GAS TURBINES FOR ENERGY NETWORK SYMPOSIUM
BANFF, ALBERTA, CANADA
OCTOBER 2019

19-GTEN-302

HYDROGEN IN NATURAL GAS – COMBUSTION AND COMPRESSION

Rainer Kurz*†, Luke Cowell, Terry Tarver**, Avneet Singh****

Solar Turbines Incorporated(†rkurz@solarturbines.com)
*****Solar Turbines Incorporated***

Keywords: *Hydrogen, Natural Gas Pipelines, Gas Turbines, Compressors*

Abstract

Increasing the use of renewable energy requires new approaches to energy storage and energy transport. One of these approaches is to 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 regrading combustion systems, as well as the impact on compressors and pipeline hydraulics.

Thus, the transport efficiency of the pipeline, safety aspects, and in particular questions about the capability of existing and new infrastructure to use natural gas – hydrogen mixtures as fuel are addressed in this paper.

Hydrogen increases the reactivity of natural gas fuels, showing increased flame velocity, reduced autoigniton 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 will be presented and discussed. Further, the impact of hydrogen addition on pipeline hydraulics and compressor operating are considered.

Background – Why Hydrogen & Natural Gas Fuels

Decarbonization technologies are ramping up to mitigate the build up of GHGs and to minimize Global Warming. In particular, a transition to renewable energy generation technologies are in flight and accelerating (Figure 1). However, fundamental limitations with current forms of renewable energy are

-their variability over time – both short term and seasonally and

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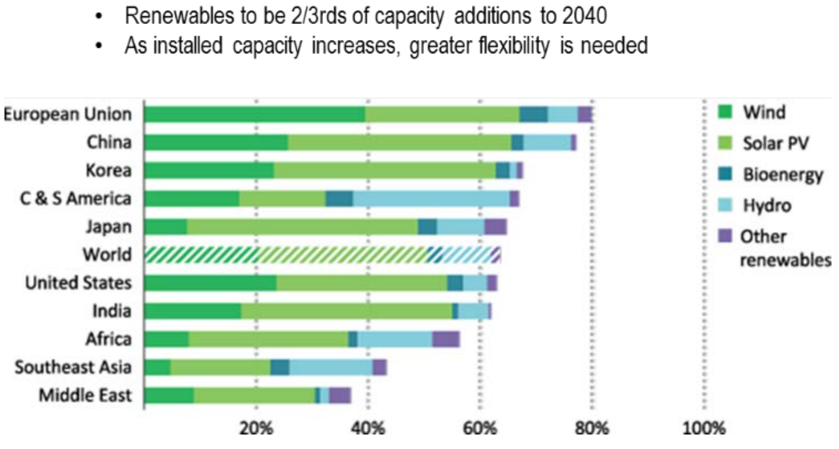
- their geographic limitations – cannot be generated everywhere which creates a need for alternate transport.



Source: International Energy Agency, *World Energy Outlook 2018*

Figure 1: Renewables in 2040,[1]

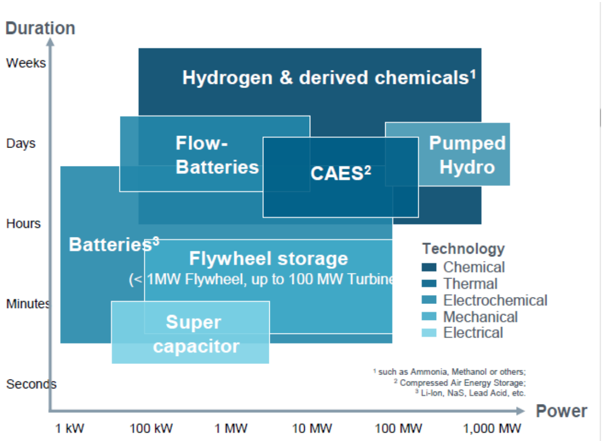


Figure 2: Energy Storage concepts ([1])

Mitigation scenarios such as P2G scenarios being evaluated include using renewable energy created during peak production periods beyond local demand to create hydrogen and then use existing natural gas transmission systems to both store and transport the energy. P2G offers advantages for longer term storage as depicted in IES chart (Figure 2). These scenarios compete with other energy storage solutions, as well as with hybrid compressor systems (Faller and Stollenwerk,[2])

An elegant solution for the energy storage problem is the use of the existing natural gas pipeline system, as storage and transport vehicle. In these concepts, surplus electricity from renewables (Wind, Solar) is used to create Hydrogen via electrolysis. This hydrogen is then injected into natural gas pipelines. Current European plans call for the capability to add up to 10% Hydrogen into the natural gas stream. Similar ideas are discussed in North America (Adolf et al.[3]). A study by Melaina et al. [4] summarizes key issues when blending hydrogen into natural gas pipeline networks. It discusses the benefits of blending, the impact on end-use systems, safety, material durability and integrity management, leakage and downstream extraction. The study finds no significant increase in safety risks, material durability, and integrity for hydrogen concentrations of 20% and less in transmission lines.

Adding hydrogen into natural gas pipelines raises, among others, two additional questions that will be discussed here:

-What is the impact of hydrogen in natural gas on gas turbine combustion and safety?

-What is the impact of Hydrogen on transportation efficiency in a pipeline?

Gas Turbine Combustion Systems

Generally two different combustion system technologies are used in industrial gas turbines. A cross-section of these combustion systems is shown in Figure 3. 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.

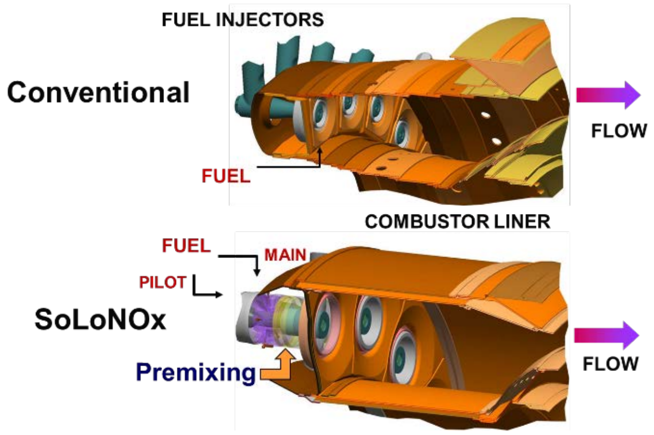


Figure 3: Comparison of Conventional and Lean Premix Combustion Systems

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 before reaching the flame front at a reduced fuel-air ratio and corresponding reduced flame temperature. A detailed description of a DLE combustion system and a comparison with the conventional fuel systems can be found in Cowell [5]. 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.

Hydrogen and Natural Gas Blends as a Gas Turbine Fuel – Areas of Concern

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 these changes introduce are discussed [6]. Other less measurable changes to the combustion process such as flame shape can have an impact on combustion dynamics and on combustor liner wall temperatures. Secondly, Table 1 includes key fuel parameters that are important to consider regarding the gas turbine package and fuel system design and operation.

Table 1: The Variation of Key Gas Turbine Characteristics with Hydrogen Additions to Pipeline Gas Focusing on the Range of 5 to 30%.

	H2% with Balance Pipeline NG					
H2 Blend	0%	5%	10%	20%	30%	100%
Combustion Parameters						
Laminar Flame Speed (cm/s)	124	127	130	139	150	749
Autoignition Delay Time (msec)	124	112	107	104	103	76
Wobbe Index (btu/scf)	1215	1199	1183	1150	1116	1039
Flame Temperature (°F)[1]	4206	4210	4215	4225	4238	4510
Package & Fuel System						
Flammability (% vol LEL)		4.83	4.79	4.71	4.63	4
Maximum Experimental Spark 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 *Adiabatic Stoichiometric Flame Temperature Calculated for a 23000hp class Gas Turbine at Full Load Conditions*

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 with hydrogen concentration. In the range of 0 to 30% hydrogen in pipeline gas the methane reactions dominate in the combustion process and the increase is relatively modest. Each combustion system is designed for select range of flame speed variation. Diffusion flame or conventional systems generally do not have an upper level but do have a lower level where the flame speed becomes too slow and they “blow out”. This is clearly not an issue with hydrogen addition. For DLE combustion systems there is an upper limit as well. The flame speed must be significantly less than the mixture velocity in the injector in order to prevent the flame from pulling into the injector pre-mixer and causing damage. A flame propagating upstream into the DLE fuel injector is often called “flashback”. For DLE fuel injectors designed for pipeline natural gas flashback will occur at very high levels of flame speed. Determining this point for fielded DLE combustion systems is a key requirement whenever using a fuel different than pipeline gas.

Flame Temperature. The pollutant emissions (NOx, CO and UHC) from a gas turbine engine are most directly influenced by a fuels 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 the majority of pollutant emissions will vary proportionally with that fuels adiabatic flame temperature. 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% varies by approximately 30°F which will increase NOx emissions modestly for a conventional combustion system and very slightly for a DLE combustor. The corresponding change in CO or UHC are even less at 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 couple 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 will 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 (LEL/UEL). Hydrogen is highly flammable with a very broad flammability range of 4 to 75% in air. It has a slightly lower autoignition temperature 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. So, if this mixture were to ignite in the exhaust a fire would occur with some level of pressure rise that may cause damage. Looking at Table 1 it is clear that 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). The gas turbine operator with hydrogen containing fuels needs to properly assess the gas for the appropriate industry Gas Group. Based on the Gas Group the hazardous area and the selection of equipment, such as electrical instrumentation and electrical enclosures, should conform to the appropriate industry code. 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 <=.5. As can be seen in Table 1 indicates the gas group does not change until the hydrogen mixtures in natural gas increase over 20%.

Hydrogen Diffusivity As the smallest element in nature, hydrogen is very light and very permeable. Common fuel system seals that are leak tight with natural gas fuels may not seal effectively with hydrogen. High hydrogen fuels may require special leak testing of gas systems. Elastomers, including O-rings and diaphragms, are more susceptible to explosive decompression problems.

Hydrogen Embrittlement Absorption of hydrogen into metals can cause a general loss of 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%.

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 CHP configurations, to generate electricity and steam for end users.

Gas turbine applications with high hydrogen fuels are well documented [ref]. In general, the majority of existing applications 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.

Diffusion Flame Gas Turbines.

Gas Turbines with conventional combustion systems are readily capable of using a broad range of hydrogen rich fuels. Historically for applications the amount of hydrogen in fuel has been over 30%. Typical hydrogen rich fuels used in gas turbine applications have been refinery gas (~30% H2), COG (~60%), and industrial process gases (30 to 100%). The impact and requirements for the combustion system and gas turbine package are considered.

Combustion System. 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. For Solar Turbines operation with higher hydrogen fuels has not had 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 keeping it nearly constant regardless of the fuel type used. Therefore, the effect of hydrogen is very localized creating a more compact and hotter flame front but globally the average temperatures within the zones within the combustor are not substantially different.

The NOx emissions, however, are increased as depicted in Figure x which compares NOx produced with hydrogen rich fuels with NOx from high methane pipeline natural gas. The NOx 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.

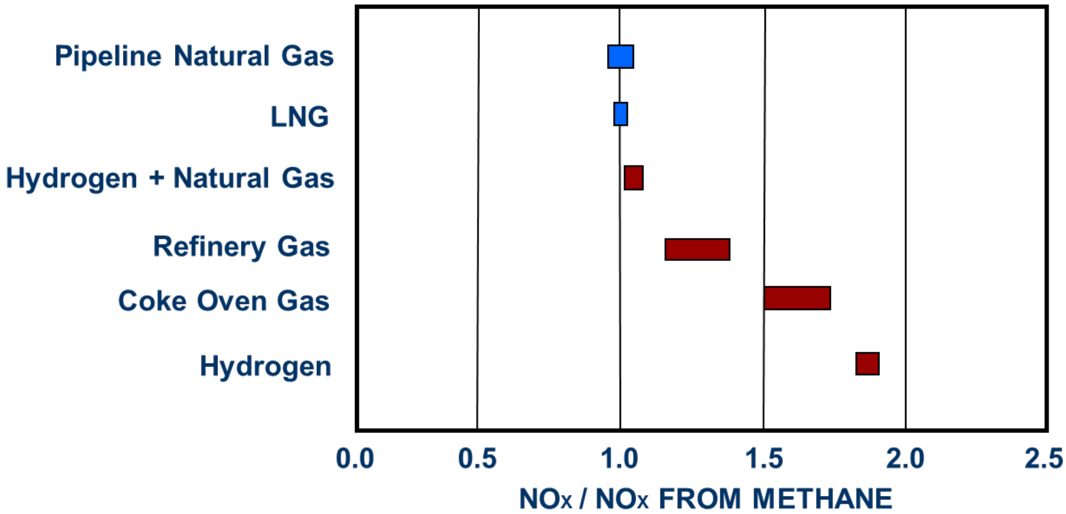


Figure 4: NOx Emissions Increase Trends with Conventional Combustion Operating with Hydrogen Rich Fuels Compared to Hydrogen in Natural Gas in the Range of 5 to 20%.

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.

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. Solar Turbines has historically required them for any applications with hydrogen greater than 4%.

- Configure and equip packages to meet Gas Group B
- 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 a guaranteed 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 Solar has determined that many of these requirements are not substantially different and risks are still low. However, if the hydrogen is increased from 10 to 20% then many of these requirements are still justified and will need to be implemented for new shipments. 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. Analysis is in progress 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 will be developed and made available.

Conventional Combustion Gas Turbine Package Experience. Solar has experience with many applications with significant concentrations of hydrogen. 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 (N_2+CO_2)

Most of the applications have been in China where over 40 gas turbine packages have been installed. A 23000hp class gas turbine installation is included in Figure 5. These units have operated with few problems and cumulatively have operated for more than 1 million operating hours. Many of these units have gone through multiple overhaul cycles. There were issues with several of the units that were ultimately traced back to fuel and air contaminants unique to these applications. After adding the appropriate filtration these units have been running without incident.

Figure 5: 23000hp class Conventional Combustion Gas Turbine Packages Operating with Coke Oven Gas (COG)

Lean Premixed / DLE Gas Turbines.

The ability of gas turbines using lean premixed combustion 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 with pipeline gas mixed with 5 to 15% hydrogen will not require significant modification. The ability of earlier generations of SoLoNOx combustion systems to use these levels of hydrogen are still being investigated. As in the previous section the impacts on the combustion system and the gas turbine package are considered.

Combustion. The lean premixed gas turbine 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 lean premixed combustion system NOx emissions are controlled by operating the combustion system at fuel lean conditions that are inherently closer to the lean extinction point. In addition, in order to prevent local hot spots, where NOx formation rates can be considerable, the fuel injector includes a fuel and air pre-mixer section. 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, which is not designed for high temperature. Secondly, as with conventional systems the flame temperature changes can impact NOx emissions. Finally, lean premixed 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 design areas of concern of the DLE combustion system are being actively investigated. At this OEM, qualification of its DLE (SoLoNOx) 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 Cowell, 2016. 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 6 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%.

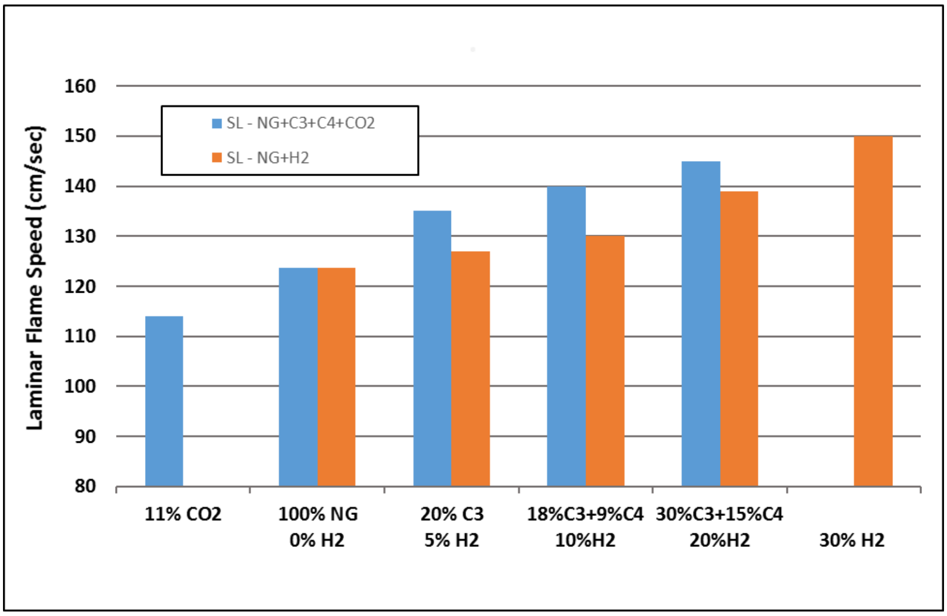


Figure 6: Flame Speed Variation Calculated for Test Fuels with varying Levels of Propane, Butane and CO2 Mixed with Natural Gas Compared to Mixtures of Hydrogen and Natural Gas.

Figure 7 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 H2 the SoLoNOx 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 H2 and natural gas mixtures.

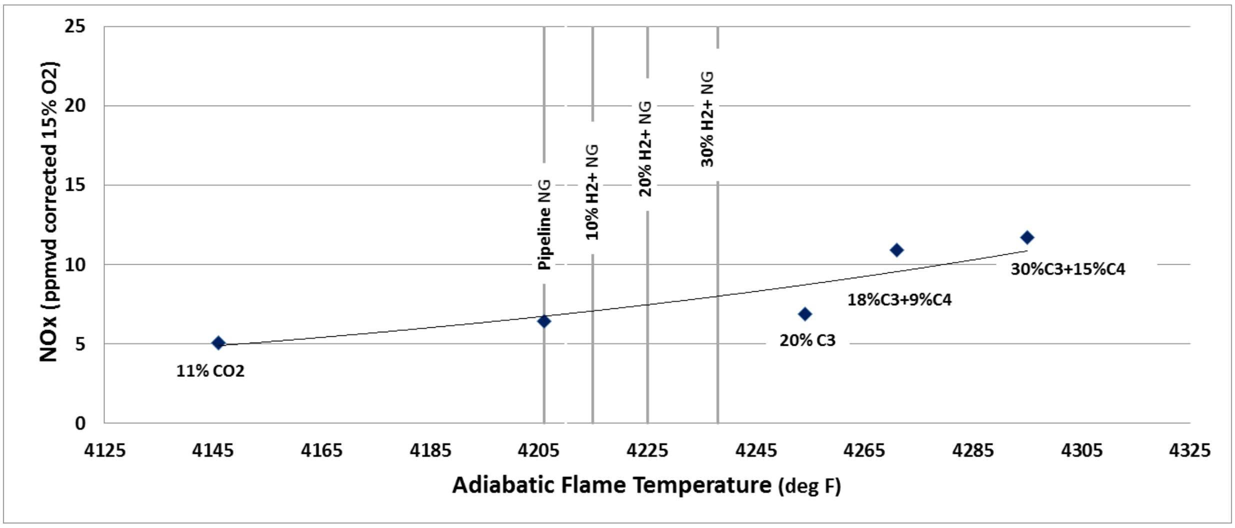


Figure 7: NOx Emissions Variation on a 23000hp class Gas Turbine at Full Load and Standard Pilot with Associated Gas Test Fuels with Different Values of Adiabatic Flame Temperature

However, 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 3. 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 7. The data in Figure 7 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 completed in the fuel variation study also indicated that with the range of fuels tested in a 23000hp class gas turbine indicated no change in combustion stability characteristics or the component temperature. 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.

It should also be noted that the test program described has been completed on the most current SoLoNOx combustor configurations. However, in the P2G scenario with hydrogen addition to the pipeline existing gas turbine packages with legacy SoloNOx combustion system also need to use this gas. Some limited testing with the higher flame speed test fuels described has been completed and with some of these configurations flashback or combustion stability issues have been identified. These configurations will all likelihood need to be upgraded to the latest configuration. A more extensive program is in progress to assess many of the more common configuration in the SoLoNOx fleet for robustness with the subject blends of hydrogen and natural gas.

Direct testing of hydrogen and natural gas fuel blends is also in progress using combustion rigs with a single fuel injector. Figure 8 highlights the early results taken 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 throughout the testing. Component temperature maps were also created, with little variation evident. Testing is in flight to assess the flashback robustness of the SoLoNOx injectors at varying levels of hydrogen content. In test work 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 SoLoNOx legacy configurations.

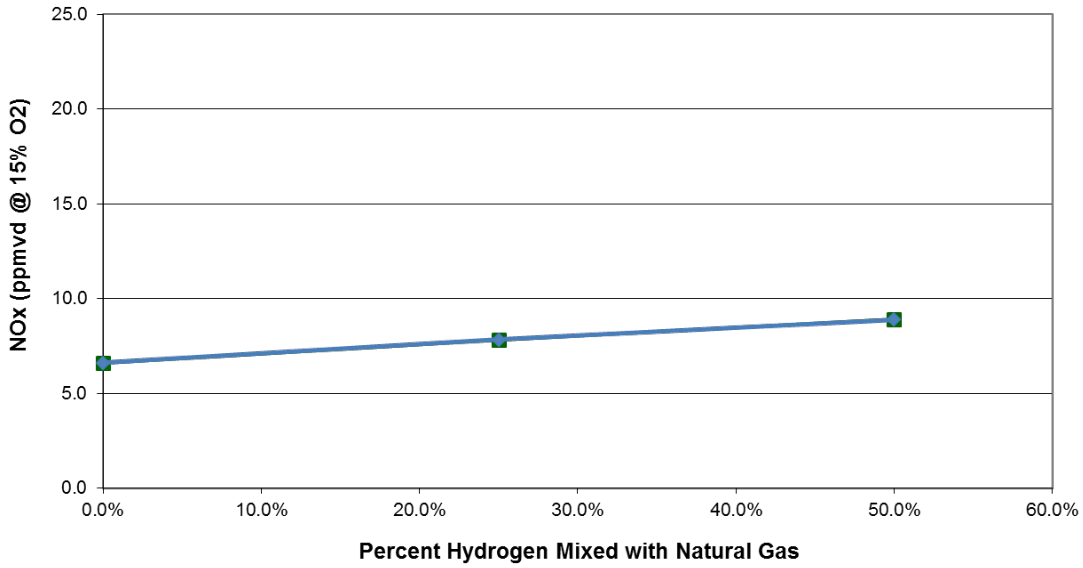


Figure 8: NOx Emissions Variation of a 23000hp class gas turbine fuel injector in Combustion Rig Testing at Simulated Full Load Conditions for a 59°F Day and Constant Pilot Level with Varying Blends of Hydrogen Mixed with Natural *Gas.*

Package Impacts. The requirements and limitations for the conventional gas turbine package also apply for the SoLoNOx package. 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.

SoLoNOx Gas Turbine Package Experience. In contrast to the conventional combustion, experience packages with SoLoNOx gas turbines operating on hydrogen is only recently starting to expand. It is worth noting that SoLoNOx experience with associated and raw natural gases has become very extensive. As illustrated in Table

1 these gases are quite comparable in the range of flame speed and flame temperature as will result with hydrogen mixed with natural gas in the range of 5 to 20%.

Direct experience on the SoLoNOx platform is limited to a refinery generator set application where a 23000hp class gas turbine has operated with natural gas mixed with up to 9% hydrogen. Qualification and mapping was completed with the unit demonstrating 15 ppm and no operational issues. The unit is started on 100% natural gas and the package was updated to be compliant with the requirements for applications greater than 4% H2. However, due to customer requirements the operating time accumulated with the 9% hydrogen fuel mix has been brief.

Units with high and medium wobbe associated and raw natural gases are much more extensively used and tested, and have few modifications from the standard configurations supporting operation on pipeline gas. The earliest shipments have been in operation for multiple years with many of these shipments reaching the overhaul interval. Operationally, these SoLoNOx engines run on associated gases in much the same was as they operate on pipeline natural gas. As indicated earlier on the applications with fuels with higher adiabatic flame temperatures the NOx emissions are higher by 2 to 5 ppm. As with all DLE gas turbines, fuel quality with adequate fuel treatment is a pre-requisite for trouble free operation.

Pipeline Transportation

Hydrogen Gas Properties relevant for Pipeline transport

Hydrogen gas has a higher mass calorific value than methane gas. Because of this property, molecular hydrogen is appreciated for space shuttle engines. A second property is that hydrogen gas has a lower mass density than methane gas. The result of the second property is that the volume calorific value is in favor of methane gas. The list of differences between methane and hydrogen is long. In the relevant range of pressures and temperatures, the Joule-Thomson coefficient has a different sign for hydrogen and methane, and the compressibility factor has the opposite trend when the gas is compressed. The dynamic viscosity is also significantly different, and finally, heat capacity, isentropic exponent, and the thermal conductivity are also different [7].

What are the impacts of these hydrogen characteristics on the transport capacity and its efficiency in the case of blending in a gas transport network?

Hydrogen gas has a higher mass calorific value than natural gas. On the other hand, hydrogen gas has a smaller normal mass density (ρ_0) than methane. In integrating both properties, the volume calorific value favors methane gas: the increase of H_2 concentration decreases the volume calorific value. In a comparison of the energy transported, H_2 in a gaseous state is less efficient than natural gas regarding the volume calorific value characteristic (Figure 9)

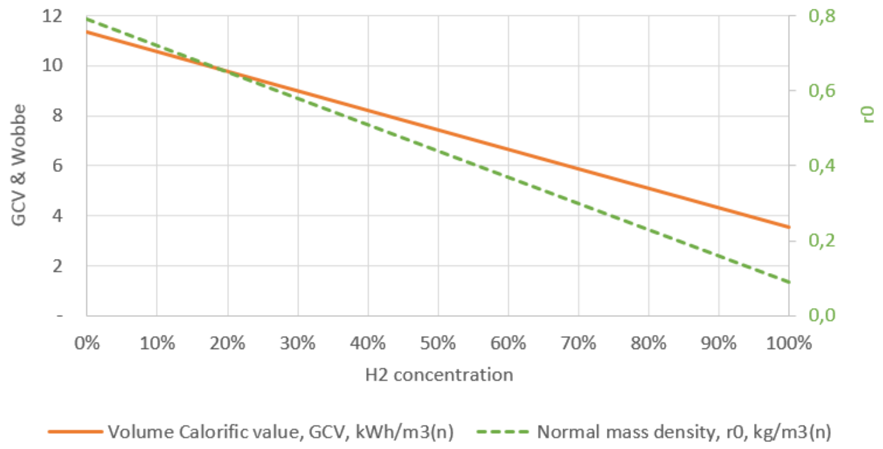


Figure 9: The volume calorific value and the mass density at normal conditions depending on the H_2 concentration. The volume calorific value is at normal volume conditions (0 °C and 1 atm) with a reference temperature at 25 °C.

The next figure (Figure 10) shows the compressibility factor (Z) depending on the H_2 concentration. It is interesting to note that the compressibility factor Z always increases with the H_2 concentration.

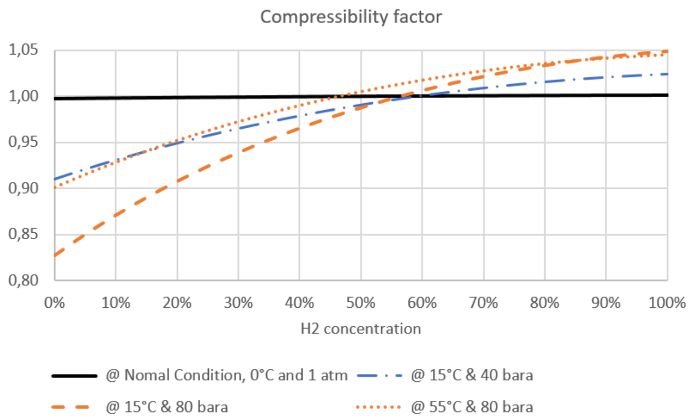


Figure 10: Compressibility factor depending on the H_2 concentration.

The knowledge of the dynamic viscosity of the studied gas is necessary to calculate the pressure losses in a pipeline. The pressure losses correlate with the Reynolds number, and the Reynolds number depends on the dynamic viscosity.

The next figure (Figure 11) shows the viscosity factor as a function of the H_2 concentration. The relationship has a minimum viscosity at about 65% hydrogen content, and therefore the gas flow will be the least constrained at around 65 % H_2 concentration.

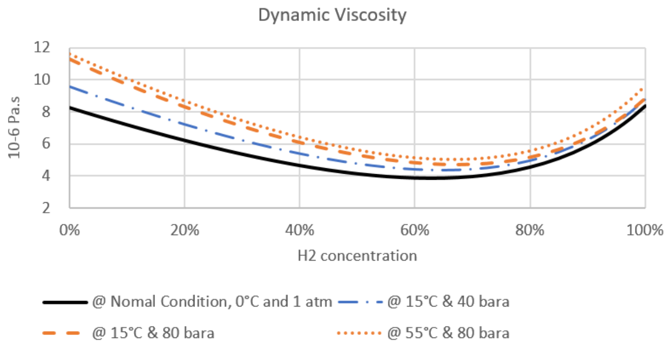


Figure 11: Dynamic viscosity depending on the H_2 concentration at different pressure and temperature conditions.

The H_2 concentration is the primary source of variability in the dynamic viscosity calculation. Pressure and temperature have little impact. The knowledge of the Joules-Thomson coefficient and specific heat capacity at constant pressure (C_p) of the studied gas is necessary to calculate the temperature evolution along the pipeline.

The following figure (Figure 12) shows the isobaric heat capacity factor depending on the H_2 concentration. The relationship suggests that after compression (hot gas), a longer distance is necessary to cool the gas as the H_2 concentration increases.

In conclusion, due to a higher temperature along the pipeline after compression, pressure losses will be more significant as the H_2 concentration increases (Bainier, [7]).

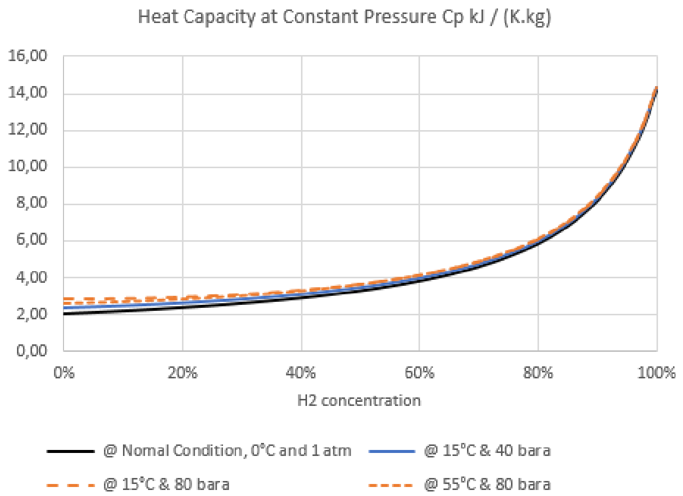


Figure 12: Heat capacity at constant pressure depending on the H_2 concentration at different pressure and temperature conditions.

Due to the low molecular weight of Hydrogen, Hydrogen compression is significantly more difficult than Methane compression. Figure 13 shows the operating points of a gas compressor, where the inlet pressure and temperature, and the discharge pressure where kept constant, while the H2 content was increased. The flow through the compressor was adjusted to keep the energy flow constant. For these conditions, compressing 100% hydrogen gas would increase the work by a factor of 10.

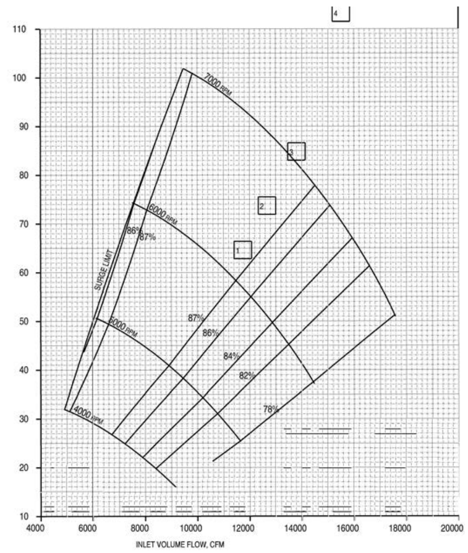


Figure 13: Compressor operating with different levels of H2 mixed into natural gas. Inlet pressure and temperature, and the discharge pressure where kept constant, while the H2 content was increased. The flow through the compressor was adjusted to keep the energy flow constant: 1-0% H2,2-10%H2, 3-20% H2,4-40%H2.

Bainier et al [7] have studied the impact of hydrogen on the transportation efficiency. Transportation efficiency essentially compared the amount of fuel burned to transport a given amount of energy over a certain distance. Using energy rather than standard flow (or mass flow) allows a direct comparison of the impact of different gas mixtures. A compressor station was modelled assuming the output of two subsequent compressor stations being the same (Figure14). The power consumption in a compressor station as a function of H_2 concentration is shown in Figure 15.

The power consumption for a situation where, for different H_2 concentrations, the same amount of energy is transported is show in Figure 16.

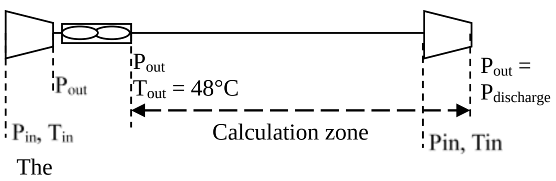


Figure 14: Pipeline segment studied

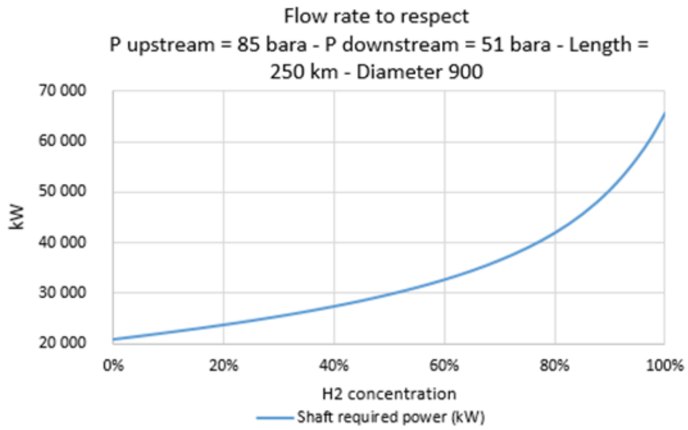


Figure 15: Power Consumption for pipeline compressor station

The results of the study shows fundamental relationships for the discussion on mixing hydrogen into natural gas pipelines:

- At the same pressure conditions and the same suction temperature, the compression work increases with the increase of H_2 concentration.
- Hydrogen has a negative Joule-Thompson Coefficient, and therefore its temperature increases when the pressure drops. For the gas, flowing into the pipeline downstream of the station cooler, the higher the H_2 concentration, the harder it is for the gas temperature to decrease along the pipeline. This characteristic has two consequences:
  - Pressure losses increase with the H_2 concentration. The higher the H_2 concentration, the higher the influence of the soil conductivity.
  - For a shorter distance between compressor stations, the compressor inlet temperature and the required compression power increase with the H_2 concentration.
  - Figure 16 shows the required increase power to transport the same quantity of energy. For the given parameters, the power increase reflects a reduction in transport efficiency.

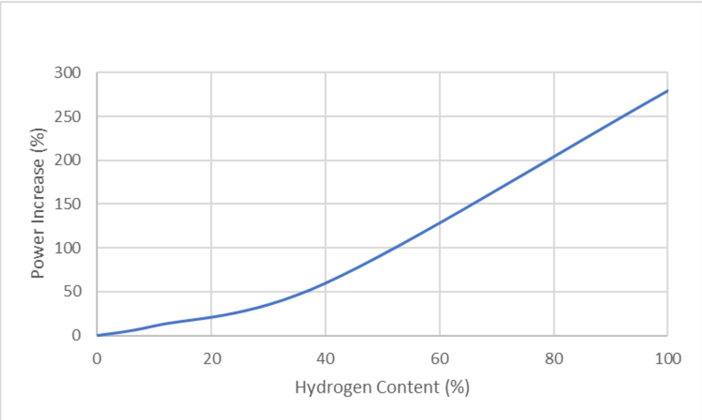


Figure 16: Power increase to transport the same amount of energy in a pipeline.

Finding a reduction in transportation efficiency when hydrogen is mixed into the pipeline is a serious drawback in the discussion on usage of hydrogen. One has to take into consideration however, that the yardstick to evaluate the use of hydrogen may not be the transportation efficiency, but rather the fact that pipelines allow for storing hydrogen. In other words, hydrogen injection into pipelines may not have to compete in terms of transportation efficiency, but rather in terms of roundtrip efficiency compared to other storage methods, like compressed air storage or batteries. Obviously, in this discussion, the efficiency of the processes that generate hydrogen, using electricity from renewables, has a big impact.

Conclusions

This study indicates injection Hydrogen into a natural gas pipelines in moderate rates is manageable with todays 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, like SoLoNOx, 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.
- The transportation efficiency of pipelines will be reduced when hydrogen is added.

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