ASIA TURBOMACHINERY & PUMP SYMPOSIUM
24-26 MAY 2022
SHORT COURSES: 23 MAY 2022
KUALA LUMPUR, MALAYSIA

HYDROGEN-COMBUSTION AND COMPRESSION

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ABSTRACT

Recently, the use of hydrogen-natural gas mixtures as a fuel, but also as a means of storing and transporting hydrogen from surplus electricity as a result of renewable energy production has drawn significant attention. One of the approaches to manage the intermittent nature of wind and solar generated electricity is to create, store and transport hydrogen in natural gas pipeline networks. Blending hydrogen into the existing natural gas pipeline network appears to be a strategy for storing and delivering renewable energy to markets. Adding Hydrogen to the natural gas requires considerations regarding combustion systems, as well as the impact on compressors and pipeline hydraulics.

This paper addresses combustion issues with various levels of hydrogen in natural gas, the transport of these mixtures in pipelines, and the compression of these mixtures. Thus, the transport efficiency of the pipeline, the impact on pipeline capacity, and the capability of existing and new infrastructure to use natural gas – hydrogen mixtures as fuel are discussed.

Used as a fuel, hydrogen-natural gas mixtures increase the reactivity, with increased flame velocity, reduced auto-ignition delay times, and a wider range of flammability. The handling of failed starts, where unburned fuel can be present in the exhaust system and may cause an explosion hazard, has to be addressed. Increasing hydrogen content also increases flame temperature which can lead to higher

NOx emissions and mitigation strategies are discussed. Results from analysis and rig testing of the combustion components with hydrogen and natural gas mixtures are presented.

INTRODUCTION

Alternative energy technologies to mitigate the build-up of greenhouse gases (GHGs) and to minimize global warming are being pursued with growing vigor. In particular, the use of renewable energy generation technologies, such as photovoltaics (PV) and wind power, is increasing steadily [1]. Figure 1 shows this trend where over 65% of the electrical power capacity additions by 2040 will be in these two types of renewable energy [2]. However, these forms of renewable energy have fundamental limitations: First, they are power sources that are variable in both the short term and long term (e.g. seasonally). Secondly, wind and PV are not suitable in all geographic locations, thus requiring power transmission. In many parts of the developed world building additional electrical transmission infrastructure is deemed undesirable. This creates a need for alternate means of energy transport, as well as the capability to store large amounts of energy. The electrical system therefore has to both accommodate the over production of electricity, as well as a lack of energy production in cases when sun or wind energy is temporary reduced or unavailable ('Dunkelflaute').

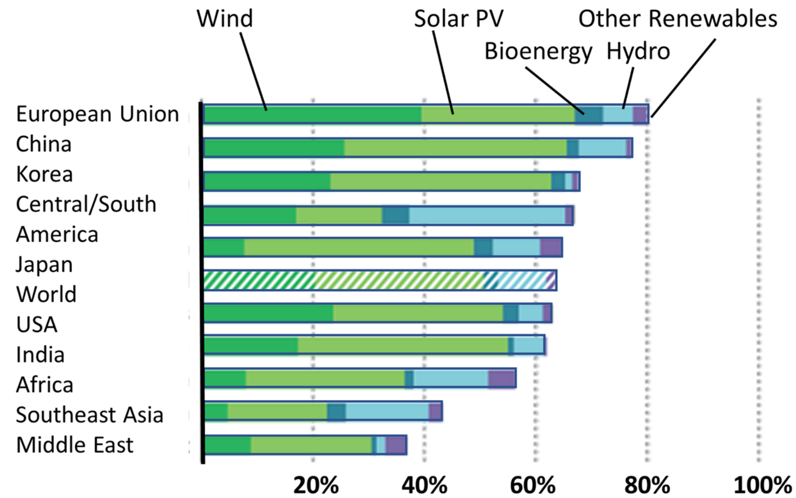

Figure 1: Share of renewable energy sources in gross capacity additions from 2018 to 2040, taken from IEA [2].

If an electrical system has to consume available electricity from renewable energy before fossil fueled power plants provide energy, the fossil fuel plants have to be able to compensate for large swings in renewable energy supply. In Figure 2, each line represents the net load, equal to the normal load minus wind and PV generation. This chart is often referred to as the duck curve, where the "belly" of the duck represents the period of lowest net load, where PV generation is at a maximum. The belly grows as PV installations increase between 2012 and 2020 [3].

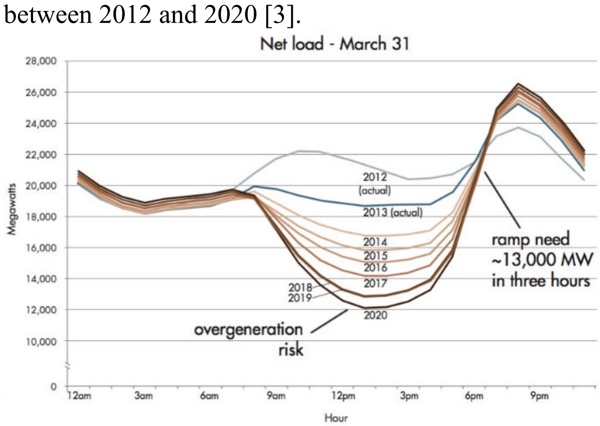

Figure 2: The 'Duck Curve', taken from Denholm et al. [3].

In many situations, renewable energy supply exceeds the demand, leading to a negative value for the electricity produced. A solution that is getting much attention is the so-called power-to-gas (P2G) approach. The P2G scenario uses excess renewable energy created during peak production periods to create hydrogen via electrolysis that is then added to the existing natural gas transmission system to both store and transport the energy. Current European plans call for the capability to add up to 10% Hydrogen into the natural gas stream. Similar ideas are being discussed in North America [4].

P2G offers advantages for longer term storage as depicted in the chart in Figure 3. This figure illustrates that for storage of large amounts of power for extended periods, generating hydrogen or other chemicals such as ammonia can be an attractive option [2]. These scenarios compete with other energy storage solutions, as well as with hybrid compressor systems [5].

The addition of hydrogen to natural gas raises many questions for gas transmission and natural gas pipeline companies, primarily, what is the impact on their gas turbine fleet? This paper examines the primary considerations in terms of impact to fuel handling, the gas turbine combustion process, and implications to the gas turbine package. Operating performance and safety considerations are being evaluated and are outlined. Hydrogen addition to natural gas pipelines will also impact the driven compressor performance [6].

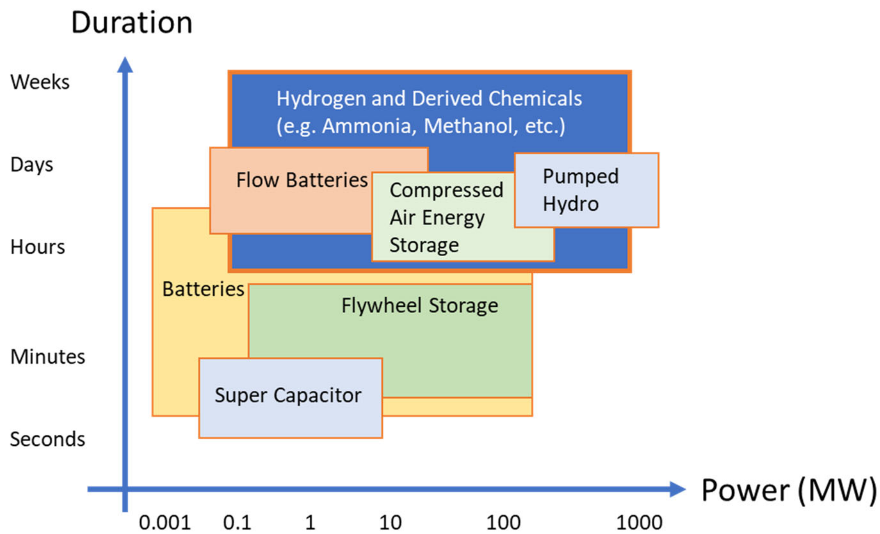

Figure 3: Comparison of energy storage concepts suitability based on storage duration required and amount needed, taken from IEA [2].

Hydrogen is the most abundant element in the universe. However, on Earth, hydrogen usually occurs as water. It is not a primary energy source. Therefore, all discussions on Hydrogen as a fuel are really about the generation of hydrogen, the transport of hydrogen, and hydrogen as an energy storage media.

Lastly, using hydrogen that was generated by processes described herein as a fuel also has challenges regarding its combustion properties. The advantage of using hydrogen as a fuel, that its major combustion product is water, has to be emphasized.

GENERATION OF HYDROGEN

Since hydrogen does not occur in molecular form naturally, it must be generated from hydrogen-containing compounds, such as water, biomass, natural gas and other fossil fuels, or else recovered from hydrogen-rich process gases such as refinery off gases.
Hydrogen "colors" colloquially refer to the way the hydrogen is generated, and so we have a rainbow of colors including some colors, like brown, grey and black, that are not part of the rainbow. For the most part, turbomachinery that either utilizes or transports hydrogen doesn't care where and how the hydrogen originated, but it is still important to understand the basic nomenclature.

Green hydrogen is produced without any greenhouse gas emissions. It is made by using electricity from renewable sources, like photovoltaics or wind power, to electrolyze water. Electrolyzers use an electrochemical reaction to split water into its components, hydrogen and oxygen.

Blue hydrogen is produced from natural gas using a process known as steam reforming, where natural gas and steam react to form hydrogen, but also carbon dioxide. To make hydrogen "blue," the carbon dioxide must be captured and sequestered. If the same process is used, but the carbon is not captured, we call the gas is called *grey* hydrogen.

Black and *brown* hydrogen are made through partial oxidation gasification from black coal or brown coal (lignite). This is the type of hydrogen that creates the largest amount of environmentally damaging by-products.

Red (also known as *pink* or *purple*) hydrogen is generated using electricity from nuclear energy. Just like green hydrogen, an electrolysis process is used. The difference is that the nuclear waste is created as a by-product of these processes. There are also some ideas to use the high temperature reactors or available steam.

Turquoise (or *cyan*) hydrogen is made by a process called methane pyrolysis. The by-product is solid carbon. Depending on the thermal process that is used for pyrolysis — for example, whether it comes from renewable sources — and the capability to store the solid carbon permanently, this can be a low- or no-carbon process.

Yellow hydrogen is produced by electrolysis directly from solar energy without the intermediate step of creating electricity. In some publications, the term 'yellow' hydrogen is used when the electricity for the electrolysis process comes from multiple sources, some of them renewable, some of them conventional.

And lastly, *white* hydrogen, is naturally occurring geological hydrogen. Yes, there is a process that involves drilling a hole in the ground to get to hydrogen, with some fracking involved; however, there is currently no large-scale exploitation of this relatively rare resource.

Why are the "colors" of hydrogen important, especially since the machinery is agnostic to its source? There are two areas where the production source can make a difference: the pressure at which the hydrogen is available and the composition of the hydrogen gas. Both relate to the fact that hydrogen compression is very energy intensive. For a given mass flow, the amount of work to get a certain pressure ratio with pure hydrogen is almost 10 times higher than that of natural gas. Of course, hydrogen has a much higher energy density on a mass basis than natural gas (the lower heating value of hydrogen on a mass basis is 2.5 times that of natural gas), but even for the same energy flow, the compression work for hydrogen is four times higher.

On the other hand, even a small amount of composition impurity of the hydrogen, such as 4-5% carbon dioxide, can substantially lower the compression work by a factor of two. Therefore, it makes a big difference at what pressure and composition the hydrogen is made available in various compression processes. Also, both the combustion characteristics and the compression work change if other components (such as carbon dioxide or methane) are part of the hydrogen produced. Lastly, the capability of hydrogen to cause material issues (such as hydrogen embrittlement) can be influenced by the presence of other substances in the gas composition.
A third consideration of the source of hydrogen has less to do with the gas itself and more with the by-products of its generation process. Specifically, in processes that produce hydrogen from fossil fuels, carbon dioxide usually also is generated. For example, if blue hydrogen is produced from natural gas using steam reforming, about 10 kilograms of carbon dioxide are produced for every one kilogram of hydrogen. In these cases, the separation, transport and sequestration of carbon dioxide is necessary to maintain greenhouse gas neutrality — and that requires additional compression infrastructure [7].

All methods of producing hydrogen come at a cost. These include the energy loss when primary energy sources are used to generate hydrogen , as well as the cost of sequestering the CO2 in the case of SMR, and the significant volumes of water needed to produce hydrogen in significant quantity, especially in the case of electrolysis and photolytics.

COMPRESSION OF HYDROGEN

Using centrifugal compressors to compressor hydrogen or high hydrogen content process gases poses special technical challenges because of the physical properties and flammability of hydrogen. Although hydrogen is processed in many industrial applications, most hydrogen compressors are found in refineries for hydrotreating, hydrogen plant, and hydrocracker applications. Within these refinery applications, feed-gas, recycle, net-gas, and booster compressors are used to compressor hydrogen over a wide range of pressures and flows. Other hydrogen compressors are found in gasification, electrolysis, and many chemical and petro-chemical plants.

The three major technical challenges of compressing hydrogen are that it is (i) an extremely light gas with a very high specific heat capacity , (ii) it can cause hydrogen embrittlement in ferrous alloys, and (iii) it has a low auto-ignition temperature in the presence of oxygen. Gases like hydrogen are difficult to compress due to their high specific heat capacity, resulting in a low pressure rise for a given amount of work. Even at relatively high impeller tip speeds of 350 m/s (1150ft/s), typical pressure ratios per stage seldom exceed 1.1. This means that long compression trains with many stages per barrel are required if a significant pressure rise is desired. Potential remedies can be low backsweep impellers and higher tip velocities.

As an example, Figure 4 shows a compression train for a refinery net-gas application. Here each of the compressor barrels operating in series has 8 centrifugal impeller stages which results in a total pressure rise from 7 bara to 18 bara. To achieve higher pressure ratios either higher impeller tip speeds or longer compression trains are required.

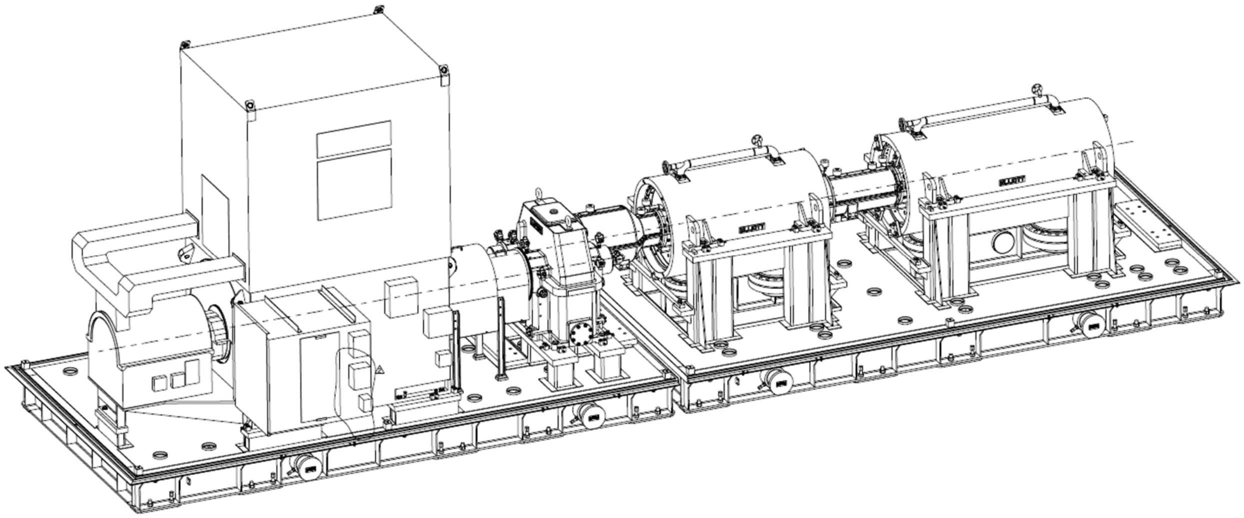

Figure 4: Two barrel tandem wet-gas hydrogen compressors driven by an electric motor.

Hydrogen embrittlement is a metallurgical interaction between ferrous metals and hydrogen gas at certain pressures and temperatures that can lead to rapid yield strength deterioration of the base metal in the compressor. Special surface coatings are available to minimize exposure and direct penetration of hydrogen into the metal. However, as a safety precaution the design yield strength of the exposed alloys must be limited to below 827 MPa. This further limits the operating speed of the compressor and its pressure rise per stage. Hydrogen molecules are small compared to most hydrocarbon gases, which makes case-end and inter-stage sealing challenging. Most hydrogen compressors utilize tandem dynamic dry gas seals and multiple static o-rings to minimize leakage flows. Nonetheless, hydrogen detection and scavenging is often required to minimize the risk of hydrogen exposure to the atmosphere and the associated explosive hazards.

COMBUSTION

Generally, two combustion system technologies are used in industrial gas turbines most frequently today. A comparison of these combustion system concepts is shown in Figure 5. The conventional or diffusion flame combustion system is characterized by high flame temperatures and is designed for concurrent mixing and burning of the air and fuel within the combustor volume. Conventional combustion gas turbines exhibit excellent turn-down with very broad fuel flexibility [8,9].

The other combustion system is a Dry Low Emissions (DLE) system that uses lean premixed combustion to operate with low emissions of NOx and CO. With lean premixed combustion, the fuel and air are premixed in the fuel injector before reaching the flame front at a reduced fuel-air ratio and corresponding reduced flame temperature. A detailed description of this manufacturers DLE combustion system and a comparison with the conventional fuel systems can be found in Cowell [10]. Both the conventional and the DLE configurations are available in either a single gas or with dual fuel capability in which both gas and liquid or two gas fuels can be used. Typically, in dual fuel applications a liquid fuel such as #2 Diesel or a second gas fuel is provided to allow continuous operation in the event of an interruption in the gas supply.

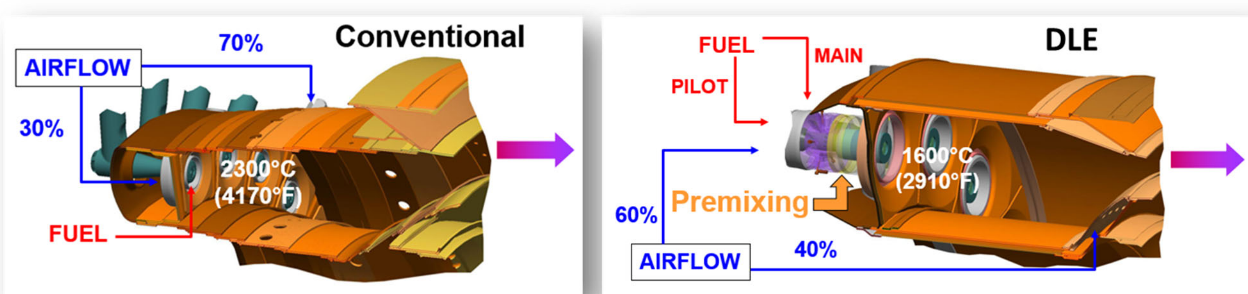

Figure 5: Comparison of conventional and DLE combustion systems.

Adding hydrogen to natural gas changes many characteristics of the fuel that need to be considered for gas turbine applications. First, from a combustion perspective the parameters listed in Table 1 are important and the impact of these changes is discussed. Secondly, Table 1 includes key fuel parameters that are important to consider regarding the gas turbine package and fuel system design and operation. It cannot be assumed that the combustion system is not modified for the fuel blends discussed – in other words, that a gas turbine designed for 100% natural gas can be operated on varying the varying H2 blends in NG without change [9].

Experience with many applications with significant concentrations of hydrogen exist. In the past decade many of these applications have been using coke oven gas (COG) on 23000hp class and 7700hp class generator sets. COG is a process waste gas created in the process to create coke for steel production. The typical gas turbine fuel created with COG has 55 to 60% hydrogen, 25 to 30% methane, 5 to 10% CO, and 5 to 10% diluents (N2+CO2).

Flame Speed is the speed that a flame will propagate through an air-fuel mixture at a given temperature and pressure. As can be seen in Table 1 the laminar flame speed increases nearly exponentially as hydrogen concentration increases. In the case where hydrogen displaces natural gas in the range of 0 to 30% hydrogen, the methane reactions dominate the combustion process and the flame speed increase is relatively modest. Each combustion system is designed for select range of flame speed variation. Diffusion flame systems generally do not have an upper level but do have a lower level where the flame speed becomes too slow to sustain itself. Clearly, adding hydrogen increases the flame speed and flame "blow-out" is not an issue. For a DLE combustion system designed for natural gas there is an upper flame speed level as well. The flame speed of the gas turbine fuel must be less than the injector pre-mixer mixture velocity design point to prevent the flame from propagating into the injector and causing damage. A flame propagating upstream into the DLE fuel injector is called "flashback." For DLE fuel injectors designed for pipeline natural gas, flashback will only occur at significantly higher levels of flame speed. Determining the risk of flashback for fielded DLE combustion systems is a key requirement whenever using a fuel different than pipeline gas [9].

Flame Temperature. The primary pollutant emissions from a gas turbine engine of NOx (oxides of nitrogen), CO (carbon monoxide), and UHC (unburned hydrocarbons) are most directly influenced by the flame temperature. The adiabatic flame temperature is the maximum temperature that the products of a given combustion reaction can reach without heat loss. In a gas turbine combustion system designed for natural gas fuel the pollutant emissions will vary proportionally with an alternate fuels adiabatic flame temperature compared to the adiabatic flame temperature of natural gas. In general, fuels with higher adiabatic flame temperature will create more NOx and less CO and UHC. As can be seen in the table the flame temperature for H2 and natural gas mixtures in the range of 0 to 30% H2 increases approximately 30°F which will increase NOx emissions modestly for a conventional combustion system and very slightly for a DLE combustor (assuming the pilot fuel ratio is not changed). The corresponding change in CO or UHC are less than 1 ppm within the typical gas turbine operating range.

Combustion Stability is characterized by the presence or lack of significant levels of combustor pressure oscillations or combustor rumble. Combustor pressure oscillations occur when the heat release from the flame couples with pressure waves in an acoustic mode of the combustor. Combustor rumble occurs when the combustor or some portion of the combustion volume is operating near the flame extinction point. In either case, if an instability reaches a critical pressure amplitude, damage to the combustor liner or attachments to the turbine section may occur. Extensive analysis, and often engine qualification, is required to verify that different fuel compositions do not significantly change the combustion stability characteristics. *Flammability Range – Lower and Upper Explosion Limits (LEL/UEL).* Hydrogen is highly flammable with a very broad flammability range of 4 to 75% by volume in air compared to natural gas in air with a range of approximately 5 to 15%. It has a slightly lower autoignition temperature than natural gas and must be treated more carefully than when using natural gas fuels to manage the risk of fire or explosion. This is clearly a concern if there is a gas leak near or in the gas turbine package but is also a concern for failed gas turbine ignition or flame-outs when unburned fuel will enter the gas turbine exhaust system. The amount of fuel that can enter the exhaust system between the time the control system detects the failure or flame-out and the fuel valve closes is long enough to completely fill the exhaust ducting. The fuel-air ratio of this mixture in the exhaust is generally below the LEL when burning natural gas so it will not burn. However, with increasing hydrogen this mixture becomes flammable. If this combustible mixture were to ignite in the exhaust system some level of pressure rise will occur, potentially causing damage to the exhaust system components. Table 1 indicates there is only a modest decrease in LEL for hydrogen and natural gas mixtures of 30% or less. This risk is minimal for most of the P2G hydrogen mixture scenarios where the hydrogen will be less than 20%. However, at 20% to 30% H2 there remains the possibility that an exhaust mixture from a failed start or flame-out may be flammable and additional study is in progress to completely characterize and mitigate this risk.

Gas Group & Maximum Experimental Safe Gap (MESG). Operating a gas turbine with hydrogen containing fuels requires to properly assess the gas for the appropriate industry Gas Group. Based on the Gas Group, the hazardous area classification and the selection of equipment, such as electrical instrumentation and electrical enclosures, conformance to the appropriate industry code is required. As an indication of the risk with H2 and natural gas blends the MESG is included in Table 1. MESG is a standard measurement of how easily a gas flame will pass through a narrow gap bordered by heat-absorbing material. It is a primary factor in determining the Gas Group – for IEC with MESG <=0.5. Table 1 indicates the gas group does not change until the hydrogen mixtures in natural gas increase to over 20%.

Hydrogen Diffusivity. As the smallest element hydrogen is significantly more permeable in many steels and other materials than natural gas. Fuel system seals that are leak tight with natural gas may not seal effectively with high hydrogen fuels. Therefore, using high hydrogen fuels may require special leak testing of the fuel system. In addition, elastomers, including O-rings and diaphragms, are more susceptible to explosive decompression with hydrogen fuels. This failure mechanism is caused when a gas (hydrogen) that has permeated into an elastomer expands violently when the pressure is reduced rapidly causing fissuring and seal failure.

*Hydrogen Embrittlement***.** Absorption of hydrogen into metals can cause reduced ductility, which is termed hydrogen embrittlement. High strength martensitic steels are particularly susceptible to embrittlement and should not be used with hydrogen rich fuels. Per NACE MR0175/ISO 15156 2003 carbide-stabilized grades and the 300 series stainless steels should be used for hydrogen fuels. These requirements are applicable for hydrogen mixtures greater than 4 vol%.

Table 1: The variation of key gas turbine combustion characteristics with hydrogen additions to pipeline gas focusing on the Range of 5 to 30%.

	H2% with Balance Pipeline NG					
H2 Blend (% by volume)	**0%**	**5%**	**10%**	**20%**	**30%**	**100%**
Combustion Parameters						
Laminar Flame Speed (cm/s)[1]	**124**	**127**	**130**	**139**	**150**	**749**
Autoignition Delay Time (msec)[2]	**124**	**112**	**107**	**104**	**103**	**76**
Wobbe Index (btu/scf)	**1215**	**1199**	**1183**	**1150**	**1116**	**1039**
Flame Temperature (°F)[3]	**4206**	**4210**	**4215**	**4225**	**4238**	**4510**
Package & Fuel System						
Flammability (% volumetric LEL)	**4.88**	**4.83**	**4.79**	**4.71**	**4.63**	**4**
Maximum Experimental Safe Gap (MESG)	**1.10**	**1.06**	**1.02**	**.94**	**.86**	**.28**
NEC/CSA & IEC Gas Groups	**D & IIA**	**D & IIA**	**D & IIA**	**D & IIA**	**D & IIB**	**B & IIC**

[1] *Calculated for equivalence ratio = 1.0 and mixture temperature and pressure of 600℉ and 1 atm.*

[2]*Calculated for Equivalence Ratio = 0.4 and mixture temperature and pressure of 1200℉ and 10 atm.*

[3] *Adiabatic stoichiometric flame temperature calculated for a 17.5MW gas turbine at full load operating conditions*

GAS TURBINE EXPERIENCE AND QUALIFICATION WITH HYDROGEN

Industrial gas turbines are used in many applications that support and use pipeline natural gas that will be impacted with the addition of hydrogen. These include gas transmission applications to drive pipeline compressors to transport the gas and for local power generation, often in Combined Heat and Power (CHP) configurations, to generate electricity and steam for end users.

The majority of existing gas turbine applications for high levels of hydrogen in the fuel gas use diffusion flame combustion. More recently experience is increasing with DLE gas turbines with considerable concentrations of hydrogen. The unique requirements and qualifications along with field experiences for both diffusion and DLE gas turbines are discussed in relation to using the expected hydrogen and pipeline natural gas fuel blends [9].

Gas turbines with conventional combustion systems are readily capable of using a broad range of hydrogen rich fuels. Typical hydrogen rich fuels used in gas turbine applications have been refinery gas (~30% H_2), coke oven gas (~60% H_2), and industrial process gases (30 to 100%H_2). The impact and requirements for the combustion system and gas turbine package have to be considered. The higher reactivity of hydrogen makes the combustion process more robust and flame-out less likely. For conventional combustion there are two primary areas of concern: 1) the potential for higher combustor liner wall or injector tip temperatures that may shorten operating life and 2) higher NOx emissions that result from increased flame temperature. Operation with higher hydrogen fuels may not have an impact on combustion system component life. This was predicted analytically and has been confirmed through the extensive operating experience described in next section. Note that although Table 1 indicates that flame temperature does increase significantly as hydrogen increases, its effect is muted by gas turbine controls which limit the gas temperature entering the turbine section to keep it nearly constant regardless of the fuel type used. Therefore, the effect of hydrogen is very localized by creating a more compact and hotter flame front. Globally, the average temperatures within the zones within the combustor are not substantially different.

Nevertheless, the NOx emissions are increased as depicted in Figure 6 which compares NOx produced with hydrogen rich fuels with NOx from high methane pipeline natural gas. The NOx creation is increased substantially due to the high temperature flame front. The NOx emissions with conventional combustion can be reduced by as much as 80% through water injection.

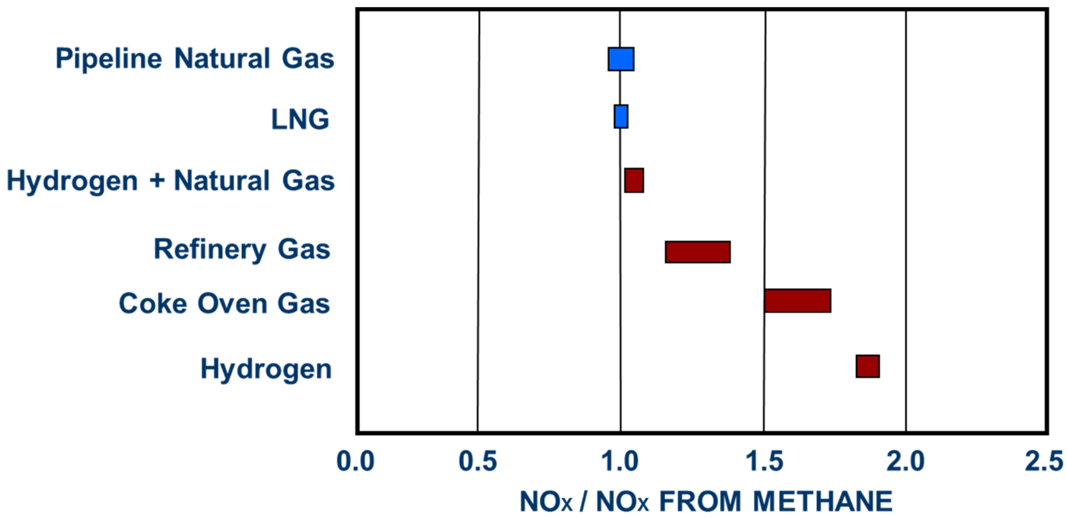

Figure 6: Trends of NOx emissions increase with conventional combustion operating with Hydrogen rich fuels compared to Hydrogen in natural gas in the range of 5 to 20%.

Clearly, for the expected P2G hydrogen and natural gas blends of 5 to 20% the effect on the conventional combustion system will be minor with less than 5% increase in NOx compared to natural gas alone and no impact on durability.

The ability of gas turbines using lean premixed combustion with hydrogen rich fuels is an area of active research and development for most OEMs. The initial assessment at this OEM is that using existing *DLE* gas turbines with the latest combustion system technology, using pipeline gas mixed with 5 to 15% hydrogen will not require significant modification. The ability of earlier generations of DLE combustion systems to use these levels of hydrogen has to be investigated. As stated in the previous section the impact on the combustion system and the gas turbine package will have to be considered. The lean premixed gas turbines are limited by the same fuel and system characteristics that were described earlier for the conventional gas turbines. However, due to nature of the combustion system design several of these characteristics are more restrictive.

As described earlier, the NOx emissions in a lean premixed combustion system are controlled by operating the combustion system at lean conditions that are inherently closer to the lean extinction point. In order to prevent local areas where the fuel -air mixture is not lean, and where NOx formation rates can be considerable, the fuel injector includes a fuel and air pre-mixer section (Figure 5). These design differences present several challenges as natural gas is mixed with hydrogen. First, due to its higher flame speed there is a greater risk for the flame to "flashback" into the injector pre-mixer. The injector pre-mixer is not designed the for high temperatures that would be the result of combustion inside the injector. Secondly, as with conventional systems, the flame temperature changes can impact NOx emissions. Finally, lean premixed combustion systems are sensitive to combustor pressure oscillations that have been "tuned out" for natural gas but as hydrogen is added to the fuel the flame shape may change due to variations in flame speed, flame temperature, and fuel density that may cause an increase in pressure oscillation amplitude levels that need to be addressed.

These areas of concern of the DLE combustion system are being actively investigated. At this OEM, qualification of DLE gas turbines has been on-going to allow usage of a broader range of fuels by focusing on these design areas and how they are impacted by the key fuel parameters listed in Table 1. This activity has included analytical and test assessments of how variations in flame speed, flame temperature and fuel density impact the combustion characteristics of emissions, combustion stability and durability (component temperature). A brief overview of this work is presented in the context of natural gas and hydrogen fuel mixes in the range of 5 to 30%. Extensive combustion rig and gas turbine testing has been completed with a range of fuels with variable flame speed and flame temperature as reported in [9]. In this study flame speed and temperature were changed by adding propane (C3), butane (C4) and CO2 into natural gas to simulate "associated gases" (raw gas recovered during oil extraction) and raw natural gas. Figure 7 shows the range of variation in laminar flame speed tested. The hydrogen and natural gas mixtures of interest in the P2G scenario are shown in comparison to highlight that the fuels tested adequately cover the range of hydrogen fuels up to 25%.

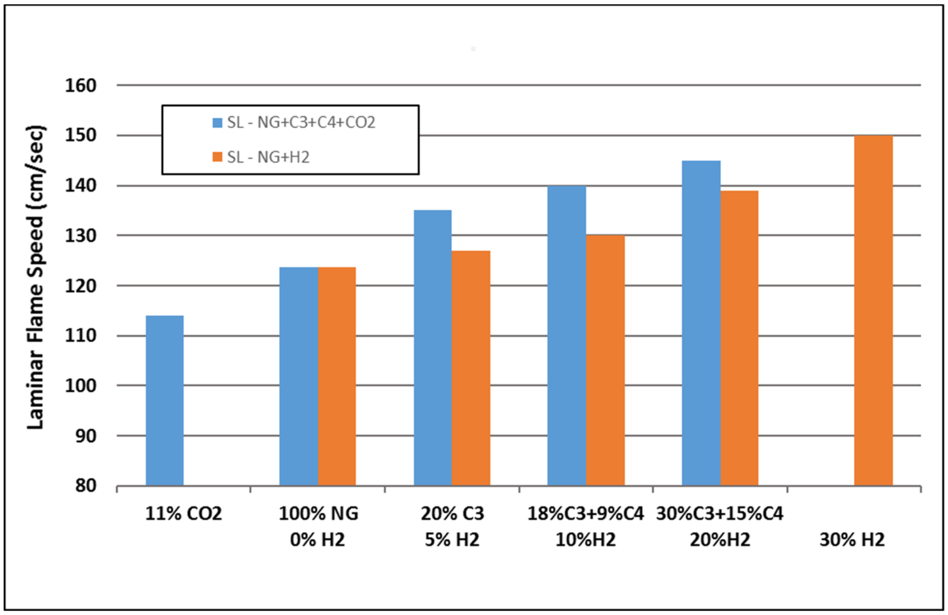

Figure 7: Flame speed variation calculated for test fuels with varying levels of Propane, Butane and CO_2 mixed with natural gas compared to mixtures of Hydrogen and natural gas. Laminar flame speed calculated for equivalence ratio = 1.0 and mixture temperature and pressure of 316°C (600°F) and 1 atm.

Figure 8 is a typical plot of emissions taken with the associated gas test fuels plotted as a function of flame temperature. The results included were taken on a 23000hp class gas turbine tested in the factory operating at full load. As outlined, emissions of NOx and CO are most influenced by flame temperature. Just as in the case for conventional combustion the gas turbine controls keep the overall gas temperature entering the turbine constant regardless of the fuel being used. However, as the adiabatic flame temperature increases the NOx emissions will increase due to the flame becoming more compact and burning hotter locally. For reference, Figure 7 includes the adiabatic flame temperature of the different NG and hydrogen blends from Table 1. Over the range of adiabatic flame temperature typical of these blends of Hydrogen a DLE gas turbine is expected to show a very slight increase in NOx of 1 to 2 ppm. Data for CO emissions are not included as these for all the data points the emissions were less than 2 ppm. Similarly, low levels are expected with H_2 and natural gas mixtures.

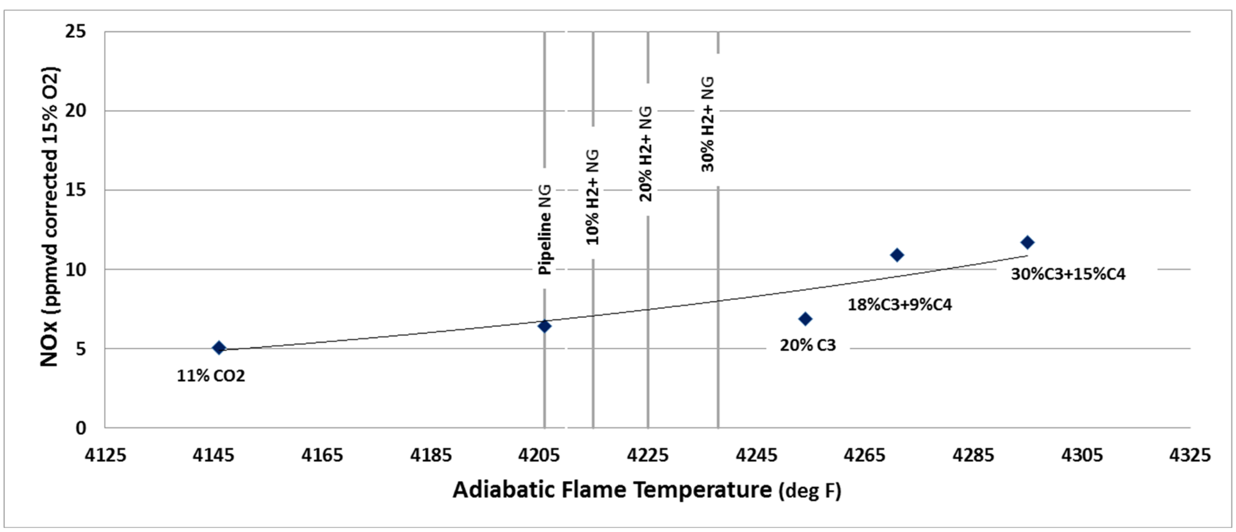

Figure 8: NOx emissions variation on a 23000hp class gas turbine at full load and standard pilot with associated gas test fuels with different values of adiabatic flame temperature

It should be noted that with the described DLE configuration an added pilot fuel circuit is used to augment flame stability at low loads and during transients as shown in Figure 5. The pilot control schedule is set experimentally and may need to be adjusted differently with hydrogen mixes as compared to the fuels tested in Figure 8. The data in Figure 8 was taken at a constant pilot level. Due to the enhanced stability generated while burning hydrogen containing fuels, the analysis indicates that lower levels of pilot may be possible.

The testing on a 23000hp class gas turbine completed in this fuel variation study also indicated that within the range of fuels tested no change in combustion stability characteristics or the component temperature was indicated. Hydrogen in the range of 5 to 20% is expected to behave in a similar way. For the component temperature an assessment against the change in flame temperature compared with the test program is entirely adequate. Similarly, in the range of 5 to 10% hydrogen little to no change in combustion stability characteristics are expected. Engine testing will be conducted for hydrogen concentrations of 20% to confirm the analytical assessments. The tests described above apply to the latest DLE generation. Hydrogen addition to the pipeline with existing gas turbine packages will require additional evaluation efforts.

Direct testing of hydrogen and natural gas fuel blends using combustion rigs with a single fuel injector is also reported. Figure 9 highlights early results taken, under conditions based on a 23000hp class gas turbine with hydrogen blended with natural gas. The rig was operated at simulated full load flow conditions at nominal day temperatures. As expected, the NOx emissions do increase slightly as the adiabatic flame temperature of the fuel gas is increased. However, the magnitude is only 3 ppm. CO and unburned hydrocarbon emissions were unchanged and low throughout the testing. Component temperature maps were also created, with little variation evident. Testing is in flight to assess the flashback robustness of the DLE injectors at varying levels of hydrogen content. For tests to date no flashback events were observed under any test conditions with hydrogen content less than 30%. This work is on-going to cover other engine models and different DLE legacy configurations [7,8].

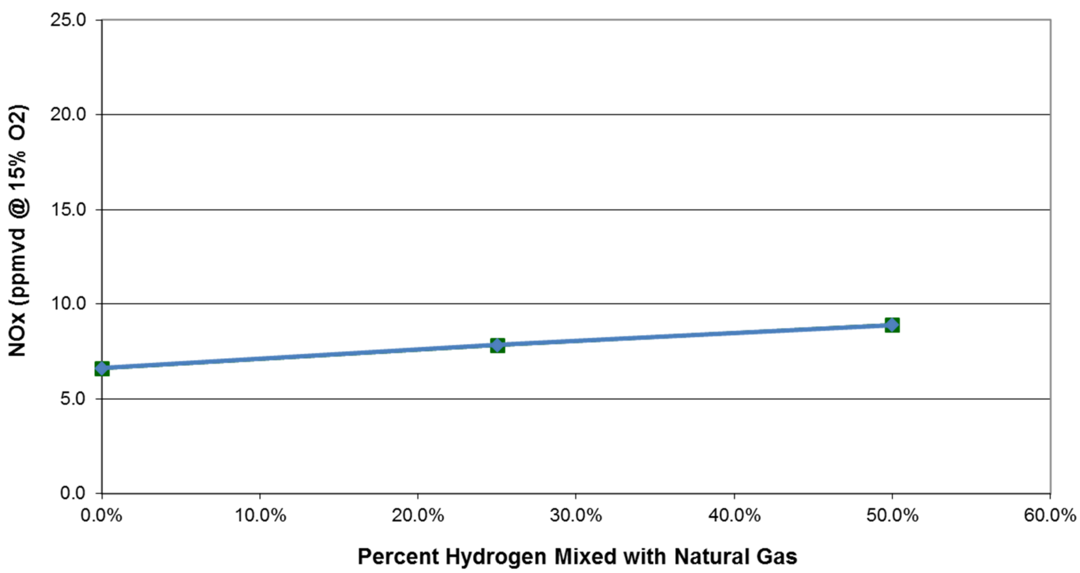

Figure 9: NOx emissions variation of a 23000hp class gas turbine fuel injector in a combustion rig test at simulated full load conditions for a 59°F day and constant pilot level with varying blends of Hydrogen mixed with natural gas.

Package Impacts

As the level of hydrogen (and other more reactive gases) increases, additional requirements and limitations are placed on the gas turbine package. For these applications the following list of additional safety requirements are added for gas turbine packages. This OEM has historically required them for any applications with hydrogen concentrations greater than 4% [9]:

- Configure and equip packages to meet Gas Group B (Table 1)
- Incorporate additional fire and gas detection devices
- For generator packages the risk of flameout is decreased by limiting applications to those that are tied to the power grid. Similarly, duct firing in the exhaust is precluded since it could be an ignition source.
- Ignition and start-up on pipeline quality natural gas or diesel fuel is required and then the fuel is transferred at a low load.
- Special exhaust purge sequences are added and used when there is a failed start or after a flame-out before a subsequent attempt to restart.
- The fuel system is configured to prevent leakage in the package by using NACE compliant materials and appropriate fuel system seals. In addition, the fuel system piping goes through an X-ray inspection process to further reduce the risk of leaks.

The P2G scenario has caused a reexamination of these package requirements for applications with 5 to 20% hydrogen in natural gas. At 10% hydrogen this OEM has determined that many of these requirements are not substantially different and risks are still low. If the hydrogen is increased from 10 to 20% many of these requirements are still justified and will need to be implemented. A possible exception is the requirement that a standard fuel be used for start-up. This requirement becomes more burdensome for existing gas turbine packages where an alternate fuel to what is provided by the pipeline is not available. However, detailed analysis is required to more precisely determine the start-up risk with this range of hydrogen. If this risk is still determined to be significant then a solution to mitigate can be developed and made available.

The requirements and limitations for the conventional gas turbine package also apply for DLE packages. Since the lean premixed combustion systems are operating at leaner conditions the margin with flame out is generally reduced. This increases the risk of a combustible mixture reaching the exhaust in the event of a flame-out. This risk is always more pronounced during the start sequence due to higher initial fuel flow rates and the potential that combustor light-off is not successful: i.e. fail to light. Again, with the lean premixed combustion system this is generally more likely. But just as was described for the packages with conventional combustion in the range of 5 to 10% hydrogen in natural gas this risk is still very low.

TRANSPORTATION IN PIPELINES

The discussion of hydrogen transport in this paper is limited to natural gas-hydrogen mixtures, pursuant the request by a number of pipeline operators. Due to the difficulties and energy requirements related to the compression of pure hydrogen, long distance transportation of pure hydrogen in pipelines seems implausible. We have therefore analyzed the situation where hydrogen-natural gas mixtures, with a range of hydrogen content, are transported in a pipeline. Considerations include the transportation efficiency (ie the amount of fuel energy spent in relation to the amount of energy delivered at the end of the pipeline, and the impact on pipeline capacity.

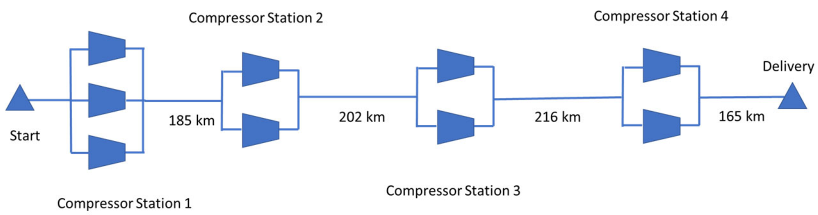

Figure 10: Pipeline simulation

For this study, a natural gas pipeline with multiple compressor stations is modelled (Figure 10). The 768 km long pipeline consists of 4 compressor stations, with a distance between stations between 165 and 216 km. The gas arrives at the first station at a given pressure, and has to be delivered at a defined pressure at the end of the pipeline. The first compressor station consists of 3 compressor trains, and stations 2, 3 and 4 have 2 compressor trains each. All compressors are driven by two shaft gas turbines (Figure 11). The gas transported is changed to reflect various hydrogen concentrations.

The simulation includes the detailed performance behavior of the gas turbine drivers and the driven compressors. The relevant performance characteristics of gas turbines, and gas turbine driven centrifugal compressors are described here. The gas turbines used are two shaft gas turbines (Figure 11), consisting of an air compressor (1-2), a combustor (2-3), a gas producer turbine (3-5) that drives the air compressor, and, on a separate shaft, the power turbine (5-7) that is connected to the pipeline compressor. As is usual practice for pipelines, the gas turbine uses pipeline gas as its fuel. Gas turbine performance depends on the ambient temperature and site elevation. Its efficiency is highest at full load. The power turbine performance is speed dependent. (Figure 12).

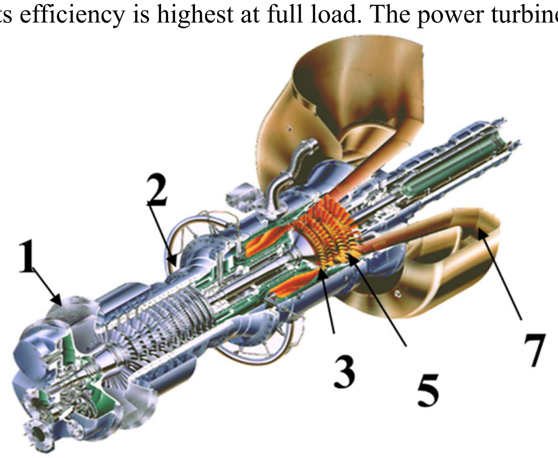

Figure 11: Industrial gas turbine (1-Compressor inlet, 2-combustor inlet,3-gas producer turbine inlet, 5-power turbine inlet, 7-turbine exit)

Changes in fuel gas composition do affect the gas turbine performance, albeit very slightly, both due to changes in fuel mass flow and composition of the exhaust gas. For example, adding 20% Hydrogen (by volume) to natural gas creates a change in engine output of less than 0.2%.

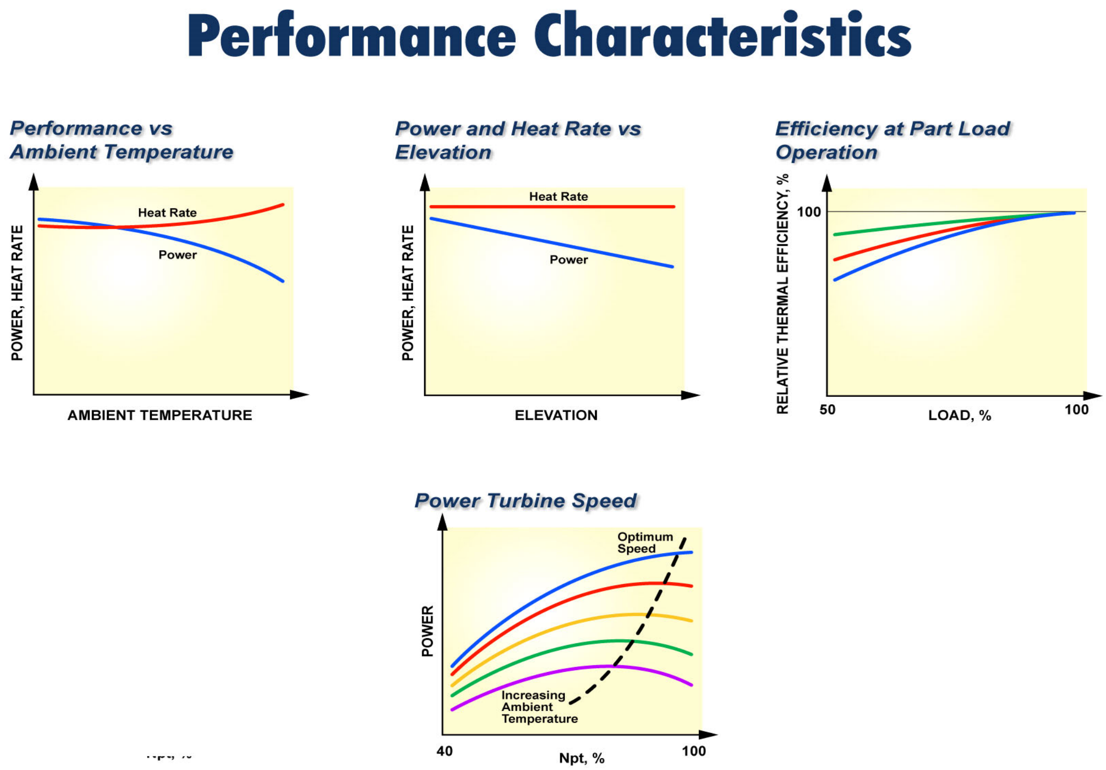

Figure 12: Typical performance characteristics of a two shaft industrial gas turbine showing the impact of ambient temperature, site elevation, load and power turbine speed.

The power turbine is directly coupled to a centrifugal compressor (Figure 13), which is used to compress gas in a pipeline. Pipeline compressor stations usually require relatively low pressure ratios, that can be accommodated with 1, 2 or 3 compressor stages. The flexibility of a gas turbine driven compressor comes from the capability to vary the compressor speed within a large range (Figure 14). A concern when compressing, transporting and storing hydrogen is the Hydrogen diffusivity, as discussed previously in the section on combustion.

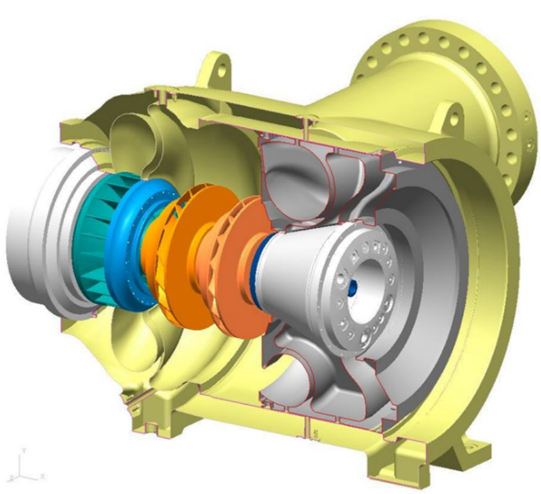

Figure 13: Typical centrifugal compressor, barrel type, with 2 stages, used in pipeline applications.

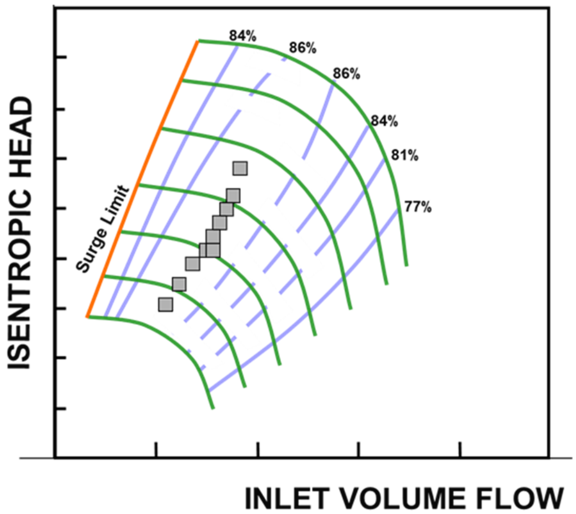

Figure 14: Typical performance map of a variable speed centrifugal compressor. The squares indicate typical operating points in a pipeline under steady state conditions.

Transport Efficiency

In the first part of the discussion, the transportation efficiency is addressed. To be able to compare different concentrations of hydrogen, the transported energy (rather than the transported flow) is kept constant. This results in different receiving pressures for the compressor stations, a different power consumption, and as a result a different fuel consumption. Since the transported gas is also used as fuel supply for the gas turbines that drive the pipeline compressors, the amount of CO_2 produced from combustion is affected. Bainier et al [6] discussed a similar concept on the impact of adding various amounts of hydrogen into a pipeline regarding transportation efficiency.

For a realistic assessment, the following scenarios have to be considered, with the base case for a pipeline operating on natural gas. The scenarios assume that various amounts of hydrogen are mixed into the pipeline. Both the power demand for the compressor stations, as well as the necessary speed of the compressors will increase (Bainier et al., [6]). Therefore, scenarios have to be considered where either the power demand or the required speed exceeds the capability of the existing equipment. It should be noted that common design practice leaves a certain margin on power and speed at the design conditions. Since we want to discuss transportation efficiency, power limitations are handled by adding compressor trains in parallel, and compressor speed limitations are handled by adding a compressor stage. In this way, we avoid having to oversize the stations for the cases with no or little hydrogen, which would make the base case less attractive due to operation in part load. Adding parallel compressor stations is also appropriate, since in real operation, the hydrogen concentration will likely not be constant, but rather fluctuate significantly based on the availability of surplus electricity. For the study, it is also assumed that the pipeline pressure capability is not de-rated [11].

The behavior of pressures and flows for the pipeline and the compressors is presented in Figures 15 to 20. Figure 15 shows the effect of adding Hydrogen to the natural gas on the receiving suction pressure of the 4 stations, while Figure 16 shows the actual flow into the compressor stations. The cases for 0%, 5% and 10% Hydrogen use the layout from Figure 7, while for the 20% case, stations 2, 3 and 4 each use an additional train, i.e they now use 3 trains each in parallel. Since the individual load on the stations was optimized for fuel consumption, the station discharge pressure stays at the maximum allowed value, except for the last station (station 4), where it floats to accommodate the specified arrival pressure. The addition of Hydrogen reduces the arrival pressure to the stations, and thus increases the pressure ratio for each station. The lowering of the suction pressure also tends to increase the actual flow entering the compressor station (Figure 16). The lower arrival pressure is due to the higher flow losses in the pipeline due to the higher flow velocities in the pipe as the volumetric flow increases. In addition, the arrival gas temperature tends to increase with the addition of hydrogen, an effect described in detail by Bainier et al [6].

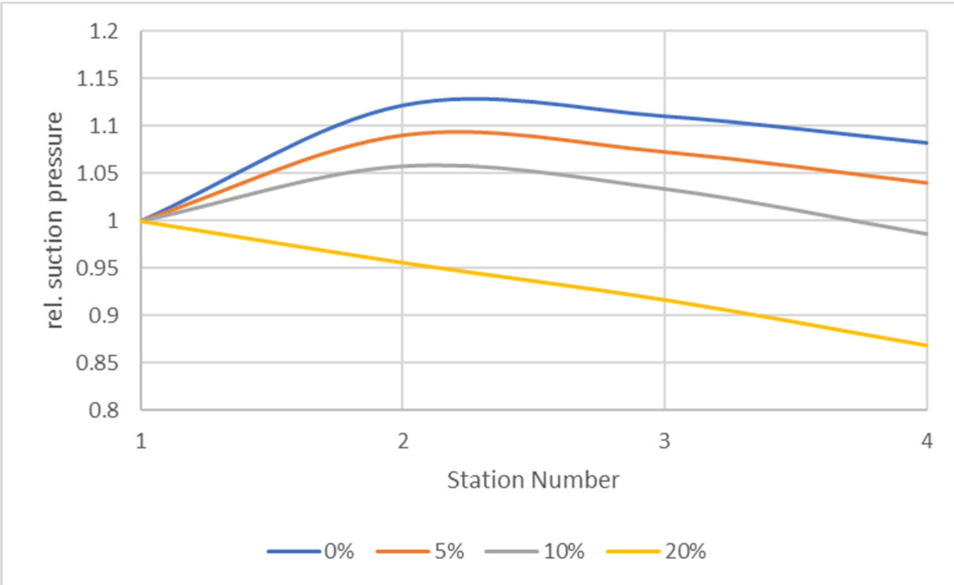

Figure 15: Suction Pressure for compressor stations 1,2,3, and 4 and different levels of Hydrogen (0% to 20%) in the natural gas; pressure normalized with the specified inlet pressure to the first station. Location of the stations is shown in Figure 10.

Figures 17 and 18 show the change in operating points for one of the pipeline compressors (in station 3) with changing hydrogen content in the pipeline gas. Because the compressor was sized for the pipeline with 0% hydrogen content, and the amount of energy transported in the pipeline is kept constant, the increased power consumption is handled by adding a third compressor train to the stations. The increased pressure ratio, and resulting increase in head, is handled by taking advantage of the compressors' capability to add a third stage within the same casing (the design for lower hydrogen concentrations uses 2 stages per compressor). Within the configuration used for the study, the transition from 10% to 20% Hydrogen requires these changes. In this context, the flexibility from a station layout with 2 units is advantageous to a layout with one single larger unit.

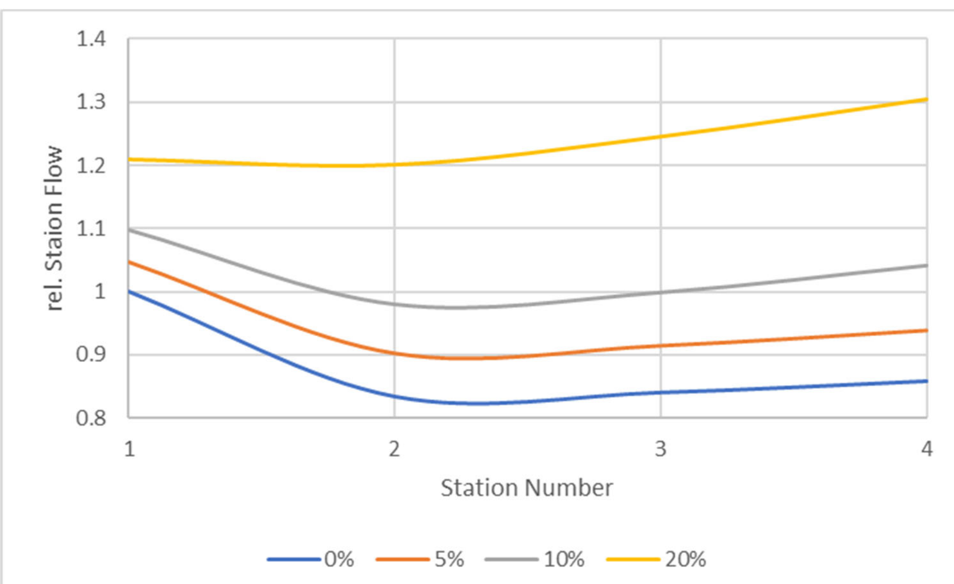

Figure 16: Actual flow for compressor stations 1,2,3, and 4 and different levels of Hydrogen (0% to 20%) in the natural gas; flow normalized with inlet flow in the first station at 0% hydrogen. Location of the stations is shown in Figure 10.

While Figure 17 displays the situation under the assumption that only the existing equipment is available, Figure 18 addresses the situation where 3 compressor units are available in the station (the results are for station 3), sized such that all 3 units operate for the high H_2 cases, while the cases with lower H_2 content, consuming significantly less power, would be covered by only 2 units running. This requires also compressors with a wide operating range so the change from 2 units to 3 units can be accommodated. The operating conditions in Figure 17 indicate that the compressor would become speed limited with a Hydrogen of a bout 10%. The compressors, as displayed in Figure 18, are sized to avoid the speed limitation even at 20% hydrogen content.

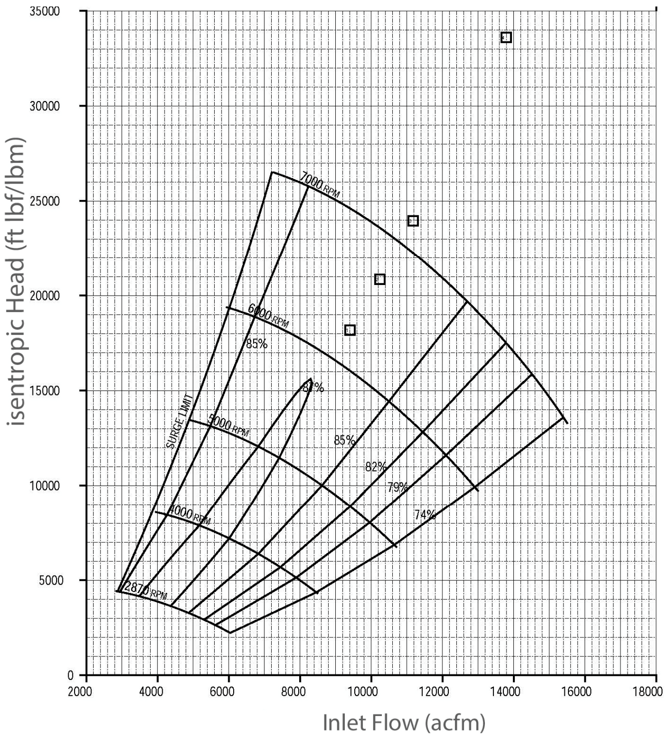

Figure 17: Change in operating points for one of the pipeline compressors with increasing hydrogen content in the pipeline gas. Compressor sized for the pipeline with 0% hydrogen content. The amount of energy transported in the pipeline is kept constant.

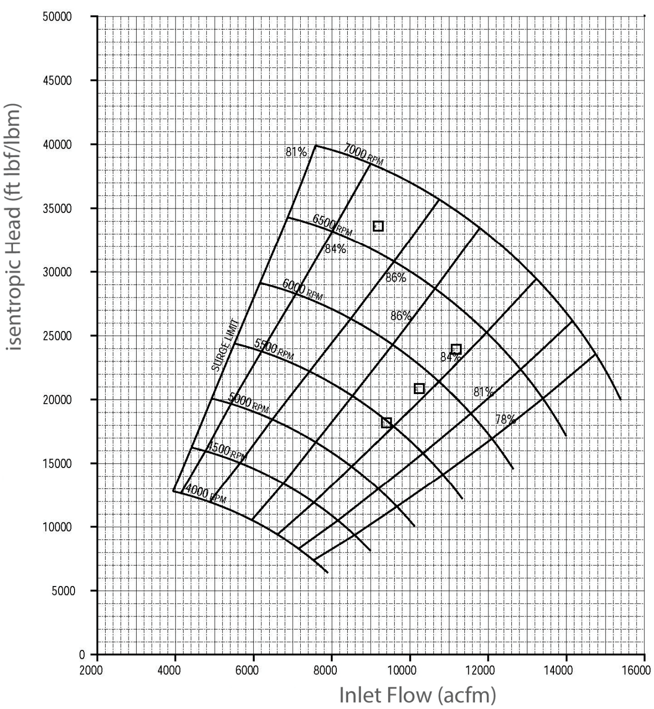

Figure 18: Change in operating points for one of the pipeline compressors with changing hydrogen content in the pipeline gas. Compressor sized such that 3 units are in operation for 20% Hydrogen content, and only 2 units are running when the Hydrogen content is 10% or less. The amount of energy transported in the pipeline is kept constant.

The result of this study indicates that the power consumption of the compressor stations along the pipeline is significantly increased. This is a direct result of increased pressure losses in the pipeline as a result of the higher actual gas flow in the pipeline which is required to maintain the same amount of energy delivered at the pipeline outlet. This additional flow causes a higher pressure drop, thus increasing the required pressure ratio for all compressor stations. The power requirement is further increased by the fact, that the gas gets lighter with increased hydrogen content, so the amount of work needed for a given pressure ratio is increased. This is to some extent compensated by the somewhat lower gas density.

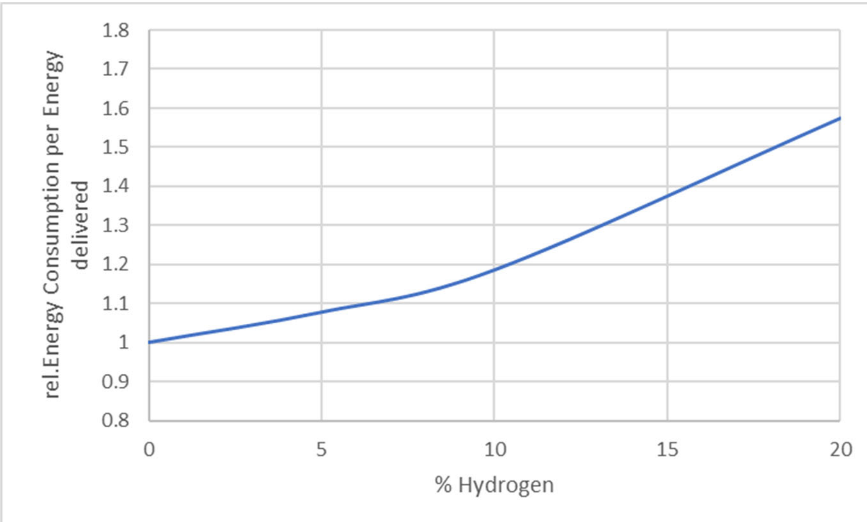

Figure 19: Transportation efficiency of the pipeline as a function of hydrogen content in the pipeline gas, normalized with the transport efficiency for 0% Hydrogen. The amount of energy transported in the pipeline is kept constant.

With the given power consumption for the transportation task, we can now calculate the fuel consumption for the gas turbines. The fuel consumption, normalized by the energy delivered by the pipeline at the outlet, is increased (Figure 19) with increasing Hydrogen content. In other words, increasing the Hydrogen content in the pipeline gas causes a reduction in transportation efficiency. Pipeline hydraulics cause an impact that is clearly not linear. A 10% Hydrogen content requires a 20% higher energy consumption, while a 20% Hydrogen content in the pipeline gas yields a nearly 60% higher energy consumption.

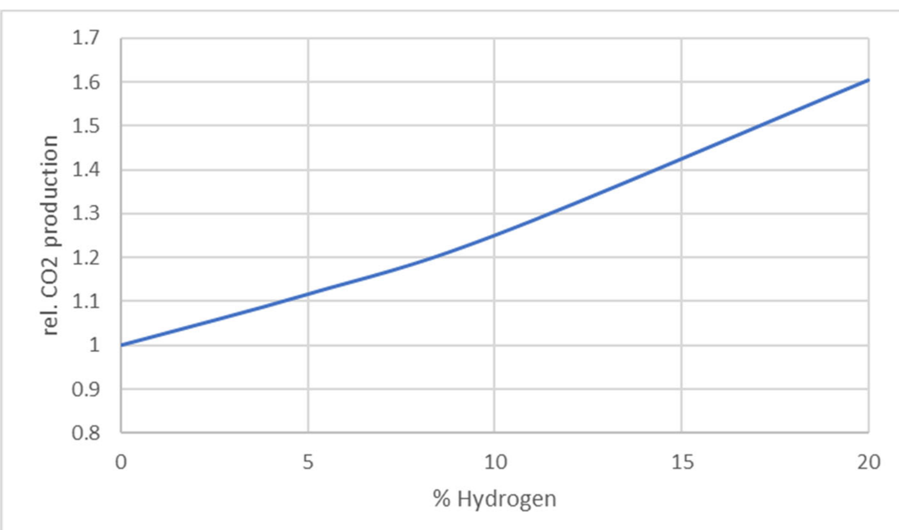

Figure 20: Impact of Hydrogen content of the pipeline gas on CO_2 output, normalized with the CO_2 output for 0% hydrogen

The increased power demand for the gas turbine driver when hydrogen is added to the natural gas in the pipeline yields a higher fuel consumption. The impact on carbon emissions is less clear. The gas turbine uses the pipeline gas as fuel, so the combustion products (CO_2 and water) will change when the fuel contains more hydrogen. For a given power consumption and gas turbine efficiency, the amount of CO_2 in the exhaust is reduced when Hydrogen is added to the fuel. This beneficial effect is countered by the fact that the

Hydrogen in the pipeline increases the power requirements, and thus the fuel consumption. Figure 20 shows the change in the amount of CO_2 produced as a function of the added Hydrogen. The increased power consumption more than compensates for the reduced amount of carbon in the fuel. Thus, the CO_2 production per energy unit delivered is increased.

Pipeline Capacity

For existing infrastructure, another question is of importance: How is the transportation capacity of an existing pipeline, sized originally for natural gas transport without hydrogen in the gas, impacted when hydrogen is added.

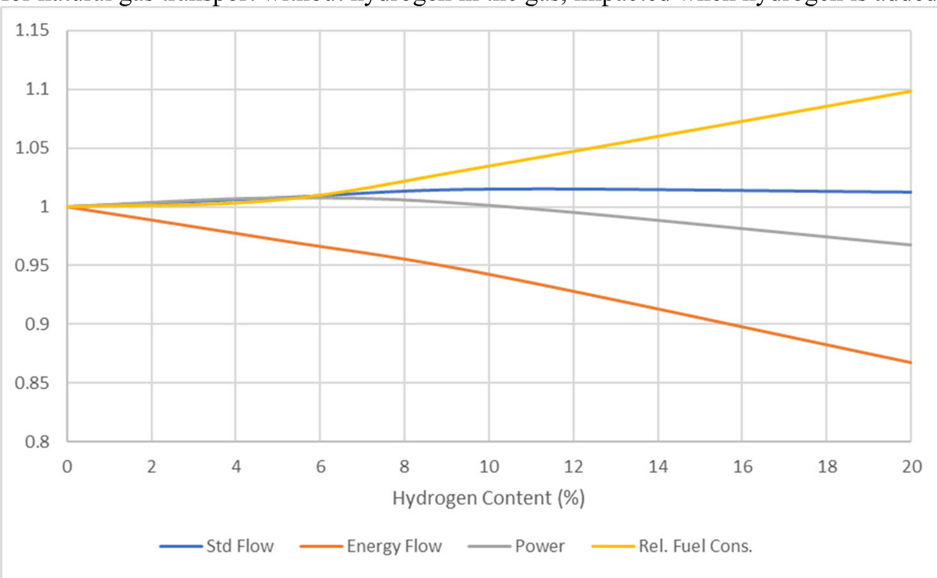

Figure 21: Energy flow, standard flow, power and fuel consumption when Hydrogen is added to natural gas, normalized by the respective parameters at 0% Hydrogen content

Capacity can be limited by available power and maximum compressor speed. If the power demand exceeds the power of the gas turbine at the design ambient conditions, we assume that the pipeline capacity is reduced. In some cases, the operator will make up the reduced capacity at design ambient with the added power available at colder. If the requirements exceed the speed capability of the driven equipment, the pipeline capacity will also be limited. In this case, the operator has the option to restage the driven compressor, for example by adding a compressor stage [12].

The simulation that was carried out assumes an existing natural gas pipeline, with the equipment optimized for operation on natural gas. The impact of adding hydrogen is simulated, while keeping pipeline inlet conditions and the supply pressure at the end of the pipeline constant. Rather than making assumptions on ambient temperature fluctuations, the power of the gas turbine is limited, and the compressor geometry is fixed. The results are outlined in Figure 21. The key finding is that the pipeline capacity, based on the energy flow at the pipeline delivery point, is reduced. At the same time, the standard flow increases initially. This is due to the same effects described for the previous simulations: To maintain a given pressure ratio, the compressor speed and power consumption is increased. The standard flow is increased initially, because hydrogen addition reduces density, but due to the lower energy density, the energy flow is reduced. In this specific example, the limiting factor is initially available power, but at about 10% hydrogen content, compressor speed (initially only at station CS 3, see Figures 10 and 22) becomes the limiting factor. Thus, the compressors cannot absorb all available power, which is apparent in Figure 21, where the consumed power drops. Just as in previous examples, the fuel efficiency (fuel consumed per fuel transported in the pipeline) drops for higher hydrogen contents. Figure 22 shows the operating points of one of the compressors in station CS 3 (Figure 10) when the hydrogen content increases. The compressors, sized for the transport of natural gas, initially had sufficient speed margin, but the increase in hydrogen in the gas forces the compressors to run faster to absorb the available power (Figure 22). Unlike in Figure 17, where the actual inlet flow increases with increased hydrogen, Figure 22 shows an eventual reduction in hydrogen flow, since the operation becomes power and speed limited.

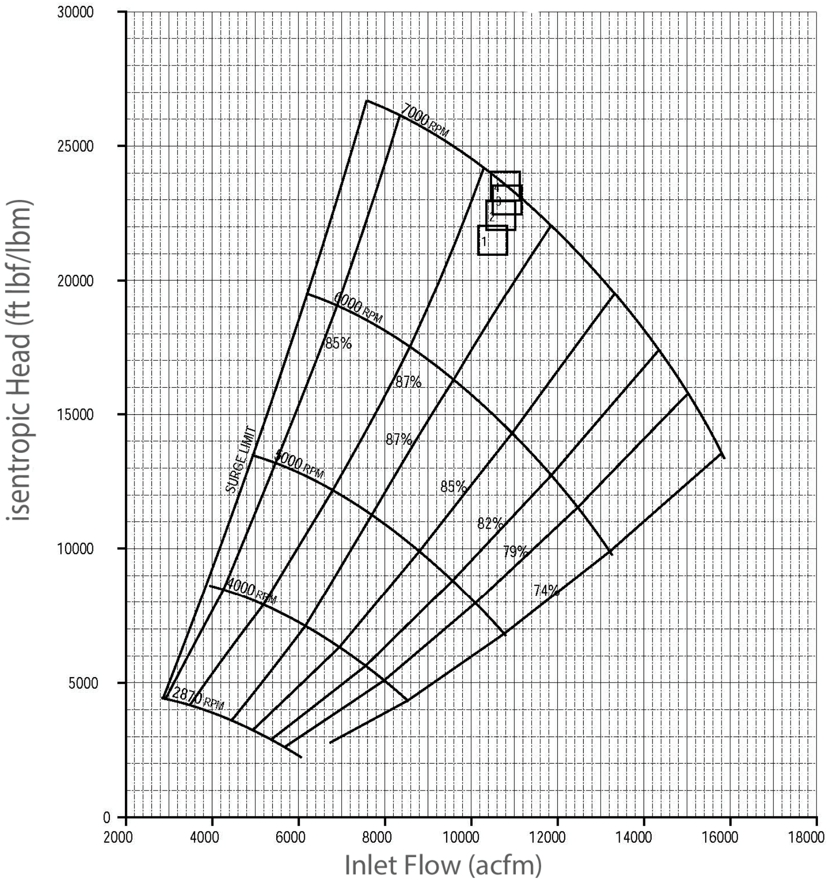

Figure 22: Compressor operating points at station CS3 (1: 0% H2, 2: 5%H2, 3: 10% H2, 4: 20% H2).

STORAGE

Despite the reduced transportation efficiency, another rationale for adding hydrogen into a network of natural gas pipelines is the capability to store surplus electricity. Storage of surplus electricity is one of the challenges in the energy industry, and historically the storage capability within an electric grid was very low. Figure 3 shows that the options for technologies to store large amounts of energy are limited. Traditional electric grids rely on base load plants (nuclear, hydro, coal, or natural gas fired), with the demand swings compensated by peaking units, often gas fired gas turbines. The grid of the future will use renewable sources as base load, but the generating capacity of renewables is subject to large swings. Thus, energy storage is an important feature of such grids.

Electricity from intermittent renewable sources (wind, solar) can be used to create hydrogen, which, unlike electricity, can be stored. This application is in competition with other concepts, such as batteries, compressed air storage, thermal energy storage, pumped thermal energy storage, hydraulic storage and others (Figure 3). Key to the evaluation of these concepts is safety, cost and the so called round trip efficiency (Laughlin,[13]). It describes the inverse of the ratio between the energy fed into the system, and the amount of that energy that can be recovered.

The average power delivered to a large metropolitan area such as Los Angeles or New York is about $1.4\text{x}10^{10}$W. Storing this power for only one hour gives $5.04\text{x}10^{13}$ J or one Hiroshima-sized atomic bomb. It is absolutely essential that explosive release of this stored energy be physically impossible (Laughlin [13]). Once this safety criterion is met, capital and maintenance costs must be minimized, even at the price of a small hit in round-trip efficiency, because storage of electricity is fundamentally about value, not about conserving energy.

In this context, the capability to use existing gas pipelines as well as existing gas storage facilities to store hydrogen is attractive, since the infrastructure already exists, and only minor modifications are necessary as long as the hydrogen concentration remains relatively low. The roundtrip efficiency, however, is relatively low, because the hydrogen is created via electrolysis. However, hydrogen storage has the potential to store large amounts of energy (Figure 3). The following estimates may serve as an example [14]: 100MW of renewable electric power yield 22000 nm3/d of Hydrogen, which, if burned in a system with 50% thermal efficiency, produce about 33MW of electricity.

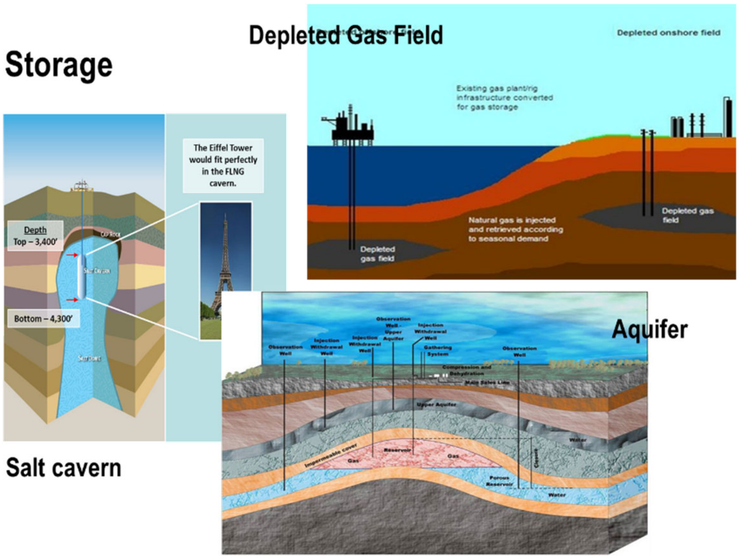

Figure23: Underground Storage [15]

Figure 23 is a representation of the various types of underground storage facilities. Concerns include the question whether formations that are gas tight for natural gas are also capable of retaining the much smaller Hydrogen molecules, and the question whether hydrogen-natural gas mixtures would get stratified. The storage pressures would be in the range of 100 to 200 bar, or higher, thus requiring significant amounts of compression.

CONCLUSIONS

This study indicates injection of Hydrogen into a natural gas pipelines in moderate rates is manageable with today's technology:

- Conventional combustion systems are proven for H2 + NG blends up to 30%. Starting on these fuels is the only risk.
- Even for Lean Premix systems, H2+ NG mixtures of 5 to 10% are not problem today.
- Concerns are related to safety, for example at failed starts. These are manageable with todays technology
- Gas compressors are able to handle hydrogen in natural gas, but the will have to run faster (ie, re-stages may be required on existing units), and will consume more power (ie additional trains may have to beaded in compressor stations).
- The transportation efficiency of pipelines will be reduced when hydrogen is added. Also, the amount of CO2 created due to the transportation effort is increased.
- The capacity of an existing pipeline will be reduced if hydrogen is added.

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