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A techno-economic analysis of future hydrogen reconversion technologies

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ABSTRACT

The transformation of fossil fuel-based power generation systems towards greenhouse gas-neutral ones based on renewable energy sources is one of the key challenges facing contemporary society. The temporal volatility that accompanies the integration of renewable energy (e.g. solar radiation and wind) must be compensated to ensure that at any given time, a sufficient supply of electrical energy for the demands of different sectors is available. Green hydrogen, which is produced using renewable energy sources via electrolysis, can be used to chemically store electrical energy on a seasonal basis. Reconversion technologies are needed to generate electricity from stored hydrogen during periods of low renewable electricity generation. This study presents a detailed techno-economic assessment of hydrogen gas turbines. These technologies are also superior to fuel cells due to their comparatively low investment costs, especially when it comes to covering the residual loads. As of today, hydrogen gas turbines are only available in laboratory or small-scale settings and have no market penetration or high technology readiness level. The primary focus of this study is to analyze the effects on gas turbine component costs when hydrogen is used instead of natural gas. Based on these findings, an economic analysis addressing the current state of these turbine components is conducted. A literature review on the subsystems is performed, considering statements from leading manufactures and researchers to derive the cost deviations and total cost per installed capacity (€/kW_{el}). The results reveal that a hydrogen gas turbine power plant has an expected cost increase of 8.5% compared to a conventional gas turbine one. This leads to an average cost of 542.5 €/kW_{el} for hydrogen gas turbines. For hydrogen combined cycle power plants, the expected cost increase corresponds to the cost of the gas turbine system, as the steam turbine subsystem remains unaffected by fuel switching. Additionally, power plant retrofit potentials were calculated and the respective costs in the case of an upgrade were estimated. For Germany as a case study for an industrialized country, the potential of a possible retrofit is between 2.7 and 11.4 GW resulting to a total investment between 0.3 and 1.1 billion €.

1. Introduction

Germany is taking a straight forward approach to the energy transition. In accordance with the law for greenhouse gas neutrality by the year 2045 (KSG §3, Subsection 2) [6], the country must transform all sectors of its energy system. A number of studies have been conducted to identify strategies for the transformation pathway from now until then ([2,10,39,44]). Today (2022), the German conversion sector accounts for 33.7% (255 million $t_{equ.\ CO2}$) of the country's total greenhouse gas emissions [1]. These studies show that transformation in this sector will primarily entail the decommissioning of nuclear, coal and natural gas power plants and the installation of renewable power generation technologies like onshore and offshore wind parks and solar photovoltaic systems. The different transformation pathways will also see an increase in hydrogen usage in the future energy system, as is shown in the following figure for the target year of 2045.

Figure 1 shows the share of hydrogen in gross electricity generation in 2045, which falls between 1.1% and 7% of total electricity generation.

1.1. Power generation in natural gas power plants

According to the power plant list of the German Federal Network Agency, the available installed capacity of natural gas-fired turbines and combined cycle power plants on the electricity market was around 18.7 GW in 2021 [5]. Compared to the total installed power plant capacity of approximately 223 GW, it is apparent that gas-fired power plants do not dominate the German electricity market today, but nevertheless make a substantial contribution [51]. Natural gas-based electricity accounted

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for around 15.2% of the total gross electricity generation of 582.9 TW h in the year 2021 [43]. The following introduction to the application of gas turbines and combined cycle power plants illustrates the indispensability of such controllable generation technologies in the overall energy landscape. Gas turbines are currently primarily used in electricity generation to cover peak loads, as they are optimally-suited for flexible operation due to their comparatively high load gradients and so short start-up times. In contrast, combined cycle plants offer slightly reduced flexibility characteristics. However, due to their generally higher electrical output and especially their high efficiency of over 60%, these power plant types can certainly be used for medium-load generation. The flexibility of power generation plants is becoming increasingly important due to the growing need for dynamic and controllable generation capacity to supplement volatile feed-in from renewable energy sources. Due to their technical characteristics, gas-fired power plants offer the possibility of providing these capacities to stabilize the grid and so cover the remaining residual load in the long term.

1.2. Techno-economic characteristics of natural gas-fired power plants

This section presents a technical and economic description of gas-fired power plants that enables a comparison with other technologies. This classification also facilitates a subsequent analysis of hydrogen-fired power plants, which can serve as a reference against natural gas-fired power plants. The market for gas-fired power plants is dominated by a few manufacturers that together account for most of the industry [49]. In the case of the current market, General Electric holds about 42.9% of its share by value, followed by Siemens with 25.7%, and Mitsubishi Power with 19.5%. The remaining sales are covered by other manufacturers, but it is clear from the cumulative 88.1% market share of these three main actors that they make up the bulk of the industry. To provide an expansive insight into the gas turbines available on the market, technical data on the turbines currently offered by the main manufacturers can be found in the appendix [49]. The specific investment costs of gas turbines are an important parameter. Typically, the investment costs relate to the installed power plant capacity (€/kW_{el}). This allows for a comparison with other generation technologies and the calculation of parameters such as the levelized cost of electricity (LCOE). To enable a classification in the case of economic considerations, the assumptions of various sources are listed in Table 1. The data always refer to the investment costs for the procurement and construction of an entire plant, with no distinction being made between the power classes.

The investment costs for installed power plants are often not known and are difficult to generalize due to project-specific parameters, which explains the deviations between the sources. The information provided by the Fraunhofer Institute for Solar Energy Systems (ISE) regarding investment costs is from 2021 and so represents the most up-to-date estimate of the information presented in Table 1. Furthermore, this study distinguishes between low and high investment costs, and includes most of the values cited in other studies. This provides a sufficient overview of the estimates. For the further analyses and comparisons, a specific investment of 500 €/kW_{el} is assumed for pure gas-fired power plants and 950 €/kW_{el} for combined cycle ones.

Table 1
Specific investment costs of natural gas-fired power plants.

	Gas turbine [€/kW_{el}]	Combined cycle power plant [€/kW_{el}]
Energietechnologien der Zukunft [52]	400	800
BCG und Prognos [48]	550	1000
Fraunhofer ISE [8]	400–600	800–1100
Ludwig Bölkow Systemtechnik [24]	385	700

2. Turbine component analysis

This chapter addresses the analysis of the individual plant components of a typical gas turbine or combined cycle power plant. The focus is on the implications and modifications that result from the substitution of natural gas fuel with hydrogen. In order to enable a holistic view of the plant in a comprehensible and concise manner, various components are grouped into categories. First, a closer examination of the individual components within the defined categories is conducted. Then, conclusions are drawn for the individual components of the categories, as well as for the entire power plant with respect to its qualification for hydrogen-based operation. The selection of the individual components for the categories listed below is based on the description by Lechner et al. (2019) [29]. For some sections of the system, there is a significantly greater need for modifications due to their purpose and task. This applies in particular to the system components that come into direct contact with hydrogen gas or contribute to the combustion process. For this reason, the fuel system, for example, was placed in a separate category, whereas other subsystems were added to the category of other plant components. Due to the high safety requirements for hydrogen fuel, which will be discussed in greater detail in later sections of this paper, the safety system was also placed in a separate category. This results in the following categorization of the plant components on which the analysis is based:

Gas turbine and auxiliary systems; compressors; burners; turbines; fuel systems; exhaust systems; instrumentation and control systems; safety systems; and other plant components.

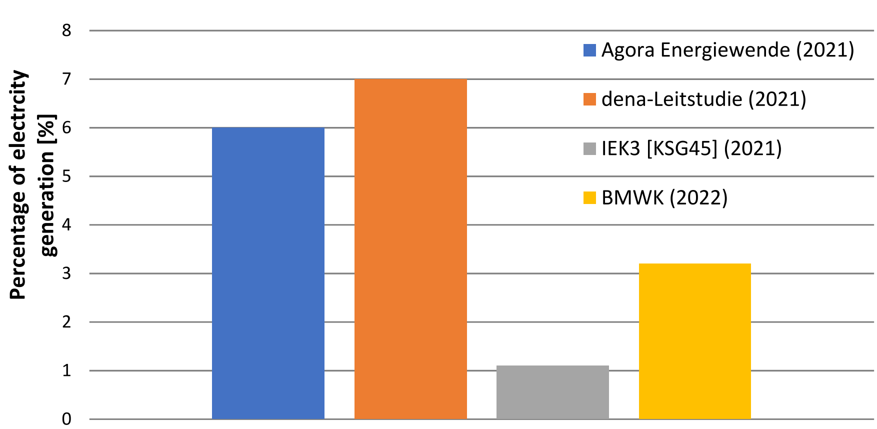

Fig. 1. Share of hydrogen reconversion in electricity generation in 2045 ([1,2,10,44]).

2.1. Gas turbine and auxiliary systems

The gas turbine, consisting of the compressor combustion chamber and turbine, forms the core of the power plant. Its function is to conduct the electricity-generating thermodynamic process. The purposes of the other plant components are primarily the preparation and support of the turbine unit, as well as after-treatment and use of the flue gas. Nowadays, the actual gas turbine is typically handed over as a so-called frame that comprises a prefabricated assembly. Upon delivery, this can be placed directly on the foundation and connected to the intake system on the one hand, and to the exhaust gas connection on the other. A connection to the fuel system is also established, which ensures the supply of the burner with the respective fuel [29]. In the following subchapters, the three essential components and the auxiliary systems of the gas turbine are examined in more detail with respect to their hydrogen compatibility.

2.2. Burner

Hydrogen fundamentally differs from other fuels in its chemical and combustion properties, especially hydrocarbons. Today's burner systems are primarily designed for operation with natural gas, which calls into question their suitability for hydrogen operation [27].

Table 2 compares the most important thermophysical and chemical parameters of hydrogen and methane, which is the main component of fossil natural gas in terms of its propensity for combustion.

The altered gas-specific variables imply some challenges for the burner system that are dealt with below. This is followed by a description of current burner concepts and the efforts of manufacturers to develop new ones.

The maximum adiabatic flame temperature achieved under stoichiometric conditions for hydrogen is over 100 °C higher than for methane. Due to this increase, increased NOx formation in the combustion chamber must be expected if no additional reduction measures are taken [12]. Compliance with the increasingly stringent NOx emission laws represents one of the central and difficult challenges for gas turbine manufacturers, and this has pre-occupied the industry for decades. A change of fuel to hydrogen exacerbates this particular problem. In addition, the higher temperatures increase the thermal load on the combustion chamber materials and coatings [34]. This poses the risk of overstressing or reducing the service life. Table 2 shows that the flame speed of hydrogen is about eight times greater than that of methane. Consequently, using a pre-mix burner that is common today would require a flow velocity eight times higher to guarantee the flame's constant position. This circumstance increases the risk of so-called flashbacks, i.e., the uncontrolled spread of the flame against the actual direction of flow [23]. This results from an imbalance between the flow velocity of the fluid and the flame's velocity. Larfeldt et al. [23] illustrate the change in flame shape due to this characteristic from which the danger of the flame developing upstream into the fuel system becomes obvious. In terms of stabilizing the flame in the combustion chamber and ensuring controlled combustion, this effect represents one of the greatest challenges in the development of new burner concepts for hydrogen gas turbines [34].

The high required gas velocities and turbulent fluid flows for fuel air mixing increase the risk of pressure loss in the combustion chamber. The limitation of this loss is an important factor in the combustion chamber's design [17]. The reason for this is a reduction in efficiency and power output as a result of the pressure loss [21].

The self-ignition delay of hydrogen is about one third that of methane [27]. In conjunction with the high flame speed described above, this underlines the fact that hydrogen is a highly reactive gas. The risk of uncontrolled spontaneous ignition of the fuel–air mixture must therefore be considered in the design of a new burner system [12]. The auto-ignition temperatures of hydrogen and methane, on the other hand, are of a similar order of magnitude, as can be seen in Table 2.

Due to the wider range of combustibility of hydrogen with air given by the volumetric ignition limits displayed in Table 2, combustion can be maintained over a wide range of fuel–air mixtures. In terms of fuel mass, this difference is even more significant [34]. On the one hand, it permits the stable operation of leaner mixtures and improves performance at partial loads [23]. On the other, this circumstance again underlines the high reactivity of hydrogen. The accumulation of a combustible mixture in areas of the gas turbine other than the combustor such as the heat recovery steam generator therefore becomes more likely [34]. In conjunction with the low minimum ignition energy and the auto-ignition temperature of less than 600 °C, the risk of an unintended explosion is not negligible.

In comparing the flame characteristics of natural gas and hydrogen, a different thermoacoustic behavior can be observed. This is expressed, amongst other respects, in a changed thermoacoustic amplitude level and other frequencies, and is due to the differences in the thermophysical and chemical properties [12].

The thermoacoustic stability or instability of a combustion chamber due to the combustion of hydrogen depends strongly on its design and operating parameters. The effects of hydrogen-rich gases or pure hydrogen on the operating conditions of the gas turbine and combustion temperature can influence this stability. If this is not considered, accelerated structural damage and flashbacks may result [3].

Furthermore, with respect to the fuel properties, the differences in specific densities and caloric heating values should be pointed out. Table 2 shows these corresponding values. Hydrogen has a gravimetric heating value that is more than twice that of methane and so is characterized by a particularly high energy content in relation to its mass. However, the low density of hydrogen results in the volumetric heating value of methane being three times as high. If the energy input in an existing burner is to remain constant, a significantly higher volumetric flow is required.

In general, the admixture of hydrogen is expressed in percentages by volume. Looking at the changes in fuel properties as a function of the volumetric hydrogen content (Fig. 2), it becomes apparent that these do not behave linearly. For example, Bohan et al. (2022) [27] show that a hydrogen content of 30% by volume already significantly reduces the auto-ignition time, whereas the flame speed initially increases only modestly, before suddenly rising sharply from a volume content of 80% hydrogen. In Fig. 3, these relationships are continuously plotted against the hydrogen content. As a result, it can be assumed that in terms of the necessary technical innovation, a change from 60 to 100% by volume cannot be compared with an admixture of 40% by volume of hydrogen.

In summary, it can be said that the properties of hydrogen are very different from those of natural gas. In particular, the high reactivity and combustion characteristics require a modification of the systems used today in order to operate gas power plants using pure hydrogen.

The original gas turbine technology is based on the use of diffusion burners [31]. Only a small portion of the air supplied by the compressor is introduced into the combustion chamber, together with the fuel. The majority flows into the combustion chamber through openings and only mixes with the fuel therein at this point [34]. The inhomogeneous

Table 2
Thermophysical and chemical quantities of hydrogen [3].

Parameter	H_2	CH_4
Relative density [kg/m^3]	0.07	0.55
Gravimetric heating value [MJ/kg]	119.93	50.02
Volumetric heating value [MJ/m^3]	10.05	33.36
Ignition limits [Vol.-%]	4–75	5.3–15
Minimum ignition energy in air [mJ]	0.02	0.29
Auto-ignition temperature [°C]	585	540
Maximum adiabatic flame temperature in air [°C]	2103	1950
Maximum laminar flame velocity in air [cm/s]	306	37.6
Mass diffusion coefficient [mm^2/s]	78.79	23.98

Specific Parameters calculated at 20 °C and 101.325 kPa.

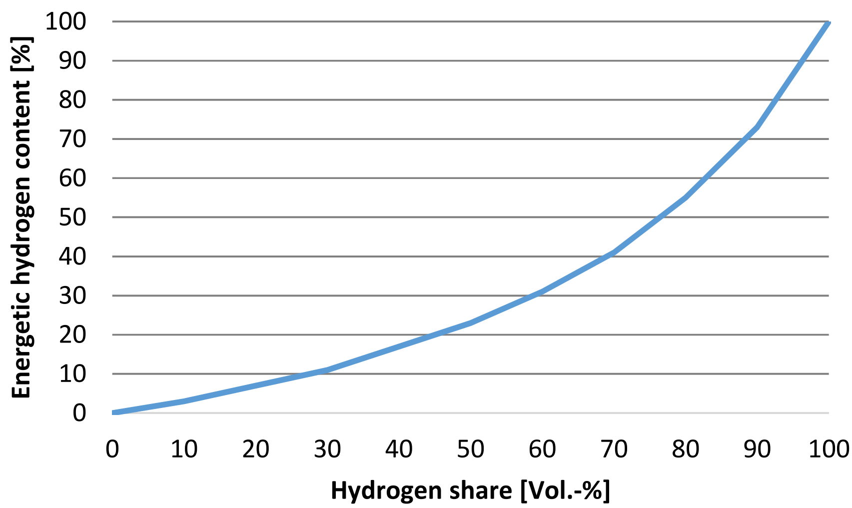

Fig. 2. Energetic hydrogen content in a hydrogen–methane mixture (based on Bohan et al. (2022) [27]).

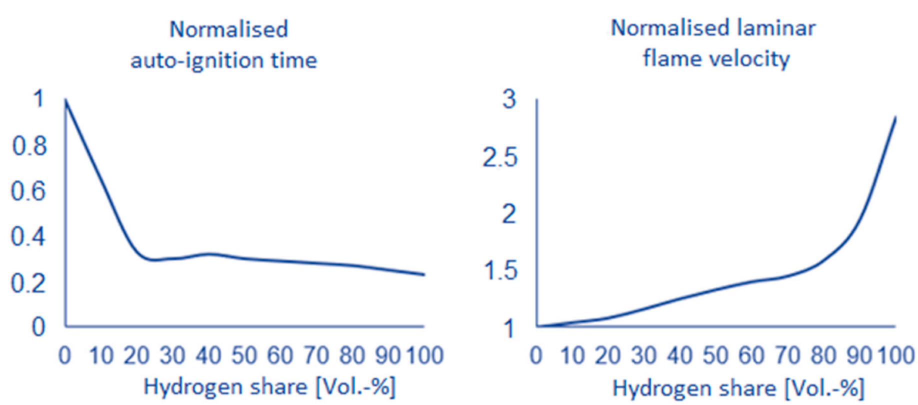

Fig. 3. Influence of hydrogen on the auto-ignition time and flame speed of hydrogen–methane mixtures (based on Bohan et al. (2022) [27]).

fuel–air mixture and the resulting inhomogeneous combustion result in high NOx and CO emissions. An advantage of these systems is their high fuel flexibility due to the avoidance of premixing [31], which enables a wide variety of fuels and fuel mixtures to be used.

The demand for ever lower emission values by environmental regulations has led to the development of so-called wet low emissions (WLE) systems. These burner systems dilute the fuel–air mixture by injecting water vapor or nitrogen to reduce NOx emissions. However, this is accompanied by efficiency losses and increased system complexity, which results in higher investment and operating costs [12, 17]. Nevertheless, one advantage of diffusion burner systems with steam or nitrogen dilution is that they can already be operated with up to 100% hydrogen today (2022) [12,27]. Despite the reduced emissions achieved using WLE burners, the continuous reduction of emission limits required the development of a new burner design. As a result, dry low emissions (DLE) systems have been designed [31]. Based on the principle of the lean combustion of premixed fuel–air mixtures, these systems enable homogeneous combustion. As a result, regions of high temperature are avoided, which can limit emissions [11]. However, due to premixing, the fuel flexibility for water-rich gases is limited compared to diffusion burners [31]. This is primarily due to the higher reactivity which places different requirements on the stabilization of the premixed flame and so makes this more difficult. Despite this fact, DLE-burners make up most of the gas turbines available on the market and old burner systems are increasingly being converted.

As noted above, the combustion of high proportions of hydrogen or pure hydrogen with diffusion burners is already possible today, but is associated with a loss of efficiency as a result of the necessary dilution [17]. Due to the above-mentioned advantages, premix burners are also considered to have high potential for the combustion of hydrogen-rich gases. For this reason, manufacturers are already developing modified DLE-burners; today's burners already tolerate limited proportions of admixture inputs. Due to the different burner systems from various manufacturers, no uniform limit of hydrogen compatibility can be defined. However, on average, a possible hydrogen admixture of 30–50 vol.-% for heavy gas turbines and 50–70 vol.-% for small gas turbines can be expected. A gas turbine with a premix burner that is capable of burning pure hydrogen is not currently available on the market [12].

According to Bohan et al. (2022) [27], a hydrogen admixture of 30 vol% could be added to DLE-burner systems without modification, and a mixture of up to 70 vol% combustion is possible with minor modifications. For hydrogen percentages above this, a new burner design would be required.

The gas turbine's burner system is one of the central components of a gas power plant. The preceding insights into the consequences of the use of hydrogen make it clear that the combustion of pure hydrogen in particular has far-reaching consequences for this component. Due to the direct contact with the fuel and the combustion, the burner is probably one of the most clearly affected plant components and undoubtedly compels modified new designs.

International Journal of Hydrogen Energy 77 (2024) 1254–1267

2.3. Compressors

In principle, the compressor is not in direct contact with the fuel or combustion products, and is therefore not directly affected by the change in fuel. However, indirectly changed operating conditions resulting from hydrogen combustion can certainly have an influence on the compressor system.

Changing the mass flow in the burner system can be a challenge. In general, the compressor and turbine are matched to each other when designing the entire gas turbine system. By manipulating the previously-defined compressor fuel and turbine mass flows, this matching could deviate from the operating point. An increase in mass flow created by introducing steam or nitrogen into the burner with a subsequent increase in the turbine mass flow would cause a change in the total pressure ratio, which is expressed in the form of an increase in the compressor discharge pressure. If this is not considered when designing or retrofitting a gas turbine, the compressor could reach and exceed the compressor surge limit. Various strategies for adapting the system are then possible. Amongst other things, it is possible to reduce the compressor mass flow to increase the pressure ratio in the compressor or remove air [9,29].

Similarly, operation with pure hydrogen without dilution leads to a reduction in the fuel mass flow. Consequently, the turbine mass flow also decreases, which means that in contrast to the case described above, the compressor pressure ratio decreases. In this operating condition, the stability of the compressor must also be checked for validity [7].

In summary, the necessity for a technical adaptation of the compressor cannot be predicted in general. The dependence of the described effects on the type of burner system and the initial design of the turbomachine makes a generalization difficult.

2.4. Turbine

Table 2 displays the increased flame temperature of hydrogen compared to methane. This fact has already been discussed in the sub-chapter on the burner system regarding NOx emissions. However, the increased temperature not only promotes NOx formation but also has effects on the turbine.

An increase in the flame temperature consequently leads to an increase in the turbine inlet temperature and so inevitably to a greater thermal load on the hot gas components, especially the first turbine blades. In addition, the higher the hydrogen admixture in the fuel, the higher the water content in the exhaust gas. The higher water content promotes the heat transfer of the fluid to the components in contact and increases the load on the components in the hot gas path even more. These effects can be avoided by improved cooling methods or by reducing the turbine inlet temperatures through throttling. This could ensure the durability of the materials and prevent a reduction in the expected service life. As throttling the temperature below the design temperature would result in reduced efficiency, it should be avoided if possible [35,37,46].

Furthermore, the increased moisture content of the exhaust gas increases the risk of high-temperature corrosion, which also affects the service life and resistance of the materials and coatings. Consequently, long-term measures and concepts must be developed to minimize these effects [12].

Thus, no generally valid statement can be made for the turbine regarding hydrogen compatibility. The difficulties described above again depend on the operating conditions and the design of the gas-fired power plant, but measures must be taken in any case. For example, lowering the combustion temperature by injecting diluents or throttling the fuel supply can constitute the means of handling them, as can improved cooling concepts in the development of new plants.

It should also be noted that the preferred strategy depends on other non-technical factors. Adapting and replacing the entire turbine when retrofitting an existing gas-fired power plant is probably not an attractive option from an economic point of view. In this case, it can rather be assumed that the original design will be reused, which means that the compensation of the higher heat transfer can rather be realized by adjusting the temperature with low efficiency losses [12]. In the development of new gas turbines for pure hydrogen operation, a new design of the turbine with minor adjustments could certainly be an advantageous option. According to the analysis, the same would also apply to the compressor.

2.5. Auxiliary systems

For the purposes of this analysis, gas turbine auxiliary systems include four systems or components. These include the lubricating oil system, cooling system, start-up system, and compressor washing system.

As the function of the gas turbine has not principally changed the adjustment of the operating parameters, no need for an adaptation was determined during the literature research conducted for this study. For this reason, plant components that can be retained in their original design will not be discussed in detail.

Under the special circumstances resulting from higher temperatures discussed above, the cooling system is affected by the change of fuel and provides increased cooling capacity. This could be expressed in a changed dimensioning of the system due to an increased cooling air demand or the development of a new concept for future plants.

The need for new cooling concepts and improved materials for the hot gas components already exists today. The efficiency of a gas turbine depends to a large extent on the turbine inlet temperature reached and an increase in this value is therefore the primary focus of manufacturers [52].

2.6. Fuel system

The physical and chemical properties of hydrogen shown in Table 2 have already been discussed in detail. It was pointed out that an increased fuel volume flow must be provided if the power output of the plant is to remain constant. Additionally, the high reactivity of hydrogen was mentioned several times. This background suggests that the entire fuel system, as well as the burner system in its optimized form for natural gas operation, must be redesigned.

In addition to the fuel supply, the tasks of the fuel system include fuel preparation control and regulation by varying the gas quantity. Finally, protection of the gas turbine against inadmissible operating conditions is an important function of this system. The main components of the system are the necessary pipelines for transport, including various valves and measuring devices, cleaning devices, and seals to prevent fuel leakage. If operation using different mixtures of fuels is desirable, a suitable mixing system must be added [29].

The significantly increased fuel volume flow requires an adjustment of the entire cross-sections and dimensions of all components of the fuel system. This fact alone makes it clear that no components of today's systems can continue to be used [12,29].

Furthermore, due to its small molecular size, hydrogen can diffuse into other materials. In the long term, this process causes microscale cracks and so changes in material properties or failures. This effect is known as hydrogen embrittlement and must be considered when analyzing and changing the fuel system. For this purpose, the steels and other materials must be examined and replaced if necessary. For example, conventional gaskets could prove unsuitable, resulting in the need for newer gaskets or welded joints [22,34].

The use of hydrogen-rich gases entails high safety requirements due to reactivity, high volatility, and the potential for unintentional ignition. For this purpose, some measures for the fuel system must be taken. In addition to the replacement of the seals, extraction systems and gas detectors can be used. The possibility of purging the entire system must be available in order to avoid uncontrolled reactions [29].

A final aspect that should not remain unmentioned in this analysis is the need for mixing systems for the combined use of natural gas and hydrogen. Depending on the operating scenario of future gas-fired power plants, this also represents a challenge. If the permanent operation of a plant based on pure hydrogen cannot be guaranteed but operation is also to take place in phases of low fuel availability by mixing natural gas and hydrogen, a mixing system must be available for regulating the fuel composition. In addition, mixed operation may require the installation of measuring devices to control fuel gas composition. In any case, this circumstance would require a renewal or redesign of the system [22]. Furthermore, the system must be able to stably burn a variation of fuel mixtures, which is another requirement. As the future of how hydrogen gas turbines will operate is unclear, the need for a mixing system remains to be seen.

Today's gas-fired power plants cover their demand for natural gas by connecting to the pipeline network and are continuously fed from it. Due to the different pressure levels, a pressure reduction station is connected between the pipeline network and plant structure of the power plant to equalize the pressure levels. As the extent to which a separate pipeline network will be operated for hydrogen fuel is not yet foreseeable, similar measures for hydrogen cannot be estimated at present. However, if a future power plant is fed from a hydrogen network, the installation of a special pressure-reducing station can be expected.

In summary, it should be clear from the points made that modification of the entire fuel system cannot be avoided in any conceivable case. The extent to which the integration of new fuel systems is feasible, especially in terms of space requirements, must be assessed on a project-specific basis.

2.7. Exhaust system

The exhaust system is the final unit of a pure gas turbine and the link between the two individual processes in a combined cycle power plant. On the one hand, the system serves to clean the exhaust gases and then expel these out into the environment. On the other, the heat required for the steam process is extracted from the exhaust gas in combined cycle power plants by the heat recovery steam generator.

The influence on the heat release process is limited. Only the increased water content in the exhaust gas can lead to undesirable developments in the form of high-temperature corrosion, as has already been described for the turbine. For this reason, it should be considered if measures for corrosion protection should be taken [45]. Whether heating surfaces should be optimized in the future cannot be fully assessed on the basis of the current state of knowledge, and this should be a subject of further research.

If the burner technology or use of dilution by nitrogen or steam cannot bring NOx emissions below the valid limit value, a selective catalytic reduction (SCR) converter must be retrofitted. This is a challenge when retrofitting old gas-fired power plants, as such systems are typically located inside the heat recovery steam generator for reasons of temperature and require a lot of space [29]. Such space may not be available, which could make installation impossible. In any case, high technical and economic effort would be required. Due to increasing investment and operating costs, SCR converter systems are also avoided wherever possible in the construction of new plants, although the space required for retrofitting is sometimes planned [41,45].

Finally, another aspect that arises because of the increased water content in exhaust gas should be mentioned. Due to the increased exhaust gas dew point caused by the greater water content, an increased mass flow of condensate recirculation is to be expected and should be taken into account when designing a hydrogen gas power plant.

In summary, it can be said that the consequences relating to the exhaust gas system can be described as manageable. This assumes that the NOx emission limits are met without the need for an SCR catalytic converter.

2.8. Safety systems

It should be noted that no international standards or routines for hydrogen-based gas turbines for power generation have yet been devised. Therefore, in the long term, a transfer of knowledge from other industries is necessary and applicable to the operation of power generation plants [12].

The volatility of hydrogen makes it more likely to accumulate in areas other than the gas turbine. For this reason, the use of fans to avoid these effects has already been mentioned and is a way to reduce the risk of explosions across the system [12,29].

Furthermore, in contrast to natural gas, the low density of hydrogen means that the gas is likely to accumulate in the upper segments of the plant. In other industries, gas detectors are used for this purpose in order to detect increased concentrations at an early stage [12]. Additionally, roof openings in buildings can help to avoid accumulation of the gas [45].

In addition to the technical modifications to the actual plant, the necessary concepts and procedures must also be adapted and checked for their validity. For example, these include explosion and fire protection concepts, as well as hazard and risk analyses [45].

This means that the safety system does not need to be fundamentally reconsidered and modified, but a revision of the previous concepts should be carried out in any case. New plant components must also be checked prior to operation and the necessary approvals obtained.

2.9. Instrumentation and control systems

The control technology is used to control, regulate, and monitor the power plant and its operation. Changes in sensor technology and the interfaces to the software, as well as the digital adaptation of safety-relevant systems, can result in an adjustment of the control technology [45]. The fuel control systems must also be adapted [12].

2.10. Other plant components

The category of other plant components includes all other subsystems and components that have not yet been mentioned. As already noted, this section does not deal with those plant components that function independently of the type of fuel and are therefore not affected by the changeover. Special attention will therefore be paid only to some aspects concerning the overall plant. In this respect, only the ancillary systems necessary for operation come into focus to a particular extent.

At the start of this paper, options for the future operation of gas-fired power plants were discussed. The question of whether hydrogen-powered plants will be fed by the pipeline network in the future, or whether locally produced hydrogen will be used, remains open. The question of whether pure hydrogen operation or flexible mixed operation will be targeted is also unanswered. Depending on the concept and strategy, future gas-fired power plants could be supplemented by storage and/or production facilities for hydrogen. These additional plant components must be taken into account during planning stages and integrated into existing or new designs.

In summary, the burner system, fuel system, and control and safety technology can be identified as central elements with respect to the need for modification. Fig. 4 summarizes this qualitatively and shows the respective degree of change in the subsystem of a turbine plant when it is operated with hydrogen instead of natural gas.

Furthermore, it can be stated that some of the necessary adaptations strongly depend on the degree of hydrogen admixture. Likewise, the retrofitting of a gas-fired power plant may require a different scope of adaptation measures than merely the new conception of a power plant designed specifically for hydrogen operation. These specific differences include the evaluation of the techno-economic effects and significance of the results for the operating parameters and characteristics, which will be examined below.

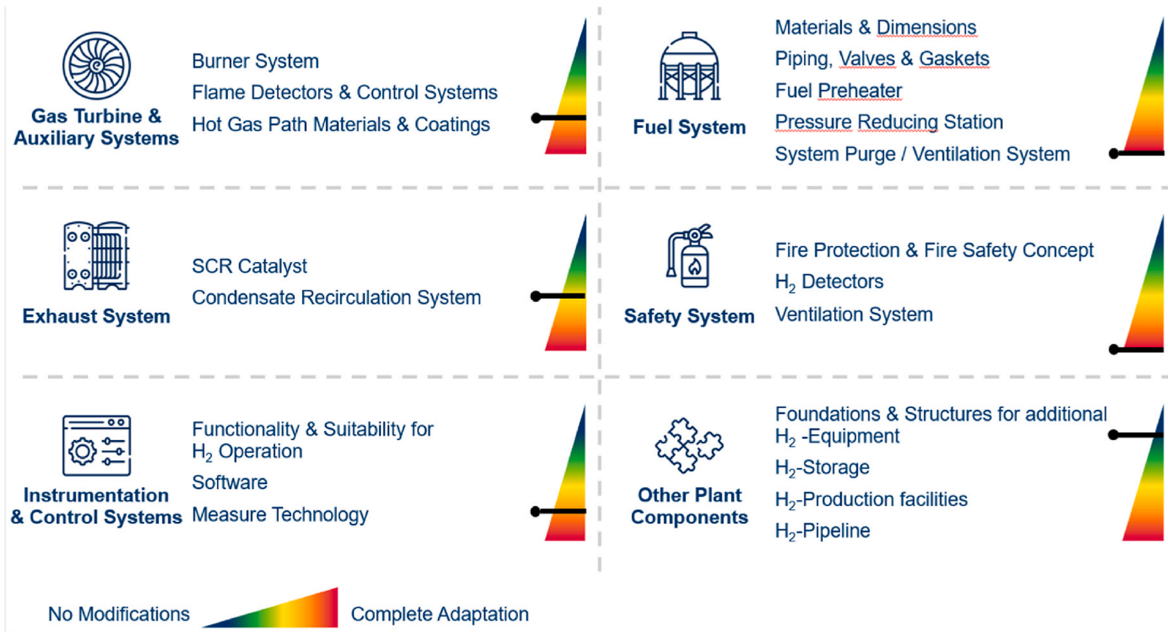

Fig. 4. Power plant system modification level when operating with hydrogen.

3. Techno-economic system analysis

3.1. Hydrogen gas power plants

Pure Hydrogen gas turbine power plants have so far only been realized in the context of research projects and pilot plants and will not find widespread market application in the near future (<5 years). In addition to the lack of technical maturity, there are other factors that currently prevent a broad market introduction. The limited production capacity for hydrogen, combined with the high cost of hydrogen today, makes it impossible to operate hydrogen-fired plants economically. Therefore, it remains to be seen when and to what extent the reconversion of hydrogen into electricity will become part of the electricity supply. Nevertheless, it has already been discussed in detail that the combustion of hydrogen can be an economically and technically sensible component of a completely greenhouse gas-neutral energy system. In the long term, complete decarbonization of gas turbines, not including the possibility of carbon capture and storage, can only be achieved by

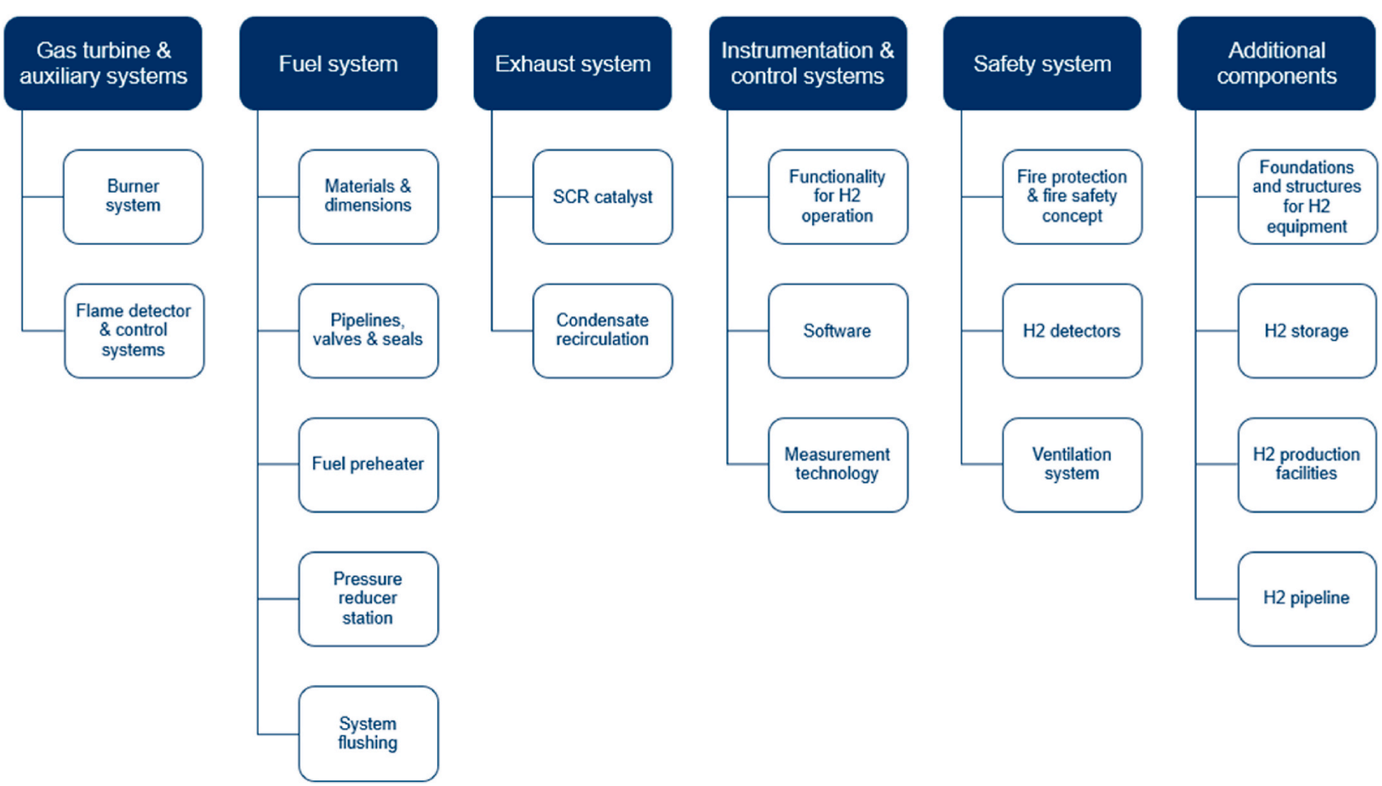

Fig. 5. Considered system components in the technical design of a hydrogen-fueled gas power plant.

running on pure hydrogen or biomethane. For the modeling of future energy systems, the consideration of pure hydrogen-fueled gas power plants, which is the topic of this subchapter, is therefore indispensable. In addition, the initial assumption of a pure hydrogen power plant provides the basis for further considerations. In the following consideration of the relevant techno-economic aspects, the effect of proportional hydrogen quantities is also considered for the sake of completeness, but the focus is on pure hydrogen operation. The component analysis provides a detailed description of all aspects that must be considered for the installation of hydrogen-fueled gas power plants. From this analysis, a clear idea of the scope of the technical adjustments to be made can already be developed and a foundation for the subsequent evaluation of the techno-economic parameters built up. To facilitate this introduction to the following chapters, Fig. 5 provides a summary of the system components affected by the fuel switch.

3.2. Economic data analysis

The economic efficiency of powerplants plays a major role in the evaluation of market success, in addition to such aspects as technical maturity functionality and environmental compatibility. An evaluation of the investment costs of hydrogen gas power plants is therefore of great importance for estimating the future share of hydrogen reconversion in modeling. Due to the expansion of renewable energies such as wind and PV, reconversion technologies are only used to supply residual loads. This corresponds to low full load hours for the power plant. For this reason, the focus is on investment costs for reconversion technologies. Variable costs, such as fuel costs, are only a secondary consideration. The following analysis focuses on the evaluation of the capacity-specific investment costs. In order to enable comparability with today's natural gas-fired power plants, percentage cost deviations are considered in the following instead of fixed cost values. This has the advantage of increased comprehensibility on the one hand, and that the results can be applied to various basic values of investment costs for natural gas-fired power plants on the other. Furthermore, it should be mentioned that the evaluation of the cost increases is purely a comparison with conventional natural gas power plants. General price-influencing factors such as global increases in material costs are not the subject of this study.

The goal of the following analysis is to conclude the percentage cost deviation of a hydrogen gas power plant compared to a conventional gas turbine one by means of arguments and assumptions. By looking at the investments at the detailed level of individual component categories of the total costs, an isolated evaluation of individual groups can be made. This makes it possible to concentrate on a focused sub-area when evaluating the cost variance considering the influence of the technical component analysis. For each subsystem category, the extent to which a cost variance can be validated should be justified by the necessary technical adjustments. Subsequently, the deviation of the total system costs can be concluded by including the cost structure. In order to implement the described procedure in this form, a cost structure must first be used as a basis that divides up the system costs of a conventional gas turbine power plant.

Such a breakdown can be found in the Gas Turbine World 2021 GTW Handbook [16], which is an industry journal that deals exclusively with the development and operation of gas turbine plants. It provides a detailed cost structure for a 100 MW aeroderivative gas power plant, a 240 MW gas power plant, a 430 MW CCGT power plant, and an 1100 MW CCGT one. In addition to the costs for the actual equipment, other factors such as budget reserves or land acquisition are also considered.

The cost description thereby covers all items of a typical construction project for a gas turbine plant. This has the advantage that aspects that do not directly concern the hardware of a plant can also be dealt with in the subsequent analysis, thus creating a holistic picture of the cost deviation. From the cost data presented as a percentage, the cost structure can be calculated for each of the four power plant types. As the analysis initially concentrates on the pure gas turbines, the average cost structure of the two pure gas power plants (110 MW and 240 MW) can be found in Fig. 6.

The respective technology changes can be assigned to these cost categories in the following. In order to combine the detailed component analysis together with the cost categories of the GTW Handbook, it was also defined what is assigned to the respective cost class.

In the following economic analysis, the technology changes discussed in the detailed component analysis are each assigned to one of the cost categories of the GTW Handbook [16]. The respective cost category is first explained. This is followed by a discussion of the extent to which a relative cost increase in this cost category can be expected if a fuel switch from natural gas to hydrogen occurs. This is then validated using various statements of different sources. In the end, the cost increases are summed up and a cost difference for the entire hydrogen turbine power plant is calculated. This cost difference is finally compared to other sources or assumptions.

3.2.1. Civil/structural/architectural

This cost factor includes all construction and design work on the buildings of the future power plant. According to the GTW Handbook [16], these are, on the one hand, the material costs. On the other, the personnel costs for the preparation of the site, the foundations and the construction of the buildings are summarized in this category. This category does not include turbine components that come into direct contact with hydrogen. As described earlier, it is possible to add additional components to the power plant, such as hydrogen storage tanks or electrolyzers. Only these expansions lead to an increase in costs, as these units must also be built and a corresponding development of the site is necessary. However, these components are independent of the power plant's operation and are not necessarily built in the immediate vicinity of it. Therefore, they are not counted as part of the power plant itself. In addition, today's natural gas power plants are supplied via pipelines from the natural gas transmission grid. The European Hydrogen Backbone [25] and many other studies [20,28,40] describe a future hydrogen supply network throughout Germany and Europe. Therefore, there is no reason why future hydrogen turbine power plants should not also be supplied via pipelines. Additional plant components such as storage or electrolyzers are therefore not considered in this paper. Accordingly, it is assumed for this cost factor that the costs do not increase compared to a conventional gas turbine power plant when changing the fuel to hydrogen.

3.2.2. Main mechanical equipment

This cost category includes the main components of the gas turbine with the compressor, combustor and expansion turbine [16]. As already described in the component analysis, all of these components are directly or indirectly affected by the fuel switch to hydrogen. From the component analysis, it is clear that the combustor must be modified for a hydrogen gas turbine. To this end, Ölberg [36] assumes in his paper that replacing the burner increases the total cost of the gas turbine by 4%. Combining this statement with the cost breakdown from the GTW Handbook [16] results in a relative cost difference of 12% from the conventional turbine power plant of the main mechanical equipment. The detailed literature analysis of the turbine components revealed no need to modify or replace the compressor during fuel switching. This was confirmed by statements from market leader General Electric. Hughes [19], in a communication on the subject of retrofitting natural gas power plants to hydrogen operation, states that only the burner unit must be replaced during retrofitting and the rest of the turbine is not affected and can be utilized as is. Based on this statement, it can be assumed that there will be no cost increase for the compressor unit in new hydrogen turbine power plants either. The analysis of the expansion turbine components showed that the combustion of hydrogen leads to increased turbine inlet temperatures. According to Wright et al. [53], these increased temperatures have a particular effect on turbine blades. The author goes on to note that single-crystalline super alloys achieve a

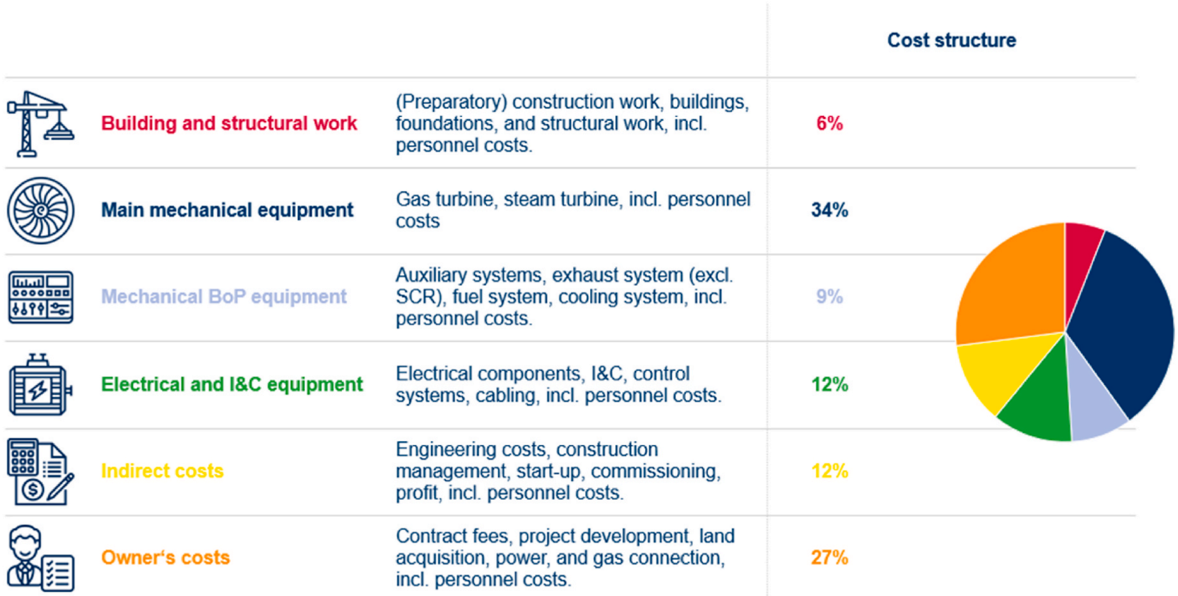

Fig. 6. Considered system components in the technical design of a natural gas-fueled gas power plant (based on the GTW Handbook 2021 [40]).

higher resistance if iridium or ruthenium are also alloyed to them. In this regard, Mahinpey et al. [32] note that although the stability and high-temperature properties of turbine blades are improved with added ruthenium, they are not suitable for commercialization from an economic point of view. Another statement made by Wright et al. [53] is the improvement in turbine system cooling. From these statements, it can be inferred that modern hydrogen gas turbines only involve modifications to the burner. The necessary changes to the compressor and turbine are avoided by revising the turbine operation so that no increased temperatures occur, and the components used so far are also sufficient for operation with hydrogen. Therefore, for this work, it is assumed that the main mechanical system experiences a relative cost increase of 12% with fuel conversion to hydrogen.

3.2.3. Mechanical BOP equipment

All mechanical auxiliary systems of the gas turbine power plant are summarized under this cost factor. These include, amongst others, the cooling system, exhaust system, and fuel system. The material costs, as well as the personnel and installation costs for these systems, are also included in this item [16].

As explained in detail in the component analysis, the fuel system must be adapted to the material properties of hydrogen. To this end, Ölberg et al. [36] assume that a new hydrogen fuel system increases the total cost of the power plant by 1%. The fuel system is integrated as part of the mechanical BOP equipment. Relating this total turbine cost increase to the cost share for gas turbines results in a relative cost increase for this category of 11% compared to conventional gas turbines Furthermore, Ganjikunta et al. [15] state that a system fueled by hydrogen-rich syngas will be about 30% larger than for conventional natural gas. The fuel system consists largely of piping and related distribution components. A 30% increase in the cross-sectional area of flow through these components results in an approximately 14% increase in the diameter of the piping components. The diameter directly relates to the material consumption of the system and is therefore used as an indicator for the cost increase. Thus, a corresponding relative fuel system cost increase of 14% can be assumed. This is of a similar magnitude to the 11% from the work of Ölberg et al. [36]. Therefore, for this study, a 15% cost increase for the hydrogen fuel system is conservatively assumed because of the uncertainty regarding the cost increase based on the hydrogen-rich syngas fuel system.

The cooling system is not directly affected by the fuel change but will be affected by the potentially higher temperatures of hydrogen combustion. As described above for the main mechanical equipment category, it is assumed that power plant operation will be adjusted accordingly in order to avoid critical temperatures. In addition, Ganjikunta et al. [15] state that the turbine manufacturers General Electric (GE), Siemens, Alstorm, and Mitsubishi already have sufficient experience in operating gas turbines at high combustion temperatures and have taken appropriate measures to increase thermal load capacity. Therefore, a high technology readiness level (TRL) is assumed. These statements allow the assumption that there will be no cost increase in the area of the cooling system when changing the turbine fuel to hydrogen.

In order to keep NOx emissions within the prescribed limits, a hydrogen turbine power plant must be equipped with a sequentially downstream SCR catalyst. TerMaath et al. [47] describe the necessary investment in an SCR catalyst, depending on the power plant capacity. The author gives a range of turbine power output of between 42 and 157 MW. The corresponding investment for an SCR catalyst is between $1.7 and 3.5 million USD. If these values are conservatively and linearly extrapolated to a 240 MW turbine, the costs reach $3.9 million. The cost distribution for a gas turbine from the GTW Handbook is based on the average cost of each cost category of a 110 MW and 240 MW gas turbine. Accordingly, according to the GTW Handbook, the cost of the mechanical BOP equipment is $13.5 million [16]. The average cost for the catalyst is $3.6 million. This corresponds to $4.6 million after adjustment for inflation [26]. Learning effects for reducing costs are neglected as a conservative assumption. Thus, relative to the cost of mechanical BOP equipment for a conventional gas turbine power plant, the installation of an SCR catalyst represents a 33% cost increase. Summarized over all subcomponents, this results in a relative cost increase of 48% for the mechanical BOP equipment.

3.2.4. Electrical, instrumentation and controls equipment

According to the GTW Handbook [16], this cost category includes all electrical equipment for instrumentation and control in the power plant. It encompasses the cost of generators, transformers, switchgear, control systems, cabling, and related personnel and installation costs. It also includes the power plant's electrical safety systems, which are described in the component analysis. Specific information on electrical equipment cost increases could not be determined during the research process. However, Ganjikunta et al. [15] state that the market leaders in gas turbine technology, General Electric (GE) and Siemens, already have extensive experience in using gas turbines with pure hydrogen or synthetic gases with a high hydrogen content. The authors note that GE gas turbines have already run over one million operating hours and Siemens turbines 750,000 operating hours on hydrogen-rich syngas (up to 95% hydrogen). As this statement dates back to 2010 and the technology and experience of turbine manufacturers has evolved since, it is assumed for this study that the electrical equipment for hydrogen turbines is at the same TRL as for today's natural gas turbines. This means that there are no additional costs for electrical and I&C equipment compared to conventional natural gas turbine power plants.

3.2.5. Indirect and owners' costs

Indirect and owners' cost are considered a common category. Indirect costs include construction management costs, commissioning costs, contractor overheads, and service charges. Owners' costs consist primarily of project development costs [16]. As can be seen, the cost categories are independent of fuel switching on the one hand, and independent of technology on the other, as they are essentially project costs. Therefore, a cost increase compared to conventional natural gas power plants is not expected. This assumption is supported by the statements of Lux et al. [30]. The author describes that hydrogen-based reconversion technologies are not currently available on an industrial scale. However, it is also noted that the extensive experience of manufacturers with natural gas turbines will be useful for the development of the respective hydrogen technologies. Accordingly, the costs of hydrogen gas turbines are equated and assumed to correspond to those of conventional natural gas turbines. Based on these statements, it can be assumed that the turbine manufacturers, who have already realized many projects using conventional gas turbine power plants, can use their project experience for new hydrogen turbines and so will not incur additional costs in this category.

3.3. Summary and literature comparison

As only cost increases were determined, it can be assumed at this point that the construction of a hydrogen gas power plant does not lead to a cost reduction. The additional costs described should be understood as representing the percentage of additional costs that result from the construction of a hydrogen gas power plant compared to a conventional natural gas power plant. Fig. 7 summarizes the respective costs for each cost category.

This results in a relative cost increase for a hydrogen power plant compared to conventional natural gas-fired turbine power plants of 8.5% in total. It can be assumed that the calculated percentage cost difference does not represent a permanent constant. Due to time effects, it is realistic that the cost increase will decrease over time. Cost reduction mechanisms in production, increasing experience with the equipment, and a reduction in development costs lead to a complete alignment of the costs of hydrogen gas turbines and conventional gas turbine power plants.

With these cost deviations, it is possible to conduct economic analyses of hydrogen gas turbines and so determine their impact in a future low-carbon energy system. Furthermore, for combined cycle power plants, a relative cost increase corresponding to the cost of the gas turbine system was obtained, as the steam turbine system remains unaffected by fuel switching.

As a final step, the cost variance is compared with other values from the literature. For this purpose, Table 3 summarizes the relative cost variances of different studies.

As the table shows, the individual cost increases lie in a wide range of between 8.5 and 50.9% additional costs. It should be noted that the values cited by Agora, Ölberg et al., and Ludwig Bölkow Systemtechnik

Table 3
Relative cost increases for hydrogen gas turbines.

	Cost increase [%]	Year	Basis of the Cost increase
Agora – Klimaneutrales Deutschland [1]	50.9%	2022	Assumption
Paper – Ölberg et al. [36]	15%	2022	Assumption
Ludwig Bölkow Systemtechnik [50]	17.1%	2018	Assumption
Paper – Pilavachi et al. [38]	23.6%	2009	Expert opinion
Own calculation	8.5%	2022	Literature verified cost variances

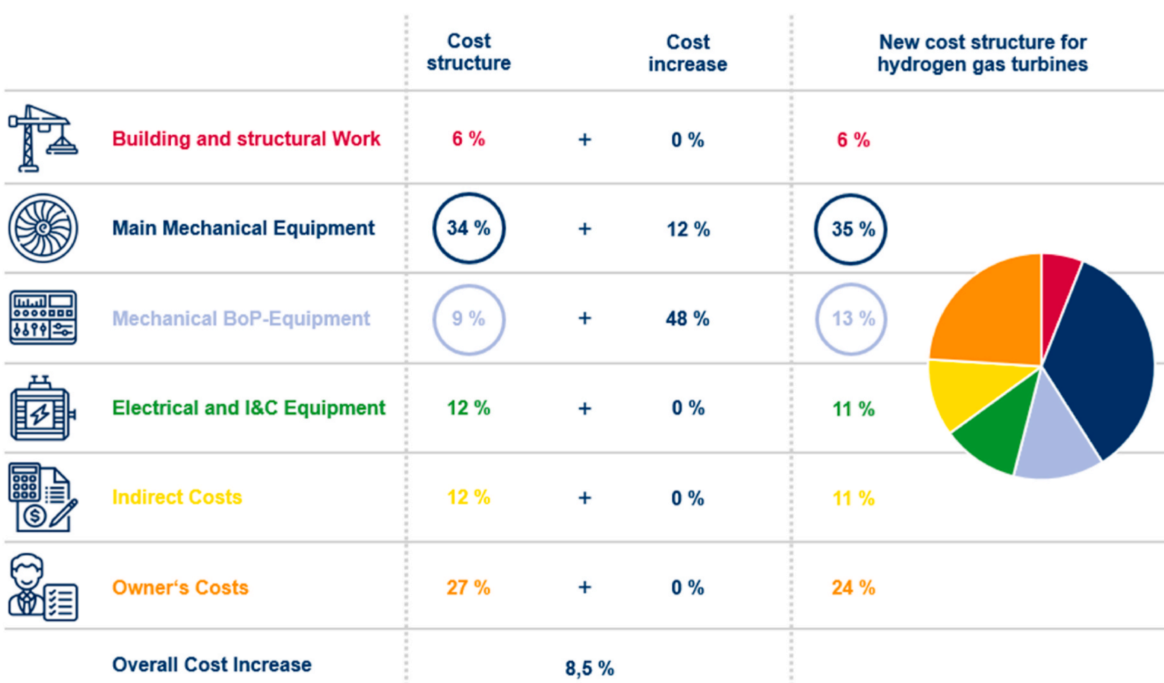

Fig. 7. Considered system components and cost increase for new hydrogen gas powerplants (based on the GTW Handbook 2021 [40]).

are only assumptions. None of these studies specify how the respective investment costs were calculated. Pilavachi et al. refer to a personal contact with Costello Holdings LLC in their paper. As this consulting firm was dissolved in 2019, it is not possible to understand how the cost increase for hydrogen gas turbines was calculated. However, the own calculations performed in this paper were cross-checked with statements from leading turbine manufacturers and the costs of power plant components.

Another finding of the incremental cost analysis is that it is possible to retrofit existing natural gas turbines by replacing the burner. In a General Electric (GE) press release from 2022 [19], Michael Hughes states that this retrofit can be accomplished in a matter of days because the combustors of GE gas turbines can be fully disconnected from the rest of the turbine frame. From this, a potential for retrofitting conventional natural gas turbines can be calculated.

4. Retrofitting potential of existing gas-fired power plants, A case study for Germany

In addition to the construction of new hydrogen gas turbines, the retrofitting of existing fossil natural gas turbines is also an economically sustainable solution for the reconversion of hydrogen back into electricity. Germany, with its clear greenhouse gas reduction targets for 2045, is used as a case study to calculate the potential deployment of hydrogen gas turbines. To further specify this topic, the German government announced in August 2023 that the electricity supply should be nearly greenhouse gas-neutral by the year 2035. Power plants with a total capacity of 8.8 GW are to be built, which will be operated with hydrogen from the beginning. In addition, further 15 GW of power plant capacity will be built, which will be temporarily operated with conventional natural gas [4]. As the expansion of the hydrogen infrastructure continues, the power plants will then be converted to hydrogen fuel, which underlines the relevance of the analysis conducted here because the technology will be planned as a hydrogen system. In the first years of the low carbon transformation, a retrofitting strategy could enable an accelerated fuel switch to hydrogen. From an economic point of view, there is also the possibility that the retrofitting of commissioned natural gas plants could prove more attractive than the time-consuming construction of new hydrogen power plants. For these reasons, a potential analysis for upgrading current natural gas power plants is inevitable. In this final section, the potential retrofitted power plant capacity that can be gained through the refurbishment of existing conventional gas-fired power plants for hydrogen operation in 2030 is calculated. For this purpose, the following assumptions have been defined. The existing power plant capacity of gas turbine and combined cycle power plants originates from the data regarding the power plant list of the Federal Network Agency from the year 2021 [5]. As an input for this study, a breakdown of the existing capacities with respect to their service life could be created from the data, based on the assumption that each plant has a technical service life of 30 years and is then no longer operated [13]. The ultimate retrofitting potential is given by the total installed power plant capacity that remains operational in each year. As a further boundary, it is assumed that gas-fired power plants are no longer retrofitted after a certain operating life has been exceeded. The reason for this is the uncertainty of operation, which means that it is not clear whether a retrofit extends the technical lifetime of an existing turbine system. It is assumed that a retrofit beyond this point in time will no longer be profitable. For this study, a distinction is made between an operating life limit of 15 and up to 20 years. Thus, if an installed power plant has reached this technical life (15 or 20 years), it is assumed that up until this point, it will be economically viable to retrofit it. All plants that are older than this are neglected for retrofitting. Finally, it is assumed that all newly-installed power plants that were not part of the power plant list in 2021 can already be classified as H2-ready and therefore are not considered to have retrofitting potential.

Based on this, the available potential retrofitting capacity in 2030 can be determined. The results of this analysis are presented in Table 4. The data on the required capacity of hydrogen gas power plants are taken from the study 'Strategies for a greenhouse gas-neutral energy supply by 2045' [44] as they pertain to a Greenhouse gas-neutral transformation of the German energy system through 2045.

Of the 18.4 GW of installed power plant capacity in 2021, 7 GW will reach its technical lifetime by 2030. This results in a retrofit potential of 11.4 GW. As can be seen, this capacity would be sufficient to provide the calculated necessary power plant capacity if the plants are retrofitted. In addition to that, in the case of possible retrofitting up to a completed operating lifetime of 15 years in 2030, a retrofitting capacity of about 2.7 GW is possible, which can be increased to about 6.6 GW assuming possible retrofitting up to a service life of 20 years. Considering demand capacity, there remains an additional required capacity of 7 GW and 3.1 GW, respectively, which must be covered by newly installed hydrogen gas power plants. If it is possible to retrofit gas-fired power plants even longer after commissioning, the capital expenditure to be made soon could be reduced. Again, it should be noted that the original service life is not necessarily extended after a retrofit. These calculations of retrofitting potential raise the question of what the refurbishment of those one-decade-old conventional power plants would cost in the case of a retrofit. For this estimation, a characterization of the power plant features according to EUTurbines [14] is used. In the analysis by EUTurbines, three different categories of power plant types are distinguished, based on the retrofitting measures to be carried out in an economical manner. In categories one and two, no or only minor modifications are required. As implied by Michael Hughes in a press release from GE [19], commissioned conventional natural gas-fired power plants belong to the third category of EUTurbines, in which plant retrofitting is technically-possible and economically-feasible. In this case, adaptation to hydrogen as a fuel is characterized by changes in the hardware and software. EUTurbines estimates requirements for investment of up to 20% of the original power plant costs [14]. With these data, the investments for the power supply with hydrogen for the year 2030 can be determined as follows. Assuming an economic retrofit up to a service life of 15 years, a corresponding potential of 2.7 GW is available. Another 7 GW must then be built as new power plant capacity. The costs for retrofitting thus amount to 270 million € and those for the new power plants to 3798 million €. With an economic retrofit up to a lifetime of 20 years, the total cost of hydrogen reconversion is reduced to 2342 million € (660 million € retrofit and 1681 million € for new builds), as significantly fewer new power plants need to be built. Retrofitting all existing natural gas turbine power plants by 2030 would cost 1145 million €.

In summary, it is apparent that the available retrofitting potential strongly depends on the time in which an upgrade is still technically and economically sustainable. Part of this analysis addresses the operation time after the original commissioning of the natural gas power plant. The longer a retrofit is technically possible and economically reasonable, the higher the possible plant capacity for a fuel switch from natural gas to hydrogen. To confirm the veracity of this, two milestone years were analyzed. First, a possible retrofit up to half of the technical lifetime (15 years), which corresponds to a retrofitting potential of 2.7 GW in 2030, was assumed. The second assumption was two third the power

Table 4
Analysis of the potentially available retrofitting capacity in GW, assuming an economical retrofitting of up to 15 or 20 years of conventional operation.

Year	Retrofitting potential total [5]	Possible retrofit in 15 (20) years	Capacity demand in 2030 [44]	Additional capacity 15 (20) years
2021vd	18.4 GW	–	–	–
2022	14.7 GW	8.7 (10.8) GW	–	–
2023	14.6 GW	8.7 (10.3) GW	–	–
2024	14.5 GW	6.6 (10.3) GW	–	–
2025	13.9 GW	6.6 (10.3) GW	0 GW	0 (0) GW
2030	11.4 GW	2.7 (6.6) GW	9.7 GW	7 (3.1) GW

plant lifetime (20 years), which corresponds to a retrofitting potential of 6.6 GW in the same year. In addition, the required capacity in the greenhouse gas reduction strategies can theoretically be met by the gas-fired power plants that will be operating in 2030 via retrofitting. However, these potentials neglect the operation time of the power plants. To fill the gap between the required capacity and economically reasonable retrofitting potential, additional new hydrogen power plants must be commissioned for 2030. The costs for retrofitting turbine plants that were originally constructed for natural gas is given by a study from EUTurbines [14]. This study estimates that upgrading this type of plant would cost 20% of the original commissioning cost. Therefore, the total cost for retrofitting a certain capacity of power plants could be estimated to be between 270 and 1145 million € for Germany. It should be noted that this additional estimation is not based on literature data or statements from turbine manufactures, and more research in this area is needed to calculate a more accurate cost value. Furthermore, it must be emphasized that there is a possibility that current natural gas turbine plants will not perform in the same manner as newly built hydrogen ones. In addition to that, it is also not clear whether every current power plant will be equally able to be retrofitted, the economic feasibility of which depends on each power unit's current and future states. This question should also be addressed in further research. However, it should also be recognized that the potential of retrofitting old plants should not be neglected and can contribute to the preservation of controllable power plant capacity.

5. Conclusions

This study outlines how the fuel switch from natural gas to hydrogen affects investments in turbine power plant technology. The calculations for these relative cost increases were conducted for a standalone gas turbine power plant and a combined cycle one. This work provides a far-reaching overview of the technology of gas-fired power plants and evaluates in detail how hydrogen-based plants differ from conventional natural gas-fired ones. Evaluation of the existing literature, in conjunction with the chemical and physical properties of hydrogen as a fuel, demonstrates that in addition to the combustion system, the auxiliary and safety systems of a gas turbine plant must be adapted. Based on this literature research, investments in different types of hydrogen-based gas turbine power plants were determined in the course of a technical analysis at the component level.

Compared to the few existing studies, this work also advances statements regarding the cost increase of the different subsystems of a hydrogen gas turbine. The verification of the cost increase of the subsystems with those in the literature and from leading gas turbine manufacturers provides, for the first time, a well-founded cost analysis for future hydrogen turbine power plants. In addition, considering the influence of individual component categories enables further analysis by which the costs of hydrogen turbines can be even more precisely determined.

The main results of this study are the quantification of the effect from the fuel switch on the capacity-specific investment costs. These findings will provide a solid data basis for the classification of hydrogen gas power plants in future energy systems. The results of the detailed literature and technology analysis yield a cost increase of 8.5% for newly-commissioned hydrogen gas power plants.

Based on this value, it is clear that pure investment in the construction of power plants and the manufacture of the respective subsystems is not significantly more expensive than that of a conventionally-operated natural gas power plant. This leads to corresponding research priorities in the field of gas turbine power plants. On the one hand, the question of how these new hydrogen gas turbines are to be supplied with their fuel remains unanswered. Today's natural gas power plants are supplied via pipelines from the transport grid, and research assumes a similar scenario in future hydrogen power plants. However, the question arises as to when a similarly well-developed transport network for hydrogen will be available in Germany and Europe. In addition to investments, fuel costs and the corresponding fuel availability will be a decisive factor for the market penetration of energy supply technologies. In the future the energy system will consist of renewable energy sources like wind and photovoltaic plants. Due to their volatility flexibility options like storages and reconversion technologies are necessary. A possibility for these temporal system flexibilities are hydrogen gas turbines. Thus, these power plants will only operate in lulls with very little full load hours compared to today controllable power plants. The question therefore arises as to how the installed power plant capacity can be remunerated in order to make investment and operation possible and economically justifiable. As case study a potential analysis for Germany calculates the retrofitting potential of today's natural gas turbines for the use of hydrogen. For the year 2030, a total of 11.4 GW of the current power plant capacity remains available for retrofitting. Depending on the timeframe, a retrofit was found to still be economically reasonable when two additional potential values were calculated. In addition, it was found that the retrofit would cost about 20% of the original expenses. The total cost estimation for a retrofit could be calculated as being in the range of 270–1145 million €. However, these potentials and costs depend on the condition of each individual natural gas power plant and further research in this area is necessary.

The final question concerns the role of future hydrogen power plants in the energy system. Will these technologies be an integral part of the energy supply planning process, and how will these plants be financed in a changing electricity market? In addition to the techno-economic feasibility discussed in this publication, a market-based analysis of the energy economical operation and remuneration is necessary. These questions therefore form the starting point for new calculations and analyses. The answers to these will provide insight into the future use of hydrogen gas turbines in a low-carbon energy system.

CRediT authorship contribution statement

Patrick Freitag: Conceptualization, Formal analysis, Methodology, Project administration, Software, Visualization, Writing – original draft, Writing – review & editing. **Daniel Stolle:** Data curation, Software. **Felix Kullmann:** Project administration, Supervision, Writing – review & editing. **Jochen Linssen:** Supervision, Writing – review & editing. **Detlef Stolten:** Supervision, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix

Table 5
Technical data and characteristics of current gas turbines available on the market [18,33,42].

Manufacturer	Model	Frequency (Hz)	OCGT Power (MW)	OCGT Efficiency (%)	CCGT Power (MW)	CCGT Efficiency (%)
Mitsubishi	H-25	50/60	41	36.2	60–121	54–54.5
Mitsubishi	H-100	50	116	38.3	171–346	57.4–58
Mitsubishi	M701DA	50	144	34.8	213–645	51.4–51.8
Mitsubishi	M701G	50	334	39.5	498–999	59.3–59.5
Mitsubishi	M701F	50	385	41.9	566–1135	62–62.2
Mitsubishi	M701J	50	478	42.3	701	62.3
Mitsubishi	M701JAC	50	448	44	650	>64
Mitsubishi	M701JAC	50	574	43.4	840	>64
Mitsubishi	H-100	60	106	38.2	150–306	55.1–56.1
Mitsubishi	M501DA	60	114	34.9	167–506	51.4–51.8
Mitsubishi	M501F	60	185	37	285–572	57.1–57.3
Mitsubishi	M501G	60	268	39.1	399–801	58.4–58.6
Mitsubishi	M501GAC	60	283	40	427–1285	60.5–60.7
Mitsubishi	M501J	60	330	42.1	484–971	62–62.2
Mitsubishi	M501JAC	60	435	44	630–1263	>64
Siemens	SGT-A05	50/60	4–5.8	29.7–33.1	–	–
Siemens	SGT-A35	50/60	31.3–33	38.3–39.4	37.7–42.6	50.2–52.8
Siemens	SGT-50	50/60	2	26	–	–
Siemens	SGT-100	50/60	5.1–5.4	30.1–30.2	–	–
Siemens	SGT-300	50/60	7.9	30.8	–	–
Siemens	SGT-400	50/60	10.4–14.3	34.8–35.6	–	–
Siemens	SGT-600	50/60	24.5	33.6	36.5–74.2	50.7–51.6
Siemens	SGT-700	50/60	32.8–35.2	37.2–38	46.7–100	53.7–54.7
Siemens	SGT-750	50/60	39.8	40.3	52.1–104.8	53.9–54.1
Siemens	SGT-800	50/60	49.9–62.5	39.1–41.1	71.9–273	57.5–60.6
Siemens	SGT-A35	50	32.2–36.8	37.4–38.9	–	–
Siemens	SGT5-2000E	50	187	36.5	275–551	53.3
Siemens	SGT5-4000 F	50	329	41	485–970	61
Siemens	SGT5-8000H	50	450	>41.2	675–1350	62.4
Siemens	SGT5-9000 H L	50	593	>43	880–1760	>64
Siemens	SGT-A35	60	33–37.6	38.5–39.9	–	–
Siemens	SGT6-2000E	60	117	35.4	174–347	52.2
Siemens	SGT6-5000 F	60	215–260	39.5–40	328–790	60.4–60.7
Siemens	SGT6-8000H	60	310	>40.4	472–1422	61.9–62.1
Siemens	SGT6-9000 H L	60	440	>43.2	655–1310	>64
GE	LM6000	50/60	44.7–57.2	38.7–41.4	58.8–153.3	51.2–55.6
GE	6 B.03	50/60	45	33.4	70–141	51.9–52.4
GE	6 F.01	50/60	57	38	84–170	57.1–57.5
GE	6 F.03	50/60	88	36.8	135–272	56.9–57.4
GE	TM2500	50	34.6	34.9	49.2–99.2	49.7–50.1
GE	LM2500	50	22.2–36.3	34.4–38.5	33.3–103.3	49.6–55.1
GE	LM9000	50	72.3	40.8	95.7–192.8	54.1–54.6
GE	LMS100	50	106.5–113	42.6–43	127–269.7	51–51.5
GE	9 E.03	50	132	34.3	205–412	53.1–53.5
GE	9 E.04	50	147	36.9	218–439	55–55.3
GE	GT13E2-190	50	195	38.5	280–563	55.3–55.6
GE	GT13E2-210	50	210	38	305–613	55.1–55.5
GE	9 F.03	50	265	37.8	412–825	59.1–59.2
GE	9 F.04	50	288	38.7	443–889	60.2–60.4
GE	9 F.05	50	314	38.6	493–989	60.7–60.9
GE	9HA.01	50	448	42.9	680–1363	63.7–63.8
GE	9HA.02	50	571	44	838–1680	64.1–64.3
GE	TM2500	60	37	36.6	51.1–103.1	50.5–50.9
GE	LM2500	60	22.9–37.2	35.7–39.2	33.5–104.6	50.7–55.7
GE	LM9000	60	72.7	40.7	95.9–193.3	53.9–54.4
GE	LMS100	60	108–116	42.6–42.8	128–271	51.2–51.5
GE	7 E.03	60	90	33.8	140–283	52.4–52.9
GE	7 F.04	60	201	38.5	309–622	59.7–60.1
GE	7 F.05	60	239	38.5	379–762	60.2–60.5
GE	7HA.01	60	290	42	438–880	62.3–62.6
GE	7HA.02	60	384	42.6	573–1148	63.4–63.6
GE	7HA.03	60	430	43.3	640–1282	>63.9

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