vgbe position paper

H2-ready

September 2022

H_2 ready position paper

vgbe energy e.V. represents plant operators who use hydrogen in energetic processes. With the present position paper, the association brings the view of its member companies into the current debate on the definition of “H_2 readiness”.

Contents

1 Positions at a glance

The following positions are restricted only to systems for the energetic use of hydrogen for the generation of electricity and/or heat. The generation, transport and storage of hydrogen are not taken into account.

Energetic use of hydrogen currently not economical

The present position paper is focused on technical aspects, however, the economic viability and safeguarding of investments in such plants play a central role. Under current conditions, the operation of plants for the energetic use of hydrogen is not economical without additional funding and therefore requires supplementary financial support.

H_2 readiness means operation with 100 % hydrogen

A plant is considered H_2-ready if it can be operated 100 % with hydrogen during its lifetime – if necessary, in different retrofit steps. Other hydrogen-based or carbon-free energy sources (e.g. ammonia) are not covered by the present position paper.

H_2 readiness includes all options for energy use in new and existing plants – e.g., gas turbines, combustion engines, (industrial) boilers and fuel cells. The entire system has always to be considered and therefore the system boundaries have to be defined around the entire plant. In addition, reliable information is needed on whether hydrogen is supplied by blending it into the existing natural gas network (up to 100 %) or via separate networks.

H_2 volume share does not correspond to CO_2 savings

For realistic assessment of the decarbonisation effects resulting from the use of hydrogen, it is necessary to take into account the differences in the physical properties of natural gas and hydrogen. Different densities and calorific values mean that the H_2 volume share does not adequately represent decarbonisation. Therefore, the equivalence consideration via the heat input (thermal firing capacity – TFC) is a suitable measure of decarbonisation for equal plant output. For example, a share of 30 % hydrogen by volume in the fuel gas mixture corresponds to a share of 11.4 % of the firing thermal capacity leading to CO_2 savings of 11.4 %.

Licensing requirements have to be determined

The currently applicable legal requirements for plants using hydrogen as source of energy are partly unclear and are to be revised in the near future. Detailed requirements for such plants, e.g., with regard to emissions, have to be added as supplement or extension in the 13th and 44th Federal Immission Control Ordinances (BImSchV). The current regulations do not provide any uniform and meaningful specifications for the use of hydrogen in combustion plants with regard to emission limits. For example, when firing 100 % H_2, only the flue gas NO_x emissions and possibly ammonia concentration are relevant.

2 Scope and potential of decarbonisation

From the plant operators´ viewpoint, the definition for H_2 readiness covers all plant components and process steps that are necessary for operating the energy plant, as well as ancillary facilities that are spatially and operationally related to the plant components and process steps (see Figure 1)

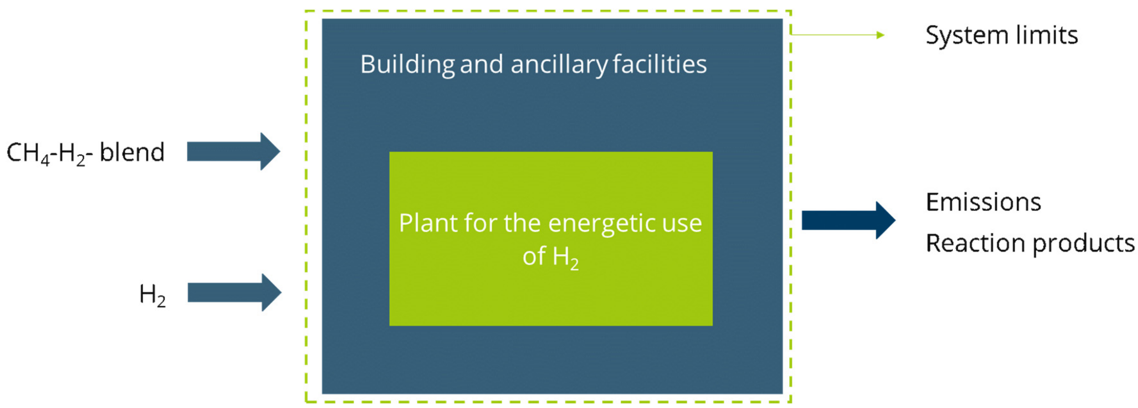


Fig. 1: System limits for the definition “H_2 ready”

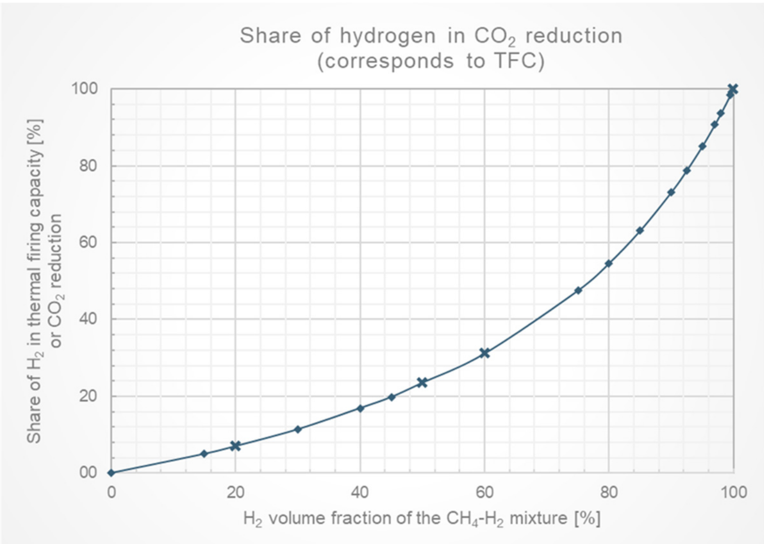
The natural gas-hydrogen blend or hydrogen is taken over at the interface between plant and gas grid. It is assumed that a maximum of 20 vol.-% H_2 (7 % TFC) can be added to the existing natural gas grid[1]. According to plant operators´ assumptions, the next step will be the implementation of 100 % hydrogen supply. If it is possible to supply both, i.e., a natural gas-hydrogen mixture and 100 % hydrogen, any mixing ratio between natural gas and hydrogen can be set within system limits with the aid of appropriate equipment.

[1] Deutscher Verein des Gas- und Wasserfaches e. V. (DVGW)-Merkblätter G 260 und G 650

The purity of hydrogen plays a subordinate role for energy use. The purity levels of 3.5 to 7.0 (99.95 % to 99.999990 %) that are common in industry can be used in the applications considered in the present position paper. The only exception is the application in fuel cells, which requires a minimum purity of 3.7 supplemented by the requirements of DIN EN 17124.

Decarbonisation through hydrogen

Hydrogen can be used energetically to reduce or avoid CO_2 emissions in electricity and heat generation. Hydrogen usually replaces natural gas, which consists mainly (> 80 % by volume) of methane and thus releases CO_2 during combustion. The different physical properties of H_2 and methane must be taken into account to determine the decarbonisation potential of hydrogen. In particular, the differences in density and calorific value mean that it is not possible to draw a direct conclusion about CO_2 reduction from the hydrogen content in % by volume. This relationship is illustrated Figure 2. It is revealed that hydrogen contents of less than 50 % by volume have only a relatively small influence on CO_2 reduction (compared to pure natural gas combustion).



H_2 volume fraction	[%]	0	20	40	50	60	80	100
Share of H_2 in TFC* or CO_2 reduction	[%]	0	7	17	24	31	55	100

*thermal firing capacity (TFC) is the heat supplied to a heat engine (e.g. a gas turbine or a gas engine) per unit of time.

Fig. 2: *CO_2 reduction depending on H_2 volume in the natural gas-hydrogen mixture, source: Freimark, M.; Gampe, U.; Buchheim, G.: Considerations on H_2 co-combustion in gas turbines, vgbe, 2022*

3 Definition of H_2 ready

A plant is considered H_2-ready if it can be operated 100 % with hydrogen during its lifetime – if necessary, in different retrofit steps. An admixture of up to 6 % TFC (approx. 17 vol.%) and of 25 % TFC (approx. 52 vol.%) are possible technical intermediate steps. It depends on the technology used and the economic efficiency whether one or more intermediate steps are sensible.

However, it can be assumed that without appropriate incentives, hydrogen, which is initially expensive, will be used primarily in sectors other than electricity and heat generation. Thus, only after a transitional period with an admixture of up to 6 % TFC (approx. 17 vol.%) in the existing natural gas network, fuel switching to 100 vol.% hydrogen can be expected. Regardless of the economic constraints, mixing devices located within system boundaries at an energy plant can produce – depending on availability – any natural gas-hydrogen mixture between 100 vol.% H_2 and 100 vol.% natural gas.

The following has to apply to **new built plants** that still operate, at least partially, with natural gas during a transitional period:

As far as allowed by the state of the art, plant design is to be laid out for 100 % H_2 operation or be retrofittable for this purpose. Currently, significant retrofitting costs for 100 % H_2 operation are to be expected, this even applies to new built plants. The effects of retrofitting in terms of investment, operating costs, electrical efficiency and emissions approval are to be considered in advance.

Basically, it is technically feasible to retrofit **existing plants**. However, any retrofit has to be assessed individually and compared with alternative new built plants.

The special safety-related properties of hydrogen and natural gas-hydrogen mixtures have to be taken into account during conversion.

Tab. 1: Safety properties of hydrogen and methane (as the main constituent of natural gas), source: GESTIS (Information system on hazardous substances of the German Social Accident Insurance) *database of substances and vgbe*

	Hydrogen	Methane
Lower explosion limit	4.0 vol.-%	4.4 vol.-%
Upper explosion limit	77 vol.-%	17 vol.-%
Ignition temperature	560 °C	595 °C
Density at 0 °C and 1 bar	0.0899 kg/m^3	0.7175 kg/m^3
Ratio of density compared to air	0.07	0.56
Minimum ignition energy	0.019 mJ	0.29 mJ
Explosion group	IIC	IIA
Tendency of flashback of flames	higher than with natural gas	-
Reactivity	higher than with natural gas	-
Change of temperature at isenthalpic relaxation	increase	decrease
Flame velocity	270 cm/s	30 cm/s
Lower Wobbe index s.t.p.	40.90 MJ/m^3	48.17 MJ/m^3
Lower heating value H_i	120 MJ/kg	50 MJ/kg
Specific mass of combustion air	0.286 kg/MJ	0.345 kg/MJ

	Hydrogen	Methane
Adiabatic combustion temperature for stoichiometric combustion (λ = 1) *	2,427 °C	2,274 °C
Mass fraction water vapour in humid flue gas (λ = 3)	8.09m %	4.26m %
Relative volume flow of combustion gas for equal TFC	330 %	100 %
Diffusivity	higher	-
NO_x emissions	higher	-
Leckage rate at given leakage (volume)	2.8	1

* Example for combustion air 20 bar/400°C, dry, 100% burnout, without fuel pre-heating

These properties require comprehensive adaption and/or review of all explosion protection measures when switching from natural gas to 100 % hydrogen. This, e.g., results in the following requirements:

- Unlike natural gas, H_2 accumulates in high points due to its lower density. Therefore, vent openings have to be arranged at the highest point.
- The wider explosion range (range between lower and upper explosion limit) and the lower density require explosion zones with larger dimensions.
- The significantly lower minimum ignition energy requires much more critical classification of electrostatic charges (equipotential bonding, earthing chain, leakage resistance including floor covering ≤ 10^8 Ω, etc.).
- For equipment protected against explosion, the modified explosion group has to be considered.

It also has to be taken into account that

- the hydrogen flame is hardly visible in daylight and can only be perceived by the development of heat,
- gas mixtures of hydrogen and air do not segregate due to gravity.

Mixtures of hydrogen and natural gas have to be considered separately. Natural gas-hydrogen mixtures up to 10 mol-% H_2 (approx. 3 % TFC, 10 vol.-% H_2) have already been investigated in the research project "Safety-related properties of natural gas-hydrogen mixtures" of the Federal Institute for Materials Research and Testing (BAM) [2]. It was shown that none of the investigated parameters is relevantly influenced in this range.

3.1 Materials and hydrogen

The special challenges posed by hydrogen make materials technology an important cross-sectional issue. Molecular hydrogen accumulates on steel surfaces without forming a protective oxide layer and dissociates there to form atomic hydrogen which then penetrates into steel structures. Such hydrogen accumulation in the metal structure leads to a change in material properties resulting in hydrogen embrittlement of the material, reduction of service life and possibly even failure of the component. Therefore, the choice of materials to be used in hydrogen applications is limited. Thus, when retrofitting existing systems, the type and condition of materials to be used are be thoroughly assessed. This also applies to sealing materials, since hydrogen can penetrate not only steel but also plastics to a greater extent.

The material-relevant experience in handling hydrogen, which is available extensively in other sectors such as the chemical industry, are being made usable for the energy industry by vgbe and its member companies. In addition, it is necessary to determine binding material parameters for the energetic use of hydrogen, including transport.

[2] Schröder, V. et al., Safety-related properties of natural gas-hydrogen mixtures, BAM, Final report on research project 2539, https://www.bgetem.de/redaktion/arbeitssicherheit-gesundheitsschutz/dokumente-und-dateien/brancheninformationen/energie-und-wasserwirtschaft/gasversorgung/abschlussbericht-zum-forschungsvorhaben-2539-sicherheitstechnische-eigenschaften-von-erdgas-wasserstoff-gemischen site visited on May 4, 2022

3.2 Gas turbines

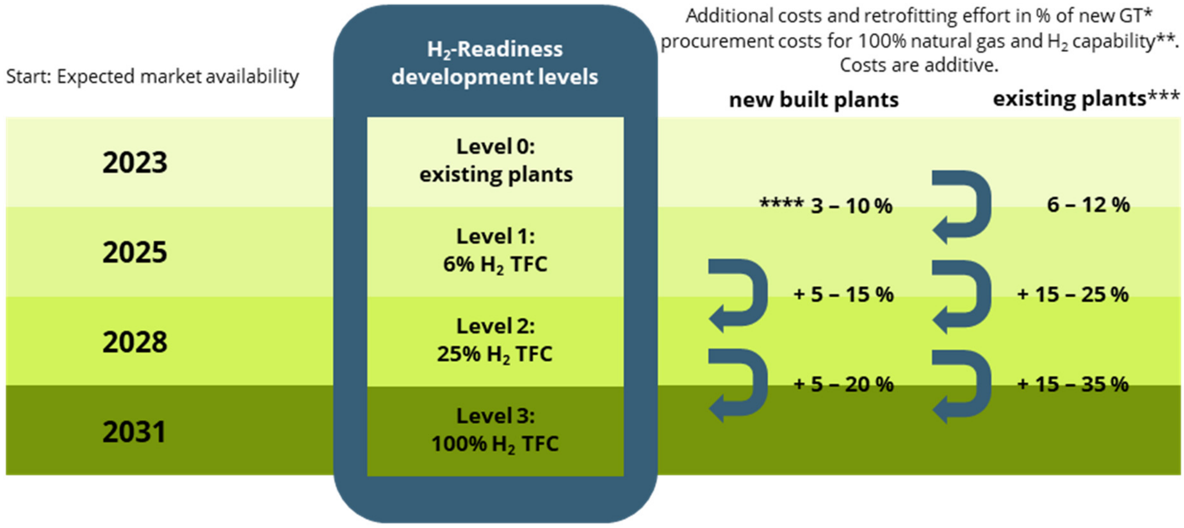
Existing gas turbine technology can be largely used for designing gas turbine plants (GTP) for H_2 combustion. It is not necessary to design and manufacture completely new gas turbines (GT) for H_2 firing. Upgrading of proven design concepts is suitable not only to avoid extensive capital expenditure in the transformation period, but also to save a lot of time when switching large fleets of existing gas turbines to H_2 operation[3].

These gas turbines have to be able to burn gas mixtures of natural gas and hydrogen in a wide range up to 100 % hydrogen and also tolerate rapid changes in the composition of mixtures. In addition to new plants, manufacturers are also to develop and offer conversion options for existing plants. Politics is to create appropriate funding to initiate the necessary technical development. Plants have to be classified according to the share of H_2 in the thermal firing capacity (TFC) in order to take into account the different levels of H_2 readiness and the amount of decarbonisation.

In the field of turbomachinery with hydrogen combustion, generally applicable regulations for design, material selection, etc. are almost not available in Europe. Such regulations have to be drawn up in the near future. Until then, the rules and regulations of the American Petroleum Institute (API) are an alternative.

Due to the as yet unforeseeable availability of H_2 and the combustion technology that is also not yet available on the market, a leap from 0 to 100 % hydrogen does not appear to be expedient. Staged fuel switching with regard to the portion of H_2 is therefore considered sensible, both for new plants and for conversion solutions in existing plants.

[3] Freimark, M.; Gampe, U.; Buchheim, G.: Considerations on H_2 co-combustion in gas turbines, vgbe, 2022



* The scope of retrofitting refers to the retrofitting of all components necessary for operation, but the cost reference is the gas turbine as core component

** A pre-planned modular design of the ancillary systems can significantly reduce retrofitting costs for new plants (H_2 capability)

*** In many cases, retrofitting existing systems can make much more economic sense, even if measures to extend the service life, etc. still have to be carried out on the GTP

**** Additional costs for H_2 capability

Fig. 3: Development levels of H_2 readiness for gas turbine plants

A standard-design GT of equal performance for natural gas operation is the basis for cost analysis, which is subject to great uncertainties.

In many cases, retrofitting of existing systems can make much more economic sense, even if measures for extending the GT service life, etc. still have to be taken.

The most important aspects of the individual systems of gas turbine plants in connection with H_2 readiness are listed below – further details can be found in the vgbe Factsheet "H_2 readiness of gas turbine plants".[4]

- **Gas supply:** In order to enable continued operation of as many existing plants as possible, the initial admixture of H_2 into the existing natural gas network should not exceed a share of H_2 in the TFC of 3 % (corresponds to approximately 9 vol.-% H_2) and, if necessary, 6 % (corresponds to approximately 17 vol.-% H_2) in a second step.
- **Fuel gas system:** Depending on the amount of H_2 to be admixed, the fuel gas system has to be upgraded for increased fuel gas volume flow – factor 3.3 > – and changed material stresses.

[4] vgbe Factsheet "H_2 readiness of gas turbine plants", vgbe, 2022

- **Combustion system and gas turbine:** For Level 1 (natural gas with H_2 TFC content of up to 6 %, see Figure 3), burners are to be provided that can be replaced as part of an upgrade for Level 2 (approx. 6 % to approx. 25 % H_2 TFC content, see Figure 3) without any significant change to the combustion chamber. Level 3 (from approx. 25 % H_2 TFC, corresponding to approx. 52 vol.% H_2, see Figure 3) requires replacement of the burners according to state-of-the-art combustion technology and, if necessary, also replacement of the combustion chamber by an enlarged version with adapted cooling concept. The flame monitors have to be suitable for both: 100 % natural gas and 100 % hydrogen firing (depending on the level of readiness). Operation with 100 % natural gas to 100 % H_2 has to be possible without any load restrictions.
- At Level 3, i.e., with a high H_2 content of up to 100 %, the injection of water or steam into the combustion chamber is considered a possible alternative to catalytic flue gas cleaning. This applies in particular to gas turbines with few operating hours.
- **Waste gas system, including heat recovery steam generator:** Increased steam loading requires thorough considerations for downstream heat exchangers and heat recovery steam generators regarding the influence of possible condensates due to changed dew point on associated heating surfaces.
- **Control technology and machine protection:** In principle, the architecture of power and speed control of the gas turbine does not require any conceptual changes.
- **Fire and explosion protection:** The entire explosion protection concept needs to be adapted.
- **Conversion of existing plants:** Up to a level of admixture of approx. 3 % H_2 TFC, most plants only need marginal or no conversion at all. Up to 6 % H_2 TFC, conversion is normally possible without any problems. However, the specific configuration is always decisive and has to be assessed individually. Between 6 to 25 % H_2 TFC, conversion is technically possible in most cases. From 25 % H_2 TFC, conversion may only be possible with great efforts – e.g., new burner technology has to be retrofitted.
- When determining the NO_x limiting values for H_2 combustion, the technical feasibility of retrofitting existing plants (e.g. installation of catalytic converters) and the expected full-load utilisation hours are to be taken into account.

3.3 Gas engines

State-of-the-art gas engines, which are based on natural gas as design fuel, cannot be switched to pure hydrogen combustion without appropriate modifications, which results in limitations. However, it is possible to adapt the engine technology to hydrogen operation. To this end, the following measures have to be taken in particular:

- Adaption of the burner procedure/combustion chamber
- Adaption of the safety concept
- Modification of gaseous components (fuel systems, pipe and tube system etc.)

Maturity of technology is expected as of 2025 which allows the use of larger hydrogen engines (approx. 10 MW range) in pilot applications. A broad series application is foreseeable as of 2028. Within this time frame, it will also be possible to convert corresponding engine systems.

A lot of state-of-the-art gas engines are already suitable for operation with up to 7 to 9 % TFC (20 to 25 % by volume) H_2. Depending on the type and equipment of the gas engine plant, minor modifications may be necessary. If engines are to be operated in dual-fuel mode in the future, i.e., either 100 % natural gas or 100 % hydrogen, it is to be taken into account that the efficiency will be lower than with an engine designed and optimised for just one fuel.

3.4 Industrial boilers

New boiler plants should be able to burn mixtures with 6 % TFC (17 vol.%) H_2 without requiring any further adaptations. In addition, these plants are to be designed in such a way that they can deal with higher hydrogen contents without major constructional and engineering adaptations.

The maximum possible admixture for existing plants is estimated at approx. 25 % TFC (52 vol.%) H_2 – however, it may differ from plant to plant. If retrofitting is needed, the focus is to be on combined heat and power plants.

For new and existing plants, the following issues are to be considered with regard to H_2 readiness:

- For boiler plants, the admixing of H_2 into the existing natural gas grid is also to be limited in a first step; for example, to 6 % TFC (17 vol.%) of H_2.
- It is to be proven that the heating surfaces are designed for higher flue gas volumes and modified heat release, or in the case of existing installations, that the heating surfaces are sufficiently dimensioned.
- Avoidance or reduction of combustion chamber pulsation (this also applies to GT).
- Application of H_2-low-NO_x burners and special ignition burners (this also applies to GT).
- Application of suitable materials in flue gas duct if temperatures fall below dew point.
- Handling of nitrous oxide (N_2O) and its recording by measurement (this also applies to GT).
- Avoidance and minimisation of ammonia slip upon the application of catalysts.
- Specifications for determining emission limit values in the case of mixed firing by taking into account technical options and changing flue gas composition (this also applies to GT).
- Application of H_2-adopted safety and monitoring engineering.
- Avoidance of explosion zones in boiler house.

3.5 Fuel cells

The Proton Exchange Membrane Fuel Cell (PEMFC) is the most promising technology which is currently available up to 1 MW_{el} (technology readiness Level 8: corresponds to the last stage of complete market maturity). This type of fuel cell is designed for 100 % hydrogen, i.e., the criteria for H_2 readiness are fully met. For the market ramp-up of the hydrogen economy, PEMFCs play a subordinate role – especially due to their limited capacity. In a future 100 % hydrogen system, however, this technology and fuel cells in general have the potential to play an important part, as efficiencies of up to 90 % appear possible with simultaneous use of electricity and heat.

In the case of fuel cells, special requirements concerning the purity and quality of hydrogen also have to be taken into account.

3.6 Emissions from thermal use

In the case of 100 % H_2 combustion, locally increased combustion temperatures result in increased NO_x emissions and higher water vapour in the flue gases.

Currently it is common practice to relate all limit values to a dry reference state. In the case of hydrogen combustion, this approach reaches its limits, since the main waste gas components are water vapour, N_2 and NO_x (in gas turbines also approx. 13 % O_2). Due to increased water vapour, the NO_x emissions are too high if calculated as “dry”.

NO_x emission limit values for 100 % H_2 combustion in gas turbines are not included in the 13th BImSchV (Federal Immission Control Act) for combustion plants. Instead, these values are to be determined on a case-by-case basis by the responsible authority. For other types of installations covered by the 13th BImSchV and for medium-sized combustion installations under the 44th BImSchV, the requirements for “other gases” apply when firing hydrogen. However, these values do not adequately take into account the special features of hydrogen combustion. Thus, hydrogen combustion is to be considered in the amendments to the European Industrial Emission Directive (EU IED), which are already under way, as well as in the associated BAT (Best Available Technology) Reference Documents and BAT conclusions with requirements properly tailored to hydrogen combustion. It is indispensable to establish suitable hydrogen-specific NO_x limit values at European level in the amended EU IED and the MCP (Medium Combustion Plant) Directive, which is still to be revised, as well as in the national implementation in the 13th and 44th BImSchV as vital basis for decision-making in connection with upcoming investments in new plants and modernisation and upgrading/retrofitting of existing plants.

Appropriate, staged NO_x limit values should be developed for the phase of transition from natural gas to hydrogen combustion. Furthermore, a limit value for carbon monoxide (CO) is to be defined in order enable flexible plant operation up to corresponding minimum load points. When setting the NO_x limit values, the classification used for gas turbine plants in the EU IED is to be applied according to the annual operating hours (less than 500, 500 to 1,500 and more than 1,500).

Especially for installations with less than 1,500 annual operating hours and increased start-ups, a pollutant content rule should be considered, i.e., the absolute emission quantities/a are fixed thus allowing for a certain degree of flexibility with regard to the limit values.

Existing and new plants have to be assessed differently. In most cases, it will be impossible to retrofit existing plants with DENOx devices due to the design of the heat recovery steam generators or boiler houses. Practicable and economically feasible limit values have to be determined in order to ensure continued use of existing plants.

Until hydrogen supply to power plant sites will be secure and safe, new plants erected in accordance with H_2 readiness or existing plants retrofitted for this purpose, have to be able to be safely and securely operated with 100 % natural gas and 100 % hydrogen as well as variable mixed operation.

4 Perspective

vgbe and its member companies are convinced that hydrogen, which is produced climate-neutrally, will play a central role as a universal source of energy in the energy system of the future. Therefore, the association supports the goals formulated at national and European level for the expansion of the hydrogen economy.

With the present position paper, vgbe outlines the technical, economic and regulatory challenges which exist for the thermal use of hydrogen from the viewpoint of energy plant operators. The members of vgbe energy e.V. are already implementing or planning hydrogen utilisation projects. Therefore, they are very interested in actively shaping the further technical development and the regulatory framework in cooperation with all stakeholders of the energy industry.

The main positions of vgbe with regard to the thermal use of hydrogen can be summarised as follows:

1. A plant is considered H_2 ready if it can be operated at 100 % with hydrogen during its service life – if necessary in various retrofitting steps.
2. The use of hydrogen is technically possible in gas turbines, engines and industrial boilers as well as in fuel cells. The economic viability of such plants cannot be demonstrated yet.
3. Higher NO_x emissions are to be expected from hydrogen combustion than from natural gas combustion. This circumstance should be taken into due account with practicable specifications for the approval and promotion of plants.
4. Materials requirements have to be transferred and defined in German regulations and any data gaps have to be filled.

About vgbe energy e.V.

vgbe energy e.V. is the international technical association of energy plant operators. Its members are companies that operate plants for power, heat and cooling generation, energy storage and sector coupling worldwide. Currently vgbe comprises 436 member companies located in 34 countries. The present installed plant capacity of vgbe member companies amounts of over 300 GW.

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