Put gas on standby

Unabated gas plants' future role in the power system should be predominantly limited to backup reserve to allow for flexible low carbon forms of supply to fully emerge.

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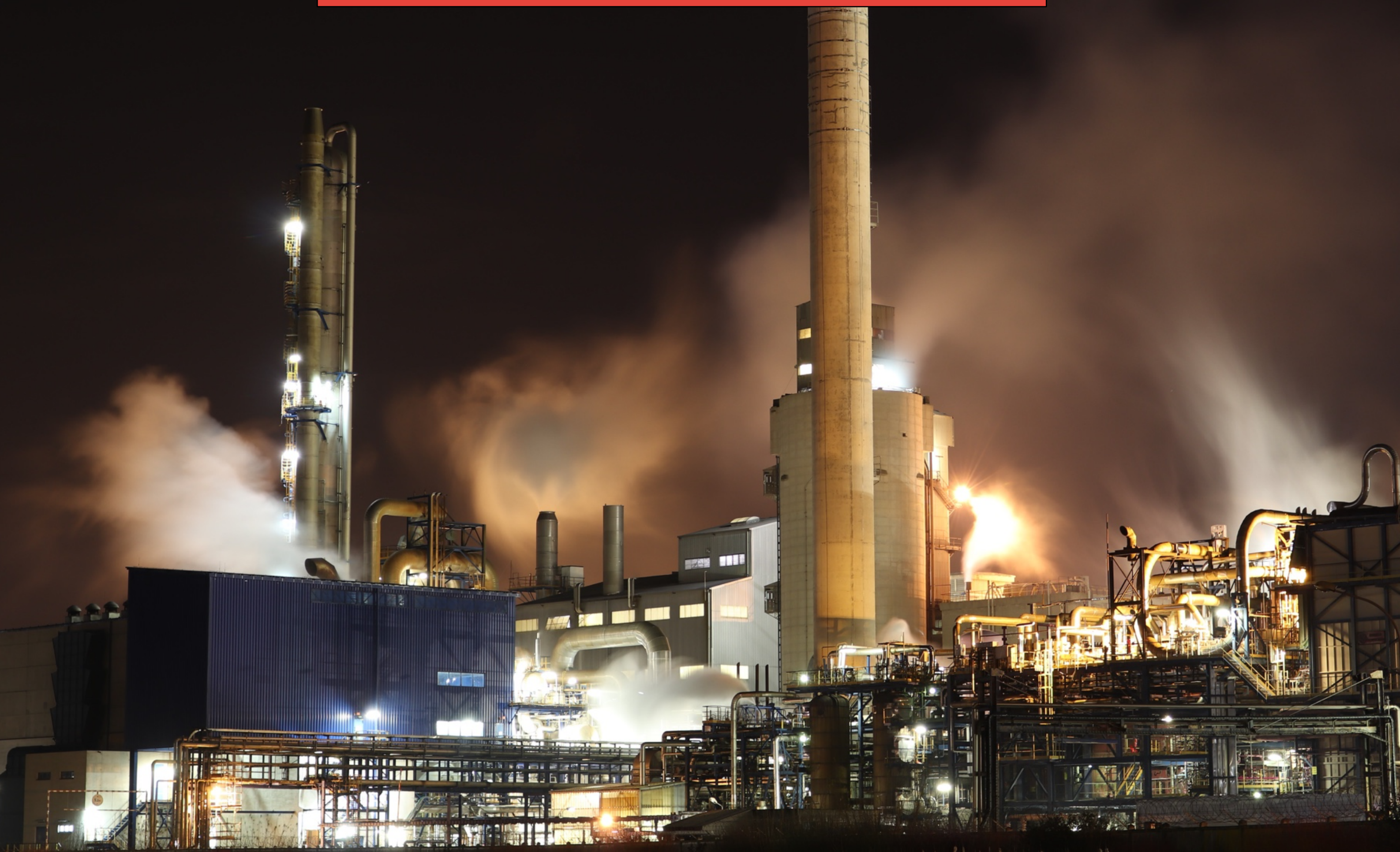

Report

October 2021

About Carbon Tracker

The Carbon Tracker Initiative is a team of financial specialists making climate risk real in today's capital markets. Our research to date on unburnable carbon and stranded assets has started a new debate on how to align the financial system in the transition to a low carbon economy.

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All errors and omissions are solely the responsibility of the Power & Utilities team.

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Contents

1 Gas has role to play but this should be limited

Events in 2021 have brought the extreme levels of price and supply volatility present in the global gas market to the fore of discussions over future energy system dynamics.

Wholesale gas prices have risen to record highs across key supply hubs, highlighting the levels of market risk that gas-fired power stations are exposed to, and demonstrating the urgent requirement for increased investment in alternative forms of flexible supply which are steadily emerging.

Even before this year's crisis however, gas-fired power stations across Europe and the US were already confronting declining operating profitability and rapidly growing competition from low carbon sources. A steady shift towards the primary use of such technologies is vital if net zero emissions goals are to be achieved.

While small amounts of unabated gas-fired capacity may well be required to remain available in these regions and to sit predominantly idle as back up peaking capacity to ensure long-term system supply security, we believe that this should be the limit to such units' future role.

This report aims to demonstrate that stakeholders committing to the long-term funding of such assets are already risking the loss of billions of dollars, while the risks of continued investment will only grow further.

2 Key Findings

The decline of gas' power sector role is already underway. We find that 22% of the European and around 31% of US gas-fired power generation capacity included in our model is already unprofitable, while we project these figures to steadily increase over the coming years.

The economics of gas-fired power generation in Europe and the US are growing in fragility. Gas-fired power generating assets across these geographies are increasingly vulnerable to the effects of swings in highly volatile fuel and carbon prices, further upward moves for which will bring forward key crunch points for plant owners.

Capacity payments will not save all gas plants. The required restructuring of capacity market schemes to limit funding for unabated gas to ensure alignment with latest climate goals will leave European capacity running at significantly lower operating margins.

Existing gas capacity modelled is already more expensive to operate than new renewables. Virtually the entirety of the gas plant capacity included in our model is more expensive to operate than either new onshore wind or solar, meaning investors involved in each country we have assessed already have a cheaper and lower risk low carbon alternative to continued gas investment available to them, while we project that renewables will become even cheaper to run over time.

Renewables with battery storage installed will also be cheaper to run than gas units by the end of the decade. New solar and onshore wind farms with battery storage capacity are increasingly competitive and will become cheaper to run than the majority of existing gas plants by 2030.

Most new build gas capacity planned will be unable to recover initial investment and should be cancelled. More than two thirds of gas-fired power plant capacity planned or under construction in Europe – a total of 23.7 GW – and all of the 28.1 GW planned in the unregulated grid areas of the US will be unable to recover original investment, even if allowed to run for full planned lifetimes. Some $24 bn is at risk from investment in new gas plants in the US and $3.7 bn in Europe.

Continued long-term operation of unabated gas is incompatible with legally-binding climate targets. Gas-fired power stations are now Europe's largest source of power sector emissions and reduced operation over time is vital if net zero targets are to be achieved.

Close to $16 bn could be stranded if gas-fired assets are closed in line with the timeframe required to deliver net zero emissions by 2050. Profitable units forced to close before the end of their planned operating lifetimes will leave more than $10 bn of investment in Europe and $5.8 bn in the US at risk of stranding.

An additional $16 bn could be saved however by closing loss-making gas plants early in line with a net zero 2050 target. Savings of $8 bn and $7.9 bn will be achieved by owners of loss-making units in Europe and the US respectively through the earlier plant closures required to deliver net zero by mid-century.

3 Executive Summary

This report is Carbon Tracker's first in a series which calls into question the case for long-term investment in gas-fired power plants globally. It follows on from our "*Do Not Revive Coal*" report but switches attention to the fossil fuel that has long been viewed as a major part of the long-term climate solution.

We find, however, that the economics for continued investment in existing gas plant capacity based in the EU, UK and the US are growing in fragility. We project that 22% of the European and 31% of the US capacity included in our model is already unprofitable to operate, with these figures expected to steadily grow over the coming years.

For the owners of gas plants that are projected to remain profitable for the long-term, the prospect of forced unit closures earlier than planned through policy measures designed to align power system trajectories with net zero targets brings significant levels of stranded asset risk.

New renewables are already cheaper to invest in than existing gas capacity across the geographies covered in this report and even when battery costs are added to the levelised cost of energy for such assets, although inflection points for when these fall below the long-run marginal cost for running existing gas plants are pushed later into the 2020s for most countries, existing gas capacity still faces strong competition from onshore wind and solar farms able to offer reliable grid services.

By just 2023, around half of the operating European gas plant capacity included in our model will be more expensive to run than either new onshore wind or solar capacity installed with battery storage, with this rising to more than 85% by 2030. Renewables with battery storage technology installed in the US will take longer to become cost competitive, but we still project that close to half of the country's gas plant capacity will be more expensive to run by the early 2030s.

For planned new build capacity, we have extended the project finance model built for our coal report to gas plant projects planned in major supply hubs in Europe and the US, with our results providing a clear message to potential investors — building new gas plants is ill-advised and will produce projects that are unlikely to yield returns on investment in most regions.

Gas continues to have a role to play in the energy transition, but investors should not be fooled into believing that the fuel will be immune to the economic challenges facing coal and lignite within the power sector. Although some existing gas-fired capacity may be required to sit idle in reserve to ensure system reliability for the long-term, this should be limited and not relied upon for day-to-day supplies.

GAS PLANT PROFITABILITY CALCULATION

We have aggregated, for each country or region, the proportion of installed gas plants expected to be unprofitable for each year until 2065. We have analysed the financials of 835 individual operational gas-fired power generating units across Europe, making up some 189 GW of capacity, while our models for the US comprise some 2,200 individual units making up some 513 GW of operating capacity.

An unprofitable gas unit is defined as one where total revenue minus long-run marginal cost (LRMC) gives a value of less than zero. Total revenues include in-market (i.e. those achieved in wholesale power markets) and out-of-market (i.e. ancillary and balancing services and capacity markets) sources, while LRMC includes fuel, carbon (where applicable), variable operating & maintenance (VOM) and fixed operating & maintenance (FOM) costs. Across time the overall profitability is expected to exhibit a downward trend, mainly due to increasing carbon cost and reduction in usage. However, capacity market mechanisms or other forms of out-of-market payments can at least partially offset the loss-making effect.

$$\text{Profitability} = \text{Total revenue} - \text{Long-run marginal cost (LRMC)}$$

$$\begin{aligned}\text{Total revenue} = {} & \text{In-market revenue} \\ & + \text{Out-of-market revenue (ancillary/balancing and capacity markets)}\end{aligned}$$

$$\begin{aligned}\text{LRMC} = {} & \text{Fuel cost} + \text{Carbon cost (where applicable)} \\ & + \text{Variable operation and maintenance cost (VOM)} \\ & + \text{Fixed operation and maintenance cost (FOM)}\end{aligned}$$

We do not assume revenue or cost hedging in our modelling, which may be the reason why units considered to be unprofitable here continue to operate or remain available to the market.

The proportion of unprofitable units is represented in percentage and calculated by dividing the total capacity of unprofitable units in that country/region by corresponding total gas capacity. Percentage values may fluctuate over time given the expected commissioning or decommissioning of gas plants across the period.

$$\text{Percentage of unprofitable gas capacity} = \frac{\text{Capacity of units with profitability } < 0}{\text{Total installed capacity}}$$

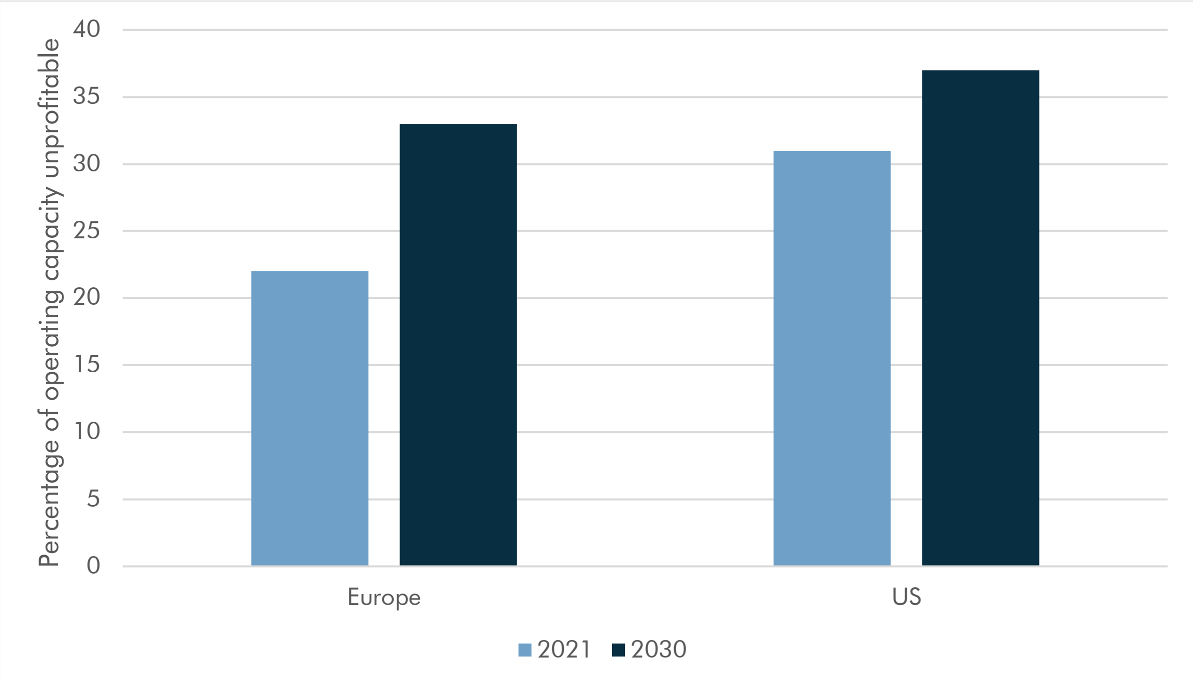
The decline of gas’ power sector role is already underway

The flexible nature of gas-fired power generation, with units able to respond quickly to changes in swings in grid power supply and demand, plays a valuable role in assisting the integration of renewables across Europe and the US as the power sector adapts to the retirement of coal-fired units.

Switching from the use of one fossil fuel to another is unlikely to be a long-term success strategy for decarbonisation however and investors must wake up to the reality that gas plants will not enjoy the long operating lifetimes that they have in the past unless significant developments in abatement technologies are achieved over the coming years.

Some 22%, or around 43 GW, of existing European gas-fired power generating capacity included in our model is already unprofitable to run, while in the US some 31% or 159 GW is already loss-making and we project these figures to steadily increase over the coming years, based on current pollution regulations and policy.

Figure 1 Proportion of operating gas plant capacity unprofitable to operate under base case assumptions



Source: Carbon Tracker analysis

Table 1 Status of gas-fired power generation in nations with more than 1 GW capacity installed

Country	Gas plant capacity in operation (GW)	Gas plant capacity under construction or in planning (GW)	Percentage of operating gas unprofitable today	Percentage of operating capacity unprofitable by 2030	Percentage of operating capacity unprofitable by 2035
Austria	4.3	0	100%	100%	100%
Belgium	5.3	3.0	8%	39%	64%
Bulgaria	1.2	0	100%	100%	100%
Czech Republic	1.3	0	100%	100%	100%
Finland	1.8	0	100%	100%	100%
France	7.6	0.7	0%	5%	16%

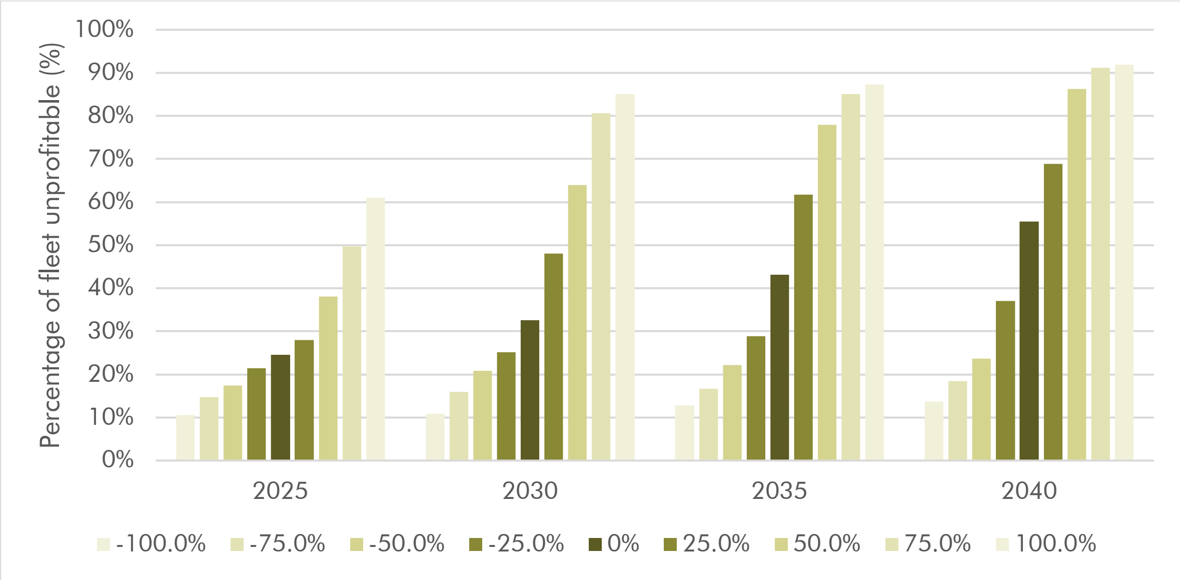
Germany	23.7	4.1	88%	90%	90%
Greece	5.2	4.7	6%	10%	35%
Hungary	2.9	2.3	17%	100%	100%
Ireland	3.8	0.1	4%	7%	18%
Italy	41.2	9.7	0%	0%	1%
Latvia	1.1	0	100%	100%	100%
Lithuania	1.1	0	3%	3%	3%
Netherlands	13.9	0	2%	32%	84%
Poland	3.3	5.1	0%	11%	35%
Portugal	3.9	0	48%	100%	100%
Romania	3.4	3.0	100%	100%	100%
Spain	26.8	0	0%	22%	55%
UK	33.2	9.7	4%	13%	13%
US	513.5	33.7	31%	37%	39%

Source: Carbon Tracker analysis

Crunch points for plant owners could be brought forward still if carbon and fuel costs turn out higher than our base case figures, as has clearly been the case during 2021. Price movements in both of these markets have been highly volatile in recent years owing to a combination of structural reforms to the European carbon market, gas storage and supply issues across Europe, and as the COVID-19 pandemic has driven large swings in demand.

Prices under the EU's Emissions Trading System have increased more than tenfold in just four years, while at the time of writing values have nearly doubled from where they had begun the 2021 calendar year alone. As can be seen in figure 2, sensitivity analysis we have run shows that a further 50% rise in European carbon prices from our base case numbers would leave some 64% of operational gas capacity unprofitable to run by 2030, although we acknowledge that part of the effect of higher carbon prices will likely be offset by an associated rise in power price.

Figure 2 Impact of percentage changes in European carbon price from base case numbers on proportion of gas fleet unprofitable



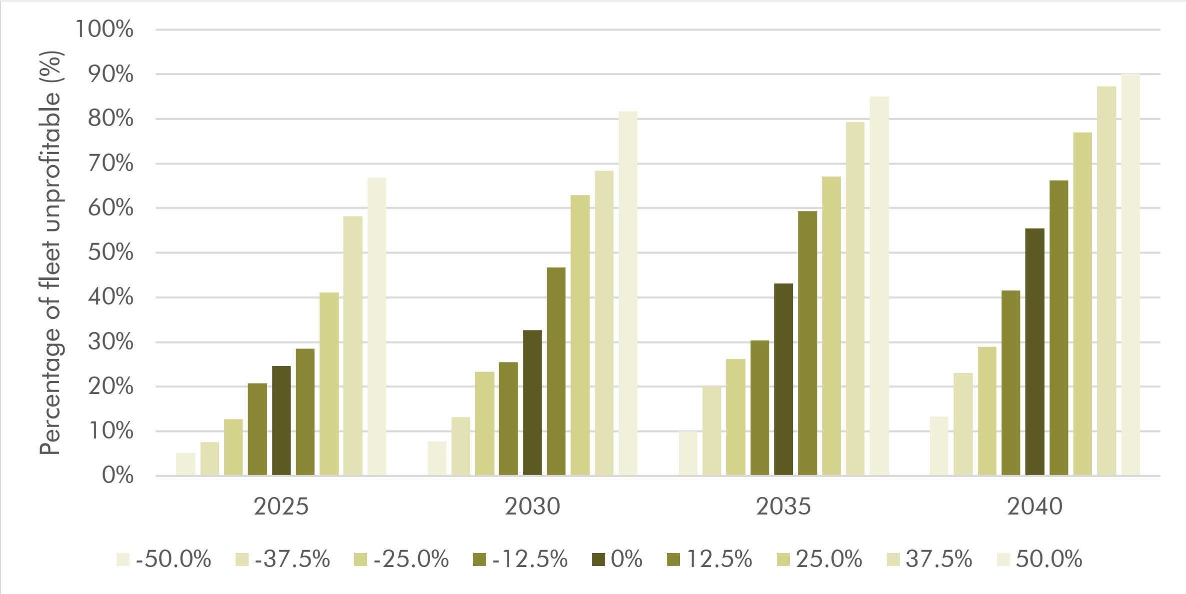
Source: Carbon Tracker analysis

Similarly, European gas prices have surged to record highs in 2021, amid depleted storage supplies. Even before this year however, the average year-on-year change in the spot price at the UK's NBP gas hub was more than 25% over 2018-20, while at the Dutch TTF annual spot price changes have averaged around 37% over this same period[1]. Although these have not all been upward price moves, these price swings show the levels of volatility that gas plants are exposed to for their fuel costs.

Shown in figure 3, our sensitivity analysis on average fuel price paid by European gas-fired plants shows that a 25% increase from our base case figures could leave more than 60% of the units included in our model unprofitable to run by 2030[2].

[1] *Prices sourced from Bloomberg.*
[2] Details of the fuel and carbon costs we have used for our model can be found in our methodology document, a link to which is provided in the appendix.

Figure 3 Impact of percentage changes in fuel prices from base case numbers on proportion of European gas fleet unprofitable



Source: Carbon Tracker analysis

Gas plant operating margins could narrow to critically low levels if capacity payment mechanisms are restructured as required

Capacity market mechanisms that aim to ensure reliability of power supply during periods of weaker output from renewables or higher demand for electricity have been launched in the UK, Ireland, France, Belgium, Italy and Poland in recent years, while similar schemes operate across the US power system in various forms. Such schemes offer financial incentives to plant operators to make capacity available to the system when it is most needed.

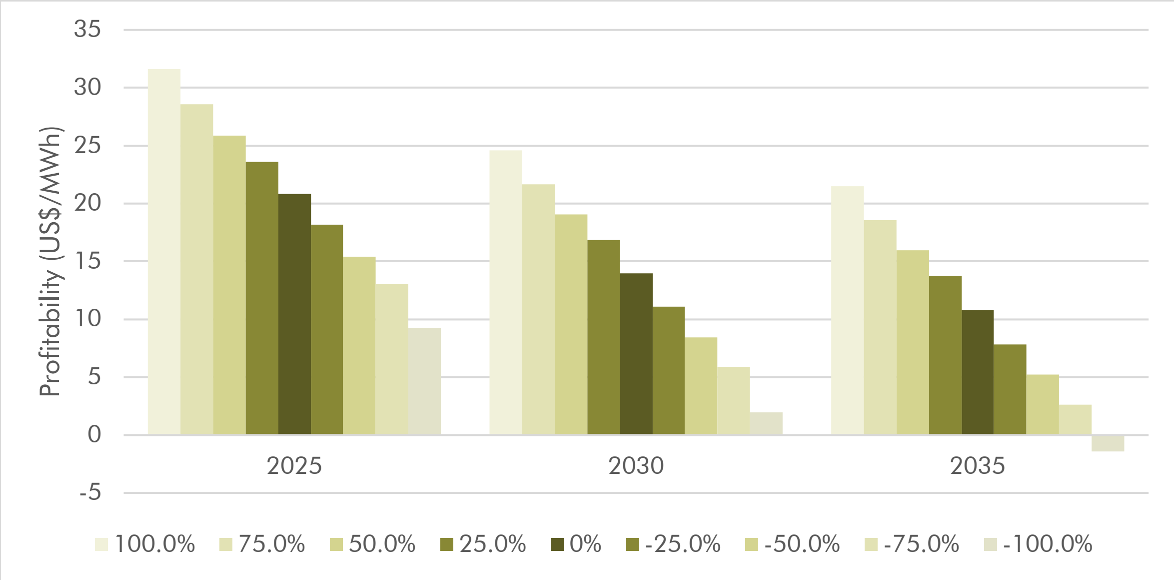
However, financially supporting the continued operation of ailing unabated fossil fuel-fired power stations, beyond those required as backup reserve, appears incompatible with latest climate targets. Investors should not place heavy reliance upon the long-term receipt of capacity payments. A limited amount of unabated peaking gas-fired capacity may be required for the long-term by some countries to ensure system reliability, but these units should predominantly sit idle for the majority of hours in favour of the use of low carbon technologies for primary energy supplies.

Where the continued use of capacity markets is deemed necessary to ensure grid stability or system reliability, we urge policy makers to consider restructures to reduce the amount of unabated gas units that are contracted over time in favour of carbon neutral forms of flexible capacity.

We find that relatively small decreases in the level of capacity payment received pull operating margins for gas plant generators in the countries where capacity markets are in place down to critical levels.

In Italy for instance, we project the average gross operating profitability per unit of generation for the country's gas-fired power stations would be left only narrowly above $10/MWh by 2030 if capacity payment levels fall by just 25% from those awarded in recent auctions. While in the event that Italian unabated gas units lose access to capacity market payments by 2035, average gross operating profits would fall below $0/MWh.

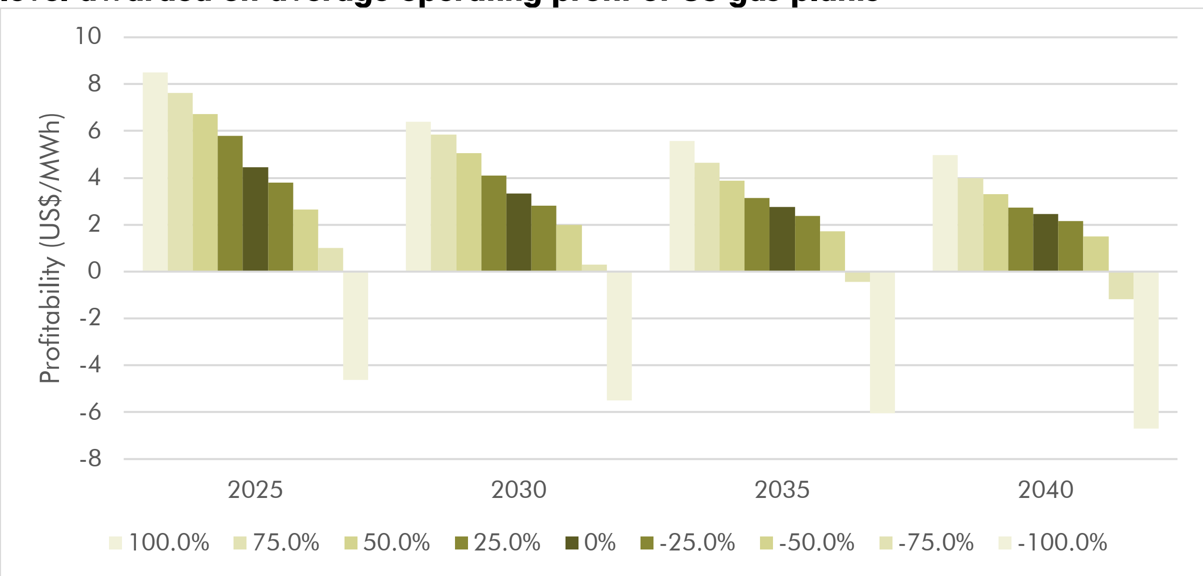
Figure 4 Impact of percentage changes in capacity market payments from current levels awarded on average operating profit of Italian gas plants



Source: Carbon Tracker analysis

For the US, average operating profitability per unit of generation will be left at only around $2/MWh by 2030 if capacity payments halve from current levels, although even if capacity payment levels doubled we project that the country's gas fleet would still be left running at an average operating profit of less than $10/MWh[3].

Figure 5 Impact of percentage changes in capacity market payments from current level awarded on average operating profit of US gas plants



[3] Capacity payments in the US are modelled at Regional Transmission Organisation (RTO) level and applied only to the merchant units we have included (59% of US model). Due to the lack of transparency on capacity contracts, we assume that all gas units in the grid are eligible for payments. For each RTO, we take the median price of a contract (averaged over all zones) per day and estimate a total payment per unit per year. Specifically in the case of MISO where a fuel breakdown is available, we scale down payments according to the amount of gas capacity awarded and gas capacity modelled in the grid. We cover all contract delivery years awarded as of July 2021. Capacity payments are then assumed to continue at the same level until 2040, after which they are assumed to be phased out.

Operating costs for existing gas are already above those for new renewables

Our models show that it is already cheaper to invest in low-cost renewable energy capacity across both the EU and the US than it is to continue running an existing gas plant. We showcase this by comparing the levelised cost of energy (LCOE) for renewables with the long-run marginal cost (LRMC) of gas[4].

We project that by just 2023, median LCOEs for both new onshore wind and solar farms in Europe will sit at levels less than half the median LRMC for operational gas[5], while the same will occur in the US by the middle of the decade.

We have also modelled LCOE numbers for new wind and solar capacity across Europe and the US with added estimated costs for a four-hour lithium-ion battery installed included. This time period is sufficient to mean that renewable energy produced earlier in the day can be shifted to and supplied to the grid during the peak demand evening hours and therefore provide comparable grid services to peaking gas plants.

Our results show that although this does delay the point at which existing gas capacity becomes more expensive to operate, competition for existing gas units from new renewables able to offer reliable grid services will steadily increase.

As shown in figure 6 below, the median LCOE for new onshore wind capacity installed with battery storage capability in Europe will fall below the LRMC for gas in 2027 according to our models, with this key inflection point for new solar capacity then estimated to come in 2030.

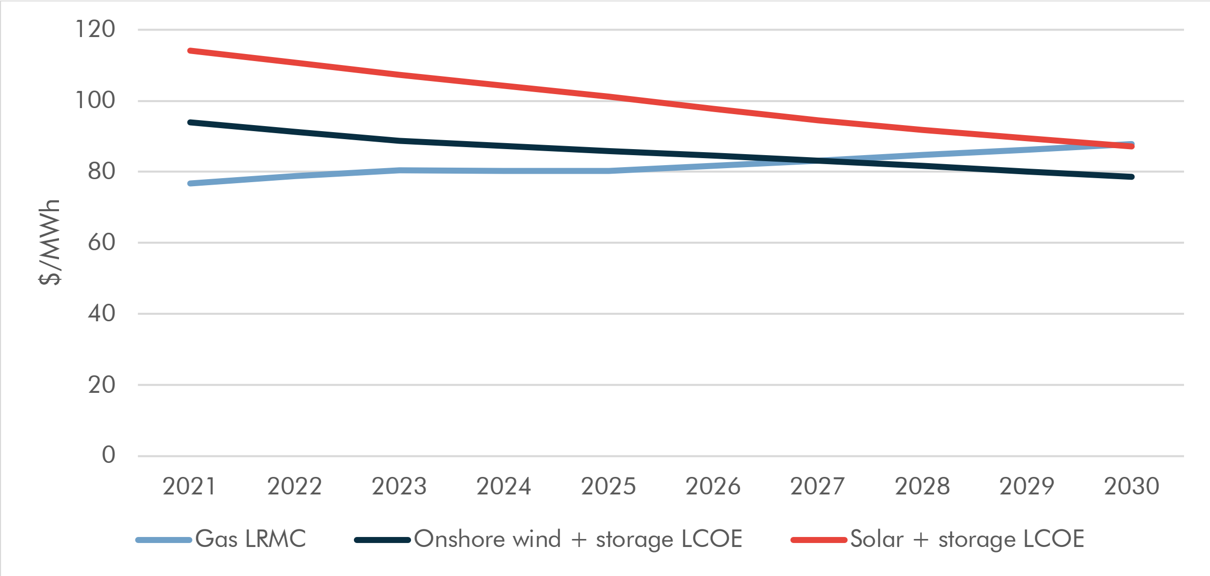
[4] The LCOE is equal to the sum of all capital and operating costs divided by the total amount of generation over the operating lifetime, while our LRMC calculations represent the operating costs (including fixed operating and maintenance costs) faced by gas-fired power generators of supplying an additional unit of energy. By comparing the LCOE of new renewables to the LRMC of gas, we are highlighting that operating gas plants are at risk of being stranded by new renewables due to the much lower costs associated, even without factoring in the capital and financing costs of gas.

[5] We have cross-checked our LCOE estimates for solar and onshore wind with estimates from BloombergNEF (BNEF) (2020), IRENA (2020) and EIA (2021). Broadly speaking we find that the mid-range of our estimates are within the mid country ranges forecast by the referenced sources.

For example, for onshore wind in the US, our estimate is around 17% lower than BNEF's mid-range and 3% higher than EIA's estimate. While for US solar, our mid-range estimate is 30% below the mid-range estimates of BNEF but only 0.3% below the EIA's estimated LCOE. For Germany, our model estimates an LCOE 4% and 7% below the BNEF estimations for onshore wind and solar PV respectively.

Details of our modelling for LCOE and LRMC can be found in the gas methodology document, a link to which is included in the appendix section of the report. Charts showing a comparison of our country estimates versus the referenced sources for onshore wind and solar can also be found in the appendix.

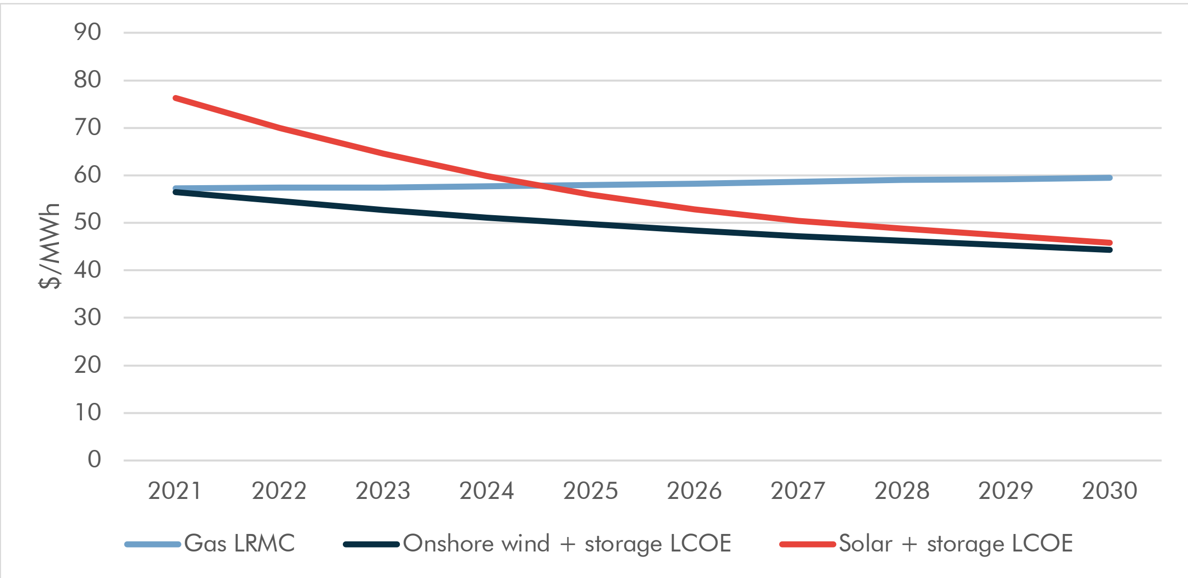
Figure 6 Median European LRMC of gas versus median LCOE of new renewables with storage



Source: Carbon Tracker analysis

For the US, we project that the LCOE for new onshore wind with battery storage costs added on would still turn out narrowly below the LRMC for existing gas capacity from today, while costs for solar with battery storage installed are then projected to fall below gas by just 2025.

Figure 7 LRMC of US gas versus LCOE of new renewables with storage



Source: Carbon Tracker analysis

Close to $16 bn could be stranded if plant closures are brought forward for net zero alignment

Our models identify the extent to which projected revenues from profitable gas-fired power units may be lost owing to early closures brought about through government policy aimed at aligning national power systems with climate targets. For plants that are already loss-making, our results identify the savings that investors would achieve if their assets end operation earlier under timescales aligned with Paris Climate Agreement aims or net zero targets, compared with the significantly larger losses that would be incurred if plants are left to run for their entire planned lifetimes.

We model that under the IEA's Beyond 2 Degrees Scenario (B2DS), which outlines the necessary power sector alignment trajectory for emissions to ensure the global mean temperature rise does not surpass the 1.75˚C midpoint of the Paris Agreement's ambition range, some $7.5 bn of potential operating profit for gas-fired assets located in Europe would be stranded compared with business-as-usual (BAU). Just under half of this, or $3.5 bn, is locked in operating gas plants in Italy, while a further $2.8 bn is at risk in the UK. For the US, some $2.2 bn is at risk of stranding under B2DS.

These figures will rise even further however if policy makers drive the earlier closures of unabated gas-fired plant units that are likely to be required to deliver economy wide carbon neutrality targets for 2050. The power sector's contribution towards this is likely to be required to come much earlier than mid-century, with US President Joe Biden this year pledging to deliver a carbon free power sector by 2035 as part of wider net zero aims[6], while the UK's climate advisory body the Committee on Climate Change has urged government to formalise a target for the same year[7] — a recommendation which Prime Minister Boris Johnson recently indicated he would accept. These target years were identified with the rollout of carbon capture and storage technology included however which our models have not incorporated.

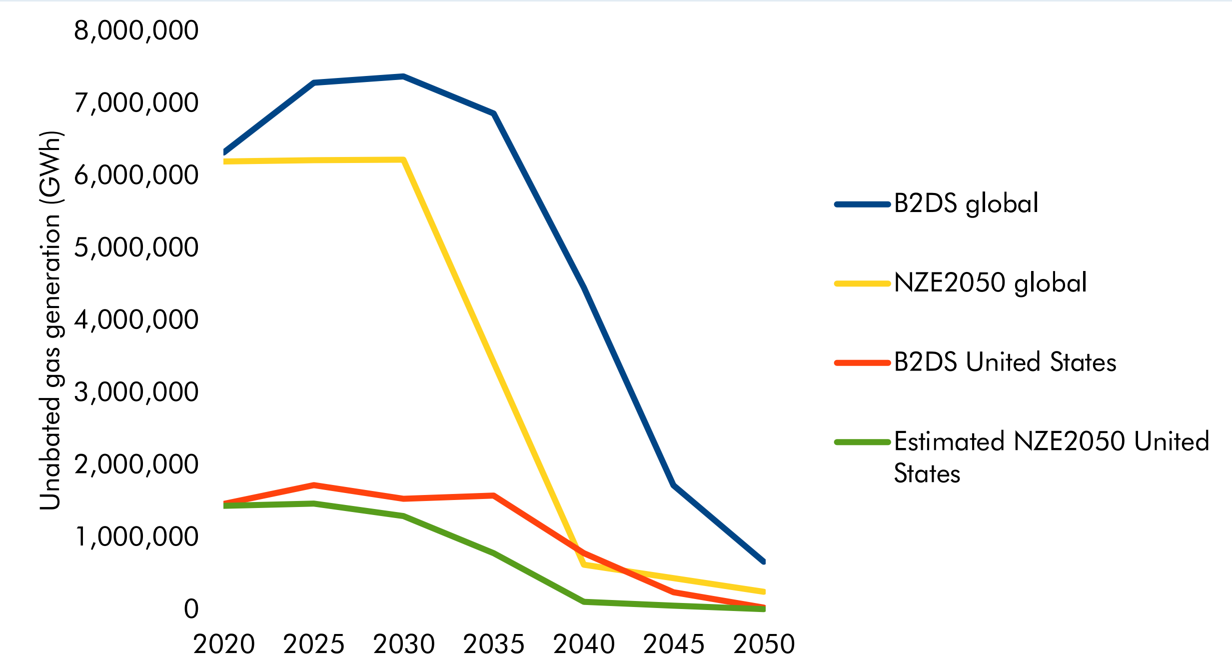
[6] Biden wants carbon free electricity by 2035 – (Energylivenews.com)
[7] UK power 'must be zero carbon by 2035' – Renews.biz

CARBON TRACKER'S NET ZERO 2050 SCENARIO

Carbon Tracker's net zero 2050 scenario is a regional interpolation of the IEA's global NZE2050 scenario and the B2DS. This is an interim scenario to model a net zero 2050 phaseout of coal and gas while we await the release of a more granular scenario by the IEA.

To estimate how coal and gas generation would decline under the more restrictive criteria of net zero emissions by 2050, we scale each regional trajectory in the B2DS according to the ratio of the global NZE2050 to the global B2DS unabated coal and gas generation trajectories.

This is illustrated by the chart below:



Regional NZE2050 unabated gas generation (year) = Global NZE2050 unabated gas generation (year)/Global B2DS unabated gas generation (year) x Regional B2DS unabated gas generation (year).

We acknowledge that this interim scenario is not as rigorous as a regional integrated assessment model. However, this is beyond the scope of our report and we will adopt regional NZE2050 data when it becomes available.

We have modelled the impact of the completed phase out of unabated gas across Europe and the US for alignment with net zero targets for 2050, with our results showing that the positive stranded asset risk figure for operating gas-fired plants in Europe jumps to $10.1 bn under this scenario, while the amount of potential value at risk of destruction in the US increases to $5.8 bn.

On the other hand, we also find that $6.5 bn of operating losses that will be incurred by unprofitable gas plants in Europe under a BAU scenario will be avoided in the event of early closure under B2DS, in addition to some $3.7 bn in the US. These savings then rise to $8 bn and $7.9 bn respectively under our net zero scenario estimates.

We recommend that such companies fully evaluate the risk that the necessary earlier closure of gas units will present to their investments and consider planning orderly wind downs of assets in such a way that maximises shareholder value. Plant owners that opt to wind down loss-making assets earlier than planned at project inception can save shareholders significant levels of funds.

Majority of new gas plant projects are economically unviable

Our models show that roughly two thirds (or 23.7 GW) of the planned or under construction gas plant capacity included in our European project finance model, and all of the 28.1 GW planned for build in unregulated grid areas of the US already generates a negative net present value (NPV) even under a BAU scenario.

This means developers for these projects are expected to be unable to recover their initial investment even if the plant is allowed to run for its full planned lifetime.

As shown in table 2 below, NPV values for new build gas plants in the UK fall further into negative territory under B2DS and our net zero scenario projections, while the NPV of Italy's planned pipeline falls by close to half under our projections for a net zero scenario.

Table 2 NPVs of new build gas plant pipelines by country

Country	Total NPV of projects under BAU ($mn)	Total NPV of projects under B2DS ($mn)	Total NPV of projects under net zero ($mn)
Belgium	-403.1	-130.2	-273.3
Greece	-441.4	-387.8	-508.4
Italy	3,694	2,551	1,901
Poland	-399.9	-354.1	-346.7
Romania	-2,721	-1,686	-1,644
UK	-3,466	-4,188	-4,439
TOTALS FOR EUROPEAN MODEL	**-3,738**	**-4,195**	**-5,311**
US	-24,337	-22,997	-22,741

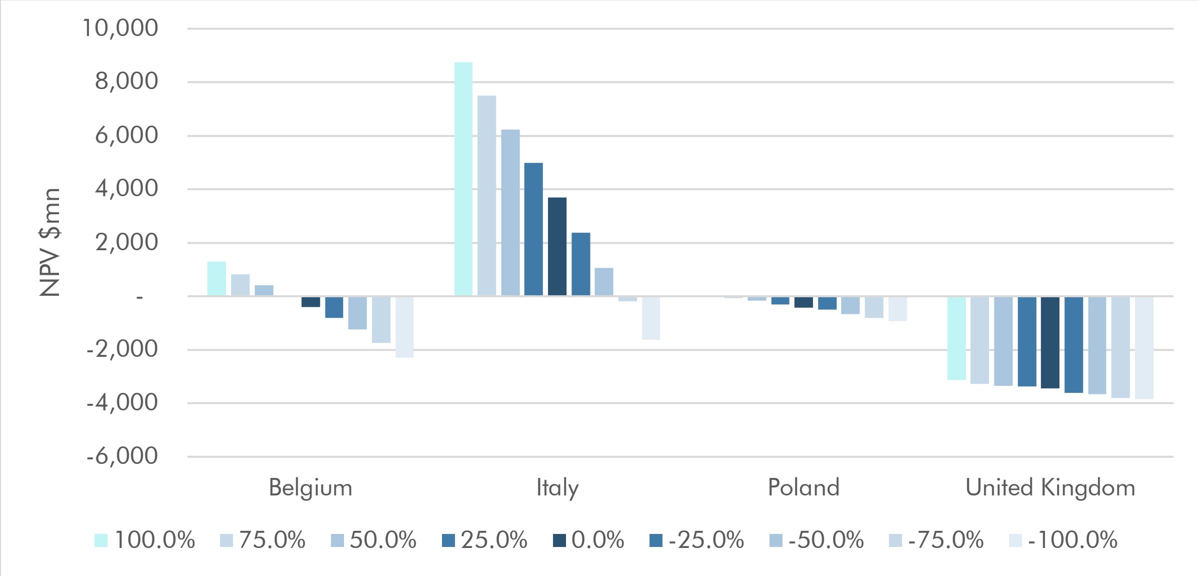
Source: Carbon Tracker analysis

We estimate that if the European projects included in our model were to proceed under BAU, a total of more than $3.7 bn, or more than $7.4 bn when Italy's positive NPV value is excluded, would be at risk of value destruction across the continent, while more than $24 bn is at risk in the US. The levels of investment at risk in Europe rise to $4.2 bn under B2DS and to $5.3 bn under our net zero scenario projections.

The NPVs of the planned pipelines in Belgium, Greece, Poland, Romania, and the US remain negative under our climate-constrained scenarios, although are marginally improved compared with BAU. This might seem counterintuitive, but the earlier closure of facilities in these countries reduces the number of years that units will operate while loss-making.

Our models also show that capacity market mechanisms will largely be unable to provide the basis for the long-term viability of most of the new build units included in our model, while we find that the level of payments being distributed under Italy's scheme to new plants could be significantly reduced, freeing up government funds which could instead be used to support low carbon innovation.

Figure 8 Sensitivity of new build gas NPV to percentage changes in capacity payments from current levels awarded

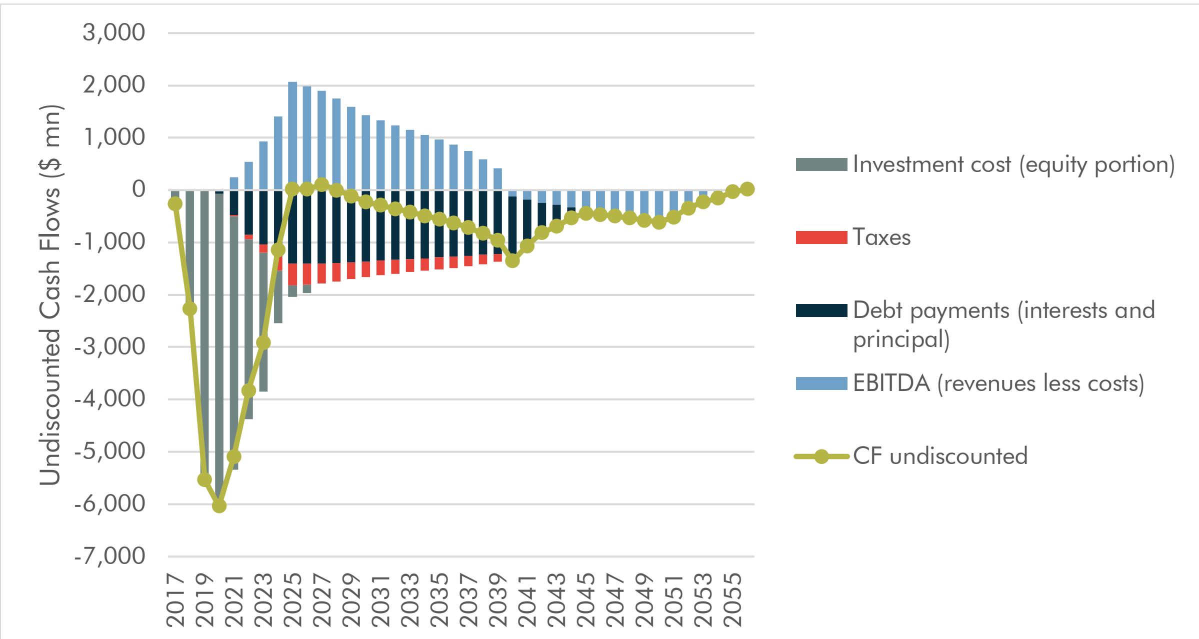


Source: Carbon Tracker analysis

If most projects appear likely to struggle to recover their initial investment even under a BAU scenario, shareholder losses could rise significantly under less favourable conditions, such as rising carbon costs, gas prices or falling power market prices.

Developers and investors for any projects that either already generate a negative NPV, or are projected to operate at levels where the NPV could be swung close to negative territory under the scenarios we model should seriously consider cancellation to avoid significant value destruction.

Figure 9 Aggregate lifetime undiscounted cash flows for planned new build gas in Europe and US



3.1 High level recommendations

Capacity market mechanisms should be reviewed and restructured to limit incentives for unabated gas plants. The continued funding of existing and new unabated gas plants without limits threatens to undermine both national and regional climate targets and makes the prospect of delivering them virtually impossible. If capacity markets are deemed essential to ensure a nation's grid stability, policy makers should restructure such mechanisms in a way to reduce over time the amount of existing unabated gas-fired capacity that is awarded contracts in favour of other forms of reliable capacity. The funds freed up can be redirected towards supporting low carbon technology innovation or to initiatives aiming to strengthen grid system reliability.

A majority of planned new build gas plant capacity in Europe and the US will be unviable and should be cancelled. Developers and investors for any projects that generate a negative NPV should seriously consider cancellation to avoid significant value destruction. Even the receipt of capacity payments fails to swing NPVs positive in the majority of countries that we have modelled.

Policy makers across Europe and the US should consider setting end dates for unabated gas use for power generation. Government intentions for long-term gas use remain largely unclear across the regions covered in this report, yet the continued operation of unabated gas-fired facilities without limits appears incompatible with legally-binding climate targets already in place. While a small number of units may be required in the long-term to sit as emergency reserve, identifying phase out deadlines for the majority of facilities will allow plant owners to begin preparations for winding down assets and devise strategies to maximise shareholder return.

4 The decline of gas' power sector role is already underway

Although the shift in power sector fuel dominance in Europe and the US from coal to gas in recent years has allowed for momentum to build in the phase out of coal use and for initial emissions reductions to be achieved, it has also served to position gas as the next target for decarbonisation if long-term climate goals are to be achieved.

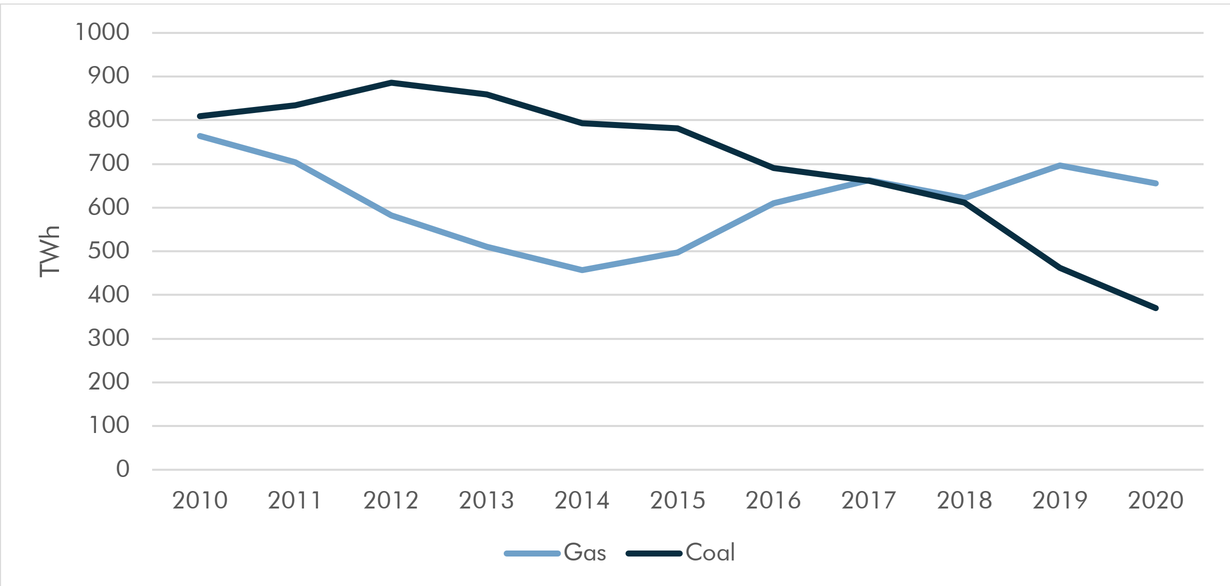
The decline of gas' dominance, and profitability, is already underway. Sensitivity analyses we have run, which model the projected change in profitability from movements in capacity market payments, gas prices and carbon costs present a clear picture to investors that key crunch points for gas may arrive much earlier than expected and that strategies for winding down assets should be planned well in advance.

The justification for continuing to allocate capital towards gas plants is also rapidly reduced when the comparable economics to new renewables are laid out. Investment in new onshore wind and utility-scale solar projects is already cheaper than the costs of running existing gas plant capacity across both Europe and the US, while even operating costs for new renewables with storage capacity are projected to fall below those for gas this decade.

Gas plant emissions becoming main obstacle to power sector climate goals

Gas-fired power plants have experienced a resurgence in use across Europe and the US in recent years. Combined-cycle gas turbine (CCGT) facilities have been the largest single source of electricity generation in the UK since 2015 and in the US since 2016, while they have dominated the generation mixes of Italy, Spain and the Netherlands for more than a decade[8].

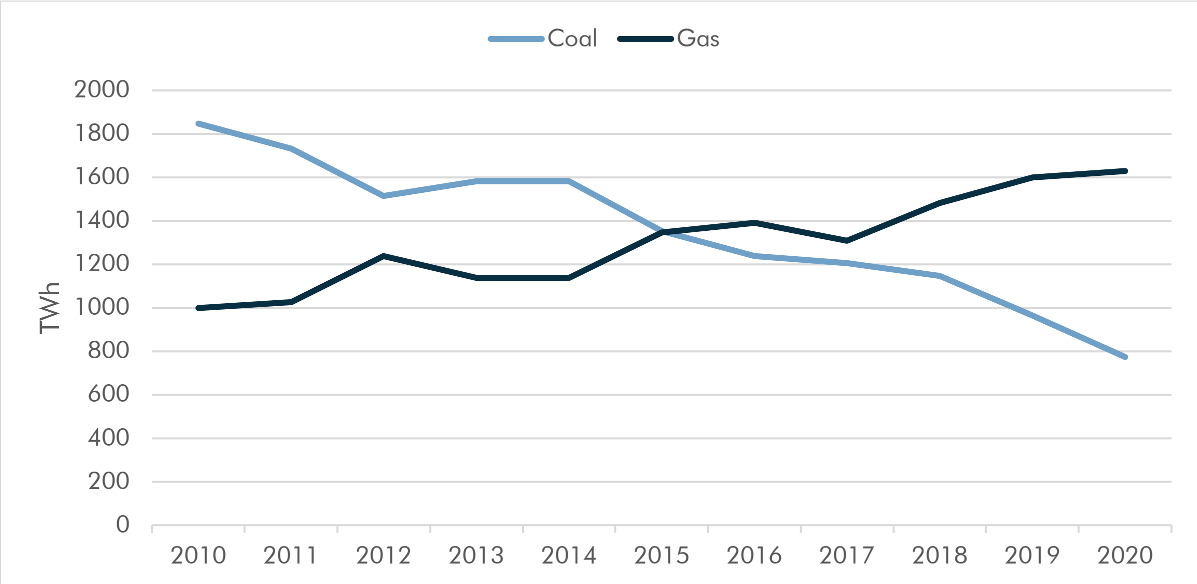
Figure 10 EU27 + UK gas, coal power generation



Source: Ember

[8] IEA primary energy supply data

Figure 11 US gas, coal power generation



Source: IEA

The coal-to-gas switch in fuel dominance has served to shave an initial proportion of power sector emissions and gas plants are undoubtedly playing a role during the early stages of the energy transition in allowing more polluting coal-fired facilities to be shut down without creating security of supply issues for the system.

Gas' medium-term role in the energy transition must not be prolonged however if climate targets are to be achieved, and the economic implications for investors of this are extensive.

The European Commission's Executive Vice-President, Frans Timmermans[9], who has led the Commission's work on the European Green Deal and first European Climate Law, earlier this year acknowledged that gas may still have some role to play in transitioning the EU's economy from a reliance on coal to zero emissions electricity supplies, but was firm in insisting that fossil fuels, including gas, have no long-term viable future within the EU[10].

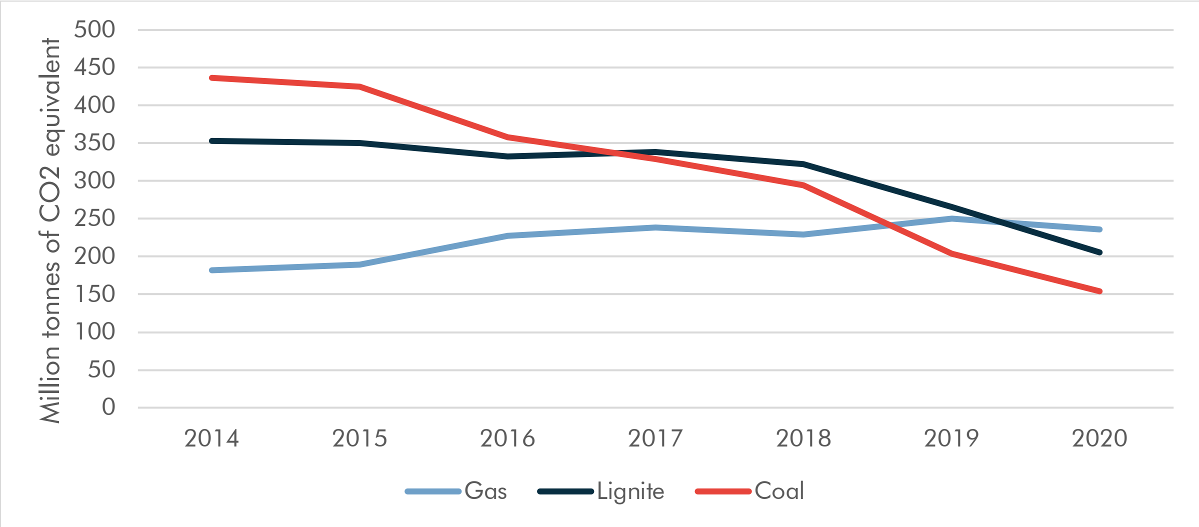
This requirement for increased action brings policy and financial risk for investors, with the likelihood growing that end dates for unabated fossil fuel-fired power generation will need to be set over timeframes more compressed than those planned by plant owners.

Although the carbon intensity of gas-fired power generation is lower than coal and lignite, substantial levels of emissions are still produced and the "clean" fuel label that gas has attracted in the past is highly misguided.

Gas plants became the EU's largest source of power sector emissions in 2020, producing a combined 236 million tonnes of CO2 equivalent (CO2e), or 34% of the sector's total emissions[11]. This was more than the emissions produced by both the EU's steel and chemicals sectors combined and compared with output of 154 million tonnes CO2e from the bloc's remaining coal-fired capacity.

[9] Frans Timmermans bio
[10] Frans Timmermans speech from Eurogas Annual Meeting – March 2021
[11] Gas power plants overtook lignite in 2020 to become Europe's #1 power sector emitter (Ember-climate.org)

Figure 12 EU power sector emissions by source



Source: Ember

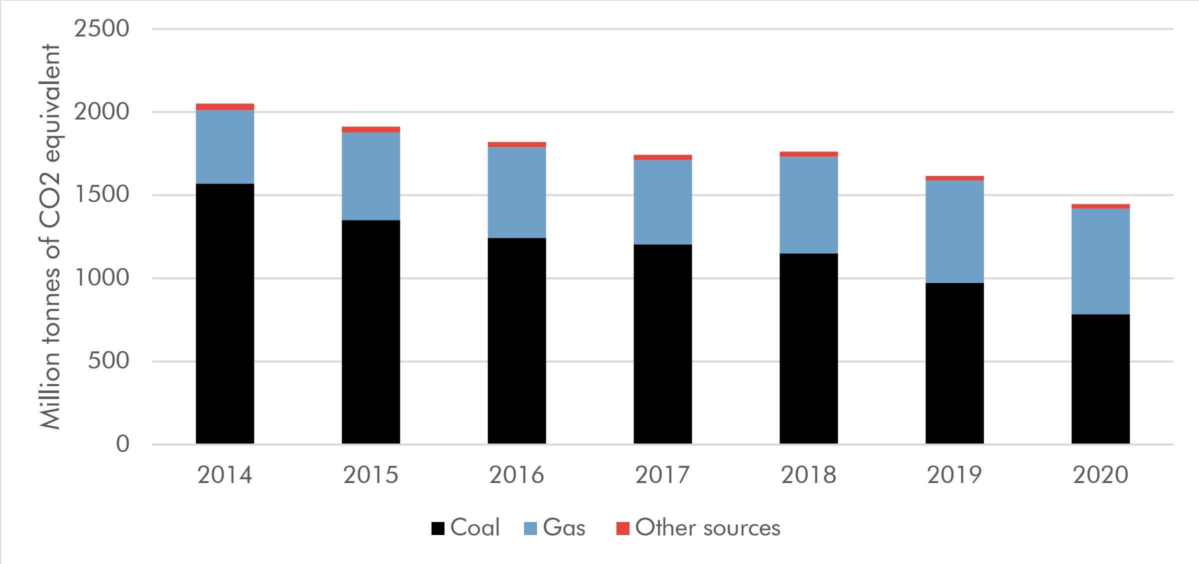
Gas plant emissions inside the EU during 2020 were down by just over 5% from 2019, but this reduction was a consequence of the COVID-19 driven decline in power demand that was seen, rather than by any conscious emissions reduction efforts and the IEA has forecast an increase in output back to around 2019 levels this year[12].

In the US meanwhile, power sector emissions from gas-fired power plants have increased year-on-year for three consecutive years and reached a record of 635.2 million tonnes of CO2e in 2020 despite the effects on power demand brought by the pandemic.

Gas units accounted for roughly 44% of the US power sector's overall CO2 emissions in 2020, with this proportional share having now doubled since 2014[13], as shown in figure 13.

[12] IEA Global Energy Review 2021 – Natural Gas
[13] US Energy Information Administration (EIA) – Monthly Energy Review

Figure 13 US power sector emissions by source



Source: EIA

Although the rise in gas emissions has largely been a consequence of replacing coal-fired capacity, plans for how this pollution source can be tackled are also required.

Nearly a quarter of European gas-fired capacity is already unprofitable

Our results show that 22%, or roughly 43 GW, of the operational European capacity we have included in our models – based inside the EU or the UK - is already unprofitable to operate, even when capacity market payments are included, while in the US some 31% or 159 GW of the country's current fleet is operating at a loss.

Operating profits for gas-fired generators in Europe improved during 2020 following sharp falls in fuel and carbon costs brought by COVID-19. However, this is likely to have been only a temporary reprieve.

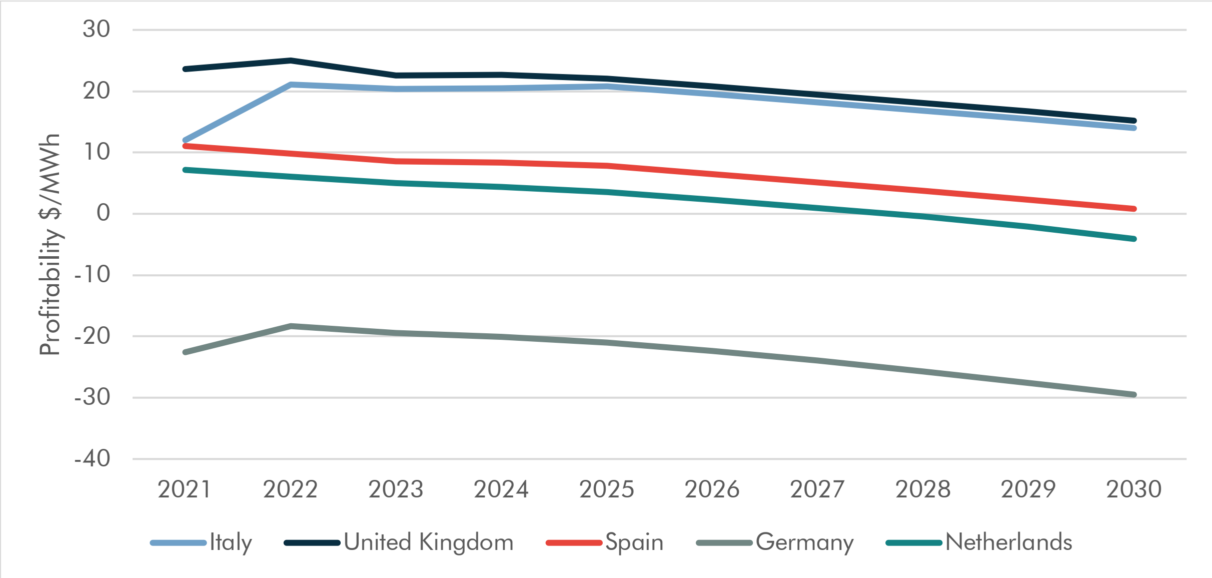
Both gas fuel costs and carbon market prices have recovered strongly since and profitability for the majority of countries is consequently expected to fall significantly this year and continue to decline.

In Germany, operating profits from the country's 23.7 GW of gas-fired power capacity are estimated to have averaged just over $4/MWh during 2020, according to our models. The fleet is expected to fall sharply back to loss-making status this year however, following the spike in gas prices, with operating profits per unit of generation produced averaging around -$20/MWh both this year and next, according to our models.

The average operating profitability per unit of generation for the gas-fired fleets of Spain and the Netherlands meanwhile are projected to tumble by nearly half year on year in 2021, with steady declines over the next 15 years meaning both countries' fleets are expected to turn loss-making on a gross basis by the mid 2030s.

In fact, our models show that the gas-fired power plant fleets of only seven European countries are expected to be generating overall profit by 2035, the top five of which — Italy, the UK, France, Ireland and Poland — have capacity market mechanisms offering financial incentives to gas plant owners to keep facilities online.

Figure 14 Average operating profitability per unit of generation of European gas plants by country



Source: Carbon Tracker Analysis

US plant profitability is already marginal and will continue narrowing

For the US, some 31% of the country's operating gas plant capacity is already unprofitable to operate according to our models, and although we project this figure to rise relatively slowly over the remainder of the 2020s compared with our European model, owing to an absence of carbon pricing and cheaper gas prices, just under 40% of US units are expected to be loss-making by 2030. However, the structure of the US power market means that only the units located in unregulated grid areas are likely to run into economic difficulties.

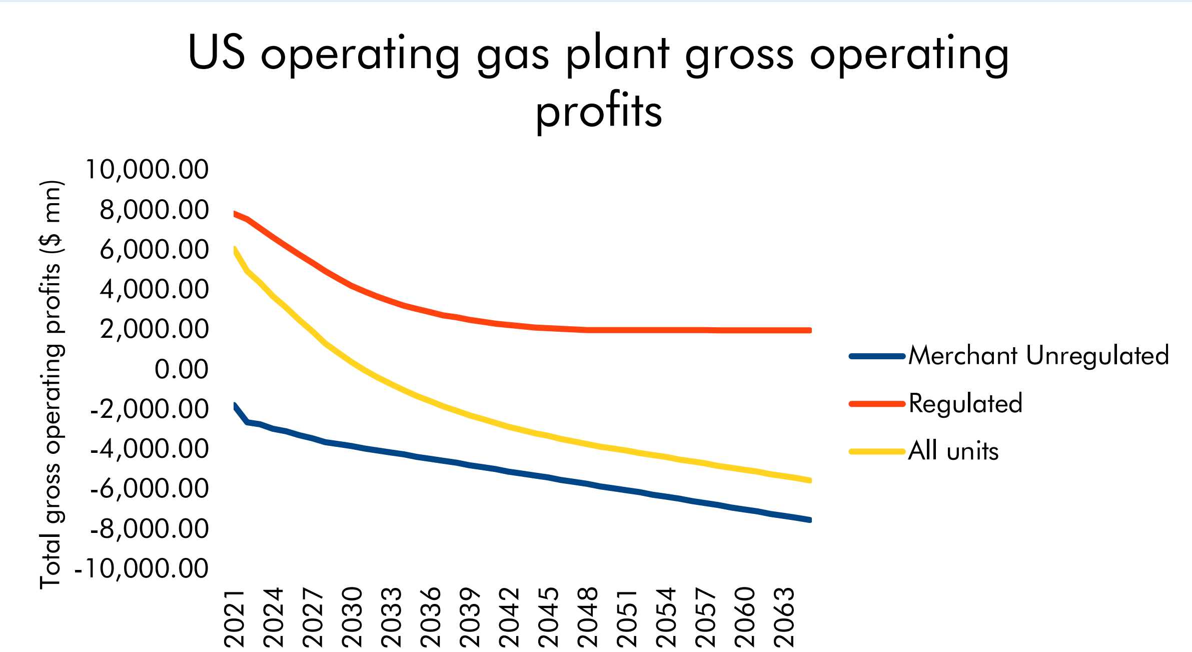
STRUCTURE OF THE US POWER MARKET

The US power system is split between traditional regulated and merchant markets, with 41% of the capacity included in our model located in regulated areas. This means that the vertically integrated utilities operating within these regions and the power stations they own typically hold monopolies dictating that local customers can only access electricity from them.

The distinction between regulated and merchant markets is key to understanding the investment risk that US utilities hold for both the future operation of existing gas-fired assets, and the funding of new build units.

Regulated utilities are able to pass the risk of investments onto their customers without consumers having the option of switching away to another supplier. As a result, although such firms are still required to seek state approval for power plant investments and to justify their requirement, customers ultimately bear the risk and utility investment decisions consequently do not always follow economic logic.

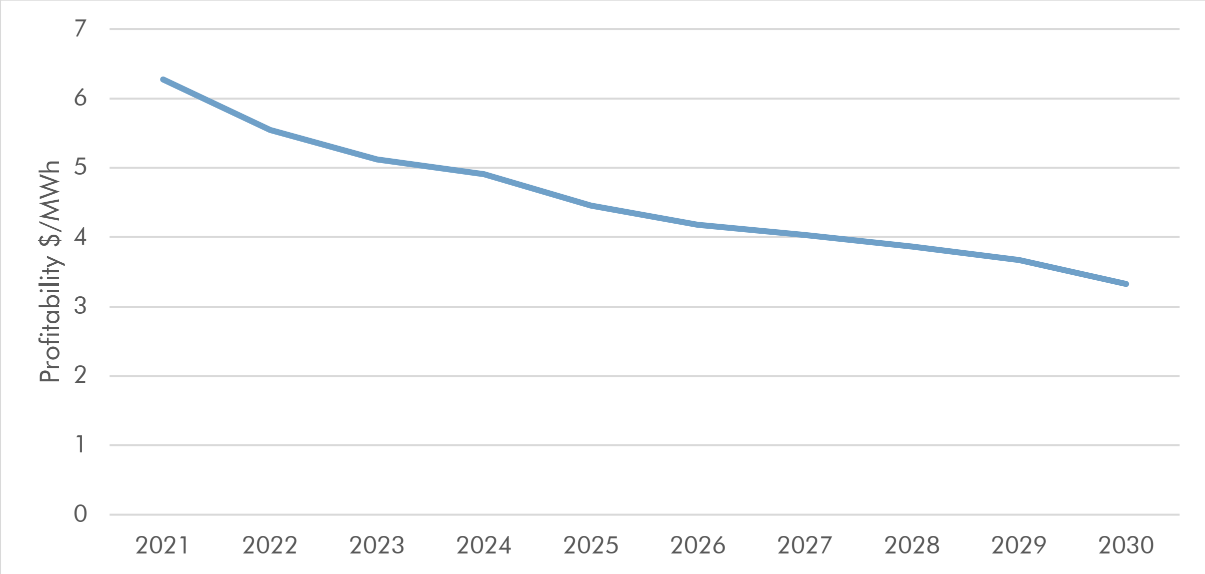
Merchant utilities operating in deregulated areas however have much greater risk exposure for their investments, while competition between utilities helps to ensure that decisions are made with a view to achieving lowest cost and profitability.



Operating profits of gas units in the US have already narrowed in each of the past four years and are projected to continue declining. By 2030, we project average gross profitability per unit of generation to have fallen by close to half from 2021 levels, to only around $3.50/MWh. By 2031, average operating profits per unit of generation for the country's operating gas plants are estimated to be insufficient for the US fleet to generate overall profit regardless of whether fuel prices rise from current levels.

This base case scenario also does not assume any rollout of carbon pricing measures which may be used by US policy makers to align power sector emissions with climate targets, and the profitability of the fleet could decline at a much faster rate if these are enforced.

Figure 15 Average operating profitability per unit of generation of US gas plants



Source: Carbon Tracker Analysis

Gas plant profitability will be squeezed by carbon price increase

Although the less carbon-intensive nature of gas compared with coal means that carbon costs for gas plant owners will have a more muted impact on profitability than has been seen for coal-fired assets in Europe, investors would be unwise to completely ignore the effect that further carbon price increases might have for gas plant economics.

Sharp price increases to record levels within the EU ETS market in recent years has driven carbon allowance values to above €60/t CO2e compared with less than €5/t CO2e in mid-2017. These gains have come following structural reforms to the market's supply dynamics, while further supply tightening is now planned to align the allowance volume trading with the EU's updated 2030 emissions reduction target for a 55% cut in output from 1990 levels. This makes the prospect of additional carbon price rises for European generators a very real risk.

The cost of allowances has become a significant consideration for gas-fired plant owners and our models show that further increases could have detrimental impacts on future operating profits for existing capacity.

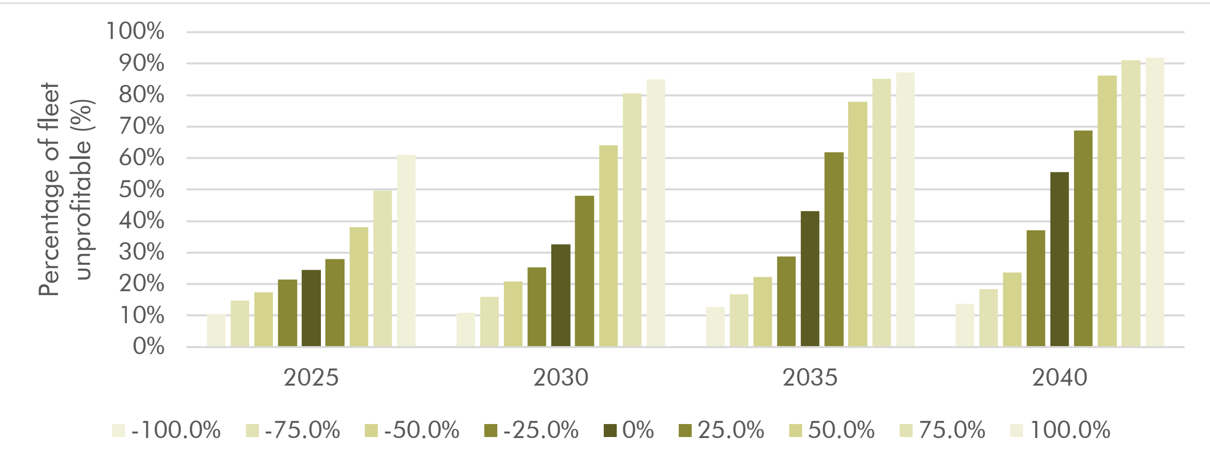
Figure 16 EU ETS price

Source: Ember Climate[14]

As can be seen in figure 17 below, sensitivity analysis we have run show that a further 50% rise in European carbon prices from our base case numbers, which would take values to around €110/t CO2e by 2030, would leave some 64% of operational gas capacity unprofitable to run by that year.

We acknowledge that our sensitivity analyses clearly change only one variable factor at a time and that the actual impact of steeper carbon price moves may be at least partially offset by an associated rise in power price. The assessment highlights the elements which potential gas plant profitability will be most vulnerable to and investors should be wary that highly volatile carbon and gas fuel costs are two of the factors we have concluded to be most influential. These are also two elements which renewable investments hold zero risk exposure to by comparison.

Figure 17 Impact of percentage changes in European carbon price from base case numbers on proportion of gas fleet unprofitable



Source: Carbon Tracker analysis

[14] Ember Climate Carbon Price Viewer

Gas plant owners should hold minimal expectations that EU leaders will offer protectionism against a rising carbon price either.

The treatment of gas and its place in the EU's plans for future energy supplies has dramatically shifted in recent years. Gas plant projects had been set to receive subsidy backing from the EU from its Just Transition Fund, which has been created to support those EU territories most adversely affected by the energy system changes required for climate neutrality to be achieved. This position was reversed late last year though, with EU leaders agreeing to end support for investments linked to any form of fossil fuel[15].

Small swings in fuel prices can have detrimental impacts for profitability

Natural gas fuel costs are inevitably often the largest single cost item for gas-fired power stations. Gas prices are subject to international commodity market movements however which can result in significant variations for cost from year to year.

Such price moves can be the difference between existing gas-fired power generation capacity being profitable to operate or not and volatile fuel prices should make the continued investment case for such assets even less attractive when compared with renewables which require near-zero marginal costs for operation.

Gas price volatility shows little sign of easing globally, with the increased influence of liquefied natural gas creating additional market dynamics, while depleted gas storage facilities across Europe have driven values up to record levels in 2021.

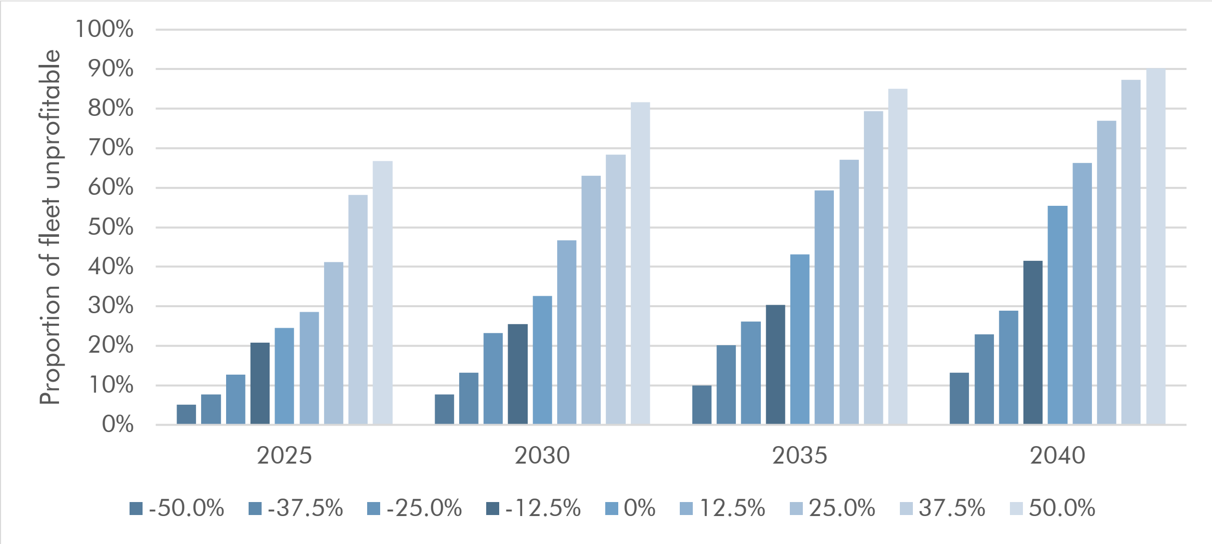
Even before this year however, the average year-on-year change in the spot price at the UK's NBP gas hub has been more than 30%, while at the Dutch TTF annual spot price changes have averaged around 37%[16]. Although these have not all been upward moves, these price swings show the levels of volatility that gas plants are exposed to for their fuel costs.

Our sensitivity analysis on average fuel price paid by European gas-fired plants shows that just a 25% increase from our base case figures for 2021 — based on an average of values recorded over the 2018-19 period — would leave 40% of the continent's gas fleet unprofitable to run from today, even when capacity market payments are received. A 50% rise in average fuel cost meanwhile would leave 74% of gas plants in the red from this year.

[15] EU agrees its green transition fund will not support natural gas – (Euractiv.com)

[16] *Prices sourced from Bloomberg.*

Figure 18 Impact of percentage changes in fuel prices from base case numbers on proportion of European gas fleet unprofitable



Source: Carbon Tracker analysis

Total gross operating profits from the European gas-fired plants included in our model are estimated to reach around \$6.7 bn in 2025 under the base scenario. A 25% increase in average fuel cost is enough to swing the economics to an overall operating loss of around \$370 mn that year however and would leave units running at an average level of -\$5/MWh.

Similarly in the US, a 25% increase in fuel cost from our base case numbers swings the proportion of the country's operating gas fleet that is unprofitable to run to around half by 2025.

Even if natural gas prices turn out at favourable levels for gas plant owners, volatility, and the possibility of swift changes in market direction continues to leave investment in existing gas a risky strategy.

The security of supply of natural gas is also of particular concern for owners of European gas-fired facilities. The EU imports the majority of the gas it uses, bringing the risk that supply could be cut or reduced at any point in time — a disadvantage that gas plants do not share with low cost and low risk renewables which do not face any such security issues.

Unproven technology gambles should not keep gas online

Investors should not pin hopes on being able to continue operating existing gas-fired capacity by retrofitting units with costly carbon capture and storage (CCS) technology or other unproven emissions reduction technologies.

Pilot schemes for CCS development have repeatedly failed to stimulate large-scale deployment and the number of power stations globally to currently have the technology installed remains extremely limited.

We believe that the use of CCS should be predominantly targeted towards the industries that are hardest to abate and that sectors such as energy where there are cheaper and more widely available solutions in place should focus on building strategies around these.

Investors risk greater financial losses by delaying the closure of unprofitable units and relying too heavily on hopes that unproven technologies will at some stage provide the basis for long-term commercial viability. There are no guarantees that emissions reduction technologies will develop at the rate required for them to have a meaningful part to play in the EU meeting its long-term climate goals and plans for winding down operations of gas-fired power facilities should not be contingent upon their availability.

5 Gas plant operating margins could narrow to criticially low levels if capacity payment mechanisms are restructured as required

Capacity markets have been rolled out across the regions covered in this report over the past decade, with governments aiming to ensure system reliability by offering owners of flexible units, or flexible energy technology initiatives, out-of-market payments to ensure the adequacy of the electricity system.

Such mechanisms have been in place in the US in various forms since the early part of the 2010s and remain in the grid areas operated by New England and New York states, as well as the PJM grid region which encompasses the wholesale electricity markets of 13 states and the District of Columbia[17].

The launch of the UK's capacity market in 2014, when the first auction of capacity payment contracts — set for delivery from 2018 — was held, has since been followed by the adoption of similarly modelled European schemes in Italy, France, Ireland, Belgium and Poland.

The payments provided by capacity market contracts can be the difference between a unit generating an operating profit or not, but we believe that a heavy reliance by investors upon these out-of-market revenues would be misguided.

Structure of capacity mechanisms already coming under review

Both the structure and continued requirement of capacity market mechanisms have come under review in recent years, bringing the risk that existing gas plant capacity begins to increasingly miss out on available contracts.

Belgium, for example, has identified an auction period of just 10 years for its own capacity market mechanism and currently plans to end the issuance of contracts under the scheme in 2034[18], although payments will continue beyond this year until contracts expire. The UK government, meanwhile, included an assessment of whether its capacity market is still needed, despite this not being required by wider legislation, in its 2019 five-year review of the mechanism[19]. Although this concluded in its continuation, the programme is likely to come under greater scrutiny during the next review scheduled for 2024 given that the UK has since set its legally-binding net zero emissions target for 2050 and interim goals for 2030 and 2040.

The UK has already restructured its scheme to allow renewable plant owners to compete for a share of funding available, in addition to the introduction of emissions limits on eligibility criteria, while competition for agreements is expected to further increase as costs for other forms of flexible generation capacity beyond gas continue to decrease.

Italy's scheme, which held its first capacity contract auction five years after the UK's in 2019 for launch in 2022, also permitted renewables to compete from the beginning. Contract awards to wind, solar and hydro plants have so far been limited, but are expected to steadily grow, as are the number of agreements issued to battery and pumped storage hydro facilities.

17 Capacity Markets: The Way of the Future or the Way of the Past – Energy Systems Integration Group
18 Cost Assessment of the Capacity Remuneration Mechanism – Belgian Ministry of Economy (page 4)
19 Capacity Market Five-year Review (2014-19) – UK Department for Business, Energy & Industrial Strategy

With funding the continued operation of unabated fossil fuel-fired assets appearing a stumbling block to Europe's long-term climate ambitions, it is likely that member state governments running capacity market mechanisms will come under pressure to review their schemes over the coming years. There is a prevalent risk to investors that payments received will not be around forever, or will be steadily reduced.

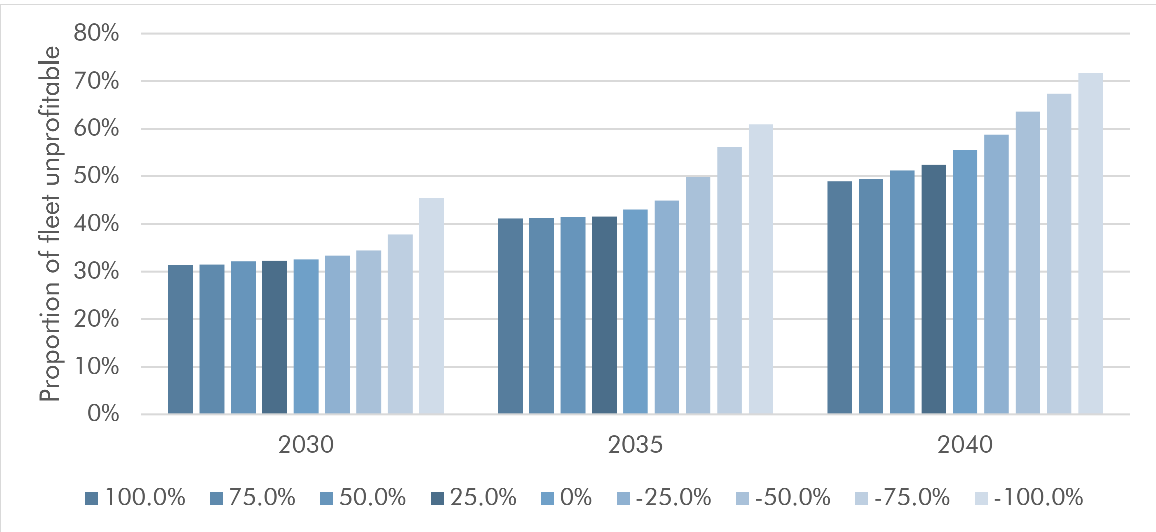
Capacity market mechanisms are currently disproportionately awarding gas-fired plants with contracts instead of encouraging the development of innovative low-carbon alternatives to provide system stability. While a limited amount of unabated gas plant capacity is likely to continue to receive payments for the long-term, policy makers should aim to keep this to a minimum to ensure that such schemes are aligned with climate goals.

Gas plant operating profitability falls sharply when capacity payments are lowered

We have run sensitivity analysis depicting the impact on the profitability of Europe's operating gas plant fleet of percentage changes in the level of payment received by those units that currently hold agreements for future years under their respective countries' capacity market schemes.

The results show that half of Europe's existing gas-fired plant capacity would be unprofitable to operate by 2035 if capacity market payments are halved from current levels that have been awarded, while more than 60% would be in the red by that year if such funding was not available to unabated gas units.

Figure 19 Impact of percentage changes in capacity market payment level on proportion of European gas plant fleet unprofitable

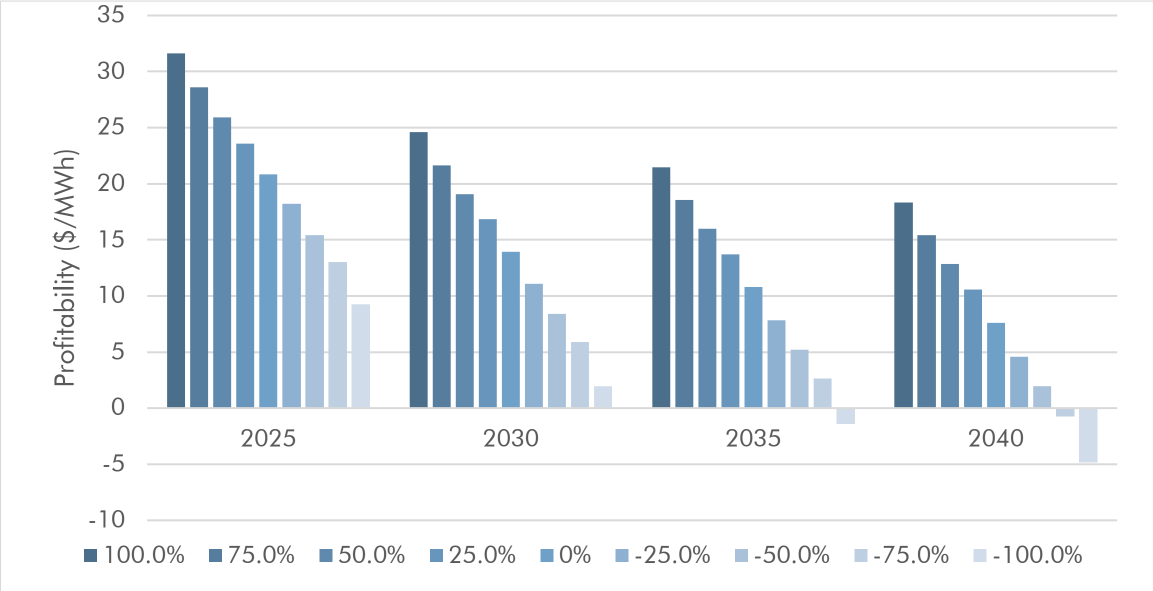


Source: Carbon Tracker analysis

The impact of lowering capacity market payments is more stark at country-level however and when analysing the decline in average operating profitability of individual units.

In Italy, we project the average gross operating profitability per unit of generation of the country's gas-fired power stations would sit below $10/MWh by 2030 if capacity payment levels were halved from current levels. Without the country's capacity market in place at all, average operating profits would fall below $0/MWh by 2035.

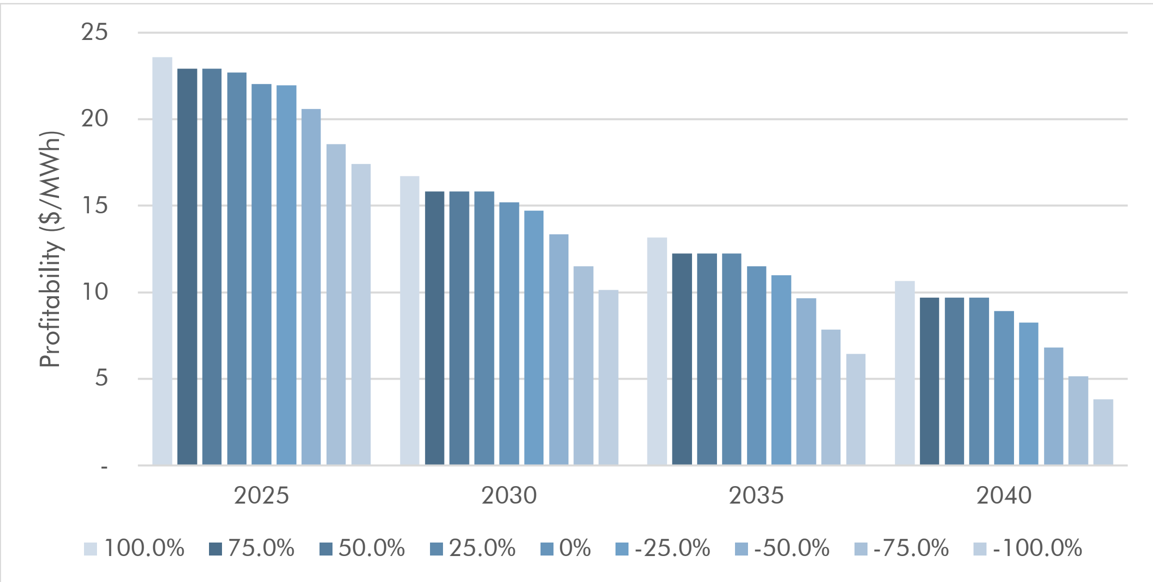
Figure 20 Impact of percentage changes in capacity market payment level on average operating profit of Italian gas plants



Source: Carbon Tracker analysis

In the UK, a 50% reduction in capacity payment levels from current levels would leave units operating at an average level of below $10/MWh by 2035 and at only around $6.50/MWh if payments are not distributed at all by that year.

Figure 21 Impact of percentage changes in capacity market payment level on average operating profit of UK gas plants



Source: Carbon Tracker analysis

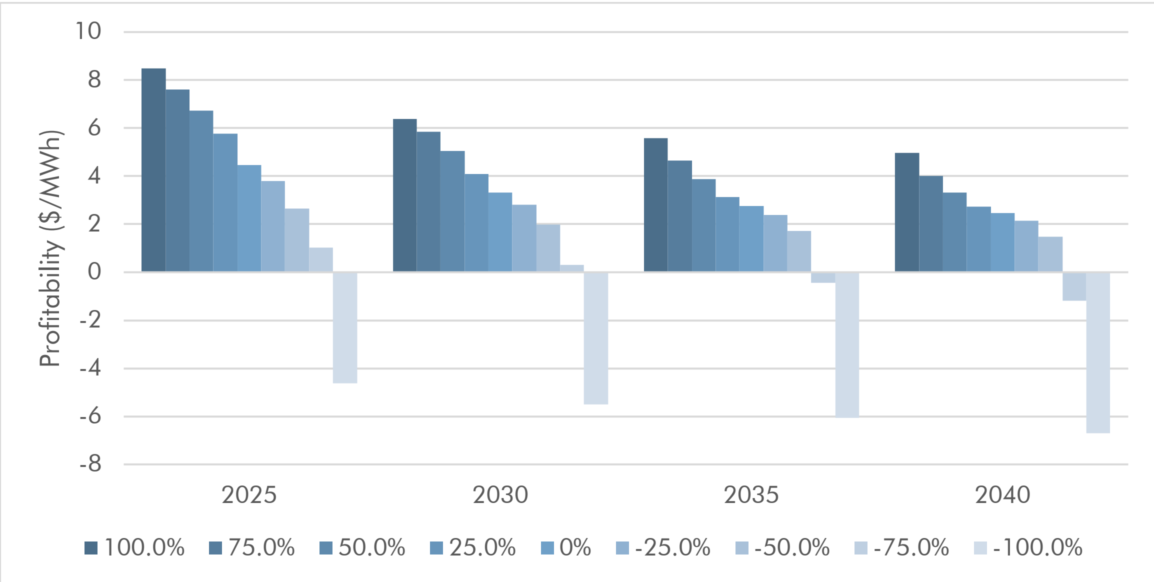
We project that the average operating profitability of gas units in France, Ireland and Poland also falls significantly when capacity payment levels are reduced. A 50% reduction in capacity payments issued to French generators by 2030 would leave the average operating profit per unit of generation there at only narrowly above $1/MWh, compared with $7/MWh if payments remain in place at current levels.

For Poland's operating gas plants, a 50% reduction in capacity payments would leave average operating profitability per unit of generation at only around $2.50/MWh by 2030 and below $0/MWh by 2035.

While in Ireland the same reduction would leave average operating profitability below $10/MWh by 2030 and then below $5/MWh by 2035.

For the US, average operating profitability per unit of generation will be left at only around $3/MWh by 2030 if capacity payments halve from current levels, although even if capacity payment levels doubled we project that the country's gas fleet would still be left running at an average operating profit of less than $10/MWh.

Figure 22 Impact of percentage changes in capacity market payment level on average operating profit of US gas plants



Source: Carbon Tracker analysis

6 Operating costs for existing gas are already above those for new renewables

We have calculated the projected LCOE of new onshore wind and solar facilities across the geographies covered in this report and used these to analyse cost competitiveness by comparing to the LRMC of continuing to run existing gas-fired units.

Our results show that the entirety of the European gas plant capacity included in our model is already more expensive to operate than either new onshore wind or solar in each country we have assessed meaning investors already have a cheaper and lower risk low carbon alternative to continued gas investment available to them.

We have also added estimated costs for the installation and operation of a four-hour lithium-ion battery with onshore wind and solar capacity onto our LCOE figures later in this chapter, with our model results showing that these will also fall below operating costs for existing gas capacity by the end of the current decade.

Renewables costs in Europe and the US have fallen sharply in recent years as the rapid deployment of onshore wind and solar capacity has served to pull down operating finances through economies of scale. This decline is expected to continue and contrasts with the rise of LRMC for gas amid steeper carbon costs and falling capacity factors.

The LCOE of new solar in Italy is already projected to be less than half the LRMC of existing gas this year, while costs for new onshore wind projects are expected to turn out more than 25% lower than the costs of operating gas, according to the results of our models.

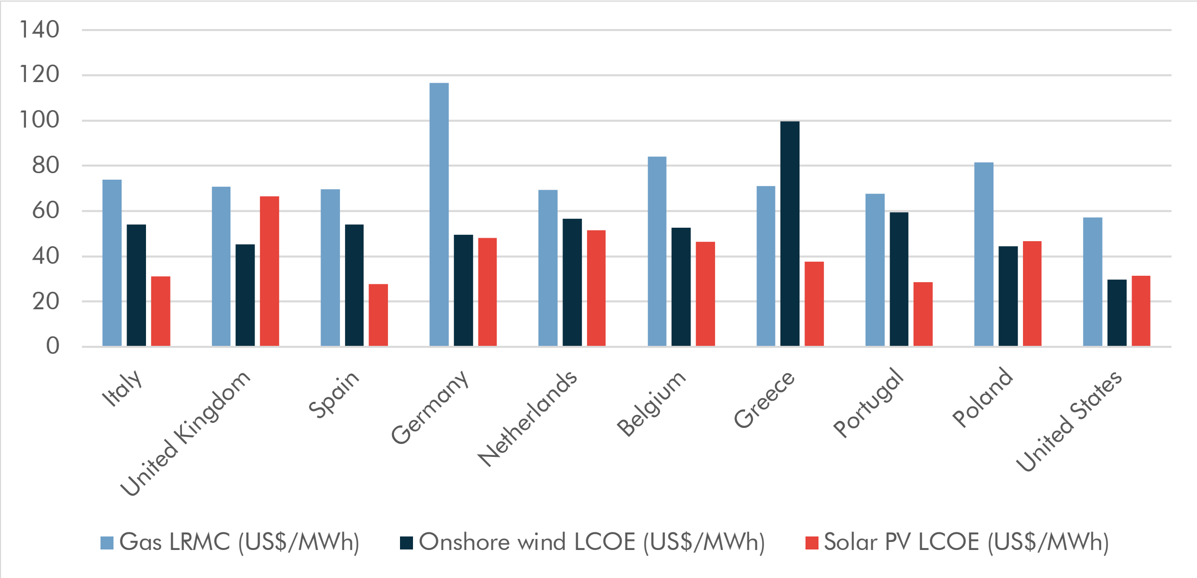
The costs of new solar in the UK are significantly higher than those in Italy, but still already come in below the LRMC of existing gas, while UK new onshore wind build is estimated to have an LCOE more than a third lower than gas this year. By the end of the decade, onshore wind running costs in the UK are projected to be at levels less than half those of existing gas, while solar costs will be around 37% below gas.

The trend continues across other European nations. We project that the LCOE of new solar in Spain will turn out nearly 60% below the LRMC for existing gas this year, while by 2030 solar costs could be more than 75% lower than gas. The LCOE for new onshore wind in Spain meanwhile is already around 22% below the LRMC of existing gas, and is projected to fall to a level more than 40% below by 2030.

In the Netherlands, operating costs for new renewables are also already lower than those for existing gas capacity, while solar costs are projected to fall to levels less than half those of gas by 2030, according to our models.

Both new onshore wind and solar investment options are already cheaper than the costs associated with the continued operation of existing gas plants in the US, and we project the costs for both renewable technologies will fall to levels less than half the LRMC for gas by 2030.

Figure 23 LRMC of operating gas versus LCOE of new renewables today

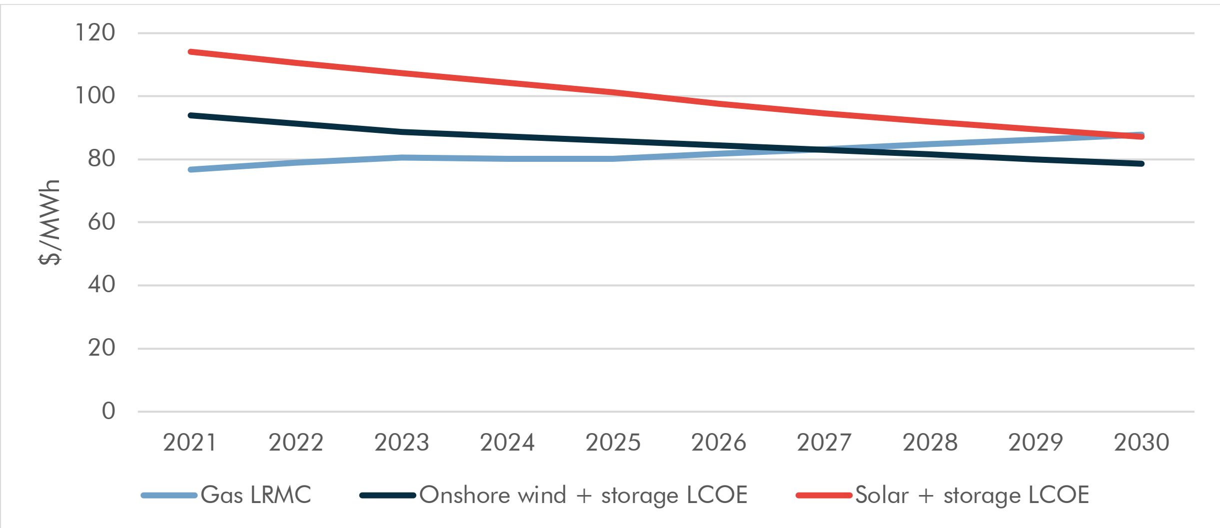


Source: Carbon Tracker analysis

Although adding in the costs of installing and running battery storage capacity alongside new onshore wind and solar farms does take LCOEs at today's levels back above the LRMC for running existing gas in most of the countries included in our model, both technology and system development over the coming years are expected to see even these fall to levels below gas by the end of the decade.

This means that zero carbon emissions capacity, able to provide comparable grid services to peaking gas-fired power plants, will be available at a lower cost to the system by the early 2030s[20].

Figure 24 Median European LRMC of gas versus LCOE of new renewables with storage

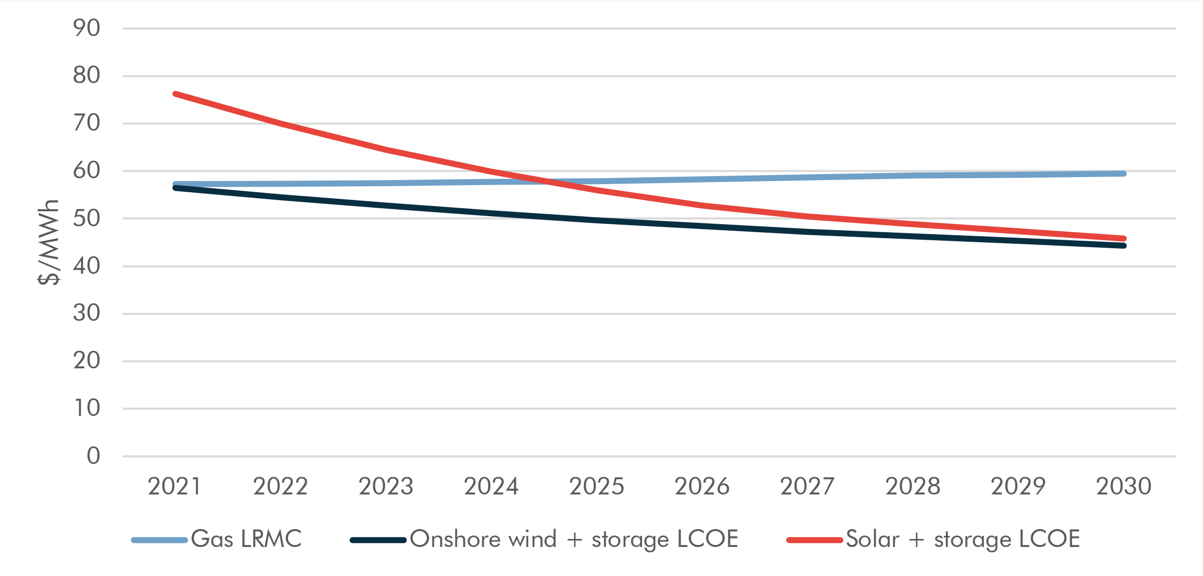


Source: Carbon Tracker analysis

[20] *Full details of how we have calculated our estimated four-hour lithium-ion battery storage costs estimates are included in our methodology document, a link to which is provided in the appendix.*

For the US, we project that the LCOE for new onshore wind with battery storage costs added on would still turn out narrowly below the LRMC for existing gas capacity from today, while costs for solar with battery storage installed are then projected to fall below gas by just 2025.

Figure 25 LRMC of US gas versus LCOE of new renewables with storage



Source: Carbon Tracker analysis

The rationale behind continuing to pile capital into prolonging the life of existing gas-fired units is highly questionable when the comparative economics to cheaper and lower risk renewables are laid out. Investors who continue to back gas ahead of renewables are not only exposing themselves to the risk of stranded assets but are also potentially missing out on higher rates of return from the renewables sector.

6.1 Country focus

In this section we analyse the status of existing gas plants in Europe's five largest gas-fired power generating nations – Italy, the UK, Spain, Germany and the Netherlands – as well as the US. We break down the economics of continued operation at national level and outline the implications for investors of earlier plant lifetime curtailments.

Italy

Italy has Europe's largest gas-fired power generating capacity, with just under 42 GW of included in our model. Around 40.2 GW of this comes from the country's CCGT units, while an additional 1.5 GW is installed at small-scale OCGT facilities designed to react flexibly to swings in power demand or supply. Gas-fired power plants currently account for roughly half of Italy's electricity supplies[21].

The country also has an abundance of renewable energy capacity installed, with its 59.2 GW[22] trailing only Germany and Spain within Europe, while Italy has the sixth largest solar energy portfolio globally[23].

[21] IEA data
[22] *Includes wind, solar, hydro bioenergy, geothermal, marine and pumped storage units.*
[23] International Renewable Energy Agency data.

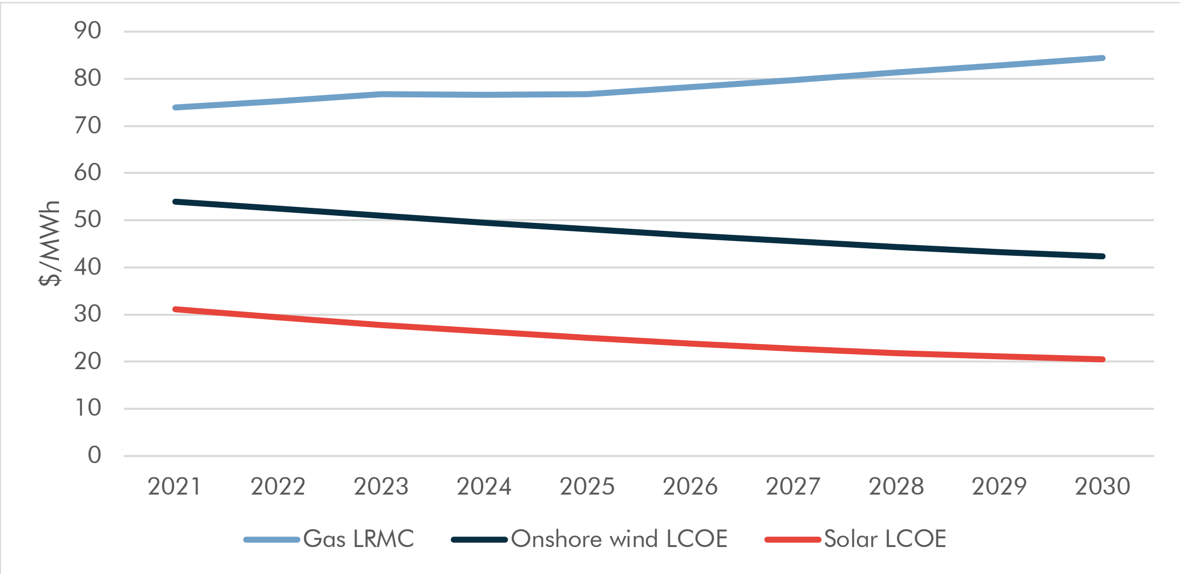
Italy's Minister for Ecological Transition, Roberto Cingolani, said earlier this year that an additional 65-70 GW of renewable capacity will be required this decade to ensure that renewables provide at least 70% of electricity by 2030, as part of the country's efforts towards the EU's updated goal for that year of achieving an overall 55% reduction in emissions from 1990 levels[24].

The government has supported the development of renewables through a subsidy programme in recent years, but even without these payments, the economics in support of investment in new renewables over existing gas-fired units are overwhelming.

As highlighted above, the LCOE of new solar in Italy is already less than half the LRMC of existing gas, and is projected to account for less than 25% by 2030.

The LCOE of new onshore wind capacity meanwhile is projected to be around 27% below the LRMC of existing gas this year, and is expected to fall to levels around half by the end of the decade.

Figure 26 Italian LRMC of gas versus LCOE of new renewables



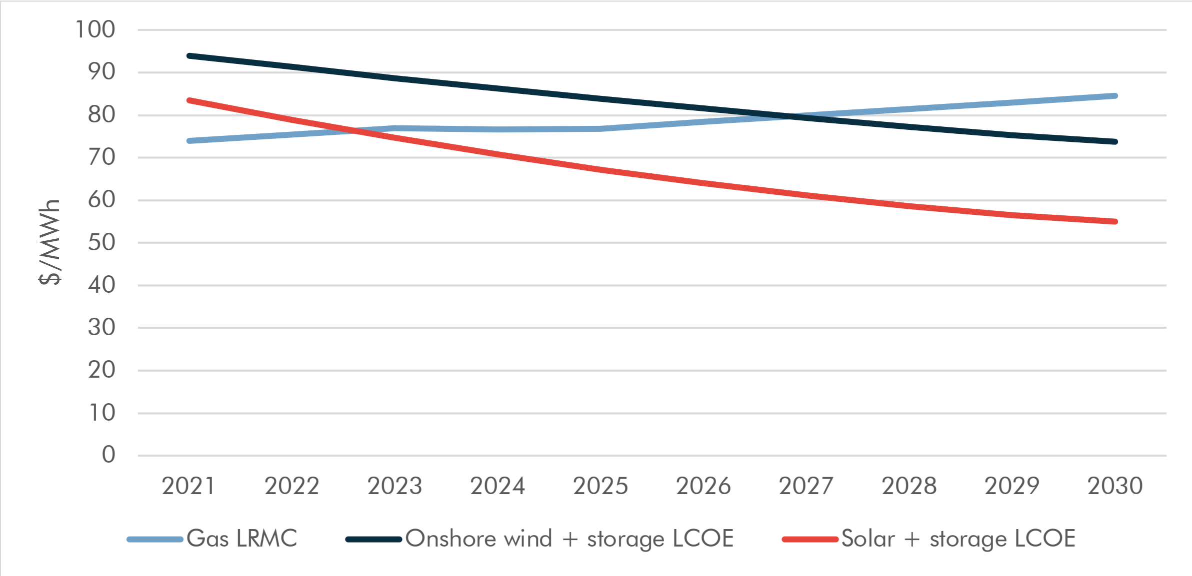
Source: Carbon Tracker analysis

Even when storage costs are added to our LCOE projections for new onshore wind and solar capacity in Italy, the point at which operating costs for renewables fall below existing gas is only delayed by three years, with the LCOE for new solar with battery storage installed estimated to fall below gas by 2023, according to our models.

As shown in figure 27 below, we then project that the LCOE for new onshore wind capacity installed with battery storage capability will fall below the LRMC for Italy's operating gas plant fleet in 2027.

[24] Italy to produce 70-72% of power from renewables in 2030 to reach EU targets – Reuters

Figure 27 LRMC of Italian gas versus LCOE of new renewables with storage



Source: Carbon Tracker analysis

Italy's capacity market scheme, which will begin to distribute payments to contracted plant owners from next year, is projected to drive average operating profitability per unit of generation for gas units up to an average of above $20/MWh by 2025 according to our model, but the effect of steeper carbon costs and reduced capacity factors is then projected to pull this average back down below $15/MWh by the end of the decade.

If the country's capacity market scheme was not in place, average operating profitability of gas plants in Italy would fall below zero by 2035. Even when capacity market payments are included however, Italian gas plants remain vulnerable to turning loss-making in the event of any greater-than-expected increases in carbon or fuel costs. Our models show that just a 25% rise in the average fuel cost from our base case number would pull the average operating profitability per unit of generation down to only around $2.50/MWh by 2030 and below zero by 2035, while average operating profitability also falls below zero if carbon costs reach levels 50% above our base case number by 2035.

We would urge the Italian government to review the structure of its capacity market mechanism with a view to reducing over time the amount of fossil fuel fired capacity that is supported under the scheme. Outlining plans for either restructuring or setting an end date for capacity payments for unabated gas around the same time the country confirms its planned national climate neutrality target for 2050 would make this goal appear more achievable.

The risk of forced closures earlier than planned at project inception under B2DS leaves investors in Italian gas-fired assets with positive stranding risk of around $3.5 bn, which is estimated to rise to around $5 bn under our net zero projections. We strongly advise that such parties urgently plan strategies for winding down the operation of assets when required in a way that maximises shareholder returns.

UK

We have included around 33.2 GW of UK gas-fired generation capacity in our model, with 31.4 GW of this CCGT capacity and 1.7 GW sourced from OCGT facilities.

CCGTs have been the UK's largest single source of power generation since 2015, after the introduction of a government-enforced carbon price support mechanism drove significant reductions in coal-fired plant output and left gas more profitable to operate as the primary source of base load power.

The UK also has extensive renewable capacity built however, as well as significant potential for further growth, particularly in the offshore wind sector. The country ended 2020 with around 49.2 GW of renewable capacity, with the largest share of this coming from solar farms which make up 27% of the total. Onshore wind facilities follow closely behind, making up just over 26%[25].

The UK was one of the first globally to write a target for reaching net zero emissions by 2050 into national law, but the government has so far been vague over the amount of renewable power capacity that will be required to deliver this. Industry groups however have indicated that the country's onshore wind capacity may need to more-than-double from current levels and reach at least 30 GW by the end of the decade to align the power sector with a net zero trajectory[26].

The government's contracts for difference renewable subsidy scheme has driven the rapid deployment of new capacity since its launch in 2014, providing investors with certainty over returns for the length of their agreed contract. Onshore wind farm developers have not been able to apply for funding through this scheme for the past five years, but the technology has been readmitted into the eligibility criteria for subsidies in the 2021 allocation round[27].

Investment in new renewables comfortably beats the continued funding of existing gas plant capacity regardless of these subsidy payments however.

The LCOE of new onshore wind capacity in the UK is projected to turn out around 36% below the LRMC of existing gas this year and will sit more than 50% lower by the end of the decade.

Solar costs in the UK meanwhile remain notably higher than onshore wind currently, but are still already low enough to beat gas, with the LCOE of new units estimated to be 6% lower than the LRMC of existing gas this year, and 37% lower by 2030.

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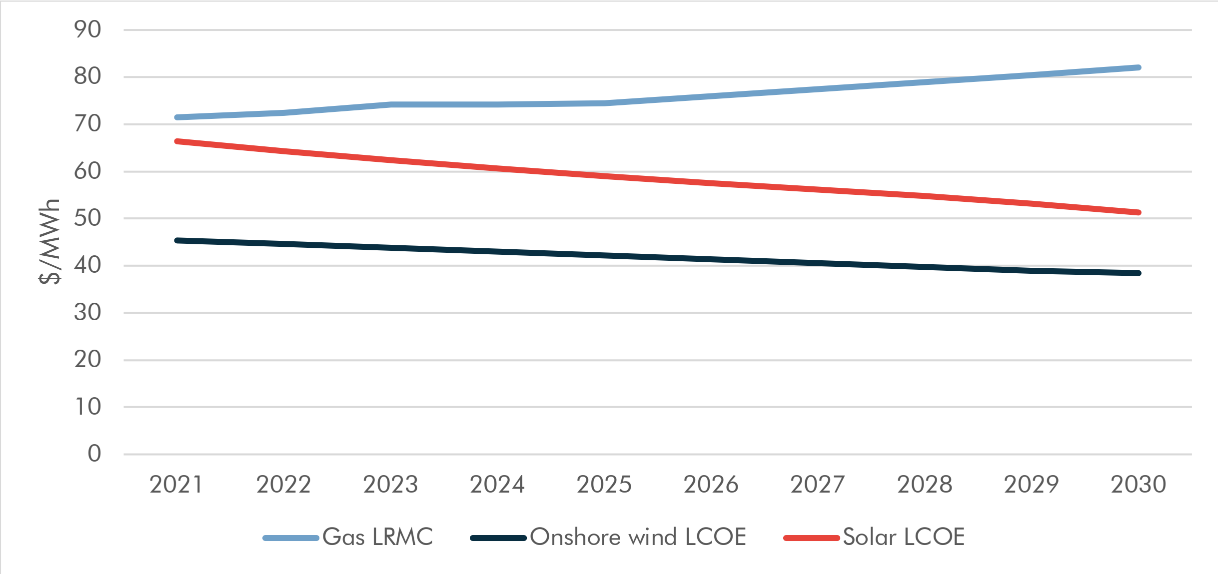
[25] ENTSO-E data.
[26] Report: UK must more than double onshore wind capacity by 2030 to meet climate targets – edie.net
[27] UK confirms onshore wind CfD return – ReNews.biz

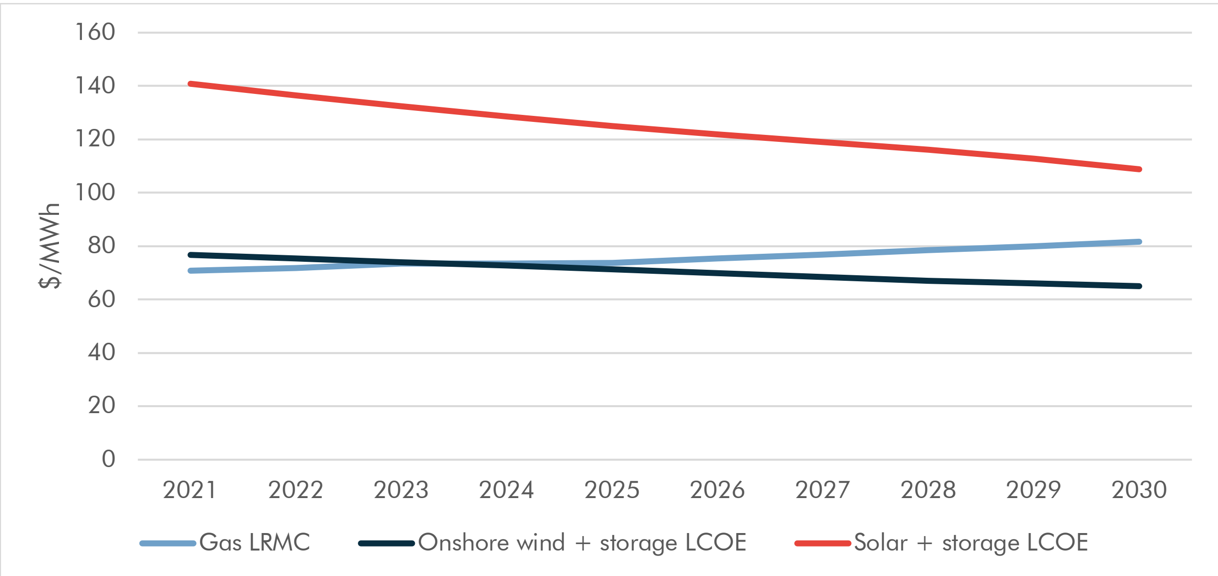
Figure 28 UK LRMC of gas versus LCOE of new renewables



Source: Carbon Tracker analysis

When battery storage costs are added to our LCOE estimates for new renewables in the UK, high operating costs for the country's solar farms do push the point at which new solar installed with storage capability falls below costs for existing gas to the mid-2030s. We project that the LCOE for new onshore wind capacity installed with battery storage in the UK will become cost competitive with the operation of existing gas plant capacity as early as 2024 however.

Figure 29 LRMC of UK gas versus LCOE of new renewables with storage



Source: Carbon Tracker analysis

We project that the average operating profitability of the UK's existing gas fleet will steadily decline over the next 15 years and could reach critically low levels during the 2030s in the event that the country's government opts to reduce or wind-up payments for unabated gas units under its national capacity market scheme, or operating costs for units increase. We project that the absence of capacity market payments would leave average operating profitability per unit of generation of UK gas at around $6.50/MWh by 2035, while a 25% increase in fuel costs from our base case number would pull average operating profitability down to only around $2/MWh that year, even when capacity market payments are still included.

We believe that the long-term use of unabated power sector gas in the UK is incompatible with the country's net zero 2050 target and that the government should provide a clear time scale for its intended phase out of all unabated fossil fuel use for power generation to deliver this goal. A small amount of gas-fired capacity may be required to remain available in emergency or stability reserve over the coming decades, but should not be relied upon for day-to-day primary bulk power supplies.

Forced closures earlier than planned by gas plant owners under B2DS, which we believe will be driven by a mix of economics and policy, leaves the UK with positive stranded asset risk of around $2.8 bn, rising to $3.5 bn under our net zero scenario projections. We urge investors in such assets to minimise losses by planning winding down strategies well in advance.

Spain

Spain has around 26.8 GW of operational gas-fired plant capacity included in our model, with the vast majority of this – 26.7 GW – installed at CCGT plants.

Gas plants have been Spain's largest source of power generation in most years since displacing coal in the mix in 2005. Output peaked in 2008, and steady growth in wind and solar capacity installation sharply reduced gas plant operational requirements over the following five years, although coal plant closures more recently have driven a slight recovery, with gas-fired power generation turning out at an eight-year high of 84.5 TWh in 2019[28].

Meanwhile, Spain has Europe's second-largest portfolio of renewable power generation capacity. The country has 62.4 GW installed, with the largest share of this – 27.1 GW coming from wind capacity – leaving Spain as the world's fifth highest wind power producing nation, behind only China, the US, Germany and India[29].

The country last year joined the UK in writing a target of reaching net zero emissions by 2050 into national law, while the government's 2021 clean energy bill identifies an aim for renewables to account for at least 74% of electricity production by the end of this decade[30].

The Spanish government has supported the rapid deployment of renewables with generous subsidies in recent years, further boosting the incentive for investment in this sector over allocating further capital to the country's existing gas-fired assets.

The case for choosing investment in new solar over gas is already clear however, with the LCOE for solar parks in Spain among the lowest in Europe. This is projected to turn out more than 50% below the LRMC for existing gas this year, while by 2030 solar costs could be more than 75% lower than gas.

The LCOE for new onshore wind in Spain meanwhile is already around 22% below the LRMC of existing gas, and is projected to fall to a level more than 40% below by 2030.

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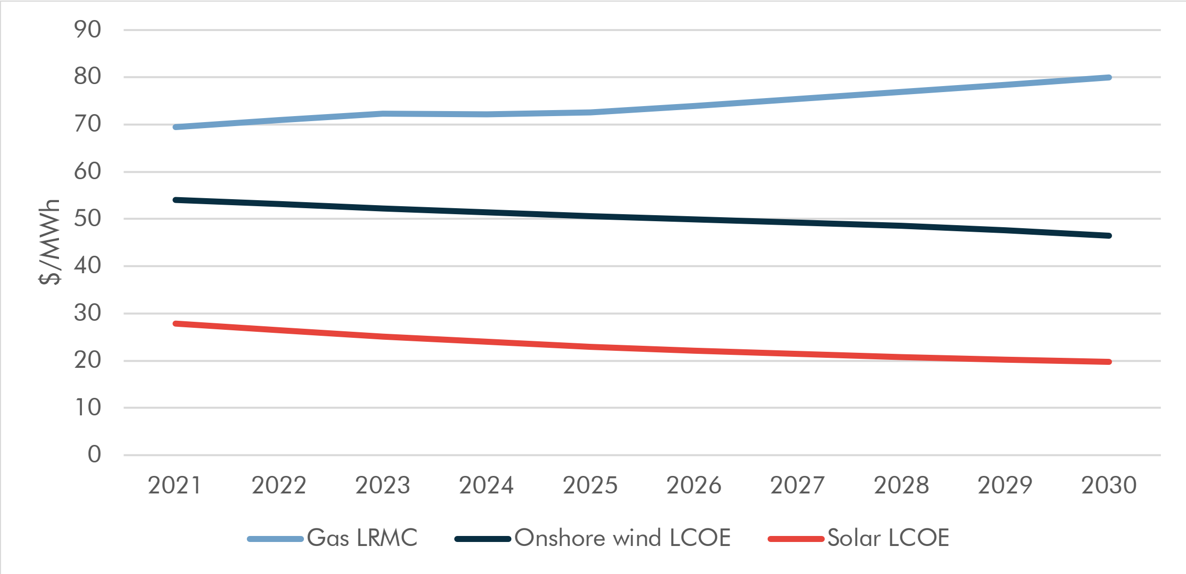
[28] IEA data
[29] International Renewable Energy Agency data
[30] Spain approves 'milestone' clean energy climate bill – AlJazeera.com

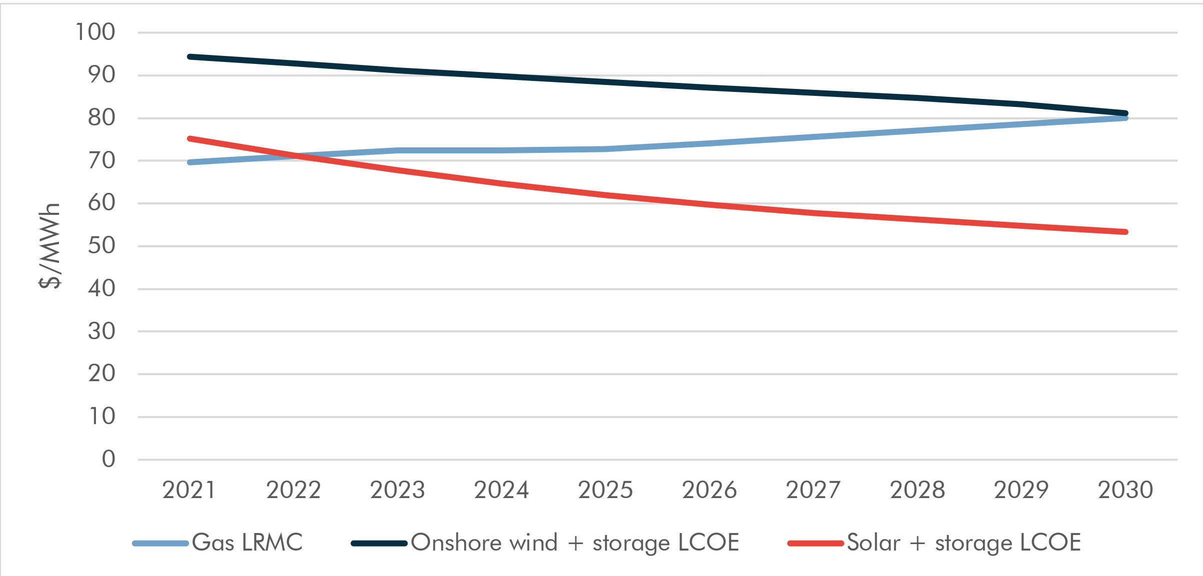
Figure 30 LRMC of Spanish gas versus LCOE of new renewables



Source: Carbon Tracker analysis

Even when battery storage costs are added to our LCOE projections for new solar capacity in Spain, the point at which these estimated operating costs fall below the projected LRMC for existing gas is pushed back to just 2023. The LCOE for new onshore wind capacity is left above the LRMC for gas throughout this decade when storage costs are added, but even these projects will become cost competitive with gas by the 2030s.

Figure 31 LRMC of Spanish gas versus LCOE of new renewables with storage



Source: Carbon Tracker analysis

Spain's entire gas plant fleet is expected to remain profitable to operate for the majority of this decade, but the impact of higher carbon prices and reduced usage during the 2030s drives a significant squeezing of margins and more than half of the country's capacity is projected to become unprofitable to operate by 2034. This rises to more than 75% by 2040.

Profitability even this decade is set to steadily fall, with units projected to be operating at levels not far from break-even by the late 2020s. The average operating profitability per unit of generation of Spanish gas-fired units is estimated at less than $5/MWh by 2028, making margins extremely vulnerable to turning negative in the event of upward swings in fuel or carbon costs. Average operating profits are projected to fall below zero by 2032 according to our base model.

With Spain's legally-binding net zero goal also likely requiring phase out of unabated fossil fuel use, we urge the Spanish government to provide a clear timeframe on this.

Germany

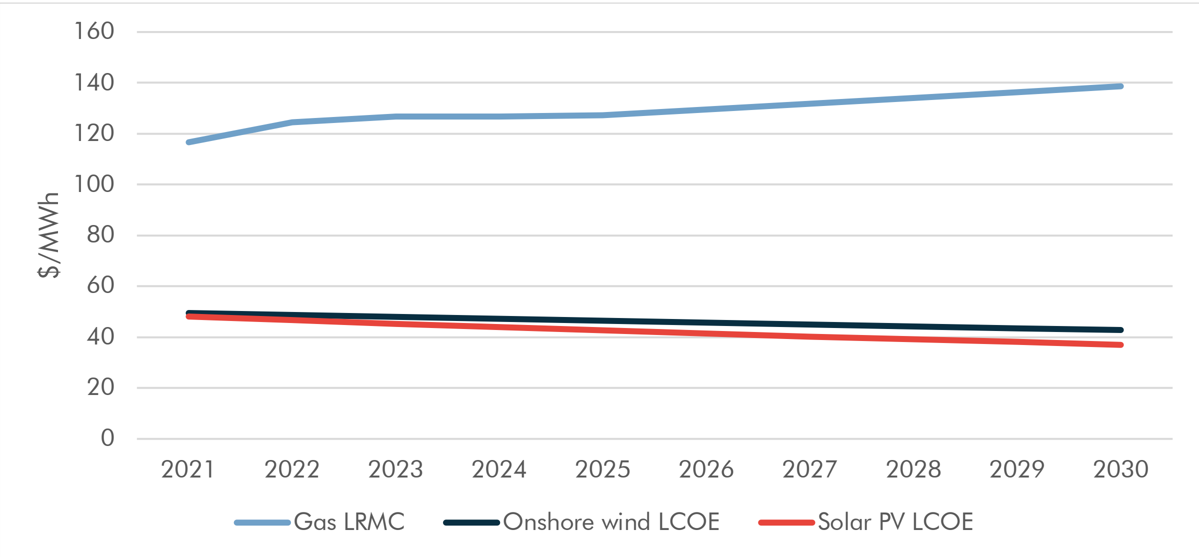
Germany has around 23.7 GW of operational gas-fired power generation capacity included in our model with the majority, some 17.5GW, installed at CCGT facilities.

Gas-fired power generation in Germany has historically trailed well behind output from the country's vast lignite and coal-fired fleet, but turned out higher than coal in both 2019 and 2020[31] as coal plant margins came under greater pressure from the rally in European carbon prices.

Meanwhile, Germany has comfortably Europe's largest renewable energy capacity portfolio, with approximately 137 GW installed. This also leaves the country as the world's fifth largest renewable energy generator, behind only China, the US, Brazil and India.

The case for investors to opt against the continued funding of existing gas in Germany could not be clearer. Operating costs for new wind and solar are already at levels less than half the estimated running costs for existing gas in Germany according to our models, and we forecast that this disparity will continue to increase over time.

Figure 32 LRMC of German gas versus LCOE of new renewables

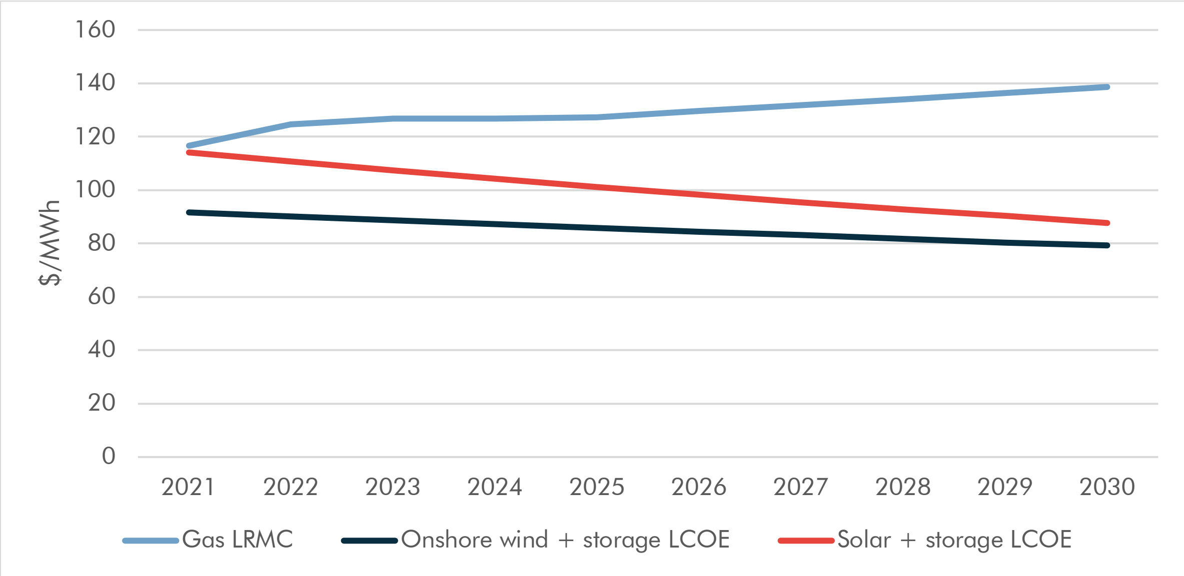


Source: Carbon Tracker analysis

Even when we have added battery storage costs to our projected LCOE figures for new onshore wind and solar farms in Germany, these still turn out lower than the projected LRMC of gas from today.

31 Fraunhofer Energy-Charts data

Figure 33 LRMC of German gas versus LCOE of new renewables with storage



High operating costs for gas-fired plants in Germany leaves just under 90% of the country's fleet already unprofitable to run today, with little sign of a recovery expected.

The country's fleet consequently comfortably generates an overall negative stranded asset risk figure, with the earlier closure of units under B2DS projected to save German gas plant operators around $2.7 bn in operating losses which would be incurred in later years if left to run for full planned lifetimes under BAU. The size of this potential saving rises to $3.6 bn under our net zero scenario projections meanwhile.

The German government took the step to move its target for reaching carbon neutrality forward by five years to 2045 earlier this year – a goal matched only by Sweden in the EU[32]. We would urge policy makers to identify the phaseout timeframe for unabated gas plants deemed to be required to deliver this new goal to allow plant owners to devise strategies for winding down their assets.

Netherlands

The Netherlands has around 13.9 GW of gas-fired power generation capacity included in our model, with 12.7 GW installed at CCGT units and 1.1GW in OCGT facilities. The remaining volume is located at older steam turbine plants.

Gas-fired power stations have been the country's largest source of electricity for more than 30 years. Output peaked in 2010 and subsequently declined to a near 20-year low in 2015 amid improved profit margins for Dutch coal-fired plant operators, but recovered to an eight-year high in 2019 as the country's phaseout of coal use began[33].

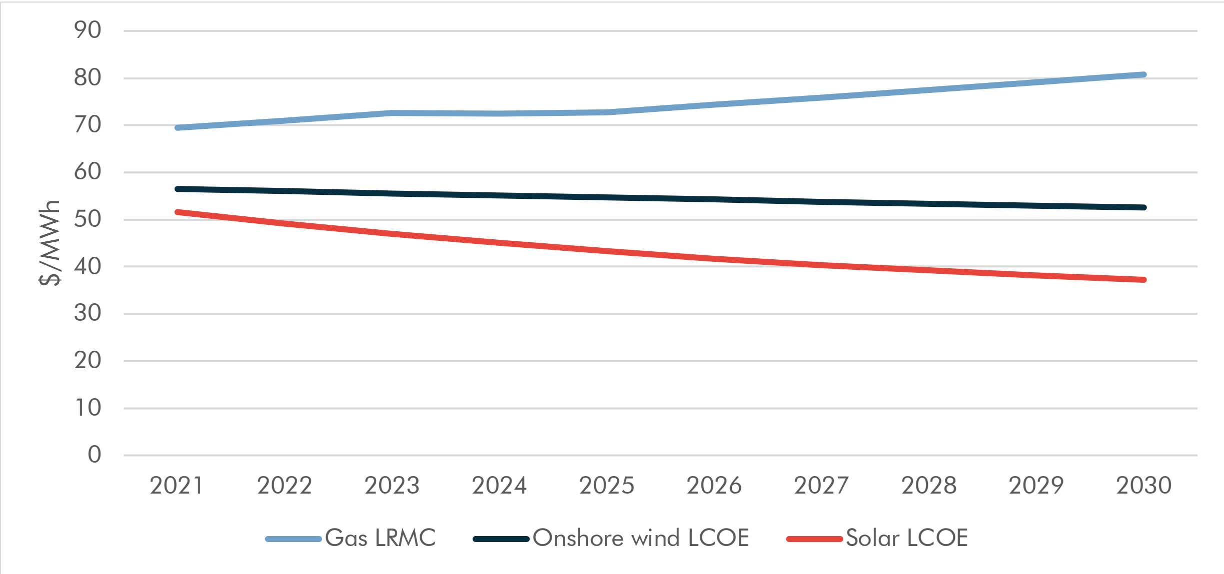
The country has steadily increased its renewable energy capacity in recent years, particularly in the offshore wind and solar sectors, where installed capacities reached 2.4 GW and 7.9 GW respectively in 2020 compared with only around 350 MW and 1.4 GW in 2016[34].

[32] Germany raises ambition to net zero by 2045 after landmark court ruling – Climatechangenews.com
[33] IEA data
[34] ENTSOE data

This should encourage investors to switch attention away from the continued funding of existing gas units and towards renewables, the operating costs for which will continue to fall with accelerated deployment.

The operating costs for new renewables in the Netherlands are already lower than those for existing gas capacity in the country, with solar costs projected to fall to levels less than half those of gas by 2030, according to our models.

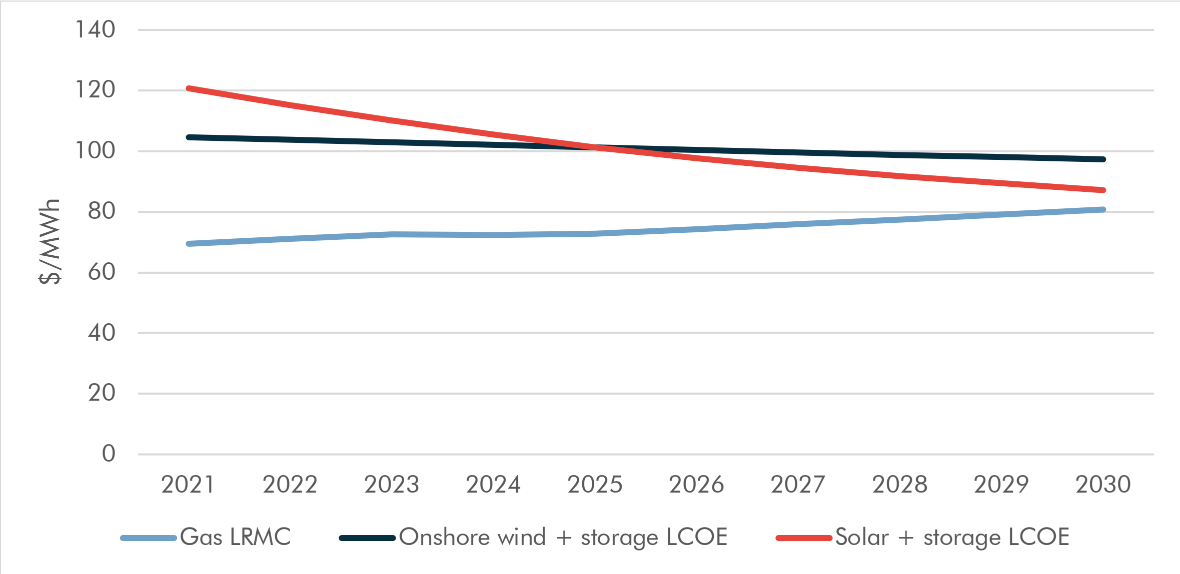
Figure 34 LRMC of Dutch gas versus LCOE of new renewables



Source: Carbon Tracker analysis

When storage costs are added to our projections for the LCOE of new onshore wind and solar in the Netherlands, both technologies are left at cost levels above the LRMC for running existing gas throughout the remainder of the 2020s. The LCOE for new solar with storage costs included is projected to rapidly decrease over the course of the decade however and is expected to become cost competitive with existing gas plant capacity by the early 2030s.

Figure 35 LRMC of Dutch gas versus LCOE of new renewables with storage



Source: Carbon Tracker analysis

Average operating profits per unit of generation for Dutch gas-fired plant operators are projected under our model to fall sharply over the course of this decade and to fall below zero by 2028. By 2031, we project that steeper carbon prices and reduced capacity factors will have pulled the average operating profit per unit of generation in the Netherlands down to below -$5/MWh.

US

We have included 513.5 GW of installed gas-fired power generation capacity in the US in our model. Some 308.5 GW of this comes from CCGT facilities and a further 131.5 GW from OCGTs. The remaining 73.5 GW is then sourced from smaller steam turbine units.

Gas-fired power stations have been the largest source of electricity in the US since 2016, with production levels having risen sharply over the 2010s. US gas plants produced a record of 1,629 TWh in 2020, compared with output of just 1,018 TWh in 2010[35].

The US has also significantly increased its renewable power generation in recent years however, having added just under 100 GW of new capacity over the 2015-20 period to leave the country's total of around 311 GW behind only China in the world[36].

US President Joe Biden has this year identified a plan to set the country on a path towards an economy-wide net zero emissions position by 2050. As part of this, his administration has pledged to aim for a carbon neutral power sector by 2035 and has indicated intent to use a clean energy standard scheme to deliver the renewable energy deployment required to source at least 80% of the country's electricity from emissions-free sources by 2030[37].

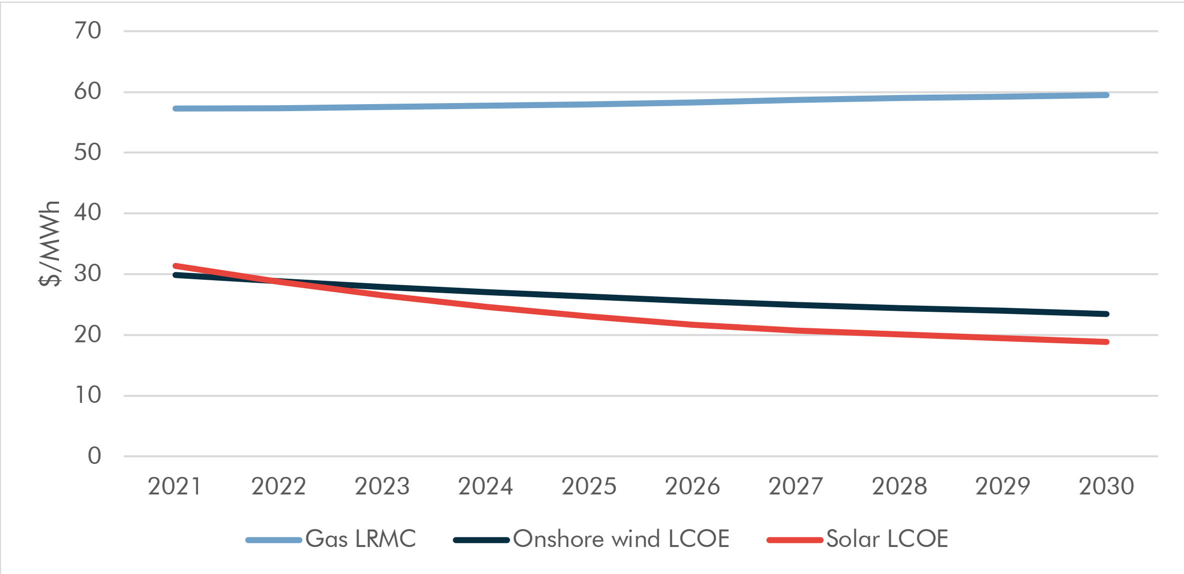
[35] IEA data
[36] IRENA data
[37] White House will seek law to require carbon-free power from US utilities – Reuters.com

Biden has suggested that he could incentivise accelerated renewable energy capacity deployment by extending tax credits for clean energy production and by creating incentives for the construction of the transmission system infrastructure required to facilitate increased capacity[38].

Even without additional incentives, the case for investing in new renewable capacity over continuing to run existing gas-fired power capacity in the US is clear. The LCOE for new onshore wind capacity in the country has already fallen to levels close to half the estimated LRMC for existing gas, while running costs for new solar sit at levels around 45% below those for existing gas.

By 2030, the LCOE for new solar farms is projected to have fallen to levels close to 70% below the LRMC for existing gas according to our models, while although the rate of decrease in onshore wind costs is estimated to be slower than for solar, we forecast that the LCOE for this technology will have fallen to a level more than 60% below the LRMC for existing gas.

Figure 36 US LRMC of gas versus LCOE of new renewables

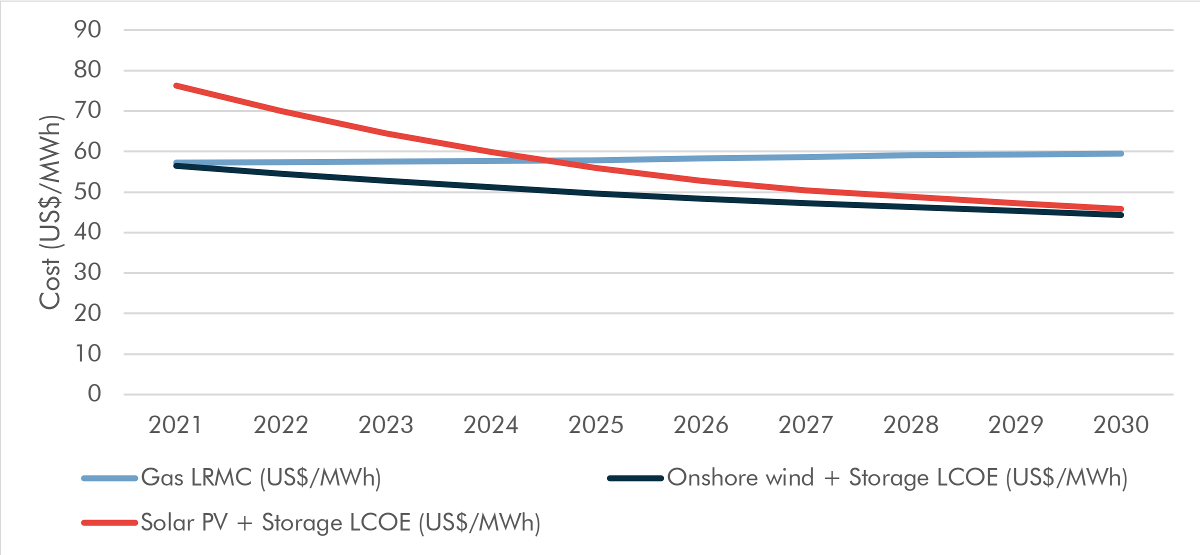


Source: Carbon Tracker analysis

As in the summary above, we also project that the LCOE for new onshore wind with battery storage costs added on would still turn out narrowly below the LRMC for existing gas capacity in the US from today, while costs for solar with battery storage installed are then projected to fall below gas by just 2025.

[38] Biden tax plan replaces US fossil fuel subsidies with clean energy incentives – Reuters.com

Figure 37 LRMC of US gas versus LCOE of new renewables with storage



Source: Carbon Tracker analysis

7 Close to $16 bn could be stranded if gas plant closures are brought forward for net zero alignment

We calculate stranding for existing units as the difference in the net present value of operating cashflows[39] between BAU and climate constrained alternative scenarios, the IEA's B2DS and our own net zero scenario estimates. Our calculation for operating units assumes there is no debt or asset balance outstanding, which may not be the case and could imply potential writedowns or early closure. This means that our estimations should be considered as the lower limits for stranded risk and that these may be higher in reality.

A positive stranded asset risk value means, based on existing market structures, investors and governments could lose money under climate constrained scenarios, compared with BAU, as the closure of profitable gas plant capacity is brought forward. A negative stranded asset risk figure meanwhile means that investors could avoid losses through earlier closure as the number of hours that a unit operates while being loss-making will be reduced. Further detail on our stranded asset risk calculations is provided in the report methodology document.

We model that under B2DS operating gas-fired assets located in Europe would strand some $7.5 bn compared with a BAU scenario, while a further $2.2 bn is at risk in the US. These figures however jump to $10.1 bn and $5.8 bn respectively under our net zero alignment projections.

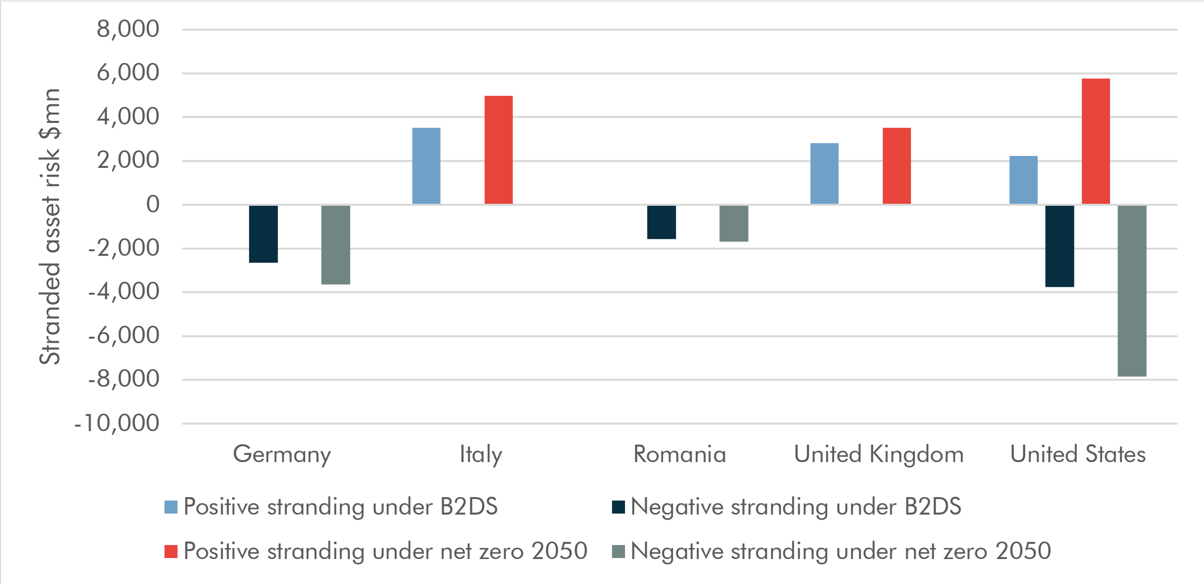
Italian plants account for virtually half of this stranded asset risk, with some $5 bn at risk of stranding under our net zero projections, while $3.5 bn locked in UK gas plants is also at risk of stranding.

On the other hand however, we also find that $6.5 bn of operating losses that will be incurred by unprofitable gas plants in Europe under a BAU scenario will be avoided in the event of early closure under B2DS, in addition to some $3.7 bn in the US. These savings then rise to $8 bn and $7.9 bn respectively under a net zero phase out time frame.

Around 45%, or $3.6 bn of these savings projected for Europe under net zero will be achieved in Germany, where close to 90% of the country's 23.7 GW of capacity is already unprofitable to operate today, while Romanian plant operators would prevent around $1.7 bn of potential losses by closing facilities under the timeframe required to deliver net zero.

[39] *We define profitability as revenues (in-market and out-of-market revenues) less long run marginal costs. We do not assume revenue or cost hedging in our modelling. Our methodology is covered in detail in the gas methodology document available in the appendix.*

Figure 38 Nations exposed to more than $1 bn positive or negative asset stranding from gas plant investment



Source: Carbon Tracker analysis

8 Majority of new gas plant projects are economically unviable

Despite the limited time left available to align global power sector emissions with the declining trajectory required to keep temperature limits within those specified under Paris, relative extensive pipelines of planned new build gas plant capacity remain.

Investors and policy makers are seemingly ignoring the clear commercial and climate arguments against funding new unabated gas plant projects, the majority of which are unlikely to recover their initial costs.

We have extended the project finance model built for our "*Do Not Revive Coal*" report to under-construction and planned gas plants in the European countries with the largest non-CHP project pipelines — the UK, Italy, Greece, Belgium, Romania and Poland, as well as the US. The model assesses the viability of a gas plant over its lifetime by calculating each project's net present value (NPV).

The NPV is the sum of future cash flows, taking into account investment costs, operating profits, financial costs, depreciation and taxes of a project, discounted to the weighted average cost of capital (WACC). A negative NPV should be taken as a firm signal for investors to cancel a project.

Under a BAU scenario, we assume that each new gas plant will run for 30 years. We calculate the NPV for each project under BAU, B2DS and net zero scenarios, the latter two of which would bring an earlier curtailment of the plant's lifetime.

PROJECT FINANCE MODEL

Data for under construction and planned projects was obtained from Global Energy Monitor.

We estimate overnight investment costs and forecast operating profits, debt financing obligations, and tax expenses to determine a project's viability.

Investment costs are dependent on the power plant technology (CCGT or OCGT) and are based on in-house estimates.

For CCGTs in the US, Italy, Greece and Romania we base our estimates on the reported costs of some of the projects under development. We collected investment data at plant level from a multitude of sources such as company statements, annual reports and third-party analysis. For the UK, we use official government sources while for Belgium and Poland we use averages of the other countries in the model. For CCGTs, we select a cut-off for plants smaller than 300 MW to avoid over estimating costs for small plants.

For OCGTs in Europe we use estimates provided by the UK government, while for the US we use in-house estimates based on an inventory of costs of projects under development. We have only included the US gas plant projects which are planned for development in unregulated grid areas in this part of our model.

For our cost estimates we consider the effect of economy of scale, applying a scale factor of 0.5 (0.4 for US). The scale factor has been determined to represent the distribution of costs found in our costs database.

Investment costs = Reference cost x $\left(\frac{\text{Reference capacity}}{\text{Installed capacity}}\right)$ x scale factor

Country	Technology	Reference size (MW)	Reference cost ($/kW)	Scale factor
UK	CCGT	1200	766	0.5
UK	OCGT	300	511	0.5
Italy	CCGT	870	488	0.5
Italy	OCGT	300	511	0.5
Greece	CCGT	843	433	0.5
Greece	OCGT	300	511	0.5
Romania	CCGT	420	683	0.5
Romania	OCGT	300	511	0.5
Poland	CCGT	833	593	0.5
Poland	OCGT	300	511	0.5
Belgium	CCGT	833	593	0.5
Belgium	OCGT	300	511	0.5
US	CCGT	1,102	884	0.4
US	OCGT	233	712	0.4

Operating profit forecasts are based on the modelling assumptions used in our global gas power economics model.

Corporate tax rates were estimated at the country level and sourced from KPMG.

We also assume a debt financing term of 20 years and a linear depreciation of 30 years.

Construction periods are assumed to be three years for CCGTs, and two years for OCGTs and steam turbine units.

Financial parameters such as WACC, interest rate and debt-to-equity ratio have been estimated at country level based on data extracted from Bloomberg.

We extracted a database of financial indicators for power utilities from Bloomberg (updated Q2 2021) and allocated specific values to each country based on the average values of the public listed utilities developing projects in that country. Due to a lack of data for Romania we used the average values of the other countries for interest rate and debt-to-equity ratio.

We did not calculate a project specific WACC because in many cases such granular data was not available or was extremely limited.

We assumed the same interest rate during construction and operation of the project. We assumed that the investment is split equally during the years of construction.

Variable	UK	Italy	Poland	Greece	Belgium	Romania	US
Inflation (%)	1.8%	1.1%	2.6%	1.2%	1.8%	2.5%	2.4%
Project lifetime (years)	30	30	30	30	30	30	30
Loan (%)	39%	52%	63%	66%	59%	56%	46%
Equity (%)	61%	48%	37%	34%	41%	44%	54%
WACC	9.1%	6.3%	11.8%	4.8%	5.0%	8.5%	6.7%
Loan term (years)	20	20	20	20	20	20	20
Interest rate (%)	1.0%	0.6%	1.6%	0.1%	0.7%	0.8%	1.7%
Capital tax rate (%)	19.0%	27.9%	19.0%	24.0%	25.0%	16.0%	27.0%

The vast majority of planned gas capacity is NPV negative

Our models show that more than two thirds (or 23.7 GW) of the planned or under construction gas plant capacity included in our European model already generates a negative NPV even under a BAU scenario. This encompasses the entirety of pipeline capacity in the UK, Greece, Belgium Romania and Poland.

This means developers for these projects are expected to be unable to recover their initial investment, even if the plant is allowed to run for its full planned lifetime.

We assume that a developer and lender will only allow a project to proceed when a positive NPV is generated and that decisions to build are based purely on economic reasons. On this basis, all planned new build gas capacity that generates a negative NPV should be cancelled.

Under B2DS and net zero scenarios, NPV values for new build gas plants in the UK fall further into negative territory, while the NPV of Italy's planned pipeline tumbles by close to half under our net zero projections. The NPVs of the planned pipelines in Belgium, Greece, Poland and Romania remain negative under our climate-constrained scenarios, although are marginally improved compared with BAU. This might seem counterintuitive, but the earlier closure of facilities in these countries reduces the amount of years that units will operate while loss-making.

We estimate that if all projects included in our European model were to proceed under a BAU scenario, some $3.7 bn would be at risk of value destruction across Europe from new gas plant investment, or more than $7.4 bn when Italy's positive NPV value is excluded. This overall figure rises to $4.2 bn under B2DS and to more than $5.3 bn under our net zero scenario projections.

Our results for the US pipeline of new gas plant capacity planned present a similar picture for investors, with the entirety of the 28.1 GW of capacity planned in unregulated grid areas included in our model generating a negative NPV under all scenarios. The extent to which planned new build projects in the US will struggle to recover initial investment is alarming, with more than $24 bn of value potentially at risk for investors there according to our models. This figure marginally improves under B2DS and net zero, as the number of years of unprofitable operation for new units would be reduced.

Table 3 NPVs of new build gas plant pipelines by country

Country	Total NPV of projects under BAU ($mn)	Total NPV of projects under B2DS ($mn)	Total NPV of projects under net zero ($mn)
Belgium	-403.1	-130.2	-273.3
Greece	-441.4	-387.8	-508.4
Italy	3,694	2,551	1,901
Poland	-399.9	-354.1	-346.7
Romania	-2,721	-1,686	-1,644
UK	-3,466	-4,188	-4,439
TOTALS FOR EUROPEAN MODEL	**-3,738**	**-4,195**	**-5,311**
US	-24,337	-22,997	-22,741

Source: Carbon Tracker analysis

The UK's large 9.7 GW pipeline will be responsible for the bulk of value at risk in Europe, with $3.5 bn likely to be lost if all 20 new gas plant projects planned there proceed even under BAU.

If most projects across Europe appear likely to struggle to recover their initial investment even under a BAU scenario, shareholder losses could rise significantly if market costs increase by plausible margins over the course of their planned lifetimes, or if gas' share in the European power generation mix decreases at an even quicker rate than expected.

The combination of increasing competition from renewables and rising carbon prices leave the prospect of loading capital into new gas a very risky strategy.

Developers and investors for any projects that either already generate a negative NPV, or are projected to operate at levels where the NPV could be swung close to negative territory under either of the climate constrained scenarios we model, should seriously consider cancellation to avoid significant value destruction.

Capacity markets failing to keep new gas viable

In addition to being the favoured mechanism used for incentivising the availability of reliable backup supplies to the power system by several EU member states and regional grid operators in the US, capacity markets have also been used by governments since their launch to push planned new build gas projects closer to final investment decisions.

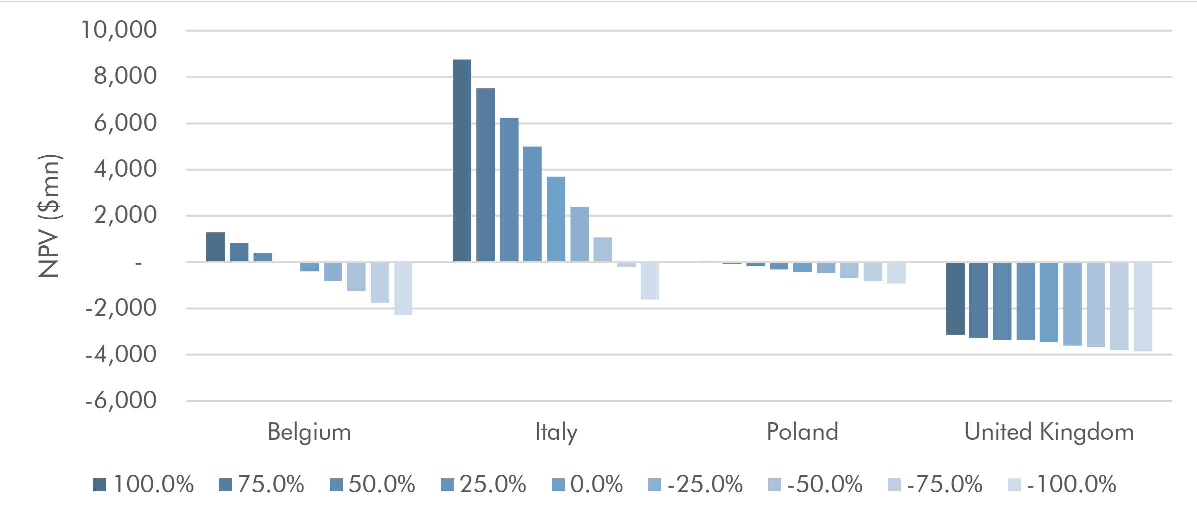
The contracts distributed to developers of such new build projects are for up to 15 years in length and continue to be issued across the EU, despite this time period meaning governments are effectively locking themselves in to funding gas into the 2040s once build time after the capacity agreement has been awarded is taken into consideration. We find that such policies are largely incompatible with long-term climate goals as a result.

Nations offering capacity payments to new build capacity are not only ignoring the clear climate arguments against funding new unabated fossil fuel fired capacity, but also the underlying economics which show that a majority of projects set to receive such contracts will still be unable to recover their initial investment.

However in Italy, we find that the country's capacity market mechanism is overly compensating new build gas plant developers and that the level of payment issued could be reduced by as much as 50% whilst keeping the country's planned fleet NPV positive. This would potentially free up funds which could be distributed instead towards low carbon technology innovation.

Policy makers for nations with capacity market mechanisms in place must urgently review the structure of their schemes and consider whether supporting potentially unprofitable projects which may undermine efforts to achieve long-term climate targets is the best use for taxpayer funds.

Figure 39 Sensitivity of European new build gas NPV to percentage changes in capacity payments



Source: Carbon Tracker analysis

New projects are highly sensitive to changes in fuel and carbon costs

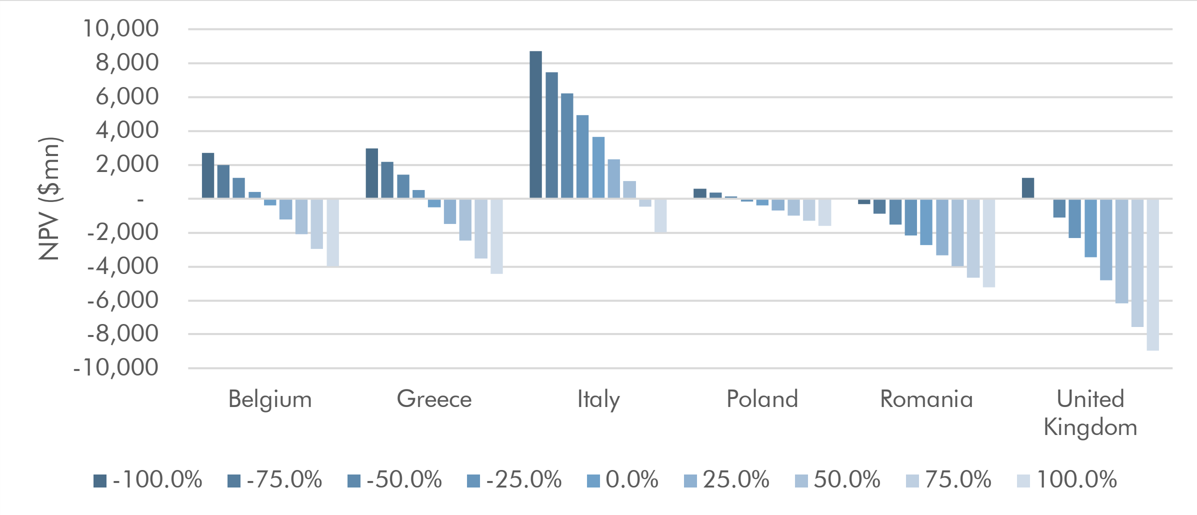
We also conducted sensitivity analyses to assess the economic fragility of new gas plant projects to changes in related costs that will be faced over the duration of each unit's operational lifetime.

Our results show that if carbon costs faced by new build gas plants over their lifetime in Italy turn out 50% above our base case numbers, the pipeline's projected NPV would tumble by more than half, while in the event of carbon prices turning out 75% higher than our base case numbers, the NPV of Italy's pipeline would turn negative.

Similarly elsewhere in Europe, carbon costs 50% above our base case numbers more than halves our projected NPVs for the gas plant pipelines in Belgium, Greece and Poland, while sharp drops are also recorded for the UK and Romania.

For the NPVs of these nations' pipelines to turn positive, we project that carbon prices would need to fall by around 25% from our base case numbers for Belgium and Greece, while a 75% decrease would be required for the UK. We project that Romania's planned pipeline will remain NPV negative even if carbon pricing is completely removed, highlighting the extent to which the projects there are unviable to develop.

Figure 40 Sensitivity of European new build gas NPV to percentage changes in carbon costs from base case numbers

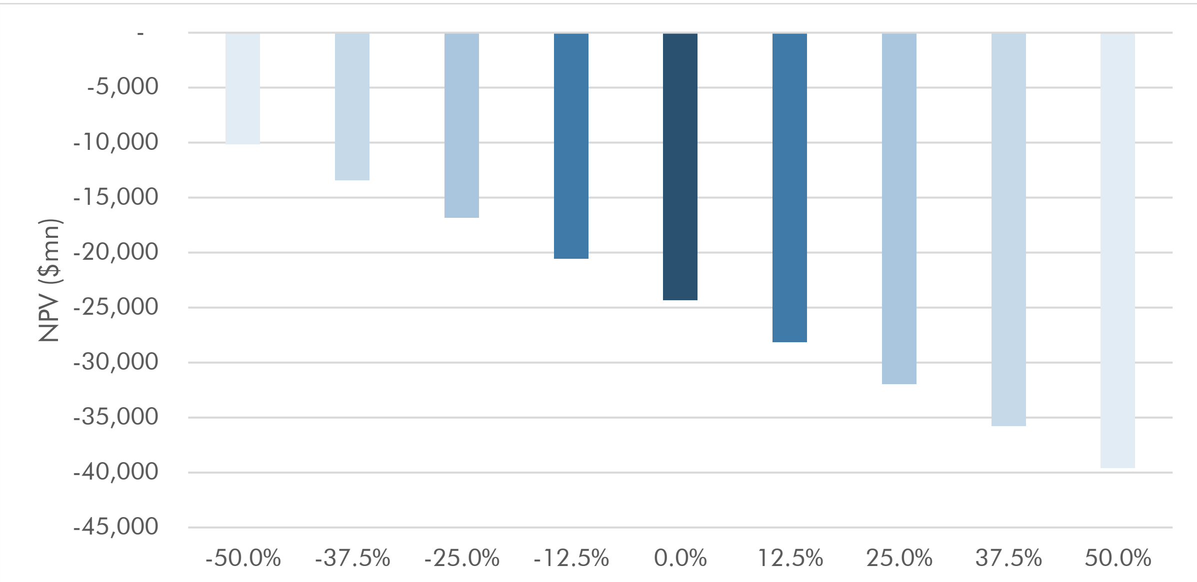


Source: Carbon Tracker analysis

Gas price increases are projected to have significant impacts on planned gas plants' potential profits, with our models showing that the NPV of Italy's planned pipeline would tumble by some 32% if gas prices turn out just 12.5% above our base case projections.

Our model also shows that change in fuel price is the factor to which the projected NPV of the US pipeline of new build gas is most sensitive. If gas prices turn out 25% above our base case numbers, we estimate that more than $30 bn would be at risk of destruction for investors.

Figure 41 Sensitivity of US new build gas NPV to changes in fuel cost



Source: Carbon Tracker analysis

8.1 Country focus and case study

In this section we shall highlight the key findings of our project finance model at a country level and provide individual break downs of projected cash flows for each nation. We also include a unit level case study which provides project specific economics. The combined country level totals published below are the sum of outputs of our individual project figures.

CASE STUDY MODELLING UK – 840 MW UNIT

This case study covers a UK-based planned gas-fired unit with a capacity of 840 MW – roughly the average size of the projects included in our project finance model.

We assume a total investment cost of just over $770 mn, a three year construction period starting in 2019, with the equity portion of the investment ($471 mn) spread evenly over that period. The unit is expected to start operations in 2022 and run for 30 years under BAU. We assume a capacity factor declining only narrowly from 35% to 33% over the course of its lifetime. Fuel costs are estimated at an average of $36/MWh over the life of the project, while carbon costs rise from a starting value of $23/MWh in the unit's first year of operation to $33/MWh in its final year before retirement under BAU.

According to our models, the project will generate a net profit throughout its planned operational lifetime, but total profits are still estimated to be insufficient for the unit to recover initial investment. This is even despite our model continuing to apply capacity payments to the project beyond the end of its current 15-year agreement to 2037.

As a result, the developer risks losing around $120 mn of investment under a BAU scenario. This figure would rise to around $243 mn under B2DS, under which the unit is estimated to be retired in 2032.

We acknowledge that some new build gas plant developers plan to install pre-combustion CCS technology, which if successful will reduce the carbon costs for the project. Our models do not account for the successful delivery of such unproven technology however and project the financial impact of units if they were to proceed unabated.

Table 4 Financial Statements Model Projections - UK gas plant unit

$mn	2019	2020	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050	2051 (end of BAU lifetime)
Revenues	-	-	-	230	247	246	244	243	235	232	230	228	228
Costs	-	-	-	-169	-172	-171	-172	-188	-190	-192	-194	-196	-196
EBITDA	-	-	-	61	75	74	73	55	46	40	36	32	31
Taxes	-	-	-	-6.3	-8.9	-8.8	-8.5	-5.3	-3.6	-2.7	-2.0	-1.2	-1.1
Loan installments	-	-	-	-15.1	-15.1	-15.1	-15.1	-15.1	-15.1	-15.1	-	-	-
Interest	-	-	-	-2.8	-2.6	-2.5	-2.3	-1.6	-0.9	-0.1	-	-	-
Equity cashout	-157	-157	-157	-	-	-	-	-	-	-	-	-	-
After-tax cash flow	-157	-157	-157	37	49	48	47	33	26	22	34	31	30
Outstanding debt	-	-	-	286	271	256	241	166	90	15	-	-	-
Yearly NPV (discounted)	-157	-301	-433	-404	-370	-338	-311	-221	-177	-155	-135	-122	-120
EBITDA margin (%)	-	-	-	26.7	30.5	30.2	29.7	22.6	19.4	17.2	15.7	14.1	13.8
Debt Service Cover Ratio	-	-	-	3.1	3.8	3.7	3.7	3.0	2.6	2.4	-	-	-
WACC	9.09%												
NPV BAU	-120												
NPV B2DS	-243												

Source: Carbon Tracker analysis

UK

We have included a planned pipeline of 20 UK new build gas plant projects in our project finance model, equal to a combined 9.7 GW of potential generation capacity.

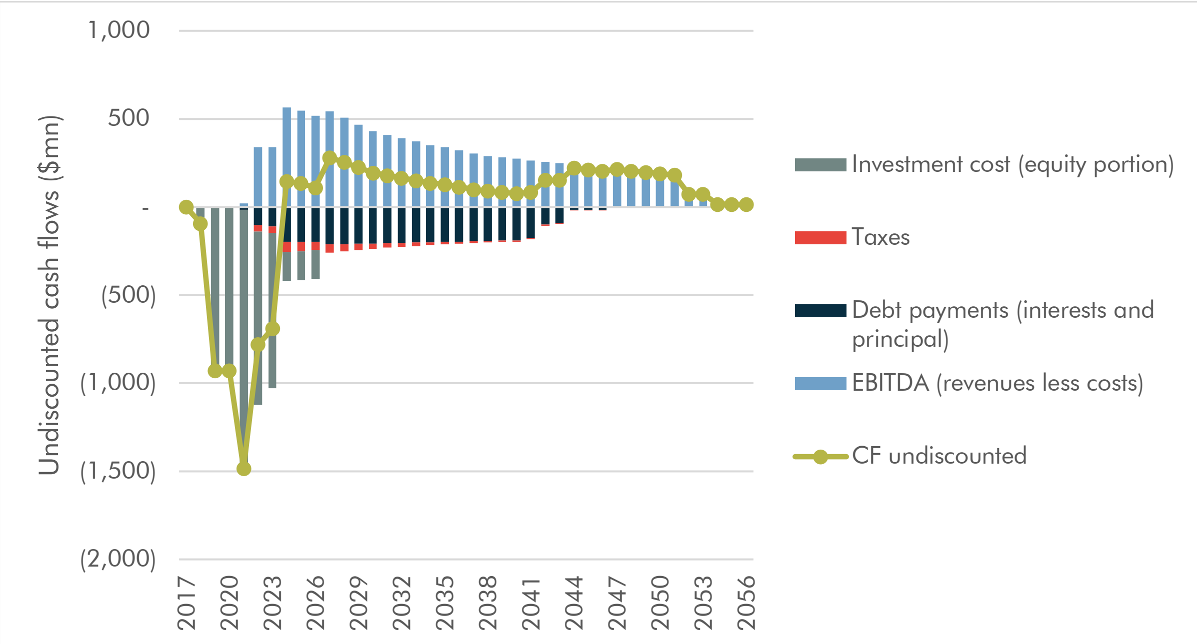
Projects range from OCGT facilities of around 300 MW in size, to CCGTs with 900 MW capacity.

The size of the UK's potential pipeline of new build gas has been significantly higher in the recent past, but developers have cancelled or shelved as much as 9.4 GW of planned gas-fired capacity including plans for new gas plants on the sites of retired coal plants at Selby, Eggborough and Ferrybridge.

We find that 100% of the UK's remaining planned capacity already returns a negative NPV under BAU, leaving a total of around $3.5 bn of value is at risk of destruction if the entire pipeline is developed.

Although total undiscounted cashflows for the country's planned projects are projected to remain positive throughout expected lifetimes, revenues are still expected to fall short of initial investment once debt payments and taxes have been deducted.

Figure 42 Aggregate lifetime undiscounted cashflows for planned new build gas in the UK



Source: Carbon Tracker analysis

With the lifetimes of some of the larger unabated CCGTs planned in the UK projected to be brought to an end around 20 years earlier (if the UK government introduces policy associated with further aligning the country's power sector emissions with both the aims of the Paris Agreement and the country's legally-binding 2050 net zero target) the extent to which project returns fall short of initial investment could turn out significantly higher.

Some planned facilities in the UK could be limited to lifetimes of only around 10 years under a B2DS, and we estimate that the amount of value at risk of destruction in the UK from investment in new gas rises to around $4.2 bn under this scenario (and to $4.4 bn under our net zero scenario projections).

We acknowledge that some developers have announced intentions to upgrade facilities through the installation of CCS technology as appropriate routes to market develop, but believe that this is a risky bet for investors and that projects should not proceed reliant upon this technology reaching the point of widespread commercial deployment. The uncertainties surrounding retrofitting costs for such plans may well mean that project owners find CCS installation is unfeasible when it does become available.

Although the UK government mandates that any new gas built with a generation capacity of more than 300 MW now needs to be "carbon capture and storage ready", plant developers have got around this rule in recent capacity contract auctions by putting forward proposals for plant units with capacities just below this threshold at 299 MW. This allows them to proceed unabated for the long-term and remain eligible for continued funding. The removal of this loophole is currently under discussion and we would urge the UK government to press ahead with this plan to remove it.

Italy

We have included 13 new build gas plant projects planned in Italy in our model, with these equal to a combined 9.6 GW of potential generation capacity. Similarly to the UK, the number of projects in Italy's pipeline has decreased over the past year, with more than 5 GW of potential new build gas-fired capacity having been cancelled by the project developer or firmly blocked from proceeding by local authorities.

Projects range from OCGTs of 220 MW in capacity, to CCGTs of more than 900 MW.

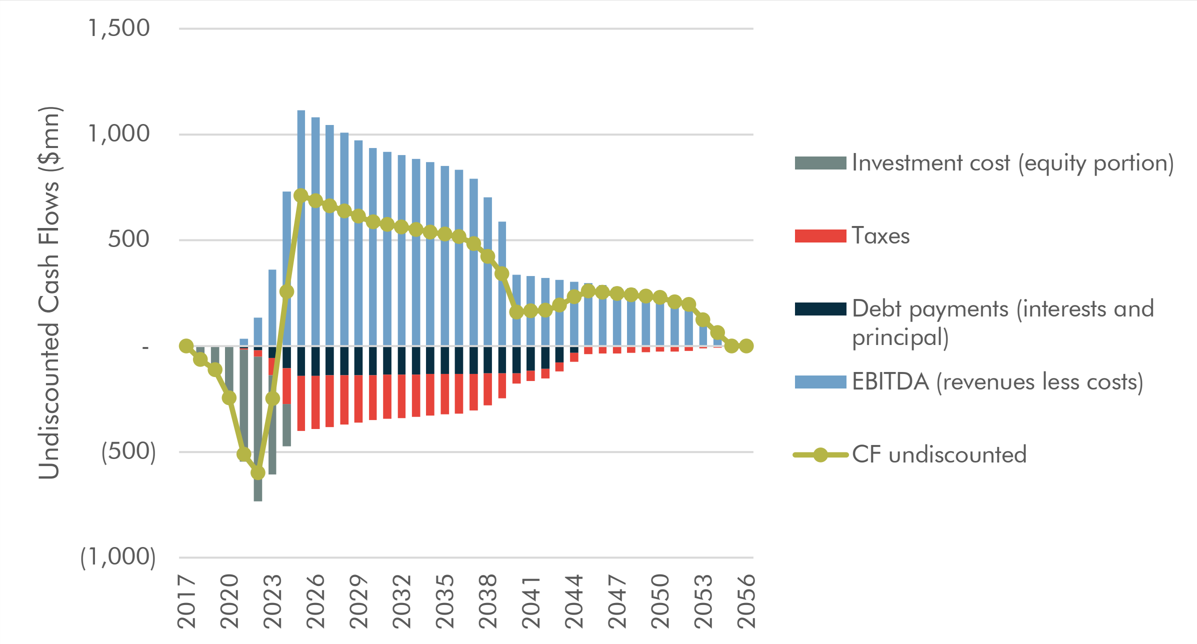
We find that Italy's entire planned pipeline generates a positive NPV, although this falls relatively sharply under our projections for B2DS and net zero scenarios. An estimated NPV of $3.7 bn under BAU falls to $2.6 bn under B2DS and to $1.9 bn under net zero.

New build Italian gas plant revenues are boosted by the overly generous payments provided by the country's capacity market mechanism. Successful projects will receive capacity payments at levels of up to €75,000/MW following recent auctions, which compares with just £18,000/MW distributed in the UK.

As we have shown in our sensitivity analyses above, Italian capacity payments could be significantly reduced to ease taxpayer burden or to lower consumer bills, while a complete removal of these payments would pull the overall NPV of Italy's planned new build gas fleet into negative territory.

The Italian government could reduce capacity payments by as much as 50% from the current levels contracted to be paid out and the NPV would still remain positive, reflecting the level of funds which could be freed up for use in boosting low carbon technology innovation.

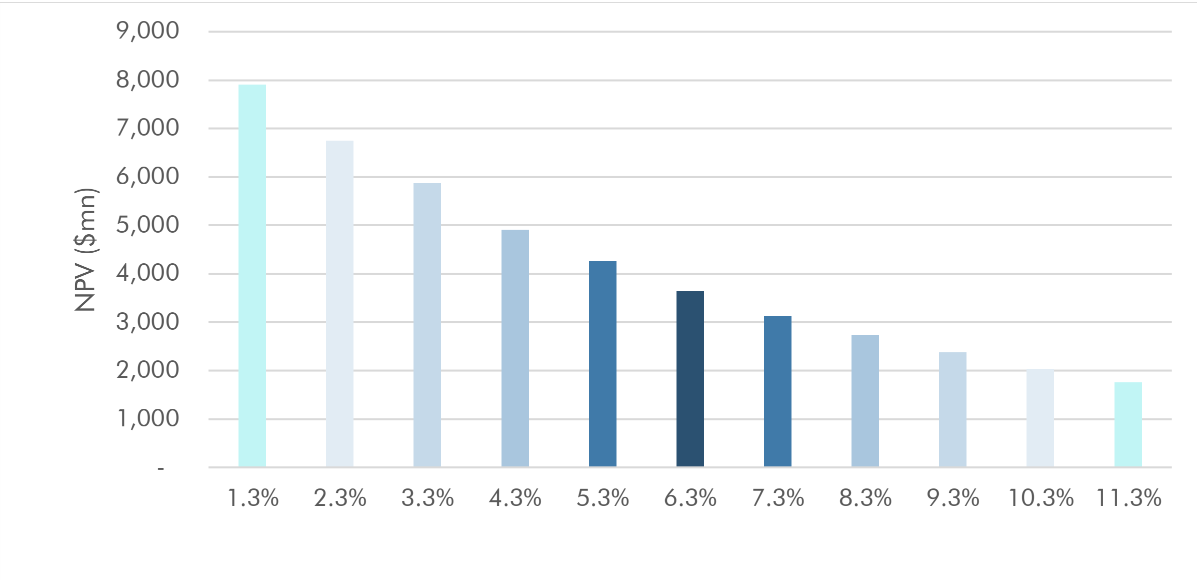
Figure 43 Aggregate lifetime undiscounted cashflows for planned new build gas in Italy



Source: Carbon Tracker analysis

New build gas units in Italy will remain vulnerable to swings in carbon and fuel costs even with capacity market payments continuing at current levels, while our models show that just a three-percentage point increase in the 6.3% WACC we use for Italian units would reduce the pipeline's NPV by around half.

Figure 44 Impact of percentage point changes in WACC from base case for new build gas in Italy on pipeline's NPV



Source: Carbon Tracker analysis

Greece

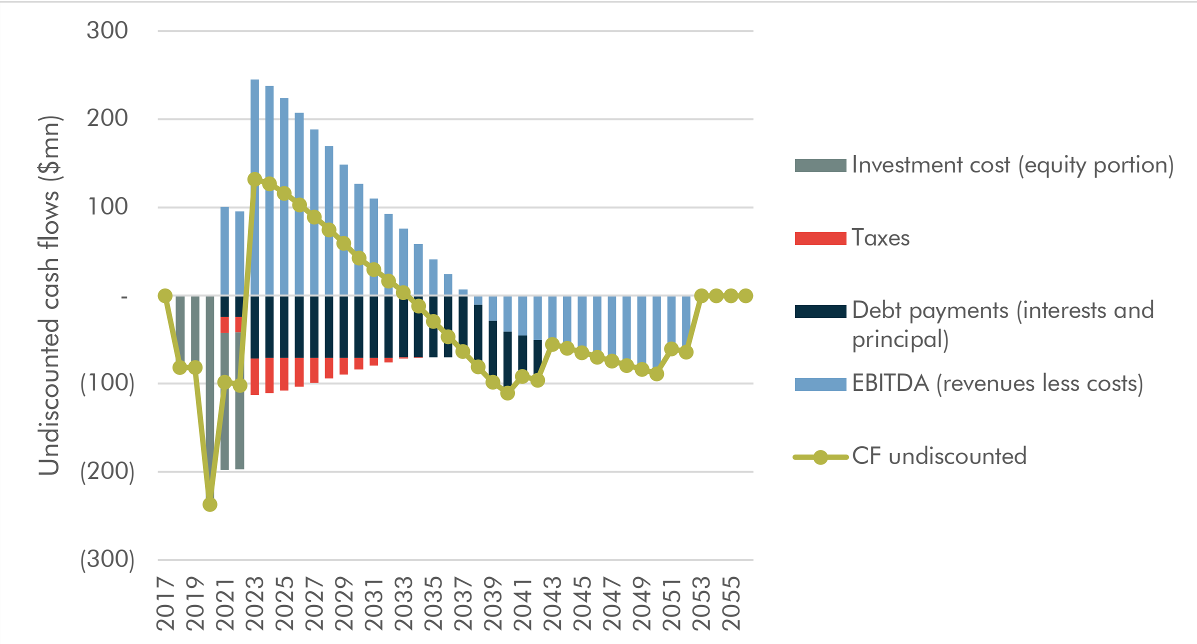
Greece has a pipeline of six new build gas plant projects included in our model, equal to a combined 4.7 GW of potential generation capacity.

All six projects are planned CCGT units, which range roughly 650-875 MW in capacity.

We find that the entirety of Greece's new build pipeline generates a negative NPV under all our scenarios, with more than $440 mn of value at risk of destruction if all of the planned projects proceed to development.

Greece has the lowest WACC of any of the countries included in our project finance model, of just 4.77%, while upfront costs for new build gas are notably lower compared with other nations.

Figure 45 Aggregate lifetime undiscounted cashflows for planned new build gas in Greece



Source: Carbon Tracker analysis

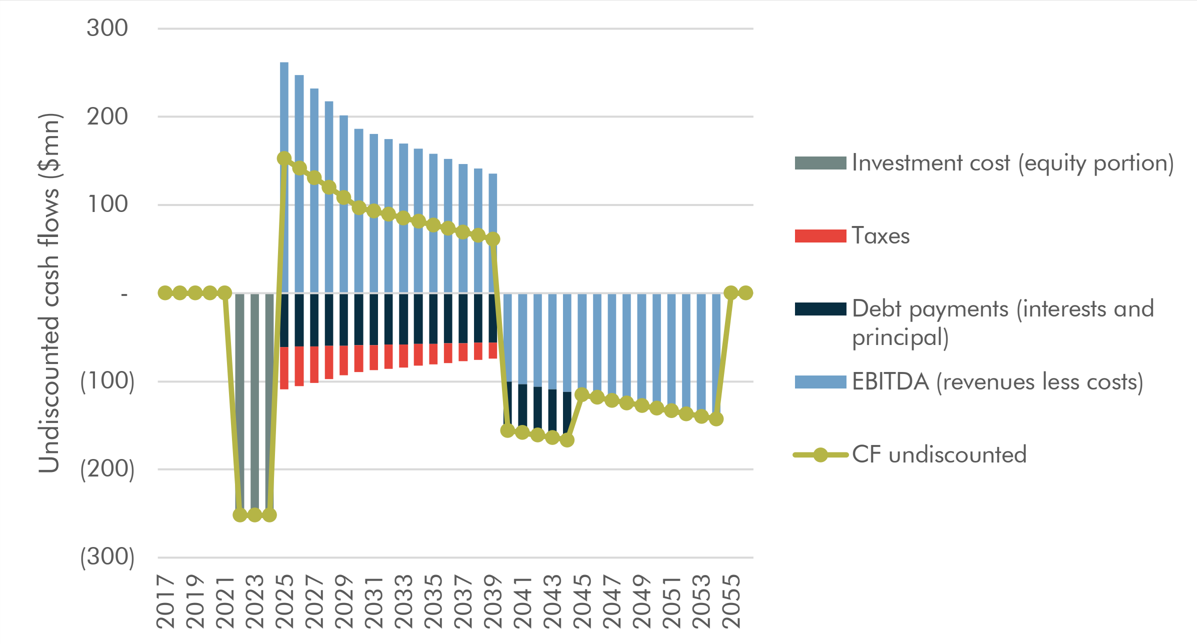
We still find however that Greek new build units will quickly begin to struggle, with undiscounted cashflows projected to fall below zero in the 2030s, as carbon costs begin to bite.

Belgium

Belgium has four planned new build gas plant projects, equal to a combined 3 GW of potential generation capacity.

All four projects are planned CCGT developments, ranging 330-900 MW in capacity. We find that all four generate negative NPVs under all of our scenario projections.

Figure 46 Aggregate lifetime undiscounted cashflows for planned new build gas in Belgium



Source: Carbon Tracker analysis

Projected undiscounted cashflows tumble sharply during the 2040s, as generators lose access to capacity payments, the allocation of which is due to end in Belgium in 2034.

We calculate that around $403.1 mn of value is at risk of destruction for investors under BAU if all four of Belgium's planned developments proceed. This falls to $130.2 mn under B2DS, as the number of years of loss-making generation are cut, with a median retirement year of 2035 projected for these projects under this scenario — some 20 years earlier than planned under BAU.

Poland

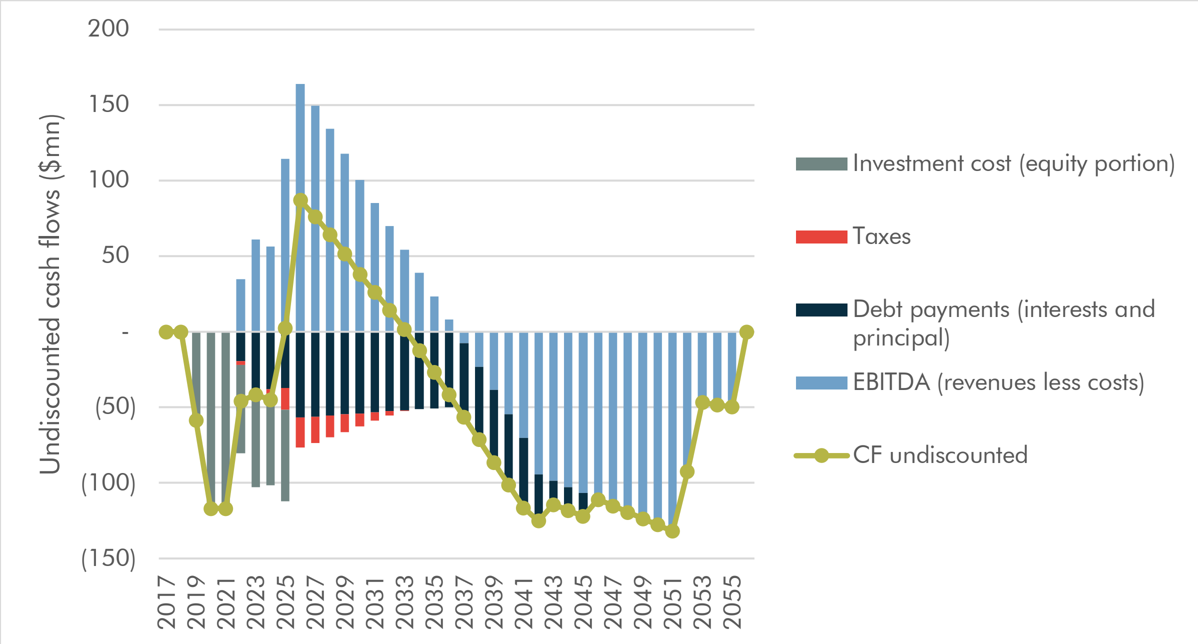
Poland has three new build gas plant projects, equal to a combined 2.3 GW of potential generation capacity.

All three planned projects are relatively large-scale CCGTs, ranging 750-800 MW in capacity.

We find that all three are unviable to build based on the negative NPVs they generate under BAU.

Poland has the highest WACC out of the countries we include in our project finance model, of 11.81%, while cumulative upfront costs for the projects are projected to total around half that of the Italian pipeline, despite there being an additional 10 projects planned in Italy.

Figure 47 Aggregate lifetime undiscounted cashflows for planned new build gas in Poland



Source: Carbon Tracker analysis

As can be seen in figure 47 above, undiscounted cashflows fall into negative territory in the 2030s and decline further from there. We find that around $400 mn of value would be at risk of destruction for investors if all three Polish projects proceed.

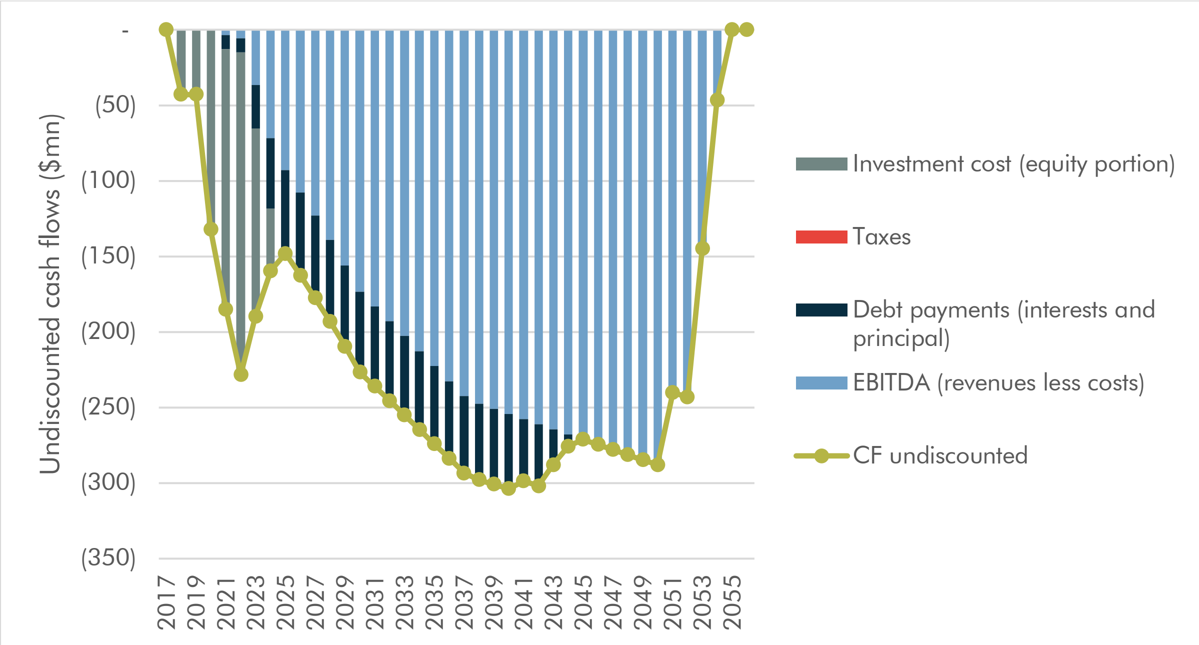
Romania

Romania has seven planned new build gas-fired power plants, equal to a combined 2.4 GW of potential generation capacity.

All of these projects are planned CCGT developments, although of relatively small-scale, ranging just 150-400 MW.

We find that all of Romania's planned projects generate a negative NPV.

Figure 48 Aggregate lifetime undiscounted cashflows for planned new build gas in Romania



Source: Carbon Tracker analysis

The economics against investment in new build gas-fired power stations in Romania is stark. Our models show that high costs and low wholesale power market revenues in the country will mean that undiscounted cashflows turn out below zero from the start of operation and fall further over the course of planned lifetimes.

High upfront costs for Romanian projects leave cumulative levels only narrowly below those seen in Greece, despite Greek plans to build more than 2 GW additional capacity.

We find that as much as $2.7 bn of value is at risk of destruction for investors if Romania's entire planned pipeline proceeds to development and we strongly urge project owners to review the viability of these schemes.

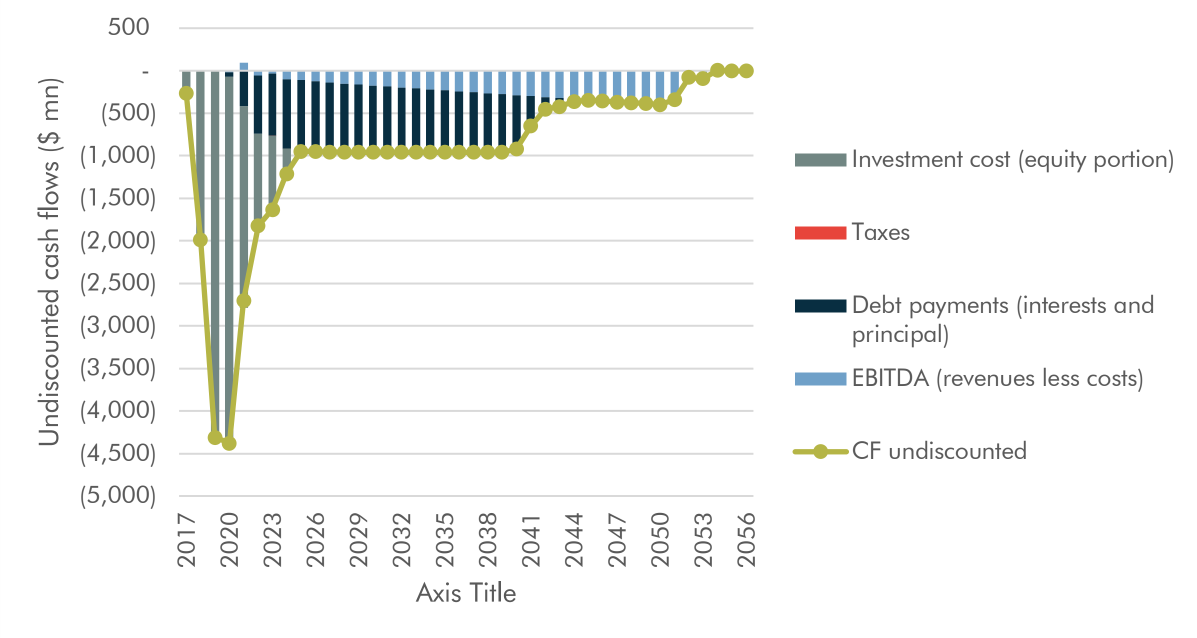
US

We have included an estimated pipeline of 74 new build gas-fired power plant projects in the US, equal to just over 28 GW of combined potential generation capacity. We have only included the units that are planned for build in unregulated merchant grid areas of the country.

These comprise a combination of large-scale CCGT units of up to 1.3 GW in capacity, small-scale OCGT facilities, as well as a single steam turbine plant project.

Our models project that the US pipeline generates a negative NPV under all of our scenarios, leaving more than $24 bn at risk of value destruction under BAU if the entire pipeline proceeds to development.

Figure 49 Aggregate lifetime undiscounted cashflows for planned new build gas in the US



Source: Carbon Tracker analysis

As can be seen in figure 49, cumulative revenues are expected to be limited for US new build gas units from the start of their planned operating lifetimes, and decline further into the 2030s and 2040s, with undiscounted cashflows left below zero throughout planned lifetimes.

9 Appendix

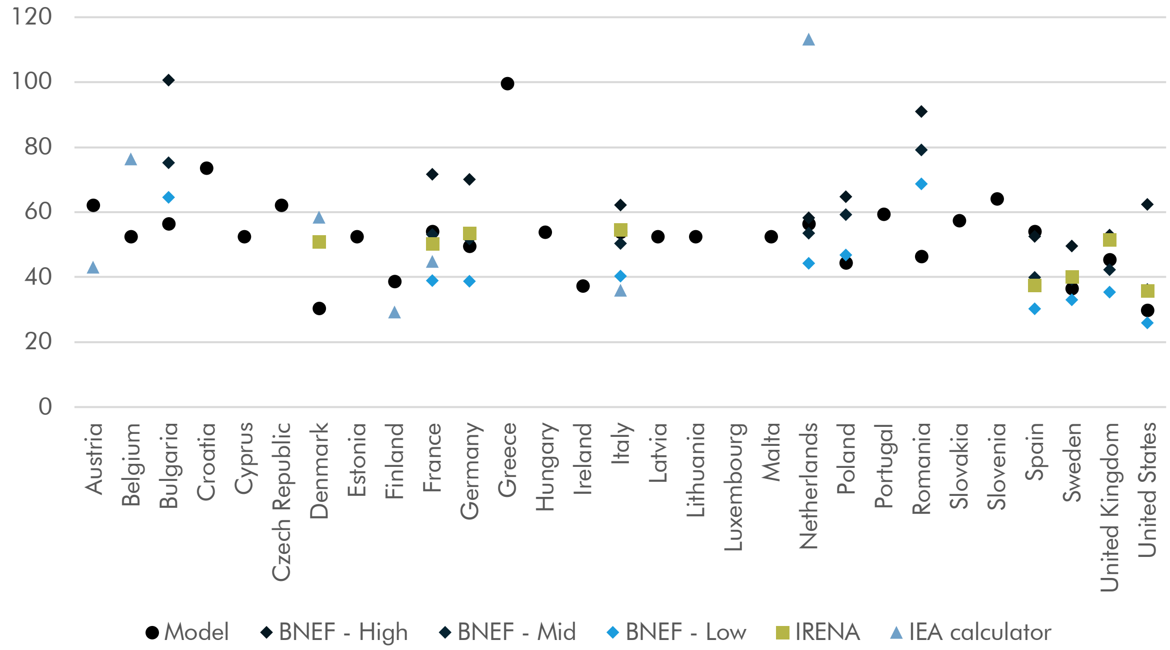
9.1 Gas methodology

Available at:

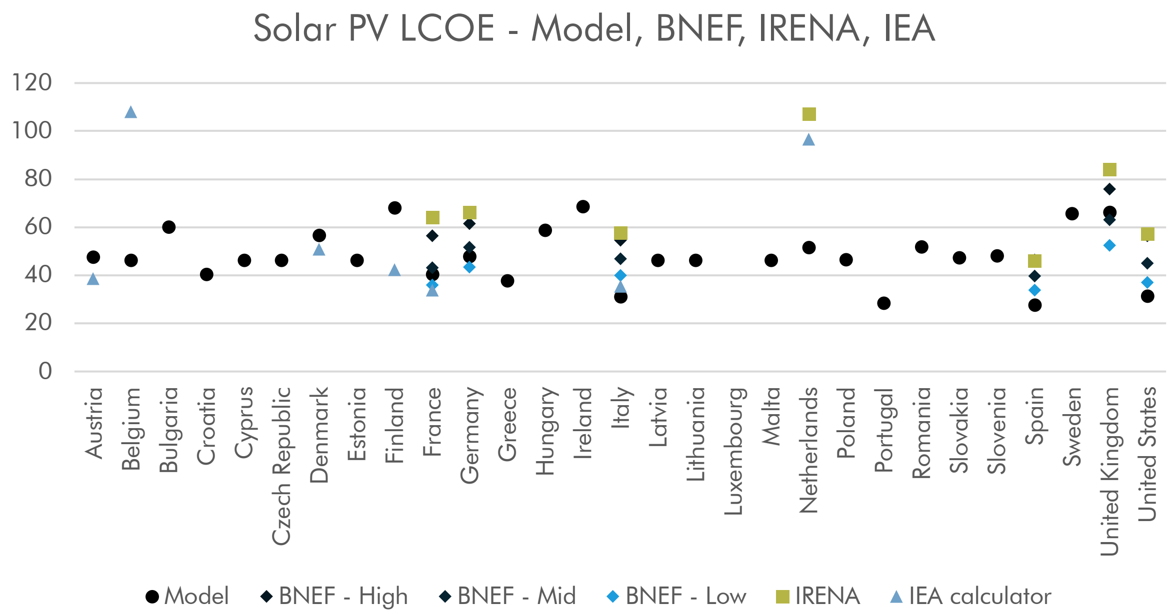
Link to be confirmed

9.2 LCOE estimates

Onshore wind estimates: Carbon Tracker model, BNEF, IRENA and IEA



Solar estimates: Carbon Tracker model, BNEF, IRENA and IEA



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