this test plan*. Testing and analysis of the results was not performed in consultation with equipment manufacturers and, due to the nature of laboratory testing, may not reflect the impacts observed in a field environment.

Table 3 summarizes the equipment tested, noting that the efficiency of water heaters and furnaces are shown in terms of the uniform energy factor (UEF) or annual fuel utilization efficiency (AFUE), common in North America [33,34]. For the water heaters, measurements of inlet and outlet water temperatures and flow rates facilitated an energy balance. The furnace testing used an air handler unit (AHU) for ducting, which was instrumented for air-side temperature and pressure measurements, allowing for an air-side energy balance to be completed. Fuel flow was measured using the previously described fueling rig.

Each steady-state operating point was deemed complete based on observation of the burner surface and exhaust temperatures. For water heater tests, the test was concluded once the aquastat setpoint temperature was reached and the ignition controller turned off the burner. The ignition process used existing hardware, either a pilot light or electronic ignition, and for each fuel the tests were conducted from a “cold” start with the furnaces at room temperature (~20 °C) and with water heaters after they had been flushed with cold water such that the inlet and outlet temperature from the water heater were within 2.8 °C of the incoming water temperature at the time of testing, and a re-ignition attempt immediately after the previous test to represent a "hot" start. Throughout all test points, emission measurements (CO, CO_2, NO_x, O_2, THC on a dry basis) and stack temperature were measured to determine the appliance performance and combustion efficiency.

Table 3. Equipment used in in situ laboratory testing.

Equipment Name	Burner Type	Description and Key Features
Standard Water Heater	"Pancake" Burner	Standard NO_x, 0.62 UEF, 189 L, 11.7 kW input
ULN Water Heater #1	ULN Burner #1	Ultra-low NO_x, 0.64 UEF, 151 L, 11.7 kW r input
ULN Water Heater #2	ULN Burner #2	Ultra-low NO_x, 0.58 UEF, 151 L, 11.1 kW input
Non-Condensing Furnace	"In-Shot" Burners	Standard NO_x, 80% AFUE, High Fire = 23.4 kW, Low Fire = 18.8 kW
Condensing Furnace	"In-Shot" Burners	Standard NO_x, 95% AFUE, Input (Single Stage) = 16.4 kW

Specific to the water heaters, a cycling test and the first draw with full recovery was completed for the standard water heater and ULN water heater #1, with only methane and the fuel blend containing 30% hydrogen to measure the recovery efficiency as defined by the U.S. standard [33]. Each water heater also underwent a "slug test" where the water heater was operated continuously by imposing a constant draw with the fuel mixture containing 5% hydrogen initially. The fuel supply then was switched to the mixture containing 30% hydrogen. The water heater was further operated for at least 5 min, and then the fuel was switched again to the mixture containing 5% hydrogen. This test was conducted to see if rapid changes in fuel composition would negatively impact the stability of the burner.

3.2. Field Equipment Sampling

To supplement the laboratory tests, field sampling was performed at a natural gas utility training facility, wherein a wide range of common fuel-fired equipment is operated in a simulated residential environment, with 5–7 groups of equipment installed in 14 mock homes. Sampling occurred over the span of a week, where hydrogen blending was performed on-site with pipeline natural gas into the network serving this facility, which is located in a high-altitude region (>1 km above sea level).

The appliances were tested as installed using unmodified controls. Emission measurements were taken at locations that were most convenient to minimize the alteration of appliance operation. In some instances, the exhaust flue was partially removed from the appliance to provide a location for measuring emissions, but no other modifications were made that could have provided better access to measurement locations. Table 4 highlights the residential equipment sampled, which excludes dryers due to challenges with drawing an accurate sample from a highly diluted exhaust stream without significant modification to the appliance. Relevant to the equipment emission sampling periods, the actual hydrogen blending and fuel heating values are shown in Table 5.

For all stack measurements, a Bacharach model PCA400 was used for the emission tests. The emissions analyzer was calibrated prior to travel by the manufacturer, with a National Institute of Standards and Technology (NIST) traceable certificate of calibration available upon request. The measurement ranges and accuracies for each of the reported measurements and derived values are listed below in Table 6. Except for dryers, most appliances were able to be run in a continuous fashion to allow enough time for the sensors to become fully saturated and meet response time requirements.

Table 4. Equipment used in field sampling.

Location	Equipment Name	Burner Type	Description and Key Features
A	Water Heater #1	"Pancake" Burner	Standard NO_x, 0.59 UEF, 151 L, 11.7 kW input
B	Water Heater #2	"Pancake" Burner	Standard NO_x, 0.59 UEF, 151 L, 11.7 kW input
D	Water Heater #3	ULN Burner #2	Ultra-low NO_x, 0.62 UEF, 144 L, 10.6 kW input
E	Water Heater #4	"Pancake" Burner	Standard NO_x, 0.59 UEF, 151 L, 10.6 kW input
D	Furnace #1	"In-shot" Burners	Standard NO_x, 80% AFUE, Input (Single Stage) = 25.8 kW
E	Furnace #2	"In-shot" Burners	Standard NO_x, 80% AFUE, High Fire = 14.7 kW, Low Fire = 10.3 kW
B	Wall Furnace #1	"In-shot" Burners	66% AFUE, Input = 14.7 kW
G	Wall Furnace #2	"Ribbon" Burners	Input = 23.4 kW
C	Fireplace #1	Perforated Burner	Input = 8.8 kW
A	Range/Oven #1	Standard Range Burner	Max. Input = 15.5 kW
E	Range/Oven #2	Standard Range Burner	Max. Input = 19.9 kW
F	Range/Oven #3	Standard Range Burner	Max. Input = 19.2 kW

Table 5. Gas quality details during field sampling.

Sampling Day	Hydrogen Blend (Actual %)	Heating Value (Average, MJ/m^3)
1 *	4.49	37.63
2	5.18 ± 0.39	37.56 ± 0.15
3	0.00	38.90 ± 0.26
4 **	10.02 ± 0.43	35.95 ± 0.11

* Applies to Location D only. ** Applies to Water Heater #3 only.

Table 6. Field emission sampling analyzer details.

Qty.	Range	Resolution	Accuracy	Response Time
O_2	0 to 20.9%	0.1%	±0.3 %	T90 < 20 s
CO	0 to 10,000 ppm	1 ppm	±10 ppm (0 to 200) ±5% reading (201 to 2000)	T90 < 40 s
NO	0 to 3000 ppm	1 ppm	±3 ppm (0 to 50) ±5% reading (51 to 2000)	T90 < 30 s
NO_2	0 to 500 ppm	1 ppm	±3 ppm (0 to 50) ±5% reading (51 to 500)	T90 < 40 s
T_{flue}	−20 °C to 1200 °C	0.05 °C	±0.5 °C	T90 < 70 s

Most of the tests used sample periods of 10 min with data collected at 5 s intervals. The emissions analyzer was purged outdoors in fresh air before each 10 min sample run. The emissions analyzer also underwent CO auto-zeroing during each startup. As cooling would occur in the corrugated stainless-steel tubing (CSST) where used, a sheathed Type K thermocouple was added to the ambient temperature port of the side of the Bacharach PCA400 to give an indication of the flue gas temperature in addition to the sample gas temperature. This helped to provide a rough determination of appliance operation. The sample lines water trap was adjusted to the vertical position to ensure proper sampling.

The filter in the water trap assembly was checked daily to ensure no water had condensed in the probe/CSST and bypassed the water trap to soak the filter. Examples of appliance exhaust sampling methods are shown in Figure 7.

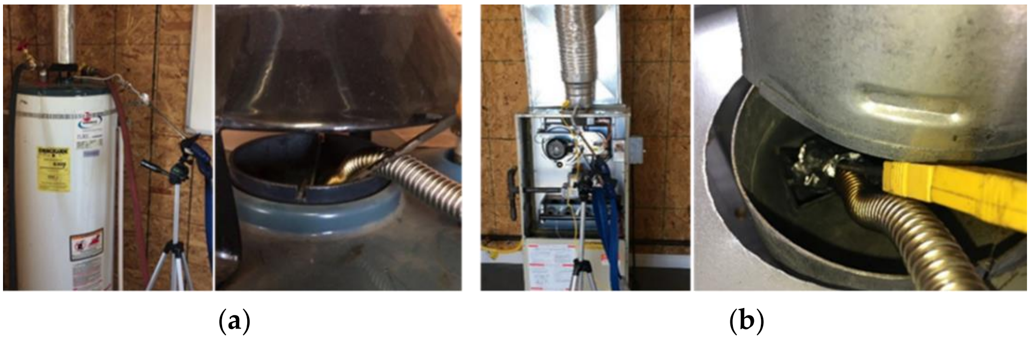


Figure 7. Field-testing exhaust sampling examples for: (**a**) water heaters; (**b**) furnaces.

4. Results

4.1. Laboratory Testing

With the partially premixed combustion simulators built and commissioned, recreating storage-type water heaters and warm-air furnaces, four common burners in use in North America were installed and tested with natural gas and 0–30% hydrogen blended with methane, using 5% increments. ULN burner #1 was operated “as-shipped” and with a common orifice to the “pancake” burner to match nameplate input rates, the latter noted as “orifice”. For in situ testing, three water heaters were installed and operated with natural gas and hydrogen/methane blends ranging from 0 to 30%, with cold starts (cold tank), hot starts, “slug tests” varying fuel mixtures dynamically, and a recovery efficiency test for two of the three water heaters. Of the three water heaters used, each contained one of the burner types tested in simulator testing. Two furnaces were installed and tested with the same range of fuel mixtures, a non-condensing dual-stage furnace and a condensing single-stage furnace. All in situ water heaters and furnaces were tested “as-shipped”, without adjustments to the burner or its operating settings.

4.1.1. Simulator Test Results

All water heater burners and their pilot lights were consistently able to operate with natural gas and 0 to 30% mixtures of hydrogen blended into methane. Ignition was not an issue with all mixtures and flashback was not observed. ULN burner #2 had a localized and slightly lifted flame in a region on the flame holder which became more pronounced with greater hydrogen fractions, though this did not present an observable operational issue.

For furnace “in-shot” burners, hot and cold starts were performed for both high and low firing cases. Within less than 0.3 s from the initiation of the ignitor, the flame typically reaches the full length of the viewing tube, though it required 2–5 s to reach an appearance of a steady flame. While the steady state flame structure appeared to be impacted by hydrogen blending, with a shortened flame with up to 30% hydrogen blended in, ignitions were not observed to differ in duration or nature with increasing hydrogen. No sustained issues were observed with startup over the range of firing rates and mixtures, both for cold and hot starts, though an intermittent stability issue determined to be an artifact of the test setup is discussed later.

Still images of the burners from all tests are shown in Figure 8, where for “blue” flames (pancake and in-shot) it is difficult to draw conclusions, though it is important to note that the shift in color between more teal and blue flames is unexplained and is likely influenced by lighting/camera factors. For radiant burners, ULN #1 and #2 water heater burners, the cooling of the burner is apparent with increasing hydrogen, as is the portion of ULN #2, which has a slightly lifted flame in the rear, closer to the ignitor, both attributed to the reduced heat output.

Figure 8. Still images of water heater and furnace burners during simulator testing.

For all water heater burners and most furnace burner test cases, there were no adverse combustion characteristics observed when the hydrogen content in the fuel was increased during the ignition of pilot/main burners. A typical ignition of the in-shot burner at high-fire and 30% H_2 mixture is shown in Figure 9. The exception was one stability issue intermittently observed, namely flashback with a 20 and 25% H_2 mixture, though this was determined to be an artifact of the simulator test setup. Initially when observed, subsequent efforts to re-create this flashback via rapid cycling of the burner were successful, but only every 5–10 on-cycles.

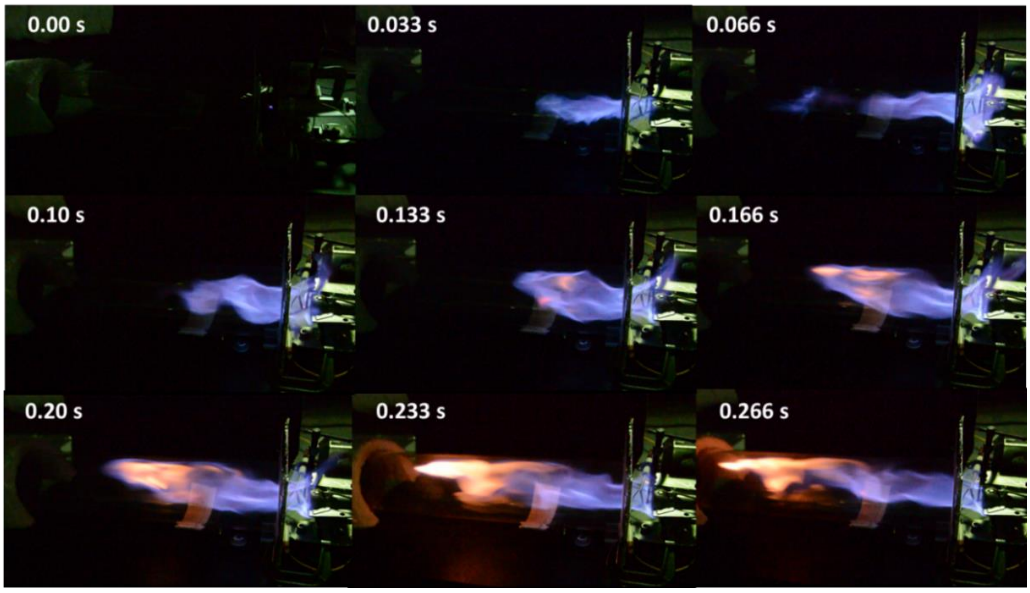


Figure 9. High-fire "hot" ignition of in-shot burner with 30% H_2 mixture.

The authors sought to recreate this flashback event systematically and isolate the impact of (a) duration between ignition calls when short-cycling and (b) the fuel mixture. A series of tests were repeated for natural gas, 10% hydrogen, 20% hydrogen, and 30% hydrogen, operating 10 sequential ignition cycles at high fire with a 15 s on-cycle and a range of delays between cycles of 2, 5, and 10 s. The inducer fan remained at the same setting as with prior testing. Finally, for the 30% hydrogen mixture only, the delay to energize the ignitor was varied between the default setting of 0.5 s up to 1.5 s. Over all conditions, flashback was not recreated, which suggests that other factors outside of burner operation, potentially including environmental factors, were responsible for the seemingly random flashback events. Despite the inability to systematically recreate flashback, initial observations confirm that the simple flow-through design of the "in-shot" furnace burners makes is more susceptible to flashback.

As expected, input rates were observed to decline with increasing hydrogen blends, with Figure 10 highlighting the decline for each water heater burner, with a scaled comparison of the calculated shift in WI. As with parallel studies, actual de-rating differs from the WI-based prediction, likely due to non-idealized hydrodynamics relative to orifice sizing practices. For the pancake burner and ULN burner #2, both radial burners with the orifice assembly within the combustion chamber, the WI-based prediction underestimates the de-rating suggesting the addition of hydrogen has a non-linear impact on burner fuel and air flow. By contrast, for the ULN #1 burner with its ample and rectilinear flow path and orifice assembly external to the combustion chamber, the WI-based prediction overestimates de-rating, suggesting that these dynamics are less important. Furnace de-rating from simulator tests does not show consistent declines, due to the constant inducer fan and artifacts of the simulator design, with high-fire and low-fire input rates only decreasing between 0 and 30% H_2 by 1.4 and 1.9%, respectively. The heat input rate was obtained by taking the average of the stabilized fuel flowrate measurements. Therefore, the experiment error was mainly from the Elster DTM-200A Gas Meter, which was ±1% of the heat input rate readings.

Regarding the NO_x and CO emissions in Figures 11 and 12, water heater and furnace burners show moderate shifts in CO emissions and declines in NO_x emissions with increasing hydrogen blended, owing in the large part to the excess air dilution impacts. In terms of magnitude with the data shown below for the three burners, the one exception is ULN #2 with CO emissions, showing slightly greater than ±1 10 ppm air free (AF) CO, which may be due to observed localized flame lifting. Furnace in-shot burners show similar increases in CO emissions from 25 to 30% H_2. Measured NO_x emission levels of the ULN burners were under 50 ppm; therefore, the accuracy was ±3 ppm of the analyzer readings. The pancake burner and the in-shot burner NO_x emission levels were above 50 ppm. Therefore, their emission levels were ±5% of the readings. ULN #2 burner had the highest CO emissions, which had an accuracy range of ±5% of the readings. The measurement accuracy of the rest burners was ±10 ppm. It should be noted that the emission analyzer and sampling system was not optimized for ultra-low NO_x measurements, and so unaccounted for uncertainties for ULN #1 and ULN #2 water heaters may still be present.

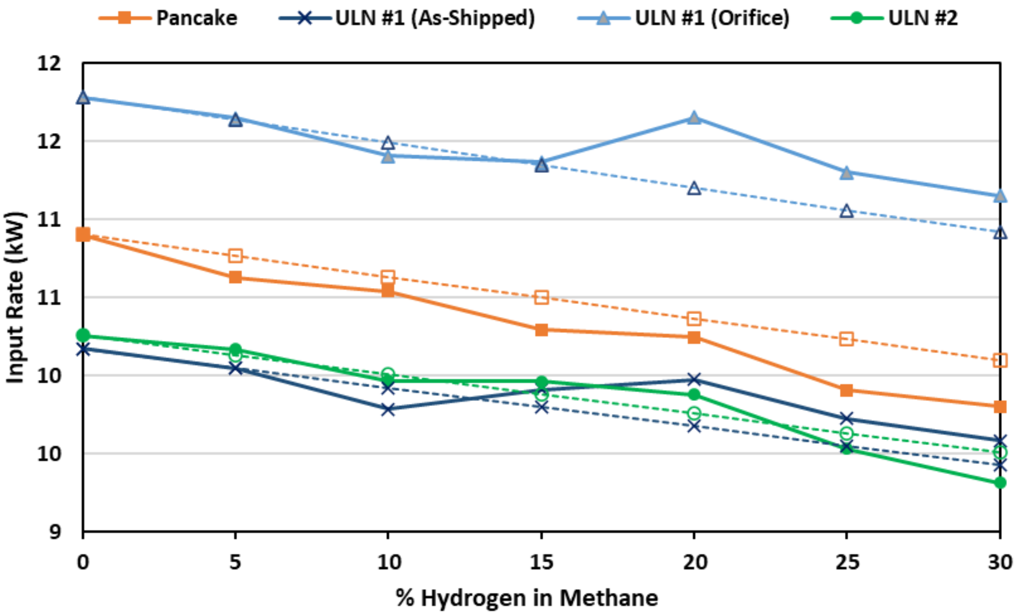


Figure 10. De-rating of water heater burners as measured (solid lines) and compared to Wobbe Index shift calculation (dashed lines).

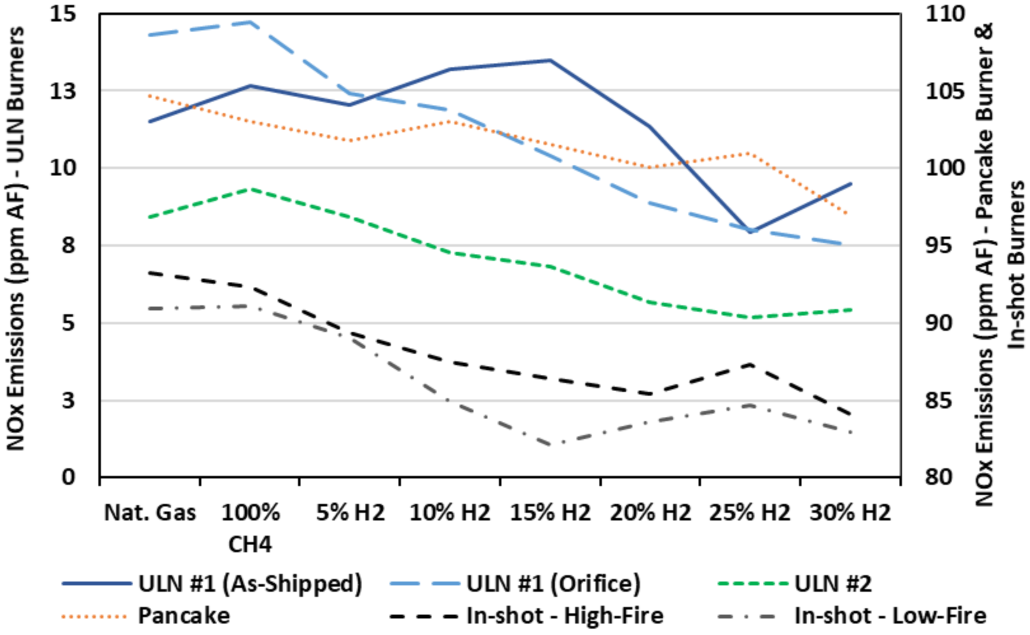


Figure 11. NO_x emissions (air-free) for simulator tests.

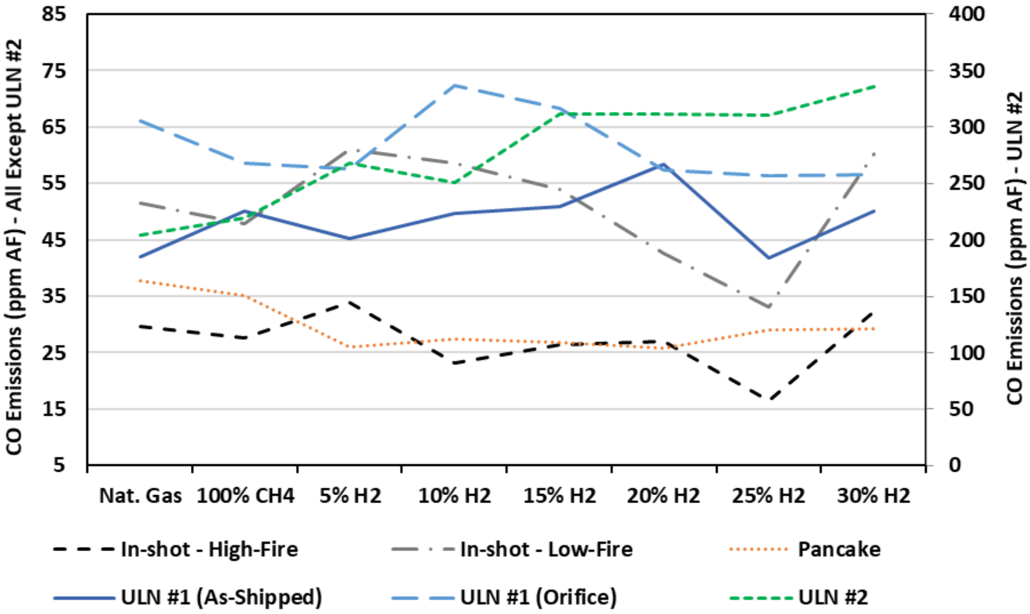


Figure 12. CO emissions (air-free) for simulator tests.

4.1.2. In Situ Test Results

For water heater testing, as with open air testing, there were no observable issues with ignition from a cold start or hot cycling for the three water heaters from 0 to 30% hydrogen, with pilot lights functional over the full range as well. When observed in the open air, with examples in Figure 13, ULN water heater #2 did not have the same noticeable lifted flame portion towards the burner rear while operating within the water heater seen in the figure below, suggesting this was largely an artifact of the simulator operation itself (e.g., insufficient draft through the burner inlet).

Figure 13. Standard water heater (**Left**, Steady State) and ULN Water Heater #2 (**Right**, 30 s After Ignition) operating in situ with 30% H_2.

For both furnaces over all conditions tested, the cold and hot startups were successful except for one instance of flashback, due to an operational error. Ignitions were successful and there was no discernable difference between the natural gas, 100% methane, and 30% hydrogen blended fuels, although the visual access was much more limited than simulator testing, as seen in Figure 14. According to the images below, the condensing furnace combustion was not noticeably different across the range of fuels used, for example. In the instance of flashback, the system was operating with natural gas, shut down, then switched to a 5% hydrogen mixture. Typically, there would be a purge time between switching fuels of ~1 min, followed by operating the system. During the purge time between natural gas and 5% hydrogen/methane, the flame receded to the orifice for ~20 s, after which the flame returned to stabilize at the flame holder at the end of the burner. There were abnormalities with recorded measurements, such as inlet pressure, suggesting that there was a test rig malfunction, and despite repeated attempts to recreate this flashback via transition from natural gas to 5% hydrogen blended fuel, this flashback event was not repeated. While inconclusive, this suggests that furnaces may be more sensitive to rapid shifts in hydrogen content than water heaters, which is worthy of subsequent investigation.

Further investigation into the combustion stability of in-shot burners is necessary, but was beyond the scope of this study.

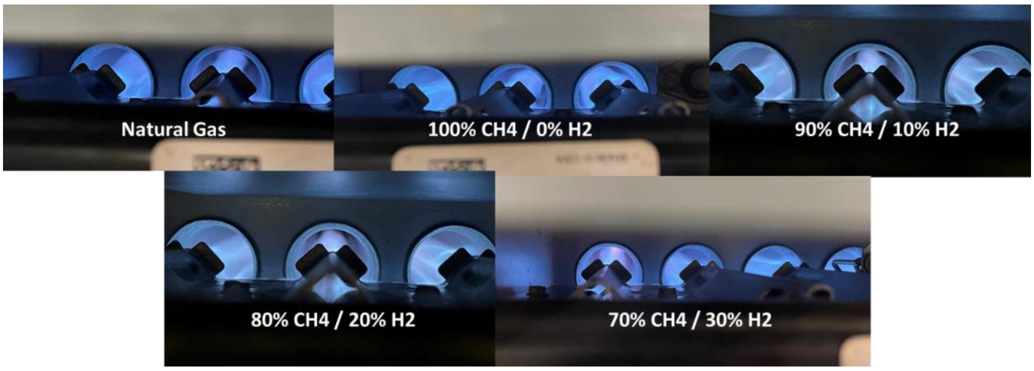


Figure 14. Visualization of condensing furnace burners at a steady state.

Concerning ignition, most furnaces use a "rolling ignition", wherein one burner is ignited and the flame "rolls" across the other burners to compete ignition. This sequence is clear from the images below in Figure 15 for the non-condensing furnace with a 30% hydrogen blend. Comparing across high vs. low fire, cold vs. hot start, and a range of fuel compositions, the timing of this rolling ignition was quantified, where cold starts, higher hydrogen blends, and high firing rates all tend to delay ignition across the four burners, with a maximum increase of 233 ms from 5% H_2 to 30% H_2 observed for the right-most burner. Visual access prevented a similar analysis of the condensing furnace, in addition to its use of multiple ignition points.

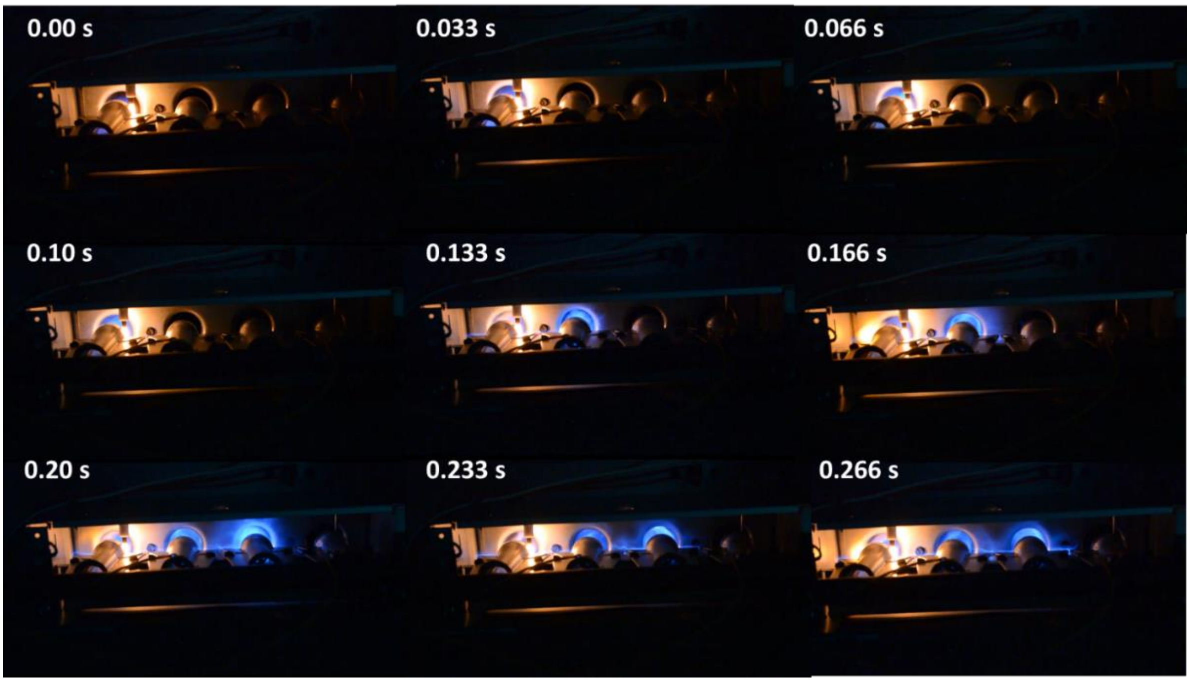


Figure 15. Rolling ignition of a non-condensing furnace at a 30% H_2 blend.

As anticipated, de-rating was observed for all water heaters from 0 to 30% hydrogen blends, ranging from 7.4% (ULN #1) to 9.1% (ULN #2) and 11.2% (Pancake). When comparing these values in Figure 16, the deviation from WI-based de-rate tightens. In the case of ULN #1, it shows a near perfect prediction of de-rating with the WI. As with the individual burners being tested, the experimental error was from the Elster DTM-200A Gas Meter, which was ±1% of the heat input rate readings. Both the pancake and ULN #2 type water heaters show slight underprediction of de-rating by the WI decline, though the difference is smaller than that of open-air burners. A key distinction between the ULN #1 burner and the other burners in this study is that the orifice ejecting fuel is positioned outside of the combustion chamber, a feature clear from the burner photos in Figure 5. By contrast, the orifice for the "pancake" burner is wholly within the chamber and for the ULN #2 burner is exposed to the ingested primary air. This points to a difference in the static pressure inside the combustion chamber and at the gas orifice, which explain the differing observations. The static pressure inside the water heater combustion chamber was not measured, so this hypothesis remains to be confirmed. Capacity decline with hydrogen blending for furnaces was not steady, though an overall decline of 7.8% for the condensing furnace and only 2.3% for the non-condensing furnace, from 0 to 30% H_2, respectively, was observed. A subsequent investigation is needed to study the impact of furnace operation as a function of inducer fan settings for single-stage, multi-stage, and modulating furnaces.

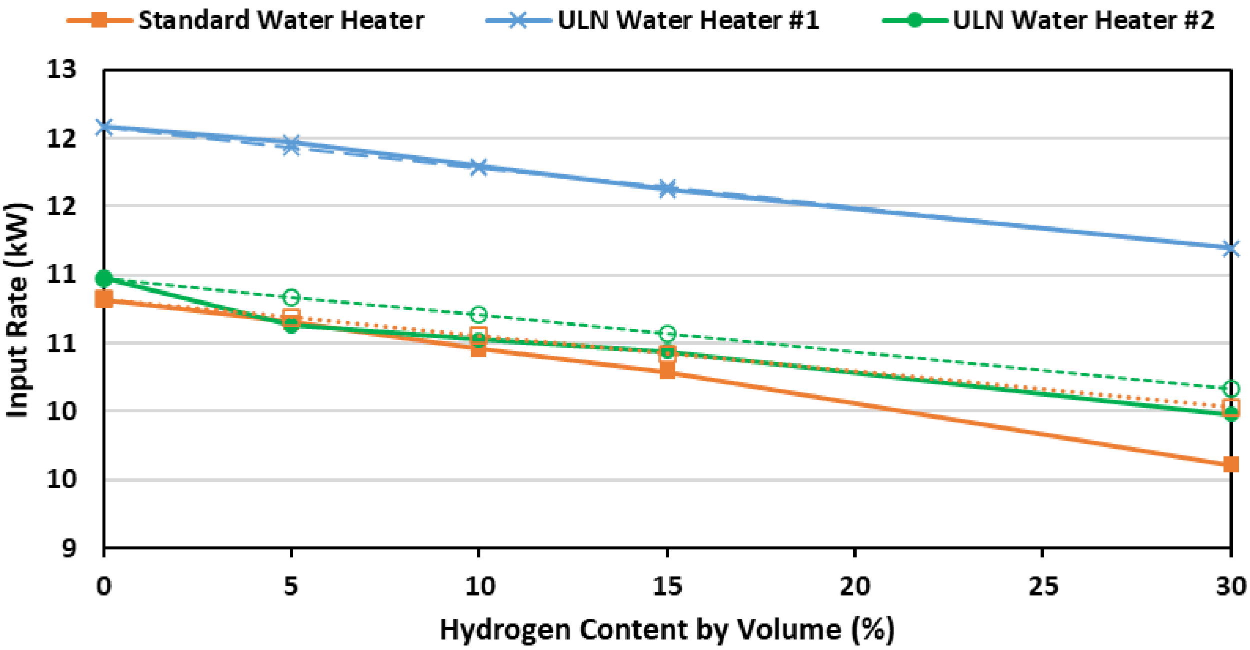


Figure 16. De-rating of water heaters as-measured (solid) and comparing to Wobbe Index shift calculation (dashed).

Regarding emissions, CO declined or remained flat for the pancake and ULN burner #1 type water heaters within narrow ranges. For the ULN burner #2 type water heater, a steady increase in CO emissions from 30 to 63 ppm AF was observed, though emissions were well below the allowable 400 ppm AF for certification via ANSI Z21.10.1. For the furnaces, the O_2 and CO_2 showed increasing dilution, from 0 to 30% H_2 blends, with CO_2 from 7.5 to 5.9% (condensing) and 6.5 to 3.7% (non-condensing high-fire). For both furnaces, a moderate increase in CO emissions was observed, at 50 ppm AF (condensing) and 10 ppm AF (non-condensing high-fire). For NO_x emissions, a consistent decline was observed with all water heaters, reducing both ULN burner NO_x emissions by approximately half, while furnaces showed a similar but less pronounced decline, as plotted in Figure 17. The CO/NO_x emission measurement accuracy was consistent with the individual burner testing. For the condensing furnace, a moderate increase (~5 °C) in burner surface temperatures up to the 30% hydrogen blend was observed, while a small decrease (~2.5 °C) was seen with the non-condensing furnace at high-fire over the same range. The temperature measurement accuracy range was ±0.5 °C. More significant shifts in surface temperatures were observed with the natural draft water heaters, as shown in Figure 18, where steady declines were observed for the radiant ULN #1 burner, while the standard pancake burner showed increases.

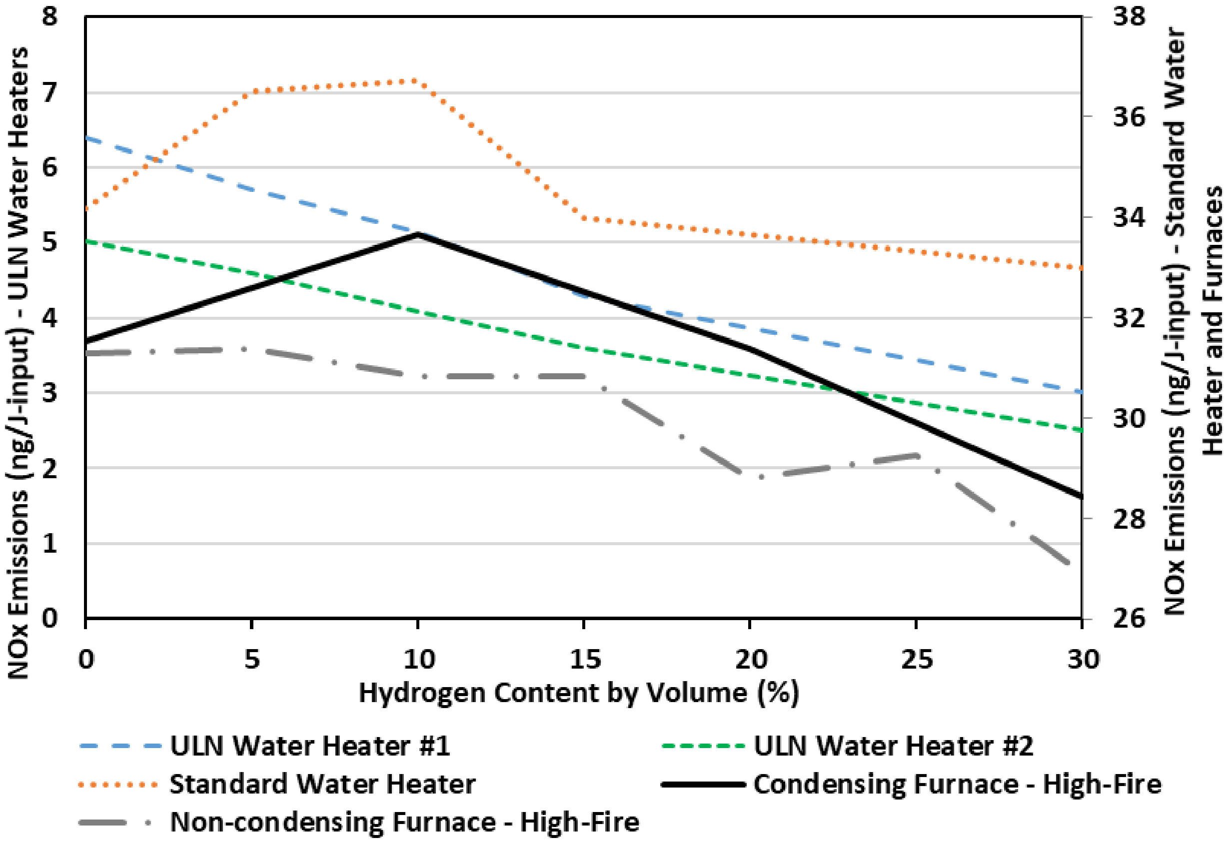


Figure 17. NO_x emissions (ng/J-input) for in situ tests.

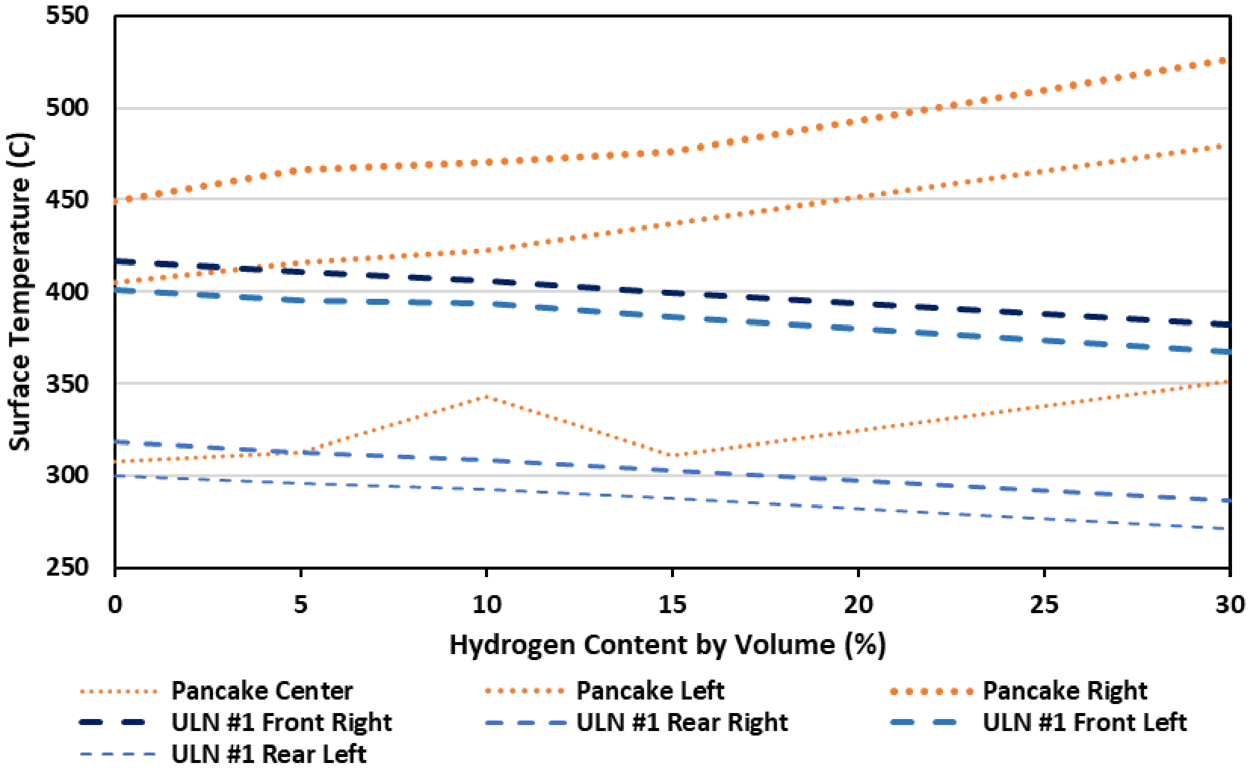


Figure 18. Burner surface temperatures during water heater in situ tests.

For the standard water heater and ULN water heater #1, the recovery efficiency test was performed as defined in the U.S. Dept. of Energy test method, which calculates an equivalent steady-state efficiency during storage tank reheating as the recovery efficiency as summarized in Figure 19. This efficiency is used in place of the true steady-state efficiency in the calculation of the uniform energy factor (UEF). Additionally, during this test, exhaust temperature and flue-gas composition were used to estimate the excess aeration. Note that for the standard water heater, the recovery duration for the 30% hydrogen blend increased by 10.4%, while the ULN water heater #1 ran for 20.7% longer (an artifact of the recovery efficiency procedure). Shifting from 100% methane to 30% hydrogen/70% methane increased the measured total excess air and decreased the flue gas temperatures. For the standard water heater, the impact of dilution was apparent as a minor efficiency penalty counteracting the expected improvement in efficiency due to de-rating. For the ULN #1 burner, a radiant burner in contrast to the "pancake" burner, the radiant heat transfer may be improved with the 30% hydrogen case in addition to the overall reduced excess aeration. Additionally, the greater increase in recovery time for the ULN water may also play a role in progressing toward steady-state operation. It should be noted here that the temperature measurement accuracy was ±0.5 °C, and the excess air level error was under ±3% (contributed by oxygen measurement). Therefore, the efficiency variation from 100% methane to 30% hydrogen/70% methane was within the measurement accuracy range.

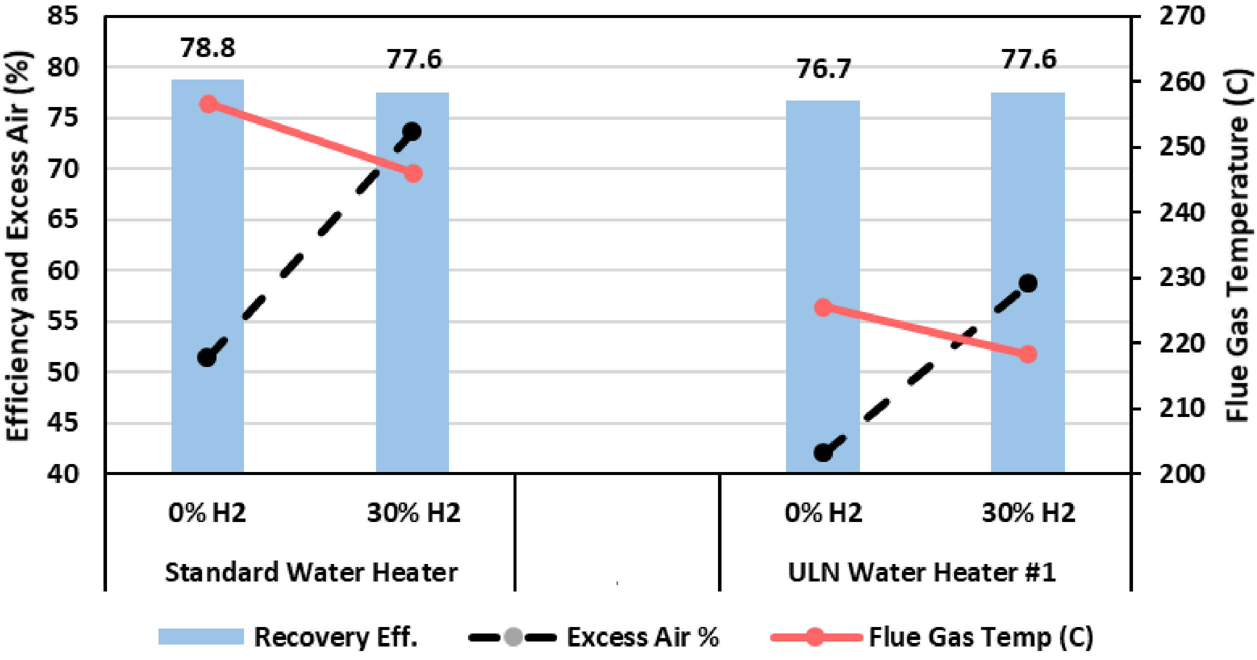


Figure 19. Impact of hydrogen blending on water heater efficiency, excess air, and flue gas temperature.

For the "slug test", the standard water heater and ULN water heater #1 were operated with a 5% hydrogen mixture, then rapidly shifted to a 30% mixture, repeating this cycle while the unit was operating. The plots in Figures 20 and 21 show the results for this test, with the sharp rise and decline in O_2 (inverse for CO_2) as the hydrogen concentration was shifted, with a tandem fall and rise in flue gas temperatures. For the "pancake" burner, the CO and NO_x emissions were not significantly impacted in this shift, while they were for the ULN water heater. Throughout the "slugs" shifting from 5 to 30%, there was no noticeable impact on the stability of the flame and equipment operation.

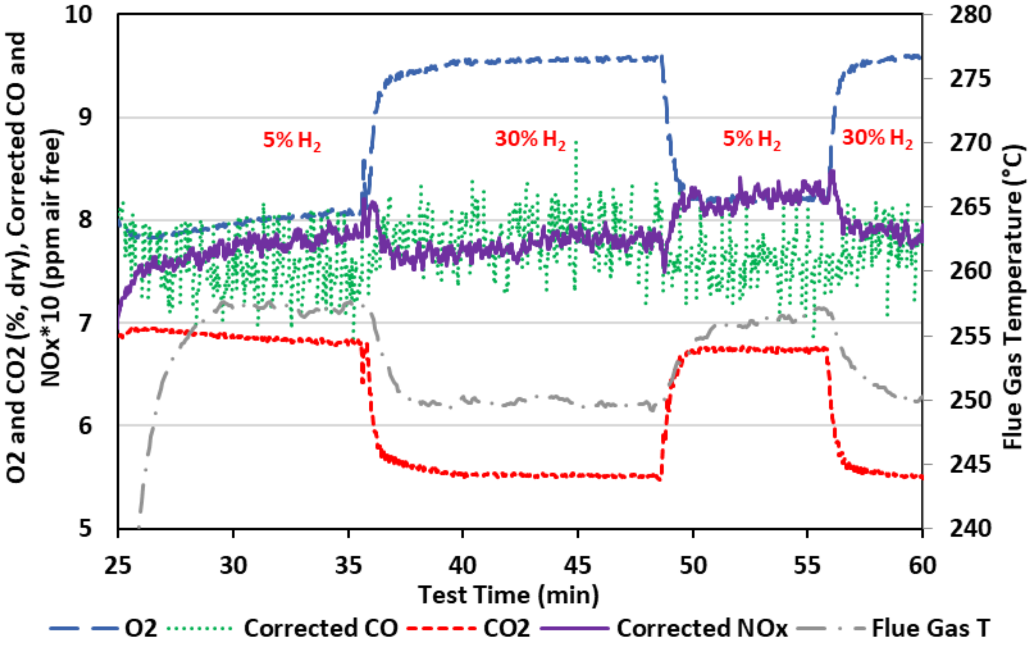


Figure 20. Slug test results for standard water heater.

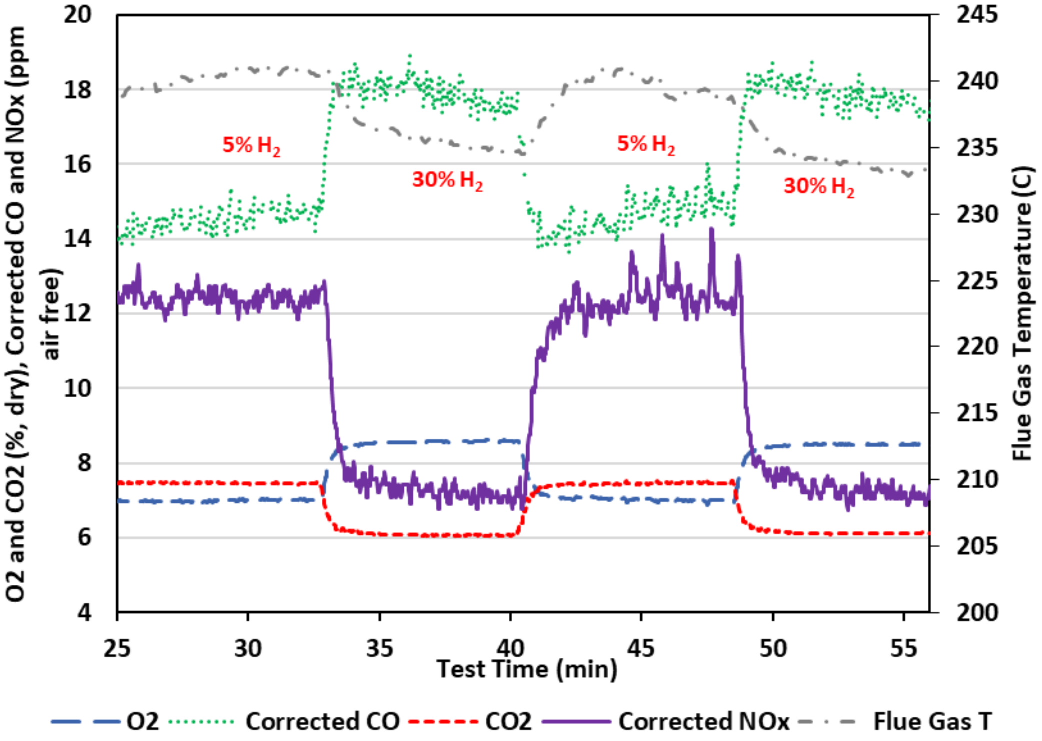
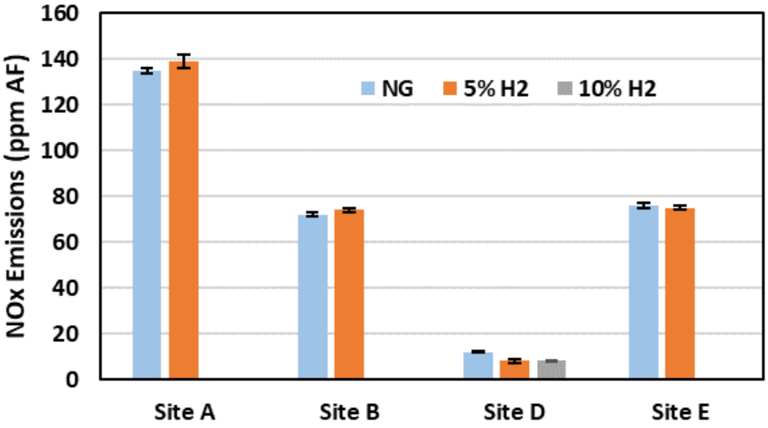


Figure 21. Slug test results for ULN water heater #1.

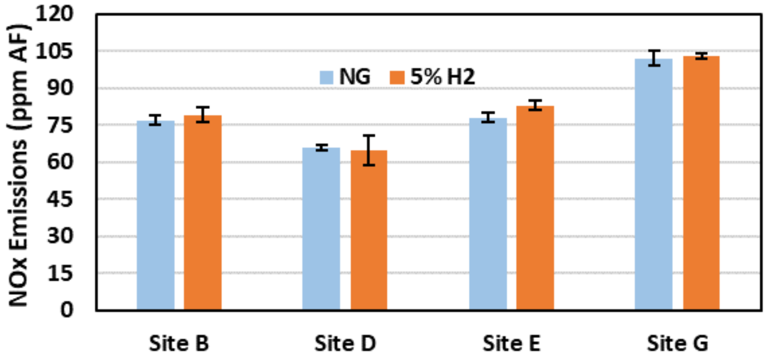
4.2. Field Equipment Sampling

Within the limitations of the field measurements, no significant difference in NO_x emissions was observed between natural gas and hydrogen mixtures. There were other factors outside of the control of this study, such as ambient temperature, humidity, and other weather conditions that may have affected the results.

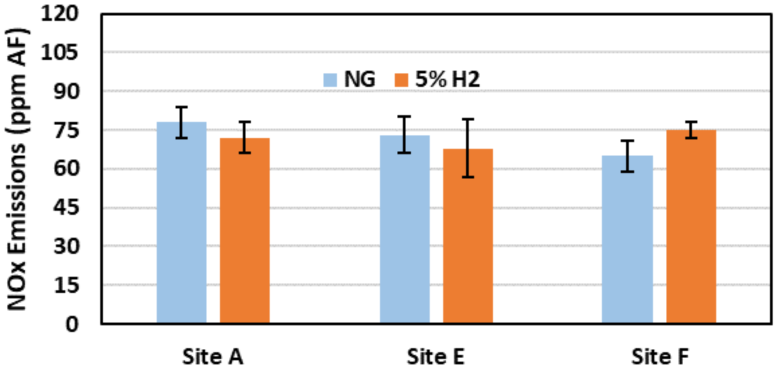
Figure 22 shows the NO_x emissions of representative appliances operating using natural gas and natural gas/hydrogen mixtures. Generally, the 5% hydrogen addition to natural gas did not influence the NO_x emissions for these appliances.



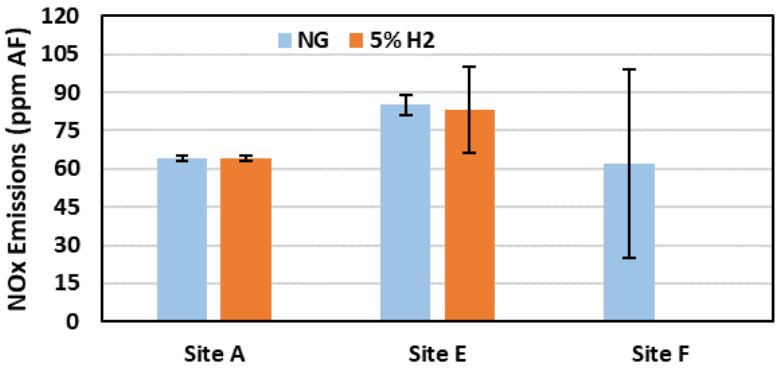
Water Heater



Furnace



Range



Oven

Figure 22. NO_x emissions of field-sampled equipment.

For the water heater at Site A, which was a manufactured housing-type water heater, the NO_x emissions were the highest, reaching 140 ppm in air-free conditions. The water heaters at Site B and E were conventional storage water heaters, and the NO_x emissions of these water heaters were around 75 ppm. The water heater at Site D was an ultra-low NO_x variety, which had the lowest NO_x emissions level (<10 ppm) among all appliances tested.

Warm-air furnaces at four testing locations had relatively similar NO_x emissions. The furnaces at Site B, D and E had NO_x emissions under 80 ppm. The highest NO_x emissions of furnaces were from Site G, which was a natural draft wall furnace.

Range cooktop and oven emissions were also collected. The NO_x emissions of these burners were similar among various testing sites. It should be noted that kitchen flames are usually less enclosed compared to water heaters and furnaces; therefore, the error of the emission readings are larger.

The results from sampling dryers were not reported. Due to the high dilution rate of the exhaust (~20% O_2 in the sample), the emission readings were outside of reportable accuracy. According to visual observation, it is believed that 5% hydrogen addition did not have significant impacts on the performance of the dryers. It is suggested that future dryer emission testing requires accessing the burner assembly. The fireplace emissions measurement had a similar problem. The measured NO_x emissions of the fireplace were around 10 ppm with a high dilution, and therefore, more data need to be collected on fireplaces. No evidence was observed that shows that hydrogen addition had any significant influence on CO emissions from the appliances tested.

5. Summary

5.1. Conclusions

In this effort and following a thorough review of the current state of knowledge, the authors sought to better characterize the impacts of hydrogen-blended natural gas up to 30% by volume on common partially premixed combustion equipment, including water heaters, furnaces, and miscellaneous appliances, from a whole equipment point of view and concerning the burners used. Through laboratory testing, using purpose-built "simulators" and in situ tests, and field sampling in a simulated operating environment, a series of short-term tests were performed on these components and equipment with the aim of characterizing performance, efficiency, emissions, and other factors as a function of hydrogen blending up to 30% by volume. In general, all appliances and their burners were able to tolerate this shift in fuel composition, without notable excursions in process temperatures or emissions, and anticipated trends were confirmed and further quantified for these appliances, ranging from the de-rating of heat input, to the increase in excess aeration, and to the NO_x and CO emissions. For these unadjusted, partially premixed type combustion appliances, the dominant impact of hydrogen blending is the increase in excess air, often resulting in lower NO_x emissions, surface temperatures, and other parameters.

The authors emphasize that these findings, if generalized, only apply to natural-gas appliances from mainland United States and Canada, and are as follows:

1. The combustion stability of the burners and appliances tested was not impacted by up to 30% of H_2 by volume, as evidenced by lack of flashback, flame lift, and CO emissions above 400 ppm AF.
2. While de-rating of appliances can be approximated by the WI comparison, it is not exact and higher levels of de-rate are likely to be observed in the field.
3. The efficiency of the appliances tested only varied by ~1–1.5% with 0 to 30% hydrogen-blended fuels, which is consistent with prior observations, though the changes in flue gas temperature and excess aeration did not always point to the same result. The overall efficiency ratings should be investigated in more detail; the decarbonization benefit of H_2 blending can be decreased or increased by changes in appliance efficiency.
4. Within the limits of the instrumentation and procedures used, NO_x emissions from laboratory and field measurements point to either no change or a decrease with increasing blends of hydrogen up to 30% by volume.

5. The most sensitive burners to hydrogen blending were of the “in-shot” variety, used by warm-air furnaces, tested in the laboratory. Flashback events observed were inconsistent and likely caused by either test procedures or sensitivities of the specific test stands used. Further investigation into these burners is recommended.

In broader terms, other follow-on research is recommended concerning the nuances amongst equipment and between blending levels, including (a) the atypical de-rating behavior of the non-condensing furnace, (b) disaggregating the impact of hydrogen on radiant burner output, (c) characterizing the nature and impact of ignition timing, (d) generalizing the impact of hydrogen on specific burner design features (e.g., key dimensions), (e) examining the errant flashback events observed during testing, and (f) establishing actual blend limits for the variety of partial-premixed burners and appliances in use.

5.2. Recommendations

Concerning the decarbonization of gas grids using hydrogen, a broader issue remains that the industry’s knowledge of how hydrogen-blended natural gas impacts the wide diversity of stationary combustion equipment is based on a limited dataset. For residential and commercial buildings, the authors recommend expanding investigations similar to this effort in the following ways, to:

1. Expand the dataset: further quantify the emissions, efficiency, and safety impacts on a wider range of equipment types, including a greater diversity of water and space heating equipment, cooking equipment, and other miscellaneous fuel-fired appliances. Additionally, expand the scope of testing, including higher hydrogen blends, the impact of the balance fuel (e.g., natural gas), indoor and equipment component, new versus aged equipment, emerging technologies (e.g., fuel-fired heat pumps), and explore the operating envelope (fuel pressure, over/under-firing, venting matters, environmental conditions, etc.).
2. Quantify long-term impacts: long-term impacts are even more poorly understood, ranging from hydrogen-blended natural gas impacts on equipment operating life, maintenance needs, material and component degradation, and on the infrastructure (e.g., piping, venting).
3. Gain experience in the field: true in situ testing will be valuable in the field, to verify laboratory-based findings, in addition to (a) quantifying impacts on installation, operation, and maintenance of equipment, (b) establishing best practices concerning re-commissioning and troubleshooting equipment issues, (c) implementing simple retrofit packages to enable hydrogen-blended fuel tolerance, and (d) establishing the use case(s) for enhanced sensors for equipment and building systems.
4. Modernize codes and standards: to operate the equipment in this study with a 30% hydrogen/natural gas blend is to go outside its certification for safety, performance, and possibly efficiency and emissions. Modernization of these associated codes and standards is essential in parallel to expanding these laboratory and field datasets.

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Appendix A

This informative appendix provides an overview of the fuel gas quality impacts of hydrogen blended into natural gas. In practice, the effect of increasing the quantity of hydrogen blended into natural gas on equipment is highly equipment-specific. However, general trends from the fuel properties can be illustrative. For hydrogen blended into methane, >95% of delivered natural gas in North America [25], key gas quality metrics are shown in Figure A1 as a function of hydrogen blended by volume.

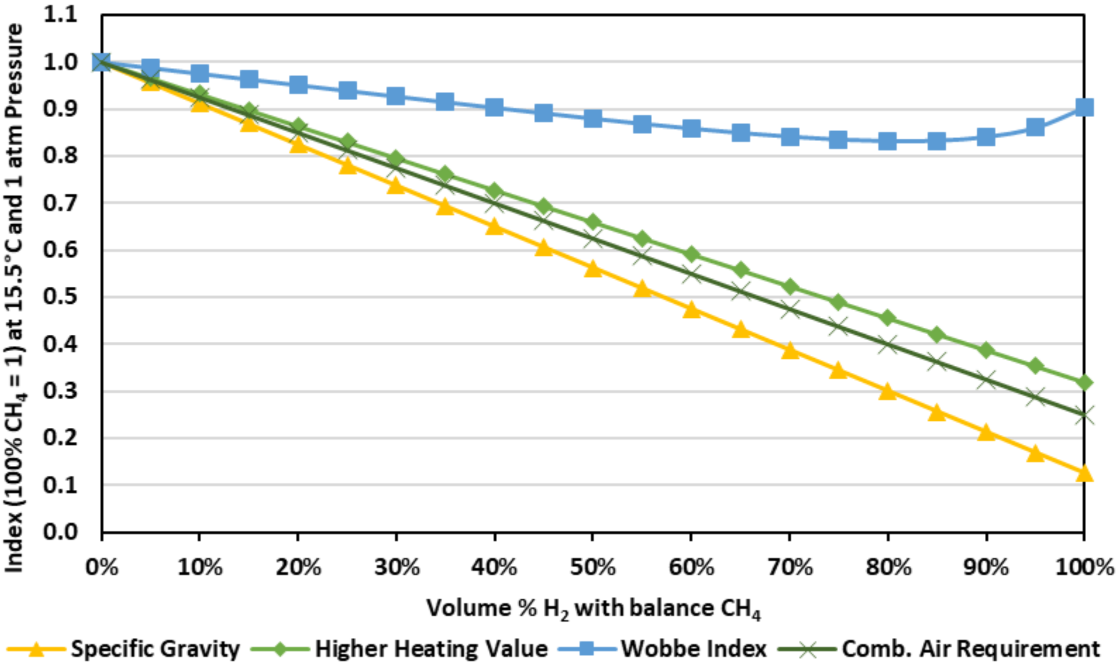

Figure A1. Impact of hydrogen blended into methane on key gas quality properties.

For equipment operating on distribution networks maintained at low pressures, typically 34 to 138 mbar delivered for typical homes and businesses, the most significant impact is the reduced volumetric density, as specific gravity (SG) is reduced by 17% for a 20% hydrogen blend and by 87% for pure hydrogen, where values for natural gas are typically 0.60 to 0.70. Similarly, the higher heating value (HHV) is reduced by 14% for a 20% hydrogen blend and 68% for pure hydrogen, driven by this volumetric density impact. A commonly used metric to judge the interchangeability of gaseous fuels, the Wobbe Index (WI), is defined in Equation (A1). As shown in Figure A1, WI is stable over the range of hydrogen addition, reducing by only 5% for a 20% hydrogen blend and by 10% for pure hydrogen. In practice, fuels with the same WI should yield the same heating rate for a given appliance with a fixed orifice pressure. However, it is imperfect for predicting the response from equipment with modern combustion controls or for certain fuel mixtures.

Analogous to the WI, the combustion air requirement (CAR), as defined in Equation (A2), posits that for appliances without active control of the air-to-fuel ratio, representing the majority of those in buildings, the actual air-to-fuel ratio is assumed to be a function of the fuel density alone for a given appliance with a fixed orifice pressure, and thus the excess aeration can be predicted for a change in fuel as the product of the air-to-fuel equivalent ratio (λ), and this index is assumed to be constant. From Figure A1, the stoichiometric combustion air-to-fuel ratio declines significantly, by 15% with a 20% hydrogen blend and by 75% for pure hydrogen, indicating the sharp reduction in combustion air necessary for hydrogen versus methane. Note that as with the WI, the CAR is imperfect in its predictive accuracy, as fuel and air mixing is a complex, turbulent process influenced by changes in fuel viscosity and other properties. The fact that hydrogen addition impacts λ is fundamental, making subsequent predictions of flame speed, emissions, and other impacts very difficult.

$$\text{Wobbe Index} = \text{HHV}/\sqrt{\text{SG}}, \tag{A1}$$

$$\text{Combustion Air Requirement} = \frac{(\text{Air to Fuel Ratio})_{\text{stoichiometric}}}{\sqrt{\text{SG}_{\text{fuel}}}}, \tag{A2}$$

It is important to emphasize the nuances of CO_2 emission reduction from blending hydrogen into natural gas, as hydrogen is primarily viewed as a decarbonization vector. In Figure A2, the following illustrative comparison is made, examining the impact of normalizing to a volume, mass, or energy basis.

1. Scaling to a mass basis is not common, as the delivered fuel is measured on a volumetric basis (ft^3, m^3). Nonetheless, hydrogen's significantly higher energy density on a mass basis (e.g., Btu/lb, MJ/kg) is shown to increase by more than 2.5 times for pure hydrogen. However, when plotted as a function of volume of hydrogen added (horizontal axis), the CO_2 emission factor on a mass basis is highly non-linear.
2. Scaling to a volumetric basis is appropriate in some circumstances, and with zero on-site CO_2 emissions from hydrogen, the emission factor declines proportionately with blending (e.g., 10% blend reduces CO_2 emissions by 10%). In practice, this is only appropriate when there is not manual or automatic compensation for the reduced heating rate (e.g., decorative gas fixtures).
3. Scaling to an energy basis is appropriate in most cases, where the fuel-fired equipment manually or automatically compensates for the reduced heating rate. For example, in a furnace operating normally as controlled by a thermostat for a given heat demand, the furnace will consume more blended fuel with longer operating times to compensate for the fuel's reduced heating value, yielding a net CO_2 reduction of 7.2% at 20% H_2 (energy basis).

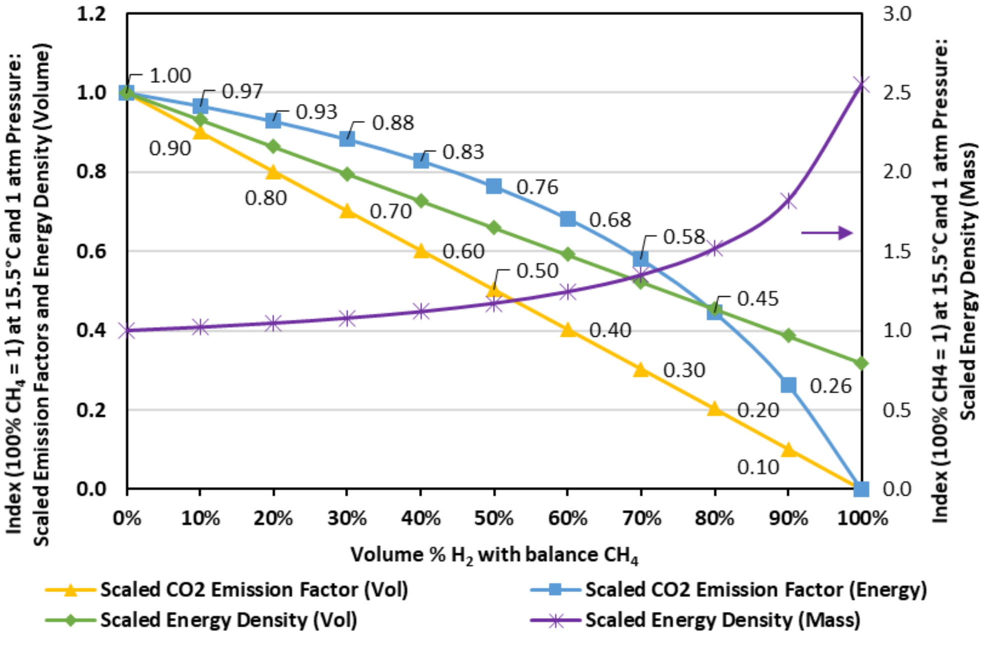

Figure A2. Impact of blended hydrogen in methane on CO_2 emission factors.

Note that this discussion neglects any upstream CO_2 emissions in hydrogen production, transmission, and distribution, in the same manner as for "site" electricity. Additionally, testing is necessary to assess the CO_2 emissions reduction from specific equipment, as the operating efficiency has been shown to be impacted by changes in the fuel mixture [22,23], as shown in this paper.

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