Is offshore wind still good for billpayers?

Prepared for RenewableUK

March 2024

About this report

Aurora Energy Research has been commissioned by RenewableUK to conduct analysis on the impact of different levels of offshore wind on consumer bills in a Net Zero power sector for Great Britain, in comparison to other low carbon technologies. The analysis is designed to present the cost to the consumer under different routes to reach Net Zero and highlight the role of a mix of technologies, including offshore wind, in reaching a Net Zero target.

This report considers a base case scenario in which the GB power sector reaches 'Net Zero by 2035', as well as four bespoke scenarios with varying levels of offshore wind capacity and demand. Note that the different scenarios represent possible routes the GB power sector could take under different sets of constraints. They are not necessarily realistic indicators of how the sector will develop.

We also provide a summary of recent literature on the impact of power prices on economic development, and an overview of levelized cost of electricity (LCOE) ranges for three scalable low-carbon technologies.

Main contacts

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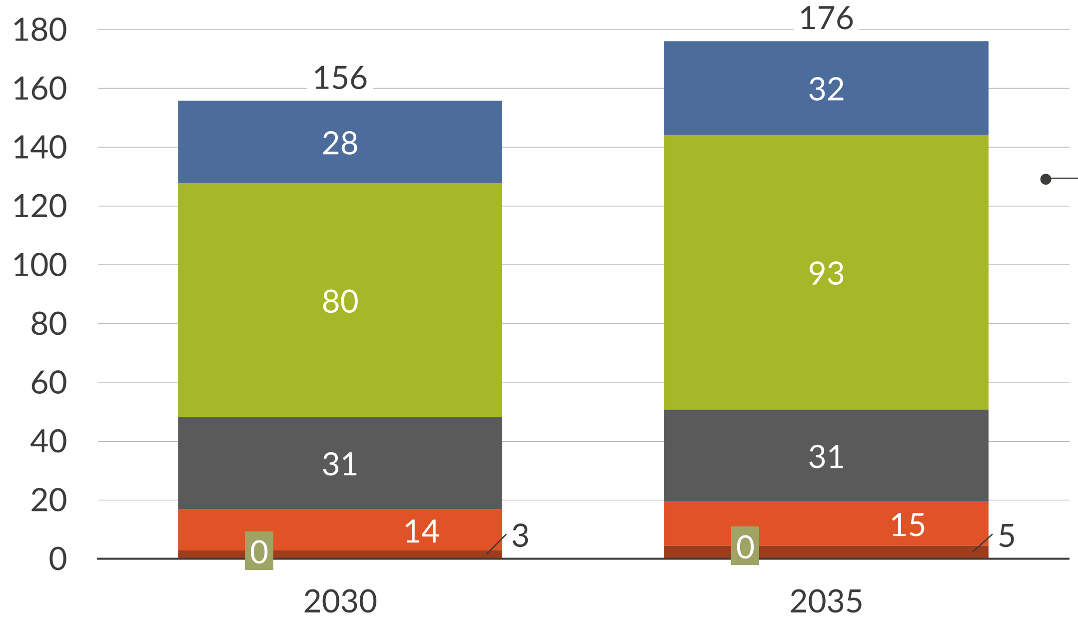
Based on current trajectories, achieving Net Zero in the power sector under the current policy and market environment is unlikely before the 2050s

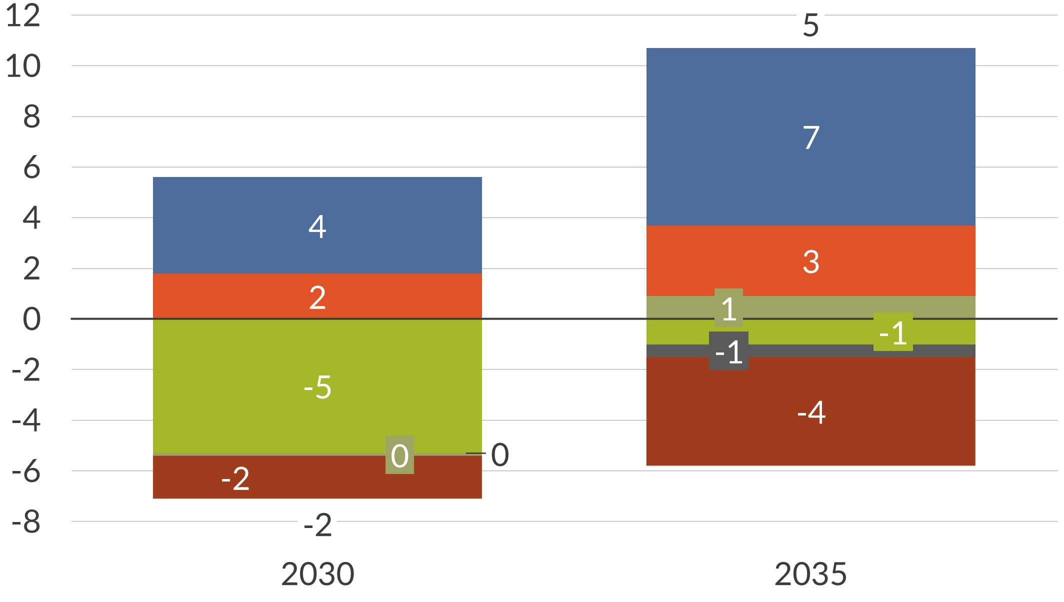
Reaching Net Zero in 2030 or 2035 would require extensive system change and investments

- There are several possible pathways to Net Zero, each with its own challenges
- Aurora's standard view of NZ35 requires a rapid increase in renewables deployment alongside enabling technologies, including BECCS

Installed Capacity in BAU
GW



Delta to BAU in respective years
GW



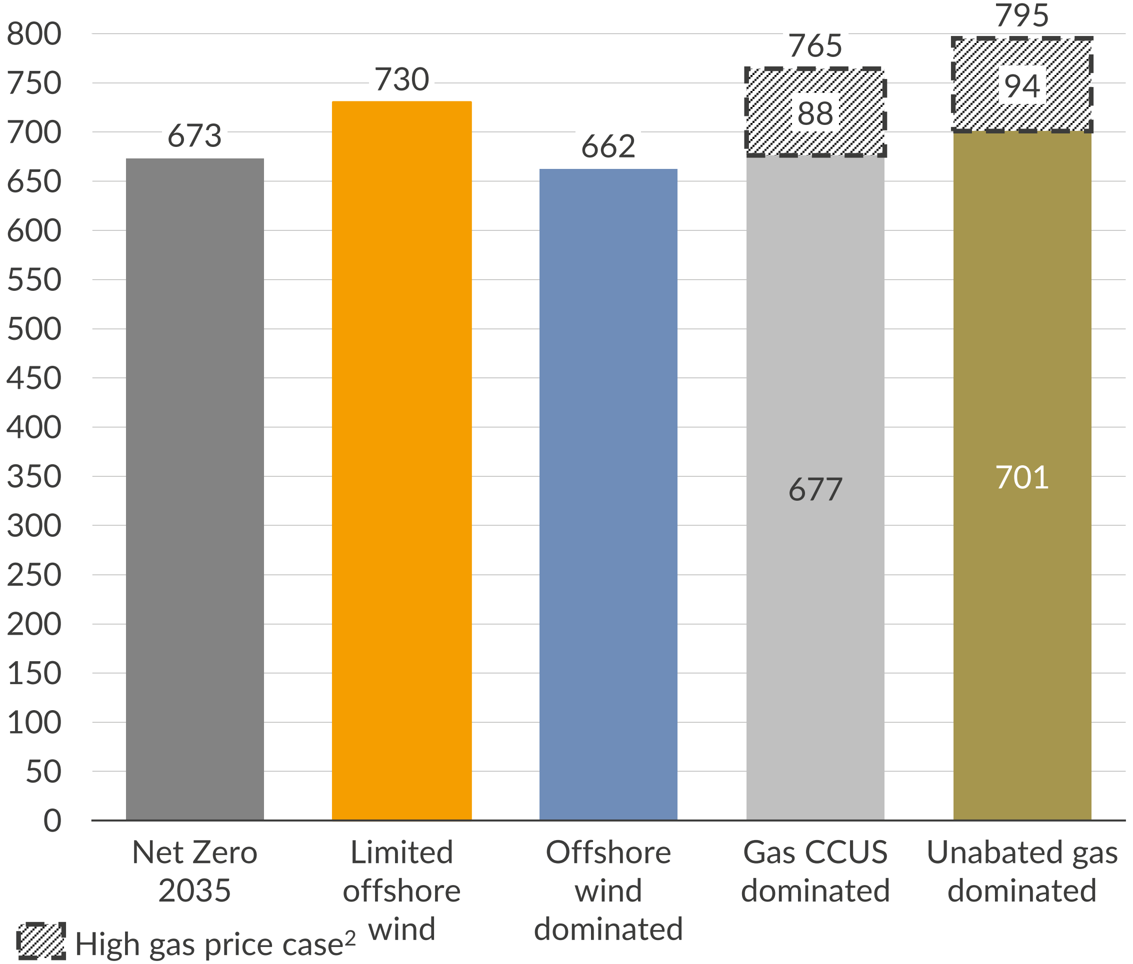
Other[3] | Intermittent Renewables | Unabated thermal | Interconnectors | BECCS | Nuclear[2]

1) Includes negative emissions from BECCS assuming a factor of -941 gCO2 /kWh; BECCS capacity initially offsets emissions, then generates greater negative emissions as the system decarbonizes (renewables, gas CCS, hydrogen). 3 GW of additional BECCS expected post-2030/2035 for growing demand.; 2) Assumes Hinkley Point C, Sizewell C and Bradwell B delays, with an upsizing of expected future capacity; 3) Includes capacity from storage, demand-side response (DSR), hydrogen peaking plants, hydrogen CCGTs, biomass and gas CCS .

Source(s): Aurora Energy Research

Replacing future CfD-backed offshore wind generation with most other low carbon technologies shows an increase in overall cost to the consumer

Wholesale electricity generation cost per household, 2025-2050 average
£/household[1]/yr, real 2022



Moving towards Net Zero 2035 without new CfD supported offshore wind results in a higher cost to the consumer

Aurora has modelled a number of bespoke market scenarios, described further in the following slides. The key takeaways are as follows:

- A system that reaches Net Zero 2035 **without any new CfD backed offshore wind** (Limited offshore wind scenario) has **the highest system costs**, as more economical wind generation is replaced with expensive interconnector imports and gas generation
- A system that reaches the 50GW offshore wind target by 2030 (Offshore wind dominated scenario) reduces system costs compared to the base case. However, economical but variable-output offshore wind generation needs expensive gas peaker generation to balance it out, reducing its benefits
- The scenarios with **additional gas CCS and unabated gas generation have higher total system costs** than the base case due to the additional generation costs associated with gas, which **are significantly exacerbated** in the case of sustained high gas prices (denoted by the shaded bars)

CfD supported offshore wind is crucial for delivering a cost-efficient system for billpayers moving towards Net Zero 2035, by displacing expensive generation from interconnectors and gas-fired assets. The offshore wind dominated system helps to **reduce UK's reliance on European power** through lower interconnector imports and provides and **a buffer against global gas price volatility,** protecting consumers during times of periodic or sustained high gas prices.

1) Total number of households in GB is assumed to be 28.2 million. 2) The 'gas CCUS dominated' and 'unabated gas dominated' scenarios are modelled assuming periodic gas price spikes as a base case. The high gas price case refers to these scenarios being modelled assuming sustained high gas prices

Source(s): Aurora Energy Research

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Reaching Net Zero by 2035 would require an acceleration in the deployment of low-carbon technologies like offshore wind

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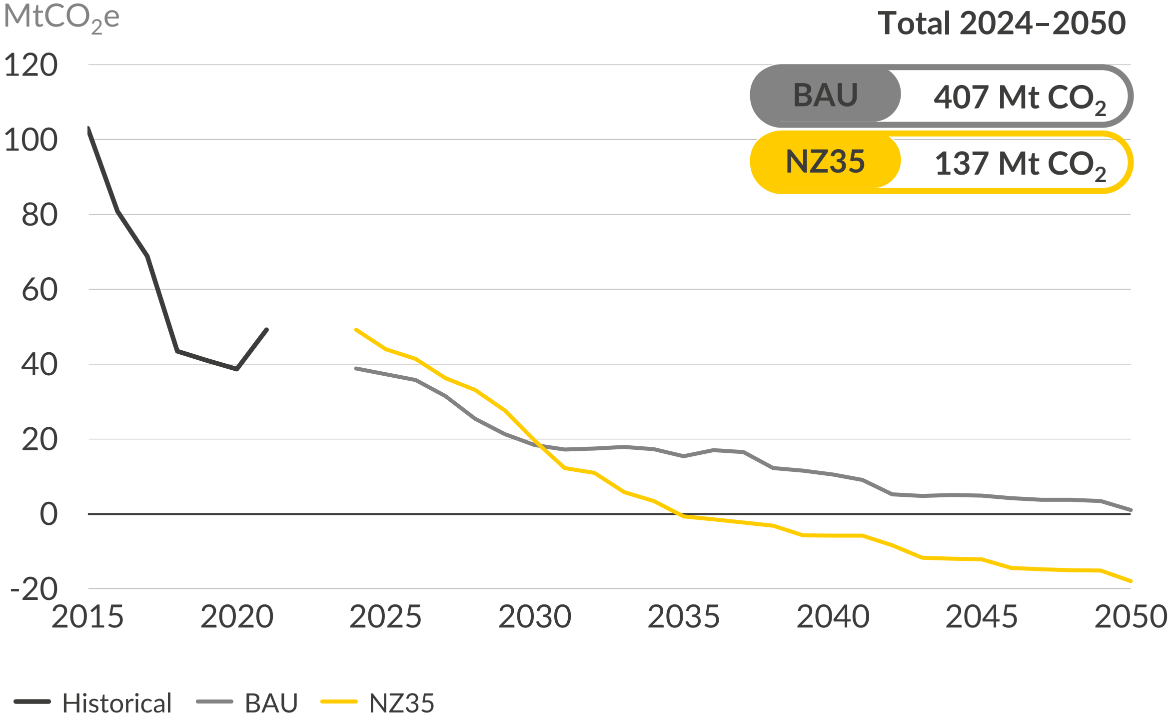
BAU, NZ35

The current market framework has GB on a course to reach Net Zero only in 2051, much later than current political targets

- Under the 'business as usual' (BAU) trajectory, GB is only expected to reach Net Zero power sector carbon emissions by 2051
- Aurora models a Net Zero 2035 (NZ35) scenario which represents an increased rate of consistent emissions decline in order to meet this target

Power Sector Carbon Emissions[1]

$MtCO_2e$

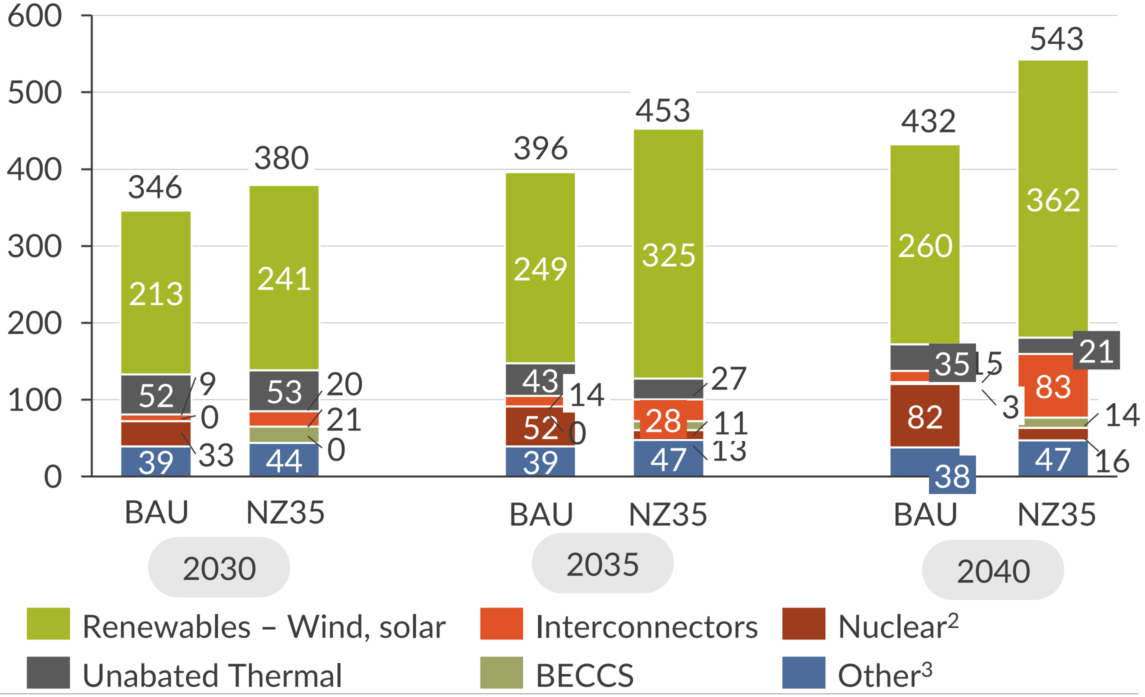


Transitioning to Net Zero by 2035 requires a significant shift in the energy generation mix compared to BAU scenarios

- Renewable generation needs to be approximately 13% higher than BAU's 213 TWh by 2030
- The NZ35 trajectory implies renewables would be 40% greater than BAU's projection of 260 TWh by 2040, while unabated thermal generation would be a third less

Generation and net imports,

TWh



1) Includes negative emissions from BECCS assuming a factor of -941 gCO2 /kWh; BECCS capacity initially offsets emissions, then generates greater negative emissions as the system decarbonizes (renewables, gas CCS, hydrogen). 3 GW of additional BECCS expected post-2030/2035 for growing demand.; 2) Assumes Hinkley Point C, Sizewell C and Bradwell B delays, with an upsizing of expected future capacity; 3) Includes generation from pumped storage, demand-side response (DSR), hydrogen peaking plants, hydrogen CCGTs, biomass, gas CCS, hydro, and battery storage technologies.

Source(s): Aurora Energy Research

A Net Zero power system requires a mix of technologies, each facing its own barriers to deployment

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1 Renewable deployment

Solar
Competing land use priorities, reliance on scarce materials which may compromise supply chains, and protracted planning processes delaying implementation.

Onshore wind
Onshore wind's expansion is hampered by regulatory barriers, specifically the de-facto ban in England, and occasional exclusion from Contract for Difference (CfD) mechanisms.

Offshore wind
Potential delays from prolonged timelines, supply chain limitations, extensive environmental planning, and sites restricted through the leasing process.

2 Low-carbon baseload power

Nuclear
Growth is hindered by high initial costs, complex construction processes, regulatory and design approval bottlenecks, skilled labor shortages, and the necessity for substantial government backing amid financial limitations.

3 Flexible capacity

Interconnectors
Deployment benefits from government-supported cap-and-floor mechanisms, with carbon leakage concerns mitigated by typically low-carbon, cost-effective import sources.

Long duration energy storage
A pipeline of LDES projects exists, but large-scale capital deployment to enable their construction will rely on secure revenue streams

Battery storage
A significant pipeline of short-duration assets exists, yet their deployment towards Net Zero power by 2030 necessitates enhanced grid connection processes and expanded market support, particularly in Balancing Mechanism access.

4 Carbon removal technologies

BECCS
Net Zero is heavily dependent on negative emissions technology, However, there is no current regulatory framework to ensure standards.

Gas CCS
Gas CCS technology is constrained by its reliance on unproven large-scale technology, a shortage of suitable storage sites, and mass deployment is required by 2035 without support schemes having been finalized.

Source(s): Aurora Energy Research

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Levelised cost of electricity (LCOE) and total system cost analysis are two ways of analysing power system composition

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X Deep dive on following slides

A Levelised cost of electricity (LCOE)

Methodology

- Levelised cost of electricity (LCOE) is the present value of lifetime costs expressed per unit of expected lifetime generation. In other words, LCOE is the amount an asset needs to earn per unit of electricity generated if it is to recover all its costs
- It is a simple high-level metric by which the relative costs of different technologies can be compared.

B Total system cost analysis

Methodology

- Total system cost analysis is a more complex approach to understanding the value of a certain capacity and generation mix
- It considers not just the investment cost of a particular type of asset, but all the key costs involved in running a power system . It applies not to a particular technology or asset type, but to a system as a whole
- In this study, we have broken system costs down into five components, namely wholesale market costs, balancing mechanism costs, capacity market costs, subsidy spend and network costs

The levelized cost of electricity of a given technology increases with higher CAPEX or lower load factors, and vice versa

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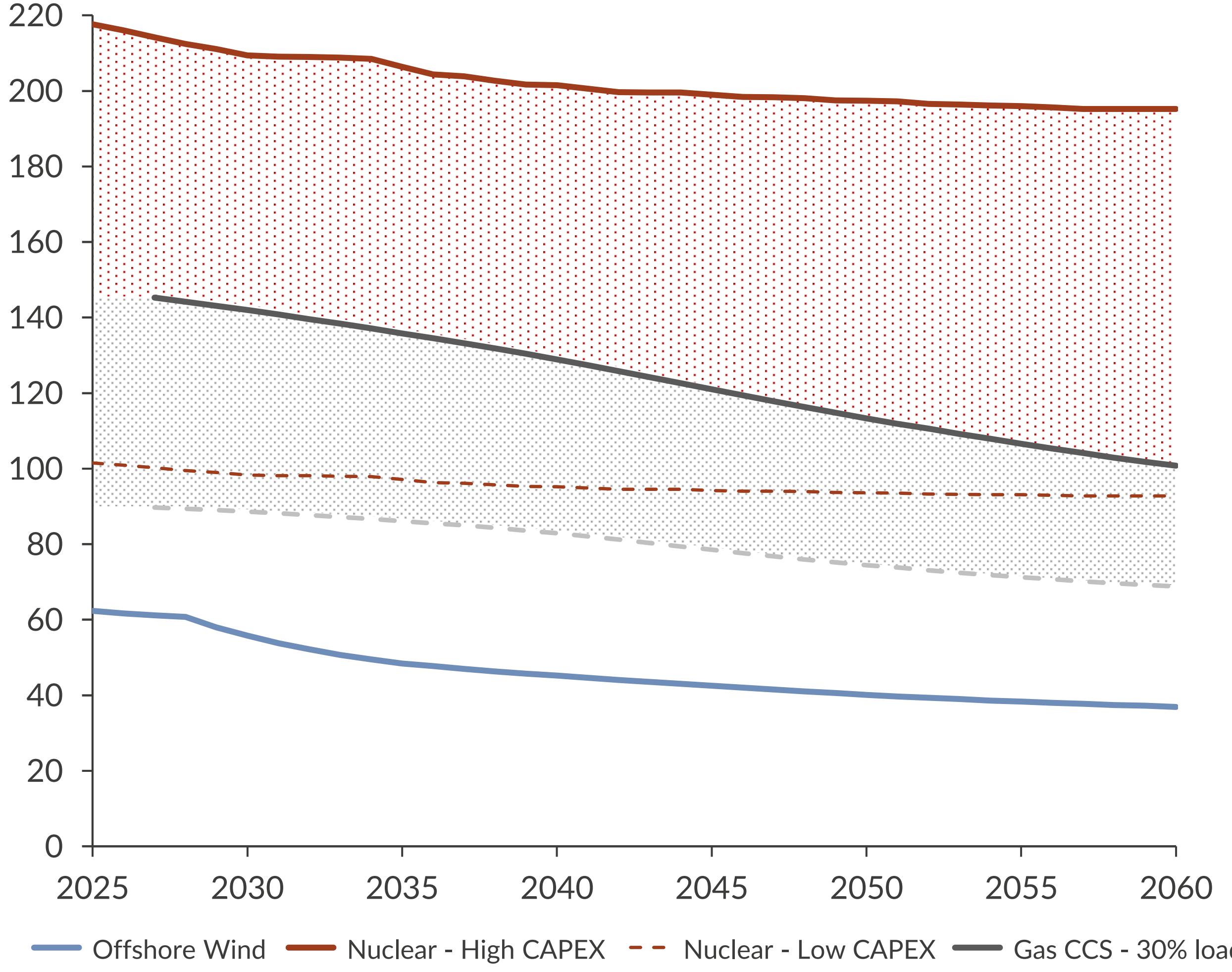
Levelised cost of electricity generation from different sources

£/MWh (real 2022)



- This chart presents a forecast of LCOEs for three low carbon technologies. A range is provided to account for the uncertainty involved in forecasting factors like technology CAPEX and load factors

Nuclear

- Nuclear LCOE has been presented as varying between a high and low CAPEX range of £10,000/kW to £6,000/kW[1]
- This is because while nuclear CAPEX is high at present, there is scope for CAPEX reductions in future plants, due to learnings from Hinkley Point C

Gas CCS

- The LCOE of dispatchable technologies such as gas plants depends on the load factor at which they operate, with a higher load factor implying a lower LCOE
- Hence the LCOE of gas CCS is presented using a range of load factors, with the 30% load factor representing Aurora's estimate of gas CCS utilisation, and the 90% load factor representing 'available generation', i.e, the level up to which load factors could theoretically increase

Discount rates

- LCOEs are also sensitive to the discount rate, which is used to discount future costs and generation
- The LCOEs presented here are based on a discount rate of 8% for nuclear (government-backed financing), 11% for gas CCS (merchant basis) and 6.5% for offshore wind (CfD-supported)

1) Based on announced CAPEX and capacity of Hinkley Point C in the UK and six planned nuclear reactors in France

Aurora has modelled four bespoke scenarios with varying levels of offshore wind, in addition to the Aurora Net Zero 2035 scenario

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Summary of bespoke scenarios modelled

Scenario	Description	Offshore wind capacity in 2035	Key output changes in 2035
Base case – NZ by 2035	▪ The GB power system meets the government target of Net Zero emissions by 2035	▪ 51 GW	▪ N/A
Limited offshore wind	▪ Only merchant offshore wind built beyond 2024 - to be determined endogenously be the model based on plant economics ▪ Offshore wind that has been commissioned through CfD AR4, with an expected COD of 2027 will still materialise	▪ 32.1 GW	▪ +3.9 TWh Gas peakers ▪ +37.7 TWh Interconnectors ▪ +8.4 TWh Onshore wind ▪ - 84.5 TWh Offshore wind
Offshore wind dominated	▪ UK reaches its target of 50 GW of offshore wind by 2030, relying on CfD supported buildout ▪ Aurora will produce a CfD strike price forecast using our in-house strike price estimation tool used in a previous RenewableUK engagement	▪ 52.9 GW	▪ +6.8 TWh Offshore wind ▪ -3.9 TWh Gas peakers ▪ -0.4 TWh Gas CCGT
Gas CCUS dominated	▪ No CfD contracts for offshore wind awarded beyond 2024 ▪ CfD supported offshore wind in the base case to be replaced by gas CCUS generation by 2035 ▪ A gas price forecast incorporating periodic price spikes to be used	▪ 29 GW	▪ +105.6 TWh Gas CCS ▪ -100.5 TWh Offshore wind ▪ -2.9 TWh Gas peakers
Unabated gas dominated	▪ No CfD contracts for offshore wind awarded beyond 2024 ▪ CfD supported offshore wind in the base case to be replaced by unabated gas generation by 2035 ▪ Unabated gas includes gas CCGTs, OCGTs and gas recips ▪ A gas price forecast incorporating periodic price spikes to be used	▪ 29 GW	▪ +35.1 TWh Gas peakers ▪ +52.3 TWh Gas CCGT ▪ +7.5 TWh Interconnectors ▪ -100.4 TWh Offshore wind

Source: Aurora Energy Research

These wide-ranging changes come at an increased system cost from 2025-2030, 5% above BAU (business as usual)

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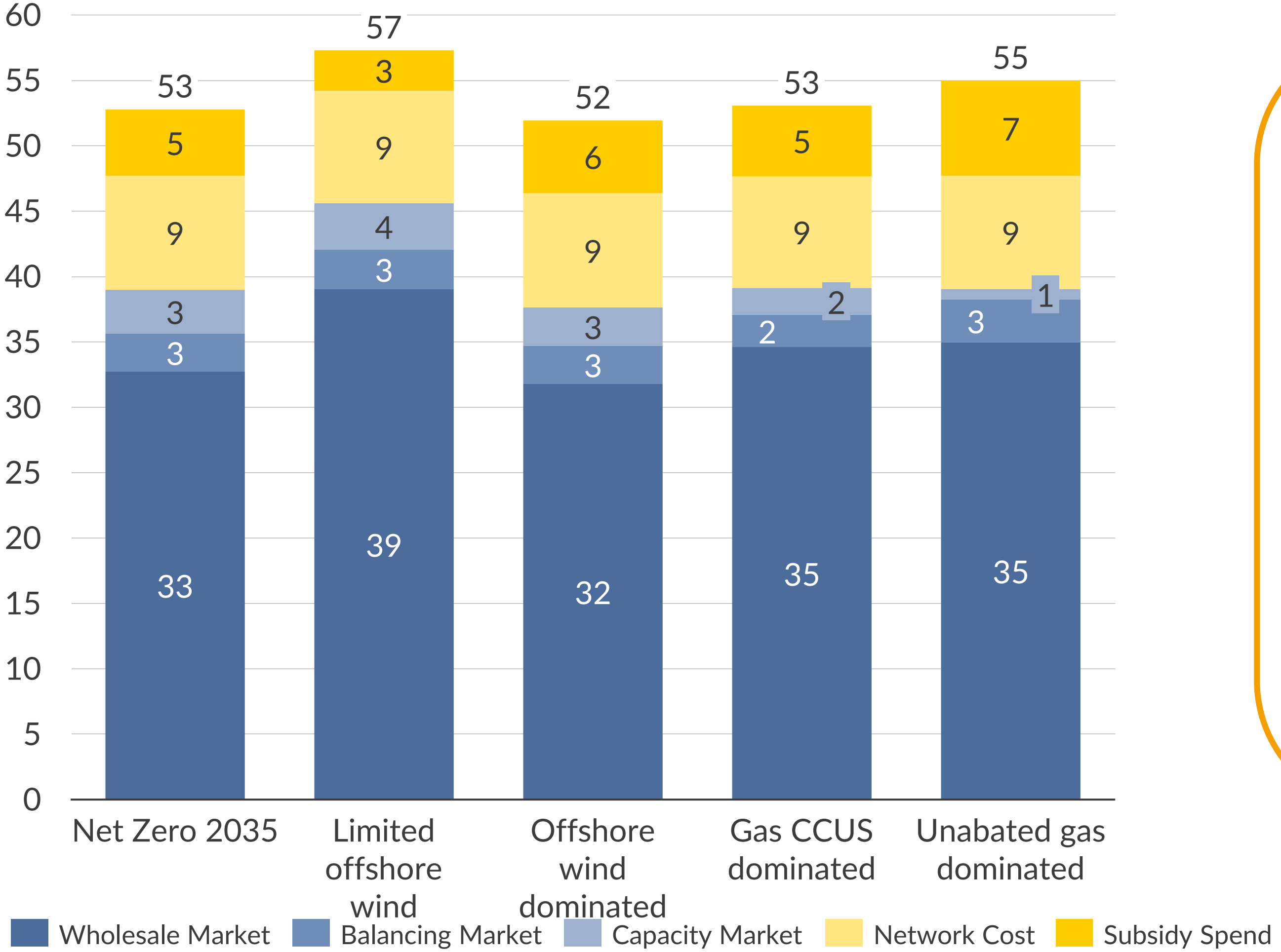
Average annual system costs for different market scenarios, 2025–2050
£bn, real 2022



Key results from system cost analysis

Aurora has modelled a number of bespoke market scenarios, described further in the following slides. The key takeaways are as follows:

- A system that reaches Net Zero **2035 without any new CfD supported offshore wind** (Limited offshore wind scenario) has the **highest system costs**, as more economical wind generation is replaced with expensive interconnector imports and gas generation
- A system that reaches the **50GW offshore wind target by 2030** (Offshore wind dominated scenario) **reduces system costs marginally** compared to the base case. However, economical offshore wind generation needs expensive gas peaker generation to balance it out, reducing its benefits
- The scenarios with **additional gas CCS and unabated gas generation** (Gas CCUS dominated and Unabated gas dominated scenarios, respectively) **have higher total system costs** than the base case due to the additional generation costs associated with gas

1) In real terms, based on 27.5 million GB households, for system-related costs only, not including retail price mark-ups.

Source(s): Aurora Energy Research

Aurora has used a bottom-up approach, calculating different components of system cost for each bespoke scenario (1/2)

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Market-based costs		Description
Wholesale Market	Wholesale production	▪ Wholesale production costs cover the costs of producing units of power within the wholesale market. Costs reflected here include fuel and carbon costs as well as other variable O&M costs (the short run marginal cost - SRMC), but do not reflect CAPEX or fixed O&M costs ▪ Different technologies have different production costs, reflecting different costs of fuel ▪ **Total wholesale production costs are calculated as: short run marginal cost x generation**
	Wholesale margins[1]	▪ Wholesale margins reflect the revenues achieved by a plant, minus its production costs ▪ In any given period, the wholesale price is set by the SRMC of the highest cost plant that must dispatch to meet demand, such that plants that have lower SRMCs can earn an “inframarginal rent” ▪ Plants typically recover a proportion of their CAPEX and fixed O&M costs through wholesale margins achieved (CAPEX costs are also recovered through balancing and ancillary revenues, subsidies and the capacity market) ▪ **Wholesale margins (WM) are calculated as: WM spend (WM price x generation) – WM production costs (SRMC x generation)**
Balancing Mechanism	Balancing costs	▪ Balancing costs represent the total cost of balancing the system and can be calculating by considering the total volume of balancing actions required, and the price at which balancing actions were procured ▪ Higher balancing volumes are typically required in periods with high renewable generation ▪ **Balancing costs are calculated as: net imbalance volumes x imbalance price**
Capacity Market	Capacity Market costs	▪ Capacity market costs reflect the costs incurred to bring sufficient capacity on the system to ensure loss of load standards are met ▪ Capacity prices reflect the “missing money” problem faced by some technologies, which are required for system stability but which do not achieve sufficient revenues from other markets to remain available to the system ▪ All technologies which receive a capacity market contract in a given year receive the same capacity market price, but have different de-rating factors, which reflect each technology’s contribution to ensuring a stable power system ▪ **Capacity Market (CM) costs can be calculated as: CM clearing price x capacity x derating factor**

Total power cost to the consumer calculations exclude H_2 production costs (blue and grey hydrogen production, hydrogen imports and storage and electrolysers) and (gas) heating cost to the consumer. Note that the hydrogen price is still used but only to determine the SRMC of hydrogen burning power plants. Additionally, CAPEX is recovered through revenues in the wholesale market, balancing mechanism, capacity market, subsidies and ancillary services.

1) Calculated for all plants receiving the wholesale price. CfD payments allow renewable assets to achieve a fixed “strike price” for power produced. In periods where the wholesale price < strike price, a top-up is provided, however in periods where the wholesale price >strike price, the asset owner must pay back the difference. Both top-up payments and paybacks are accounted for under the low-carbon subsidies cost, which results in calculated wholesale margins being an overestimated.

Source(s): Aurora Energy Research

Aurora has used a bottom-up approach, calculating different components of system cost for each bespoke scenario (2/2)

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Non-market-based costs		Description
Subsidies	Low-carbon subsidies	▪ Low carbon subsidies cover the **cost of subsidies for CfDs, ROCS and REFIT plants** ▪ Negative payback payments from CfD plants to suppliers when wholesale prices are above strike prices are included within this category
	Non-RES subsidies	▪ Non-renewable subsidies cover support or subsidies needed to bring non-renewable plants, particularly nuclear and low carbon flexible capacity, onto the system if they would not otherwise build out on an economic basis. ▪ **Non-RES subsidies are calculated as: Full lifetime technology costs – sum of market revenue (wholesale, balancing, capacity market[1] & ancillary services)**
Network	Transmission	▪ Transmission costs reflect the costs of operating the transmission network in each scenario and are calculated based on the Ofgem RIIO[2] network price control methodology ▪ Transmission system expenditure is driven by the volume of new build transmission connected capacity and the volume of new boundary transfer capacity. Boundary transfer capacity is an important measure of the imbalance in generation and demand in different regions across GB. Scenarios with a higher imbalance between regions will have higher boundary transfer costs ▪ Transmission system expenditure is not charged to generators or demand (or ultimately the consumer) in the year the expenditure occurs; but is also determined by an allowable return on the rate asset value (the depreciated value of the transmission system), amongst other factors, with rules clearly laid out by Ofgem ▪ For each scenario, **we calculate the transmission system expenditure and then follow the Ofgem formula to determine total network costs in any given year**
	Distribution	▪ Distribution costs reflect the costs of operating the distribution networks in each scenario and are calculated based on the Ofgem RIIO[2] network price control methodology ▪ Distribution system expenditure is driven by the volume of new build distribution connected capacity and by the level of peak demand in each scenario, with higher demand peaks requiring additional distribution expenditure to manage ▪ Distribution system expenditure is not charged to generators or demand (or ultimately the consumer) in the year the expenditure occurs; but is also determined by an allowable return on the rate asset value (the depreciated value of the distribution system), amongst other factors, with rules clearly laid out by Ofgem ▪ For each scenario, **we calculate the distribution system expenditure and then follow the Ofgem formula to determine total network costs in any given year**

1) Renewable subsidy schemes typically do not allow capacity market revenues to be stacked, however some support schemes for low carbon flexibility (such as the proposed cap and floor scheme for pumped hydro/long duration storage) do allow capacity payments to be paid; 2) Revenue = Incentives + Innovation + Outputs; this methodology determines the allowable transmission costs chargeable by the network operator.

Source(s): Aurora Energy Research

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Removing CfD supported offshore wind from Aurora's Net Zero 2035 scenario leads to a 17.5% increase of solar PV capacity in 2035

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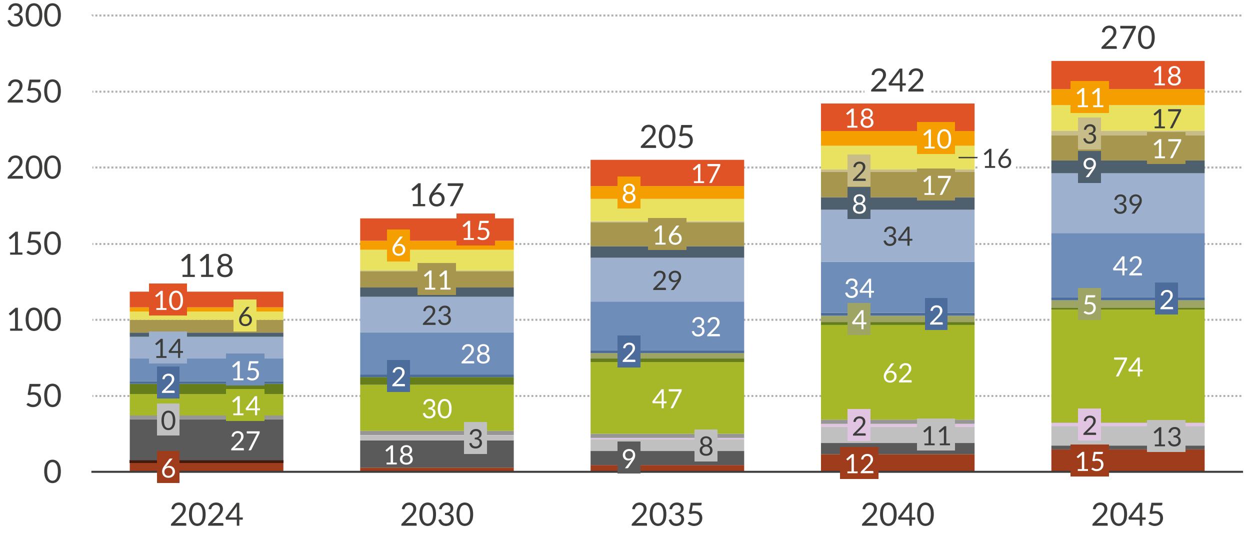
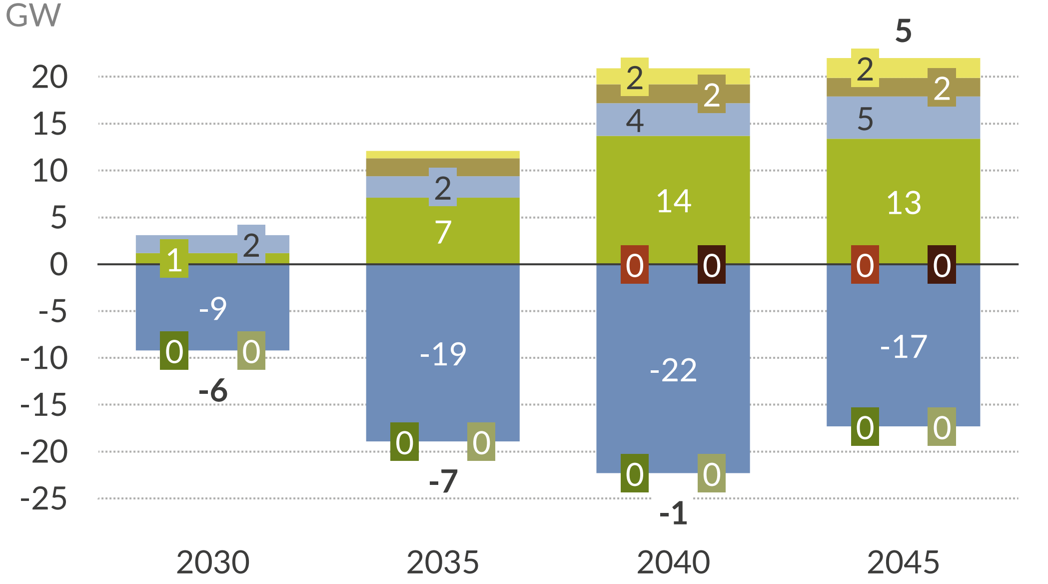
Limited offshore wind

Total installed capacity in Limited offshore wind scenario
GW



Delta between Limited offshore wind and NZ 2035 base case
GW



- In this scenario, **any future CfD supported offshore wind capacity (CfD AR6 or later) does not build, with the gap in generation being filled by the most economical merchant sources of power**
- CfD-backed offshore capacity is predominantly replaced mainly by merchant renewables, namely solar, with smaller additions of onshore wind
- Gas peaker capacity is 2 GW higher than the base case by 2035. Being a price setting technology, this is expected to increase the average wholesale market clearing price
- Battery capacity also increases, helping to balance out new renewable capacity

Nuclear, Coal, Gas CCGT, Gas CCS, Hydrogen CCGT, Other thermal[3], Solar, Other RES[2], BECCS, Hydro, Offshore wind, Onshore wind, Pumped storage, Gas / oil peaker[1], Hydrogen peaker, Battery storage, DSR, Interconnectors

1) Peaking includes OCGT and reciprocating engines; 2) Other RES includes biomass, EfW, hydro, and marine; 3) Other thermal includes embedded CHP

Source: Aurora Energy Research

To make up the shortfall of generation from CfD supported wind, a significant proportion is replaced with imported high-cost energy

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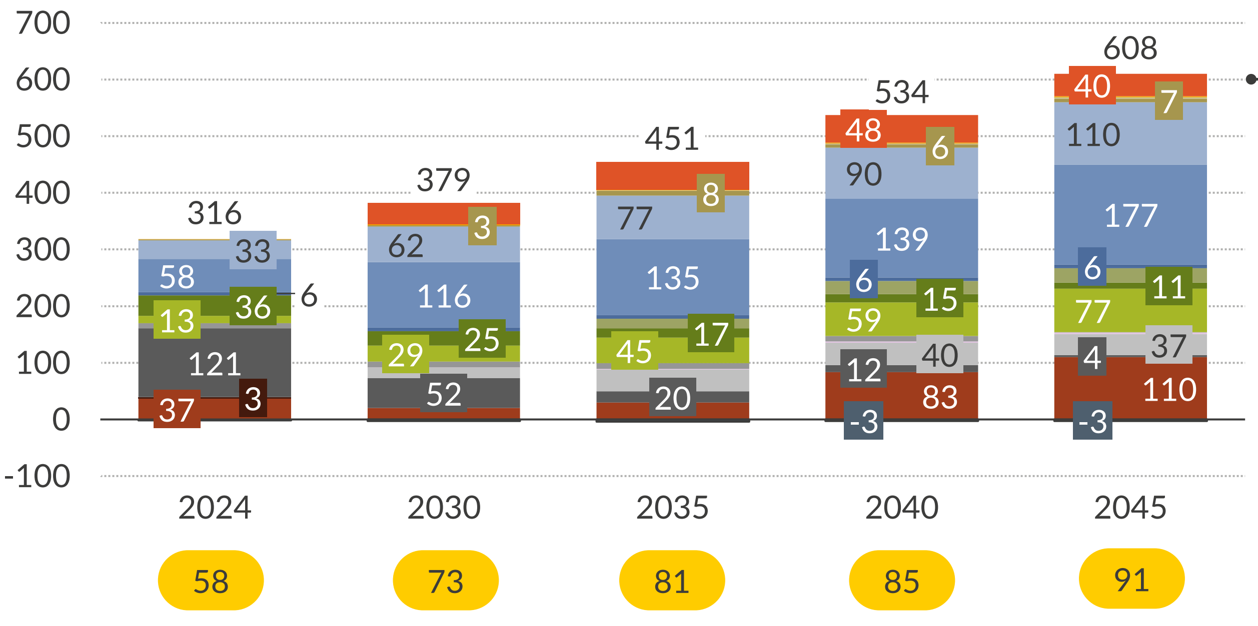
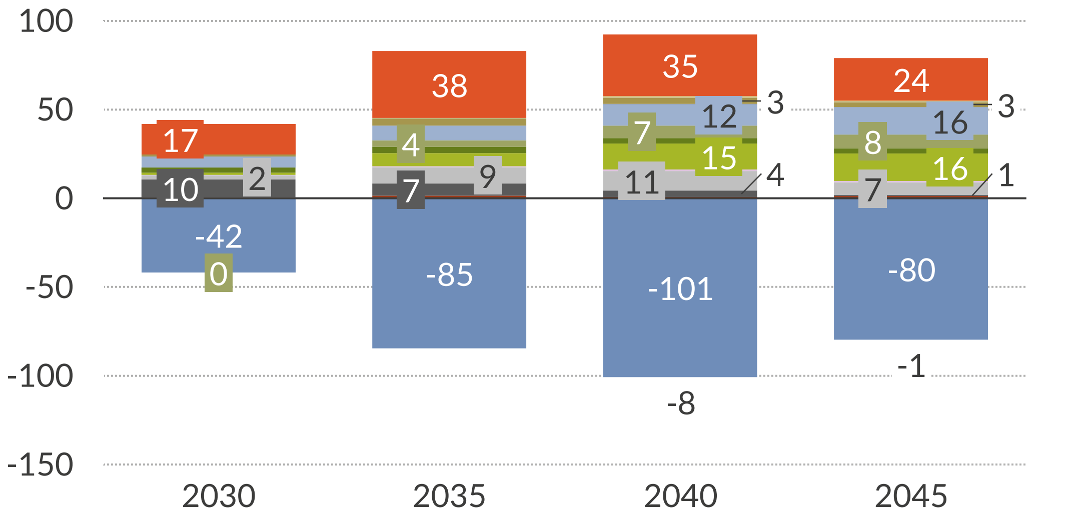
Limited offshore wind

Total generation in Limited offshore wind scenario
TWh



Delta between Limited offshore wind and NZ 2035 base case
TWh



- Relative to the base case, the loss of CfD-backed offshore generation is predominantly replaced by interconnector imports (38 TWh higher than the base case in 2035), which indicates higher wholesale market prices in GB attracting imports
- High SRMC gas and hydrogen fired generation also goes up by 20 TWh
- Generation from the additional renewable capacity increase by only 23 TWh, compared to an 85 TWh loss in offshore wind generation, indicating an overall upward pressure on prices compared to the base case

Nuclear | Coal | Gas CCGT | Gas CCS | Hydrogen CCGT | Other thermal[3] | Solar | Other RES[2] | BECCS | Hydro | Offshore wind | Onshore wind | Pumped storage | Gas / oil peaker[1] | Hydrogen peaker | Battery storage | DSR | Interconnectors | xx % of demand met by low-carbon generation[4]

1) Peaking includes OCGT and reciprocating engines; 2) Other RES includes biomass, EfW, hydro, and marine; 3) Other thermal includes embedded CHP; 4) Calculated as the sum of nuclear, gas CCS, hydrogen CCGT, wind, solar, BECCS, and other renewables generation over demand

Source: Aurora Energy Research

The removal of CfD-backed offshore wind results in an increase in power prices from gas generation which outweighs the reduction in subsidy spend

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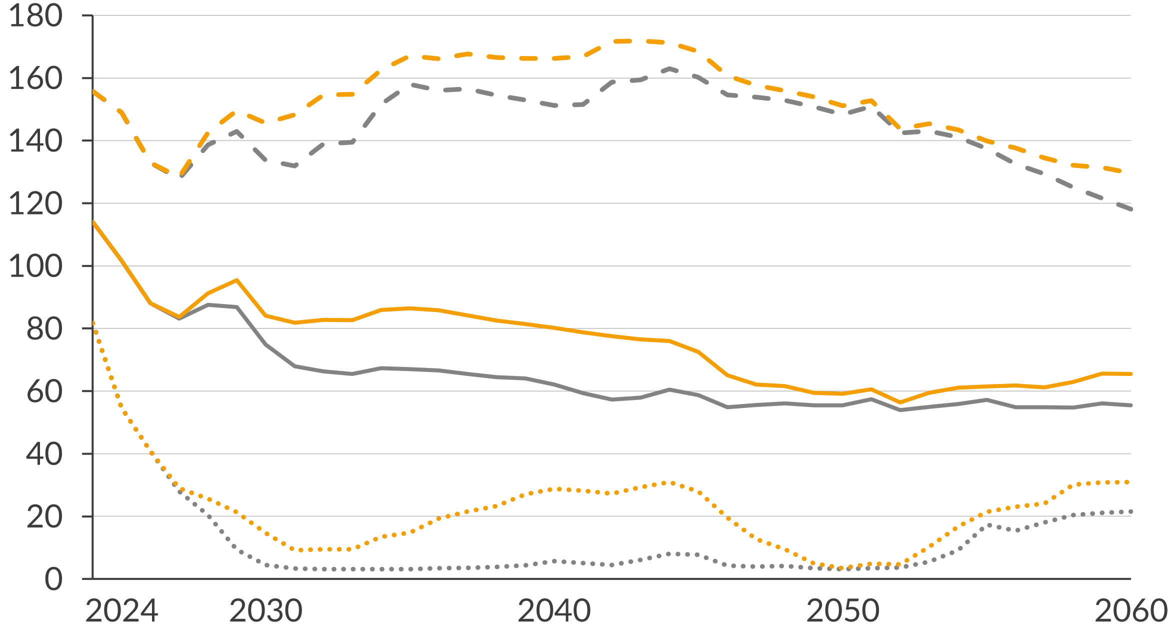
Limited offshore wind

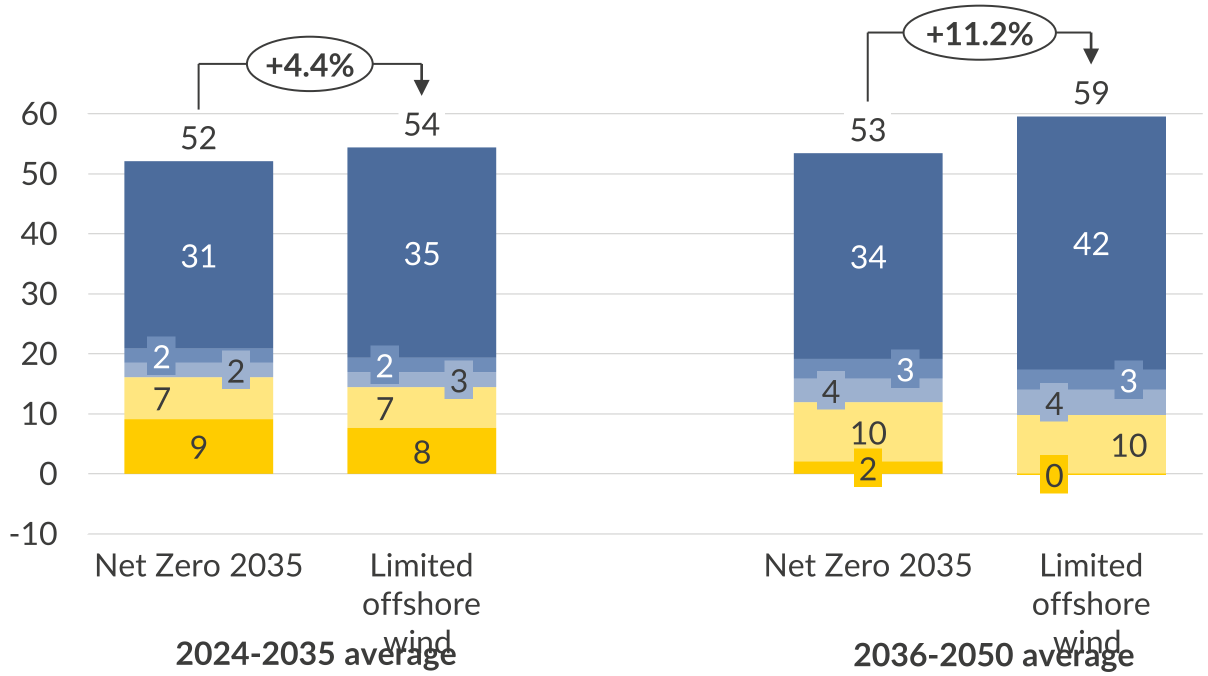
Wholesale market price
£/MWh (real 2022)



- Higher top percentile prices than the base case are linked to increased gas generation which tends to generate in more expensive price hours
- Higher baseload prices are linked to more interconnector imports and gas generation
- Higher bottom percentile prices are due to less renewables in the capacity mix – these set prices in the lowest priced hours

NetZero 2035 (Base case) 5th Percentile 95th Percentile
Limited offshore wind Baseload price

System cost breakdown
bn £ (real 2022)



- This scenario's average system cost is ~8% higher than the base case, driven by an increase in wholesale market costs, indicative of increased high-cost interconnector imports and gas generation
- Subsidy spend decreases as this system has much less CfD-backed offshore wind online, but this is not enough to make up for increased wholesale market costs

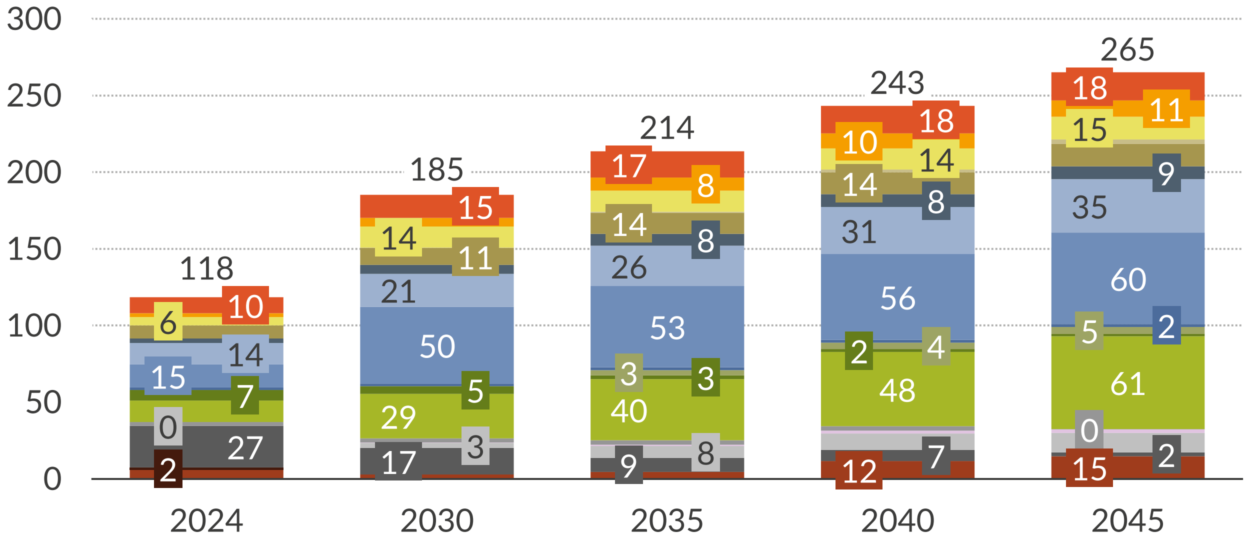
Subsidy Spend Capacity Market Wholesale Market
Network Cost Balancing Market

Source: ReseAurora Energy arch

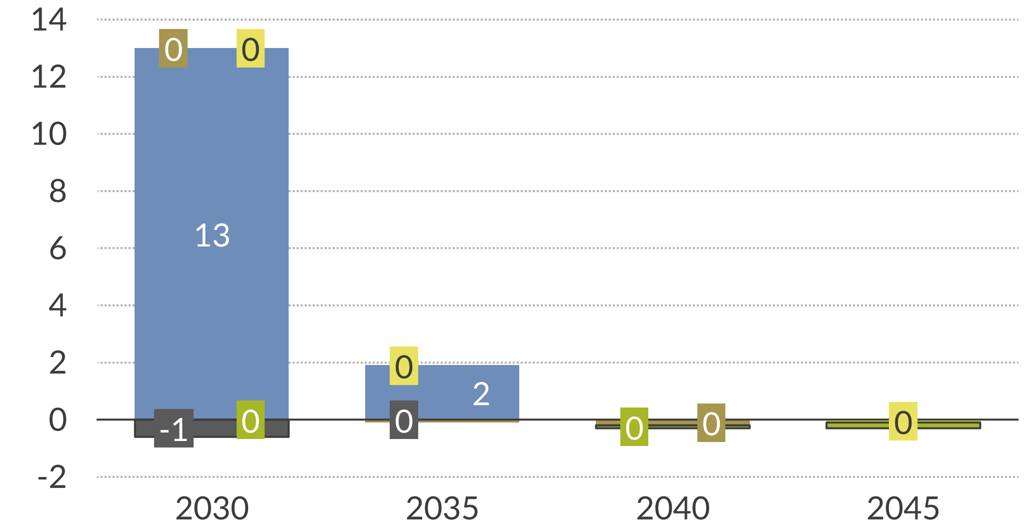
Increasing offshore wind capacity by 13 GW by 2030, leads to 1 GW of gas CCGT becoming uneconomical and going offline

Offshore wind dominated

Total installed capacity in Offshore wind dominated scenario



Delta between Offshore wind dominated and NZ 2035 base case



- In this scenario, **the government target of 50 GW of offshore wind by 2030 is met through the accelerated buildout of CfD supported capacity**
- Increasing offshore wind capacity by 13 GW by 2030 does not cause any other significant changes to the capacity mix, except for 1 GW of gas CCGT mothballing in 2030
- This scenario merges with the base case by 2040, as that is when offshore wind capacity in the Net Zero scenario is expected to reach 50 GW

Nuclear, Coal, Gas CCGT, Gas CCS, Hydrogen CCGT, Other thermal[3], Solar, Other RES[2], BECCS, Hydro, Offshore wind, Onshore wind, Pumped storage, Gas / oil peaker[1], Hydrogen peaker, Battery storage, DSR, Interconnectors

1) Peaking includes OCGT and reciprocating engines; 2) Other RES includes biomass, EfW, hydro, and marine; 3) Other thermal includes embedded CHP

Source: Aurora Energy Research

In 2030, the additional offshore wind generation replaces higher cost gas CCS and CCGT generation as well as interconnector imports

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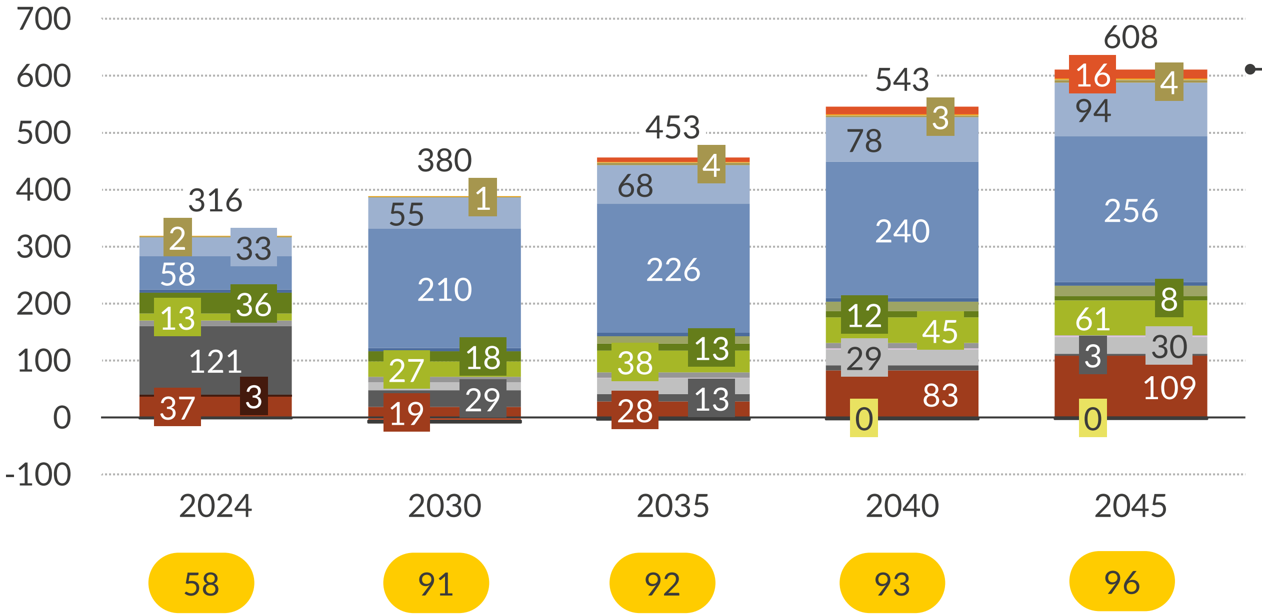
Offshore wind dominated

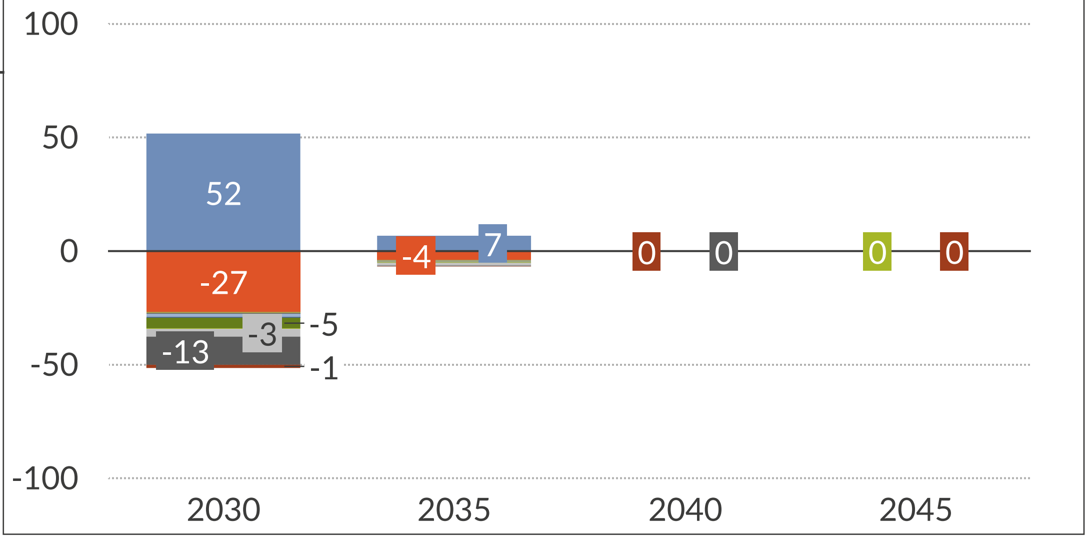
Total generation in Offshore wind dominated scenario

TWh



Delta between Offshore wind dominated and NZ 2035 base case

TWh



- The addition of 52 TWh of generation from offshore wind by 2030 displaces generation from more expensive technologies
- 27 TWh of interconnector imports are taken out of the generation mix in 2030, in addition to 17 TWh of gas-fired generation
- Generation in this scenario merges with the Net Zero base case by 2040

Nuclear, Coal, Gas CCGT, Gas CCS, Hydrogen CCGT, Other thermal[3], Solar, Other RES[2], BECCS, Hydro, Offshore wind, Onshore wind, Pumped storage, Gas / oil peaker[1], Hydrogen peaker, Battery storage, DSR, Interconnectors

xx % of demand met by low-carbon generation[4]

1) Peaking includes OCGT and reciprocating engines; 2) Other RES includes biomass, EfW, hydro, and marine; 3) Other thermal includes embedded CHP ; 4) Calculated as the sum of nuclear, gas CCS, hydrogen CCGT, wind, solar, BECCS, and other renewables generation over demand

Source: Aurora Energy Research

Increasing CfD supported offshore wind capacity brings down consumer costs as lower wholesale market prices outweigh the increase in subsidy

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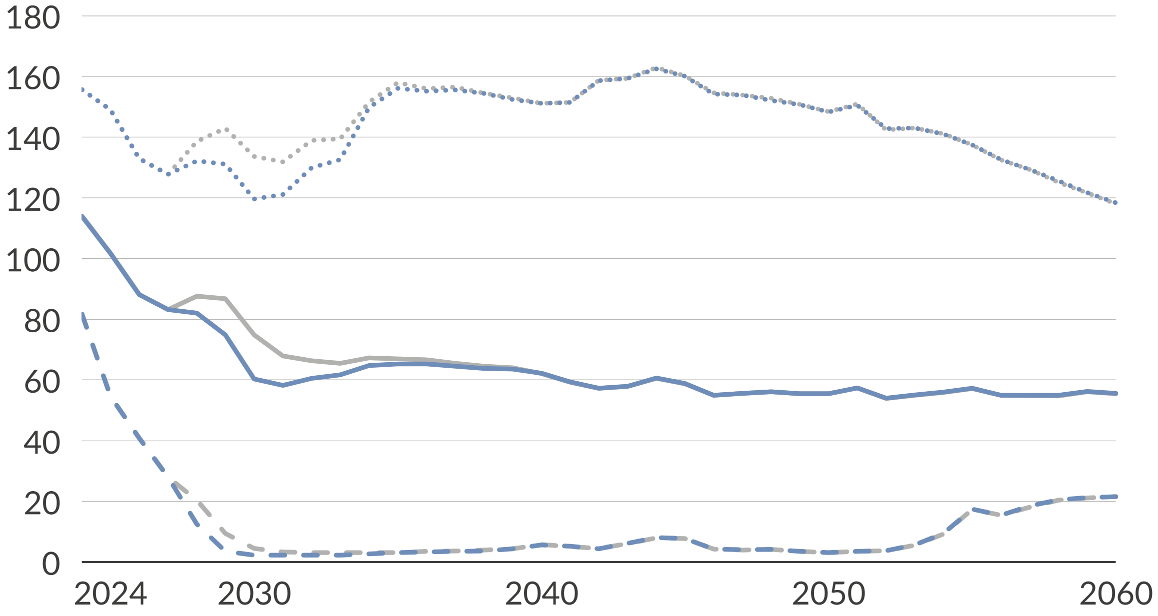
Offshore wind dominated

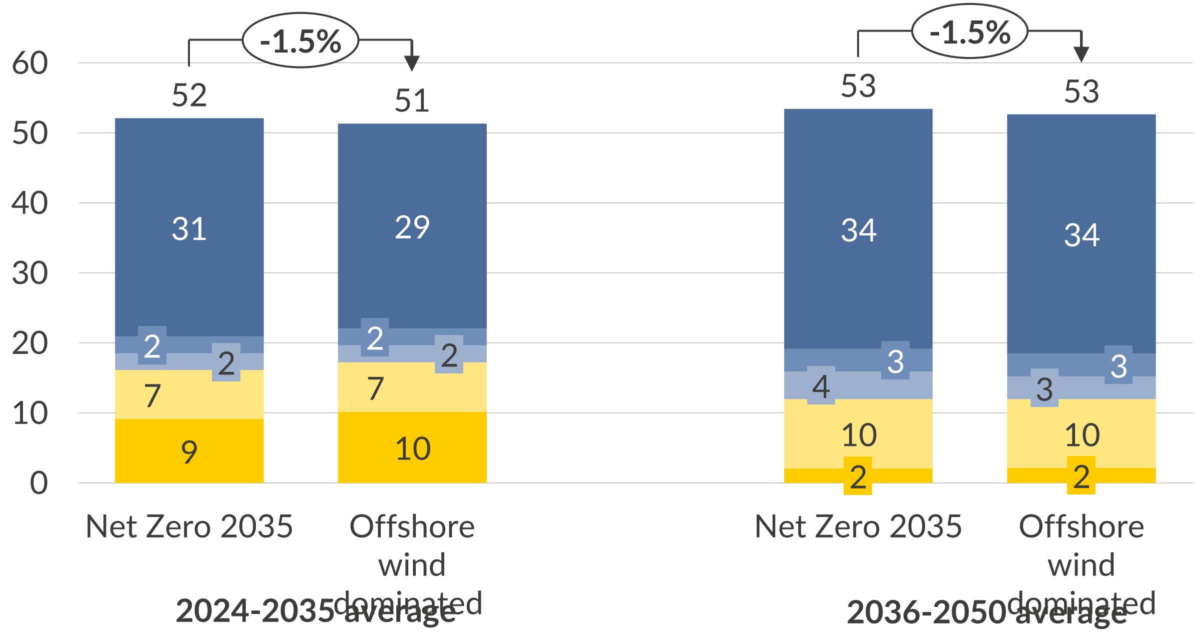
Wholesale market price
£/MWh (real 2022)



- The addition of offshore wind capacity causes bottom price to be lower than the base case between 2027 and 2030, after which prices are in line with renewable SRMCs
- Baseload and top prices are also lower prior to 2035 due to less IC imports and gas generation
- Power prices and the generation mix align with the base case around 2035

NetZero 2035 (Base case) · 5th Percentile · 95th Percentile · Offshore wind dominated · Baseload price

System cost breakdown
bn £ (real 2022)



- System costs decrease marginally (by 1.5%) with the coming online of 50 GW of offshore wind capacity by 2030
- The increase in subsidy costs is outweighed by the decrease in wholesale costs as more economical offshore wind generation displaces expensive interconnector imports and gas generation

Subsidy Spend · Capacity Market · Wholesale Market · Network Cost · Balancing Market

Source: Aurora Energy Research

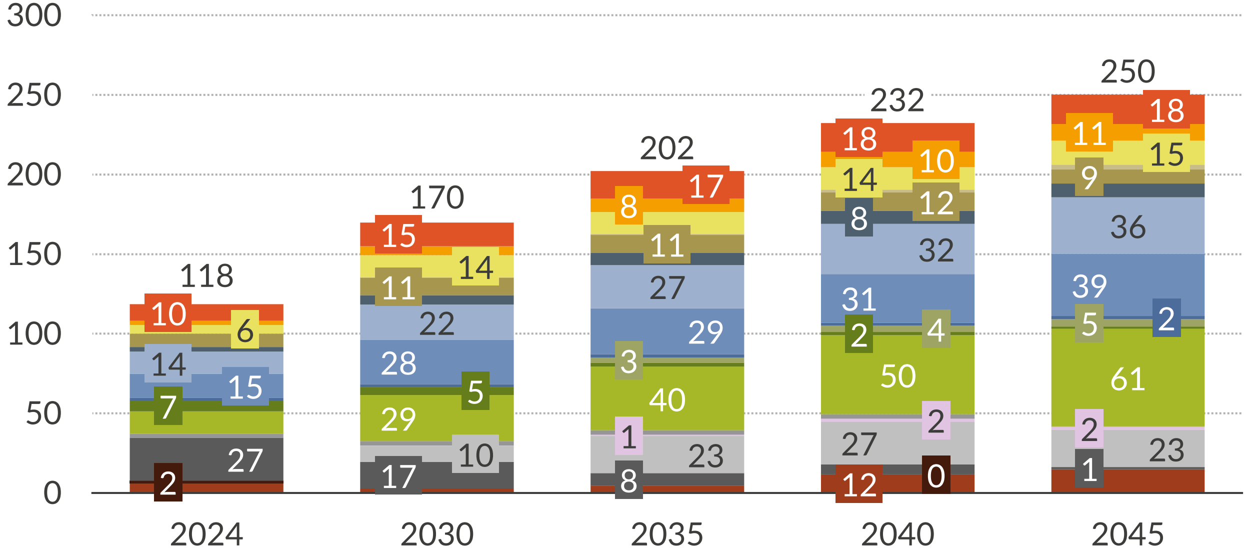
Replacing CfD-backed offshore wind with baseload gas CCS capacity also leads to peaking gas capacity being displaced from the system

AURORA

Gas CCUS dominated

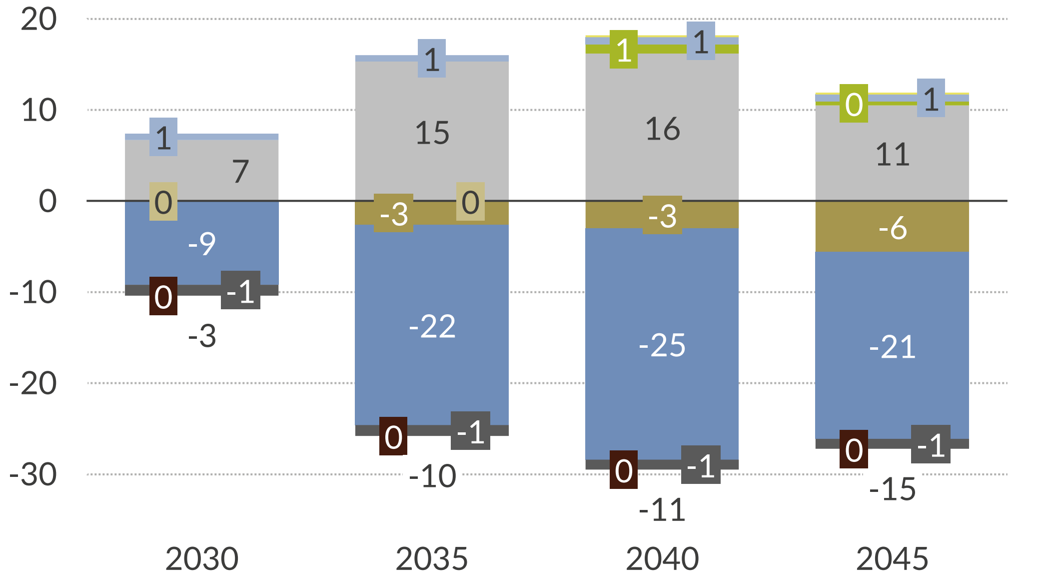
Total installed capacity in Gas CCUS dominated scenario

GW



Delta between Gas CCUS dominated and Net Zero base case

GW



- In this scenario, new CfD supported offshore wind capacity is replaced by gas CCS, which refers to gas-fired CCGTs combined with Carbon Capture and Storage (CCS) units. These operate in the same way as a regular gas CCGT, but with up to 95% less CO2 emissions
- The addition of baseload gas CCS capacity into the system, combined with the removal of offshore wind capacity, reduces the need for flexible capacity, leading to a lower buildout of gas peakers. The system has 3 GW less of gas peakers in 2035, compared to the base case
- It should be noted that no gas CCS capacity exists in GB at present and so the likelihood of successful mass deployment of this technology in the next 5 to 10 years is uncertain
- Gas CCS is assumed to operate at a load factor of 60-50%

Nuclear, Coal, Gas CCGT, Gas CCS, Hydrogen CCGT, Other thermal[3], Solar, Other RES[2], BECCS, Hydro, Offshore wind, Onshore wind, Pumped storage, Gas / oil peaker[1], Hydrogen peaker, Battery storage, DSR, Interconnectors

1) Peaking includes OCGT and reciprocating engines; 2) Other RES includes biomass, EfW, hydro, and marine; 3) Other thermal includes embedded CHP

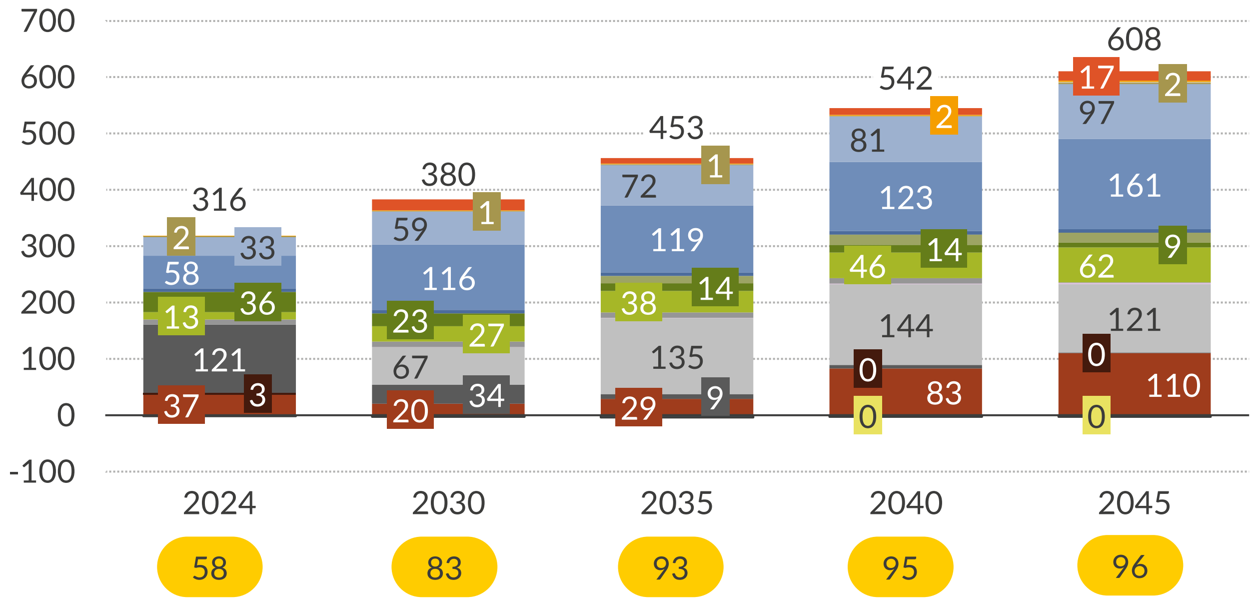
Source: Aurora Energy Research

In 2030, the additional offshore wind capacity replaces 16 TWh of Gas CCS and Gas CCGT generation

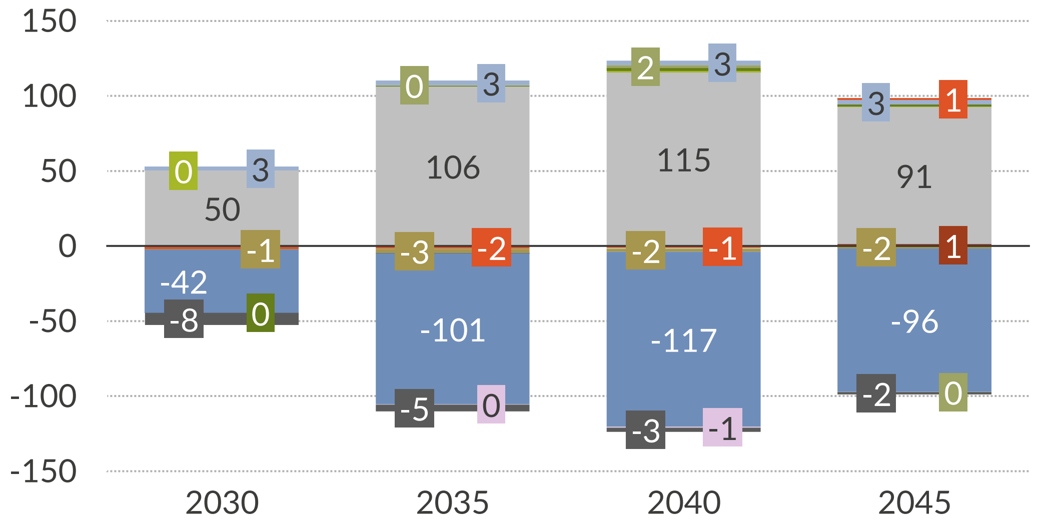
AURORA

Gas CCUS dominated

Total generation in Gas CCUS dominated scenario
TWh



Delta between Gas CCUS dominated and Net Zero base case
TWh



- Gas CCS plants are expected to have a lower running cost than unabated gas CCGTs. This is because they would face up to 95% less carbon costs, which would make up for the small loss in efficiency expected from adding on CCS capability to a CCGT
- The additional gas CCS generation displaces higher cost interconnector imports and gas peaking generation
- It also displaces some gas CCGT generation, as this is now a higher cost source of baseload power compared to gas CCS

Nuclear | Coal | Gas CCGT | Gas CCS | Hydrogen CCGT | Other thermal[3] | Solar | Other RES[2] | BECCS | Hydro | Offshore wind | Onshore wind | Pumped storage | Gas / oil peaker[1] | Hydrogen peaker | Battery storage | DSR | Interconnectors

XX % of demand met by low-carbon generation[4]

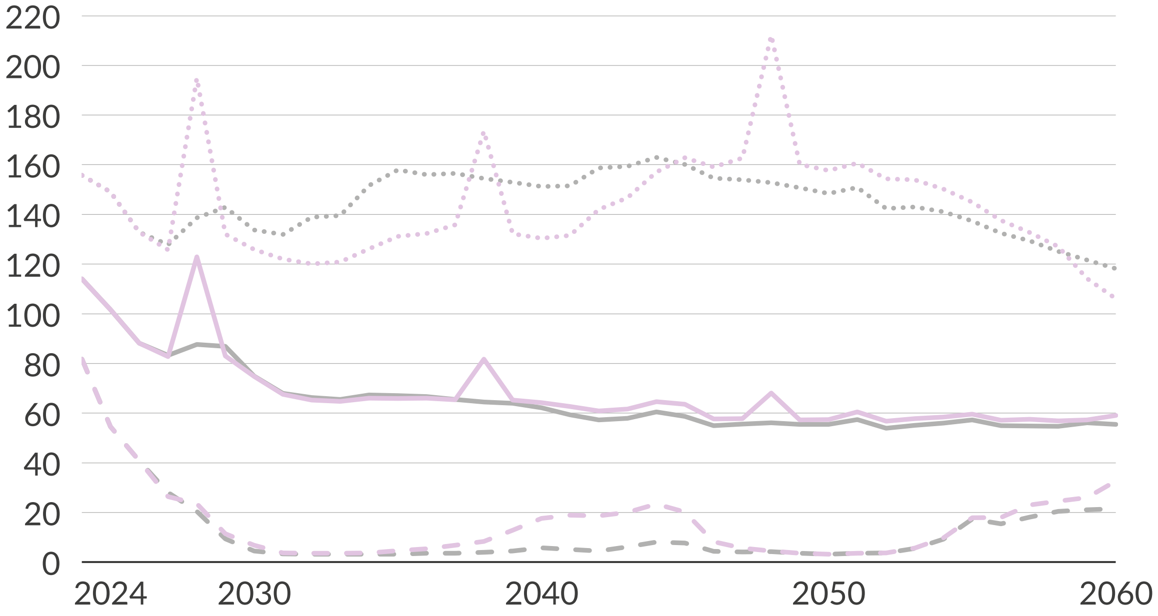
1) Peaking includes OCGT and reciprocating engines; 2) Other RES includes biomass, EfW, hydro, and marine; 3) Other thermal includes embedded CHP ; 4) Calculated as the sum of nuclear, gas CCS, hydrogen CCGT, wind, solar, BECCS, and other renewables generation over demand
Source: Aurora Energy Research

Replacing CfD supported offshore wind with gas CCS capacity has a negligible effect on average total system costs

AURORA

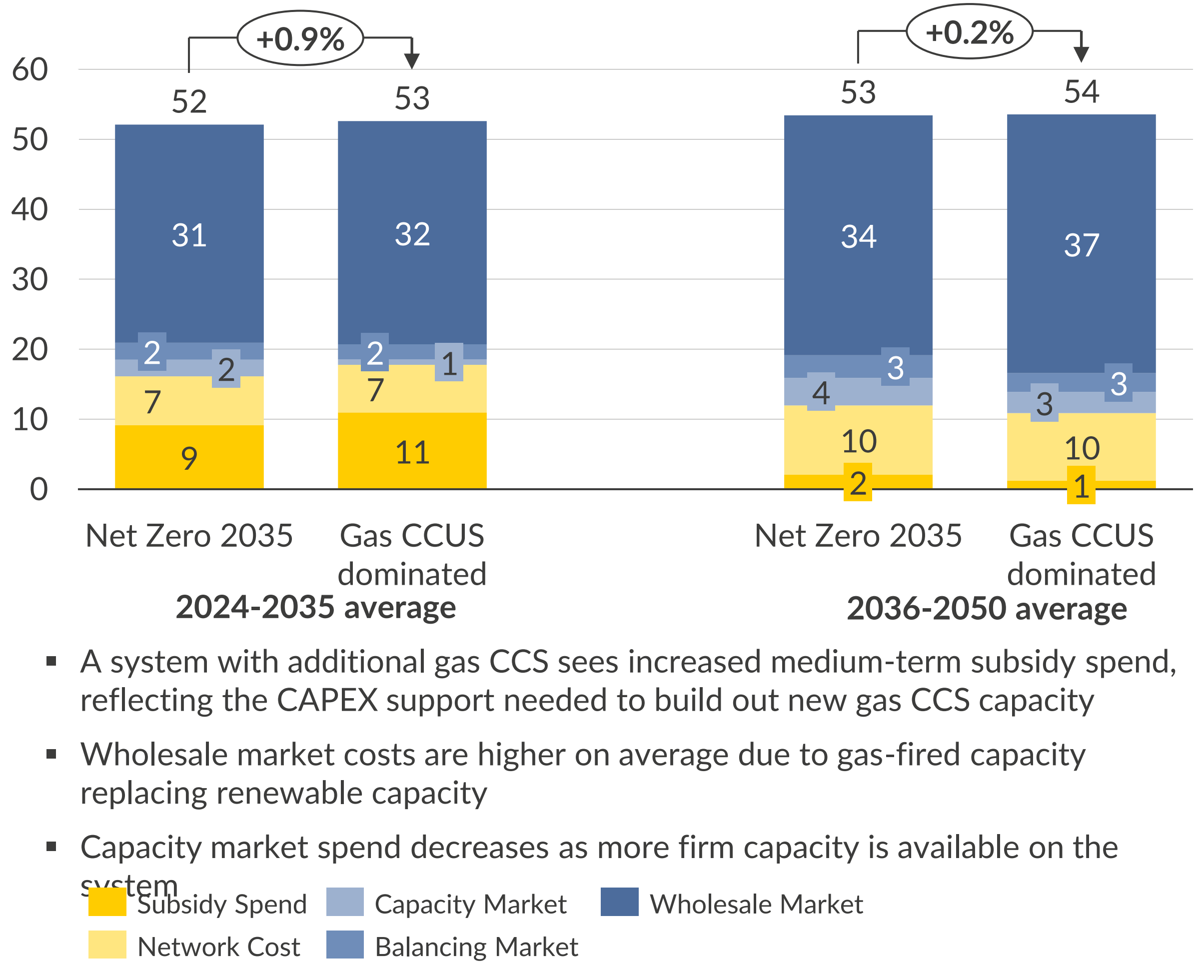
Gas CCUS dominated

Wholesale market price
£/MWh (real 2022)



- This scenario assumes periodic price spikes which could be caused due to a number of extrinsic shock events such as geopolitical conflict or infrastructure disruption
- Although it has more gas-fired generation compared to the base case, top prices are lower up to 2050 as baseload gas CCS displaces more expensive gas peakers
- The effect of price spikes is seen to be localised to one year at a time

System cost breakdown
bn £ (real 2022)



- A system with additional gas CCS sees increased medium-term subsidy spend, reflecting the CAPEX support needed to build out new gas CCS capacity
- Wholesale market costs are higher on average due to gas-fired capacity replacing renewable capacity
- Capacity market spend decreases as more firm capacity is available on the system

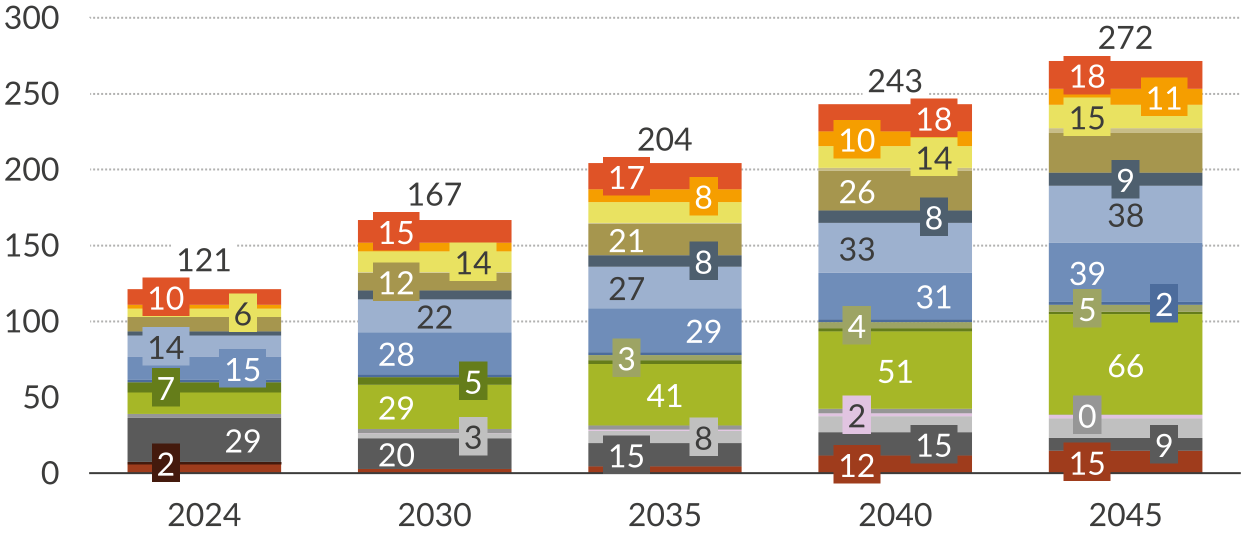
Source: Aurora Energy Research

A system in which CfD-backed offshore wind capacity is replaced with unabated gas capacity does not reach Net Zero by 2035

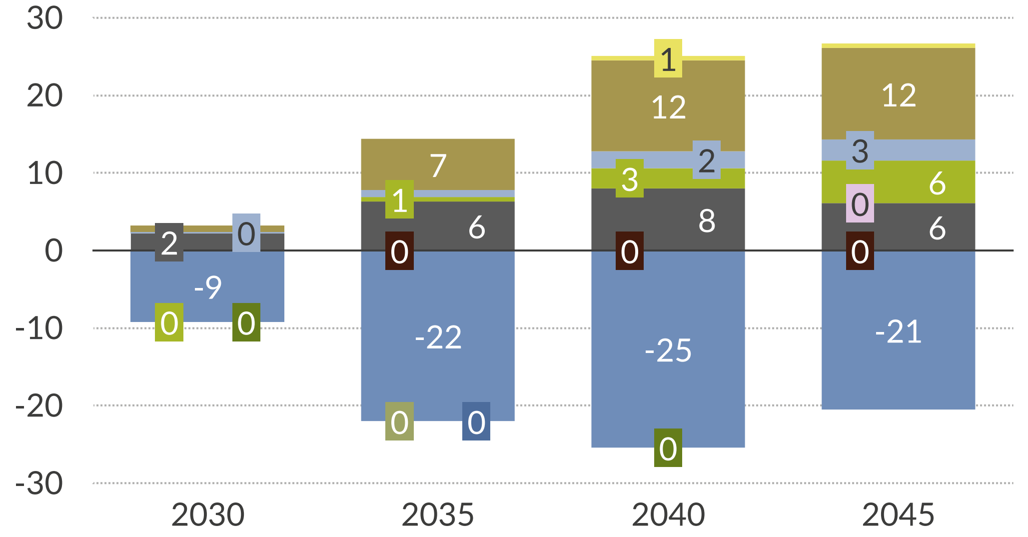
AURORA

Unabated gas dominated

Total installed capacity in Unabated gas dominated scenario
GW



Delta between Unabated gas dominated and Net Zero base case
GW



- In this scenario, we have assumed that peaking as well as baseload gas capacity replaces offshore wind
- This scenario sees a delta of 7 GW of peaking capacity and 6 GW of CCGT capacity compared to the base case in 2035
- There is also some buildout of merchant renewables, namely onshore wind and solar

Nuclear, Coal, Gas CCGT, Gas CCS, Hydrogen CCGT, Other thermal[3], Solar, Other RES[2], BECCS, Hydro, Offshore wind, Onshore wind, Pumped storage, Gas / oil peaker[1], Hydrogen peaker, Battery storage, DSR, Interconnectors

1) Peaking includes OCGT and reciprocating engines; 2) Other RES includes biomass, EfW, hydro, and marine; 3) Other thermal includes embedded CHP

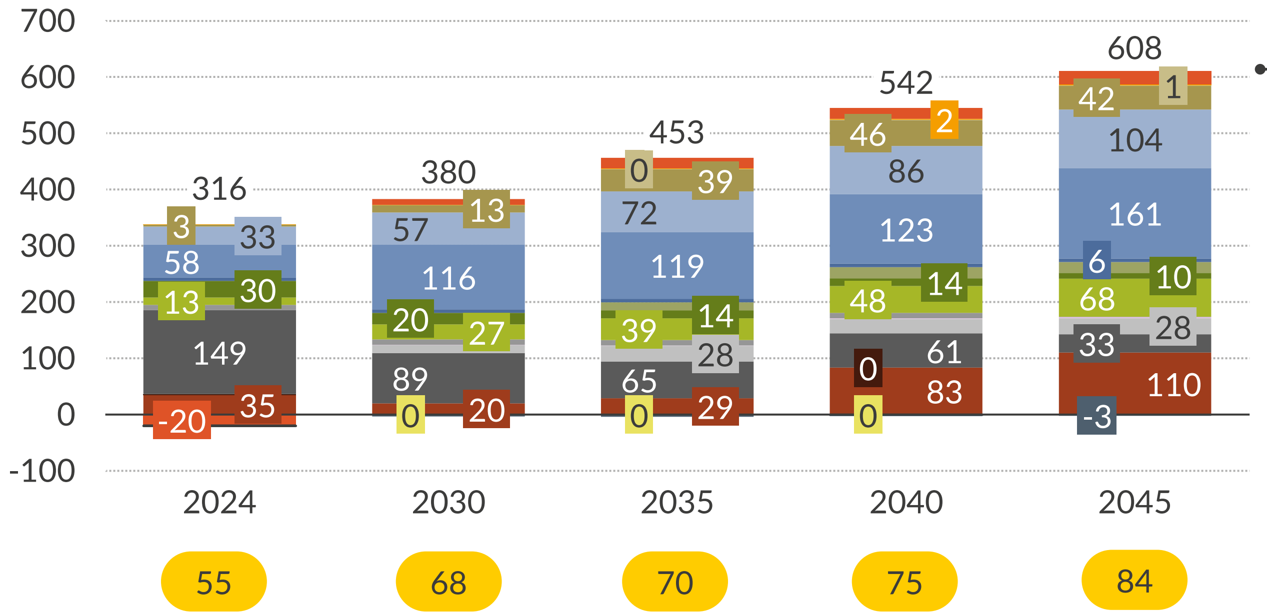
Source: Aurora Energy Research

Although significant gas-fired capacity is added in this scenario, interconnector imports are still required to replace all lost offshore wind generation

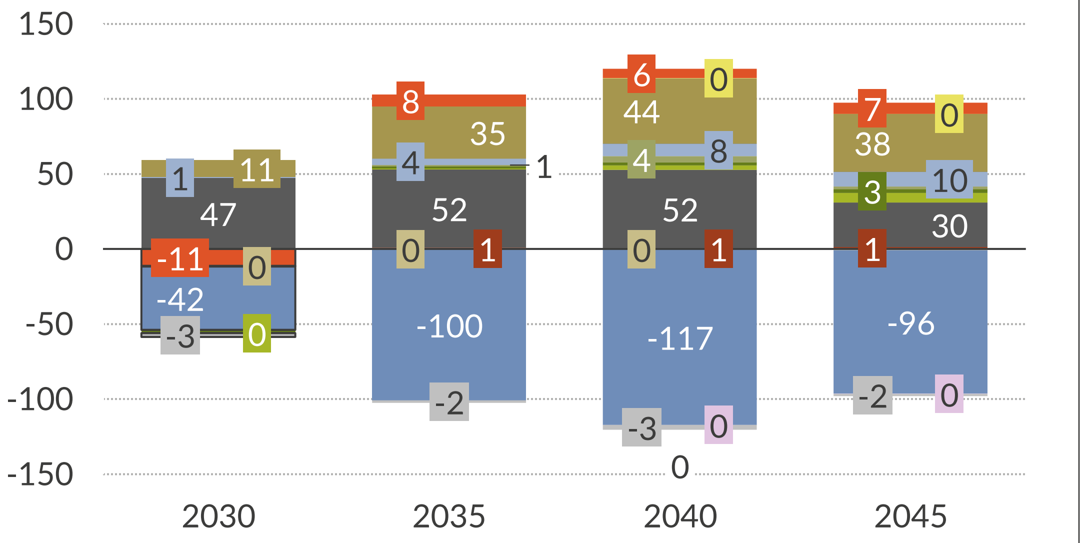
AURORA

Unabated gas dominated

Total generation in Unabated gas dominated scenario
TWh



Delta between Unabated gas dominated and Net Zero base case
TWh



- The increase in the penetration of renewables in the system leads to fewer high price periods during which gas assets typically run. Due to worsening economics for unabated gas assets moving forward, they are unable to make up for the total reduction in offshore wind generation, despite sufficient gas-fired capacity being present on the system
- In 2035, Unabated gas dominated scenario has 100TWh less offshore wind than the base case. This is replaced by 52 TWh of CCGT generation and 35 TWh of gas peaker generation, plus 7.5 TWh of interconnector imports. This scenario also incentivises additional merchant renewable generation
- CCGTs are assumed to run at load factors of 50 to 35% and gas recips at 35 to 25% (with load factors decreasing over time)

Nuclear, Coal, Gas CCGT, Gas CCS, Hydrogen CCGT, Other thermal[3], Solar, Other RES[2], BECCS, Hydro, Offshore wind, Onshore wind, Pumped storage, Gas / oil peaker[1], Hydrogen peaker, Battery storage, DSR, Interconnectors

xx % of demand met by low-carbon generation[4]

1) Peaking includes OCGT and reciprocating engines; 2) Other RES includes biomass, EfW, hydro, and marine; 3) Other thermal includes embedded CHP ; 4) Calculated as the sum of nuclear, gas CCS, hydrogen CCGT, wind, solar, BECCS, and other renewables generation over demand

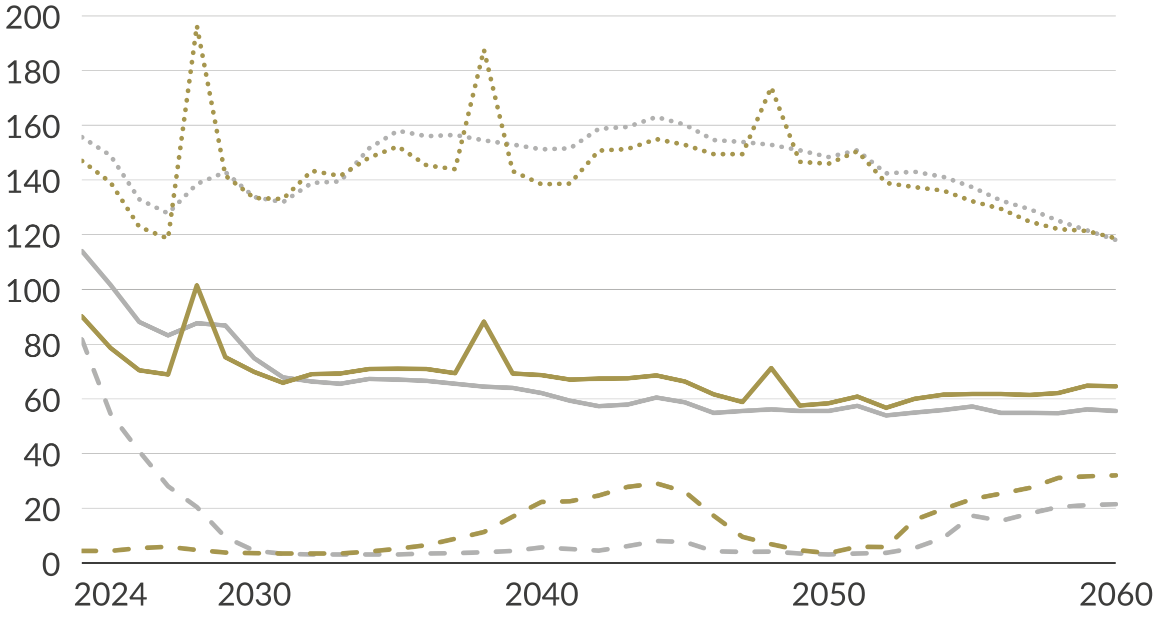
Source: Aurora Energy Research

Increased gas-fired capacity on the system leads to higher power market prices on average

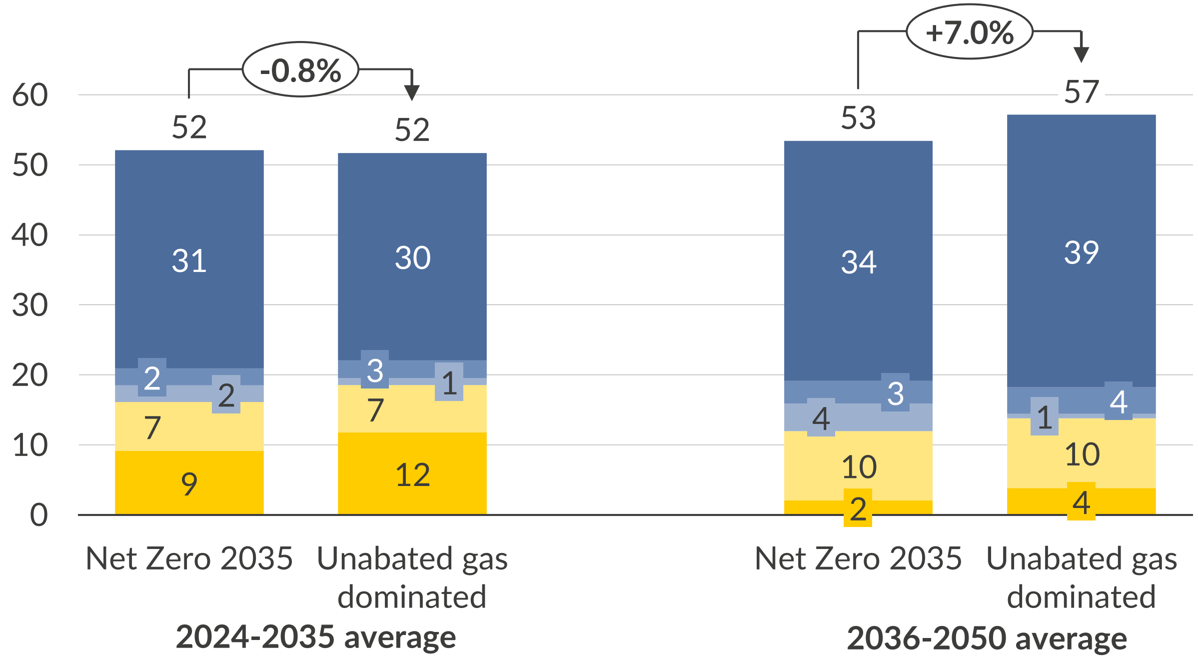
AURORA

Unabated gas dominated

Wholesale market price
£/MWh (real 2022)



System cost breakdown
bn £ (real 2022)



- Top prices decrease as the addition of baseload gas-fired capacity (CCGTs) in addition to the loss in variable offshore wind generation reduces the need for gas peakers on the system
- However, baseload prices are higher in the base case as a majority of generation is now being provided by expensive gas plants
- Periodic gas price spikes cause corresponding temporary increases in power price

NetZero 2035 (Base case) · 5th Percentile · 95th Percentile · Unabated gas dominated · Baseload price

- Scenario 5 has the highest total system costs of all scenarios due to the presence of large amounts of expensive gas-fired generation on the system (reflected in wholesale market costs)
- Subsidy spend also increases in order to bring new gas plants online amid weakening CCGT and peaker economics

Subsidy Spend · Capacity Market · Wholesale Market · Network Cost · Balancing Market

Source: Aurora Energy Research

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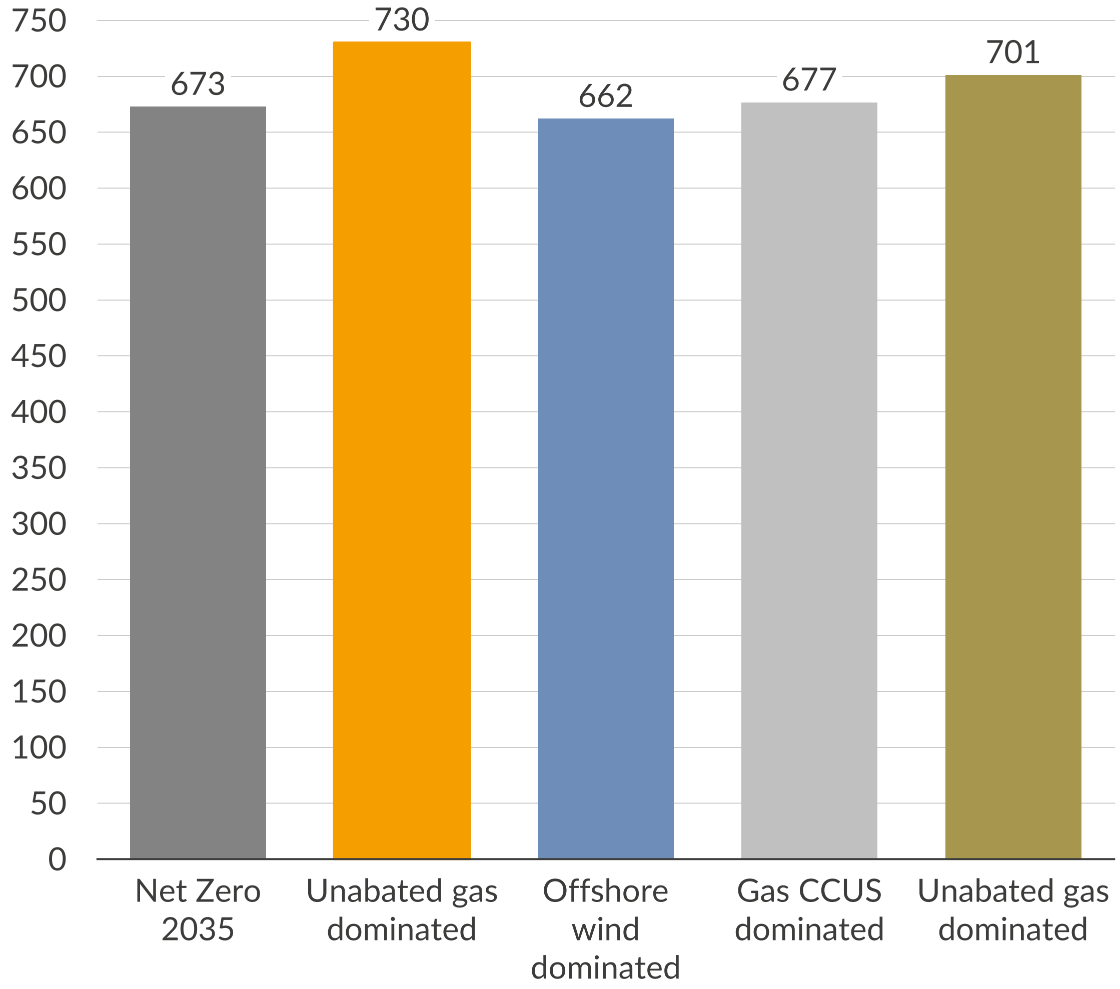
AURORA

Scenarios with no new CfD supported offshore wind typically increase electricity cost per household, especially when it is replaced by gas generation

AURORA

Wholesale electricity generation cost per household, 2025-2050 average
£/year/household, real 2022



An increased share of renewables in the energy mix is projected to benefit consumers with lower costs over 2025-2050

Methodology

- We multiply the total system costs for the different scenarios modelled previously by the proportion of total power demand from the domestic sector (36%) and divide that by the number of households in GB (28.2 million)
- This gives us the 'electricity cost per household' metric, which can be used to compare the impact of different power systems on consumer bills in a simplified manner

Relevance

- Three scenarios with no new offshore wind show higher household bills than the base case, as more economical offshore wind typically has to be replaced by expensive gas generation or interconnector imports
- A scenario in which 50GW of offshore wind is built by 2030 sees lower household bills than the base case. However, this would require accelerated policy and subsidy support for offshore wind as well as accelerated grid development
- This indicates that a realistic and cost-effective approach to Net Zer o2035 requires a mix of technologies, of which offshore wind and other renewables form a key pillar, in addition to baseload nuclear, abated gas, hydrogen, as well as biomass with carbon capture (BECCS)

Source(s): Aurora Energy Research

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AURORA

An increase in electricity costs has been found to increase inflation and reduce GDP growth in the UK

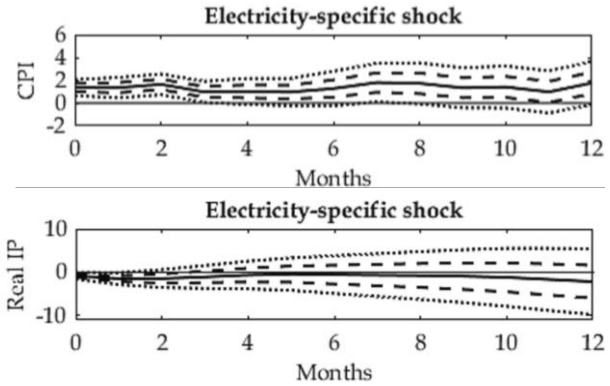
AURORA

Aurora has reviewed and summarized recent literature studying the impact of changes in electricity price on the economic landscape of developed nations, with a focus on the United Kingdom

Title	Key findings

The electric shock: Causes and consequences of electricity prices in the United Kingdom[1]

- Electricity price increases significantly contribute to CPI inflation in the UK, with electricity-specific shocks having a substantial inflation pass-through effect.
- Marginal negative impacts on real industrial production are observed following electricity-specific shocks; however, the industrial sector shows resilience with production recovering within two months.
- Higher electricity prices place additional pressure on household and business budgets, potentially reducing consumer spending and investment, thereby causing a ripple effect on economic growth and employment rates



Introducing a large panel dataset of economy-wide real electricity prices and estimating long-run GDP and price elasticities of electricity demand for high-and middle income panels[2]

- In high-income European economies, including the UK, higher electricity prices escalate production costs, directly restraining GDP growth by compelling businesses to reduce output or increase product prices.
- Increased electricity costs diminish consumer disposable income, leading to lower spending on goods and services, which, in turn, indirectly suppresses GDP growth.
- The rising cost of electricity can drive investment towards energy efficiency and renewable energy sources, potentially altering the composition of GDP by fostering growth in these sectors.

Model	GDP Elasticity	Price Elasticity	GDP w/o Price Elasticity
ADL (1,1,1)	0.544****	-0.119*	0.695**
ADL (1,0,0)	0.629****	-0.0941***	0.810****
Static	0.551****	-0.0720***	0.611****

1) Ganepola, C. N., Shubita, M., & Lee, L. (2023). The electric shock: Causes and consequences of electricity prices in the United Kingdom. *Energy Economics*, *126*, 107030. https://doi.org/10.1016/j.eneco.2023.107030; 2) Liddle, B. (2022). Introducing a large panel dataset of economy-wide real electricity prices and estimating long-run GDP and price elasticities of electricity demand for high-and middle-income panels. Journal of Energy History / Revue d'Histoire de l'Énergie [Online], (7). Retrieved from https://energyhistory.eu/en/node/293

Similar results have been found in studies conducted in European Union countries

AURORA

Despite varying approaches to examining the effects of electricity price surges, scholars ultimately converge on similar conclusions regarding their impact on the UK economy.

Title	Key findings
Revisiting the impact of energy prices on economic growth: Lessons learned from the European Union[1]	▪ Higher residential electricity prices are linked to negative GDP growth, indicating a conservation effect where increases in residential energy costs can dampen economic expansion. ▪ Increases in industrial electricity prices positively influence economic growth, suggesting that within certain limits, higher prices in this sector may reflect or contribute to economic vitality. ▪ The interconnectedness of energy markets is highlighted by the causal relationship showing that rises in industrial electricity and crude oil prices can lead to increased residential electricity prices, affecting both residential and industrial energy consumers.

Conclusions

- Rising electricity prices drive inflation, reducing consumer disposable income and spending, which indirectly hampers GDP growth. This underlines the broad economic strain on residential consumers from escalating energy costs.
- The industrial sector exhibits resilience to electricity price hikes, with production bouncing back quickly. Elevated electricity prices, within certain thresholds, can signal or bolster economic health, emphasizing the complex relationship between energy costs and industrial productivity.
- Increased electricity costs catalyze investment in energy efficiency and renewables across both residential and industrial sectors. This not only adapts to rising expenses but also potentially shifts GDP composition towards sustainable growth, marking a strategic pivot towards green energy solutions.

1) Dagoumas, A. S., Polemis, M. L., & Soursou, S.-E. (2020). Revisiting the impact of energy prices on economic growth: Lessons learned from the European Union. Economic Analysis and Policy, 66, 85–95. https://doi.org/10.1016/j.eap.2020.02.013

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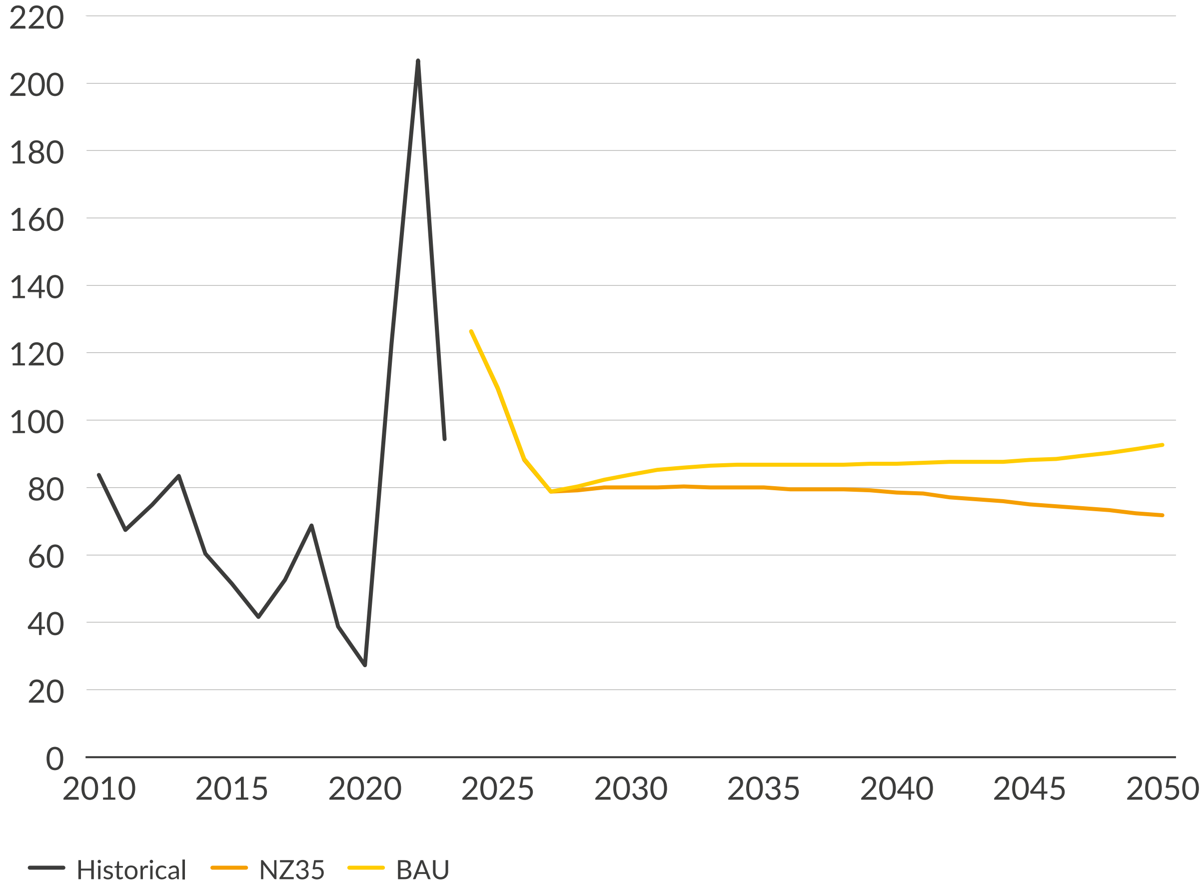
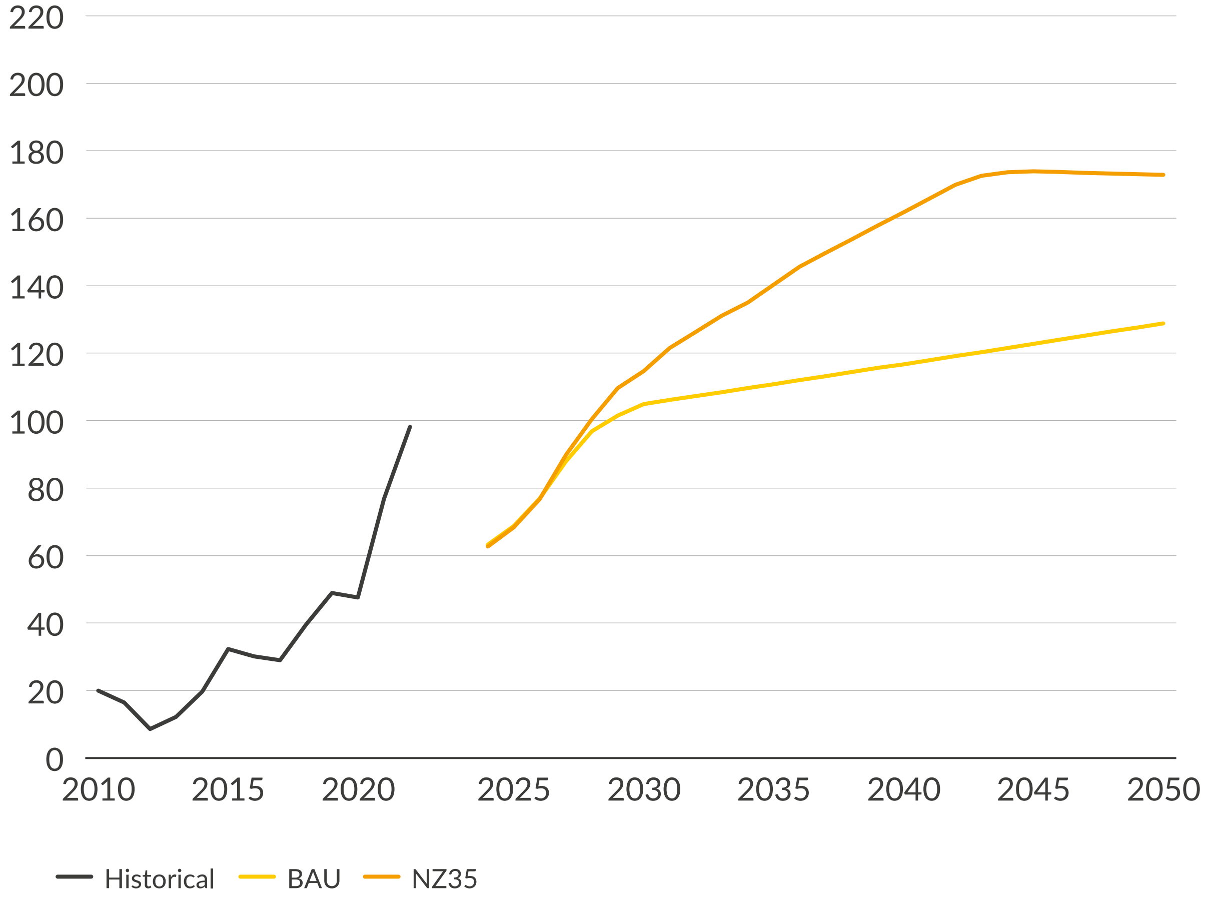
To reach Net Zero in 2030 carbon price mechanisms must be addressed to displace carbon intensive power sources

AURORA

Natural gas prices
p/therm (real 2022)



Carbon prices (UK ETS + CPS)
£/tCO_2 (real 2022)



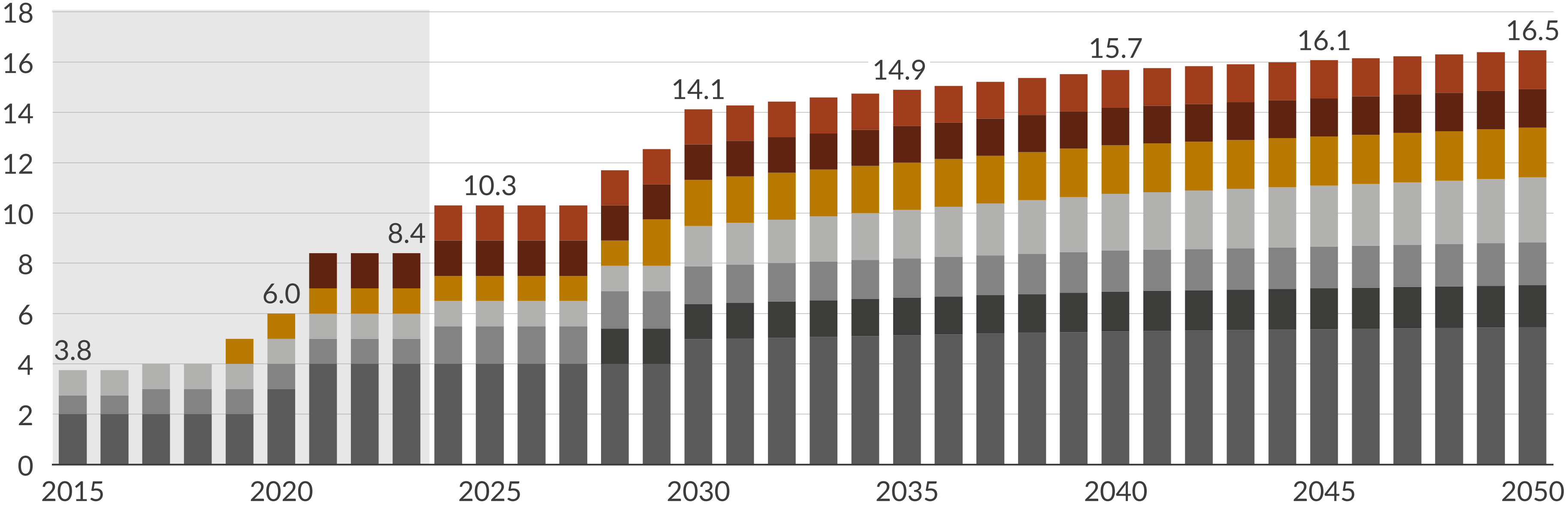
Source(s): Aurora Energy Research

Given the high amount of uncertainty about interconnector deployment, we assume total capacity to reach 14.9GW by 2035

AURORA

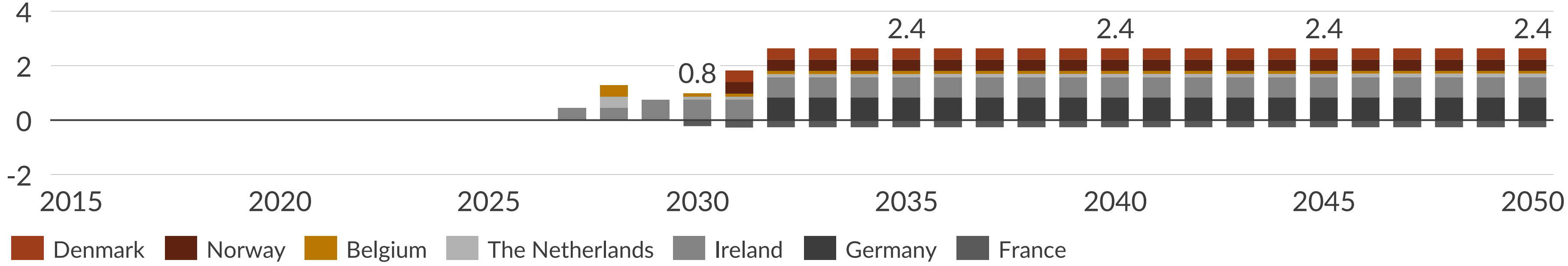
Installed interconnector capacity[1] – Aurora BAU

GW



Installed interconnector capacity delta[1] – Aurora Net Zero Scenarios

GW



- Given the uncertainty around interconnector deployment post-Brexit, we assume total capacity to reach 14.1 GW by 2030 and 16.9 GW by 2060
- Beyond the projects which have already started construction, we consider it possible for three more projects to deploy up to 2030[2]: one each to Belgium, the Netherlands and France
- After 2030 we anticipate further gradual capacity build-out, in line with expanding renewable capacities

1) Based on end-of-year capacity; 2) The capacities of the three projects currently in development are de-rated in our scenario according to their development stage to reflect historic success rates.

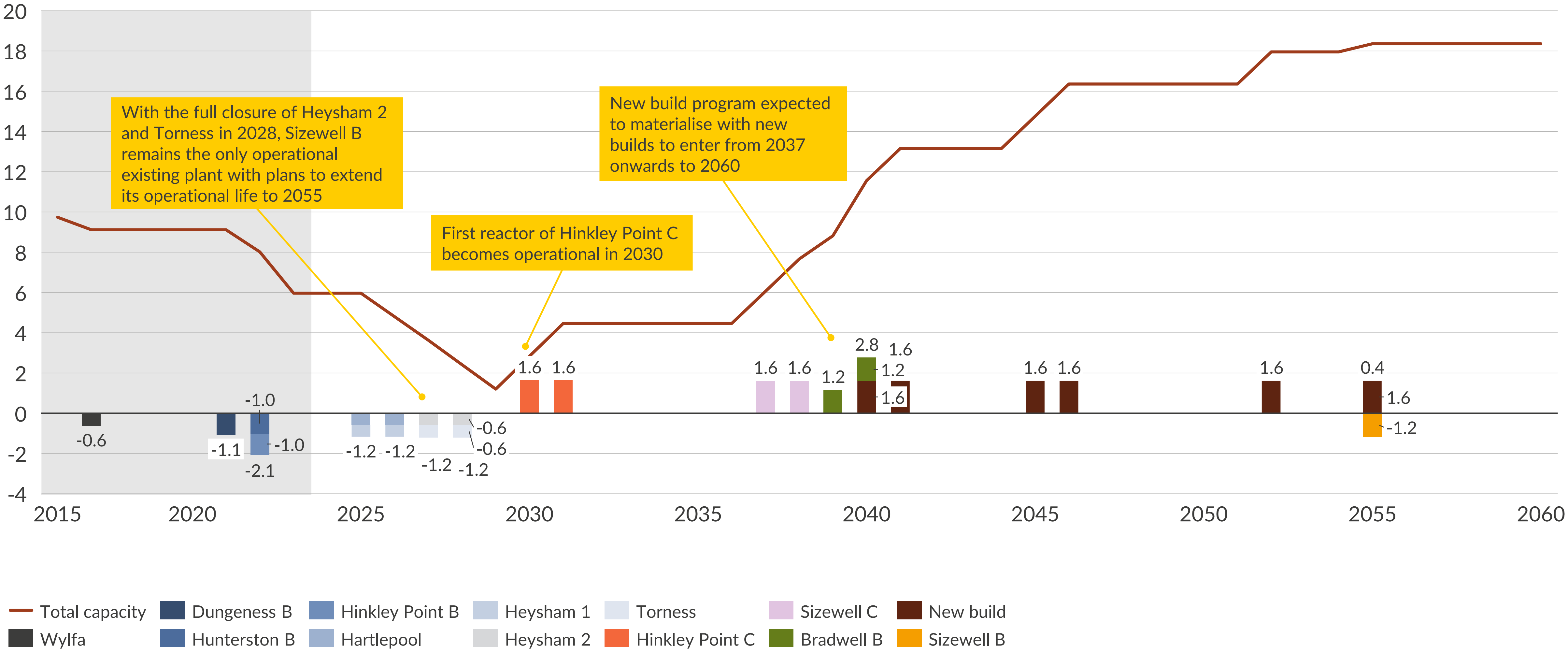
Source(s): Aurora Energy Research, Ofgem, European Commission

In all scenarios Aurora assumes 5GW of existing nuclear will decommission by 2030, while 13.9GW of new builds deliver beyond Hinkley Point C

AURORA

Installed nuclear capacity – All scenarios

GW



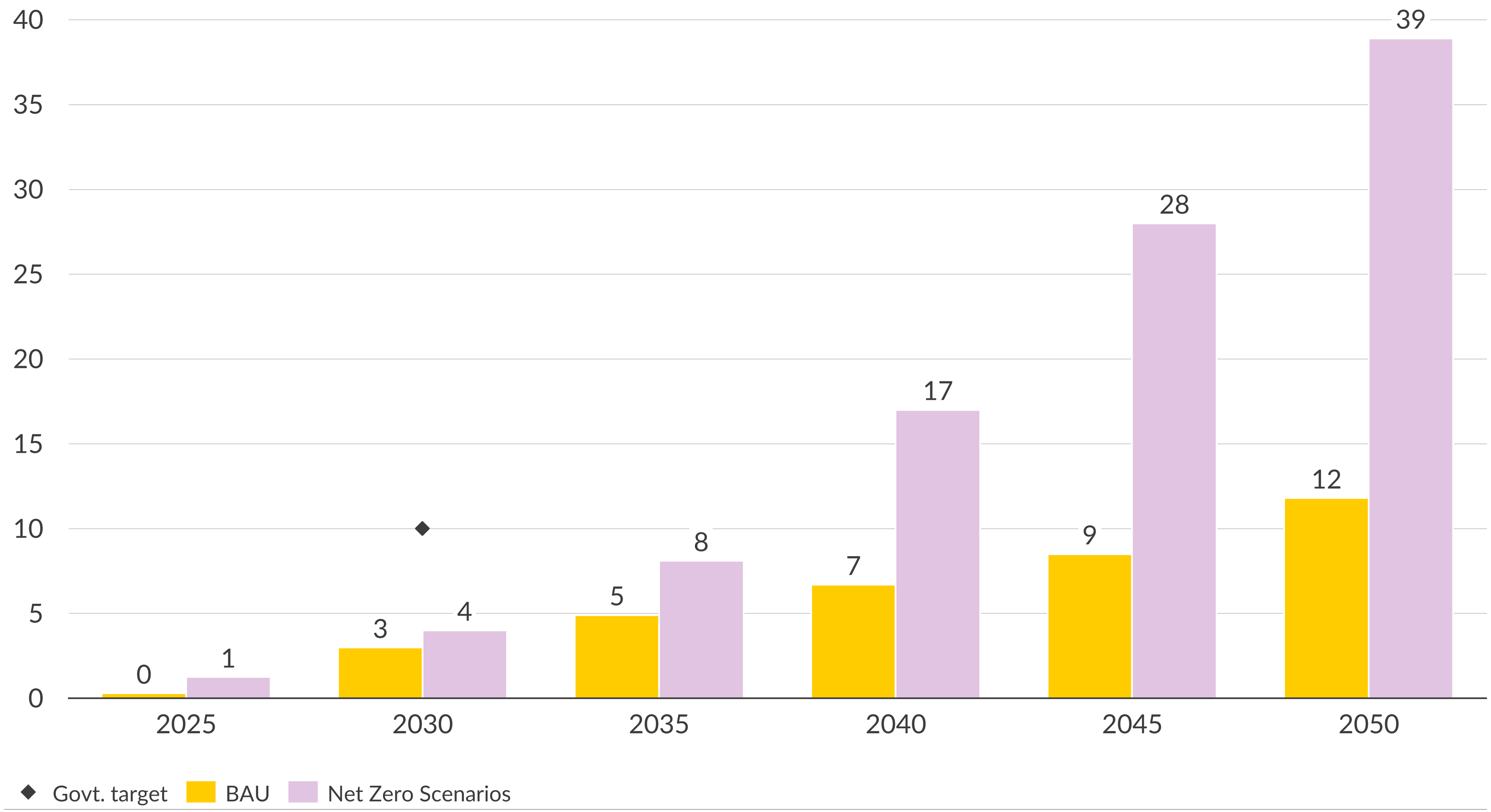
1) Line chart represents end-of-year capacity.

Source(s): Aurora Energy Research

Government targets 10GW of low carbon hydrogen production by 2030, electrolyser capacity is expected to reach 12GW by 2050

Electrolyser capacity timeline

Installed capacity GW (H_2)



- Aurora's BAU scenario assumes 3GW of low carbon hydrogen production by 2030 with a mix of electrolysis and gas reformation
- For green hydrogen production which directly impacts the power sector, we assume 5GW of large-scale alkaline electrolysers by 2035
- In the Net Zero scenarios, further electrolyser capacity is anticipated, reaching 8GW in 2035
- The Government's ambition is for up to 10GW of low carbon hydrogen capacity by 2030 as published in the 2022 British Energy Security Strategy (BESS) and the August 2022 Hydrogen Strategy Update

Source(s): Aurora Energy Research

Contents

Unique, proprietary, in-house modelling capabilities underpin Aurora's superior analysis

4 Integrated Models

- Hydrogen (AER-HY)
- Carbon (AER-ETS)
- Power markets (AER-ES)
- Global Commodities & Gas (AER-GLO/GAS)

INPUTS

- Technology
- Policy
- Demand
- Commodity prices[1]
- Weather patterns

Dispatch model

- ½ hourly or hourly
- Iterative modelling
- Dynamic dispatch of plant
- Endogenous interconnector flows

Continuous iteration until an equilibrium is reached

Investment decisions module

- Capacity market modelling
- Capacity build / exit / mothballing
- IRR / NPV driven
- Detailed technology assessments

OUTPUTS

- Capacity mix
- Generation mix
- Wholesale & imbalance prices
- Capacity market prices
- Profit / Loss and NPV
- Electric vehicle charging

1) Gas, coal, oil and carbon prices fundamentally modelled in-house with fully integrated commodities and gas market model

Source(s): Aurora Energy Research

Aurora's GB locational balancing model simulates power flows across key network boundaries to forecast system actions in the balancing mechanism

AURORA

Aurora's **locational balancing capabilities** simulate thermal constraints and associated system actions used to manage power flows across the B6 and B8 network boundaries. These additional features aim to capture the impact of thermal constraints on market prices which influence the capacity and generation mix in GB.

1 Inputs

Identify key constraints and assumptions for their future transfer capabilities

- **Identify B6 and B8 boundaries as key bottlenecks** in the GB transmission network
- **Plant Mapping -** allocating plants to specific balancing zones
- **Demand Mapping** – allocating demand to specific balancing zones

2 Balancing Module

Solve for system and energy balancing actions

- **Solve system balancing** by re-dispatching with boundary transfer (thermal) constraints, using unconstrained dispatch as starting point
- **Determine energy balancing** merit order stacks based on weather and demand uncertainty and wholesale market opportunity costs
- **Calculate system price** based on energy balancing actions

3 Balancing Market Outcomes

…to determine the balancing market volumes and prices at half-hourly granularity

- **Average accepted bids/offers** by balancing zone
- **Balancing Mechanism profits** by plant
- Stochastic system-wide **Balancing Mechanism price**
- System-wide **Gross Imbalance Volumes (**Net Imbalance and Bidirectional balancing)

4 Market-wide Outcomes

These are fed into the model's build decisions to determine asset-specific revenues

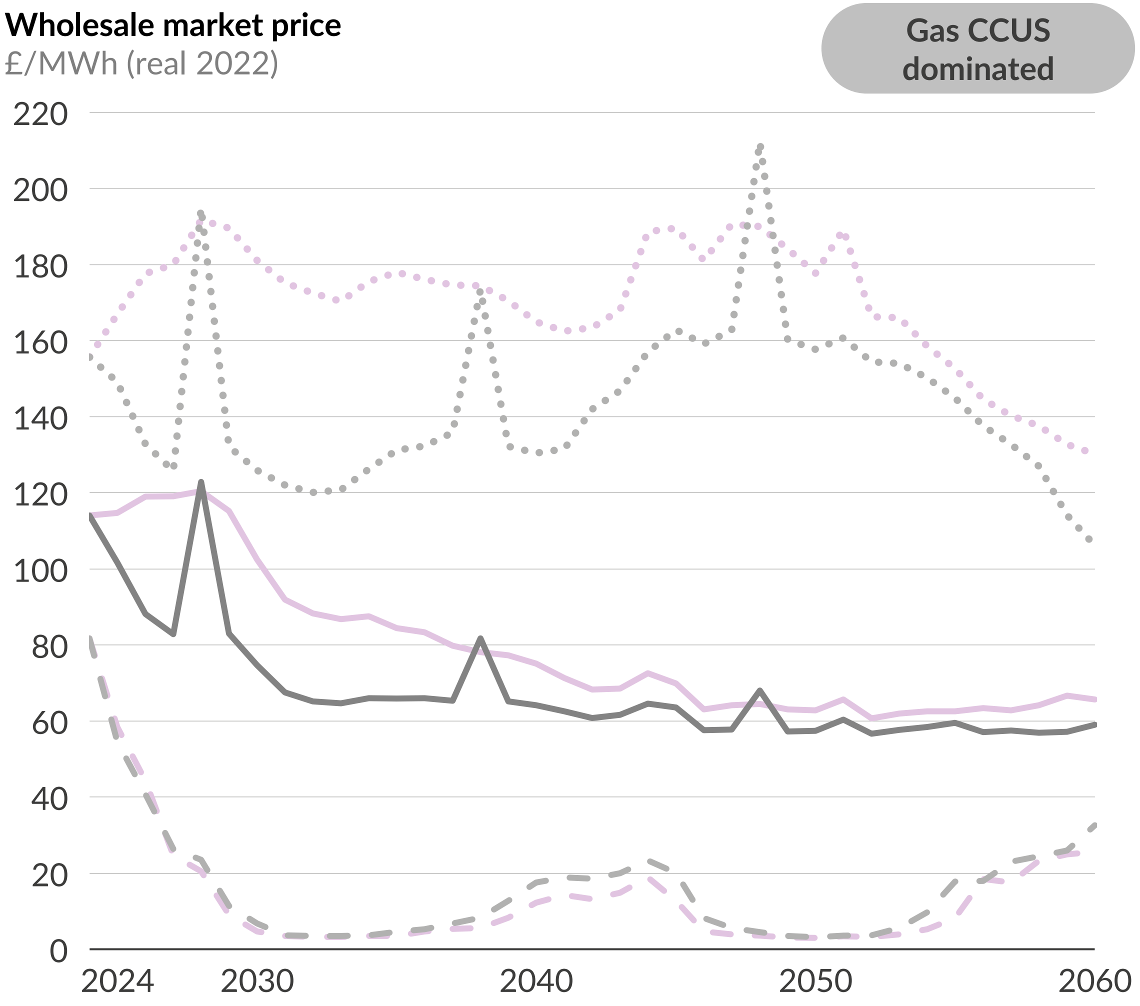
- **Capacity build decisions**

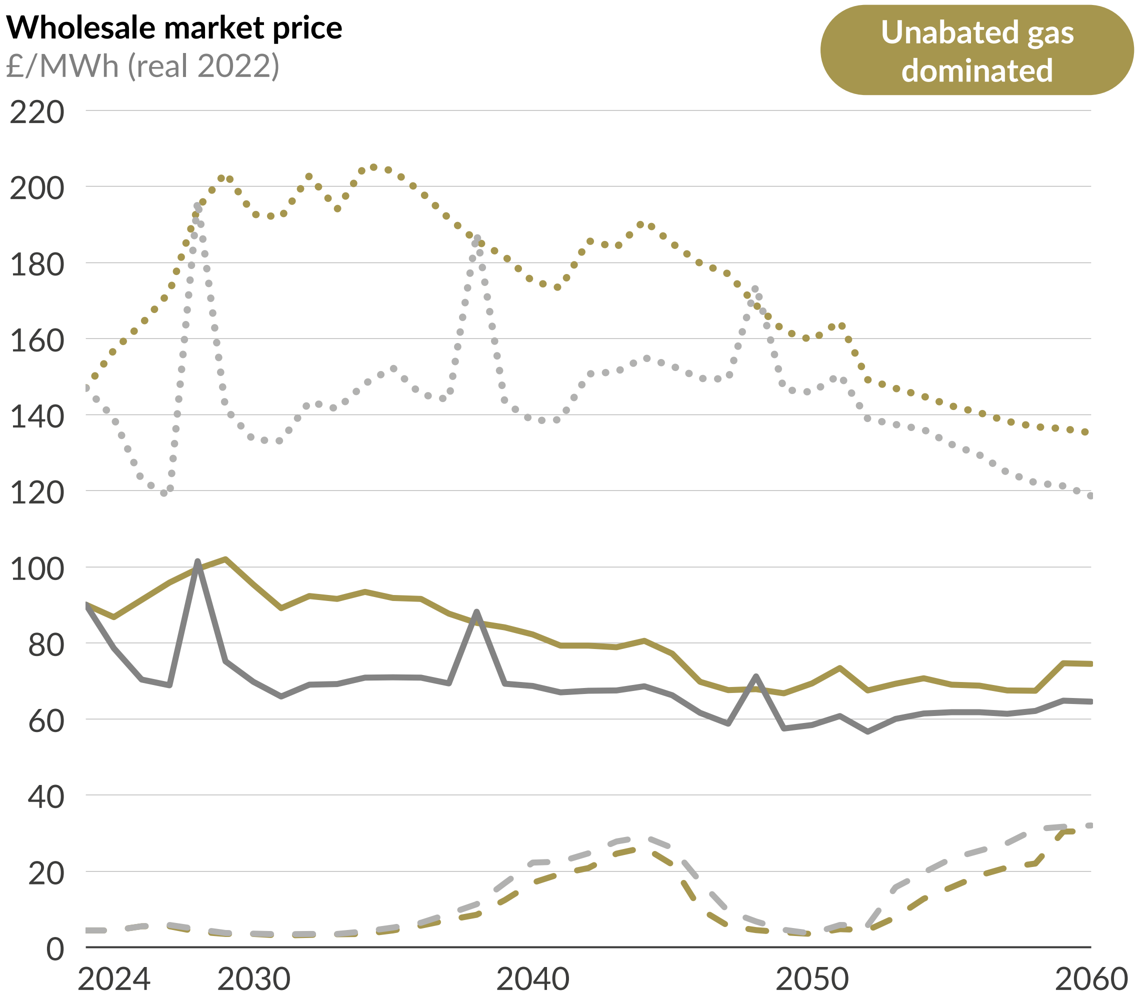
Source(s): Aurora Energy Research

Contents

MS: Scenario updates

Wholesale market forecast for unabated and CCS gas scenarios, modelled with a constant high gas price compared to the previous gas price series with periodic spikes





Previous forecast | Gas CCUS dominated | Unabated gas dominated | 5th Percentile | Baseload price | 95th Percentile

Source: ReseAurora Energy arch

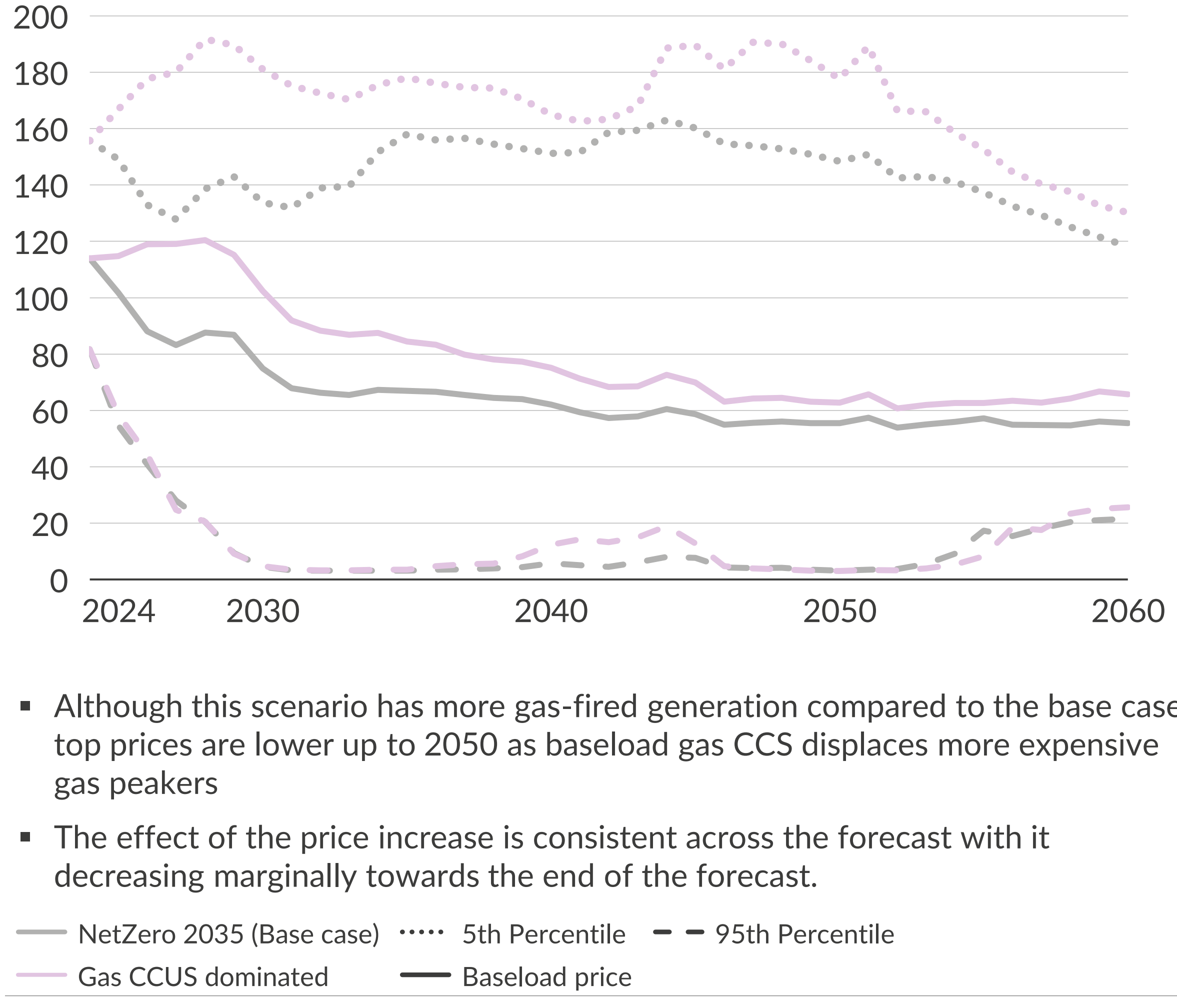
Replacing CfD-backed offshore wind with gas CCS capacity at a high gas price increases average total system costs significantly in the short term

MS: Scenario updates

Gas CCUS dominated

Wholesale market price

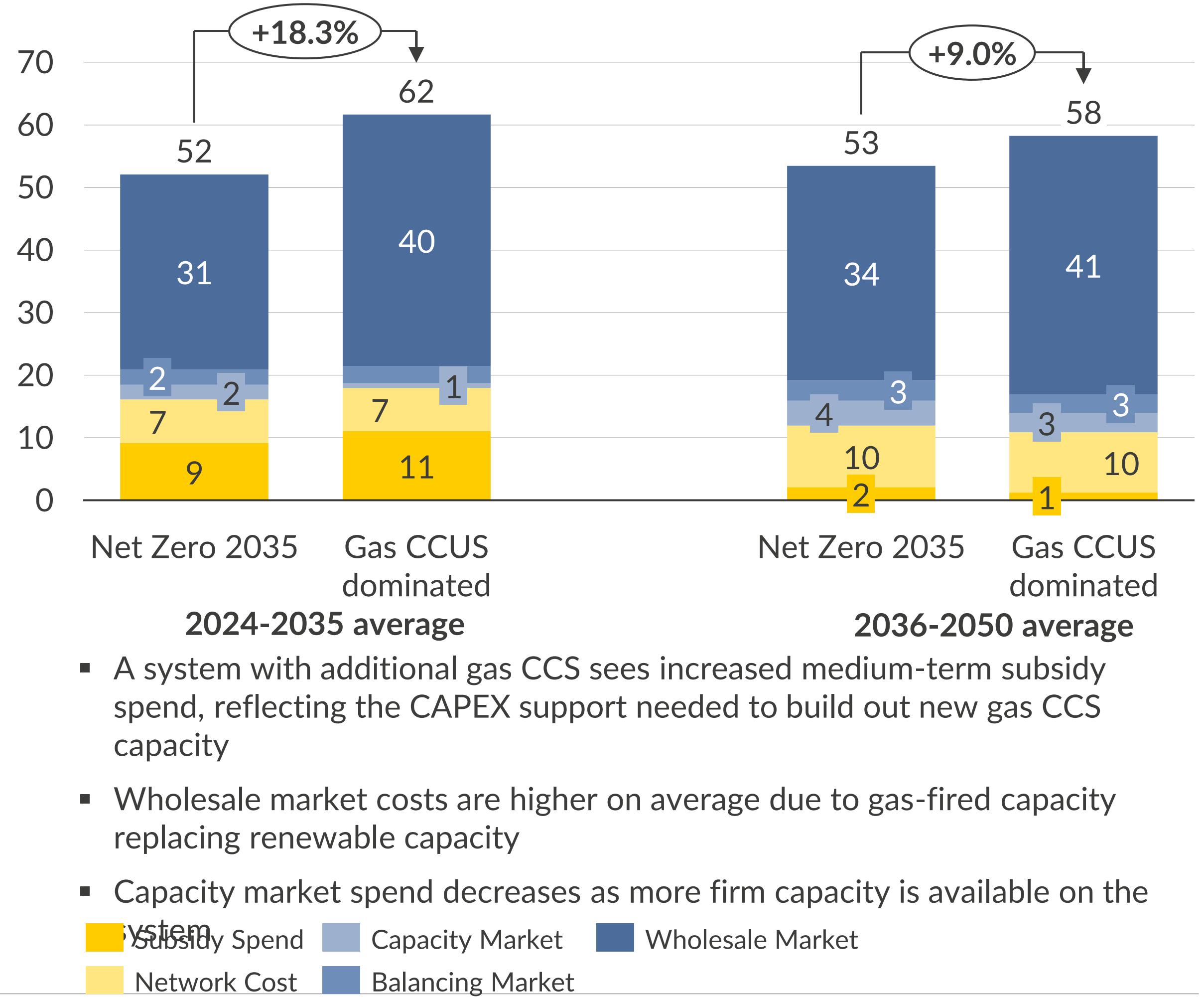
£/MWh (real 2022)



- Although this scenario has more gas-fired generation compared to the base case, top prices are lower up to 2050 as baseload gas CCS displaces more expensive gas peakers
- The effect of the price increase is consistent across the forecast with it decreasing marginally towards the end of the forecast.

System cost breakdown

bn £ (real 2022)



- A system with additional gas CCS sees increased medium-term subsidy spend, reflecting the CAPEX support needed to build out new gas CCS capacity
- Wholesale market costs are higher on average due to gas-fired capacity replacing renewable capacity
- Capacity market spend decreases as more firm capacity is available on the system

Source: Aurora Energy Research

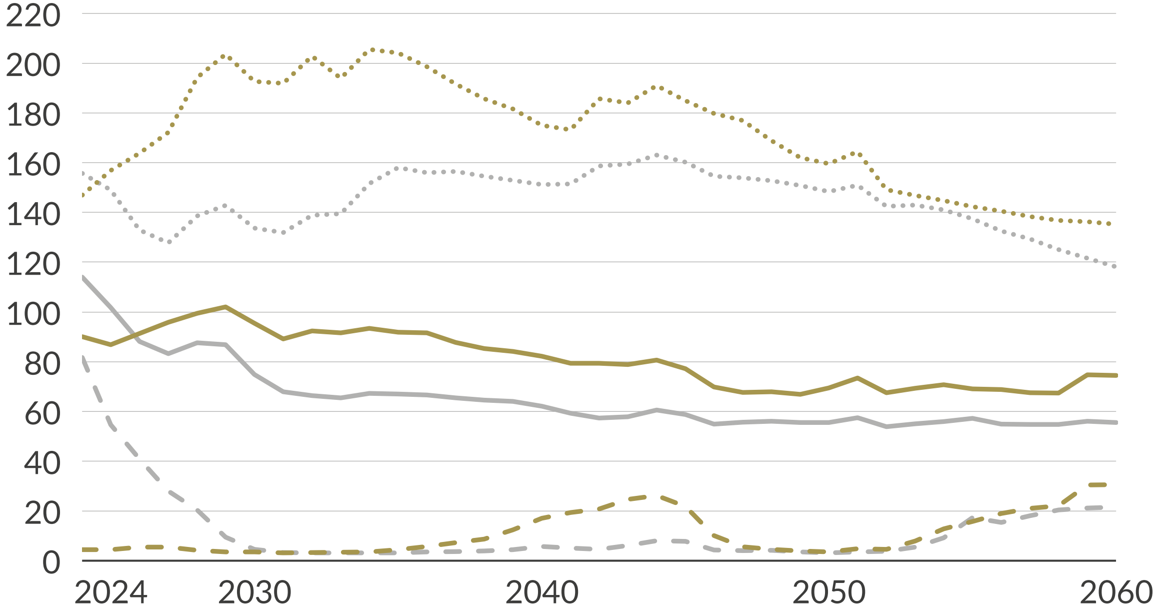
The effect of prolonged high gas prices in a gas-heavy system is a significant increase in wholesale power prices and overall system costs

MS: Scenario updates

Unabated gas dominated

Wholesale market price

£/MWh (real 2022)

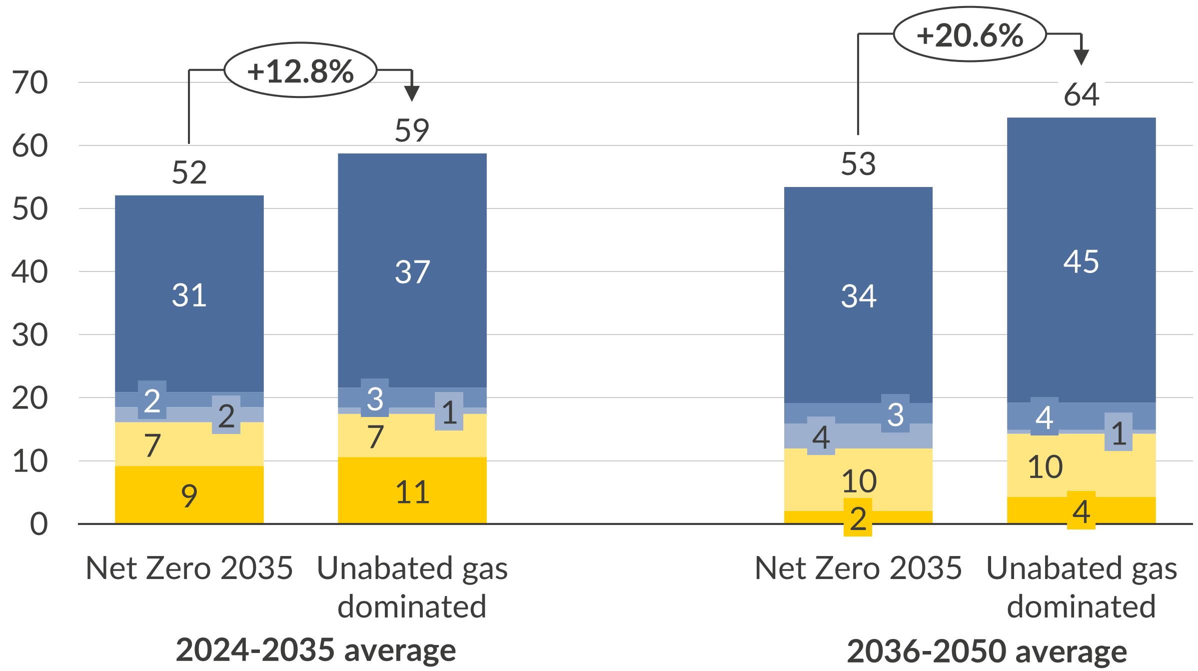


- Top prices decrease as the addition of baseload gas-fired capacity (CCGTs) in addition to the loss in variable offshore wind generation reduces the need for gas peakers on the system
- However, baseload prices are higher in the base case as a majority of generation is now being provided by expensive gas plants
- Periodic gas price spikes cause corresponding temporary increases in power price

NetZero 2035 (Base case) 5th Percentile 95th Percentile
Unabated gas dominated Baseload price

System cost breakdown

bn £ (real 2022)



- This scenario has the highest average total system costs of all scenarios due to the presence of large amounts of expensive gas-fired generation on the system (reflected in wholesale market costs)
- Subsidy spend also increases in order to bring new gas plants online amid weakening CCGT and peaker economics

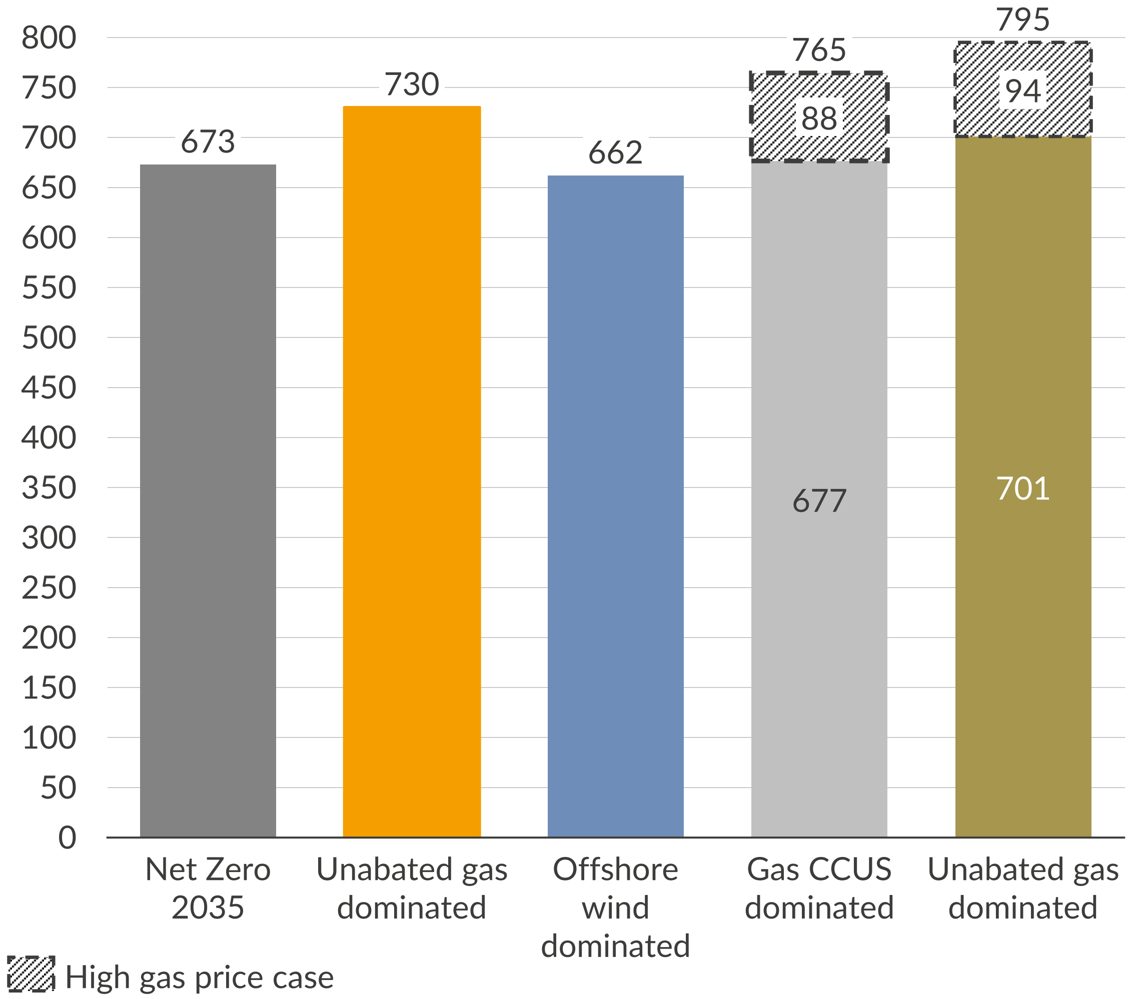
Subsidy Spend Capacity Market Wholesale Market
Network Cost Balancing Market

Source: Aurora Energy Research

Scenarios with no new CfD supported offshore wind typically increase electricity cost per household, especially when it is replaced by gas generation

MS: Charts + commentary update (scenario 3 cut)

Wholesale electricity generation cost per household, 2025-2050 average
£/year/household, real 2022



An increased share of renewables in the energy mix is projected to benefit consumers with lower costs over 2025-2050

Methodology

- We multiply the total system costs for the different scenarios modelled previously by the proportion of total power demand from the domestic sector (36%) and divide that by the number of households in GB (28.2 million)
- This gives us the 'electricity cost per household' metric, which can be used to compare the impact of different power systems on consumer bills in a simplified manner

Relevance

- Three scenarios with no new offshore wind show higher household bills than the base case, as more economical offshore wind typically has to be replaced by expensive gas generation or interconnector imports
- A scenario in which 50GW of offshore wind is built by 2030 sees lower household bills than the base case. However, this would require accelerated policy and subsidy support for offshore wind as well as accelerated grid development
- This indicates that a realistic and cost-effective approach to Net Zer o2035 requires a mix of technologies, of which offshore wind and other renewables form a key pillar, in addition to baseload nuclear, abated gas, hydrogen, as well as biomass with carbon capture (BECCS)

Source(s): Aurora Energy Research

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