REPORT

Impact of lower financing costs of gas on low-carbon alternatives

Prepared for Greenpeace e.V.
29.08.2022

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Introduction

As the European power system moves towards decarbonization, investments need to be directed towards sustainable activities to reach the EU climate and energy targets. As a common classification system of sustainable economic activities, the EU Taxonomy that entered into force in 2020 aims to support such sustainable investments.

In 2022, certain gas and nuclear activities were included in the transitional list of investments that meet the EU Taxonomy requirements. Transitional activities are those that contribute to climate change mitigation, subject to strict conditions and without crowding out investment in renewables, but that cannot yet be replaced by technically and economically feasible low-carbon alternatives.[1]

The report focuses on the impact of the inclusion of the specified gas activities in the EU Taxonomy and does not take nuclear activities into account. The analysis is done in three steps. In a first step, we assess how the inclusion impacts the European power market, both looking at market designs with capacity markets and without (the latter referred to as energy-only-market) to render the assessment valid for different market designs existing in the European Union. In a second step, we analyze the impact on the deployment of low-carbon flexibility technologies and renewables. Finally, we assess the technical screening criteria set by the Taxonomy Regulation and the delegated act under profit-maximizing dispatch behavior of a gas asset to understand the extent to which gas plant operators would need to deviate from their profit-maximizing dispatch to meet the Taxonomy criteria. We assess only direct output power emissions and do not take life cycle emissions into account.

How does the inclusion of gas in the EU Taxonomy impact the European power market?

Analysis of power market without capacity markets

This section provides a theoretic economic analysis of the impact of including gas plants in the EU Taxonomy for energy-only power market systems (without capacity markets, e.g. Germany)

The inclusion of gas power generation in the EU Taxonomy means that it becomes easier for project developers of gas assets which meet the Taxonomy criteria to raise capital (debt and equity). The reason is that the sustainability label allows access to broader financing options, as the demand for sustainable investment options is growing. One reason is that the increasing commitment to net zero targets make banks and investors favor sustainable investments to reach their individual goals. As a result, the weighted average cost of capital (WACC) of gas power plants is lower.

Lower financing costs reduce the levelized cost of electricity production (LCOE) for gas power plants and increase their profitability *ceteris paribus*[2]. Figure 1 illustrates the nexus between WACC and LCOE and

[1] Article 10(2) of Regulation (EU) 2020/852 of the European Parliament and of the Council of 18 June 2020 on the establishment of a framework to facilitate sustainable investment, and amending Regulation (EU) 2019/2088

[2] *Ceteris paribus* is a concept often used in economics and means that one variable or input factor is changed while all other parameters are held constant.

shows that the LCOE of an exemplary combined-cycle gas turbine (CCGT) power plant in the German market would be 4 % lower if the WACC decreased from 12 % to 9 %[3].

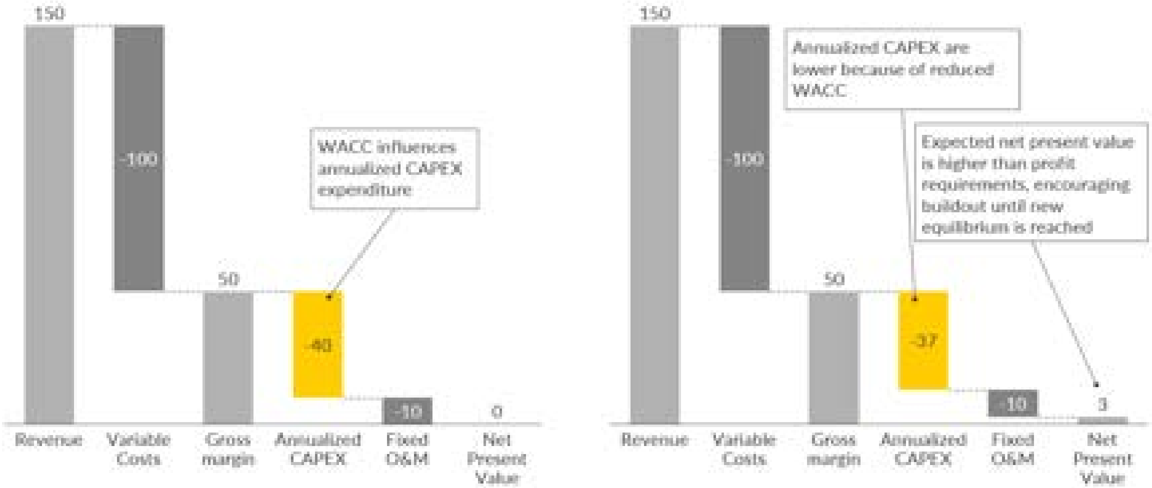

Figure 2 compares the cost and revenue streams of a generic gas power plant with higher WACC (right-hand side) to those of an identical plant facing lower financing cost (left-hand side)[4]. Because the cost of capital is reflected in the interest rate on annualized capital expenditure (CAPEX) payments, annualized CAPEX is lower with a lower WACC. Compared to a situation with high capital costs, lowering the WACC means therefore that the net present value[5] is higher than profit requirements for gas assets. This triggers additional build-out of gas capacity. More gas capacity lowers expected profits because of price cannibalization between gas power plants. A new, higher level of capacity will be reached once the profit requirements again match expected profits.

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[3] Based on model output for yearly generation and variable costs of an exemplary CCGT plant from Aurora Energy Research's in-house integrated electricity market model for the German market (July Central Scenario). Underlying assumptions: First year of operation: 2025; lifetime: 30 years; CAPEX: 665 EUR/kW; fixed O&M costs: 28 EUR/kW/year. The assumption that lower WACC leads to lower LCOE holds in general, not only for this specific asset.

[4] Numbers are only for illustration purposes and do not reflect a real business example.

[5] Net Present Value refers to the value of all future cash flows (positive and negative) over the entire life of an investment discounted to the present.

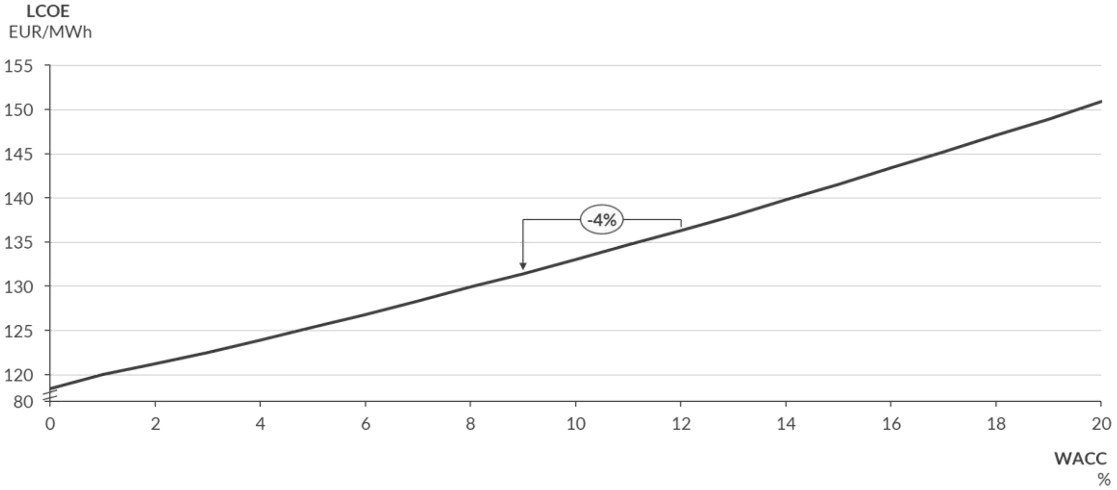

Figure 1: Levelized electricity costs as a function of the weighted average cost of capital for an exemplary combined-cycle gas turbine (CCGT) power plant in the German market

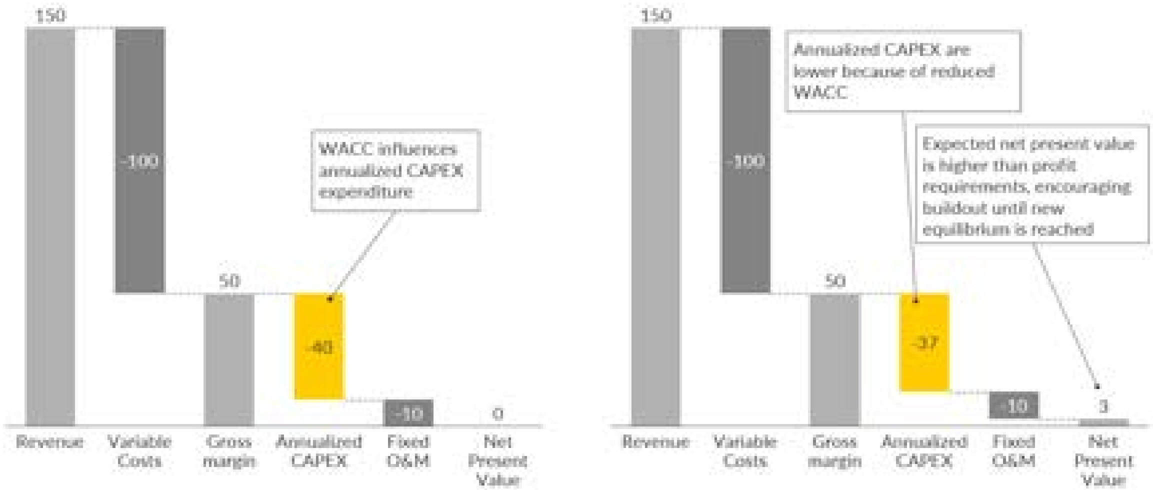

Figure 2: Cost and revenue streams of an exemplary gas plant in the energy-only market with higher WACC (left-hand side) and lower WACC (right hand side), in EUR/kW p.a.

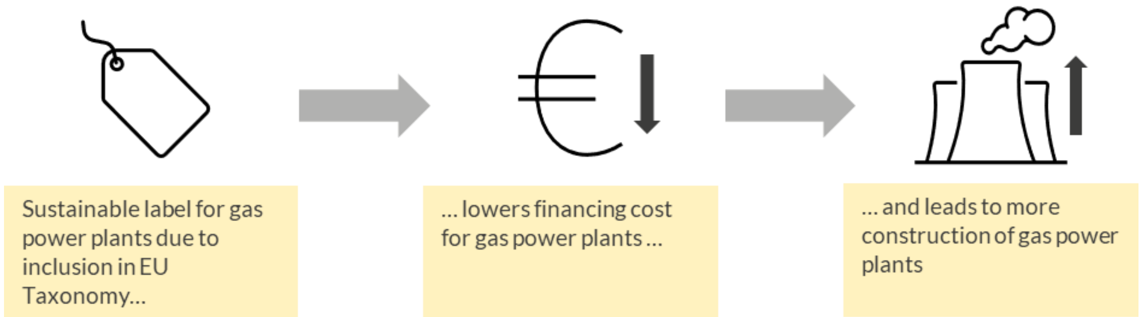

Figure 3: Schematic representation of the impact of classifying gas-fired power plants as sustainable under the EU Taxonomy

While a lower WACC impacts investment decisions and capacity buildout, it is important to note that the marginal costs of gas assets are not affected by the EU Taxonomy. That is because the plant specific short-run marginal costs of electricity production are independent of the cost of capital.

Analysis of power market with capacity markets

This section provides a theoretic economic analysis of the impact of including gas plants in the EU Taxonomy for power market systems with capacity markets in place (as in the case of e.g. Belgium, France, Poland). We assume that the price formation on capacity markets occurs through clearing supply and demand, which in turn are based on competitive bidding.

The impact of the inclusion of gas plants in the Taxonomy on the LCOE of gas-fired power plants via lower capital costs is the same as explained in the previous section: a lower cost of capital decreases the annualized CAPEX and hence the LCOE.

For power market designs with capacity markets, the lower WACC means that operators of gas-fired power plants require lower capacity market revenues to achieve the required profit level. This effect is visualized on the right-hand side of Figure 4: Because of the reduced WACC, the gross margin which needs to be achieved by the gas plant to maintain the required profit level is lower. Therefore, the plant operator has a tolerance for lower capacity market revenues.

The reduced capacity market revenue requirement has an influence on the bidding strategy of gas asset operators in capacity auctions as is shown in Figure 5: The chart on the left-hand side outlines an exemplary auction under a scenario in which gas activities are not listed in the Taxonomy. In this case, the gas power plant capacity is not procured because its bid is higher than the clearing price set by the next cheaper project of an alternative technology[6]. In the auction sketched on the right-hand side, we simulate the effect of the lower financing costs for gas activities following the inclusion to the Taxonomy. The bids of all other technologies are held constant, but the gas project bids in with a lower price due to its reduced minimum revenue boundary as explained in Figure 4. In this concrete example, the bid of the gas power plant is now lower than that of the project which formerly secured the last successful bid. This means that the gas power plant capacity moves up the merit order and is procured in the auction.

In summary, gas power plants can enter capacity market auctions with lower bids because of the inclusion of gas activities in the transitional list of investments under the EU Taxonomy and will *ceteris paribus* be procured more often. Therefore, we expect more gas power plant capacity to be built in countries with capacity markets in place.

[6] Note that other technologies and their respective bids are not specified in the chart. The reason for this is that the merit order of capacity market auctions is country specific and depends a lot on the power plant portfolio and the market design (i.e. the existence of other revenue channels and the definition of de-rating factors).

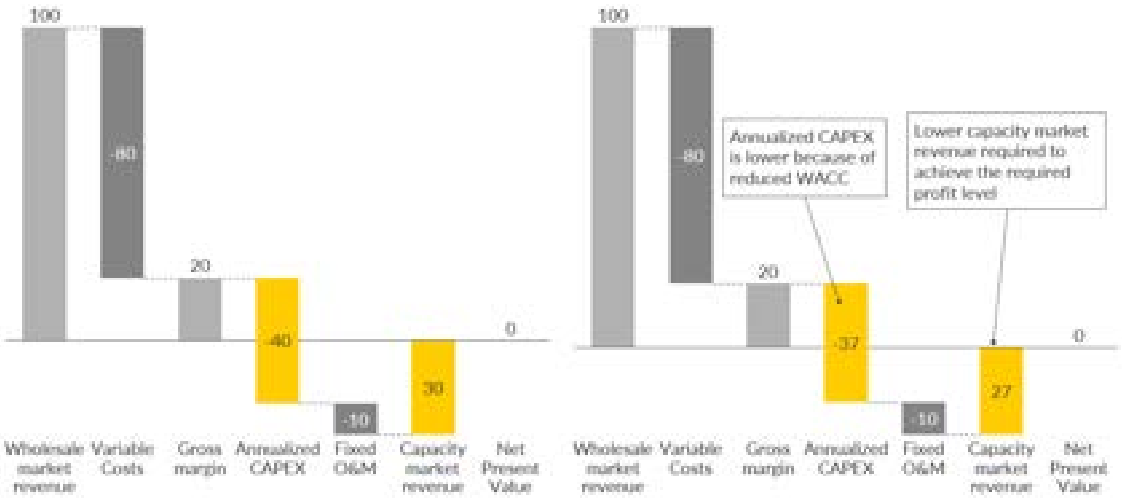

Figure 4: Cost and revenue streams of an exemplary gas plant in a country with capacity market depending on the WACC level (lower WACC on right hand side), EUR/kW p.a

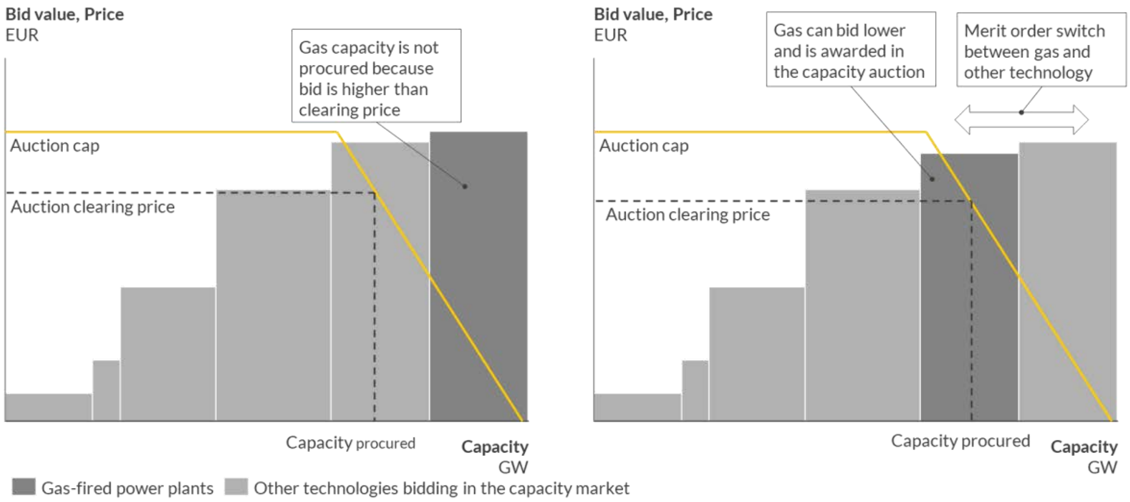

Figure 5: Exemplary capacity market auction results under a high WACC assumption for gas activities (left-hand side) and a low WACC assumption for gas activities (right-hand side)

How are low-carbon alternatives impacted?

The second part of our report analyzes how low-carbon alternatives are impacted by the inclusion of certain gas activities in the EU Taxonomy, as Article 10.2 of the Taxonomy Regulation sets out as a mandatory requirement that an investment shall only be covered by the Regulation if it "does not hamper the development and deployment of low-carbon alternatives". We look both at alternative flexibility technologies as well as at the impact on renewables.

The impact on alternative flexibility technologies

The share of intermittent renewables in the European capacity will increase strongly to reach climate neutrality in 2050. The higher share of renewables leads to more sudden changes in generation. In Figure 6 ramping requirements in the German power system are shown for different years. Ramping requirement is defined as the change in non-dispatchable renewable power generation per hour. In the Aurora Net Zero scenario[7] in 2050, the average ramping requirement amounts to 10.9 GW/hour, with a maximum of 63.6 GW/hour. It becomes clear that with increasing renewable deployment, the need for flexibility in the system increases.

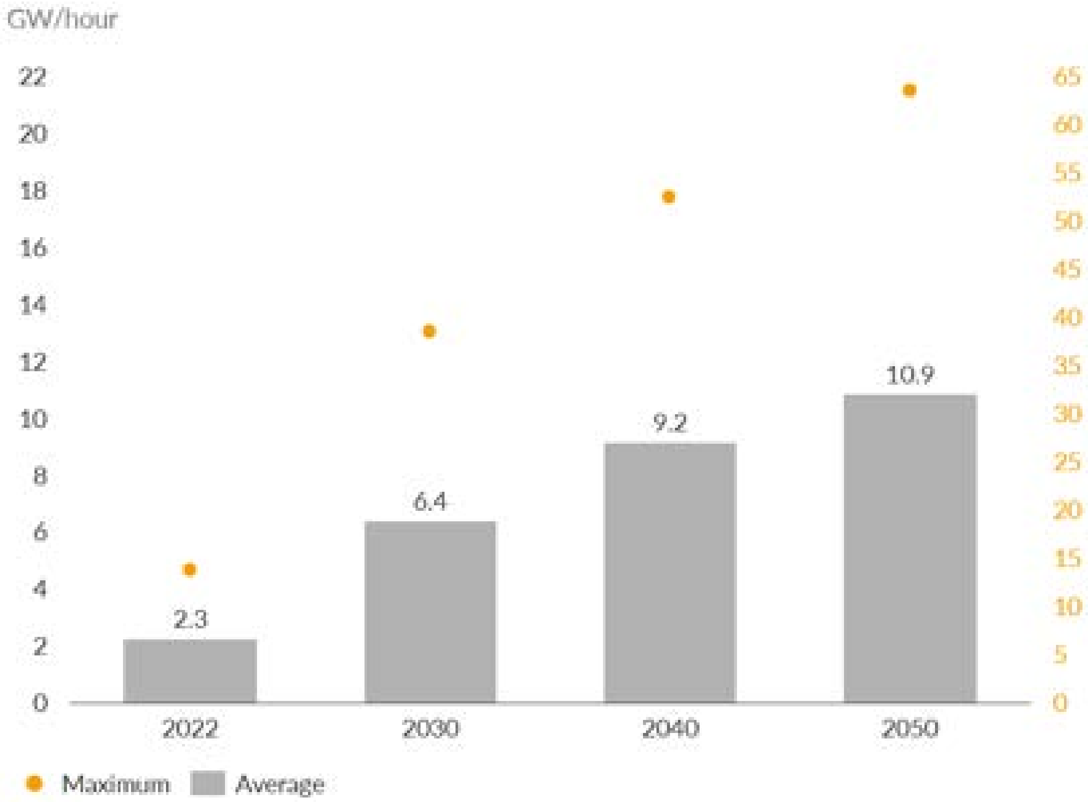

Figure 6: Ramping requirements in Germany in GW/hour in Aurora Net Zero Scenario[8]

Gas turbines are a source of flexibility for the power system. As shown in the first chapter of this report, the inclusion of gas activities in the Taxonomy leads to lower financing costs of gas assets and thus encourages capacity build-out of gas power plants. If more gas power plants are built under the current Taxonomy, other technologies account for a smaller share of the flexibility mix.

Besides gas, different alternative flexibility technologies such as storage, batteries, and demand-side-response are available. If gas activities were not included in the Taxonomy, incentives to increase the flexibility of the power system would remain. The needed flexibility would thus have to be built anyway, based on price signals (either through an energy-only-market or through a capacity market). However, gas power plants would not have the advantage of lower financing costs. Consequently, the technologies providing flexibility would be more diversified, and gas power plants would represent a smaller part of the total system flexibility.

This means that the additional gas power plants built due to lower financing costs replace alternative low-carbon flexibility options. This is true both in energy-only-markets and in markets with a capacity market. In an energy-only-market, additional gas assets will shift the merit order. This effect is illustrated

[7] The Aurora Net Zero scenario is a target-driven scenario and assumes that Germany will reach carbon neutrality by 2045.
[8] Based on hourly variation of non-dispatchable renewables in the Aurora Net Zero scenario from April 2022.

in Figure 7: With a higher gas capacity in the system, more electricity generated by gas power plants is available in hours with scarce renewable production in which prices are high. The additional power supply from gas plants pushes more expensive technologies such as demand-side-response out of the merit order and thereby lowers the price in those periods. As a result, other flexible technologies such as storage plants whose business model is based on wholesale market arbitrage (charging in low-price hours and discharging in high-price hours) will see revenues go down, disincentivizing their buildout.

In a market design with a capacity market, technologies compete directly against each other, and the lower revenue requirement of gas power plants can cause a merit order switch in the capacity auction as illustrated in Figure 5.

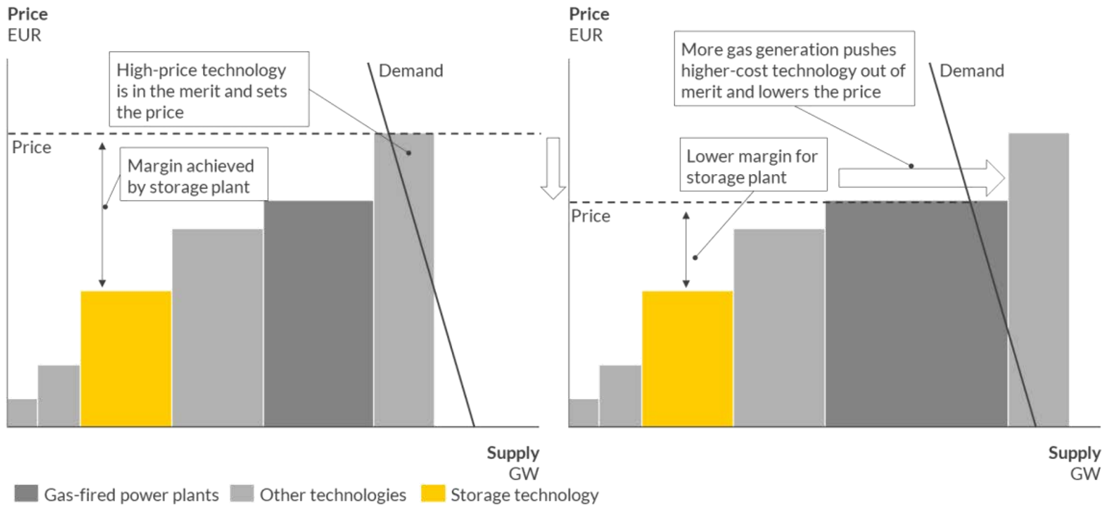

Figure 7: Merit order and price formation in the wholesale market in a system with lower gas capacity (left-hand-side) compared to a system with higher gas capacity (right-hand-side)

It is important to note that different flexibility options are not a perfect substitute for each other. Flexibility options differ in costs, but also in use cases: while gas power plants can provide nearly continuous additional power in case of low renewable production, they cannot absorb power from the system in hours in which renewable production surpasses demand. Lithium-Ion-batteries on the other hand can do the latter but have limited storage durations of only up to a few hours. Flexibility technologies also differ regarding emissions. There are flexibility options without direct CO_2-emmissions, such as batteries, pumped hydro storage and demand-side-response.

The impact on renewables

As shown in the paragraph above, the inclusion of certain gas activities in the Taxonomy would lead to a higher share of the power system's flexibility requirement provided by gas power plants. This does not only impact alternative low-carbon flexibility technologies, but also renewables.

Impact of flexibility technologies on curtailment of renewable energy

The reason for this is that flexible technologies differ in their purposes. One task of flexible technologies is to fulfill the ramping requirements, that means to quickly provide power to the system in moments of low renewable production. Gas power plants can provide this kind of flexibility. However, flexibility also plays an important role in moments of high renewable production. In order to absorb the high amount of renewables, the system needs flexibility on the demand side, for example through batteries, storage and demand-side-response. Gas power plants cannot provide this kind of flexibility.

An illustrative example is shown in Figure 8 below. A battery charges in low-price hours typically characterized by high or even excess renewable generation. At a later point, the battery can inject the stored electricity during a high-price window, in which renewable generation is low.

Based on the same logic, demand-side-response allows to shift demand to hours with more renewable production and therefore cheaper prices, aligning consumption with the physical needs of the power system.

What all these examples have in common is that they allow to avoid renewable curtailment. This is not the only benefit of alternative flexibility technologies. Another important point is the impact on the price formation. In contrast to gas assets, alternative flexibility technologies provide flexibility in hours of high renewable production and thus low power prices. In turn, they represent additional demand in times of high renewable production and thus stabilize the low-price periods. This in turn is positive for renewables, as it hedges the risk of extended low-price periods.

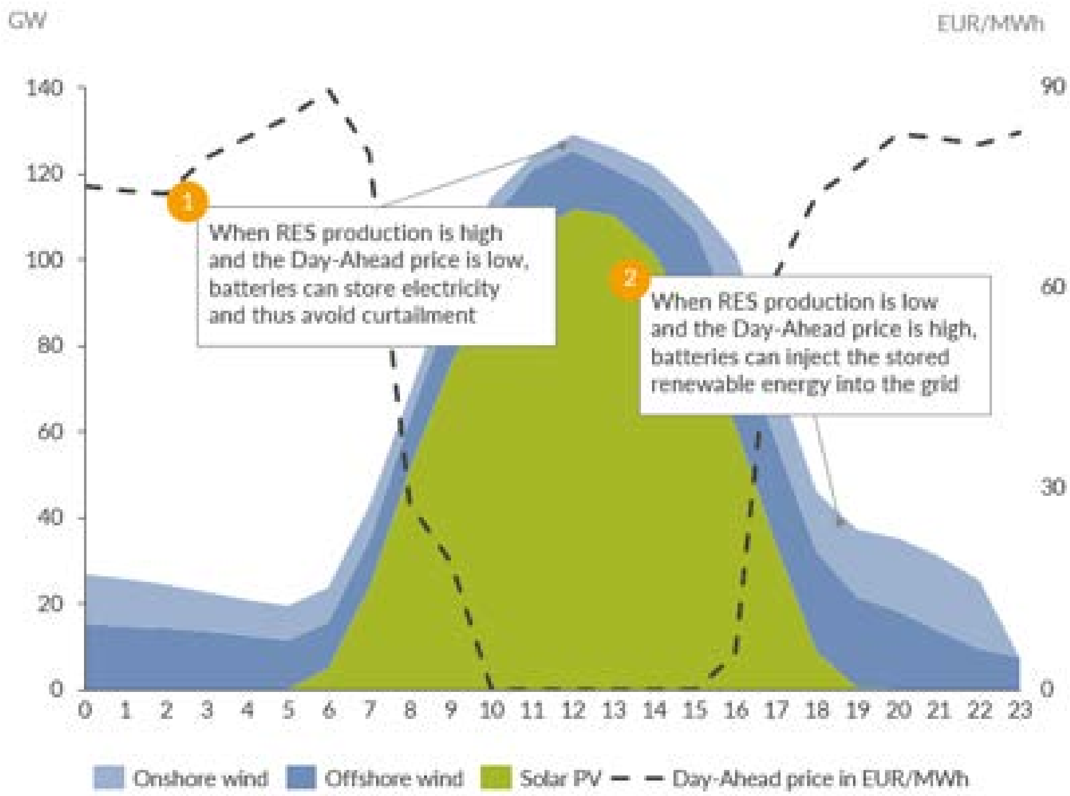

Figure 8: Renewable generation and Day-Ahead price on a spring day 2030 in Germany in our Central scenario

<u>Case study: Long Duration Energy Storage in Germany</u>

In our study "Prospects for Long Duration Energy Storage in Germany", published in July 2022, we quantified the impact of Long Duration Energy Storage (LDES) on renewable curtailment. We define LDES as a storage technology with a storage duration between 8 and 96 hours.

Two power market scenarios were modelled for this study. The Baseline Scenario assumes a Net Zero power system in Germany to be achieved by 2035. In the LDES scenario, an additional capacity of long-duration storage of 15 GW is added to the market. This means that we need less hydrogen peakers[9] to maintain the same level of security of supply.

The difference in electricity production between the LDES and the baseline scenario is shown in Figure 9.

Figure 9: Electricity production delta between the LDES and the Baseline Scenario in TWh

We observe three main effects from the introduction of LDES to the power system:

1. Higher renewables utilization: LDES absorb renewable electricity by charging in hours in which renewables production exceeds demand; curtailment can be reduced by up to 30%
2. Lower natural gas use: LDES discharge in high price hours and thereby reduce the amount of electricity generated by conventional gas plants as well as the CO_2 emissions caused in the process
3. Lower need for hydrogen in the power sector: After the transition from natural gas to hydrogen, LDES lower the amount of power generated by H_2-fuelled plants which translates to a 13% reduction of hydrogen use in the power sector. This reduction decreases Germany's H_2 import dependence and mitigates risks in case of H_2 procurement bottlenecks

[9] Hydrogen peakers refer to hydrogen-fueled power plants.

This illustrates that a higher share of alternative low-carbon flexibility technologies can lead to less renewable curtailment.

Assessment of technical screening criteria under profit-maximizing dispatch

Gas activities are only deemed sustainable activities under the EU Taxonomy if they fulfill a set of conditions. These conditions are necessary to receive a green label for financing. Even though yearly verifications are carried out by an independent third party, the green label is attributed before the plant starts its operation.

In our analysis we focus on the so-called technical screening criteria, that set out specific conditions for electricity generation from fossil gaseous fuels to be labelled as sustainable. Regarding emissions, the criteria can be summarized in two cases[10]:

- Life-cycle greenhouse gas emissions from the generation of electricity using fossil gaseous fuels cannot exceed **100 g CO_2e/kWh**
- For facilities that obtain a construction permit before 31 December 2030 and that fulfill additional requirements[11], direct greenhouse gas emissions must be lower than **270 g CO_2e/kWh** of the output energy, or annual greenhouse gas emissions must be lower than **550 kg CO_2e/kW** of the facility's capacity over 20 years

Several stakeholders voiced their concerns that the methodology of calculating the emissions as an average over 20 years for the 550 kg CO_2e/kW criteria could lead to gas assets "front-loading" their production and emissions. This could mean that the amount of CO_2 emitted until the fuel-switch is so significant that average emissions are not reduced far enough in the period of emission-free operation to meet the limits specified in the Taxonomy at the end of the lifetime. If this materializes, it would essentially constitute a lock-in. As to the 270 gCO2e/kWh criterion, it cannot be reached even by the most efficient gas assets without addition measures such as carbon capture and storage or mixed fuel use.

Consequently, to help understanding the lock-in risk, we focus on the 550 kg CO_2e /kW emission targets of the technical screening criteria and analyze if the criteria would be met by a profit-maximizing gas asset. This approach allows to understand the extent to which gas plant operators would need to deviate from their profit-maximizing dispatch to meet the Taxonomy criteria.

Case study

In our case study, we model the dispatch of a CCGT plant which comes online in 2028 and generates power for 20 years until 2047. At the end of 2035, the plant is retrofitted and undergoes a fuel switch to hydrogen instead of natural gas in order to be compliant with the provisions of the EU Taxonomy. We assume a thermal efficiency of 53.5 % and an emission intensity of 343 g/kWh when the plant is fueled

[10] Commission Delegated Regulation (EU) 2022/1214 of 9 March 2022 amending Delegated Regulation (EU) 2021/2139 as regards economic activities in certain energy sectors and Delegated Regulation (EU) 2021/2178 as regards specific public disclosures for those economic activities

[11] Requirements include among others that existing high emitting electricity generation activity is replaced, that the gas power plant is designed to use low-carbon gaseous fuels and the switch takes place by 31 December 2035. Detailed requirements can be found in Section 4.29 of Annex 1, Delegated Regulation 2022/1214

with natural gas[12]. For the model configuration, we use the Aurora Central Scenario and look at a hypothetical power plant in Germany. The Central Scenario reflects what our market experts consider to be the most likely developments in the power market and the wider economy until 2050. The German government's emission targets are not met, and a significant share of conventional power generation remains in the system beyond 2035.[13]

The result of our modelling is that **under profit-maximizing dispatch behavior, a gas-fired power plant with market entry in 2028 and fuel switch at the end of 2035 would not comply with the 550 kg CO_2e/kW emission limit criterion set out in the EU Taxonomy**. This finding is robust to using an alternative assumption setup, the Aurora Net Zero Scenario, for our dispatch analysis. It is important to note, that **the result does not mean that it would be impossible to operate a gas-fueled power plant in compliance with the criteria set out in the Taxonomy.** If the power plant reduced its production compared to the profit-maximizing schedule during the gas-firing period, it would be able to comply with the criteria. Furthermore, the result depends on the assumption made on the year of market entry of the gas power plant. However, it should be noted that the modelling only looks at direct output emissions. This means that the upstream emissions in the supply chain (H2 generation, methane leakage) are not modelled.

The reason for the failure to meet the 550 kg CO_2e /kW criterion is that the profit-maximizing utilization of the power plant during its conventional operation phase and the resulting amount of CO_2 emissions are so high that the average emissions per unit of capacity over the lifetime are still above the threshold even after 12 years of emission-free operation. This is illustrated in Figure 10: Average emission intensity per kW of installed capacity over the lifetime and full-load hours of a gas plant with profit-maximizing dispatch which depicts the average emissions per kW of plant capacity over the whole plant lifetime for each year and the full-load hours of the plant[14]. To comply with the criterion, the plant owner would have to operate the plant below its profit-maximizing utilization and forego revenues during the first 8 years of conventional use.

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[12] Note that to consider technological progress, the thermal efficiency is higher and the emission intensity lower than what average CCGT plants currently achieve.

13The Central Scenario represents Aurora's best view for the evolution of the German power market until 2050, our Central forecast predicts power sector emissions of 57 MtCO2 in 2050. In our Central scenario, we expect the government target of 80% RES share in 2030 to be missed by 11% points. This is mostly due to long planning and project realisation periods for onshore wind, public acceptance issues and uncertainty whether skilled workforce will be available to achieve the ambitious RES buildout targets.

[14] Note that full-load hours see a very sharp decline after the retrofit of the plant in 2035. The reason for this is that variable production costs increase with the switch to hydrogen, because green hydrogen will remain significantly more expensive than natural gas in the medium term. Higher short-run variable costs mean that the power plant moves down the merit order and its power is therefore *ceteris paribus* called up in fewer hours on the day-ahead wholesale market. Other conventional gas plants, which are still in the system, will dispatch first, reducing the feed in of the hydrogen turbine plant to only few extreme periods with very high scarcity of renewables generation.

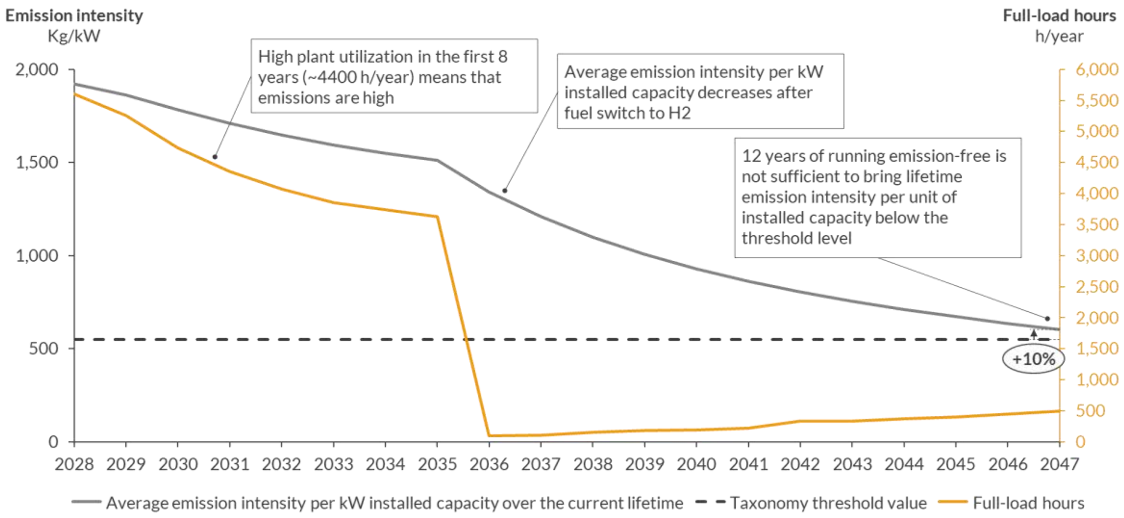

Figure 10: Average emission intensity per kW of installed capacity over the lifetime and full-load hours of a gas plant with profit-maximizing dispatch schedule in the Aurora Central Scenario for Germany

Sensitivities

The question whether the gas plant can fulfill the criteria of the EU Taxonomy under profit-maximizing dispatch depends on both the composition of the power system and the year of market entry of the plant. Another important question is whether the assumption of a switch to hydrogen as early as in 2035 is realistic.

<u>1. Aurora Net Zero Scenario</u>

The composition of the power system matters because it determines the dispatch of power plants in the wholesale market. The assumptions made around the buildout of renewables and storage capacity is of particular importance because more wind production and battery dispatch in high price hours means that less gas generation is needed (imagine an expansion of the power discharged by the storage technology in Figure 7, pushing gas out of the merit order). Therefore, the production of the gas plant in conventional use is lower, less CO_2 is emitted and the likelihood that the 550 kg CO_2e /kW criterion is met increases.

As mentioned in the introduction, we have implemented the case study in our Central Scenario, in which renewables and battery capacity buildout falls short of the trajectory required for a swift decarbonization of the power sector. To analyze the impact of a faster buildout of renewable and storage capacity, we have additionally modelled the profit-maximizing gas plant dispatch in the Aurora Net Zero Scenario configuration of our power market model, in which the decarbonization of the power sector proceeds quicker and is closely aligned to policy targets.

Figure 11 illustrates the impact of using the Net Zero Scenario instead of the Central Scenario on the profit-maximizing plant dispatch and the development of the average emission intensity per unit of plant capacity installed. As expected, the average load factor of the CCGT from 2028 to 2035 is lower (~ 4200 h/year compared to ~ 4400 h/year in the Central Scenario). However, the resulting emission reduction in the first 8 years of operation is still not sufficient to meet the 550 kg CO_2e /kW threshold at the end of the 20-year period.

Note that another effect of modelling the plant dispatch in the Net Zero Scenario is that the running hours of the retrofitted CCGT after the fuel switch are higher. This is because compared to the Central Scenario, in the Net Zero Scenario the installed conventional gas capacity converts to hydrogen earlier and therefore the relative position of the retrofitted hydrogen-fueled plant in the merit order is better in the Net Zero Scenario. However, the higher utilization of the plant during its emission-neutral operation has no effect on the CO_2 emitted in the first 8 years of its lifetime and therefore does not lower the per-unit of capacity average.

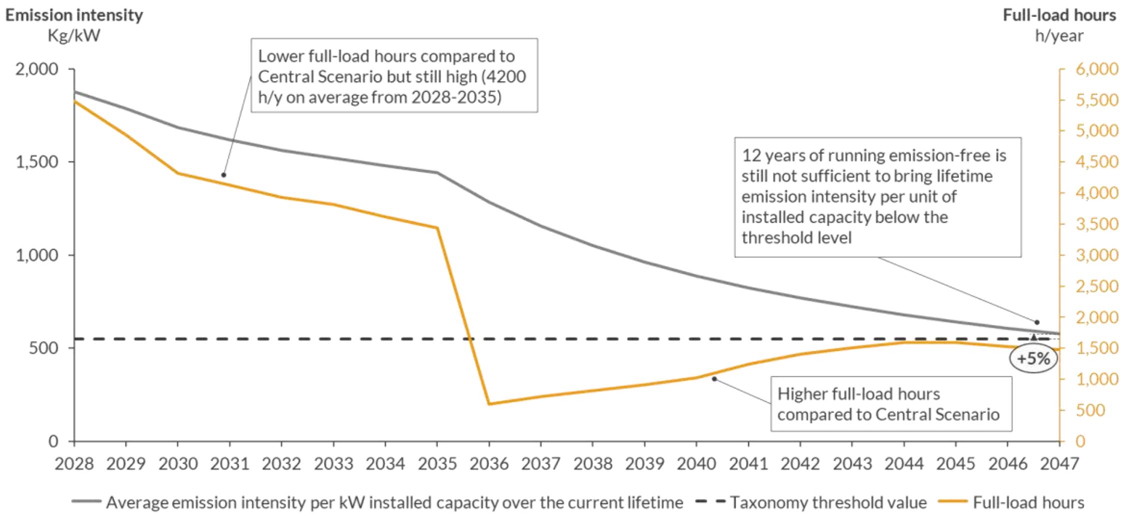

Figure 11: Average emission intensity per kW of installed capacity over the lifetime and full-load hours of a gas plant with profit-maximizing dispatch schedule in the Aurora Net Zero Scenario for Germany

<u>2. Later market entry of the plant</u>

To be eligible to the 550 kg CO2e /kW criteria, the construction permit needs to be granted by end of 2030. A later market entry is therefore also possible. We therefore assess if the capacity-specific emission threshold will be met if the gas asset enters the market in 2031. If the gas-fired power plant is commissioned later and therefore runs for fewer years in conventional operation (and longer as a hydrogen-fired power plant), average emissions per unit of plant capacity will go down. Figure 12 shows the results of a variation to the dispatch analysis in which the plant comes online three years later, in 2031. **The capacity-specific emission threshold of 550 kg CO_2e /kW over a 20-year period would in this case be met.** The reason for this is that the total quantity of CO_2 emitted by the plant is now significantly lower because of the reduction of the conventional run time from 8 years to 5 years, (since the fuel switch still takes place at the end of 2035 in compliance with the Taxonomy). Total CO_2 emitted per kW plant capacity during the conventional operation period goes down by 44 % from 12.1 t/kW to 6.6 t/kW.

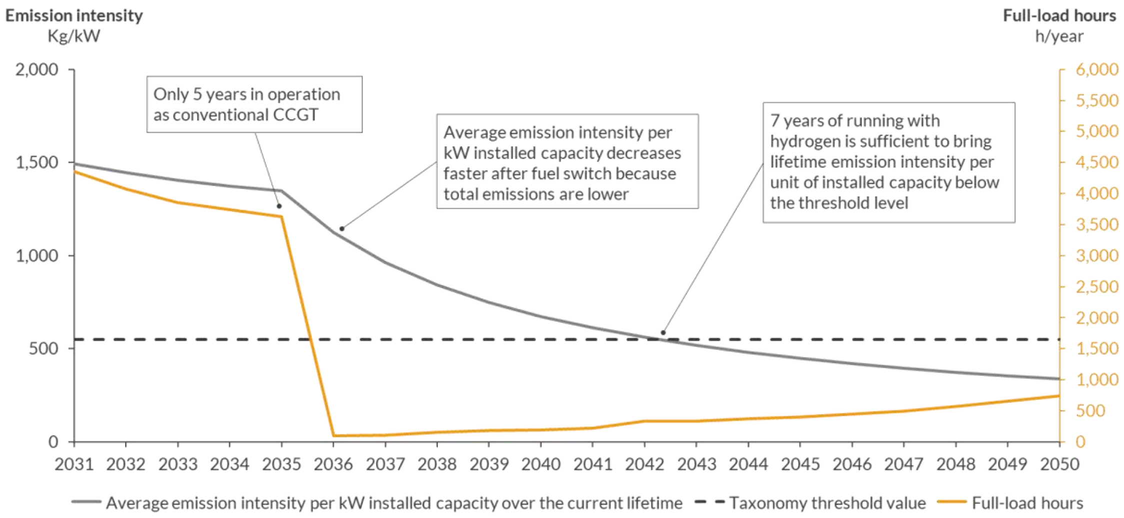

Figure 12: Average emission intensity per kW of installed capacity over the lifetime for a plant with market entry in 2031 and a profit-maximizing dispatch schedule in the Aurora Central Scenario for Germany

3. Later fuel switch

Besides the 550 kg CO_2e /kW criterion, gas assets falling in the second category of the EU Taxonomy gas activities additionally need to switch to full use of renewable and/or low-carbon gaseous fuels by 31 December 2035. So far, this criterion was met in the examples analyzed. However, uncertainties exist as to which extent a fuel switch by 2035 is technically and economically feasible when considering uncertainties around the availability, price, and transport infrastructure of green hydrogen.

To assess the consequences of a delayed fuel switch, we therefore again model the profit-maximizing dispatch of a hypothetical CCGT plant with market entry in Germany in 2028 and an operating period of 20 years. In contrast to the previous analyses, the plant only undergoes a fuel switch to hydrogen at the end of 2040, instead of 2035. For the model configuration, we use the Aurora Central Scenario.

As can be seen in Figure 13, in this scenario the average emissions per unit of plant capacity would stand at 870 kg CO_2e /kW at the end of the plant lifetime, almost 60% above the threshold value. The total lifetime emissions per kW of the plant would amount to 17 tons instead of 12 tons in the case of a fuel switch at the end of 2035. A delayed switch to lower carbon gaseous fuels would therefore pose a significant risk to the achievement of climate targets.

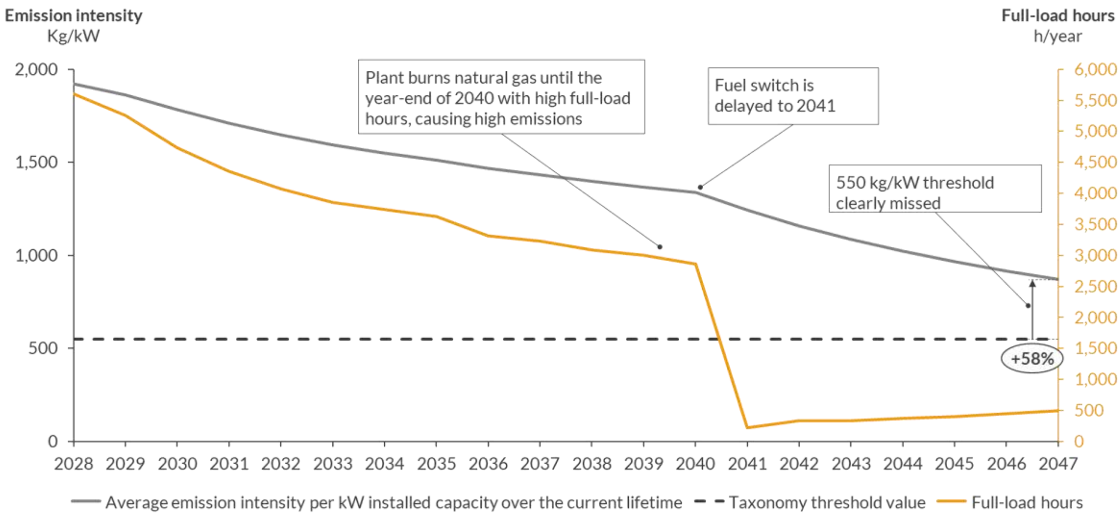

Figure 13: Average emission intensity per kW of installed capacity over the lifetime and full-load hours of a gas plant with profit-maximizing dispatch and delayed fuel switch to hydrogen in 2040

Conclusion

With the inclusion of gas activities to the Taxonomy, the relative attractiveness of investments in gas-fired power generation improves compared to alternative technologies. This is likely to initiate more gas capacity build-out, both in energy-only markets and power markets with capacity markets. A stronger gas capacity increase impacts low-carbon alternatives, as gas capacity build-out replaces alternative flexibility technologies and leads to less diversity in flexibility technologies. Different technologies have not only different costs and emission profiles, but also different purposes. Gas assets can provide flexibility when renewable production is low and additional power production is needed. However, gas cannot support renewables with flexibility when their production is high. Other flexible technologies, such as storage, batteries, and demand-side-response, can increase their power consumption and thereby reduce curtailment of renewables and stabilize prices in low-price periods.

To understand the extent to which gas assets would need to adapt their dispatch to comply with the requirements of the EU Taxonomy, we analyzed the profit-maximizing dispatch behavior of a gas-fired power plant which transitions to hydrogen combustion at the end of 2035. We find that the 550 kg CO_2e /kW emission limit is not always met. The result depends on the assumption made on the year of market entry of the gas power plant: If the gas asset enters the market later, it runs for less years as a natural gas-fired power plant and is thus more likely to meet the criterion. The result is further impacted by the time of the fuel switch. In case the gas asset delays its fuel switch by five years to end of 2040, the average emissions per unit of plant capacity would stand at 870 kg CO_2e /kW after 20 years, almost 60% above the threshold value. It is important to note that the result does not mean that it is technically or economically impossible to operate a gas-fueled power plant in compliance with the technical screening criterion.