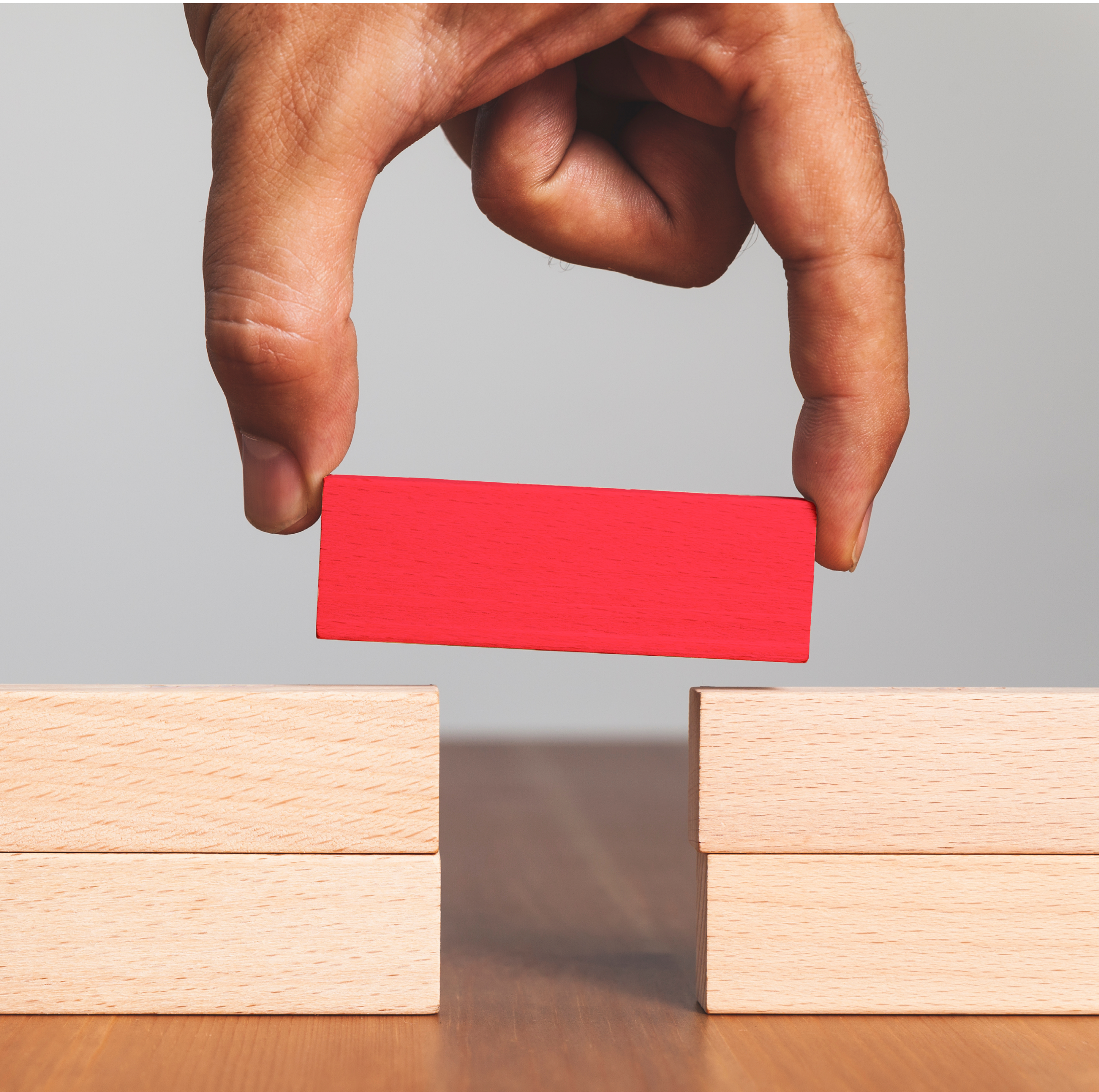
Filling the Supply Gap: Does Germany Need New Gas?



Filling the Supply Gap: Does Germany Need New Gas?

ROY MANUELL & **MATTHEW JONES** AUGUST 2021

17GW

Germany will retire a large total of baseload generation capacity over the next decade as it closes its entire nuclear fleet by the end of 2022 and reduces coal and lignite capacity to 17GW by 2030.

Executive summary

- Germany will retire a large total of baseload generation capacity over the next decade as it closes its entire nuclear fleet by the end of 2022 and reduces coal and lignite capacity to 17GW by 2030.
- The country's need for flexibility will significantly increase as a result and according to official plans, Germany will opt to build gas assets to ease the supply burden. This is due mainly to the intermittency of wind and solar and the relative immaturity of the country's storage market.
- Uncertainty clouds the route to market for this gas capacity with the country having opted for a strategic reserve rather than a capacity market in recent years - the latter being a system that has become increasingly popular across Europe.
- This means that the German government may need to directly commission gas capacity to act as reserve in the event that energy-only market revenues are considered insufficient or too uncertain to incentivise privately-funded gas buildout. The alternative would be to opt for a capacity remuneration mechanism (CRM).
- For this paper, we ran a scenario analysis in which Germany builds no new gas capacity from 2022 onwards to measure the impact on prices, generation, net trade and emissions. This study also serves to underline the potential risk of a weak gas investment environment that we contextualise within the capacity market debate.
- The results demonstrate that in the event of no additional gas buildout after 2022, Germany would see a substantial increase in hourly price spikes above a high outlier range but the strong interconnectivity between Germany and its neighbours also helped to dampen the impact of no gas expansion.
- Overall, in this paper we will discuss the potential routes to market for new gas capacity, the risks of no gas buildout and analyse what this may mean more generally for Germany and its supply on a 2030 horizon.

ICIS Long-Term Power Forecasts

ICIS Power Horizon is a pan-European power model that matches supply and demand, dispatching supplies starting from the lowest cost. It mimics the functioning of wholesale power markets, with the marginal cost equalling spot market prices. ICIS Power Horizon forecasts prices, generation, net flows, emissions, and the merit order in every hour through to 2050. In this paper we will focus on our Base Case that assumes a 90% economy wide emissions reduction by 2050 with corresponding renewable capacity expansion and carbon prices in order to meet this target.

Over the past five years, European countries have launched or announced that they will launch a new wave of capacity remuneration mechanisms (CRMs)

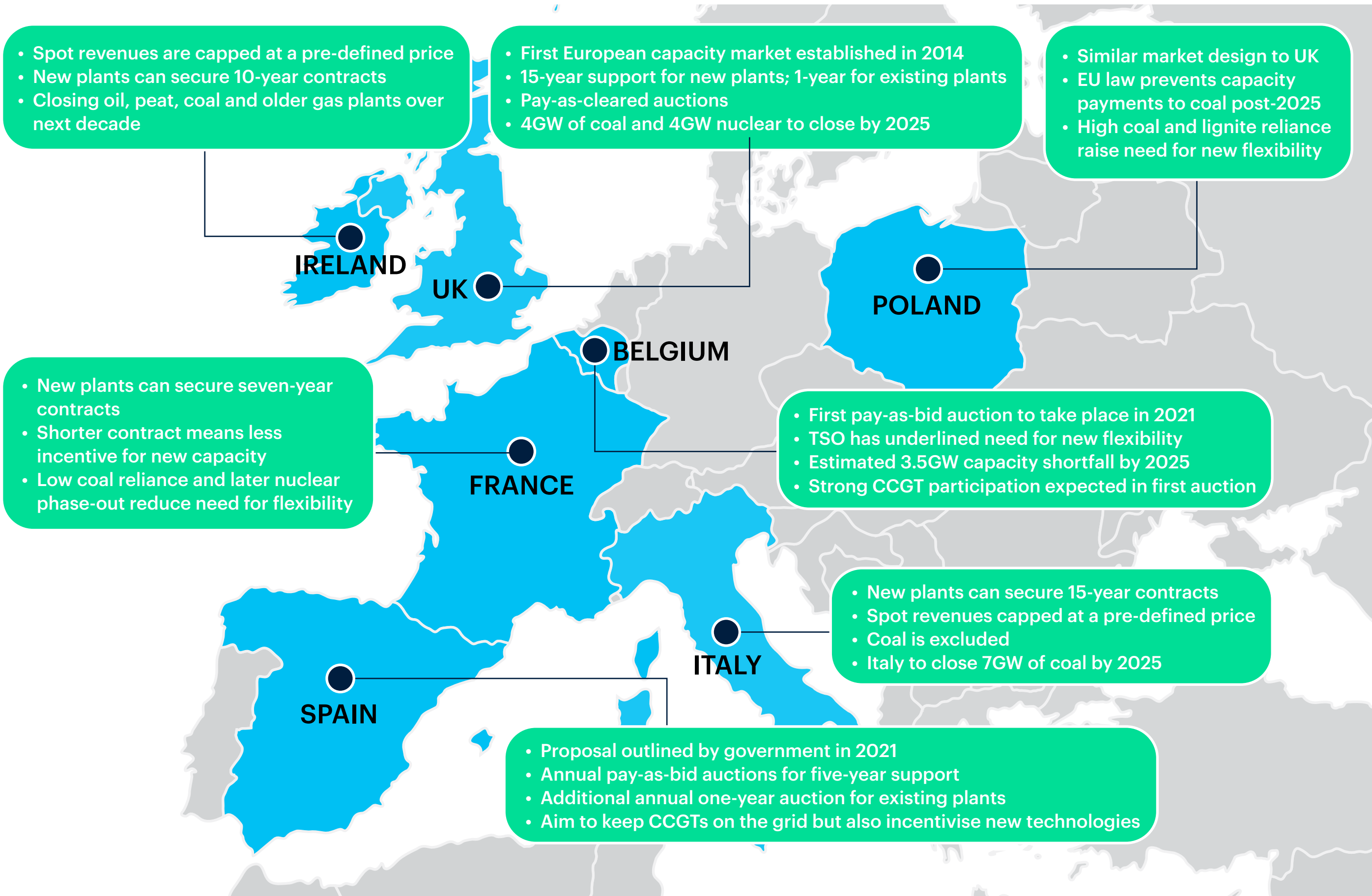
Europe's new wave of capacity markets

Over the past five years, European countries have launched or announced that they will launch a new wave of capacity remuneration mechanisms (CRMs), many of which were based on the UK model that was established in 2014. Each capacity market tends to have unique features but they each place an obligation on capacity availability during periods of supply tightness while also providing an incentive for both existing flexible generation to remain on the market and for fresh investment in flexible generation assets. Support is typically given via capacity payments that are awarded in a competitive bidding process.

The German reserve model

In contrast, Germany decided in 2016 against introducing a capacity market on the basis of cost and instead opted for the strategic reserve.

The strategic reserve contains mostly lignite-fired plants and some hard coal assets but will increasingly include CCGTs, such as several in-construction assets that the government confirmed would be built as reserve capacity in the early 2020s.



8GW

Over the next 18 months, Germany will have closed 8GW of nuclear capacity and around 5GW of coal and lignite capacity, which will lead to a period of significantly tight supply between 2023 and 2025, high net imports and stronger prices relative to neighbouring markets.

The functioning of the strategic reserve kicks in when wholesale prices reach a certain level that indicates critical supply is needed and the relevant assets are then called upon to generate. In terms of compensation, the power plants in the reserve receive a flat annual rate to cover their operating expenses and then an additional high rate for each kWh generated. These plants cannot sell power into the energy-only market.

Other EU states disagree with Germany's current financing of reserve coal capacity and submitted a formal complaint to Brussels in 2018. The EU is looking into the German model as possibly in breach of state aid law.

The plants currently in reserve receive a high level of compensation simply to remain on standby and then generate at high hourly prices. This is especially costly given that they tend to be the older lignite units whose margins have and will continue to be hit hard by strong carbon prices over the coming decade.

Germany's supply crunch

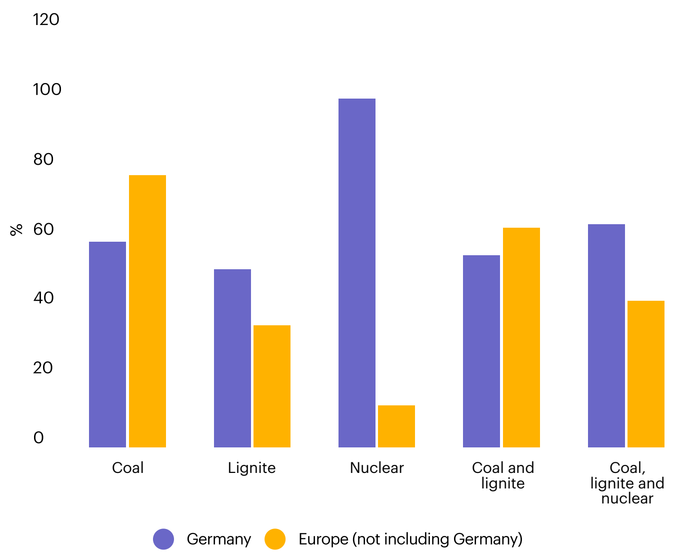
Germany will close the highest total of baseload generation capacity in Europe over the next decade as it completes its nuclear phase-out by the end of 2022 and closes a large number of coal and lignite plants in line with a 2038 full phase-out trajectory.

Over the next 18 months, Germany will have closed 8GW of nuclear capacity and around 5GW of coal and lignite capacity, which will lead to a period of significantly tight supply between 2023 and 2025, high net imports and stronger prices relative to neighbouring markets.

Between 2021 and 2030, we forecast that German capacity closures will account for 20% of all coal, 50% of lignite, and 40% of nuclear capacity closures across Europe. We consider Europe here to be the EU27 plus Great Britain, Norway and Switzerland as these are the markets we directly model.

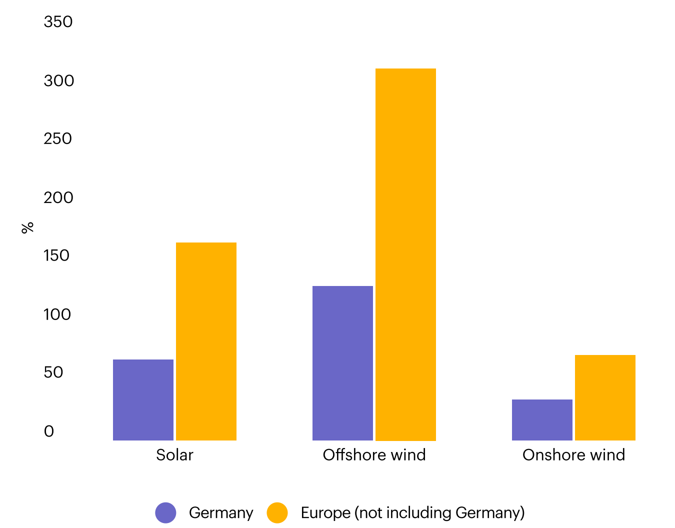
At the same time, we forecast that German wind and solar capacity expansion will lag behind the European rate of growth. This is due to the fact that other states will rapidly ramp up capacity buildout - something Germany had already achieved over

Percentage of 2021 capacity to have closed by 2030



Source: ICIS

Renewable capacity growth 2021 to 2030

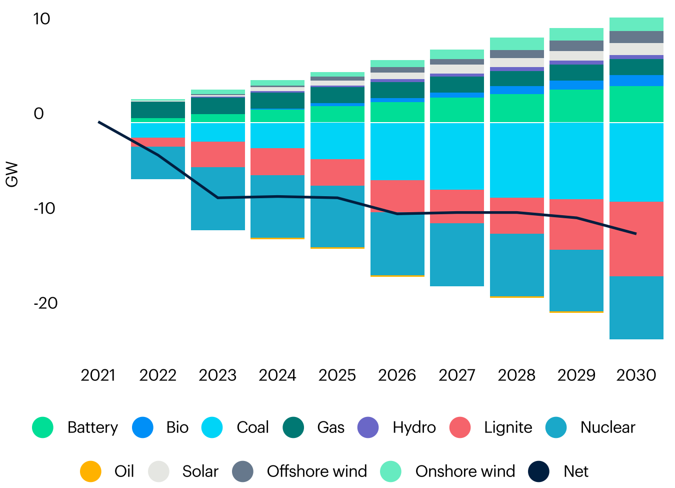


Source: ICIS

The German government's narrative is that renewable expansion will be sufficient to replace the outgoing thermal generation combined with some additional gas capacity.

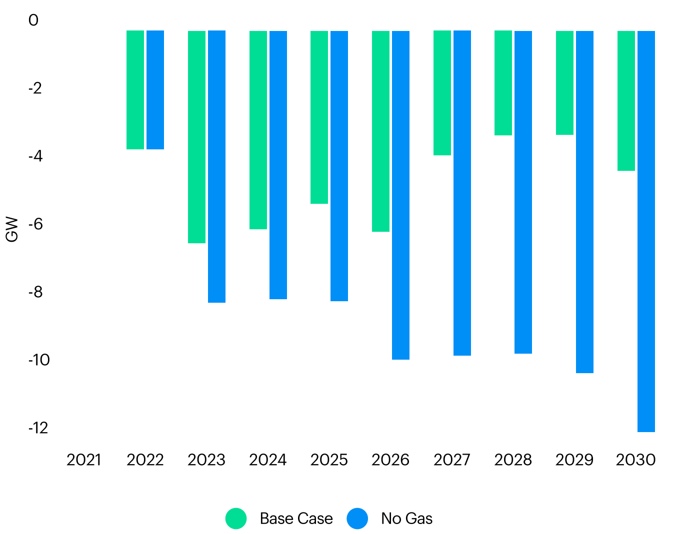
the previous decade. Furthermore, we are likely to see a continued slowdown in German onshore wind capacity growth over the next few years with tenders undersubscribed and legislative deterrents stunting growth. That said, the German government's narrative is that renewable expansion will be sufficient to replace the outgoing thermal generation combined with some additional gas capacity.

De-rated capacity by technology relative to 2021 – No Gas scenario



Source: ICIS

German de-rated capacity change relative to 2021



Source: ICIS

The German government's narrative is that renewable expansion will be sufficient to replace the outgoing thermal generation combined with some additional gas capacity. While renewable expansion will certainly play a key role in alleviating the supply crunch in Germany, we do not expect this to occur really until the second half of the decade when we forecast German offshore expansion to pick up to meet the government's 20GW target by 2030.

By applying a de-rating factor to German capacity, we can measure the net capacity change relative to 2021 levels and therefore reveal to a greater extent the looming reality of the German capacity crunch.

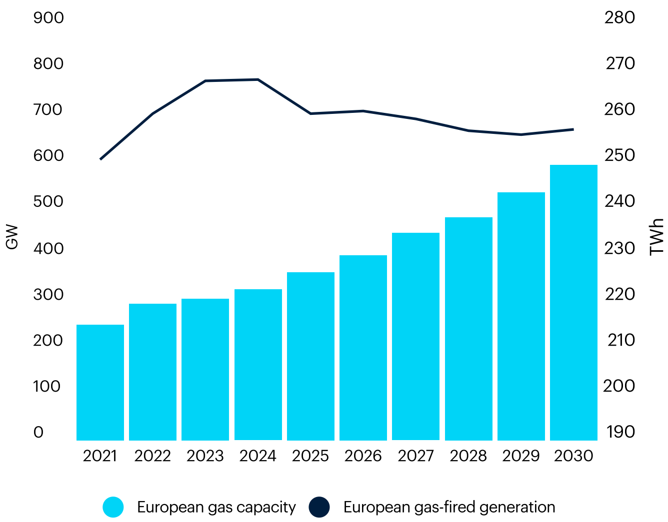
Due to the loss of coal, lignite and nuclear plants, German de-rated capacity falls by around 6GW in the mid-2020s before gas expansion plays a major role in easing the reduction post-2025. However, if we consider the de-rated capacity with no gas expansion, we can see the significant capacity shortfall that reaches more than 10GW relative to 2021 levels by 2030, thus further underlining the requirement for additional gas or other flexibility.

The result on generation is significant. We expect nuclear alone to generate 62TWh of German power in 2021 - around 12% of total output. Combining this lost future production with the reduction from coal and lignite closures, we forecast Germany to move from a strong net exporter with an annual average export level of 42TWh between 2016 and 2020, to 15TWh in 2021. We then forecast Germany to flip to a net importer of power from 2022 onwards as the country increasingly relies on its neighbours for flexibility. A further analysis on this trend is explored in our previous research paper.

The need for flexibility

We expect European gas-fired capacity to increase to 2030 and this is driven by a group of countries that have opted to expand capacity to ease the phase-out of coal and nuclear in some cases. These countries such as

Gas expansion in Europe



Source: ICIS

Germany, Poland and Belgium seek to ensure security of supply via capacity mechanisms as well as other investment incentives as stated in National Energy and Climate Plans (NECPs).

While European generation rises and remains above 2021 levels out to 2030, gas-fired power production peaks in 2023 and 2024 - the years immediately following the German nuclear phase-out - before gradually decreasing to 2030 and beyond as renewable expansion increases.

On a Germany-specific level, the government has assumed in its NECP that gas capacity will rise to 36GW by 2030 from around 27GW in 2021, citing the requirement for flexibility as the driving reason for the 9GW addition.

Potential alternative sources of future flexibility such as batteries and other forms of demand-side response (DSR), hydrogen and hydropower each have drawbacks that mean Germany will not be able to rely on strong capacity expansion over the next decade. These involve a current lack of regulatory clarity in the case of batteries, the current cost of production in the case of hydrogen, and a lack of appropriate sites in Germany regarding the expansion in the case of hydropower. The near-term scalability of more nascent technologies such as batteries and hydrogen means that they will likely assume a more supportive role in terms of flexibility within a 2030 time horizon and then have a greater influence beyond this point.

In terms of incentivising new technologies such as batteries, offering revenue stacking potential and new streams of revenue, as has been the case in the UK, will be key to growth in the near term as emerging markets continue to mature and reduce costs. For example, in the latest UK CRM auctions at the beginning of 2021, a total of 17 battery projects cleared.

The UK example has provided battery operators and potential investors with a much stronger level of confidence in the market and has in part enabled the country to grow the technology at a fast rate and the UK now accounts for almost one-third of European capacity.

In Germany, however, with a much less mature legislative framework for batteries, encouraging sufficient capacity growth to significantly ease the outgoing baseload generation is unlikely to occur before 2030.

36GW

The German government has assumed in its NECP that gas capacity will rise to 36GW by 2030 from around 27GW in 2021, citing the requirement for flexibility as the driving reason for the 9GW addition.

Routes for gas capacity expansion in Germany

This leaves gas as the main option as a source of domestic flexibility for Germany over the coming decade aside from interconnection as we will discuss later. The question is how this new gas capacity could be brought to market and whether it will serve only as reserve capacity.

Capacity market reform

- Germany could implement capacity market reform. As in the case of other European markets, a capacity market has the potential to incentivise new build gas plants as well as provide a new route to ensuring finance for existing assets by offering a competitive means of securing support on a five to 15-year period for new plants and shorter-term subsidy for the existing gas fleet.

A structural move to a capacity market mechanism would surely drive this switch even faster with plants also able to sell power directly to the energy-only market.

- Members of the German gas industry and large utilities such as Uniper have already campaigned for a competitive capacity market mechanism to provide clearer investment and financing signals for gas as a future technology.
- This could also incentivise other technologies such as battery storage to participate in auctions, as seen in the UK.
- The question of reserve capacity and amending the current system is likely to intensify following the German federal elections in Autumn 2021 and reform will depend on the new government. The Green Party, for example, is campaigning for an overhaul of the reserve system.
- Germany is already shifting towards replacing coal and lignite reserve capacity with that of gas as in the case of the Irsching 6 and Marbach 4 plants, both 300MW, that were commissioned by the government with the purpose of acting as reserve capacity from 2022 onwards.
- A structural move to a capacity market mechanism would surely drive this switch even faster with plants also able to sell power directly to the energy-only market.

Mothballed plants returning

- Due to high levels of coal-to-gas fuel switch in recent years following carbon price strength and European gas market oversupply, we have seen high competition to close coal plants in German tenders for closure, as well as several previously-mothballed gas plants announcing a return to the grid.
- For example, Uniper's Irsching 4 and 5 had remained in reserve as part of an agreement with the government despite multiple applications to close for good throughout the last decade, but the units re-entered the market at the start of 2020 due to more favourable economic conditions.
- Given our generally bullish carbon price expectations over the next decade and fuel switch potential, other mothballed units may now also seek a return to the market in similar fashion.

Smaller peakers

- It is likely that many of the new plants that are built will be smaller assets that will be used at times of peak demand as opposed to large CCGTs.
- These new gas peakers are likely to be similar in size to the 300MW Irsching 6 and may also be strategically commissioned in order to serve as reserve capacity in areas of the country that struggle when demand is very high and wind generation low. This is mainly in the southern regions that is a demand-intensive area of the country with weaker grid connection. The commissioned construction of small peakers to be placed in a reserve is the most likely eventuality in the absence of a CRM reform.

It is likely that many of the new plants that are built will be smaller assets that will be used at times of peak demand as opposed to large CCGTs.

Uniper has pledged to convert several of its coal units to gas such as the Scholven C coal unit that successfully bid to close in the third coal closure tender that took place in June 2021.

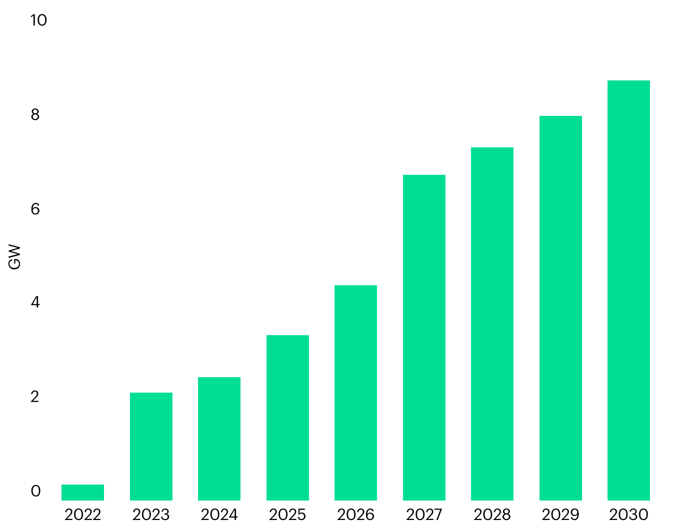
Coal conversions

- Uniper has pledged to convert several of its coal units to gas such as the Scholven C coal unit that successfully bid to close in the third coal closure tender that took place in June 2021.
- This is an example of an operator utilising at least in part the compensation granted in competitive coal closure tenders to finance a coal-to-gas conversion. Another example was the Vattennfall Moorburg coal plant that won compensation to close in the first tender in December 2020 and will convert to a green hydrogen production site.
- Given the German government's legislative commitment to hydrogen expansion, we may see an increase in similar projects with state support also provided and, in some cases, a coal-to-gas conversion prior to a subsequent hydrogen conversion, as will be the case for Scholven C. We expect this to mainly take place in the late 2020s onwards.

Shelved projects

- The need to provide a clearer financing pathway for new large capacities remains however, and several planned projects have been shelved in recent years.
- This has been due to the likely longer-term phase-out of gas, meaning there is substantial risk in building too large an asset, as well as the current lack of capacity market.
- For example, a long-delayed 900MW gas-fired plant due to be built in west-Germany was finally cancelled due to financial risk and legislative uncertainty.
- A separate 2GW plant in Karlsruhe, also long-delayed, now has now also been cancelled.
- These two examples underline the notion that new gas-fired capacity is likely to be brought online mainly to satisfy peak demand and strategically placed in weaker supply areas of the country but will mainly consist of smaller projects that are easiest to bring online from both a financial and infrastructural perspective on the short term.

Gas capacity added relative to 2021 levels - ICIS Base Case



Source: ICIS

As things stand, the state financing of new gas plants is likely to comprise of several smaller peaking assets that are commissioned to be transferred directly into the strategic reserve as well as some coal-to-gas conversions that are partly funded by compensation from coal closure tenders. That said, in order to incentivise the almost 10GW of capacity growth as cited in the German NECP, it remains uncertain how this level of capacity will be built without a move to a capacity market to support a stable

In total, between 2021-2030, Germany would generate around 110TWh less gas in the No Gas scenario, of which 80% of the total reduction would be in the 2026-2030 period.

secondary revenue stream, prompting the question in the following section of analysis.

What happens in the event of no new gas build-out?

We ran a scenario analysis using our long-term power model in which none of the additional gas capacity that we expect to be brought online in Germany after 2022 in our Base Case is built. We did so to measure the effect on prices, generation, regional power trade and emissions. We will call this the 'No Gas' scenario in which Germany would have 9GW less gas-fired capacity by 2030 relative to our Base Case.

Of the additional 9GW we expect to be built between 2022 and 2030 in our Base Case, approximately 4GW is new CCGT capacity, 2GW is new OCGT of an average efficiency and the remaining 3GW is more inefficient OCGT capacity that we expect to be built primarily as reserve capacity but called upon to generate during periods of tight supply.

The results indicated that while prices would increase in both scenarios in the absence of new gas capacity build-out, there would not be a dramatic bullish impact, suggesting that supply was tighter but not in a critical condition from an average annual price standpoint. The impact of the lack of gas capacity was most pronounced in the 2026-2030 period in both scenarios.

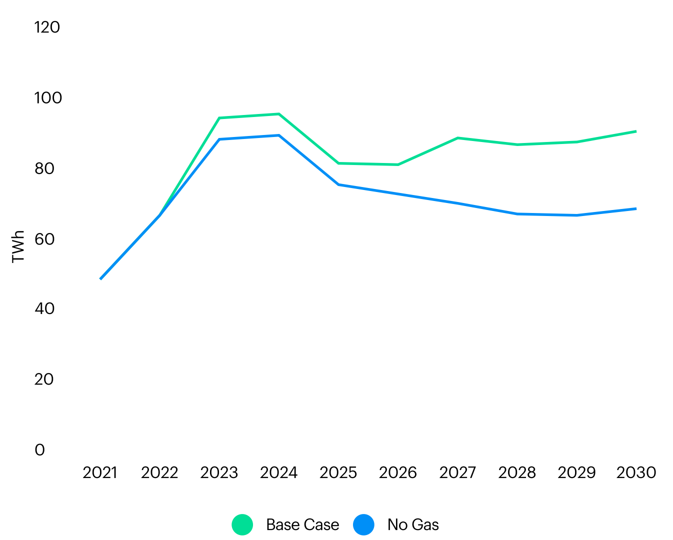
In total, between 2021-2030, Germany would generate around 110TWh less gas in the No Gas scenario, of which 80% of the total reduction would be in the 2026-2030 period. This equates to an annual average reduction of an approximately 18TWh per year over the second half of the decade.

In this period, Germany would import more from neighbouring markets such as the Netherlands, Belgium and Austria that collectively would raise average annual exports to Germany by at least 13TWh between 2026 and 2030 in the No Gas scenario.

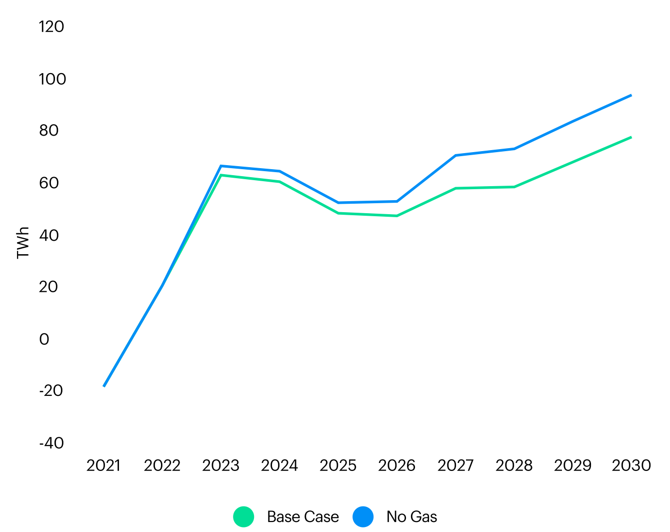
The remaining generation would come from additional German coal and lignite output to ease the baseload supply reduction and this equates to an annual average of 5TWh in the No Gas scenario during the 2026 to 2030 period.

The relatively higher level of additional imports to additional coal generation in the No

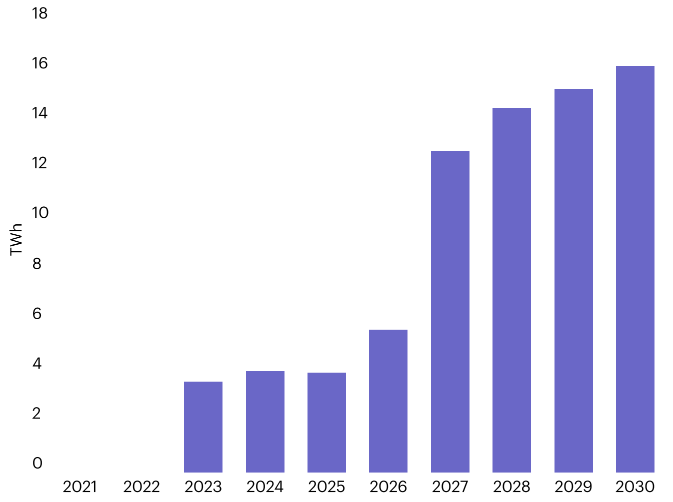
German gas generation



German net imports



Change in exports to Germany in No Gas scenario



Note: Positive value denotes net imports Source: ICIS

German power prices

Source: ICIS

Gas scenario suggests that continental supply is secure enough to export more gas-fired output to fill the German supply gap rather than allow for more coal output.

This is facilitated by expected German interconnection expansion of 7GW between 2021 and 2030. Indeed, the Netherlands, Belgium, France and Austria generate a combined annual average of 4.5TWh of additional gas generation between 2026 and 2030 to export to Germany in the No Gas scenario.

The overall effect on emissions of the additional continental gas output as well as German coal and lignite means an increase of around 5m tonnes of CO2 in the No Gas scenario in 2030. The total added emissions between 2021-2030 would stand at more than 20m tonnes of CO2. Therefore, no new gas capacity would effectively keep coal and lignite generation in the German mix for longer.

Looking more closely at the price impact, German prices would rise by €2/MWh in the No Gas scenario by 2030. The added gas-fired generation and export demand would also raise Dutch, Belgian and Austrian prices by €1/MWh in 2030 in the No Gas scenario. The impact on France would be less then €0.5/MWh in 2030.

Drawing a conclusion from these results, we can say that while not insignificant, this price increase is relatively moderate on an annual level given the 9GW reduction of gas capacity in the No Gas scenario. The results do not reflect a drastic security of supply issue but generally tighter regional power supply dynamics that lead to increased gas burn outside of Germany. This is also due in part to the fact that of the additional 9GW of capacity, roughly one-third would be from relatively inefficient peaking OCGT capacity under our current Base Case assumptions and would therefore not generate during most hours of the year.

We then analysed the impact of no gas buildout at the hourly price level to identify potential hours of critical supply that would occur especially during periods of low wind and high winter demand. We found that in the event of no additional gas buildout after 2022, Germany would see a substantial increase in hourly price spikes above a high outlier range that we assume to be 1.5 times the interquartile range above the upper quartile.

By comparing the Base Case and No Gas scenarios, we observe that from 2026 to 2030, the total number of hours with high outlier prices is 477 in the scenario with no additional gas build and just 17 hours with the gas capacity expansion. That said, given our modelled results without gas buildout, the average price of the high outliers remains relatively stable around €100/MWh, similar to that of our Base Case. While the increase in frequency of these highly-priced hours represents a key driver behind the higher annual average power price, the relative stability of the prices themselves does not necessary indicate a critical condition of supply. This is also mitigated by our forecast expansion of battery storage capacity in Europe including Germany that feeds in additional supply at times of demand shortage in our modelling.

That said, a key point to add is that our Base Case only uses one historical normal weather year as a basis for forecast years. In the event of more extreme weather years in the future, as is likely, the critical supply risk will increase without the additional gas build, given the strong increase in frequency of high outliers and this therefore underlines the need for new flexible generation capacity.

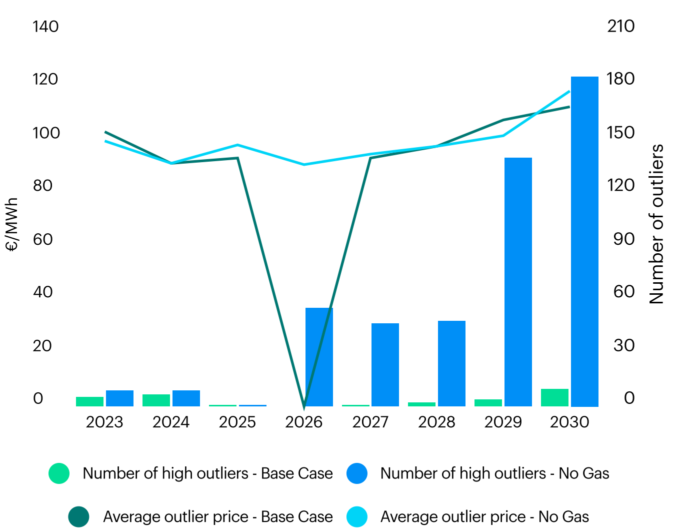
Neighbouring countries also see an increase in highly-priced hours in the No Gas scenario reflecting the idea that regional interconnectivity acts to ease tighter German supply in the absence of the additional gas. Taking 2026 as an example year in our Base Case, France would see two hours at a high outlier price, Belgium 52, the Netherlands 41, Austria 47, and Poland 117 - a total of 259 hours of high-price outliers among key German power trade markets. In a scenario without gas capacity expansion, this number rises to 359 - an increase of almost 40%. In terms of the average prices of these outliers, the story is similar as with Germany with prices very similar to the outlier prices as seen with the German gas capacity expansion.

For example, average outlier prices between 2026 and 2030 in the Netherlands were €2.50/MWh lower in the No Gas scenario than in the Base Case, with Belgium also seeing a drop. In France and Poland there was a marginal increase of an average of €1/MWh or less, while in Austria - which also saw a strong increase in exports to Germany during the period in the No Gas scenario - average outlier prices were more than €3/MWh higher.

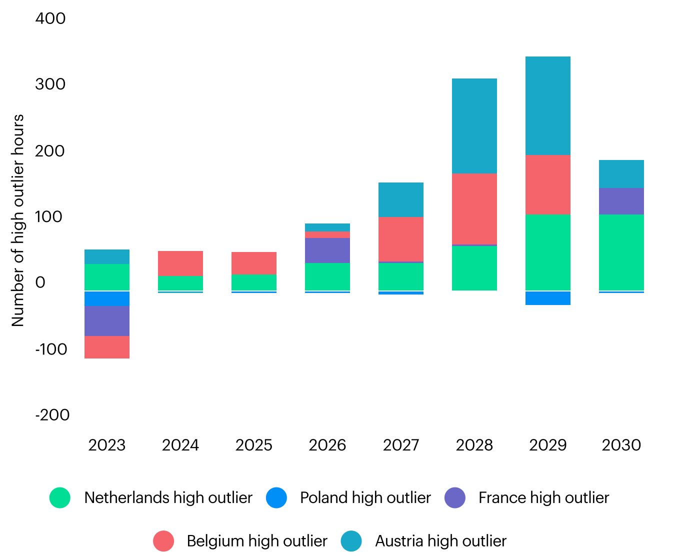
Despite the increase in the frequency of high outlier prices, again the stability in price itself suggests that there is sufficient interconnection to manage the reduction in German gas supply over the next decade but that all continental markets joined to Germany will also pay higher prices at times of tightness.

To summarise, the overall effect of no additional gas buildout in Germany after 2022

German hourly prices - high outliers



Number of hours priced as high outliers



However, in the event of extreme weather, then the lack of gas buildout would cause significant supply issues due to the much higher total number of hours priced at or close to €100/MWh.

would be particularly bullish in the late 2020s, increase the frequency of hours priced in Germany and its continental neighbours at close to €100/MWh, and raise carbon emissions from the power sector due to higher and in some cases less-efficient European gas-fired generation as well as the added German coal and lignite production.

However, the results do not paint a picture of extreme supply shortage, assuming a normal weather year due to the flexibility provided by strong regional interconnectivity as well as the expected additional of DSR technologies to ease the effect of price spikes. However, in the event of extreme weather, then the lack of gas buildout would cause significant supply issues due to the much higher total number of hours priced at or close to €100/MWh.

Conclusion: What does this mean for German gas capacity expansion?

Given the significant decrease in de-rated capacity and subsequent supply crunch that will define the German power market in the 2020s, our modelling shows that the country will need some degree of added flexibility. This is underlined by the much higher frequency of hours of potential critical supply shortage in the event of no new gas buildout. This effect would be further exacerbated in the event of a more extreme weather year than that which we modelled and a much higher risk of extreme prices in Central Western Europe in the event of no new German gas capacity.

That said, our modelling shows that there is a level of flexibility provided by interconnection between Germany and its neighbouring countries and the relatively moderate impact of no new German gas buildout on prices in the event of a normal weather year. This suggests that Germany may not require as much as the 9GW stated in the government's NECP to provide the necessary flexibility and that it may

also consider alternative forms such as increased interconnectivity and new storage technologies rather than such strong gas buildout.

Therefore, a high level of uncertainty remains regarding whether Germany would need to introduce a capacity market to bring on new gas capacity that could also generate in the energy-only market, or whether a small number of peaking plants directly commissioned for its reserve system, combined with other means of flexibility such as interconnectors, would be a better means of securing supply in the late 2020s.

ICIS fuel price assumptions

Roy Manuell
Analyst

Matthew Jones
Lead Analyst