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HYDROGEN AS A FUEL

FOR COMBINED HEAT AND POWER (CHP) PLANTS

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Contents

In recent years, hydrogen as a fuel has gained momentum and popularity, mostly as a viable storage medium of energy in the context of decarbonization. Industries, governments, and other stakeholders over the past years have started to delve into the potential use of hydrogen (H_2) as a fuel. Despite recent advances in hydrogen utilization technology, there are numerous technical issues that need to be addressed to assure that hydrogen can be utilized as a decarbonizing fuel for combined heat and power plants. This report provides an overview of challenges that need to be addressed to reduce barriers for hydrogen's uptake and ultimately contributing to the goal of minimizing carbon fuel dependency.

Hydrogen production

Hydrogen can be produced via a variety of methods, as depicted in Figure 1, based on where it is used. Depending on its mode of production, hydrogen is categorized with basic color codes or nicknames used within the energy industry for different types of hydrogen. These are assigned to hydrogen without a universal naming convention (Brown & Roberts, 2021).

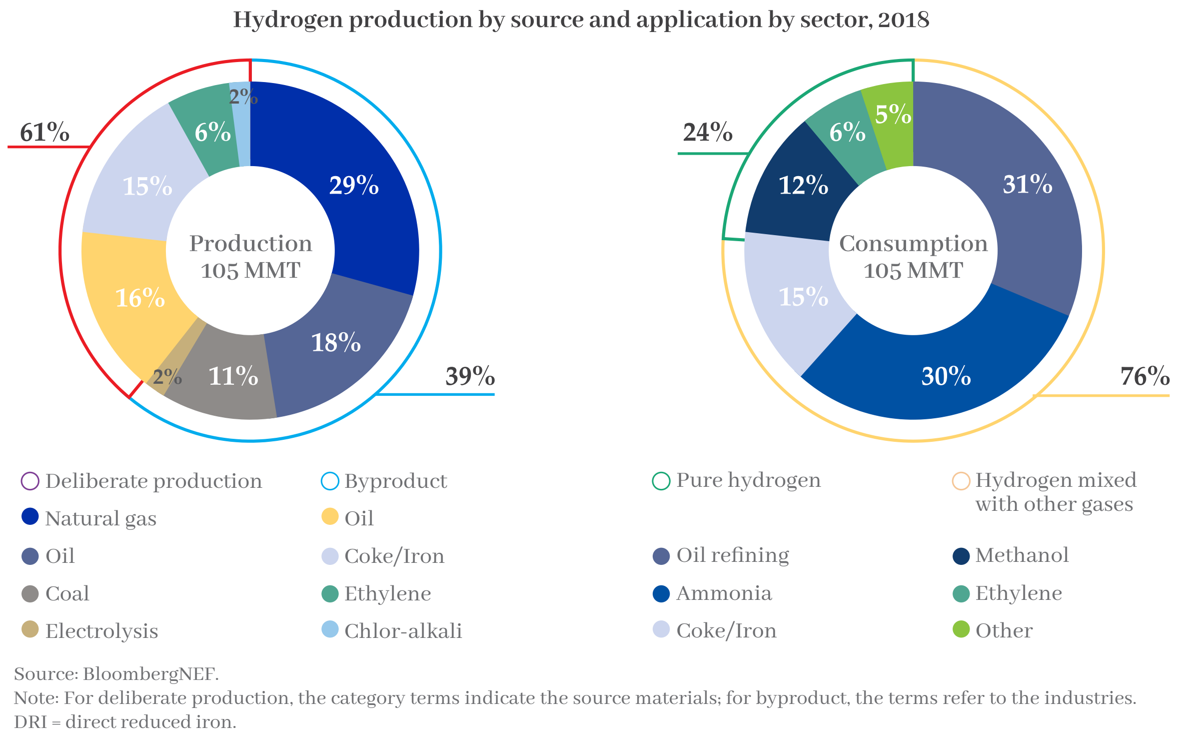


Figure 1. Current production of hydrogen (Global Gas Report, 2020)

Types of hydrogen fuel

Green hydrogen: Green hydrogen is associated with hydrogen that is produced without GHG emissions through a sustainable and environmentally friendly method. The most common method is electrolysis, utilizing electricity to split water into hydrogen and oxygen. The key to this method of producing green hydrogen is that the electricity for electrolysis comes from renewable sources, such as wind, solar, or even waste biomass that have no associated GHG emissions.

Blue and gray hydrogen: Blue hydrogen uses a process called "steam reforming," according to which steam is utilized to produce hydrogen from natural gas. This process does produce GHGs, but they are captured and stored. Gray hydrogen is produced through the same process, but in this case, there is no capture of resulting emissions and GHG is released into the atmosphere.

Brown and black hydrogen: Brown hydrogen (from brown coal) and black hydrogen (from black coal) are produced via gasification, a well-known method that converts carbon-rich materials into hydrogen and carbon dioxide. Similar to gray hydrogen, byproducts of gasification are released into the atmosphere. Typically, when hydrogen is produced using a fossil fuel (i.e., methane, coal) and the carbon is captured, it is called blue hydrogen.

There are also other colors such as yellow (direct water splitting), pink (from nuclear energy), white (extracted from underground) and gold (produced from microbes), but these most likely will not be prominent for the next 20 to 30 years.

Consequently, hydrogen can be produced through a number of methods that result in different levels of emissions. There is resistance to the use of hydrogen as a fuel (Patt, 2021), given that it could take up to six times more electricity to produce the necessary hydrogen, when compared to using a heat pump to heat the same building.

Infrastructure to transport hydrogen to power plants

The three main methods for transporting hydrogen, which are very dependent on the distances and the volumes transported, are pipes, trucks, and ships.

Currently, the most viable way of transporting hydrogen is through pipelines in a similar way to natural gas (NG), where hydrogen flows under pressure through pipes. Modifying existing gas pipelines to carry hydrogen could be up to 90% less costly than building new hydrogen dedicated networks. Additionally, the existing pipelines are already socially accepted (routes, including rights of way and use). Typically, blends of up to 5%-20% hydrogen by volume can be tolerated by the pipes used in gas distribution networks, as these operate at lower pressures and often use different materials (Global Gas Report, 2020).

The cost of the materials used for hydrogen pipes are also broadly comparable to natural gas pipes. These factors give pipelines a particular advantage over other modes of hydrogen transport. In addition, hydrogen, being lighter than methane, travels nearly three times faster through a pipe. A 100 km journey via a high-capacity pipeline, moving more than 100 tons per day, costs around $0.10/kg today, with the potential of being even lower when large-scale hydrogen storage technologies become widespread (Global Gas Report, 2020).

Large-scale pipeline infrastructure must be compatible with hydrogen transportation as hydrogen can cause steel embrittlement in the existing pipelines.

Hydrogen embrittlement (HE) is defined as the deterioration in the mechanical properties of the material, such as the tensile strength, elongation to failure, and fracture toughness (King, 2009). There are three distinct forms of hydrogen embrittlement (Hirth & Johnson, 1976):

- delayed failure
- reduced plasticity
- brittleness in contact with gaseous hydrogen

Hydrogen embrittlement is more likely to occur in steel with higher strength (tensile strength >830 MPa or hardness >22 HRC) and at higher applied or residual stress. Severe cold working also increases its probability (King, 2009).

A potential solution to this problem is to transport pure hydrogen using modern distribution pipes made of polyethylene, as most plastic materials are not susceptible to hydrogen embrittlement. There are claims of several advantages of polyethylene pipes over metallic materials, such as corrosion resistance, reduced weight, increased durability, lower cost, and improved environmental efficiency (Raghothamarao, 2021).

> **Modifying existing gas pipelines to carry hydrogen could be up to 90% less costly than building new hydrogen dedicated networks.**

Another possible solution is to internally coat the pipelines using cured-in-place (CIP) technologies to prevent embrittlement and allow 100% hydrogen operation (ACER, 2021). In both cases, the existing pipelines will need either a retrofit or a replacement and cost will depend on a litany of factors (type of material, volumetric % of hydrogen into the blend, location).

Furthermore, when the mixture of natural gas/hydrogen is pumped through the network, it will pass through existing compression stations as well as the gas metering and reducing stations, which can work with the volumetric percentage of hydrogen that the existing pipeline network can carry. There are some issues that need to be addressed. Importantly, due to the low molar mass of hydrogen and larger volumetric flow, the power needed for hydrogen transport can roughly be estimated as three times higher when compared to NG to achieve similar energy flow.

One technique to overcome this challenge can be to operate the compressor stations utilizing reduced compressor power. Operating at less than its maximum capacity would lead to a lower cost of transportation due to avoiding the cost of additional compression but will also result in lower capacity. This can be the better alternative particularly during the early stages of hydrogen market growth, when the volumes of hydrogen to transport are low (ACER, 2021).

There is also the challenge of materials compatibility in other processes; despite existing commercial solutions for hydrogen-ready compressors, it is currently not possible to retrofit gas turbo-compressors (TC) to operate with gas containing more than 40% hydrogen in volumetric terms. Some studies forecast that by 2030 the industry-standard compressors driven by gas turbine engines could possibly be converted to operating on 100% hydrogen, but currently there are no technologically ready solutions yet reported for full commercial scale operations. To make this possible, new hydrogen-resistant fan materials are needed that can withstand higher centrifugal forces. In the case of electric-driven compressors, no major changes are required for the engines, but changes must be made for the compressors (ACER, 2021).

It remains unclear whether the cost of retrofitting or replacing existing gas-engine driven compressor stations with 100% pure hydrogen would be feasible in the future (ACER, 2021).

In addition to the aforementioned predicaments, given the low mass of hydrogen as a volume, there are issues with regard to leak tightness of both metallic and polymer seals. All such components must be able to cope with higher H_2 fractions than already used in industry, and systems need to be implemented to assure the tightness of each component. Additionally, when it comes to leak detection, various solutions, like FID (flame ionization detection-based on a hydrogen flame), DIAL (differential infrared laser, absorption spectroscopy) have been proposed as suitable for hydrogen leakage detection, but their efficiency remains to be tested, especially for hydrogen percentages higher than 5% (Altfel & Pinchbeck, 2013). Therefore, the full compatibility of commercial valves and leakage detection systems with higher hydrogen percentages remains to be tested in a larger spectrum than it currently is.

In conclusion, NG networks will have to undergo changes and removal of components that are not hydrogen compliant such as:

- deployment of pipeline monitoring technologies for identifying cracks
- changing valve fittings and seals within the pipeline or applying an internal coating
- establishing a retrofit of compressor stations to have the whole system hydrogen compatible

The level of difficulty for achieving all of this depends on the current status of the infrastructure as well as the quantities that need to be transported to power plants.

Using pure hydrogen and hydrogen blended with natural gas as fuel

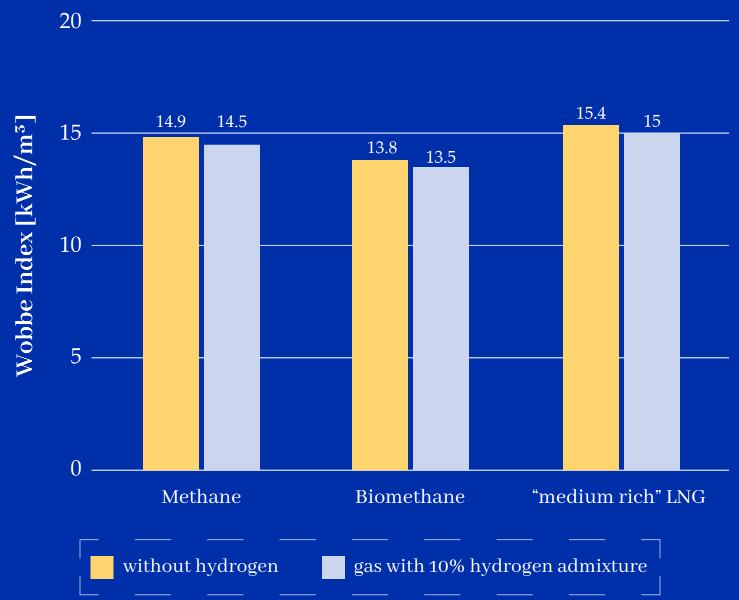
Mixing hydrogen with natural gas creates a fuel blend with different properties and changes the combustion reaction. Aspects discussed hereafter apply to burning pure hydrogen as a fuel and will also cover the mixture of hydrogen and natural gas as a fuel, mainly because this application is more mature.

A tool to quantify this interchangeability between different fuels is the **Wobbe index (W)** (CIMAC WG17 Gas Engines, 2015). This is defined as the ratio between the higher heating value-Vc (nominator) of the fuel and the square root of the specific gravity of the fuel (denominator).

$$W = \frac{Vc}{\sqrt{Gs}} \quad (1)$$

If the two gases have identical Wobbe indices, then for given pressure and valve settings, the energy output will also be identical, meaning gases with the same W produce the same heat load in a gas burner.

Mingling hydrogen with natural gas slightly decreases W (10% hydrogen lowers W by ~ 3%). This is depicted in Figure 2 where we can juxtapose the W of pure methane, biomethane (simplified analysis: C_1=methane: 96%; CO_2:4%), and a "medium rich" LNG (C_1: 92%; C_2: 5%; C_3: 2%; C_4: 1%) (percentages are vol% in this graph). The W range is 13.8 kWh/m³-15.4 kWh/m³ for the gases without hydrogen admixture and 13.5-15.0 kWh/m³ if 10% hydrogen is introduced



Wobbe index of different gases without / with 10% hydrogen admixture

Figure 2. Wobbe index (W) of various fuels with hydrogen in the admixture. (Altfel & Pinchbeck, 2013)

(Wobbe index reference temperatures: 0 °C (volume), 25 °C (combustion), 1.01325 bar). As seen, mingling 10% hydrogen into the fuel does not cause important variations. However, if biomethane is considered, local Wobbe specifications can prevent hydrogen injection because biomethane already has a low Wobbe index.

Another important number that is used to describe the fuel mix is the methane number (MN) (CIMAC WG17 Gas Engines, 2015). This refers to the knock behavior of fuel gases when burned inside internal combustion engines (ICE). Knock is a form of abnormal combustion, and it can be defined as a phenomenon that leads to high pressure oscillation in the combustion chamber of an engine as a result of the spontaneous auto-ignition of end-gases ahead of the propagating flame in the combustion engine (Altfel & Pinchbeck, 2013). The auto-ignition of these end gases occurs as a result of an increase in temperature experienced by the end gases, which is brought about by the compression exerted by the propagating flame and heat transfer through radiation from the propagating flame. The knock behavior is influenced by the specific gas composition and especially the amounts of higher hydrocarbons (C3, C4, C5) and hydrogen in the fuel gas. As figures of merit, the Methane Number (MN) of pure methane is 100, for pure hydrogen it is 0, and for rich LNG it is around 65-70.

Figure 3 shows the MN of various gases without/with 10% hydrogen admixture (Altfel & Pinchbeck, 2013). In contrast to the W index, the MN of different gases without H_2 shows a greater variation (from 100 to 74) than the effect of 10% hydrogen. However, if the natural gas already has a low MN (e.g., rich LNG) the admixture of 10% hydrogen can result in an unacceptably low MN from a combined heat and power plant operator's perspective, leading to lower energy produced from the installation. This is an important factor that needs to be considered when a CHP installation is designed to use a NG/H fuel mixture.

Finally, a parameter to be considered is the flame speed, a rather complex combustion parameter that describes flashback and flame stability. The flame speed has been found to increase with hydrogen addition, among other things, because the air quantity needed to burn the mixture changes. When it comes to gas engines, there is a

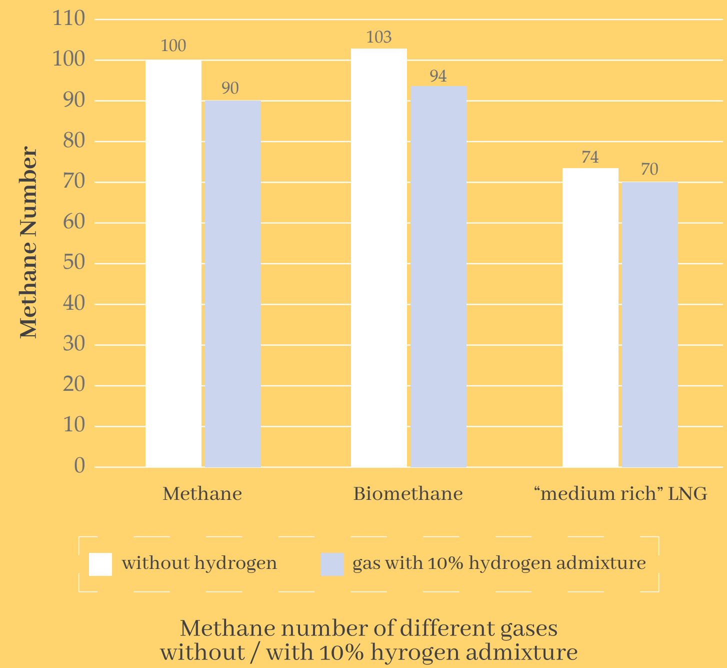


Figure 3. Methane number (MN) of various fuels with hydrogen in the admixture. (Altfel & Pinchbeck, 2013)

~5% increase of the laminar flame speed for hydrogen admixture of 10%, whereas in gas turbines. a hydrogen admixture of 10% may result in a ~10% increase in turbulent flame speed. This has the potential to cause a litany of issues such as flashbacks, hydrogen leakage, different flame temperatures, and altered operability and efficiency (Schaffert, et al., 2020).

Hydrogen and natural gas in **CHP installations**

Electricity production using gaseous fuels and combined heat and power plants offers the greatest potential for CO_2 reduction, taking into account that the combining of these technologies enables maximum fuel utilization and minimal emissions at the same time, reaching commercial efficiencies well above 80%. These CHP plants can either use gas engines or gas turbines that are compatible with a blend of hydrogen and natural gas and have manufacturer-dependent characteristics. However, a number of technical obstacles need to be addressed before being able to fully utilize hydrogen/NG blends.

Hydrogen-ready plants are not new. Innio has been operating gas engines with a high hydrogen (>15%) content since 1997. Waste gases from steel production and synthetic gases with high hydrogen content of up to 60 vol% are in operation, and recently, CHP plants have utilized hydrogen blending to natural gas up to 70 vol% (Laiminger, Url, Payrhuber, & Schneider, 2020). The first combined heat and power plant has already been scheduled to operate on a blend of 0 to 100 vol% hydrogen within 2022 (Laiminger, Url, Payrhuber, & Schneider, 2020).

This is similar for gas turbines; Siemens has already developed series that have been burning mixtures of hydrogen and methane, mostly for petrochemical customers, e.g., coke oven gas applications, where the fuel mixtures are characterized by high hydrogen (50-65 vol%) content and refinery gas experience with hydrogen content of up to 85 vol% (Siemens Gas and Power GmbH & Co. KG., 2020). In contrast to gas engines, no fuel flexible gas turbine that can handle pure hydrogen is commercially available (ETN Global, 2020). The development of combustion systems that can handle the full range of 0%-100% hydrogen contents blended with natural gas is even more challenging, but it is required for potential fluctuations in future hydrogen fuel supply (ETN Global, 2020).

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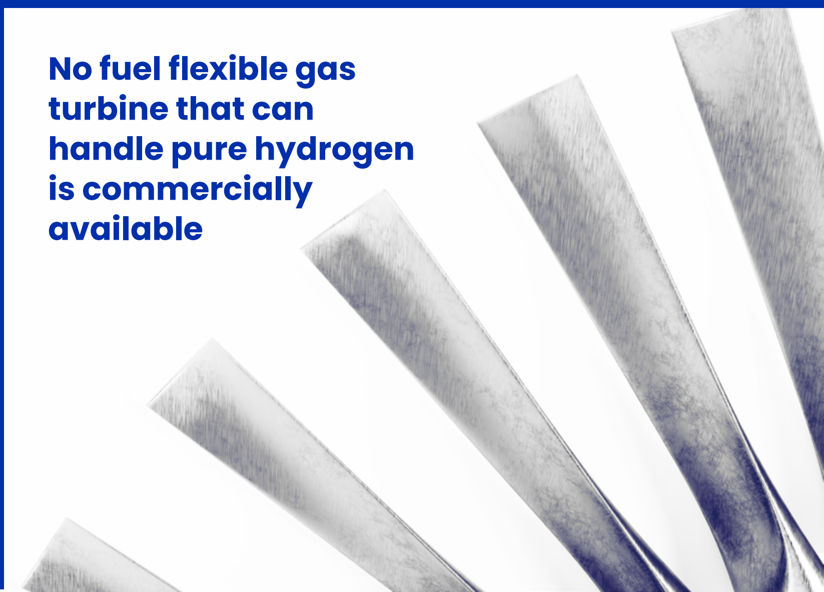

Figure 4. Projects with different gas qualities (H_2 content) (© Innio Jenbacher) (Laiminger, Url, Payrhuber, & Schneider, 2020).

Gas engines

As previously mentioned, any increases in flame speed and reactivity caused by hydrogen addition to natural gas typically causes cylinder peak pressures to rise. Moreover, hydrogen addition leads to improved engine efficiency but presents the following drawbacks (Altfel & Pinchbeck, 2013):

- ⇧ **Increased engine wear and increased non-compliant NOx emissions.**

- ⇩ **Reduced power output or tripping, for engines with knock control;** this will affect sensors that measure the necessary air inside the combustion chamber, which consequently will send an inaccurately lower measurement of oxygen in the exhaust gas. This causes the control system to change the air-fuel ratio, resulting in a leaner mixture than intended, thus influencing performance and increasing both emission levels, particularly NOx, and the possibility of misfiring. The aforesaid error will also increase the risk of occurrence of explosions in intake, crankcase, and exhaust will increase with hydrogen admixture.

- ⇧ **Increased combustion and end-gas temperature,** which leads directly to enhanced sensitivity for engine knock and increased NOx emissions due to higher temperatures.

The latter can have repercussions on the allowed hydrogen content, since even low fractions of hydrogen can precipitate engine knock, when juxtaposed to the natural gas as fuel. If the knock resistance of the fuel is at the lowest value acceptable for an engine or population of engines and no adaptation of engine operation is possible, then no hydrogen can be added to this gas.

For natural gases with compositions with a relatively high knock resistance (and consequently, engines that burn that type of gas have a substantial knock "reserve"), the exact amount of maximum hydrogen addition is complicated by other performance issues, such as the large diversity of engine types and field adjustments of the mounting system due to it being subjected to higher loads.

There are no controls in the majority of existing CHP plants to allow for any adaptation of engine conditions for fluctuating fractions of hydrogen addition, so modifications are needed. This can be important in regard to NOx emissions; many gas engines are not capable of adapting their operating conditions for hydrogen addition (air-fuel ratio, timing) and/or are at the permitting NOx limit, hence they cannot admit any hydrogen in the fuel mixture.

As a solution against engine knock, NOx, and engine wear, the peak pressures and temperatures can be lowered to those that will negate the effects of hydrogen. However, it's clear that unless the hydrogen fraction, and the natural gas composition to which it is added, can be constant, adaptations will have to accommodate fluctuating amounts of hydrogen.

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Gas turbines

In regard to gas turbines and the extensive literature existing on gas turbines for gases containing high and mostly fixed fractions of hydrogen, mingling natural gas and hydrogen in the fuel mixture for installed gas turbines is quite rare.

Current commercial uses of gas turbines have a limit on the hydrogen volume fraction in natural gas that depends on the design of the turbine, NOx emissions, and many other factors (i.e., type of natural gas). For the existing typical CHP installations and depending on the case, percentages of 5% (Altfel & Pinchbeck, 2013) and up to 70% (Ansaldo Energia (Press Release), 2018) (ETN Global, 2020) can be considered, with the latter percentage certainly applied to newer generations and the former being valid for older gas turbines. Thirty percent can be considered as a general upper limit for hydrogen admixture to natural gas for older designs, depending on whether the existing installation can accept modifications allowing for a fuel mixture, the design of the turbine, and other factors.

Recent turbine designs reach up to 30%-50% volume for heavy duty engines, 50%-70% volume for smaller engines (IGT), and 20% volume for micro gas turbines (ETN Global, 2020). The amount of hydrogen capacity depends largely on the type of combustion technology the gas turbines utilize. Burners that use dry low emissions (DLE) technologies (using staged combustion and lean-premixed fuel-air mixtures) can more easily allow for higher blends (up to 50%-70%) than wet low emissions (WLE) (up to 25%) that apply water or steam injections in the combustion zone to lower the flame temperature (Ansaldo Energia (Press Release), 2018) (Siemens Gas and Power GmbH & Co. KG., 2020). Achieving these percentages also depends on the local NOx emission regulations, with DLE systems reaching higher hydrogen volumetric percentages due to having relatively lower emissions.

However, both technologies can have hydrogen/NG difficulties. Firstly, burning hydrogen will increase the moisture content in the exhaust gas, causing higher heat transfer to the gas turbine hot gas path components. This means that due to the higher moisture content, hot corrosion is more likely to occur within the turbine. Additionally, the turbine needs a cooling system capable of preventing overheating of components. By the same token, hydrogen has higher flame temperatures compared to natural gas, which means NOx emission will be higher without abatement. Regarding the latter issue, DLE and WLE systems can both be used against these increased NOx emissions, but both have their own drawbacks.

DLE systems have the following issues to contend with (Siemens Gas and Power GmbH & Co. KG., 2020):

- ⇨ Higher flame speeds with hydrogen increase the risk of the flame burning closer to the injection points, traveling back (flashback) into mixing passages or burning too close to liner walls, causing damage. This risk increases as the hydrogen content in the fuel is increased and with increasing combustion inlet and flame temperatures.
- ⇨ Hydrogen's lower auto-ignition delay compared to methane increases the likelihood of igniting the fuel in the mixing passages, again leading to damage.
- ⇨ Changes to thermoacoustic noise patterns because of the different flame heat release distribution can reduce the life of combustion system components.

WLE systems that use diffusion flames for fuel burning require dilution to control NOx emissions, which are driven by high flame temperatures (Siemens Gas and Power GmbH & Co. KG., 2020). Dilution is achieved by the introduction of nitrogen (N_2), steam, or water into the flame; hence nitrogen dilution has the advantage of often being available at the plant as a byproduct of gasification processes. Also, using the nitrogen produced as a byproduct to dilute the fuel reduces plant operating costs. Moreover, steam dilution is significantly more efficient than nitrogen dilution in terms of emission reduction; and in combined cycle or in some configurations, steam dilution has a relatively smaller plant efficiency impact. Nonetheless, an important drawback to WLE systems is their reduced efficiency, given they achieve lower burning temperatures. Furthermore, for single shaft gas turbines, the surge margin can be a challenge with diluted high-hydrogen fuels, due to changes in the balance of volumetric flow between the compressor and the turbine. This can be addressed successfully by compressor and/or turbine modifications, but the task remains somewhat laborious and complex (Siemens Gas and Power GmbH & Co. KG., 2020).

To sum up, for both DLE and WLE technologies, the final uptake of hydrogen within the burning mixture depends on the NOx emissions. Therefore, the hydrogen limit on CHP using gas turbines truly depends on the turbine's design and local certification requirements.

As a general conclusion for both cases, gas engines and gas turbines are both able to cope with a hydrogen/NG blend, with the former tolerating better fuel variations than the latter, given their higher flexibility in handling different fuels (Wärtsilä Corporation, 2015).

The addition of hydrogen in the fuel composition variation is possible but can have an adverse impact on gas turbine operation, despite being within the range allowed in the grid and manufacturers' specifications. New plants are more able to cope with higher hydrogen contents, given the amount of retrofits the existing plants might need. In all circumstances, a case-by-case approach might be the most suitable way to proceed, with special attention to the exact details. An important step could be the application of common emission criteria to gas turbines, gas engines, and other combustion processes, accelerating and facilitating the use of these admixtures.

Gas engines and gas turbines are both able to cope with a hydrogen/NG blend, with the former tolerating better fuel variations than the latter, given their higher flexibility in handling different fuels

Conclusion

As explored from production to consumption, currently, using hydrogen as a fuel for CHP plants with a goal of reducing greenhouse gases is technically plausible. Nevertheless, quite a number of technical challenges remain that need to be addressed before considering widespread use of hydrogen and natural gas fuel mixtures to fully exploit the coming hydrogen economy. These challenges come from all aspects, from production and transportation of these fuel mixtures to different burning technologies and their installations. While they are certainly far from prohibitive to the expansion of hydrogen as a fuel for CHPs, they certainly pose a challenge when building a roadmap for hydrogen/natural gas admixtures.

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