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Hydrogen power and heat with Siemens Energy gas turbines

Reliable and flexible carbon-free energy

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Today, gas turbines play a vital role in addressing the threat of global warming and making energy greener. Gas turbines are in the category of the cleanest fossil-fuel based power generation solutions and are ideally suited to manage the intermittency of increasing renewable loads by providing reliable and on-demand power. Gas turbines will remain an even more important element in power grids as electrification trends toward full decarbonization and the hydrogen economy starts to unfold.

By burning hydrogen as a fuel, either through co-firing or complete displacement of natural gas, gas turbines can provide low-carbon or even carbon-free power solutions. Gas turbines play a key role in enabling a smooth transition from a fossil fuel-based to a fully decarbonized power system because they provide highly flexible and dispatchable generation to support future grids largely dominated by intermittent renewable power. These capabilities make gas turbines ideally suited to helping to meet the World Energy Council's trilemma of secure, affordable, and environmentally sustainable energy.

In the future, increasing use of hydrogen fuels will enable the conversion of thousands of gas turbine operating units worldwide into reliable and environmentally sustainable decarbonization agents. Therefore, owners of existing gas turbine power plants and the ones soon to be developed can be confident of their plants' roles in supporting the future energy transition.

Karim Amin
Member of Executive Board
Executive Vice President – Generation
Siemens Energy

Thorbjörn Fors
Executive Vice President – Industrial Applications
Siemens Energy

1 Why use hydrogen as a fuel for gas turbines?

The need for hydrogen to decarbonize power generation

Global warming, caused by anthropogenic emissions such as carbon dioxide, methane, and other greenhouse gases, threatens to disrupt the ecosystems on which we all depend. In October 2018, the Intergovernmental Panel on Climate Change (IPCC) released a special report that details the impacts of global warming of 1.5 °C and higher above pre-industrial levels. Revising their original target of keeping global warming below 2 °C, the IPCC warned that warming above 1.5 °C is not sustainable in the long-term. Instead, the IPCC now recommends reducing the target for global temperature increases to just 1-1.5 °C until the end of the century [1].

The IPCC's target of limiting the global temperature rise to no more than 1.5 °C requires limiting annual global emissions to 25–30 gigatons (Gt) carbon dioxide (CO_2) equivalent per year range by 2030 [1], however in 2019 annual worldwide emissions reached 33 Gt CO_2 [2]. The energy sector is a major contributor to global greenhouse emissions with a global share of around 41% while the remaining 59% are emitted from other sectors such as industry, mobility and residential [2].

For the last few decades, the focus for reducing the carbon emissions in the energy sector has been on the development of renewable generation using mainly wind and solar energy. While renewables do not produce carbon emissions, they introduce a high level of intermittency due to changing weather conditions and variations in solar irradiation. This is often coupled with mismatches between the demand and supply of energy. While demand-side management can play a large role in handling these mismatches, supply management through curtailment of renewables during times of oversupply, energy storage, and providing backup power with dispatchable, flexible conventional power plants is also required. In recent years, a variety of storage options have emerged allowing short-term storage during the day as well as long-term storage through whole seasons. While batteries are well-suited to help manage the daily peak shift from midday to evenings, energy storage in chemical form appears as the only viable solution to store energy for longer periods and for seasonal storage.

Of the conventional thermal-fuel generation technologies, combined cycle power plants are the most efficient and clean option. The use of natural gas fired open cycle gas turbines, instead of coal power plants, reduces specific carbon emission already by 25% to 50%. Higher reductions of carbon emissions can be achieved by deploying combined cycle power plants which yield another 20% to 23% reduction. Compared to separately producing electricity in a combined cycle plant and producing heat in a fossil-fuel fired boiler, cogeneration of heat and power in combined heat and power plants further reduces the specific CO_2 emissions. The total energy efficiency of modern gas turbines with cogeneration can surpass 90%.

Carbon neutrality is becoming a key long-term goal for countries and organizations. The European Union (EU) has set an example by aiming to reach this goal by 2050. However, switching from coal to natural gas power generation and improving efficiency can only be the first step towards it. As a next step, displacement of natural gas fuel with sustainable hydrogen (H_2) is a viable means of enabling carbon neutral power plant operation as hydrogen combustion produces no CO_2. Additionally, blending natural gas and hydrogen can substantially lower carbon emissions and provide a steady reduction of emissions as the hydrogen portion in the fuel is continuously increased over time. For hydrogen mixtures the relationship between CO_2 reduction and hydrogen volume content is non-linear as shown in Figure 1.

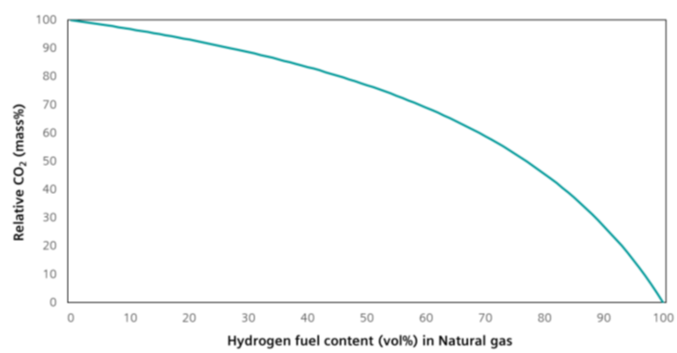

Figure 1: The relationships between hydrogen content in natural gas [volume %] and relative CO_2 emissions from the combustion process

Substituting natural gas with hydrogen over time means that investments in gas power plants today will have long-term viability, as mixing hydrogen into the natural gas stream for gas turbine operation will help such plants remain eligible for capacity mechanisms. New regulations put more stringent requirements on carbon emission from power and heat generation.

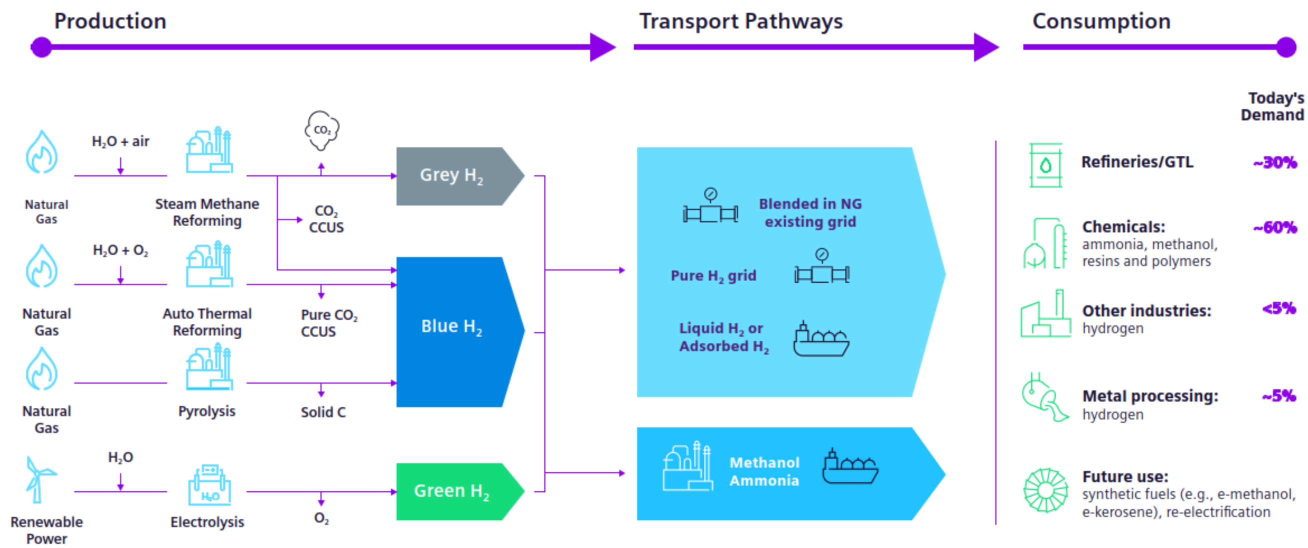

Figure 2: The production, transportation, and uses of hydrogen.

In the long-term, hydrogen fueled gas turbines and combined cycle power plants will enable a fully decarbonized power system, where renewable energy provides the backbone of all energy consumed, and the combined and simple cycle power plants provides the residual load for periods of low renewable energy production (e.g. dark wind still periods) as well as enabling large scale, seasonal storage of renewable electricity.

The hydrogen fuel blending not only lowers CO_2 emissions of gas turbines, it also ensures that the gas turbines can act as long-term electricity storage by means of hydrogen re-electrification. Hydrogen can serve as a chemical storage vehicle by being produced through electrolysis (or other processes) during times of excess renewable energy generation and then used to fuel gas turbines or sold to other industries as shown in Figure 2.

As shown in Figure 1, to reach a 50% reduction in CO_2 emissions from the gas turbine combustion process, approximately 77vol-% hydrogen co-firing is needed. The operation of hydrogen in gas turbines is not economically competitive with natural gas today and governmental support, carbon taxation and/or legislation is essential to accelerate the deployment of hydrogen as a fuel. Co-firing in small quantities or in a smaller gas turbine already improves the emission footprint with an acceptable economic impact. For example, adding only 10 vol% hydrogen in the fuel will reduce CO_2 emissions by 2.7%, which would result in a reduction of 30,000 metric tons of CO_2 for a reference 850 MW combined cycle power plant that runs for 6,000 hours a year at an average 60% efficiency.

The impact of hydrogen gas turbines on the power sector

In January 2019, the EU Turbines industry association members committed to developing gas turbines capable of operating on 100% hydrogen by 2030 [3]. This shows the gas turbine industry's commitment to decarbonization and will make it possible to use gas turbines for completely carbon emissions-free operation.

The use of hydrogen in gas turbines has several benefits to the power sector. For operators, the use of hydrogen fuels reduces the carbon emissions of existing generation plants. It allows these facilities to participate in low carbon energy markets and prevents stranded assets due to regulations on emissions reductions. For the grid, gas turbines operating on hydrogen fuel or hydrogen fuel mixtures are dispatchable and make flexible generation capacity available to keep the grid stable. For the power sector, continuing to use the installed fleet of gas turbines avoids capital costs and CO_2 emissions associated with building new facilities to support the intermittent renewable energy market. Gas turbines in combined heat and power arrangements in various applications can provide steam and heat that would otherwise need to be substituted by electric heaters or biomass plants.

In the IEA Net Zero 2050 scenario [4], hydrogen for electricity generation is estimated to increase to 875 TWh by 2030,1857 TWh by 2040 and 1713 TWh by 2050. This would mean according to IEA, an average blend of 9% hydrogen by 2030 and 85% hydrogen by 2050.

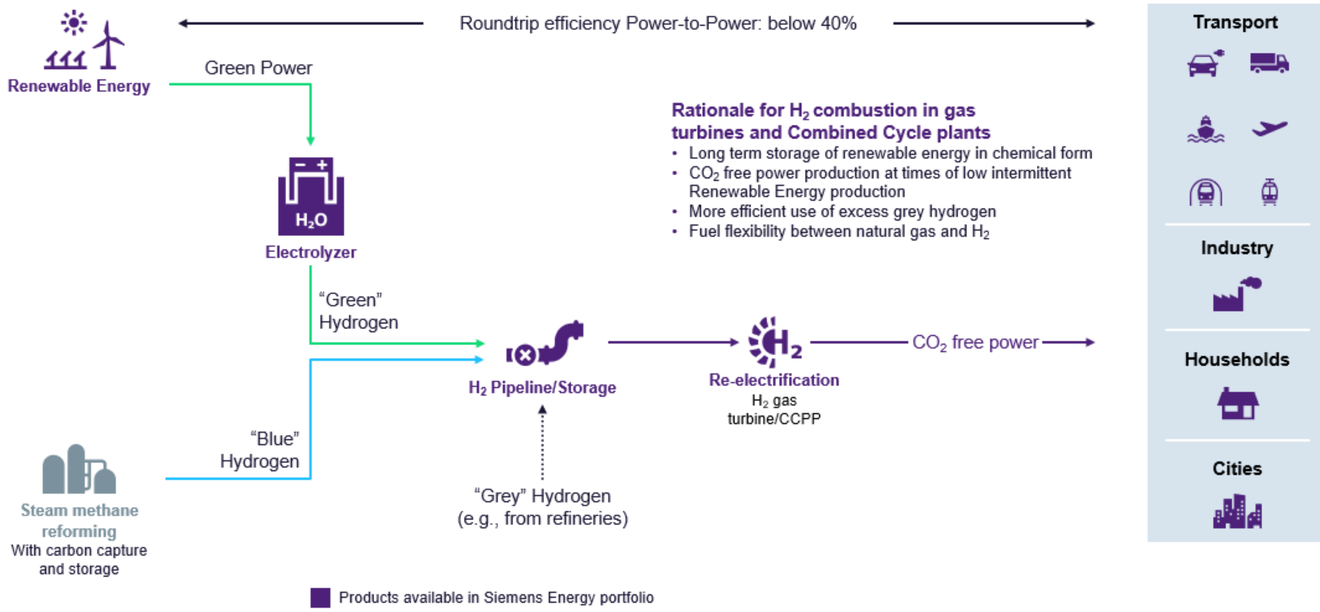

Figure 3: Sources of hydrogen generation.

Application paths for gas turbines

There are various application paths emerging for gas turbines related to operation on 100% hydrogen or hydrogen blends mixed with other fuels, e.g natural gas or biogas.

Renewable electricity or electricity from other zero carbon sources could be used to generate hydrogen in times of electricity oversupply, which is then stored until needed. Up to 100% hydrogen can then be burned in peaking or intermittent operation gas turbine and combined cycle power plants to provide zero or low carbon electricity and compensate for insufficient amounts of renewable electricity, thus providing sustainable residual (backup) power. Gas turbines are the optimal solution since it can provide both fast power for shorter intervals as well as operation for days, weeks and even months on stored hydrogen. In Combined Heat and Power (CHP) plants, the exhaust heat from the hydrogen combustion could be reused to a large extent to improve the energy efficiency of the hydrogen used in the re-electrification process, e.g. for district heating or process heat production.

Where does the hydrogen come from?

The source of the hydrogen should be considered when assessing its impacts on carbon emissions in power generation applications. Hydrogen production can be classified according to its carbon footprint and production method:

Green Hydrogen
Hydrogen production with zero associated CO_2 emissions, such as electrolysis using electricity from 100% renewable sources. Emerging technologies may also be classified as green if there are no CO_2 emissions associated with the electricity required for the process.

Blue Hydrogen
CO_2 capture systems are fitted to the hydrogen production technology and the CO_2 sequestered in underground aquifers, depleted oil and gas fields, or used in industry (ex: Food & Beverage). CO_2 capture is not 100% efficient, so some CO_2 will always be released to the atmosphere. This fact, coupled with typical upstream methane emissions make blue hydrogen a largely, but not 100% sustainable hydrogen. Depending on the carbon capture effectiveness, blue hydrogen reduces GHG emissions usually between 70 and 85% compared with grey hydrogen.

Black / Grey / Brown Hydrogen
Hydrogen is produced conventionally from natural gas with Steam Methane Reforming (grey), lignite (brown) or bituminous coal (black), using coal gasification. In all these cases, CO_2 is produced during the hydrogen production process and released to atmosphere. To date, more than 90% of the worldwide hydrogen is supplied via this route. Using these for power generation would generate even larger amounts of CO_2 emissions than with natural gas. However, the use of surplus hydrogen-rich flare gases from petrochemical sources, e.g. in a combined heat and power plant is economically a very attractive option already today, which increases the efficiency of the hydrogen utilization compared with a more traditional combustion in a stand-alone boiler.

Turquoise Hydrogen
Hydrogen produced through methane pyrolysis with carbon sequestration. While this is also a low carbon pathway for producing hydrogen, it is not yet commercially available.

Other Hydrogen sources
There is also additional color classification of producing hydrogen through electrolysis from:

- Nuclear energy (Pink Hydrogen)
- Solar power (Yellow Hydrogen)

In addition to electrolysis, new technologies are being developed to produce hydrogen from renewable sources. According to the Net Zero 2050 scenario by IEA by 2050, approximately half of the hydrogen production will come from reforming of fossil fuels with CCS (blue) and half from renewable sources (green), with green hydrogen becoming more competitive over time.

Hydrogen carriers
There are various carbon neutral hydrogen carriers suitable for storage or long-distance transport, e.g. via synthesis of ammonia and Liquid Organic Hydrogen Carriers (LOHC). Plans are being made to allow transportation of hydrogen in liquid form or via hydrogen carriers by ship to allow worldwide trading in case pipeline supply of hydrogen is technically or commercially not a viable option. According to the Hydrogen Council, the optimal carrier depends on the intended end-use, purity requirements, transport distance and the need for long-term storage [5]. The long-term optimal choice of carrier depends on a range of factors: Liquid hydrogen is most efficient if the destination requires liquid or high-purity hydrogen, and has benefits if hydrogen needs to be distributed with trucks after landing at port. This is typically the case for hydrogen refueling stations for cars or trucks. In contrast to ammonia and LOHC, liquid hydrogen does not require dehydrogenation or cracking to convert into gaseous hydrogen, which not only saves costs but also avoids purity challenges caused by carrier residues. The main drawback of liquid hydrogen is its relatively low volumetric energy density compared with ammonia, which limits the amount of hydrogen per ship, the energy required for liquefaction and the boil-off losses that occur with every day of storage. While liquefaction is a proven and commercialized technology, liquid hydrogen shipping and large-scale storage – which requires suppliers to manage the boil-off losses – remain in the early stages of deployment.

Hydrogen transport via pipelines (blended/dedicated)
Hydrogen produced from any source (green, blue or grey) can be injected into the existing natural gas network. In this case, any consumer (industrial, commercial or domestic) would be required to operate gas-fired equipment using natural gas with a hydrogen content. This may pose a challenge to the gas network itself and to many consumers and additional investment would be required to have all connected hardware able to run with hydrogen in the fuel. The hydrogen percentage could vary depending on the purity of the injected hydrogen, the injection frequency (continuous or intermittent), the complexity of the network, and the distance of the consumer from the point of injection.

While some customers of natural gas could easily adapt to consume a methane-hydrogen blend (e.g. gas turbines), other sectors may have difficulties accepting higher hydrogen blends, and some (like the chemical industry) are interested in the methane molecule itself, rather than only in the energy content of the gas. In addition, many small natural gas appliances are limited to less than 20% hydrogen content, hence requiring limiting the blending quota in varying operating conditions (both the natural gas consumption and the production of hydrogen from renewable energy show significant, frequently opposite seasonality). Such an approach will require regulators to redefine the permissible specifications for "pipeline quality" natural gas. High pressure transmission pipelines can be adapted to carry different hydrogen contents with limited retrofit requirements. While changes to valves and compression stations will be required, the pipes themselves would usually not require replacement. Unchanged, pipelines today are unlikely to exceed 25 vol% hydrogen due to concerns over leakage through seals, welds, and valves or other mechanical constrains.

Hence, an alternative (and more feasible option) to hydrogen blended into existing pipelines is a second, dedicated hydrogen pipeline to run in parallel to the natural gas lines, repurposed from an existing natural gas pipeline. Older gas networks built for town or city gas, e.g. old German town gas pipes, can already accept hydrogen contents of up to 50%. Cross-linked polyethylene (XLPE) pipes used in low pressure natural gas distribution systems appear to be suitable for up to 100% hydrogen. In the long term, gas networks can be rebuilt to carry 100% hydrogen. The highly integrated European natural gas transmission networks represent an economically advantageous way to distribute large quantities of energy as required. The pipeline networks are available, socially accepted, and can be gradually converted to hydrogen operation with an investment of an estimated 10-15% of the cost of new construction. [6]

As different approaches (blended vs. pure hydrogen) might be used in different regions, gas turbines must therefore be able to operate in the future on any fuel gas from 100% natural gas to the maximum hydrogen content permissible on the pipeline network.

2 Hydrogen combustion

Hydrogen combustion fundamentals

Hydrogen differs from hydrocarbon fuels by its combustion characteristics, which pose unique challenges for gas turbine combustion systems designed primarily for natural gas fuels. Flame temperatures for hydrogen under adiabatic and stoichiometric conditions are almost 300 °C higher than for methane. Hydrogen's laminar flame speed is more than three times that of methane and the auto-ignition delay time of hydrogen is more than three times lower than methane, as shown in Figure 4 for flame temperatures of 1600 °C and gas turbine conditions. With these characteristics hydrogen is a highly reactive fuel and controlling the flame to maintain the integrity of the combustion system and reach the desired level of emissions is a formidable challenge for research and development teams.

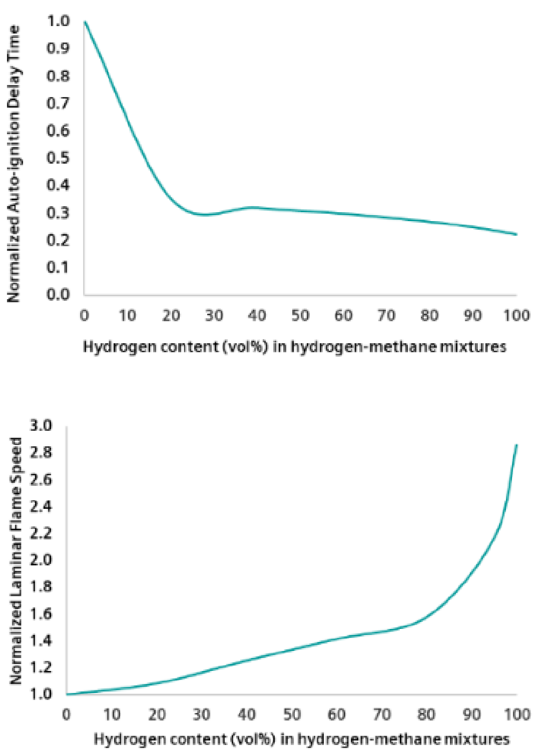

Figure 4: Hydrogen's impact on auto-ignition delay and flame speed for hydrogen-methane mixtures.

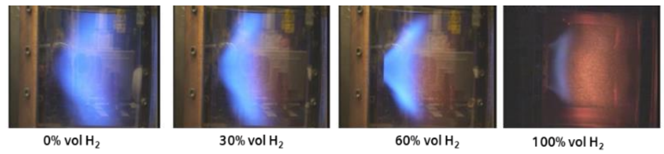

Figure 5: Flame position changes with increasing hydrogen fuel content, showing the most compact flame at 100% hydrogen. Also note how the 100% hydrogen flame is not as luminous as the natural gas flame [7].

Dry Low Emission (DLE) combustion technology

In dry low emissions combustion systems, fuel and air are mixed prior to combustion in order to precisely control flame temperature which, in turn, allows the control of the rates of chemical processes that produce emissions such as nitrogen oxides (NO_x). The relative proportions of fuel and air is one of the driving factors for NO_x but also for flame stability. Hydrogen's higher reactivity poses specific challenges for the mixing technology in DLE systems:

- Higher flame speed with hydrogen increases the risk of the flame burning closer to the injection points, travelling back into mixing passages, or burning too close to liner walls leading to damage (see example in Figure 5). This risk increases as the hydrogen content in the fuel is increased and with increasing combustion inlet and flame temperature
- Hydrogen's lower auto-ignition delay compared to methane increases the likelihood of igniting the fuel in the mixing passages leading to damage
- Changes to thermoacoustic noise patterns because of the different flame heat release distribution can affect combustion stability and reduce the life of combustion system components.

Siemens Energy DLE combustion systems generally use swirl stabilized flames combined with lean premixing to achieve low NO_x emissions without dilution of the fuel. The acceptable fuel fraction of hydrogen depends on the specific combustion system design and engine operating conditions. Hardware and control system changes are required for higher safety, meet NO_x emission limits and manage varying fuel compositions. Siemens Energy is in the process of extending the hydrogen capability of its DLE systems, with more details provided in the following sections.

As hydrogen capabilities are still under development for the different turbine families, some operational restrictions may be required at high hydrogen contents. These may include derating, the use of a conventional fuel for startup and shutdown, and higher NO_x emission levels which may require the need for post-combustion emission control like Selective Catalytic Reduction (SCR) systems. In the long term, we envisage performance levels with hydrogen combustion comparable to natural gas operation.

Non-DLE combustion technology

Non-DLE technology uses diffusion flames or partially premixed flames. There are several advantages and disadvantages associated with non-DLE systems:

- In general, these systems handle a large envelope of fuel compositions, and 100% hydrogen is possible on various Siemens Energy non-DLE gas turbines
- Diffusion flames require dilution to control NO_x emissions, which are driven by high flame temperatures. Hydrogen has higher flame temperatures compared to natural gas, which mean NO_x emission will be higher without abatement. Dilution is achieved by the introduction of nitrogen (N_2), steam, or water into the flame:
    - Nitrogen dilution has the advantage of often being available at the plant as a byproduct of gasification processes. Using the nitrogen produced as a byproduct to dilute the fuel reduces plant operating costs.
    - Steam dilution is significantly more efficient than nitrogen dilution in terms of emission reduction and in combined cycle or Combined Heat and Power (CHP) configurations steam dilution has a relatively small plant efficiency impact.
    - Injection of water into the combustor reduces the combustion flame temperature, thereby reducing NO_x and has the added benefit of boosting power output of the gas turbine.

High costs associated with dilution due to the injection of nitrogen or demineralized water make diffusion flames with this abatement technology rather unattractive.

- For single shaft gas turbines, surge margin can be a challenge with diluted high-hydrogen fuels due to changes in the balance of volumetric flow between the compressor and turbine. This can be managed by compressor and / or turbine modifications.

3 Hydrogen capabilities in Siemens Energy gas turbines

Siemens Energy gas turbine hydrogen operating experience

Siemens Energy fleet experience with high hydrogen content fuels is extensive, with more than 55 units around the world amassing more than 2.5 million operating hours since the 1960s. High hydrogen gas turbine applications have been built for a range of industries and span the power range of the Siemens Energy gas turbine portfolio. Experience has been gained on unabated diffusion flame, Wet Low Emissions (WLE), and Dry Low Emissions (DLE) combustion technologies. Although many of these references are based on hydrogen-rich synfuels, which offer a different combustion behavior compared with a natural gas-hydrogen fuel mixture, Siemens Energy has gained a high level of experience in managing hydrogen on a plant level and within our gas turbine systems (see Figure 6).

Siemens Energy gas turbines can operate on high percentages of hydrogen fuel, with the specific capability of a unit depending on the gas turbine model and the type of combustion system. See Figure 7 for the high-hydrogen options across the portfolio for new unit applications that are available on specific request. For already installed units the current capabilities are given in the gas turbine manual. Higher hydrogen mixtures for those existing power plants and options for upgrading are discussed in Section 5.

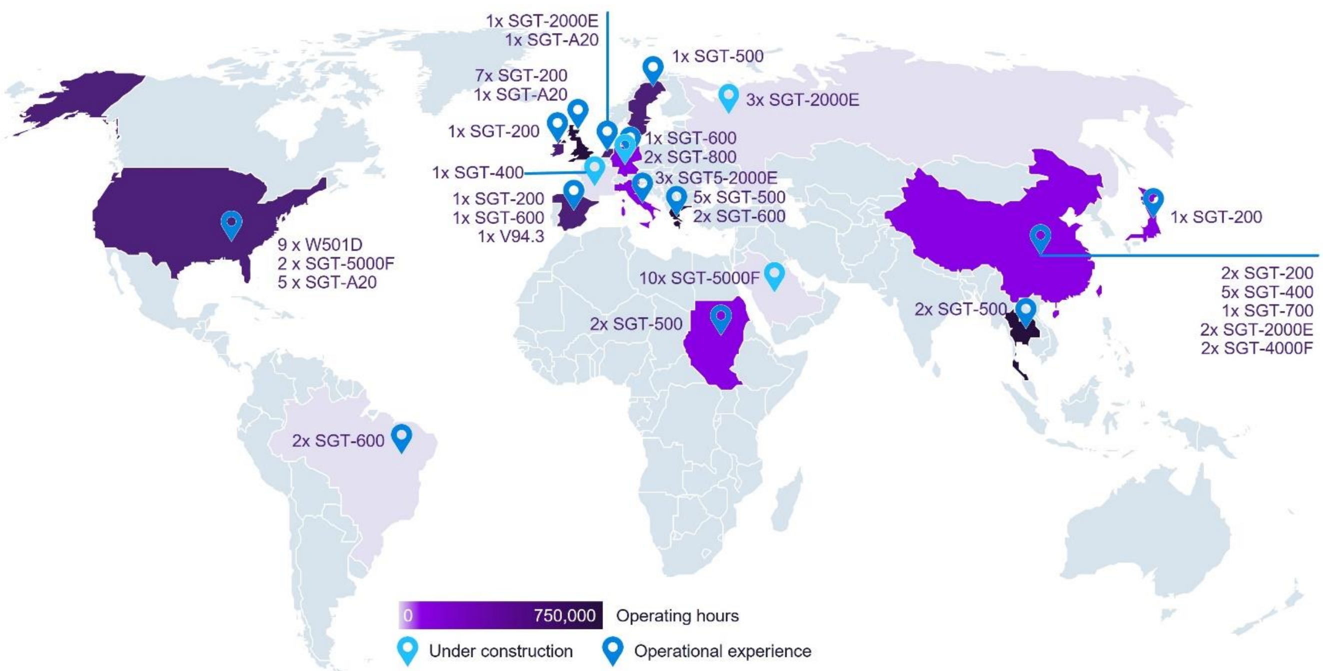

Figure 6: Siemens Energy's high hydrogen fleet experience.

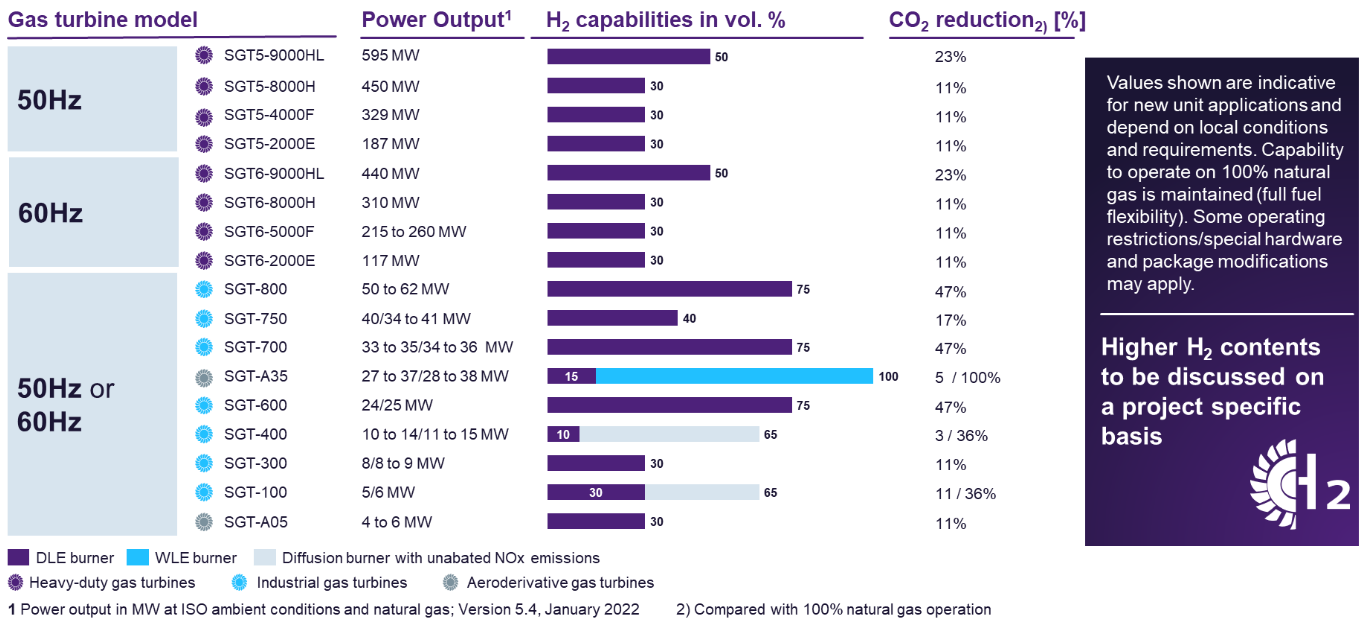

Figure 7: Siemens gas turbine portfolio hydrogen co-firing capability for new unit applications. Retrofit capabilities of existing units may vary due to unique site constraints, combustion systems, implementation timing and other factors.

Detailed information on GT families

Large gas turbines

DLE technology
Around the beginning of this century, gasification processes were developed to convert coal or refinery residues via gasification and carbon monoxide (CO) shift reaction into CO_2 and hydrogen. Following conversion, CO_2 is removed prior to feeding the synthetic gas (syngas) to the gas turbine. These Carbon Capture and Storage (CCS) syngases are characterized by a very high reactivity, as the thermal input to combustion is almost completely from hydrogen. Significant development of these processes occurred during the 2000s and 2010s with governmental support (EU, United States Department of Energy (US DOE) [8], and German Federal Ministry for Economic Affairs and Energy (BMWi) [9]). One of the central focus areas of these governmentally funded programs was research and development of combustion technology for DLE systems in large gas turbines, with the goal of substantially reducing or eliminating dilution in order to maximize plant efficiency. While CCS-gasification plants are not yet commercially viable, the related research into highly reactive hydrogen fuels has contributed to the development of future pure hydrogen capable DLE technology.

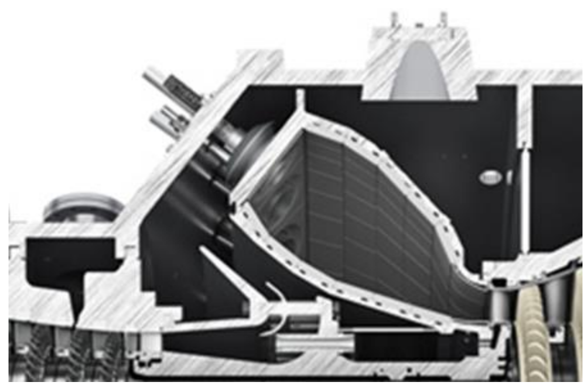

Figure 8: SGT-4000F annular combustion chamber.

Siemens Energy heavy-duty large gas turbines SGT5/6-2000E and SGT5/6-4000F use the HR3 burner design. Based on a hybrid burner concept, the HR3 has a central pilot swirler and a concentric diagonal swirler with gas injection through the swirler vanes (SFI). The SGT6-5000F and SGT5/6-8000H use Ultra-Low NO_x Platform Combustion System (ULN/PCS) systems which integrate SFI technology into a premixed pilot and concentrically arranged main swirlers. These burners combined have accumulated many millions of operating hours and offer a wide range of fuel flexibility including the capability to run on mixtures of natural gas and up to 30 vol% hydrogen. The latest SGT5/6-9000HL engines use the advanced combustion for efficiency (ACE) system, which is capable to run on up to 50 vol% hydrogen. By 2030, large gas turbine DLE systems are targeted to be capable of running on 100% hydrogen.

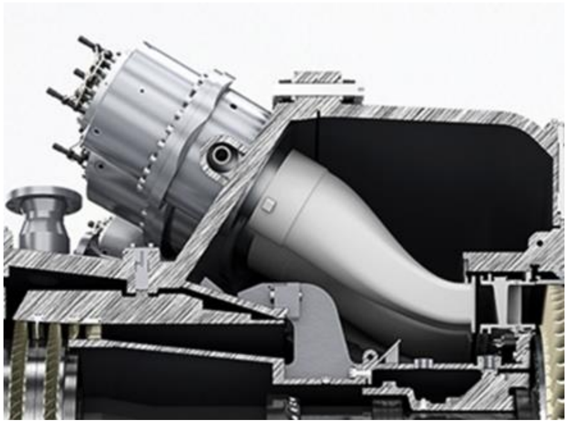

Figure 9: SGT-5000F combustion system.

Siemens Energy 2000E utility scale gas turbines operating in the petrochemical industry, with the requirement to run on up to 27.2 vol% hydrogen, launches commercially in 2022 with DLE technology. This extension of the Siemens Energy standard capability was achieved through incremental and retrofittable changes to the geometry of the burners to improve flashback resistance at higher hydrogen contents. It was tested and validated through a high-pressure combustion test at engine conditions. Validation testing has indicated that NO_x emissions will not exceed 50 mg/Nm3 during both operation on natural gas and with the hydrogen fuel mixture.

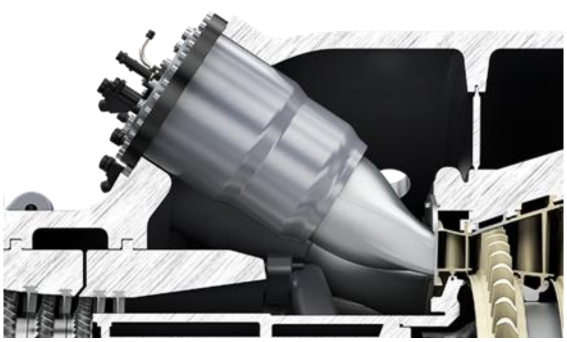

Figure 10: SGT5/6-9000HL combustion system.

Non-DLE Technology

Since the early 1990s, Siemens Energy has gained experience operating its large gas turbine products employing non-DLE combustion technology on hydrogen fuel mixtures, specifically in applications of gasification processes with different feedstocks (coal, waste from the petrochemical industry, and biomass) and waste gases from steel mills (coke oven and blast furnace gases) [10]. These syngases are mixtures of varying composition, but typically have significant fractions of hydrogen and CO, as well as inert gases (N_2, CO_2, steam).

Medium industrial gas turbines

DLE technology

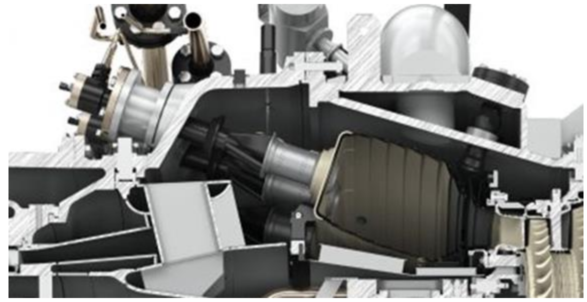

Figure 11: 3rd generation DLE combustion system.

The SGT-600, 700 and 800 use 3rd generation DLE technology with a cylindrical duct downstream of a conical swirler for optimal premixing. Over the last decade, further development and testing of the burner has steadily improved its hydrogen capability. Rig and engine testing over the last three years has cleared 75 vol% hydrogen on the SGT-600, SGT-700 and on the SGT-800. The SGT-600 has run an engine test with close to 80 vol% hydrogen, and a variant of the 3rd generation DLE burner, that is used in all three engines, has been tested at the Siemens Energy Clean Energy Center in Berlin with up to 100% hydrogen fuel at engine-like conditions. This significant achievement was enabled by additive manufacturing which allowed for more efficient combustion system aerodynamics.

The SGT-750 engine is equipped with the 4th generation DLE burner. The 4th generation burner has a central premixed pilot with radial main swirler, contrasting it from the HR3 burner which uses a diagonal swirler. The 4th generation burner has been tested for various fuel compositions including hydrogen-methane mixtures and the SGT-750 has proven operation up to 40 vol% hydrogen fuel [11]. Latest by 2030, medium industrial gas turbines are targeted to be capable of running on 100% hydrogen in DLE mode.

Siemens Energy has sold two SGT-600 for the Braskem refinery in Brazil, with capability to operate on 60 vol% hydrogen in DLE combustion mode keeping NO_x emissions controlled to 25ppmv. This power plant started operation in 2021 under an Operation & Maintenance contract where Siemens Energy takes responsibility for delivery of power and heat to the adjacent refinery with reliability and availability guarantees.

Non-DLE technology

Siemens Energy has gained extensive experience with high-hydrogen fuels on SGT-500 and SGT-600 industrial gas turbines burning refinery fuel gases with up to 90 vol% hydrogen content. For example, 10 SGT-500 units in the field have gathered more than 800,000 combined operating hours on high-hydrogen fuels using non-DLE systems since 1979.

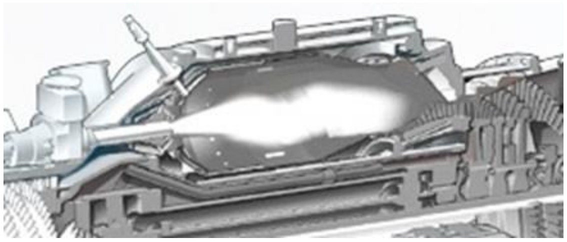

Figure 12: SGT-500 Non-DLE combustion system.

Aeroderivative gas turbines

DLE technology
The Siemens Energy aero-derivative engines, like the SGT-A35 (see Figure 13), use axially staged DLE burners with radial swirlers in the primary stage and secondary non-swirling premixing ducts axially downstream, which are stabilized by the hot gases from the primary stage. Axial staging is commonly used in multi-shaft engines to ensure optimal operability for all powers and conditions and to minimize thermo-acoustics as the heat release profile through the combustor can be varied for a given constant power. The SGT-A35 combustion system has the capability to run with up to 15 vol% hydrogen today, and the A05 is capable of 30%.

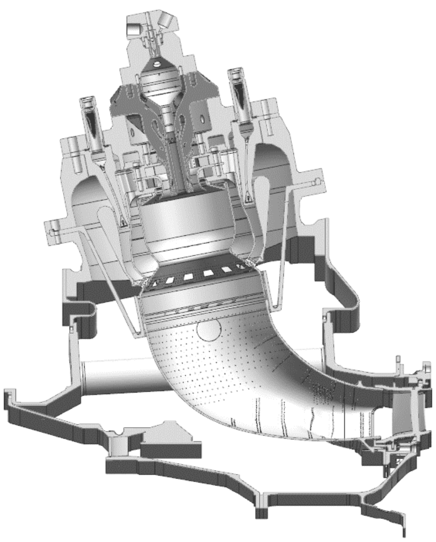

Figure 13: SGT-A35 DLE combustion system.

Non-DLE technology
Non-DLE systems in the Siemens Energy aeroderivative gas turbine family are adapted from aerospace engine applications. These systems can operate on both gas and liquid fuels, with NO_x controlled by using water injection to reduce flame temperature. The SGT-A35 uses the Phase II combustion system and is capable of operating on 100% hydrogen. The SGT-A20 has significant experience operating on high-hydrogen fuels (up to 78 vol%) in petrochemical applications. Rig testing of the SGT-A65 and SGT-A45 combustion system has been conducted to understand the emissions characteristics of hydrogen-methane mixtures and pure hydrogen with water dilution.

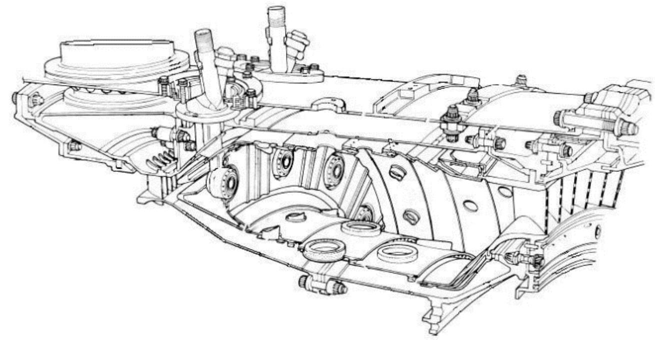

Figure 14: SGT-A35 Non-DLE combustion system.

Small industrial gas turbines

DLE technology
Siemens Energy small industrial gas turbines SGT-100, 200, 300 and 400 use G30 burner technology, a proven radial swirler premixing design which has gone through significant fuel flexibility programs, driven by petrochemical customer demand. This combustor technology can burn mixtures of hydrogen and methane up to 30 vol% on the SGT-100 and 300, which is being further developed for increased hydrogen fractions through the Siemens Energy hydrogen roadmap. The SGT-400 combustion system has been developed to run on up to 10 vol% hydrogen [12]. Latest by 2030, the small industrial gas turbines are targeted to be capable of running on 100% hydrogen in DLE mode.

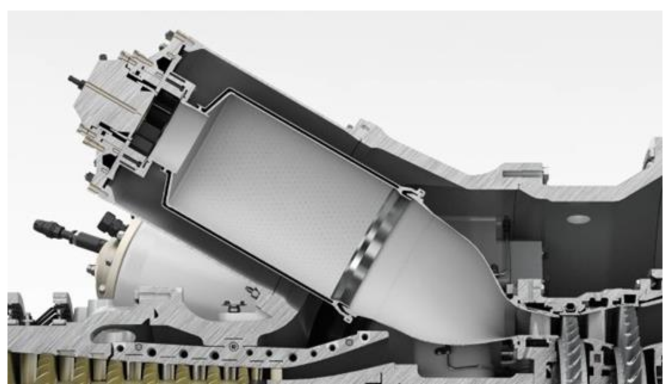

Figure 15: SGT-400 DLE combustion system.

Under the HYFLEXPOWER project, Siemens Energy is on a path to demonstrate 100% hydrogen combustion with the SGT-400 in DLE mode in 2023. Details of the project are shown under the next chapter in this section.

Non-DLE technology
The SGT-200 and SGT-400 with non-DLE combustion systems have more than one million operating hours in coke oven gas

applications, which are characterized by high hydrogen (50-65 vol%) content, and significant amounts of carbon dioxide and carbon monoxide. The SGT-200 has refinery gas experience with contents of hydrogen up to 85 vol% with more than 800,000 operating hours.

Technology enablers and Siemens Energy roadmap toward 100% hydrogen gas turbines

Siemens Energy is employing several key technology enablers to further develop the hydrogen capability of its gas turbines.

High fidelity Computational Fluid Dynamics (CFD)
Advanced CFD tools allow Siemens Energy combustion engineers to run analyses on fuel burners to identify the key design measures needed to increase a combustion system's hydrogen fuel capabilities. Combustion CFD tools provide engineers with a clearer picture of the flame structure, as demonstrated on the SGT-800 fuel injector study in Figure 16. The tools are calibrated for Siemens Energy designs and verified through years of combustion development and verification testing allowing reliable evaluation of design options in the

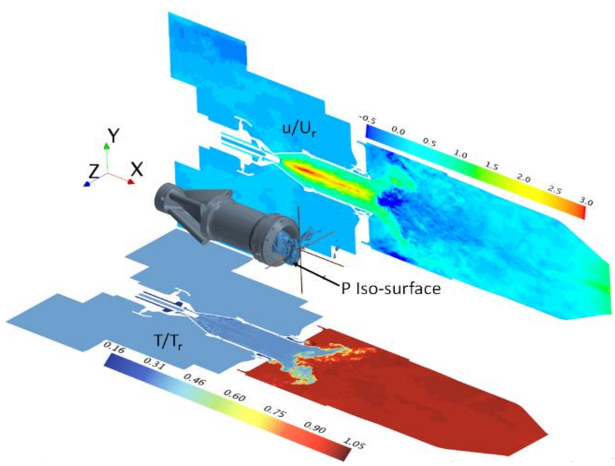

Figure 16: CFD flow field overview from a study of SGT-800 3rd generation burner with high-hydrogen fuels [13].

early phases of a project. With increasing share of hydrogen, thermo-acoustics of the flame changes as explained in Section 2. To account for this effect, Siemens Energy is engaged with universities to implement the latest advances from the research community into our tool suite and to take those effects into account during early stages of the design process.

Additive manufacturing
Siemens Energy has built up an additive manufacturing (AM) business to establish prototype and serial manufacturing capability. Over the recent years tremendous efforts have been made in the fields of materials and processes, industrialization, and design for function. Materials such as IN 625 and Hastelloy X have been fully characterized to enable designers to utilize the benefits of AM. Moreover, the productivity of the respective processes was significantly improved via increased layer thicknesses and transfer to industrial multi-laser machines. Key, however, is the integration of AM in a bigger scale production landscape including de-powdering, removal of supports, heat treatment, and respective quality control. Today a global fleet of more than 50 laser-powder bed machines produces metal parts for Siemens Energy gas turbines in our production facilities located in Orlando, Florida, USA, Worcester, United Kingdom and Finspång, Sweden. Figure 17 shows final AM built premixed combustion swirlers for heavy-duty large gas turbines.

Figure 17: Additive manufactured premixed combustion swirlers for heavy-duty large gas turbines.

In addition, Siemens Energy's additive manufacturing capability enables the integration of innovative design features and allows technology validation time to be accelerated by up to 75%. This enables a faster response to changing customer needs. As shown in Figure 18, additive manufacturing is supporting the development of combustion technology that can overcome the challenges of hydrogen applications. It enables the creation of complex cooling features and fuel routing that would not previously have been possible with conventional manufacturing techniques. These features are vital when it comes to ensuring stable combustion of hydrogen.

Figure 18: Fuel burner design progressions from welded (top left) to SLM additive manufacturing (bottom right) for 3rd generation DLE burner.

High pressure combustion testing

Despite all the advances that were made in past years in the area of CFD, combustion today is still a complex field that cannot be modelled with theoretical models alone. Testing our combustion systems at pressure and temperature conditions is therefore still an important part of our design process. All new developments undergo rigorous testing to ensure safe operation at the customer site. The Clean Energy Center in Berlin is Siemens Energy's facility for high pressure (35 bar) combustion tests, shown in Figure 19. The facility supports testing of components and systems for the entire Siemens Energy gas turbine portfolio – from large gas turbines down to small industrial designs – and allows for a wide variety of fuels to be tested. In 2019, hydrogen testing capability was added to ensure support of the increased demand for hydrogen applications. With this in-house capability, Siemens Energy ensures new knowledge is shared across our fleet and timely support is provided to customer projects for special fuels like hydrogen.

Figure 19: Clean Energy Center facilities for high pressure combustion tests, Berlin, Germany.

The HYFLEXPOWER Project – Technology for Deep Decarbonization with 100% Hydrogen Power-X-Power

Siemens Energy has an ambitious technology approach to utilize a building block strategy for the development of H_2-natural gas flexible combustion systems for as many of our gas turbine products as possible. A set of core technology elements—many described in this white paper—will be developed which can be applied across the product portfolio.

The technology is planned to be initially demonstrated in an existing SGT-400 based cogeneration facility in Saillat-sur-Vienne, France (Figure 21) within the EU-funded HYFLEXPOWER project. In 2020, a Siemens Energy-led consortium including ENGIE, Centrax, Arttic, German Aerospace Center (DLR) and four European universities, at Smurfit Kappa PRF's site, launched the implementation of HYFLEXPOWER, the world's first industrial power-to-X-to-power demonstrator with an advanced H_2 gas turbine. The integrated hydrogen project as shown in Figure 20 will demonstrate hydrogen production from renewable energy in an electrolysis facility, hydrogen compression and storage and its further re-electrification in a highly efficient Combined Heat and Power (CHP) plant. For this, the existing SGT-400 industrial gas turbine will be upgraded to allow for combustion of stored hydrogen into electricity and thermal energy. During two demonstration campaigns, the facility will be powered with a mix of natural gas and hydrogen. Initial testing will be conducted with mixtures of natural gas with hydrogen content up to 30% in 2022. The main goal is ultimately aiming for the demonstration of the advanced plant concept for up to 100% hydrogen operation in 2023 in DLE operation mode.

By taking this approach, the overall development timeline and cost of the 100% H_2 DLE combustion technology for the GT portfolio will be minimized. Additionally, the risk for the larger, higher firing temperature gas turbines will be mitigated by first validating the technology elements in smaller, lower firing temperature gas turbines.

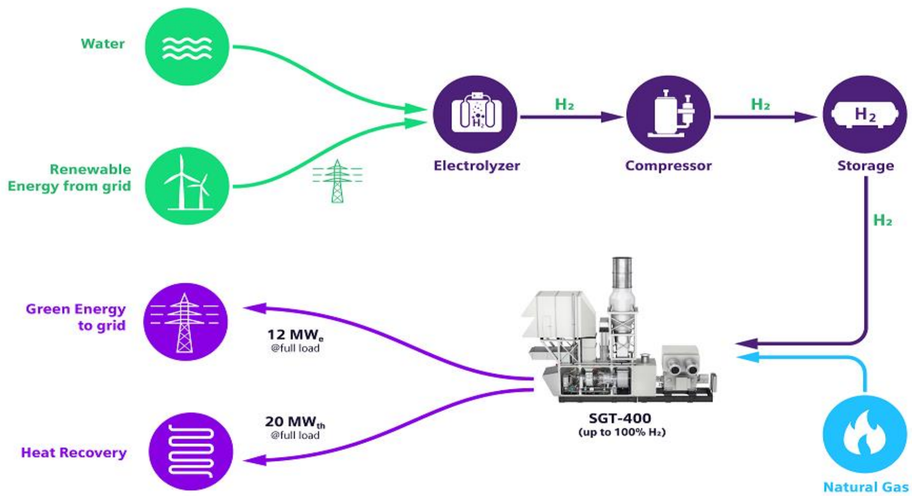

Figure 20: Schematic of EU funded HYFLEXPOWER Project.

Figure 21: Smurfit Kappa SGT-400 Cogeneration plant in Saillat-sur-Vienne, France.

Figure 22: Siemens Energy's Zero Emission Hydrogen Turbine Center.

Siemens Energy Zero Emission Hydrogen Turbine Center
Siemen Energy has developed a demonstration plant at our gas turbine manufacturing facility in Finspång, Sweden, to show how hydrogen and gas turbines, renewable energy production and energy storage work together in a future flexible and sustainable energy system. Excess energy from gas turbine tests and electricity from solar panels are used to produce hydrogen in an electrolyzer. The hydrogen is stored and used later as a fuel for gas turbine testing. In the local microgrid created, it will be possible to optimize the use of energy through storage as hydrogen and/or in batteries. Hydrogen produced in the plant will also enable continued research and development to optimize the use of hydrogen in gas turbines and reach Siemens Energy's goal to run gas turbines on 100% hydrogen contributing to a full decarbonization of the power sector.

The project is developed in the framework of Era Net Smart Energy Systems with support from the European Union's Horizon 2020 research and innovation program and the Swedish Energy Agency. [14]

Hydrogen roadmap for Siemens Energy gas turbines
Our 100% hydrogen gas turbine program combines extensive technology development for industrial and utility power generation applications. Since the 1960s, Siemens Energy has gained experience with high-hydrogen fuels on non-DLE combustion systems. Beginning in the early 2000s Siemens Energy has invested in the development of DLE hydrogen combustion technology. By 2030, Siemens Energy intends to have gas turbines with the capability of operating on 100% hydrogen fuel with DLE technology. To achieve this target, we are continuously developing the necessary technologies and implementing these new designs into our product portfolio.

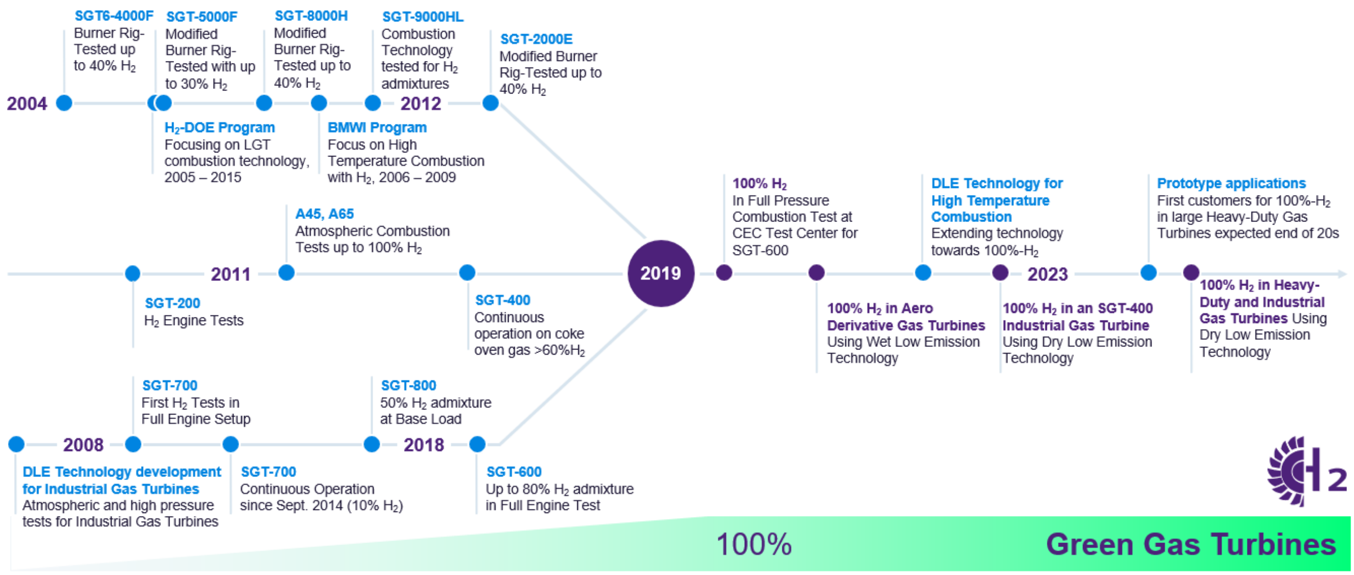

Figure 23: Siemens Energy 100% hydrogen gas turbine roadmap.

Summary

Over the last few decades, hydrogen capability in the Siemens Energy gas turbine portfolio has been developed to meet customer and project demands. These demands have differed significantly across the portfolio and the proven capabilities clearly reflect this. The higher capabilities, for example in the industrial gas turbine portfolio, were driven by demand from the industrial and petrochemical sector. We now see demand rising in the energy sector for high-hydrogen capabilities due to the drive toward energy decarbonization. Siemens Energy is answering this demand with a development roadmap as shown in Figure 23.

4 Hydrogen capabilities of power plant systems

Additional systems required for hydrogen co-firing

Hydrogen operation capability in power plants has additional requirements on the systems and components upstream and down-stream of the gas turbine.

In case of supply of a blended hydrogen/natural gas mixture, all components in the fuel gas system upstream of the gas turbine need to be assessed regarding their hydrogen compatibility. Depending on blending ratio, temperature and pressure, this could affect components in different systems such as pipes, valves, filters/strainers, preheaters, measuring devices and transmitters.

Additional gas conditioning systems are required when there is a separate hydrogen supply to the plant. In addition to the requirements mentioned above in the fuel gas supply system, a hydrogen and natural gas mixing station with valves, gas composition and flow measurement would be required and also the gas supply pressure would need to be slightly increased.

Power plant component considerations for hydrogen co-firing

Gas fuel supply system:
Because the fuel gas system is handling the hydrogen directly, the necessary hydrogen resistance needs to be confirmed for the implemented components and materials. Furthermore, adapted requirements on pressure, flow and temperature to the gas turbine need to be considered in the design of the gas fuel supply system, possibly requiring increased pipe diameters to accommodate the increased fuel volume flow when burning hydrogen.

Heat Recovery Steam Generator (HRSG):
Downstream of the gas turbine the influence of hydrogen co-firing is smaller than upstream, but some mitigation may need to be taken. Compared to natural gas firing, the HRSG must handle exhaust gases with different compositions, volume flows and in some cases changes to the exhaust temperature. In addition, provisions for ventilation may be required in cases of unburned hydrogen entering the HRSG, e.g., after a failed start or a flame-out event. In case of a supplementary firing system, additional aspects such as the flue gas characteristics need to be investigated.

Selective Catalytic Reduction (SCR) system:
Due to the increased NO_x emissions associated with burning hydrogen, the provision of a Selective Catalytic Reduction (SCR) System may become necessary depending on the applying local emission regulations. If a SCR may be required at a later stage when increasing the hydrogen content over the years, sufficient space in the HRSG needs to be provided for a later retrofit.

Buildings and Ventilation:
Due to the different characteristics of hydrogen as a fuel, the definition of the hazardous areas in the power plant needs to be revisited. Special consideration must be taken on the active and passive ventilation of the buildings to handle any leakage of hydrogen and the installation of suitable gas detectors to detect such leakages.

Electrical Equipment:
Electrical systems in areas susceptible to hydrogen presence will require a gas group classification according to IEC Group IIC (in NFPA regions alternatively NEC 500 Class I Div 2 Group B).

Power plant performance:
Due to the different physical properties of hydrogen compared to natural gas, the following effects on power plant performance will need further investigation: NO_x emission handling, design pressure drop, fuel gas preheating, combustion stability and dew point in the cold end of the HRSG/stack.

Hydrogen readiness for new gas turbine-based power plants

In the next years, newly built gas power plants will mainly run with natural gas, due to the already significant GHG reduction when using natural gas compared with other dispatchable fuels (e.g. coal) and the unavailability of large amounts of hydrogen as fuel. However, new power plants being built today will very likely be required to be converted at a later stage to burn a blend of hydrogen up to 100% during the lifetime of the plant, hence requiring provisions for cost-efficient later retrofit for hydrogen operation.

This demands for hydrogen-ready power plant solutions with a prepared pathway up to 100% hydrogen capability. In this case the power plant is designed to be converted to hydrogen operations at a later stage. A new power plant can also be designed and build to operate with a defined share of hydrogen without any technical modifications. In that way the power plant is already hydrogen capable, according to the limits of the current capabilities of the respective gas turbine. However, today's new power plants will typically start operating with natural gas for a number of years. It is therefore crucial to have the option of new natural gas fired power plants solutions that can easily be upgraded and converted to hydrogen operations as hydrogen becomes available to the operator. By doing so, natural gas fired power plants are future-proof and will be fit to meet the amount of hydrogen for which it has been made ready, with minimal conversion costs. The efforts to upgrade these power plants may vary for each power plant, as they are built according to specific requirements agreed between the plant operators and the technology providers.

Hydrogen-readiness power plant concept certification

Siemens Energy is the first company worldwide to have received a third-party certification for its "H_2-Ready" power plant concept.

Depending on the required roadmap of hydrogen co-firing requirements over time, Hydrogen-readiness allows the design of power plants that enable a later retrofit to hydrogen co-firing with minimal costs and disruptions, while keeping the additional front-end investment limited. The detailed configuration of a hydrogen-ready plant will always be determined project-specific in line with the expected hydrogen co-firing roadmap for the plant.

Figure 24: Hydrogen ready power plant concept certification

The independent Certification Guideline for H_2-Readiness of Combined Cycle Power Plants, provided by international certification provider TÜV SÜD, covers the three phases in the life cycle of the plant:

1. Bidding Phase - when the concept of the hydrogen-Readiness is established according to the client's H_2-roadmap (Concept Certificate - Generic).
2. Project Phase – when the concept is implemented into the design and construction of a H_2-Ready power plant (Project Certificate – Project specific).
3. Transition Phase – when the plant is converted into a H_2 fired plant, once hydrogen is available (Transition Certificate – Project specific).

The "H_2-Ready" concept certificate provides a roadmap describing how a new power plant can be converted over time to co-fire hydrogen or even burn pure hydrogen, limiting future conversion cost and making the power plant future-proof. The certificate was awarded through the analysis of an SCC-800 combined cycle power plant which was designed H_2-ready according to the certification guideline. Except for the gas turbine and associated package, the concept may also be used for other gas turbine plant configurations. On a project specific case, the certification process can be further expanded with "H_2-Ready"- certificates for the plant specific construction (Project Certificate) and retrofit phases (Transition Certificate).

Hydrogen-readiness categorization for new gas turbine power plants according to EU Turbines

Under the framework of the EU Turbines Association in which Siemens Energy is a member, key gas turbine manufacturers in the power plant industry will voluntarily indicate with each newly built power plant a specific category of hydrogen-readiness fulfilled by the power plant [15].

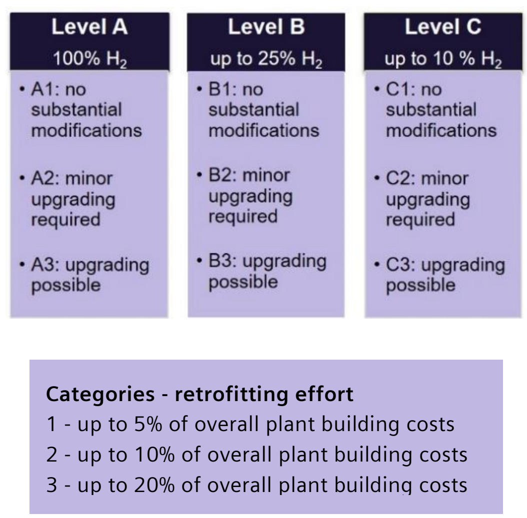

Figure 25: Hydrogen readiness levels and retrofitting effort categorization as defined by the EU Turbine Association [15].

At this moment, there is no clear pathway on the introduction of hydrogen into the gas infrastructure in different countries, requiring industry to prepare for different scenarios. As hydrogen will remain a scarce resource over the next decade, the most likely scenario is that a limited number of hydrogen valleys and a backbone grid connecting these valleys and large-scale generation facilities will be available. These regions and hydrogen pipelines will be extended in the future. In the remaining gas grid, especially the distribution grid, we may see a blending of hydrogen into the existing natural gas grid. The maximum blending share is expected to remain limited to around 25% by volume. Above that level there will, in many applications, most likely be a switch to pure hydrogen in one step. By 2050, this switch will be fully concluded.

Accordingly, the EU Turbines Association defines three levels of readiness according to the hydrogen content of the gas used combined with a categorization of required retrofitting effort as shown in Figure 25.

Fully integrated and optimized Hydrogen Power Plant solution

Siemens Energy has developed an optimized and integrated hydrogen power plant solution for both new unit and service upgrade that provides an optimized configuration for power and heat when designing for a hybrid plant with a combination of renewable energy, electrolysis, hydrogen compression and storage, heat pumps and/or heat extraction (see Figure 26). By combining power with heat production, the renewable energy to hydrogen back to energy roundtrip efficiency can be increased to a high 70%.

Based on the well-established SPPA-T3000 technology, the Omnivise Hybrid Control system has been specifically designed to manage such complex integrations in a microgrid-type arrangement. Together with the optional Dispatch Optimization it secures the most efficient use of the connected renewable energy to produce green hydrogen as well as power and heat from the power plant.

Clean Energy Certification

Beyond the scope of hydrogen and new power plants, Siemens Energy is taking a holistic view of the entire energy production and consumption market and the value of certifying cleanliness.

Siemens Energy intents jointly with DENA and TÜV SÜD to establish a partner ecosystem for the verification and certification of renewable energies, products and goods made from them along the entire Power-to-X value chain. By concepting, erecting, piloting, and the subsequent operation of the digital service 'Clean Energy Certification', the development of sustainable hydrogen, Power-to-X, and hydrogen re-electrification markets as essential building blocks of the energy transition shall be supported.

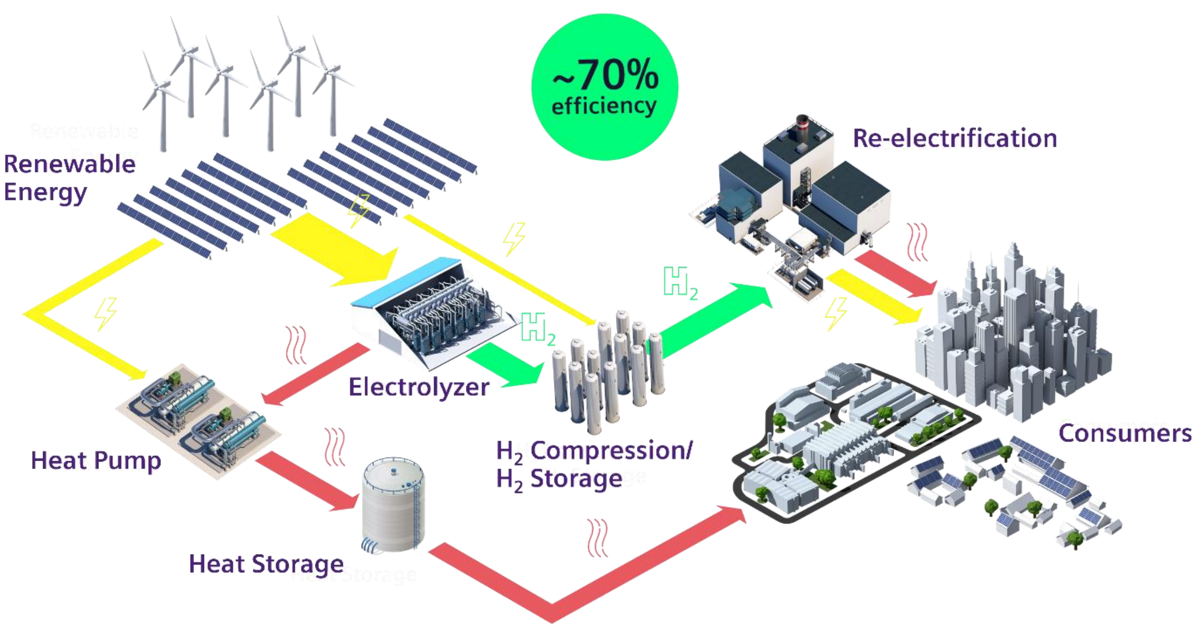

Figure 26: Schematic of fully integrated Hydrogen Power Plants Solution

5 Upgrading Siemens Energy gas turbines for higher hydrogen fuel content operation

The requirement to upgrade existing gas turbines to hydrogen operation

Several reasons encourage gas turbine operators to consider hydrogen fuel retrofits:

- Upcoming stricter regulation on emissions and use of fossil fuels due to the Paris agreement (COP21), other initiatives (e.g. European Green Deal, EU Taxonomy), political instruments and country targets (more than 100 countries target or discuss targets on net zero emissions).
- Increasing carbon pricing through CO_2 taxes or emissions trading
- Customer pressure, companies and owners´ commitments to reduce carbon footprint as well as requirements from investors and financing institutions (e.g. European Investment Bank (EIB))
- Future blending of hydrogen in existing natural gas networks and pipelines requiring existing gas turbines installed in compressor/pumping stations and existing power plants to cope with a certain hydrogen content in the fuel
- The possibility to store excess production of electricity from renewables as hydrogen (Power-to-X) and to utilize it when demand is higher. Hydrogen re-electrification is positioned to be the technology of choice for providing decarbonized residual load in a fully renewable based power system, where hydrogen serves as large scale, seasonal and long-term storage of renewable energy
- The possibility to utilize hydrogen rich off-gas from refinery and chemical processes

These reasons, combined with the long lifetime expectancy of gas turbines and combined cycle power plants of more than 30 years, means that every new gas turbine built today is likely to be still in commercial operation in the 2050s, when the energy system should be largely decarbonized. Hence, gas turbine-based power plants that recently began operation or being built today are very likely to be retrofitted to operate on low-carbon fuels such as hydrogen to avoid any stranded assets in the generation fleet.

What about the installed fleet of Siemens Energy gas turbines?

The current hydrogen capability for existing gas turbines is specified in the gas turbine manual. Retrofit capabilities of existing units to higher blending factors may vary due to unique site constraints, combustion systems, implementation timing and other factors.

If higher hydrogen fuel contents are desired, please check with your Siemens Energy point of contact. Siemens Energy will clarify if higher contents are possible without any further changes to the system, which additional retrofits may be required and whether service overhaul times would be affected.

For medium size industrial gas turbines, the standard capability with limited modifications efforts is up to 15 vol%. An analysis of the existing site needs to be conducted to identify whether components need to be changed. The medium sized gas turbines with 3rd generation DLE systems (standard for all SGT-700 and SGT-800 and an option for SGT-600) have the capability to burn hydrogen with levels of up to 75 vol%. SGT-750 with 4th generation DLE can burn up to 40 vol% hydrogen. Upgrading existing units for hydrogen contents up to these levels is possible.

For gas turbines with WLE systems, the hydrogen fuel capability will be driven by the certification standard of package systems and will usually be around 25 vol%, depending on local rules. However, a check by Siemens Energy should always be conducted, to clarify certification requirements and any impacts on service overhaul times. It is also possible to increase the hydrogen capability of these units with an upgrade.

For the Siemens Energy large gas turbines SGT-2000E and SGT-4000F, the H2DeCarb upgrade package is available for higher hydrogen contents. This package needs to be adapted to each project specifically. The SGT-2000E with this upgrade package can operate with up to 30 vol% hydrogen fuel, while the SGT-4000F can operate on up to 15 vol% hydrogen and the 1000F and V64.3 up to 10 vol% hydrogen. For the SGT-5000F up to 30% is possible with the ULN 3.0 combustion system and other site-specific upgrades.

For other machines in the Siemens Energy fleet, upgrades to higher hydrogen contents can be requested based on a project specific pre-study.

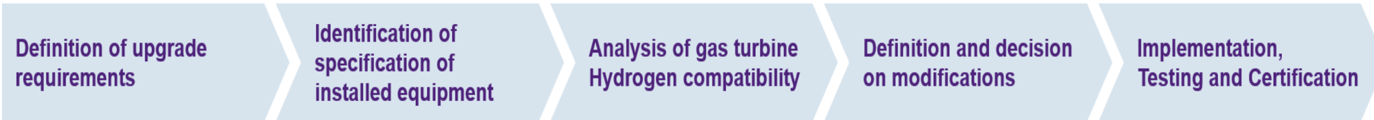

Figure 27: Process for assessment, definition, and implementation of hydrogen upgrades.

Can I upgrade my gas turbine power plant?

High-hydrogen fuels not only pose challenges for the combustion system of the gas turbine, but also to the gas turbine package and plant as well. The package design must be evaluated to ensure all components and systems are capable of safely running with higher hydrogen contents in the fuel. Upstream of the combustion system, hydrogen fuels can require changes to component materials, pipe sizes, as well as sensors and safety systems. Downstream, the exhaust path including the HRSG must be evaluated. Varying exhaust gas properties can impact heat transfer and corrosion rates, possibly impacting the life of components. We recommend a plant specific analysis of all factors and develop the most appropriate solution.

The effort to upgrade a Siemens Energy gas turbine package for higher hydrogen content depends highly on the age of the gas turbine and the status of the installed auxiliary package and power plant. To implement a hydrogen upgrade for our customers, we use the process defined in Figure 27.

There are several physical properties of pure hydrogen and natural gas-hydrogen mixtures that need to be considered. Hydrogen's lower density will lead to higher volumetric flow rates, higher flow velocities and/or higher skid edge pressures, requiring a review of gas fuel skid capacities. For example, as the amount of hydrogen in the fuel mixture increases, the required fuel volume flow will increase up to three times when comparing natural gas to pure hydrogen at the same pressure.

Hydrogen is a smaller molecule than methane, which will result in higher leakage rates, and therefore appropriate plant modifications are required. Additionally, hydrogen's wider flammability range and low ignition energy makes it more likely that fuel leaks could ignite. The connections in the gas system, package ventilation design, and gas detection systems must be assessed for suitability for high-hydrogen fuel operation, both with respect to material suitability and explosion risks. For example, a change to stainless steel material might be needed to prevent embrittlement and enclosed electrical components may need to meet specific certification requirements (e.g.: International Electrotechnical Commission (IEC) gas groups IIC and IIB+H_2). For the flame detection in the package enclosure a combination of ultraviolet (UV) and infrared (IR) radiation detectors might be required.

Combustion control systems may require modification to adapt to the changes in fuel properties when increasing the hydrogen content in the fuel. Depending on the concentration and engine configuration, the use of additional thermocouples may be required which would be monitored by the control system to avoid hardware damage by flashback.

The scope of an upgrade package is related to the target amount of hydrogen in the fuel and the specific technical requirements for the application. For higher hydrogen contents, the development of an upgrade package may have to balance between the scope of the modification, the associated retrofit costs, the remaining lifetime of the plant, the regulatory emission requirements, outage intervals and resultant performance levels. In the end, the decision on what specific measures should be implemented on an existing unit always depends on the blending requirement, the site-specific configuration of the gas turbine and its surrounding systems.

We are continuously working on improving our upgrade packages to ensure that owners of Siemens Energy gas turbines can upgrade their assets for higher hydrogen fuels.

Abbreviations

ACE Advanced Combustion for Efficiency
BMWi Bundesministerium für Wirtschaft und Energy (German Federal Ministry for Economic Affairs and Energy)
CCS Carbon Capture and Storage
CFD Computational Fluid Dynamics
CHP Combined Heat and Power
CO Carbon Monoxide
CO_2 Carbon Dioxide
DLE Dry Low Emissions
DOE Department of Energy
EIB European Investment Bank
EU European Union
G30 Name of Combustion System
GHG Greenhouse Gases
HR Hybrid Burner
HRSG Heat Recovery Steam Generator
H_2 Hydrogen
IEA International Energy Agency
IEC International Electrotechnical Commission
IPCC Intergovernmental Panel on Climate Change
IR Infrared
LOHC Liquid Organic Hydrogen Carriers
MW Megawatt
Nm3 Normal Cubic Meter
NO_x Nitrogen Oxides
N_2 Nitrogen
NEC National Electric Code
NFPA National Fire Protection Association
O&M Operation and Maintenance
PCS Platform Combustion System
PPMV Parts Per Million Volume
SCR Selective Catalytic Reduction
SFI Swirler Fuel Injection
SLM Selective Laser Melting
TWh Terawatt-hour
UK United Kingdom
ULN Ultra-Low NO_x
US United States
UV Ultraviolet
WLE Wet Low Emissions
XLPE Cross-linked polyethylene

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Authors

Main Authors:
Jenny Johansson, Johan Leirnes, Katie Walton, Ertan Yilmaz, Erik Zindel.

Contributors:
Peter Adamsson, Kathleen Bohan, Ghenadie Bulat, Anders Haeggmark, Thomas Johnke, Eva Verena Klapdor, Jenny Larfeldt, Sebastian Piegert, Bernd Prade, Nakul Prasad, Sebastian Ruijgrok, Peter Seyller, Monika Sturm, Michael Welch, Greg Wendt.

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