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ENERGY RESEARCH

The impact of decarbonising heating on the power sector (C)

Energy sector modelling to support the second National Infrastructure Assessment

Prepared for the National Infrastructure Commission
October 2023

Contents

Executive Summary

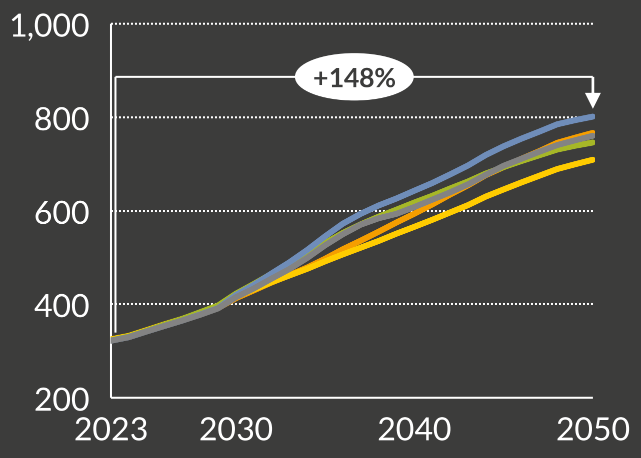
- The UK power sector faces the dual challenge of decarbonising electricity supply by 2035 while meeting the growing demand load brought on by the electrification heating, transport, hydrogen production and industry
- The increased renewable rollout required will need to be complimented by increased abated thermal and low-carbon flexible generation in order to balance the increasing variability and intermittency of supply and demand
- The UK power market's emissions have decreased steadily over the last decade driven by decarbonisation policy (the share of renewable generation at 38% in 2021, up from 12% in 2013). In contrast, low-carbon heating policy lags behind, with heating emissions still accounting for 20% of total emissions in 2021, up from 12% in 1990
- Previous analyses produced by Aurora Energy Research ("Aurora") for The National Infrastructure Commission ("NIC") investigated the decarbonisation of the power sector and the heating sector separately:
  - Project A: explored how different forms of power system flexibility can support the deployment of renewable energy in order to achieve Net Zero in GB
  - Project B: explored how different types of low carbon heating can be used to decarbonise the building stock in GB
- This report, Project C, aims to combine the insights gained from Project A and B in order to investigate how the decarbonisation of the heating sector will impact the power sector, focusing on demand, capacity build-out and utilisation, total system costs and costs to consumers
- Aurora has modelled five power market scenarios on behalf of NIC, testing different low-carbon heating whilst ensuring the power sector's 2035 Net Zero goals and CCC CB6[1] emissions reduction targets for heating are still met
  - Power market input assumptions: the market scenario assumes unabated gas generation is banned from 2035[2]
  - Heating sector input assumptions: the impact of hydrogen boilers for heat decarbonisation – proportion and rate of deployment – was varied across scenarios to isolate the impact of hydrogen heating on the power system. Heat pumps were used to compliment hydrogen boilers in each scenario to reach decarbonisation[3]
- The scenarios were designed to test three key dimensions:
  1. The final proportion of hydrogen in the heating system and the impact that has on demand and the power system
  2. The rate of hydrogen boiler adoption in the heating system and how that affects the needs of the power system
  3. The production of hydrogen for the heating system and how the flexibility of electrolysers effects power demand

1) The UK's sixth carbon budget stipulates a 47-62% reduction in building emissions by 2035, relative to 2019 levels. 2) The scenario "Unabated Gas Ban" from Part A was used as a basis power market scenario here. 3) Part B determined that peak demand implications of electric resistive heating were large, meaning it was not considered as a main decarbonisation technology in this report.

Source: Aurora Energy Research

Executive Summary

Power *demand*
TWh



Demand

- Decarbonisation via electrification will increase the load on the power system by 118-148% across the scenarios over the forecast period, with all scenarios exceeding 700 TWh of power demand by 2050, up from 320 TWh in 2022
- Scenarios with higher proportions of hydrogen boilers have higher total power demand as hydrogen boilers have a lower round trip efficiency compared to electric heating[1] – the additional power demand required by electrolysers offsets the reduced electrical heating load from hydrogen boilers displacing heat pumps
- This effect can be partially mitigated by having a higher proportion of flexible electrolysers on the system – this reduces peaking capacity requirements, thus lowering the need for flexible generation requirements[2]

Peak demand

- The decarbonisation of heating contributes to peak power demand growth due to the daily and seasonal variability of heating requirements. Peak demand increases by 50-76% over the forecast in all scenarios, exceeding 95 GW by 2050, up from 60 GW in 2022
- Peak power demand is mainly driven by inflexible electrolysers capacity and electrified heating – scenarios dominated by heat pumps have the highest peak demand requirements
- Increasing heat pumps by 12 million units (to reach 83% of GB's heating) will increase peak power demand by 10 GW; Increasing inflexible electrolysers by a further 7 GW will take boost peak power demand by a further 6 GW

Scenario name	Heating sector assumptions	Year	Hydrogen boilers
Scenario 1, Benchmark	Avg. H2 boiler by 2050; Slow H2 boiler rollout	2035	4%
		2050	23%
Scenario 2	No H2 boiler by 2050	2035	0%
		2050	0%
Scenario 3	Min H2 boiler by 2050; Fast H2 boiler rollout	2035	10%
		2050	13%
Scenario 4	Max H2 boiler by 2050 ; Fast H2 boiler rollout	2035	17%
		2050	38%
Scenario 5	Max H2 boiler by 2050 ; Fast H2 boiler rollout Max flexible electrolysers	2035	17%
		2050	38%

1) Electric heating systems, including electric resistive heating and heat pumps, are more efficient compared to using H2 boilers. This is due to their direct efficiencies ranging from 90% to 500%, compared to approximately 80% for H2 boilers, as well as the round-trip efficiency losses associated with H2 production (electrolysers have around 75% efficiency).
2)Lower flexible generation reduces hydrogen peaker generation, lowering overall hydrogen production and electrolyser demand.

Source: Aurora Energy Research

Executive Summary

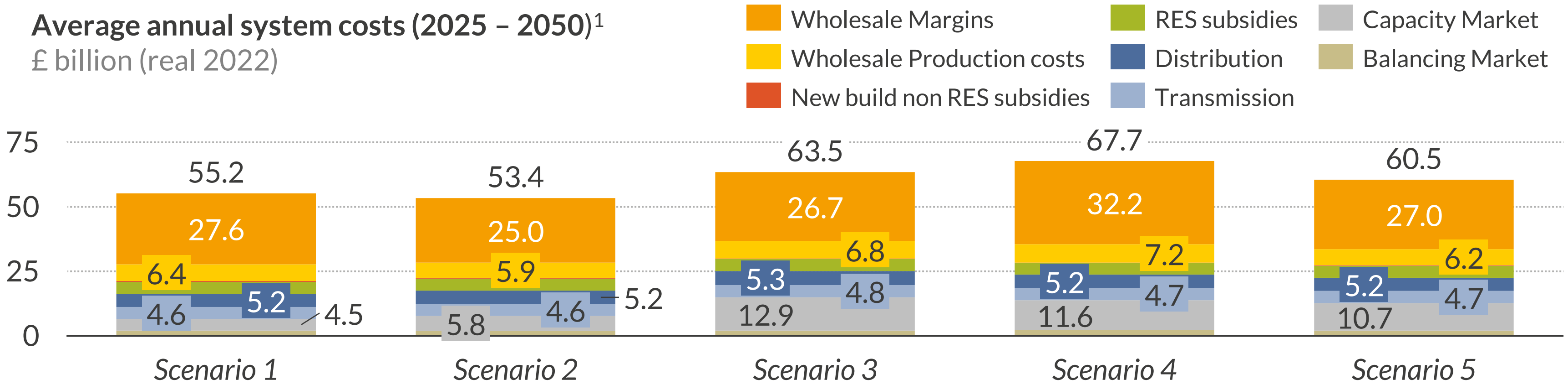
Capacity and generation

- Heating systems that depend on hydrogen for heating will result in higher demand and thus higher prices causing a greater economic buildout of intermittent renewable capacity. The increased electrolyser demand will absorb the excess low-carbon generation
- In contrast, systems with more heat pumps, and corresponding lower power demand, have a reduced economic build out of renewables and increased interconnector export due to lower power prices
- A more rapid deployment of hydrogen boilers will cause the growth in power demand to outpace capacity additions, straining the power system in the 2030s and 40s, boosting the value case for flexible generation. This tighter system will rely on additional battery and pumped hydro capacity build in the 2030s to ensure security of supply is met

Costs

- Overall, annual system costs are increased by a faster deployment of hydrogen boilers in the heating sector, a higher proportion of hydrogen boilers and a higher proportion of inflexible electrolysers – Scenario 4 meets all three of those criteria, which pushes average annual power system costs to £67.7 billion and average annual consumer costs[2] to £119/MWh
- Scenario 2 has the lowest costs – £53.4 billion average annual system costs and £104/MWh average annual consumer costs[2] – brought down by no hydrogen being used for heating and a slower decarbonisation of the heating sector

Average annual system costs (2025 – 2050)[1]
£ billion (real 2022)



1) Note the 2023-2024 period is excluded from these calculations as current high gas prices distort results. 2) Average consumer costs 2025-2050 (Excluding Climate Levy, Supplier Charges & VAT)

Source: Aurora Energy Research

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The simultaneous decarbonisation of the power sector and decarbonisation of heating will increase the need for flexible generation

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Requirements of economy wide decarbonisation

Unabated baseload thermal generation phase-out in the power sector

Increased renewable capacity deployment in the power sector

Electrification of other sectors (transport, heat, industry, hydrogen production)

Key uncertainties of heat decarbonisation

- How much additional load will the decarbonisation of the heating sector place on the power sector?
- How is this load impacted by the mix of heating technologies used to decarbonise buildings?
- What happens to peaking capacity requirements as the heating sector is decarbonised?
- Do certain heating technologies exacerbate peak demand more than others?
- Does the adoption rate of different heating technologies impact the way the power sector grows to absorb heating?

Effect on power markets

Wholesale Markets

- Changing generation mix, driven by increasing intermittent renewables and demand growth, results in price volatility

Capacity Markets

- Retiring baseload thermal plants coupled with higher renewable penetration reduces firm capacity on the system. Coupled with higher peak demand, the procurement of more dispatchable capacity is needed

Balancing mechanism

- Higher imbalance volumes are driven by increased renewable penetration and demand side variability

Ancillary Services

- Volume of synchronous generators on the system reduces as thermal plants retire, whilst renewable roll out results in increased need for system services

Power system needs

Need for **dispatchable capacity** that is not dependent on weather conditions in order to generate

Need for **flexible capacity** that can ramp up and down quickly over different time horizons to meet residual demand

Need for **capacity that can support broader system operability**

Key takeaway:

- Growing renewable generation coupled with increasing power demand (load and variability) will strain the power system. This will drive up power system costs as higher capacities of of low-carbon flexible generation will be needed to maintain security of supply.

Source: Aurora Energy Research

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For each scenario, Aurora's model finds the optimum economic technology mix based on the input parameters given

Aurora's modelling is based on a profit maximisation approach, with the model solving to find the most optimum economic technology mix whilst still meeting security of supply standards

INPUTS

- Commodity prices
- Demand
- Policy
- Technology
- 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
- Carbon emissions

- For each scenario, Aurora's model will consider the input assumptions provided and take decisions on additional capacity build out that is required in order to meet demand.
- Build decisions are NPV/IRR driven. The resulting technology mix will be the most economic option available, given the input assumptions made. However, network costs are not accounted for here.
- The model solves to ensure security of supply standards are met.
- Carbon emissions are an output of the model and the model does not optimise for emissions.

Source: Aurora Energy Research

Key input assumptions were made in collaboration with NIC

- **Commodity prices**
  - E.g. Gas, carbon & H2 prices
- **Demand**
  - Total and peak power demand, broken down in demand vectors (H2, transport, heating etc). Demand inputs account for the "smartness" of demand and its ability to shift to periods of lower power prices
- **Policy**
  - Capacity targets for renewables and low carbon technologies that are needed to meet emissions targets, but would not build out without subsidies or policy support
- **Technology**
  - E.g. CAPEX, performance, learning rates
- **Weather patterns**
  - Weather driven load factor patterns for renewables

Aurora modelled 5 new power market scenarios with varying proportions of hydrogen in heating to test the impact on the power system across 3 dimensions

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The scenarios were designed to test the impact of using hydrogen for heating on the power system. 3 key dimensions were tested:

1. The **final proportion of hydrogen** in the heating system and the impact that has on demand and the power system
2. The **rate of hydrogen adoption** in the heating system and how the speed of adoption affects the size and needs of the power system
3. The **production of hydrogen** needed for the heating system and how the flexibility of electrolysers impacts peak power demand

Scenario name	Power market assumptions[1]	Heating sector assumptions	What is this scenario testing?
Scenario 1	Unabated gas is banned from 2035	Avg. H2 boiler by 2050 Slow H2 boiler rollout	What would be the impact on the power system of a **medium** amount of hydrogen boilers being used in the final heating mix (23% H2 boilers by 2050)? What would be the impact on the power system of a **slow** ramp up of H2 boilers in the medium term?
Scenario 2	Unabated gas is banned from 2035	No H2 boiler by 2050	What would be the impact on the power system of no hydrogen boilers being used in the final heating mix (0% H2 boilers by 2050)?
Scenario 3	Unabated gas is banned from 2035	Max H2 boiler by 2050[2] Fast H2 boiler rollout	What would be the impact on the power system of a **high** amount of hydrogen boilers being used in the final heating mix (38% H2 boilers by 2050)? What would be the impact on the power system of a **fast** ramp up of H2 boilers in the medium term?
Scenario 4	Unabated gas is banned from 2035	Min H2 boiler by 2050[3] Fast H2 boiler rollout	What would be the impact on the power system of a **low** amount of hydrogen boilers being used in the final heating mix (13% H2 boilers by 2050)? What would be the impact on the power system of a **fast** ramp up of H2 boilers in the medium term?
Scenario 5	Unabated gas is banned from 2035	Max H2 boiler by 2050[3] Fast H2 boiler rollout Max flexible electrolysers	What would be the impact on the power system of a **high** amount of hydrogen boilers being used in the final heating mix (38% H2 boilers by 2050)? What would be the impact on the power system of a **fast** ramp up of H2 boilers in the medium term? What would be the impact of the power system of a **higher proportion** of flexible electrolysers and a lower proportion of inflexible electrolysers?

1) From previous analyses produced by Aurora for NIC : Project A, the "Unabated gas ban Scenario". 2) H2 boiler technology adoption trajectories for Scenario 3 were based on previous work produced by Aurora for NIC, Project B "Mid Hydrogen Scenario". 3) H2 boiler technology adoption trajectories for Scenarios 4 and 5 were based on previous work produced by Aurora for NIC, Project B "High Hydrogen Scenario".

Sources: Aurora Energy Research, NIC

The scenarios were designed to assess the impact of different heating technology mixes on the power system

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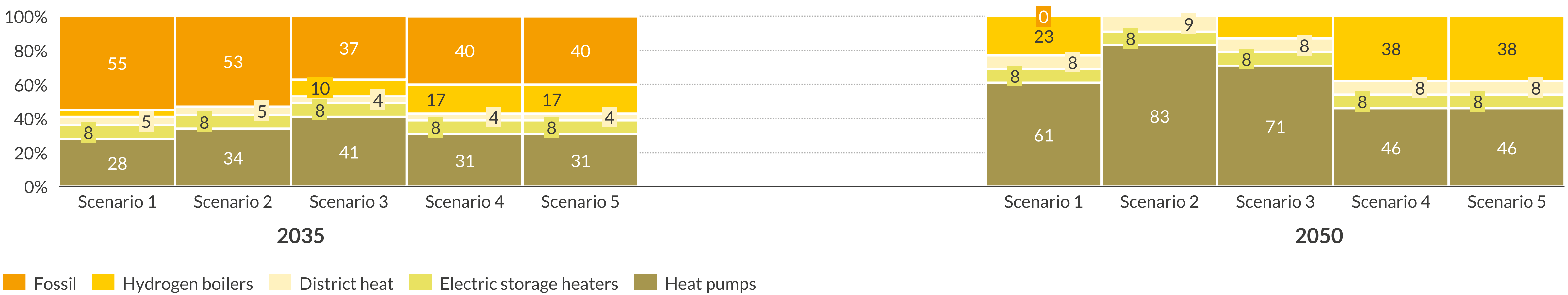
Proportion of heating units per scenario
%

Name	Power market assumptions[1]	Heating sector assumptions	Year	Heat pumps	Electric resistive heating	Heat networks	Hydrogen boilers	Fossil
Scenario 1	Unabated gas banned from 2035	Avg. H2 boiler by 2050 Slow H2 boiler rollout	2035	28%	8%	5%	4%	55%
			2050	61%	8%	8%	23%	0%
Scenario 2	Unabated gas banned from 2035	No H2 boiler by 2050	2035	34%	8%	5%	0%	53%
			2050	83%	8%	9%	0%	0%
Scenario 3	Unabated gas banned from 2035	Min H2 boiler by 2050[2] Fast H2 boiler rollout	2035	41%	8%	4%	10%	37%
			2050	71%	8%	8%	13%	0%
Scenario 4	Unabated gas banned from 2035	Max H2 boiler by 2050[3] Fast H2 boiler rollout	2035	31%	8%	4%	17%	40%
			2050	46%	8%	8%	38%	0%
Scenario 5	Unabated gas banned from 2035	Max H2 boiler by 2050[3] Fast H2 boiler rollout Max flexible electrolysers	2035	31%	8%	4%	17%	40%
			2050	46%	8%	8%	38%	0%

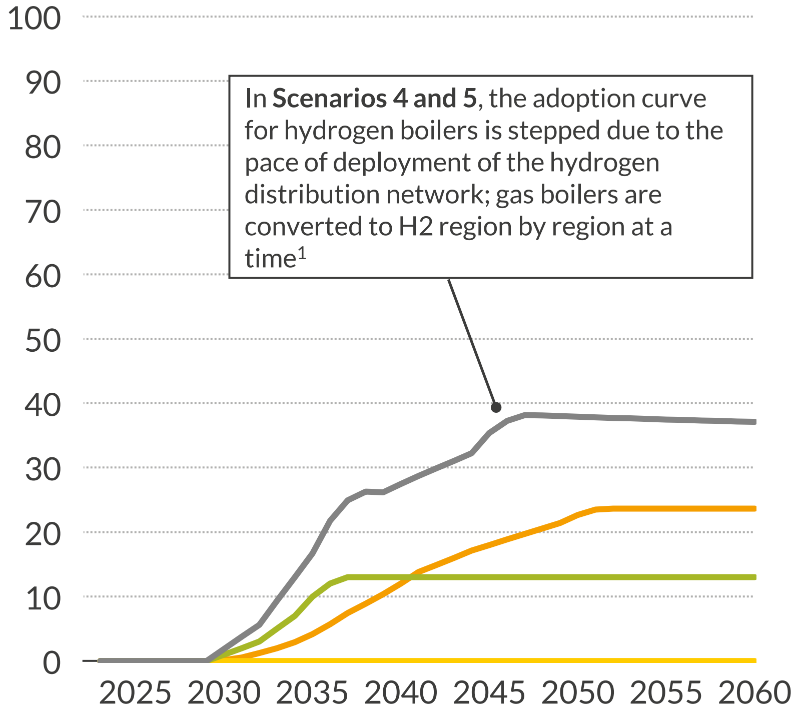


1) From previous analyses produced by Aurora for NIC : Project A, the "Unabated gas ban Scenario". 2) H2 boiler technology adoption trajectories for Scenario 3 were based on previous work produced by Aurora for NIC, Project B "Mid Hydrogen Scenario". 3) H2 boiler technology adoption trajectories for Scenarios 4 and 5 were based on previous work produced by Aurora for NIC, Project B "High Hydrogen Scenario".

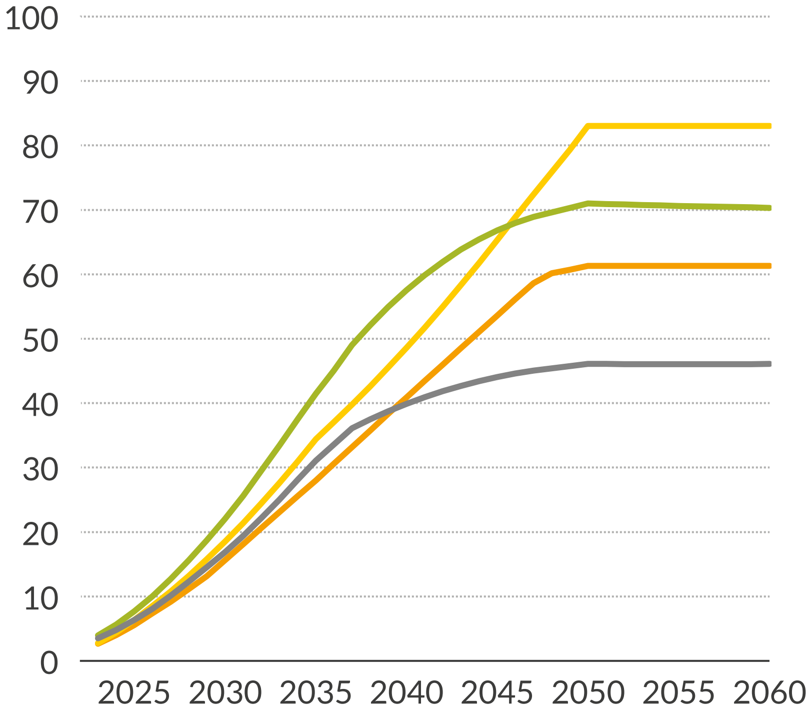
Sources: Aurora Energy Research, NIC

The proportion of hydrogen boilers and heat pumps is varied in each scenario, with fossil fuels phased out in by 2050 in all scenarios

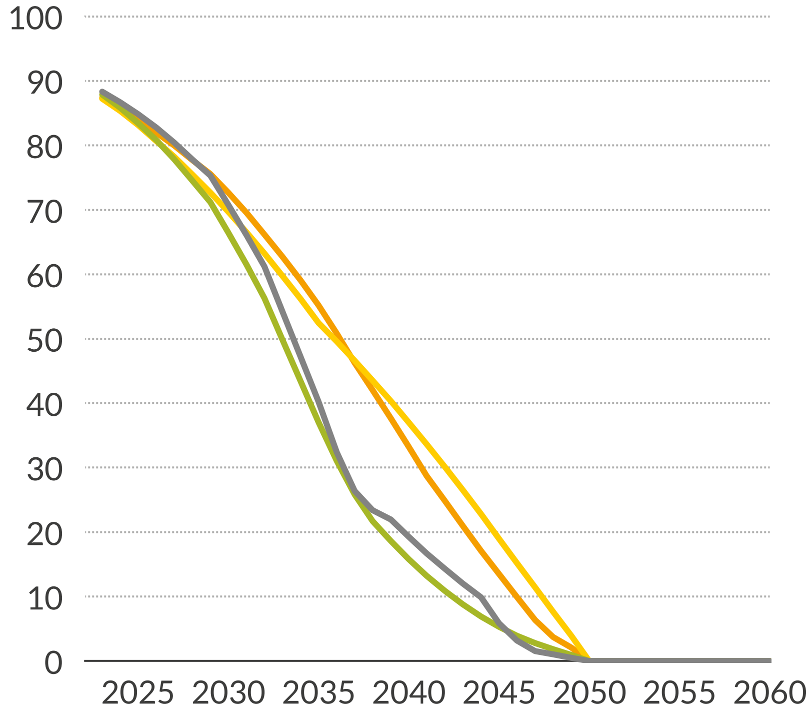
Trajectory for hydrogen boilers roll-out
%



Trajectory for heat pumps roll-out
%



Trajectory for fossil fuel heating technologies roll-out
%



- Scenarios 3, 4 and 5 have an earlier and larger rollout of hydrogen boilers. Scenarios 3, 4 and 5, which achieve 13% and 38% hydrogen boilers by 2050, follow the technology adoption rate developed in previous analyses conducted by Aurora for NIC[1]

- Earlier retirement of fossil fuel heating technologies in Scenarios 3, 4 and 5

Scenario 1 Scenario 2 Scenario 3 Scenario 4 and 5

1) Following the archetypal analysis developed in previous work produced by Aurora for NIC, Project B, to reflect a realistic adoption rate of hydrogen boilers for the mix of archetypes in GB.

Source: Aurora Energy Research

Demand inputs and capacity timelines have been adjusted in each scenario to reflect different heat decarbonisation and load needs

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Commodity prices, demand assumptions and power sector capacities in 2050

Input assumption in 2050		Scenario 1, Benchmark	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Commodities	Gas price	£23/MWh	*Benchmark*	*Benchmark*	*Benchmark*	*Benchmark*
	Carbon price	£161/tCO2	*Benchmark*	*Benchmark*	*Benchmark*	*Benchmark*
	H2 price	£52/MWh	*Benchmark*	*Benchmark*	*Benchmark*	*Benchmark*
Demand	Total demand	767 TWh	709 TWh	746 TWh	801 TWh	760 TWh
	Peak demand[1]	100 GW	106 GW	102 GW	96 GW	89 GW
	H2 demand[2]	304 TWh	175 TWh	249 TWh	390 TWh	390 TWh
Capacity	Total system capacity	336 GW	338 GW	348 GW	354 GW	350 GW
	Interconnector capacity[3]	18 GW[4]	*Benchmark*	*Benchmark*	*Benchmark*	*Benchmark*
	CCS capacity[3]	27 GW	27 GW	29 GW	27 GW	27 GW
	Pumped storage[3]	4.5 GW	4.5 GW	5.2 GW	5.2 GW	5.2 GW
	Inflexible electrolysers[3]	9 GW	9 GW	9 GW	9 GW	2 GW
	Flexible electrolysers[3]	38 GW	10 GW	26 GW	57 GW	64 GW

Additional Pumped hydro and Gas CCS capacity are required in Scenarios 3, 4 and 5 to alleviate the load on the power system caused by the earlier ramp up of H2 boilers and to ensure no loss of load in these scenarios

1) Average Cold Spell Peak demand. 2) H2 demand includes demand from industry, transport and heating. 3) Assumed policy driven subsidised/ supported capacities. 4) 75% availability

Sources: Aurora Energy Research, NIC, NGESO, CCC, BEIS

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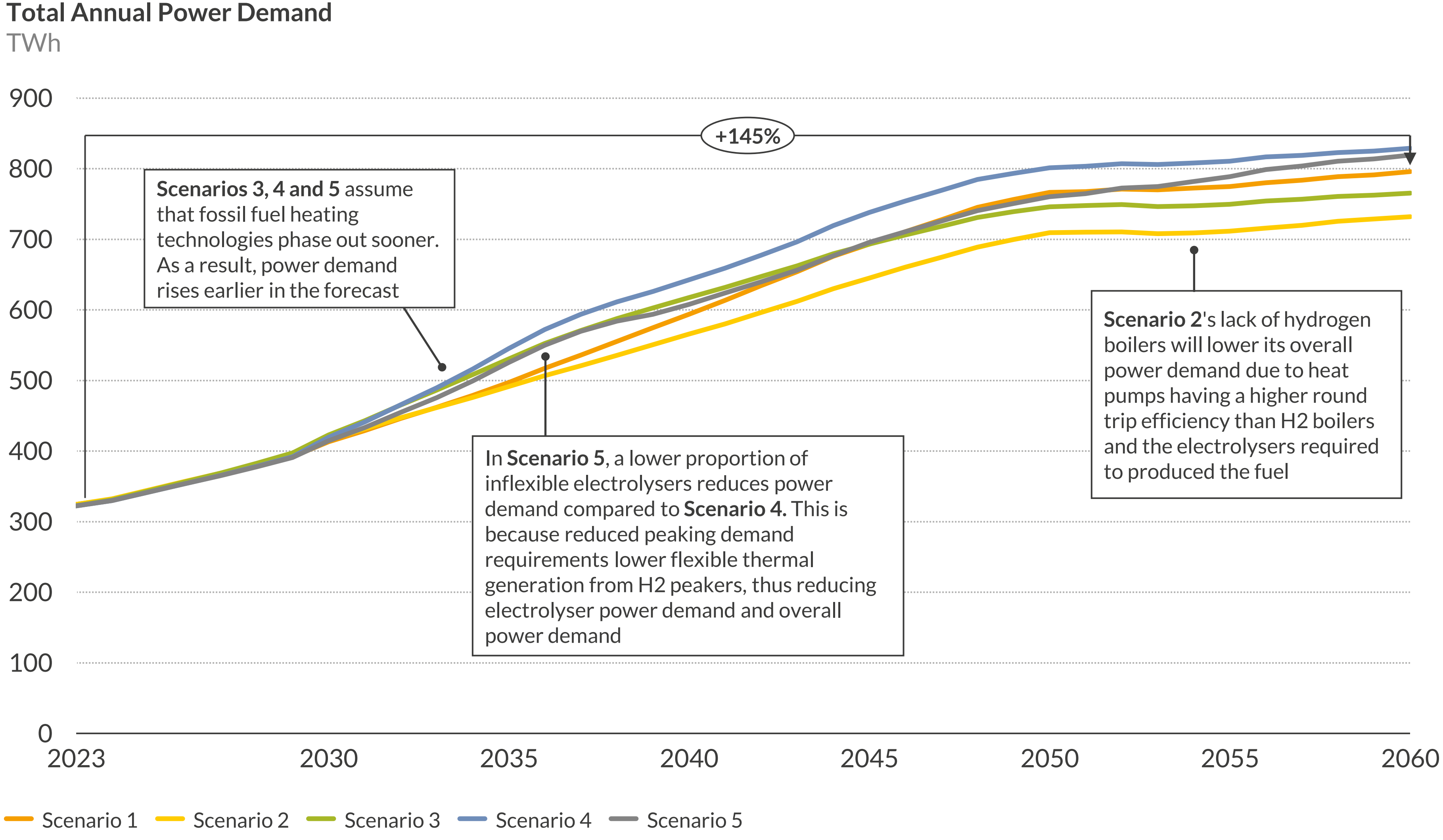
The decarbonisation strategy implemented in the heating sector will determine the size of the power system by 2050



1) Average between 2023 and 2050. 2) Electric heating systems, including electric resistive heating and heat pumps, are more efficient compared to using H2 boilers. This is due to their direct efficiencies ranging from 90% to 500%, compared to approximately 80% for H2 boilers, as well as the round-trip efficiency losses associated with H2 production (electrolysers have around 75% efficiency).

Sources: Aurora Energy Research, NIC

Scenario 1

Total demand rises by 471 TWh from 2023-2060 in the Benchmark scenario, driven by decarbonisation via electrification (mainly of heating)

Scenario 2

Scenario 2 has 4%[1] lower total demand than Scenario 1 on average, resulting in the smallest power system. It has a higher proportion of heat pumps and no hydrogen for heating compared to 1[2], lowering total demand requirements

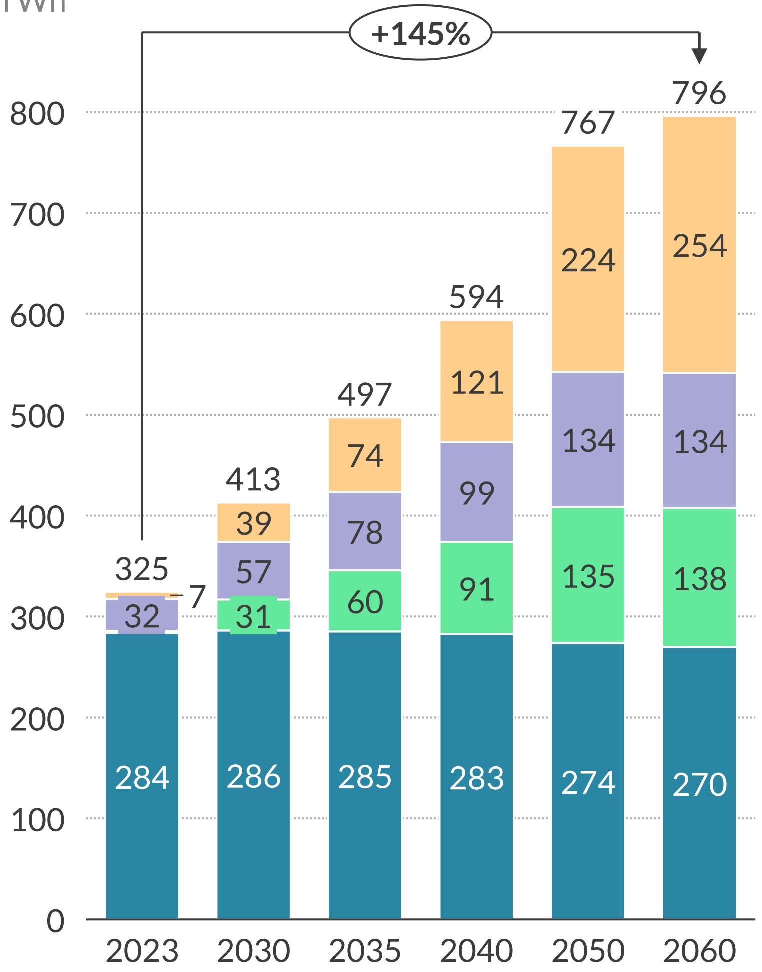
Scenarios 3 and 4

Scenario 4 has on average 6%[1] greater total power demand than Scenario 1. It assumes the highest proportion of hydrogen for heating across scenarios, which has a lower round trip efficiency compared to electric heating[2]

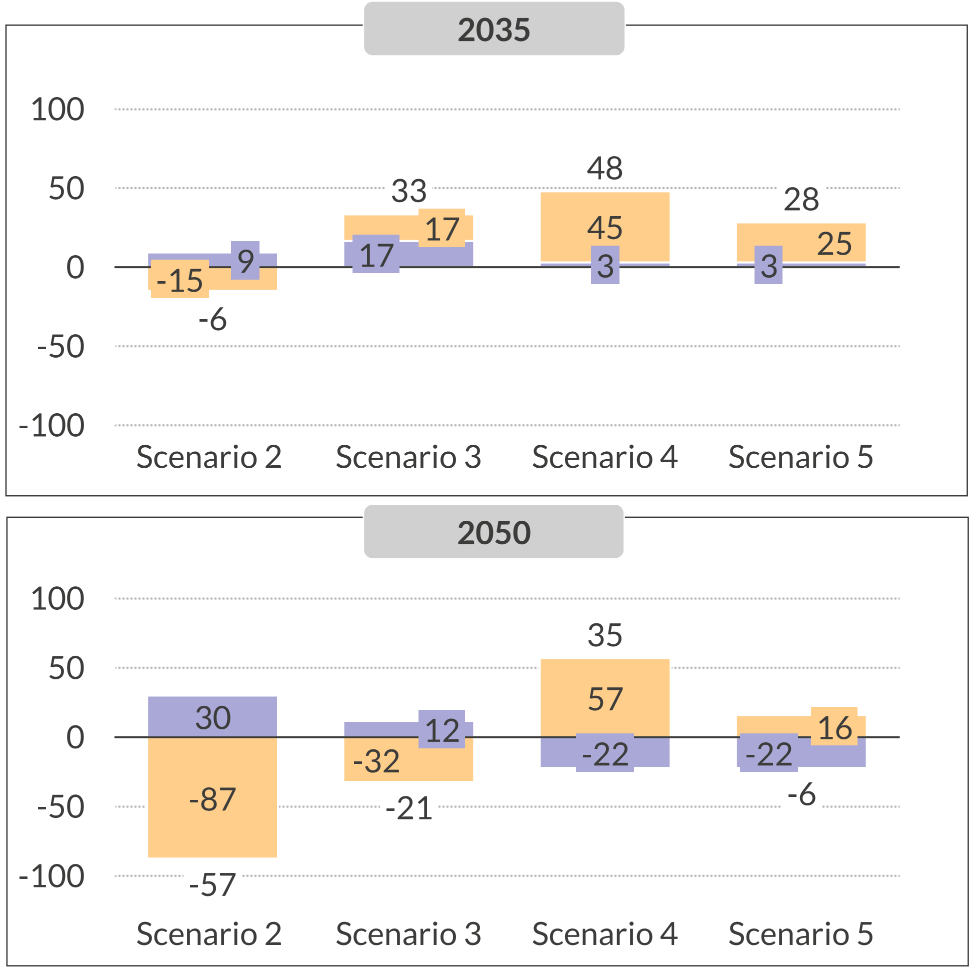
The earlier retirement of gas and oil boilers in **Scenario 3** compared to the Benchmark rises power demand sooner in the forecast, resulting in a 7% higher demand in 2035 than Scenario 1. After 2045, the trend shifts, with less heating demand met by hydrogen in Scenario 3 than in 1, which is balanced by heat pumps (3% lower power demand in 2050)

Earlier retirement of fossil fuel heating technologies in Scenarios 3, 4 and 5 results in larger demand deltas in 2035 compared to Scenario 1

Total Annual Power Demand, Scenario 1
TWh



Difference in each scenario relative to Scenario 1, TWh



Base demand | EV demand | Electric heat demand | Electrolyser demand[1]

1) Electricity, in TWh, demanded by electrolysers is a function of total hydrogen demand: transport, industry, power and heating. This is solved within the power market model. 2) Scenarios 1,2,3 and 4 have the same absolute number of inflexible electrolysers. 3) Electric heating systems have efficiencies ranging from 90% to 500%, compared to c.80% for H2 boilers. 4) Scenario 1 has a 23% share of hydrogen for heating in 2050, whereas Scenario 3 only has 13% by 2050

Sources: Aurora Energy Research, NIC

Scenario 2

This scenario assumes no hydrogen for heating, which decreases the electrolyser power demand. These power savings are slightly offset by a higher load on the power system, as less heating demand is met by hydrogen and more by heat pumps

Scenarios 4 and 5

Scenario 4[2] has the highest net demand increase compared to the Benchmark at 48 TWh higher by 2035. This is driven by an earlier and larger rollout of H2 boilers[3]. **Scenario 5** has the same total electrolyser capacity as Scenario 4 but fewer inflexible electrolysers. This reduces peak demand in 5, lowering peaking requirements and decreasing H2 usage as a fuel in the power sector. As a result, electrolyser demand is lower in Scenario 5 than in 4

Scenario 3

The faster deployment of H2 boilers in Scenario 3 compared to 1 increases electrolysers demand in 2035. After 2045, the trend shifts, with Scenario 3 having a lower percentage of H2 than 1 by 2050[4], which is balanced by heat pumps

Electrification of heating boosts peaking demand by more than 50%, as the power system takes the burden of heat demand variability

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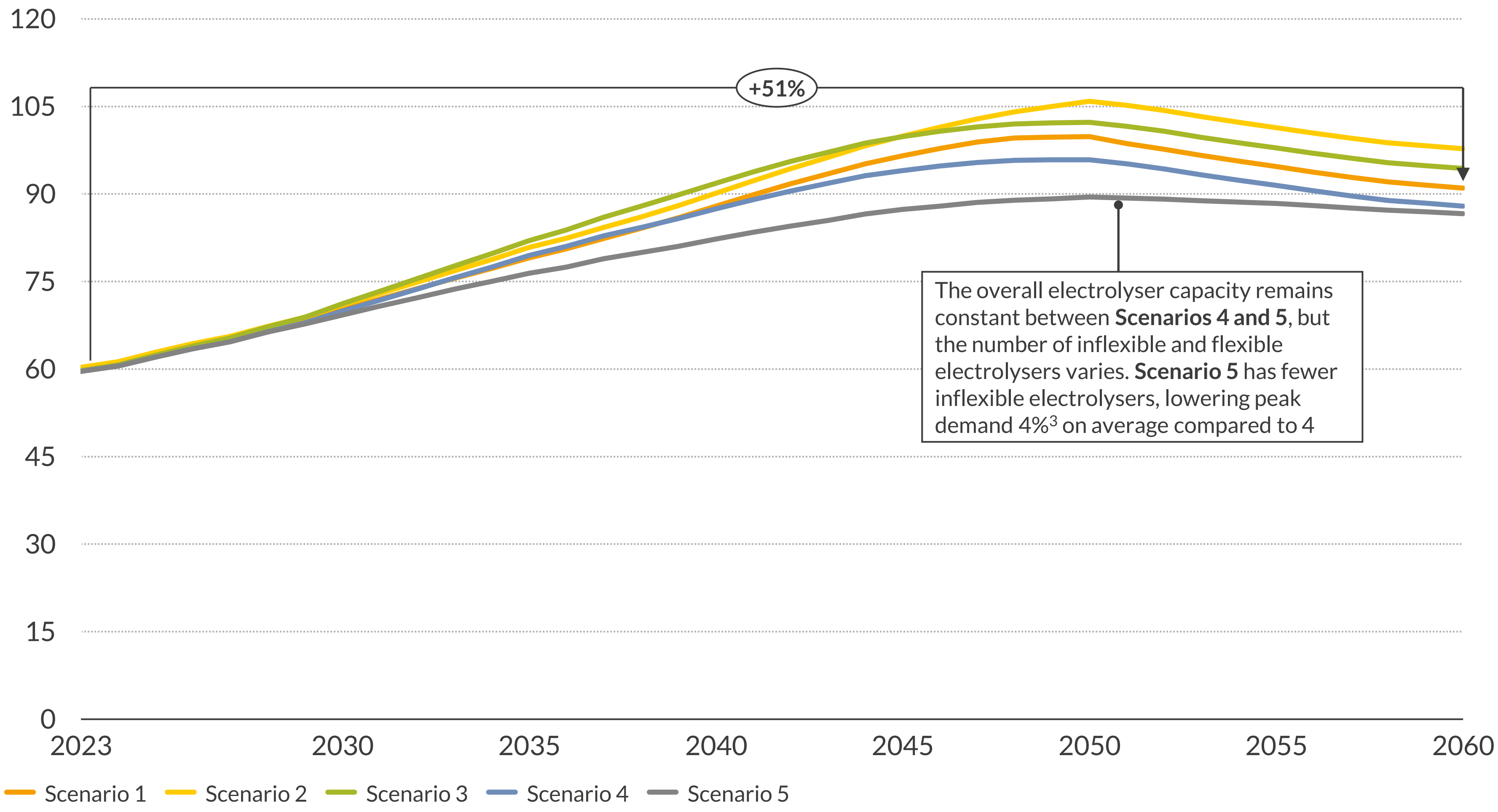
ACS peak demand[1]
GW



1) Average Cold Spell. 2) The number of dumb heat pumps is assumed to be the same in all scenarios. Any differences in heat pump deployment among scenarios are reflected in the number of smart heat pumps.3) Average between 2023 and 2060.

Source: Aurora Energy Research

Scenarios 1, 2 ,3 and 4

These scenarios have the same absolute number of inflexible electrolysers and dumb heat pumps. Differences in peak demand are driven by variations in the number of smart heat pumps[2]

Scenario 2 has on average 4%[3] greater peak demand than Scenario 1. This is because, in Scenario 2, heat pumps are primarily used to decarbonize the heating sector, with no H2 boiler deployment

Scenario 3 has an earlier retirement of fossil fuel heating technologies, resulting in a higher share of heat pumps by 2035 than Scenarios 1 and 2, increasing peak demand. After 2046, the trend shifts, as Scenario 3 uses more H2 to meet demand, slowing the adoption of heat pumps in comparison to Scenario 2, lowering the total peak demand of the system

Scenario 4 has 2%[3] lower peak demand than 1 on average. This is because it assumes a higher proportion of hydrogen for heating and a lower share of heat pumps by 2050 compared to 1[2], lowering peaking demand requirements

Higher deployment of heat pumps and inflexible electrolysers amplify demand peaks

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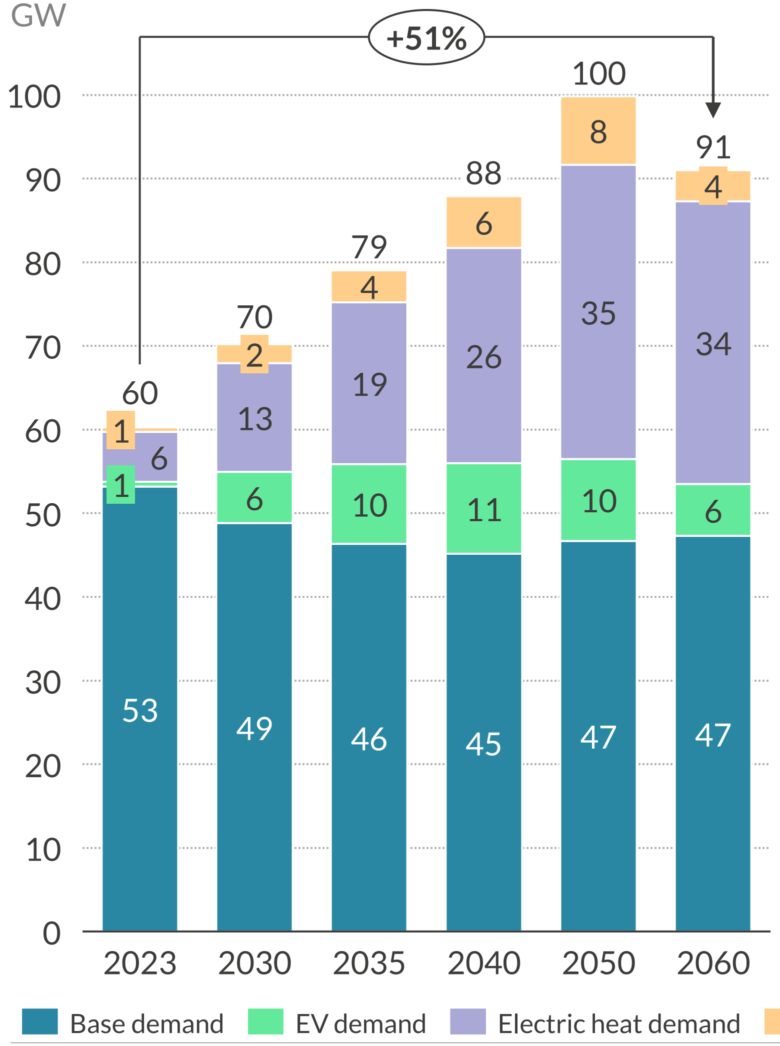
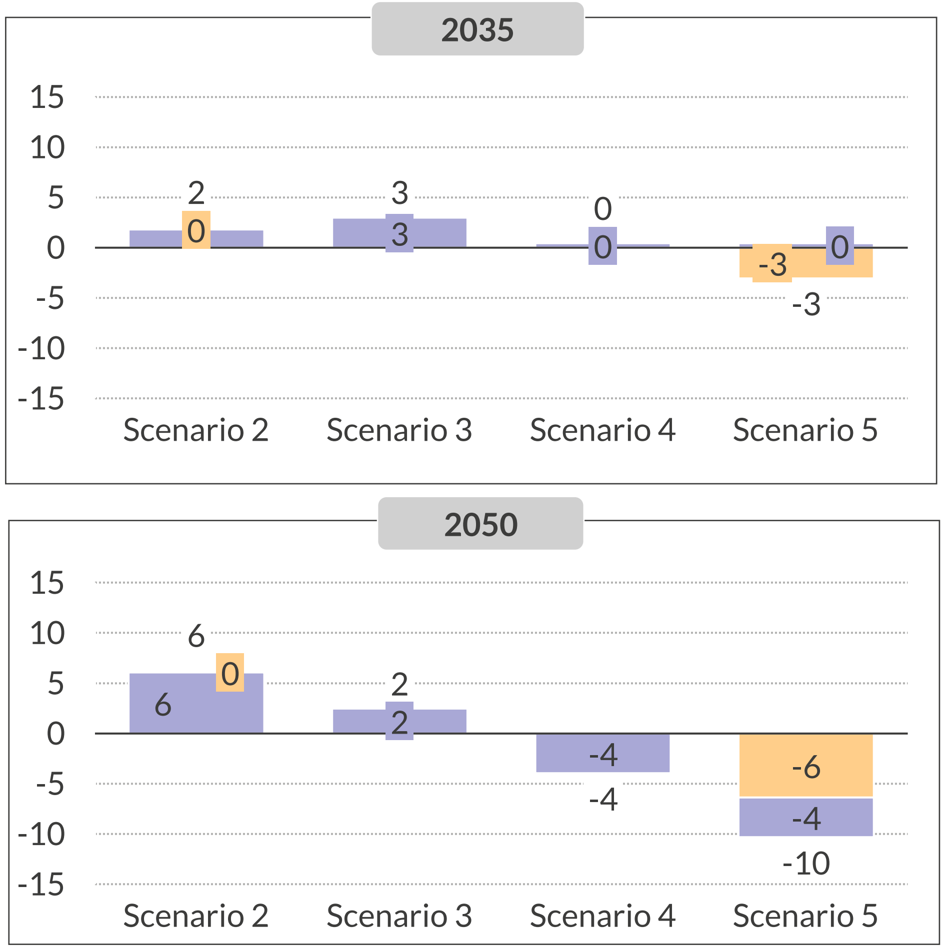
ACS peak demand[1], Scenario 1
GW



Difference in each scenario relative to Scenario 1, GW



Differences in ACS peak demand across scenarios are caused by variations in inflexible electrolysers capacities and the number of heat pumps[3]. Inflexible electrolysers and heat pumps affect peak demand, as they have limited capacity to shift demand away from peak periods

Scenarios 3 and 4

Scenarios 1, 3 and 4 have a different H2 demand throughout the forecast. However, the number of inflexible electrolysers remains constant across these scenarios[4], resulting in a similar hydrogen contribution to peak demand. Differences in Scenarios 3 and 4 relative to Scenario 1 can be attributed to variations in heat pump deployment[3]. In 2050, Scenarios 3 and 4 assume 71%[5] and 46%[5] share of heat pumps, respectively, compared to 61% in Scenario 1

Scenario 5

Scenarios 4 and 5 have the same delta in electric heat peak demand relative to the Benchmark as they both have the same share of heat pumps[3]. However, Scenario 5 assumes a lower number of inflexible electrolysers and a higher number of flexible electrolysers, reducing peak demand compared to 4 and 1

1) Average Cold Spell. 2) Electricity, in TWh, demanded by electrolysers is a function of total hydrogen demand: transport, industry, power and heating. This is solved within the power market model. 3) The number of dumb heat pumps is assumed to be the same in all scenarios. Any differences in heat pump deployment among scenarios are reflected in the number of smart heat pumps. 4) Scenarios 1,2,3 and 4 have the same absolute number of inflexible electrolysers. 5) Proportion of heating units

Sources: Aurora Energy Research, NIC

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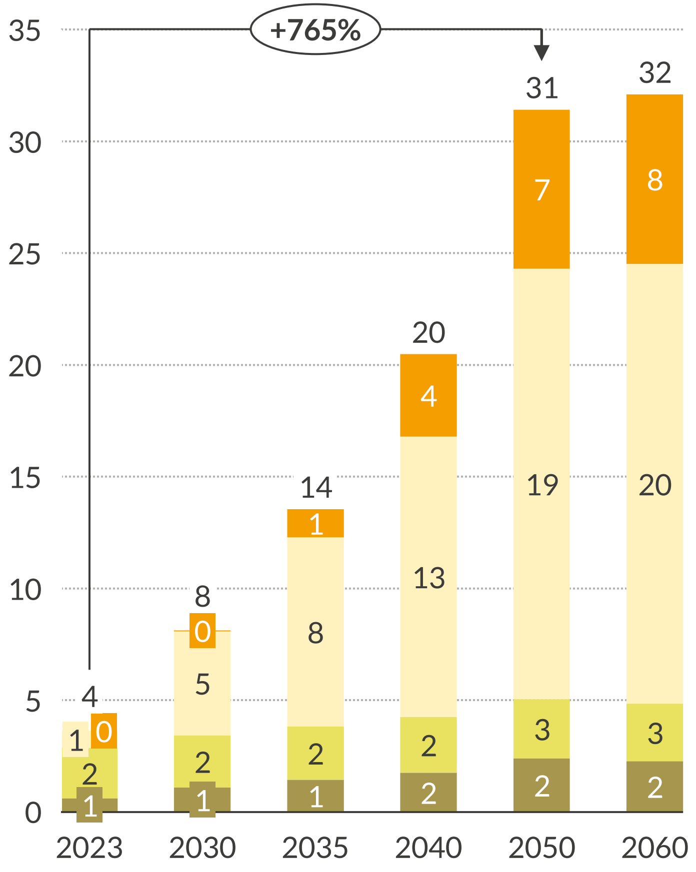
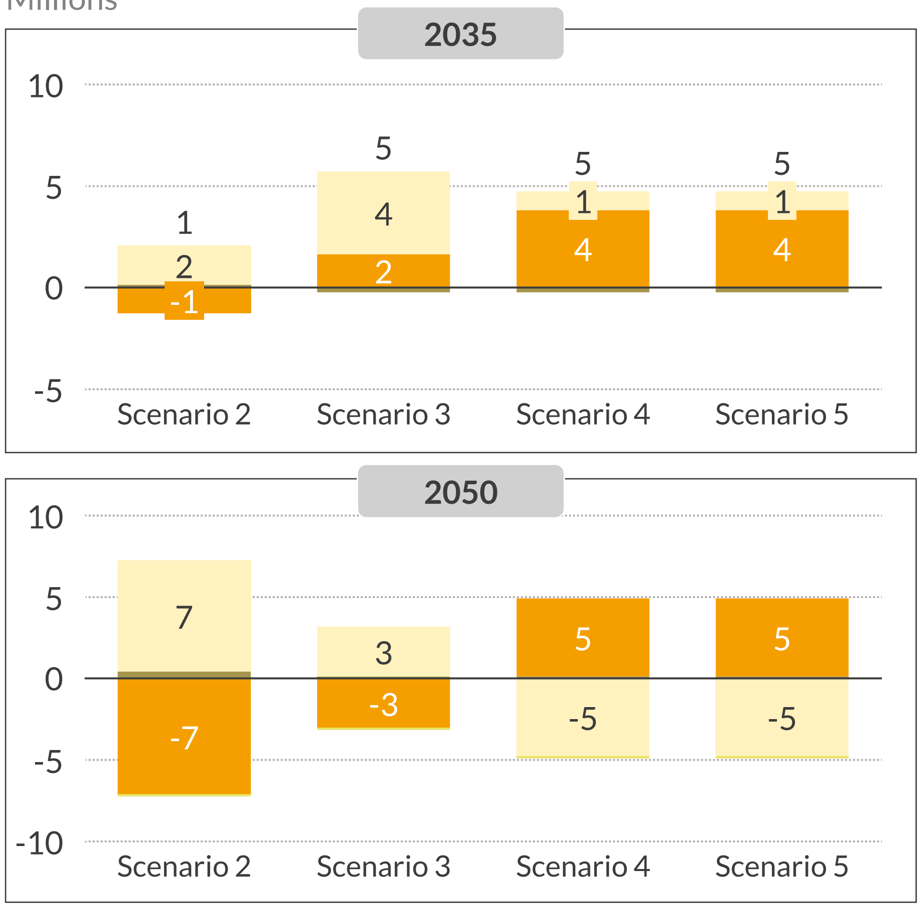
AURORA

Heat pumps and H2 boilers are deployed to decarbonise the heating sector in all scenarios

Total number of low-carbon heating units in GB, Scenario 1
Millions



Difference in low-carbon heating units relative to Scenario 1
Millions



Hydrogen boilers | Heat pumps[1] | Electric resistive heating[2] | Heat networks[2]

1) Including smart and dumb heat pumps. 2) Electric resistive heating was limited to 8% of total GB heating units and heat networks were limited to 9% of total GB heating units. 3) An additional 0.4 units of heat networks are required by 2050 too to displace the lack of H2 boilers.
Sources: Aurora Energy Research, National Grid, Office for National Statistics

Scenario 1
The decarbonisation of the heating sector results in a 765% increase in the total number of low-carbon heating units between 2023 and 2050, with approximately c.31 million heating units by 2050, including 7.1 million H2 boilers

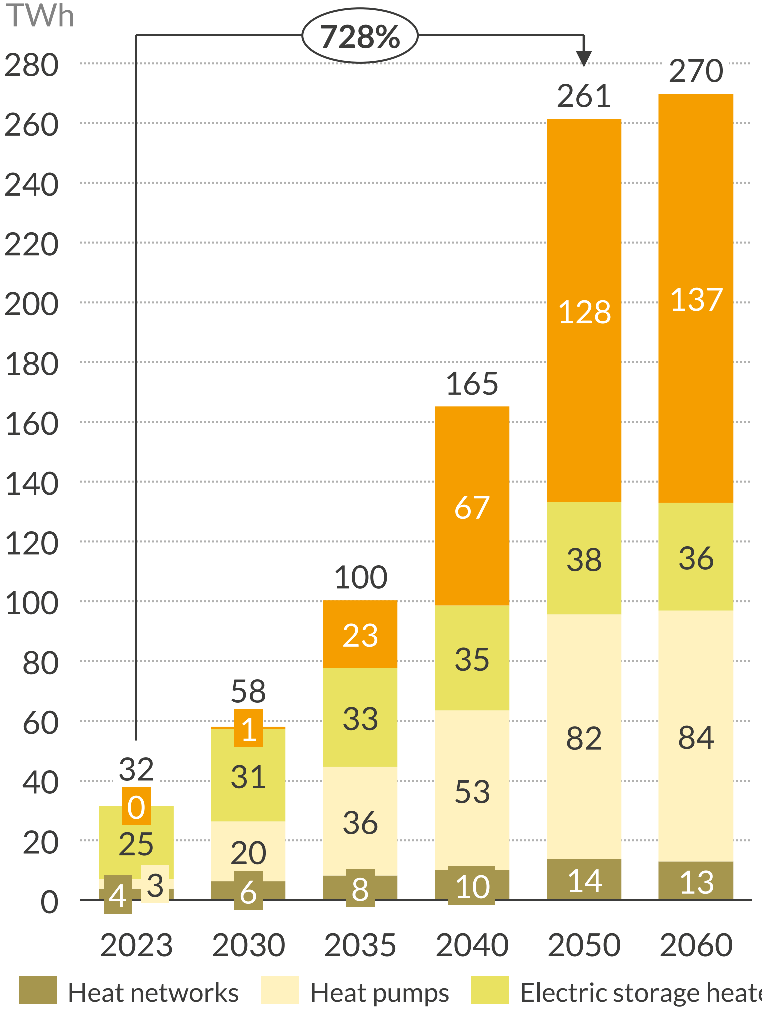
Scenario 2
No H2 boilers are deployed in this scenario. As a result, to achieve decarbonisation of the heating sector, Scenario 2 has 6.8 million more heat pumps by 2050 than Scenario 1[3]

Scenarios 3, 4 and 5
Scenarios 3, 4 and 5 have an earlier retirement of fossil fuels heating technologies than Scenario 1 resulting in 4.5 million (Scenario 4 and 5) and 5.5 million (Scenario 3) more low-carbon heating units by 2035 . This rises power demand sooner in the forecast

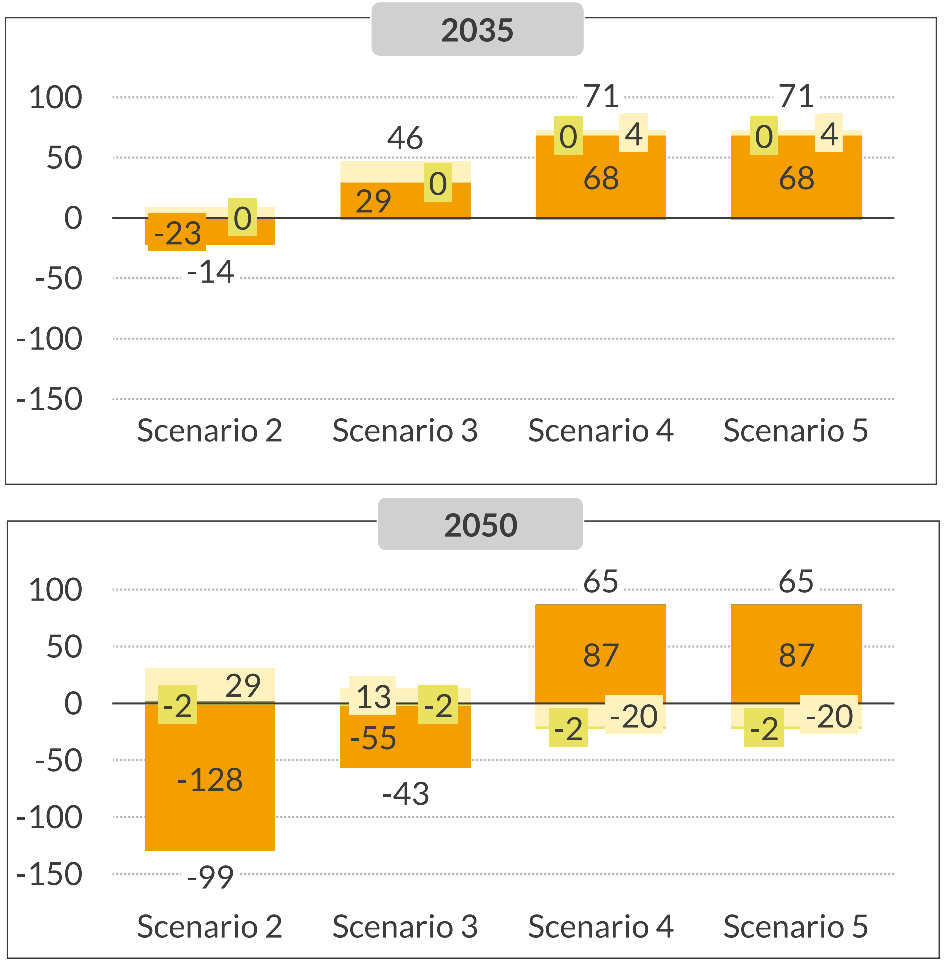
In 2050, Scenario 4 has 4.8 million more hydrogen boilers but 4.8 million fewer heat pumps than Scenario 1. Additionally, in Scenario 3, less heating demand is met by hydrogen, which is offset by 3 million more heat pumps

Earlier deployment of hydrogen boilers in Scenarios 3, 4 and 5 increases the load on the power sector in the 2030s and 40s

Heating demand by low-carbon technology, Scenario 1
TWh



Difference in each scenario relative to Scenario 1, TWh



Scenario 2
Scenario 2 has the highest net demand decrease compared to the Benchmark scenario at 99 TWh lower by 2050. This is driven by the assumption that no hydrogen for heating is used. Hydrogen has a lower round trip efficiency compared to electric heating[1], reducing total heating demand requirements in Scenario 2

Scenarios 3, 4 and 5
These scenarios have an earlier and larger rollout of H2 boilers than Scenario 1 and 2, leading to larger demand deltas in 2035. This is a result of scenario design based on Project B, in which the hydrogen uptake is not linear but rather stepped driven by the pace of deployment of the hydrogen distribution network

In 2050, Scenarios 4 and 5 assume higher share of H2 for heating, reducing heat pumps requirements by 20 TWh compared to the Benchmark. In Scenario 3, less heating demand is met by H2 by 2050, which is offset by a 13 TWh increase in heat pump demand

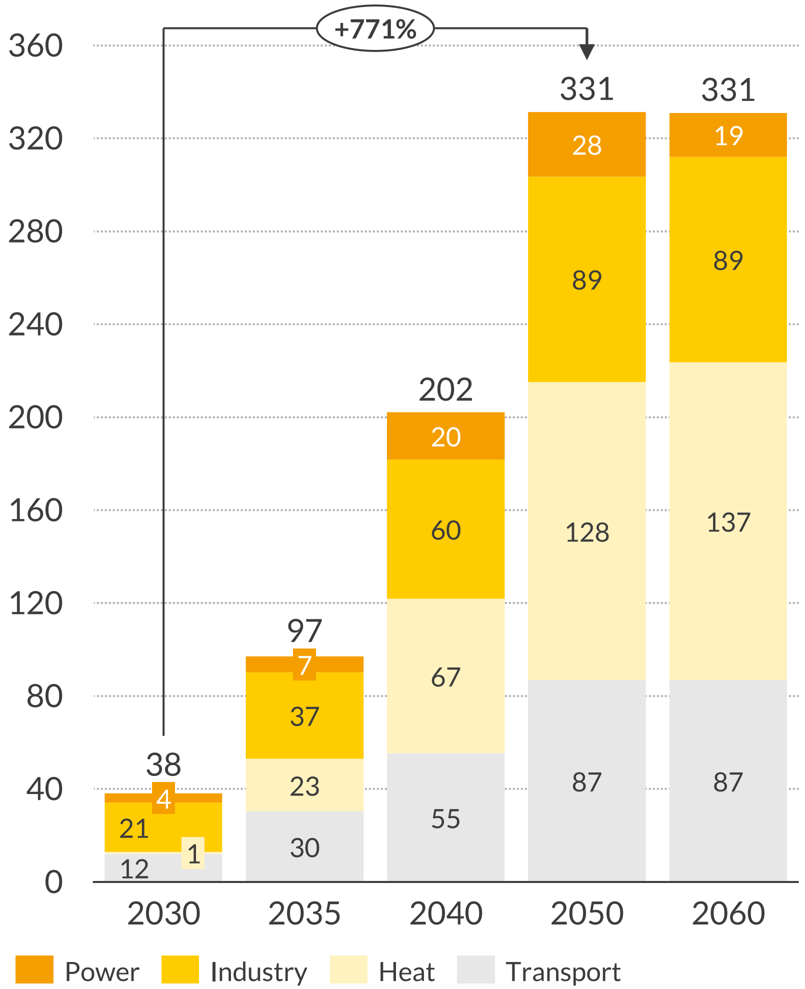
1) Electric heating systems are more efficient than H2 boilers, due to their efficiencies ranging from 90% to 500%, compared to 80% for H2 boilers, as well as the round-trip efficiency losses of H2 production (electrolysers are 75% efficiency). 2) Electric resistive heating was limited to 8% of total GB heating units and heat networks were limited to 9% of total GB heating units.

Sources: Aurora Energy Research, NIC

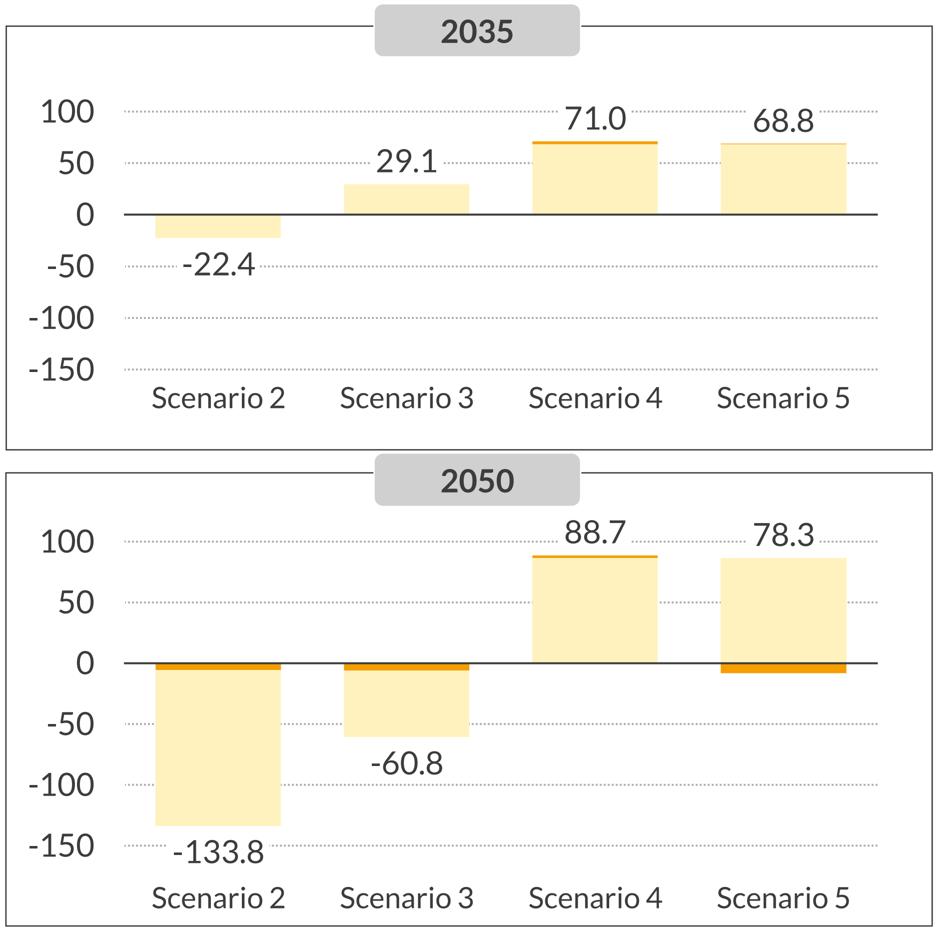
Contents

Specific hydrogen for heating assumptions have been adjusted in each modelled scenario, to test their impact on the power sector

Total hydrogen demand, Scenario 1
TWh



Difference in Hydrogen demand relative Scenario 1
TWh



Source: Aurora Energy Research

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Scenario 1

Total hydrogen demand increases by 771% between 2030 and 2050, with 27% of demand coming from the industry and transport sectors, 8% from the power sector and 39% allocated to decarbonise heating in GB

Industry sector demand grows by >300% (89 TWh) to 2050 as hydrogen is used to decarbonise processes that rely on fossil fuels to reach extremely high temperatures and as feedstock

Hydrogen could also be a primary energy replacement option for the heating sector, with Scenario 1 assuming 128 TWh of H2 heating demand in 2050

Hydrogen demand for industry and transport is assumed to be constant across all scenarios, with variations in hydrogen demand in the heating sector. In **Scenario 2**, the decarbonisation of heating entirely takes place through electrification, whereas **Scenario 4 and 5** have the highest hydrogen demand (390 TWh by 2050)

Electrolyser capacities were adjusted in each scenario to ensure hydrogen supply is able to satisfy differing hydrogen boiler demand

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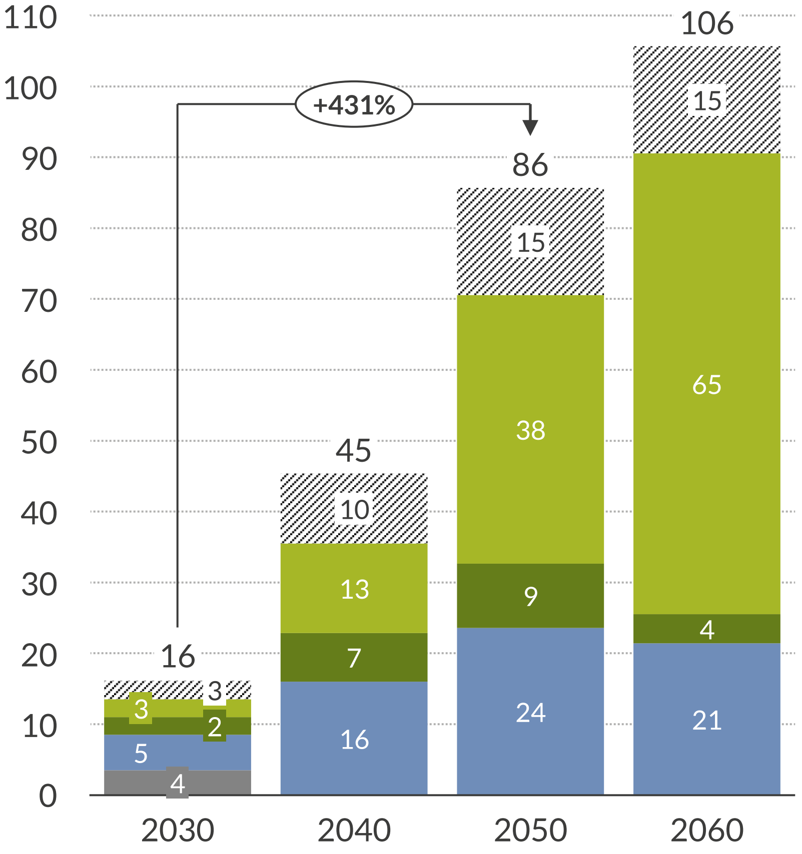
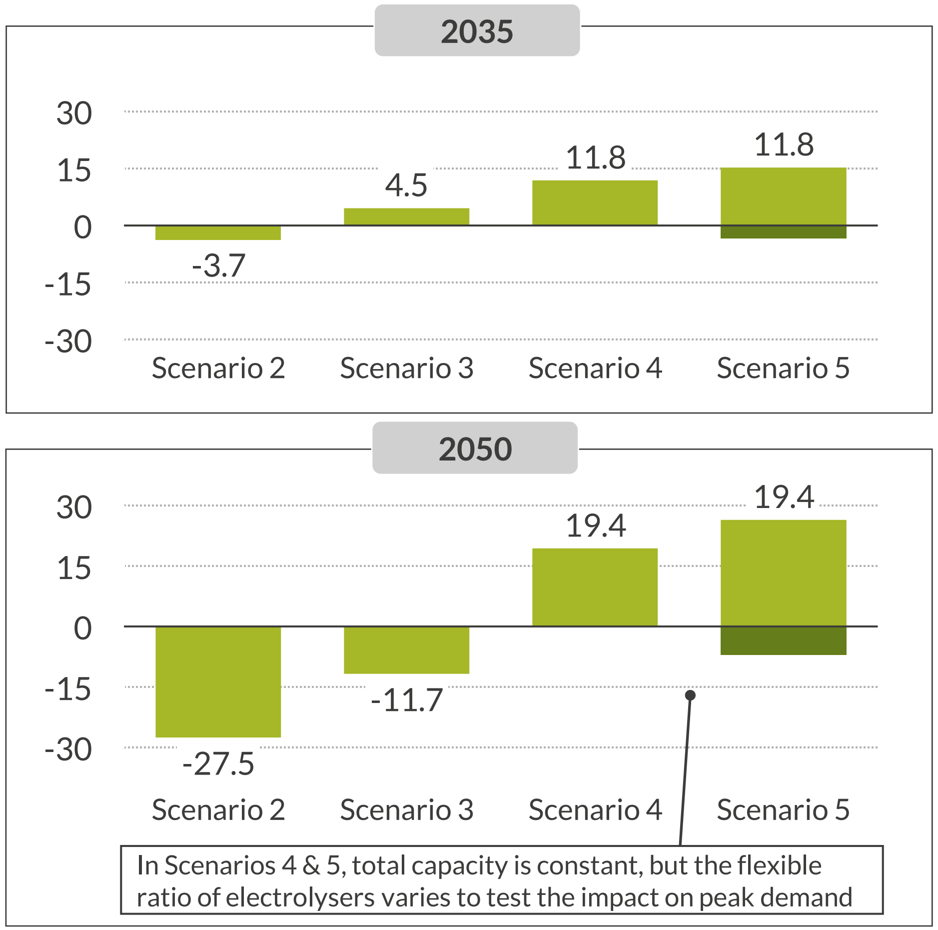
Capacity of hydrogen production technologies, Scenario 1
GW



Difference in Hydrogen production capacity relative to Scenario 1
GW



Salt cavern storage | Flexible electrolysers[1] | Inflexible electrolysers[1] | SMR/ATR and CCS[2] | SMR[3]

- To match the growth in hydrogen demand, total production capacity increased by 413% in Scenario 1 (including storage), with **flexible electrolyser capacity dominating the mix by 2050**
- Hydrogen is not used in the heating sector in Scenario 2, limiting total hydrogen production capacity to under 60 GW by 2050
- In contrast, the hydrogen-reliant heating sector in Scenarios 4 and 5 means total hydrogen production capacity exceeds 100 GW by 2050, almost double that of Scenario 2
- **Hydrogen capacity assumption changes are limited to green hydrogen production only** in order to isolate the impact of the heating decarbonisation on the power sector. However, the ratio of blue/grey to green hydrogen production averages approximately 20:80 over the forecast period in the scenarios due to the variability of flexible electrolyser utilisation[4] and hydrogen imports

1) Produces green hydrogen, uses electricity and has no on-site emissions. 2) Steam methane reforming or Autothermal reforming with carbon capture and storage, produces blue hydrogen and emits residual carbon dioxide. 3) Steam methane reforming, produces grey hydrogen and emits carbon dioxide. 4) Flexible electrolyser generation is a function of the power price as they will only generate hydrogen when economically profitable, meaning their production is a modelling output rather than an assumption.

Source: Aurora Energy Research

Contents

Gas prices stabilise from recent highs by the late 2020s, and steadily rise to £23.3/MWhth by 2050, with carbon prices increasing to £161/tCO_2 by 2050

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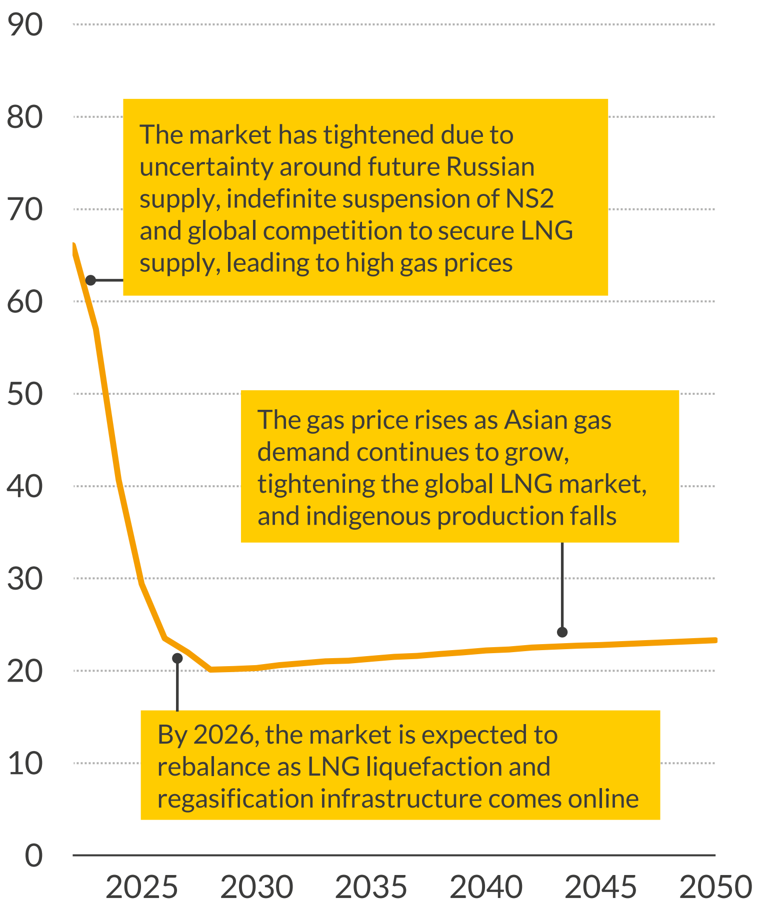
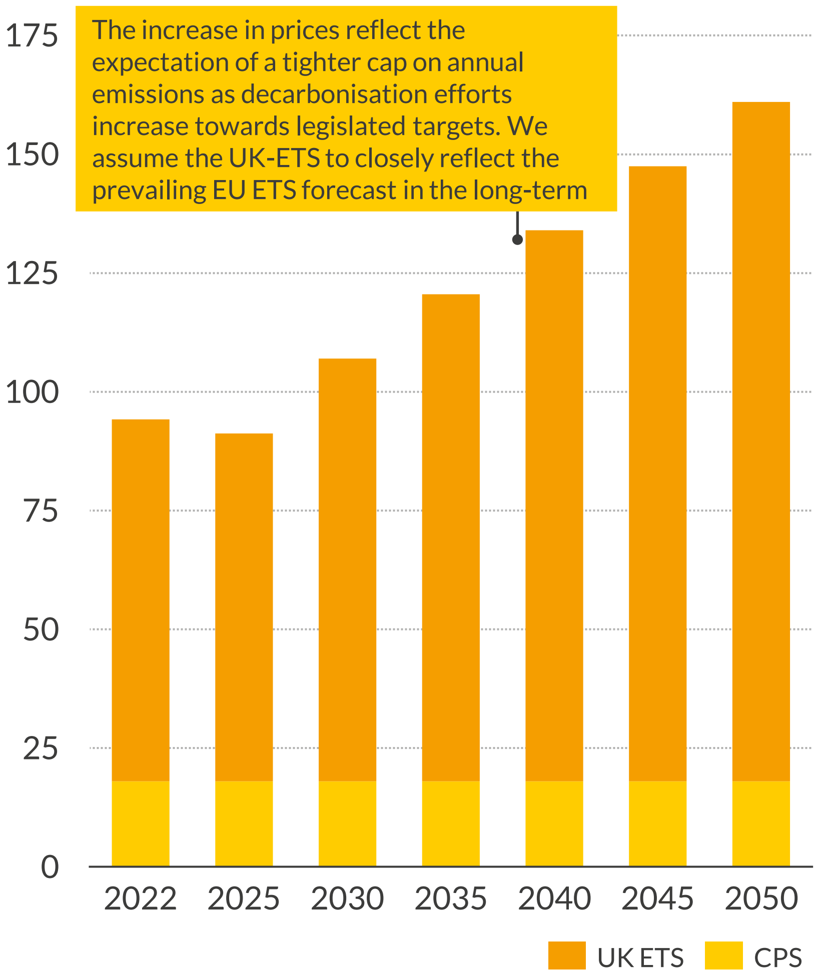
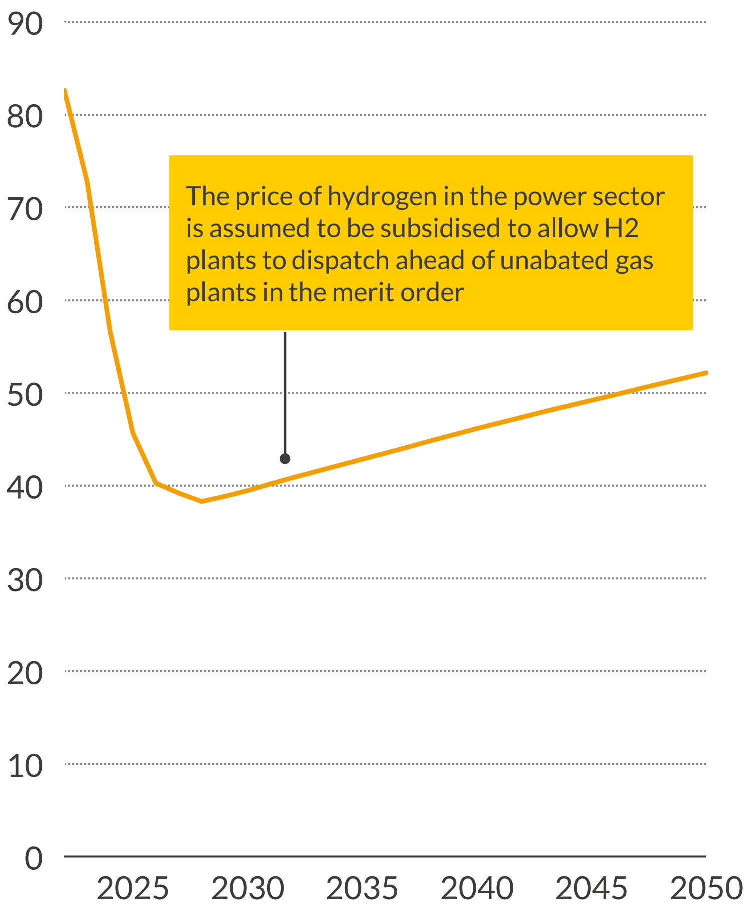
Gas price
£/MWhth (real 2021)



Total GB carbon price (UK ETS + CPS)[1]
£/tCO_2 (real 2021)



Hydrogen price
£/MWh (real 2021)



1) This is economics based and not based on the social cost of carbon

Sources: Aurora Energy Research, EIKON, FES 2022

Additional Pumped hydro and Gas CCS capacity are required in Scenarios 3, 4 and 5 to alleviate the load on the power system

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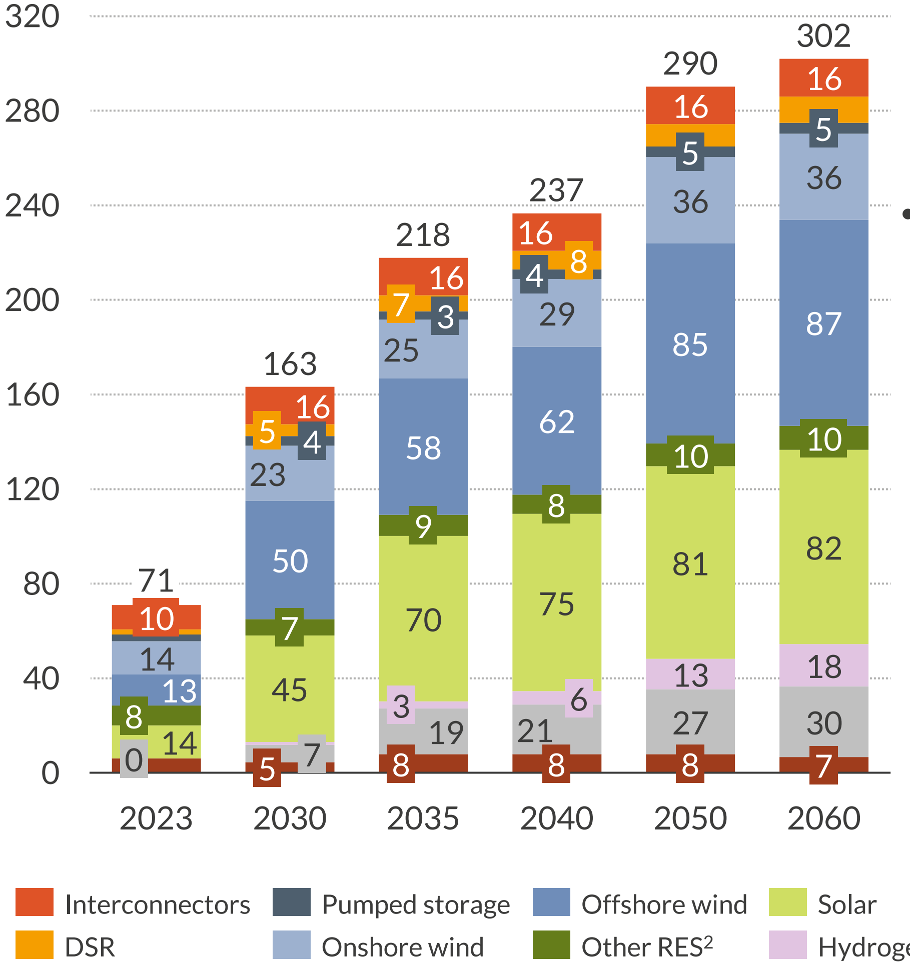
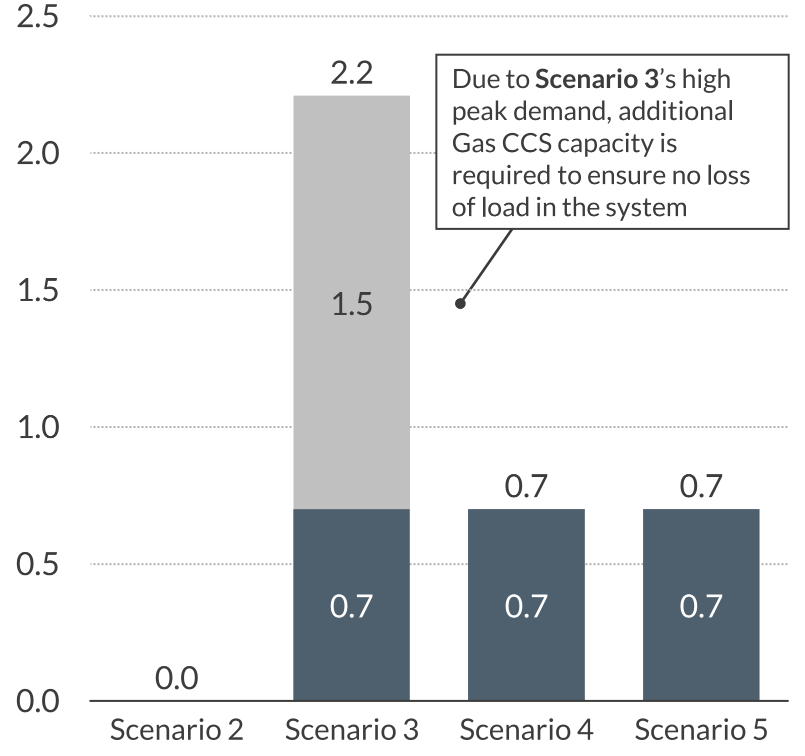
Exogenous capacity timeline, Scenario 1[1]
GW



Exogenous capacity deltas compared to Scenario 1, 2050[1]
GW



- Exogenous capacity refers to capacity build decisions that are assumed will take place in the Benchmark scenario and inputted directly to the model
- New-build capacity timelines are created for
  - Offshore & onshore wind, Solar, Gas CCS, H2 CCGTs, Nuclear, BECCS, Interconnectors, Pumped hydro/hydro, Demand side response (DSR)
- Both CCS and H2 CCGTs are exogenously added capacities (H2 peakers build economically only). Currently, CCS is favoured over H2 CCGTs in GB policy given the lower costs, greater scalability and higher round trip efficiencies – this means CCS reaches higher capacities in the exogenous timeline than H2 CCGTs
- Existing assets are also given an expected retirement timeline
- Scenarios 3, 4 and 5 assume an additional 0.7 GW of pumped storage capacity by 2050 to alleviate the load on the power system from earlier adoption of H2 boilers
- Additional capacity will build on an economic basis, in order to ensure system supply standards are met

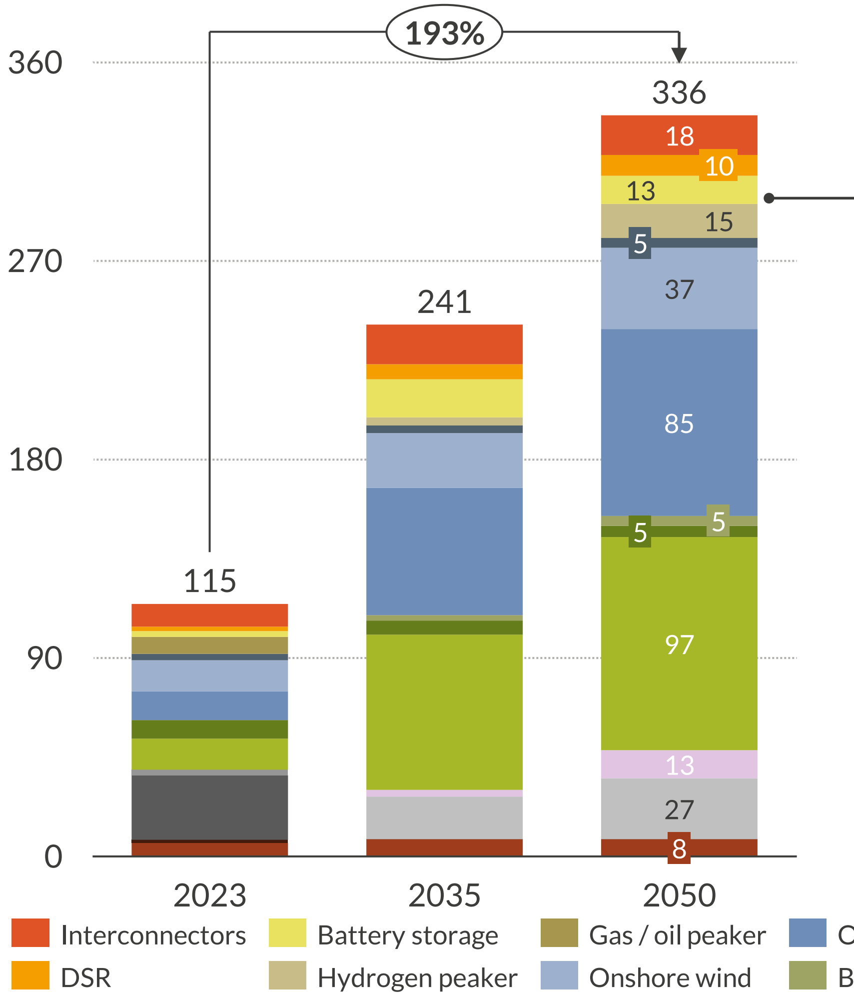
1) Please note that this shows only input capacities (exogenous) but does not show capacity that economically builds within the model (endogenous). Total resultant capacity is shown in section IV. Resultant system composition and emissions. 2) Other RES includes hydro, BECCS, biomass & EfW.

Source: Aurora Energy Research

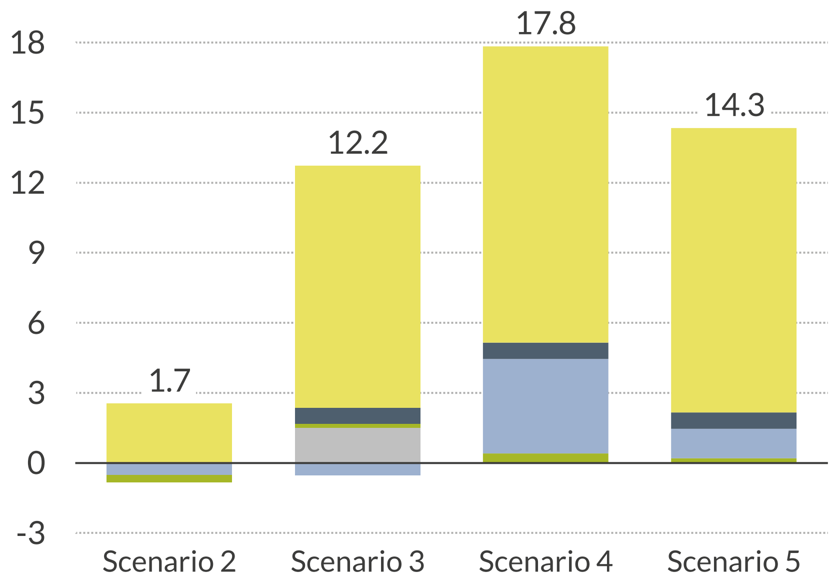
Contents

Total installed capacity approximately triples in all scenarios by 2050, with intermittent renewables dominating the mix

Scenario 1 total installed capacity,
GW



Total capacity deltas compared to Scenario 1, 2050
GW



Total capacity deltas compared to Scenario 1, 2050
%

0.7% 3.6% 5.3% 4.3%

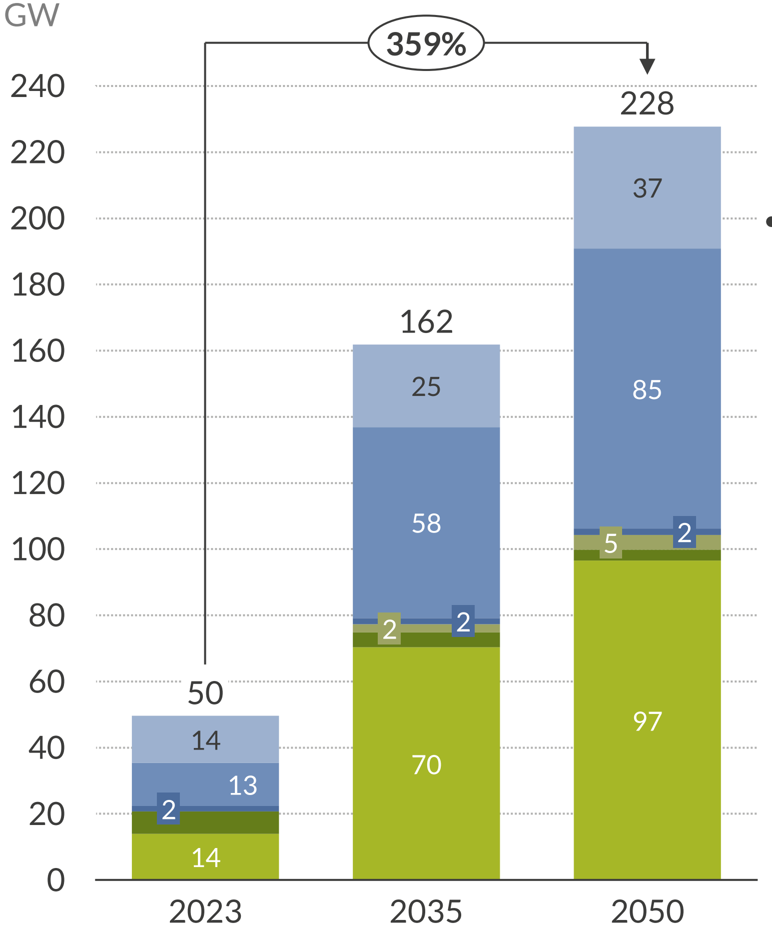
- Overall, the **installed capacity will need to grow significantly** in all scenarios to offset the removal of unabated gas in 2035 while meeting the demand load from decarbonising heating
- A heating sector that relies on **hydrogen boilers** more than in Scenario 1 **will need 4-6% more capacity** to meet increase demand, causing great renewable and battery build in Scenarios 4 and 5 by 2050
- In contrast, if more **heat pumps** are used than Scenario 1, higher peaking requirements **will increase the need** for **flexible capacity** (batteries, pumped hydro and CCS) but not intermittent renewables, as seen in Scenarios 2 and 3
- But **ultimately**, the **faster decarbonization of heating** in Scenarios 3, 4 and 5 is **the main driver of increased capacity** build out compared to Scenario 1, as system tightness in the medium-term is most efficiently alleviated by rapid battery deployment

1) Other RES includes biomass and EfW.

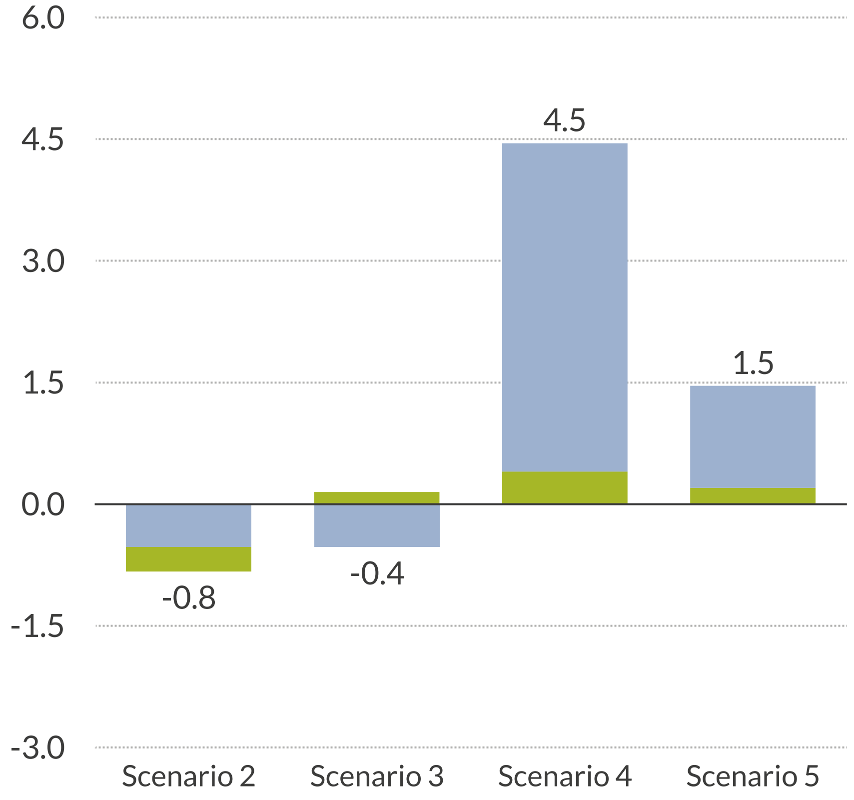
Source: Aurora Energy Research

Differences in renewable deployment across scenarios are mainly driven by variations in demand assumptions

Scenario 1 total installed renewable capacity, GW



Renewable capacity deltas compared to Scenario 1, 2050 GW



Onshore wind | Offshore wind | Hydro | BECCS | Other RES[1] | Solar

1) Other RES includes biomass and EfW. 2) Scenario 1 has a 23% share of hydrogen for heating in 2050, whereas Scenario 3 only has 13% by 2050. 3) Average between 2023 and 2050.

Source: Aurora Energy Research

Scenario 2
Lower total power demand in this scenario leads to a smaller power system. As result, in this scenario, less merchant renewable capacity will be built

Scenario 3
Less heating demand met by hydrogen in Scenario 3 by 2050[2] results in a lower total power demand than in Scenario 1, lowering requirements for renewables

Scenario 4
Scenario 4 has the highest net RES capacity increase compared to Scenario 1 at 4.5 GW higher by 2050. This increase in merchant build out of onshore wind and solar PV is mostly driven by a 6%[3] greater total power demand in Scenario 4 relative to Scenario 1

Scenario 5
A lower proportion of inflexible electrolysers in Scenario 5 compared to 4, reduces power demand, resulting in a lower net RES capacity increase than in Scenario 4

Total renewable generation follows the same pattern as renewable capacity deployment

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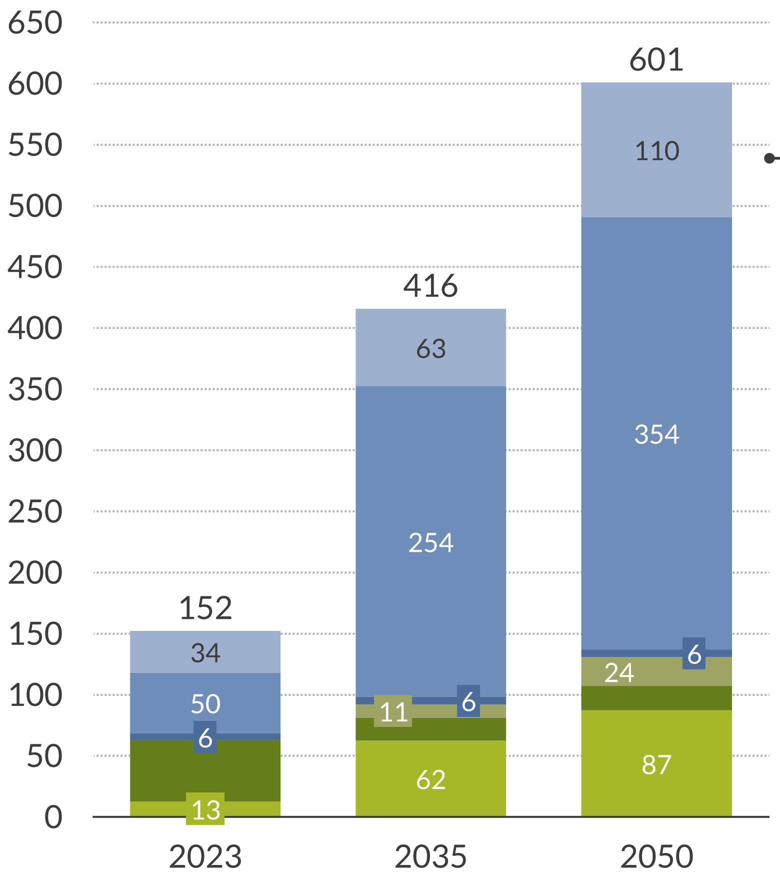
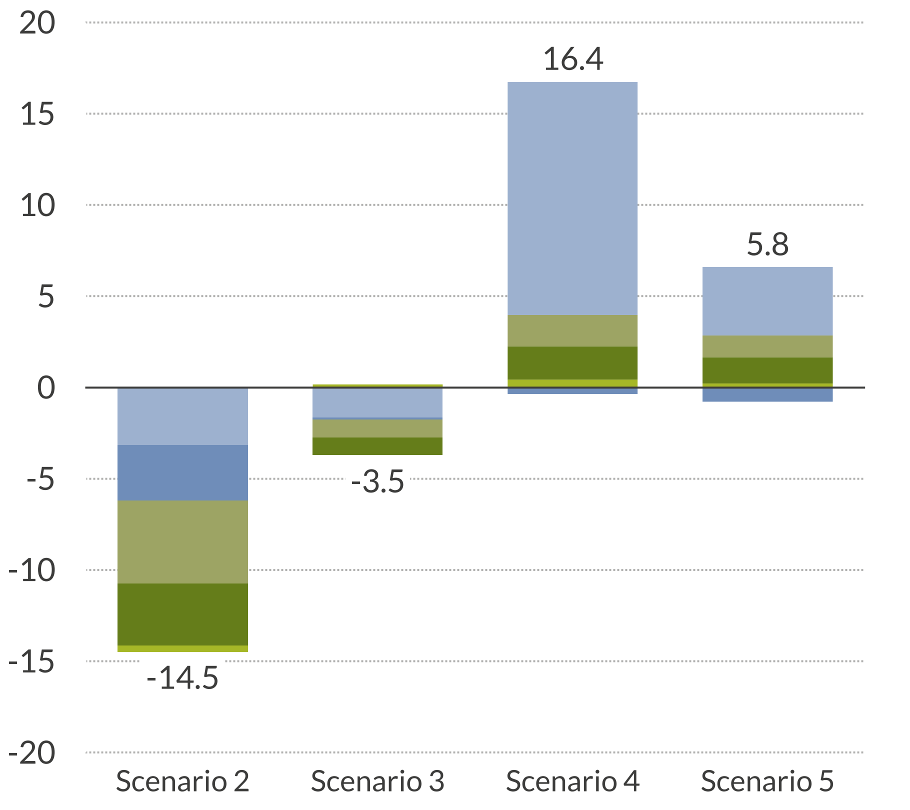
Scenario 1 total RES generation
TWh



Renewable generation deltas compared to the Scenario 1, 2050
TWh



Onshore wind | Offshore wind | Hydro | BECCS | Other RES[1] | Solar

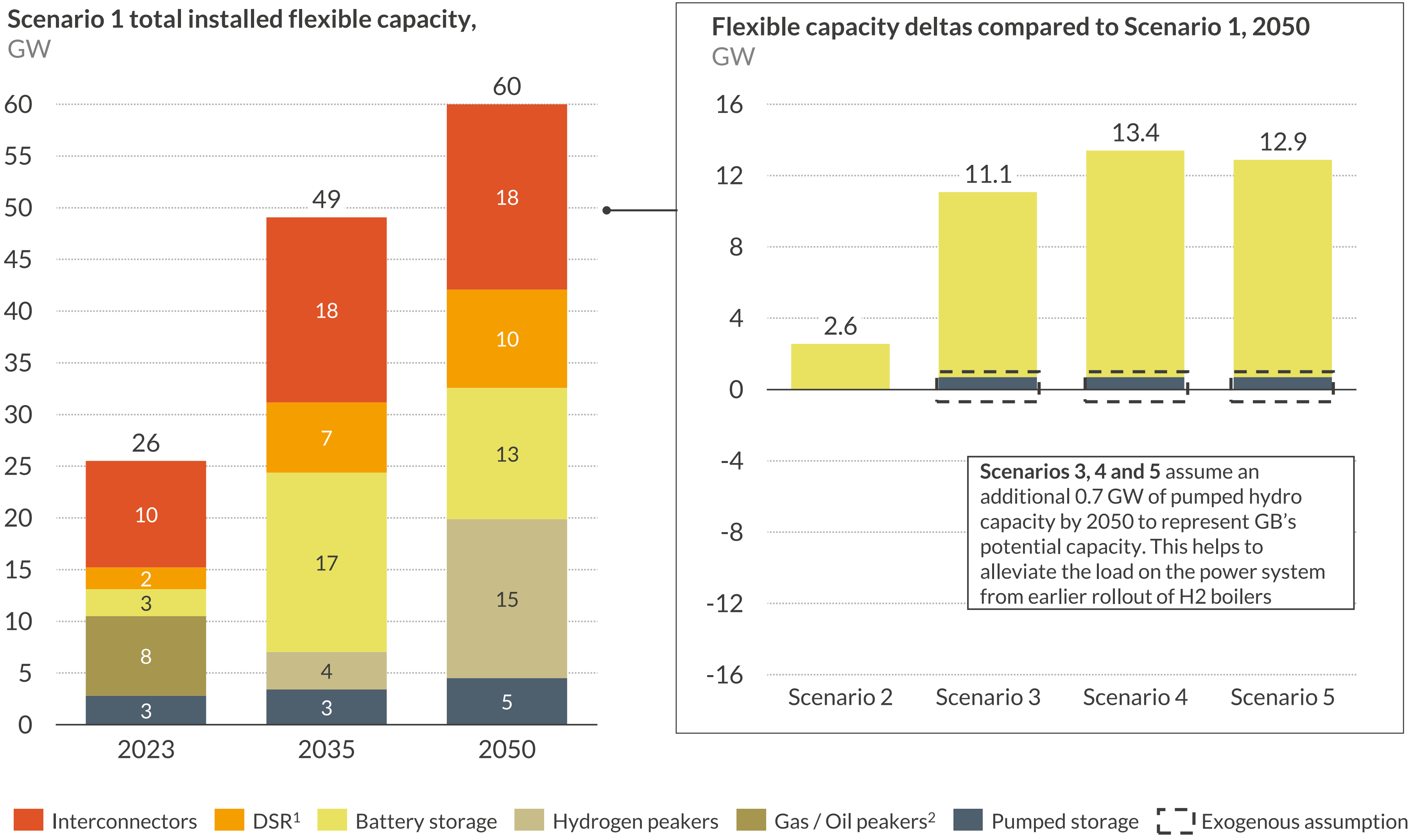
Scenario 2
In this scenario, heating is decarbonized through more efficient forms of electrification, leading to the smallest power system across all cases. The resulting lower renewable capacity deployment reduces renewable generation

Scenario 4
Total renewable generation follows the same patterns as renewable capacity deployment. Therefore, the increased total power demand in Scenario 4 increases renewable generation volume requirements by 3% in 2050 compared to the Benchmark scenario

1) Other RES includes biomass and EfW.

Source: Aurora Energy Research

Battery deployment in 3, 4 and 5 accelerates in the mid-forecast, due to the scenarios' faster H2 boiler adoption



1) Demand Side Response. 2) Gas / Oil peakers includes gas recips, OCGTs and oil peakers

Source: Aurora Energy Research

Scenario 2
With less flexible demand, Scenario 2 has higher peak demand than 1. Higher battery buildout is therefore required

Scenario 3
Flexible capacity is 11 GW higher than in 1, due to 2% higher peak demand in 2050

Scenarios 4 and 5
These scenarios have a higher battery buildout due to greater total demand and higher intermittent renewable capacity. Since unabated thermal assets are banned after 2035, the only flex technologies available are abated thermal generation and storage. Batteries have lower costs and can take advantage of the lower prices caused by increase renewable capacity in these scenarios. To help alleviate the high load on the power system in the 2030s and 40s in Scenario 4 and 5, caused by faster H2 boiler deployment, approximately 90% of battery growth happens before 2035.
Scenario 5 has the same H2 boiler buildout as 4, but it has reduced inflex electrolyser capacity, reducing its flexible capacity requirements due to reduced peak demand

A larger power system in Scenario 4 increases the need for interconnector imports due to high wholesale prices

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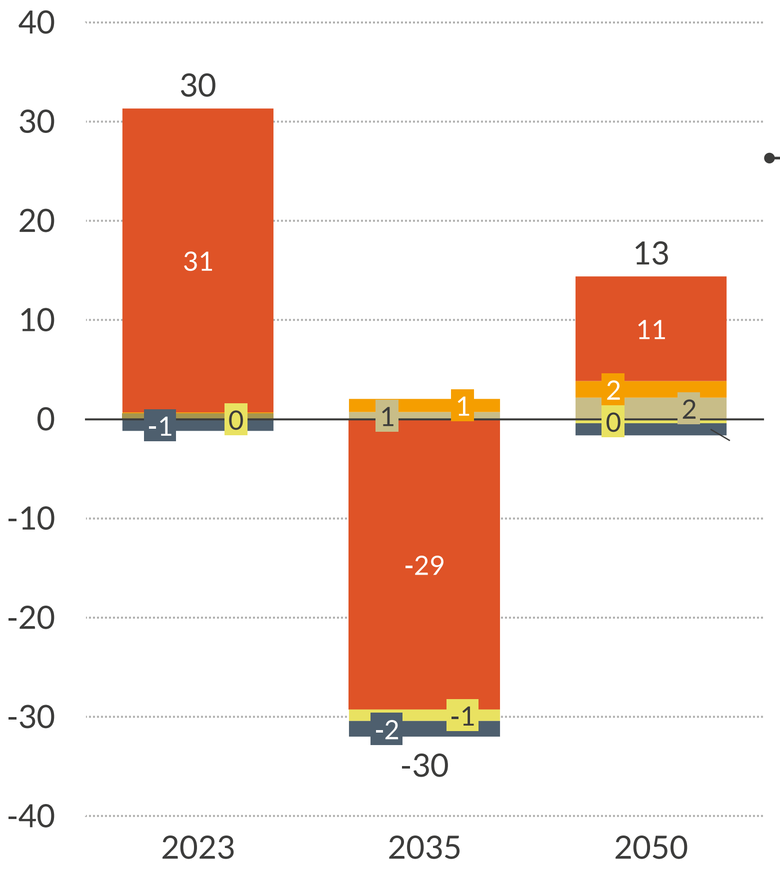
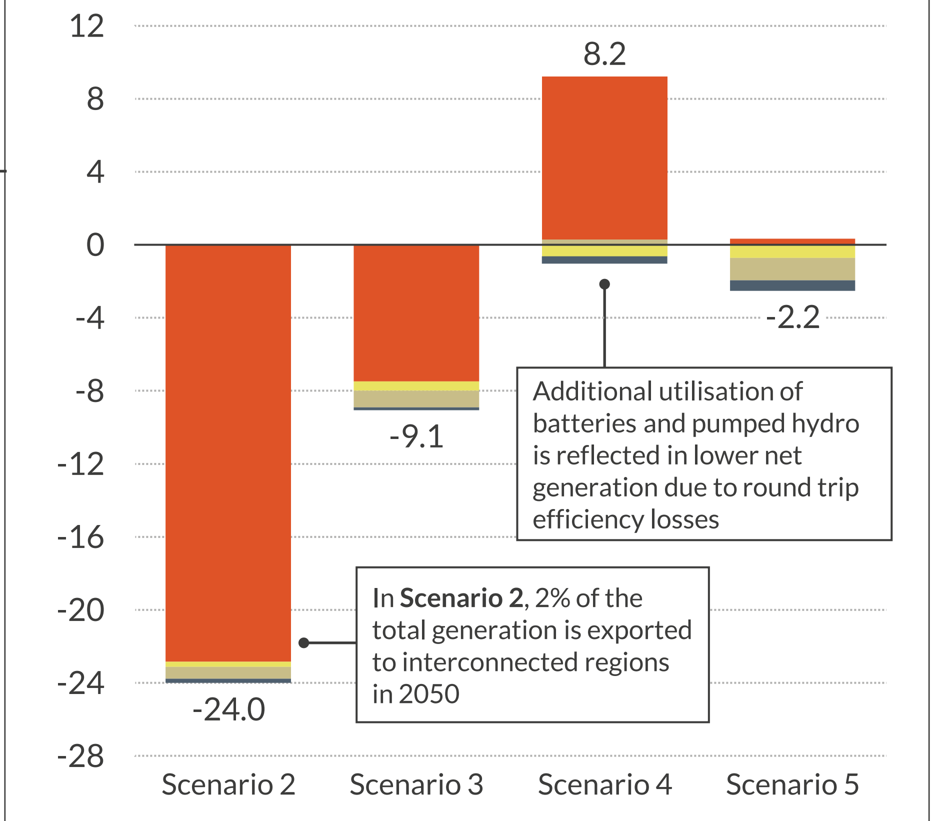
Scenario 1 total flexible generation
TWh



Flexible generation deltas compared to Scenario 1, 2050
TWh



Interconnectors | DSR[1] | Battery storage | Hydrogen peakers | Gas / Oil peakers[2] | Pumped storage

Scenario 2
Lower total demand reduces wholesale prices (17% lower than in 1 in 2050), resulting in 12 TWh of interconnectors net exports in 2050 in Scenario 2

Scenario 3
Lower total demand in Scenario 3 decreases wholesale prices by 15% in 2050 relative to Scenario 1, resulting in 7.5 TWh less of interconnector's net imports

Scenario 4
Baseload wholesale prices are on average[3] 8% higher in Scenario 4 than in Scenario 1. This is driven by increased total demand, resulting in higher net imports

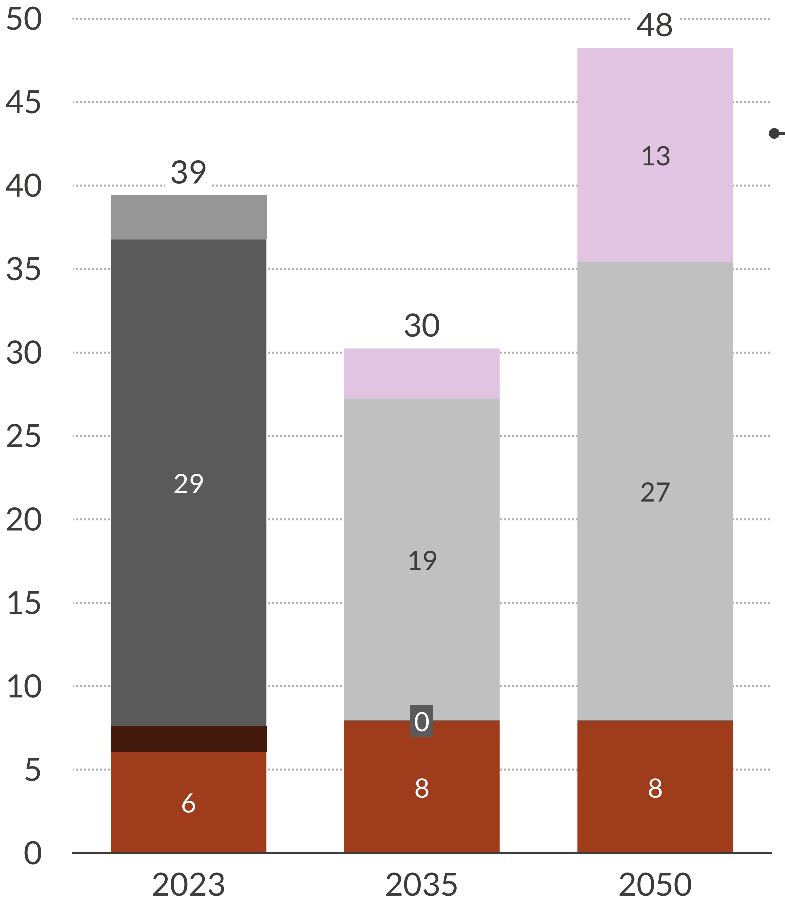
Scenario 5
Higher demand side flexibility in this scenario decreases peak demand, lowering the need for supply side flexibility. This reduction in hydrogen peakers generation decreases electrolyser demand in the system, lowering total power demand requirements

1) Demand Side Response. 2) Gas / Oil peakers includes gas recips, OCGTs and oil peakers . 3) Average between 2023 and 2050

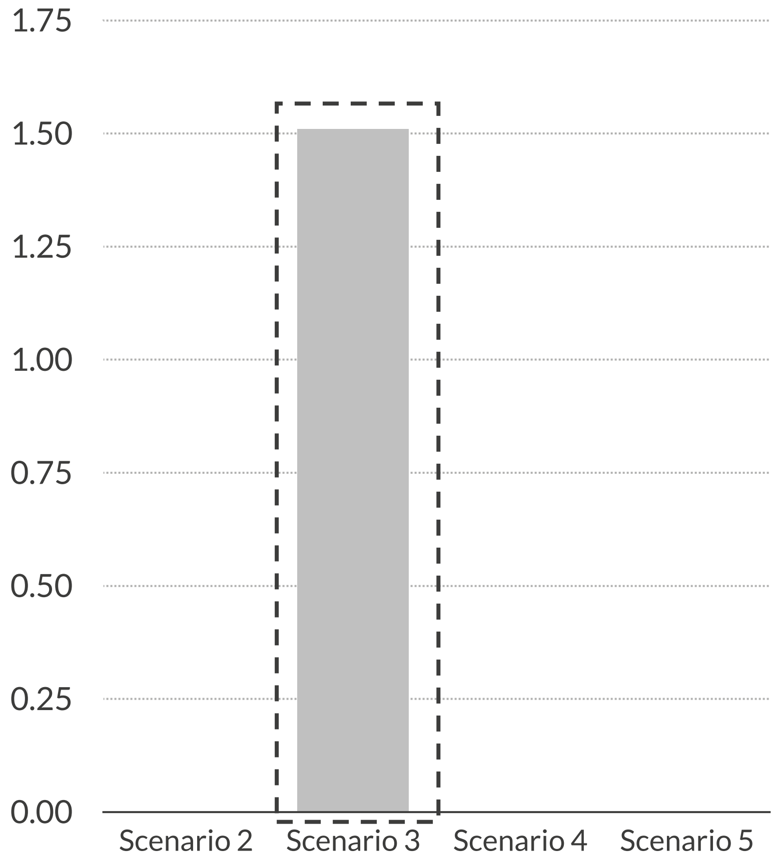
Source: Aurora Energy Research

An additional 2 GW of Gas CCS capacity by 2050 is required in Scenario 3 to ensure no loss of load in the system

Scenario 1 total installed baseload capacity
GW



Baseload capacity deltas compared to Scenario 1, 2050
GW



Other thermal[1] | Hydrogen CCGT | Gas CCS | Gas CCGT | Coal | Nuclear | Exogenous assumption

All scenarios have unabated gas power generation banned from 2035. Therefore, existing unabated gas CCGTs must retire or convert to Gas CCS or H2 CCGTs by 2035. A ban on unabated gas in 2035 means increased deployment of Gas CCS and H2 CCGTs is required to meet demand in the 2030[2]. Renewables alone are insufficient to meet demand growth requirements

The buildout of renewables is supplemented with a higher deployment of baseload capacities to ensure there is no loss of load

Scenario 3
Due to the fast roll-out of hydrogen boilers and the high share of heat pumps assumed in this scenario, an additional 2 GW of Gas CCS is required on the system by 2050 compared to the Benchmark. This additional capacity is required to ensure there is no loss of load in this scenario

1) Other thermal includes embedded CHP. 2) Both CCS and H2 CCGTs are exogenously added capacities (only H2 peakers build economically). Currently, CCS is favoured over H2 CCGTs in GB policy – this means CCS reaches higher capacities in the exogenous timeline than H2 CCGTs
Source: Aurora Energy Research

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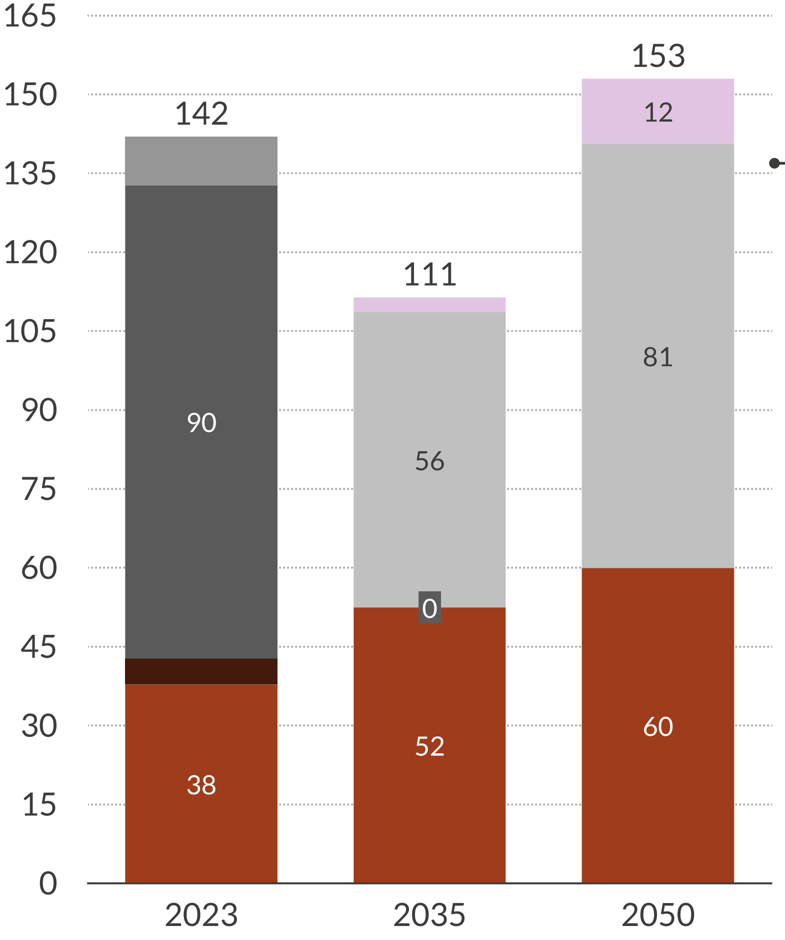
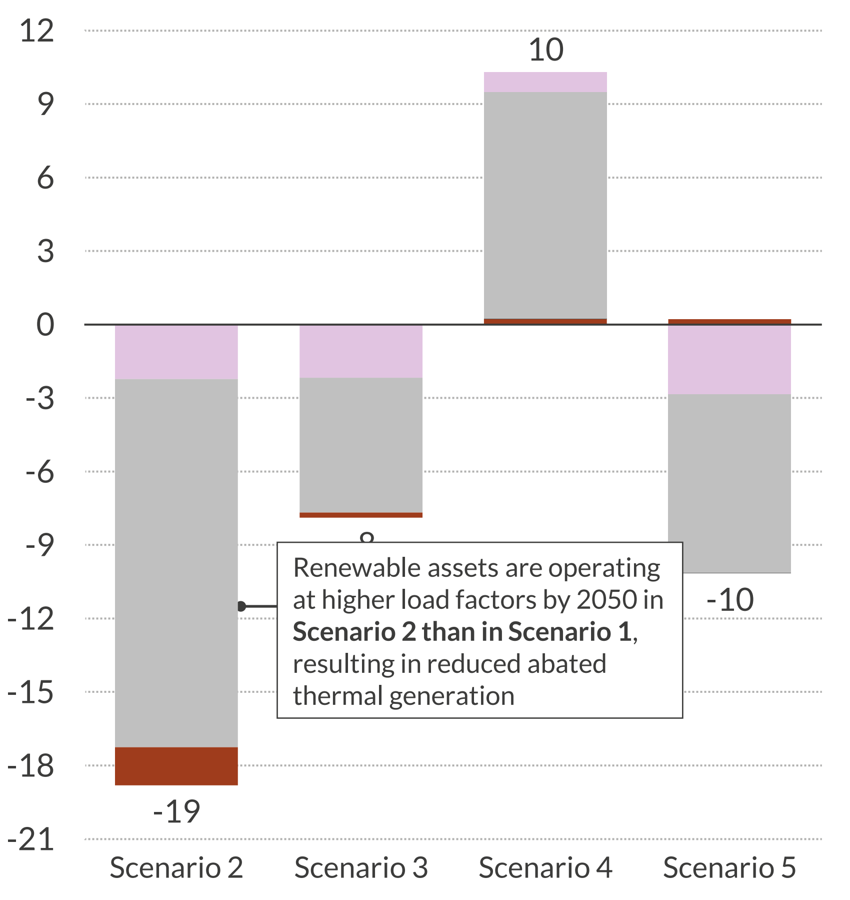
Variations in demand assumptions result in the baseload capacities being utilised to different extents in Scenarios 1, 2, 3, 4 and 5

Scenario 1 baseload generation[1]
TWh



Baseload generation deltas compared to Scenario 1, 2050[1]
TWh



Other thermal[2] | Hydrogen CCGT | Gas CCS | Gas CCGT | Coal | Nuclear

1) These charts show all generation (baseload and otherwise) from Gas CCGTs, Gas CCS, Coal, Nuclear, Hydrogen CCGT and other thermal. Traditionally, these technologies act as baseload power suppliers; however, as renewable rollout accelerates, some thermal generation can be pushed higher up the merit order and forced to act as flexible capacity. 2) Other thermal includes embedded CHP. 3) Average between 2023 and 2050.

Source: Aurora Energy Research

Scenario 1
The increased deployment of Gas CCS required to meet demand after banning unbated thermal generation in 2035, results in 81 TWh of Gas CCS by 2050. Baseload generation falls by 22% between 2023 and 2035 but rises by 37% in 2050 as the power system grows

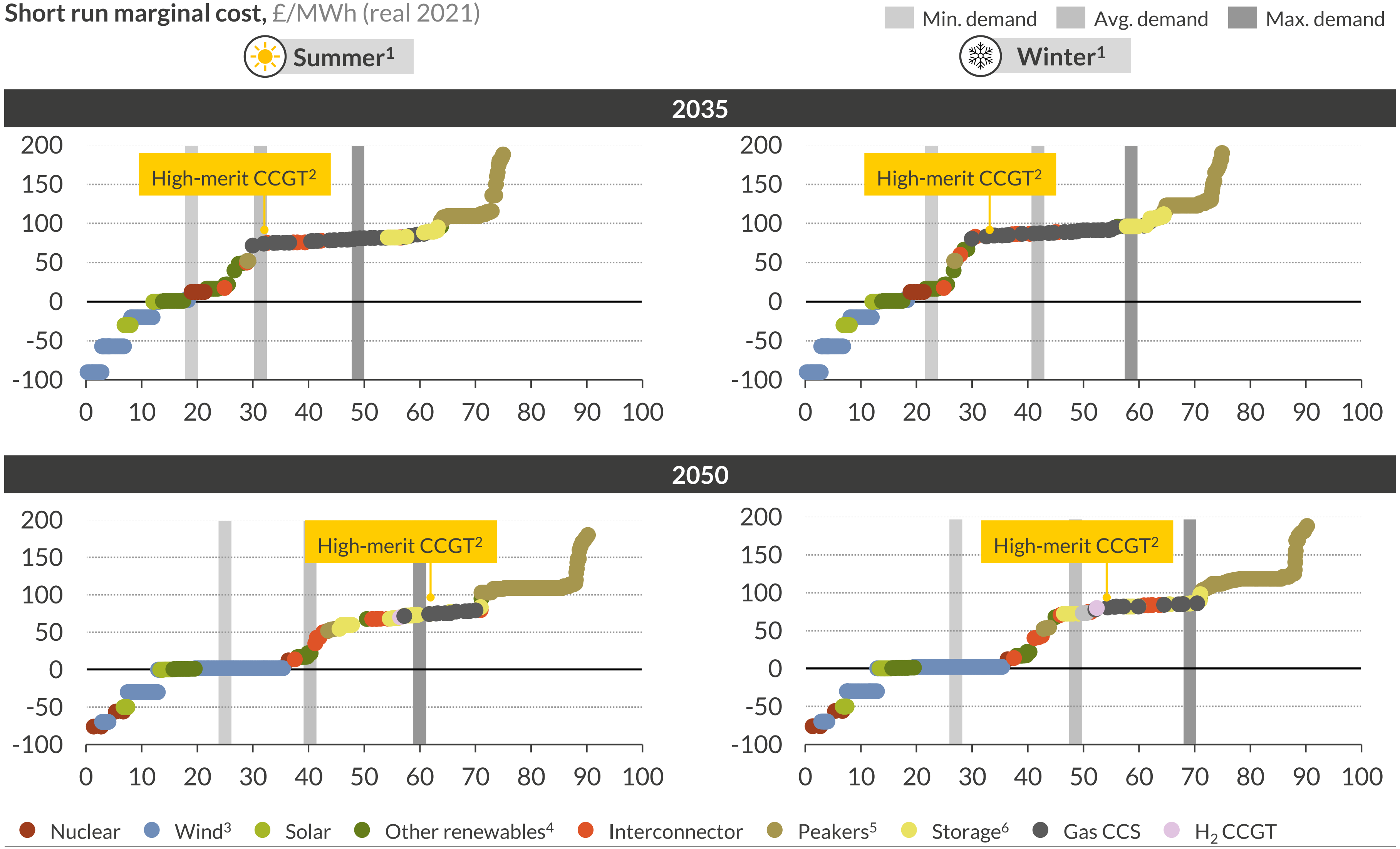
Scenario 2
Lower electricity demand results in a smaller power system overall compared to 1, reducing baseload generation by 19 TWh in 2050

Scenario 4
Higher total electricity demand in this scenario increases generation volume requirements. As a result, Gas CCS and H2 CCGTs are typically operating at higher load factors by 2050, compared to Scenario 1

Scenario 5
Scenario 5 has 1%[3] higher total power demand than the Benchmark scenario. However, it also has 6%[3] lower peak demand than 1, reducing the need of baseload generation by 10 TWh in 2050 compared to Scenario 1

Hydrogen and gas peaking assets are at the top end of the merit order, whilst subsidised renewables are at the lower end

Short run marginal cost, £/MWh (real 2021)



1) Summer is defined as April – Sept and winter as Oct to March. 2) Assuming 54% HHV efficiency. 3) Includes both offshore and onshore wind. 4) Includes biomass, EfW, hydro and CHP. 5) Includes OCGT, recips, H2 peakers, gas peakers and DSR. 6) Includes batteries and pumped storage.

Source: Aurora Energy Research

- The merit order of generation is shown for the Benchmark and is determined by the short run marginal cost of each technology in the capacity mix.
- Power supply in GB is typically dispatched in preference of:
  - Low-marginal cost assets such as nuclear/renewables
  - Thermal baseload assets such as CCGTs
  - Peaking assets as such recips
- The highest cost plant that dispatches in any given period sets the wholesale power price.
- More renewable deployment will result in low-cost assets meeting more than minimum demand by 2035, whilst the retirement of CCGTs results in high-cost peakers setting the price more often.

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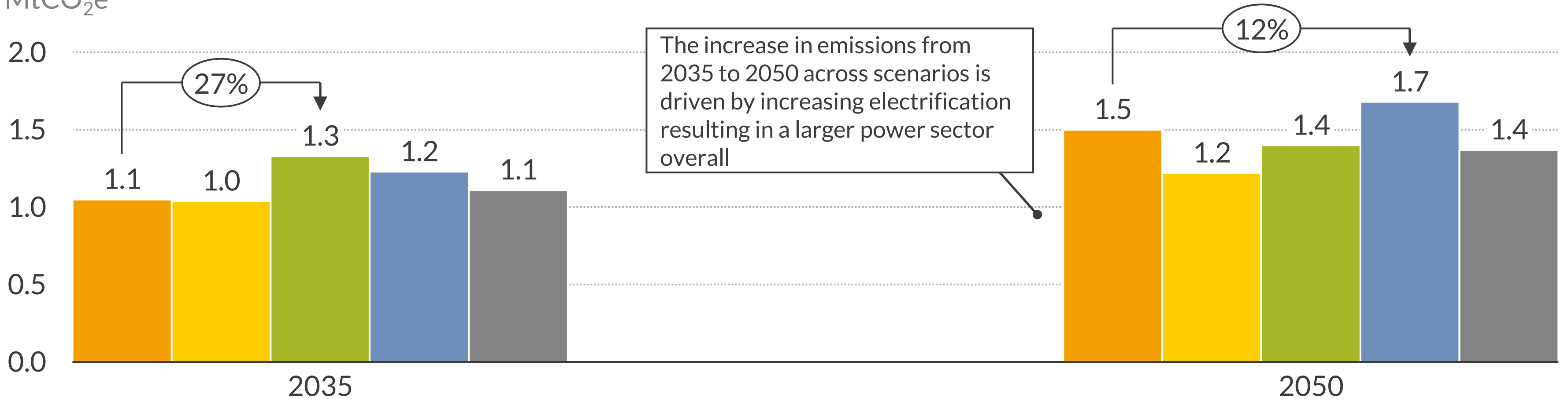
Earlier and larger rollout of H2 boilers in Scenario 4 increases emissions from the power sector in 2035 compared to Scenario 1

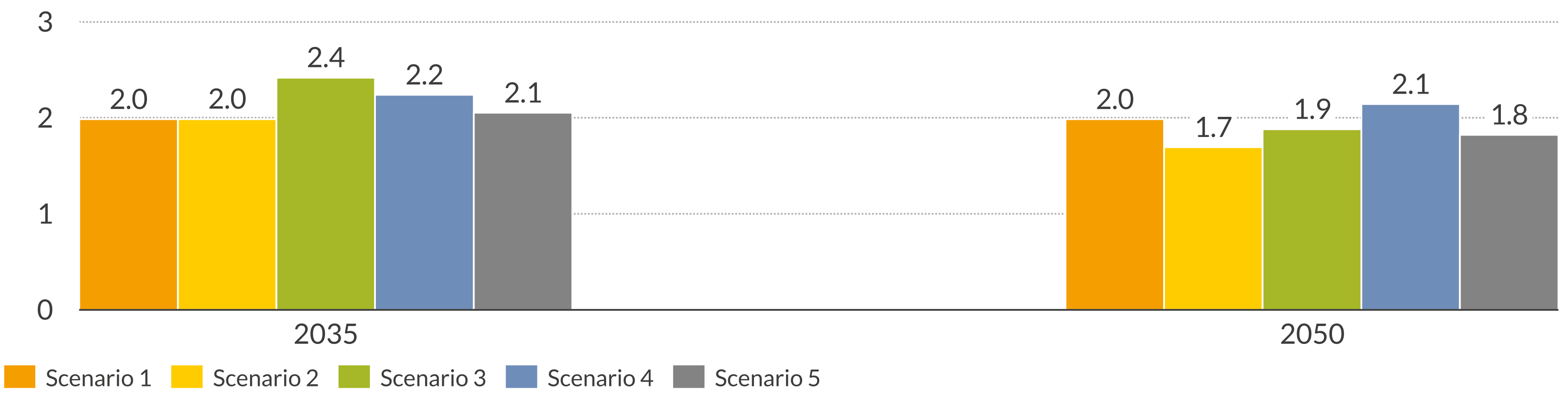
Power sector carbon emissions

$MtCO_2e$



Power sector carbon intensity

CO_2e/kWh



1) Scenario 1 has a 23% share of hydrogen for heating in 2050, whereas Scenario 3 only has 13% by 2050

Source: Aurora Energy Research

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Scenario 2
This scenario assumes no hydrogen for heating, resulting in the smallest power system across all cases. This reduces emissions by 0.3 $MtCO_2$ compared to Scenario 1

Scenario 3
Earlier retirement of fossil fuel heating technologies and reduced flexible demand compared to Scenario 1, increase the need for Gas CCS capacity in Scenario 3, boosting emissions by 27% in 2035. However, in 2050, reduced power demand due to a lower share of H2 boilers in Scenario 3[1], offsets the effect of higher inflexible demand in the system, reducing emissions by 7% relative to the Benchmark

Scenarios 4
Increased total power demand results in a 12% rise in emissions in 2050 relative to the Benchmark, as a larger power system requires higher generation volumes. This increases Gas CCS generation by 11% in 2050 compared to Scenario 1, resulting in greater the carbon emissions

Contents

Total power system costs[2] are calculated for each scenario, based on its capacity and generation mix and resulting prices (1/3)

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Cost components		Methodology
Wholesale costs	Wholesale production costs	▪ 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 can be calculated as: short run marginal cost x generation**
	Wholesale margins[2]	▪ 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 has to dispatch in order for demand to be met, meaning that plants that have lower SRMC can earn an “inframarginal rent” (see slide 48). ▪ 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 do not account for additional payments made via CfDs, ROCs or REFIT contracts, which are accounted for separately, and within this component we assume all plants receive the wholesale price. CfD payments allow renewable assets to achieve a fixed “strike price” for power produced. In periods where the wholesale price is lower than the strike price, a top-up is provided, however in periods where the wholesale price is higher than the strike price, the asset owner must pay back the difference. Both top-up payments and paybacks are accounted for under the low-carbon subsidies component, which results in calculated wholesale margins being an overestimate of actual wholesale margins. **Wholesale margins can be calculated as: wholesale market spend (wholesale market price x generation) – wholesale production costs (SRMC x generation)**

1) This excludes H2 production costs (blue and grey hydrogen production, hydrogen imports and storage and electrolysers) and heating system costs. Note that the hydrogen price is still used but only to determine the SRMC of hydrogen burning power plants.
2) CAPEX is recovered through revenues in the wholesale market, balancing mechanism, capacity market, subsidies and ancillary services.
Source: Aurora Energy Research

Total power system costs[1] are calculated for each scenario, based on its capacity and generation mix and resulting prices (2/3)

	Cost components	Methodology
Balancing Mechanism	Balancing Costs[2]	▪ 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 can be calculated as: net imbalance volumes x imbalance price**
Capacity Market	Capacity Market[2]	▪ 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 security of supply but which do not achieve sufficient revenues from other markets to remain available to the system. ▪ All technologies which achieve 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 security of supply. **Capacity Market costs can be calculated as: CM clearing price x capacity x derating factor**
Subsidies	Low Carbon Subsidies[2]	▪ 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[2]	▪ 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 can be calculated as: Full lifetime technology costs – sum of market revenue (wholesale, balancing, capacity market[3] & ancillary services)**

1) This excludes H2 production costs (blue and grey hydrogen production, hydrogen imports and storage and electrolysers) and heating system costs. Note that the hydrogen price is still used but only to determine the SRMC of hydrogen burning power plants.
2) CAPEX is recovered through revenues in the wholesale market, balancing mechanism, capacity market, subsidies and ancillary services 3) 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

Sources: Aurora Energy Research

Total power system costs[1] are calculated for each scenario, based on its capacity and generation mix and resulting prices (3/3)

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Cost components		Methodology
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) This excludes H2 production costs (blue and grey hydrogen production, hydrogen imports and storage and electrolysers) and heating system costs. Note that the hydrogen price is still used but only to determine the SRMC of hydrogen burning power plants.
2) Revenue = Incentives + Innovation + Outputs; this methodology determines the allowable transmission costs chargeable by the network operator
Sources: Aurora Energy Research

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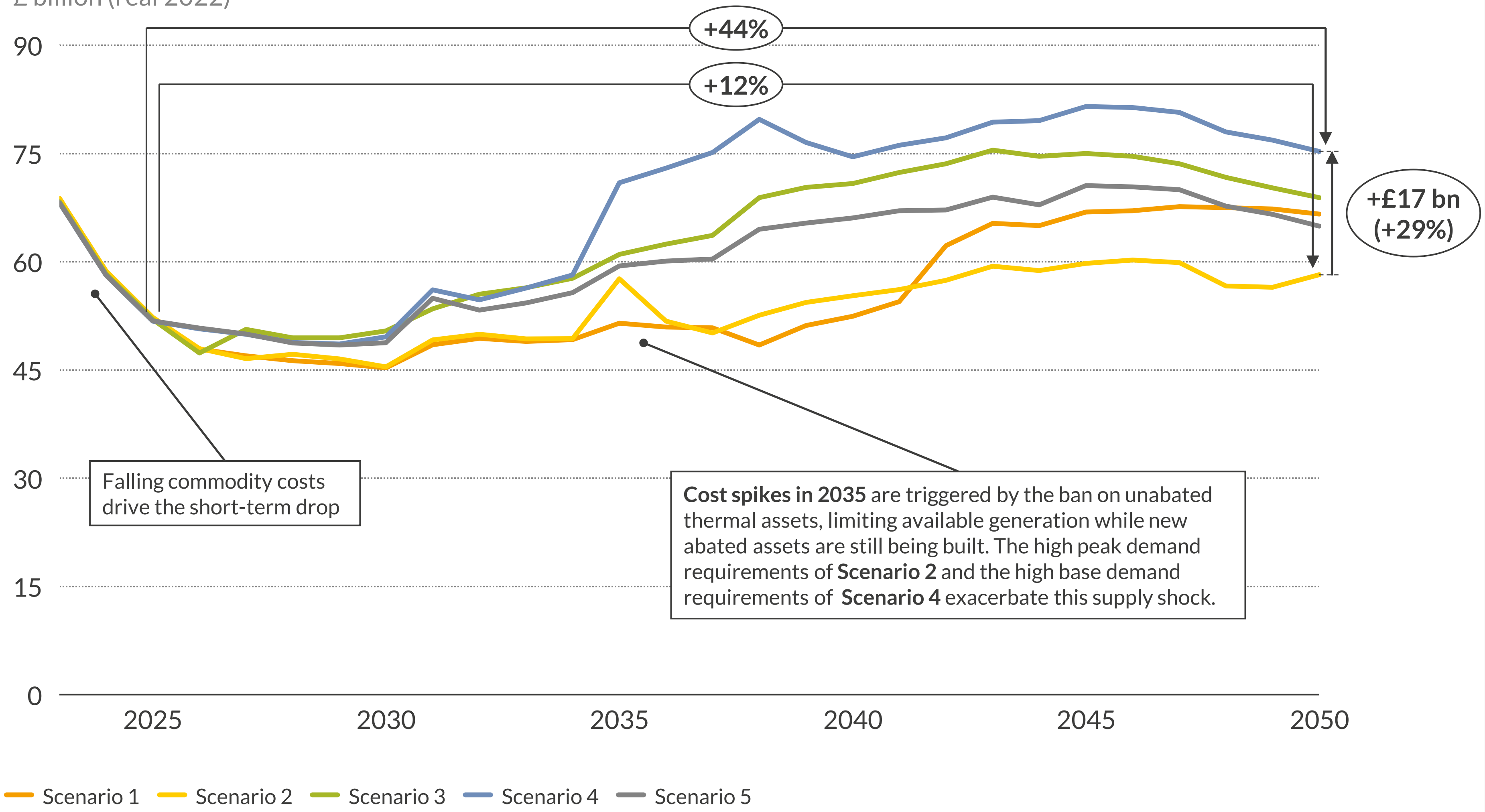
Total power system costs rise to 2050 in all scenarios as growing demand causes higher prices and increased capacity needs[1,2]

Total power system costs[1]
£ billion (real 2022)



1) This excludes H2 production costs (blue and grey hydrogen production, hydrogen imports and storage and electrolysers) and heating system costs. 2) This period accounts for prices from 2025-2050 and excludes prices prior to 2025. Note the 2023-2024 period is excluded from these calculations as current high gas prices distort results.
Source: Aurora Energy Research

- Total power system costs increase in all scenarios over the forecast[2], with costs varying by £17 billion in 2050 between Scenario's 2 and 4
- The fall of currently-high commodity prices drives a drop in system costs in the late 2020s, after which growing power demand underpins a rise in power prices, increasing system costs to 2050
  - Scenario 4's costs trend the highest, due to its high demand (and power prices)
  - Scenario 2's costs trend the lowest, due to its low demand (and power prices)
- In addition to demand and power prices, rising subsidisation needs drive up system costs as firm capacity requirements increase. This is most evident in Scenarios 3, 4 and 5 due to their rapid heating decarbonisation

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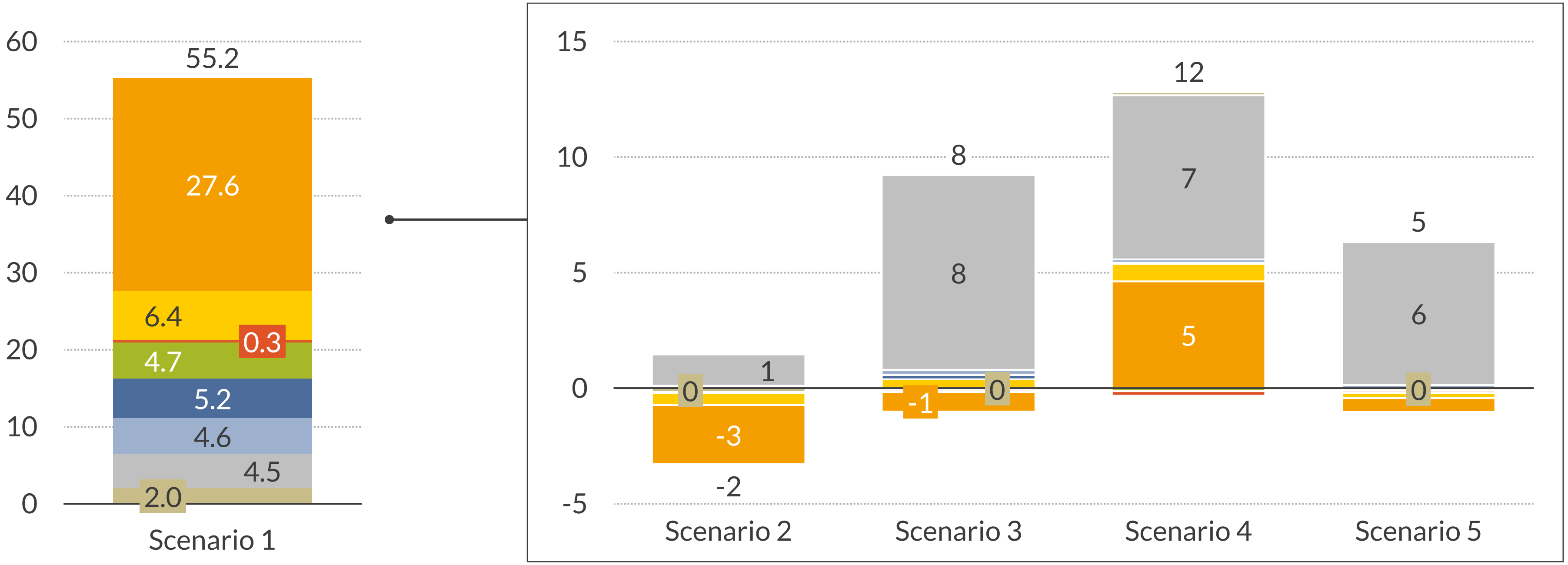
Average annual power system costs range from £67.7 billion/a to £53.4 billion/a between scenarios

Average annual power system costs (2025 – 2050)[1,2]

£ billion (real 2022)

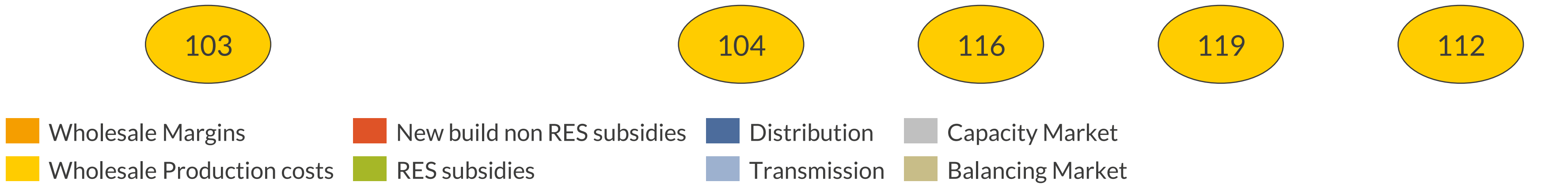
Difference in each scenario relative to Scenario 1

£ billion (real 2022)



Average consumer power costs (2025 – 2050) (Excluding Climate Levy, Supplier Charges & VAT)

£/MWh (real 2022)



1) This excludes H2 production costs (blue and grey hydrogen production, hydrogen imports and storage and electrolysers) and heating system costs. 2) Note the 2023-2024 period is excluded from these calculations as current high gas prices distort results. 3) Wholesale costs include both wholesale margins and wholesale production costs. 4) 38% hydrogen for heating by 2050

Source: Aurora Energy Research

Wholesale market costs[3] are the largest cost component of total system costs and are driven by changes in commodity prices, demand and supply mix

Scenarios 3, 4 and 5 have 15%, 23% and 10% greater average annual system costs, respectively, than Scenario 1. This is driven by an earlier retirement of fossil fuel heating technologies, which causes power demand to rise sooner in the forecast. As a result, in the medium term, a high load is placed on the power system, increasing capacity market spend in these scenarios as additional firm capacity is required to ensure no loss of load in the system. Additionally, **Scenario 4** has higher wholesale costs than Scenario 1 driven by increased power demand due to a high share of hydrogen for heating[4]

Scenario 2's lack of hydrogen boilers will lower its overall power demand, reducing wholesale costs and thus system costs compared to Scenario 1. However, its average annual system costs are on par to Scenario 1 due to lower overall demand (larger denominator)

Wholesale market costs: the deployment of H2 boilers in Scenarios 1, 3, 4 and 5 increases wholesale costs due to higher power demand

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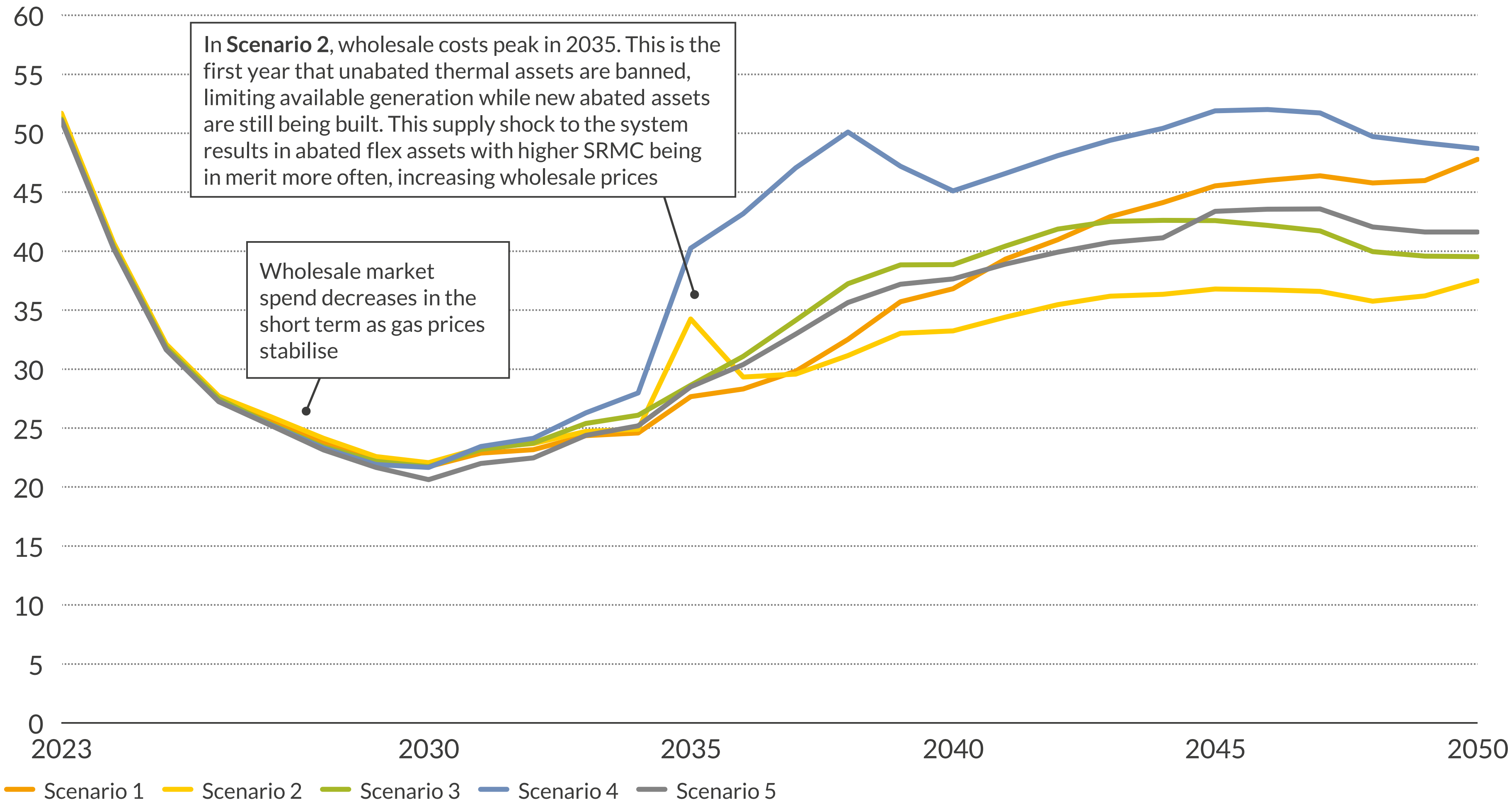
Annual wholesale costs[1]
£ billion (real 2022)



1) Wholesale costs include both wholesale margins and wholesale production costs .2) Wholesale margins reflect the revenues achieved by a plant, minus its production costs. For Hydrogen burning power plants, note that this includes the price of hydrogen fuel. 3) Scenario 1 has a 23% share of hydrogen for heating in 2050, whereas Scenario 5 has 38% by 2050 .4) Average between 2023 and 2050

Source: Aurora Energy Research

Scenario 2
Lower total demand results in lower wholesale market spend compared to the Benchmark, as more expensive peaking assets are pushed out of merit more often. As a result, lower cost plants will set the marginal price more frequently

Scenario 4
Scenario 4 has the highest wholesale costs across scenarios. This is driven by a high proportion of hydrogen for heating, which increases electrolysis demand and thus total power demand. Additionally, earlier H2 boilers adoption results in a high load on the power system in the 2030s and 40s, further increasing the wholesale margins[2] in this period, as plants with a higher SRMC will need to dispatch in order for demand to be met

Scenario 5
Even with a higher proportion of H2 for heating[3] by 2050, Scenario 5 has 2%[4] lower wholesale costs on average than 1. This is driven by a lower number of inflexible electrolysers in Scenario 5, which reduces peak demand, pushing high-cost peaking assets out of merit more often and lowering wholesale prices

Wholesale margins refer to the difference between the SRMC of an asset and the marginal bid price; higher frequency of top prices increases margins

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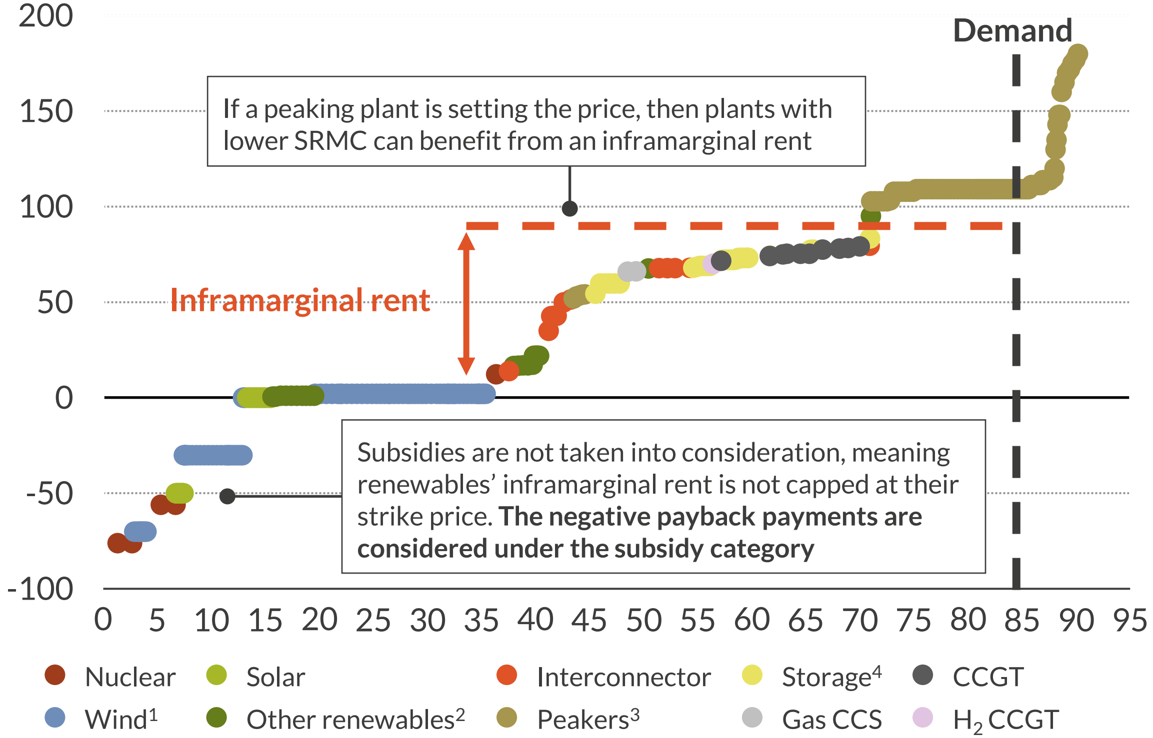
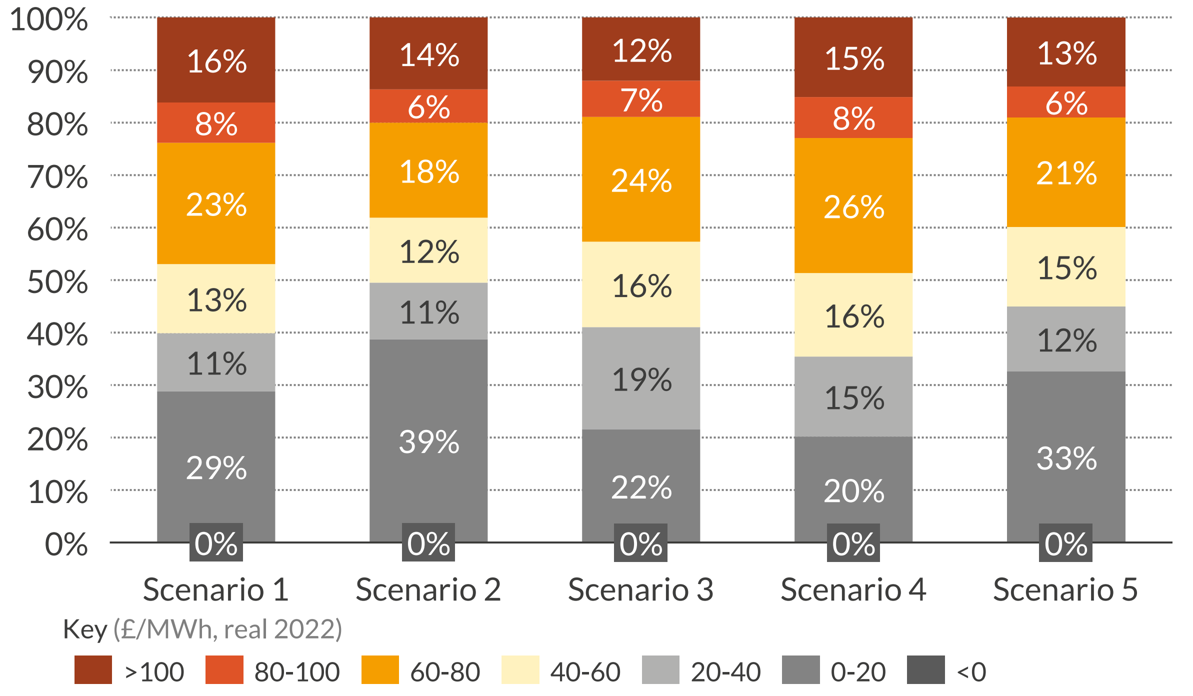
Short run marginal costs
£/MWh



Frequency distribution of the electricity price in 2050
%



- Peaking assets have the highest SRMC, setting the price at £100-200/MWh
- When calculating wholesale margins, subsidised RES achieves the wholesale price. The delta between the wholesale price and the strike price (for subsidy top ups and paybacks) is then accounted for in the subsidy section

- Higher frequency of top prices, where peakers set the price more often, leads to higher wholesale margins for other technologies
- Lower demand leads to higher frequency of low prices as the price is set by high SRMC assets less often, lowering wholesale margins. More RES generation can also help increasing the frequency of low prices by pushing higher SRMC assets out of merit

1) Includes both offshore and onshore wind. 2) Other renewables includes biomass, EfW, hydro and CHP. 3) Peakers includes OCGT, recips, H2 peakers, gas peakers and DSR. 4) Storage includes batteries and pumped storage.

Source: Aurora Energy Research

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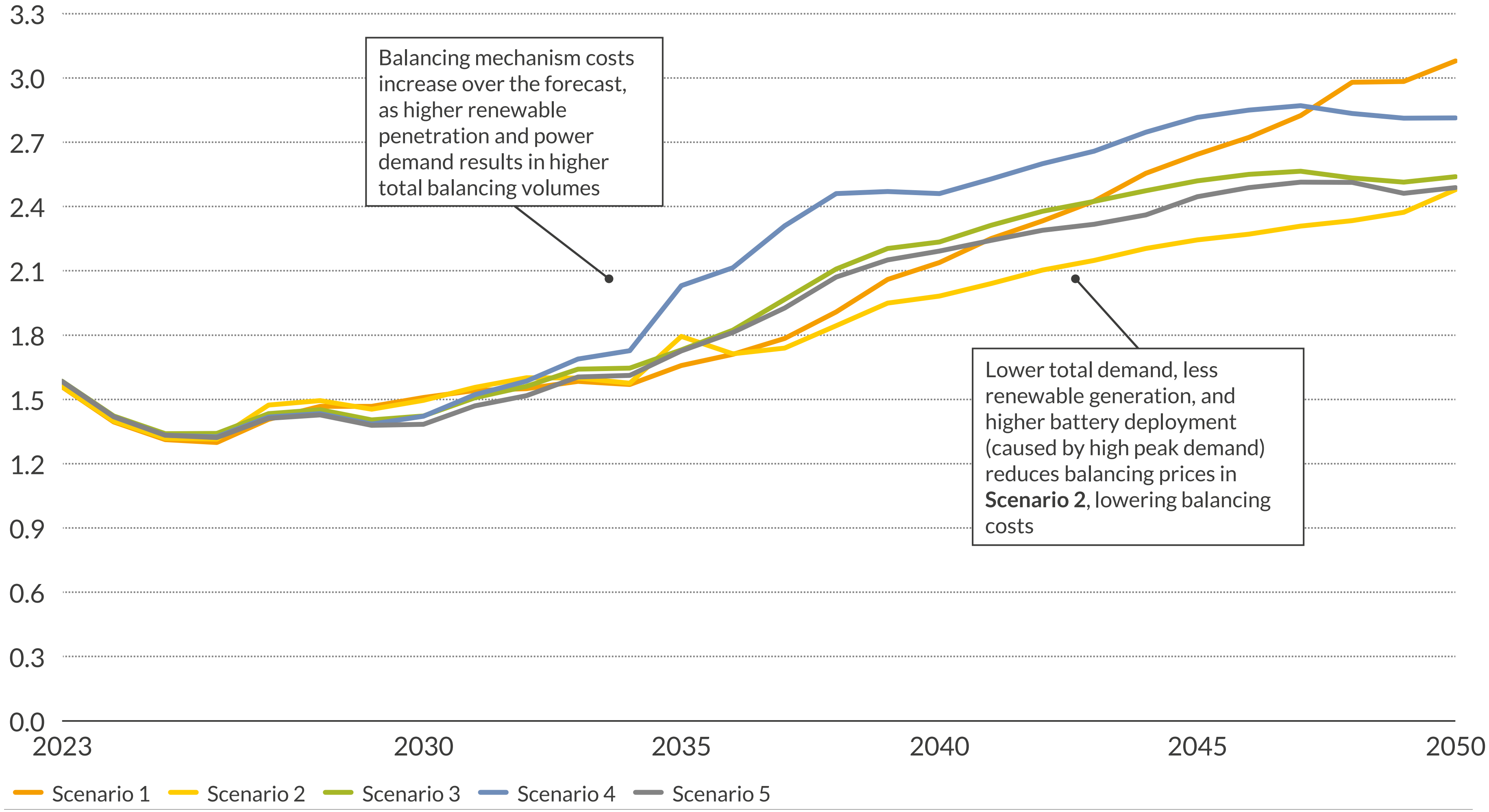
Balancing Mechanism Costs: More renewable generation and lower flexible capacity deployment leads to higher balancing costs

Annual balancing costs

£ billion (real 2022)



Source: Aurora Energy Research

Scenario 4

Scenario 4 has higher balancing spend than Scenario 1 as increased total power demand leads to higher intermittent renewable generation. This increases volatility in the system and, as a result, net imbalance volumes. Additionally, accelerated decarbonisation targets and earlier and faster H2 boilers deployment in this scenario, causes system tightness in the mid- term, increasing the total volume of balancing actions required

Scenario 5

Scenario 5 has lower Balancing costs than Scenario 4 as it assumes lower proportion of inflexible electrolysers. This reduces peaking demand, lowering requirements of flexible thermal generation from H2 peakers, thus reducing electrolyser power demand and overall power demand. As a result, balancing prices are lower than in Scenario 4

Subsidies: Earlier deployment of H2 boilers in Scenarios 3, 4 and 5 increases the need for firm capacity on the system, raising CM[1] costs

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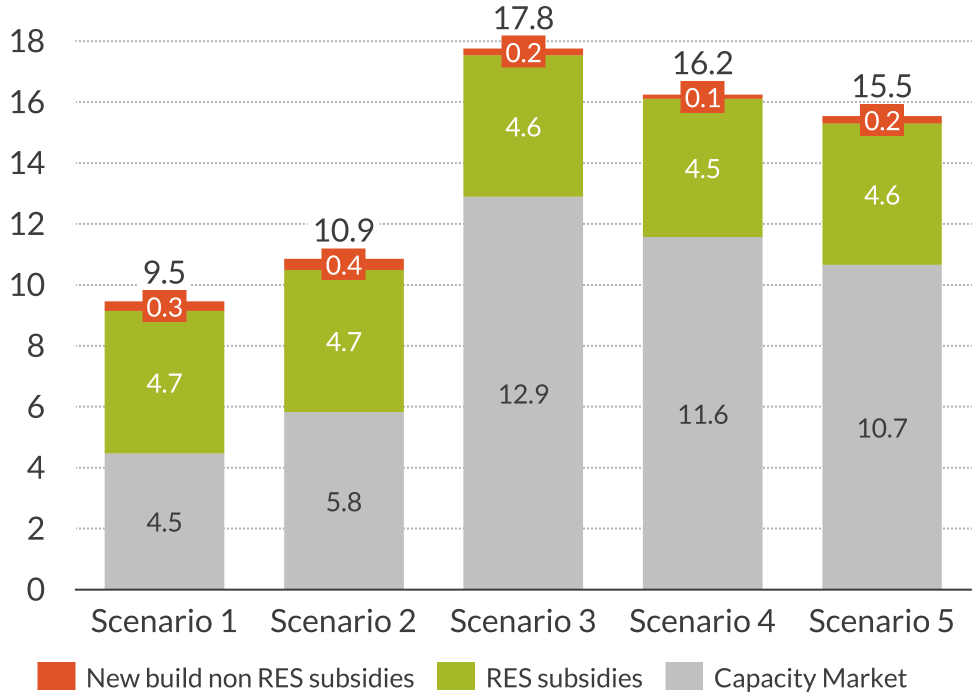
Average power system subsidy costs (2025 – 2050)

£ billion (real 2022)

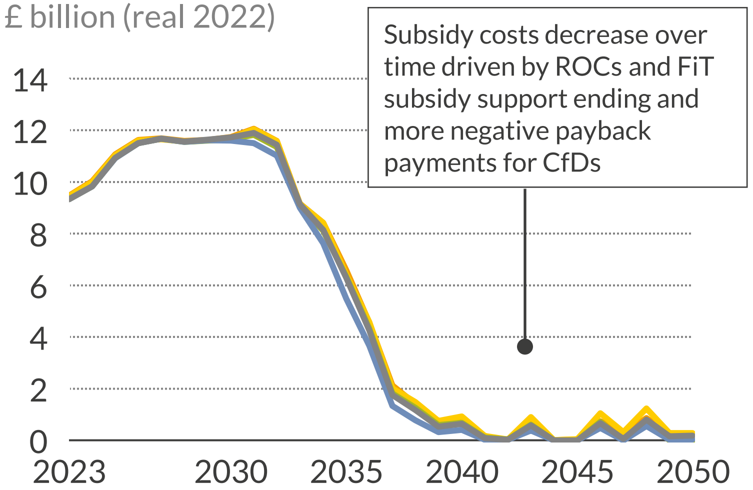


Average power subsidy costs[2], as seen on consumer bills (2025 – 2050)

£/MWh (real 2022)

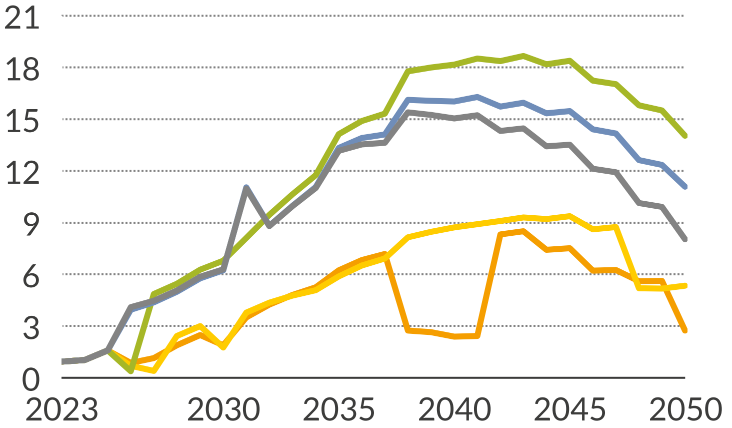
Annual power subsidy costs[3]

£ billion (real 2022)



Annual capacity market costs

£ billion (real 2022)



Renewable Subsidies

Low carbon subsidies cover the cost of subsidies for CfDs, ROCs and REFIT plants. This category also includes negative payback payments from CfD plants to suppliers when wholesale prices are above strike prices

Earlier and faster adoption of H2 boilers in Scenarios 3, 4 and 5, increases power demand in the mid-term, resulting in higher wholesale prices. This increases the negative payback payments from CfD plants to suppliers, since strike prices will be below wholesale prices more often, reducing RES subsidies costs compared to Scenarios 1 and 2

Capacity Market (CM)

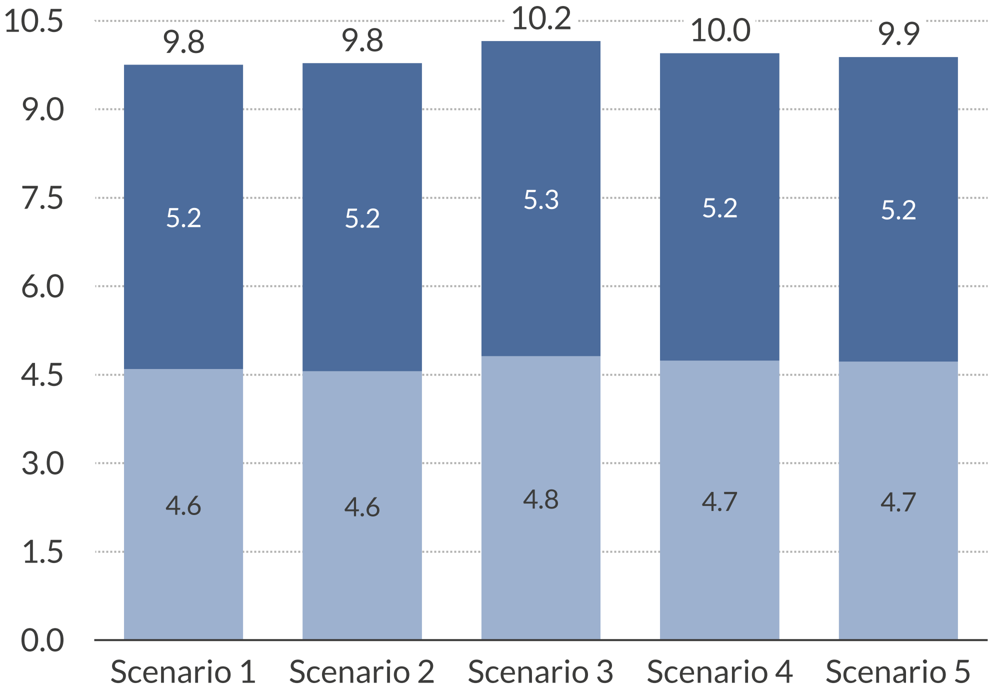
CM spend reflects the costs of ensuring there is sufficient firm capacity on the system. CM costs are higher in Scenarios 3, 4 and 5 as more firm capacity is required in the 2030-40s to alleviate the load on the power system from earlier rollout of H2 boilers[4]

1) Capacity market. 2) Including new build non RES subsidies, RES subsidies and Capacity Market. 3) Higher revenues from wholesale, balancing and capacity markets in Scenarios 3, 4 and 5, particularly from 2035 to 2040, reduces the need for new build non RES subsidies .4) Additional Gas CCS capacity in Scenario 3 helps offsetting the peak in capacity market spend in 2031 that occurs in Scenarios 4 and 5. Scenario 1's slower heat decarbonisation means less firm capacity is required, leading to a dip in the 2040s.

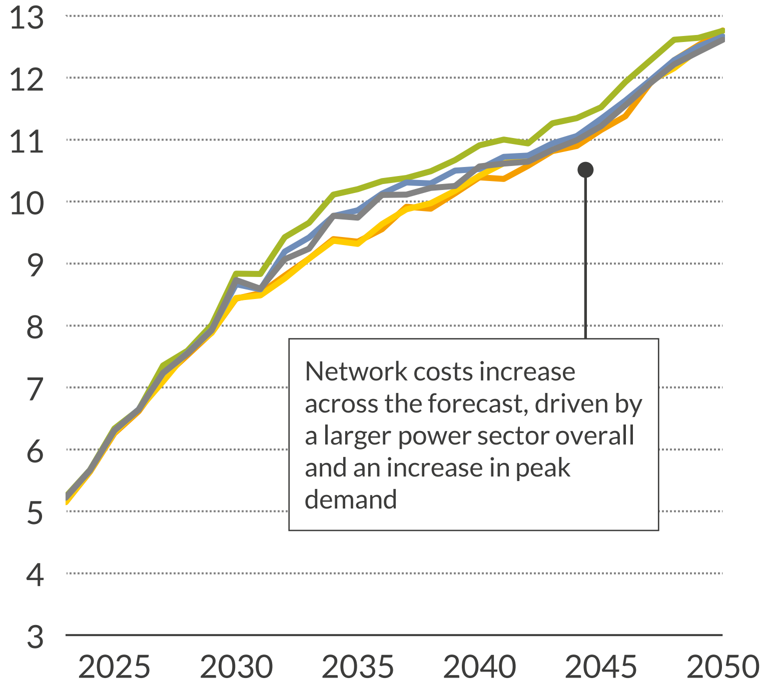
Source: Aurora Energy Research

Power network costs: rapid decarbonisation in Scenarios 3, 4 and 5 leads to higher infrastructure costs driven by new-build capacity needs

Average power network costs (2025 – 2050)[1,2]
£ billion (real 2022)



Annual power network costs[1]
£ billion (real 2022)



Average power network costs, as seen on consumer bills (2025 – 2050)
£/MWh (real 2022)

Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
18	19	18	18	18

Infrastructure costs are driven by new-build capacity, the proximity of supply to demand and the connection type (transmission vs distribution) for capacity mixes

Total transmission and distribution costs are greater in **Scenarios 3, 4 and 5** due to higher power demand in the mid-term from earlier H2 boilers rollout, leading to a larger sized power sector overall. As a result, higher infrastructure investment is required

Scenario 3 has the highest transmission system expenditure across scenarios as it requires an additional 2 GW of Gas CCS, which is transmission connected, to ensure no loss of load in the system. This is due to the high peak demand in this scenario, driven by a fast rollout of H2 boilers and a high share of heat pumps, which amplify demand peaks

Scenario 3 also has the highest distribution costs as higher peak demand and overall total power demand increases the need for distribution capacity deployment

1) This excludes H2 network costs (pipelines, transportation and storage) and heating system costs. 2) Note the 2023-2024 period is excluded from these calculations as current high gas prices distort results.
Source: Aurora Energy Research

Contents

Rapid deployment of H2 boilers will lead to increased consumers' power bills due to higher wholesale costs and capacity market spend

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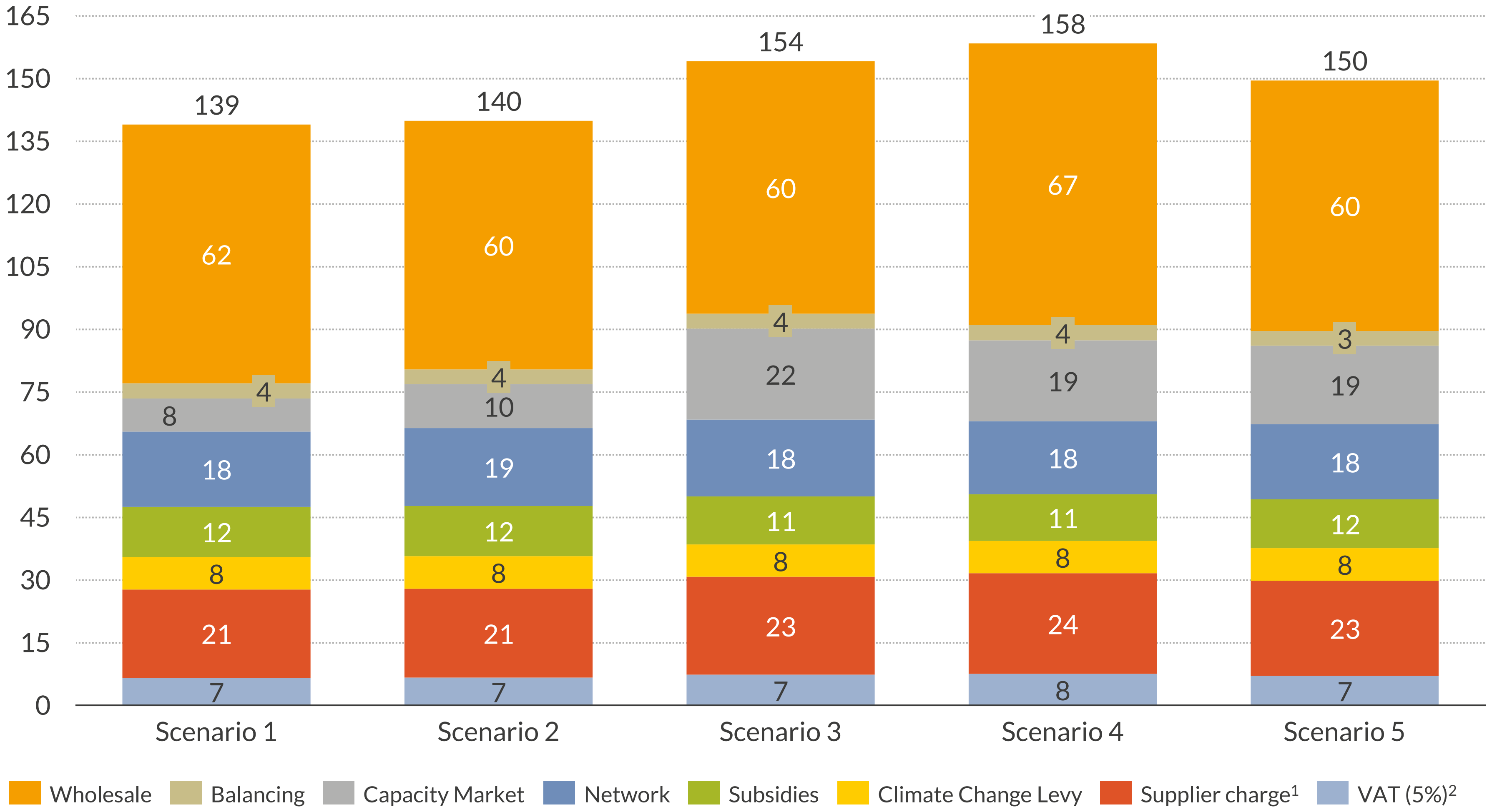
Average consumer power bills (2025 – 2050) (Including Climate Levy, Supplier Charges & VAT)
£/MWh (real 2022)



1) Supplier charges are comparable as the assumption is that when suppliers set their prices, they would aim to cover their operating costs while still making a profit. These costs include items like customer service and billing. 2) VAT is a government tax on services and goods. VAT is relatively similar across all scenarios as homeowners are required to pay 5% on consumer electricity bills.
Source: Aurora Energy Research

Differences in consumer bills across scenarios can be mainly explained by variations in wholesale market costs and capacity market spend

Scenarios with faster deployment of H2 boilers and earlier retirement of fossil fuel heating technologies (**3, 4 and 5**), have higher capacity market spend to ensure loss of load standards are met, increasing consumer bills

Additionally, **Scenario 4**, which has the highest consumer bills among scenarios, has also increased wholesale market costs. This is driven by the assumed high proportion of hydrogen for heating in this scenario, which increases electrolysers demand and thus overall power demand, resulting in higher wholesale prices

Consumer bills reflect power system costs only and do not account for the cost of deploying demand (e.g. EVs, electrified heating systems, electrolysers)

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Key input assumptions have been considered across scenarios to isolate and examine the impact of different heat forecasts on the power system

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Input assumptions

Input	Assumption	Source
CB6 compliance	All scenarios meet the UK's sixth carbon budget emission target by 2035[1]	CCC CB6
Heating units	All scenarios have the same number of total heating units	Project A - NIC
Heating unit consumption	All scenarios have the same heating unit consumption assumptions for each technology	Project B - NIC
Inflexible electrolysers	All scenarios have the same absolute number of inflexible electrolysers	Scenario 1 – Project C - NIC
Dumb heat pumps	All scenarios have the same absolute number of dumb heat pumps	Scenario 1 – Project C - NIC
Gas Ban from 2035	All scenarios have unabated gas power generation banned from 2035	-

1) The UK's sixth carbon budget stipulates a 47-62% reduction in emissions by 2035, relative to 2019 levels

Sources: Aurora Energy Research, NIC

System cost components are levied via different mechanisms however are ultimately recovered through consumer bills

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Total system cost components

Electricity
Total spending on all power produced to meet demand

Balancing
Spending needed to balance the system

Capacity Market
Spending needed to bring forward new capacity

Network
Total spending on transmission and distribution network

Subsidies
Spending required to bring in capacity to meet decarbonisation targets

Hydrogen
Costs of hydrogen production and generation

Consumer Bills

System Costs + Supplier Charges + VAT

Households

Consumer Bill

Supplier Charges

When suppliers set their prices they will try to cover their operating costs as well as make a profit. These costs cover things like customer service and billing, typically around 20%

VAT

VAT is a government tax on services and goods. Homeowners are required to pay 5% on consumer electricity bills

Total system costs represent power system costs only, and do not account for the deployment of EVs, decarbonised heating systems or other demand side technologies. Costs also do not account for the total costs of operating the gas or potential future hydrogen network.

Source: Aurora Energy Research

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