Power sector modelling:
System cost impact of renewables
Report for the National Infrastructure Commission

24 May 2018

This report was commissioned as part of the evidence base for the National Infrastructure Assessment. The views expressed and recommendations set out in this report are the authors' own and do not necessarily reflect the position of the National Infrastructure Commission.

Report details and disclaimer

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Power sector modelling: System cost impact of renewables	22 May 2018	Oliver Kerr (oliver.kerr@auroraer.com) and Anna MacDonald (anna.macdonald@auroraer.com) **Modeller:** Jonathan Black	Felix Chow-Kambitsch (felix.chow@auroraer.com)

General Disclaimer

Forward looking statements

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List of abbreviations

BEIS – Department of Business, Energy and Industrial Strategy

CCC – Committee on Climate Change

CCGT – Combined Cycle Gas Turbine

CCS – Carbon Capture and Storage

CO2 – Carbon dioxide

CPS – Carbon Price Support

DSR – Demand-side Response

ETI – Energy Technologies Institute

EV – Electric Vehicles

GW – Gigawatt

kW – Kilowatt

MtCO2e – Metric tons of carbon dioxide equivalent

MW – Megawatt

NIA – National Infrastructure Assessment

NIC – National Infrastructure Commission

OCGT – Open Cycle Gas Turbine

Ofgem – Office of Gas and Electricity Markets

RES – Renewable energy

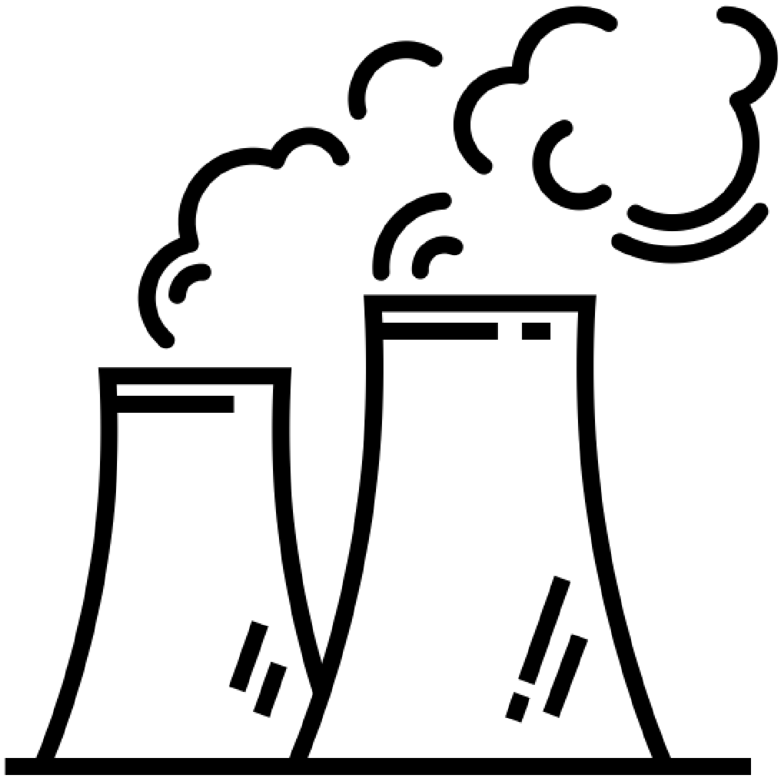
ROCs – Renewables Obligation Certificates

TWh – Terawatt hour

Executive Summary

By 2050, almost all power sector generation will need to be zero carbon if GB is to meet the ambitious emissions goal mandated by the 2008 Climate Change Act

- This study considers the implications for power sector decarbonization of two different approaches to reducing emissions in the heat sector—electrification and hydrogen / greener gas—while road transport is assumed to follow an ambitious pathway to electrification
- Decarbonisation in heat and transport will have implications for electricity demand, the generation mix, and how much CO_2 the power sector is able to emit without overshooting the economy-wide emissions limit
- Regardless of what happens in the rest of the economy, however, we find that almost all power sector generation will need to be zero carbon by 2050 in order for carbon targets to be met



Executive Summary

Both nuclear and renewables can offer cost-effective paths to power sector decarbonisation

- We find that a mostly renewable or mostly nuclear system both offer among the most promising pathways to decarbonisation, but the level of ambition required in each case is significant:
  - A high nuclear world would mean building up to 29 GW of nuclear capacity by 2050 – equivalent to 9 new Hinkley Point Cs
  - A high renewable world could require up to 26 GW of onshore wind, 68 GW of offshore wind, and 99 GW of solar by 2050
- In terms of cost-effectiveness, there is little to choose between a high renewable and high nuclear world, provided there is sufficient flexibility on the system to deal with renewable integration costs. However, we would note that this is highly sensitive to cost assumptions, with renewable costs more likely than nuclear to fall faster than expected
- With different low-carbon technologies often held up as silver bullet solutions, the fact that both renewables and nuclear can achieve cost-effective decarbonization has the potential to help move the policy discussion beyond technology tribalism. At the same time, both options are likely to present challenges with respect to public acceptance
- Hybrid renewable and nuclear solutions can also be cost-effective, though they are less appropriate for systems characterized by high peak demand and low flexibility from thermal generation, since this increases renewable integration costs

Executive Summary

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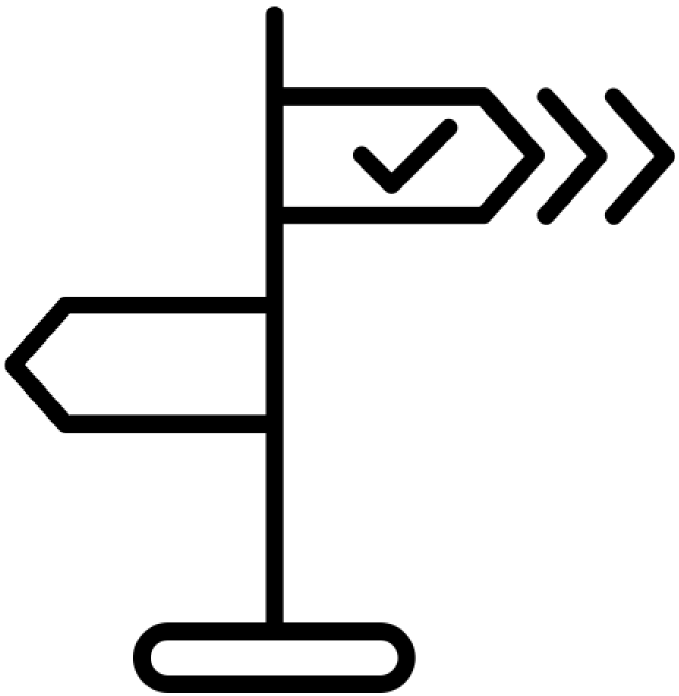
Government policy needs to choose a path and provide the supporting investments needed to enable efficient and cost-effective roll-out

- Pursuing an aggressive renewables policy without adequate support for flexible technologies could increase total system costs by up to £7 billion per year on average, 2030-50
    - In a flexible system, reaching 70-80% renewable production by 2050 is the cost-optimizing option, with no new nuclear beyond Hinkley Point C needed to meet carbon targets
    - In a less flexible system, more than 40% renewable production by 2050 increases the cost to consumers
    - In a high renewable world, system flexibility is therefore critical to cost-effective decarbonization
- Cost-effectiveness in a high nuclear world is less reliant on flexibility
    - In a high nuclear world, the importance of interconnectors, batteries, and DSR declines

Executive Summary

Uncertainty around future technology costs and availability, electricity demand and emissions in heat and transport, and the potential for disruptive change all make the "optimal" power sector decarbonization pathway less easy to identify—but low regrets options are at hand

- Policies to support system flexibility are always a low regrets option and are key to enabling a high renewable world
- It is difficult to reach carbon targets cost-effectively without new nuclear except at very high levels of renewable penetration
- At the same time, its long lifetime increases the chance that nuclear investments could prove sub-optimal over the long term, particularly given the potential for rapid renewable and battery cost declines
- CCS rarely appears to be a cost effective option for reducing power sector emissions



Executive Summary

Further uncertainties

- The 17.9 GW of interconnectors assumed in this study play a big role not just in the provision of flexibility, but also in meeting carbon targets, accounting for up to 15% of generation by 2050. If future policy accounts for the emissions associated with imports rather than assuming them to be carbon-free, GB would have to build a significant amount of additional low carbon generation to meet 2050 carbon targets
- Network costs are a critical component of whole system costs and could undermine the cost-effectiveness of renewables. More work is needed to understand how they will evolve over time in different future scenarios
- Breakthrough new technologies are inherently difficult to predict but have the potential to fundamentally disrupt power system economics
- A significant change in the relative costs of nuclear and CCS could lead to different outcomes, though any role for gas CCS is severely limited in a zero carbon power sector

Contents

Foreword

- The National Infrastructure Commission (NIC) has commissioned Aurora Energy Research to **model the decarbonisation pathways** of the power sector
- Aurora have been asked to provide an independent study on the **cost trade-off between renewables and other low carbon technologies** in meeting the UK's carbon targets. Total system cost estimates should account for the cost of balancing and backing-up renewables as well as network costs
- Aurora have also been asked to test **how system costs of renewables differ across scenarios**, including two demand scenarios of how heat is decarbonised (i.e. hydrogen / greener gas vs electrification) and two supply scenarios of which technologies can enter (i.e. any technology vs no new nuclear)
- As part of the NIC's mandate, they publish the National Infrastructure Assessment (NIA) once a parliament to analyse the UK's long-term infrastructure needs. The NIC intends to use the power system cost estimates from this study to inform their own analysis and recommendations in the NIA
- This power sector modelling is conducted in parallel with modelling of the heat sector, which was commissioned by the NIC from another provider

Aurora's aim is to explore the impact of varying amounts of renewables under alternative ambitious future pathways

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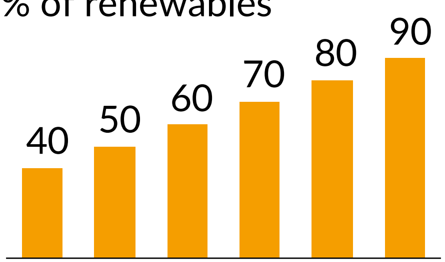
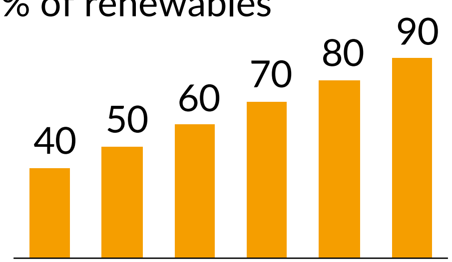
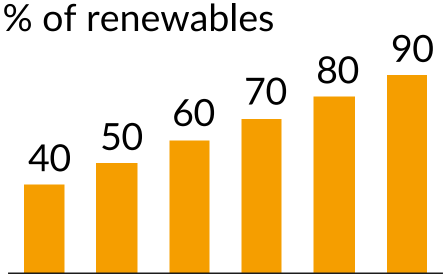
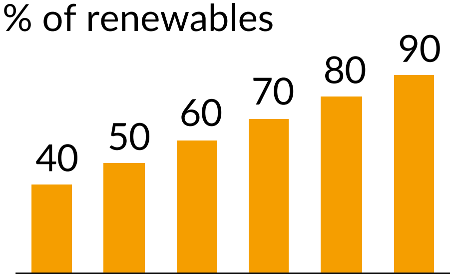
Future policy combinations

Heat demand scenarios	Supply scenarios: Anything goes (the generation mix can be made up of any technology)	Supply scenarios: No nuclear
Electrification	% of renewables 	% of renewables 
Hydrogen / greener gas	% of renewables 	% of renewables 

Additional key assumptions across scenarios:

- Carbon targets met
- High interconnector capacity
- High Electric Vehicles (EV) adoption

- We consider two demand scenarios based on how heat is decarbonised, and two supply scenarios based on which technologies can enter the power market
- For each supply and demand scenario combination, the power sector is modelled for six different renewables targets for 2050
- Scenarios are chosen to represent a broad range of supply and demand dimensions. This allows a wide range of possible outcomes to be tested

This study involves using NIC's assumptions in Aurora's power model, and then simulating future scenarios

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1 Align assumptions book with NIC

- Match assumptions to NIC house views, to enable consistency with previous studies
- Update assumptions on wind, solar and battery costs based on latest information

2 Demand modelling of EVs and heat

- From annual demand assumptions, add seasonal and daily shape
- Add impact of EVs and heat electrification to demand

3 Power market modelling

- Using Aurora's GB power market model, simulate power sector for the different supply /demand /renewables combinations
- Calculate and aggregate all components of system cost

4 Sensitivity testing

- Test robustness of power market modelling by repeating analysis with different assumptions on flexibility, technology cost etc.

- Aurora implemented the power modelling, with input and feedback from the NIC at each stage of the process
- The assumptions and scenario design have been made to reflect the NIC's views where possible, Aurora views are used for the remaining assumptions
- The power modelling uses Aurora's proprietary model, run by Aurora analysts with results returned to the NIC

1 Assumptions are largely provided by the NIC, with the remainder from Aurora

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	Assumption	Provided by	Original source
Carbon policy	Carbon budget	NIC	CCC carbon budget until 2035 NIC provided carbon targets to 2050
	Coal and gas costs	NIC	BEIS
	Carbon price	Aurora	Aurora
Planned capacities	Nuclear timeline	NIC	NIC
	Interconnector timeline	NIC	Ofgem
	EV numbers	NIC	NIC provided EV targets. Aurora extrapolation of equivalent sales timeline
Generation cost	Renewable + nuclear capex	Aurora + NIC	Aurora for wind and solar BEIS for nuclear ETI for all other included technologies
	Battery costs	Aurora	Aurora
	Carbon Capture and Storage (CCS)	Aurora + Element Energy	Aurora for plant. Element Energy for CO2 transport & storage
Demand	Annual energy demand	NIC	BEIS analysis for NIC[1], with Aurora analysis for further granularity
	Heat demand	NIC + Element Energy	Element Energy, with Aurora analysis for further granularity

- By default, assumptions are provided by NIC to ensure consistency with previous studies
- Aurora's input is used for assumptions that require more up-to-date revisions
- As the owner of the heat modelling workstream, Element Energy's input is used for the CCS and heat demand assumptions

1. *Congestion, Capacity, Carbon: priorities for national infrastructure – Modelling Annex*, National Infrastructure Commission (2017)

2 The impact of EVs and heat electrification on half-hourly electricity demand is modelled

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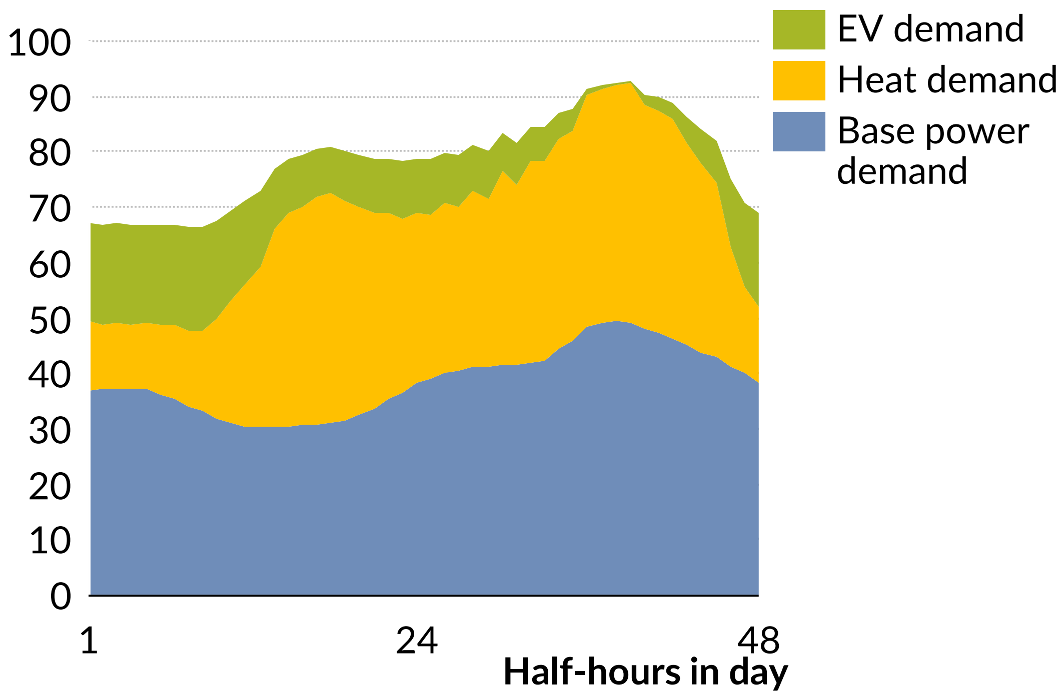
EV assumptions

Heat electrification assumptions

Convert high level assumptions into half-hourly demand for electricity

Demand level, 2040 half-hourly average, GW



- Annual assumptions of EVs and heat electrification were provided to Aurora by the NIC. To explore the impact of these assumptions on the power sector, Aurora used this data to create half-hourly demand profiles for each year
- EVs are assumed to have smart charging, meaning they follow price signals to charge primarily overnight, avoiding adding to the evening peak and thereby helping to smooth out the daily electricity demand shape. Vehicle-to-grid capability is also assumed for 10% of cars and 80% of vans
- The time-of-use pattern of heat electrification is provided by Element Energy

3 Aurora's model of the GB power market is used for this study

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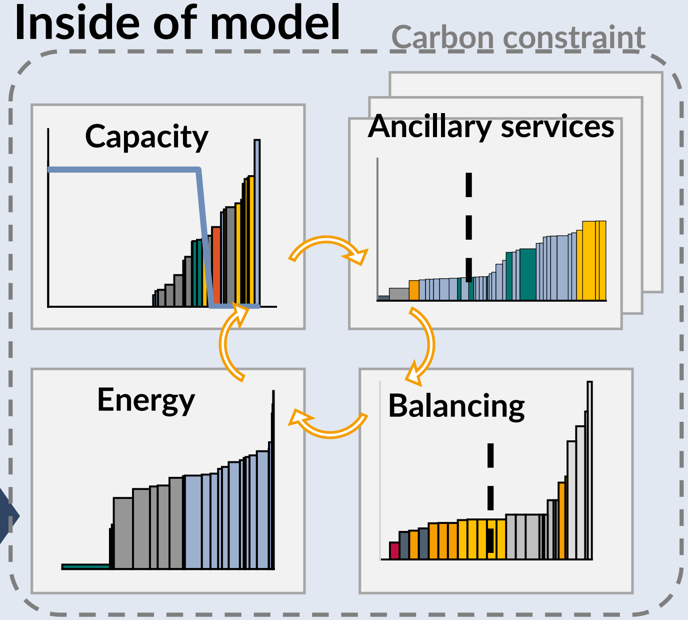
Input assumptions

- **Technology** (capex, performance, learning rates)
- **Policy** (changes to existing regulation, renewables build out, nuclear build out)
- **Fuel prices**

Inside of model



Entry and exit based on profit maximisation is an output of the model

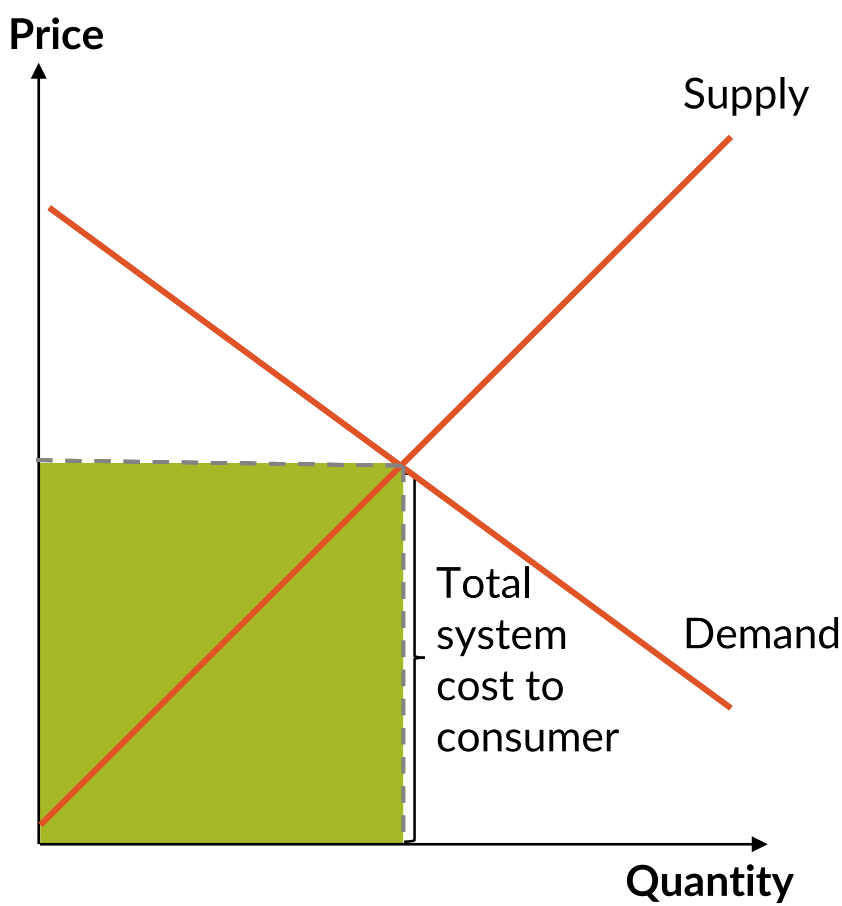
- Peaking plants
  - OCGTs
  - Gas recips
    - Embedded
    - Transmission connected
  - Diesel recips
- DSR
- Storage
  - Lithium ion
  - Flow batteries
- CCGT
- Coal
- Subsidy-free wind & solar

Market outcomes

- New build entry and exit decision
- Half-hourly electricity and balancing prices
- Yearly capacity market prices
- Plant level revenues

- Aurora's proprietary energy models are developed and maintained in-house
- The power market model solves the capacity, energy, and balancing /ancillary markets together to produce consistent forecasts across all markets
- Assumptions used are relatively few and basic. The capacity mix in each forecast is determined by economic entry and exit

3 Total system cost to consumers is the main output variable for each power market simulation



Total system cost components

Electricity
Total spending on all power produced to meet demand

Balancing
Spending needed to balance the system

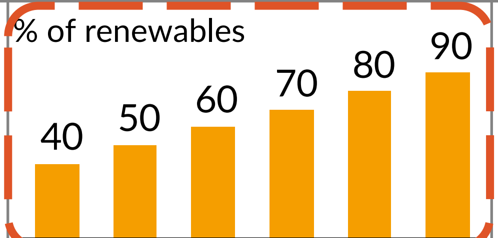
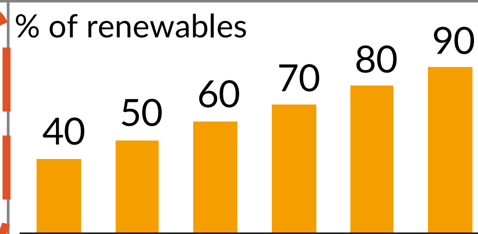
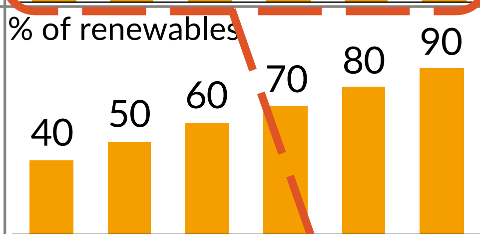
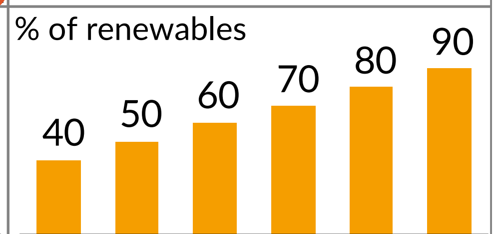
Capacity Market
Spending needed to bring forward new capacity

Network
Total spending on transmission and distribution network

Renewable subsidies
Spending required to bring in the target % of renewables

- The total system cost is used to compare scenarios with one another to inform policy decisions
- Cost of integrating renewables are accounted for, especially in balancing and network costs
- Relevant additional outputs for the modelling include:
  - Capacity mix
  - Generation mix
  - Average and peak electricity demand
  - Emissions

4 Sensitivity testing is done around technology and policy assumptions

		Supply scenarios	
		Anything goes (the generation mix can be made up of any technology)	**No nuclear**
Heat demand scenarios	**Electrification**		
	Hydrogen greener gas		

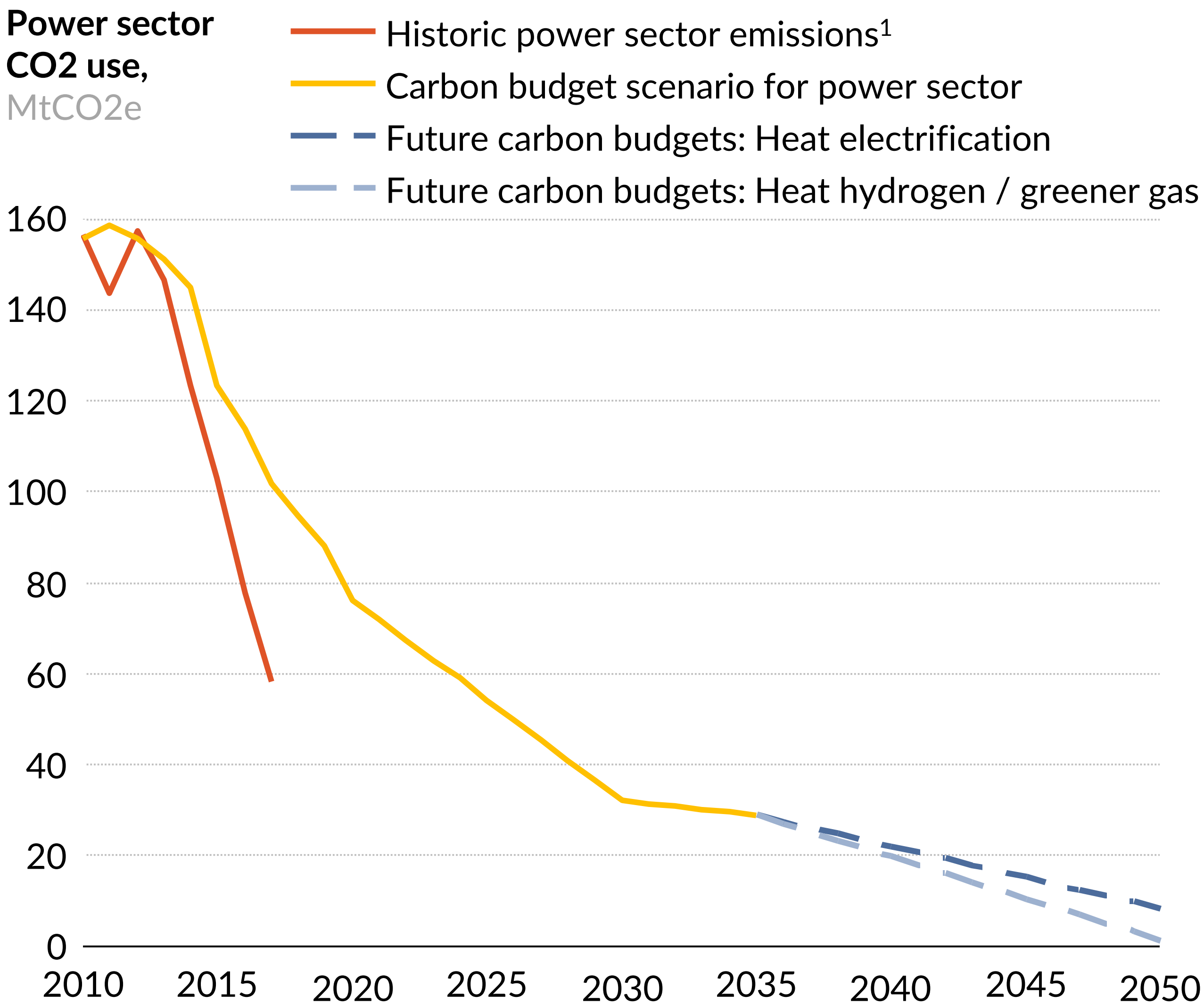
Around the “Electrification” + “Anything goes” scenario, sensitivity testing is done for the following assumptions:

- Low system flexibility
- No smart charging of EVs
- Restriction of new onshore wind
- The entry of Tidal power
- Low CCS cost (anything goes and hydrogen / greener gas)

- In order to show robustness and generalisability of results, sensitivity tests are done around key assumptions jointly identified by NIC and Aurora
- Assumptions for EVs, interconnectors and other sources of flexibility are key drivers for the cost of integrating renewables, and are therefore included in the sensitivity tests

Contents

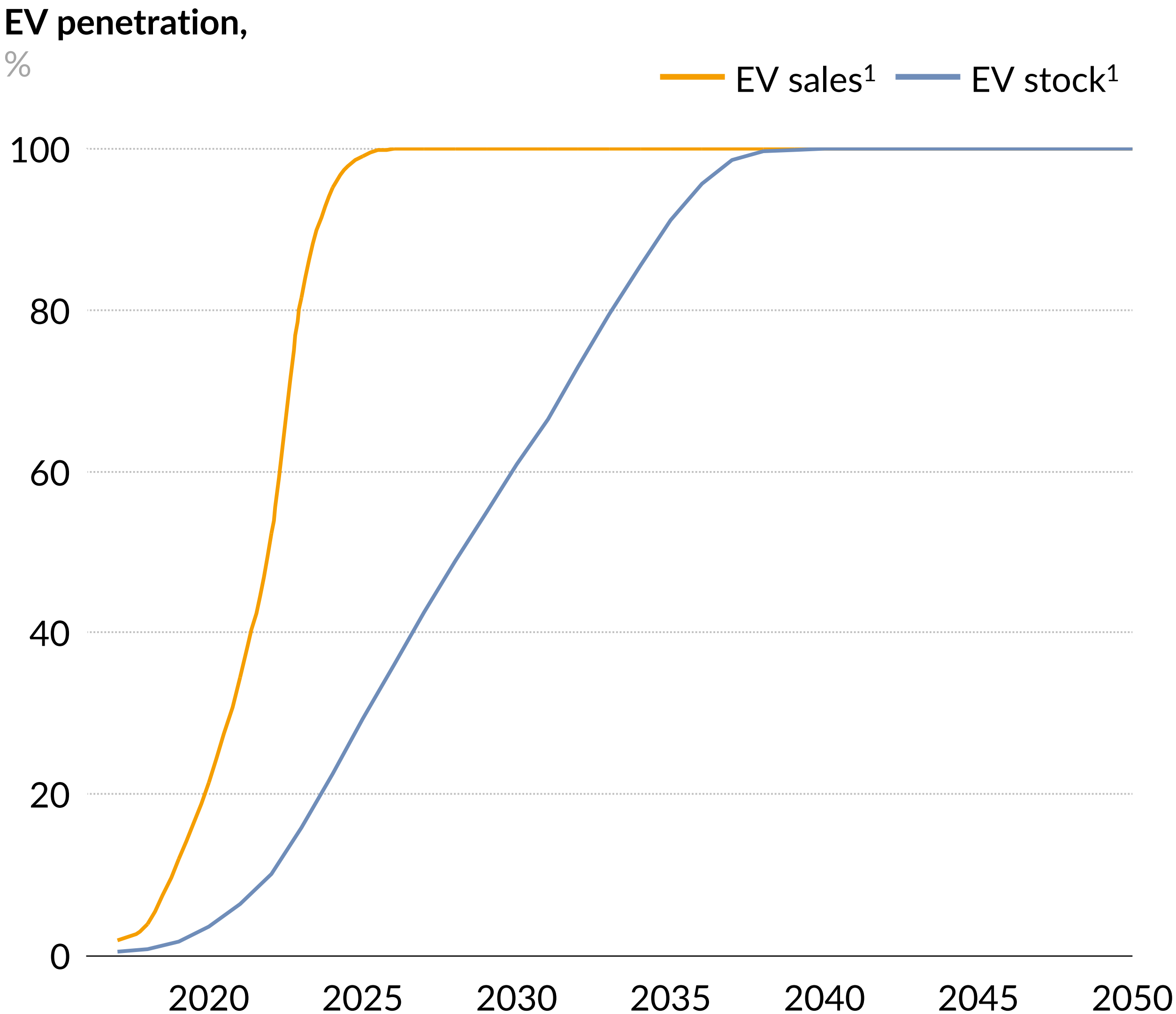
The power sector must reach near zero carbon emissions by 2050



1. CCC data for 2010-2016. Aurora estimates using BEIS data for 2017.

- To help meet CO2 targets set in the Climate Change Act 2008, the CCC recommends decarbonisation pathways for the power sector
- The CCC recommends that the power sector should be almost completely decarbonised by 2050
- 2050 carbon targets depend on the emissions from the heat sector:
  - Heating with hydrogen / greener gas produces more emissions, requiring the power sector to decarbonise more
  - Heat electrification merges the heat and power sectors, such that the power sector require less decarbonisation

Growth in EVs must be incorporated, which may pick up rapidly



1. NIC assumptions with Aurora analysis

- An ambitious pathway of EV adoption is assumed, to reflect NIC views based on previous research on EVs
- Increasing EVs affect electricity demand by increasing total demand, peak demand and overnight demand
- EVs are assumed to have "smart charging", smoothing out demand from evening peak periods to overnight periods
- Vehicle-to-grid is assumed for 80% of the van fleet and 10% of the remaining vehicles, allowing EVs to buy and sell into the power market like a battery

Sources: NIC, Aurora Energy Research

Along with electricity demand from heating, the power sector must grow up to 65% by 2050

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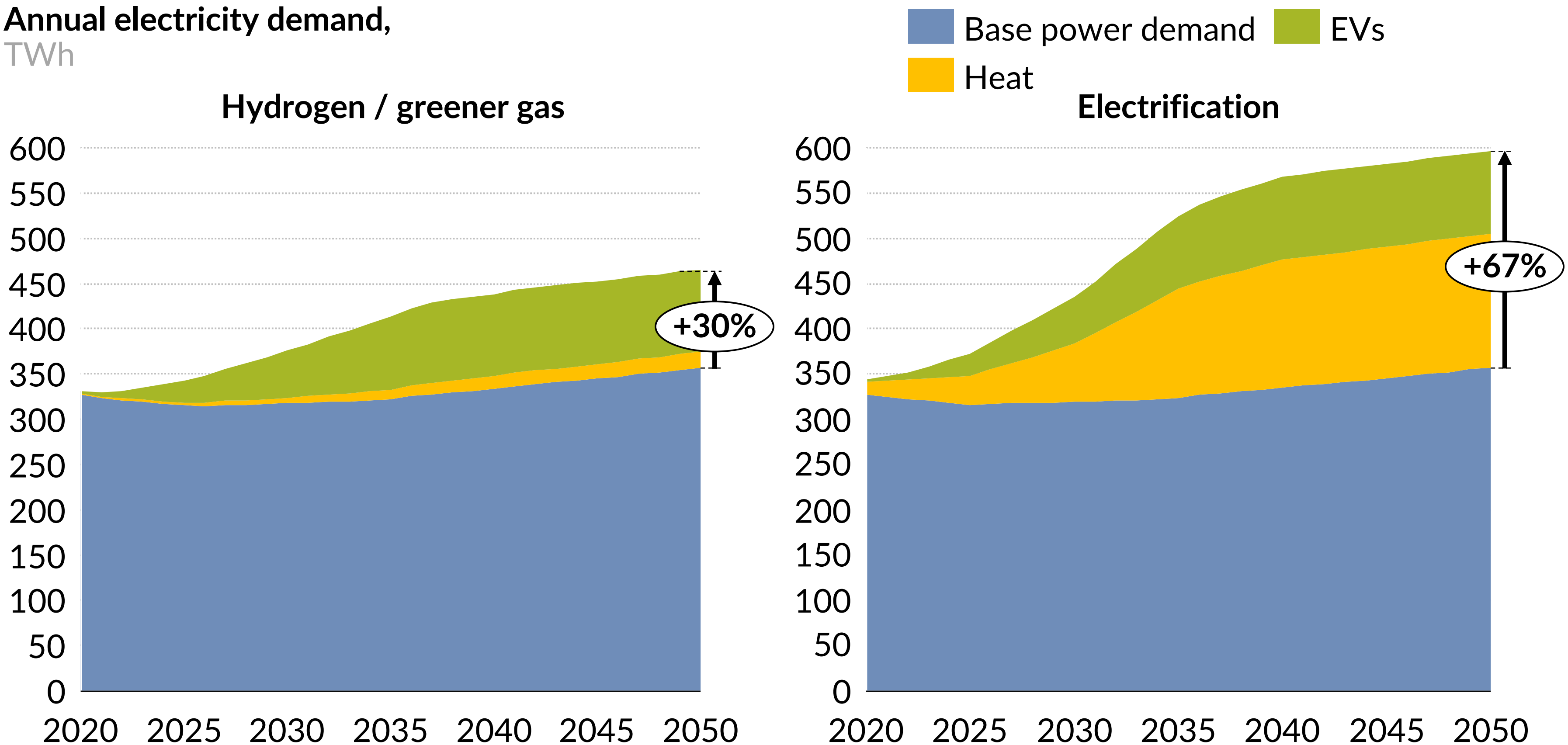
Annual electricity demand,
TWh



- EV adoption increases electricity demand by 25.5% and heat by 4.9% in 2050
- Hydrogen based heating puts less strain on the electricity system

- Heat electrification significantly increases electricity demand

Sources: Aurora Energy Research, NIC, Element Energy

Decarbonisation targets will require drastic transformation from today's generation fleet

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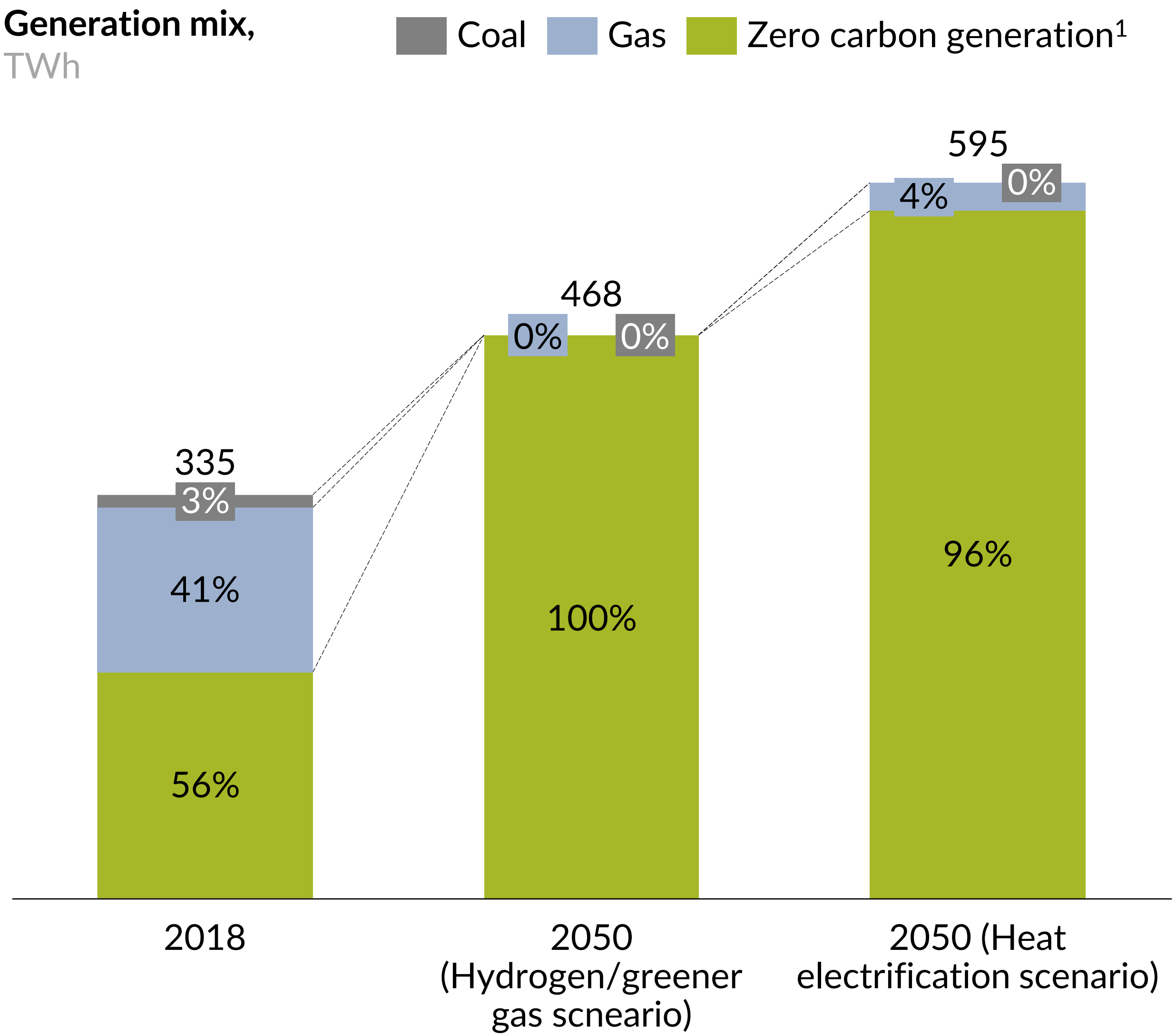


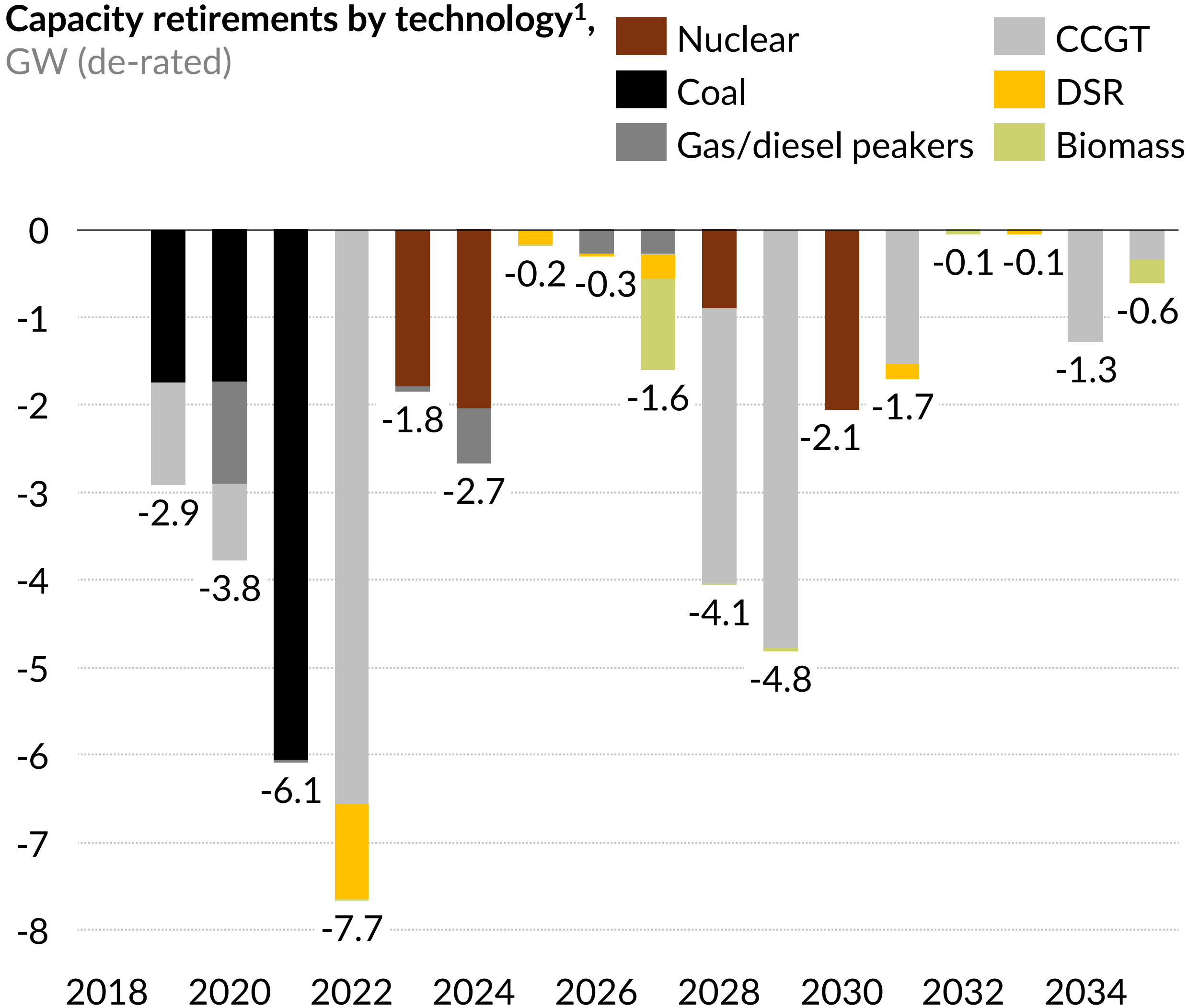
1. Zero carbon generation includes nuclear, solar PV, onshore wind, offshore wind, biomass, interconnectors, hydropower and bio CCS

- 44% of 2018's electricity demand is met by carbon based generation. This must be reduced to zero or close to zero by 2050 if GB is to meet its carbon targets
- The growth in electricity demand results in further need for growth in renewable generation, more than tripling today's zero carbon generation over the next three decades
- The Carbon Price Support (CPS) and recent commodity price developments mean the remaining coal plants hardly run in 2018
- The heat electrification scenario allows for slightly more carbon in the power sector, though demand is also higher

Sources: Aurora Energy Research

Up to 50 GW of existing capacity looks set to retire by 2035, creating space for new zero carbon generation

Capacity retirements by technology[1], GW (de-rated)



- The remaining coal fleet must retire by 2025 due to Government policy but most are expected to retire by 2022 due to unfavourable economics, as in the case of Eggborough
- Nuclear retirements are due to the old age of existing plants
- Over 1GW of biomass is expected to retire in 2027 as their Renewable Obligation Certificates (ROCs) support ends
- Some DSR retirements are expected due to regular attrition and access to only one year capacity contracts[2]
- Plant retirements allow for new capacity to be procured through the Capacity Market, potentially allowing new zero carbon generation to enter

1. Retirements based on supply scenario: "Anything Goes" & demand scenario: "Electrification" 2. Capital intensive capacities can access Capacity Market contracts of up to 15 years

Source: Aurora Energy Research

To explore a range of pathways, different renewables % are tested; remaining capacity is determined economically

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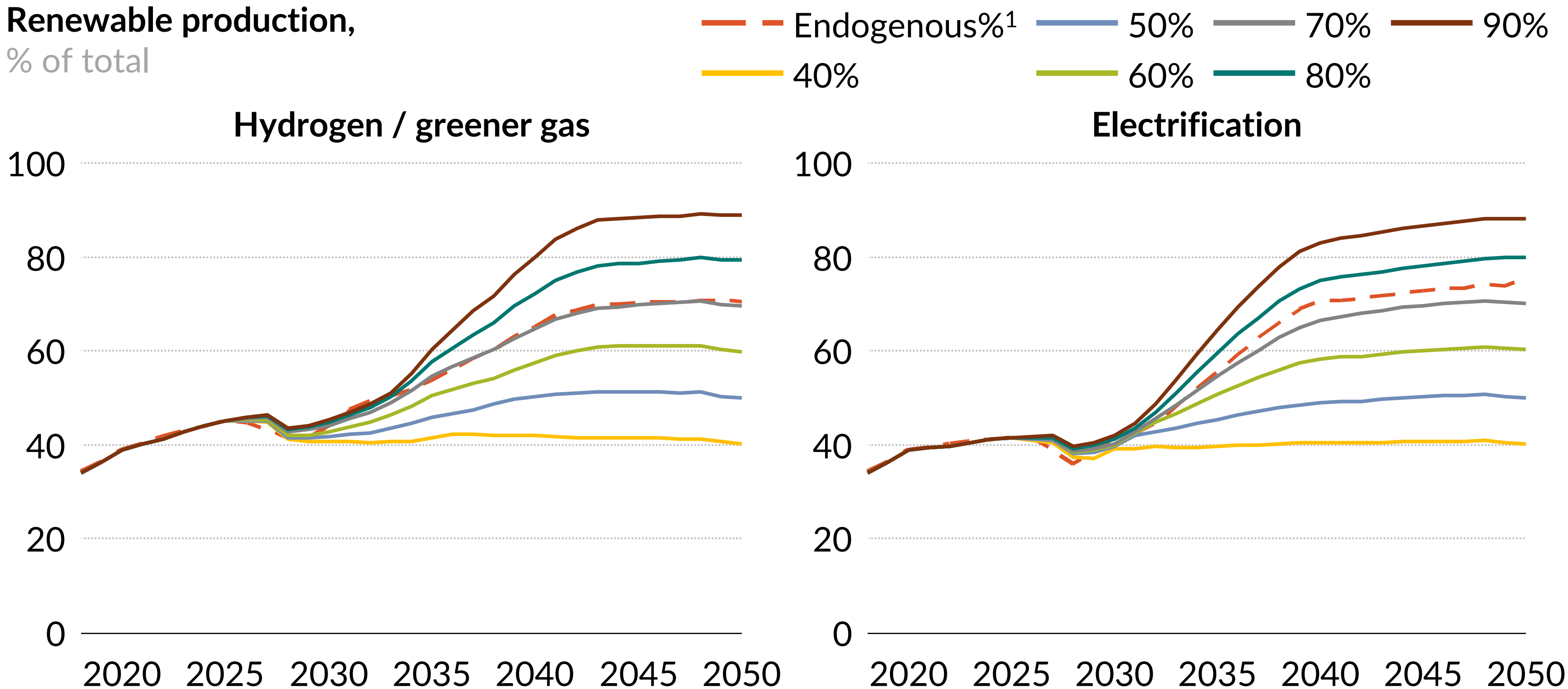
Generation technologies	Methodology for capacity
Exogenous timelines:	
1 Renewables: Solar, onshore wind, offshore wind, biomass etc.	▪ Follows **assumed timeline to reach target %** penetration level by 2050 ▪ The technology mix is based on a separate analysis on **economic entry**
2 Existing nuclear	▪ **Capacities assumed** based on announced intentions of asset owners and Ofgem
3 Interconnectors	
Endogenous economic entry and exit:	
4 New nuclear	▪ **Economic entry and exit** based on profit maximisation ▪ **"Shadow" carbon price** is set to guarantee carbon targets are met ▪ Limits on overall capacity and annual new build capacity based on what is feasible ▪ **Cost improvements** over time assumed for nuclear, CCS and batteries
CCS (gas and biomass)	
5 Thermal: CCGT, OCGT, coal	
Flexible: Recip engines, DSR, batteries (Li-ion and flow)	

- Technologies with exogenous timelines are assumed to follow a pre-determined pathway in the power market modelling
- Endogenously determined technologies will enter and exit based on profit maximising decisions
- The modelled power system must meet carbon targets. The carbon price is used to incentivise the mix of endogenous technologies to achieve this

1 Renewable targets between 40% and 90% are set for 2050

Renewable production,
% of total



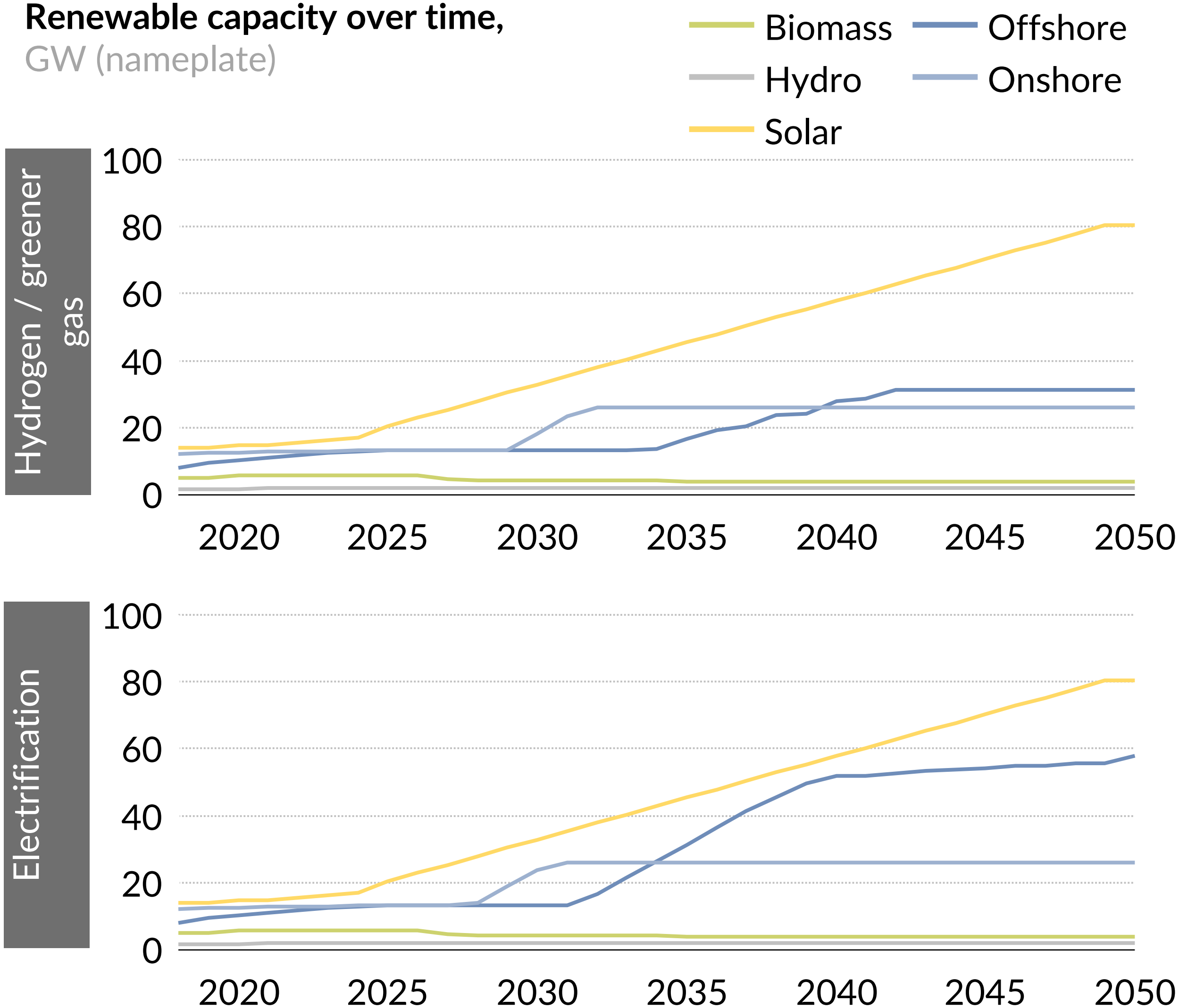
- 2050 renewables targets are set at 10% intervals, with the targets reached gradually over the next three decades, based on endogenous build pathways
- As demand is growing, absolute amount of renewables is increasing in all cases
- Renewables capacities until 2025 are the same across all scenarios as this is largely already determined by current policy

1. Instead of following an assumed timeline, the endogenous entry simulation allows renewable technologies to enter based on profit maximising decisions

Source: Aurora Energy Research

1 Endogenous renewable modelling informs the capacity timelines used to meet 2050 renewable targets

Renewable capacity over time,
GW (nameplate)



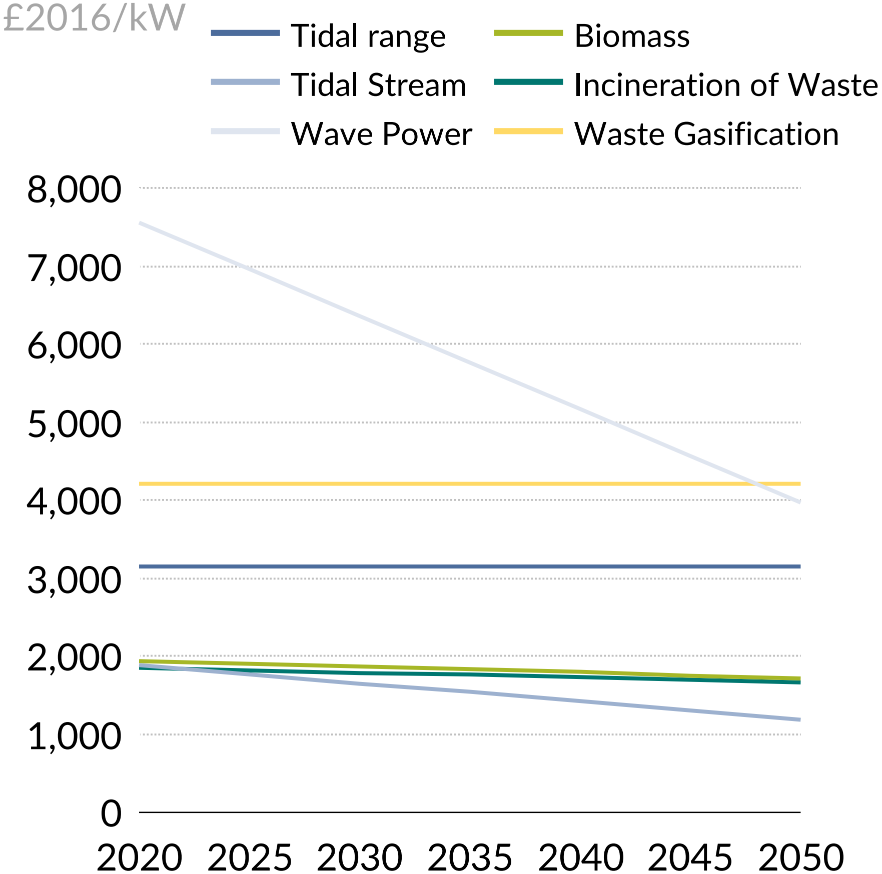
1. Instead of following an assumed timeline, the endogenous entry simulation allows renewable technologies to enter based on profit maximising decisions

- We ran scenarios with endogenous renewable entry to see which technologies enter economically to meet the carbon constraint[1]
- This then informs the mix of renewables used to meet the 2050 RES production targets in each scenario
- In both demand scenarios, solar is the first to enter, followed by onshore in the late 2020s, and finally by offshore
- Renewables enter economically slightly earlier in the heat electrification scenario due to higher prices as a result of higher demand
- Onshore wind almost reaches and solar approaches their maximum production constraints (provided by the NIC) of 140 TWh and 80 TWh respectively

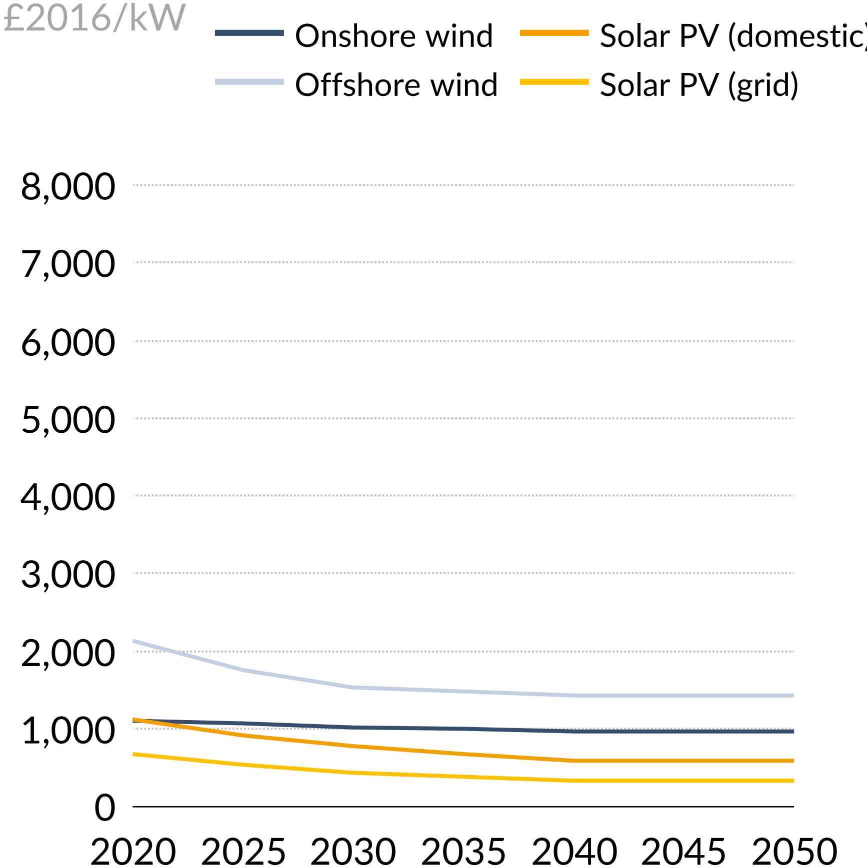
Source: Aurora Energy Research

1 The falling cost of renewables are accounted for; the technology mix is determined by relative economics

Capex (Source: ETI),
£2016/kW



Capex (Source: Aurora),
£2016/kW

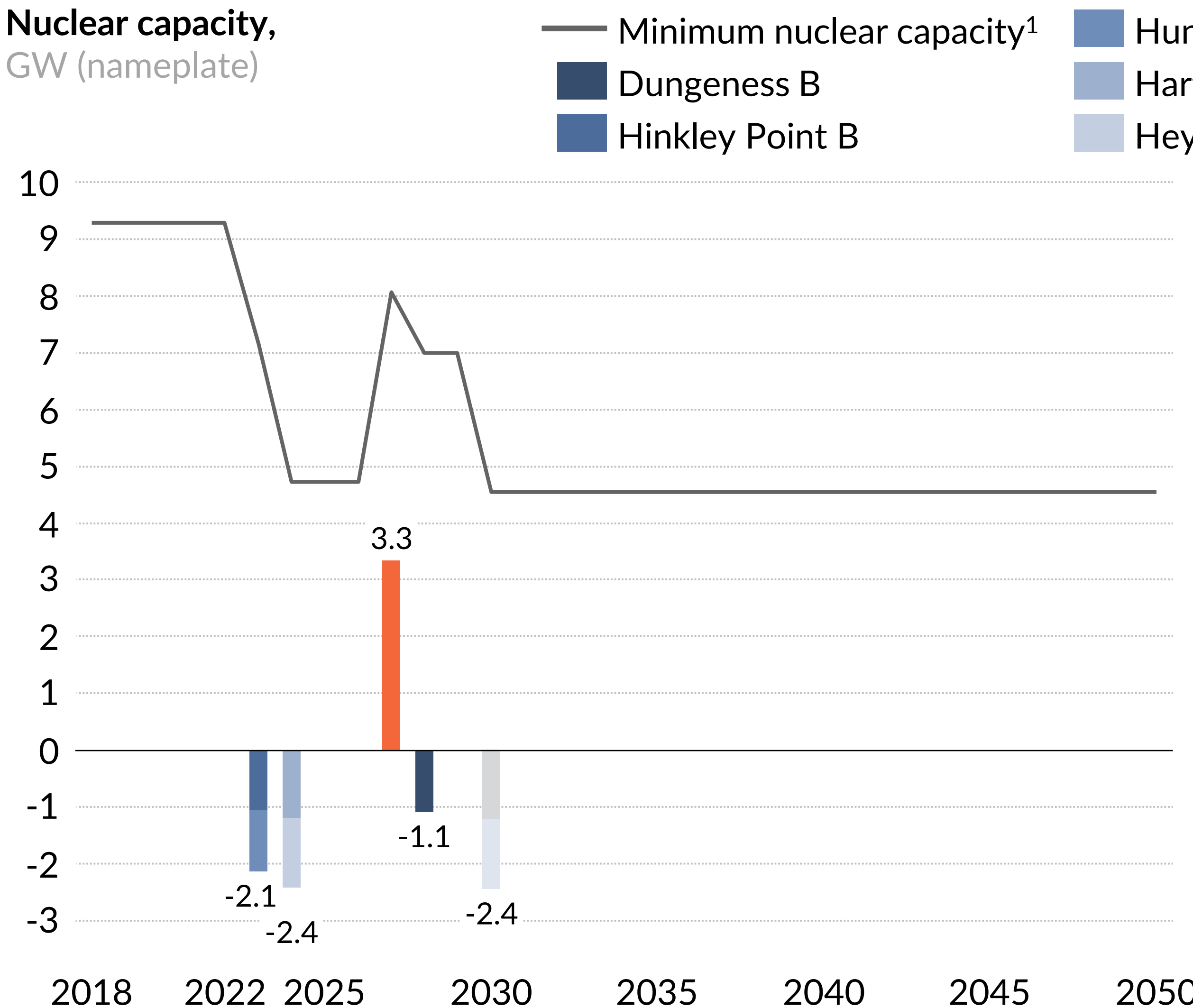


- Taking these costs, the mix of renewables assumed is based on a separate analysis in which all renewables enter based on profit maximisation

- The resulting technology mix sees solar PV and onshore wind entering first followed by offshore wind. Small amounts of biomass also enter, but the other remaining technologies do not

Sources: ETI, Aurora Energy Research

2 Existing nuclear plants have clearly planned retirements; Hinkley Point C is the only new plant assumed



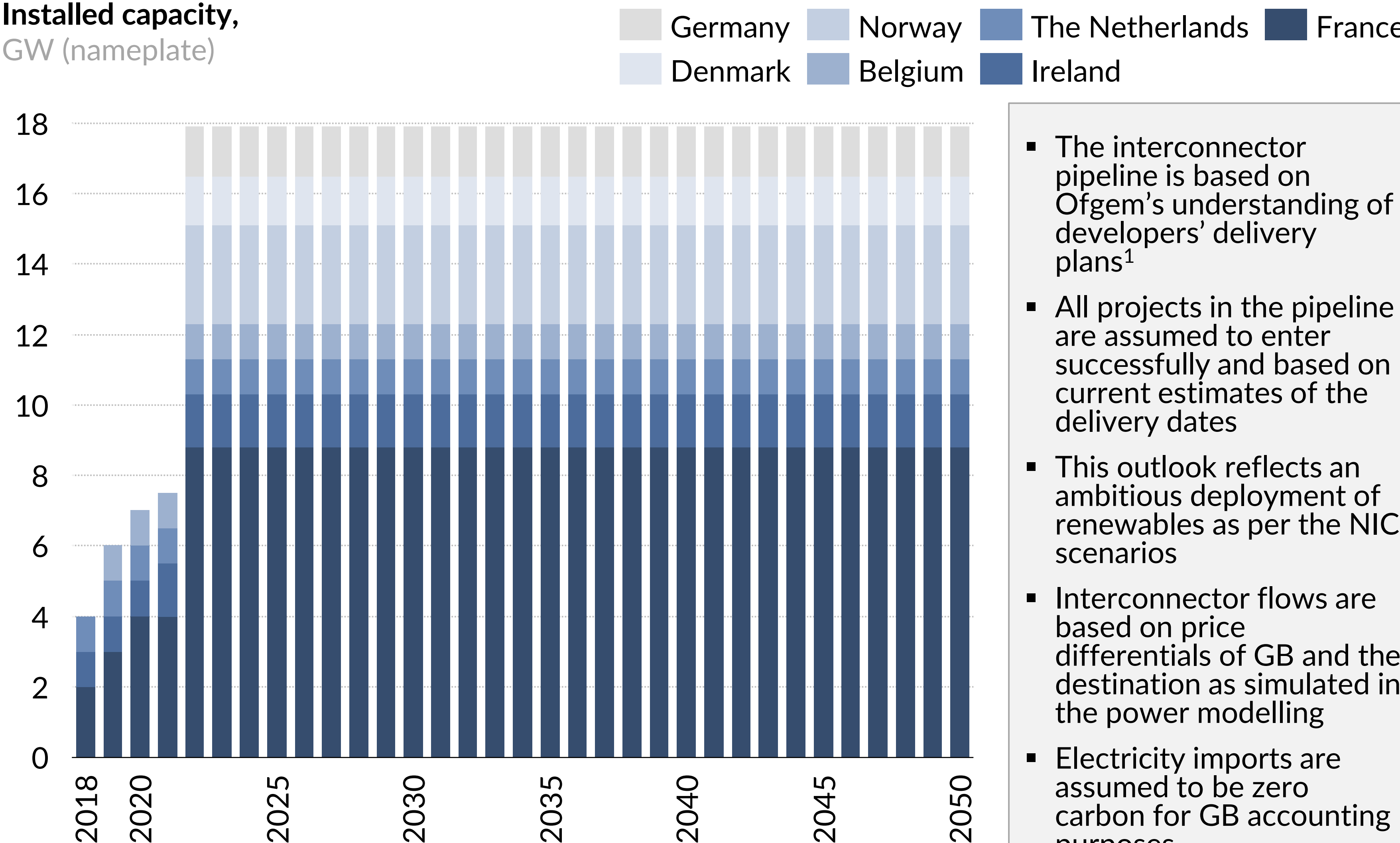
- Existing nuclear plants (Sizewell B) and Hinkley Point C are already committed. They set a lower bound of 4.6GW for nuclear capacity in all future pathways
- The plant owners publish scheduled retirement and commissioning dates. No life extensions are modelled, apart from Sizewell B until 2055, reflecting NIC's assumptions
- Additional nuclear plants will enter based on economic decisions, facilitated by the carbon constraint (i.e. "shadow" carbon price)

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

Source: NIC

3 An ambitious increase in interconnectors is assumed, reaching 18GW by 2022

Installed capacity,
GW (nameplate)

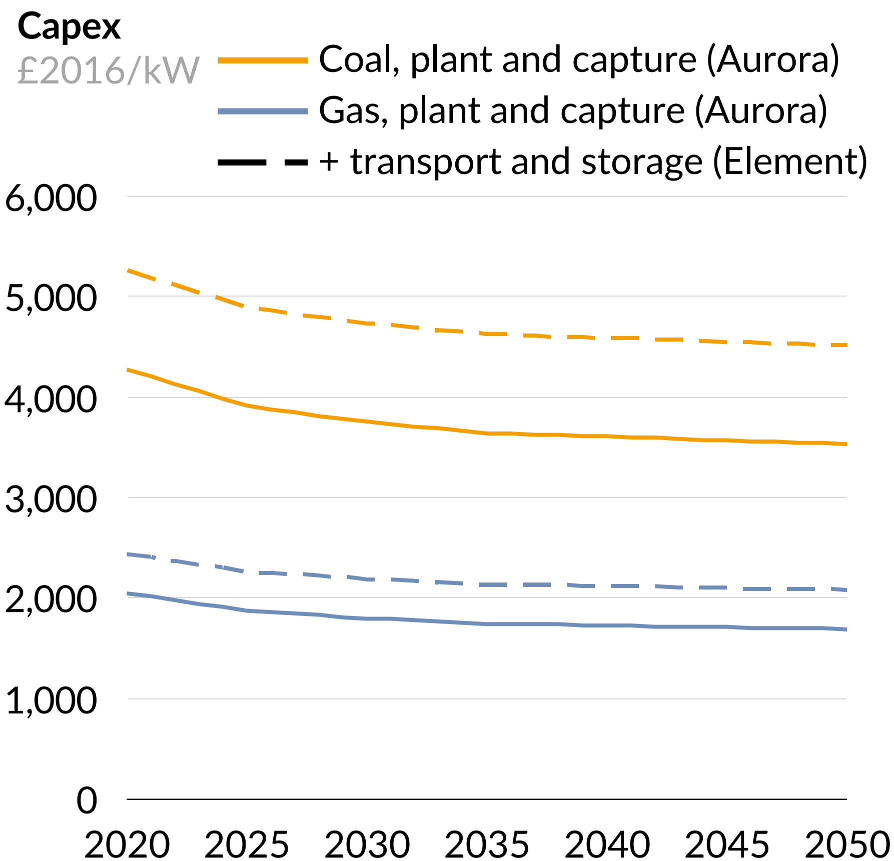


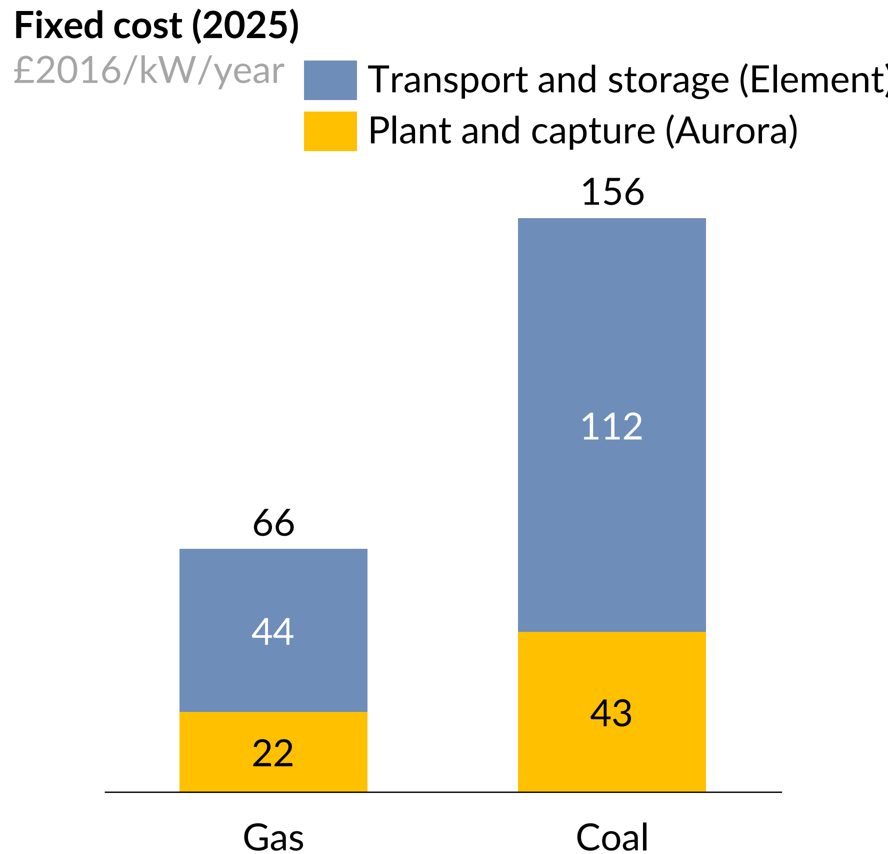
- The interconnector pipeline is based on Ofgem's understanding of developers' delivery plans[1]
- All projects in the pipeline are assumed to enter successfully and based on current estimates of the delivery dates
- This outlook reflects an ambitious deployment of renewables as per the NIC scenarios
- Interconnector flows are based on price differentials of GB and the destination as simulated in the power modelling
- Electricity imports are assumed to be zero carbon for GB accounting purposes

1. Ofgem's outlook includes Window 1, Window 2 and three additional interconnectors applying for a cap and floor arrangement – ElecLink, NEMO and Aquind

Sources: Ofgem, NIC

④ In addition to capital costs, CCS incurs ongoing costs for the transport and storage of carbon





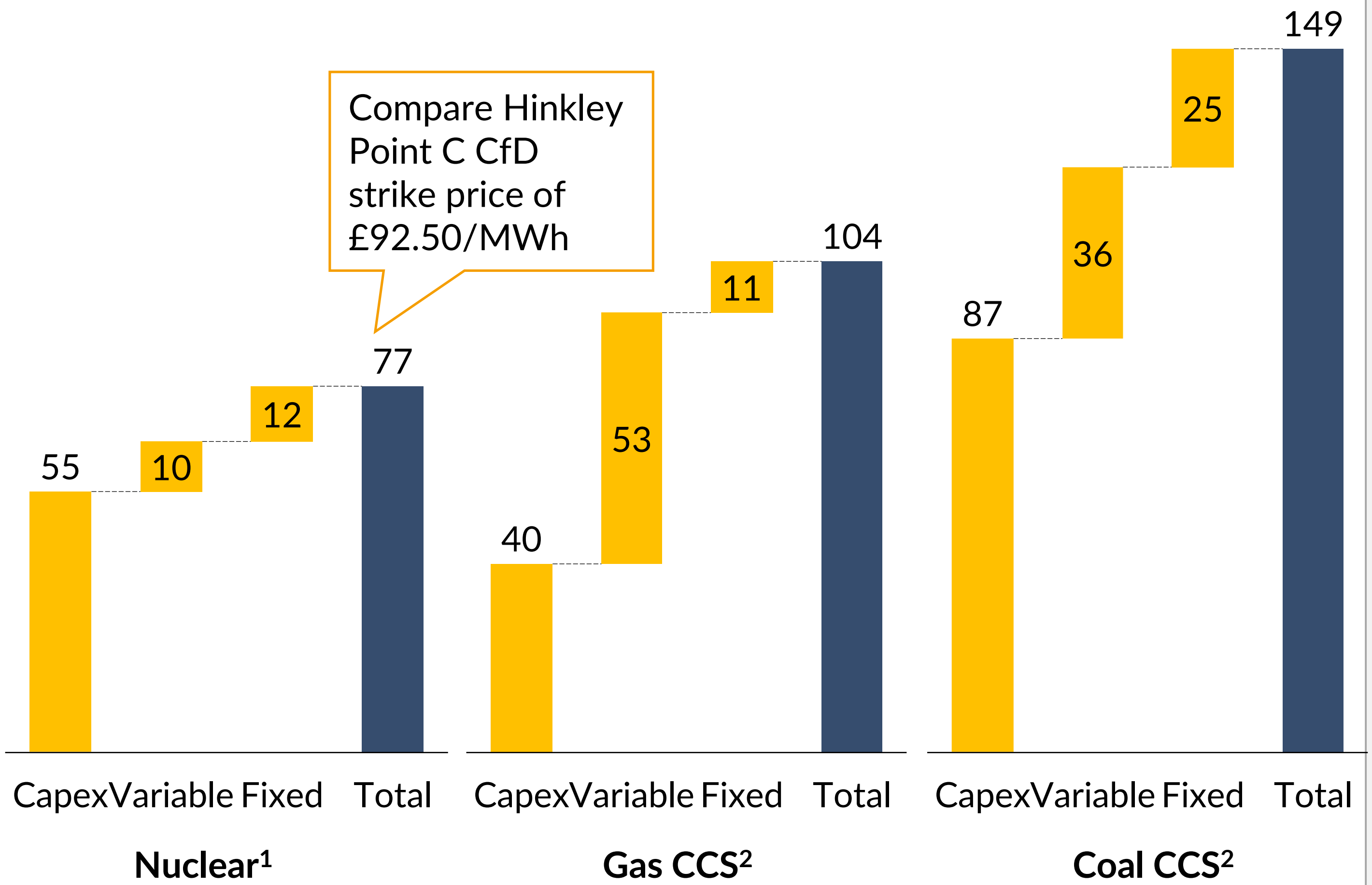
- Even in the hydrogen/greener gas based heating scenario, where CCS is used in the heat sector, there is an incremental cost to CCS due to higher capacity requirements for carbon transport and storage

- As the CCS assumptions for carbon transportation and storage must be consistent with the heat analysis, Element Energy's assumptions are adopted

Sources: Aurora Energy Research, Element Energy

4 The levelized cost of nuclear is 25% lower than CCS, suggesting nuclear would out compete CCS

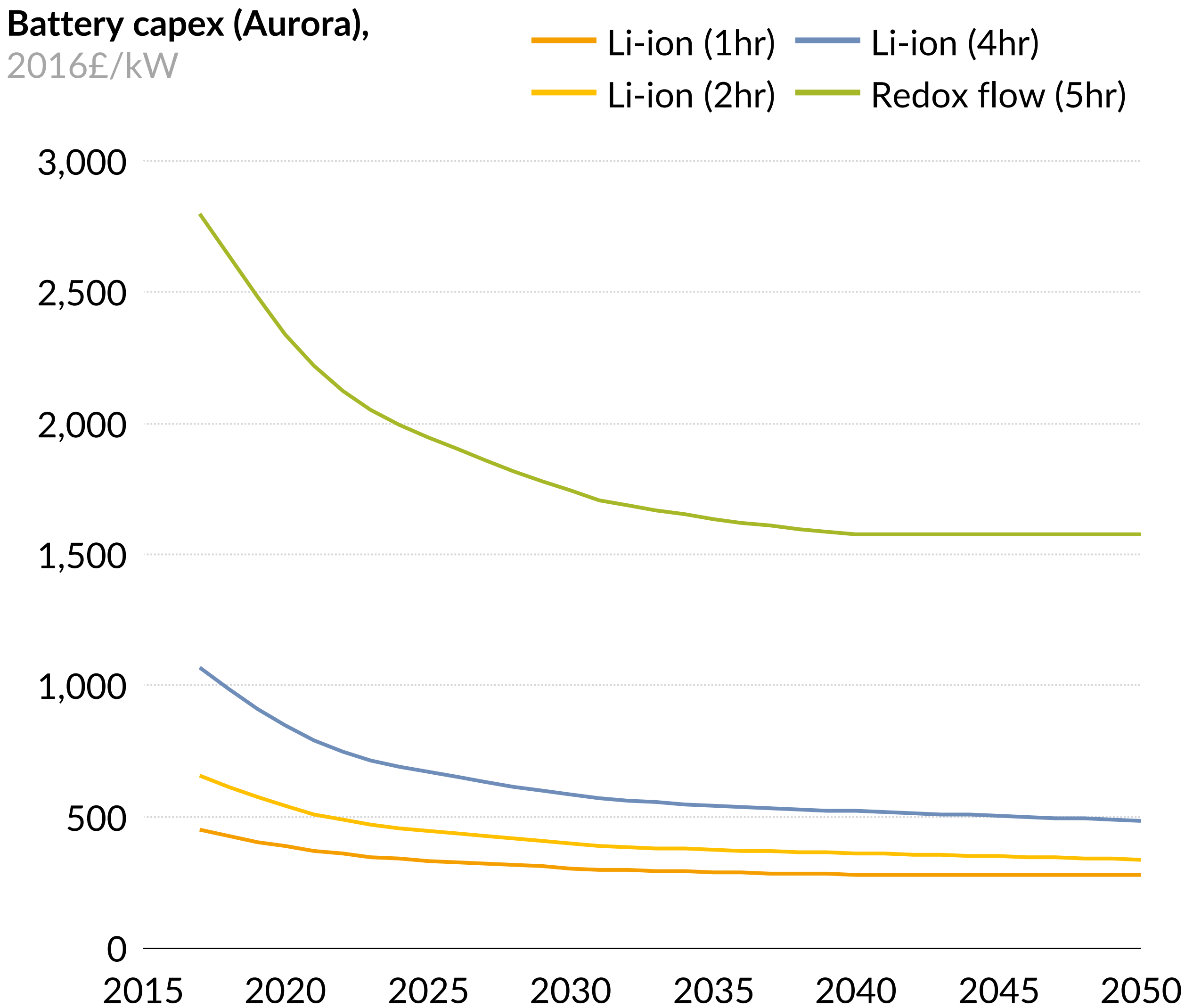
Levelized cost of electricity for plants commissioning in 2025,
£2016/MWh



- Nuclear and CCS are the main sources of low carbon power other than renewables
- While the capital cost of gas CCS is lower than that of nuclear, the high variable costs makes its power more expensive overall
- However, we assume flat nuclear costs while CCS experiences some learning over time
- Coal CCS is unlikely to be economic given its high cost
- Results are highly sensitive to cost assumptions – an additional sensitivity was run to understand the impact of even lower CCS costs

Sources: 1. BEIS, analysis by Aurora Energy Research 2. Element Energy for CO2 transport & storage, plant costs and analysis by Aurora Energy Research

5 Battery cost reductions are assumed to continue, until the cost of materials becomes a limiting factor

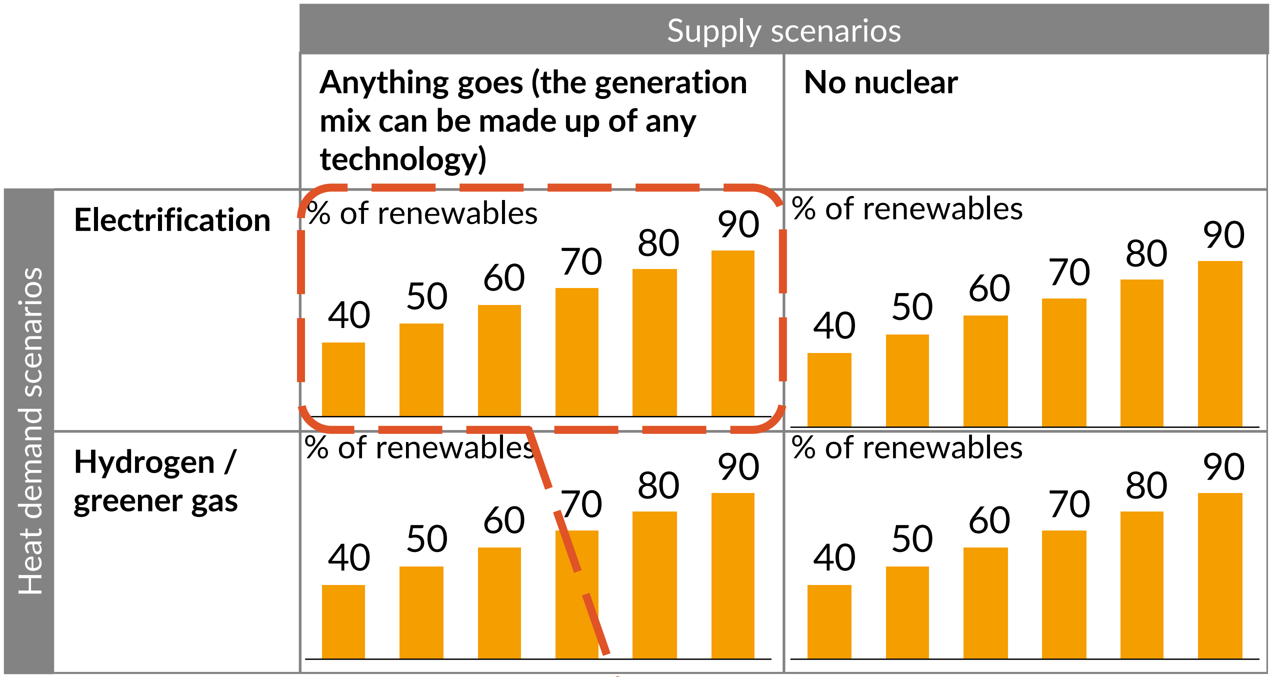


- Fall in battery costs expected to continue due to high levels of R&D and adoption of EVs
- Aurora's battery capex forecasts show total installed costs, including cell, balance of system and connection costs
- Battery costs expected to plateau as the technology matures and the cost of materials becomes a limiting factor
- Despite having higher capital costs, flow batteries experience less degradation from use than li-ion batteries

Source: Aurora Energy Research

Contents

To begin, we explore a path to decarbonization in which all low carbon technologies can compete in a flexible system

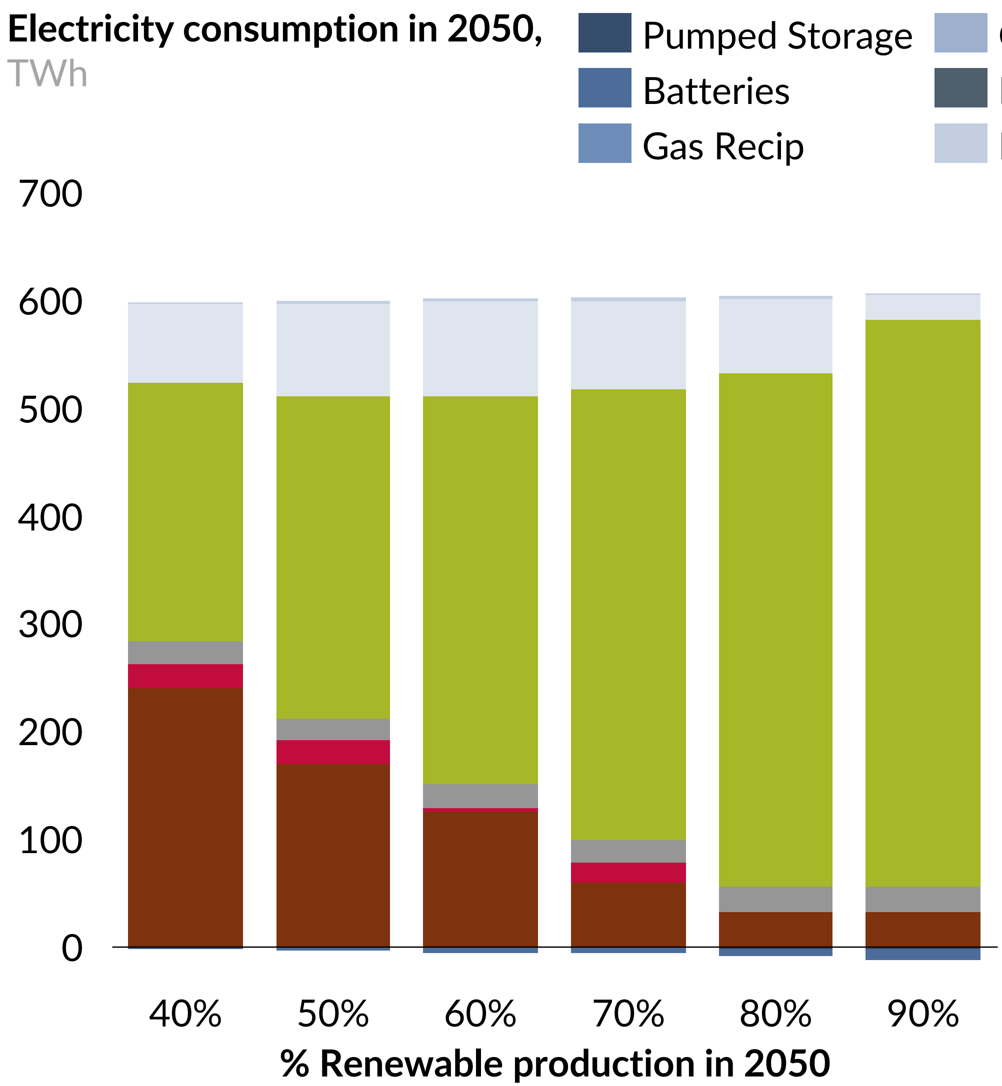


The following slides are based on the scenarios where heat is electrified and all technologies are allowed to compete

- Both nuclear and renewables are currently an important part of the government's strategy for meeting GB 2050 carbon targets
- Flexibility is also high on the government agenda, with Ofgem plans for 17.9 GW of interconnectors and both batteries and EVs an important part of the government's industrial strategy
- We start by exploring a scenario in which all low carbon technologies can compete to reduce emissions in a flexible world where heat is decarbonized via electrification

Scenario: Supply - anything goes, Demand - electrification

Carbon targets can be met by a mostly renewable system, mostly nuclear system, or a hybrid of the two

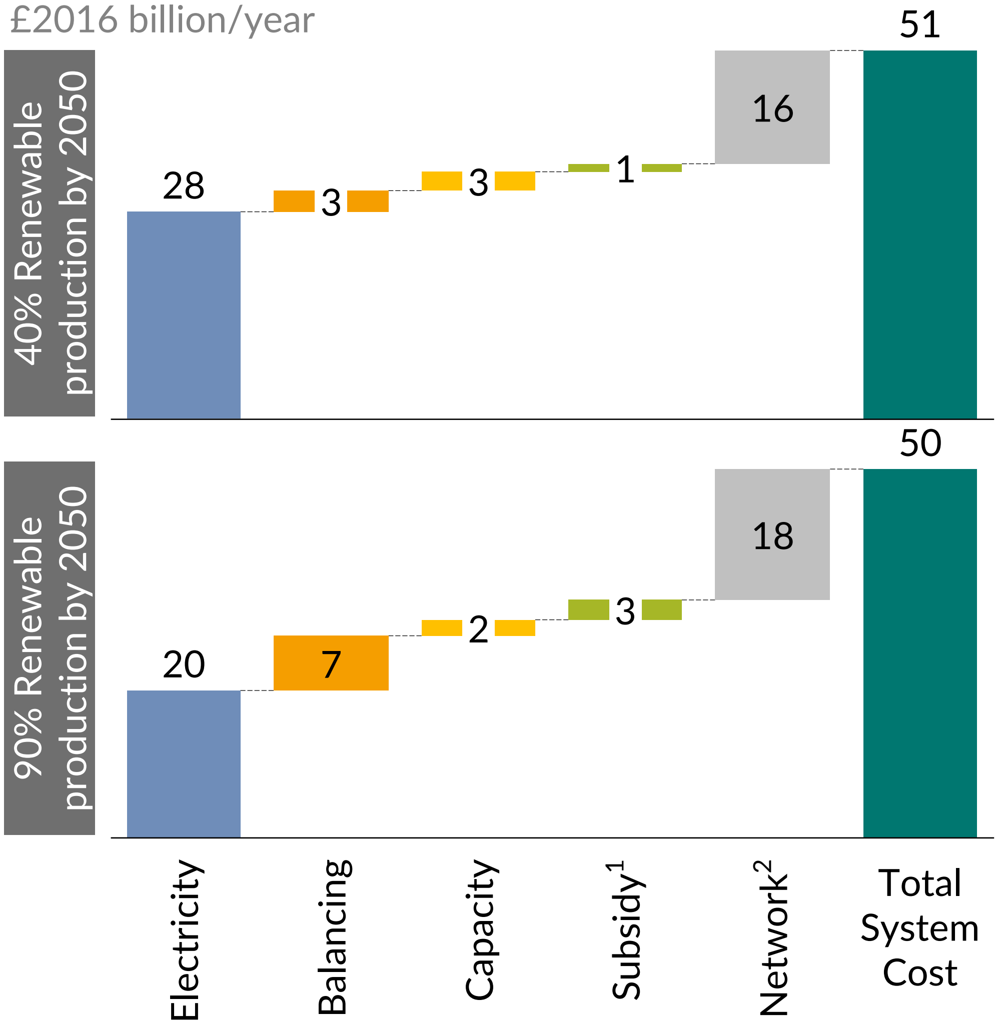


- In the "anything goes" scenario, we forced the model to meet a carbon constraint with varying levels of renewable production by 2050
- All other technologies were allowed to compete based on which were most profitable
- There are multiple paths to meeting carbon targets, with varying levels of renewables all possible
- When renewables build-out is constrained, nuclear is the clear winner
- In the late 2040s, CCS begins to become cost-competitive with nuclear with a small amount of entry in the low RES scenarios

Source: Aurora Energy Research

In terms of cost-effectiveness, there is little to choose between a high renewable and high nuclear system

Average system cost (2030-2050),
£2016 billion/year



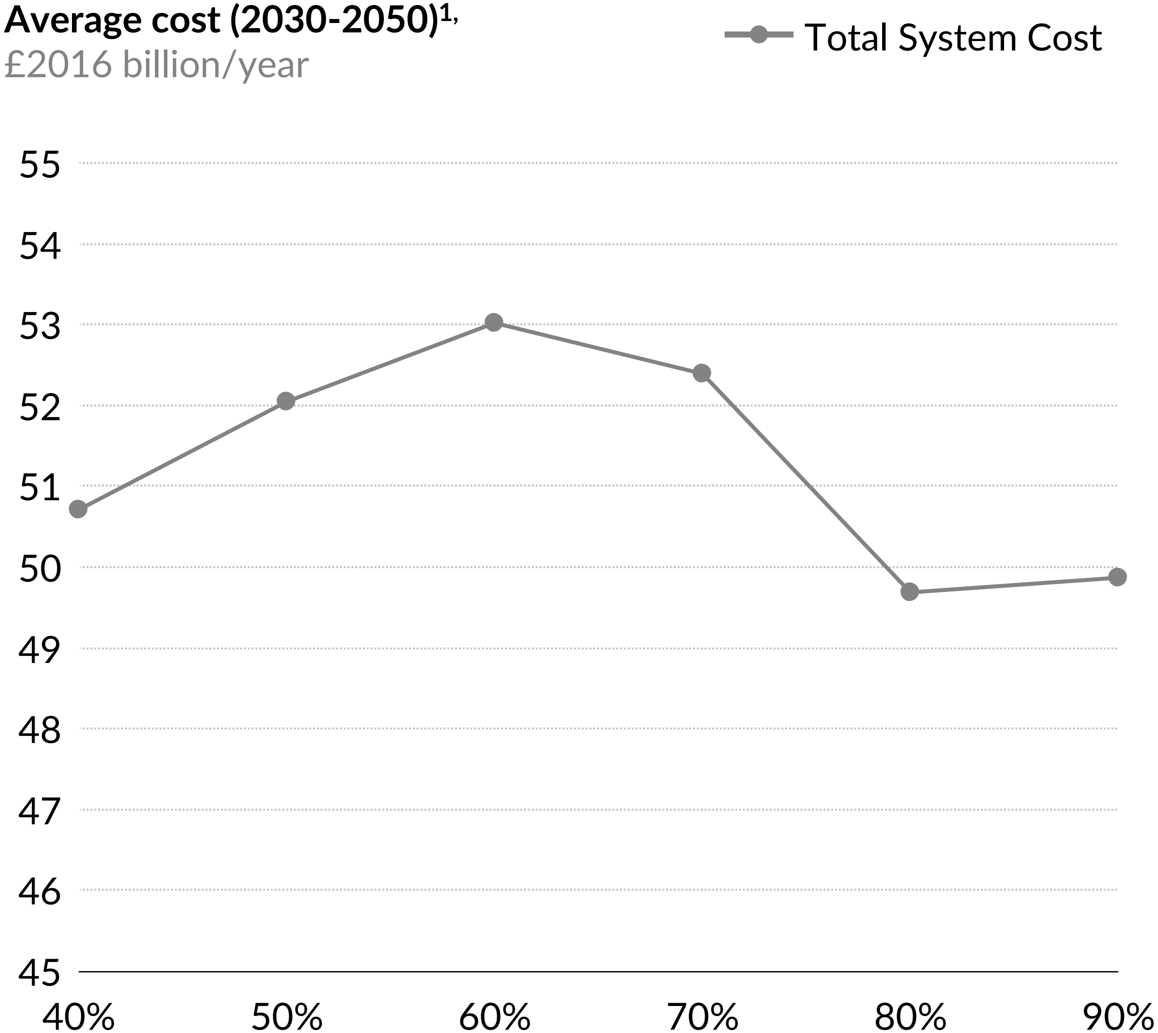
- There is no clear winner between nuclear or renewables at extreme renewable penetration levels
- High levels of renewable penetration depress wholesale electricity market spending by £8bn/year on average – but this is offset by the need for £5bn/year in additional balancing costs to cope with increased levels of intermittent generation
- Network costs make up over 30% of total system costs and are dependent on the type and location of power plants. Renewables, and particularly offshore wind, are associated with higher network costs.
- While the impact on consumers is marginal, government would have to pay an extra c.£1.5bn/year on average in subsidies to achieve 90% renewables build out

1. Subsidy includes legacy climate costs (e.g. CfD, RO, FIT) in addition to any additional subsidies needed to reach renewable penetration target – see Appendix for methodology 2. Network costs include transmission and distribution costs – please refer to methodology in Appendix.

Source: Aurora Energy Research

Hybrid systems of renewables and nuclear are less likely to be cost effective

Average cost (2030-2050)[1,]
£2016 billion/year



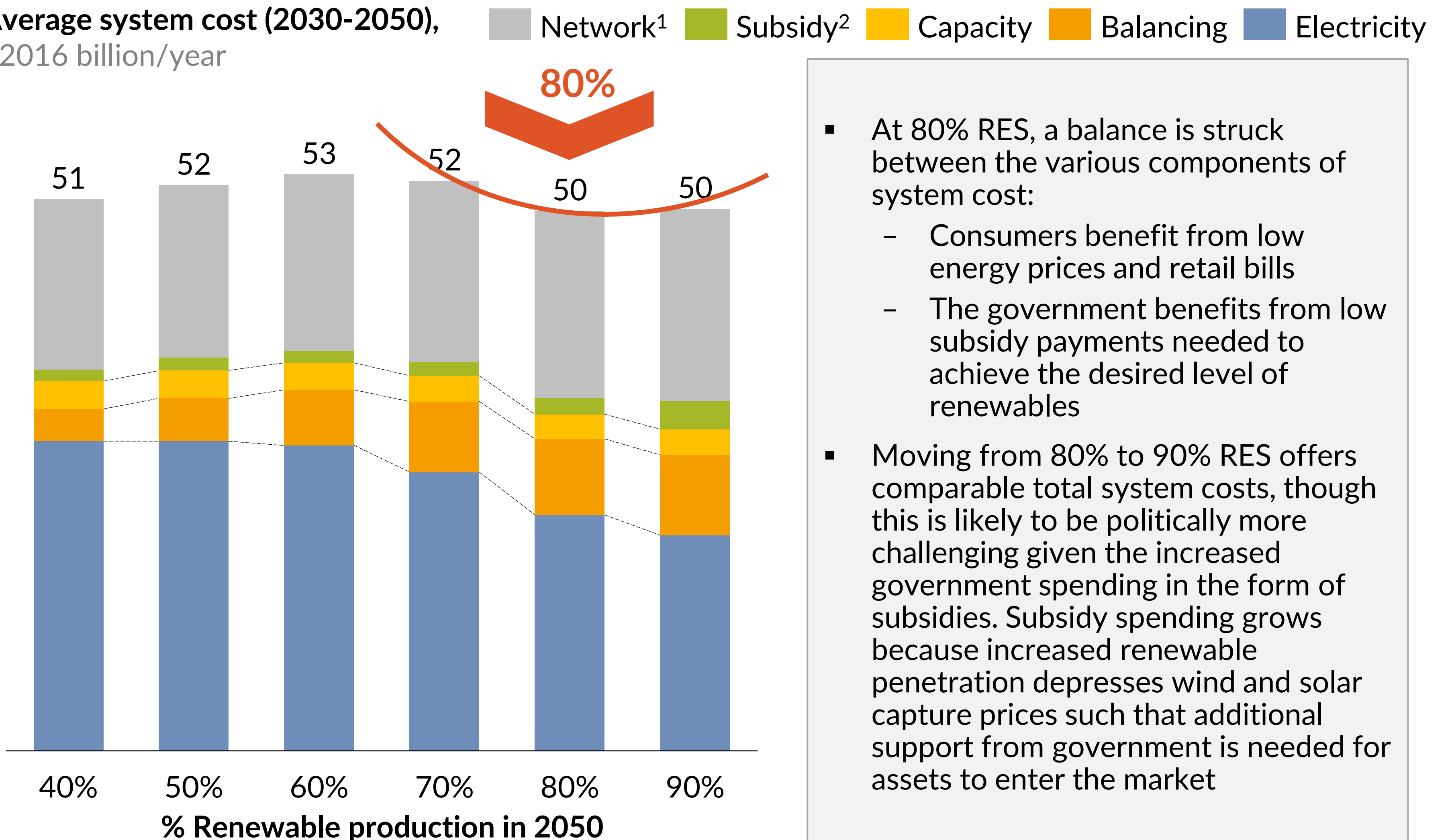
- Renewable integration costs tend to be higher in a hybrid system where carbon targets are met by a mixture of renewables and nuclear
- High levels of renewable integration require a high degree of system flexibility
- This flexibility can be provided by:
  - Interconnectors
  - Storage
  - DSR
  - Fast ramping thermal generation
- Nuclear is typically not a great source of flexibility due to high ramping costs

1. Average total system costs presented here are c. £15bn more per year than current 2018 levels of £35bn.

Source: Aurora Energy Research

In a system with a high degree of flexibility, 80% RES becomes the cost-optimizing option

Average system cost (2030-2050), £2016 billion/year

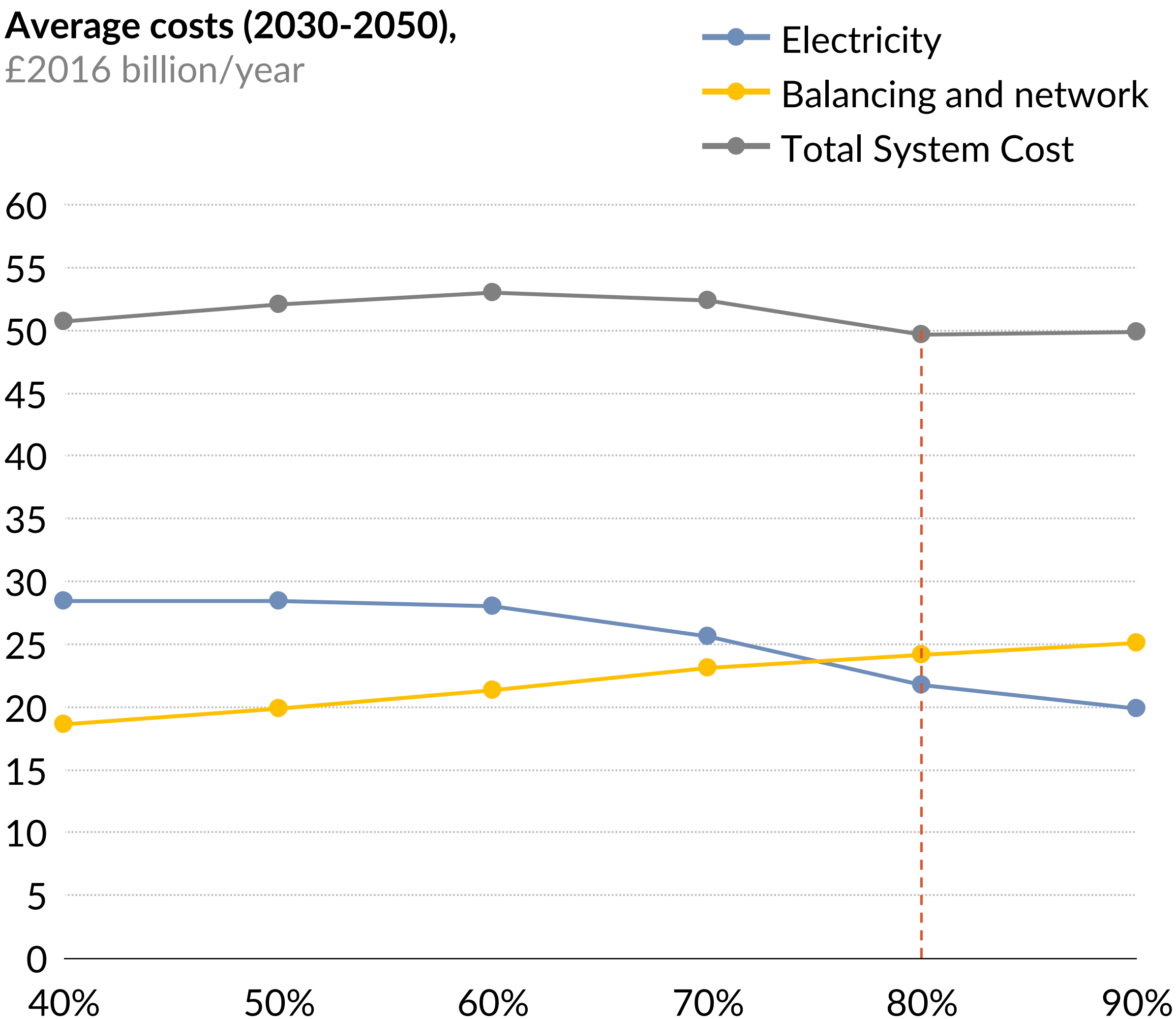


- At 80% RES, a balance is struck between the various components of system cost:
  - Consumers benefit from low energy prices and retail bills
  - The government benefits from low subsidy payments needed to achieve the desired level of renewables
- Moving from 80% to 90% RES offers comparable total system costs, though this is likely to be politically more challenging given the increased government spending in the form of subsidies. Subsidy spending grows because increased renewable penetration depresses wind and solar capture prices such that additional support from government is needed for assets to enter the market

1. Network costs include both transmission and distribution – please see Appendix for methodology. 2. In this and all following slides, subsidy includes legacy climate costs (e.g. CfD, RO, FIT) in addition to any additional subsidies needed to reach renewable penetration target – see Appendix for methodology.

Source: Aurora Energy Research

The main drivers of total system cost are wholesale electricity, network and balancing costs

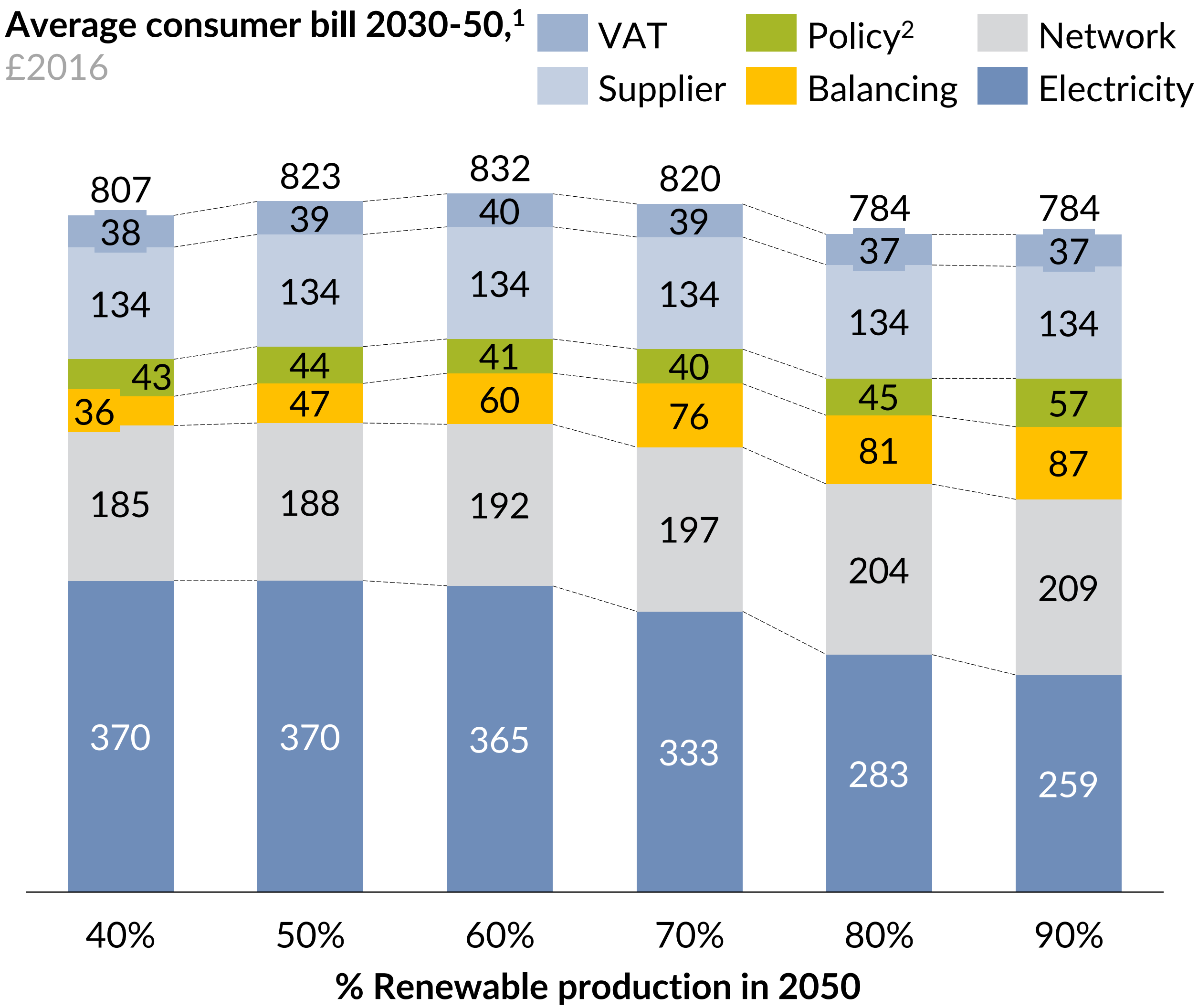


- Wholesale electricity spending, balancing and network costs are the three main drivers of total system costs
- Renewables have low marginal costs so tend to depress the power price
- On the other hand, intermittent renewables like wind and solar tend to be associated with higher balancing costs
- Close to 80% renewable production is the sweet spot where reductions in wholesale electricity spending more than offset increases in network and balancing costs as renewable penetration increases
- At 90% renewables, the power price effect is outweighed by increases in network and balancing costs

Source: Aurora Energy Research

Scenario: Supply - anything goes, Demand - electrification

The pathway to 80% renewable production in 2050 could save consumers up to £58 per year



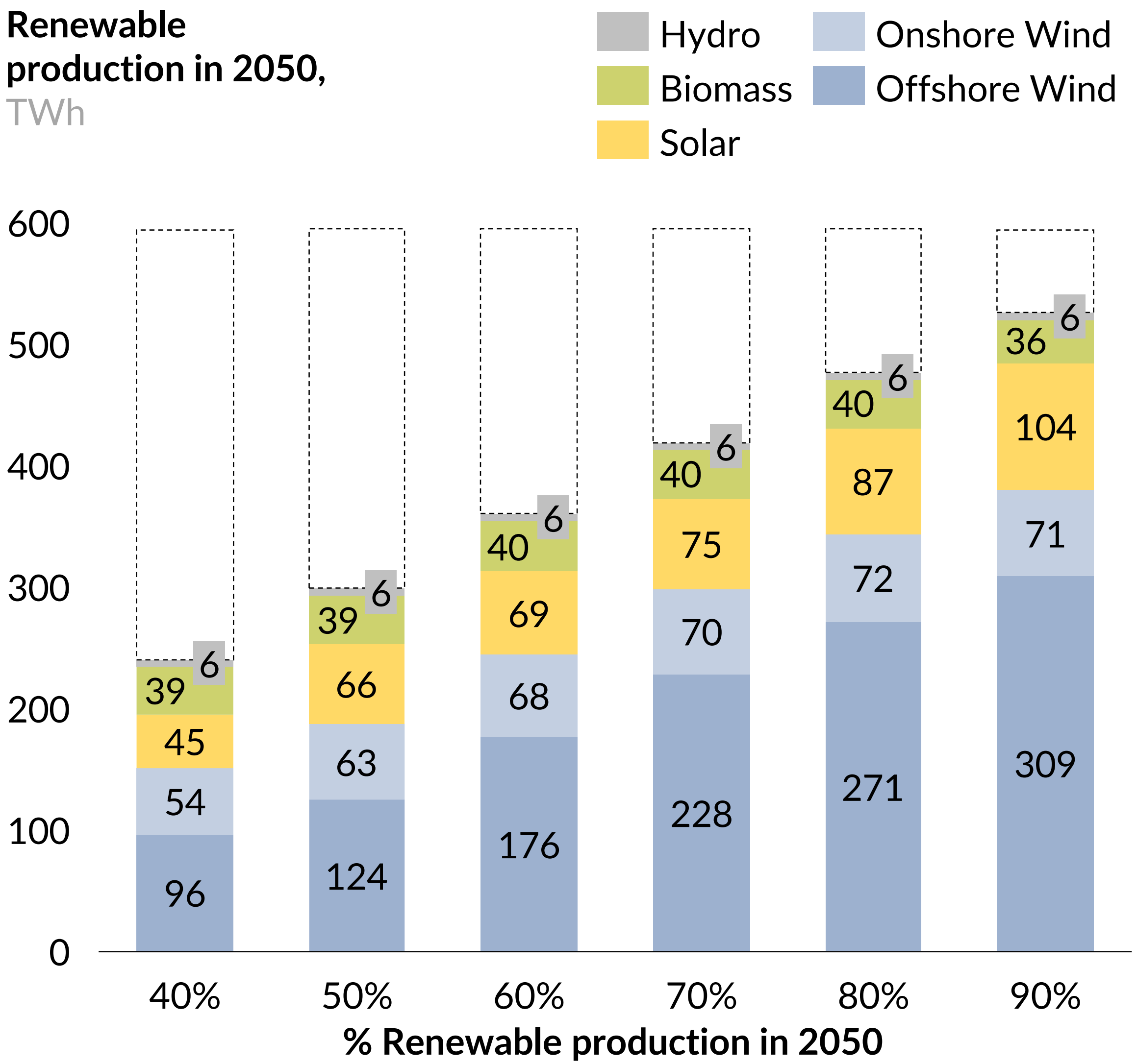
- Average system costs vary by over £3 billion per year between scenarios and this is reflected in tangible variations in consumer bills
- Greater network infrastructure and balancing services are required as renewable percentages increase, costing consumers up to £24 and £51 per year on average
- These increases are counteracted by heavily reduced wholesale costs. 80% RES leads to the lowest consumer bills at £58 per year cheaper than the least optimal scenario with 60% RES

1. For comparison, average consumer bills in 2018 are around £598 incl VAT (modelled) 2. In this and all subsequent slides related to consumer bills, "policy" includes costs related to the Capacity Market, legacy climate costs (e.g. RO, FIT and CfD) in addition to any additional subsidies needed to bring forward the required renewable capacity

Source: Aurora Energy Research

Scenario: Supply - anything goes, Demand - electrification

Offshore wind accounts for most renewable generation and can meet nearly half of demand at 90% renewables



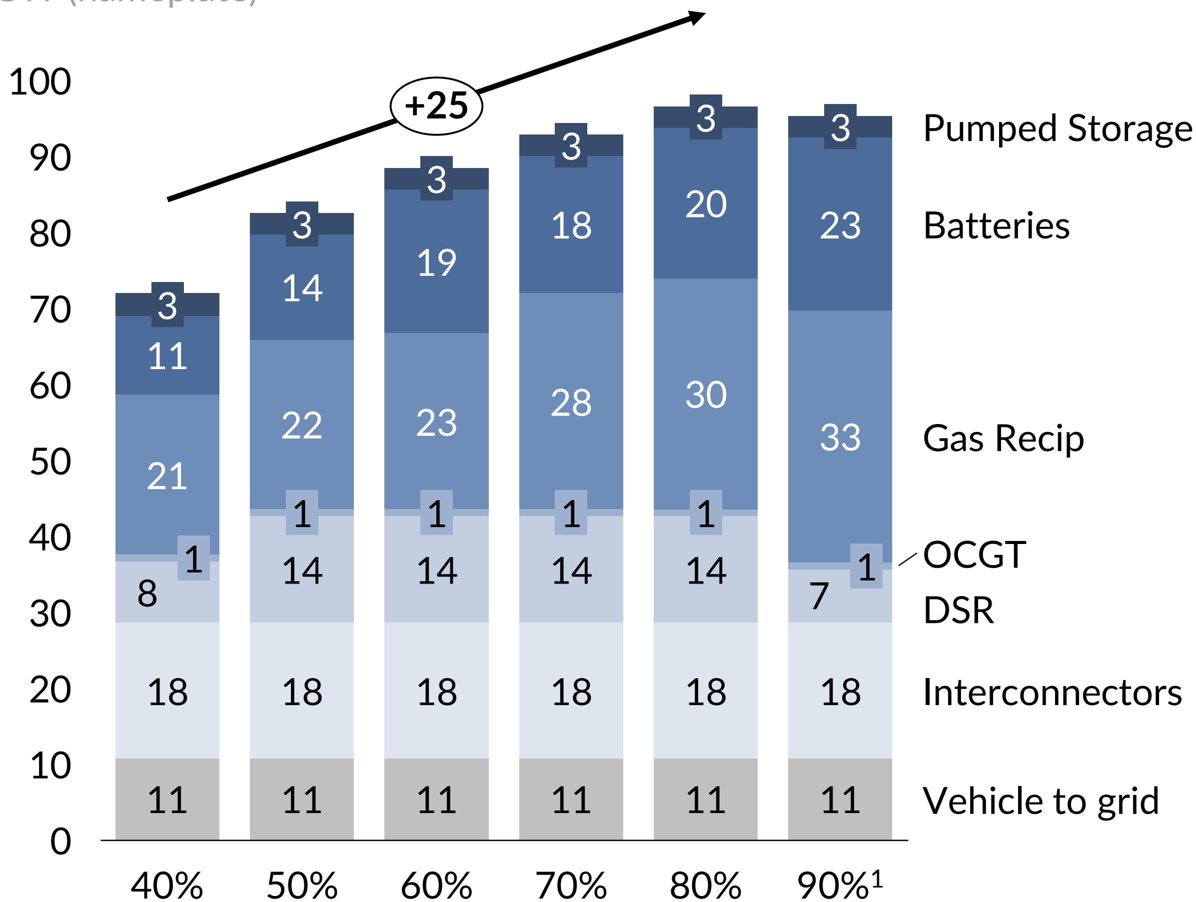
- Renewable capacity follows an assumed timeline to reach the target penetration level by 2050. This is based on a separate analysis in which renewables are allowed to enter endogenously based on whether it is economic to do so
- Solar is the first technology to enter economically in the early 2020s, followed by onshore wind and then offshore in the early 2030s
- Above 60% RES, onshore wind approaches its resource availability limit of 26 GW
- Biomass is rarely economic to build without subsidies
- Hydro is fundamentally limited by site availability

Source: Aurora Energy Research

Scenario: Supply - anything goes, Demand - electrification

A large amount of flexible capacity is required to meet peak demand and frequency fluctuations at high RES

Flex capacity in 2050,
GW (nameplate)

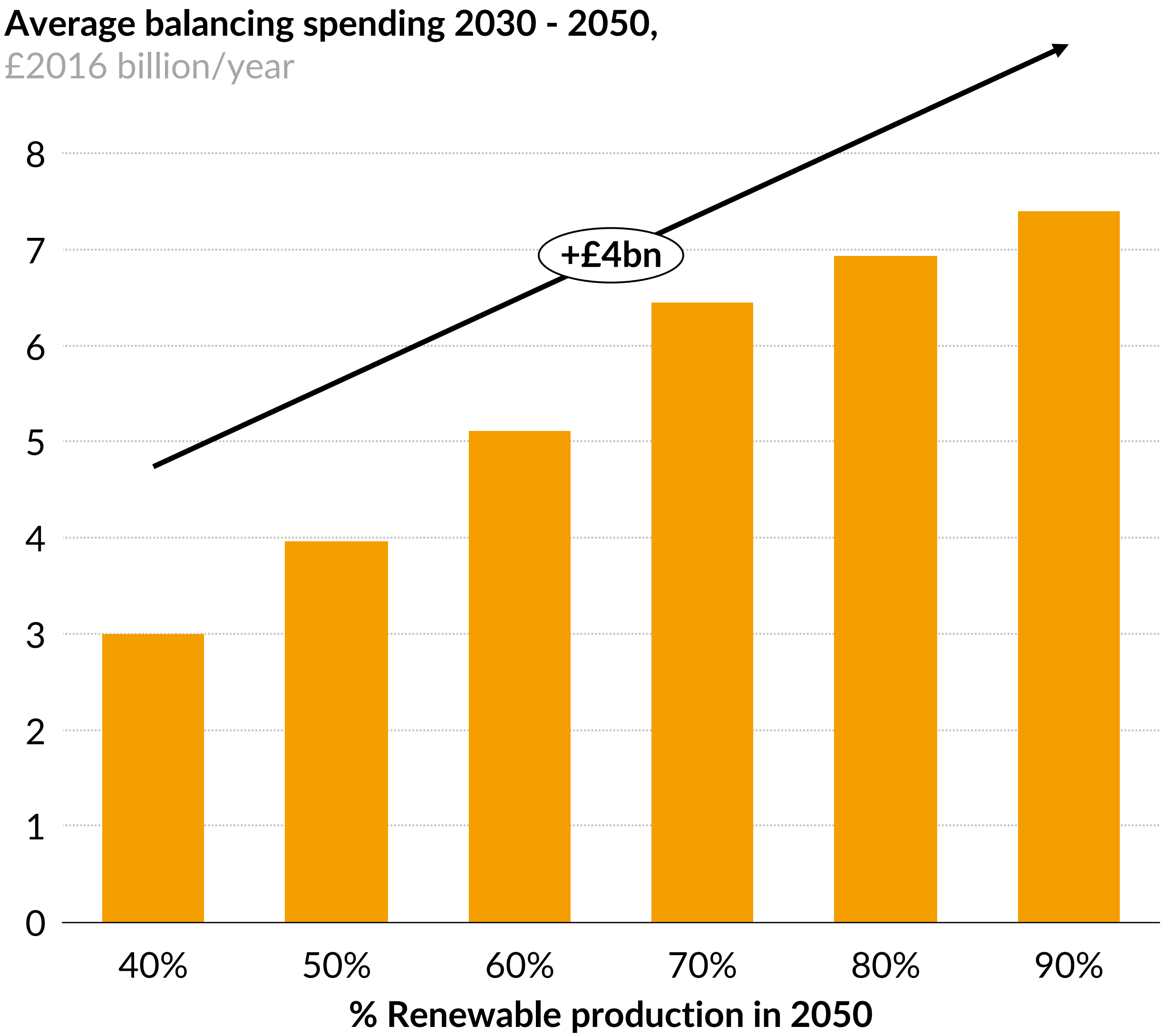


- Large amounts of flexible capacity are required with increasing levels of RES to provide security of supply and cope with intermittency
- Gas reciprocating engines and batteries are the technologies of choice when it comes to providing system flexibility at high %RES penetrations. Twice as many batteries and 50% more gas recips are needed to bring in 80% RES relative to 40% RES. This is due to their fast response time, low cost and high capture prices.
- 4 hour Li-ion and even longer duration redox-flow batteries dominate as a result of their longer durations

1. At 90% RES, DSR is replaced by gas reciprocating engines and batteries, which are less constrained in terms of running hours (each DSR project is limited to 250 hours per year). Interconnectors also export higher volumes, helping to support GB wholesale prices. Therefore while nameplate flex capacity declines slightly compared to the 80% RES scenario, there is no decline in the amount of flexibility

Source: Aurora Energy Research

Balancing spending at 90% RES is 2.5x higher than at 40% RES

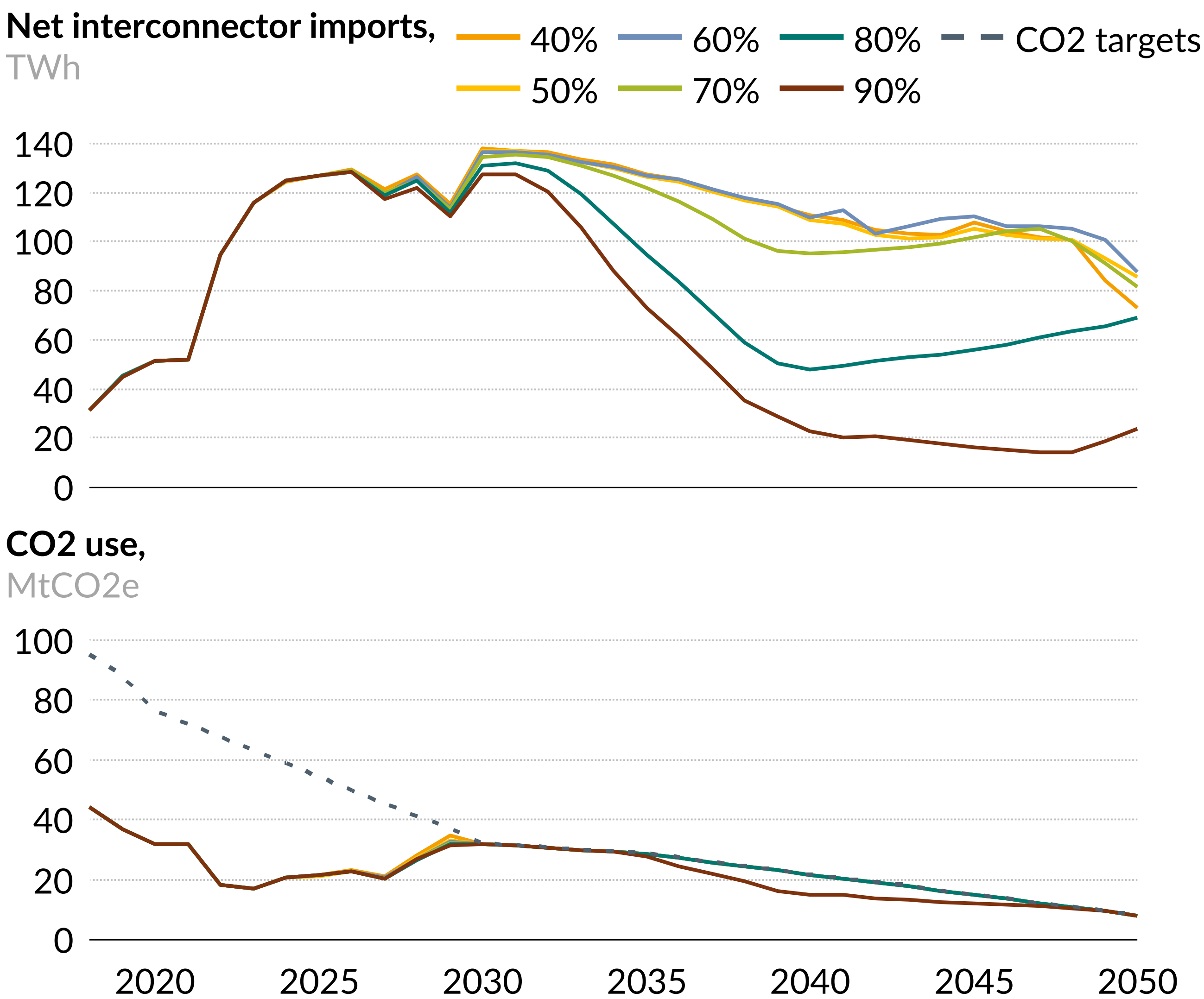


- Increased renewable capacity leads to more intermittent generation, which requires higher spending on balancing services
- In the lower RES scenarios, flexibility is predominantly met by interconnectors

Source: Aurora Energy Research

Scenario: Supply - anything goes, Demand - electrification

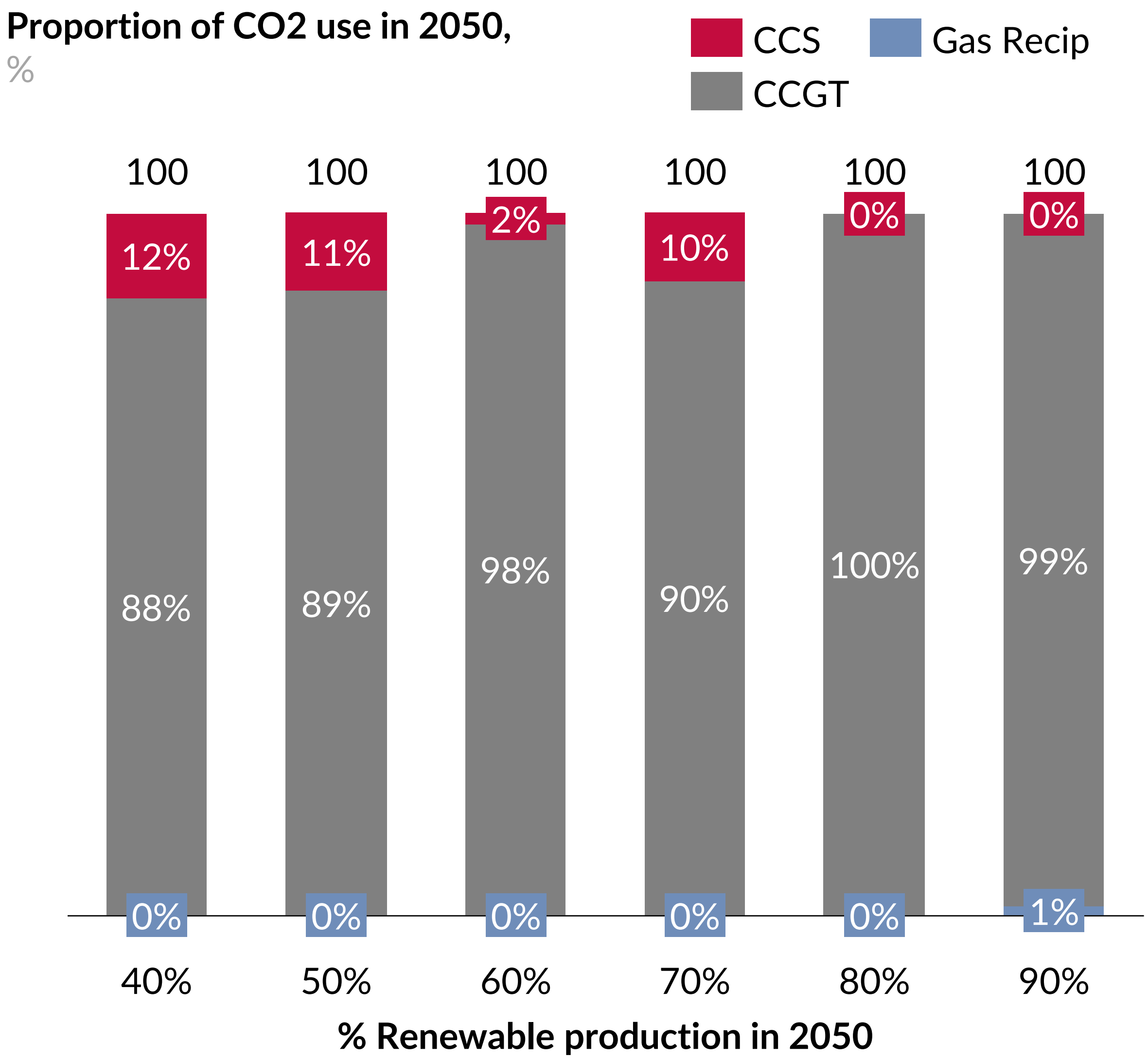
Interconnector imports play a key role in meeting carbon targets and enabling renewable integration



- According to government policy, interconnector imports are by default zero carbon
- Before 2030, imports help GB undershoot carbon targets at all levels of RES penetration
- Over time, net imports decrease, especially at high RES levels as GB increasingly exports excess RES generation to the continent, helping to sustain higher domestic wholesale electricity prices
- Carbon constraints begin to bite in the early 2030s when retiring thermal capacity needs to be replaced with low carbon generation

Source: Aurora Energy Research

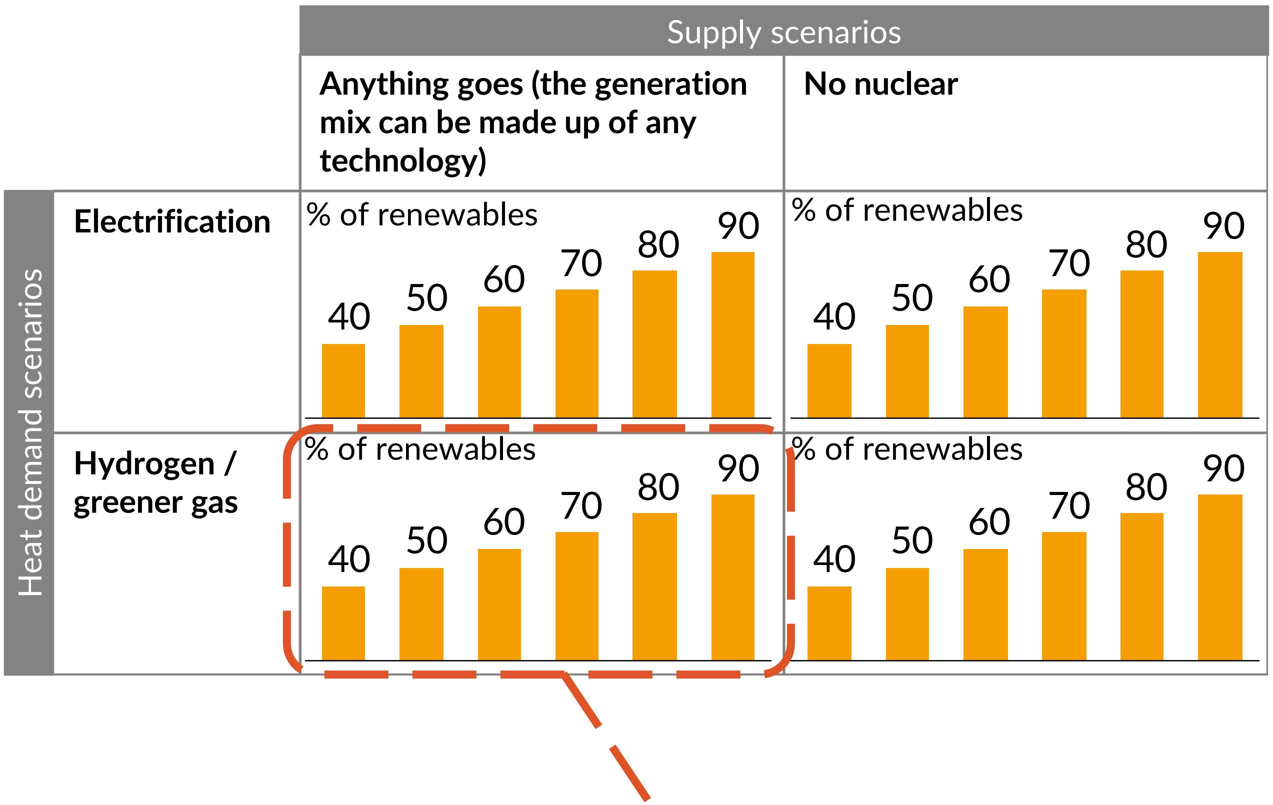
CCGT produces most of allowed emissions in the heat electrification scenario



- The heat electrification scenario has a less stringent carbon target than the hydrogen/greener gas based heating scenario
- This allows CCGT to play a greater role in meeting demand and providing both system flexibility and a dependable source of dispatchable generation
- Most emissions are from CCGT – especially at high levels of renewable penetration which do not see any CCS build out
- There is no CCS at very high levels of renewables since power prices are not high enough to bring on CCS economically

Source: Aurora Energy Research

An alternative path to meeting GB carbon targets is decarbonizing heat through hydrogen and greener gas



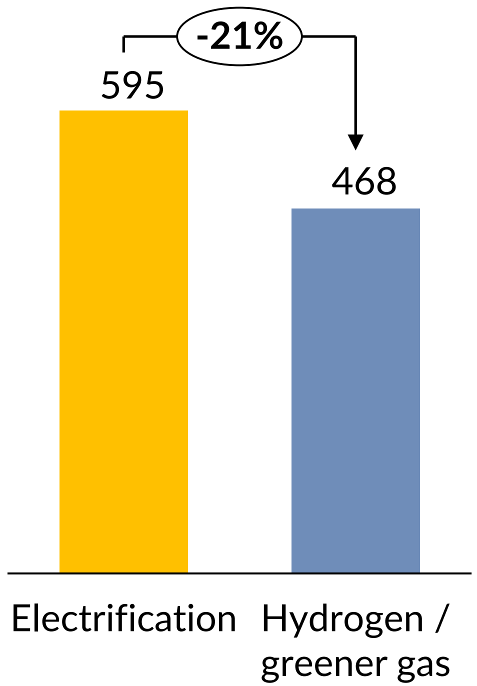
The following slides are based on the scenarios where the heat uses hydrogen/greener gas and all technologies are allowed to compete

- An alternative option for decarbonizing heat is through the use of hydrogen and greener gas rather than heat pumps
- We explore the implications of this heat decarbonization strategy for the power sector while still allowing all technologies to compete in a flexible world of high interconnector capacity and relatively cheap batteries

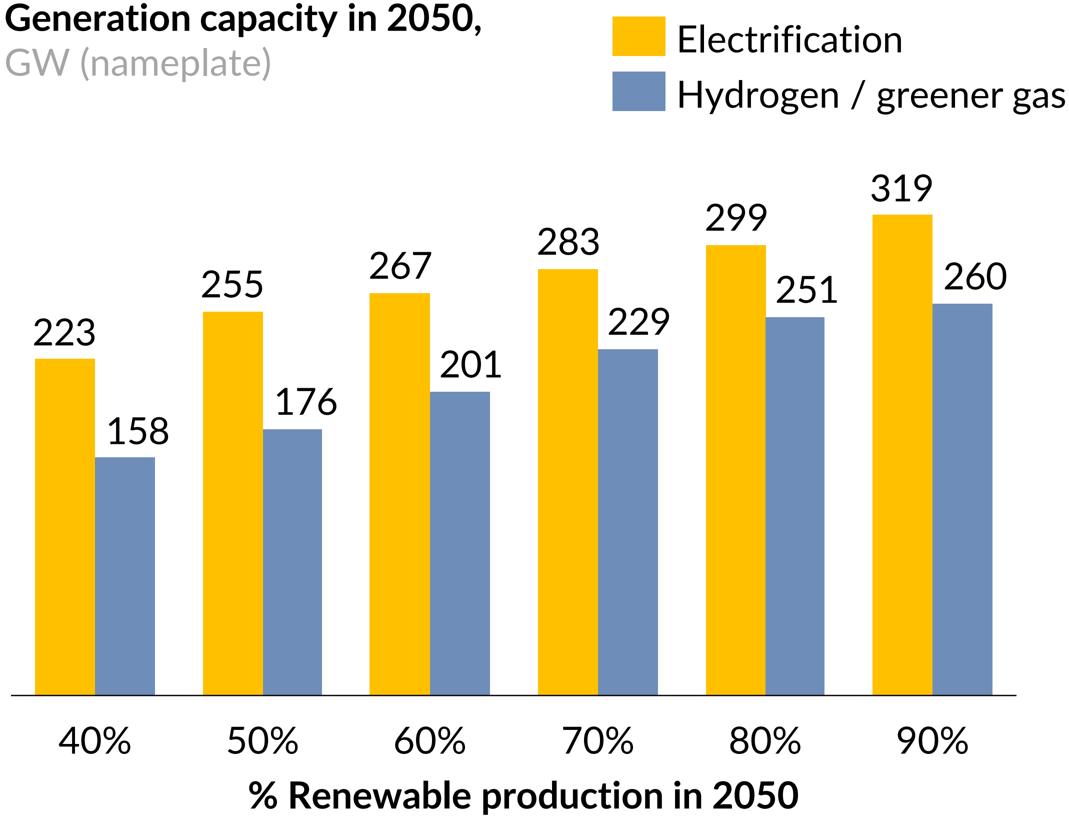
Scenario: Supply - anything goes, Demand - hydrogen / greener gas

Less capacity is needed to meet demand when heat is not electrified, leading to lower power system costs

Electricity consumption in 2050,
TWh



Generation capacity in 2050,
GW (nameplate)

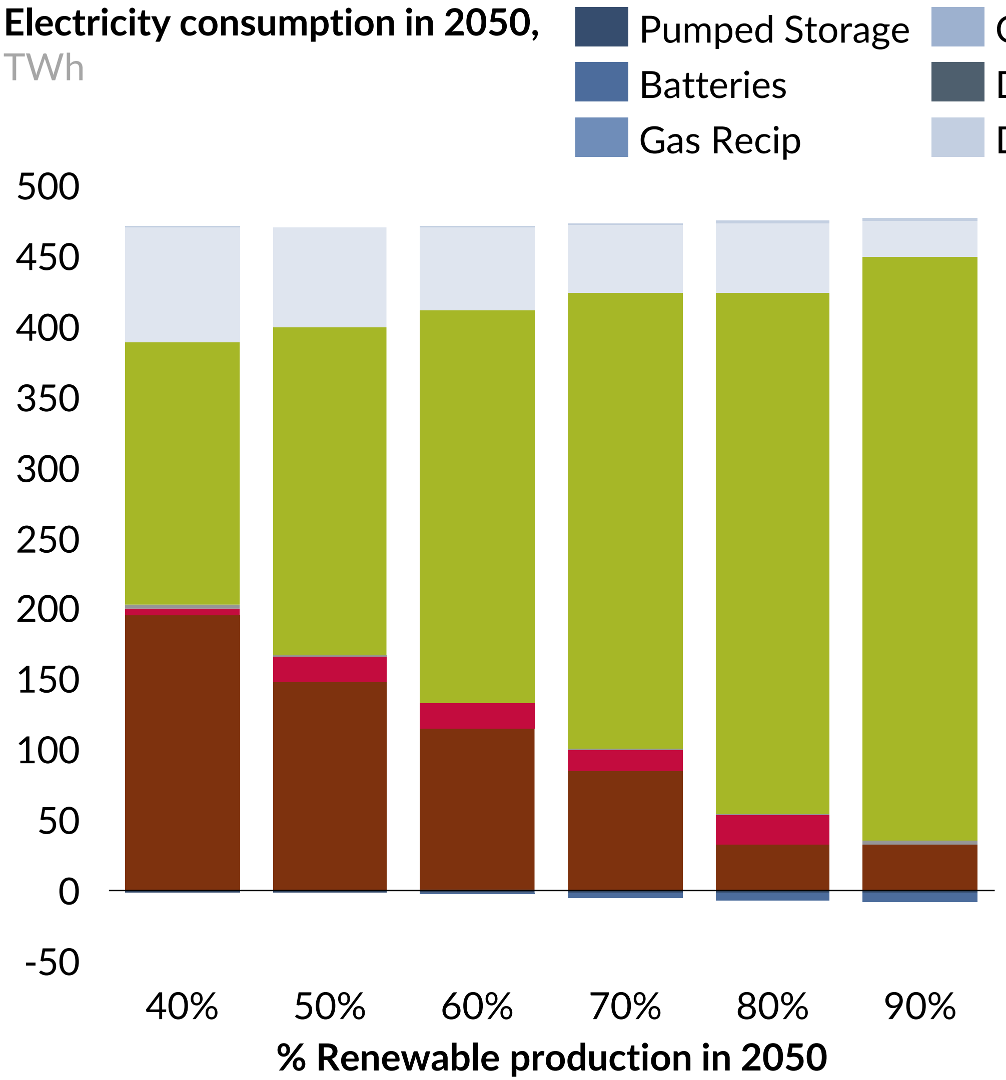


- In a world where heating is based on hydrogen/greener gas rather than electricity, both peak and average electricity demand is lower
- This means less generation capacity is needed to meet supply, which leads to lower power system costs

Source: Aurora Energy Research

Stricter carbon targets relative to the electrification scenario lead to some substitution from conventional thermal to CCS

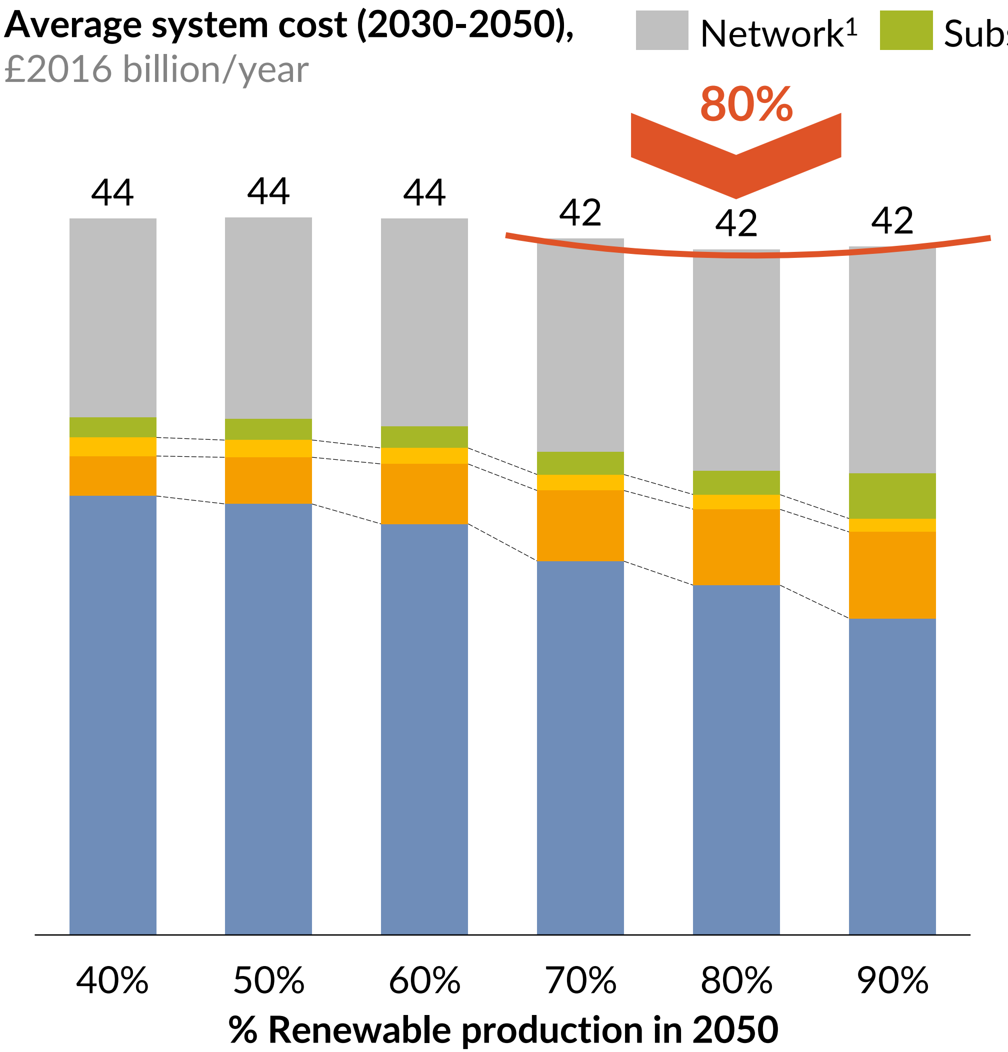
Electricity consumption in 2050, TWh



- Similar to the heat electrification scenario, there are multiple paths to meeting carbon targets, with varying levels of renewables all possible
- When renewables build-out is constrained, nuclear is the clear winner
- The more stringent carbon target in this scenario means less conventional thermal generation – some of which is replaced by CCS which provides some of the same flexibility as CCGT but with reduced emissions
- CCS becomes more viable relative to the heat electrification scenario since more stringent carbon targets lead to a higher CO2 price

Source: Aurora Energy Research

In a system with a high degree of flexibility, 80% RES becomes the cost-optimizing option

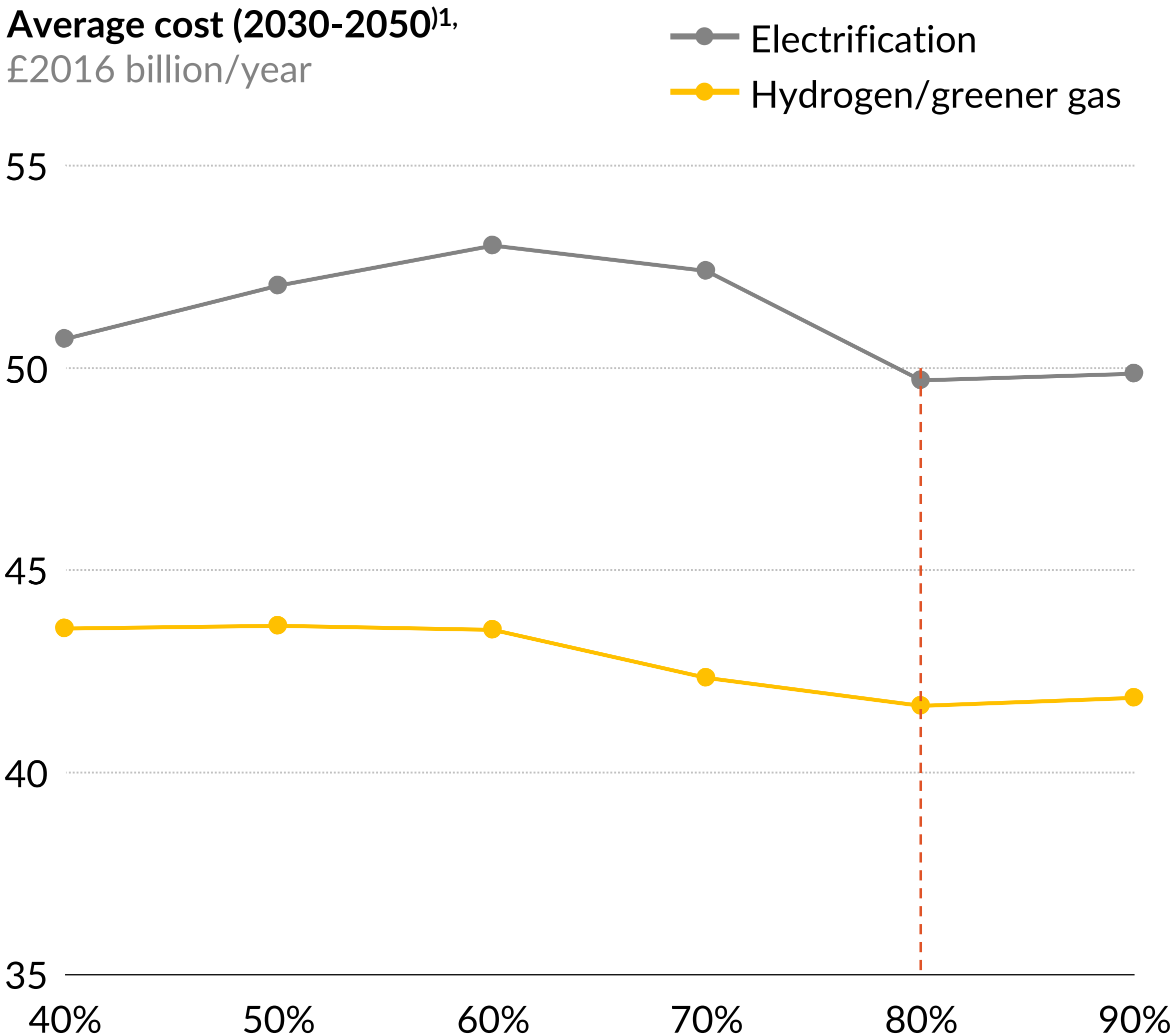


- Above around 60% RES, a balance is struck between the various components of system cost:
  - Consumers benefit from low energy prices and retail bills
  - The government benefits from low subsidy payments needed to achieve the desired level of renewables
- 80% is the optimal level of RES, though there is little to choose between 70%-90% in terms of power system costs
- While total costs are similar, moving from 70% to 90% RES increases the need for subsidies to reach the target level of renewable capacity

1. Network costs include both transmission and distribution – please see Appendix for methodology. 2. In this and all following slides, subsidy includes legacy climate costs (e.g. CfD, RO, FIT) in addition to any additional subsidies needed to reach renewable penetration target – see Appendix for methodology.

Source: Aurora Energy Research

Higher RES penetrations still lead to lower costs, though there is a greater tolerance for hybrid RES and nuclear systems



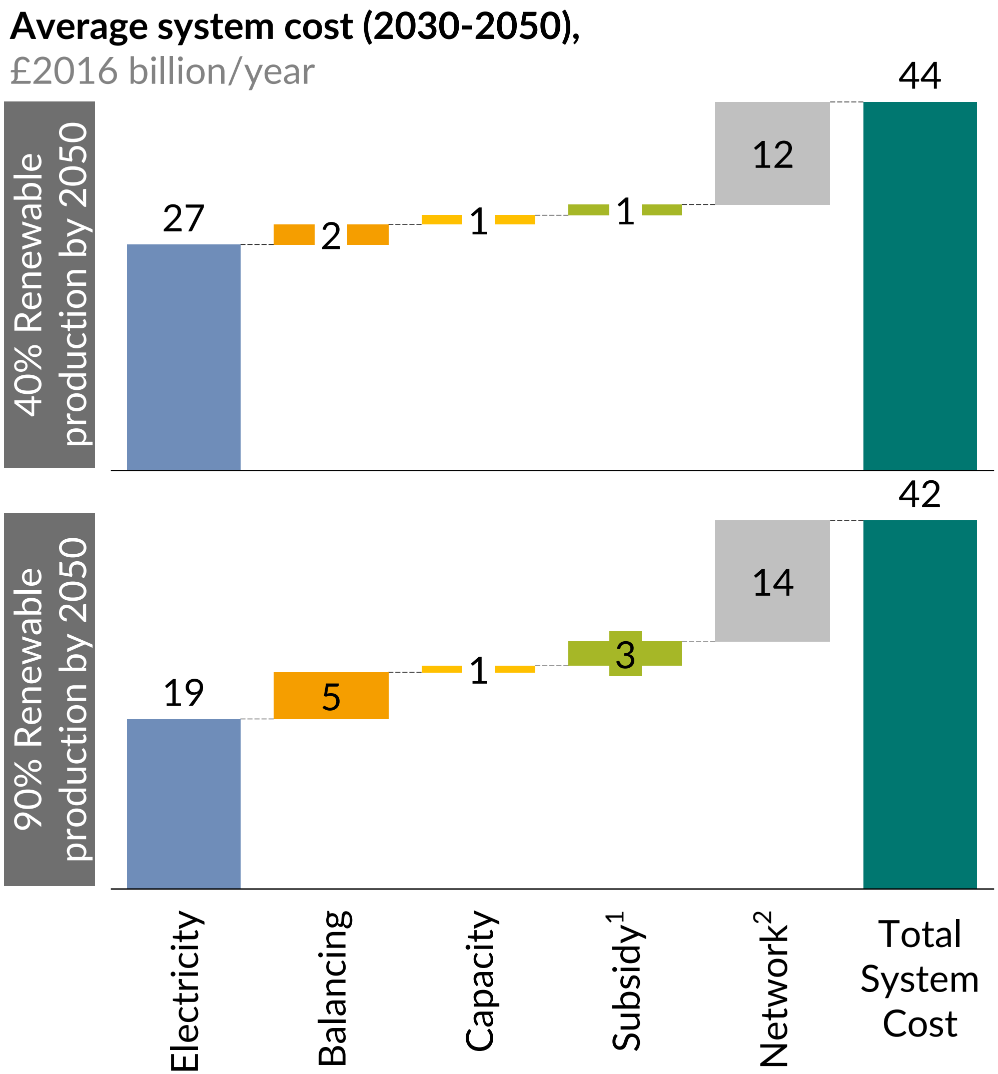
- Similar to the heat electrification scenario, 80% renewables is the cost-optimizing option
- While high RES appears to be the best option, this scenario has greater tolerance for hybrid nuclear and RES systems (50%-70% RES) which do not increase costs to the same degree as in the heat electrification scenario
- This is because the challenge of integrating renewables is easier in a hydrogen/greener gas based world because there is less wind and solar on the system in absolute terms, so it matters less that nuclear is not flexible

1. Average total system costs presented here are c. £8bn and c. £15bn more per year, for hydrogen/greener gas and electrification respectively, than current 2018 levels of £35bn.

Source: Aurora Energy Research

Scenario: Supply - anything goes, Demand - hydrogen / greener gas

Very high levels of renewables increase balancing, subsidy and network spending, but significantly cut power prices



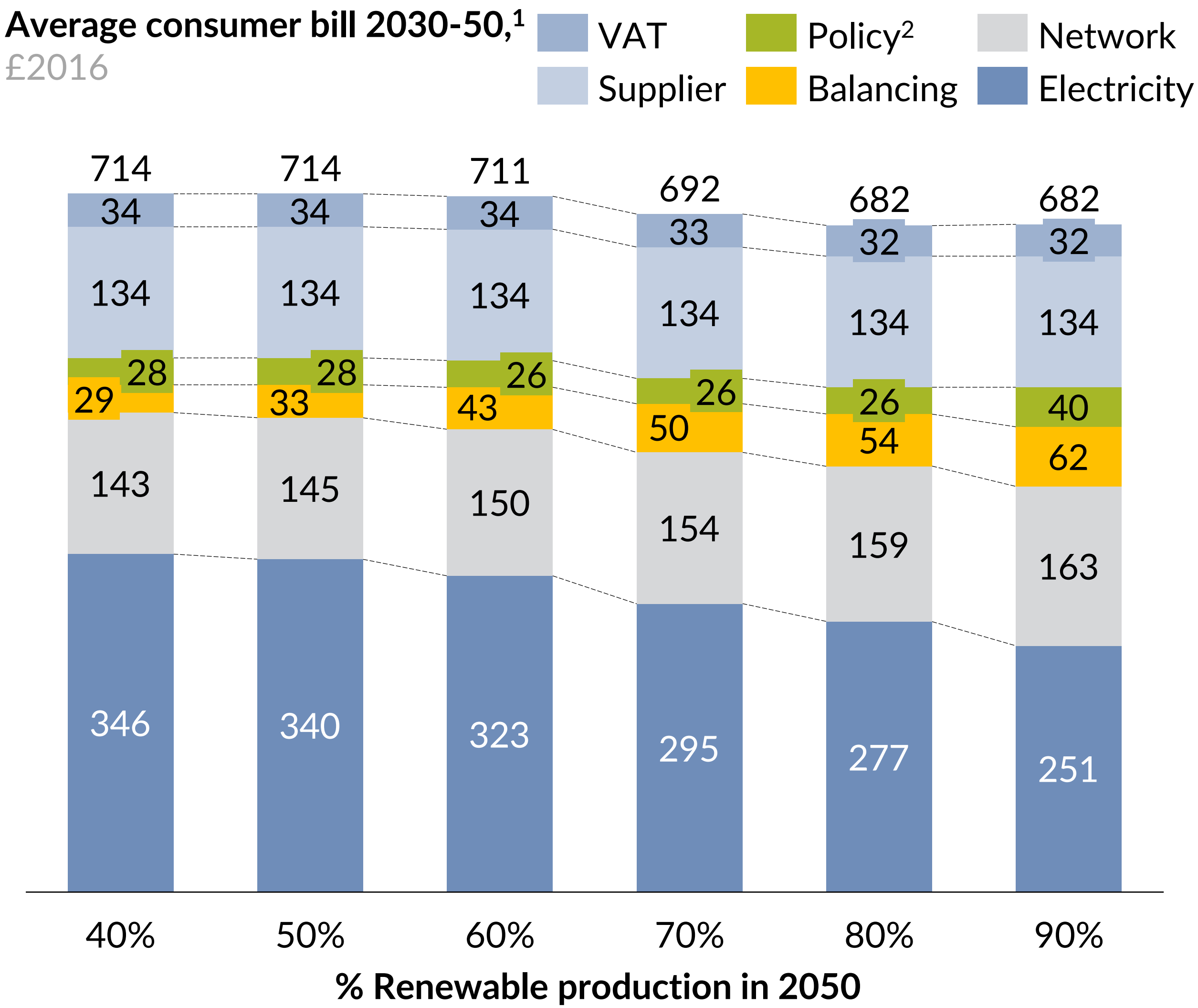
- At higher levels of renewables, an increase in network costs, balancing, and subsidy spending is more than offset by a decrease in wholesale power prices
- Very high levels of low marginal cost generation at 90% renewables significantly depress wholesale electricity prices
- This means an additional £1.5 billion per year is needed in government subsidy spending to reach the desired renewable capacity by 2050, since profits in the wholesale market are insufficient to cover costs and bring forward new projects
- Spending and balancing services and the transmission and distribution network infrastructure also increase – though not enough to offset the reduction in wholesale power prices

1. Subsidy includes legacy climate costs (e.g. CfD, RO, FIT) in addition to any additional subsidies needed to reach renewable penetration target – see Appendix for methodology 2. Network costs include transmission and distribution costs – please refer to methodology in Appendix.

Source: Aurora Energy Research

Scenario: Supply - anything goes, Demand - hydrogen / greener gas

The pathway to 80% renewable production in 2050 can save consumers £30 per year



1. For comparison, average consumer bills in 2018 are around £598 incl VAT (modelled) 2. In this and all subsequent slides related to consumer bills, "policy" includes costs related to the Capacity Market, legacy climate costs (e.g. RO, FIT and CfD) in addition to any additional subsidies needed to bring forward the required renewable capacity.

- As with heat electrification, the 80% RES system is still the most favourable in terms of consumer bills
- The greater tolerance for hybrid nuclear and RES systems leads to a smaller maximum variation in consumer bills in the hydrogen/ greener gas based heat scenario than with heat electrification of £30 per year instead of £58
- Consumers are required to pay less towards subsidising renewables. These subsidy payments do not vary drastically with %RES until very high penetrations of 90% RES require additional subsidy

Source: Aurora Energy Research

Scenario: Supply - anything goes, Demand - hydrogen / greener gas

CCS produces most of allowed emissions in the hydrogen / greener gas based heat scenario

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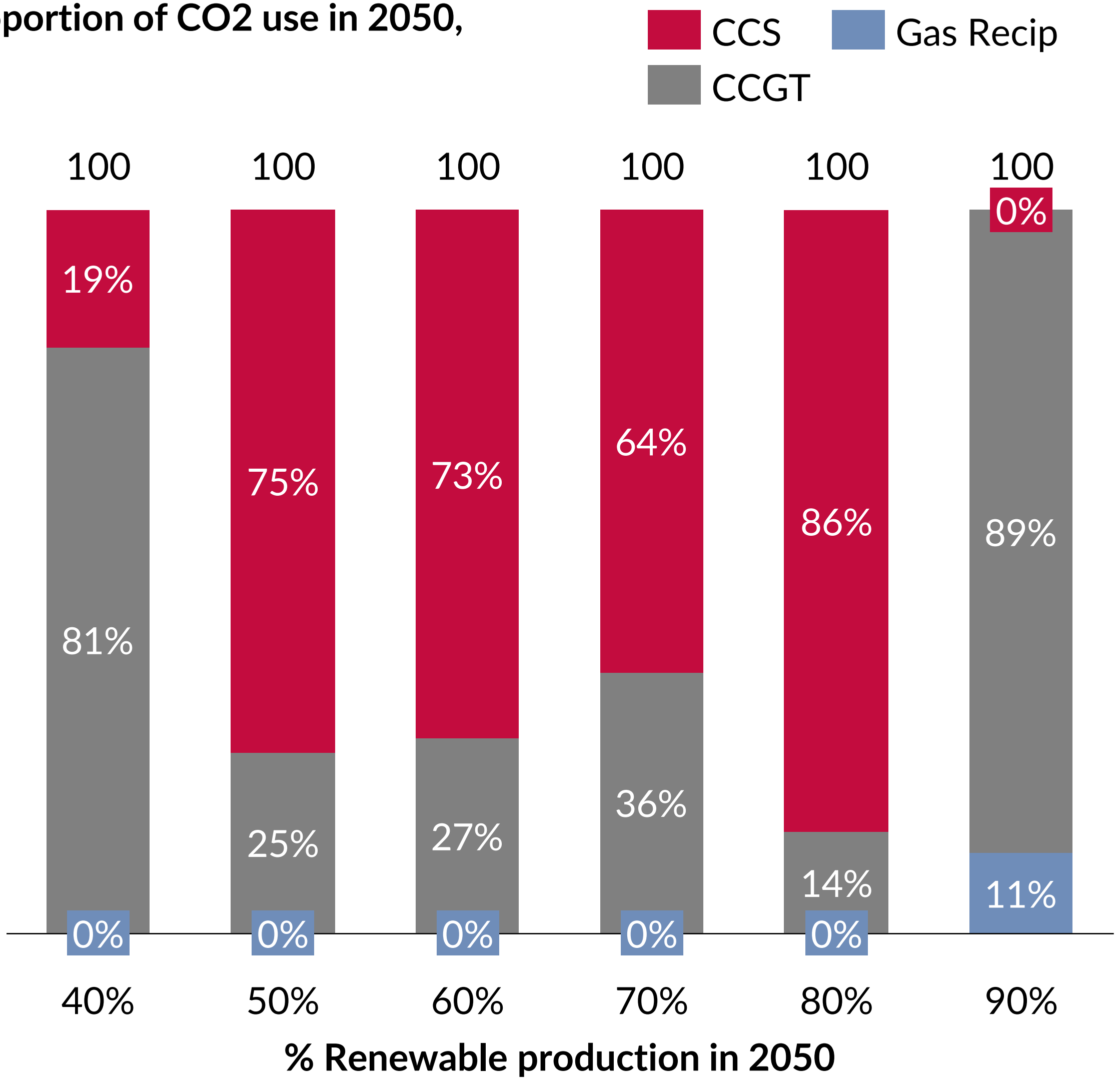
Proportion of CO2 use in 2050,
%



- The hydrogen/greener gas based heat scenario has to get close to zero emissions by 2050
- As a result, CCGT cannot play such a prominent role in the energy system and is replaced by CCS
- While an important source of low carbon baseload, the CCS capture rate of 90% means that the technology is still responsible for some emissions
- At 90% RES, gas recips are an important source of flexibility so contribute more to emissions by running for more hours

Source: Aurora Energy Research

Contents

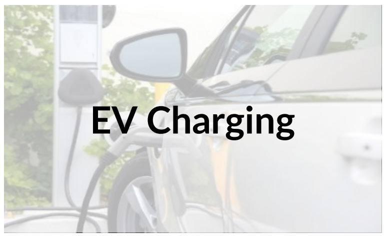
Exploring alternative policy and technology pathways can help to draw out key insights for policymakers

- The results presented so far are contingent on a number of key assumptions, notable among which are:
  - Availability of all major low carbon technologies, including nuclear
  - A high level of flexibility in the system, including 17.9 GW of interconnectors and 14 GW of DSR potential
  - Reliance on the most economic renewables, including significant amounts of onshore wind and solar
  - Smart EV charging which avoids large increases in peak demand
  - Ambitious carbon policies that differ from the current GB policy trajectory
- At the same time, there are many possible futures for the GB energy system, and exploring different pathways through alternative scenarios and sensitivities can help to draw out important insights for policymakers
- Specifically, scenario and sensitivity analysis can help to identify relatively “low regrets” options – particularly important when making decisions under a considerable degree of uncertainty

We have explored a number of alternative scenarios and sensitivities

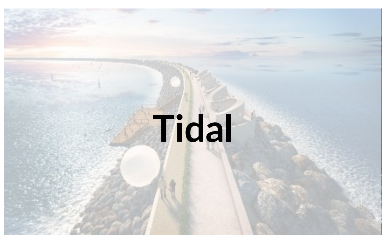
What is the impact of restricting nuclear?

How important is system flexibility?



What is the impact of less smart EV charging?

How does restricting onshore wind development impact system costs?



What is the impact of replacing cheaper renewables with tidal?

To what extent are various systems resilient to extreme stress events?

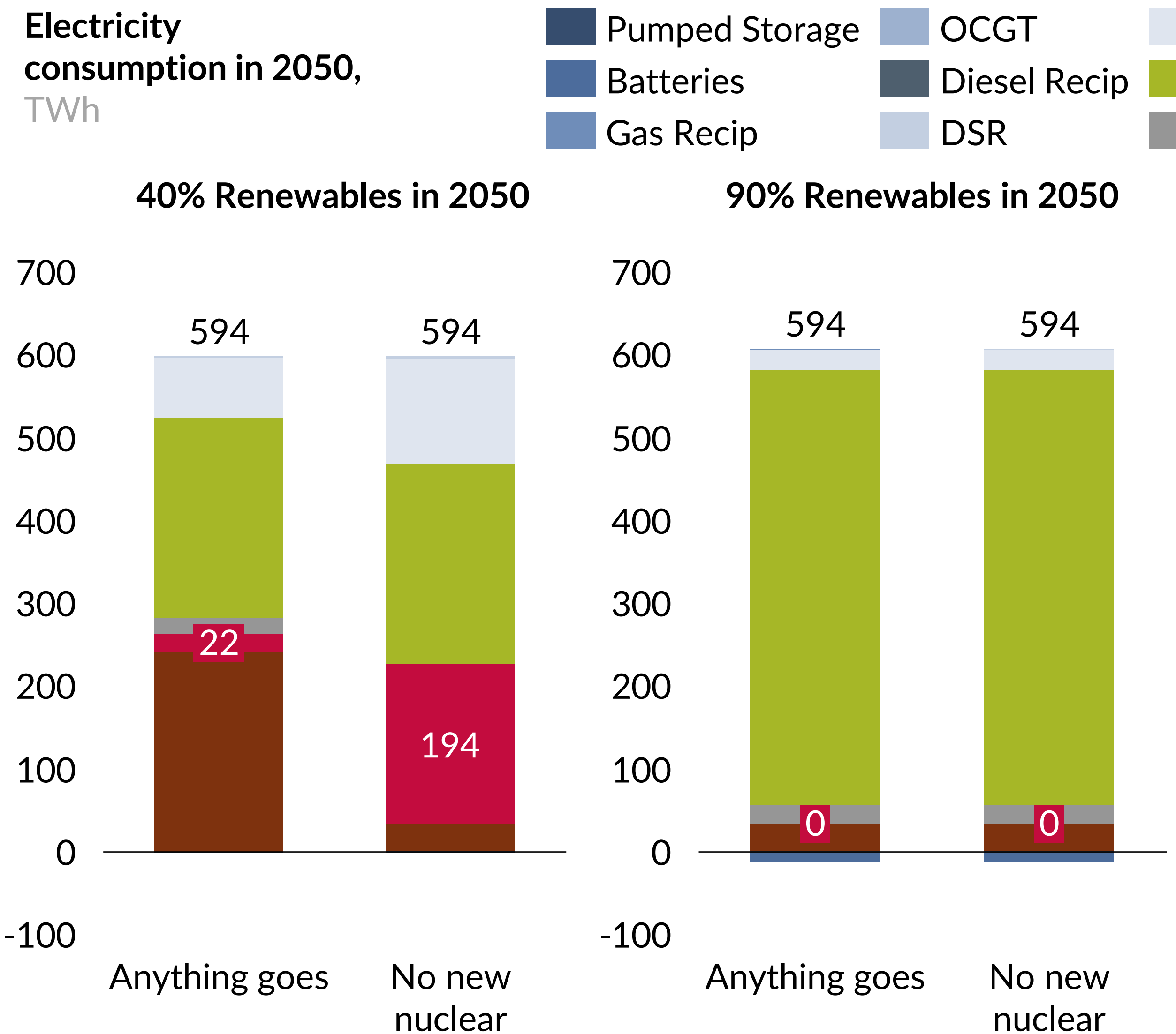
Do lower CCS costs significantly change outcomes?

What is the impact of restricting nuclear?

Lesson 1: Without nuclear, CCS becomes the main source of low carbon baseload power, increasing system costs particularly in the low renewable pathways

CCS replaces nuclear that would have entered if not for the restriction

Electricity consumption in 2050, TWh

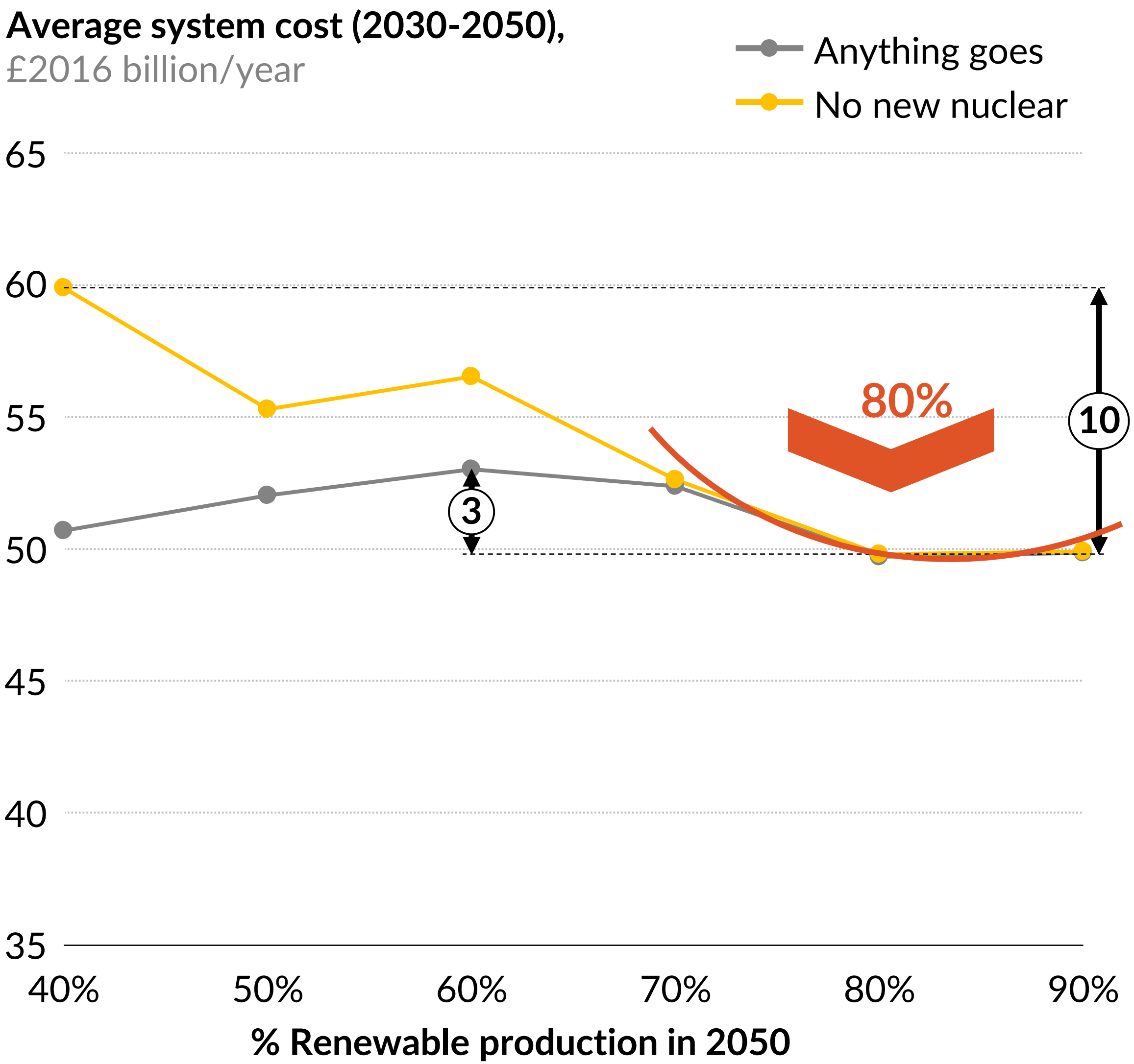


- At low levels of renewables, substantial CCS enters to replace the restricted nuclear. This is because CCS is the only low carbon technology other than renewables when new nuclear is not allowed
- Not all of the nuclear production is replaced by CCS, as interconnectors also import more due to the higher generation cost of CCS
- At high levels of renewables, no new nuclear would have resulted so CCS likewise does not play a role

Source: Aurora Energy Research

With CCS as the only alternative to renewables, cost implications of renewables becomes more significant

AURORA ENERGY RESEARCH



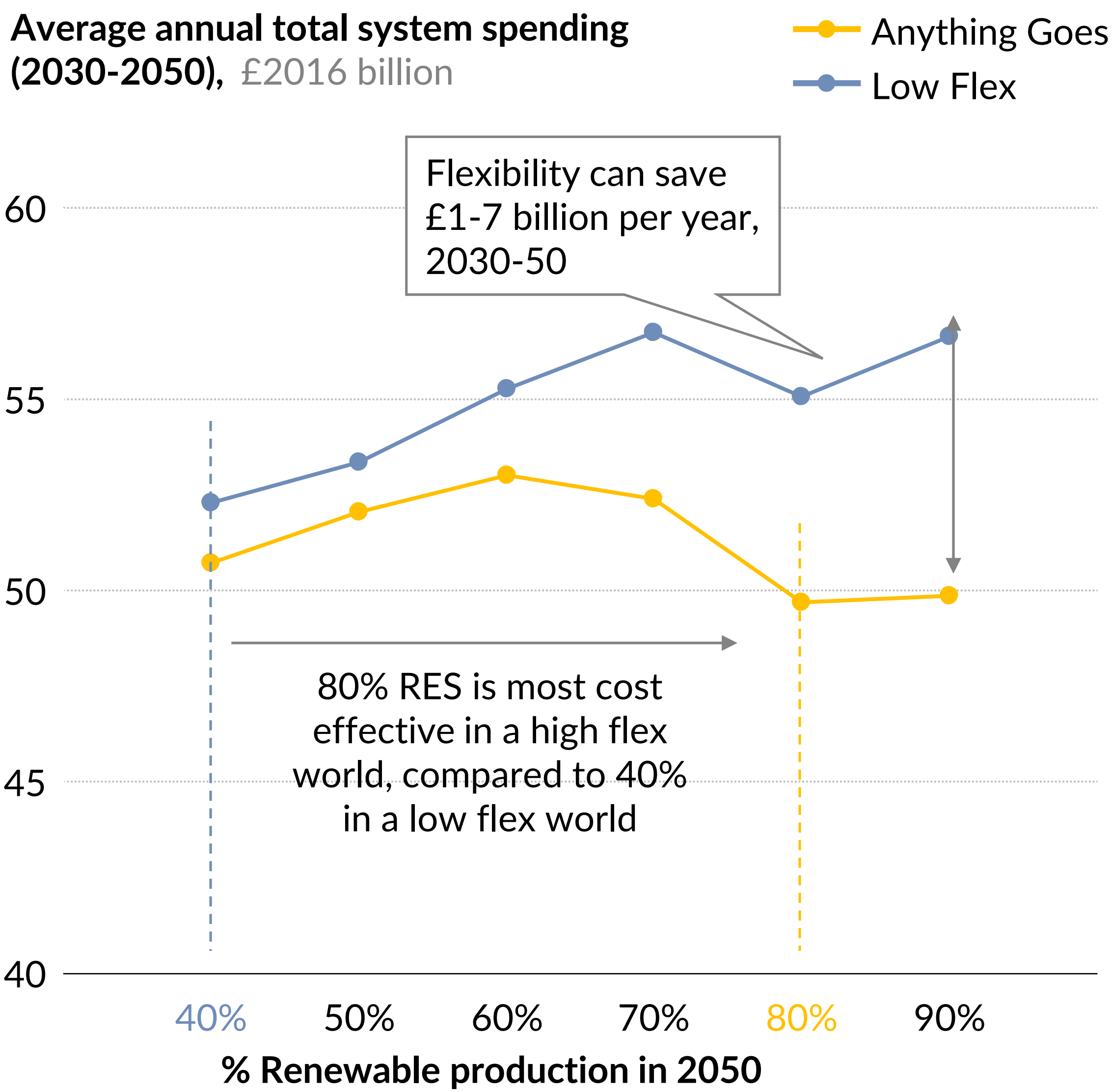
- Without new nuclear the lowest system cost level of renewables remains unchanged at 80%, as no new nuclear or CCS is required in this case
- In order to reach carbon targets at lower renewables levels, CCS must be incentivised to enter despite its higher costs
- As a result, the level of renewables has a much larger impact on system cost in the No new nuclear than in the Anything goes case

Source: Aurora Energy Research

What is the value of a flexible system?

Lesson 2: Low system flexibility makes renewables more costly to integrate and increases total system costs between £1-7 billion per year on average, 2030-50

A low flex system increases total system costs and makes renewables more costly to integrate



- Aurora explored a lower flexibility scenario including:
  - 10% higher battery costs
  - 7GW less DSR availability (compared to 14GW in anything goes scenario)
  - 8.4 GW of interconnectors (compared to 17.9 GW in anything goes scenario)
- Lower system flexibility increases total system costs, especially at higher levels of renewables penetration
- In absence of cheap flexible generation, more nuclear, CCS and thermal capacity is procured. Despite not procuring a larger total system in terms of nameplate capacity, these technologies inherently drive up costs and make carbon targets more difficult to meet
- In a low flexibility world, 40% is the optimal level of renewables on the system as opposed to 80% in a high flex world
- Flexibility has the potential to save between £1 billion and £7 billion per year on average, 2030-50

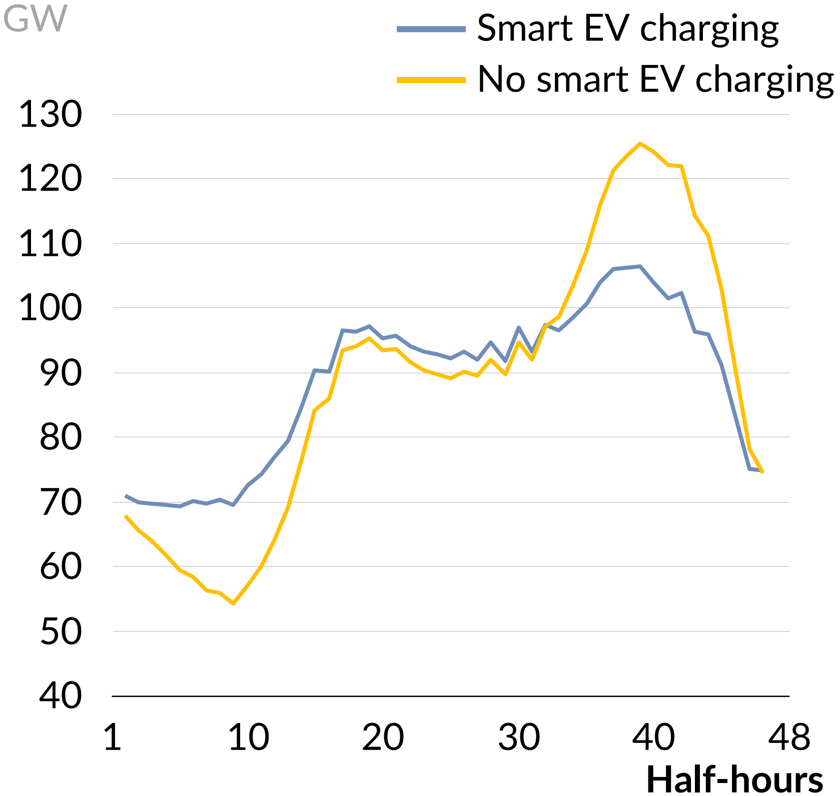
Source: Aurora Energy Research

What is the impact of less smart EV charging?

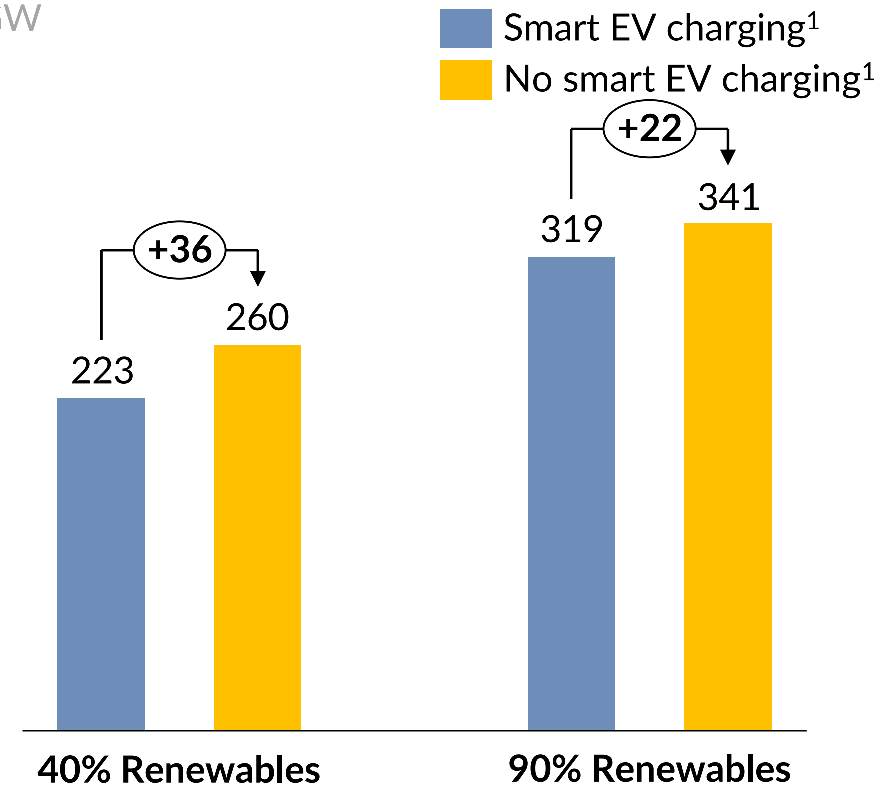
Lesson 3: Road transport electrification without policies to incentivise smart charging increases peak demand and results in higher costs to consumers

Without smart EV charging peak demand would be higher, requiring up to 36GW of additional generation capacity

Demand level, half-hourly average in Jan 2050,
GW



Nameplate capacity in 2050,
GW



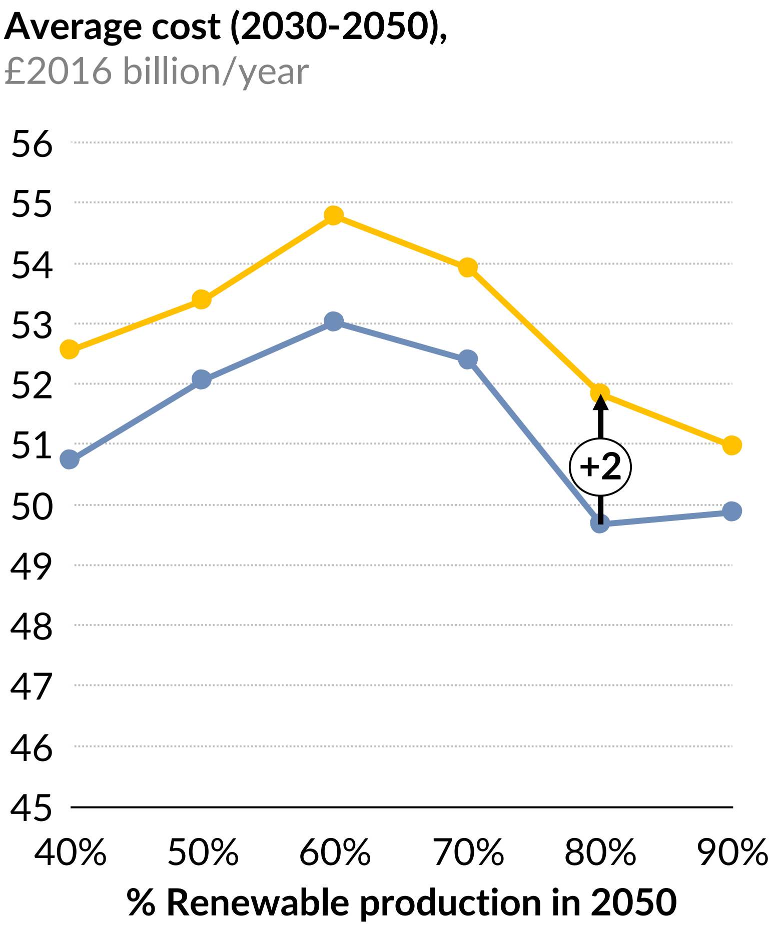
- Without smart charging, peaks and troughs of demand are more extreme.

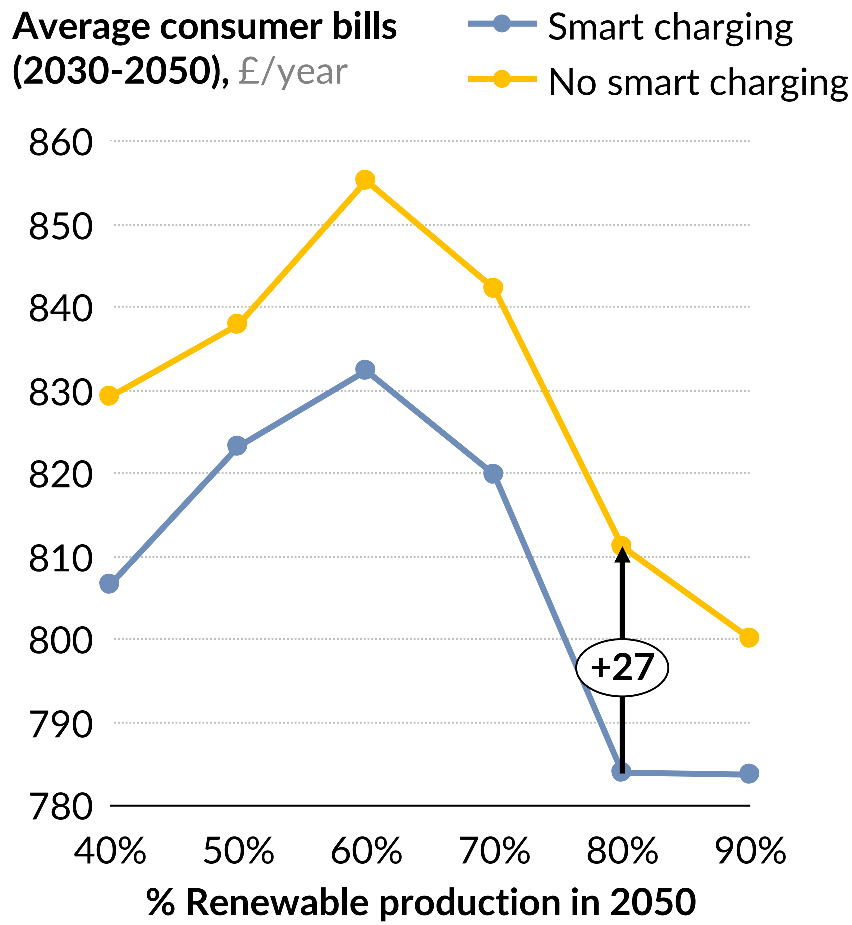
- As a result of higher demand peaks, as much as 36GW more capacity is procured in when smart charging is not available

Source: Aurora Energy Research

Scenario: Supply - anything goes, Demand – electrification, Sensitivity: Unsmart EVs

Road transport electrification without smart charging could increase costs up to £2 billion per year





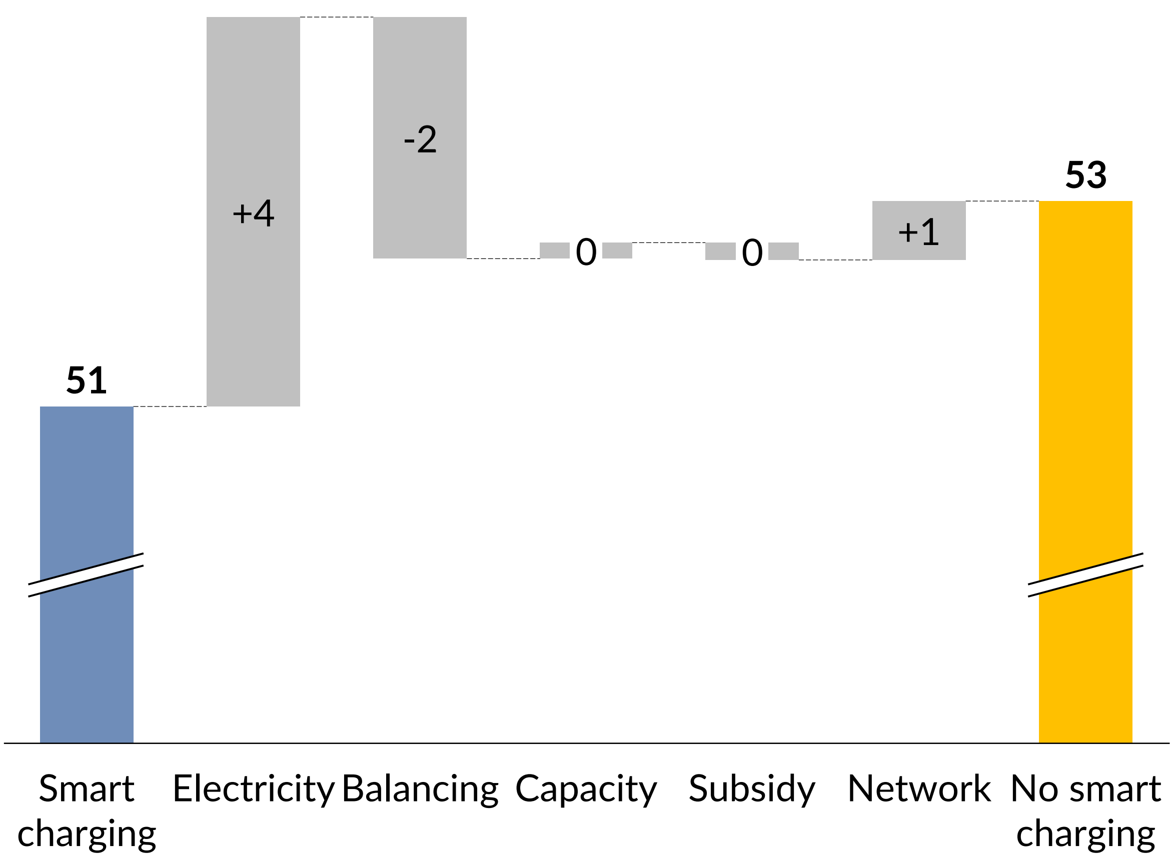
- Pursuing aggressive targets for road transport electrification without putting in place the necessary policy incentives for smart charging could increase power system costs by £2 billion per year on average (2030-50), adding up to £27 per year on average to consumer bills (2030-50)

Source: Aurora Energy Research

Wholesale power prices and network costs are the main drivers of the cost increases without smart charging

Drivers of cost increase without smart charging,

Average cost (2030-2050), £2016 billion/year[1]



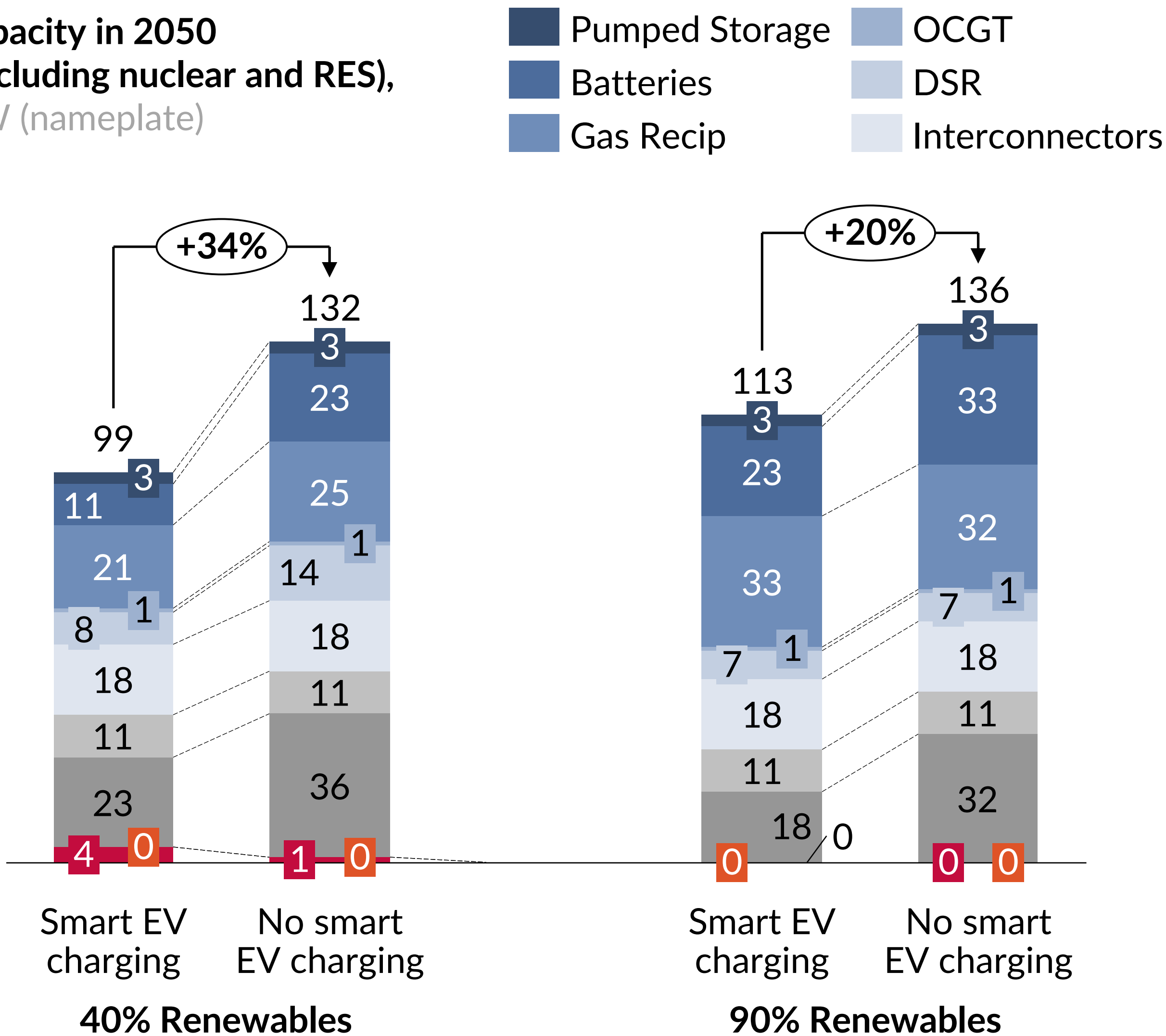
1. Costs have been averaged over all different RES penetrations levels to give a sense of the main drivers of cost increases when moving from smart to not smart charging.

- Without smart charging, peak demand increases. In all except 90% RES, this increase in demand is met in part with additional nuclear (2-4 GW), which increases the carbon price and, by extension, wholesale electricity prices
- A system with no smart charging brings forward considerably more flexible generation, including around 10GW of additional batteries across the board. This results in lower balancing costs
- One might expect capacity or subsidy spending to increase, but higher electricity prices mean that assets are able to make their required return and enter economically without the need for additional policy support
- Network costs increase as a result of the increased capacity needed to meat peak demand

Source: Aurora Energy Research

Increased peak demand leads to a large increase in flexible generation capacity

Capacity in 2050 (excluding nuclear and RES), GW (nameplate)



- The system with no smart charging brings forth as much as 13GW more thermal plants, 4GW more gas recip engines, and 12GW more batteries. This provides substantial generation flexibility to the system
- The lack of smart charging does not increase total demand, only peak demand. The additional capacity have low running hours as they only run a few hours in the winter peaks

Source: Aurora Energy Research

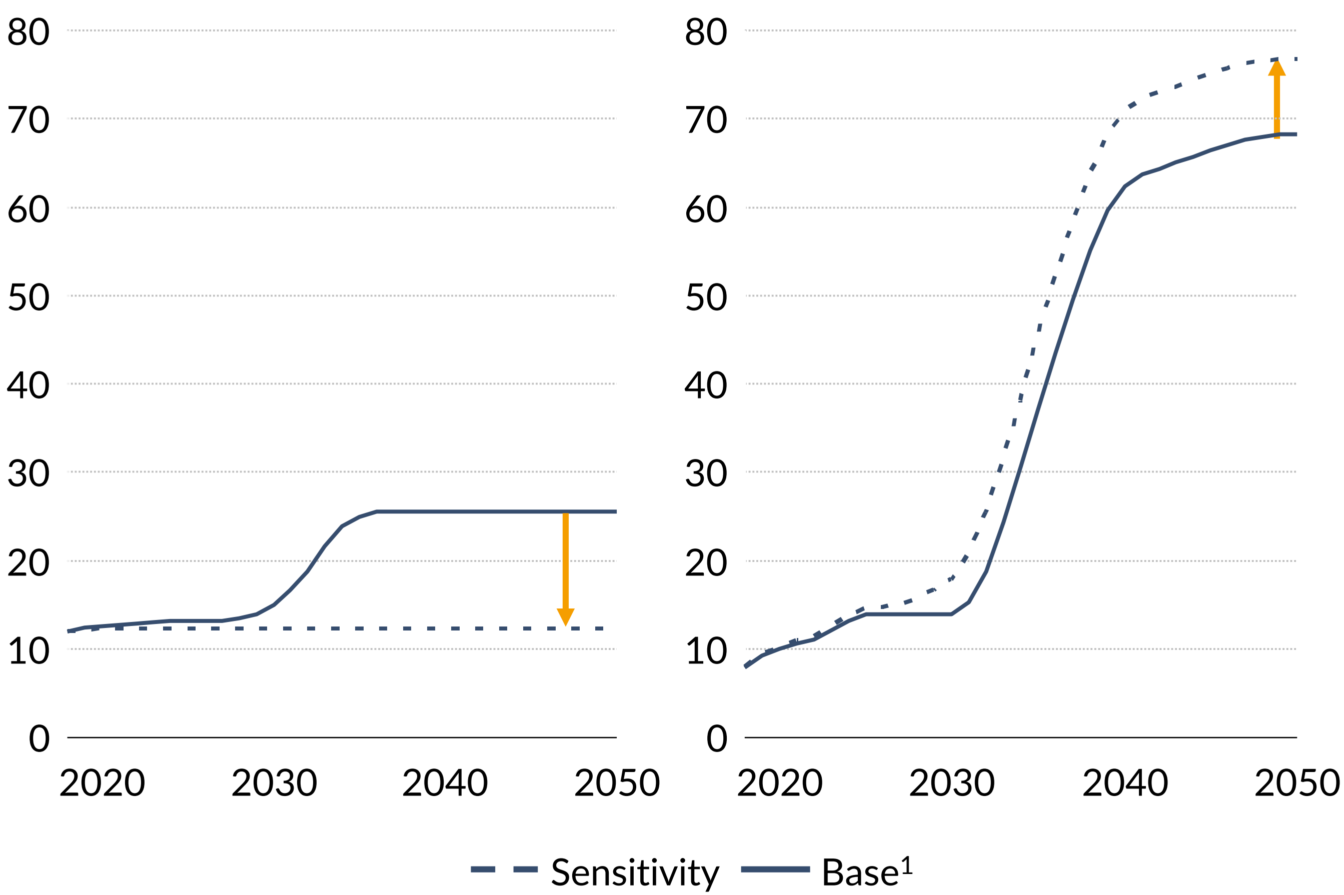
What is the impact of limiting new build onshore wine?

Lesson 4: Limiting new build onshore wind in favour of offshore has a limited impact on consumer bills, but important implications for government subsidy spending

We ran a scenario to explore the impact of limiting new onshore wind build

Onshore capacity, GW (nameplate)

Offshore capacity, GW (nameplate)



- Aurora endogenous modelling of renewables indicates that onshore wind is among the most economically viable renewable technologies
- However, onshore wind is currently excluded from participating in CfD auctions.[2]
- This sensitivity explores the implication of this policy on total system cost and consumer bills by preventing any new build onshore wind other than projects already in the pipeline and replacing it with offshore

1. Based on 90% RES from the supply/demand scenario: anything goes & electrification of heat. 2. Recent pronouncements may indicate the early stages of a change in direction for government policy

Source: Aurora Energy Research

Limiting onshore wind could increase government subsidy spending by £0.5bn p.a. until 2035

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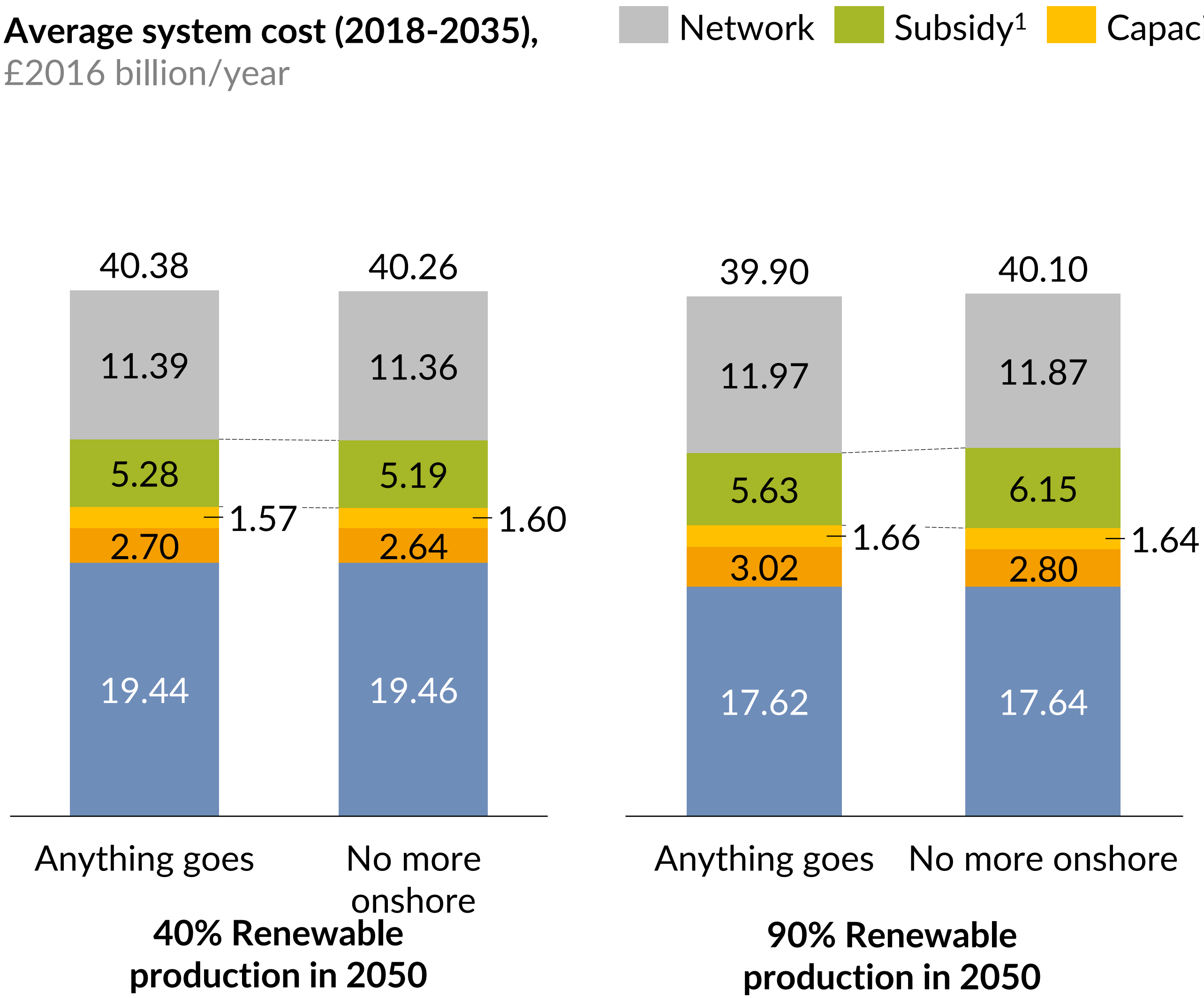
Average system cost (2018-2035), £2016 billion/year



- While offshore wind is more expensive than onshore wind, higher per MW costs are largely offset at the system level by lower balancing and network costs
- Still, limiting onshore wind could increase total system costs by up to £0.2bn/year at higher RES penetrations
- The result is a limited (<£1/year) impact on consumer bills, but significant implications for government subsidy spending
- Replacing onshore wind with offshore wine would require Government to spend an additional ~£0.5 billion per year

1. Subsidy includes legacy climate costs (e.g. CfD, RO, FIT) in addition to any additional subsidies needed to reach renewable penetration target

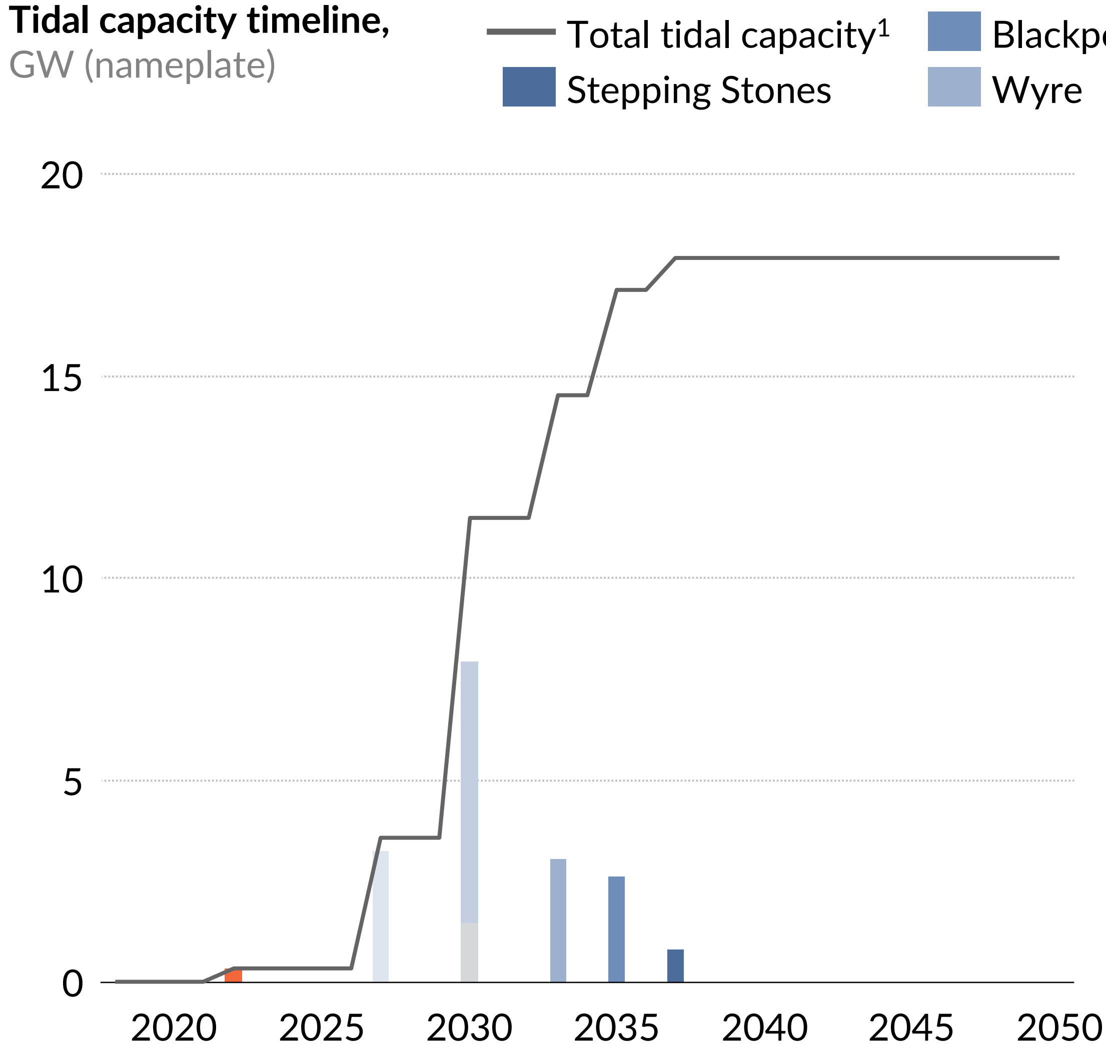
Source: Aurora Energy Research

What is the impact of replacing cheaper renewables with tidal?

Lesson 5: Meeting carbon targets with tidal power could cost the government up to £2bn a year in subsidy spending

We explore the impact of tidal playing a much greater role in meeting GB carbon targets

Tidal capacity timeline, GW (nameplate)

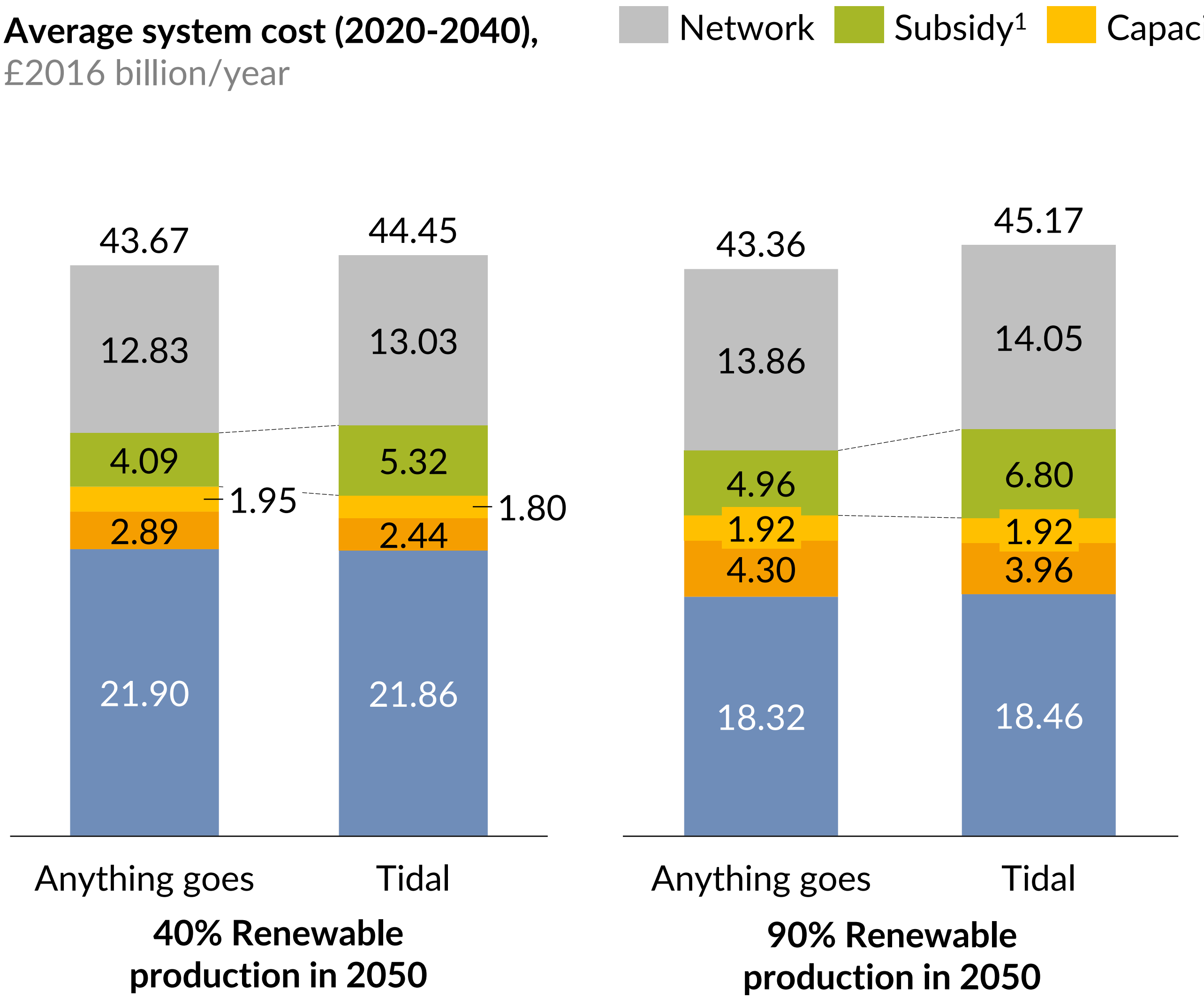


- No tidal power entered economically in any endogenous model run
- However, tidal power offers another alternative source of low carbon power to help meet GB 2050 targets
- For this sensitivity, we assumed all tidal projects highlighted in the Hendry review get built, displacing offshore wind, and seek to examine the impact on total system costs

Source: NIC, Aurora Energy Research

Replacing cheaper renewables with tidal power drives up total system costs due to additional required subsidy support

Average system cost (2020-2040), £2016 billion/year



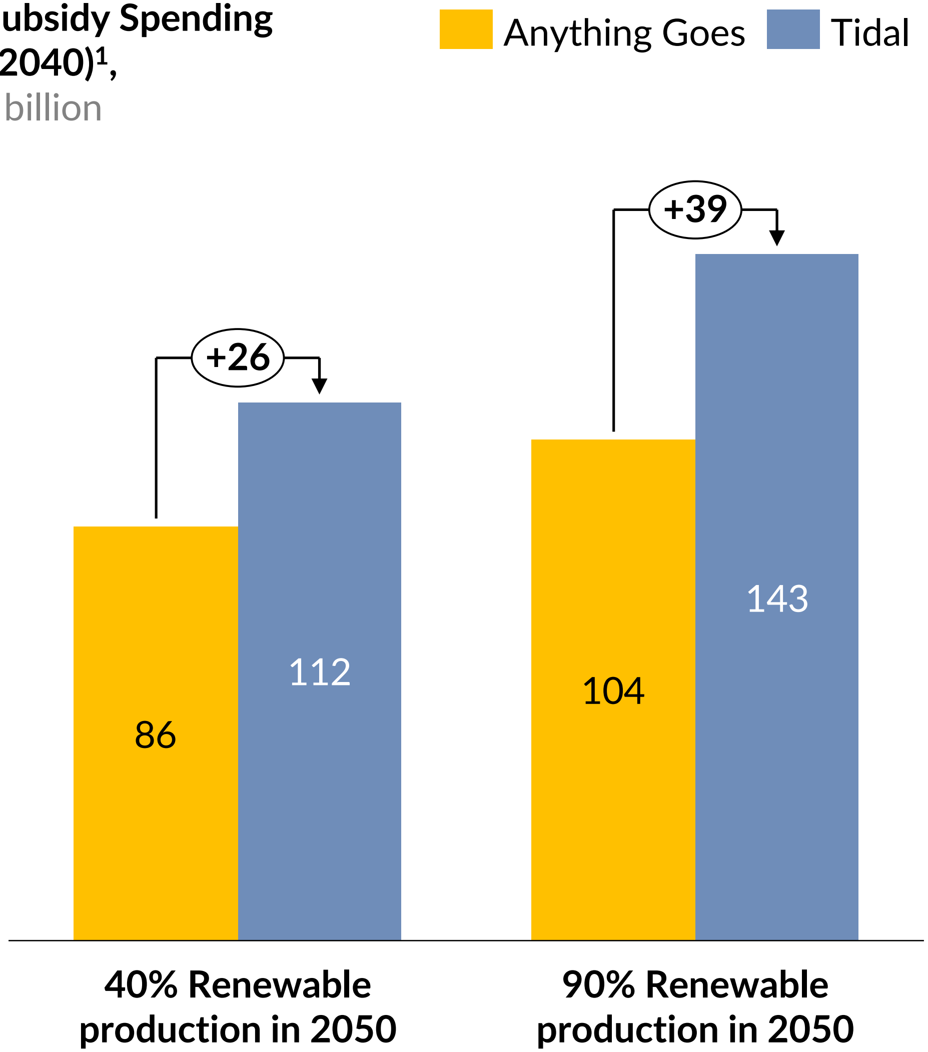
- Tidal generation is inherently more predictable than onshore wind, reducing the need for balancing services in both cases
- Reductions in balancing costs are not enough to offset the additional subsidy spending of £1-2bn p.a. required for tidal projects to break even
- The observed increase in total system costs has a direct, negative impact on consumer bills which increase by an average of £10 and £24 p.a. at 40% and 90% RES respectively

1. Subsidy includes legacy climate costs (e.g. CfD, RO, FIT) in addition to any additional subsidies needed to reach renewable penetration target

Source: Aurora Energy Research

Meeting carbon targets with tidal increases government subsidy spending by up to £2bn/year, 2020-40

Total Subsidy Spending (2020-2040)[1],
£2016 billion



1. Subsidy spending includes RO, FiT, CfD spending plus any additional subsidy required for power plants to be economic.

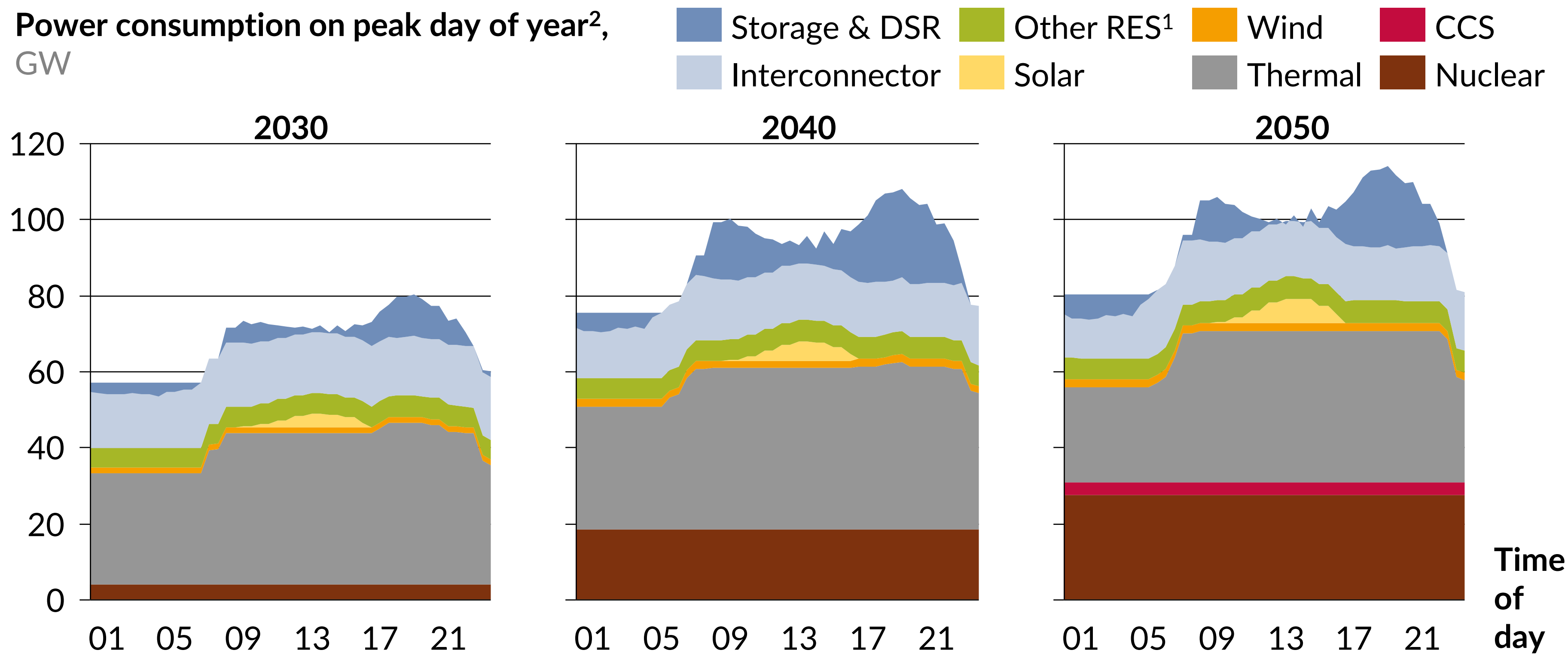
- Replacing offshore wind with tidal is a more costly way for government to meet carbon targets
- Offshore wind becomes economic in 2030s without subsidies, tidal never becomes competitive without government support
- Consequently, additional government subsidies are required to procure the same amount of low carbon generation with tidal rather than offshore
- Whilst tidal can be considered a more predictable source of generation than offshore wind, it adds additional constraints to the system as it is only able to generate power at fixed times of the day. This leads to low load factors and 10.2 GW more tidal capacity to generate the same amount of electricity as the displaced offshore wind
- Greater thermal and baseload capacity is needed when offshore wind is replaced with tidal

How resilient are different technology pathways?

Lesson 6: Very high renewable systems may be more vulnerable to extreme winter system stress events

A system with 40% RES is resilient to an extreme winter stress event in all years without loss of load

Power consumption on peak day of year[2], GW



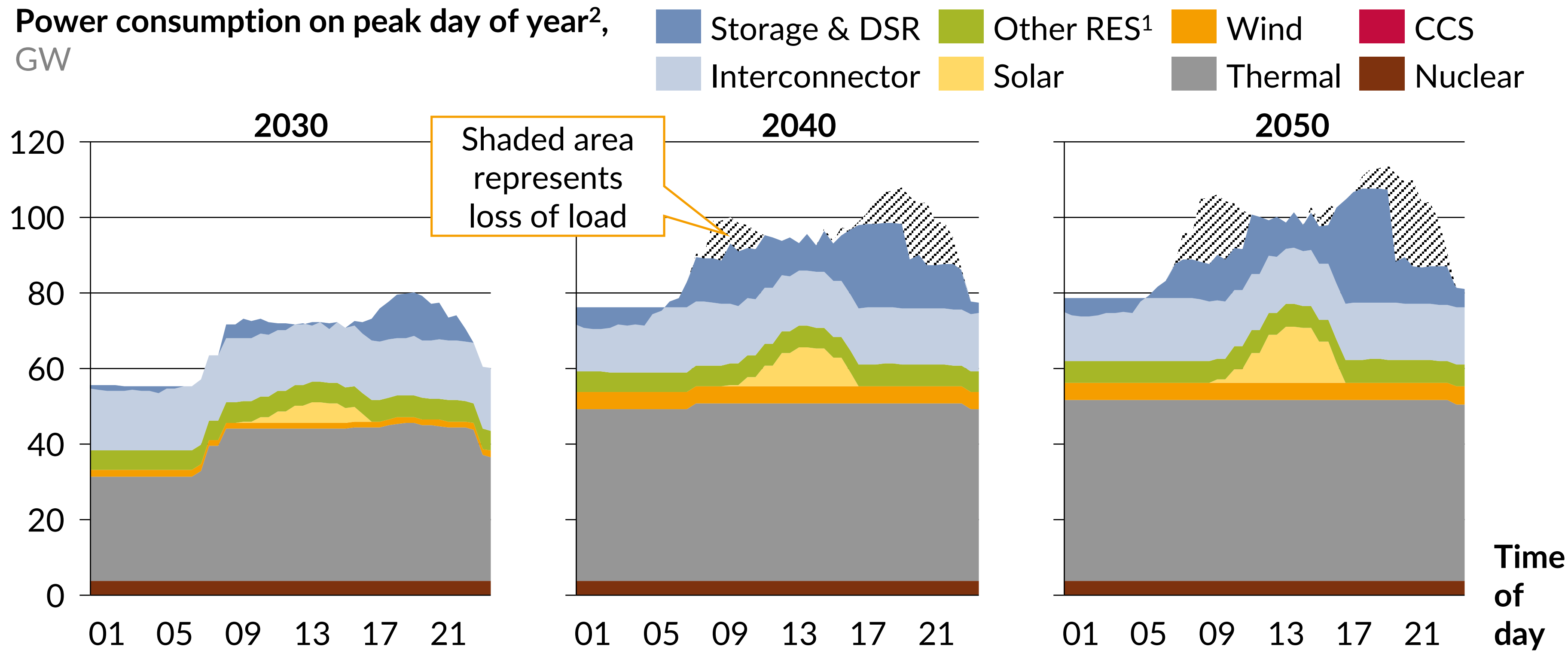
- Aurora modelled an extreme winter stress event with a ~5GW increase in demand and a 5% cap on onshore and offshore wind load factors (based on analysis, 95% confidence interval)
- In the 40% RES scenario, the generation mix is sufficiently robust to meet peak demand during the stress event without loss of load
- Flexible technologies like interconnectors, storage, and DSR play a big role in meeting the peak
- While thermal load factors are low most of the year due to carbon constraints they play an important role in meeting demand during a stress event e.g. average CCGT load factor in 2050 is just 10% but in the stress event it meets 17% of demand

1. Other RES includes biomass and hydropower; wind includes both onshore and offshore; thermal includes CCGT, reciprocating engines, and OCGT; CCS includes gas and bio CCS; interconnectors refers to net imports. 2. Results based on the supply/demand scenario: 40% RES, Anything goes & electrification of heat

Source: Aurora Energy Research

A system with 90% RES may experience loss of load in an extreme winter stress event

Power consumption on peak day of year[2], GW



- In the 90% RES scenario, there is less dispatchable technology capable of meeting the extreme stress event when wind load factors are limited to 5%
- In particular, there is less nuclear or CCS able to contribute to meeting the peak relative to in a 40% RES world
- Despite 17.9 GW of interconnectors, imports are fundamentally limited by what is happening in other countries. It is not unlikely that there would be some international correlation of weather-related stress events.
- More work is needed to test the resilience of systems with different levels of renewables to a extreme stress events and their cost implications. In theory it would be possible to set procurement targets high enough to ensure no loss of load during such events, though this is not likely to be something the system operator would consider since it is unlikely to be cost effective.

1. Other RES includes biomass and hydropower; wind includes both onshore and offshore; thermal includes CCGT, reciprocating engines, and OCGT; CCS includes gas and bio CCS; interconnectors refers to net imports. 2. Results based on the supply/demand scenario: 90% RES Anything goes & electrification of heat

Source: Aurora Energy Research

Do more optimistic CCS cost assumptions lead to more build out?

Lesson 7: Reducing CCS transport and storage costs brings in more gas CCS earlier, though capacity is limited by strict emissions targets

Optimistic CCS costs lead to 12GW more CCS capacity by 2050 as it competes with nuclear

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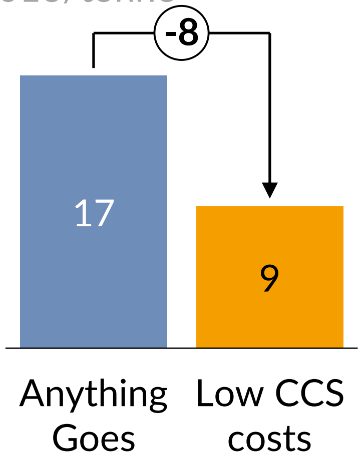
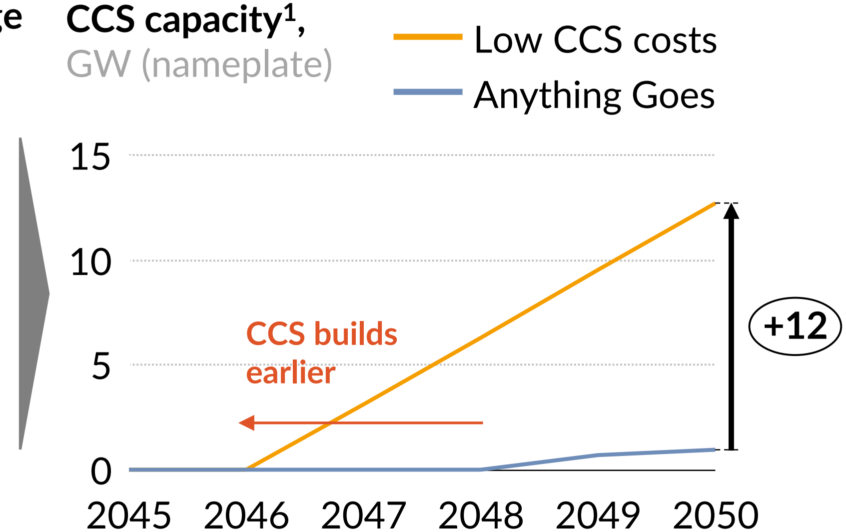
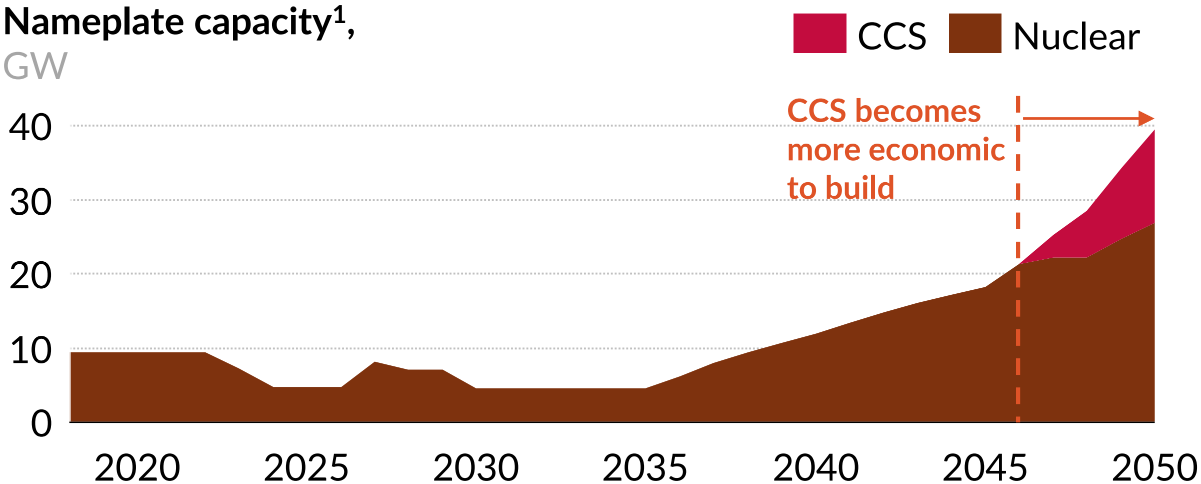
CO2 transport and storage costs,
£2016/tonne



CCS capacity[1],
GW (nameplate)



Nameplate capacity[1],
GW



1. Results presented for 40% RES production by 2050

- Reducing CO2 transport and storage costs by almost 50%, by considering infrastructure sharing with heat gasification, allows CCS to become cost competitive with nuclear earlier in the 2040s
- CCS capacity is seen to double in some scenarios, however total capacity is still relatively small due to the strict carbon targets that must be met by 2050
- This sensitivity has a negligible effect on total system costs
- Whilst able to reduce CO2 emissions of a plant, CCS still has associated CO2 emissions. Strict carbon targets of 1MTCO2e therefore inherently limit the long term value of CCS in the energy market

Source: Aurora Energy Research

Contents

Conclusion

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Challenge for the future

- The GB power market will require significant changes from the current generation mix to reach its 2050 carbon targets of near zero emissions
- EVs and heat electrification could increase electricity demand by as much as 65% over the next three decades

Policy lessons

- Under a flexible system, increasing renewables up to 70-80% of generation delivers the lowest system cost pathway, costing up to £3bn/year less than lower renewables pathways
- However, flexibility matters to the cost of integrating renewables. A system bound by carbon targets, with fewer interconnectors, DSR and batteries would see 40% renewables as the lowest system cost pathway
- Nuclear is the lowest cost alternative to renewables; CCS only enters if nuclear is restricted, increasing the cost savings from higher renewables
- A high renewables pathway risks loss of load in extreme weather stress events, although system costs calculations already include the cost of such occurrences

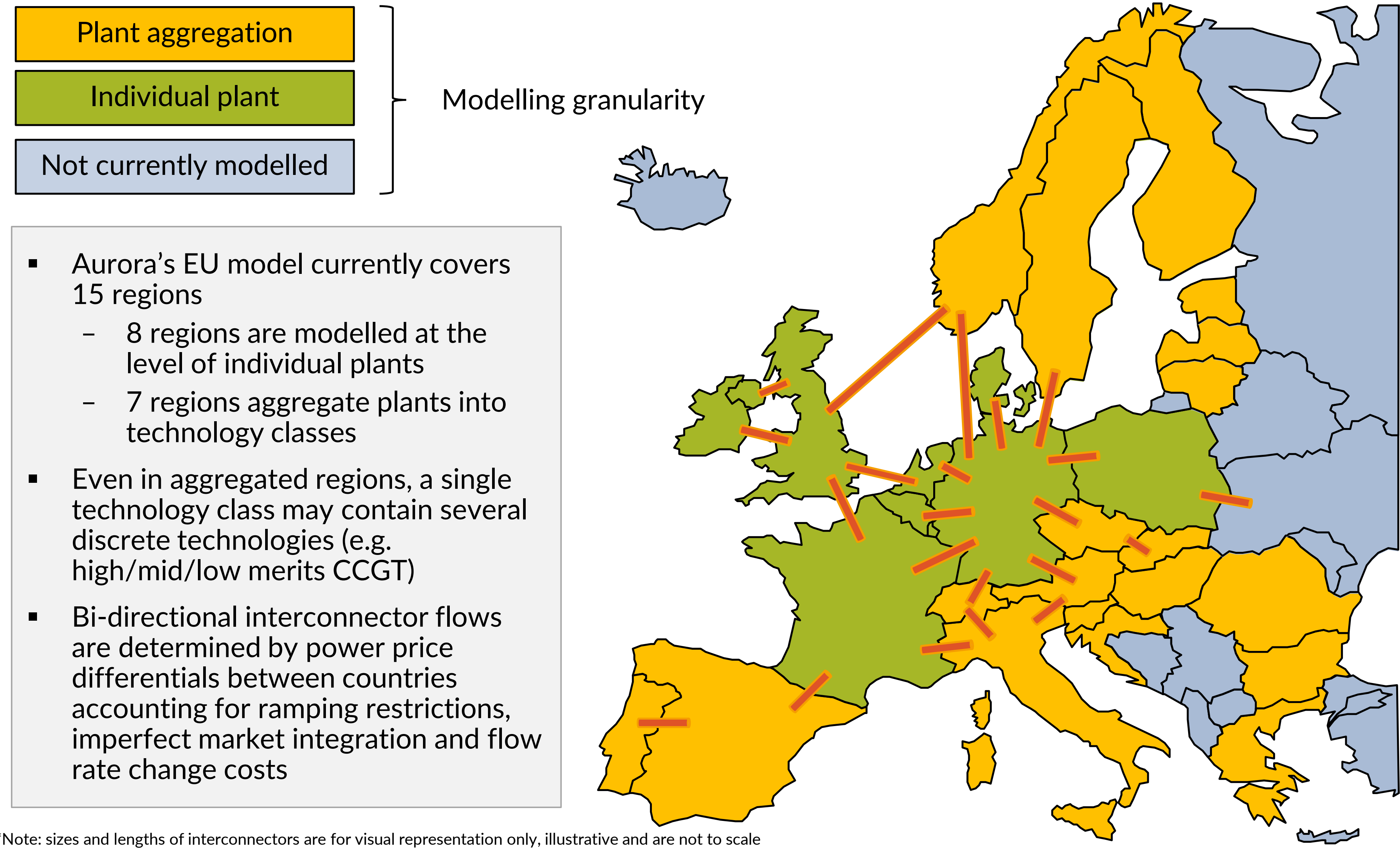
Technology lessons

- Amongst renewables, solar PV, onshore wind and offshore wind are the main sources of new renewables to enter economically under a carbon target. Building Tidal power requires a subsidy, but the impact on total system cost is minimal
- Large amounts of flexible capacity, including DSR, batteries and gas reciprocating engines, are required with increasing levels of renewables
- Smart EV charging reduces the capacity required of the power sector and can save consumers £28/year on average. A lack of smart EV charging can increase total system costs by £2bn/year.

Contents

Appendix i: Modelling Methodology

We model the whole of Europe in an integrated manner



- Aurora's EU model currently covers 15 regions
  - 8 regions are modelled at the level of individual plants
  - 7 regions aggregate plants into technology classes
- Even in aggregated regions, a single technology class may contain several discrete technologies (e.g. high/mid/low merits CCGT)
- Bi-directional interconnector flows are determined by power price differentials between countries accounting for ramping restrictions, imperfect market integration and flow rate change costs

*Note: sizes and lengths of interconnectors are for visual representation only, illustrative and are not to scale

Source: Aurora Energy Research

The model iterates between dispatch and investment decision modules to find an equilibrium set of prices and capacities such that all market participants make their required return

1

Input

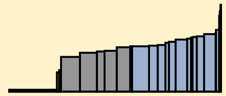
- **Technology** assumptions (plant parameters)
- **Policy** assumptions (e.g. renewables subsidies, CO_2 prices)
- **Demand** assumptions (based on in-house analysis on the effect of EVs)
- **Commodity price** assumptions (based on in-house AER-GLO model)

2

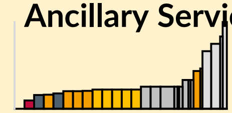
Time horizon: 2018 - 2050

Dispatch module (on an hourly/half-hourly basis)

Wholesale market



Balancing Mechanism/ Ancillary Services



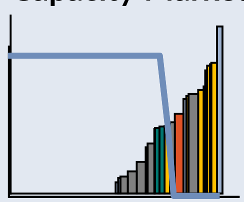
- **Dynamic dispatch** of plant, considering ramping costs and rate restrictions, and availability of plants and individual generators to form the supply stack
- **Endogenous interconnector flows** according to estimated gradient between domestic and foreign electricity spot prices
- **Iterative modelling** between wholesale and balancing markets

Iterations across modules to
- reach equilibrium solution
- ensure internal modelling consistency

3

Investment decision module (on an annual basis)

Capacity Market



- **Detailed modelling of the Capacity Market** mechanism and associated bid levels/clearing prices
- **Forecasts investor behaviour** for correct entry/exit of plants based on modelling of future cash flows
- **Entry and exit of technologies modelled endogenously**, not assumed

4

Output

- **Capacity mix** (New build entry and exit decisions)
- **Generation mix** (at technology/plant level)
- **Wholesale & imbalance prices** (half-hourly granularity)
- **Capacity Market prices**
- **Profit & loss and NPV for modelled technologies**

Source: Aurora Energy Research

Input assumptions include technology, policy, demand and commodity prices

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1 **Input** → Dispatch module / Investment decision module → Output

Technology assumptions

- Plant efficiencies (incl. efficiency improvement over time)
- Plant availabilities
- Plant costs: fixed & variable O&M costs, capex, refurbishment cost, mothballing cost
- Ramping costs and speeds
- Subsidised/un-subsidised mode of dispatch
- Discount rate by revenue stream (for NPV calculation
- (other technical parameters)

Policy assumptions

- Carbon cost regime (e.g. Carbon Price Support in GB)
- Mandated plant closure (e.g. coal)
- Renewables outlook based on RO/FiT/CfD support schemes
- (other policy parameters)

Demand assumptions

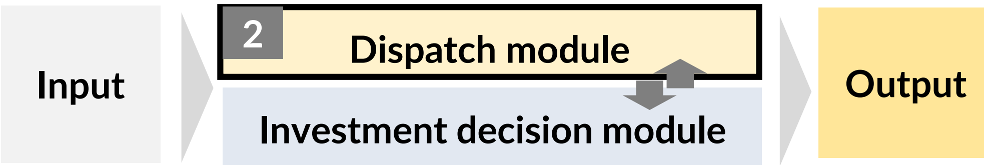
- Annual demand time series, which is processed into half hourly data including noise as a proxy for stochastic availability
- Number of EVs and heat pumps, also processed to half hourly profile

Commodity price assumptions

- Coal price forecast
- Gas price forecast
- EU-ETS price forecast
- Commodity prices are typically derived from separate Aurora CGE modelling, though can also be user-defined

Source: Aurora Energy Research

Based on user-defined inputs, the dispatch model optimizes plant behaviour to minimize costs



- Regional dispatch is optimized to minimize costs while accounting for:
  - Gross production and demand, including losses
  - Interconnector imports and exports
  - Ramping constraints
  - Loss of load
  - Spilled power
  - Plant availability and outages
  - Any additional user-defined constraints (e.g. emissions)
- Costs include
  - Capex, fixed and variable
  - Ramping
  - Spill and loss of load
  - Mothballing and refurbishment

Source: Aurora Energy Research

Our dispatch module includes a fundamentals-based balancing mechanism module

Input | 2 Dispatch module / Investment decision module | Output

1 Demand: Net imbalance volume

- Aurora uses a statistical regression model to understand main drivers of net imbalance volume (NIV)
- Allows us to predict:
  - How imbalance volumes change over time
  - What variables affect how long or short the system will be in an hour

2 Supply: Balancing market

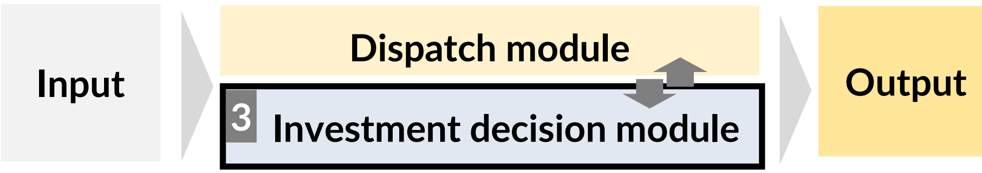
- We build up a plant by plant picture of available balancing supply using our market model's plant running patterns
- In each half-hour, a stack is formed and the 'auction' is solved for a given NIV

3 Balancing mechanism forecast

- Half-hourly cash out prices
- Which plants ramp and their bids and offers
- Valuation impact for each plant based on balancing revenues and imbalance charges

Source: Aurora Energy Research

Capacity investment decisions are based on plant economics



- In regions like GB which have a Capacity Market:
  - Annual procurement targets are set by the user
  - The model finds the cheapest plants to meet the target de-rated capacity and outputs a Capacity Market price
  - Already existing plants receive 1-year contracts
  - New building plants can receive multi-year contracts
  - Each technology has a specific de-rating factor (i.e. how much can 1MW of each tech count towards the target)
  - The model iterates between the dispatch and investment decision modules until it reaches a consistent, equilibrium set of prices and capacities such that each asset is just able to make its required level of return

Source: Aurora Energy Research

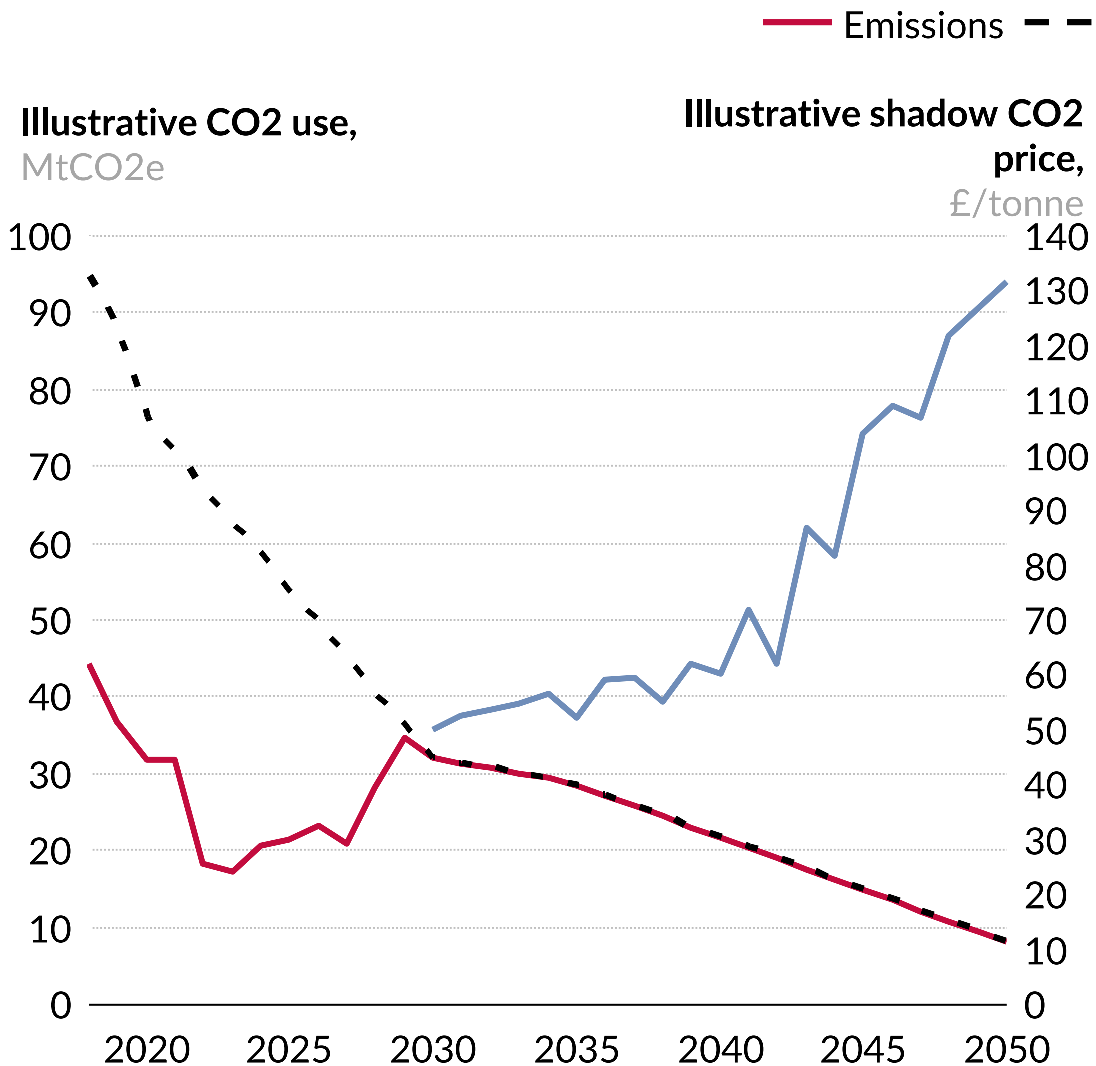
Input assumptions include technology, policy, demand and commodity prices

Input | Dispatch module / Investment decision module | 4 Output

Annual data (plant-level)	• Capacity details • Short-run marginal cost • Capture price • Production (net and gross) • Fuel use and CO_2 production • Fraction of capacity curtailed • Wholesale, balancing and capacity market revenues and profits
Annual data (regional level)	• Total capacity • Demand and embedded demand • Baseload and peakload power price • Energy unserved/spill • Export and import • Fuel and commodity prices and use
Half-hourly data	• Plant short-run marginal cost • Marginal plant and system marginal costs • Wholesale and balancing prices • Capacity margin • Gross and net production • Curtailment volume • Storage and pump production details • Energy unserved • Transmission data • Spread • Embedded demand

Source: Aurora Energy Research

The emissions target is met via a carbon constraint, which results in a shadow carbon price



- Annual emissions are capped at the user-defined carbon constraint
- Once this constraint is hit, the model calculates a shadow carbon price i.e. the price of carbon that would be necessary to bring emissions in line with the constraint
- This shadow carbon price is then factored into the marginal cost of thermal generators, which changes dispatch economics and ensures the constraint is not exceeded

Source: Aurora Energy Research

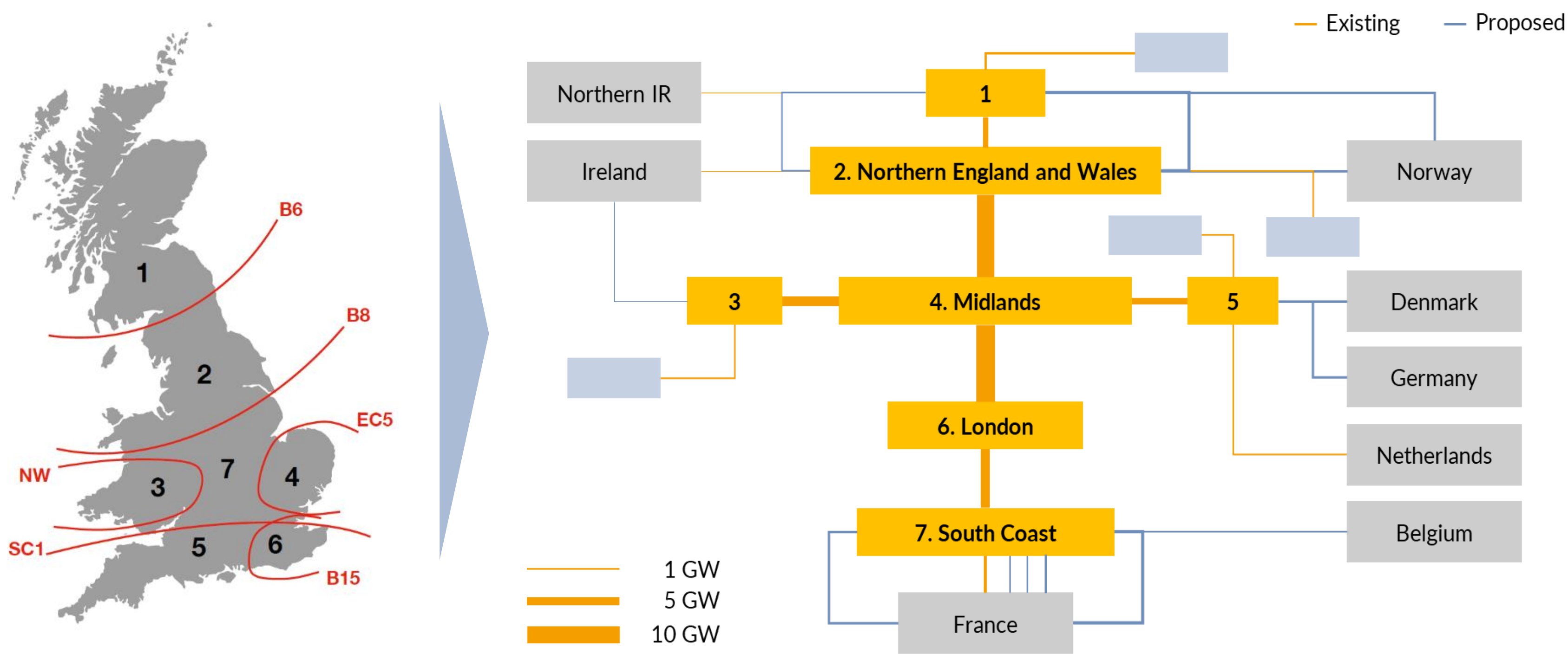
Contents

We have developed a network cost model to determine transmission and distribution spending in different scenarios

- Network costs are an important component of total system costs
- We developed a model to help us understand the implications for transmission and distribution network spending of different levels of demand (average and peak) and different supply mixes associated with each scenario and level of renewables
- Our network cost model takes capacity outputs and half-hourly supply and demand data from our market model and uses them to calculate investment in new transmission and distribution infrastructure
- We combine both top-down and bottom-up approaches:
  - Bottom-up: the drivers of network costs are based on outputs from out power market model
  - Top-down: the unit cost for drivers is calibrated to historical expenditure
- We calculate both total network expenditure (TOTEX) and annual TNUoS and DUoS spending
  - Network TOTEX is recovered through two ways
    - Fast: OPEX is recovered in the year it is incurred, directly passed through to TNUoS/DUoS
    - Slow: CAPEX is recovered over time, as a return on rate asset value (RAV) and annual depreciation (also components of TNUoS/DUoS)
- In this study, network costs refer to TNUoS and DUoS rather than TOTEX
- This model may underestimate network costs in cases of high offshore wind deployment

Source: Aurora Energy Research

Aurora's network cost approach is based on Ofgem and National Grid methodologies



- Aurora's network cost model is based on the breakdown of transmission and distribution costs provided in the RIIO annual report[1], and the partition of the network into zones, as was proposed by the National Grid in the *Network Options Assessment 2017/18* report
- Power demand, generation and interconnector flows are disaggregated by zone and boundary conditions are used to calculate the required investment on the transmission and distribution network reinforcement
- Aurora's network cost model simplifies the GB network into seven interconnected nodes, with internal and external connections

1. RIIO ET-1 Annual Report 2015-16 https://www.ofgem.gov.uk/system/files/docs/2017/02/riio-et1_annual_report_2015-16.pdf

Source: Aurora Energy Research

The network cost model calculates TOTEX based on geographically distributed supply and demand

1. Network node map
2. Capacity changes from market model
3. Geographic allocation of new demand/supply[1]
4. New network infrastructure required
5. **Cost of network = TOTEX**

- Existing generation is mapped onto seven interconnected network nodes
- New capacity built in the power model is geographically allocated across the seven nodes and to either the transmission or distribution system
- The model calculates the additional network infrastructure required by the capacity additions from the dispatch model
- The cost of network is calculated annually based on existing and new build network costs

1. New capacity is distributed across nodes or allocated a specific node if location dependent (eg. tidal technologies and nuclear)

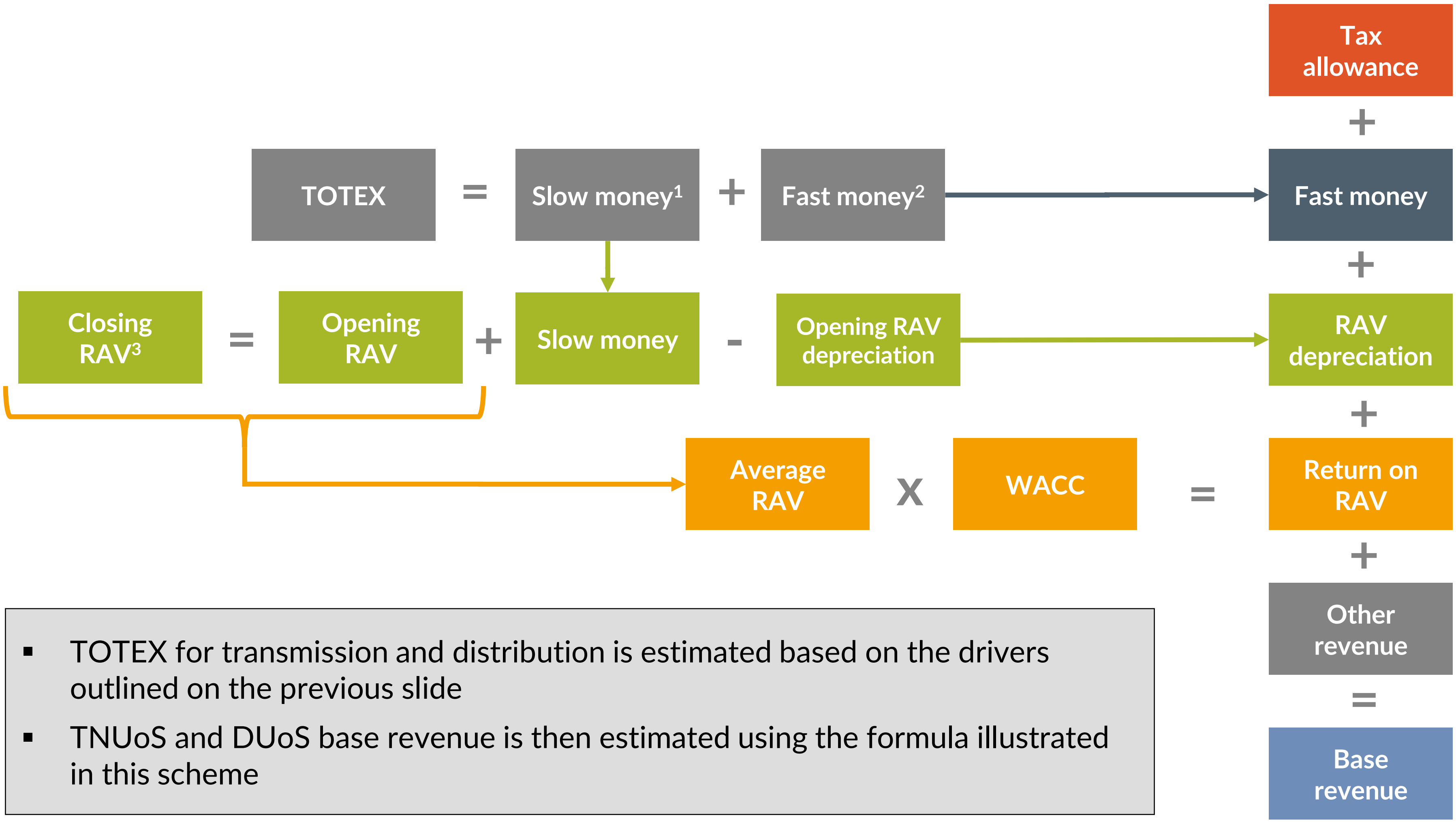
Source: Aurora Energy Research

Both yearly and half-hourly market model outputs from each scenario are used as inputs into our network cost model

Driver of network costs	Market model output used as input to network cost model
New transmission generation (MW)	• Calculated from capacity timeline, after mapping all plants to transmission/distribution level
New boundary transfer capability required (MW)	• Calculated from maximum half-hourly zonal supply/demand imbalance, after taking into consideration the trade with interconnectors and mapping all plants to zones
New peak demand (MW)	• Determined based on maximum demand in each year
New distribution generation (MW)	• Calculated from capacity timeline, after mapping all plants to transmission/distribution level

Source: Aurora Energy Research

Once the TOTEX is forecasted, the model follows the RIIO procedure to determine the corresponding base revenue



- TOTEX for transmission and distribution is estimated based on the drivers outlined on the previous slide
- TNUoS and DUoS base revenue is then estimated using the formula illustrated in this scheme

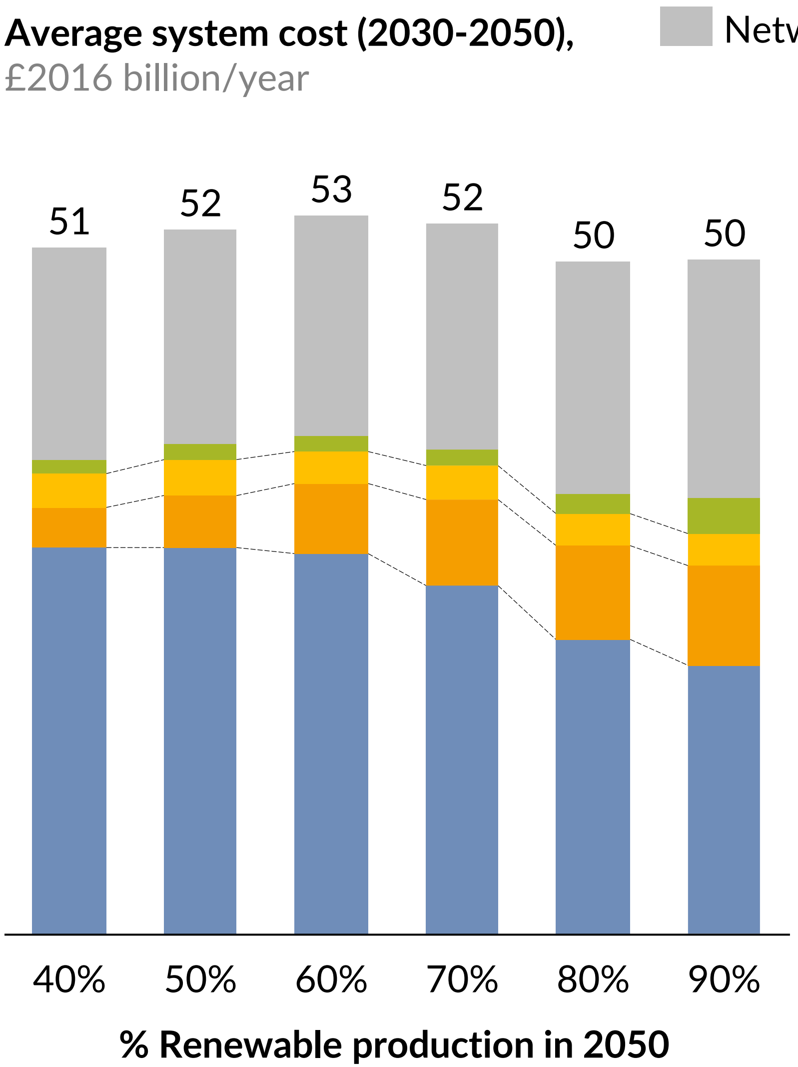
1. Slow money is TOTEX multiplied by the capitalisation rate (0.85 for transmission, 0.68-0.80 for distribution)
2. Fast money is the remainder of the TOTEX, after removing slow money.
3. RAV stands for the rate asset value

Sources: Aurora Energy Research, RIIO Annual Report 2015-16

Contents

Existing subsidies have been accounted for in addition to any "top-up" subsidies required to make RES projects profitable

Average system cost (2030-2050), £2016 billion/year



- Subsidies are a component of total system costs at all RES levels and in all scenarios
- Two components of the costs associated with subsidies are constant across all scenarios and are calculated based on existing contracts:
  - Renewables Obligation (RO)
  - Feed in tariff (FIT)
- Other components vary across scenarios, depending on the power price:
  - Contract for Difference (CfD)
  - Additional "top-up" subsidies
- CfD spending for all existing contracted assets is calculated based on renewable capture prices in each scenario
- Additional "top-up" subsidies are needed in some scenarios at higher levels of renewable penetration when reaching the target level of RES capacity depresses wind and solar capture price such that new projects are unable to enter economically without government support. This is illustrated further on the following slide

Results based on the supply/demand scenario: Anything goes & electrification of heat

Source: Aurora Energy Research

High RES scenarios depress the capture prices such that renewables may need additional subsidies to enter

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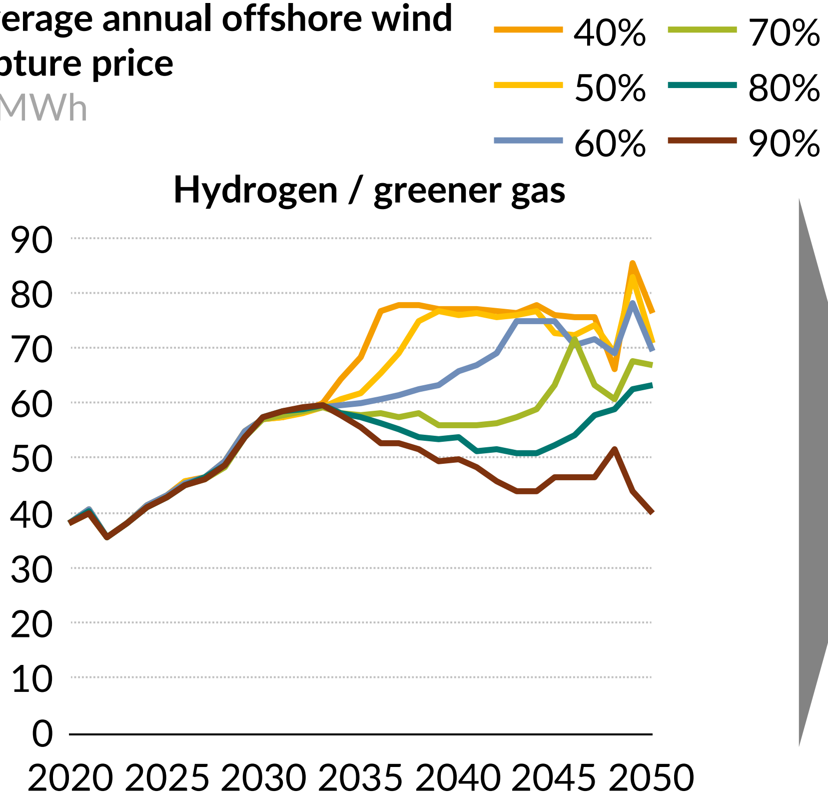
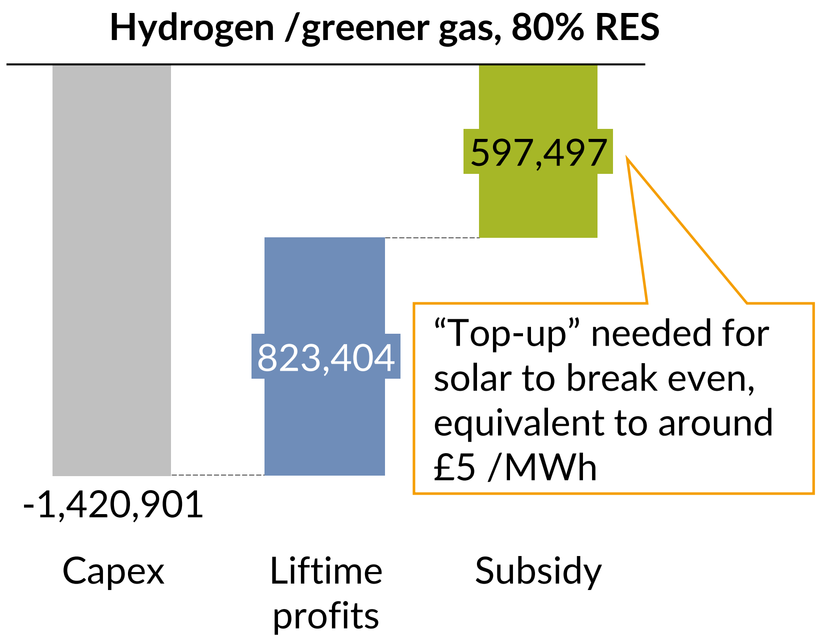
Average annual offshore wind capture price
£/MWh



PV of costs and revenues for offshore wind commissioning in 2040
£/MW



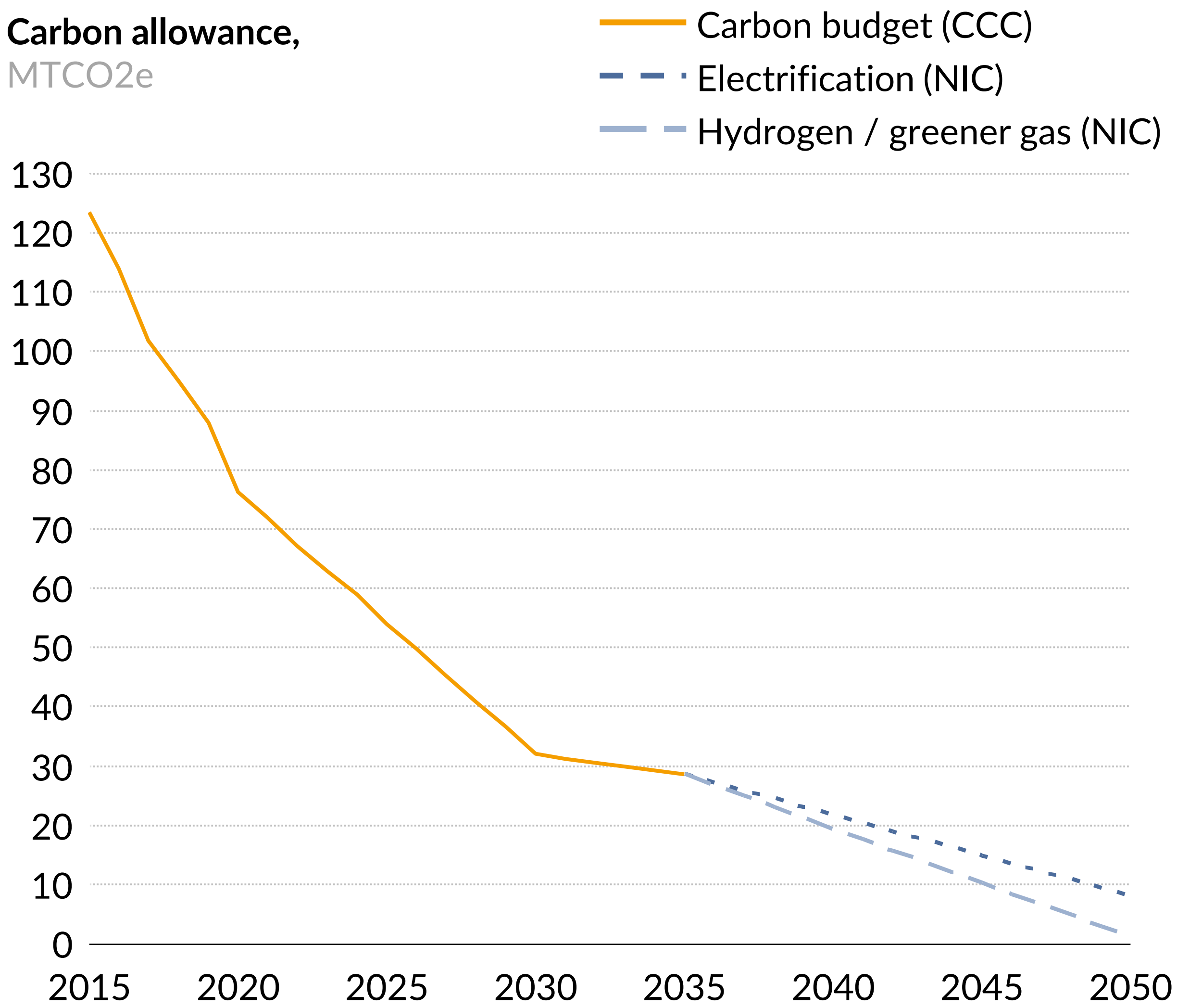
- The renewable timelines modelled are based on endogenous runs in which renewables enter when it is profitable to do so
- As such, in most scenarios, no additional subsidy is required to bring on renewables since high carbon prices as a result of the carbon constraint mean that new projects can enter economically
- In scenarios with very high levels of RES, however, price cannibalization depresses renewable capture prices such that they become unprofitable. In these instances, we calculate the additional "top-up" subsidy that would be required such that renewables break even and the desired level of RES production in 2050 is met

Source: Aurora Energy Research

Contents

Appendix ii: Assumptions Book

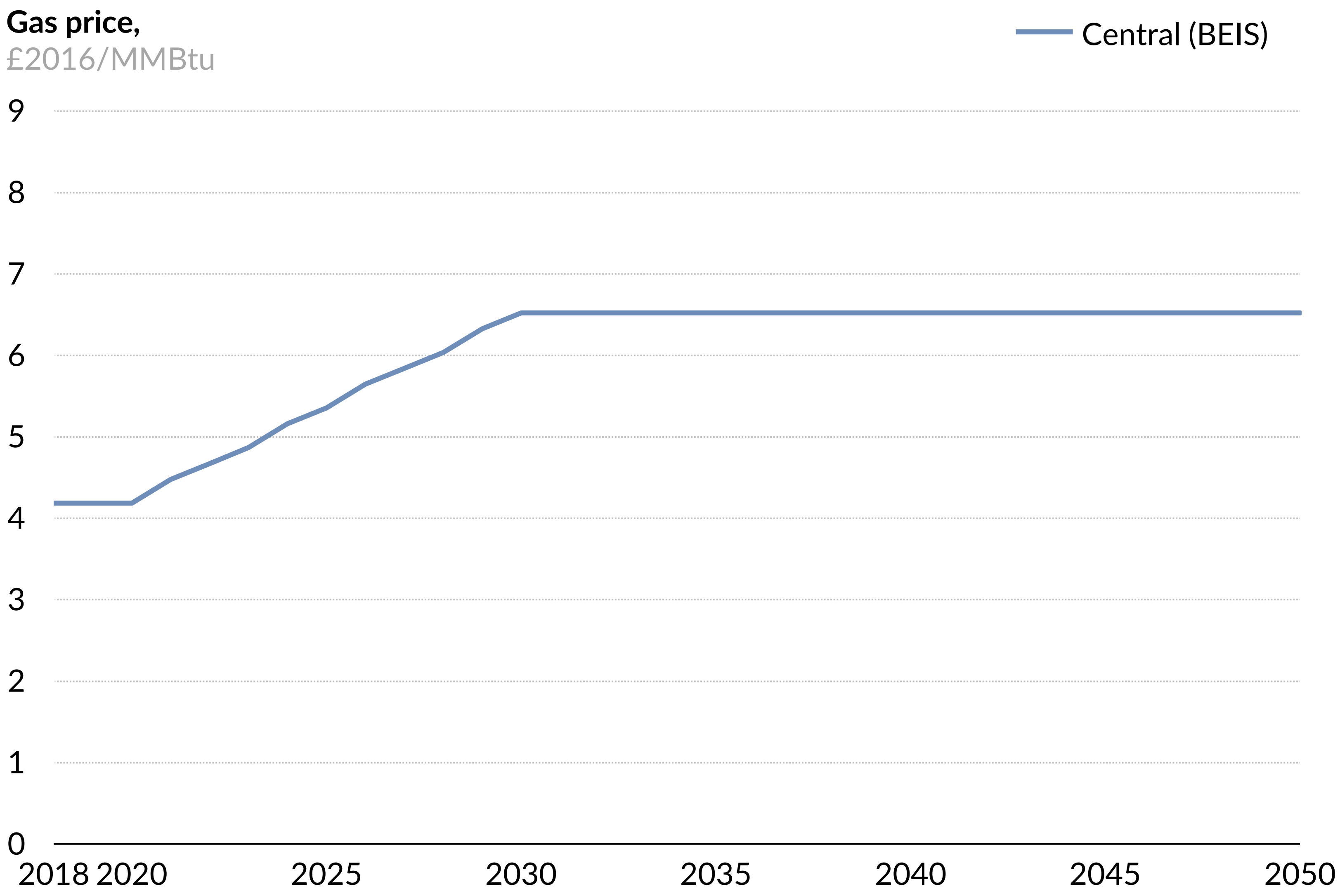
We have adopted a carbon constraint in line with the CCC's Fifth Carbon Budget central case



- Aurora has adopted annual power sector carbon targets to 2035 in line with the Climate Change Committee's 5th carbon budget central scenario
- We have extrapolated this to meet the 2050 targets recommended by NIC
- The different targets reflect the need for greater power sector decarbonization in the hydrogen/biomass demand scenario

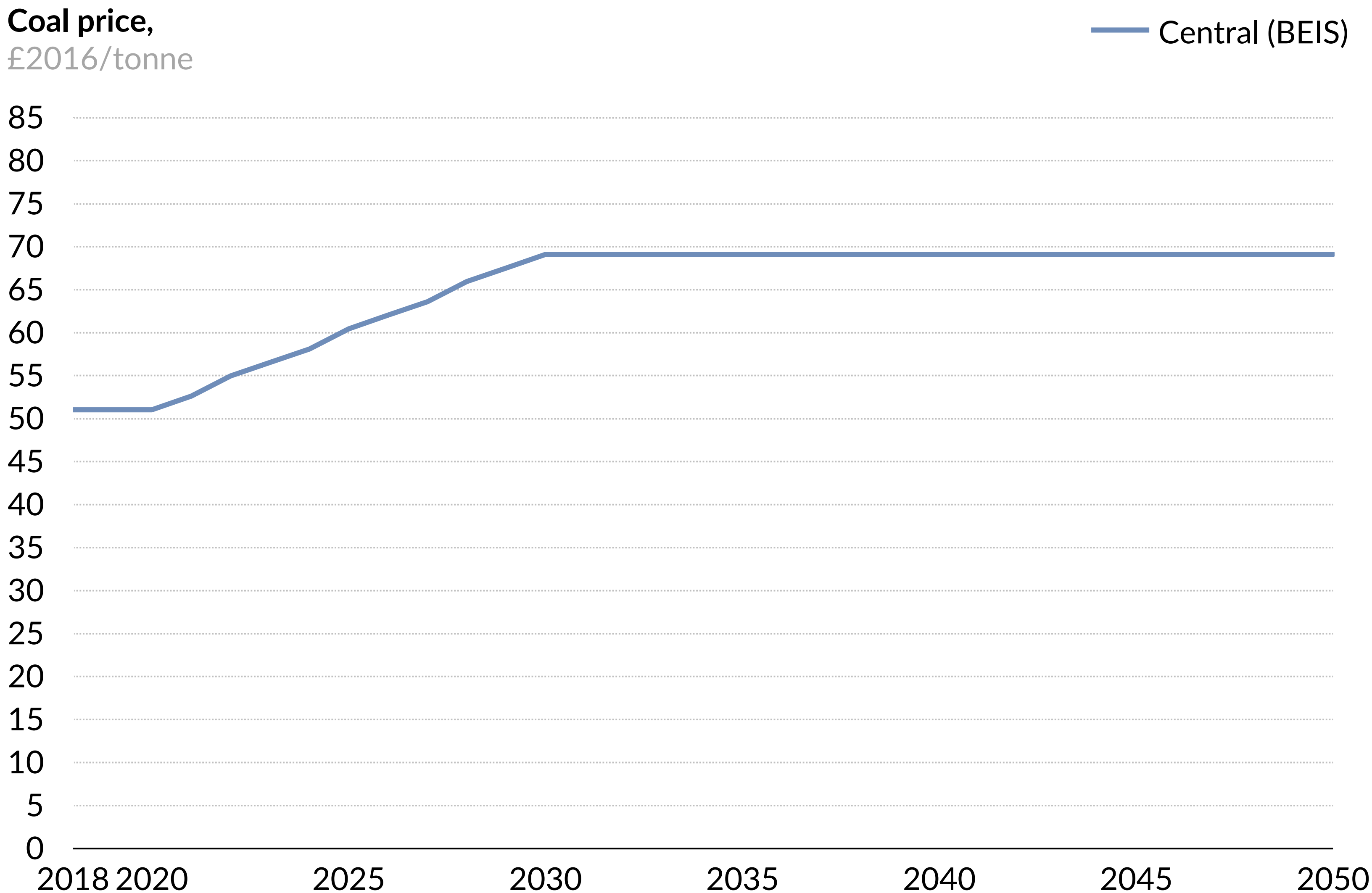
Sources: Climate Change Committee Fifth Carbon Budget; NIC

We have adopted BEIS' central gas forecast and assumed it remains constant from 2040-2050



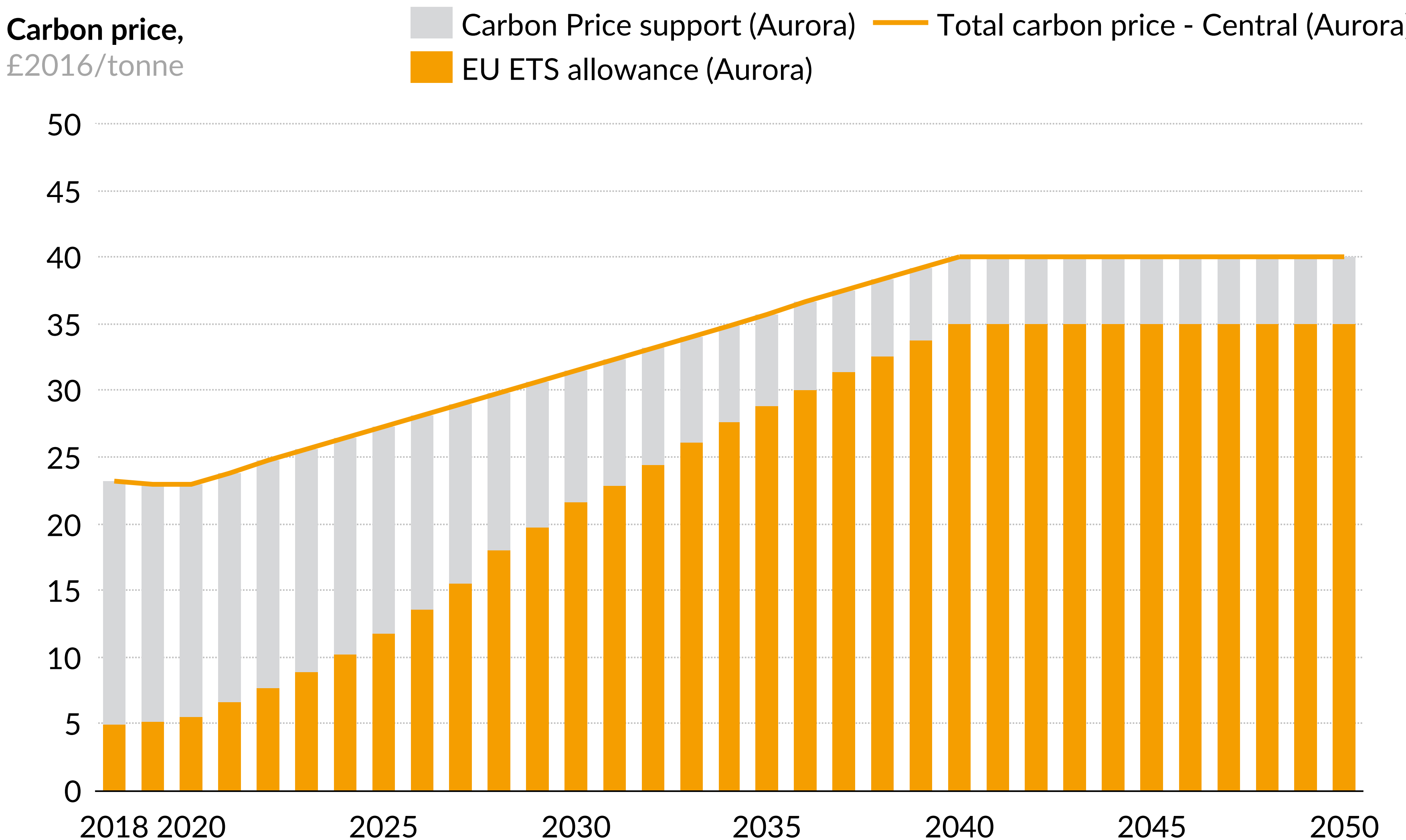
Source: BEIS

We have adopted BEIS' central coal forecast and assumed it remains constant from 2040-2050



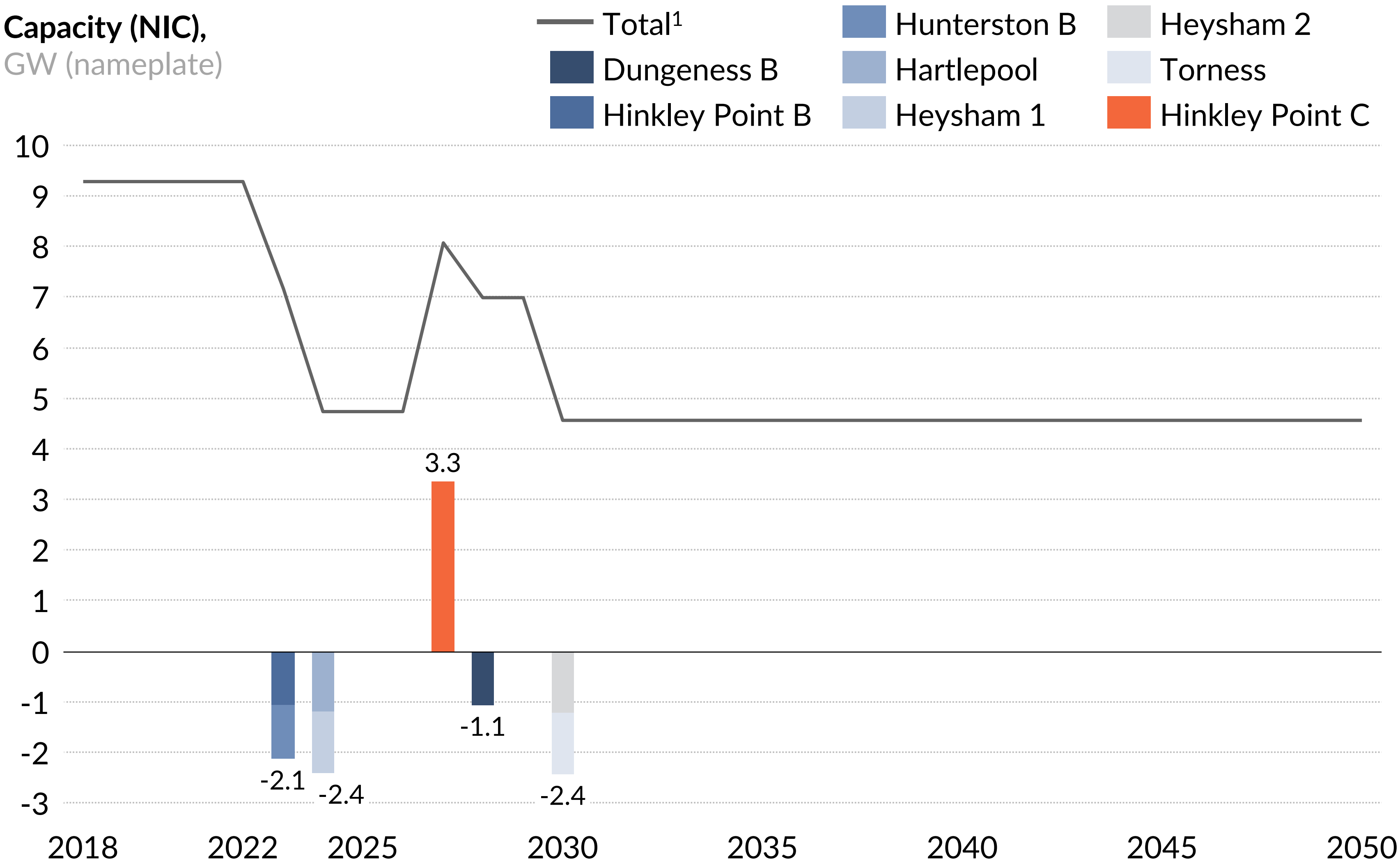
Source: BEIS

The NIC has chosen to adopt Aurora's carbon price trajectory



Source: Aurora Energy Research

We assume no new exogenous nuclear build after Hinkley Point C and retirements as per scheduled

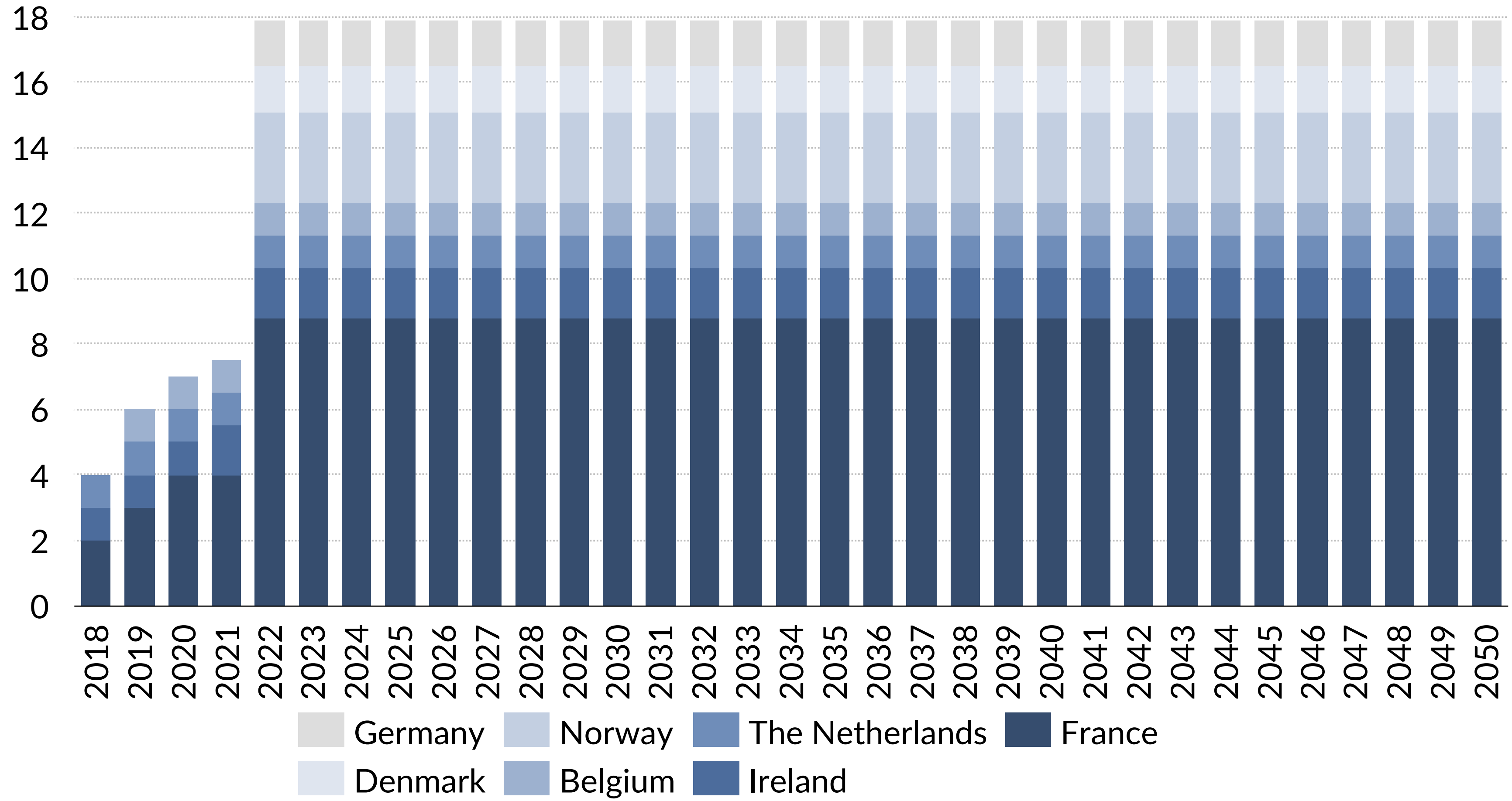


1. Line chart represents end-of-year capacity.

Source: NIC

NIC has assumed all window 1 & 2 projects to be delivered on time by 2022 in line with Ofgem

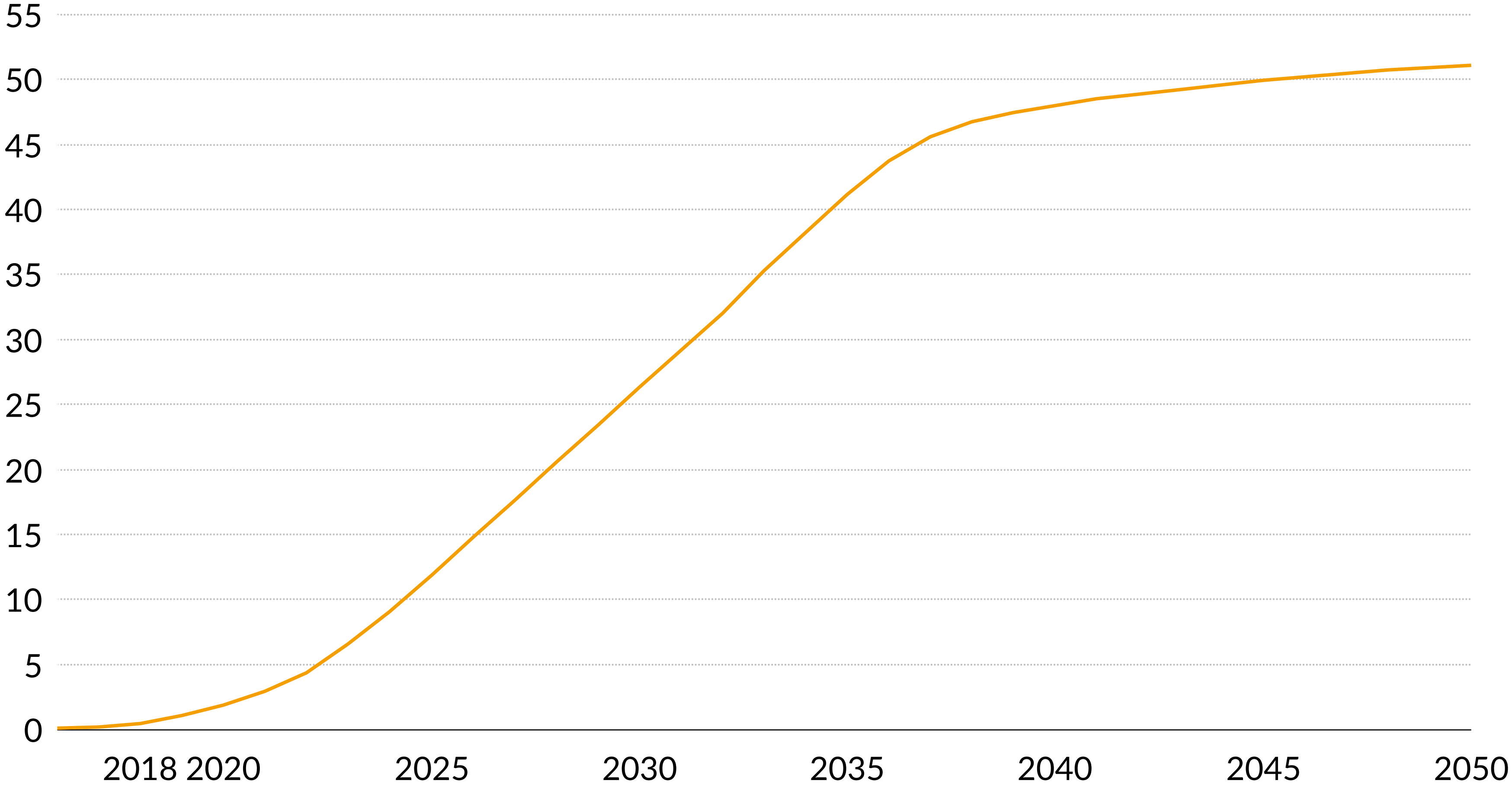
Installed capacity (Ofgem),
GW (nameplate)



Sources: Ofgem, NIC

The NIC assumes 100% stock of EVs by 2040

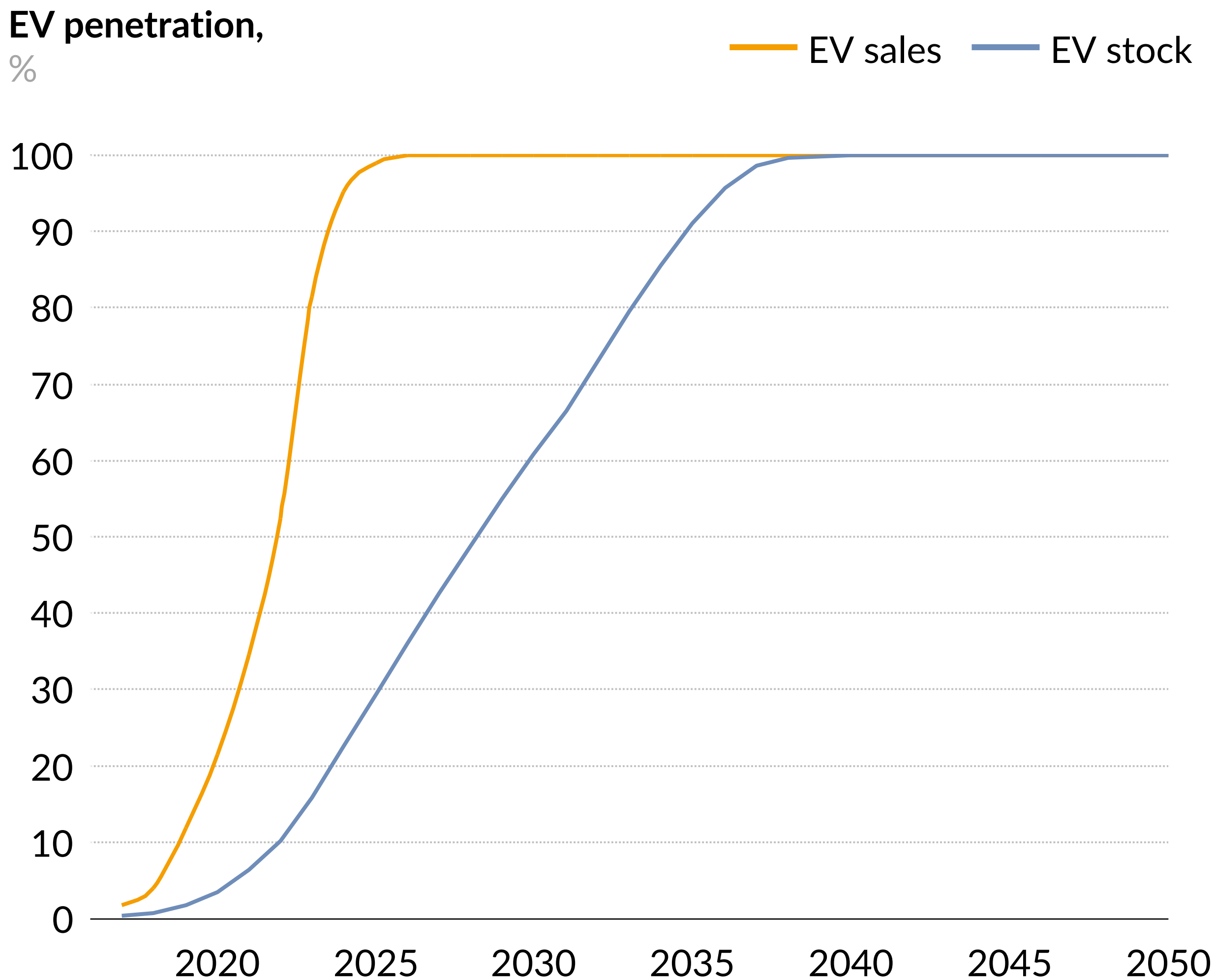
Total number of EVs in GB[1]
Millions



1. Includes vans and cars

Sources: NIC, Aurora Energy Research analysis

This implies 100% EV sales as early as 2025, up from less than 2% today

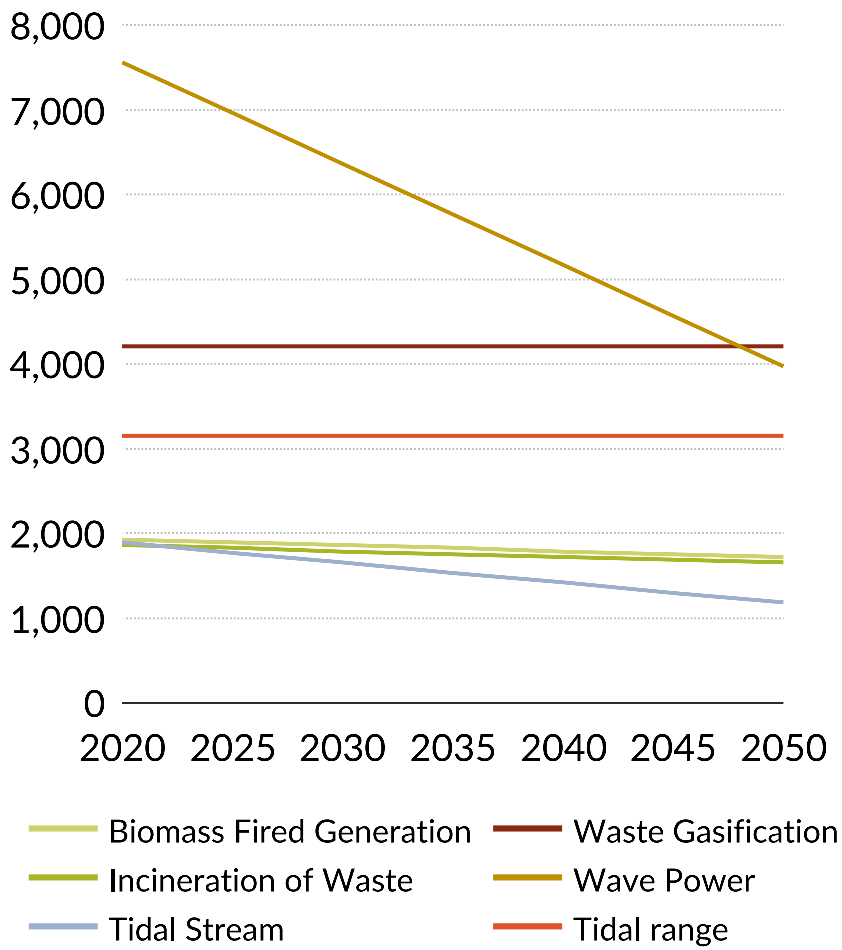


- EV stock = Sum of EV sales – EV retirements
- EV sales = total car sales x EV sales percentage
- Car lifetime is assumed to be 15 years
- Aurora modelled % sales and % stock based on NIC targets

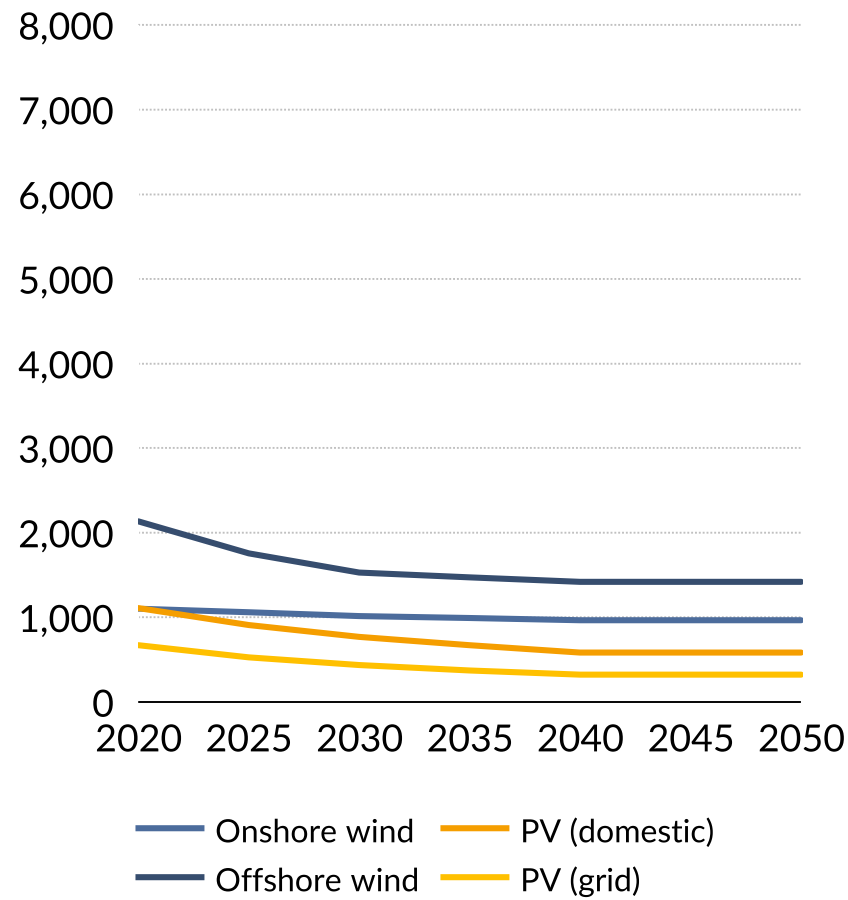
Sources: NIC, Aurora Energy Research analysis

We have adopted ETI's costs for all renewable technologies excluding wind and solar

Capex (ETI low technology costs)[1], £2016/kW



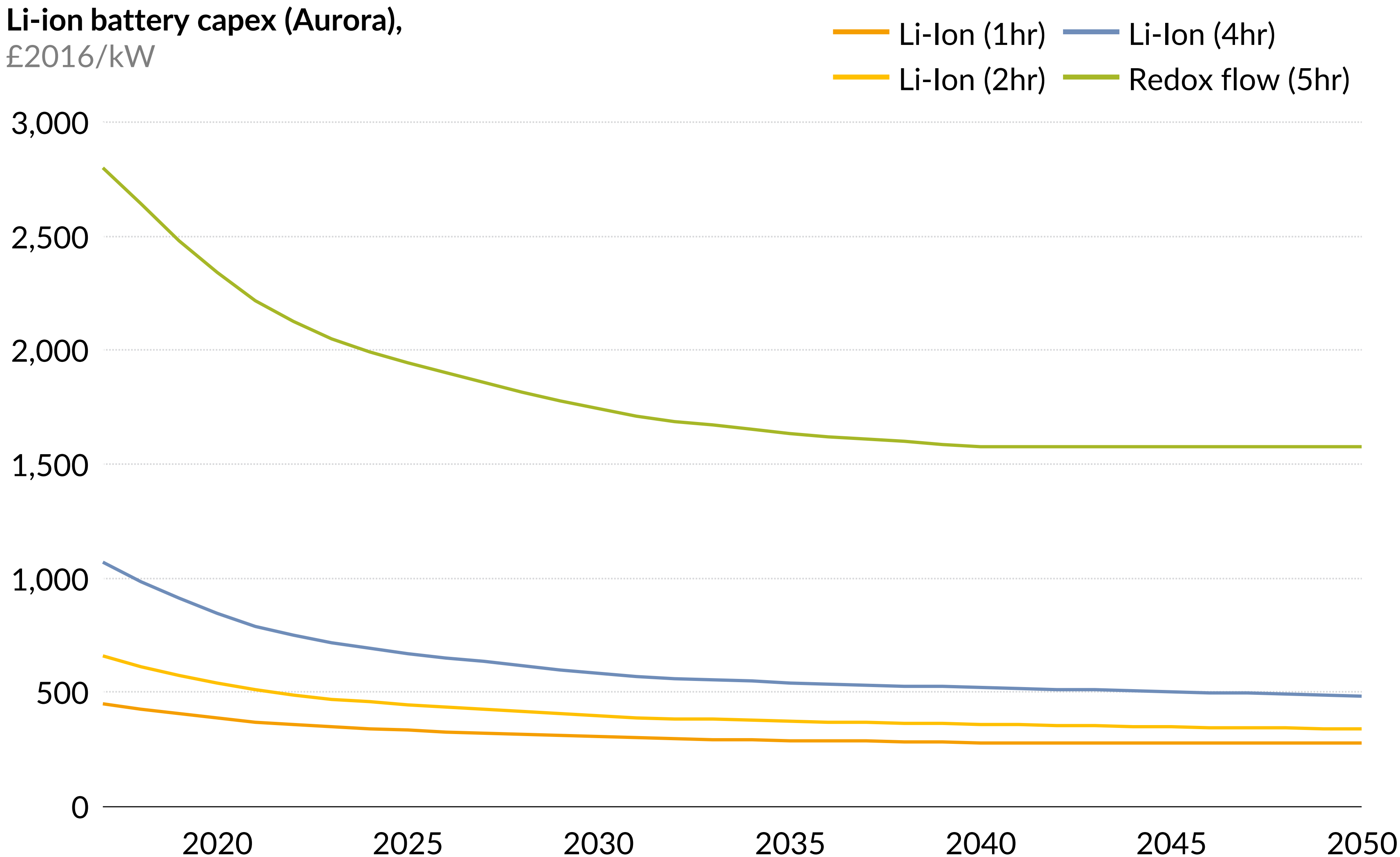
Capex (Aurora), £2016/kW



Nuclear costs assumptions were based on the BEIS central case for an Nth of a kind plant commissioned in 2025 but no cost reductions due to learning were assumed.

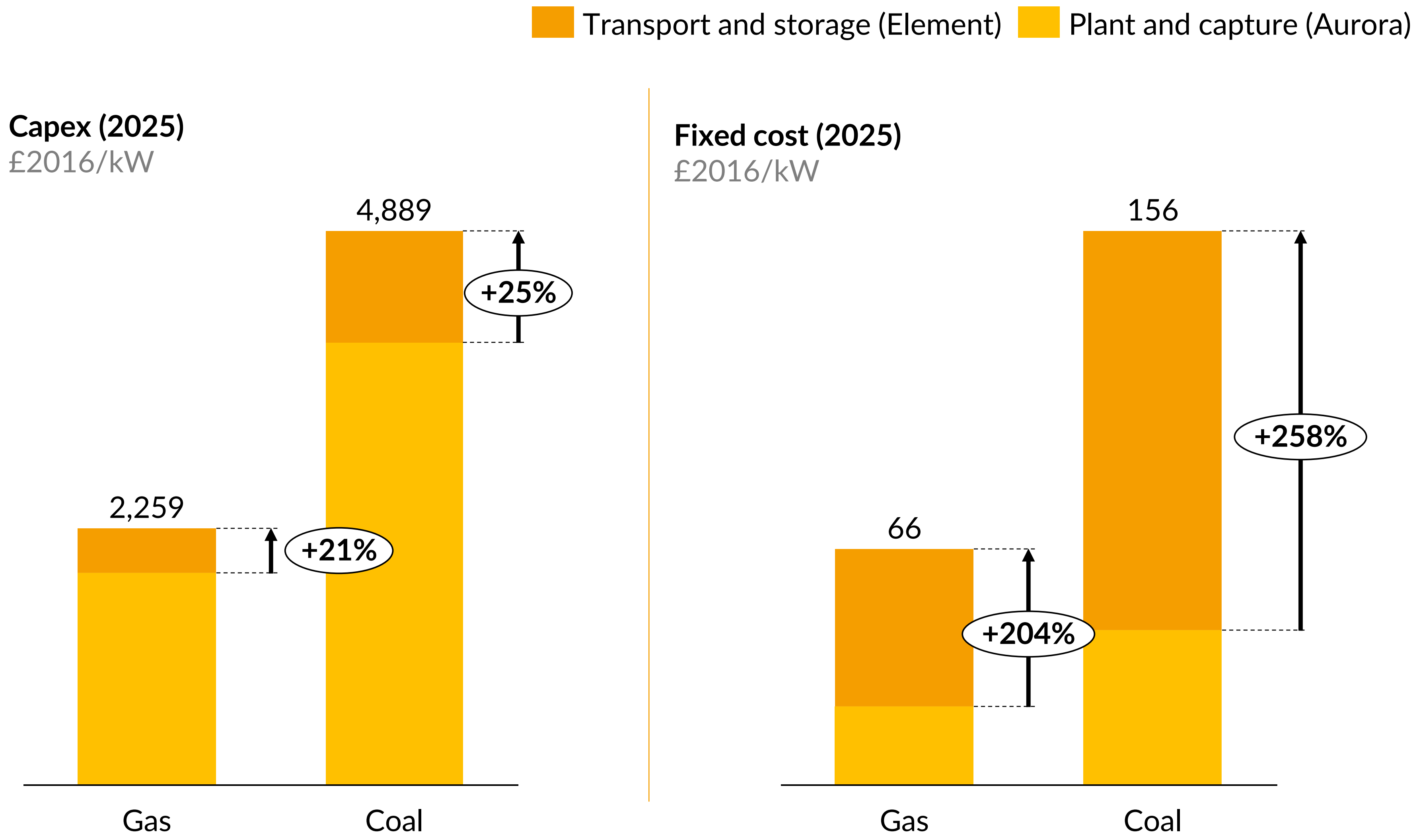
Sources: ETI, Aurora Energy Research

We have modelled a range of different battery types and durations



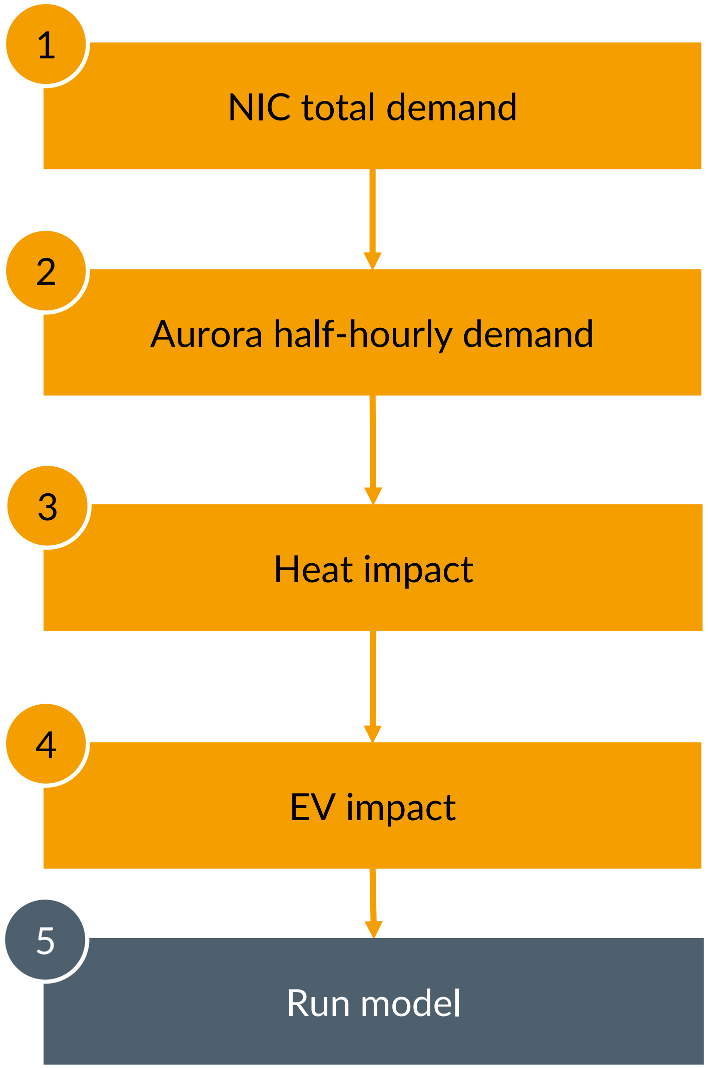
Source: Aurora Energy Research

Transportation and storage of carbon can add up to 25% to CCS Capex



Sources: NIC, Element Energy

We have modelled demand on a half-hourly basis accounting for both EVs and heat

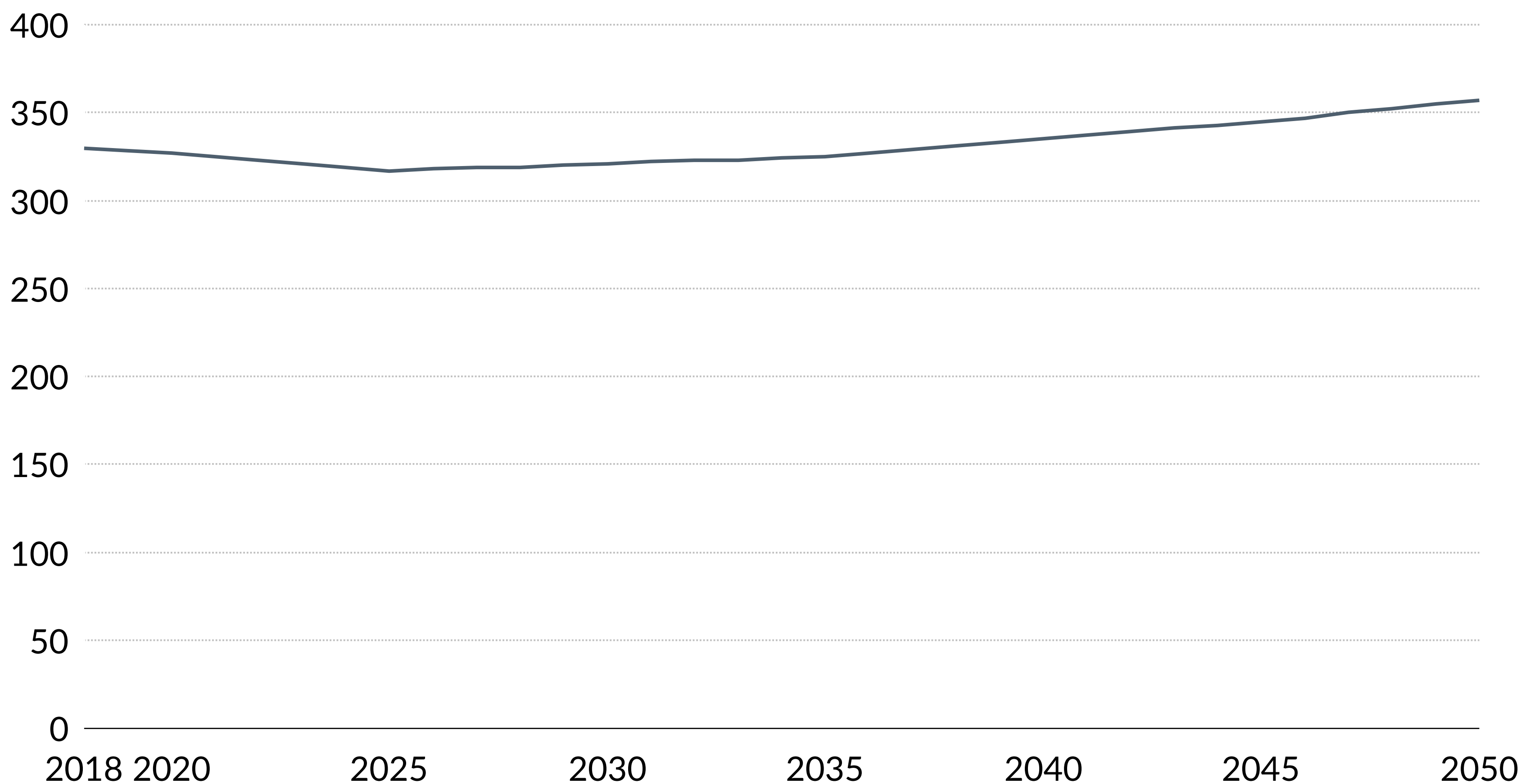


- We have taken NIC annual aggregate demand and created half-hourly demand profiles for each year
- These have been adjusted for EVs and heat to create final demand curves to be used in the modelling
- The following slides show each step in more detail

We started by taking NIC data for annual electricity demand net of growth in EVs or heat

1

Annual electricity demand[1],
TWh

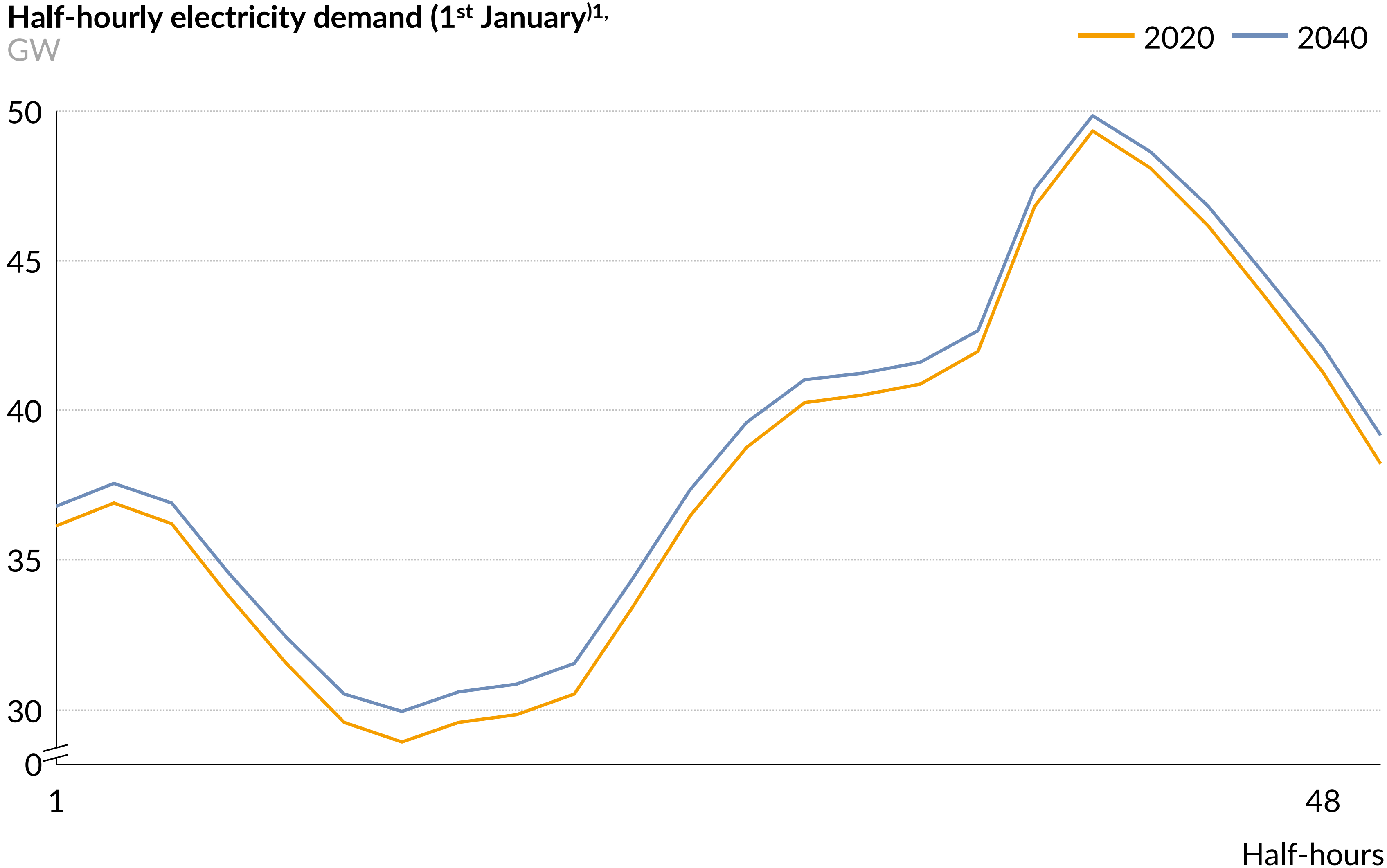


1. Electricity demand net of heat and transport

Sources: NIC, BEIS

We converted NIC annual demand into half-hourly data

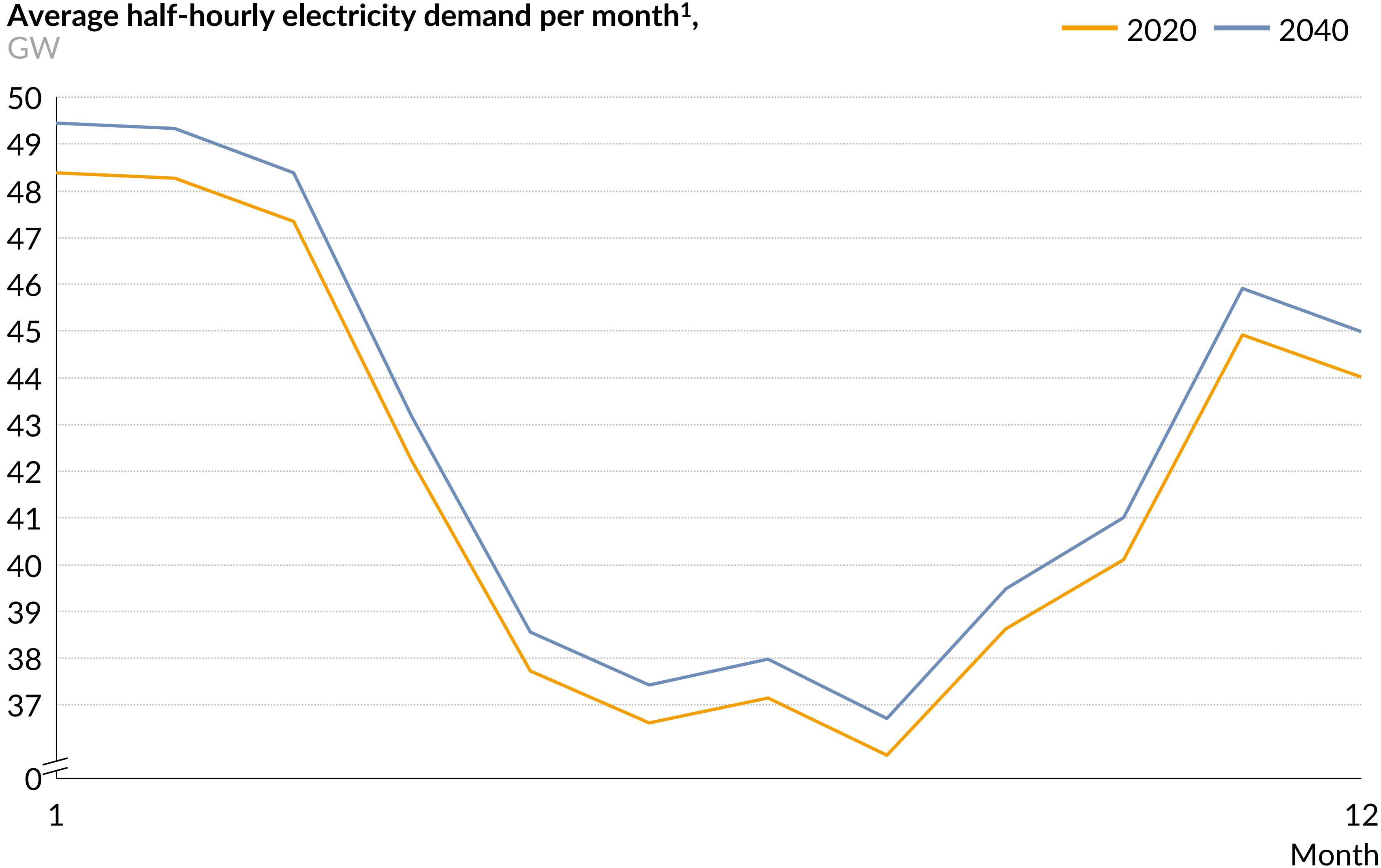
Half-hourly electricity demand (1st January)[1],
GW



1. Electricity demand net of heat and transport

2 Seasonal patterns reveal lower demand in summer and higher demand in winter

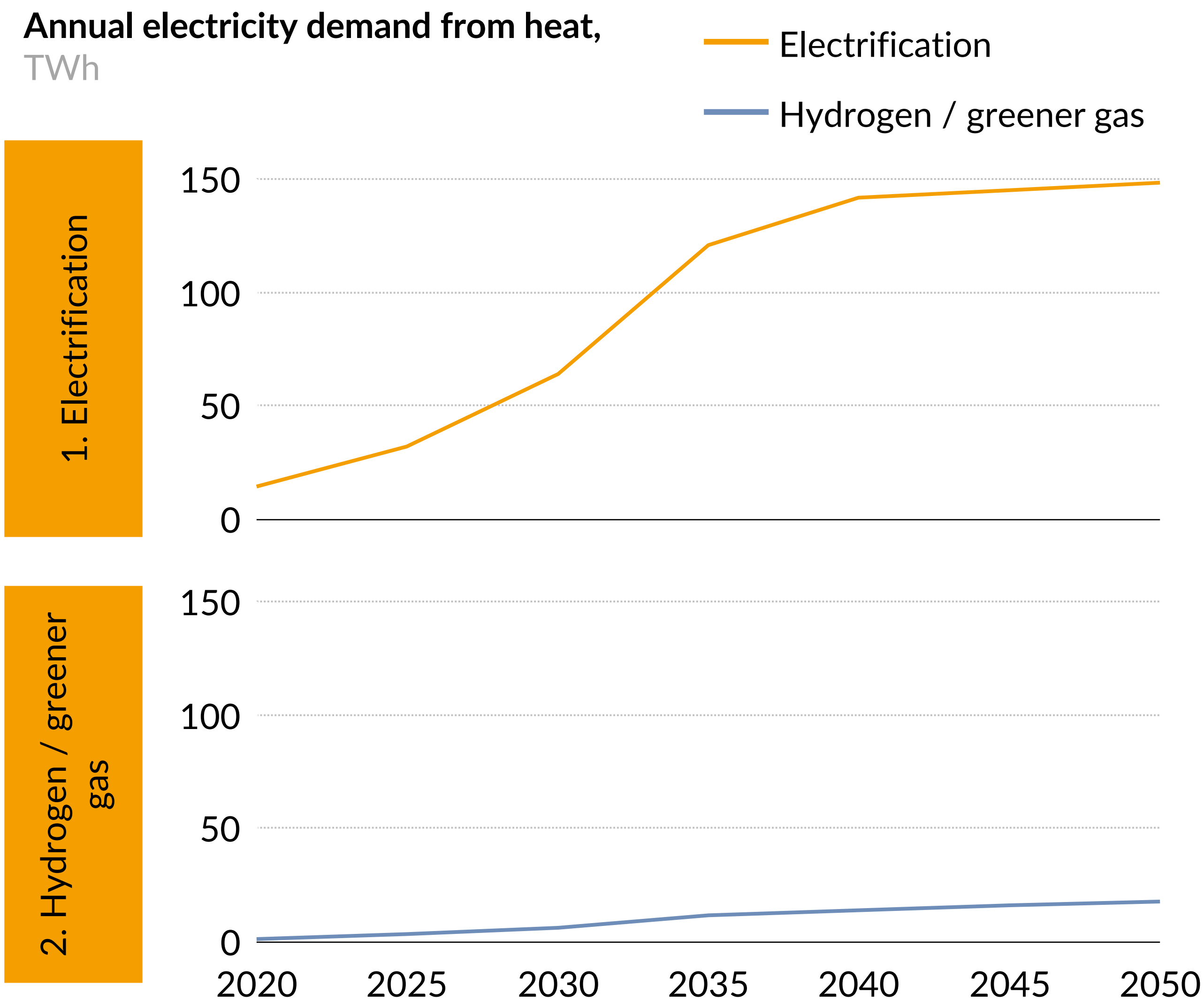
Average half-hourly electricity demand per month[1],
GW



1. Electricity demand net of heat and transport

Sources: Aurora Energy Research, NIC, BEIS

3 For heat, we began by taking Element data for heat electrification across the two different scenarios



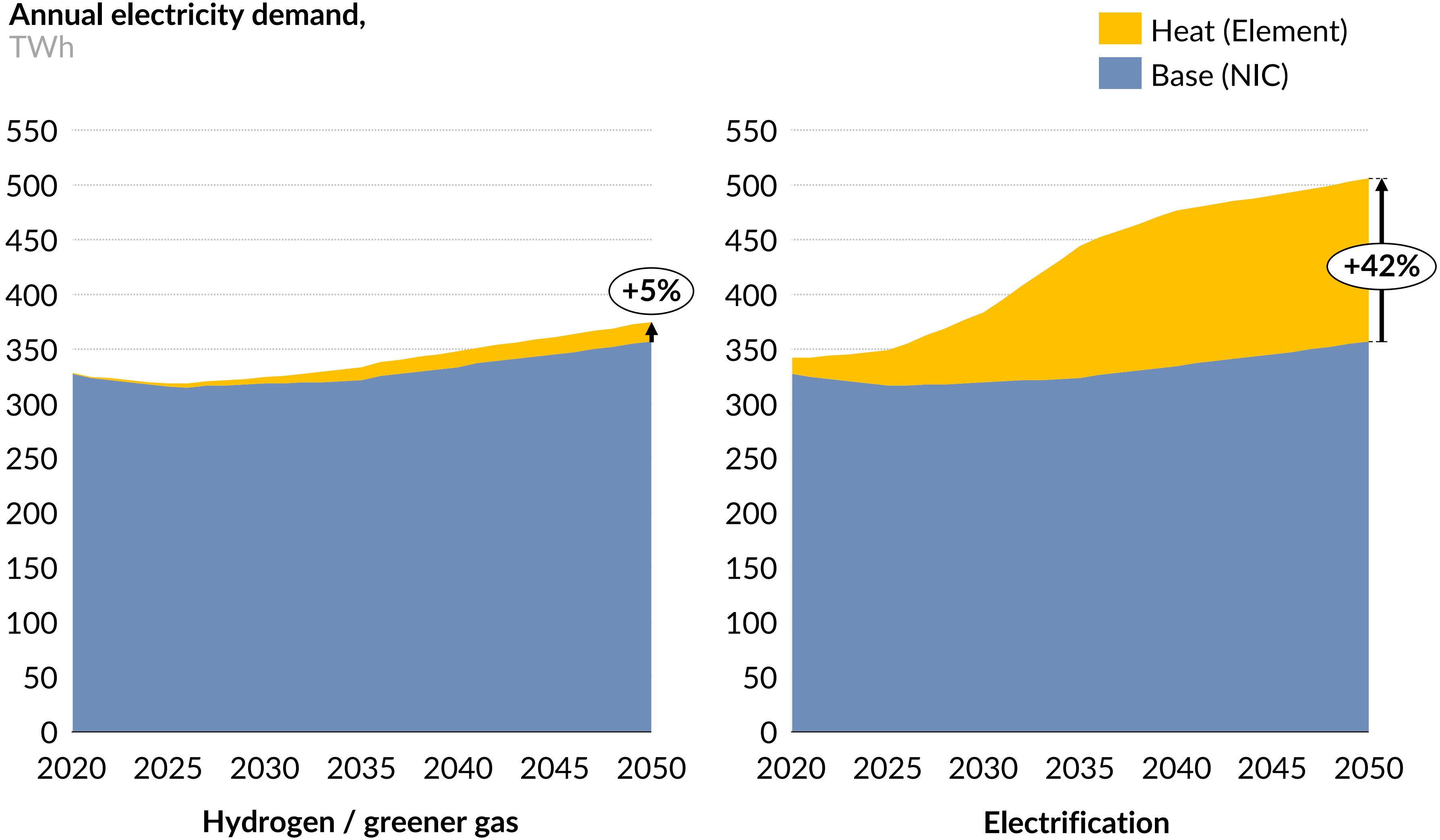
- Electrification of heat through heat pumps leads to significantly higher electricity demand by 2050
- In the other scenario, hydrogen does most of the heavy lifting in terms of decarbonization, with little electrification of heat

Source: Element Energy

3

Electrification of heat leads to 42% higher annual demand compared to the base case

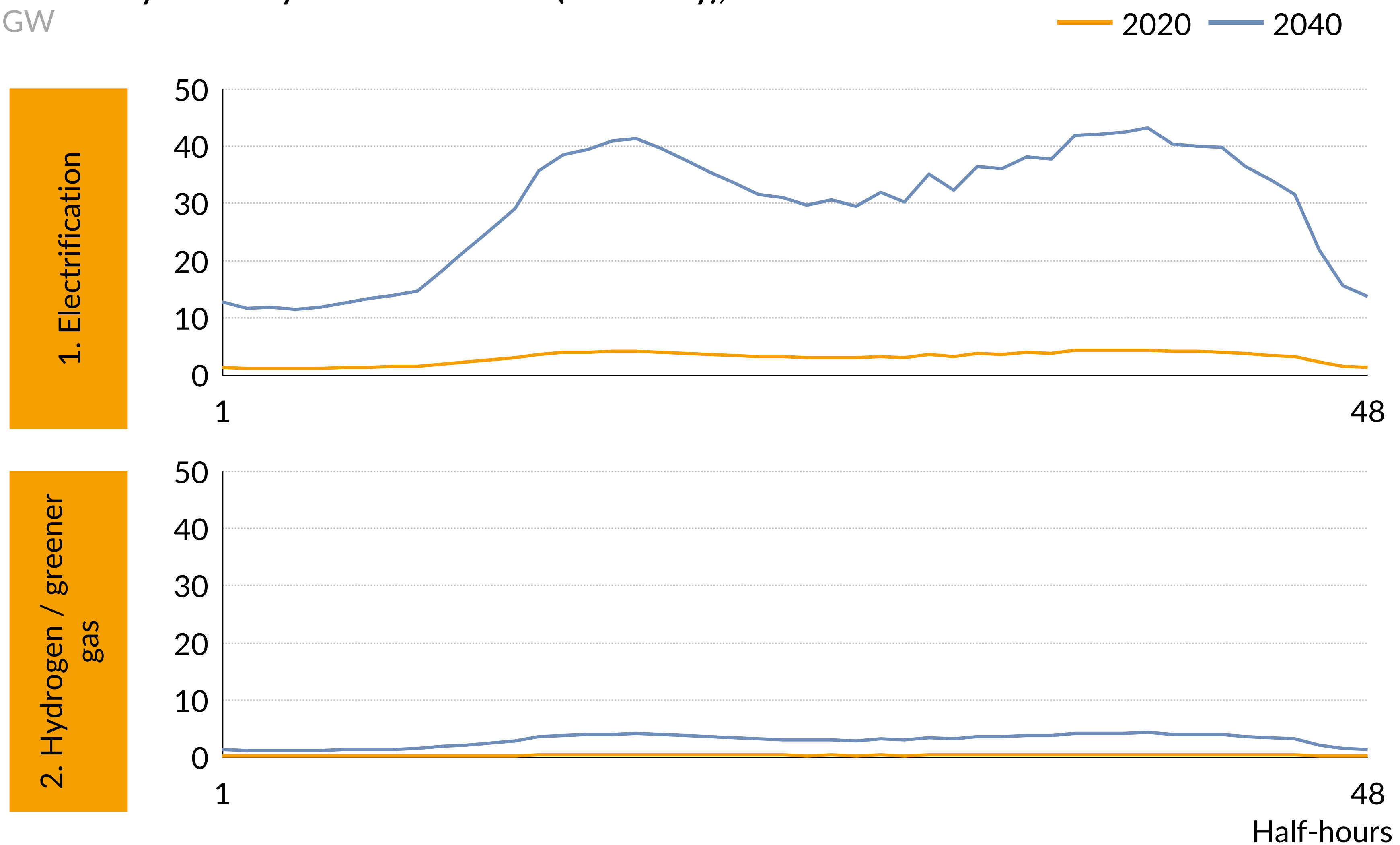
Annual electricity demand, TWh



Sources: NIC, Element Energy

We converted Element electrification data into a half-hourly demand profile for each year

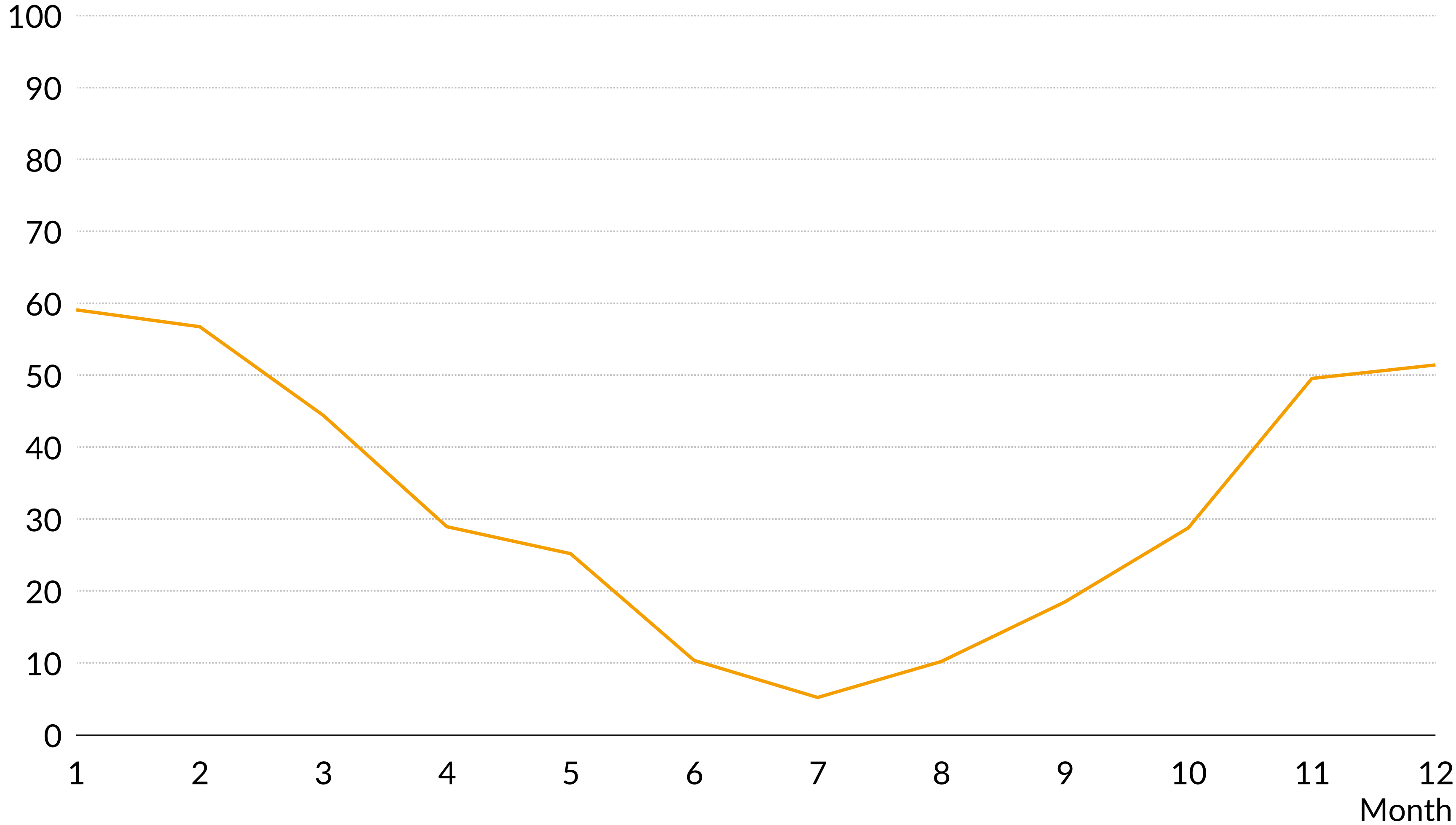
Half-hourly electricity demand from heat (1st January),
GW



Sources: Aurora Energy Research, Element Energy

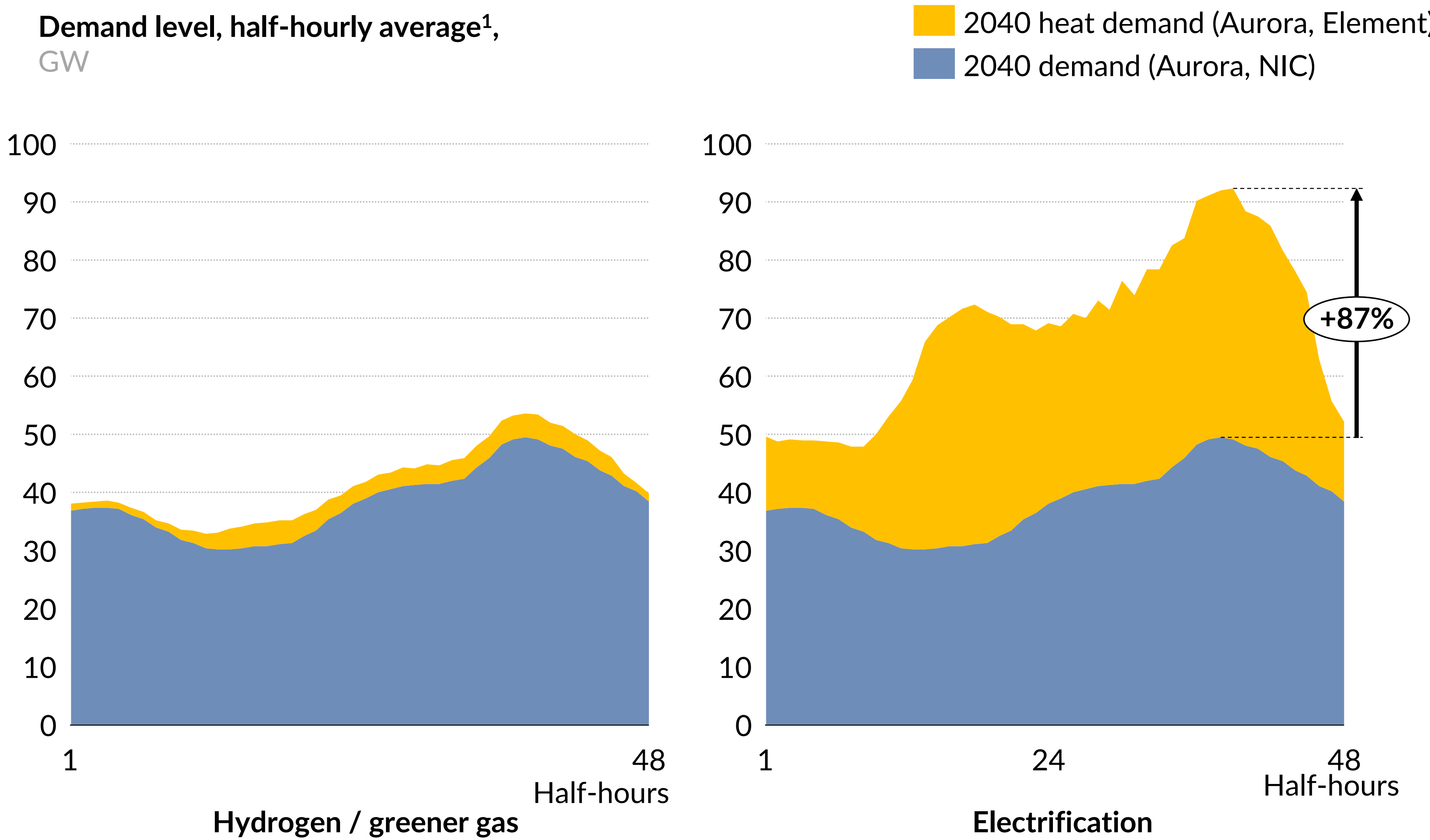
As expected, demand for heating is significantly higher in the winter months

Average heat pump load factor by month,
Percentage (%)



Source: Element Energy

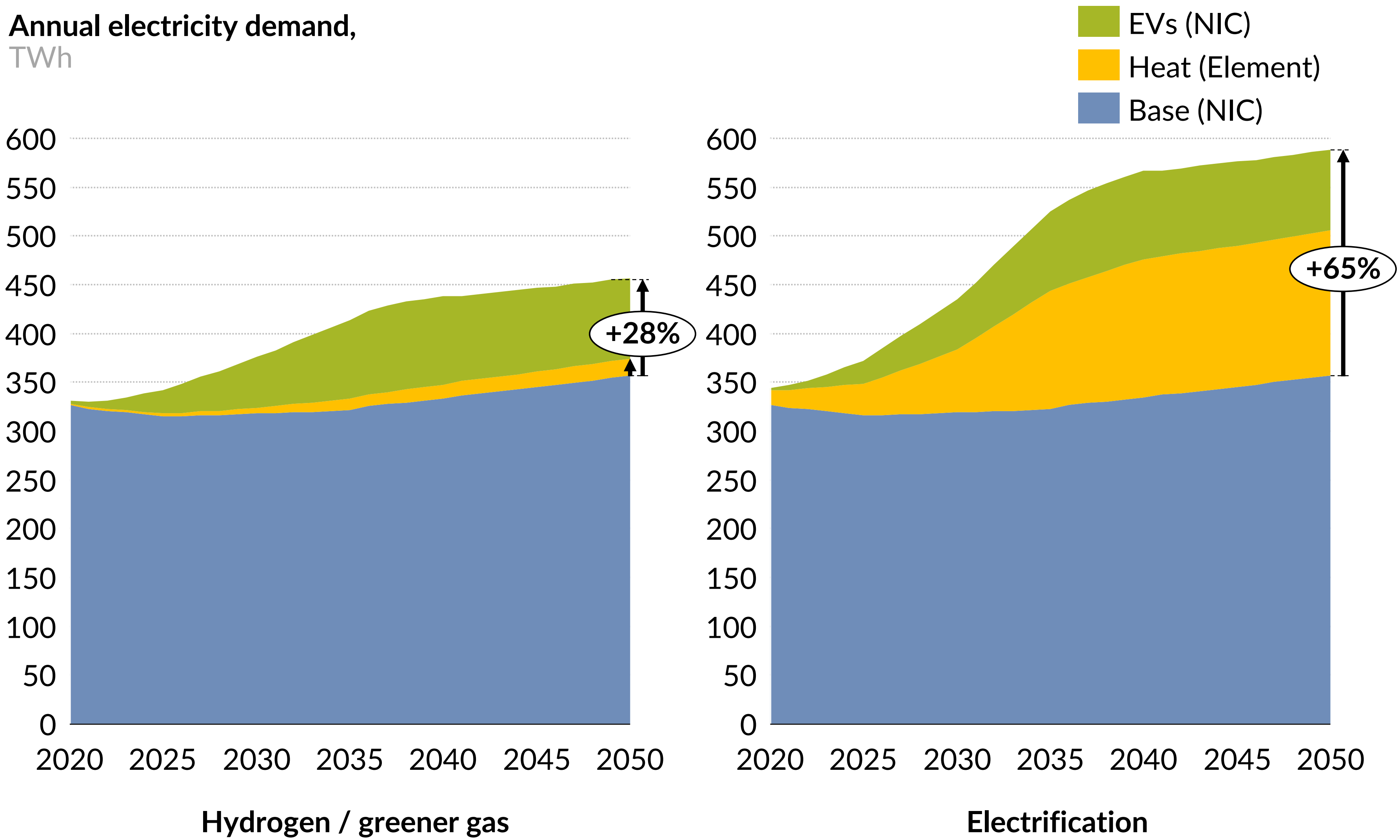
4 This can lead to an additional 40+GW of peak demand on winter evenings in the heat electrification scenario



1. HH demand profiles for 1st January 2040

Sources: Aurora Energy Research, NIC, BEIS

Adding EVs increases annual average demand still further

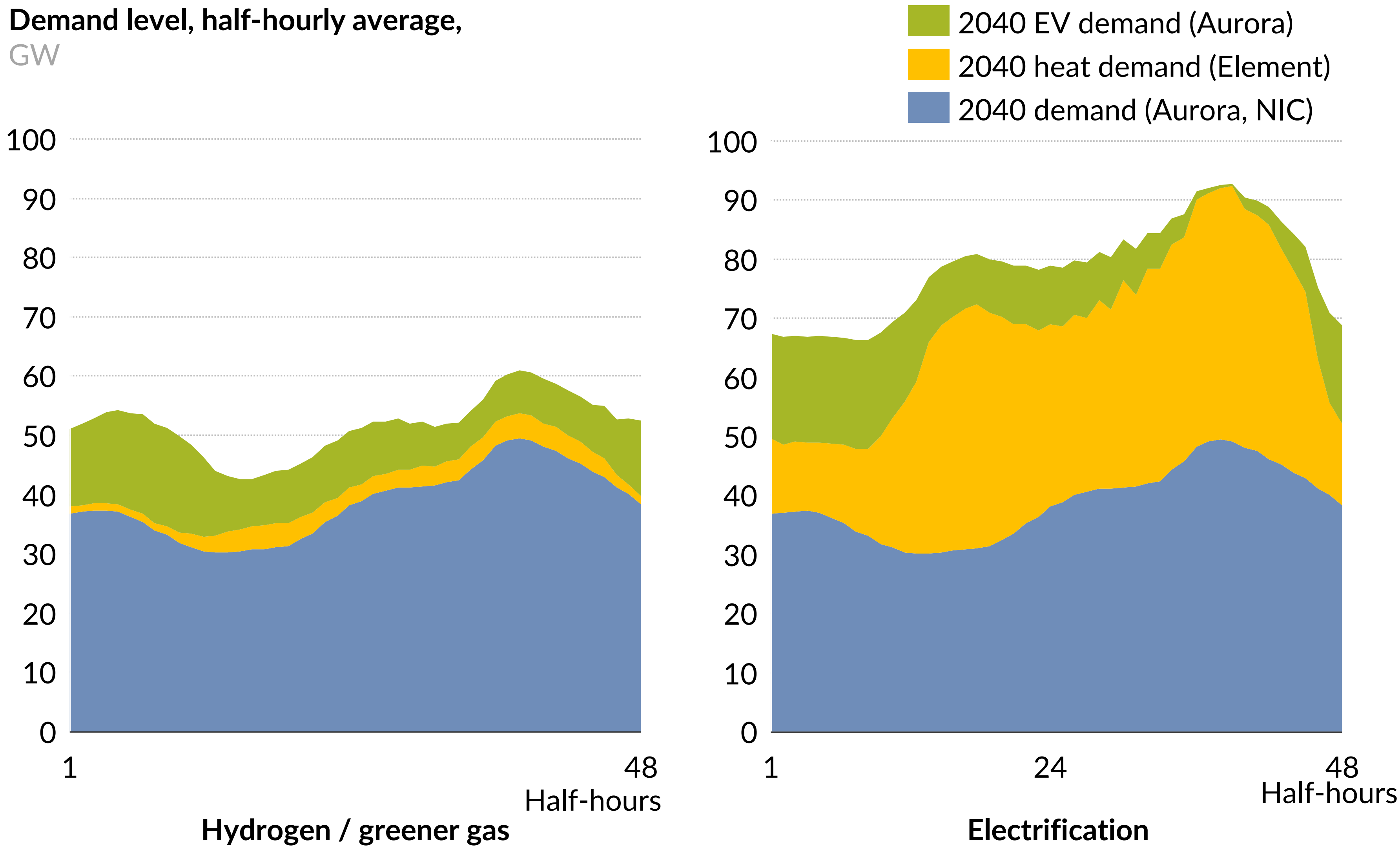


Sources: Aurora Energy Research, NIC, Element Energy

4

Smart charging leads to a higher but somewhat flatter daily profile, with more baseload demand overnight

Demand level, half-hourly average, GW



HH demand profiles for 1st January 2040

Sources: Aurora Energy Research, NIC, BEIS