ETN White Paper – Hydrogen Summary

The main objective of this summary is to raise the awareness among the EU institutions on the possibilities for hydrogen gas turbines to be integrated in the future energy systems.

Contributions to the summary should be aimed to achieve the main objective, considering how to enable and optimize the use of hydrogen in gas turbines by:

* Highlighting potential use, applications and benefits.
* Highlighting state of the art, barriers (technical and regulatory) and research needs in order to pave the way for future funding opportunities at EU level.

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# Advantages of hydrogen gas turbines (2 pages)

Combined cycle gas turbines are already the cleanest form of thermal power generation but combusting hydrogen instead of natural gas would make it virtually carbon free and unlike wind and solar energy, the generated power can be dispatched at will and supplied continuously. Hydrogen gas turbines would, in fact, complement the intermittent nature of wind and solar power since they can be used as back-up power with the green hydrogen that is produced via electrolysis process with excess renewable power during abundant periods of wind and daylight. Blue hydrogen, produced by natural gas reformation, can also be a carbon free resource for gas turbines if carbon capture technology is utilized. All in all, hydrogen gas turbines can be an enabler for long term energy storage.

Gas turbines use the robust and flexible natural gas infrastructure to source their fuel. With little to no modifications a blend of hydrogen with natural gas can be transported within this existing infrastructure which makes the entire system reusable without extreme capital costs. Some countries such as The Netherlands, already inject up to 12% hydrogen into their natural gas grids so this idea can be extended to other countries to at least start burning a blend of natural gas and hydrogen in gas turbines to reduce carbon emissions. However, new piping infrastructure would be necessary for 100% hydrogen transport but combusting hydrogen at the point of production would be a solution to this problem during the initial phase.

There is no necessity to design and manufacture entirely new gas turbines for hydrogen combustion. The sole component to be modified is the combustor so, theoretically, most of the existing gas turbines can be retrofitted to either partially or fully burn hydrogen. This conversion would not only avoid large capital spending but also save time in switching large fleets of current gas turbines to hydrogen. An additional major benefit of this would be a new lifeline to existing state-of-the-art gas turbines that are sitting idle or being underutilized in many European countries. This would also make a significant contribution to society and industry as the workforce is either being laid off or shifting to other sectors.

Major OEMs are working on development of dry low NOx burners for hydrogen gas turbines which is mostly standard on natural gas burning turbines. Comparing the current turbines to hydrogen turbines, both with dry low NOx burners, thermal efficiency and power output would be very similar provided that the fuel system is modified to supply larger volumes of hydrogen due to its small molecule size. Since the turbine inlet temperature would stay unchanged, no adverse effects on the maintenance of the existing equipment are expected either.

Heating sector is one of the largest carbon emitters worldwide and hydrogen gas turbines can also be used as combined heat and power plants which would be a very efficient way to decarbonize the heating infrastructure.

Last but not least, unlike fuel cell vehicles, hydrogen gas turbines would consume huge amounts of low purity hydrogen generating large and stable mass demand that can contribute to the reduction of hydrogen production costs. In this regard, governmental funding schemes for gas turbine R&D in Europe and Japan can be key contributor towards a hydrogen society.

# Pre-conditions of an H2 power plant (3-5pages)

## H2 production

Hydrogen as fuel can be generated via four main paths:

1. With power and water via electrolysis, while decarbonisation is achieved by a high share of renewables in electricity generation
2. By reforming natural gas and decarbonisation via Carbone capture and storage (CCS) or Carbone capture and usage (CCU)
3. Solid fossil fuel i.e. coal is to be converted to hydrogen via gasification and upgrading and being Carbon free via also CCS or CCU
4. Biomass can be the base for hydrogen via digestion, gasification, reforming and followed by an upgrading process. It is Carbon neutral or even negative when combined with CCS

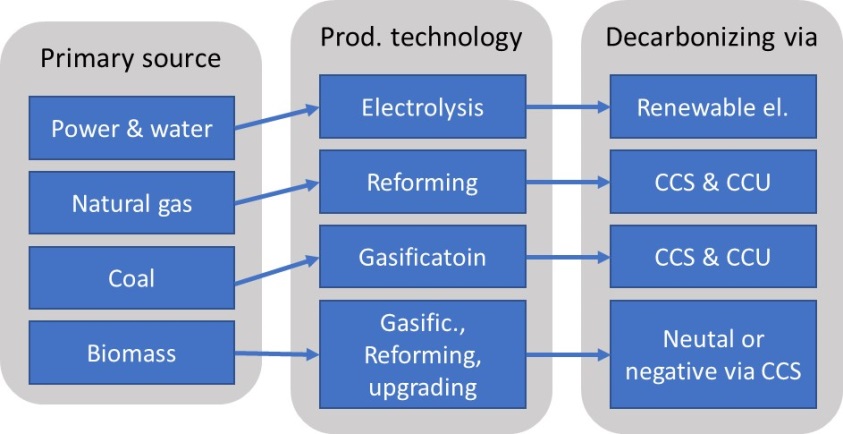


Figure 1: Four possible paths to produce hydrogen

Figure 1 visualized the four paths schematically.

An essential pre-condition for using hydrogen as fuel in power generation is based on its availability. Especially when being generated from sources which are of fluctuating character is intermediate storage of fuel and its availability at the site essential.

Main technologies to produce hydrogen and representing current state of the art technologies are electrolysis to split water into hydrogen and oxygen and reformation of hydrocarbons.

***Electrolysis:*** The process to use electrolysis and deliver hydrogen as fuel is shown in **Fehler! Verweisquelle konnte nicht gefunden werden.**. For electrolysis itself are currently three technologies at the market or close to market introduction[[1]](#footnote-1). Solid Oxide Electrolyser Cells (SOEC) are a new and maybe upcoming technology is represented by the Solid Oxide Electrolyser (SOEC) which have a higher efficiency than the other two, operate at higher temperatures, but are still in development. The energy balance in Figure 2 is based on lower heating values. The heat input is the energy needed for vaporizing the water to steam. The electricity input is the energy needed to split the steam to hydrogen and oxygen. The difference between input (100) and the out (84) represents the "latent heat of vaporization" of the produced hydrogen. Most of this energy may potentially be recovered through flue gas condensation in a subsequent combustion process. If the process is operated at 700 °C, approx. 22 % of the total energy may be supplied as heat. As SOEC did not yet reach the maturity level of the other technologies it might be considered in future but not for a near term installation. However, technology is demonstrated and developers expect it to be commercially available from about 2025 on. However, the state-of-the art SOECs suffer from significant degradation (increase in cell resistance) at high current densities (when current densities get significantly above 1 A/cm2).

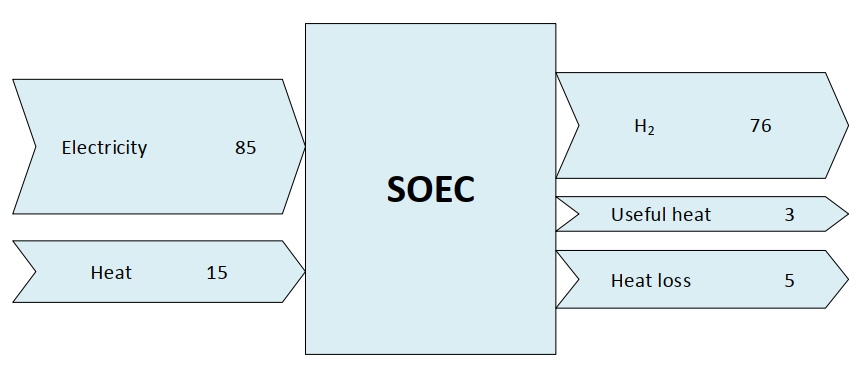


Figure 2: Example of energy balance for an SOEC [1]

Low Temperature Proton Exchange Membrane Electrolyser Cell (LT PEMEC) is operating at a temperature of between 65–700˚C (expected to increase to 90 °C in the future). An energy balance is shown in Figure 3, indicating that the efficiency is around 54%. Presently, commercially sold PEM electrolysers have a high stack cost. To meet the capital cost requirements of the PEM electrolyser a large and viable reduction in cell stack cost is needed e.g. through the development/identification of new bipolar plate and current collector (CC) materials, and substitution of the catalyst by other less expensive and/or more active catalysts.

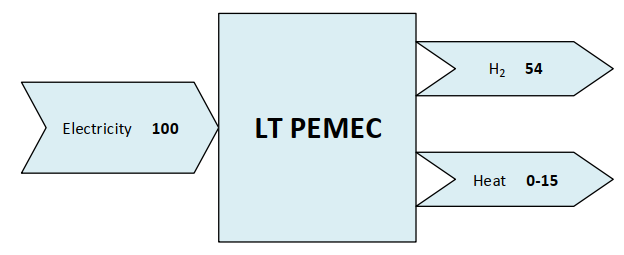


Figure 3: Example of an energy balance of a PEMFC [1]

Alkaline Electrolyser Cell (AEC) are well established and Currently most commercially available electrolysers are based on alkaline electrolysis. The anode and cathode typically consist of nickel-plated steel and steel, respectively. The anode compartment and cathode compartment are separated by a micro-porous diaphragm to avoid blending of the product gases. Operation temperature of 80 °C and 30 bar in pressure is industrial standard.

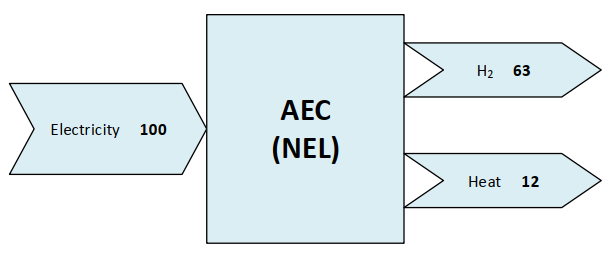


Figure 4: Example of an energy balance of an Alcaline electrolyser [1]

Hydrogen production[[2]](#footnote-2) based on hydrocarbons fuels is in most cases using the technology of *Steam-Methane Reforming.* This is a well-established process in which steam of temperatures between 700°C and 1 000°C is used to generate hydrogen from fuels with high methane content. This might be natural gas, upgraded biogas or syngas but is also possible to convert ethanol, propane or gasoline. In the most used process of methane reforming is, at a pressure of between 3 and 25 bars methane reacting with steam, forming hydrogen, carbon monoxide and some carbon dioxide. However, a catalyst is necessary for this reaction as well as heat to generate the high temperature steam. The process is followed by a water-gas shift reaction which converts the carbon monoxide, again in the presence of a catalyst, to carbon dioxide and additional hydrogen. Afterwards are carbon dioxide and impurities removed. Reaction equations become:

**Steam-methane reforming reaction**  
CH4 + H2O (+ heat) → CO + 3H2

**Water-gas shift reaction**  
CO + H2O → CO2 + H2 (+ small amount of heat)

An alternative process is partial oxidation. In this process reacts methane and other with a limited amount of oxygen. As the reaction is below stoichiometric condition it results mainly hydrogen and carbon monoxide plus nitrogen, in case air is used instead of pure oxygen. A small amount of carbon dioxide as well as other compounds is also produced. The process is again flowed by a water-gas shift reaction, as described above. Instead of the steam reforming process is this one exothermic, thus releasing heat. Process dynamics is much faster than that of steam reforming and it also requires less space due to smaller components. However, the produced amount of hydrogen per unit methane is lower than in a steam reforming process with the same type of fuel. The reaction equations are as follows:

**Partial oxidation of methane reaction**  
CH4 + ½O2 → CO + 2H2 (+ heat)

**Water-gas shift reaction**  
CO + H2O → CO2 + H2 (+ small amount of heat)

Already existing power plants are well equipped to install large scale electrolyser as they have the required interfaces such as electrical connections and water supply and competences to operate such plants.

## H2 Storage and transport

As indicated above might be storage and transport of hydrogen required. Storage to compensate changing hydrogen production rates especially when using a high share of fluctuating renewables and transport in case of large distances between the location of production and the location of power generation. Storage and transport are closely connected to the status of the hydrogen and / or if it is in its pure form or bound to other molecules. These different states are:

* Compressed hydrogen with the pressure to some extend depending on the later use and limitation of the storage container. In large scale application is transport via pipelines assumed to be most efficient[[3]](#footnote-3). As the hydrogen we are looking at is foreseen to burn in gas turbines and produce electricity in case of lack of renewable energy, producing and storing the hydrogen on site is the most direct and easiest way in case there is a overproduction of renewables. High pressure storage seems to me the most feasible one if we can also recuperate some energy during expansion.
* Storage of hydrogen in a liquid from requires cooling and pressure increase of the hydrogen while transport is usually organized via trucks and trailers. While the process is more energy intensive than compression it is less energy intensive at the re-fueling station[[4]](#footnote-4). Research mainly focuses on improved energy efficiency of the process and cost reduction of the required hardware.
* Storage and transport of hydrogen in form of Ammonia is technology receiving more attention but, compare to previous two less established. Research to reduce energy consumption of the process is ongoing[[5]](#footnote-5)
* Liquid organic hydrogen carrier is still in the research phase, but might form an alternative technology in future[[6]](#footnote-6),[[7]](#footnote-7).

Figure 5 below visualizes options for storage and transport depending on the status of Hydrogen.

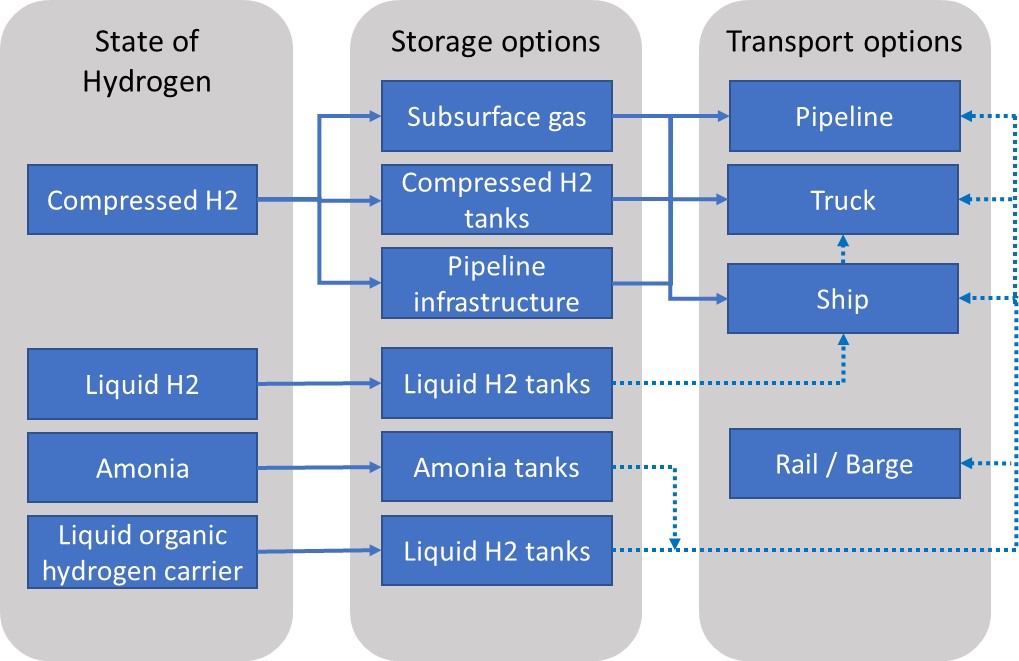


Figure 5: Options for Hydrogen transport and storage depending on the hydrogen status

Plants for electrolysis and reforming to produce hydrogen, for liquification and compression for storage and transport are for most of the above-mentioned technologies well known. However, research needs to be done when considering whole integrated system, especially in connection with system dynamics and when considering and integrating fluctuating renewables and the try to match energy production and demand with all power generation and storage technologies involved.

## Stability of fuel supply

The stability of fuel supply depends largely on the source and production process as indicated above. As future energy systems are going to continuously increase the share of renewable energy sources while at the same time reducing fossil fuel sources increases also the share fluctuating renewables. As production and demand profiles will not match is it necessary to store energy in form of fuel. Hydrogen based power generation will then take over the role of dispatchable backup power for balancing demand and generation as well as stabilizing the grid. Storage and storage capacity are therefore essential elements of a stable fuel supply and thus a reliable and stable energy system.

## Plant installation and commissioning, plant standards and norms

At the current time are installations of power plants using hydrogen as fuel limited and those installed have the character of test units. There are therefore no routines or standards existing for plant installation and commissioning. Existing might be separate ones for process plants and power generation plants, but none for plants which include both, local hydrogen production and storage and power generation. Especially in connection with option 1, the production of hydrogen based on renewable electricity and water is a close location beneficial as it avoids transport of hydrogen and therefore reduced associated losses. Co-location is also expected to reduce the overall geographical footprint and environmental impact as it will make use of already exiting electrical infrastructure and avoid the installation or modification of infrastructure for gas transport.

# Hydrogen combustion (5-10pages)

## State of the art

* Diffusion flames with nitrogen or steam dilution:

Combustion systems with diffusion flames and nitrogen or steam dilution are state-of the art systems which can handle up to 100 vol.% hydrogen. However, these systems have several disadvantages, e.g. efficiency penalty compared to systems without dilution, higher NOx level compared to lean-premixed technology, higher plant complexity and thereby higher capital and operational costs. Especially for large gas turbines running in a combined cycle or CHP configuration, steam dilution is significantly better than nitrogen dilution with respect to emission reduction and plant efficiency impact. Premixing of fuel with the diluent is preferred being more effective in terms of emission reduction. Although these systems can handle different fuels, a ‘safe’ fuel (diesel or natural gas) is used for start-up of the plant in most cases. Compared to gas turbines operated on natural gas or diesel, significant hardware modifications in the auxiliary system are needed to handle the increased fuel flow rate. Surge margin issue is handled by either compressor modifications or by reducing the inlet air mass flow.

* Lean premixed systems:

The lean-premixed combustor technology offers a much higher potential but this technology is less mature and not sufficiently developed yet with respect to the operation on fuels with very high hydrogen contents or even pure hydrogen together with a high fuel flexibility.

Several OEMs offer gas turbines which can handle H2 contents in the fuel up to 30 - 60 vol.%. However, no fuel flexible gas turbine that can handle pure hydrogen is nowadays commercially available and additional R&D activities are needed to pave the way for such a technology. Even more challenging but required for potential fluctuations in future hydrogen fuel supply is the development of combustion systems that not only can handle high hydrogen contents but the full range of 0-100%.

Examples of H2 limits in the fuel tolerated by heavy duty and industrial gas turbines in commercial operation of different OEMs:

* up to 30 vol.% H2 in natural gas for large gas turbines ranging from 117 MW to 593 MW (Siemens)
* up to 60 vol.% H2 in DLE mode for smaller GTs such as SGT-600 (Siemens)
* 0-50 vol. % H2 in natural gas for the GT36 H-class engine (Ansaldo Energia)
* 0-30 or 0-45 vol. % H2 in natural gas depending on the respective combustion hardware for the GT26 F-class engine (Ansaldo Energia)
  + - up to 25 H2 vol. % in natural gas for the AE94.3A F-class engine (Ansaldo Energia)
    - H2 limits of commercial MGTs?
* Elapsed research programs on H2 combustion:

Previous EU-funded projects have focused on the potential to integrate hydrogen-rich syngas combustion turbines with pre-combustion carbon capture and storage systems. For example, extensive hydrogen combustion research was undertaken at DLR in conjunction with Siemens and Alstom as partners in the EU FP6 ENCAP project (EU Grant 502666)[[8]](#footnote-8).

At higher TRL-level demonstration in the EU FP7 H2IGCC project (EU Grant 239349), blends of hydrogen and nitrogen were examined up to 85 %vol H2 in 15 %vol N2 in a modified Ansaldo Energia (Italy) lean premixed burner at Cardiff University (UK) up to 2 MW and 4 bara, with a number of swirl vane fuel injector geometries investigated, particularly with respect the influence on flashback, NOx emissions, and thermoacoustics[[9]](#footnote-9). Further to this testing, full engine scale combustion trials up to 83 %vol H2 in 17 %vol N2 were conducted at SESTA Lab (Italy) [1]. In the same H2IGCC project, developments in turbulent flame speed measurements for H2-containing fuel blends (70-30 %vol H2-N2, 85-15 %vol H2-N2, and 100% H2) were made at PSI (Switzerland)[[10]](#footnote-10).

Lower TRL-level research funded by the UK Engineering and Physical Sciences Research Council has focused on blending hydrogen into the natural gas grid (EPSRC Flex-E-Plant project, EP/K021095/1) up to 15% vol H2 in CH4 for pressurized burner testing[[11]](#footnote-11) and up to 40% vol H2 in CH4 for atmospheric burner testing[[12]](#footnote-12). Additional projects have evaluated CO2 as a diluent for pure hydrogen combustion in SMR-CCS systems (EPSRC Advanced Gas Turbine project, EP/M015300/1), which showed the possibility of ultra-lean pure hydrogen combustion in fully-premixed operation and stable pressurized operation with CO2 dilution[[13]](#footnote-13).

Industrial pilot projects in the EU considering either blending of natural gas with hydrogen or pure hydrogen gas turbines are also underway. For example, the Nuon Magnum Carbon-Free Gas Power project, in the Groningen region, which is a partnership between Nuon, Gasunie, Equinor, and Mitsubishi Hitachi Power Systems to convert one of Magnum’s three 440 MW CCGT to 100% hydrogen by 2023[[14]](#footnote-14). Another pilot project, such as Hotflex/ComSos (EU H2020 Grant 779481), a partnership between VERBUND, Graz University of Technology, and Sunfire in Mellach, Austria, aims to blend “green hydrogen” made from renewable energy into the 838 MW natural gas-fired CCGT power plant[[15]](#footnote-15). Further complementary EU research programs include the EU H2020 EnableH2 project which has a specific focus on the use of hydrogen as a fuel in the aviation sector (EU Grant 769241)[[16]](#footnote-16).

Outside of the EU, hydrogen gas turbine research funding has been led by countries including the United States and Japan. From 2005-2015, approximately $15M - $30M annually was provided in research funding for the US DOE Office of Fossil Energy Hydrogen Turbine Program, including large grants to General Electric (Award NT42643) and Siemens (NT42644), among other industry and university partnerships[[17]](#footnote-17). Lower-TRL fundamental hydrogen combustion research is also currently being supported in the US, considering computational modeling of flashback (DOE Agreement FE0012053) and pilot scale natural gas conversion to hydrogen for use in gas turbines (DOE Agreement FE0031615). In Japan, a “Basic Hydrogen Strategy” is currently being implemented by the New Energy and Industrial Technology Development Organization with funding levels of nearly 10 Billion JPY (~€80M) for hydrogen gas turbine development, hydrogen supply chain, and power to gas technology[[18]](#footnote-18).

## Challenges and Research Needs in Combustion

In the transition to a hydrogen based energy system fuel flexible gas turbines are needed to utilise blends of hydrogen and other gaseous fuels e.g. natural gas. Combustors need to scope with a wide range of NG/H2-mixtures as well as with fast changes (tolerable gradients must be evaluated) in the fuel composition.

The DLE technology has the potential to enable fuel flexible operation at 0-100% H2 with low emissions. However, further development effort is required . to derive technical solutions with respect to the following challenges associated with high hydrogen contents in the fuel:

* Autoignition: Higher autoignition risk due to lower ignition delay time
* Flashback: Higher flashback risk due to higher flame speed or lower ignition delay time
* Changed thermo-acoustics frequencies
* Increased NOx emissions
* Other combustion related challenges
  + Higher pressure drop due to lower Wobbe Index
  + Reduced lifetime / need for more cooling of hot gas path components due to increased heat transfer as a result of higher water content in combustion products

Research at practically relevant conditions (high pressure and air preheat, high combustor exit temperature, high flow rates and high Re-number) are needed. Academic studies at reduced pressure level and size can sufficiently capture conditions for micro gas turbine applications but clearly fall short for larger scale gas turbine combustion systems. Correlations and well defined validation cases are missing.

The presence of hydrogen strongly alters the combustion properties of “hydrogen blends” with respect to natural gas. Adding hydrogen to natural gas tends to increase its flame speed, to reduce its ignition delay time, and to enlarge its flammability limits. These features affect positively the flame stabilization in terms of flame anchoring and may also widen the emission compliant turn down ratio (part load performance). At the same time, increasing the presence of hydrogen will change the thermoacoustic behaviour of the combustion system and increase the local flame temperature which will potentially results in higher pollutant emissions (NOx) at the exit of the combustor if no additional measures are taken.

* **Autoignition:**High reactivity of hydrogen inherently increases the auto ignition risk in the premixing section which needs to be addressed in future combustor development. This might be of a particular challenge in some systems with very high air inlet temperatures, e.g. in modern high-efficient gas turbines or MGTs due to the recuperator.

To protect burners and fuel injectors from being overheated or damaged, burners typically are instrumented with thermocouples if more reactive fuels are used. In advanced, highly efficient gas turbines more and more complex burner design, e.g. multi-nozzle arrangements are needed and therefore this method of protecting burners will become challenging and expensive. Other methods of detecting and preventing autoignition events leading to a flame stabilisation in undesired locations are needed especially when increasing H2 fraction in the fuel.

* **Flashback:**Burning hydrogen-rich fuels inherently increases the flashback risk because of a higher flame speed or a shorter ignition delay time compared to natural gas. In some systems with very high air inlet temperatures this might be a particular challenge.

To protect burners and other components from being overheated or damaged because of a flashback initiated flame stabilisation in undesired locations (e.g. premixing section) methods of detecting and avoiding flashback have to be developed and applied in gas turbines.

* **Thermoacoustics:**  
  Compared to natural gas flames, hydrogen flames exhibit a significantly different thermoacoustic behavior. This is due to the higher flame speed, shorter ignition delay time and different flame stabilization mechanisms resulting in different flame shapes, positions and different reactivity.

Therefore, the risk of combustion dynamics in modern gas turbines operated on hydrogen-rich fuels is expected to increase compared to natural gas operation. This implies that undesired and dangerous phenomena, such as combustion instabilities, flashback and lean blow out, are likely to occur not only at steady conditions, but also and more dangerously during transient operation, e.g. when rapid power changes are required and/or fuel composition changes (see Figure 6 below depicting an example of damage[[19]](#footnote-19)).

For developing stable combustion systems for hydrogen-rich flames various measures are required so that high pressure pulsations are avoided. In addition to this, the turbulent flame speed of hydrogen is pressure dependent (unlike that of natural gas). This in turn means that current low TRL testing strategies based on atmospheric rigs, e.g., the prediction of engine thermoacoustics via measuring flame transfer functions, is not possible and would have to be adapted.

Hence, besides a deeper understanding of the physical mechanisms contributing to combustion dynamics, also real-time, reliable monitoring and control systems are required to make combustors more efficient and flexible, and guarantee gas turbine availability.

Figure 6 Damages due to high-frequency (2350 Hz) thermoacoustic instabilities due to inappropriate tuning of the machine [19].Figure 6 depicts an example of damage:



Figure 6 Damages due to high-frequency (2350 Hz) thermoacoustic instabilities due to inappropriate tuning of the machine [19].

* **Higher flame temperature, NOx emissions:**  
  The higher adiabatic flame temperature of H2 will results in higher NOx emissions if no additional measures are undertaken. It will be particularly a challenge to achieve stricter NOx-limits foreseen in the future.

Lowering the flame temperature by engine derating would result in efficiency and power debits.

For retrofit projects applying post-combustion De-NOx technology (SCR) is very difficult and costly. Therefore, reducing the combustor NOx emissions is the better way.

* **Other combustion related challenges:**
  + **Wobbe Index change:**Compared to burning natural gas at the same thermal power a larger volumetric fuel flow rate is need when burning hydrogen because of a factor of about three lower volumetric Lower Heating Value (LHV) of hydrogen. In addition, hydrogen has a lower Wobbe Index (WI) which is the most commonly used parameter for specifying the acceptability of a gaseous fuel in a combustion system. The significance of the Wobbe Index is that for a given fuel supply and combustor conditions (temperature and pressure) and a given control valve positions two gases with different compositions, but the same Wobbe Index, will give the same energy input to the combustion system. Thus the greater the change in Wobbe Index the greater the required flexibility of the combustion systems and associated control.

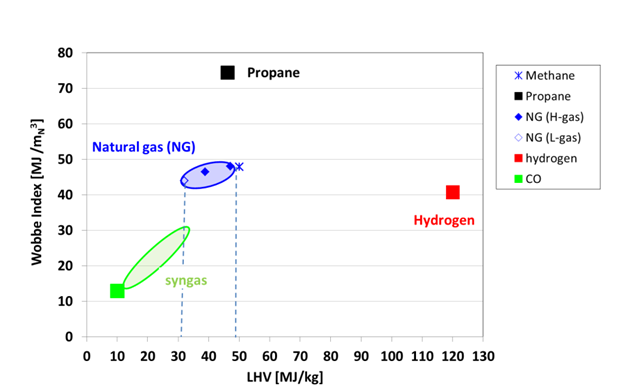


Figure 7 Wobbe Index as a function of the Lower Heating Value for different fuels.

* + **Reduced lifetime /improved cooling of hot gas path components**Burning hydrogen instead of natural gas will increase the moisture content in the exhaust gas causing a higher heat transfer to the gas turbine hot gas path components. This will require an adaptation of the cooling in order to avoid overheating of components. In addition, due to the higher moisture content hot corrosion is more likely to occur. Therefore, measures need to be undertaken to avoid these effects.

## Additional comments, suggestions, questions

* Additional figures would be good
* How to deal with references?
* Comment on other CO2-free energy carrier options (e.g. Ammonia, Methane, Methanol , ..) to be added in the H2 summary?
* **Other integration topics** (not combustion related; Should be treated in other chapters of the H2 summary document, e.g. “pre-cautions of a H2 power plant”)**:** 
  + Sealing and ventilation of closed volumes must be considered seriously due to wide flammability limits of H2
  + Determine the mixing technology in case the mixture is made on site at the power plant. What is the degree of homogeneity of the mixture needed?
  + Potential of embrittlement, e.g. fuel supply lines/valves/seals
  + In order to control and protect the gas turbine, fast online measurements of H2 concentration is needed for mixed fuels (H2/NG)
  + Higher moisture in exhaust:
    - Higher heat transfer in hot gas path, due to higher water content of combustion products. Hot corrosion could lead to degradation in lifetime.
    - Condensation in ambience/visible white plume 🡪 acceptable for people? Maybe need to partially condense in stack or other means
    - Faster mixing with ambient air at stack

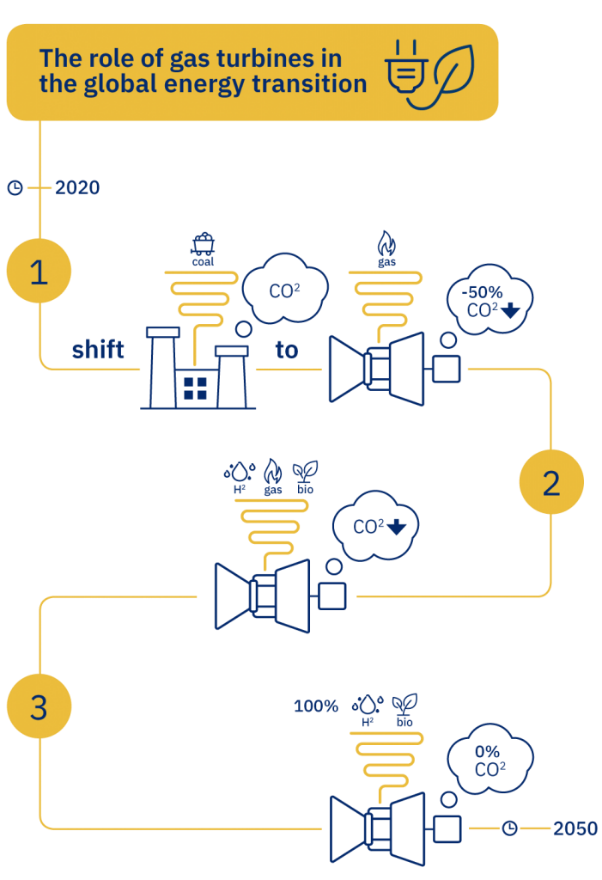
# Retrofit of existing gas turbines (5-10pages)

## Rationale

The global decarbonization of power generation will be driven by adding more renewable solar and wind generation to the electricity grid. These renewable sources provide a fluctuating electricity supply that needs to be balanced by other forms of power generation to provide a stable electricity supply that can power our whole society in a reliable, affordable and sustainable way.

Gas turbines are very well positioned to fulfil this crucial balancing role, both during the energy transition and after 2050 because:

* In combined cycle configuration (CCGT) they produce the same amount of electricity at 50% of the CO2 emissions compared to coal- fired power generation;
* Mixing in increasing amounts of renewable gas fuels (green hydrogen, biogas, syngas etc.) with natural gas will further reduce their CO2 emissions;
* They will be running entirely on renewable gas fuels before 2050 to realize 100% carbon neutral gas-fired power generation;
* They are flexible, suited for frequent starting and able to provide fast response on grid needs, making them complementary to the variable renewable electricity sources.



In 2019 over a quarter of the European electricity production is realized by coal-fired power generation. At the same time Europe has a large existing fleet of relatively new, highly efficient and very flexible gas turbine combined cycle plants that operate at a limited percentage of their total capacity.

By accelerating a shift from coal-fired power generation to gas-fired power generation Europe can make a massive step forward in decarbonizing the power generation sector during the next ten years with relatively limited efforts and investments.

Development of retrofit solutions for existing gas turbines will be a key enabler for this. Initially this can be relatively small modifications to existing burners, allowing co-firing of hydrogen to significant fractions (>30 vol%, 11% of energy). This shall be followed by new types of burners allowing up to 100% of hydrogen firing without the need for diluents for emission control.

## State of the art

In GE’s literature (see GEA33861[[20]](#footnote-20) for a brief summary), particularly high values in terms of hydrogen concentration can be found in aeroderivative gas turbines, configured with single annular combustor (SAC) and also in single nozzle and multi-nozzle combustors applied to GE’s heavy-duty gas turbines in B, E and F class. Values up to 90-100% are presented for diffusion combustion, hence needing significant amounts of dilution (steam or nitrogen) and NOx control with e.g. SCR.

GE’s DLE and DLN combustion systems are capable of operation with limited amounts of hydrogen in the fuel. The DLE combustor, which is found on GE’s aeroderivative gas turbines, is limited to 5%vol. hydrogen. The DLN1 combustion system, which is available on GE’s 6B, 7E, and 9E gas turbines, can operate with up to 33%vol. hydrogen when blended with natural gas.

GE’s DLN 2.6+ combustors go up to ~15% (by volume). The associated fuel systems for these combustors are typically only configured for a maximum of 5% (by volume) hydrogen and would require upgrading to safely operate at higher hydrogen concentrations20.

As part of the US Department of Energy’s Advanced IGCC/Hydrogen Gas Turbine program, GE developed a low-NOx hydrogen combustion system based on small scale jets in crossflow for rapid mixing of fuel with air streams (Multi-tube -mixer, Figure 8)[[21]](#footnote-21).

Preliminary tests suggest up to 50%vol. levels could potentially be reached.

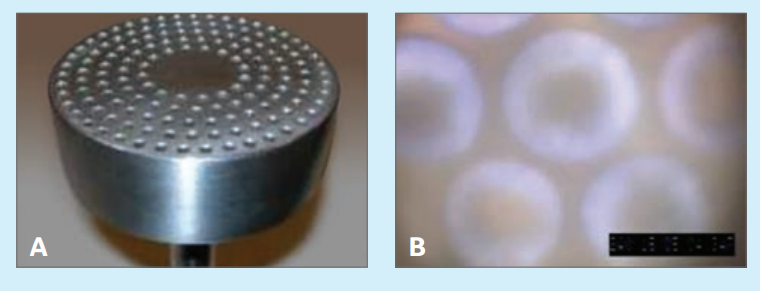


Figure 8 Multi-tube mixer (left panel) and its operation with a blend of H2 and N2 (right panel)

Aeroderivative GTs equipped with the DLE annular combustion system (the LM family) can burn up to 5%vol H2 [3]. Higher capability is achieved with DLN1 multi-can combustors installed on Frame 5 units (up to 10%vol H2) and larger Frame 6B, 7EA and 9E (up to 32% vol. H2); DLN2 combustion systems, employed in different versions on Frame 52E and on F-class larger frames, are currently accepting up to ~15% vol. H2 [4]. The impact fuel composition on guaranteed NOx emissions for DLN1/DLN2 combustors (normally rated between 5 and 25 ppmvd on natural gas, depending on engine size and combustor version) is usually evaluated case by case considering the whole composition and site conditions; the effect on NOx guaranteed values of the sole hydrogen in the above mentioned concentration can be from null to moderate. GE is currently developing design solutions to increase the allowable H2 concentration to 50% vol. on both DLN1 and DLN2 combustion systems (field validation not yet available) [4, 5, 6]. For what concerns the NovaLT family, the engines are equipped with piloted premixed burners arranged in annular combustors, capable to modulate the fuel split between pilot and premix lines along the operating range and based on fuel composition. This flexibility allows the engines to burn up to 100% H2, with consequently variable NOx emission levels. BHGE is working since several years on the development of novel burner technologies to allow the reliable application of lean premixed systems with high hydrogen fuels [7].

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For Siemens Gasturbines Upgrades are in principal available for the Service Fleet. The specific capability of admixing hydrogen into an existing Gas Turbine set-up always needs to be checked for each site.

For Siemens Gas Turbines 2000E and 4000F the standard Upgrade package H2DeCarb for Higher H2 contents is available. For the 2000E with this package machines are able to operate with up to 30% H2 admixture. For the 4000F upgrade up to 15% H2 admixture is possible.

Even higher ratios for newer versions and on specific request are possible.

For other machines of the Siemens heavy duty portfolio upgrade of the machines to higher H2 contents can be requested, too.

For industrial gas turbines the standard capability is up to 10% by volume in the existing packages (15% standard for new units), but it all depends on the actual package generation design. An analysis needs to be conducted on the existing site to find the components that need to be exchanged to be able to get to a higher mix of hydrogen. The Industrial Gas Turbines today with 3rd generation DLE system (standard for all delivered SGT-700 and SGT-800 and option for SGT-600) have a high capability to burn hydrogen with levels of 50%-70% by Volume.

Aero-machines, running with WLE system the possible H2-capbility is normally higher. However, also here a check by Siemens should always be conducted, to clarify if Service overhaul times are affected by higher concentrations than already guaranteed.

The effort to upgrade a Siemens gas turbine package to higher H2 contents highly depends on the age of the gas turbine and the status of the installed auxiliary package and power plant, which sometimes might be a third-party solution. The following items normally need to be considered and checked site specifically:

* Steel type used in the Gas turbines auxiliaries system for piping, valves and gaskets. A change to stainless steel might be needed.
* project specific check regarding the explosion protection concept, with which the gas turbine was delivered as new apparatus design.

Following items usually need to be updated to account for the changed combustion characteristics due to increased H2 content in the fuel:

* The control system of the gas turbine in order to account for changes in the H2/NG mixture, if this is not fixed.
* Depending on the concentration and engine configuration use of additional Thermo-couples and respective implementation of their monitoring into the control system to avid flashback.
* Upgrade or installation of combustion monitoring systems (for detection and active measures in case of combustion instabilities)
* The Gas detection system needs to be verified when catalytic detectors are required with higher levels of hydrogen
* Combination UV and IR detectors required to detect the flame with increased hydrogen

The scope on the upgrade packages is related to the specific requirements and requested scope and target amount of H2 admixture respectively. For higher H2 ratios the upgrade packages consider options to balance between modification scope and performance level. In order to keep the NOx level emission compliant in some cases the primary zone temperature might need to be reduced. By implementation of upgrade measures, the performance impact due to reduced overall combustion temperature can often be compensated for service machines. In the end, the decision on what specific measures should be implemented into a serviced frame is always depended on the project specific setup of the gas turbine and its surrounding system.

In order to further increase the upgrade potential, the main gaps and respective R&D needs are in the development of the combustion system with respective High-Pressure Rig Tests needed. Those are mostly quite expensive and time-consuming. Additionally, the integration in existing power plants and with the additional components that would be installed for green-hydrogen production (i.e. electrolysers, storage and fuel mixing set-up), is very complex. Here, limited experience exists and additional effort is anticipated for the first prototype installations.

The advantage of the Ansaldo GT26 gas turbine with reheat technology is an additional degree of freedom balancing the power of the two combustion chambers (Figure 9). A variation of flame temperature of the first burner is an effective parameter to maintain low NOx emissions as well as offsetting the impact of fuel reactivity on the auto-ignition delay time of the downstream reheat burner[[22]](#footnote-22), [[23]](#footnote-23).

The C2+ operation concept utilizes this degree of freedom to optimize combustion behavior for fuels containing C2+[[24]](#footnote-24). Since H2 and C2+ have a similar behavior in terms of reactivity, the C2+ operation concept can also be applied to H2 fuel mixtures. Extensive single burner high pressure tests at full scale were performed for existing Ansaldo GT26 standard premix and standard reheat burners (GT26 upgrade 2006 and upgrade 2011) with 15 to 60 vol.-% H2-doped natural gas. Emissions and flame instabilities were monitored, and several flame position tests were carried out22. It could be confirmed that for the latest upgrades (2011) machines can cope with hydrogen contents of up to 30%H2 with no changes in hardware and without performance penalty. With further validation and minimal de-rating, the H2 limit can be extended to 45%H2.

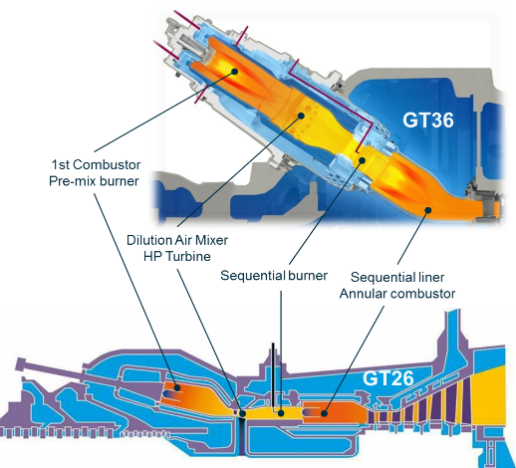


Figure GT26 / GT36 layout.

The sequential combustion system additional degree of freedom can be exploited to and even larger extent in the Ansaldo Energia GT36. Since this engine does not have a high-pressure turbine between the upstream and downstream combustion chambers (Figure 9), sequential combustion is implemented into a CPSC (Constant Pressure Sequential Combustion) configuration, without any penalty to be taken, when lowering the temperature between the two combustion stages.

The GT36 is nowadays offered for commercial operation with hydrogen contents of up to 50%vol. Further validation is ongoing, including high pressure tests[[25]](#footnote-25), 23. Tests done so far demonstrate the potential of this system to be brought into operation with the full range of natural gas and hydrogen blends. With the hardware as is, operation with up to 70% was demonstrated feasible with minimal or no de-rating, without dilution or SCR needs; with further optimization this level is expected to be further extended. Being the CPSC system layout a can-combustor, retrofits to other can engines are in principle possible.

The AE94.3A acquired broad experience on hydrogen operation in a commercial power plant, operating with hydrogen in natural gas with concentrations up to 25%vol., cumulating several hundred kEOH on two units at various hydrogen / natural gas blends.

An extension of the gas turbine capability to consume hydrogen to 25%, with 35% tested, of the total fuel was recently described in [Bullard et al]: the LEC-III combustion system, combined with automated tuning (AutoTune system) was shown capable to retrofit and commercial introduction of significant quantities of hydrogen fuel into the gas supply of an existing commercial E-class gas turbine in Europe. The commercially operating plant provides combined heat (in the form of process steam) and power. Three 9E machines are approaching 2 years of commercial operation with this flexible hydrogen package

The “FlameSheet Combustor”[[26]](#footnote-26), specifically developed and proven as a commercial solution for being retrofitted with low emissions and high fuel flexibility is available for implementation in E & F -Class GTs with hydrogen capability of up to 40% by volume released for commercial implementation. Blending of hydrogen upto 80% by volume has been demonstrated on combustion rig tests. A Dutch government subsidized program with several industry/academic partners is in progress to combustion rig demonstrate 0-100% hydrogen capability with sub 9ppm NOx emissions in 2019/2020. The FlameSheet is already in commercial operation on seven F-class GE machines and is a simple retrofit for existing GE, Siemens and MHI, E and F-class machines.

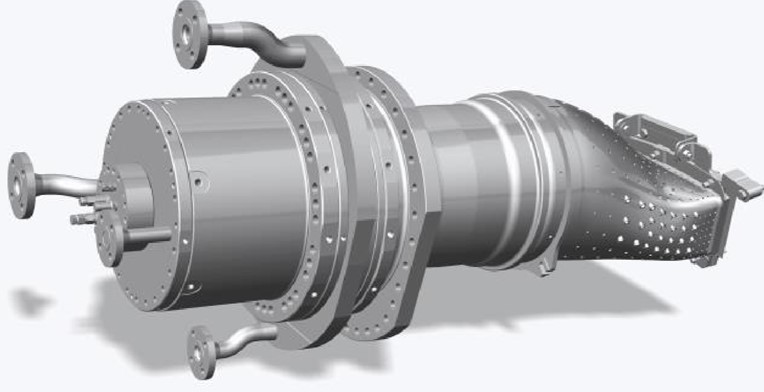
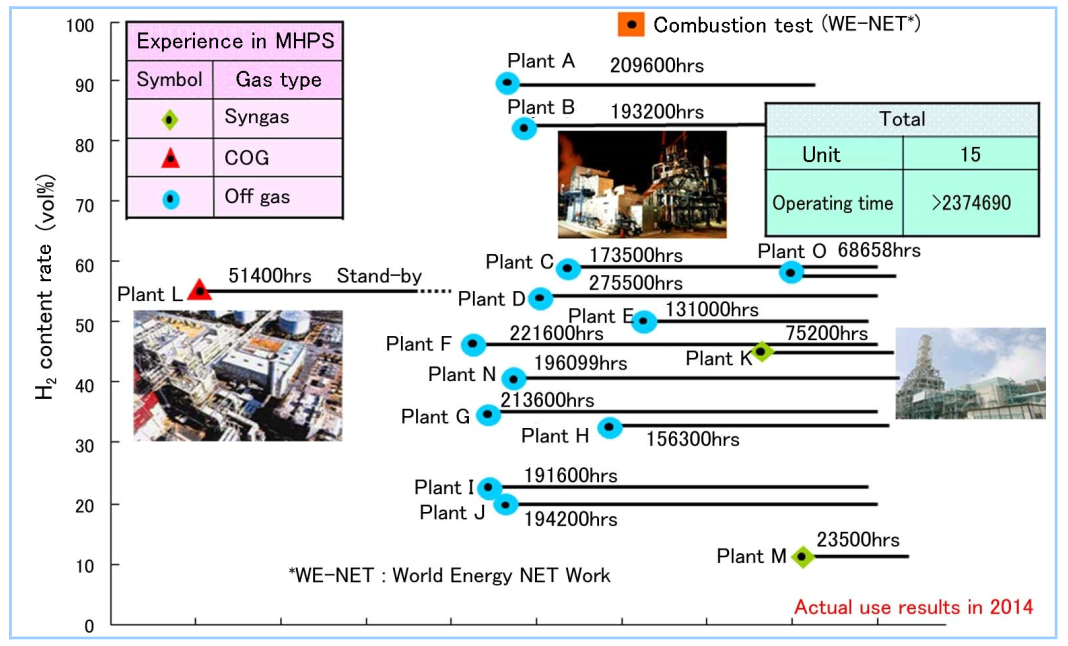


Figure 10 FlameSheet for E/F class GE, Siemens and MHI machines

MHPS has various units having been running on syngas, refinery gas, coke oven gas (COG), and blast furnace gas (BFG) [1,2]. Many of them use a diffusion-type combustor which typically requires water or steam injection (see fig. below) [2].

  
Currently, MHPS is refining its existing natural gas fired combustors to cope with a larger volume of hydrogen. Its Dry Low NOx (DLN) combustor is based on lean premixed technology, aiming at the lowest possible local flame temperature to keep NOx under control. That approach however is not easily suitable for fuels with high hydrogen concentrations due to auto ignition occurring in the premix zone. As a result, the combustor is being modified at the MHPS Takasago Works facility in Japan to achieve a mix of hydrogen and natural gas that could be used in large-frame GTs.  
Due to the shortcomings of diffusion-based combustion, MHPS opted for the development of the multi-cluster diffusion burner to protect against flashback. Each nozzle can mix air and hydrogen, aiming at smaller diffusion flames, with higher local velocities and higher degree of mixing, producing a lower local flame temperature, and therefore lower NOx.  
Work on this project is in the early stages. The new combustor has been tested on a small gas turbine using Liquefied Petroleum Gas (LPG). It calls for replacement of the fuel nozzle, combustor basket, transition piece, ignitors and flame detectors. Fuel lines must also be augmented to cope with a larger fuel flow. MHPS aims at retrofitting this technology into existing GTs. However, the attainment of a combustor running in a gas turbine on 100% hydrogen is not targeted for commercial operation until 2030.   
In the meantime, supported by New Energy and Industrial Technology Development Organization (NEDO), the company has successfully completed a firing test with 30% hydrogen at 1,600°C using DLN technology, with new design features aimed at better flashback resistance [1,3].

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## Research needs

There is a requirement for research to address systems, materials, operations and control of gas turbines for their safe and economically effective transition to a hydrogen containing fuel stream. There are break points to consider, namely;

* Low levels of hydrogen mixed with natural gas, to a level that does not necessitate significant changes to materials, designs, and control and protection. These levels may be considered to be in the range of [0-30 vol%]
* Higher levels of hydrogen, which necessitate a wider retrofit scope, and which probably then economically suggest that hydrogen fuel capability should be maximized given the assumption of fuel delivery, combustion module, control and protection retrofit.

In a perfect arrangement, from a fuel trading perspective, retrofitted gas turbines would be able to operate on a 0-100% hydrogen/natural gas mix. The nature of hydrogen processing, delivered from stochastic renewables generation, also implies the need for flexibility in fuel diet.

There is existing OEM and turbine service research work which addresses some of the above – mostly on a gas turbine model-by-model basis. It is more advanced at the lower hydrogen combustion fueling levels and significantly less advanced at high hydrogen firing levels. University research contributes to the fundamental understanding of the combustion processes.

### General

* Safety requirements for H2 systems and H2-NG mixture systems including inertisation/purging
* Material selection (piping, valve types)
* Retrofit needs for fuel delivery system, control system and combustion system

### Retrofit of existing DLN systems

In the combined cycle plant located in Brindisi (South of Italy), operated by Enipower, the largest Italian operator of chp power plants, a DLN type combustion system has been in operation since 2007, serving two AE94.3A gas turbines (F-Class ), able to handle a blend of hydrogen and natural gas, limited to date - due to permit reasons - at 15% by volume of hydrogen (NOx emission limit lower than 50 mg/Nm3 as hourly average and 40 mg/Nm3 as daily average).

The hydrogen fed to the gas turbines comes from an off-gas stream (typical composition 65% H2 and about 35% CH4) available in the petrochemical complex where power station is installed, a distillation by-product of a Steam Cracking unit; its use optimizes the energy balance of the complex as well as reducing the consumption of natural gas and the CO2 emissions of the power plant.

The gas turbines are equipped, from the very beginning, with an annular combustion chamber with 24 DLN type burners, with a premixed main flame and diffusive type pilot flame, fed exclusively with natural gas in order to guarantee flame stability in the whole operating range of the gas turbine and avoid the risk of flashbacks.

Annular type combustion chambers are particularly critical especially for humming phenomena, also due to the reciprocal influence of the single burners on the overall thermo-acoustic behaviour.

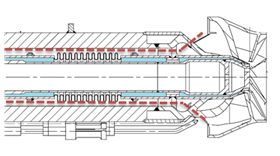
The original AE94.3A fuel supply system and its control logics (natural gas) were then adapted to supply a blend of natural gas and hydrogen only to the main premix line.

The sudden increase of renewable energy sources, which occurred in Italy especially from 2009-2010, has significantly changed the utilization pattern of combined cycle units, pushing all operators to seek ever higher operating flexibility and minimum load decrease, to limit economic exposure in unfavourable market conditions, especially for must-run units such as those operating in cogeneration mode.

Recently (2016-2018), a new Ansaldo Energia DLN burner (Dual Pilot), has been successfully tested on test rig scale and in power plant real operation, different from the initial one, which theoretically allows to use fuel mixtures with an H2 content up to 30% vol., that is equivalent, considering that the quantity of off-gas is relatively steady over time, to reduce the minimum load of the two units that use it (H2 % vol. increase), thus allowing the adoption of other technical solutions already implemented on the units of the fleet to maximize operating range.

In the same way the burner test will allow to increase, at higher GT loads and therefore in more efficient conditions, the amount of hydrogen that can be fed, also coming from renewable sources (blue or green H2).

The new burners are equipped with a hybrid pilot (diffusive and premixed) which ensures flame stability and at the same time reduces the concentration of NOx at highest GT loads, also with higher concentration of H2 in the fuel mixture.

Schematic drawing with details of the double pilot gas channel (red “diffusive” and “ciano” premix pilot) and of the burner longitudinal section that shows also the main “premix flame” gas annular distributor

Experience after more than 10 years using H2/natural gas mixtures has shown no significant impacts on overall operating efficiency. NOx emissions are on average lower than 30 mg/Nm3 with H2 content up to 15% vol.

### Full Retrofit for Flexible 0 - 100% hydrogen firing

There is a requirement for research to address systems, materials, operations and control of gas turbines for their safe and economically effective transition to a hydrogen containing fuel stream. There are break points to consider, namely;

* Low levels of hydrogen mixed with natural gas, to a level that does not necessitate significant changes to materials, designs, and control and protection. These levels may be considered to be in the range of [0-30 vol%]
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## Fuel Flexibility

The rate of change of fuel mix (natural gas : hydrogen) will be a key requirement to be met by future powerplant, most of which will for the foreseeable future comprise retrofit units from the existing installed asset base. It is considered likely that a natural gas-dominant or liquid fuel start up fuel feed will be the basis on which these units will be safely managed on start up and maybe also on shut down.

The operators of these assets will look for gas turbine solutions that do not constrain fuel delivery ie that match the variation in hydrogen concentration in the fuel pipeline, due to variations in hydrogen production*.*

For gas turbines connected to the gas transmission network, it is not possible to control the composition of fuel delivered to the plant. While the proportion of hydrogen introduced into the networks may increase gradually over time, it is anticipated that regional initiatives will cause the hydrogen content to increase much more rapidly in some locations, for example, the proposed HyNet project in the north-west of England. Operators must therefore try to anticipate the likely rate of introduction of hydrogen at each of their plant locations, and implement the modifications necessary for the expected fuel composition range. If hydrogen is introduced into the network in a planned and coordinated manner, operators will be able to schedule the required upgrades. There is currently significant uncertainty throughout Europe in this respect.

Short-term fluctuations in hydrogen content, due to intermittent production rates from renewable generation, could be minimized by gradually blending into the network. This would require regulation by the network operators. If this is not possible, faster fuel composition analysis would need to be built into the gas turbine control.

## Impact on Plant Performance and flexibility

The research done so far suggest that gas turbine power output should be similar to natural gas fired units subject to a combustion system replacement for high hydrogen firing rates. The increased reactivity of hydrogen as a fuel and its higher flame speeds force new combustion and fuel injection designs to be adopted for high rate hydrogen fueling. A likely problem will be the degree to which a plant capable of high hydrogen combustion rates can then operate on high natural gas firing rates. The probability is that there will be compromises on emissions or output or power output ramp rates at some point of the hydrogen : natural gas scale. Due to the higher reactivity of hydrogen, the turndown is likely to be improved when operating at the higher hydrogen contents as CO emissions will be reduced.

For grid support services that rely on a high ramp rate (e.g. frequency response) it is likely that some short-term adaptation of the fueling mix and a more complex fuel delivery control system may be required. These solutions may alter between engine type so applicable regulations may need to reflect a range of engineering solutions.

## Dry Low NOx Combustion

The current research literature suggests that high rate hydrogen firing should be able to achieve current levels of NOx emissions without the addition of diluents ie Dry Low NOx is expected to be an achievable solution for most gas turbine retrofits. This assumes near-perfect fuel/air mixing, however, and in reality the NOx emissions are expected to increase significantly (~50-100%) at higher levels of hydrogen (especially for the higher pressure-ratio designs). The nature of hydrogen versus natural gas will drive injector and combustor hardware design changes for high hydrogen firing. An area for validation and research is then low emissions capability when hydrogen firing concentrations drop to lower levels. Larger fuel nozzle effective areas are required for operation on 100% hydrogen, to accommodate its lower volumetric heating value. It may therefore be necessary to modify the burner design and control concept to switch in/out individual fuel circuits, depending on the fuel composition.

Permitted NOx limits are unlikely to be relaxed in future. Post-combustion NOx control is expensive and often not feasible for retrofit (even if installed, Selective Catalytic Reduction (SCR) units would require upgrading/enlarging to deal with the increased NOx formation). Combustion system development must therefore focus on reducing the NOx levels without the need for SCR. The use of a diluent for NOx control is also undesirable, as this normally requires a de-rate and increased maintenance.

## Impact on Hot Gas Path Parts Lifetime

It is likely that hot gas path temperature profiles will alter with the retrofit of a hydrogen-flexible combustion system. Whilst it is possible that temperature variations will decrease with micro-injector style (multi-point) fuel injectors it is also almost inevitable that that original hot gas path components will see temperature profiles that are different to those that they were originally designed for. The variations will be more, or less, significant per engine type – so this can’t be generalized.

It is correct to assume that each retrofit solution should be qualified as a mini-New-Product-Introduction, with appropriate qualification and risk management of key engine hot gas path components. A mix of validation by similarity, increased inspection, and analysis of ex-service components will be part of this qualification process.

If a diluent (water or steam) is required for NOx control, this will typically reduce the maintenance interval for the hot gas path components.

## Requirements for Retrofit Packages

Most customers for asset retrofits will be large ie utility or refinery or large process customers. Their project requirements will include risk mitigation and qualification of new product as part of the requirements for any project. This implies that any hydrogen fuel retrofit will be either the purchase of a highly qualified and defined option or module for a mainstream gas turbine model or it will be a pilot programme purchase of such a product. This work will not be likely to be carried out as a single engine modification, due to the high product development investment cost.

The retrofit package is likely to include:

-Core gas turbine combustion module replacement

-Instrumentation and fuel control system modification

-Plant fuel delivery system modification, including modified purge, metering, gas composition monitoring, safety systems (including package sensing and ventilation upgrades) and the provision of a start-up fuel supply.

-It is likely that the economics of such a retrofit assume re-use of existing hot gas path designs of components.

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