ETN
Global

URGENCY AND POSITIONING OF GAS TURBINES IN FUTURE POWER SYSTEM

A quantitative assessment of dispatchable capacity needs

ETN Global Report

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Executive Summary

The Urgency and Positioning of Gas Turbines in Future Power System report provides the results of investigations into the need for dispatchable capacity. The investigation is based on projections of the demand for dispatchable electricity supply, derived from the European Network of Transmission System Operators for Electricity (ENTSO-E) Ten Year Network Development Planning report from 2024. Data is analysed for 2030 and 2040 and considers the expected assets for electricity production, storage, and interconnectors for Europe. The Netherlands, Germany, and the United Kingdom are considered as specific countries, but the analysis could easily be expanded to other countries.

Dispatchable electricity supply can be delivered by either storage, thermal, or nuclear assets. For storage assets, the available excess electricity for charging is the limiting factor. The use of nuclear assets is subject to the energy policy of individual countries. Thermal assets, such as gas turbines (GT), are subject to CO_2 reduction targets, which necessitates decarbonisation, for example, by H_2 firing or CO_2 capture. These policy considerations are also presented per country.

In 2030, limited availability of excess renewable electricity constrains the contribution of storage technologies. As a result, GTs are required to provide most of the positive residual energy in all three countries, particularly in the 11-24 h operating range. Long-duration energy storage (LDES) has only a limited impact at this stage due to insufficient charging volumes. At the same time, coal phase-out and ageing GT fleets increase the need for timely capacity additions, especially in Germany.

By 2040, higher renewable penetration increases negative residual energy and technically enables larger contributions from storage. However, this requires very substantial LDES capacities, which economic viability, permitting timelines, and infrastructure integration remain uncertain. Even with optimistic LDES deployment, GTs continue to provide critical multi-day firm capacity. In scenarios without large-scale LDES rollout, GTs remain the dominant provider of dispatchable energy.

Across all countries evaluated, projected GT full-load hours decline, often below 2,000 h/year. This indicates that future GT economics cannot rely solely on wholesale electricity markets. Capacity remuneration mechanisms and dedicated low-carbon dispatchable power business models are required to ensure availability and incentivise decarbonisation.

Fleet analysis shows that 29-60% of existing GT capacity will exceed 35 years of lifetime by 2040. Given manufacturing backlogs and development lead times of five to eight years, delayed investment decisions directly translate into security of supply risks.

Overall, the analysis demonstrates that GTs remain a structural component of reliable power systems in 2030 and 2040. Their role evolves from bulk energy provision to strategic firm capacity, system stability support, and long-duration system balancing. Timely planning, stable policy signals, and investment frameworks aligned with extended asset development cycles are required to ensure that sufficient low-carbon dispatchable capacity is available during the energy transition.

Acknowledgments

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1. Objective

The objective of this investigation is to assess how gas turbine (GT) power plants can contribute to security of supply and grid stability in a future, low-carbon electricity system characterised by declining dispatchable power generation capacity and increasing variability induced by renewable power generation. Three exemplary countries have been selected for the comparison: the Netherlands, Germany and the United Kingdom (UK). Each of these countries exhibits its own characteristics: the Netherlands show high penetration of wind and high availability of natural gas; Germany is greatly connected within the European energy system with a high renewable electricity share; UK is connected to Europe via gas pipeline and electricity interconnectors with high potential for wind power generation and high availability of natural gas.

The taskforce developed a shared, evidence-based view among GT operators, original equipment manufacturers (OEMs), service providers, and academia on the role of GTs as dispatchable assets. Using publicly available data and representative system examples, the analysis identifies applications in which GTs offer technical and system-level advantages compared with alternative technologies.

The investigation quantifies the time-critical demand for capacity additions to highlight the urgency of action while demonstrating that GTs are capable of low- or zero-carbon operation using alternative fuels (e.g., H_2) and processes (e.g., carbon capture). The results provide policy makers and grid operators with a clear, technically grounded basis for decisions on dispatchable capacity planning, market design, and regulatory frameworks.

2. Positioning of Gas Turbines

The positioning of GTs in current and future energy markets depends on market needs and grid developments. Due to their flexibility, GTs are deployed in different manners (e.g., fast response or load following) and for different purposes (e.g., grid balancing or industrial heat and power). While GTs have historically been deployed as flexible units to support conventional baseload technologies (e.g., coal-fired and nuclear power plants), their current operation is strongly influenced by the rate of renewable energy deployment. Understanding energy market trends and GT capabilities is crucial to derive their role and position in future energy markets.

2.1. Energy Market Trends

Global electricity demand is expected to expand significantly through 2050 as electrification deepens across transport, industry, and buildings. At the same time, renewable generation (e.g., wind, solar, hydropower, and other renewables) is increasing rapidly in today's markets and is projected to provide the major share of generation in the future [1]. Both trends place increased pressure on generation, flexibility, and grid infrastructure. Even in high renewable scenarios, dispatchable capacity is required to manage system stability, cover periods of low renewable output, and provide system inertia and reserves. Overall, the role of dispatchable power supply is expected to evolve from energy provision towards security of supply, reliability, and flexibility. As renewable penetration can result in negative residual load (i.e., total electricity demand minus intermittent renewable generation), energy storage technologies are emerging as semi-dispatchable solution. However, their application needs to be distinguished as short-duration, e.g., battery electric storage systems (BESS), mid-duration, e.g., pumped hydro storage (PHS), and long-duration energy storage (LDES).

BESS are expanding rapidly and provide crucial short-duration grid services such as frequency response, voltage support, and short peaking capacity. BESS are predicted to reach significant scale by 2040 (i.e., hundreds of GW globally) [2], but economic constraints limit their viability for multi-day energy provision beyond ~4-6 hours ('h') without prohibitive cost [3].

PHS is the most widely deployed energy storage technology with nearly 190 GW of installed capacity worldwide in 2024 [4]. PHS offers unique potential to store surplus renewable energy over hours to days and provides essential flexibility, inertia, and grid balancing services that BESS cannot economically deliver at multi-hour durations. Projects are rapidly expanding with annual global capacity additions forecasted to double to 16.5 GW by 2030, mainly driven by development in China and other emerging markets [5]. However, in other markets with high PHS deployment (e.g., Europe), capacity additions are more geographically constrained and remain a topic of interest primarily in selected countries (e.g., Spain and Austria) [5]. In general, expansion faces high upfront costs, long permitting and construction lead times, and geographical and environmental siting constraints, requiring strong policy support and streamlined planning frameworks to unlock its full potential in supporting decarbonised power systems. [6]

LDES technologies (e.g., compressed air energy storage [CAES] or thermal storage) are emerging to cover sustained periods of low renewable output (>8 h). Despite growing interest and investment, deployment is nascent and likely to accelerate later in the decade. LDES expansion could reach tens of GW by 2025 and potentially over 100 GW by 2040 under rapid decarbonisation scenarios. [7]

However, the availability of sufficient excess renewable electricity is a prerequisite for BESS, LDES, and PHS technologies to fulfil their anticipated role within the future energy system. Otherwise, conventional dispatchable technologies (e.g., coal-fired, nuclear, or gas-fired) remain essential.

Global coal-fired generation is projected to decline as new renewable and low-carbon capacity comes online and policies increase carbon pricing. IEA analysis shows coal's share in power generation falling significantly by the mid-2030s, though coal may persist in some regions (mainly China and India) depending on policy and economic context [1]. As coal-fired generation is retired, the energy system loses traditional baseload and firm capacity.

Nuclear capacity faces mixed prospects: complete shut-downs have already happened in some countries (e.g., Germany) and declines are expected in some regions while new high-capital reactors emerge in others. In Europe, overall nuclear capacity could fall by ~23 % between 2021 and 2035, with expansions in selected markets such as France and the UK [8]. However, nuclear power is forecasted to grow in terms of absolute generation, driven by restarts (e.g., in Japan) and new builds (e.g., in USA, Japan, South Korea, and France) [1]. Nevertheless, nuclear power alone cannot deliver the required dispatchable capacity growth in an adequate timeline.

Open-cycle (OC) and combined-cycle (CC) gas turbine power plants can firm variable renewable outputs due to their fast start-up, ramp rate, and dispatch flexibility. Modern GTs can ramp quickly to respond to sudden reductions in wind or solar output, providing frequency regulation and reserve capacity that variable renewables cannot inherently supply [9]. As a result, dispatchable assets will remain essential, but shift their operation profile from bulk generation towards supporting security of supply during times of low renewable penetration and high demand [1]. A recent development is increasing demand from newly built data centres, particularly for artificial intelligence (AI) applications. The current electricity demand from data centres is estimated at 415 TWh/yr, which is equal to ~1.5 % of global demand. However, a predicted 15 % annual increase in demand leads to around 945 TWh/yr in 2030. Various energy sources are projected to deliver the required electricity for data centres with natural gas-based generation foreseen to provide ~250 TWh in 2030 [10].

Electricity supply and consumption technologies operate over different economically viable time periods. The relative occurrences of operation durations (in hours) are shown in *Figure 2.1* for actual deployment of BESS, PHS, coal-fired units, and GTs in various EU27 countries in 2025. The distribution of occurrences is further evaluated in clustered regimes. The distribution of occurrences for BESS and PHS are comparable for charging ('ch') and discharging ('dch'). For BESS, most operation occurs for 0-4 h (ch: 90 %, dch: 89 %), clearly indicating economically viable operation up to 4 h under current market conditions. For PHS, most operation occurs for 5-10 h (ch: 60 %, dch: 46 %) and 0-4 h (ch: 29 %, dch: 44 %). GTs are deployed across the duration envelopes, with most occurrences for 11-24 h (39 %) and 0-10 h (34 %). With the phase-out of coal-fired units, GTs are expected to cover a major share of their dispatchable energy. As coal-fired units are mainly operated in long-duration intervals > 24 h (69 %), GT operation in the EU can be expected to shift to longer duration intervals in the near future. However, when renewable penetration is high enough to cover the electricity requirement at particular times (e.g., at noon), the requirement for long-duration GT operation will reduce.

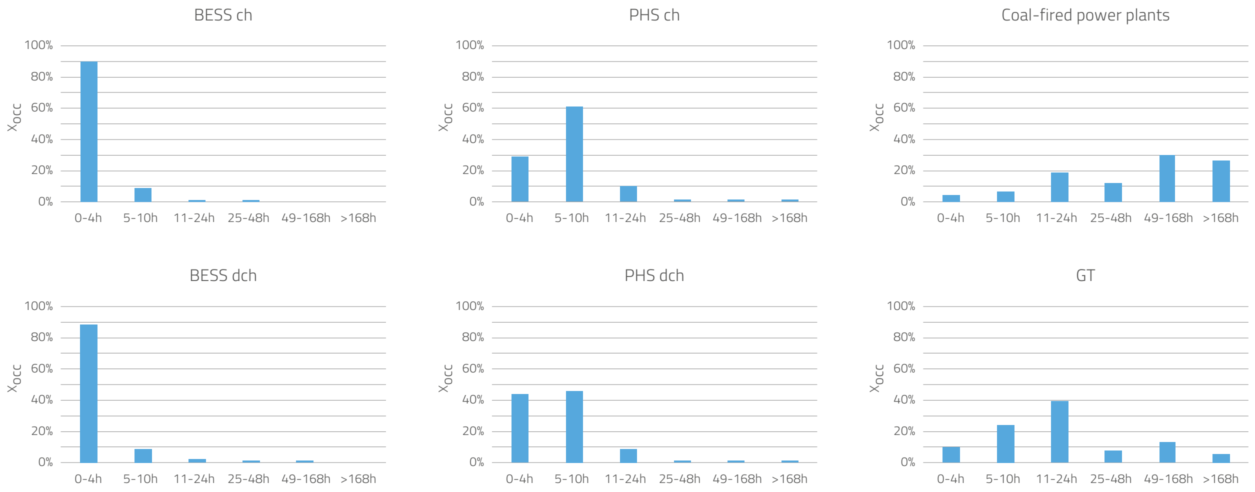

Figure 2.1: Relative occurrence x_{occ} of different operation durations per interval Δt_{op} for individual technologies (BESS: battery electric storage system, PHS: pumped hydro storage, coal-fired power plant, GT: gas turbine, ch: charging, dch: discharging) in various EU27 countries in 2025, based on data from the ENTSO-E Transparency Platform [13].

2.2. Role of Gas Turbines

Gas turbine operation can be characterised by operating hours per year and starts per year for peaking, cyclic, mid and base operation. *Figure 2.2* provides an overview of annual starts and hours of OCGT and CCGT power plants in the Netherlands (9.0 GW) and Germany (9.3 GW) in 2025, and the UK (18.7 GW) in 2021 that are included in the ENTSO-E Transparency Platform database [13]. The assessment for the UK is limited to 2021, as no further information has been reported to the database since the UK left the EU. Given the significant shift in GT operation across all European countries in recent years, the high annual hours and low number of starts observed for the UK in 2021 should be interpreted with caution, as current operation is expected to be similarly constrained as in Germany and the Netherlands. With few GTs exceeding 6000 hours (only UK in 2021), only 3 % of GT power plant operation can be attributed to the base operation regime. A further 45 % of GTs are operated in the mid operation regime with most of these assets being deployed for industrial power generation. The remaining GTs are deployed for low number of hours and many starts per year, with 12 % and 40 % deployed as cyclic and peaking units, respectively.

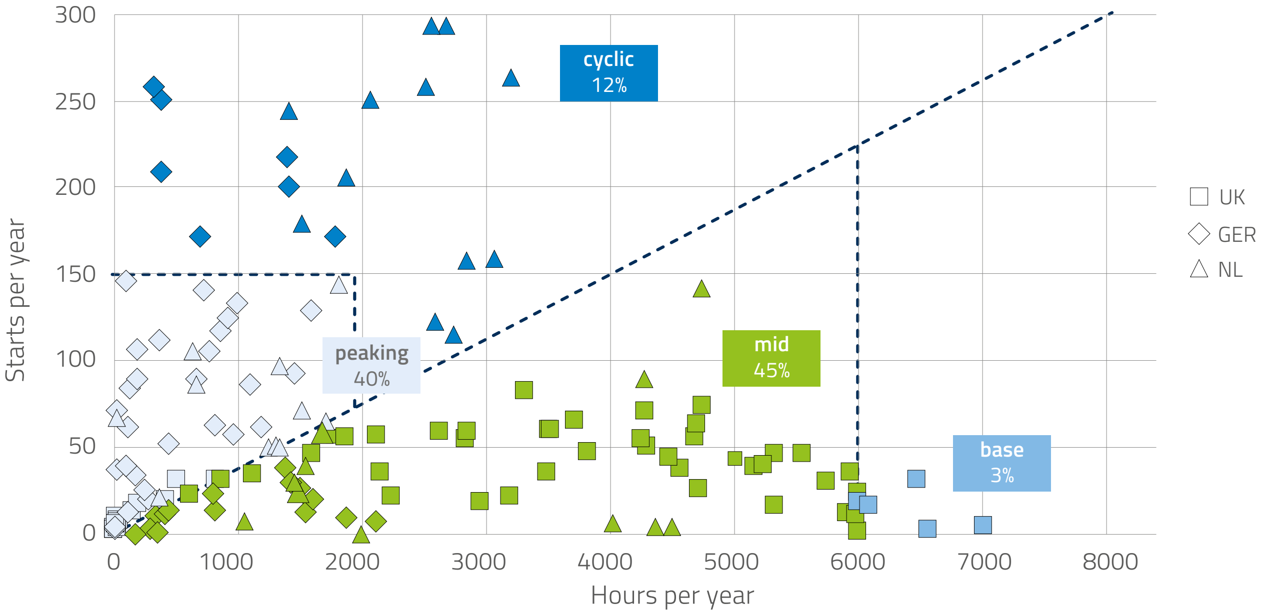

Figure 2.2: Operating profiles of OCGT/CCGT power plants in the Netherlands (NL) and Germany (GER) in 2025 and the United Kingdom (UK) in 2021, based on data from the ENTSO-E Transparency Platform [13], and clustering (peaking, cyclic, mid, and base) adapted from [14].

The electricity system requires several services that can be categorised as constraint management, adequacy, wholesale, and grid stability. *Table 2.1* shows these categories, individual markets, products and technology suitability for each of the services.

GTs have the possibility to provide these services inherently with only minor limitations. BESS contribute short-duration voltage and frequency support but lack long-duration capacity without significant cost escalation. LDES potentially covers the same services as BESS. However, due to the absence of commercial-scale deployments and dedicated remuneration schemes, there is a high uncertainty about which services LDES can provide economically [9]. The role of storage technologies will always depend on the availability of excess renewable energy or low-price intervals for electricity procurement.

Ancillary markets (including spinning reserves, regulation, and system stability metrics) increasingly value ramping capability and reserve provision. GTs participate in ancillary markets due to fast response times. BESS provide high-speed frequency response but are limited in duration, emphasising a complementary role rather than a substitute for firm capacity [2], [15].

Table 2.1: Overview of suitability of technologies for grid service markets.

Category	Market	Product	Compensation	OCGT	CCGT	BESS	LDES	🟩	🟧	🟦	⬛
Constraint Management	Voltage Control	Reactive Power	Energy	🟩	🟩	🟩	🟩	Possible	Possible under conditions	Potentially possible (technology not mature enough)	Not possible
	Congestion	Redispatch	Energy	🟩	🟩	🟩	🟩				
	Restoration	Black Start	Capacity	🟩	🟩	⬛ (1)	⬛ (1)				
Adequacy	Capacity Market	Capacity Renumeration Mechanism NL	Capacity	🟩	🟩	🟩	🟩				
	Strategic Reserve		Capacity	🟩	🟩	⬛ (3)	🟦				
Wholesale	Day Ahead		Energy	🟩	🟩	🟩	🟩				
	Intraday		Energy	🟩	🟧 (4)	🟩	🟦				
	Balancing		Energy	🟩	🟧 (4)	🟩	🟦				
Grid Stability	FCR (<30 s)	Frequency Containment Reserve	Capacity	🟧 (2)	🟧 (2)	🟩	🟦				
	aFRR (<5 min)	Automatic Frequency Restoration Reserve	Both	🟧 (2)	🟧 (2)	🟩	🟦				
	mFRR (<12.5 min)	Manual Frequency Restoration Reserve	Both	🟩	🟧 (2)	🟩	🟦				
	RR (<60 min)	Replacement Reserves	Both	🟩	🟩	🟩	🟩				
	Inertia		Capacity	🟧 (2)	🟧 (2)	🟧 (2)	🟧 (2)				

Notes

(1) Black Start facility shall be able to operate for >24 h. Limited number required.
(2) Possible when plant is in operation
(3) Meant for solving critical security of supply issues, so time limitation is not desirable
(4) Depending on power plant condition (cold/warm/hot) for start-up
OCGT: Open Cycle Gas Turbine | CCGT: Combined-Cycle Gas Turbine | BESS: Battery Energy Storage System
LDES: Long-Duration Energy Storage

Black start capability requires units that can be started without external grid power. Many GT power plants configurations are suitable for black start operations, making them critical assets to restore grids after wide outages. Other firm power plants with black start capability exist but are fewer in number, reinforcing the role of GTs in resilience planning. While inverter-based resources and distributed technologies are advancing, GTs likely remain essential for large-area restoration scenarios through 2035 and into 2050 [1].

As a result of emerging energy market trends, GT OEMs face strong demand for their products. GE Vernova expected ~80 GW of GTs under contract by 2025, which lead to the decision to increase the annual production capacity to 20 GW by mid-2026 with option to further increase to ~24 GW in 2028, equal to 90-100 heavy-duty GT units per year. GE Vernova states that production slots are sold-out until 2028, and less than 10 GW is left for sell in 2029 [16]. Similar developments are stated by Siemens Energy with the annual GT production capacity to be increased from 17 GW in 2024 to 22 GW in 2025-2027 with further plans to increase to >30 GW between 2028-2030. Orders for new capacity nearly doubled from 2024 (16 GW, 100 units) to 2025 (26 GW, 194 units) with secured orders of 36 GW with over 200 units [17]. Similar developments are published by Solar Turbines (2.5 times annual production capacity between 2025-2030 [18]), Baker Hughes (2 times annual production capacity by the first half of 2027, sold-out until end of 2028 [19]), Mitsubishi Heavy Industries (+30% annual production capacity announced [20]) and Doosan Enerbility (delivering 18.7 GW by 2028 only to North America data centres [21]).

As stated in Chapter 2.1, future energy system scenarios predict considerable contributions from GTs. However, if operated using natural gas, carbon-related emissions (e.g., CO_2) are inherent. For that reason, three prominent options are available for future GT use in zero-emission scenarios. First, GTs are being engineered for blended or 100% H_2 operation. The use of H_2 reduces carbon-related emissions by up to 100% depending on the blending rate. Remaining emissions are linked to using ambient air for combustion, particularly N_2, which provokes NO_x formation due to high-temperature combustion. Subsequent exhaust gas aftertreatment systems, such as selective catalytic reduction (SCR), are suitable for required NO_x reduction, if needed at all. Fully H_2-capable GTs are announced to be commercially available by 2030 [22], while SCR catalysts are already state-of-the-art. The second option is to integrate natural gas-fired GTs with post-combustion carbon capture and storage (CCS) to provide low-carbon firm power [23], [24].

While CCS technology is commercially available with many technologies claiming TRL 9 [25], the high upfront cost and the efficiency penalty due to the heat required for amine regeneration hinder its commercial breakthrough. Furthermore, fractions of CO_2 emissions will be emitted due to techno-economic limitations (e.g., <100 % capture rate during nominal operation including start-up). Recognising this limitation, some jurisdictions have set annual thresholds, e.g., the UK government with <5 % CO_2 emissions unabated anually [26]. A third, more niche, alternative is the use of alternative fuels, such as ammonia (NH_3) or bioliquids such as hydrotreated vegetable oil (HVO) or methanol. The use of the NH_3 is still subject to R&D, while HVO has been demonstrated on commercial scale [27], although the widespread implementation is hindered by limited feedstock availability [28].

3. Quantitative Analysis and Methodology

To quantify the need for dispatchable power in the future, an analysis is performed based on hourly data from the Ten Year Network Development Planning (TYNDP) report (version 2024) by the European Network of Transmission System Operators for Electricity (ENTSO-E) [29], [30]. The data is generated for Europe for the target years 2030 and 2040 by a least-cost energy system analysis utilising a Plexos [31] model. The selected weather year is 2009 [29], [30]. It considers the expected developments in electricity demand, production and storage assets, interconnectors, and prices. From the data, the residual load P_{RL} is derived as the difference between the electricity demand P_D, the variable renewable electricity supply P_{VRES} and the net imports P_{IMP}, and which needs to be supplied by dispatchable assets like energy storage systems and/or thermal assets.

$$P_{RL} = P_D - P_{VRES} - P_{IMP}$$

Two situations can be distinguished:

- $P_{RL} > 0$ (dispatchable power is required to meet the demand)
- $P_{RL} < 0$ (excess renewable power supply that could be used to charge energy storage systems)

An example is given in *Figure 3.1*, which plots the residual load for the Netherlands for 2030 and 2040 as a time series on the left and a year duration curve on the right for the Netherlands, Germany, and the UK.

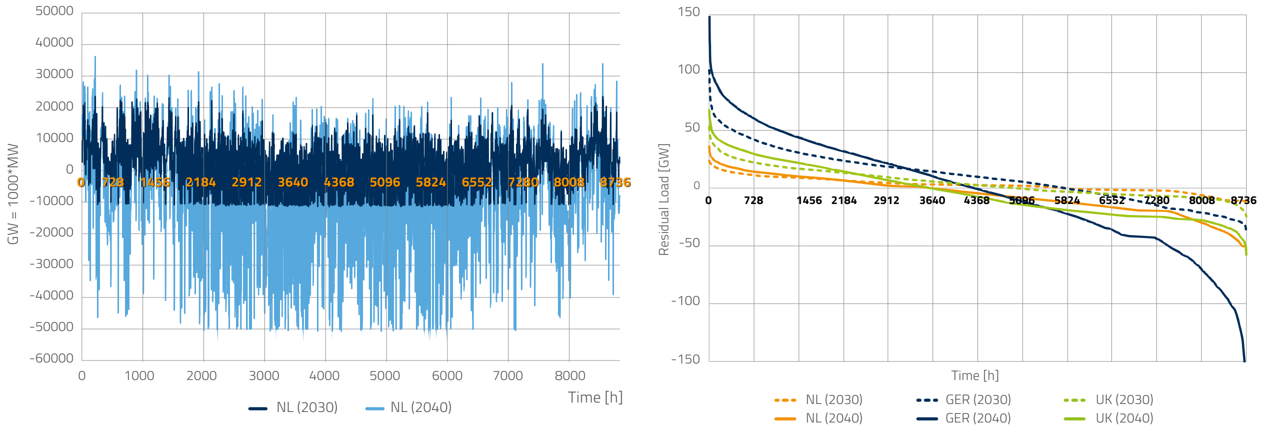

Figure 3.1: Residual load as a time series for the Netherlands (left) and as load duration for the Netherlands, Germany and the UK (right).

As a next step, the residual load is decomposed into power blocks Q characterised by power (MW) and duration (h), as illustrated in *Figure 3.2*. From these power blocks, required positive and negative volumes (TWh) and capacities (GW) for defined durations can be derived. The selected durations are 1-4 h, 5-10 h, 11-24 h, 24-48 h (1-2 days), 48 -168 h (2-7 days) and >168 h (>7 days). It must be mentioned that the negative P_{RL} blocks are not uniquely linked to the positive P_{RL} blocks with the same duration as their occurrences are distributed throughout the year and the analysis does not allow the consideration of time-resolution. Furthermore, the charging volumes will not translate fully into discharging volumes due to the round-trip efficiency (RTE) of storage systems. In addition, negative P_{RL} volumes can be used for electrolytic production of H_2 for later consumption in power generation or as feedstock. However, energy storage via H_2 to power (H2P) is associated with a lower RTE of 42 %, when assuming 80 % electrolysis efficiency and 60 % re-electrification efficiency using a CCGT.

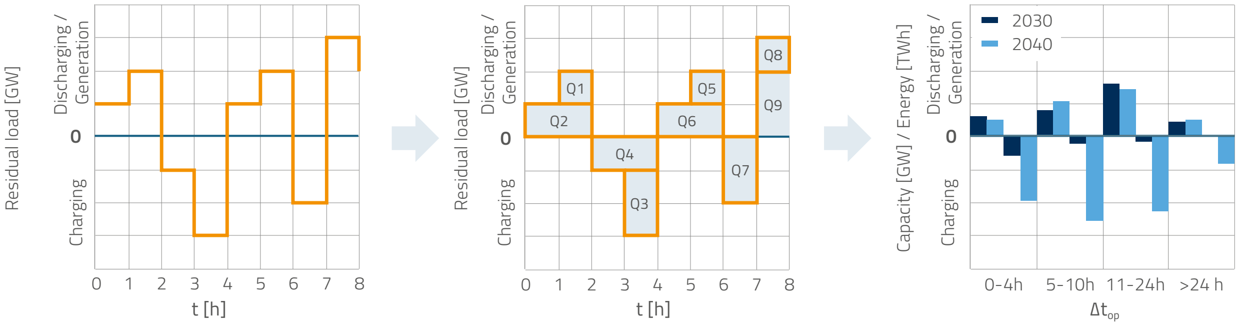

Figure 3.2: Decomposition of residual load into power blocks with defined duration and volume.

Based on the defined power blocks, the role of charging and discharging / generation technologies is evaluated based on the allocated electricity and installed capacities (*Figure 3.2*). The allocation accounts for technology-specific characteristics and typical BESS and PHS deployment durations (refer to *Figure 2.1*). Charging and discharging technologies (i.e., BESS, PHS, and LDES) are characterised by a RTE (BESS: 90 % [32], PHS: 75 % [32], and LDES: 50 % [33]). First, energy storage technologies are deployed to shift negative residual energy, prioritising BESS, PHS, and LDES in first, second, and third order, respectively. After all negative residual energy has been utilised, GTs are deployed to supply the remaining positive residual energy. The technologies are allocated based on the following methodology:

1. BESS and PHS are only deployed (charging and discharging) in the 0-4 h and 0-10 h range (*Figure 2.1*), respectively. Charging electricity is limited by the current capacity per country (PHS only) and a maximum capacity factor of 50 % for charging (BESS and PHS).

2. Charging in the respective duration interval accounts for either (i) the maximum negative residual energy available (i.e., not all positive residual energy is supplied) or (ii) the negative residual energy required to fulfil maximum positive residual energy demand by considering the RTE (i.e., not all negative residual energy is used).

3. LDES is deployed using the total remaining negative residual electricity in all duration intervals and discharged beginning from shortest to largest duration interval until all stored energy is discharged.

4. GTs are deployed to deliver the remaining positive residual energy.

Two cases are analysed for comparison: (a) without LDES (i.e., step 3. is omitted) and (b) with LDES. For the latter, LDES is considered any technology that is not H2P, as energy storage via H_2 incorporates both electrolysers and GTs. In (a), the potential of energy storage via H_2 and re-electrification in GT is assessed to give a potential for GT decarbonisation.

4. Results

For the evaluation, three countries (i.e., the Netherlands, Germany, and the UK) have been chosen to represent energy system trends in the European Union. First, an introduction to each country's energy system landscape is provided and compared with the assumptions from the ENTSO-E report. Second, the residual load methodology is applied to each country separately. The results are discussed using the individual country's policy developments and energy system characteristics as context. In a final step, the individual countries' results are further processed by considering different storage technologies to mitigate the residual load. The goal is to derive the role of GTs in future energy systems.

4.1. The Netherlands

In 2026, the energy system in the Netherlands incorporates 41.2 GW renewable generation (i.e., solar: 29.3 GW and wind: 11.9 GW). Gas-fired capacities account for the largest share of dispatchable technologies (18.4 GW or 81 %, including small scale gas engine CHP's), followed by coal-fired generation (4.0 GW). Nuclear power (0.5 GW) and biomass (0.4 GW) play a minor role. Due to geographical limitations, no PHS capacities exist [13].

Energy System and Political Developments

ENTSO-E estimates that GT capacity, encompassing both OCGT and CCGT technologies, will account for 12 GW in 2030 and 13.6 GW in 2040. The installed capacity in 2025 was approximately 12 GW. Battery capacity is expected to be 9.3 GW in 2030, rising sharply to 30.8 GW by 2040. Wind capacity (offshore and onshore) is projected to increase from 11.9 GW in 2026 to 23.6 GW in 2030, and further to 44.6 GW in 2040. Solar capacity is also on a steep growth trajectory, expanding from 29.3 GW in 2026 to 59.3 GW and 102.4 GW in 2030 and 2040, respectively.

Given the significant availability and demand for negative and positive residual energy, respectively, with durations between 11-24 h, LDES emerges as an appropriate solution. GTs operating on H_2 may be considered as part of the LDES landscape and will compete with other LDES technologies. However, the rapid expansion of renewable capacity introduces uncertainty; should this growth fail to materialise, the availability of electricity for charging will decrease, necessitating greater reliance on GT assets.

From a policy perspective, several pivotal developments are underway. From 2030 onwards, coal is legally prohibited for power generation. While the Dutch government has ambitions for nuclear energy, the single operational nuclear plant will be out of service by 2040, and no new nuclear capacity is anticipated before that time. Expanding offshore wind capacity also presents significant challenges, prompting the government to reconsider its targets. Meanwhile, TenneT's annual Adequacy Review [34] highlights growing concerns about security of supply. In response, the government is contemplating the introduction of a Capacity Remuneration Mechanism (CRM) to ensure the availability of gas-fired capacity.

There is no clear pathway for H_2 at present, with delays in rolling out the H_2 backbone pipeline and inconsistent support mechanisms for preparing power plants for H_2 (co-)firing. Awareness is increasing regarding the vulnerability of offshore infrastructure and the Netherlands' growing dependence on energy imports, particularly natural gas.

Future Role of Gas Turbines

Figure 4.1 presents the outcomes of the residual load methodology for the Netherlands. The figure reveals a pronounced demand for positive residual load in the 11-24 h range. If sufficient electricity is available for charging, LDES could fulfil this requirement. In cases where charging electricity is insufficient, thermal assets will be necessary to meet the demand.

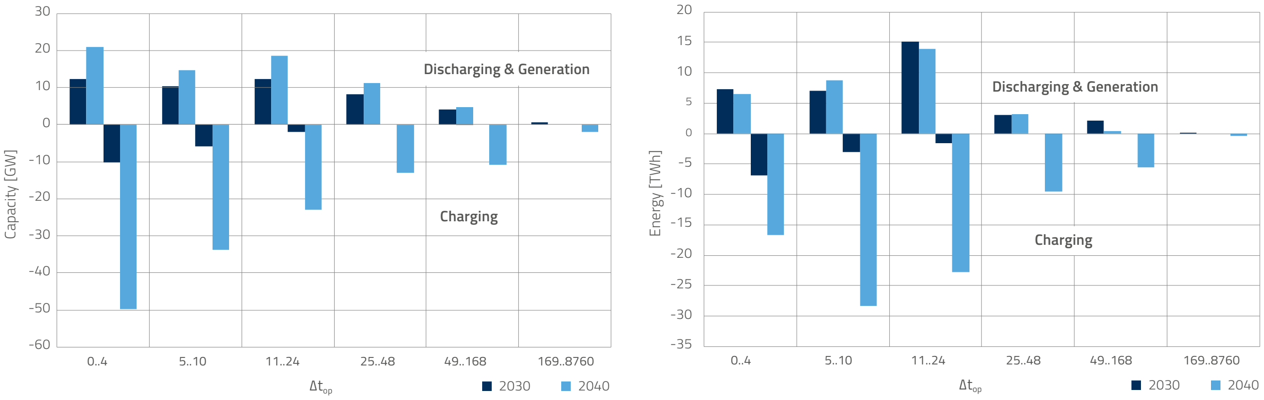

Figure 4.1: Residual load (left: capacity, right: energy) analysis for the Netherlands.

By 2030, a total of 34.6 TWh must be discharged or generated, with only 11.5 TWh available for charging. Consequently, at least 23.1 TWh will need to be supplied by thermal assets, specifically GTs. In 2040, the situation changes considerably, as 32.9 TWh must be discharged or generated, while 83.2 TWh is available for charging or H_2 production. This scenario necessitates an average RTE of 40% to maintain system balance.

4.2. Germany

In 2026, the energy system in Germany incorporates 181.2 GW renewable generation (i.e., solar: 104.0 GW and wind: 77.2 GW). Gas-fired capacities account for the largest share of dispatchable technologies (35.3 GW or 40 %), followed by coal-fired power (30.2 GW), and biomass (8.9 GW). Following the phase-out of all nuclear assets in 2022, no nuclear power exists. PHS compromises 9.4 GW [13].

Energy System and Political Developments

Offshore and onshore wind capacity is projected to increase from 77.2 GW in 2026 to 145 GW in 2030. Solar capacity is also on a steep growth trajectory, projected to expand from 104 GW in 2026 to 215 GW in 2030 [35]. The expansion of renewable generation is accompanied by strong growth in BESS capacities from 10.3 GW for in-home BESS and 1.9 GW for grid-scale in 2025 [36] to 67 GW for in-home BESS and 24 GW for grid-scale BESS capacities in 2037. Further expansion to 98-113 GW for in-home BESS and 43-54 GW for grid-scale BESS are anticipated until 2045. These estimates do not include the potential for vehicle to grid (V2G) battery dispatch from electric vehicles [37]. The significant renewable capacity additions potentially lead to high negative residual loads which cannot be used by BESS alone, and therefore LDES becomes essential. In cases where charging electricity is insufficient or inadequate in duration, thermal assets such as GTs will be necessary to meet the demand. GTs operating on H_2 may be considered as part of the LDES landscape and will compete with other LDES technologies. Currently, the German government foresees only H_2, and thus H_2-fired GTs, as LDES technology [37].

The transition of the German energy landscape goes further than renewable generation and storage. Stepwise phase-out of all coal-fired capacity by 2038 removes a large share of dispatchable power supply [38]. Simultaneously, renewable capacity expansion remains below policy targets, increasing reliance on dispatchable power generation during low wind and solar periods [39]. BESS currently cannot close this gap at scale, although extension is accelerating with 78 GW of new installations already approved. BESS grid connection requests peaked at 720 GW, however most requests proved non-binding as the introduction of a connection fee reduced applications by 65 % [40]. With remaining high uncertainty in BESS deployment, unavailability of sufficient negative residual load, and uncertainties regarding the techno-economic viability of LDES, the need for dispatchable capacity using thermal assets is evident. However, policy signals on dispatchable capacity deployment remain unstable. Announcements under the Kraftwerkssicherheitsgesetz ("Power Plant Safety Act") have shifted repeatedly: from 23.8 GW of H_2-ready capacity by 2035 (announced in 2023), to 10 GW of new-builds targeting 100 % H_2 by 2040 (announced in February 2024), to a mixed portfolio of 12.5 GW with CAPEX and OPEX support (announced in July 2024), followed by 20 GW of "technology-open" capacity (announced in May 2025) [41], and finally 10 GW "long-duration runnable" capacities, which is expected to be tendered in 2026 [42]. If these capacities are gas-based power generation technologies, they must be H_2-ready. Additional tenders will be published in 2027 and 2029/2030 [42]. To ensure the economic operation of technology-open dispatchable capacities, a capacity remuneration market will be introduced by 2027 [42]. Moreover, the CO_2 transport and storage act was published in 2025, and the eligibility of gas-fired plants with CCS was not explicitly excluded [43].

Future Role of Gas Turbines

Figure 4.2 presents the outcomes of the residual load methodology for Germany. In 2030 and 2040, respectively, most and second most capacity (2030: 47.6 GW, 2040: 67.8 GW) required to meet the positive residual load demand is in the 5-10 h range. In this range, BESS and PHS will play a minor role due to insufficient economics (refer to *Figure 2.1*) for BESS and limited capacity for PHS (9.7 GW in 2025). Beyond 10 h of operation, the maximum positive residual capacity amounts to 38.3 GW in 2030 and 78.7 GW in 2040. This capacity, which can be supplied by LDES and GTs, is sufficient to cover demand across the remaining longer-duration intervals.

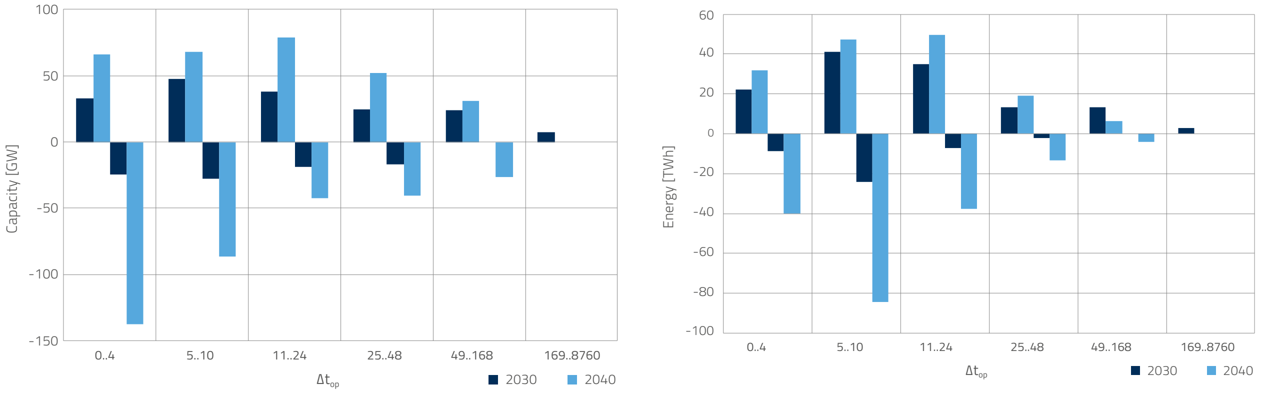

Figure 4.2: Residual load (left: capacity, right: energy) analysis for Germany.

For operation up to 4 h, positive residual energy accounts for up to 22.1 TWh and 32.0 TWh in 2030 and 2040, respectively. The highest positive residual capacity is present in the 5-10 h and 11-24 h range in 2030 (47.6 GW) and 2040 (49.7 GW), respectively. Most negative residual capacity is present in the 5-10 h range for both years (2030: 28 GW, 2040: 86.4 GW). With insufficient negative residual energy (33.1 % of positive residual energy before RTE adjustment) in 2030, BESS, PHS, and LDES cannot solely supply the positive residual energy and GTs will be required. In 2040, more negative residual energy is available than required (116 % of positive residual energy before RTE adjustment), highlighting the potential of BESS, PHS, and LDES to cover high shares of positive residual energy demand. Therefore, the role of energy storage technologies is expected to change from supportive in 2030 to essential in 2040. This also highlights the potential of H2P to substantially support GT decarbonisation from 2040 onwards.

4.3. United Kingdom

In 2025, the energy system in the UK incorporated 48.9 GW renewable generation (i.e., solar: 18.1 GW and wind: 30.8 GW). Gas-fired capacities accounted for the largest share of dispatchable technologies (~35 GW), followed by nuclear power (6.4 GW), and biomass (3.8 GW) [44]. PHS compromised 2.7 GW in 2024 [45]. The last coal-fired power plant (Uniper's Ratcliffe Power Station) closed in 2024.

Energy System and Political Developments

ENTSO-E estimates that GT capacity in UK will be 29.7 GW in 2030 and reduce to 11.8 GW in 2040. In 2025, the installed GT capacity of OCGT and CCGT (excluding CHP) was approximately 35 GW. Therefore, ENTSO-E's 2030 projection is broadly in line with the UK government's Clean Power 2030 Action Plan [46]. This plan follows analysis by the National Electricity System Operator (NESO) stating that security of power supply could be provided if the UK maintained its fleet of gas-fired power stations but limited their use to less than 5% of overall generation [47]. The UK Capacity Market is the mechanism by which generation capacity and security of supply are ensured. Measures to retain gas assets in the Capacity Market and secure multi-year agreements to encourage investment in lifetime extension are being considered. However, the renewable and energy storage build-out required for the Clean Power 2030 Action Plan is substantial, and therefore any shortfall will need to be covered by thermal assets. In addition to the existing gas capacity and consumer-led flexibility, the technologies identified to deliver the Clean Power 2030 Action Plan include 43-50 GW of offshore wind, 27-29 GW of onshore wind, 45-47 GW of solar, 23-27 GW of BESS, 12-14 GW of interconnectors, 4-6 GW of LDES, and 2-7 GW of low-carbon dispatchable power [46].

The UK government recognises that LDES is a potential solution for time shifting capacity with PHS considered the most mature. LDES scenario modelling in the UK evaluated capacity of 1.5-12 GW by 2035 and 2.5-20 GW by 2050 [48]. To promote LDES investment, the UK set out a technology-neutral cap and floor scheme for LDES in March 2025 with the first tender application window opened in April 2025. The first successful LDES projects are expected to be announced in Summer 2026 [49].

H2P, Power CCUS, and biomethane are currently considered as the leading low-carbon dispatchable power technologies required in the future UK energy system [51]. NESO suggests that up to 2.7 GW of Power CCUS and H2P capacity could be required by 2030 [47], increasing up to 48.3-55.2 GW in some 2050 net-zero scenarios. To support the additional CAPEX and OPEX of Power CCUS, the Dispatchable Power Agreement (DPA) business model has been developed by the UK government [52]. The first DPA between the UK government and Net Zero Teesside (a Power CCUS joint venture between Equinor and BP using a GE Vernova 9HA GT) was signed in late-2024 [53]. A similar H2P business model is currently under development, and the UK government has committed to launching this in 2026 [54].

Future Role of Gas Turbines

Figure 4.3 shows the results of the residual load analysis for the UK. These results show that, in 2030, the most significant capacity (~27 GW) required to meet the residual load demand is in the 11-24 h range. In this range, thermal generation (e.g., GTs) would be an option as the UK no longer has any coal-fired generation. LDES could also be a solution, however significant development of these first-of-a-kind technologies would be required. By 2040, the required capacity in the 11-24 h range increases to ~30 GW.

By 2030, 59.4 TWh must be discharged or generated for durations longer than 10 h, with only 10.7 TWh available for LDES charging or H_2 production. Consequently, at least 36.3 TWh will need to be supplied by thermal assets, such as GTs, and potentially more if LDES and electrolyser build-out is slow resulting in renewable curtailment. In 2040, 39.6 TWh must be discharged or generated for durations longer than 10 h, while 63.6 TWh is available for LDES charging or H_2 production. This scenario necessitates an average RTE of 62 % to maintain system balance, which is unlikely to be achieved with LDES or H_2 suggesting that other dispatchable technologies will be required.

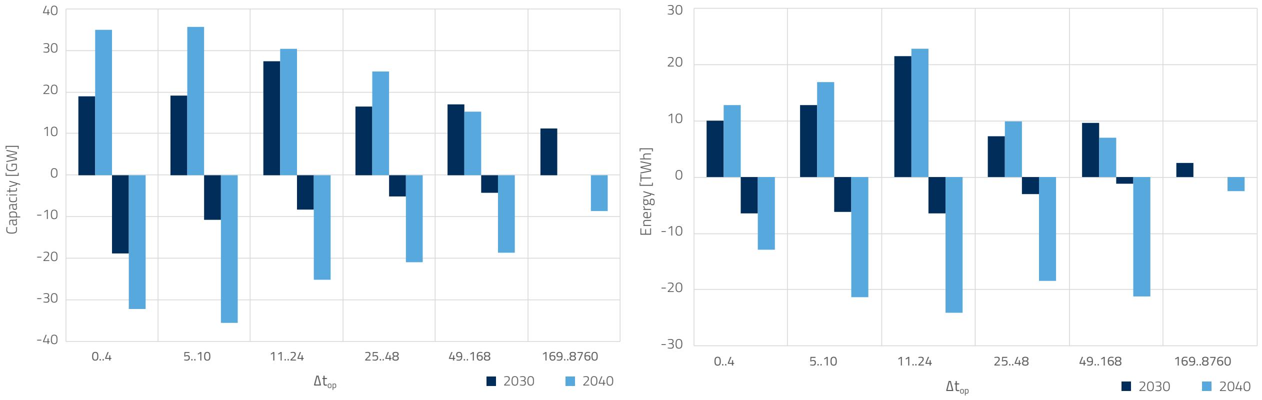

Figure 4.3: Residual load (left: capacity, right: energy) analysis for UK.

The scale of renewable energy and battery build-out and the uncertainty around first-of-a-kind LDES technology deployment in the UK presents an opportunity for GT to adapt as low-carbon technologies using CCS and H_2. However, the UK H2P business model is still under development, and the UK has, so far, only announced one potential H2P project in its Hydrogen Allocation Round. If successful, SSE Thermal and Equinor's Aldborough Hydrogen Pathfinder project would integrate a 35 MW electrolyser, a salt cavern storage, and a 50 MW H_2-fired OCGT [50].

4.4. Country Comparison

The role and positioning of GTs is derived based on the findings from the individual country analysis presented in Chapters 4.1-4.3. The future role and position of GTs, and the urgency to act, are presented here based on the current fleets deployed in the individual countries, the required capacity additions due to decommissioning, and the expected share of H_2 in GT power plants.

Future Role and Positioning of Gas Turbines

Following the application of the residual load methodology (refer to *Figure 3.2*), the positive residual energy provided by GTs and the relative occurrences of deployment in the operation intervals are shown in *Figure 4.4*. In 2030 without LDES, GTs are required to provide a significant share of positive residual energy (NL: 82 %, GER: 80 %, UK: 84 %) if contribution from other thermal assets (e.g., coal-fired, nuclear) is neglected. Most power generation is present in the 11-24 h range (NL: 53 %, GER: 34 %, UK: 40 %), with a relatively even distribution amongst the shorter and longer operation intervals. Due to the low amount of negative residual energy available for LDES, there is only minor impact on GT operation in 2030. Therefore, when LDES is taken into account, the total positive residual energy provided by GTs is reduced by only 5-10 % and the relative occurrence of each operation interval are changed only minorly (up to ±8.3 %pts).

In 2040 without LDES, GTs are required to provide lower shares of positive residual energy (NL: 80 %, GER: 59 %, UK: 63 %). Deployment of BESS capacity strongly reduces GT deployment needs in the 0-4 h range. High negative residual energy in the 5-10 h range favours energy storage and positive residual energy supply via PHS in Germany and the UK. Consequently, GT deployment up to 10 h faces diminishing shares in Germany (17 %) and the UK (9 %) compared to 2030, while shares are higher in the Netherlands in the 5-10 h range (34 %) due to missing PHS capacity. In all three countries, GTs are mainly deployed in the 11-24 h range (NL: 53 %, GER: 55 %, UK: 52 %).

Taking LDES into account in 2040, high amounts of negative residual energy available for LDES lead to a strong impact on GT operation. The total positive residual energy provided by GTs is reduced by 56 % in Germany, 79 % in the UK, and is even completely obsolete in the Netherlands. For Germany and the UK, GT deployment is strongly shifted to long duration operation, as LDES firstly discharges in short duration intervals. Therefore, dominant GT deployment is present in the 25-48 h range (GER: 48 %) and the 48-168 h range (UK: 76 %).

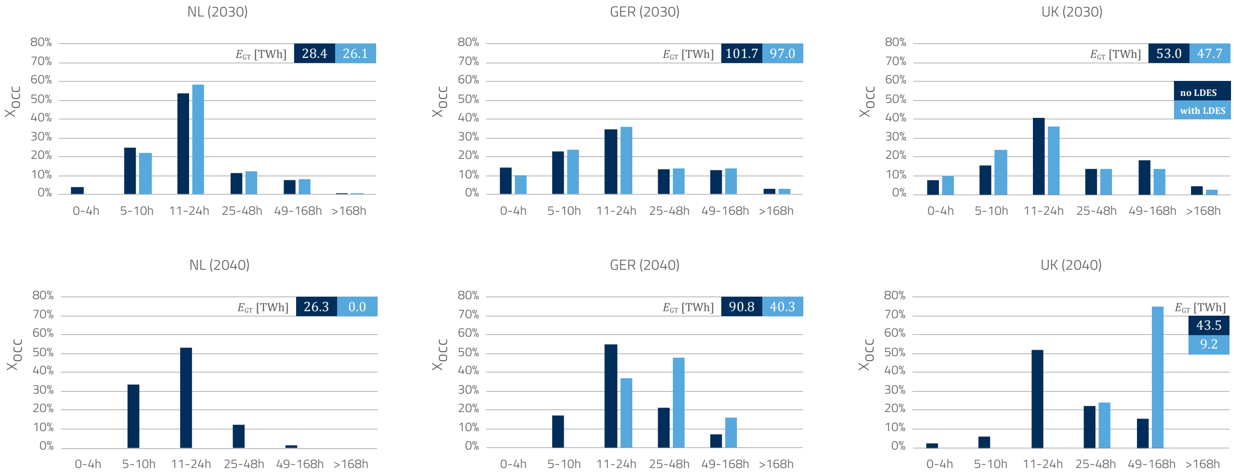

Figure 4.4: Relative occurrence x_{occ} of different operation intervals for GTs in the Netherlands (NL), Germany (GER), and the UK in 2030 and 2040 along with total supplied positive residual energy E_{GT}, in a scenario with and without LDES (excluding electrolysis).

The annual mean full load hours (FLH) of GTs derived from the ENTSO-E report [29], [30] and from this study's assessment are shown in *Figure 4.5* for 2030 and 2040. In this study, FLH is assessed as the ratio of residual positive energy to be provided by GTs and the total GT capacity. The total GT capacities for the presented scenarios (*no LDES*, *with LDES*) are equal to the maximum positive residual capacity required in the operation interval the GTs need to be deployed in. With that, the GT capacity and the respective FLH are estimated at a maximum and a minimum, respectively.

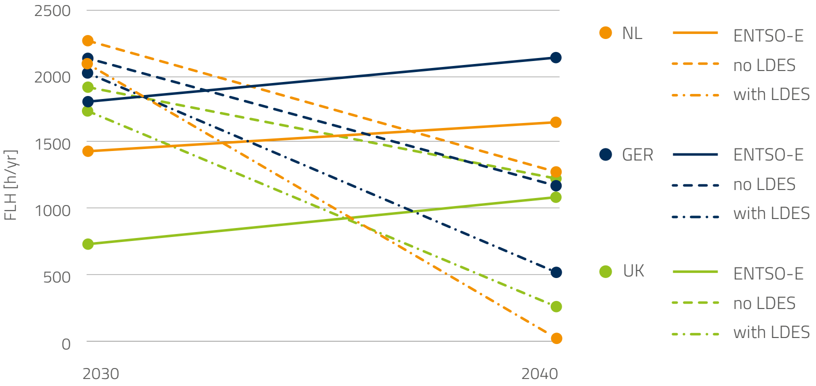

Figure 4.5: Mean annual full load hours (FLH) for GTs in the Netherlands (NL), Germany (GER), and the UK in 2030 and 2040, derived from the ENTSO-E report [30] and in a scenario with and without LDES (excluding electrolysis).

The ENTSO-E report [30] foresees highest FLH for Germany (1793-2132 h/yr), followed by the Netherlands (1424-1659 h/yr), and the UK (727-1109 h/yr). For all countries, ENTSO-E predicts an increase of FLH by 14-34 % from 2030 to 2040. Despite the phase-out of coal-fired power plants and decommissioning of old GTs, the high penetration of renewables and energy storage considered in this study rather indicates reduced GT operation in the near future, contrary to the ENTSO-E report's findings. In this study's scenario without LDES, highest FLH in 2030 is found in the Netherlands (2299 h/yr), followed by Germany (2136 h/yr), and the UK (1936 h/yr). Until 2040, GTs in all countries experience a decrease of FLH by 37-46 %. In this study's scenario with LDES, the highest FLH in 2030 is found in the Netherlands (2112 h/yr), followed by Germany (2037 h/yr) and the UK (1741 h/yr). By 2040, GTs experience a decrease of FLH by 75 % in Germany and 85 % in the UK. In the Netherlands, no GTs could be required with significant LDES deployment. The low FLH in nearly all cases (< 2000 h/yr) highlights the challenge to have a profitable operation if revenues only come from delivered electricity in wholesale markets. To maintain, and ultimately decarbonise, the projected required GT capacities will require incentives and support through regulatory mechanisms (e.g., the Capacity Market, DPA for Power CCUS, and H2P Business Model in the UK).

Fleet Development

To further illustrate the urgency for GT deployment, an analysis of the existing GT fleet development is performed and the foreseen trends of total and H_2-fired GT capacity derived from the ENTSO-E report [30] in the investigated countries, as shown in *Figure 4.6*. Regarding the current GT fleet, decommissioning is considered when the power plant surpasses 35 years of operation. Based on this, the existing GT capacity can be expected to drop by 29-60 % in all countries from 2025 to 2040.

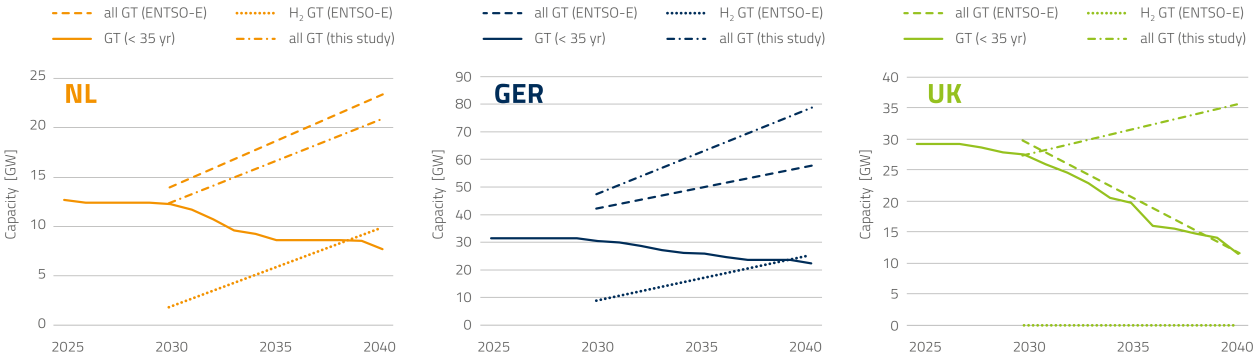

Figure 4.6: GT capacities of existing power plants (<35 years lifetime), and development of total and H_2-fired GT capacity derived from the ENTSO-E report [30] and in this study for the Netherlands (NL), Germany (GER), and the UK.

At the same time, the ENTSO-E report [30] foresees the necessity of 13.8 GW (NL) , 42.3 GW (GER), and 29.7 GW (UK) installed GT capacity in 2030. Regarding the estimated GT decommissioning, this results in the need of new capacity of 1.6 GW (NL), 12.0 GW (GER), and 2.2 GW (UK) in 2030. Retaining GTs was identified as the most cost-effective way to deliver the gas capacity required in 2030 [46]. However, even if all capacities would be kept online, a significant gap (NL: 1.1 GW, GER: 10.8 GW, UK: 0.4 GW) remains that needs to be filled with capacity additions. The required GT additions in Germany are exceeding the 10 GW capacities to be tendered in 2026 in line with the Kraftwerkssicherheitsgesetz ("Power Plant Safety Act"), but further tenders are expected in 2027 and 2029/2030 [42]. Whether the required capacities can be commissioned on time remains uncertain given the short lead-time and high GT OEM delivery times.

By 2040, more GTs in the existing fleet can be expected to go offline, resulting in a further capacity reduction by 4.6 GW (NL), 8.0 GW (GER), 15.9 GW (UK), compared to 2030. Except for the UK, this results in an increasing gap between existing and required GT capacity of 15.7 GW (NL) and 35.4 GW (GER). For the UK, this presents an interesting scenario compared with the Netherlands and Germany whereby unabated natural gas is recognised and incentivised to have a role out to 2030, yet simply retiring the existing capacity without further new build would meet the expected capacity by 2040. However, new-build, low-carbon dispatchable power such as H2P and Power CCUS will likely come online in the interim period between 2030 and 2040, although possibly not at the same rate as retirement of unabated gas assets. This could create a scenario where any delays in renewables, LDES, and/or electrolyser build-out requires life extension of unabated natural gas GTs to maintain security of supply.

Contributing to the decarbonisation goals, the ENTSO-E report [30] foresees the deployment of H_2-fired GT capacity in the Netherlands (2030: 1.9 GW, 2040: 9.7 GW) and in Germany (2030: 8.8 GW, 2040: 25.4 GW). This results in a significant share of H_2-fired GT capacity of 13-42 % (NL) and 21-44 % (GER) by 2030-2040, respectively. The assessment of H_2 use in GTs in this study shows a potential of 7-100 % (NL) and 4-47 % (GER) by 2030-2040, respectively. While H_2 production could support H_2-fired GT capacity in 2040, low H_2 availability in 2030 requires H_2-capable GT capacities to either run on natural gas or to operate with low capacity factors. The ENTSO-E report does not foresee any H_2-fired GT capacity in the UK, which does not align with NESO's annual Future Energy Scenarios report estimating 48.3-55.2 GW of H2P and Power CCUS by 2050, with a H_2 usage potential of 8 % in 2030 and 66 % in 2040 found in this study. Regarding the capacity additions, a minimum of 0.3 GW of existing GT capacity needs to be converted to H_2 use in the Netherlands by 2030. Due to the requirement of vast GT capacity addition by 2040, new, H_2-capable GT capacity is sufficient and conversion of existing GT is not required in the Netherlands (from 2030) and in Germany (by 2030). However, if capacity additions fall short of the targets, partial conversion of the existing GT fleet becomes necessary to meet the carbon reduction goals.

Due to the simplified approach in allocating LDES, the resulting capacities and energy volumes are high in 2040. The LDES capacity is conservatively estimated to match the maximum positive residual capacity (NL: 18.6 GW, GER: 78.8 GW, UK: 35.6 GW) in case no other technology is contributing to the positive residual capacity. Technically possible negative residual energy for charging accounts for 52.7 TWh (NL), 101.0 TWh (GER), and 34.3 TWh (UK). Despite technical feasibility in the chosen approach, the volume of required capacity remains questionable from an economic and installation capacity perspective.

Whereas only non-H_2-based LDES technologies have been assessed so far, energy storage via H_2 electrolysis and storage remains a suitable pathway for GT decarbonisation. Considering a slightly lower RTE (42 %) compared to other LDES technologies (50 %), the theoretically possible displacement rate of natural gas by H_2 in GTs can be assessed. With low negative residual energy in 2030, the energetic displacement by H_2 is low for all countries (4-8 %). In contrast, high negative residual energy available in 2040 has the potential for high energetic displacement by H_2 (47-100 %). In 2030, the replacement of natural gas by H_2 would result in only minor reductions in CO_2 footprint (306-320 gCO_2/kWh) for a modern CCGT with 60 % electrical efficiency. However, by 2040, the same CCGT CO_2 footprint could be significantly reduced (0-177 gCO_2/kWh). Compared to the EU Taxonomy, which states that sustainable GT operation from 2030 onwards requires a maximum carbon intensity of 100 gCO_2/kWh [56], locally produced electrolytic H_2 is not sufficient in each country to match this target. Furthermore, the produced H_2 cannot be expected to be solely used in power generation, as it is also strongly competing with hard-to-abate (e.g., steel, cement, glass) and chemical industries that have a high H_2 demand already.

5. Summary and Conclusions

Strong order backlogs and improving OEM margins reflect sustained demand for GTs from utilities, industries, and new applications such as data centres, underscoring that system-driven needs for dispatchable capacity are emerging as a dominant commercial driver [12], [57]. Looking ahead, analysts expect GT order intake to stabilise at these elevated levels. The analysis presented in this report based on data from the 2024 ENTSO-E Ten Year Network Development Planning (TYNDP) confirms that GTs remain a structural component of secure electricity supply in the Netherlands, Germany, and the United Kingdom in 2030 and 2040. This conclusion holds across scenarios considered either with or without long-duration energy storage (LDES) deployment, although the operating profile and annual full load hours of GTs will be impacted.

In 2030, limited availability of negative residual load in all three countries constrains the contribution of storage technologies. As a result, GTs are required to supply most of the positive residual energy, around 80 % in Germany, the UK, and the Netherlands when other thermal assets are excluded. The dominant operation range is 11-24 h. Even with LDES deployment, the reduction in positive residual energy provision by GTs remains limited in 2030 (up to 5-10 %) as charging volumes remain insufficient.

By 2040, higher renewable penetration increases negative residual energy, particularly in Germany and the UK. This creates the technical potential for LDES to cover a larger share of positive residual load. However, this also requires substantial storage capacities to be deployed. The economic feasibility, construction timelines, and system integration of large-scale LDES remain uncertain. Where LDES deployment falls short, GTs provide firm capacity, increasingly concentrated in longer-duration events (>24 h).

The opportunity for GTs to play a significant role in LDES is clear. However, the fuel used will become increasingly important in low-carbon systems. The availability of affordable, carbon-free/neutral fuels, such as electrolytic H_2, will impact the magnitude of GT contribution to LDES. Generating fuel from electricity is somewhat counter to the expansion of overall electrification of infrastructure. Novel non-electrolytic pathways to H_2 and synthetic fuel production offer the potential for improved affordability, round trip efficiency, and supply security. For example, direct solar thermochemical H_2 production relieves the electricity grid from H_2 production demands. Global trade of H_2 and NH_3 will also determine utilisation factors for low-carbon GT operation in balancing variable grid demand. The source of fuel is thus a key component to GT deployment supporting LDES.

Similarly, decarbonisation pathways are technically available but constrained by system conditions. H_2-based operation depends on sufficient low-cost availability, which will compete with industrial H_2 demand. In 2030, relatively minor domestic negative residual energy limits the potential H_2 displacement of natural gas to single-digit percentages. This displacement could be increased via imports, which are constrained by infrastructure and markets. By 2040, higher theoretical substitution rates are possible, but only if large-scale H_2 infrastructure and storage are realised domestically. Carbon capture and storage (CCS) provides an alternative low-carbon pathway, particularly where H_2 availability is uncertain, but is also constrained by CO_2 transport and storage infrastructure. Alternative, low-carbon fuels (e.g., bio-derived or e-fuels) may also have a role to play in specific applications.

Across all countries, GT full load hours decline in the developed scenarios, often below 2,000 hours per year. This indicates that future GT economics cannot rely solely on wholesale electricity revenues. Capacity remuneration mechanisms or equivalent reliability-based market instruments are required to ensure availability and reliability of firm capacity.

Fleet analysis highlights an additional structural challenge. Between 2025 and 2040, 29-60 % of existing GT capacity will exceed a 35-year lifetime. Germany faces the largest short-term addition requirement by 2030, exceeding currently announced tender volumes, although additional tender rounds are planned. Lead times for permitting, financing, manufacturing, and grid connection typically range from five to eight years. Given current

OEM order backlogs, delayed investment decisions directly translate into security of supply risks. Investments in GT lifetime extension, efficiency improvements, and operational flexibility may therefore become critical.

Overall, the results show sensitivity to renewable build-out, storage deployment, and policy implementation. However, under all examined scenarios, firm dispatchable capacity remains necessary in 2030 and persists in 2040, even in highly renewable systems. Gas turbines, potentially decarbonised through H_2, alternative fuels, or CCS, provide the required flexibility, start-up capability, inertia contribution, and multi-hour to multi-day energy delivery needed in the future energy system. Timely capacity planning, stable regulatory frameworks, and investment signals aligned with extended development cycles are therefore required to maintain security of supply during the transition to low-carbon electricity systems.

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Notes

Energy & Turbomachinery Network
(abbrev. ETN Global) a.i.s.b.l.
Chaussée de Charleroi 146-148/20
1060 Brussels, Belgium
Tel: +32 (0)2 646 15 77
info@etn.global
www.etn.global