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Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems

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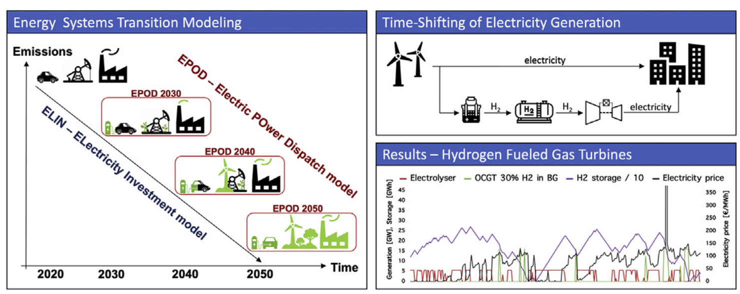
HIGHLIGHTS

- Hydrogen gas turbines competitive mainly in energy systems constrained to low levels of carbon dioxide emissions.
- Low mixing ratios of hydrogen in biogas found to be the most competitive option.
- Operation pattern of hydrogen gas turbines is highly dynamic with respect to a high number of start-stop cycles.
- The competitiveness of hydrogen gas turbines is significantly decreased if other flexibility measures are available.

GRAPHICAL ABSTRACT



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ABSTRACT

Hydrogen is currently receiving attention as a possible cross-sectoral energy carrier with the potential to enable emission reductions in several sectors, including hard-to-abate sectors. In this work, a techno-economic optimization model is used to evaluate the competitiveness of time-shifting of electricity generation using electrolyzers, hydrogen storage and gas turbines fueled with hydrogen as part of the transition from the current electricity system to future electricity systems in Years 2030, 2040 and 2050. The model incorporates an emissions cap to ensure a gradual decline in carbon dioxide (CO_2) levels, targeting near-zero CO_2 emissions by Year 2050, and this includes 15 European countries.

The results show that hydrogen gas turbines have an important role to play in shifting electricity generation and providing capacity when carbon emissions are constrained to very low levels in Year 2050. The level of competitiveness is, however, considerably lower in energy systems that still allow significant levels of CO_2 emissions, e.g., in Year 2030. For Years 2040 and 2050, the results indicate investments mainly in gas turbines that are partly fueled with hydrogen, with 30–77 vol.-% hydrogen in biogas, although some investments in exclusively hydrogen-fueled gas turbines are also envisioned. Both open cycle and combined cycle gas turbines (CCGT) receive investments, and the operational patterns

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show that also CCGTs have a frequent cyclical operation, whereby most of the start-stop cycles are less than 20 h in duration.

Introduction

In order to be in line with the Paris Agreement [1] and to mitigate anthropogenic climate change, an increased share of variable renewable electricity (VRE) generation is needed, which will present challenges for the electricity system given that supply and demand are required to be in equilibrium at all times. Consequently, with an increasing proportion of VRE, the value of flexible and dispatchable power-generation technologies will increase, although these technologies will have to be low-carbon or zero-carbon emitting types.

While gas turbines can provide flexible and dispatchable power generation, they are currently using mainly natural gas as fuel. Although natural gas-fired gas turbines have relatively low levels of emissions compared to coal-fired power plants, especially when applied in combined cycle (CCGT) arrangements, emissions from gas turbines still need to be reduced further in order to meet the terms of the Paris Agreement, which mandates carbon-neutrality by mid-century. This has been emphasized by the European Investment Bank (EIB), which in its climate strategy in 2019 stated that they would no longer fund new projects with unabated fossil fuels, starting at the end of 2021 [2]. Thus, the EIB will no longer grant funding to power generation plants that exceed 250 gCO_2/kWh_{el}, which is significantly lower than the previous limit of 550 gCO_2/kWh_{el}. An emissions limit of 250 gCO_2/kWh_{el} eliminates the use of coal as fuel (without carbon capture and storage; CCS), as well as the use of natural gas-fired CCGTs; with an assumed efficiency of 60%, the latter would have emissions of around 330 gCO_2/kWh_{el}.

Since further reductions in carbon emissions from gas turbines achieved through improvements in the thermal efficiency will be marginal for thermodynamic reasons, drastic cuts in emissions can only be achieved by fuel switching or applying CCS. There are several options for decarbonized fuels, such as biogenic synthetic natural gas (SNG) and bio-oil. However, it seems unlikely that just one fuel will be competitive in this context, and there is also the possibility that gas turbines will be able to use several fuels and fuel mixes [3,4]. In addition, much attention is currently focused on hydrogen as an energy carrier and as a means to decarbonize hard-to-abate sectors, as well as on its potential as a provider of flexibility to systems with large-scale employment of VRE. This assumes that the hydrogen is produced by electrolyzers operated in accordance with the availability of VRE generation in combination with hydrogen storage. Thus, the use of hydrogen in gas turbines can be regarded as a way to time-shift electricity generation, and the value of such time-shifting will increase with an increased share of VRE.

Previous studies reported in the literature examining the role of hydrogen in the energy system have included: detailed combustion studies to investigate the effect on flame stability; investigations of the technical impacts of blending hydrogen into the combustion process in gas turbines; and examinations of the role of hydrogen in future energy systems in general. The blend-in of hydrogen in gas turbines affects the stability of the flame because hydrogen changes the combustion chemistry. The effect on flame stability has been studied by several groups, underlining the importance of this factor. Liu et al. [5] have concluded that hydrogen-enriched methane significantly influences the flashback limits, especially for so-called Π-shaped flames. An et al. [6] have investigated flame stability during the flame shape transition for different shares of hydrogen, and conclude that flame blow-out is a risk during the transition between flame shapes. Li et al. [7] have investigated the flame stability of hydrogen-enriched syngas, finding a reduced flame stability at 50 vol.-% hydrogen. Zhang et al. [8] have studied the effects on thermoacoustic instability of hydrogen-methane blends and conclude that most experimental measurements indicate instabilities for mixing ratios above 25 vol.-% hydrogen. Yet, Ciani et al. [9], who modeled a concept that involved staged combustion, have concluded that 50 vol.-% hydrogen can be mixed in methane without derating the power output. In a separate study, Bothien et al. [10] confirmed the results of Ciani et al. [9] in a test facility, and concluded that stable combustion can be attained with up to 70 vol.-% hydrogen using staged combustion, and at levels >70 vol.-% only minor reductions in power output are expected. Similar results were obtained by Magnusson et al. [11], who successfully performed a test with a complete gas turbine ("full engine test") with 60 vol.-% hydrogen while maintaining stable combustion and nitrogen oxide (NO_x) emissions at <25 parts per million (ppm). In addition, gas turbine suppliers have stated that mixing ratios of up to 60 vol.-% are currently possible in some of their gas turbines, with some suppliers aiming to increase this to 100 vol.-% hydrogen according to a report by a gas turbine manufacturer association [12]. The combustion process and flame stability are essential for a gas turbine to function. Therefore, more-detailed investigations are required to understand fully hydrogen-enriched combustion. Despite the claims of mixing ratios of 60 vol.-% up to 100 vol.-% from manufacturers, the actual experience with using hydrogen in gas turbines with conventional pre-mixed combustors for longer time periods has so far been limited to lower shares of hydrogen, e.g., 12 vol.-% hydrogen, which has been fed to a gas turbine for 18,000 equivalent operating hours, as reported by Bonzani et al. [13]. From the above-described studies and industrial statements and experiences, we suggest that gas turbine technologies currently under development will be able to use fuels with high shares of hydrogen – or even 100% hydrogen. High mixing rates are a prerequisite for gas turbines to act as a feasible technology in a low-carbon future energy system. This is because low mixing rates, e.g., 12 vol.-%, have a limited impact on carbon emissions, as they are reduced only by about 4%, corresponding to a reduction from 330 to 316 gCO_2/kWh_{el}, which is far less than what is mandated by the new directives from the EIB. For such a CCGT plant to reduce emissions to <250 gCO_2/kWh_{el}, the mixing ratio would have to be at least 51 vol.-% hydrogen, and to reach climate neutrality the use of a complementary carbon-neutral fuel, if not using 100% hydrogen, would obviously be required unless, as mentioned above, CCS would also be applied.

The role of hydrogen in the energy system has been studied previously from various perspectives. Some studies have focused on hydrogen generated from renewable electricity as a means to replace natural gas or other fossil fuels in the energy system. A shared feature of such studies is SNG production via methanation, which has been studied by, for example, Becker et al. [14] and Gorre at al [15]. The production of SNG, however, requires a source of CO_2, and in those studies, the CO_2 was captured from fossil-derived exhaust gases, which meant that the produced SNG had a limited positive climate impact, given that fossil-derived CO_2 is emitted when the SNG is utilized.

Another possibility for utilizing hydrogen to reduce emissions when using natural gas is to incorporate the hydrogen into the existing natural gas network. This aspect has been studied by Guandalini et al. [16,17], who aimed to improve the profitability of wind power by feeding into the natural gas grid hydrogen that was generated through the electrolysis of surplus electricity, and by Ferrero et al. [18], who evaluated the cost for grid injection. The mixing in these studies is, however, exclusively with natural gas, and since there is an estimated upper limit of mixing of 20 vol.-% hydrogen in the current natural gas infrastructure [19], such blend-in levels are simply not adequate to achieve sufficiently low CO_2 emissions for gas turbines, as mentioned above.

In addition, Ferrero and coworkers have studied the cost of time-shifting electricity generation using electrolyzers, hydrogen storage, and the reconversion of hydrogen to electricity in fuel cells (FC), which has also been studied by Fang et al. [20] and Ishaq et al. [21]. Reconversion pathways for hydrogen that specifically include gas turbines have been studied by Welder et al. [22], who have evaluated four different reconversion technologies [open cycle gas turbine (OCGT), CCGT, FC and gas engine], all fed with 100% hydrogen generated by electrolysis, so as to enable a 100% renewable energy system in northwestern Germany in a Year 2050 scenario. The results indicate a cost benefit in favor of CCGTs over FC and gas engines. However, as the reconversion technologies are not evaluated simultaneously, but rather in separate model runs, the results do not capture how the different reconversion technologies could complement each other based on their different technical and economic characteristics. Jülch et al. [23] have also included CCGTs fed with 100% hydrogen as a reconversion technology when comparing the levelized cost of storage (LCOS), in a study in which they have also included CCGTs fueled with SNG, batteries, compressed air energy storage, and pumped-hydro energy storage. The results show that CCGTs fed with hydrogen have a lower LCOS than CCGTs fed with SNG, in terms of both long-term and short-term storage. The work of Jülch et al. [23] is, however, not based on an optimization model that includes all the technologies simultaneously, and thus (similar to the work of Welder et al. [22]), the interactions between the different technologies are not captured. Cloete at al [24]. Investigate the utilization factor of different technologies in a future German energy system where hydrogen is used both in industrial processes and as energy storage in the electricity system. Their work includes hydrogen-fueled gas turbines, although no analysis of their operation or competitiveness is performed.

In addition to the problematic approach of evaluating technologies individually, most of the studies in the literature are limited in terms of geographic scope, with consequences for the flexibility obtained from trade with surrounding regions. Moreover, most of the studies place emphasis on describing a system that complies with a final state that is in line with defined targets, neglecting development over time, i.e., the transition from the present electricity system into a future system that complies with the Paris Agreement. Furthermore, there are other unexplored factors that may exert significant influences on the value of hydrogen gas turbines, for instance the implications and potential synergies of hydrogen infrastructures built for other purposes, e.g., hydrogen infrastructures installed for producing fossil-free steel, for industrial clusters, and for the transportation sector.

In summary, gas turbine technologies are currently available and represent mature technologies with the technical capabilities to support VRE generation. By substituting fossil-derived natural gas with an energy carrier such as hydrogen, this technology could continue to be an attractive low-carbon alternative to balance the power generation in future energy systems. The aim of the present study is to investigate the conditions under which it can be competitive to use hydrogen produced from electrolyzers as the fuel in gas turbines. Towards this end, the following questions are addressed:

- What is the role of hydrogen-fueled gas turbines, operated fully or partly with hydrogen, in future electricity systems that are compliant with mid-century carbon mitigation goals and with the Paris Agreement?
- How would increased utilization of hydrogen in other sectors, here exemplified by an industrial hydrogen demand combined with hydrogen storage for flexibility, affect the competitiveness of hydrogen-fueled gas turbines in the electricity system?
- In what ways is the need for hydrogen-fueled gas turbines affected by the presence of other forms of flexibility (shifting of electricity use), in this work represented by vehicle-to-grid (V2G) capabilities?

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Method

The present study assesses the potential integration of hydrogen-fueled gas turbines into the European electricity system, which is analyzed using two techno-economic optimization models: the long-term investment model ELIN; and the operational dispatch model EPOD. The ELIN model, originally developed by Odenberger et al. [25] and further developed by Göransson et al. [26], is a cost-minimization model that analyzes the transition of the European electricity system, starting from the current energy system and investing in new electricity generation as present electricity generation technologies are phased out as they reach the end of their assumed technical lifetimes until Year 2050, while meeting specified constraints, such as emission trajectories for CO_2. The EPOD dispatch model, originally developed by Unger et al. [27] and further developed by Göransson et al. [26] and Goop et al. [28], is fed the results from the ELIN model, e.g., installed capacity for different years, fuel prices, and transmission capacity between regions, which are used in EPOD to identify the least-cost hourly dispatch of the power system.

The ELIN model takes its departure from a description of the currently installed capacity, including power plant age structure and cross-border interconnectors, which under assumptions regarding the technical lifetimes of power plants, allows for investigations of the development over time and the transition from the present system to a future system. As their technical lifetimes expire, existing power plants will be replaced by new-generation capacity that is suited to the new requirements of the system. Furthermore, the inclusion of presently available power plants facilitates estimations of the potential benefits of measures implemented in the existing power plant stock, such as fuel switching. The present capacity mix, which is an input to the model, is retrieved from the Chalmers Energy Infrastructure databases [29], which have almost full coverage of power plants with a rated electric capacity >10 MW.

The investment options in ELIN include onshore and offshore wind power, solar power, heat pumps, batteries, electrolyzers, hydrogen storage (compressed hydrogen in lined rock caverns), and different types of thermal generation using different types of fuels (for a full overview of the available power plant options, see Table A.1 in Appendix A). The wind and solar profiles are based on MERRA meteorological data, whereby the level of generation is calculated based on the work of Mattsson et al. [30]. Investments in hydrogen gas turbines, which are introduced in EPOD in the present study, are described in Section Hydrogen-fueled gas turbine implementation in EPOD. In addition to electricity generation and energy storage, the model also includes investments in transmission capacity between regions.

The hourly based demand profiles are obtained from the European Network of Transmission System Operators for Electricity, ENTSO-E [31], and the annual electricity demands for the Years 2020, 2030, 2040 and 2050 are taken from the work of Unger et al. [32]. The hourly demand profiles and annual electricity demand are described further in Section Scenarios.

The ELIN-EPOD modeling package has been used to investigate different research topics, such that this study builds upon and benefits from previous results [33–35]. Thus, to compare the competitiveness levels of hydrogen-fueled gas turbines and other potential flexibility measures, which relates to the third research question above, we have used a model version that includes a representation of electric vehicle (EV) transportation through smart charging and/or V2G, as described and developed by Taljegård et al. [33], and the additional emerging hydrogen demand from industry, including flexibility in the form of hydrogen storage. Thus, while this industrial hydrogen demand is assumed to remain constant over time, to minimize the system cost for supplying the exogenously defined hydrogen demand, investments in both electrolyzers and hydrogen storage are accounted for in ELIN.

The geographic scope of the model framework covers the EU26[1],[2], Switzerland (CH), The United Kingdom (UK) and Norway (NO), and the sub-regions of each country are defined in terms of European statistical NUTS-regions [36] and by electricity transmission bottlenecks in the current European transmission system, as shown in Fig. 1. Both ELIN and EPOD have perfect foresight, which means that all time-steps, in ELIN as well as in EPOD, are solved with full knowledge of all the other time-steps. In addition, technologies are represented as aggregates, which means that all plants that have the same technology, fuel use and efficiency within a region are considered as a single unit.

To ensure reasonable computational times while including the multitude of demand and supply situations in the power system, which are mainly due to variations in demand and VRE generation, the ELIN model applies a method that employs representative days to limit the number of time-steps in the analysis. This method has been developed by Nahmmacher et al. [37] and previously used by Lehtveer et al. [38] and Taljegård et al. [33]. In the present work, the intra-year time-steps are based on 30 representative days with an intra-day time resolution of 3 h, yielding a total of 240 time-steps, which is more than the 160–200 time-steps recommended by Reichenberg et al. [39] to achieve a 10% accuracy level in representing the VRE capacity. However, using this method makes it problematic for the model to reflect the true value of the energy storage between time-steps, since the time-steps are no longer in consecutive order. This poses a problem when introducing hydrogen-fueled gas turbines which, as mentioned above, are part of a storage system (electricity to hydrogen to electricity) that is able to store electricity (as hydrogen) for long periods of time (days, weeks or even months). This limitation has been highlighted previously by Lehtveer et al. [38]. To mitigate the implications of such limitations in this work, we allow complementary investments in hydrogen

[1] Austria (AT), Belgium (BE), Bulgaria (BG), Czech Republic (CZ), Denmark (DK), Estonia (EE), Finland (FI), France (FR), Germany (DE), Greece (GR), Hungary (HU), Ireland (IE), Italy (IT), Latvia (LV), Lithuania (LT), Luxembourg (LU), The Netherlands (NL), Poland (PO), Portugal (PT), Romania (RO), Slovakia (SK), Slovenia (SI), Spain (ES) and Sweden (SE).

[2] Excluding the islands of Malta and Cyprus.

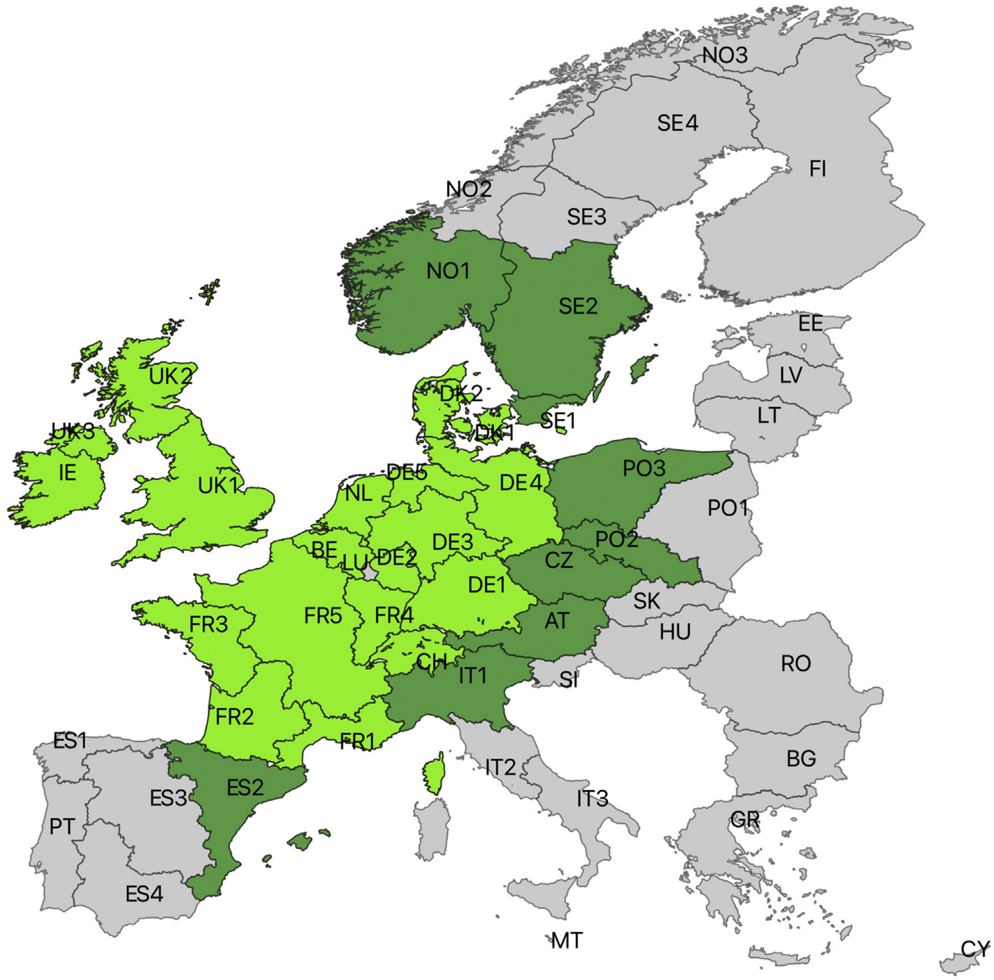

Fig. 1 – Regions in the ELIN-EPOD model package. The bright-green and dark-green regions are included in the present work, although only the bright-green regions are analyzed in the Results section. The peripheral regions in gray are excluded due to constraints related to computational capacity. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

gas turbines, electrolyzers and hydrogen storage in the EPOD model, where all the time-steps over the year are included and are place in consecutive order; thus, the value of energy storage and time-shifting of generation can be captured.

Hydrogen-fueled gas turbine implementation in EPOD

Investments in EPOD can be made in new hydrogen-fueled gas turbines or used to upgrade already existing gas turbines, fueled either with natural gas or biogas, to make them hydrogen-compatible. The investment options, for both new and upgraded units, include mixing ratios of 30, 50, 77 and 100 vol.-% of hydrogen, and the mixing ratios are fixed, meaning that a gas turbine in operation must be supplied with the hydrogen share that is coupled to the investment decision. Regarding the mixing ratio, it should be noted that the volumetric mixing ratio deviates significantly from the corresponding energy share from hydrogen, as shown in Table 1. In addition, complementary investments are allowed in the main competitors for hydrogen-fueled gas turbines, i.e., biogas-fueled gas turbines and gas turbines with CCS, as displayed in Table 2. Investments in electrolyzers and hydrogen storage (lined rock caverns) are also allowed.

Table 1 – The corresponding volume and energy shares for the different mixing ratios of hydrogen in methane.

Volume share H_2 [%]	Energy share H_2 [%]
30	11
50	23
77	50
100	100

The investments in EPOD have perfect foresight within the year evaluated (2030, 2040 or 2050). However, the investment made in one year does not influence the complementary investments in any of the other years, as the modeled years are separated from each other, in contrast to the situation in the investment model ELIN. In this context, the main economic

Table 2 – The available electricity generation technologies for investments in the EPOD model. The fuels are natural gas (NG), biogas (BG) and hydrogen (H2), where NG-H2 and BG-H2 indicate mixtures of natural gas or biogas with hydrogen.

Technology	Fuel	H_2 mixing ratio [vol.-%]	Upgrade	New	CCS
OCGT	BG	0	No	Yes	No
	NG-H2/BG-H2	30/50/77	Yes		
	NG-H2/BG-H2	100	Yes	No	
	H2	100	No	Yes	
CCGT	NG	0	No	Yes	Yes
	BG				No
	NG-H2/BG-H2	30/50/77	Yes		
	NG-H2/BG-H2	100	Yes	No	
	H2	100	No	Yes	

and technical differences between OCGT and CCGT are that the investment cost for an OCGT is approximately half that for a CCGT, whereas the electrical efficiency at nominal load is significantly higher for a CCGT, at about 60%, compared to 40% for an OCGT. The efficiency is, however, reduced during part-load operation, particularly for OCGTs. The start-up time is also a parameter that characterizes the two technologies; in the model, it is set to zero hours for OCGT and 6 h for CCGT.

The original formulations of the objective functions for both ELIN and EPOD are described in Appendix B. Equation (1) provides the updated objective function for EPOD, which allow for the above-mentioned new investments:

$$minC_{tot} = \Sigma_{i\in I}\Sigma_{p\in P}\Sigma_{t\in T}\left(c^{run}_{i,p,t}\cdot g_{i,p,t} + c^{cycl}_{i,p,t}\right) + \Sigma_{i\in I}\Sigma_{p\in P}C^{fix}_{i,p}\cdot x_{i,p} + \Sigma_{i\in I}\Sigma_{p^{new}\in P}\left(C^{inv}_{i,p^{new}}\cdot i_{i,p^{new}} + C^{fix}_{i,p^{new}}\cdot i_{i,p^{new}}\right) \quad (1)$$

where

C_{tot} is the total system cost.

I is the set of all regions.

P is the set of all technology aggregates.

P^{new} is a sub-set of P that includes all new technology aggregates available for investments in EPOD.

T is the set of all time-steps.

$c^{run}_{i,p,t}$ is the running cost of region i, with technology aggregate p at any time-step t.

$g_{i,p,t}$ is the electricity generation in region i, technology aggregate p and time-step t.

$c^{cycl}_{i,p,t}$ is the cycling cost in region i, with technology aggregate p at any time-step t.

$C^{inv}_{i,p}$ is the annualized investment cost of technology aggregate p in region i.

$C^{fix}_{i,p}$ is the fixed operational and maintenance cost of technology aggregate p in region i.

$i_{i,p}$ is the investment in region i and technology aggregate p.

$x_{i,p}$ is the capacity in region i and technology aggregate p.

The load balance equation in EPOD was updated to include new investments.

$$D_{i,t} \leq \Sigma_{p\in P}\, g_{p,t} + \Sigma_{p^{new}\in P}\, g_{p^{new},t} + b^{dis}_{bat,i,t} - b^{ch}_{bat,i,t} - p_{ely,i,t} - p^{new}_{ely,i,t} + \Sigma_{j\in I, j\neq i}\, q_{j,i,t} \;\; \forall\, i\in I,\; t\in T \quad (2)$$

where.

$D_{i,t}$ is the electricity demand in region i at time-step t.

$b^{dis}_{bat,i,t}$ is the discharging of batteries in region i at time-step t.

$b^{ch}_{bat,i,t}$ is the charging of batteries in region i at time-step t.

$p_{ely,i,t}$ is the electricity consumption of electrolyzers in region i at time-step t.

$p^{new}_{ely,i,t}$ is the electricity consumption of new electrolyzers in region i at time-step t.

$q_{j,i,t}$ is the flow of power, positive or negative, from region j to region i at time-step t.

The hydrogen energy balance in EPOD was updated to include new investments and the use of hydrogen in gas turbines, as follows:

$$s_{H_2,i,t+1} \leq s_{H_2,i,t} + \eta_{ely}\left(p_{ely,i,t} + p^{new}_{ely,i,t}\right) - D_{H_2steel,i,t} - \Sigma_{p^{new}\in P^{new}}\,\Sigma_{m\in M}\left(g_{p^{new}_{H_2GT,m,i,t}}\cdot f^{H_2}_{p^{new}_{H_2GT},m,i}\cdot\frac{1}{\eta_{p^{new}_{H_2GT}}}\right)\;\forall\; i\in I,\; t\in T \quad (3)$$

where.

$s_{H_2,i,t}$ is the hydrogen storage level in region i at time-step t.

$D_{H_2industry,i,t}$ is the industrial hydrogen demand in region i at time-step t.

M is the set of mixing ratios between hydrogen and other fuels.

$g_{p^{new}_{H_2GT,m,i,t}}$ is the electricity generation in new hydrogen-fueled gas turbines with mixing rate m in region i at time-step t.

$f^{H_2}_{p^{new}_{H_2GT,m,i}}$ is the fraction of energy from hydrogen in technology aggregate p in region i with mixing rate m.

$\eta_{p^{new}_{H_2GT}}$ is the electrical efficiency of technology aggregate p.

The limitations in upgrading existing gas turbines to become hydrogen-compatible, in terms of capacity limit [Eq. (4)] and generation limit [Eq. (5)] are:

$$\Sigma_{p^{new}\in P}\, i_{p^{new}_{H_2GTupgrade,\ i}} \leq \Sigma_{p\in P}\, x_{p_{GT},i} \quad \forall\; i\in I \quad (4)$$

$$\Sigma_{p\in P}\; g_{p_{GT},t} \leq \Sigma_{p\in P}\; x_{p_{GT},t,i} - \Sigma_{p^{new}\in P^{new}}\; i_{p^{new}_{H_2GTupgrade,\ i,t}} \quad \forall\; i\in I,\; t\in T \quad (5)$$

where.

$i_{p^{new}_{H_2GTupgrade,\ i,t}}$ is the investment in region i and technology aggregate p.

$x_{p_{GT},t,i}$ is the existing capacity in region i and technology aggregate p.

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Cost assumptions for hydrogen gas turbines

The additional capital cost for making gas turbines hydrogen-compatible is assumed to be dependent upon the mixing ratio of hydrogen, where adjustments to the burners and the combustion chamber are considered necessary, especially when introducing higher mixing ratios [40]. It is also established that most existing gas turbines can tolerate at least 30 vol.-% hydrogen without any need for changes to the gas turbine [12]. Thus, the additional cost only considers the additional components required for integrating hydrogen into the existing fuel system connected to the gas turbine. For those cases in which the mixing ratio of hydrogen is 50 vol.-% or higher, it is assumed that there are additional costs associated with the required changes in burner and combustion chamber design. Yet, if hydrogen gas turbine systems become commercially available at scale it is likely that design changes will have limited impacts on the investment cost, given that the level of complexity will not increase drastically and the amount of material will remain the same (where the major share of the material and components is still in the gas turbine itself). Thus, the largest contributor to the cost increase is the fuel handling system for hydrogen. It is important to emphasize that since there are no commercially available hydrogen-fueled gas turbines and the experience from real operations of hydrogen-fueled gas turbines is limited, the costs can only be assumed and, therefore, the cost estimates in this work are based on combining the above reasoning with the information obtained from a collaboration with an industrial partner.

The cost assumptions are presented in Table 3 as a share of the original capital cost of the gas turbines, which are shown in Table A.1 in Appendix A. The higher cost for upgrading existing gas turbines is explained in terms of the need for a production stop during the physical replacement of old components and the fact that the replacement is more time-consuming compared to installing the hydrogen-compatible components already in the assembly line in the workshop. No cost reduction over time due to learning is assumed.

Model assumptions

The EVs in each region in the model are represented by a total driving/charging demand, such that they approximate the EV batteries in the form of an aggregated battery that can provide flexibility to the electricity system even when V2G is not activated, e.g., smart charging can be allocated to preferential time periods. The assumption regarding an aggregate battery is obviously a simplification, albeit one that is necessary to limit the computational effort. A more detailed evaluation of the impact of aggregation of EVs in the energy system has been carried out by Taljegård et al. [41]. When V2G is made available, it is assumed that 30% of the EVs in each region, at any given time-step, have the potential to supply the electricity system with electricity, so as to balance the load.

The industrial hydrogen demand included in the model is assumed to be driven mainly by the steelmaking industry, as there are ongoing projects on hydrogen-based steel-making. Yet, since hydrogen is a versatile energy carrier and can be used in petrochemical processes, it should be a fair assumption that there will be an additional industrial hydrogen demand in regions with hydrogen-based steel production, as these regions are assumed to take the lead in implementing hydrogen also in other applications. Thus, this study combines assumption on hydrogen for steelmaking based on current development trends in industry with a more arbitrarily assumption on additional industrial hydrogen demand where the resulting hydrogen demand is compared with that given in the European hydrogen strategy:

- **Hydrogen for steel making:** The assumed process for steelmaking is hydrogen direct reduction (H-DR) for the production of direct reduced iron (DRI), which is converted to steel in an electric arc furnace (EAF). The assumption to use the H-DR process is based on the work by Fischedick et al. [42], who conclude that H-DR is the most attractive route for future steelmaking, both from an economic and an environmental perspective. The results by Fischedick et al. are strengthened by current statements from the steel industry, expressing their focus on hydrogen-based processes; ArcelorMittal S.A. [43], HYBRIT [44] and Voestalpine AG [45]. According to Vogel et al. [46], the combined H-DR and EAF processes require 3.48 MWh_{el} per tonne of liquid steel (tLS), where the majority, two-thirds, are used to produce the hydrogen required for the H-DR process. In the model, this electricity demand is represented by a hydrogen demand set to 2.65 MWh_{H2}/tLS, including both the demand for hydrogen in the H-DR and the demand for electricity in the EAF. The figure 2.65 MWh_{H2}/tLS is obtained by multiplying the 3.48 MWh_{el}/tLS with the electrolyzer efficiency, which is assumed to be 76%. Representing the combined hydrogen and electricity demand with a lumped demand constituted only by hydrogen is clearly a simplification, especially as the electricity demand used in the EAF does not have the same dynamic as a hydrogen demand, which can be stored in hydrogen storages. This means that the modeled approach

Table 3 – Assumed capital cost increases as percentages of the costs for conventional gas turbines for different levels of hydrogen mixing capabilities, either for upgrading existing gas turbines or investing in new gas turbines. The cost assumptions are based on discussions with an industrial partner.

Hydrogen mix [vol-%]	Hydrogen upgrade of existing gas turbines [% of base CAPEX]	New hydrogen gas turbines [% of base CAPEX]	Description of cost increase
30	1	101	Fuel system
50	7	103	Fuel system and burner tip
77	10	105	Fuel system and burner
100	25	115	Combustion chamber

overestimates the flexibility in the steelmaking industry. However, as the aim of this study is to investigate the competitiveness of hydrogen gas turbines, this approach is conservative considering that more flexibility from the steelmaking industry has a negative impact on the competitiveness of hydrogen gas turbines.

- **Additional industrial hydrogen demand:** The total industrial hydrogen demand in regions with steel production is increased by 50% from 2.65 MWh_{H2}/tLS to 4 MWh_{H2}/tLS, so as to include also an arbitrary demand for hydrogen in other industrial processes. As indicated above, there is little known about what other industrial hydrogen will materialize and, thus, the 50% increase is arbitrarily chosen.
- **Comparison with the European hydrogen strategy:** With the assumptions made regarding future utilization of hydrogen, the European industrial hydrogen demand becomes 5.1 $Mton_{H2}$ in Year 2040 and 13.1 $Mton_{H2}$ in Year 2050. Comparing these numbers with the aim of up to 10 $Mton_{H2}$ renewable hydrogen production by 2030, stated in the European hydrogen strategy [48], the assumed industrial hydrogen demand is considered reasonable, considering the fact that the hydrogen strategy also includes additional use of hydrogen such as for the transportation sector and balancing of variations from VRE generation.

In the present study, the industrial hydrogen demand for steelmaking is assumed to start in five regions (SE2, SE4, DE3, DE4, DE5; cf. Fig. 1) in Year 2040, and thereafter to expand to 18 regions by Year 2050 (BE, CZ, FR1, FR4, FR5, DE3, DE4, DE5, HU, IT3, NL, PO2, SK, FI, ES1, SE2, SE4, UK1). The estimated level of steel production in each region is based on data from the Chalmers Industry database, which is a sub-database of the Chalmers Energy Infrastructure database [29], and is further described by Rootzén et al. [47]. Details regarding the future steel demands are listed in Table A.4 in Appendix A.

The regions included in the modeling are highlighted in bright-green and dark-green in Fig. 1, whereas the peripheral regions in gray are excluded. All the bright-green regions are analyzed in the *Results* section, whereas the dark-green regions are included in the model to act as boundary regions that facilitate import and export to the bright-green regions. Thus, the bright-green regions have full representation of cross-border trade to surrounding regions, whereas the dark-green regions can be limited in terms of interconnector capacity to neighboring regions. Nonetheless, both the bright-green and dark-green regions are treated equally by the model.

Table 4 – Modeled scenarios for hydrogen-fueled gas turbines.

Scenario	Industrial H_2	EV Flexibility
1	No	No
2	Yes	No
3	No	Yes
4	Yes	Yes

Scenarios

The scenarios modeled to evaluate the competitiveness of hydrogen-fueled gas turbines (Table 4) are evaluated for Years 2030, 2040 and 2050. All the investigated scenarios include the additional demand from EVs, where Scenarios 1 and 2 assume direct recharging of EVs upon arrival at home (corresponding to the *Direct* scenario described by Taljegård et al. [33]). Scenarios 3 and 4 assume a more sophisticated charging strategy for EVs, in combination with V2G (corresponding to the *Optimization + V2G* strategy in the work of Taljegård et al. [33]), in order to evaluate the competitiveness of hydrogen-fueled gas turbines with other potential flexibility capabilities in the electricity system. Scenarios 2 and 4 include an industrial hydrogen demand, which is assumed to be constant over time. Yet, from the electricity systems perspective, the production of this hydrogen to meet the demand is flexible, since hydrogen storage is available.

Each scenario is evaluated for the following parameters, which can adopt one of two different values:

- Emissions trajectory: low/base
- Electricity demand: low/high
- Electrolyzer (ELY) cost: low/high
- Industrial H_2 demand: low/high
- New transmission lines (TL): with/without

The base emissions trajectory (Base ET) describes a linear decrease of emissions, reaching negative emissions by Year 2050, adapted from the "1.5°C" scenario [49], whereby the negative emissions correspond to 10% of the Year 1990 emission levels. The decision to enforce negative emissions is based on the European Union's aim to reach net-zero emission by Year 2050, as well as by the facts that emissions from hard-to-abate sectors, e.g., aviation and heavy transport, may have to be compensated by other sectors, and that the potential for negative emissions in the power sector is relatively good. The low emissions trajectory (Low ET) shows a more rapid decrease in emissions, defined by setting the emissions level in Year 2030 to 30% instead of 40% of the Year 1990 level, and is adapted from the "below 1.5°C" scenario [49]. The emissions trajectory is implemented as a hard constraint in the model, ensuring that emissions are less than or equal to the assumed emission trajectory limit. The emission trajectories are depicted in Fig. 2.

The total annual electricity demand in the model is a combination of the projected demands linked to traditional electricity use [32], and the new additional demands for the transport and industry sectors. Here, 'traditional' refers to the current type of electricity use without demands from transportation and electrification of industrial processes. Two different electricity demand developments are assumed in the traditional electricity system, defined as low (low electricity demand) and high (high electricity demand), in order to include the uncertainty linked to the future electricity demand in the 'traditional' sector. The rationale behind the two options is that the traditional electricity demand can either decrease due to efficiency measures on the user side or increase as a result of the general electrification trend, e.g., in

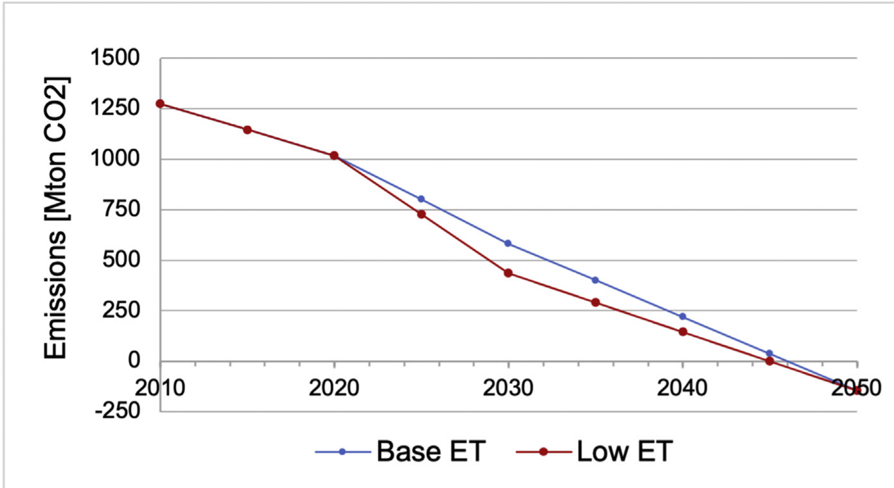

Fig. 2 — Two emissions trajectories (ET) for Europe from 2010 to 2050, whereby the emissions for Year 2050 are 10% net-negative relative to the emissions levels in Year 1990. The emissions level in the Low ET scenario for Year 2030 corresponds to 30% rather than 40% of the Year 1990 level.

the heating sector, which will offset the efficiency measures and result in a net increase in electricity demand. The assumptions made regarding the future electricity demand in the traditional electricity system is described by Unger et al. in Ref. [32], and the annual demands for countries included in this study, which develop differently due to different starting points, considering, for example, current electrification status, can be found in Tables A.2 and A.3 in Appendix A.

As the future hourly demand profiles in the traditional electricity demand are based on historical statistics from ENTSO-E, potential future changes in the electricity consumption pattern triggered by new technologies and behaviors are not captured. However, new demands from the transport and industry sectors are implemented as additional demands, which are flexible due to smart charging strategies and V2G capabilities for EVs and hydrogen storage in the industry. In addition to these flexible demands, time-shifting of generation in the power sector through the application of stationary batteries and hydrogen storage is also implemented in the model. Thus, a new dynamic is afforded to the modeled future electricity systems. It should also be mentioned that there is no price elasticity in the demand or market pricing strategies. The model is set up to minimize the total system cost while supplying the demand (and other constraints, e.g., emissions trajectories), which means that the electricity price presented is the marginal cost of electricity generation, endogenously calculated in the model. Thus, the price derived from the model should reflect what can be expected on a wholesale market, which does not include any taxes nor fees.

In addition, the capital cost of electrolyzers is either high (high ELY cost) or low (low ELY cost), where 'high' refers to the costs in Table A.1 in Appendix A [50], and 'low' represents a reduction of 50%. The high cost for the electrolyzer is taken from the Danish Energy Agency [50], which decreases from 653 €/kW_{el} in Year 2030 to 395 €/kW_{el} in Year 2050. Similarly, the industrial hydrogen demands in Scenarios 2 and 4 are set to either high (high H_2 demand) or low (low H_2 demand), where 'high' refers to the demand in Table A.4 in Appendix A, and 'low' is a reduction of 50%. Finally, the model is run with and without the possibility to invest in new transmission line (TL) capacity (with new TL, without new TL), although the option to prohibit new TL capacity is only analyzed in those scenarios in which the results indicate low levels of competitiveness for hydrogen gas turbines.

As a sensitivity study, the costs for natural gas and biomass (the latter being used to produce biogas) are varied from −25% to +100% relative to the baseline cost, to evaluate the impacts on the competitiveness of hydrogen gas turbines. The following increments relative to the baseline cost are included in the modeling: 75%, 100%, 125%, 150%, 175% and 200%.

Results

The results are presented in three sections. The first and second sections present the results for Scenarios 1 and 2, respectively, where Scenario 1 is the base scenario and Scenario 2 includes the industrial hydrogen demand. The third section presents the results for Scenarios 3 and 4, both of which include the additional flexibility from smart charging and V2G in the transport sector.

The future roles of new hydrogen gas turbines

Analyzing the investments in new hydrogen gas turbines for the near future, the results for Year 2030 show that competitiveness is limited (see Fig. 3). Investments in hydrogen gas turbines are limited to when a low emissions

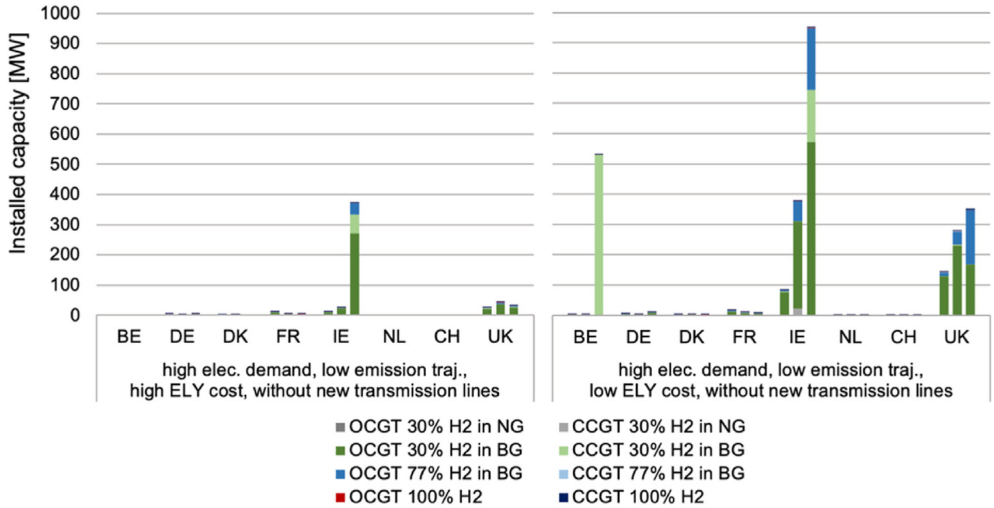

Fig. 3 – Installed capacity in Scenario 1 for new hydrogen-compatible gas turbines in Year 2030. The three columns for each country indicate increases in fuel cost assumptions regarding natural gas and biogas (NG and BG), corresponding to 50%, 75% and 100% increases over the baseline cost. The difference between the two sub-plots is the electrolyzer (ELY) cost, set to "high" or "low", respectively.

trajectory, a high electricity demand, and a lack of new investments in transmission line (without new transmission lines) capacity are assumed. In addition, to promote investments in hydrogen gas turbines, the costs of complementary fuels, natural gas (NG) and biogas (BG), must be assumed to be more than 50% higher than the baseline cost. The three columns for each country in Fig. 3 represent cost increases of 50%, 75%, and 100% for NG and BG, respectively. Still, in the cases where hydrogen gas turbines do become competitive in Year 2030, investments are seen in both OCGT and CCGT, where the hydrogen is predominantly mixed with biogas. Thus, it can be concluded that the value of time-shifting with the aid of hydrogen production, storage and reconversion to electricity by hydrogen-fueled gas turbines is limited in a near future that still allows significant levels of CO_2 emissions and that has moderate levels of VRE in the electricity generation mix.

Considering the effects of a reduced electrolyzer cost in Year 2030 (right-hand plot in Fig. 3), the results show large investments in hydrogen gas turbines for countries that made investments already when the electrolyzer cost was high (IE, UK). This is as expected, as a cost reduction for electrolyzers would reduce the cost for time-shifting of electricity generation, thereby providing greater value to the system. For most countries (DE, DK, FR, NL, CH), however, the reduction in electrolyzer cost has no impact on the investments in hydrogen-fueled gas turbines, simply because an economic incentive for time-shifting of generation is lacking, despite a reduction in the cost of electrolyzers. For BE, large investments in hydrogen gas turbines are seen only when the electrolyzer cost is low and the complementary fuel cost is doubled. This can be explained by the nature of linear optimization models, where the optimal solution is represented by a unique solution. In this case, the changes in electrolyzer cost and fuel cost alter the optimal solution, and investments in hydrogen-fueled gas turbines are made.

The investments for Scenario 1 in Year 2040 are presented in Fig. 4, where sub-plots a)-d) display the results for the four combinations of emissions trajectory and electricity demand. Comparing the investments in sub-plots a) and c) with the investments in sub-plots b) and d), it is evident that, as expected, the competitiveness is mainly driven by the emissions trajectory and is amplified by a high electricity demand.

The largest share of the investments in Year 2040 is made in new OCGT with 30 vol.-% hydrogen mixed with biogas, indicating a strong demand for peak power but a relatively low demand for time-shifting of generation, as the mixing rate is the lowest available. Still, the investments in hydrogen gas turbines, involving also investments in electrolyzers and hydrogen storage, show that there are some benefits to be derived from time-shifting, as this is the cost-optimal solution minimizing the total system cost.

With the base emissions trajectory and a low electricity demand (Fig. 4d), investments in hydrogen gas turbines, primarily OCGT with 30 vol.-% hydrogen mixed with biogas, are limited to IE and the UK. These countries are distinguished from other countries as their collective transmission capacities are limited due to them being islands, and thus, their transmission capacities are considerably lower than the transmission bottlenecks between regions in continental Europe, also after allowing for transmission investments. This limits the possibility to exploit cross-border trade as a tool for flexibility and, thus, the hydrogen gas turbines provide flexibility.

Regarding the results for Year 2050 depicted in Fig. 5, the investments in hydrogen gas turbines are significantly larger than those in Year 2040, and include both OCGT and CCGT and total investments in the GW scale for most of the countries,

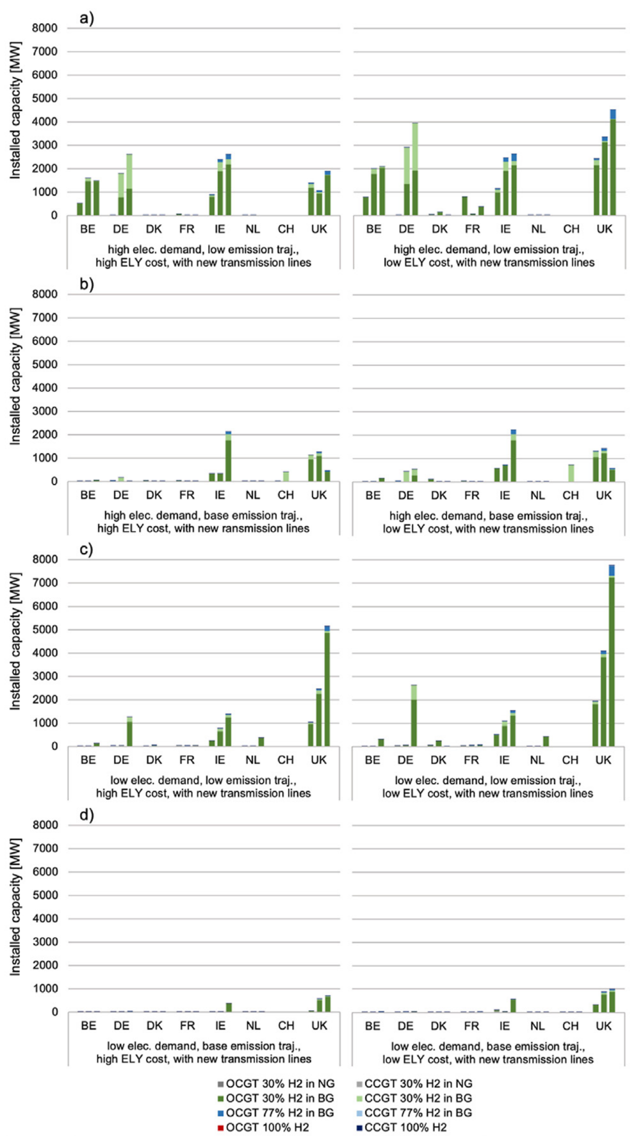

Fig. 4 – Installed capacity in Scenario 1 for new hydrogen-fueled gas turbines in Year 2040 for four different combinations of electricity demand (high/low) and emissions trajectory (base/low). Panel a), High electricity demand and low emissions trajectory; panel b), high electricity demand and base emissions trajectory; panel c), low electricity demand and low emissions trajectory; and panel d), low electricity demand and base emissions trajectory. Each country is evaluated for three different levels of assumed fuel cost for natural gas (NG) and biogas (BG), where the middle column represents the baseline cost and the left and right columns represent a cost decrease or increase of 25%, respectively. The difference between the two plots in each panel is the electrolyzer (ELY) cost, set to "high" or "low", respectively.

with the largest investment being in the UK with up to 20 GW of hydrogen gas turbines. While the estimated investment levels are obviously influenced by the assumptions made, Welder et al. [22] derived similar results, and it is clear that significant investments in load-balancing technologies, including time-shifting of generation via hydrogen, can be of value in future energy systems aimed at achieving net-zero CO_2 emissions.

In contrast to the results for Year 2030, the investments in Years 2040 and 2050 are not dependent upon limitations regarding new transmission line capacity, so new transmission capacities are allowed for in all the results for Years 2040 and 2050. In addition, hydrogen gas turbines require a smaller increase in complementary fuel cost to become competitive, i.e., the costs for NG and BG are varied by ± 25% relative to the baseline cost (middle column) for Years 2040 and 2050, instead of the increase of 50%–100% used for Year 2030.

Comparing the investments in Year 2040 to those in Year 2050, it is clear that the investments in Year 2040 differ significantly depending on the different combinations of emissions trajectory and assumed electricity demand development (Fig. 4a–d), where, as mentioned above, the emissions trajectory has the strongest influence on the investments. The corresponding investments for Year 2050 in Fig. 5 are more uniform, and the levels of investment do not differ significantly between the two emissions trajectory settings, given that they both prescribe negative emissions, albeit with different historical development patterns (see Fig. 2). With a prescribed requirement for negative emissions by Year 2050, the share of VRE in the electricity mix increases, and consequently, the value of flexible and dispatchable capacity with zero emissions increases. However, in Year 2050, investments are still present for technologies that employ fossil fuels (Fig. 5a and b), which are technologies that generate fossil-related emissions. These emissions are, however, compensated by negative emissions from bioenergy CCS (BECCS) technologies, e.g., biomass-fueled combined heat and power plants with CCS, as this is the cost-optimal solution. While it is debatable as to whether or not the combination of BECCS and fossil technologies is a feasible solution to achieve net-zero or negative emissions, this is not the focus of this work.

It is worth pointing out that the investments made in hydrogen gas turbines by Year 2050 are still primarily in gas turbines with lower mixing ratios, i.e., 30 vol.-% hydrogen mixed with biogas. Higher mixing ratios would require either electrolyzers to operate during periods with higher electricity prices or larger investments in electrolyzers and hydrogen storage capacity, as well as a higher cost for hydrogen gas turbines with increased mixing ratios. Thus, the cost-optimal solution for the system, both in terms of substituting a share of the complementary fuel in gas turbines, i.e., biogas, and in terms of shifting generation in time, is to allow for a lower mixing ratio of hydrogen. Most of the investments are also made in OCGT, indicating a demand for capacity rather than for complementary energy supply, which is logical since CCGTs require more full-load hours, due to their characteristics of higher efficiency levels and capital costs, and thus also require larger volumes of hydrogen. The result indicating a preference for OCGTs with lower mixing ratios may, however, be influenced by the assumption made regarding fixed mixing ratios, which is an aspect that is considered further in the *Discussion* section.

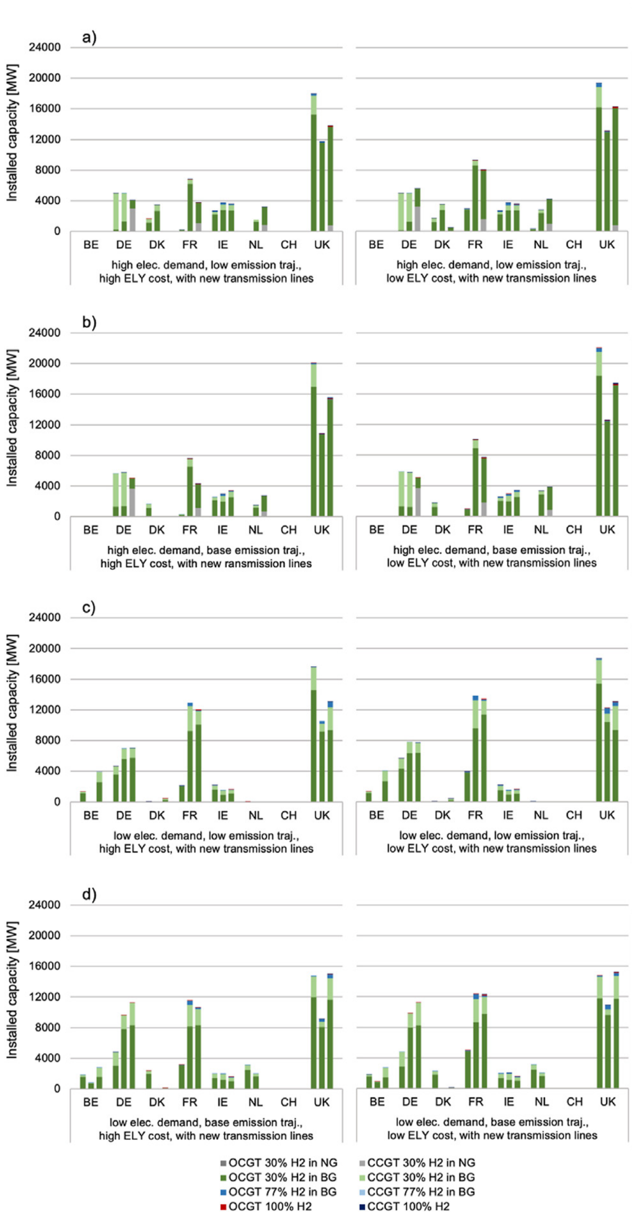

Fig. 5 – Installed capacities in Scenario 1 for hydrogen-fueled gas turbines in Year 2050 for four different combinations of electricity demand (high/low) and emissions trajectory (base/low). Panel a), High electricity demand and low emissions trajectory; panel b), high electricity demand and base emissions trajectory; panel c), low electricity demand and low emissions trajectory; and panel d), low electricity demand and base emissions trajectory. Each country is evaluated for three different levels of assumed fuel cost for natural gas (NG) and biogas (BG), where the middle column represents the baseline cost and the left and right columns represent a cost decrease or increase of 25%, respectively. The difference between the two plots in each panel is the electrolyzer (ELY) cost, set to "high" or "low", respectively.

Furthermore, the results show that the shares of electricity generated by hydrogen gas turbines are 2.5% and 6.7% of the total generation for Year 2040 and Year 2050, respectively. Considering also that the most common mixing ratio is 30 vol.-% hydrogen, which corresponds to 11% of the energy (see Table 1), the amount of hydrogen used for time-shifting electricity generation never exceeds 1% of any country's electricity production in the model runs investigated in Scenario 1.

Fig. 6 displays the load duration curves of the hydrogen gas turbines in Scenario 1, revealing that the OCGT has less than 400 full-load hours per year. Although the CCGT is operated for 3,000–4,000 h, it can be seen that this technology never operates continuously for more than 160 h, and that the majority of the start-stop cycles are less than 20 h in duration. This indicates that also CCGT could be used to balance variations due to VRE. Start-up costs are considered in the model, although the cost of frequent cycling and its effects on the lifetimes of the components are not included. This aspect has, however, been studied by Angerer et al. [51], who have suggested a technical solution to reduce thermal stress in the heat recovery steam generator (HRSG), as well as by Stoppato et al. [52], who have concluded that even if flexible operation leads to reduced lifetimes for the components of the HRSG, it appears to be feasible from the economic perspective.

The impact of an industrial hydrogen demand

The implications of including an industrial hydrogen demand in the modeling (Scenario 2) include a different dynamic to that seen for Scenario 1, in which there is no industrial hydrogen demand. This is partly because the hydrogen demand increases the electricity demand, by up to 30% depending on the country and assumptions regarding development of the electricity demand, which is covered by a significant amount of VRE generation, and partly due to flexible electrolyzer operation in combination with hydrogen storage, which provides flexibility within the system. For Scenario 2 in Year 2040, DE is the only country among those analyzed (i.e., the bright-green regions in Fig. 1) with an exogenously defined industrial hydrogen demand. Moreover, in contrast to Scenario 1 (see Fig. 4), in which DE indeed has investments in hydrogen-fueled gas turbines, there are now no investments in hydrogen-fueled gas turbines. Such investments are instead made in FR and the UK, indicating that the trade patterns between the countries in Scenario 2 have changed compared to those in Scenario 1, as revealed by comparing the annual levels of import and export of electricity to and from DE in Scenarios 1 and 2. It can be seen that the annual net import for DE increased by 37% when an industrial hydrogen demand was introduced, as shown in Table 5. This means that the fluctuations within DE can, to large extent, be handled by an increase in imports and by flexible hydrogen production, leaving the residual fluctuations to the neighboring countries.

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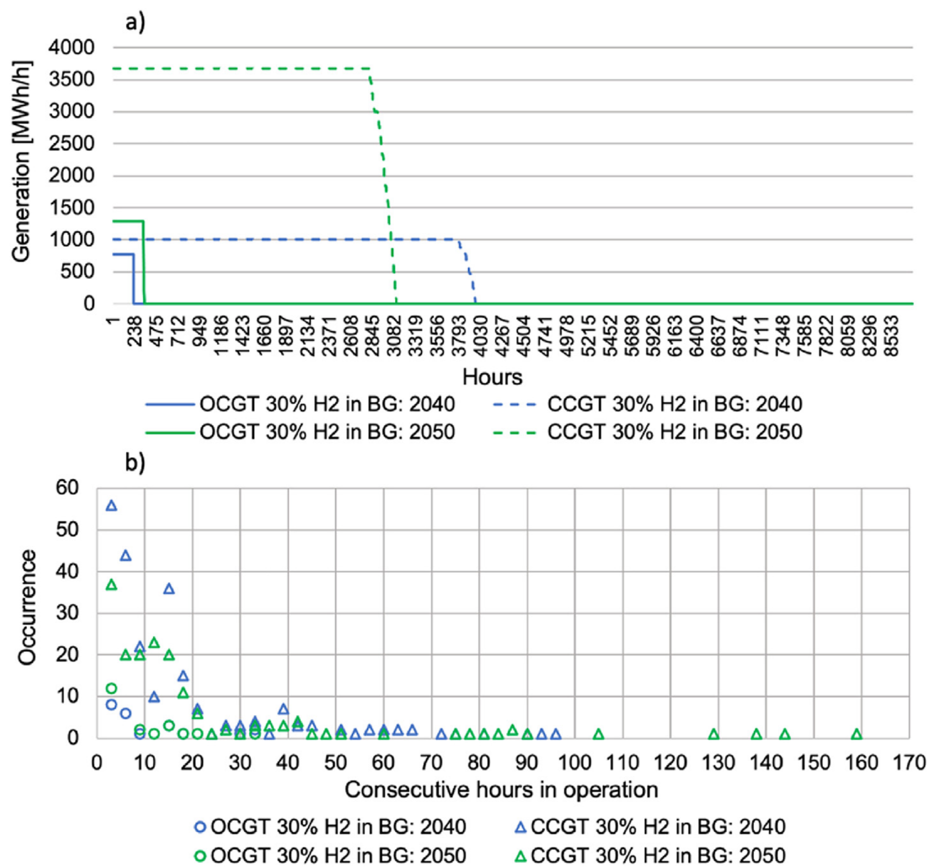

Fig. 6 – Scenario 1. Panel a): Load duration curve for OCGT and CCGT in Germany for Year 2040 and Year 2050. Panel b): Frequency of operation for different numbers of consecutive hours in operation for the same technologies as in panel a).

Table 5 – Differences in annual levels (in TWh) of import and export of electricity for Germany when an industrial hydrogen demand is introduced (Scenario 2), as compared to Scenario 1.

	Scenario 1	Scenario 2	Difference
Export	12.3	7.4	−40%
Import	100.2	127.5	+27%
Net import	87.9	120.1	+37%

In Year 2050, five of the countries analyzed (BE, DE, FR, NL, UK) have an exogenously defined hydrogen demand (Fig. 7). With an increasing industrial hydrogen demand, the investments in hydrogen-fueled gas turbines decrease, especially when moving from a low to a high demand for hydrogen, as shown in plots b) and c), respectively. Thus, large-scale production of hydrogen has a significant impact on the system composition, and it can be concluded that hydrogen production can contribute with significant flexibility, through the flexible scheduling of electrolyzers, and also without time-shifting via the possibility of using the reconversion of hydrogen back to electricity. Furthermore, in Scenario 2, the results indicate a preference for OCGT, which suggests that the value lies in the time-shifting capacity rather than in energy.

In Fig. 8, the operations of a hydrogen-fueled OCGT, electrolyzers, and hydrogen storage are plotted for two regions in Scenarios 1 and 2, one with an industrial hydrogen demand (UK1, plot a–c) and one without (IE, plot d–f). In UK1, the number of start-stop cycles for the OCGT decreases when the industrial demand for hydrogen increases, albeit with diminishing returns. Thus, a substantial drop in the number of start-stop cycles is evident when introducing a low demand for hydrogen (Fig. 8b), as compared to no exogenous industrial hydrogen demand (Fig. 8a), whereas the reduction in number of start-stop cycles does not decline proportionally when transitioning to a high hydrogen demand (Fig. 8c), as summarized in Table 6. This is explained by the fact that the operation of the electrolyzers in GW scale has a strong impact on the electricity system, acting as an inverted peak-power technology, balancing the grid through flexible hydrogen production, an effect that is not seen when the electrolyzer capacity is in the MW-scale, as in Fig. 8a, thus leading to more start-stop cycles for the OCGT, which indeed is in the GW-scale.

If we instead consider a region without industrial hydrogen demand (IE), it can be seen in Fig. 8d–f that the change in operational patterns for the electrolyzers, hydrogen storage and gas turbines is small when introducing a hydrogen demand in the neighboring region, and similarly the number of

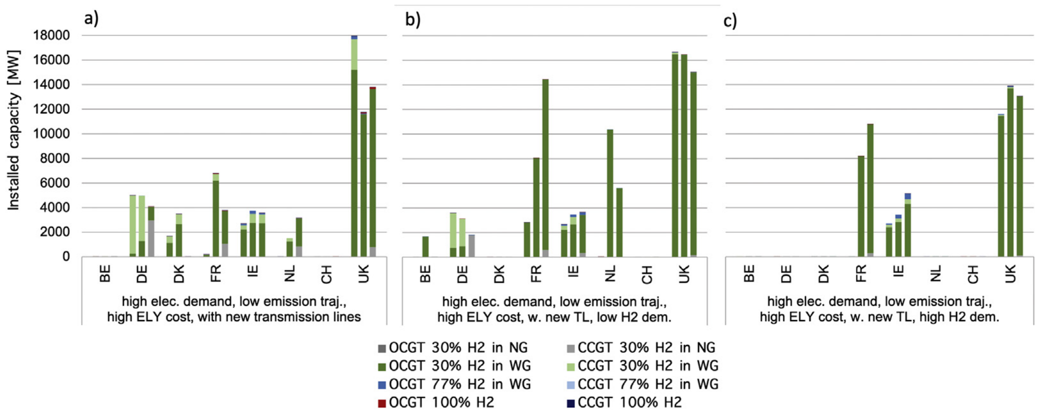

Fig. 7 – Investments in the hydrogen-fueled gas turbine capacity in Year 2050 for different levels of industrial hydrogen demand. a): Scenario 1 - no hydrogen demand. b): Scenario 2 - low hydrogen demand. c): Scenario 2 - high hydrogen demand. Each country is evaluated for three different levels of assumed fuel cost for natural gas (NG) and biogas (BG), where the middle column represents the baseline cost and the left and right columns represent a cost decrease or increase of 25%, respectively.

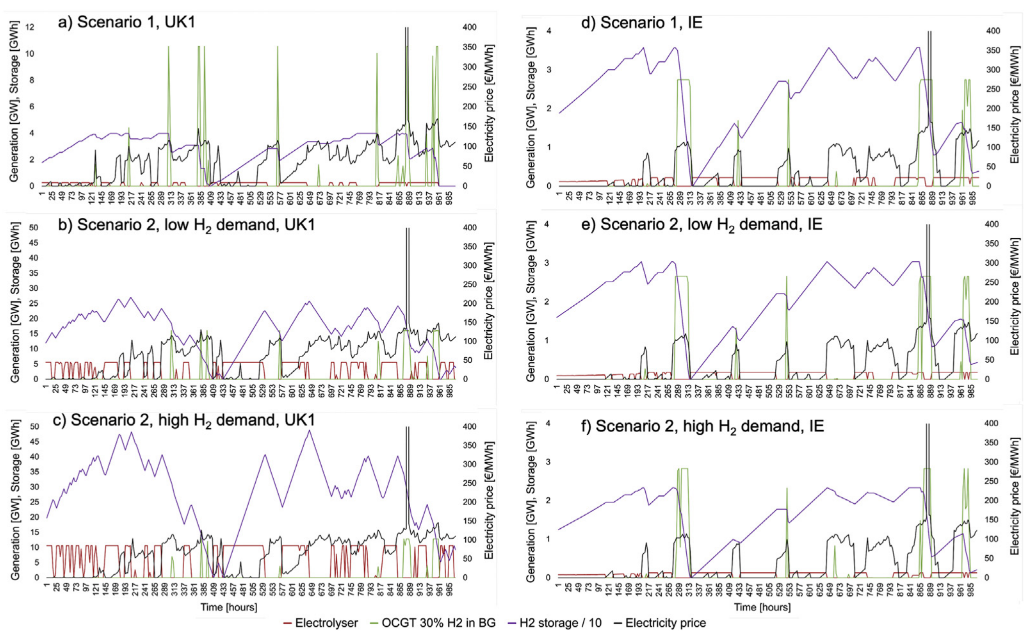

Fig. 8 – Operation of hydrogen-fueled OCGT, electrolyzer, and hydrogen storage for one region with a demand for industrial hydrogen: the UK (panels a–c), and for a region without such a demand: Ireland (panels d–f). Demand for industrial hydrogen: a)/d), none; b)/e), low; c)/f), high. The data in plots a) and d) are from Scenario 1, whereas the other data are from Scenario 2.

Table 6 – Impacts on the operation of hydrogen-fueled OCGT of the introduction of an industrial hydrogen demand to the system. As industrial hydrogen demand is only present in UK1 and FR5, the share of hydrogen used for electricity production in IE is always 100%, regardless of whether the industrial hydrogen demand is non-existent (None), low or high.

Industrial H_2 demand	Start-stop cycles			Electricity generation [GWh_{el}]			Share of H_2 used for electricity generation		
	None	Low	High	None	Low	High	None	Low	High
Region									
UK1	61	35	28	544	759	548	100%	1.1%	0.4%
IE	56	57	48	405	365	300	100%	100%	100%
FR5	34	27	19	274	523	508	100%	1.1%	0.54%

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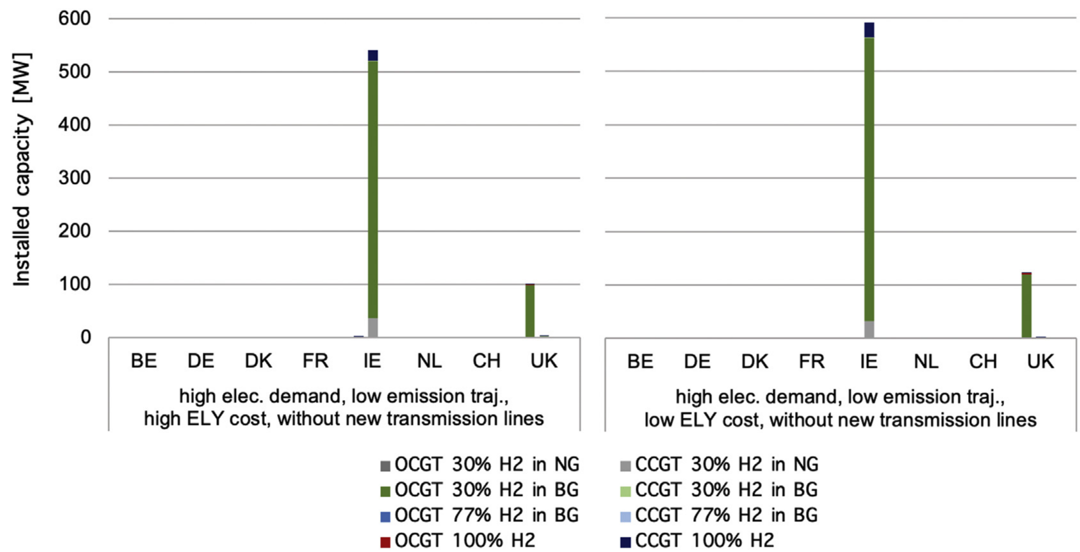

Fig. 9 – Installed capacity in Scenario 3 for new hydrogen-compatible gas turbines in Year 2050. The two columns for each country indicate increases in the fuel cost assumptions regarding natural gas and biogas (NG and BG), corresponding to increases of 75% and 100% over the baseline cost. The difference between the two sub-plots is the electrolyzer (ELY) cost, which is set to "high" or "low", respectively.

start-stop cycles for the OCGT decreases only slightly, as shown in Table 6.

Table 6 presents a summary of the operations of hydrogen-fueled OCGTs for the three countries with such capacity, as shown in Fig. 7. As mentioned above, the number of start-stop cycles decreases with an increase in industrial hydrogen demand, although the level of electricity generation in most cases does not decrease with fewer start-stop cycles (see "Electricity generation" column in Table 6). This means that the operational profile of the OCGTs shifts to fewer but longer time periods when the electrolyzer capacity is sufficiently large to balance the shorter and more frequent variations seen in Fig. 8a. When an industrial hydrogen demand is included, the amount of hydrogen used for electricity generation is in the range of 0.5%–1.0% of the industrial hydrogen demand.

The impact of flexibility from vehicle-to-grid

The modeling results show that availability of other modes of flexibility in the electricity system, in this work represented by smart charging and the V2G capabilities of EVs in the transport sector, can have detrimental effects on the competitiveness of hydrogen-fueled gas turbines. The investments in hydrogen-fueled gas turbines in several of the investigated regions, for both 2040 and 2050, are significantly reduced when smart charging and V2G are added in Scenario 3, as compared to the results for Scenario 1. In Scenario 3 (Fig. 9), the investments in hydrogen gas turbines are limited to Ireland and the UK in Year 2050, and only when the electricity demand is assumed to be high (high electricity demand), new transmission lines are prohibited (without new transmission lines), and the competing fuel cost is increased by 75%–100% over the baseline cost. Yet, the installed capacities in these regions are significantly lower than in Scenario 1, i.e., in Scenario 3 the magnitude is in the hundreds of MW rather than in the GW scale, as seen in Scenario 1. Similar results are obtained for Scenario 4, which includes both flexibility from V2G and an industrial hydrogen demand.

Discussion

The present work shows that hydrogen-fueled gas turbines are competitive only in energy systems that impose a stringent cap on CO_2 emissions, in this study represented by assumptions made for Years 2040 and 2050, and that their role is primarily to balance the fluctuations arising from high shares of VRE. The competitiveness of hydrogen-fueled gas turbines in Year 2030 is significantly weaker, and can be explained by the occurrence of fewer and less-severe fluctuations due to a lower penetration of VRE and greater dispatchable capacity being available due to the higher emissions levels permitted. However, since the model only considers an aggregate emission cap, some regions can have close-to-zero or even negative emissions in the model, while other regions can still have significant levels of emissions. This can be expected when the resources for VRE are not evenly distributed and the model minimizes the total system cost, disregarding variations in regional emissions. Still, most European countries, and in some cases even regions or local companies, have set ambitious goals for emissions reductions already by Year 2030, so hydrogen

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usage in gas turbines could still be relevant in energy systems similar to that described for Year 2030 in the present study, although not captured in this work due to limitations linked to the chosen method.

Furthermore, the objective of the European hydrogen strategy is the generation of 10 Mt of hydrogen annually by Year 2030 [53], with hydrogen produced via electrolysis and renewable electricity. This could have a beneficial effect on the use of hydrogen in the electricity sector in terms of availability, although based on the cost-optimized results in this study, the power sector is unlikely to be able to make use of large volumes of hydrogen, through conversion back to electricity in gas turbines, by Year 2030.

Another parameter that has a strong impact on the competitiveness of hydrogen-fueled gas turbines is other forms of flexibility within the electricity system. This additional flexibility, here represented by smart charging of EVs and V2G, appears to have a detrimental effect on the competitiveness of hydrogen-fueled gas turbines, as the flexibility derived from EVs can take a similar role in the electricity system. It should, however, be mentioned that the approach of modeling the EV batteries as an aggregated installation can overestimate what can be achieved with V2G [41], in terms of the longevity of the time-shifting (representing the entire car fleet rather than each individual car). In addition, it is likely that the use of batteries in private vehicles will be associated with some sort of cost, which is not included in the model.

Flexibility could also be provided to the system by the introduction of an industrial hydrogen demand, assuming that the hydrogen will be provided via electrolyzers fed with electricity from the grid. Such flexibility is demonstrated in the present work to have a negative effect on the competitiveness of hydrogen gas turbines, and this effect would likely be even greater if the industrial hydrogen demand had some inherent flexibility linked to its production process, e.g., flexibility in the steelmaking process.

The results from the investigated scenarios indicate a strong competitiveness for hydrogen gas turbines with a low mixing ratio of hydrogen in biogas, i.e., 30 vol.-% blend-in of hydrogen in biogas. The use of biogas as complementary fuel can be explained by the limitations on CO_2 emissions, especially for net-zero or negative-emissions scenarios (e.g., Year 2050 in this study), wherein all eventual emissions would have to be compensated for via BECCS. However, the combination of hydrogen and biogas raises the issue as to how the use of hydrogen would be affected if the cost and/or availability of biomass would change, as biomass has the potential to reduce emissions in many other sectors. In this work, for most of the scenarios, it can be concluded that a higher biomass cost leads to a higher usage of hydrogen.

Another aspect to consider is the flexibility of fuel mixing. In the current work, the mixing ratio is assumed to be fixed, which means that the selected mixing ratio applies to every hour of operation. If instead the use of hydrogen could be flexible within a specific interval, the use of hydrogen could be more dynamic. This would likely improve the competitiveness of hydrogen-fueled gas turbines because they could be used even when hydrogen from low-cost hours is not available. A topic for future work is to evaluate in detail how flexible fuel mixing can affect the competitiveness of hydrogen-fueled gas turbines.

Under the assumptions made, the results indicate that there is little value associated with upgrading existing gas turbines to allow for the blending in of hydrogen. This can be explained in part by the discrepancy between ELIN and EPOD regarding the need for peak power technologies due to the difference in time-step representation, where ELIN seems to underestimate the need for peak power due to its limited representation of time-steps. Upgrading existing gas turbines in EPOD would not add capacity but would merely impose a constraint on the existing capacity enforcing a certain mixing ratio of hydrogen. Thus, when there is economic viability linked to additional peak power investments new capacity will be valued over upgrades. The competitiveness of upgrades to existing gas turbines is obviously dependent upon the cost of hydrogen in relation to other competing fuels, as well as the degree to which a time-shift in electricity production would be attractive for the system. As long as emissions are still allowed, natural gas is likely to outcompete hydrogen and reduce the need for time-shifting of electricity generation. Therefore, if there is a will to achieve gradual penetration of hydrogen as a fuel in electricity generation, additional dedicated policies may be required in a transition phase, e.g., emissions performance standards for already existing power plants or dedicated support for fuel shifting, until the EU ETS adapts to targeting gas turbine technologies fueled by natural gas in general.

With respect to the cost of hydrogen-compatible gas turbines, the current industrial experience is limited, so the cost assumptions presented in Table 3 are uncertain. Still, despite additional equipment and development costs for new components, hydrogen gas turbines will not represent a fundamentally different system, which means that the total investment cost should be in the same order of magnitude as that for existing gas turbines. Furthermore, the additional cost of making gas turbines hydrogen-compatible is relatively small compared to the total cost for time-shifting of generation, which includes also the cost of a regular gas turbine without hydrogen-compatible components, electrolyzers, hydrogen storage and the operating cost. Considering these uncertainties, the cost assumptions made in this work are reasonable. Future studies on this topic may benefit from the experience gained from using hydrogen-fueled gas turbines.

This work focuses exclusively on hydrogen generated via electrolysis, so-called ‘green hydrogen’. However, with the ongoing transition of the energy system to reduce the already existing emissions and the trend towards electrification, it may be difficult to expand simultaneously the electricity generation capacity to supply all new demands (including a demand for green hydrogen). Therefore, so-called ‘blue hydrogen’ (hydrogen from natural gas steam reforming with

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CCS) may be required as a bridging technology. Studies looking into the ways in which green hydrogen and blue hydrogen could complement each other, and how the combination would influence the competitiveness of hydrogen-fueled gas turbines are warranted.

The aim of this work is to understand the potential role of hydrogen-fueled gas turbines in the time-shifting of electricity generation and the potential impact of a large-scale hydrogen demand in other sectors. Thus, considering the scope of this work, it should be acknowledged that there is a possible electrification of several sectors which are not represented in this work, such as electrification of heavy transport, petrochemical industries and refineries. Since there is little known about the level and ramp-up of electrification in these sectors, we have instead chosen to limit the analysis to steelmaking industry and road transport by electric vehicles (EVs). This, since there are concrete plans for electrification via hydrogen of steelmaking and that electrification of EVs has already started. Yet, we have added an arbitrary industrial hydrogen demand to reflect a likely indirect electrification also of other industries (together this gives a level of hydrogen use which is in line with what is envisioned in the European hydrogen strategy). There will obviously be a need for more detailed analysis of the electrification of the above mentioned sectors but such analysis is considered outside the scope of this study.

Conclusion

An energy system modeling package is applied to investigate the conditions under which gas turbines that are fully or partly fueled with hydrogen would act as a cost-competitive flexibility provider through the conversion of hydrogen back to electricity in the transition of the electricity systems of 15 European countries towards zero-level emissions by Year 2050.

From the modeling results, it can be concluded that hydrogen-fueled gas turbines can be competitive when there is a strict cap on CO_2 emissions – as in the modeling Years 2040 and 2050 – when there is strong penetration of VRE. For Year 2030, which still permits significant CO_2 emissions, and thereby allows other less-costly peak technologies, hydrogen-fueled gas turbines have little or no role to play.

For the total of 30 different hydrogen gas turbine options, with respect to the hydrogen fuel mixing ratio, open cycle or combined cycle, and choice of complementary fuel, included in the modeling, the most common investment seen in the results is in new hydrogen gas turbines with 30 vol.-% hydrogen mixed with biogas in an open cycle. Yet, there are also significant investments in combined cycles for the same fuel mixing ratio. Higher mixing ratios, here represented by 77 vol.-% and 100 vol.-% hydrogen, are also seen, albeit to lesser extents. The advantage of lower mixing ratios is explained by the benefit to the system of shifting electricity generation from low-cost to high-cost periods, periods that are usually associated with low or high production from VRE, whereas higher mixing ratios would require either more dedicated full-load hours in the electrolyzers, thereby using hours with higher electricity prices, or larger investments in both electrolyzers and hydrogen storage capacity. Thus, the lower mixing ratios observed in this study represent the optimal solution, considering both the investment costs and the benefit accrued from the time-shifting of generation. Furthermore, time-shifting the generation introduces a flexibility to the system that can smoothen the electricity price and lower the cost of low-carbon peak power by diminishing dependence on other low-carbon fuels, e.g., biogas that can become scarce due to competition for biomass resources from other sectors.

The hydrogen-fueled gas turbines considered here for a number of European countries in general have production levels in the GW scale. Their full-load hours are typically 3,000–4,000 h for combined cycles and 200–400 h for open cycles, which are similar to the reports in the literature. The present work includes a more-detailed evaluation of the operational patterns and concludes that also CCGT can be expected to operate in a more dynamic and flexible fashion compared to the present system. The results suggest that a majority of the start-stop cycles will have a duration of less than 20 h.

The modeling results show that additional flexibility within the electricity system, in the present study represented by smart charging of EVs and V2G, and hydrogen demand from an electrified industry, could significantly reduce the competitiveness of hydrogen-fueled gas turbines, especially in a case with additional flexibility provided by EVs. In the case of hydrogen demand for industrial purposes, the competitiveness of hydrogen-fueled gas turbines decreases when an industrial hydrogen demand is introduced, as the residual variations in power generation decrease due to larger investments in VRE and the smoothening effect conferred by flexible production of hydrogen.

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.

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Appendix A

Table A.1 – Cost data for the eligible technologies in the model.

Technology[d]	Investment cost[a] [€/kW$_{el}$]			Fixed O&M cost[a] [€/kW$_{el}$/yr]	Variable O&M cost[a] [€/kWh$_{el}$/yr]	Lifetime [years]	Minimum load level	Start-up time [h]	Start-up cost [€/MW]
	2030	2040	2050						
Coal									
Condense	2,049	2,049	2,049	44.9	2.1	40	0.35	12	56.9
CHP	2,049	2,049	2,049	44.9	2.1	40	0.35	12	56.9
CCS	3,810	3,277	2,018	105.5	2.1	40	0.35	12	56.9
CCS + bio-cofiring	4,210	3,677	3,418	107.6	2.1	40	0.35	12	56.9
Natural gas									
OCGT	466	466	466	15.7	0.4	30	0.5	0	20.2
CCGT	932	932	932	17.3	0.8	30	0.2	6	42.9
CHP	1,211	1,211	1,211	32.1	0.7	30	0.35	12	50.6
CCS	2,097	1,780	1,626	40.3	2.1	30	0.35	12	56.9
Nuclear									
Nuclear	4,770	4,322	4,124	153.7	0	60	0.7	24	400
Bio & Waste									
Condense	2,049	2,049	2,049	54.2	2.1	40	0.35	12	56.9
OCGT	466	466	466	7.92	0.7	30	0.5	0	20.2
CCGT	932	932	932	12.96	0.8	30	0.2	6	42.9
Waste	6,521	6,521	6,521	235.9	2.1	40	0.35	12	56.9
CHP	3,260	3,260	3,260	235.9	2.1	40	0.35	12	56.9
BECCS	4,106	3,573	3,314	105.5	2.1	40	0.35	12	56.9
Intermittent renewables									
Wind A[b] (onshore)	1,042	993	968	12.6	1.1	30	–	–	–
Wind B[b] (onshore)	1,192	1,143	1,118	12.6	1.1	30	–	–	–
Wind (offshore)	1,946	1,839	1,788	36	1.1	30	–	–	–
Solar PV A[b]	380	330	300	6.5	1.1	40	–	–	–
Solar PV B[b]	530	480	450	6.5	1.1	40	–	–	–
Small hydro	3,633	3,633	3,633	65.9	1	75	–	–	–
Hydrogen technologies									
Electrolyzer[c]	653	471	395	18	–	20	–	–	–
Lined rock cavern	11	11	11	–	–	50	–	–	–
Batteries									
Per kWh	149	102	79	–	–	25	–	–	–
Per kW	165	101	68	0.54	–	25	–	–	–

[a] Values shown for investment costs and fixed and variable O&M costs for thermal generation technologies are based on the World Energy Outlook, Edn. 2018 from the IEA [54] and the corresponding numbers for intermittent renewable technologies are obtained from the Danish Energy Agency (http://ens.dk/en/our-services/projections-and-models/technology-data).

[b] The difference between Wind A and Wind B is the distance to the existing grid, such that Wind B has to invest also in a grid connection (+€150/kW$_{el}$).

[c] Assumed efficiencies of the electrolyzers: in Year 2030, 70%; in 2040, 73%; and in 2050, 76%.

[d] CHP: Combined Heat and Power, CCS: Carbon Capture and Storage, BECCS: Bio-energy Carbon Capture and Storage, OCGT: Open Cycle Gas Turbine, CCGT: Combined Cycle Gas Turbine, PV: Photovoltaic.

Table A.2 – Electricity demand (in TWh) in the Regional Policy scenario, excluding transportation and new demands from industry, for the countries included in the study of Unger et al. [32].

	Year 2020	Year 2030	Year 2040	2050
Belgium	90	87	85	85
Denmark	35	32	31	31
France	521	541	528	526
Germany	558	526	489	475
Ireland	29	32	34	35
Netherlands	123	117	111	108
Norway	133	126	119	113
Poland	172	186	184	181
Sweden	149	141	130	124
United Kingdom	355	346	347	340

Table A.3 – Electricity demand (in TWh) in the Climate Market Policy scenario, excluding transportation and new demands from industry, for the countries included in the study conducted by Unger et al. [32].

	Year 2020	Year 2030	Year 2040	Year 2050
Belgium	92	97	109	122
Denmark	35	36	40	45
France	531	607	674	749
Germany	570	591	624	676
Ireland	30	36	43	50
Netherlands	126	131	142	154
Norway	136	141	152	161
Poland	175	209	235	257
Sweden	152	159	165	177
United Kingdom	362	388	442	484

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Table A.4 – Assumed future steel production (kt/year) [47].

Region	Year 2040[a]	Year 2050[a]
BE		4,000
CZ		5,500
FR1		4,700
FR4		3,500
FR5		6,200
DE3	31,100	31,100
DE4	2,200	2,200
DE5	4,320	4,320
HU		1,300
IT3		9,200
NL		7,000
PO2		5,000
SK		4,500
FI		3,000
ES1		3,300
SE2	1,900	1,900
SE4	3,000	3,000
UK1		8,900

[a] One tonne of steel is assumed to require 4 MWh of hydrogen in the production process.

Appendix B

The objective in both ELIN and EPOD is to minimize the total cost, including the investment and running costs in ELIN and the running cost in EPOD. Equations (B.1) and (B.2) describe the objective functions for ELIN and EPOD, respectively. In addition, the electricity demand in both ELIN and EPOD has to be satisfied for each year, region and time-step, which is enforced with the constraint listed in Eq. (B.3). A full mathematical description of the EPOD model can be found elsewhere [28].

$$minC_{tot} = \Sigma_{i\in I}\Sigma_{p\in P}\Sigma_{y\in Y}\Sigma_{t\in T}\left(C^{run}_{i,p,y,t} \cdot g_{i,p,y,t}\right) + \Sigma_{i\in I}\Sigma_{p\in P}\Sigma_{y\in Y}\left(C^{inv}_{i,p,y} \cdot i_{i,p,y} + C^{fix}_{i,p,y} \cdot x_{i,p,y}\right) \quad (B.1)$$

$$minC_{tot} = \Sigma_{i\in I}\Sigma_{p\in P}\Sigma_{t\in T}\left(c^{run}_{i,p,t} \cdot g_{i,p,t} + c^{cycl}_{i,p,t}\right) + \Sigma_{i\in I}\Sigma_{p\in P}C^{fix}_{i,p}\cdot x_{i,p} \quad (B.2)$$

$$\Sigma_{p\in P}g_{i,p,y,t} + \Sigma_{j\in I, j\neq i}q_{y,t,i,j} \geq D_{i,y,t} \;\; \forall\, i\in I,\;\forall\, y\in I,\;\forall\, t\in T \quad (B.3)$$

where.

C_{tot} is the total system cost.

I is the set of all regions.

P is the set of all technology aggregates.

Y is the set of all years in the investments period.

T is the set of all time-steps (differs between ELIN and EPOD).

$c^{run}_{i,p,y,t}$ is the running cost of region i, with technology aggregate p in year y at any time-step t.

$g_{i,p,y,t}$ is the electricity generation in region i, technology aggregate p, for year y and time-step t.

$c^{cycl}_{i,p,t}$ is the cycling cost (sum of the start-up costs and part-load costs) in region i, with technology aggregate p at any time-step t.

$C^{inv}_{i,p,y}$ is the investment cost of technology aggregate p in region i and year y.

$C^{fix}_{i,p,y}$ is the fixed operational and maintenance cost of technology aggregate p in region i and year y.

$i_{i,p,y}$ is the investment in region i and technology aggregate p in year y.

$x_{i,p,y}$ is the existing capacity in region i and technology aggregate p in year y.

$D_{i,y,t}$ is the demand for electricity in region i and year y at time-step t.

$q_{y,t,i,j}$ is the flow of power, positive or negative, from region j to region i in year y at time-step t.

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