

THE IMPACT OF PLANNED GAS-BASED CAPACITY EXPANSION IN THE POWER SECTOR OF THE CEE AND SEE COUNTRIES

REKK

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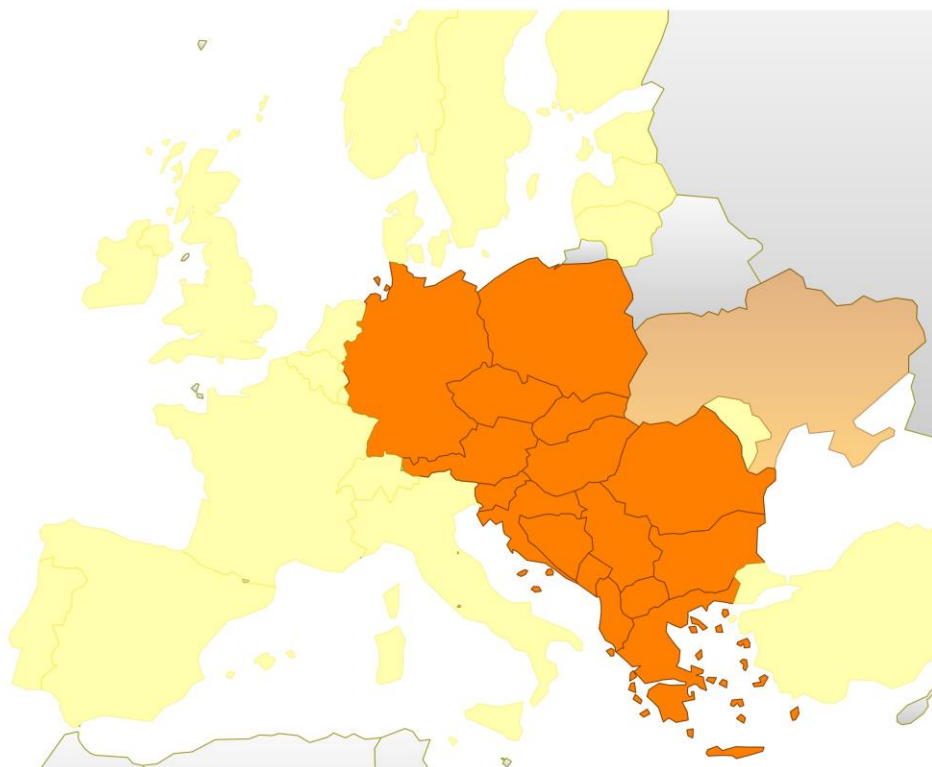
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1 Executive summary

Natural gas is considered a transition fuel in Europe; however, the end-state of the climate-neutral electricity sector in 2040 remains uncertain. Two main theoretical pathways are possible. In the first, natural gas power plants are phased out and largely replaced by renewables and, in the long run, by storage installations. The second possibility is to convert natural gas power plants to run on green hydrogen, which would require maintaining or even expanding existing natural gas capacities.

Currently, Central and Eastern European countries are planning to increase their natural gas capacities, according to their National Energy and Climate Plans (NECPs). They argue that these new investments are necessary to balance the rapidly expanding renewable energy capacities and, in some cases, to facilitate the future conversion of gas power plants to hydrogen-based operation. As a result, it is expected that total gas capacity in the region will increase by 10–15 GW by 2030 relative to 2023.

FIGURE 1. MAP OF THE REGION OF INTEREST – CENTRAL AND EASTERN EUROPE AND THE BALKANS



This study analysed the impacts of the planned gas capacity expansion in the CEE region¹ by applying a European power market model (EPMM). It focuses on four research questions:

- Are the planned 12-30 GW of new gas capacity needed in the sector from a flexibility point of view?
- What would be the impact if these new capacities are switched to hydrogen in 2030?
- Can we reach net zero GHG emissions if these gas capacities are built?
- What is the minimum gas capacity required in the system to fulfil electricity and, and reserve/balancing need?

The assessment arrived at the following conclusions:

- The new gas power plant investments will become stranded. The new gas-fired power plants have higher level utilisation rates in the first five-year period, above 45%, but a clear downward trend reduces these rates thereafter. The revenue they generate in these periods is not sufficient to reach the threshold level to break even and fully pay back the investment cost. If most of these gas plants are built, the majority would require support over the long term, probably through capacity payments, or other form of subsidy (e.g. state-owned company carried out the investment). Countries having access to lower-price natural gas (e.g. having a higher share of domestic production (e.g. Romania) or LNG terminals (Germany, Poland)) could have higher utilisation rates, even with few Euro differences. On the other hand, countries that do not have these sources should be more careful in their gas capacity expansion.
- The planned gas capacity investments do not contribute significantly to reducing electricity prices. If relative to a situation where gas capacities remain constant, 12 (medium expansion) or 30 GW (high expansion) of new gas CCGTs are added to the CEE power system, it has only a moderate price smoothing effect of 2-3 €/MWh by 2030, and even less in 2040. Only Poland experiences higher price reduction (7-9 €/MWh by 2030 and 4-5 €/MWh by 2040) , so the planned gas capacity expansion is more justified there.
- The results show that even if total gas capacities decrease over time, thus outgoing capacities only partially replaced, balanced power system operation is ensured, without extreme price events. This the system can safely operate if current (2023) total gas capacities decrease with 10-15 GWs by 2030, depending on other sectoral developments, e.g. deployment of RES and battery technologies., If the very ambitious NECP renewable targets are achieved and accompanied by higher than expected battery storage applications and DSM

¹ The Region includes Albania, Austria, Bosnia and Herzegovina, Bulgaria, Croatia, Czech Republic, Germany, Greece, Hungary, Kosovo, Montenegro, North Macedonia, Poland, Romania, Serbia, Slovakia and Slovenia.

measures, the lower level of gas capacities (total decrease of 25–30 GW relative to current state) will be sufficient.

- Switching gas power plants to hydrogen is economically unfeasible. If the new gas plants switched to hydrogen use, wholesale prices would be raised significantly, even 40€/MWh above the reference in some years. This impact could be higher if the assumed 80 €/MWh hydrogen price is exceeded. If hydrogen plants come online early when there are still existing coal capacities, the price increase could initiate coal power plants' return to operation and increase GHG emissions, as the operation of coal power plants becomes cheaper as the operation of hydrogen-fuelled gas power plants.
- Since the marginal cost of hydrogen-based production is higher than that of natural gas or coal, if one country unilaterally switches from gas to hydrogen, it will significantly harm the competitiveness of its domestic power plants relative to those in countries that do not make the switch. If curtailed RES and nuclear plants produce hydrogen during curtailment periods, it could provide 5 to 20% of the hydrogen-based power generation units' hydrogen needs, which means that operating these power plants would require significant amount of green hydrogen from other sources, such as dedicated RES power plants, or import.
- Based on the modelling results, full decarbonisation without hydrogen-fuelled power plants is not achievable by 2040, as the system lacks sufficient flexible capacity to eliminate the operation of gas-fired power plants. Across the region, a total gas capacity of 25–30 GW is required to ensure safe system operation under high renewable penetration.
- Full decarbonisation is possible if the remaining gas capacities (25–30 GW) operates on a hydrogen basis, provided that the previously mentioned high-RES-plus-storage trajectory is achieved. If this trajectory is not met, approximately 45 GW of hydrogen-fuelled gas power plants will be needed to ensure system reliability. These total capacity requirements are significantly lower than current expansion plans, which indicate a total installed capacities of 75–80 GW.
- Full decarbonisation through hydrogen-fuelled power plants (combined with sufficient RES and storage) in 2040 results in electricity prices approximately 10 €/MWh higher compared to a scenario where these plants operate on a natural gas basis.

Recommendations

- As presently planned gas capacity levels are too high, and their buildup would entail higher costs through capacity payments. Therefore, it is more advisable for countries to build these capacities in a stepwise manner, considering the

neighbouring countries' development plans as well. Based on the modelling results a total installed capacity of 25-30 GW might be sufficient in the region.

- To increase the total installed capacities relative to their current (2023) value, it would be necessary to expand capacity remuneration schemes to cover the investment costs of power plants. This is independent from the fact whether these power plants will be fuelled with gas or hydrogen. Policymakers should also take these additional costs into account when planning new capacities. Furthermore, they should ensure that remuneration schemes are kept to a minimum and harmonised in order to minimise market distortions.

- Introducing a hydrogen-based fuel switch in power generation should be carefully designed. If the hydrogen price is too high (even in the case of the modelled 80€/MWh), it will entail a significant price increase in the power sector, above 40€/MWh especially in the short run (before 2040), mainly if insufficient RES capacities are installed in parallel. If the region wide hydrogen switch is implemented only in 2040, with sufficient RES present, the price effect can be reduced to 10€/MWh.
- The hydrogen switch should be implemented in a coordinated manner across the EU, as implementation at the national level significantly hinders the competitiveness of domestic actors, thus can substantially delay the process.
- The hydrogen switch should be initiated only after the coal phase-out, in order to avoid an increase in coal-based production. It must also be ensured that hydrogen-ready power plants are not allowed to operate with natural gas after the switch.

2 Introduction

The revision process of National Energy and Climate Plans (NECPs) ensures that Member State (MS) target-setting and achievement are aligned with the 2030 EU objectives. Setting the 2040 targets in line with the 2050 decarbonisation goals has commenced in the EU. This entails the possibility of decarbonising the power sector by 2040. In this sector, the technical feasibility exists to reach zero-emission goals earlier than in other sectors, and carbon leakage effects could be controlled more strictly.

The energy transition process in Central and Eastern Europe has been significantly impacted by the energy sector price crisis of 2022-2023, driven by gas market developments and the Ukraine war. This has led to a re-evaluation of the role of natural gas in the power sector. Despite developing alternative gas routes, which have seen a shift in gas transit from Russian pipelines to LNG in most EU member states, some landlocked MSs still import Russian gas through Ukraine and the southern gas corridor. Many MSs have continued to install and plan further development of their gas-based power production by constructing new, sizeable, combined cycle gas turbine (CCGT) capacities. Among the countries with gas-focused plans are West Balkan and EU countries, including Germany, Hungary, Poland, Romania, and North Macedonia. The drivers of this expansion differ significantly.

The report is structured as follows. First, the research questions and the methodology are presented, introducing the applied model and the assumptions driving the analysed scenarios. Four thematic areas follow it. The first one assesses if the planned gas capacities in our target region are necessary for the balanced operation of the power system. Chapter 5 evaluates the impacts of these new gas capacities changing to hydrogen. Chapter 6 looks at the consequences of GHG reduction targets for 2040, while the next chapter assesses the system's minimum gas capacity requirements, which ensures the power markets' balanced functioning. Chapter 8 concludes and is followed by an extensive Annex, presenting the main assumptions in the scenarios in detail and the additional results of the sensitivity assessments.

3 Research questions and scenario set-up

The abovementioned developments raise the following four main questions about the future development of the power sectors of the CEE countries:

I. Are the planned gas power plants needed from a flexibility point of view?

While gas-fired plants represent a crucial source of flexibility provision, given their readily adjustable production profile, it is necessary to ascertain whether all planned capacities are truly required. If they cannot recover the investment cost from the flexibility markets, they will be forced to operate in the wholesale markets for significantly longer periods, resulting in substantial CO₂ emissions during their lifetime, which could extend beyond 2040. This pathway presents a significant risk of jeopardising the net-zero target of the power sector or creating stranded assets.

The impact of planned new investments on the region's electricity markets was assessed in three market environments:

- 1) How can RES generation capacities (wind/PV complemented with storage options including BESS and pumped hydro) substitute these capacities
- 2) To what extent gas is needed in the case of higher electricity demand due to electrification
- 3) To what extent do higher gas prices accelerate the decarbonisation of the power sector?

II. What would be the impact of switching the gas plants to hydrogen?

The assessment shows that if a certain proportion of gas power plants can use hydrogen in their operation (hydrogen readiness), this can significantly reduce their carbon emissions. Switching to hydrogen fuel in the new power plants has additional impacts. Depending on the price of hydrogen, wholesale prices can change substantially when these plants are price-setting units. Besides the wholesale price impacts, another question analysed in this section is whether curtailed RES production could cover a significant part of the necessary hydrogen demand. The questions to be answered are:

- What is the wholesale price impact of the gas-to-hydrogen fuel switch in 2035 and 2040 in various scenarios?
- What portion of the resulting hydrogen demand could theoretically be covered by the avoided RES curtailment?

III. How can zero GHG emissions in the power sector by 2040 be reached with these new capacities?

We assume that gas power plants convert to hydrogen at various rates in the analysed scenarios. The section looks at the interplay between the various levels of hydrogen-based electricity production, the level of RES capacity expansion, and the feasibility of achieving the 2040 carbon targets. The analysed questions are the following:

- What are the economic impacts (e.g., on prices and technology mix) of converting certain shares of gas-based generation to hydrogen?
- How would this picture change if different renewable deployment levels were assumed?

IV. What is the minimum gas capacity required in the system?

The emergence of extreme prices mainly captures this issue, as they are good indicators of capacity shortages. The section assesses these price changes in various sensitivity cases assuming varying retirement schedules of the older natural gas-based plants. It also looks beyond the wholesale price changes, as the section investigates the production mix and carbon emission changes. The resulting questions:

- Could we observe extreme wholesale price impacts in these scenarios - as indicators for capacity shortages?
- How much of the outgoing gas-based generation capacities need to be replaced to keep the system balanced and without extreme price events?

The following table summarises how the above research questions have been translated into modelling scenarios.

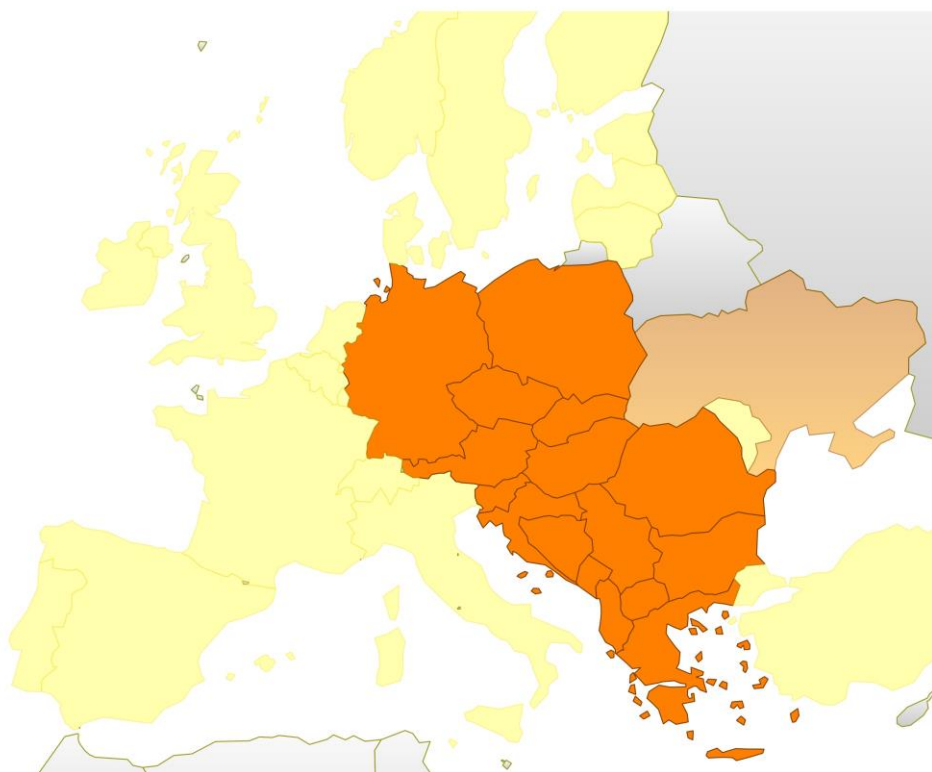
TABLE 1: SUMMARY OF THE RESEARCH QUESTIONS AND THE ANALYSED SCENARIOS

Research questions	Scenarios		
Are the planned gas power plants needed from a flexibility point of view?	Low	Medium	High
How can RES capacities and battery substitute gas capacities?	High RES - Low	High RES - Medium	High RES - High
To what extent gas is needed in the case of higher electricity demand due to electrification?	High load - Low	High load - Medium	High load - High
To what extent higher gas price accelerate the decarbonisation of the power sector?	High gas price - Low	High gas price - Medium	High gas price - High
How can zero GHG emissions in the power sector by 2040 be reached with these new capacities?	Decarbon - Low	Decarbon - Medium	Decarbon - High
What would be the impact of switching the gas plants to hydrogen?	Hydrogen - Low	Hydrogen - Medium	Hydrogen - High
What is the minimum gas capacity required in the system?	Low1 – REF RES	Low2 – REF RES	Low3 – REF RES
	Low1 – High RES	Low2 – High RES	Low3 – High RES

4 Methodology

A model-based analysis was conducted using the in-house European Power Market Model (EPMM) of REKK to answer the research questions detailed above. The modelled years were 2030, 2035, 2040. The analysed countries are indicated in Figure 2.

FIGURE 2. MAP OF THE REGION OF INTEREST – CENTRAL AND EASTERN EUROPE AND THE BALKANS



** Ukraine is part of the target region; however, due to the high uncertainty of the country's data and future plans resulting from the Russian invasion, no in-depth analysis is possible for the country within the scope of this project.*

The EPMM is a 168-hour unit commitment and economic dispatch model covering the electricity systems of 41 European countries. It simultaneously determines the equilibrium values of the wholesale electricity and reserve markets for each hour and market, taking into account the projected weather-dependent renewable generation, the electricity demand, the reserve requirements for each country, and the technological constraints and costs (minimum operating and off-time, minimum / maximum load level, start-up / shut-down costs, variable costs of generation) for electricity generation and transmission. Using these inputs, the model predicts the operating status of the power plants every hour of the week (covering almost 3,500 power plants). The calculations estimate the volume of generation at the operating units, the composition of capacities set aside for upward regulation and downward regulation, the operation of reservoir hydropower plants, the flows on all cross-border interconnectors, and the wholesale market price of electricity and the price of the upward and downward reserve capacities in each country.

The model has three market participant types: producers, consumers, and traders. They all behave in a price-taking manner: they take the prevailing market price as given and assume that their actions have a negligible effect on this price.

The EPMM models 3500 power plant units operated with 12 different fuels: natural gas, coal, lignite, heavy fuel oil (HFO), light fuel oil (LFO), nuclear, biomass, geothermal, hydro, wind, solar and tide and wave. Each plant has a specific marginal cost of production, which is constant at the unit level. In addition, generation capacity is constrained at the level of available capacity.

Power flow is ensured by approximately 110 interconnectors between the countries, where each country is treated as a single node. Thus, no domestic power system constraint is taken into account. Net transfer capacities (NTC) values indicate trading possibilities; seasonal differences are included in the modelling based on historical data from the ENTSO-E Transparency Platform. Future investments are based on ENTSO-E's latest Ten-Year Network Development Plan (TYNDP) data.

Consumers are represented in the model in an aggregated way by different price-sensitive demand curves for each modelled market. A downward-sloping linear function approximates the inverse relationship between prices and the quantity consumed. Traders connect the production and consumption sides of a market through exporting electricity to more expensive countries from cheaper ones.

5 Are the planned gas power plants needed from a flexibility point of view?

5.1 Analysed scenarios

Looking at the gas power plant investment plans of the countries analysed, we have divided the planned investments in the region into three categories according to their likelihood of being realised.

We have developed three main scenarios based on the construction status of newly built gas power plants:

- Low: in this scenario, we assume that each country finishes only those gas power plants that are already in construction (physical construction works already started).
- Medium: this scenario considers those new gas power plants that, based on the current progress, are likely to be built in the future.
- High: In this scenario, we include in the modelling the most ambitious plans of the countries based on their NECP or as the sum of individual project plans (whichever is higher).

In these basic scenarios, no hydrogen-based PP operation or CCS is considered. Based on the new capacities included in the investment plans, the analysed countries can be grouped as follows:

TABLE 2: SUMMARY OF THE ESTIMATED SCENARIOS

Decrease	No change	Moderate increase	Significant increase
Austria	Bosnia	Albania	Czechia
	Bulgaria	Croatia	Germany
	Kosovo	Hungary	Greece
	Montenegro	North Macedonia	Poland
	Slovakia	Serbia	Romania
		Slovenia	

The amount of gas capacity in each country and scenario is shown in the table below:

TABLE 3: ASSUMED GAS CAPACITIES IN THE ESTIMATED SCENARIOS

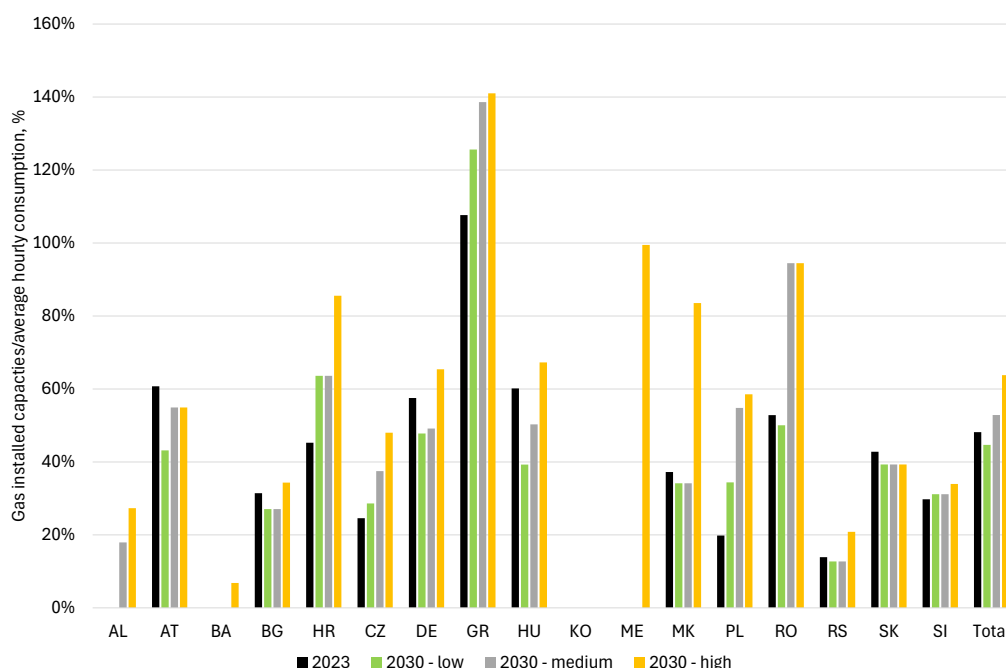
	2023	2030			2040		
	Current	Low	Medium	High	Low	Medium	High
Albania	0.0	0.0	0.2	0.3	0.0	0.2	0.3
Austria	5.0	3.9	4.9	4.9	3.9	4.7	4.7
Bosnia	0.0	0.0	0.0	0.1	0.0	0.0	0.1
Bulgaria	1.2	1.0	1.0	1.3	1.0	1.0	2.4
Croatia	1.0	1.4	1.4	1.9	1.0	1.0	1.5
Czechia	1.7	2.2	2.8	3.6	2.1	2.8	3.6
Germany	33.7	30.4	31.3	41.6	29.2	30.0	42.9
Greece	6.3	8.0	8.8	9.0	6.1	6.9	7.1
Hungary	3.0	2.3	3.0	4.0	1.6	2.2	3.2
Kosovo	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Montenegro	0.0	0.0	0.0	0.4	0.0	0.0	0.4
North Macedonia	0.3	0.3	0.3	0.7	0.3	0.3	0.7
Poland	3.5	7.0	11.1	11.9	7.0	11.1	11.9
Romania	3.0	3.4	6.5	6.5	2.3	5.4	5.4
Serbia	0.6	0.5	0.5	0.9	0.2	0.2	1.7
Slovakia	1.2	1.2	1.2	1.2	1.1	1.1	1.1
Slovenia	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Total	60.9	62.2	73.6	88.8	56.4	67.7	87.6

By 2030, gas capacities remain stable at 60 GW in the low scenario, followed by a decline to 56 GW by 2040. In contrast, the medium and high gas scenarios anticipate capacity growth to 74 GW and 89 GW in 2030, with a slight decrease to 68 GW and 88 GW, respectively, by 2040. Germany plays a crucial role in shaping regional capacity trends, but uncertainty surrounding its planned installations adds complexity to future projections.

Figure 3 shows how the installed gas capacity compares to the average hourly consumption. The ratio varies considerably; there are countries where it is above 100%, indicating that the

country could fully meet its consumption from gas power (e.g. Greece), and there are countries where this ratio is much lower, below 30%.

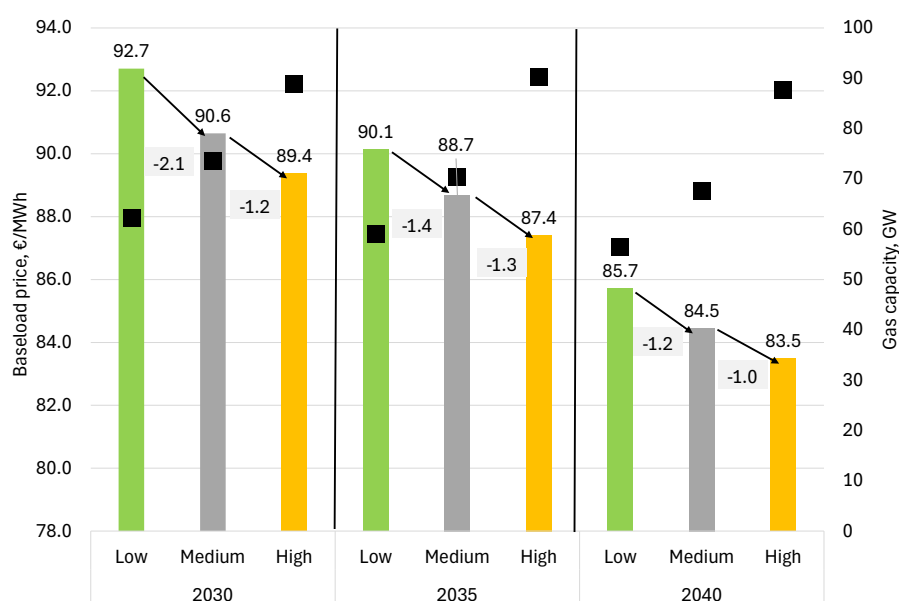
FIGURE 3. INSTALLED GAS CAPACITIES AS A PROPORTION OF AVERAGE HOURLY CONSUMPTION



5.2 Main results

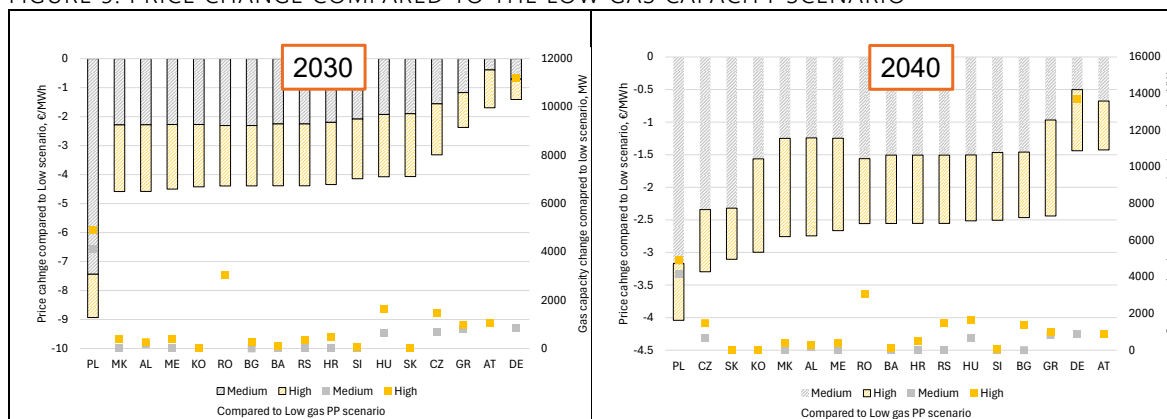
Figure 4 illustrates the modelled wholesale average electricity price and the assumed gas capacity in the three main scenarios and three modelled years. The average wholesale electricity price equals the consumption-weighted average wholesale electricity prices of the countries in the assessed region.

FIGURE 4. WHOLESALE AVERAGE ELECTRICITY PRICE IN THE REGION €/MWh



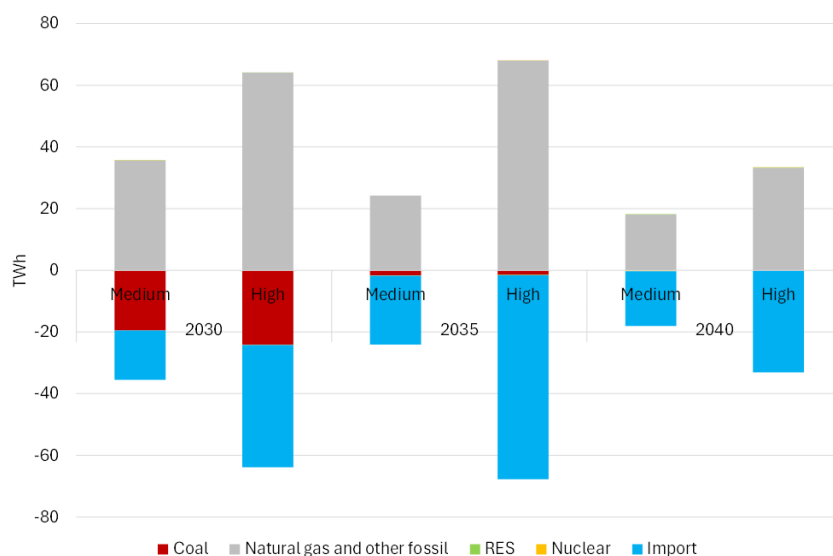
By 2030, the medium scenario projects 12 GW more gas capacity at the regional level compared to the low scenario, while the high scenario adds 30 GW. However, this results in a modest reduction in average electricity prices - 2.1 €/MWh and 3.3 €/MWh, respectively. By 2040, the price impact diminishes further as the increasing share of renewables reduces the importance of gas power plants, meaning there are fewer hours when they set the market price. The other reason why the new gas capacities have a more negligible impact on the electricity price is that most of the coal capacities will be phased out at that time, which results that new gas capacities can only substitute old gas power plants and not coal generations.

FIGURE 5. PRICE CHANGE COMPARED TO THE LOW GAS CAPACITY SCENARIO

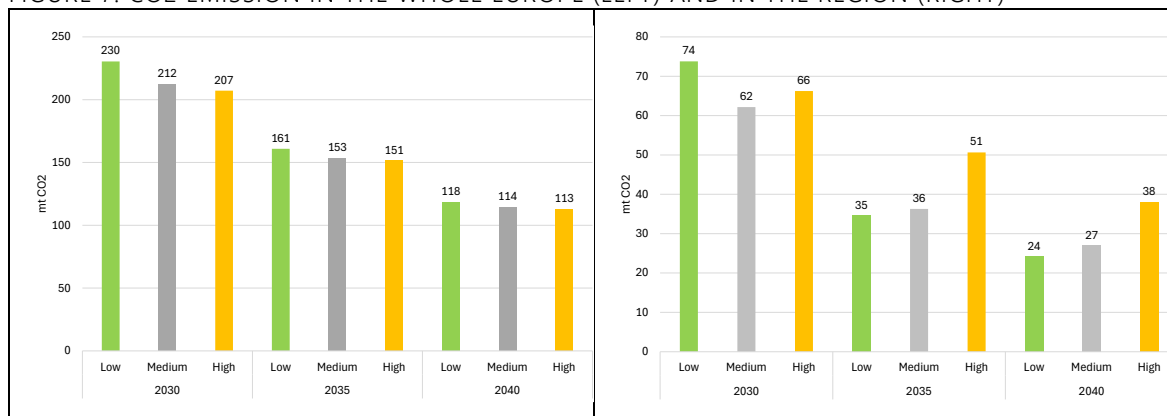


However, significant differences exist between countries, as price changes are not proportional to capacity increases. Poland stands out due to its substantial coal-to-gas switching potential and the limited grid interconnections combined with high consumption, making price impacts more pronounced, as illustrated by Figure 27. In contrast, other countries show more similar trends. While Germany plans the highest gas capacity expansion in the high scenario, its price impact remains smaller than in other countries due to the large size of its energy market.

FIGURE 6. CHANGE OF ELECTRICITY MIX COMPARED TO THE LOW SCENARIO

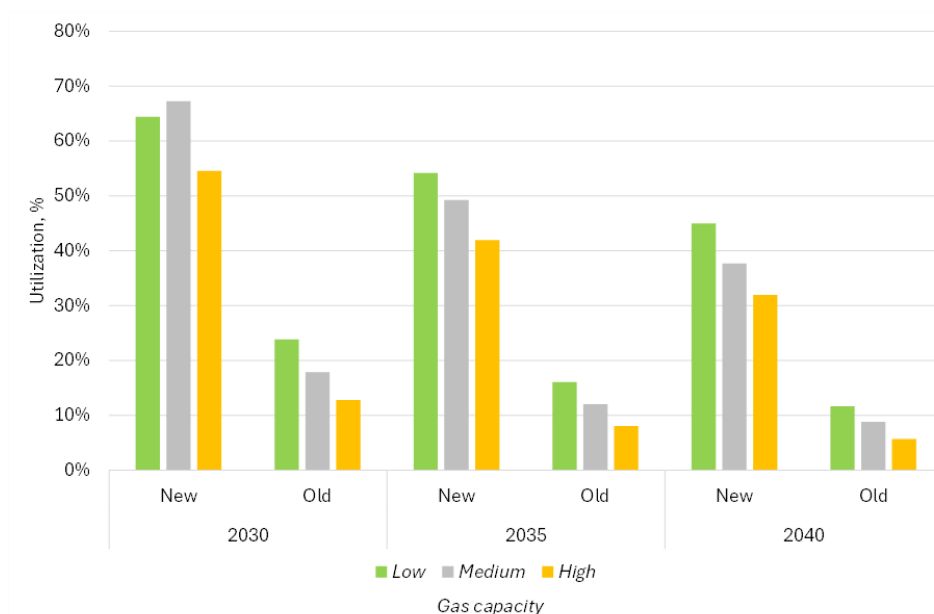


In 2030, the increase in gas production partly displaces coal-based production (mainly in Poland) and partly replaces imports. In 2035, the medium scenario shows a further minimal decrease of coal-based output compared to the low scenario. By 2040, the increase in gas production displaces imports entirely, meaning that new gas plants displace less efficient gas-fired power plants in other countries, as Figure 6 demonstrates.

FIGURE 7. CO₂ EMISSION IN THE WHOLE EUROPE (LEFT) AND IN THE REGION (RIGHT)

At the EU level, gas capacity expansion can still replace coal, especially in the short term, leading to a significant reduction in CO₂ emissions, as shown in Figure 7. By 2035 and 2040, when most of the European coal-fired power plants will be phased out, new gas power plants will replace older ones, resulting in a slight decrease in CO₂ emissions due to improved efficiency. The emergence of this effect in the assessed region is somewhat incidental, as gas is more likely to substitute imports, leading to production shifts between countries and different technologies.

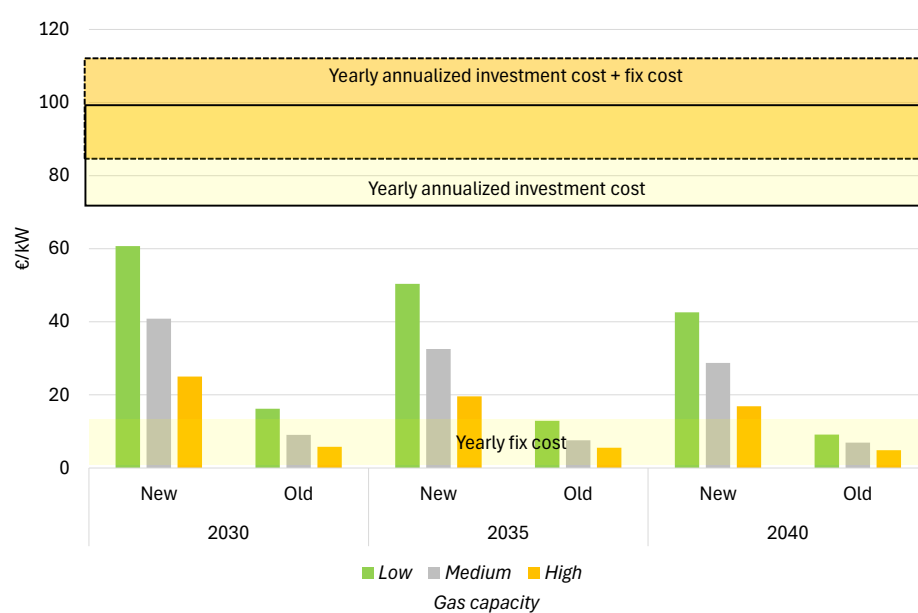
FIGURE 8. AVERAGE UTILIZATION OF THE GAS POWER PLANTS IN THE REGION



**New plants: built after 2025; old plants: built until 2025*

New power plants have relatively high utilisation rates, and although these rates decline over time, in the low scenario, a utilisation rate of around 45% can still be observed in 2040 (see Figure 8). The overall increase in gas capacity typically reduces the utilisation of both new and old gas-fired power plants, as there is a cannibalisation effect on both. The model does not account for unprofitable plants exiting the system. Still, the low utilisation of older power plants suggests that there is an increasing risk for them to become stranded.

FIGURE 9. AVERAGE SHORT TERM PROFITABILITY OF THE GAS POWER PLANTS IN THE REGION



**New plants: built after 2025; old plants: built until 2025*

Figure 9 illustrates the short-term profitability of the old and new gas power plants. The columns represent short-term profits (including the revenues from the wholesale and balancing reserve markets), which still need to be compared with investment and fixed production costs, where the yellow areas at the top of the figure indicate their levels. A profit level of around 90-110 €/kW would be necessary for long-term profitable operation. On average, across the region, the revenue per unit of capacity does not reach this level in either scenario. When examining profitability by country (see Figure 31 in the Annex), we see that only in Poland, in the low-capacity scenario, is it economically viable to build an additional gas power plant. In other countries, these power plants are expected to be built only if they receive additional support (e.g., capacity remuneration).

5.3 Sensitivity analysis

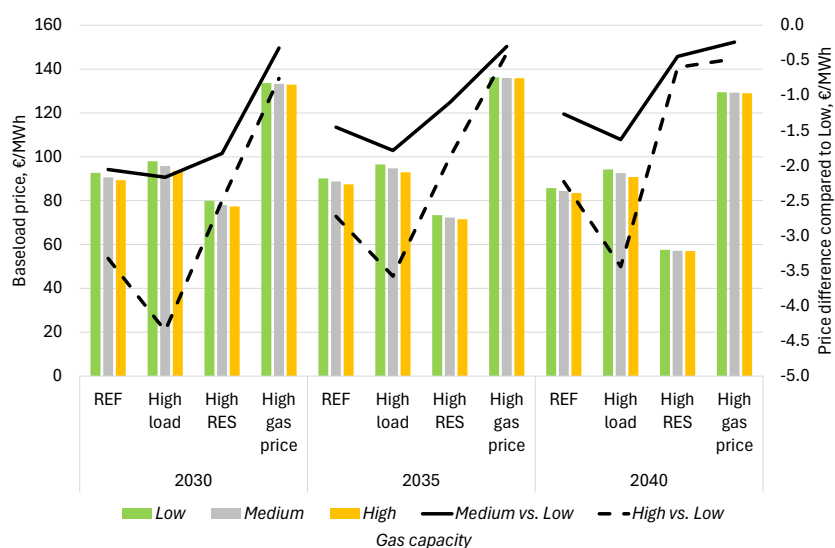
This section examines the impact of the construction of gas power plants for three sensitivity scenarios. Their main characteristics are summarised in the figure below:

FIGURE 10. THE MAIN CHARACTERISTICS OF THE ANALYSED SENSITIVITY SCENARIOS

High RES	High demand	High gas price
Question: To what extent can higher deployment of RES and batteries substitute gas power plants? - One sensitivity to all gas scenarios - Reference RES and battery capacity: 80% of the PV and wind capacities that are in the NECPs will be commissioned - Reference battery capacities will be deployed - Higher RES and battery deployment 100% of the PV and wind capacities that are in the NECPs will be commissioned - Higher battery capacities will be deployed	Question: To what extent gas is needed in the case of higher electricity demand due to electrification? - One sensitivity to all gas scenarios - Reference based on FIT55 Reference scenario - High demand: +5% higher demand in every modelled countries compared to Reference	Question: To what extent higher gas price accelerate the decarbonisation of the power sector? - One sensitivity to all gas scenarios - In the Reference scenario 33.4 (2030) and 32.3 (2040) €/MWh TTF gas price is assumed - High gas price: 92.9 (2030) and 92.1 (2040) €/MWh TTF gas price is assumed

In Figure 12, the black lines indicate how much the price decreases in the medium and high scenarios compared to the low gas penetration scenario. The difference between gas capacity scenarios is small across all sensitivities. In the case of high demand, additional gas capacities reduce prices by approximately 3.5-4.5€/MWh, as high demand amplifies the price impact. However, in a high gas price scenario, the price effect of new gas capacities is negligible. In this case, even if new gas power plants are built, they are utilised at a very low level.

FIGURE 11. MODELLED AVERAGE BASELOAD PRICE IN THE SENSITIVITY SCENARIOS



As Figure 12 illustrates, there are significant differences between the scenarios regarding the profitability of new gas-fired power plants. Under high consumption, the profit per unit of capacity for new gas-fired power plants is comparable to the annualised investment cost in the low-capacity scenario in 2030 and 2035. However, when fixed costs are considered, they still cannot operate profitably on a regional average, except in Poland.

FIGURE 12. AVERAGE PROFITABILITY OF NEW GAS POWER PLANTS IN THE REGION IN THE SENSITIVITY SCENARIOS

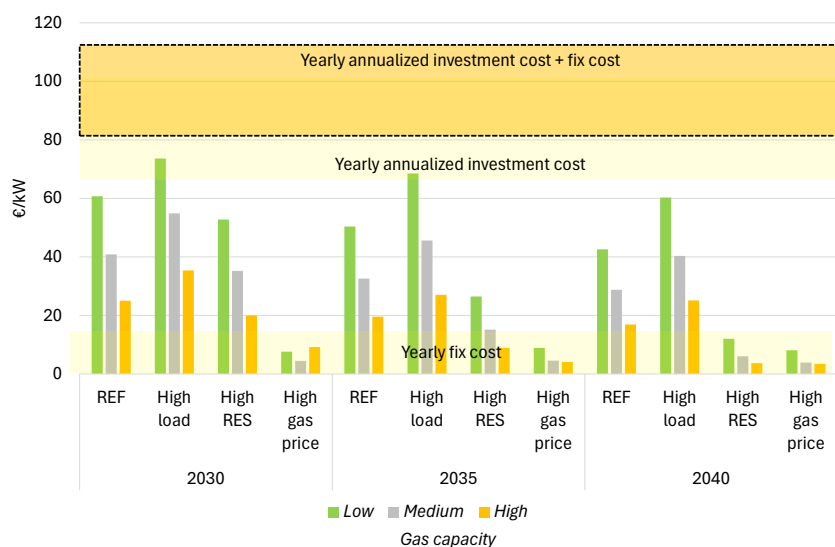
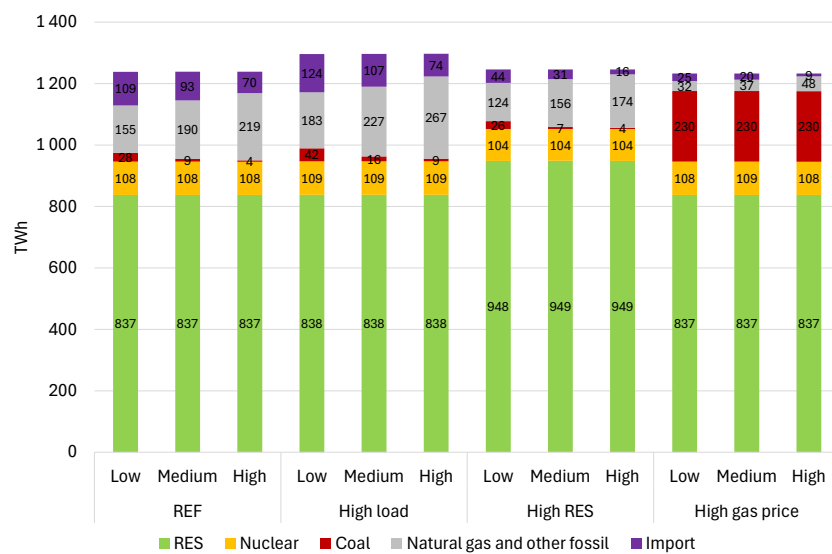


Figure 13 demonstrates that in the high gas price scenario, coal-fired power plants will be brought back to production in 2030. In the high load sensitivity case, the difference between the various gas capacity scenarios remains roughly unchanged, while the level of exports and imports adjusts instead. Higher renewable capacities displace gas-fired power plants and import as well.

FIGURE 13. ELECTRICITY MIX IN THE SENSITIVITY SCENARIOS IN THE ASSESSED REGION



6 The impact of switching the gas plants to hydrogen

6.1 Scenario description

In these scenarios, only the years 2035 and 2040 are modelled. All gas power plants built after 2010 are assumed to switch to hydrogen, and all the other gas-based producers are phased out, while coal and other fossil-fuel-based power generators remain unchanged from the low, medium, and high-capacity scenarios, meaning they can continue operating. These assumptions are not only related to the analysed Region itself but the whole of Europe.

The assumed hydrogen price for 2030 is 80 €/MWh, while the gas price is 25 €/MWh in the assumed scenarios.

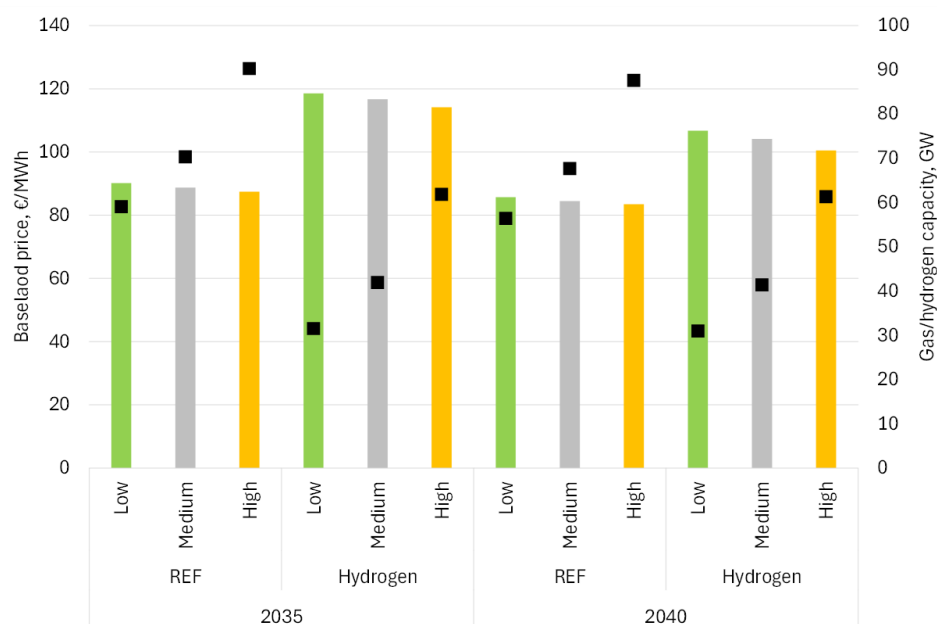
Three hydrogen scenarios were analysed:

- Low-hydrogen: 31 GW hydrogen-based power generation in the Region
- Medium-hydrogen: 41 GW hydrogen-based power generation in the Region
- High-hydrogen: 61 GW hydrogen-based power generation in the Region

Regional average wholesale prices and the hydrogen/gas capacities in the analysed scenarios are shown in Figure 14.

6.2 Main results

FIGURE 14. AVERAGE WHOLESALE PRICE IN THE REGION IN THE REFERENCE AND HYDROGEN SCENARIOS

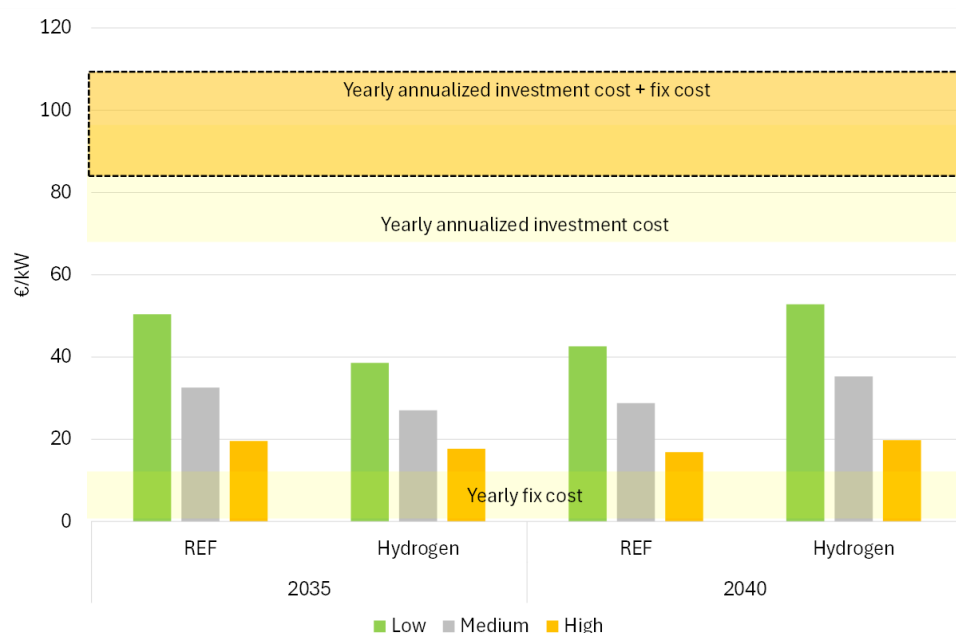


Switching to hydrogen is feasible but comes at a higher wholesale price. On average, wholesale electricity prices increase by 20-25%, primarily due to the higher cost of hydrogen compared

to natural gas and due to the much lower hydrogen capacity compared to gas capacities. Additionally, price spikes become more frequent and severe, especially in Germany, as the overall available generation capacity is reduced (see Figure 37. in Annex for more details on prices).

Figure 15 shows the profitability of the natural gas and hydrogen-based power plants in the reference scenario when no hydrogen capacities are assumed and in the hydrogen scenarios when all the natural plants commissioned before 2010 are phase-out, while the newer capacities are switched to hydrogen.

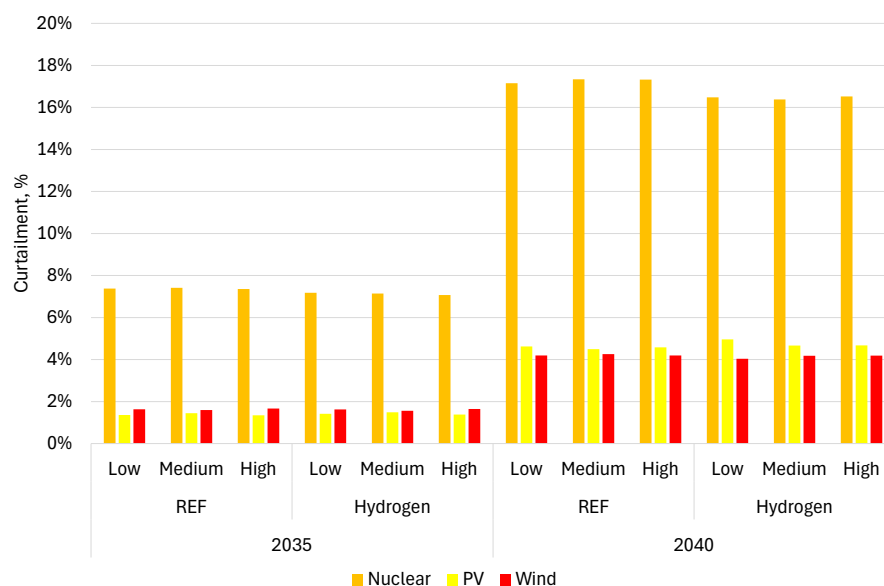
FIGURE 15. AVERAGE PROFITABILITY OF NEW POWER PLANTS IN THE REGION



In 2035, the profitability of hydrogen-based power plants decreases further compared to gas-fired plants, meaning they require higher subsidies. Although wholesale prices rise, the costs of hydrogen-powered plants are also significantly higher, offsetting potential gains. However, by 2040, their profitability will improve due to a significant reduction in overall generation capacity. We also have to note that the depicted yearly annualised investment cost and fixed cost are related to new gas capacities. Both the investment cost and the yearly fixed cost could be higher in the case of hydrogen fuelling.

In the following, we look at the amount of nuclear and RES production curtailment. We also check if this amount is used for hydrogen production and how much of the hydrogen consumption of hydrogen-based power plants is covered. The curtailed production of nuclear and RES producers is illustrated in Figure 16. The curtailment ratio is the curtailed energy divided by the potential maximum production, which later is the capacity multiplied by the availability factor.

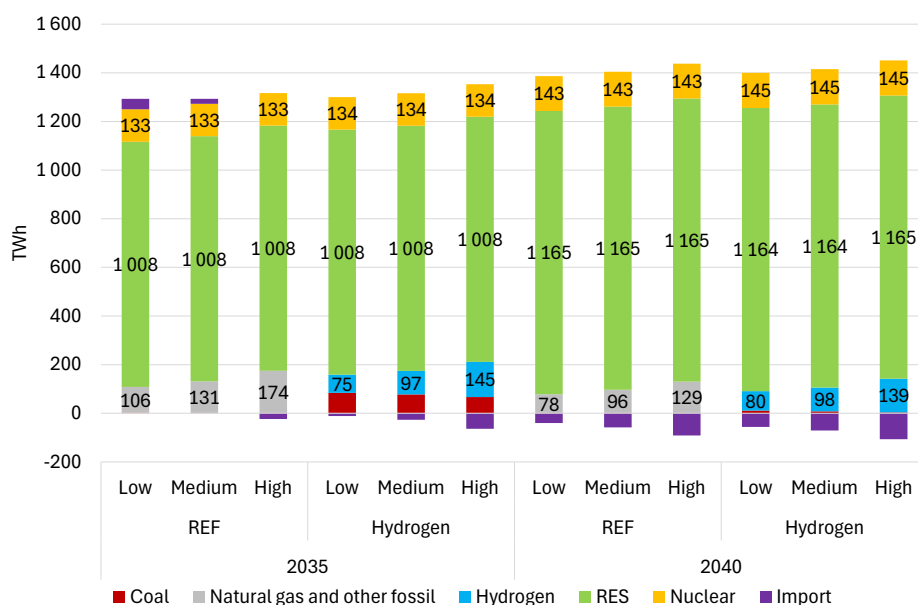
FIGURE 16. REGIONAL AVERAGE CURTAILMENT RATIO OF NUCLEAR AND RES CAPACITIES



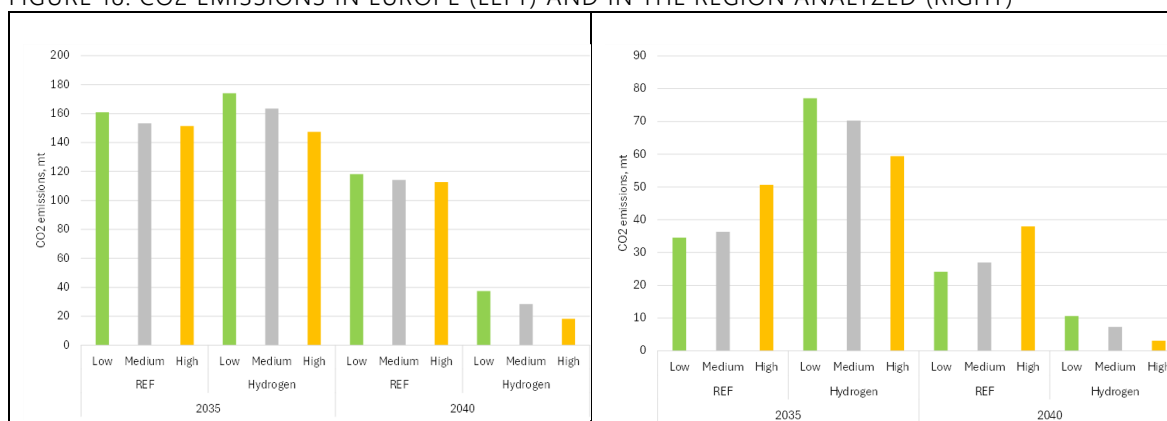
There is a high nuclear curtailment ratio and a lower – but gradually increasing – curtailment of renewable energy sources. However, switching to hydrogen does not impact curtailment levels, as there is no significant difference between scenarios. The total curtailed energy in the Region is around 23 TWh in 2035 and 71 TWh in 2040 in all three hydrogen scenarios. The total hydrogen production is 74 TWh (low), 96 TWh (medium), and 145 TWh (high) in 2035, and 80 TWh, 98 TWh and 138 TWh in 2040. The average efficiency factor of electricity production from hydrogen is around 50%, while there is another 40-60 % loss in the electrolyzers.

If the total curtailed energy were used for hydrogen production, it would account for roughly 3-7 % in 2035 and 12-22% in 2040 of the total hydrogen consumption in the power sector across the region.

FIGURE 17. ELECTRICITY MIX IN THE REGION



If all the gas power plants switch to hydrogen (or phase out) without phasing out coal-fired power plants, the CCGT capacity will largely be replaced by coal generation, leading to higher CO₂ emissions compared to the reference scenario. Accordingly, in 2035, the decline in gas production due to the switch to hydrogen will be compensated mainly by increased coal generation in the region and, to a lesser extent, by imports. By 2040, however, coal-fired power plants will be phased out, making the transition to hydrogen much more impactful with a significant reduction in CO₂ emissions. The reduction in gas-based generation remains around 30 TWh across all scenarios in 2035. However, in 2040, despite the shift to hydrogen, gas production does not decrease.

FIGURE 18. CO₂ EMISSIONS IN EUROPE (LEFT) AND IN THE REGION ANALYZED (RIGHT)

7 How can zero GHG emissions in the power sector be reached by 2040 with these new capacities?

7.1 Scenario description

In this scenario, only the year 2040 is modelled. All gas power plants built after 2010 will switch to hydrogen, while other fossil-based power generators, including the older gas-based power generators, will be decommissioned. Similar assumptions are considered modelled countries outside the Region. The same new gas capacities as in the low, medium, and high scenarios will be implemented, but they will operate using hydrogen.

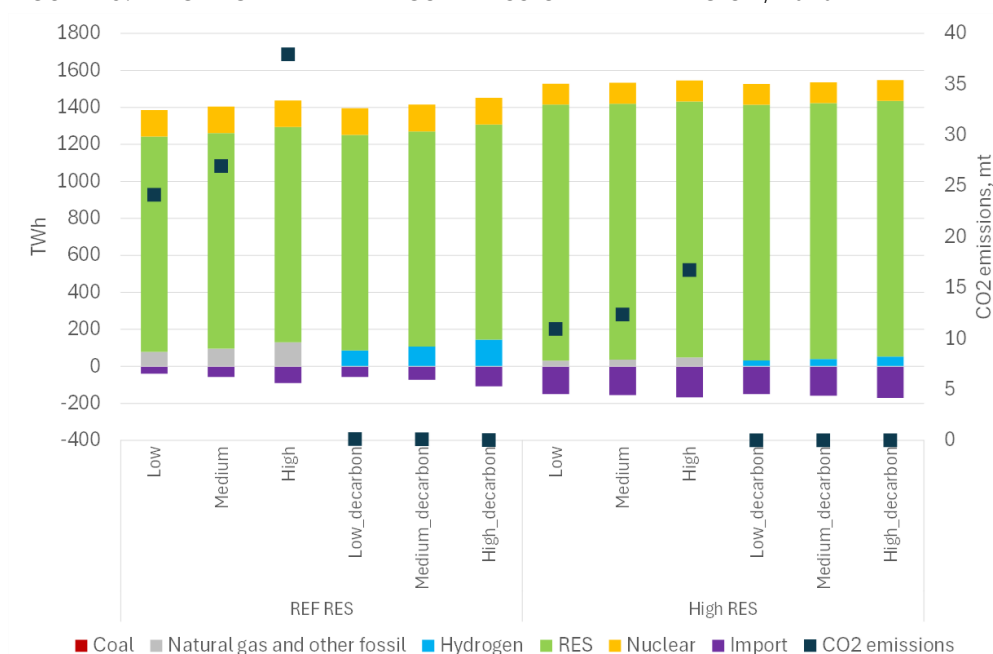
There are three decarbonisation scenarios:

- Low-decarbonization: 31 GW hydrogen-based power generation in the region by 2040
- Medium-decarbonization: 41 GW hydrogen-based power generation in the region by 2040
- High-decarbonization: 61 GW hydrogen-based power generation in the region by 2040

The impact of each decarbonisation scenario was examined for both reference (REF RES scenario) and higher renewable trajectories (high RES scenario). In the Reference RES scenario, it is assumed that in 2030, 80 % of the targeted PV and wind generations will be realised, and by 2040, similar trends will be assumed between 2025 and 2030. In the high RES scenario, instead of the 80 % RES realisation rate of the reference case, 100 % is assumed.

7.2 Main results

Figure 19 shows the electricity mix and the CO₂ emissions of the region in the decarbonisation scenarios compared to the three main scenarios. Figure 19 shows that full decarbonisation can be achieved in all three scenarios, even with low penetration of hydrogen power plants. Greenhouse gas emissions are reduced by 10 to 40 million tons per year. Natural gas production is replaced by hydrogen production and imports. With higher renewable energy penetration, less hydrogen-based power generation is required.

FIGURE 19. ELECTRICITY MIX AND CO₂ EMISSION IN THE REGION, 2040

The average prices in the same scenarios are shown in Figure 20. A significant increase is visible— from an initial average price of 80 €/MWh to around 140 €/MWh in the decarbonisation scenario. However, this can be reduced to approximately 100 €/MWh if more hydrogen power plants are built. In the high RES scenario, the price difference disappears, requiring much less hydrogen capacity.

FIGURE 20. AVERAGE BASELOAD PRICE IN THE REGION, 2040

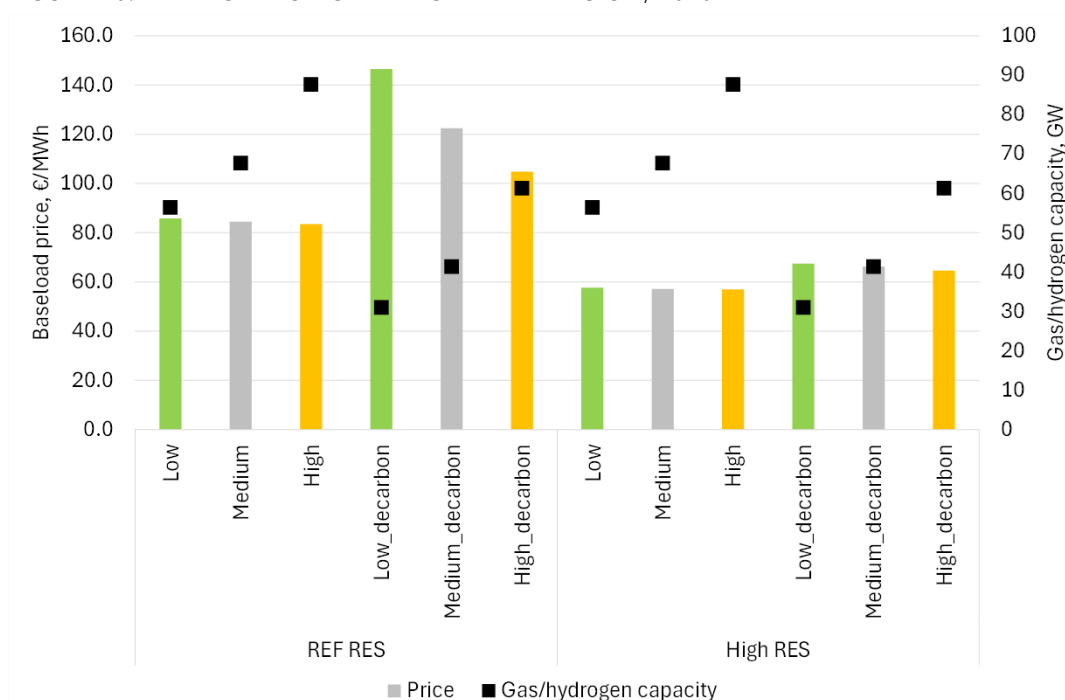
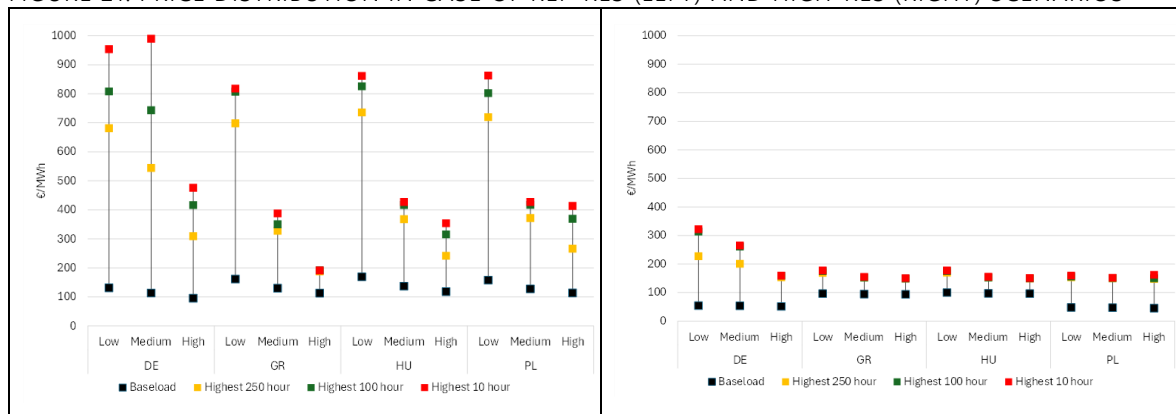


Figure 21 shows the average price of each country's largest 250, 100 and 10 hours, alongside the baseload prices. At lower RES capacities, extremely high prices occur frequently at low and

medium hydrogen capacities. In these cases, supply shortages force demand adjustments, meaning that additional flexible capacities are necessary. In the REF RES scenario, almost every country suffers from high prices, while in the high RES scenario, high prices are less frequent but still present. In the high RES case, high prices still appear in Germany, but these are significantly lower than in the reference RES scenario. Overall, it can be stated that building high RES capacities greatly enhances supply security in decarbonisation scenarios.

FIGURE 21. PRICE DISTRIBUTION IN CASE OF REF-RES (LEFT) AND HIGH-RES (RIGHT) SCENARIOS



8 Minimum gas capacity required in the system

8.1 Scenario description

In these scenarios assessing the minimum required gas capacities, all three years (2030, 2035, 2040) are modelled, with varying degrees of gas-based power plant decommissioning. Gas-fired power plants built before 1990 are phased out in the low1 scenario, those built before 2000 in the low2 scenario, and those built before 2010 in the low3 scenario by 2030. Meanwhile, coal and other fossil-fuel-based power generators remain unchanged from the low, medium, and high capacity scenarios, meaning they continue to operate as before.

The three modelled low gas scenarios are the following:

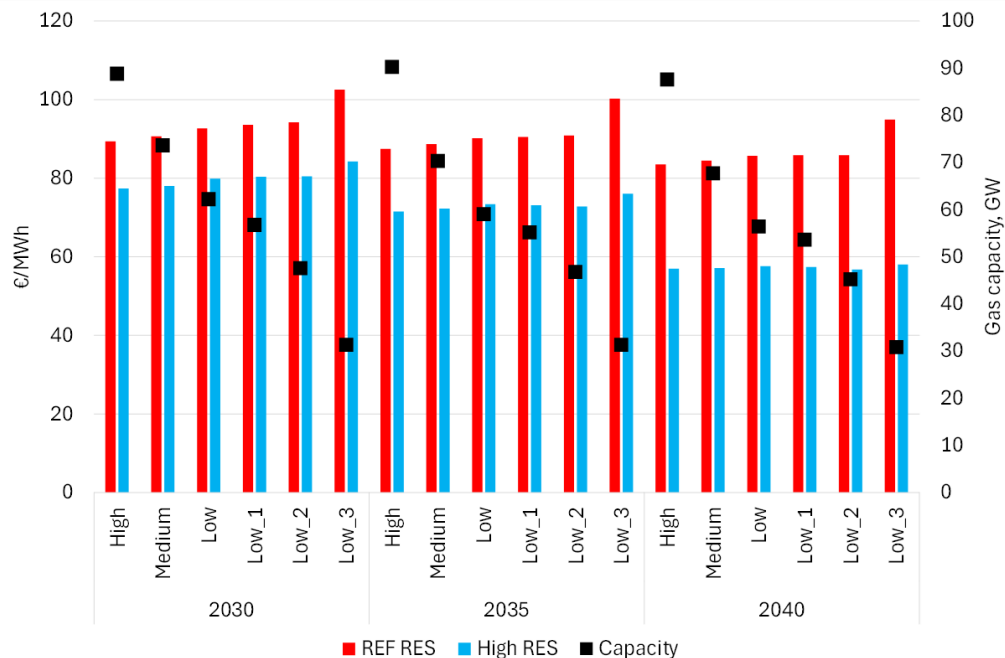
- Low1: 54 GW gas-based power generation in the region
- Low2: 45 GW gas-based power generation in the region
- Low3: 31 GW gas-based power generation in the region

These scenarios are modelled assuming reference and high RES capacity levels.

8.2 Main results

Figure 22 summarises the regional average of baseload prices and the assumed gas capacities in these scenarios.

FIGURE 22. AVERAGE REGIONAL BASELOAD PRICES ASSUMING DIFFERENT GAS CAPACITIES

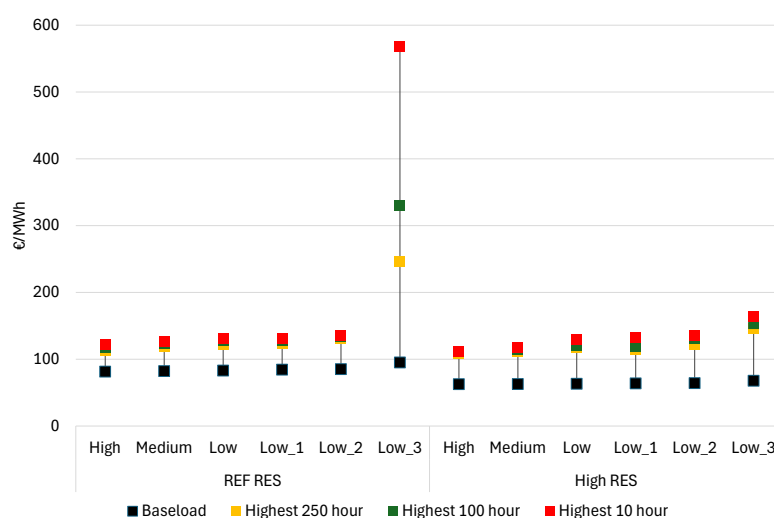


There is no significant change in baseload prices (within the same RES deployment scenarios), but a noticeable increase occurs between the Low 2 and Low 3 scenarios each year. If power plants built before 2000 were decommissioned, reducing gas capacity to around 45 GW from the current 60 GW, there would be no dramatic market changes. This suggests that the region does not require additional capacity beyond current levels; instead, new gas capacities are

primarily needed to replace ageing plants. It can be concluded that some additional gas capacity is necessary, but far less than what is currently planned in the region. If RES penetration is high, gas capacity could be reduced to Low 2 levels without significant wholesale price increase and even to Low 3 levels.

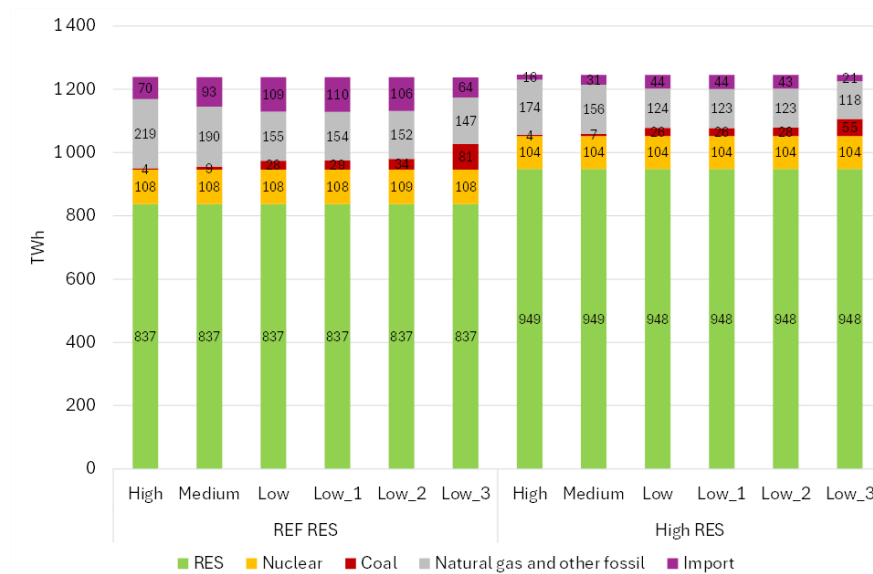
Looking at the distribution of German prices with low RES production, the Low 3 scenario (31 GW) leads to extremely high prices, indicating a significant capacity shortage. However, in a High RES scenario, these extreme price spikes do not occur, meaning that Low 3 capacity is sufficient to meet demand (Figure 23).

FIGURE 23. PRICE DISTRIBUTION IN GERMANY

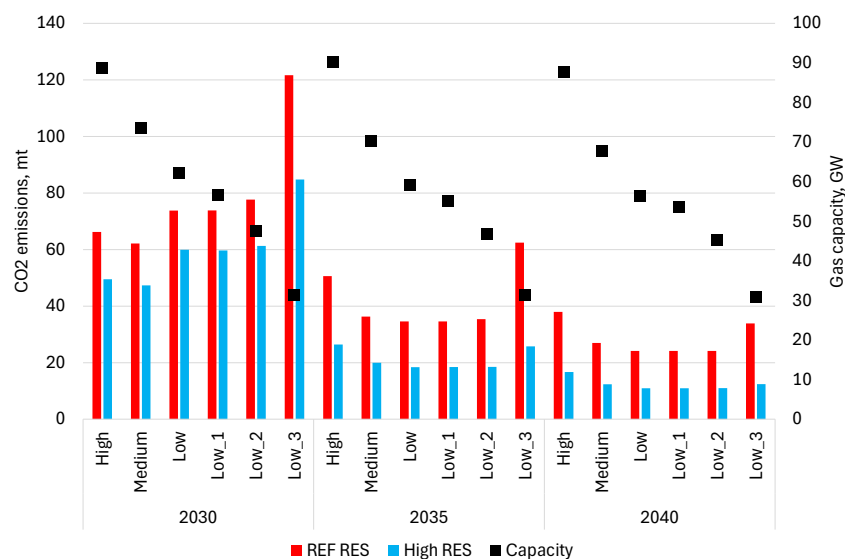


The electricity mix in the different scenarios shows that if too little gas capacity is built, there is a possibility that coal-fired power plants will operate in a high number of hours, risking meeting the carbon emission targets. In 2030, coal-fired power plants will start to produce in case of low gas-fired capacity (Figure 24).

FIGURE 24. ELECTRICITY MIX IN THE REGION



In the Low 3 scenario, where regional gas capacity falls below 45 GW, CO₂ emissions increase significantly, particularly in 2030. However, a high level of renewable energy capacity can effectively mitigate these emissions, reducing the overall carbon footprint of the power sector.

FIGURE 25. CO₂ EMISSIONS IN THE REGION

9 Conclusions

In this study, four main questions were analysed about the future development of the power sectors of the CEE countries using market modelling. The main results are the following:

I. Are the planned gas power plants needed from a flexibility point of view?

The results indicate that while new gas power plants can provide flexibility, their economic necessity and profitability remain uncertain. By 2030, the medium gas capacity scenario projects an additional 12 GW of gas capacity at the regional level compared to the low scenario, while the high scenario adds 30 GW. However, the impact on electricity prices is modest, reducing them by only 2.1 €/MWh and 3.3 €/MWh, respectively. By 2040, the effect diminishes further as the increasing share of renewables reduces the number of hours when gas power plants set market prices. Poland stands out due to its significant potential for coal-to-gas switching and limited grid interconnections, making price impacts more pronounced. Meanwhile, despite planning the highest gas capacity expansion in the high scenario, Germany experiences a more negligible price impact due to the size of its energy market. Looking at the hourly prices, we did not find extreme electricity prices in any scenario.

New power plants initially have relatively high utilisation rates, though these decline over time. Even in the low scenario, a utilisation rate of around 45% can still be observed by 2040. However, as gas capacity increases, the utilisation of both new and old gas-fired power plants decreases due to a cannibalisation effect. In most cases, the revenue per unit of capacity does not reach the necessary threshold for profitability. At the country level, Poland is the only market where, under a low-capacity scenario, building new gas power plants appears economically viable without external support. In all other countries, financial assistance or subsidies would be required for gas plants to be profitable. Under high consumption conditions, the profit per unit of capacity for new gas-fired power plants in the low-capacity scenario in 2030 and 2035 is comparable to the annualised investment cost. However, when fixed costs are also taken into account, these plants still struggle to operate profitably on a regional scale.

These results indicate that building gas capacities at a much higher level than replacing the phased-out capacities increases the risk of stranded assets. Even in the Low gas deployment scenarios, where the present 60.9 GW of gas capacity only increases to 62.2 GW, the system is balanced. Demand is satisfied without the presence of extreme price events. This is true in the high RES scenarios, where renewables reach 100% of the targeted NECP levels. There is also a timing and coordination issue amongst the MSs of the region. As many more capacities are planned than the 62.2 GW, countries might push for early implementation of new CCGTs, further increasing the risk of stranded assets and the need for extra capacity remuneration for the newly built capacities. Instead, a more stepwise approach, where investments in new gas capacities are stage, could avoid building over-capacities in gas generation.

II. What would be the impact of switching the gas plants to hydrogen?

While hydrogen offers a potential path toward decarbonisation, the transition comes at a significantly higher cost. On average, wholesale electricity prices rise by 20-25%, mainly due to the higher cost of hydrogen compared to natural gas. Additionally, price spikes become more frequent and severe, particularly in Germany, as the reduction in overall available generation

capacity tightens supply. By 2035, hydrogen-based power plants will be found to be less profitable than gas-fired plants, meaning they will require greater subsidies. Although higher electricity prices could theoretically improve profitability, the increased costs of hydrogen-based power generation largely offset these gains. By 2040, the situation will improve as overall generation capacity declines, but short-term profits remain far below investment and fixed costs. If all curtailed renewable energy were used for hydrogen production, it would only cover 10-15% of the total hydrogen consumption needed in the power sector. More importantly, if gas power plants transition to hydrogen without first phasing out coal-fired plants, coal generation will replace the combined-cycle gas turbine (CCGT) capacities, leading to higher CO₂ emissions than in the reference scenario. However, by 2040, the complete phase-out of coal generation will make the switch to hydrogen much more effective in reducing CO₂ emissions.

III. How can zero GHG emissions in the power sector by 2040 be reached with these new capacities?

The results show that full decarbonisation can be achieved under the analysed scenarios, with GHG emissions reductions ranging from 10 to 40 million tons annually. In these scenarios, hydrogen production and imports completely replace natural gas generation. A key finding is that higher renewable energy penetration reduces the need for hydrogen-based power generation. The transition to a decarbonised power sector leads to an increase in electricity prices, rising from an average of 80 €/MWh to approximately 140 €/MWh. However, this price increase can be mitigated if more hydrogen-based power plants are built, bringing the average down to 100 €/MWh. The price difference disappears in the high RES scenario, and significantly less hydrogen-based capacity is required. Conversely, at lower renewable capacities, extreme price spikes become more frequent, particularly in scenarios with low and medium hydrogen capacity. In such cases, supply shortages force demand-side adjustments, meaning additional capacity investments would be necessary. The study concludes that building high renewable energy capacities greatly enhances supply security in decarbonisation scenarios.

IV. What is the minimum gas capacity required in the system?

The findings suggest that no dramatic market disruptions would occur if gas power plants built before 2000 were decommissioned, reducing regional gas capacity from 60 GW to around 45 GW. This implies that the region does not require significant additional capacity beyond replacing ageing infrastructure. Instead, new gas capacity is primarily needed to replace older plants rather than expand total capacity. The study concludes that gas capacity could be reduced to 45 GW (Low 2 levels in the modelling) without significantly increasing prices and even to 31 GW (Low 3 levels) if renewable energy penetration is high. However, if gas capacity is reduced too drastically, there is a risk that coal-fired power plants could return, leading to higher CO₂ emissions – particularly in 2030. However, this effect can be mitigated by increasing renewable energy deployment.

10 ANNEX

10.1 Inputs

This subsection presents the most important input data and their sources applied in the modelling.

10.1.1 Coal, CO₂ and gas price

In the case of CO₂ price, several forecasts were considered:

- International Energy Agency: World Energy Outlook (2024):

For 2030, 127-131€/t carbon price is assumed depending on the scenarios, while in 2040 the range is between 141-193 €/t.

- European Commission proposal for the NECP Planning (beginning of 2023)

80 €/t for 2025 and 2030 in both the With Existing Measure (WEM) and With Additional Measure (WAM) scenarios. For 2040, in the WEM scenario, the CO₂ price is 85€/t, while in the WAM, it is much higher, 250 €/t.

- EC 2040 90% assessment (2024 February):

The price forecast by 2040 ranges between 160-290 €/t and depends upon various future assumptions.

The natural gas price forecast is based on the European Gas Market Model, developed by REKK. This model simulates the operation of an international wholesale natural gas market in Europe, covering the EU28 and the EnC Contracting Parties. It incorporates both the demand and supply side of the gas market, including pipeline, LNG and storage infrastructure at the country level. Major external markets, such as Russia, Norway, Libya, Algeria and LNG exporters are represented by exogenously assumed market prices. All long-term supply contracts and physical connections to Europe are integrated in the model.

The gas market modelling considers the following parameters:

- Moderate gas consumption decreases in the EU (gas demand and production data are based on TYNDP 2024)
- A 90% storage target is assumed for the EU
- A 35 €/MWh Japan price is assumed for the global LNG price

The coal price forecast is based on the IEA World Energy Outlook (2024), while for hydrogen price, we assume a constant 80 €/MWh price level.

4. TABLE: COAL, CO₂, TTF GAS AND HYDROGEN PRICE FORECAST

	2030	2035	2040
Coal price, €/MWh	3.1	2.9	2.9
CO ₂ price, €/t	100.0	130.0	160.0
TTF gas price, €/MWh	33.4	32.7	32.3
Hydrogen price, €/MWh	80.0	80.0	80.0

10.1.2 Electricity demand

Demand per country is an exogenous input to the model. ENTSO-E (2024) data are used to assume a specific demand pattern for each modelled country over the year, and assumptions are made about the actual level of demand for the year 2023; after that we assume the same growth rate for each country as the European Commission used for the Fitfor55 assessment in their reference scenarios.

FIGURE 26. ASSUMED ELECTRICITY CONSUMPTION IN THE REGION, GWH

	2030	2035	2040
AL	8 306	8 606	8 908
AT	78 215	78 210	82 367
BA	12 811	13 274	13 741
BG	33 691	33 372	32 181
CZ	66 528	69 564	72 684
DE	557 639	578 312	596 077
GR	55 696	57 524	60 708
HR	19 273	20 038	20 495
HU	51 586	53 655	55 721
KO	7 088	7 344	7 602
ME	3 522	3 649	3 778
MK	7 183	7 443	7 704
PL	177 404	184 606	189 422
RO	60 002	61 582	61 372
RS	37 774	39 140	40 516
SI	16 535	17 311	18 082
SK	26 538	28 261	29 590
UA	149 140	165 051	174 623
Region	1 368 930	1 426 941	1 475 573

10.1.3 RES and battery capacities in the region

TABLE 5: ASSUMED PV, WIND AND BATTERY CAPACITIES IN THE REGION, GW

	2030						2040					
	REF RES			High RES			REF RES			High RES		
	PV	Wind	Battery	PV	Wind	Battery	PV	Wind	Battery	PV	Wind	Battery
AL	984	13	0	984	13	0	2 436	51	109	2 436	51	131
AT	13 635	6 124	857	12 925	6 124	1 029	16 191	8 276	1 989	16 191	8 276	2 386
BA	523	491	6	523	491	8	1 730	1 319	73	1 730	1 319	88
BG	2 556	1 106	300	2 556	1 106	360	8 329	1 935	2 306	8 329	1 935	2 767
CZ	9 120	880	260	11 400	1 100	312	16 117	1 421	383	20 677	1 861	460
DE	172 000	116 000	6 681	215 000	145 000	8 017	290 279	169 812	22 469	376 279	227 812	26 963
GR	10 720	7 600	2 465	13 400	9 500	2 958	18 606	11 087	4 691	23 966	14 887	5 629
HR	768	2 050	100	960	2 562	120	1 428	3 298	336	1 812	4 323	403
HU	9 600	800	860	12 000	1 000	1 032	17 069	1 279	5 754	21 869	1 679	6 905
KO	339	360	0	339	360	0	878	896	0	878	896	0
ME	492	225	1	492	225	1	683	666	13	683	666	15
MK	860	85	6	860	85	7	2 155	451	70	2 155	451	84
PL	7 555	17 043	200	7 555	17 043	240	26 997	32 164	1 527	26 997	64 328	1 833
RO	6 640	6 760	438	8 300	7 200	526	11 897	9 507	2 164	15 217	11 387	2 596
RS	2 803	1 169	10	2 803	1 169	11	3 326	4 599	111	3 326	4 599	134
SI	2 800	120	171	3 500	150	205	5 230	237	1 266	6 630	297	1 520
SK	1 200	1 200	52	1 500	1 500	62	1 865	2 397	321	2 465	2 997	385
UA	10 374	5 487	9	10 374	5 487	11	24 162	11 872	109	24 162	11 872	130

10.1.4 Interconnectors

The following two tables summarise the existing capacities of cross-border trade in the region based on the ENTOS-E grid map². The new capacities are also presented, updated according to the latest available information in the TYNDP 2024 and REKK's data gathering.

² <https://www.entsoe.eu/data/map/>

TABLE 6: EXISTING (LEFT) AND NEW CAPACITIES (RIGHT) IN THE REGION, MW

Origin and destination country		NTC, MW		CEP70 increased (from 2025)	
From	To	(O→D)	(D→O)	O→D	D→O
AL	GR	456	456	570	570
AL	MK	0	0	0	0
BA	HR	993	1 035	1 241	1 294
BA	ME	538	625	672	781
BA	RS	669	643	837	804
BG	GR	1 503	1 110	1 879	1 387
BG	MK	313	125	391	156
BG	RO	516	474	645	592
BG	RS	416	354	520	443
CZ	SK	2 488	1 500	3 110	1 875
GR	TR	263	97	263	97
HR	HU	1 250	1 500	1 250	1 500
HR	RS	623	641	623	641
HR	SI	1 940	1 852	1 940	1 852
HU	RO	860	609	860	609
HU	RS	1 238	1 229	1 238	1 229
HU	SK	1 978	2 755	1 978	2 755
HU	UA	500	500	500	500
KO	ME	280	280	280	280
KO	RS	360	320	360	320
KO	MK	280	320	280	320
KO	AL	400	440	400	440
MD	UA	700	700	700	700
ME	AL	439	416	439	416
MK	GR	411	416	411	416
MK	RS	565	677	565	677
RO	UA	500	500	500	500
RO	MD	150	150	150	150
RS	ME	401	438	401	438
RS	RO	660	726	660	726
SK	UA	500	500	500	500
TR	BG	375	875	375	875

New cross-border capacities				
From	To	Year of commissioning	O → D	D → O
UA	PL	2023	1000	1000
MK	AL	2024	500	500
RO	MD	2024	500	500
UA	SK	2025	474	616
BG	RO	2025	600	600
RO	RS	2027	844	600
RO	HU	2027	617	335
RS	BA	2027	710	1130
RS	ME	2027	430	80
ME	IT	2027	600	600
AL	KO	2028	160	160
UA	RO	2029	1000	1000
RO	MD	2029	500	500
UA	SK	2030	26	41
RS	RO	2030	680	720
GE	RO	2030	1000	1000
RO	HU	2031	1117	685
GR	IT	2032	500	500
HR	BA	2034	644	298
HU	RS	2034	500	500
GR	MK	2035	500	500
RS	BG	2035	270	490
ME	RS	2035	160	410
BA	RS	2035	1180	490
UA	PL	2035	600	600
GR	TR	2035	600	600
SK	CZ	2036	500	500
RS	HR	2036	600	600
BG	TR	2037	1100	700

10.2 Additional modelling results

10.2.1 Additional results to the three main scenarios

The maps in Figure 27 illustrate the modelled wholesale electricity prices under different gas capacity scenarios for 2030 and 2040 across the analysed region. The left column shows absolute prices in a low gas capacity scenario, where prices are generally higher, particularly in Central and Eastern Europe. The middle and right columns display the price differences when comparing medium vs. low and high vs. low gas capacity scenarios.

The green shading in the middle and right columns indicates that increasing gas capacity lowers wholesale prices across most countries. The effect is more pronounced in 2030, with the region's price reductions of around 2-2.5 €/MWh. By 2040, the price reduction effect diminishes but remains noticeable. This suggests that higher gas capacities contribute to price stabilisation, but the impact weakens over time as other market factors, such as renewables, play a larger role.

FIGURE 27. WHOLESALE PRICE DEVELOPMENT IN THE ANALYSED SCENARIOS, €/MWh

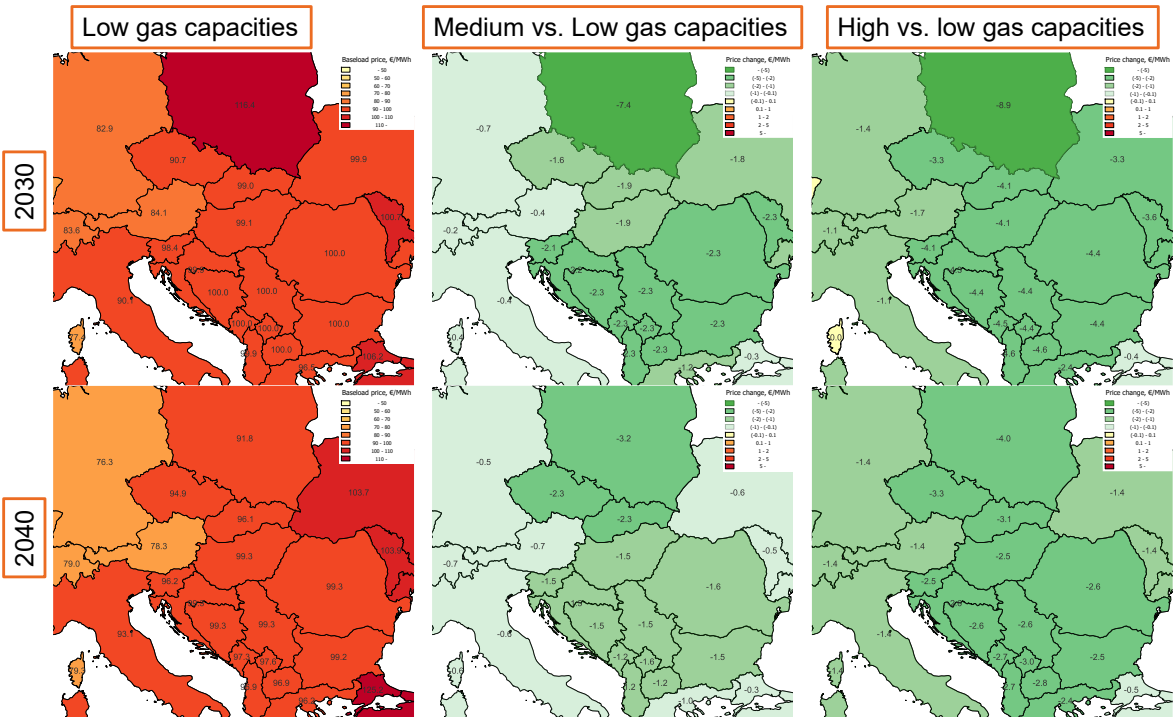
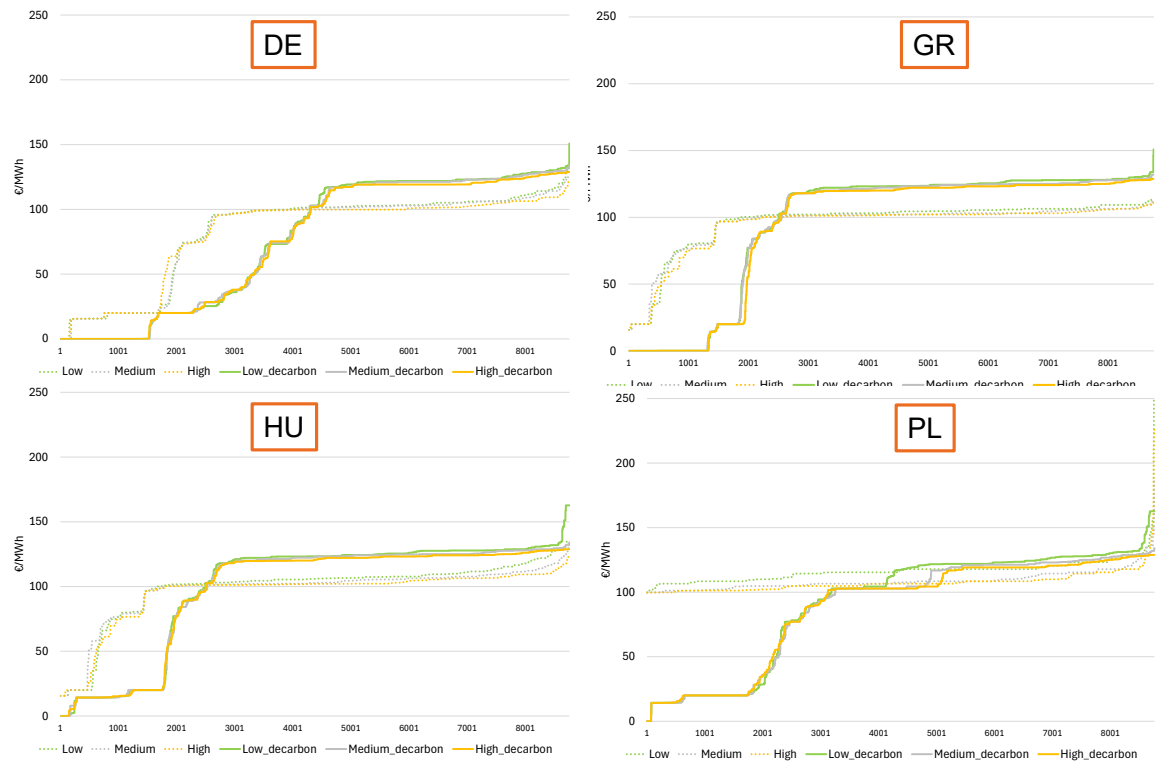


Figure 28 illustrates the hourly price distribution in some selected countries, representing the region well.

FIGURE 28. PRICE CURVES IN SELECTED COUNTRIES



Hourly prices do not differ significantly in the three scenarios for any country. In 2040, higher prices occur in the low gas capacity scenario, but only in a few hours, and they are not excessively high.

FIGURE 29. PRICE DISTRIBUTION IN SELECTED COUNTRIES

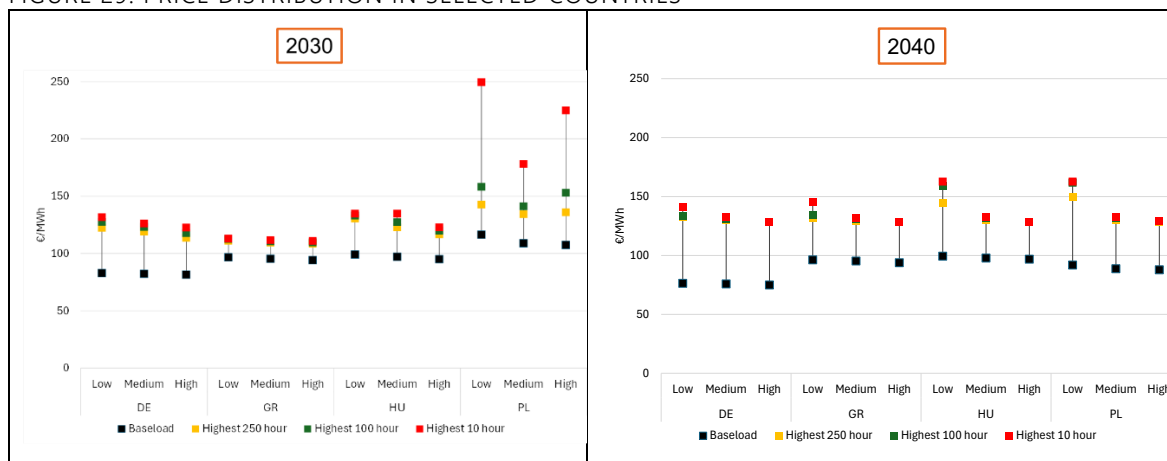


Figure 29 shows that even in the 10 hours with the highest price, we do not see extreme prices in any of the scenarios. By 2040, the gap between the highest and baseload prices will be wider.

The maps in Figure 30 show the utilisation rates of new gas power plants (%) in the three scenarios in the modelled countries in 2030 and 2040. In 2030, utilisation rates are generally higher across all scenarios, especially in Poland and some SEE countries. As gas capacity increases, utilisation rates become more evenly distributed, but high values persist in some regions.

By 2040, overall utilisation rates will decline in all scenarios due to changing market dynamics, increased renewables, and potentially lower demand for gas-fired generation. In the High gas capacity scenario, some countries (e.g., Romania) see particularly low utilisation rates, suggesting overcapacity in these areas.

FIGURE 30. UTILISATION RATES OF NEW GAS POWER PLANTS (%)

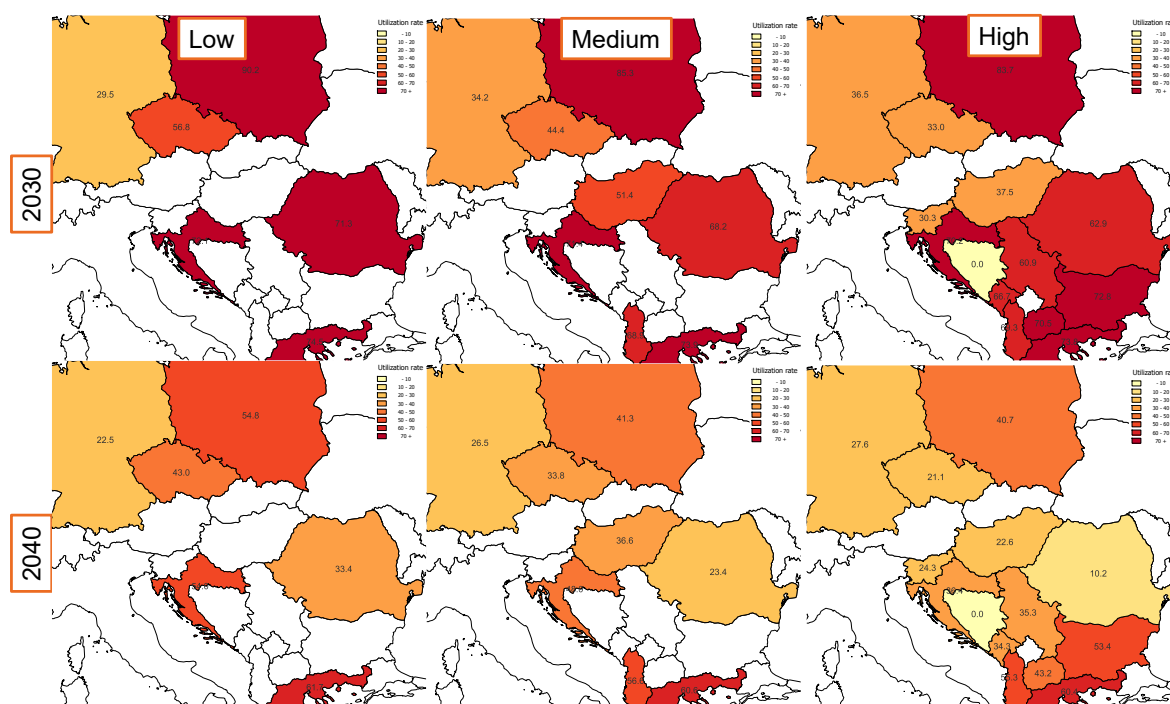
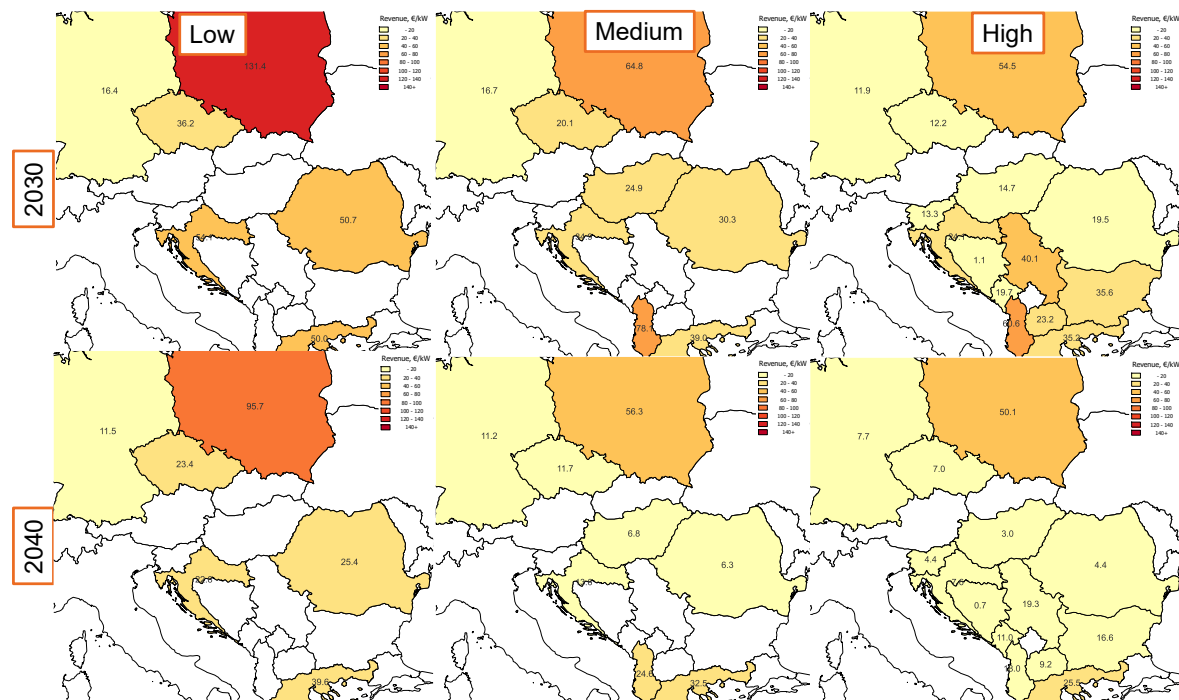


Figure 31 illustrates the short-term profit of new gas power plants (€/kW) in 2030 and 2040 under the three different capacity scenarios. A profit level of around 90-110 €/kW would be necessary for long-term profitable operation.

In 2030, Poland experience the highest short-term profits (above 130 €/kW) under the low gas capacity scenario. As gas capacity increases, both utilisation and profit levels decline across the region, suggesting that additional capacity reduces the scarcity-driven profitability of gas plants. By 2040, profits will drop significantly across all scenarios, with only a few countries maintaining moderate values.

FIGURE 31. SHORT-TERM PROFIT OF NEW GAS POWER PLANTS (€/KW)



10.2.2 Additional results to the sensitivity scenarios

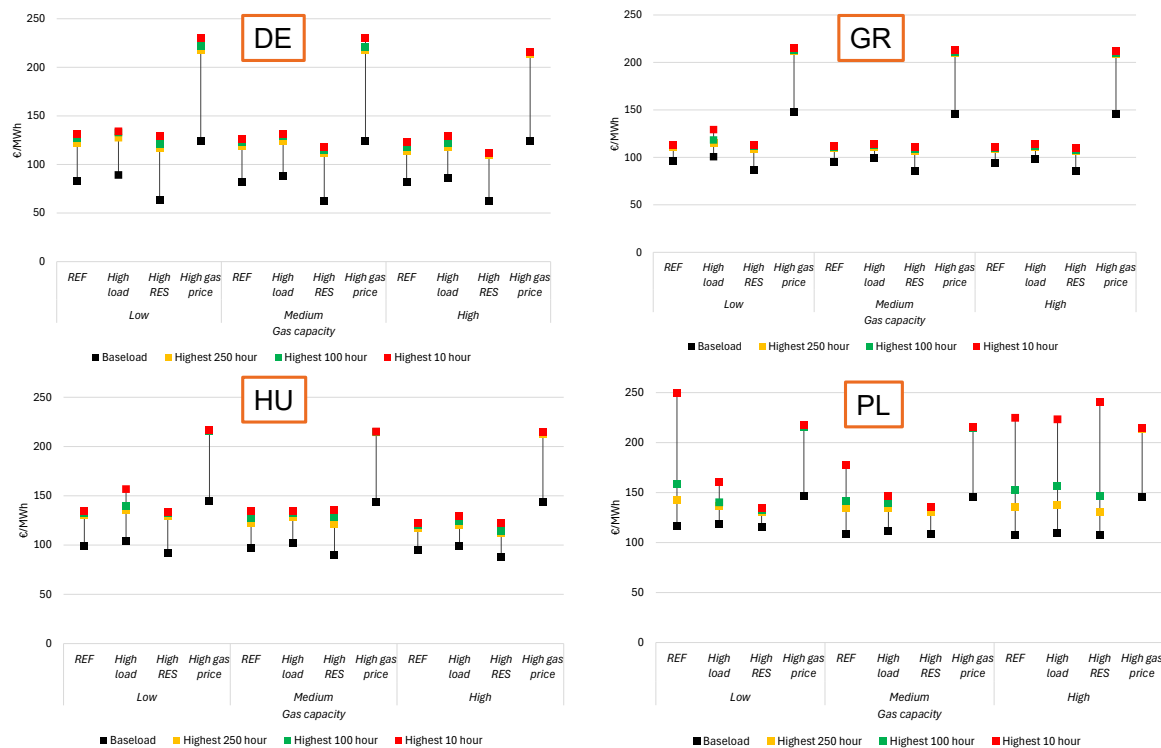
Several sensitivity scenarios were tested on the three main gas capacity scenarios. The primary input data is summarised in the Table below.

TABLE 7. INPUT DATA IN THE SENSITIVITY SCENARIOS

	PV (MW)				Wind (MW)				Battery (MW)				Consumption (GWh)			
	2 030		2 040		2 030		2 040		2 030		2 040		2 030		2 040	
	REF	High	REF	High	REF	High	REF	High	REF	High	REF	High	REF	High	REF	High
AL	984	984	2 436	2 436	13	13	51	51	0	0	109	131	8 306	8 721	8 908	9 354
AT	13 635	12 925	16 191	16 191	6 124	6 124	8 276	8 276	857	1 029	1 989	2 386	78 215	82 126	82 367	86 486
BA	523	523	1 730	1 730	491	491	1 319	1 319	6	8	73	88	12 811	13 451	13 741	14 428
BG	2 556	2 556	8 329	8 329	1 106	1 106	1 935	1 935	300	360	2 306	2 767	33 691	35 376	32 181	33 790
CZ	9 120	11 400	16 117	20 677	880	1 100	1 421	1 861	260	312	383	460	66 528	69 854	72 684	76 318
DE	172 000	215 000	290 279	376 279	116 000	145 000	169 812	227 812	6 681	8 017	22 469	26 963	557 639	585 521	596 077	625 881
GR	10 720	13 400	18 606	23 966	7 600	9 500	11 087	14 887	2 465	2 958	4 691	5 629	55 696	58 480	60 708	63 744
HR	768	960	1 428	1 812	2 050	2 562	3 298	4 323	100	120	336	403	19 273	20 237	20 495	21 520
HU	9 600	12 000	17 069	21 869	800	1 000	1 279	1 679	860	1 032	5 754	6 905	51 586	54 165	55 721	58 507
KO	339	339	878	878	360	360	896	896	0	0	0	0	7 088	7 442	7 602	7 982
ME	492	492	683	683	225	225	666	666	1	1	13	15	3 522	3 698	3 778	3 967
MK	860	860	2 155	2 155	85	85	451	451	6	7	70	84	7 183	7 542	7 704	8 089
PL	7 555	7 555	26 997	26 997	17 043	17 043	32 164	64 328	200	240	1 527	1 833	177 404	186 274	189 422	198 893
RO	6 640	8 300	11 897	15 217	6 760	7 200	9 507	11 387	438	526	2 164	2 596	60 002	63 002	61 372	64 440
RS	2 803	2 803	3 326	3 326	1 169	1 169	4 599	4 599	10	11	111	134	37 774	39 663	40 516	42 542
SI	2 800	3 500	5 230	6 630	120	150	237	297	171	205	1 266	1 520	16 535	17 362	18 082	18 986
SK	1 200	1 500	1 865	2 465	1 200	1 500	2 397	2 997	52	62	321	385	26 538	27 865	29 590	31 070
Region total	242 594	295 096	425 215	531 639	162 025	194 628	249 395	347 763	12 407	14 888	43 583	52 300	1 219 790	1 280 779	1 300 950	1 365 997
All modelled countries	561 983	671 323	938 772	1 158 872	420 711	494 243	654 496	811 422	65 217	78 260	146 163	175 395	4 045 682	4 247 967	4 354 499	4 572 224

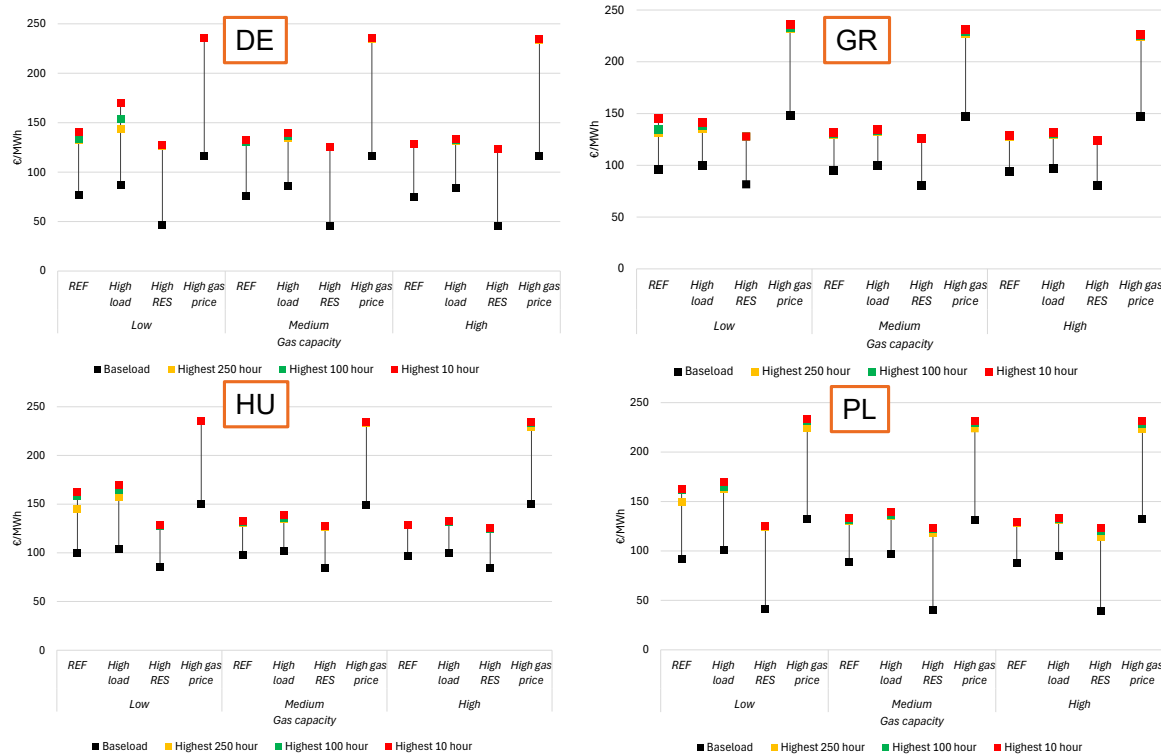
Figure 32 and Figure 33 illustrates the price distribution in the selected countries.

FIGURE 32. PRICE DISTRIBUTION IN THE SENSITIVITY SCENARIOS, 2030



The distribution of prices does not change significantly under different scenarios. In the case of high gas prices, the average of the highest 10 hours equals the average of the highest 250 hours. The low price difference between scenarios is typically due to the difference between the highest prices. In 2040, the effect is similar.

FIGURE 33. PRICE DISTRIBUTION IN THE SENSIVITY SCENARIOS, 2040



With high gas prices, CO₂ emissions at the EU level have increased significantly due to a gas-to-coal switch.

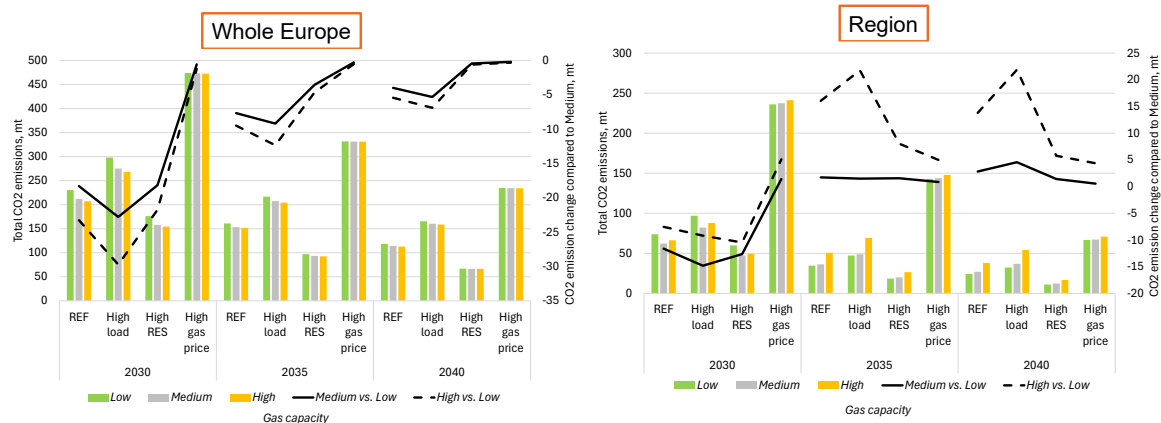
FIGURE 34. CO₂ EMISSIONS IN THE WHOLE EUROPE AND THE REGION

Figure 35 illustrates the utilisation rates of new and old power plants under the different scenarios for 2030, 2035, and 2040. The left chart represents new power plants, while the right shows old ones. For new power plants, utilisation rates are significantly higher, particularly in the reference (REF) and high load scenarios, where they reach around 60-70% in 2030 and decline gradually by 2040. Utilisation is lower in the high RES (renewables) and high gas price scenarios, reflecting the impact of increased renewable energy generation and costlier gas on gas plant operations.

For old power plants, utilisation is much lower, rarely exceeding 20%, and declines further over time.

FIGURE 35. UTILISATION OF THE NEW AND OLD POWER PLANTS

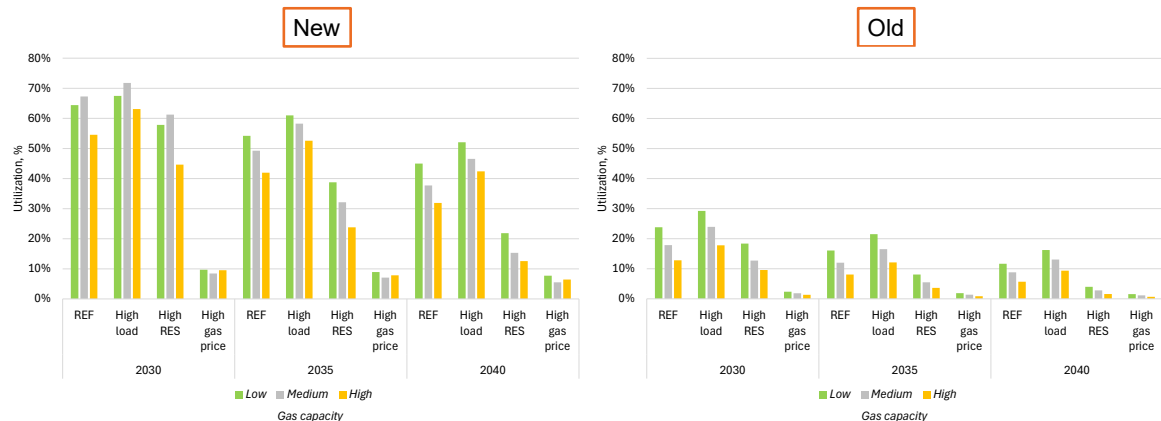
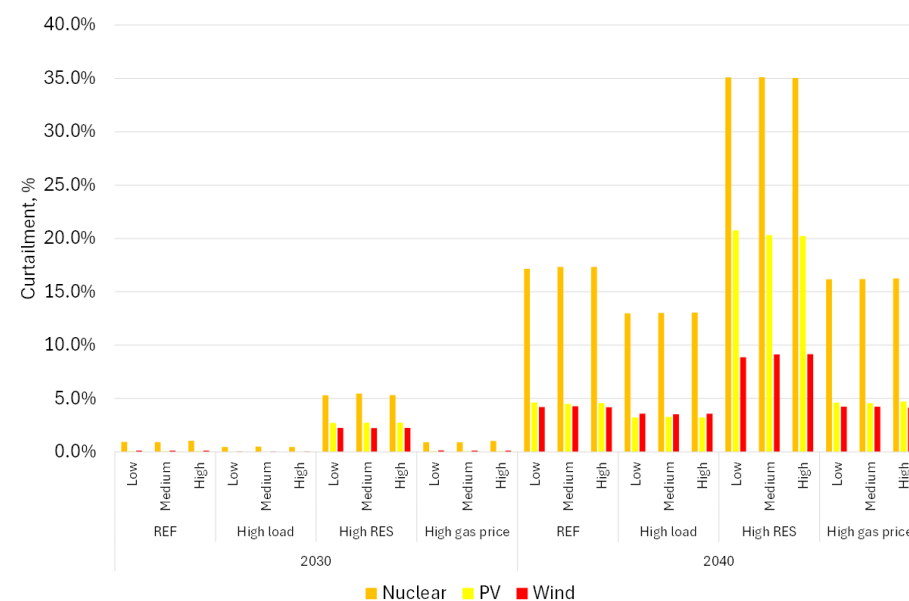


Figure 36 shows the curtailed quantity of nuclear and RES production. The RES and nuclear curtailments are much higher in the High RES scenario. High load decrease the curtailment ratio, especially in 2040. High gas prices have a limited effect on the curtailment ratios.

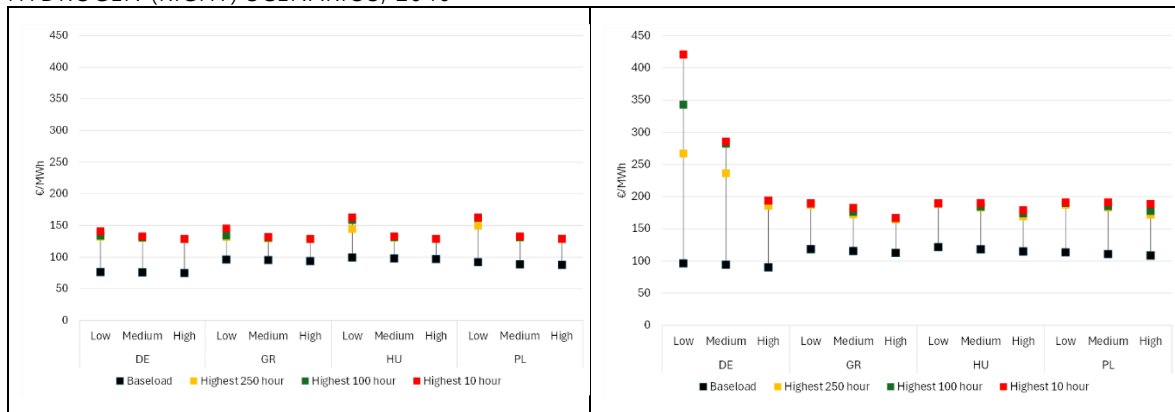
FIGURE 36. CURTAILMENT IN THE DIFFERENT SENSITIVITY SCENARIOS



10.2.3 Additional results on the impact of switching the gas plants to hydrogen

Figure 37 illustrates the price distribution in selected countries in case of switching to hydrogen.

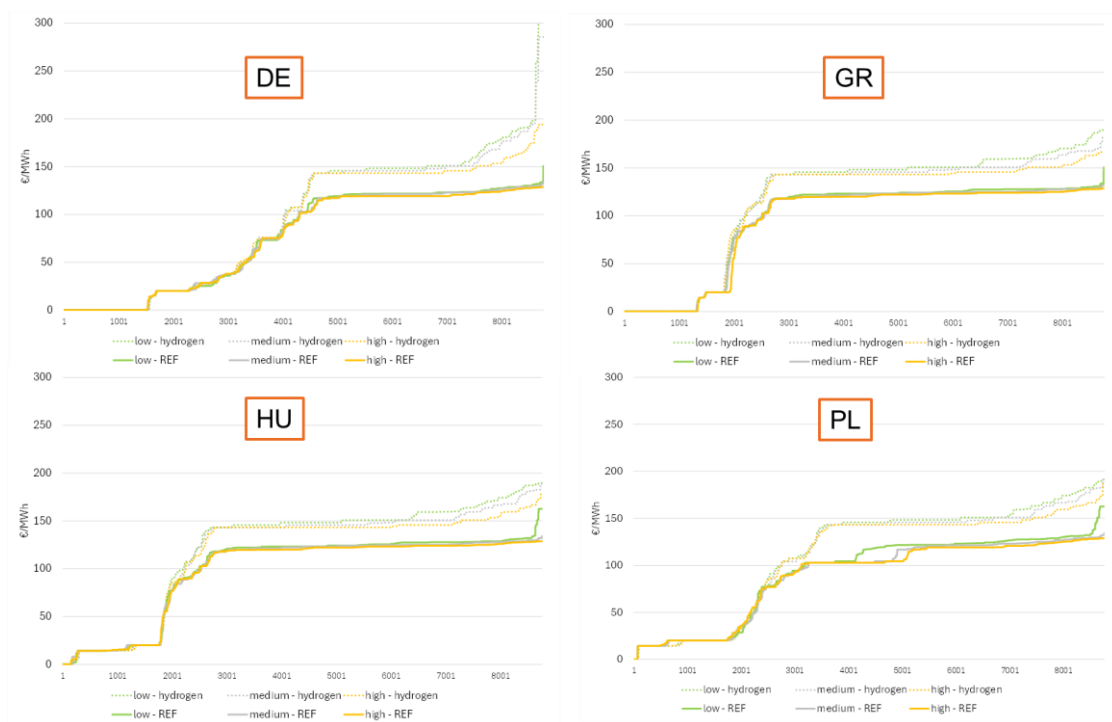
FIGURE 37. PRICE DISTRIBUTION IN THE DIFFERENT SCENARIOS IN THE REFERENCE (LEFT) AND HYDROGEN (RIGHT) SCENARIOS, 2040



Switching to hydrogen does not increase the frequency of extreme prices in most countries, with the most expensive 10-hour average remaining below 200 €/MWh. The exception is Germany, where significant price spikes can be observed in the low and medium scenarios, indicating a capacity shortage. It can be concluded that switching to hydrogen is possible but will increase the level and frequency of price spikes.

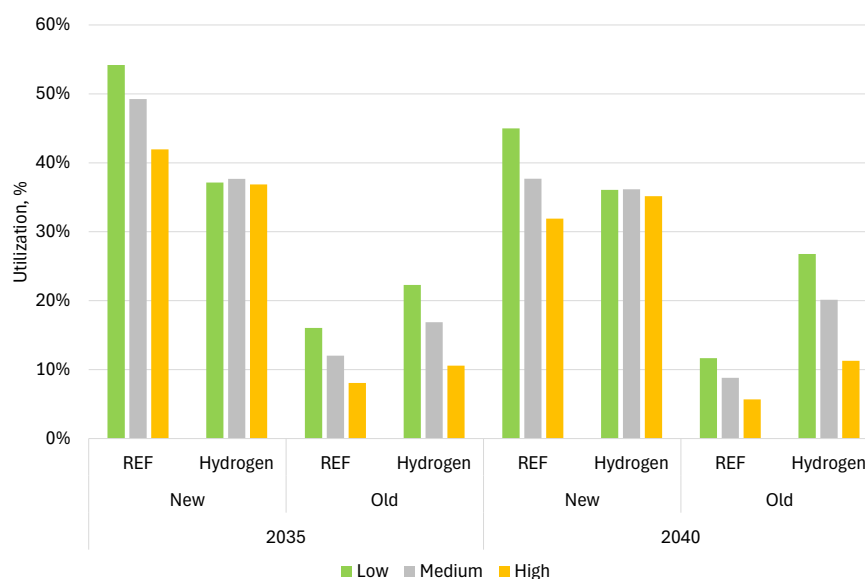
The price curves in the same countries are shown in Figure 38.

FIGURE 38. PRICE CURVES IN THE REFERENCE AND HYDROGEN SCENARIOS



The horizontal part of the price curves is shifted upwards because hydrogen is more expensive than natural gas. The frequency of high prices is higher because there is less capacity.

FIGURE 39. UTILISATION OF THE NEW POWER PLANTS



As only some gas-fired plants can also run on hydrogen, the utilisation rate will be higher for old plants being switched to hydrogen.

10.2.4 Additional results on how to achieve zero GHG emissions in the power sector by 2040 with the new capacities

The price curves in the decarbonisation scenarios compared to the reference scenarios can be seen in Figure 40 and Figure 41.

FIGURE 40. PRICE CURVES IN THE REFERENCE RES SCENARIO, 2040

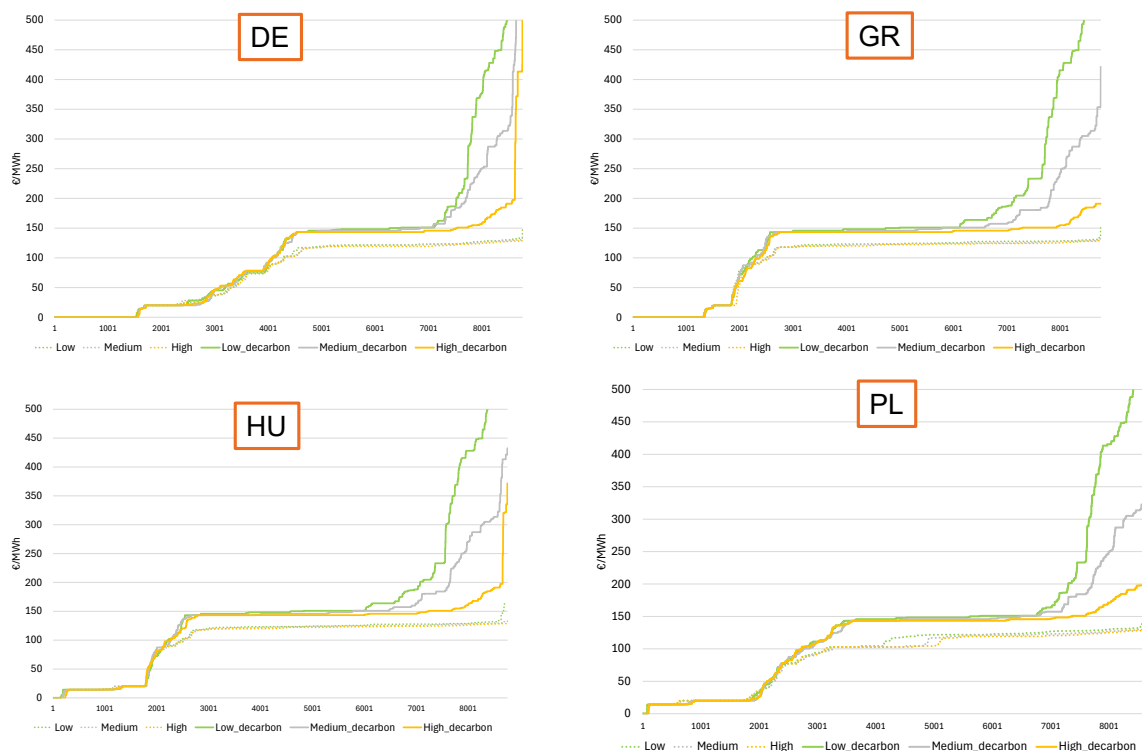
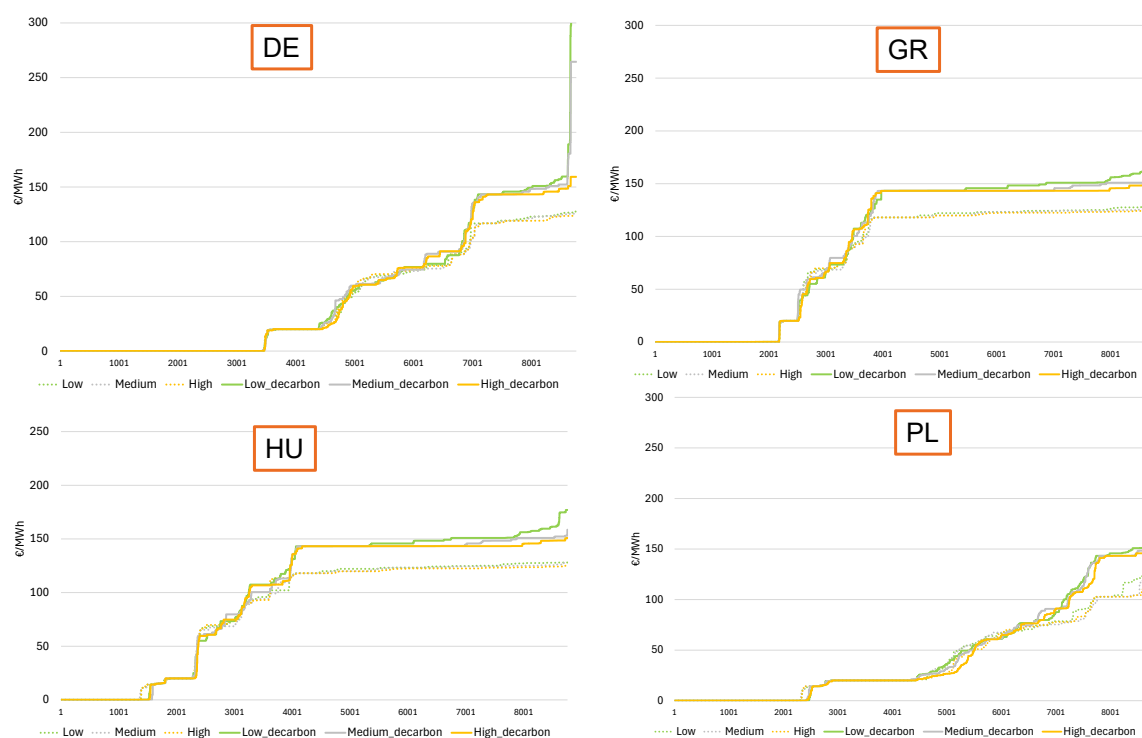


FIGURE 41. PRICE CURVES IN THE HIGH RES SCENARIO, 2040



10.2.5 Additional results on the minimum gas capacity required in the system

FIGURE 42. PRICE CURVES IN THE DIFFERENT LOW GAS CAPACITY SCENARIOS, 2030

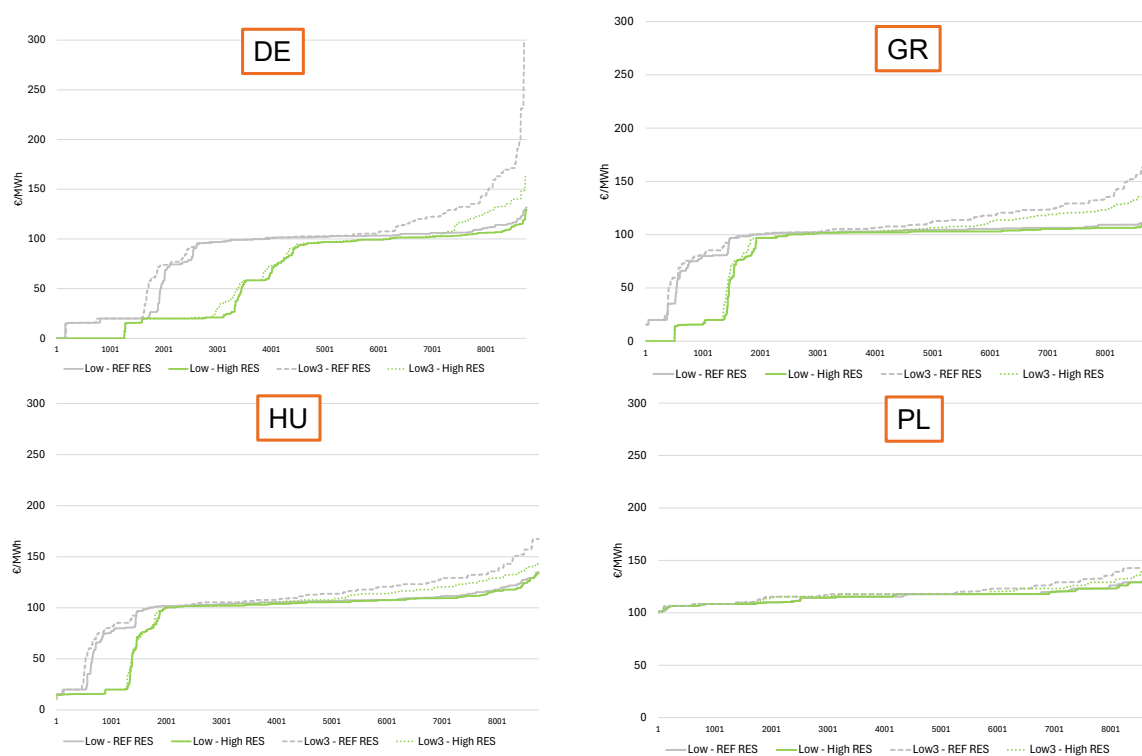
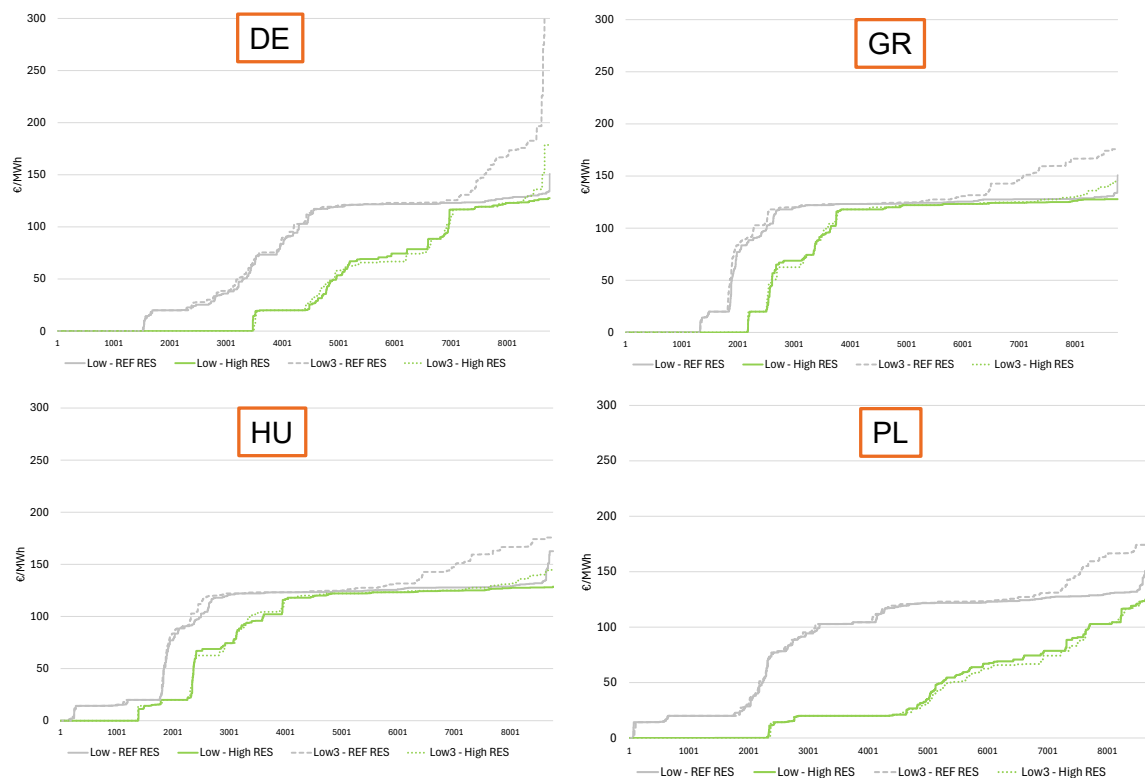
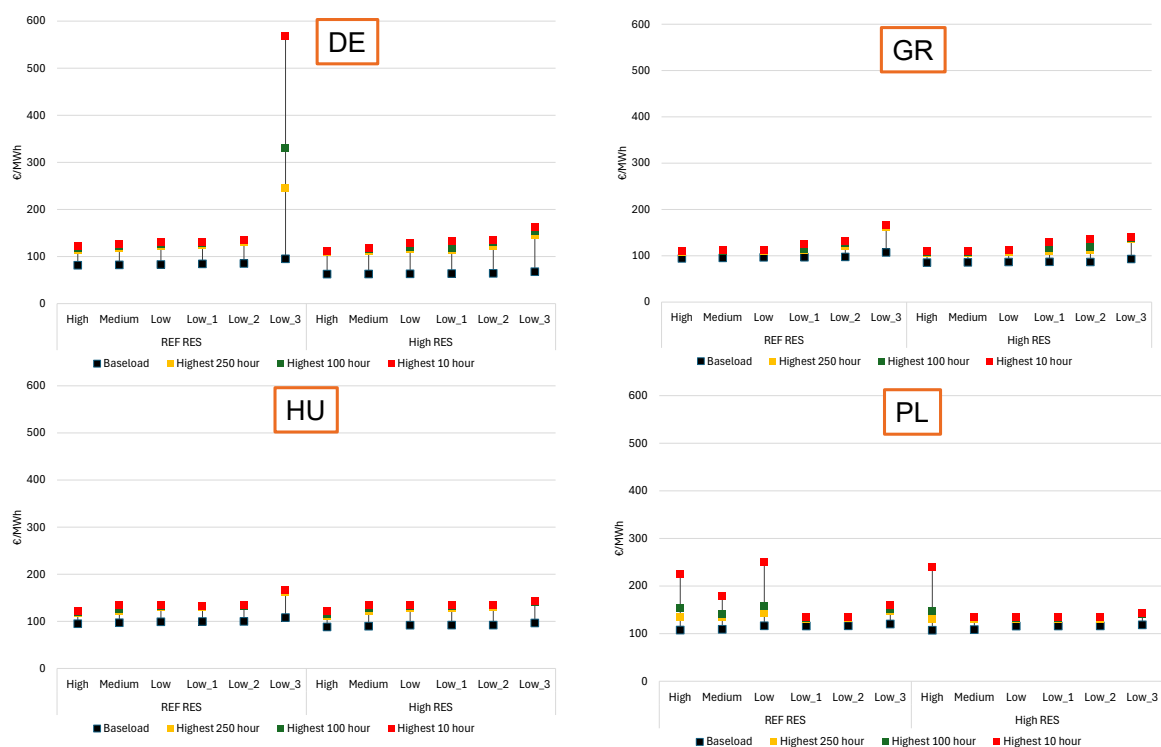


FIGURE 43. PRICE CURVES IN THE DIFFERENT LOW GAS CAPACITY SCENARIOS, 2040



At low RES capacity, high prices are already observed in relatively many hours due to capacity scarcity, while at high RES production, moderate prices are observed even at the most extreme Low3 capacity.

FIGURE 44. PRICE DISTRIBUTION IN THE DIFFERENT GAS CAPACITY SCENARIOS, 2030



With low RES production in Germany, the exceptionally high prices in the Low 3 scenario indicate a significant capacity shortage.

FIGURE 45. PRICE DISTRIBUTION IN THE DIFFERENT GAS CAPACITY SCENARIOS, 2040

