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ENERGY RESEARCH

Aurora multi-client study: GB locational marginal pricing

Group Meeting 4: Central results & scenarios

11th May 2023

Welcome to the second Group Meeting for Aurora's multi-client study on locational marginal pricing in GB

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Agenda for today:

- 13:00–14:00 Registration and Lunch
- 14:00–15:30 Session 1
- 15:30–16:00 Coffee Break
- 16:00-17:00 Session 2
- 17:00–18:00 Networking Drinks & Snacks

Aims :

- Review central scenario LMP results and how these compare to the national model and Net Zero scenario results
- Explore system costs for LMP models relative to Aurora's national model
- Review changes to LMP results under two low transmission line upgrade scenarios
- Consider an alternative demand scenario, placing high demand sources at low price nodes
- Discuss the consolidation of results into the final report for participants and public report

Meetings will be held under the **Chatham House Rule**: participants are free to use the information received, but neither the identity nor the affiliation of the speaker(s), nor that of any other participant, should be revealed. Consequently, meetings won't be recorded.

This is the final group meeting for the LMP MCS. A draft of the final report will be circulated by May 16th, with the aim of incorporating feedback and comments on the draft by the end of May.

We welcome today's attendees our third Group Meeting

Department for Business, Energy & Industrial Strategy

The Aurora project team

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Today's speakers

Christian Miller
Project manager

Alex Houston
Project manager

Alex Karlsson
Analyst

Lucy Allington
Analyst

Elliot Harris
Modeller

Ben Hambrook
Modeller

Main project team

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With support from

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We've completed most of Phases 2 & 3 of the study and will present our refined NZ-LMP and asset economics results today

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Phase 1
Develop assumptions and model design

Phase 2
Scenario analysis and model refinement

Phase 3
Asset economics

Phase 4
Policy and market design analysis

Phase 2

A. Model refinement

- Refinement of assumptions on line upgrades, transfer capacities and locational mapping of generation based on initial results
- Produce final Aurora Net Zero scenarios using both nodal and zonal models

B. Aurora Central forecasts

- Produce nodal and zonal forecasts using the Aurora Central scenario for GB
- Draw insights from comparisons between Aurora Net Zero and Aurora Central

C. Scenario Analysis

- Network reinforcement analysis using 1-2 scenarios (high and low)
- Flex demand assumptions for an additional scenario (e.g. placing of electrolysers)

Outcomes of Phase 2

Market level forecasts for yearly, monthly and half-hourly wholesale prices at hubs and zones

Phase 4

A. Demand implications

- How does responsive is flexible demand to LMP signals?
- Does an LMP model provide a signal on the placement of hydrogen electrolysers?

B. System implications

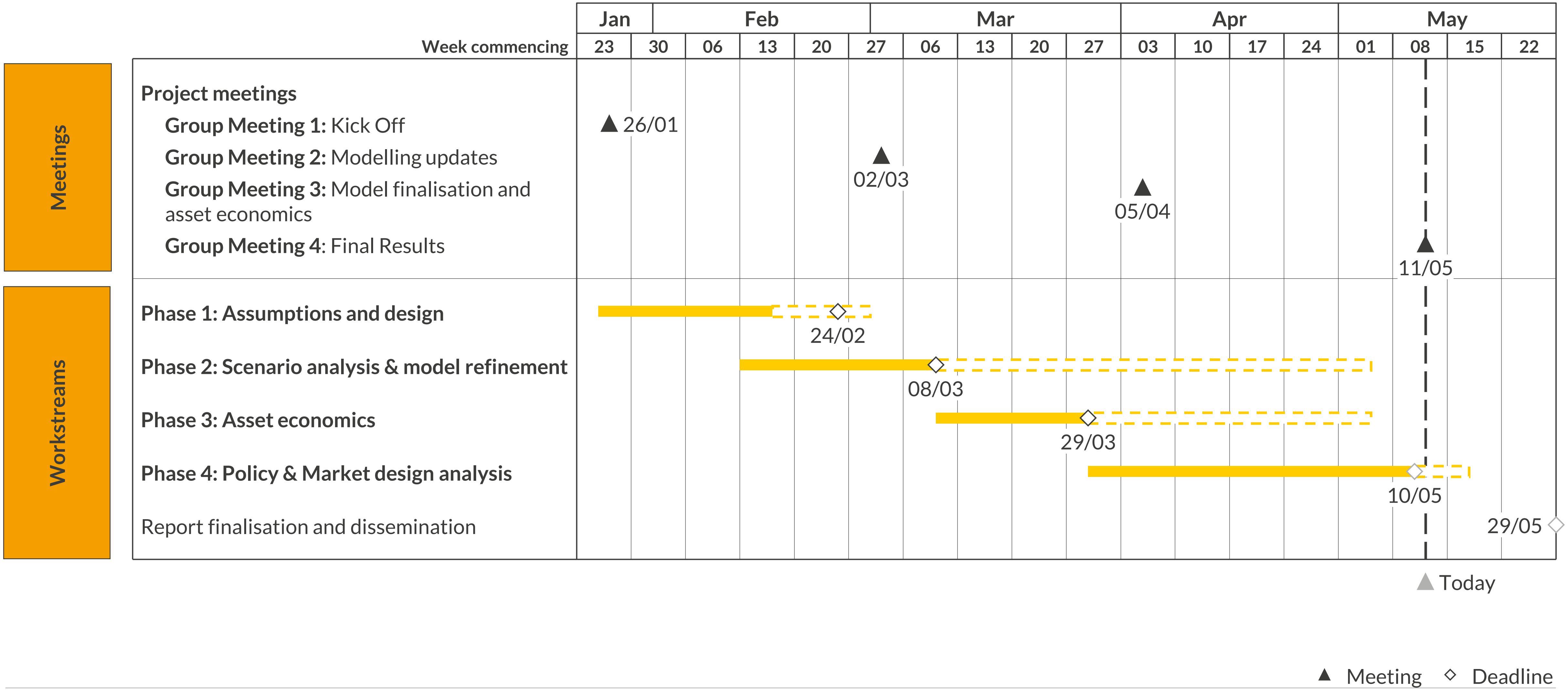
- What are the constraint costs anticipated under nodal and zonal model results compared to a national pricing system?
- How could reform of TNUoS/TLM achieve the locational signals of nodal/zonal systems under national pricing?
- How does locational pricing improve the clarity for transmission build-out?
- How does nodal model help us understand constraint volumes on the system?

Outcomes of Phase 4

Final report including analysis of the model results and implications of national, nodal or zonal systems

Note: the greyed items will be present in the first draft of the report.

We will hold one final Group Meeting in May before finalising the report for the study



In today's session we will focus on central model results, system costs and scenario analysis

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I. Aurora Central Market Scenario Results

- How do central scenario LMP results compare to National?
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- How do LMP results change when we expose demand to locational signals?

Relative to the national model, central LMP experiences more build out of peaking capacities and greater reliance on imports

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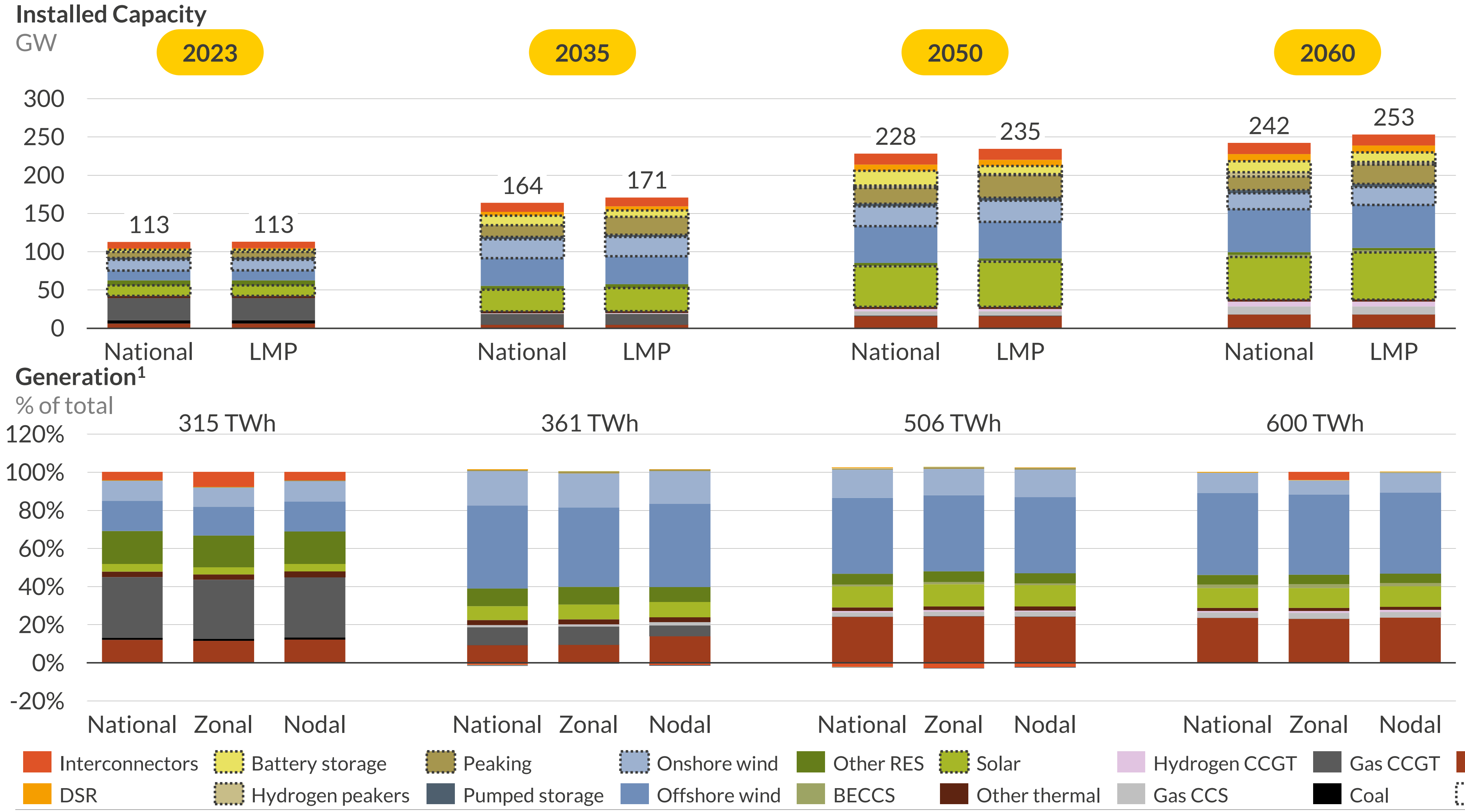

- In the zonal model, flexible and onshore RES capacities can respond to zonal price signals.
- Overall, we see slightly more buildout of these technologies in the zonal case relative to national pricing case.
- The nodal model uses build decisions from the national model.
- While total generation volumes are consistent as the models balance the same annual demand levels, generation composition differs due to congestion.
- This is primarily observed in increased interconnector imports and movement of RES generation between zones.

1) Generation including net interconnector flows.

Source(s): Aurora Energy Research

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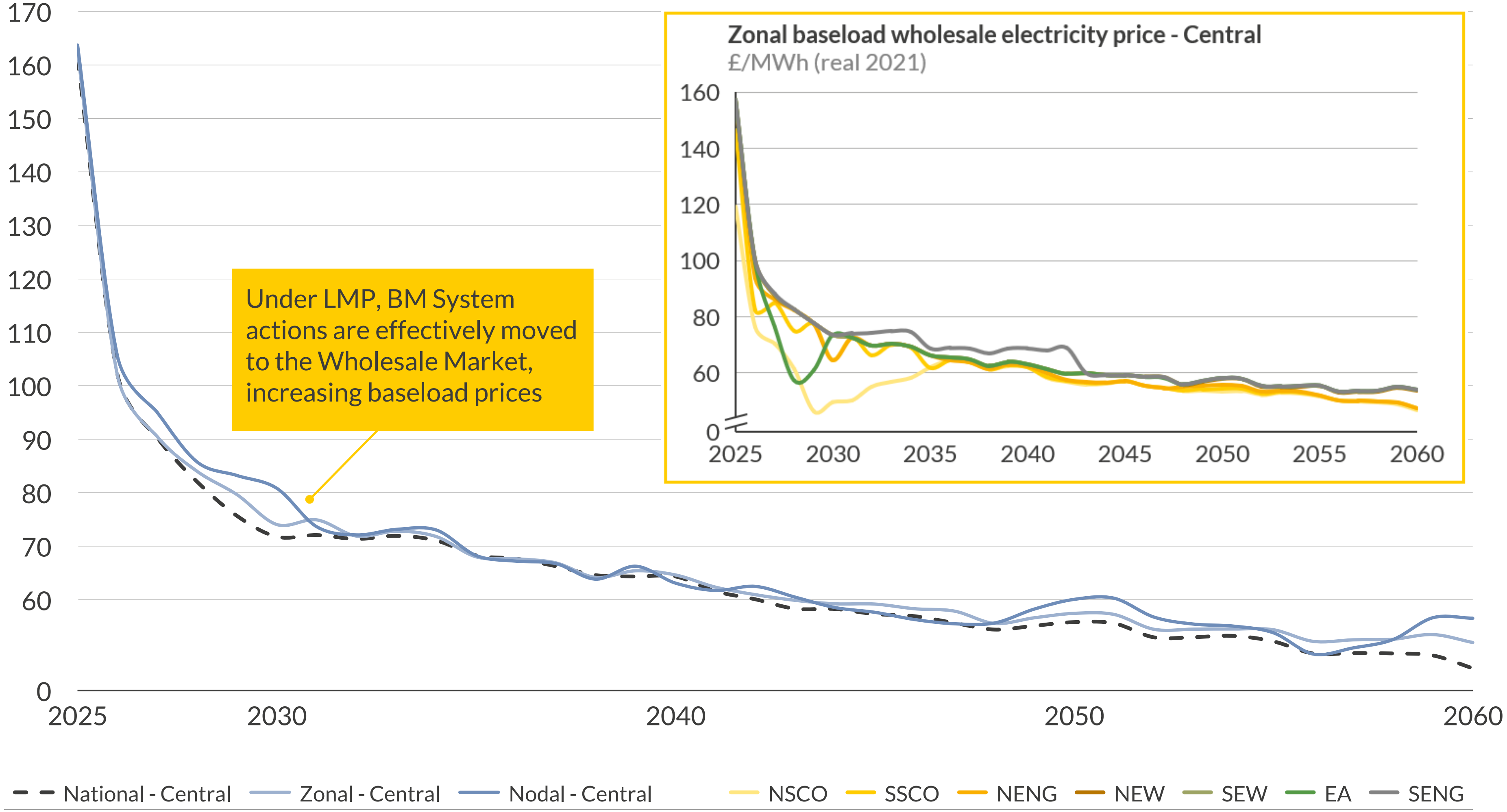
In Aurora Central, LMP generally increases baseload prices since network constraints are now considered in wholesale dispatch

Baseload Wholesale Electricity Price – Demand Weighted Average

£/MWh (real 2021)



Source(s): Aurora Energy Research

Increasing locational granularity increases baseload prices

- In general, we see that the nodal model has the highest baseload prices, followed by zonal then national which track each other more closely. The increase in Wholesale prices is driven by the cost of BM System actions now being incorporated into Wholesale Market prices
- Intrazonal congestion in the nodal model inflates prices despite line upgrades, whilst boundary upgrades in the zonal model reduce congestion to the extent that, on average, prices resemble those in the national case towards the end of the forecast
- Zonal boundary upgrades similarly lead to zones coupling in prices towards the end of the forecast, with SSCO, NSCO and NENG forming a single price zone by 2060, with a similar effect applying to SENG and EA

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Line upgrades in Aurora's zonal Central scenario reflect lower congestion revenue compared to Net Zero

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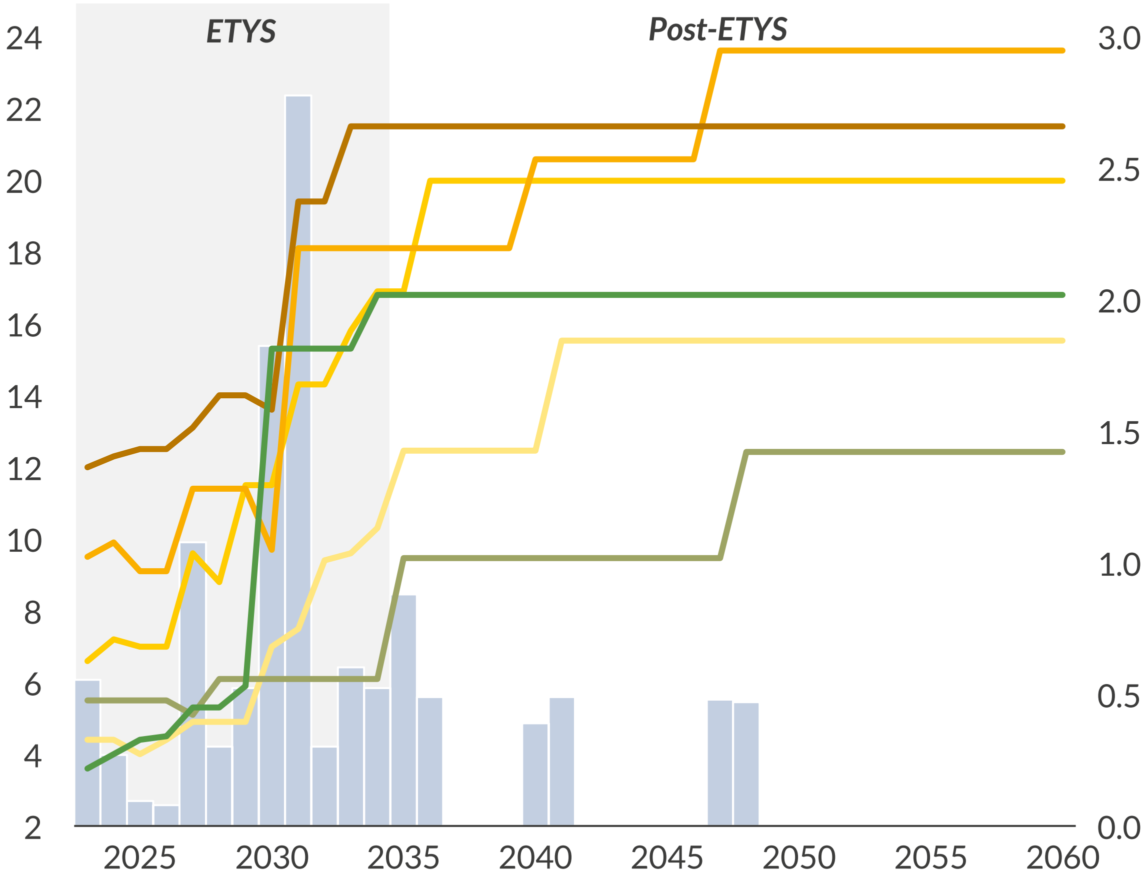
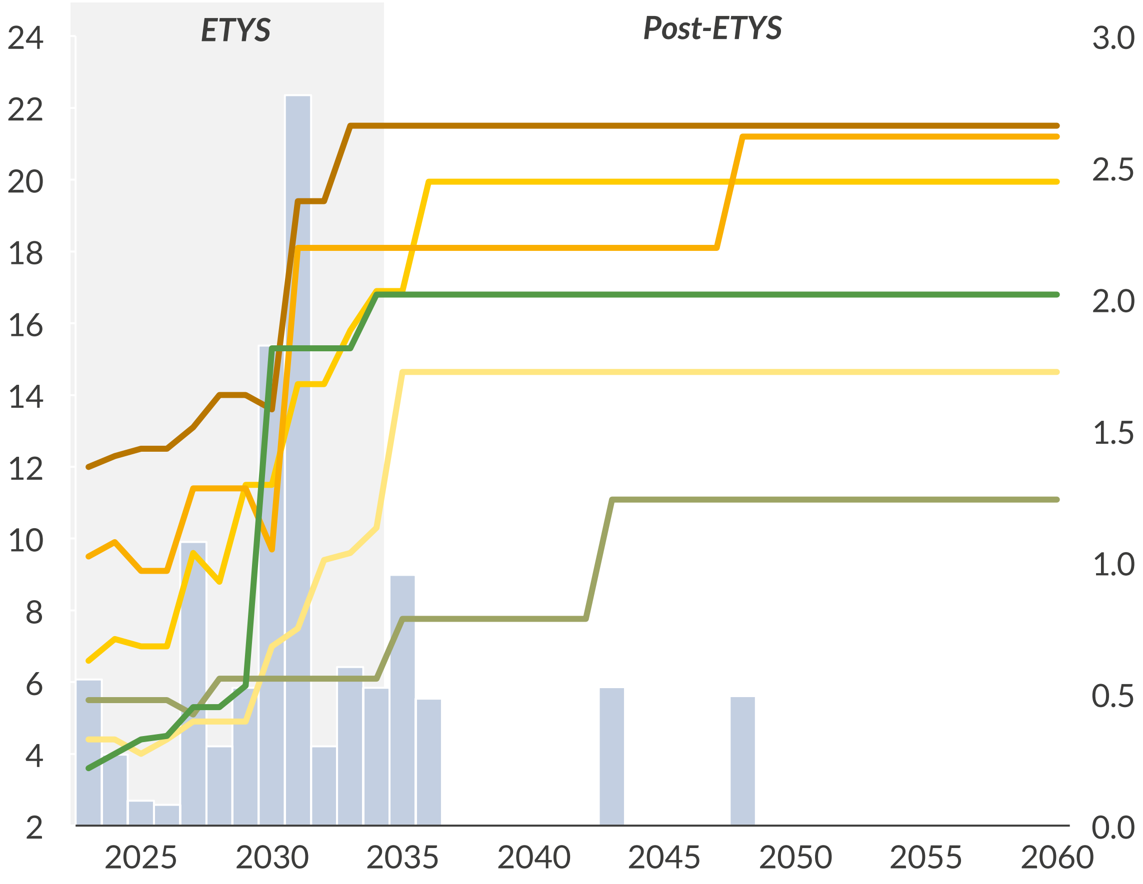
Zonal Pricing

Transfer Capacity for Net Zero GW | **Estimated Cost of Line Upgrades** £bn



Transfer Capacity for Central GW | **Estimated Cost of Line Upgrades** £bn



B4 B6 B7a B8 SC1 EC5 Upgrade cost

Source(s): Aurora Energy Research

Relative to the Net Zero, central LMP has less capacity buildout, but more of this is endogenously built within the model

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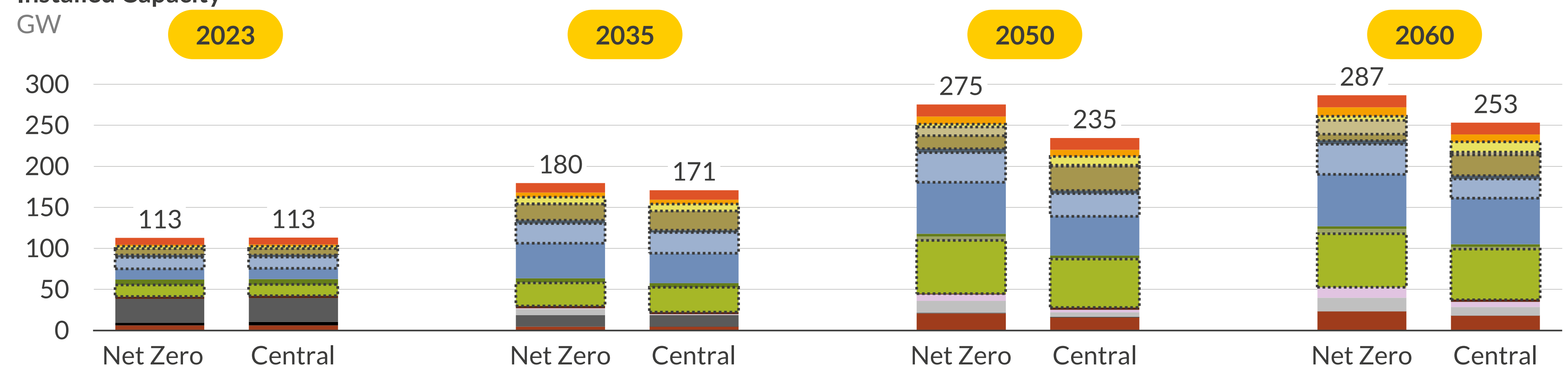
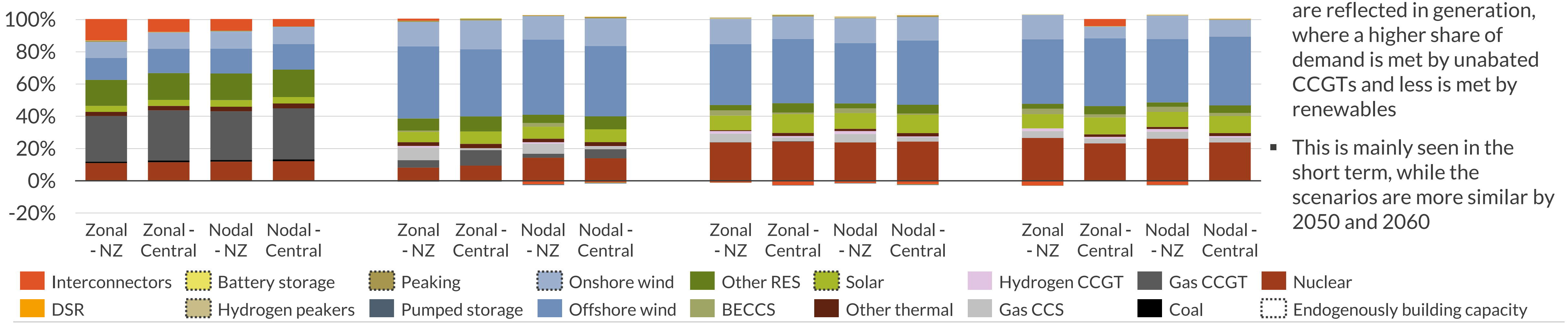
Installed Capacity
GW



- By 2060, the Central scenario has ~35GW less total capacity compared to Net Zero, reflecting reduced total demand due to slower electrification and uptake of hydrogen
- Under the Central scenario there is also less aggressive buildout of renewables and low-carbon baseload capacity

Generation[1]
% of Total



- These capacity differences are reflected in generation, where a higher share of demand is met by unabated CCGTs and less is met by renewables
- This is mainly seen in the short term, while the scenarios are more similar by 2050 and 2060

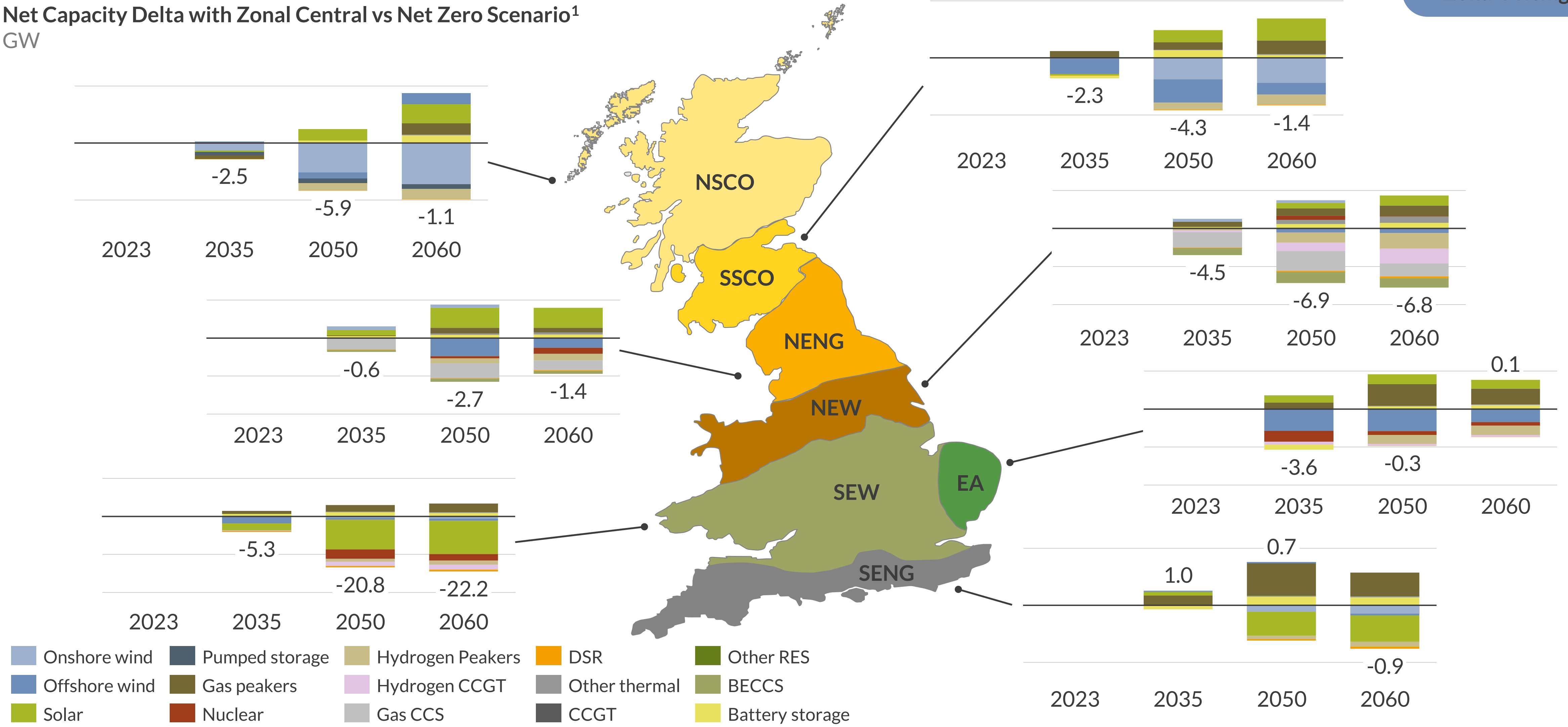
1) Generation including net interconnector flows.

Source(s): Aurora Energy Research

Capacity deltas in zonal Central vs Net Zero reflect reduced buildout of solar in the south and low-carbon baseload in the north

Zonal Pricing

Net Capacity Delta with Zonal Central vs Net Zero Scenario[1]
GW



1) Positive delta reflects greater capacity in the Central scenario vs Net Zero scenario, and vice versa. There is no capacity delta in 2023 as the scenarios diverge beyond this year.

Source(s): Aurora Energy Research

Between 2030 and 2060, Central baseload prices on average trend ~34% higher than Net Zero, driven by lower buildout of renewables

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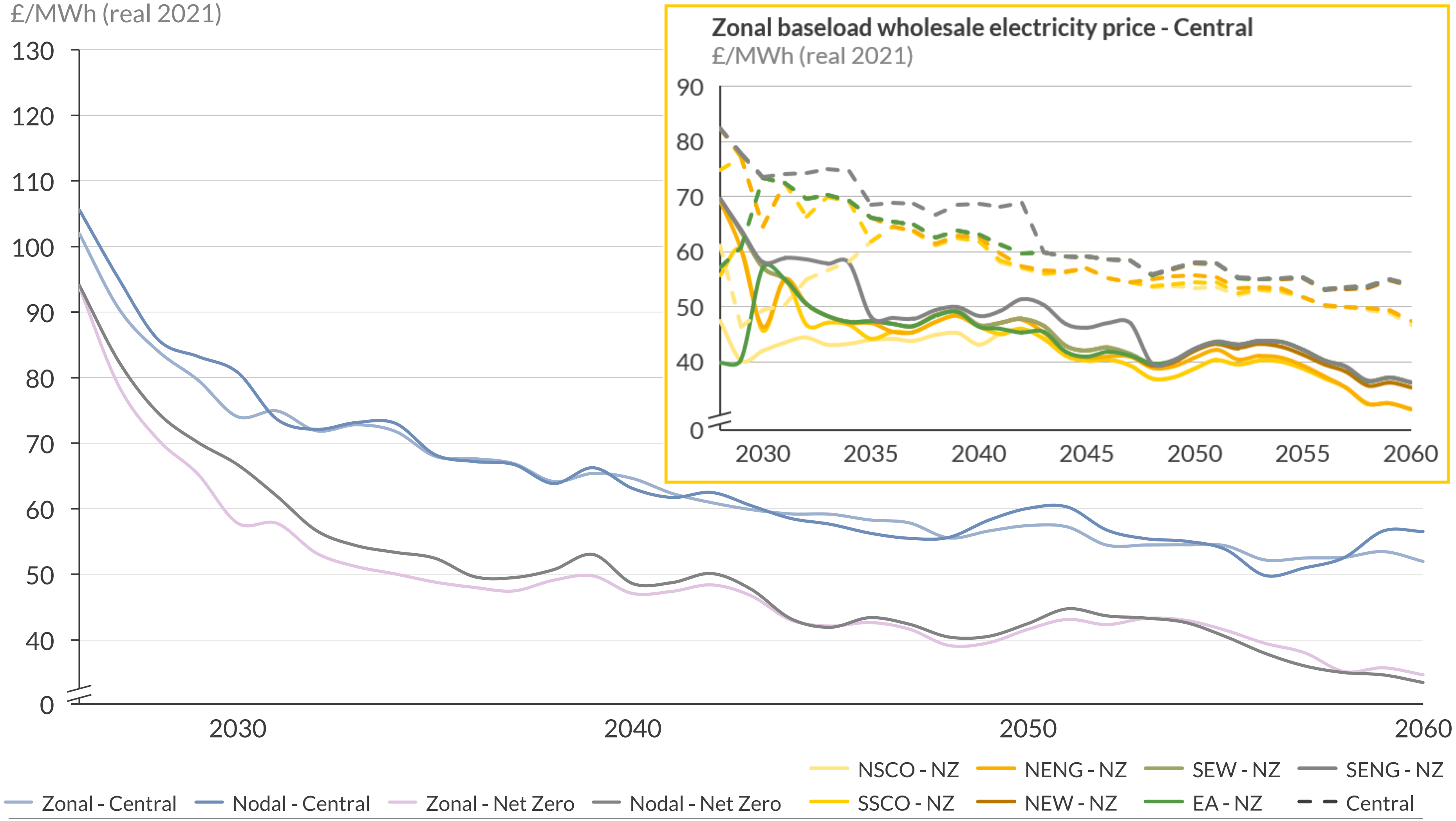
Baseload Wholesale Electricity Price – Demand Weighted Average
£/MWh (real 2021)



- Relative to Net Zero, Aurora Central sees elevated baseload prices in both the zonal and nodal models, reflecting reduced buildout of low marginal cost, low-carbon generation in the form of hydrogen CCGTs, CCGT+CCS and renewables
- Relative price differences between the 7 zones are similar in the Central and Net Zero zonal scenarios, reflecting the same ETYS line upgrades up to 2034. Prices in SENG, EA and SEW couple earlier in Central, reflecting lower congestion
- Nodal prices are generally higher than zonal prices due to the consideration of intrazonal congestion in Wholesale dispatch

Source(s): Aurora Energy Research

On average, the top prices trend upward in Central relative to Net Zero, while the bottom price remain in line between the scenarios

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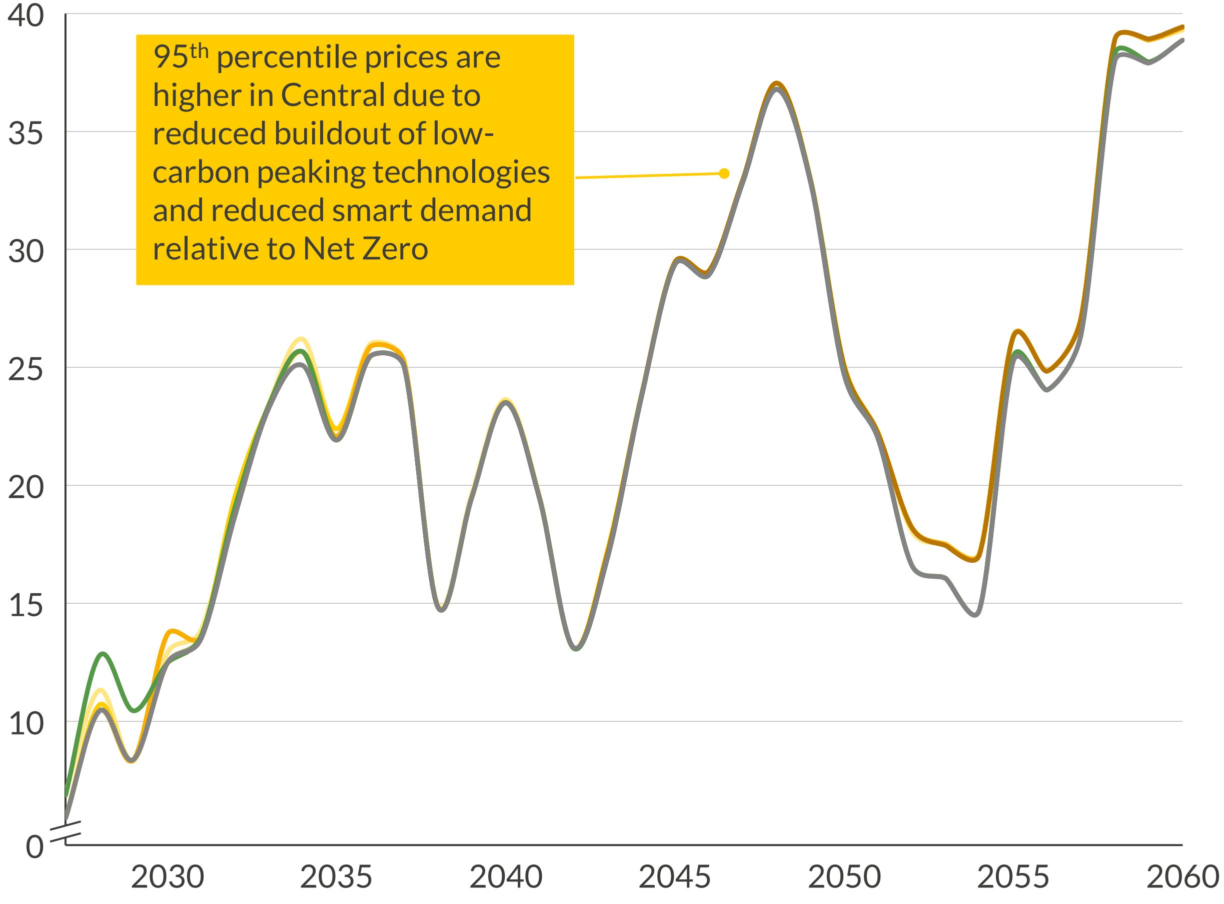
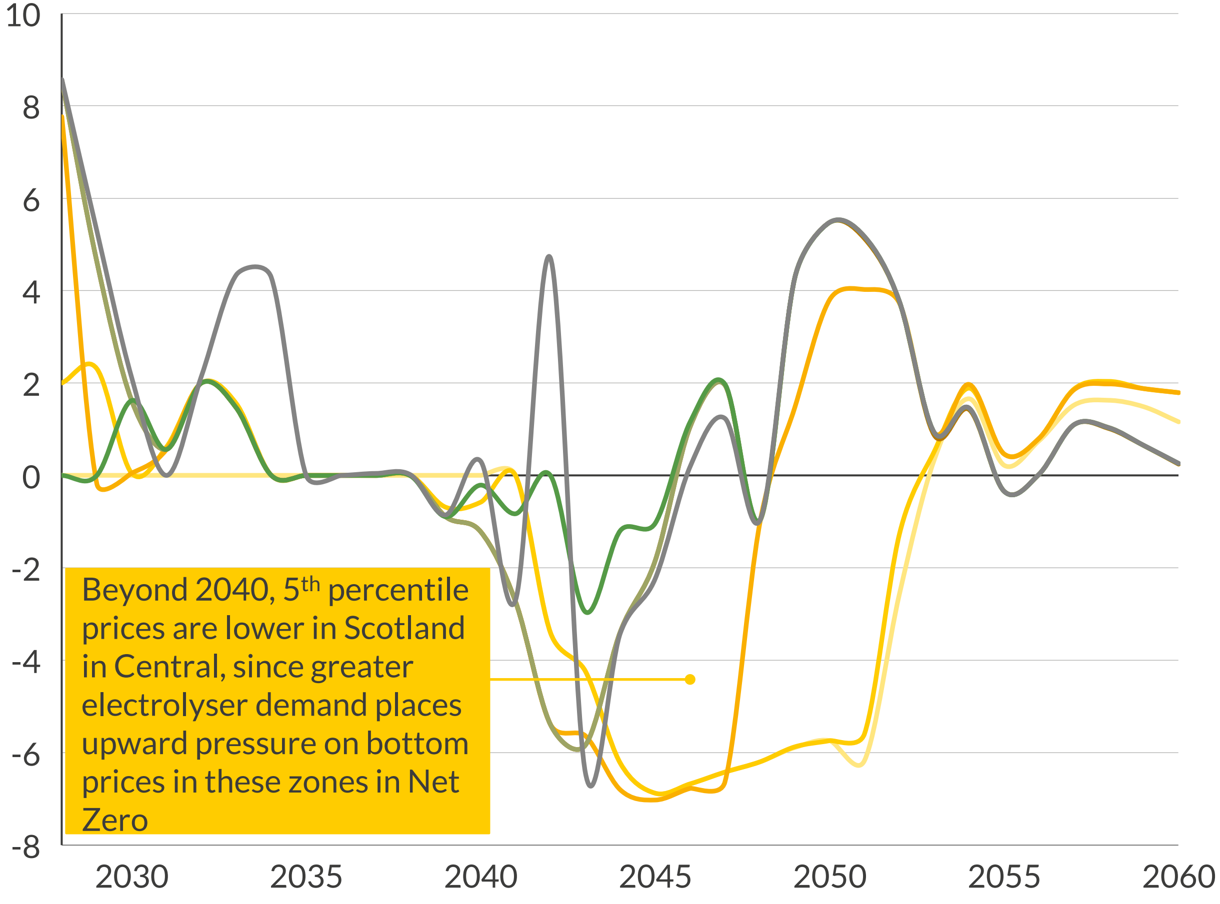
Zonal Pricing

95th Percentile Wholesale Price – Delta in Central vs Net Zero
£/MWh (real 2021)



5th Percentile Wholesale Price – Delta in Central vs Net Zero
£/MWh (real 2021)



NSCO SSCO NENG NEW SEW EA SENG

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Capacity deltas in the zonal Central scenario reflect endogenous buildout responding to system constraints and price differentials

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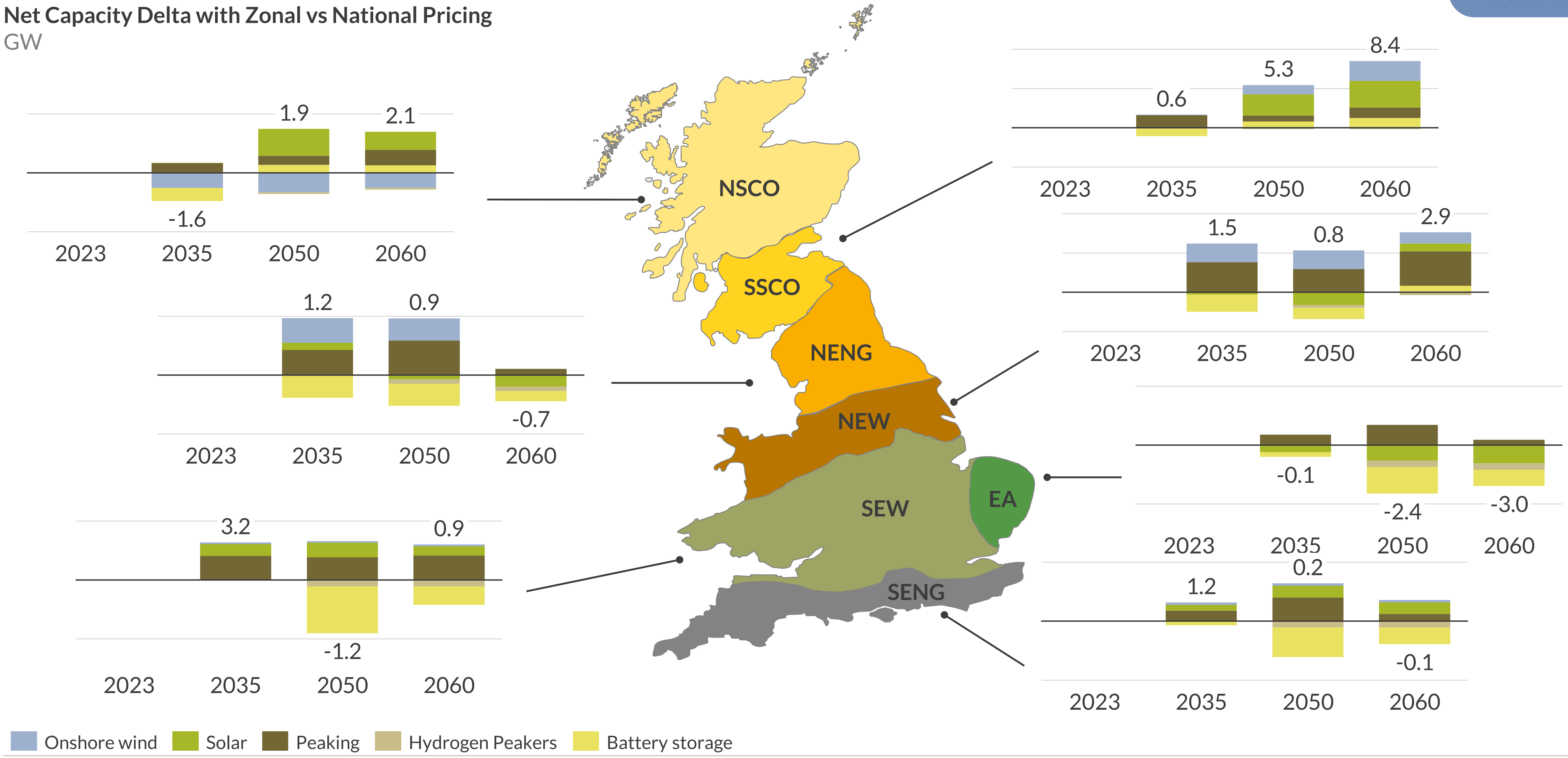
Zonal Pricing

Net Capacity Delta with Zonal vs National Pricing
GW



Source(s): Aurora Energy Research

Consideration of constraints between 7 zones results in reduced RES generation in low price zones, mainly North Scotland and East Anglia

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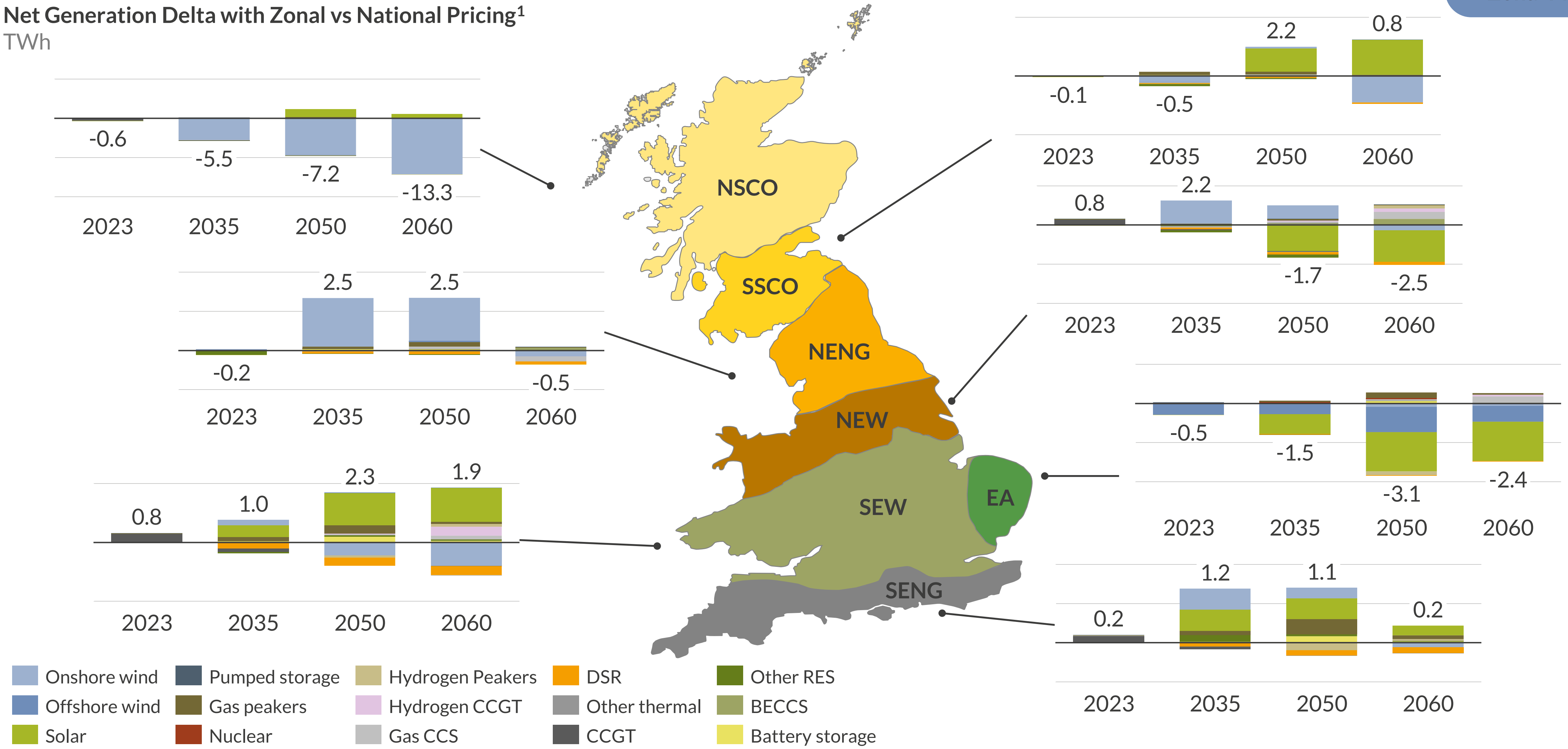
Zonal Pricing

Net Generation Delta with Zonal vs National Pricing[1]

TWh



1) Generation deltas in the zonal vs national model reflect changes in endogenous capacity buildout and interconnector imports. This is in addition to the consideration of interzonal constraints between 7 zones in Wholesale dispatch vs 3 zone locational balancing in Aurora's national model.

Source(s): Aurora Energy Research

Zonal baseload prices fall from £119-157/MWh in 2023 to £46-53/MWh by 2060 in Aurora Central

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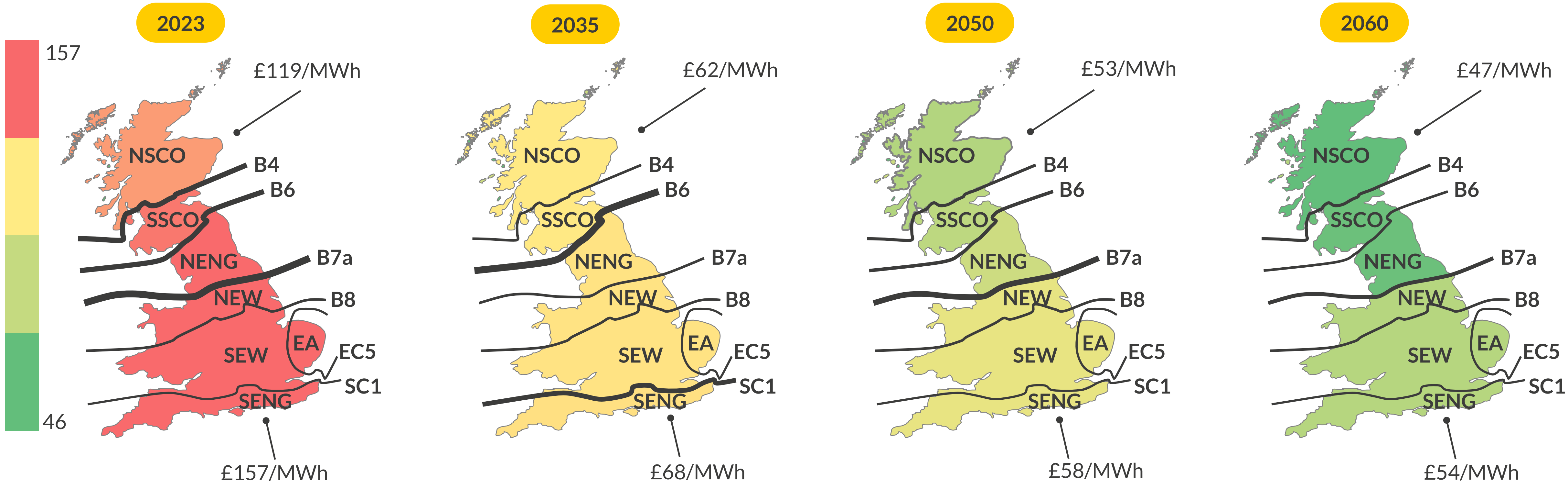
Zonal Pricing

Zonal Baseload Price
£/MWh (real 2021)



Line thickness proportional to boundary congestion

Source(s): Aurora Energy Research

Zonal 2h price spreads remain an average of 8% above national spreads between 2030 and 2050

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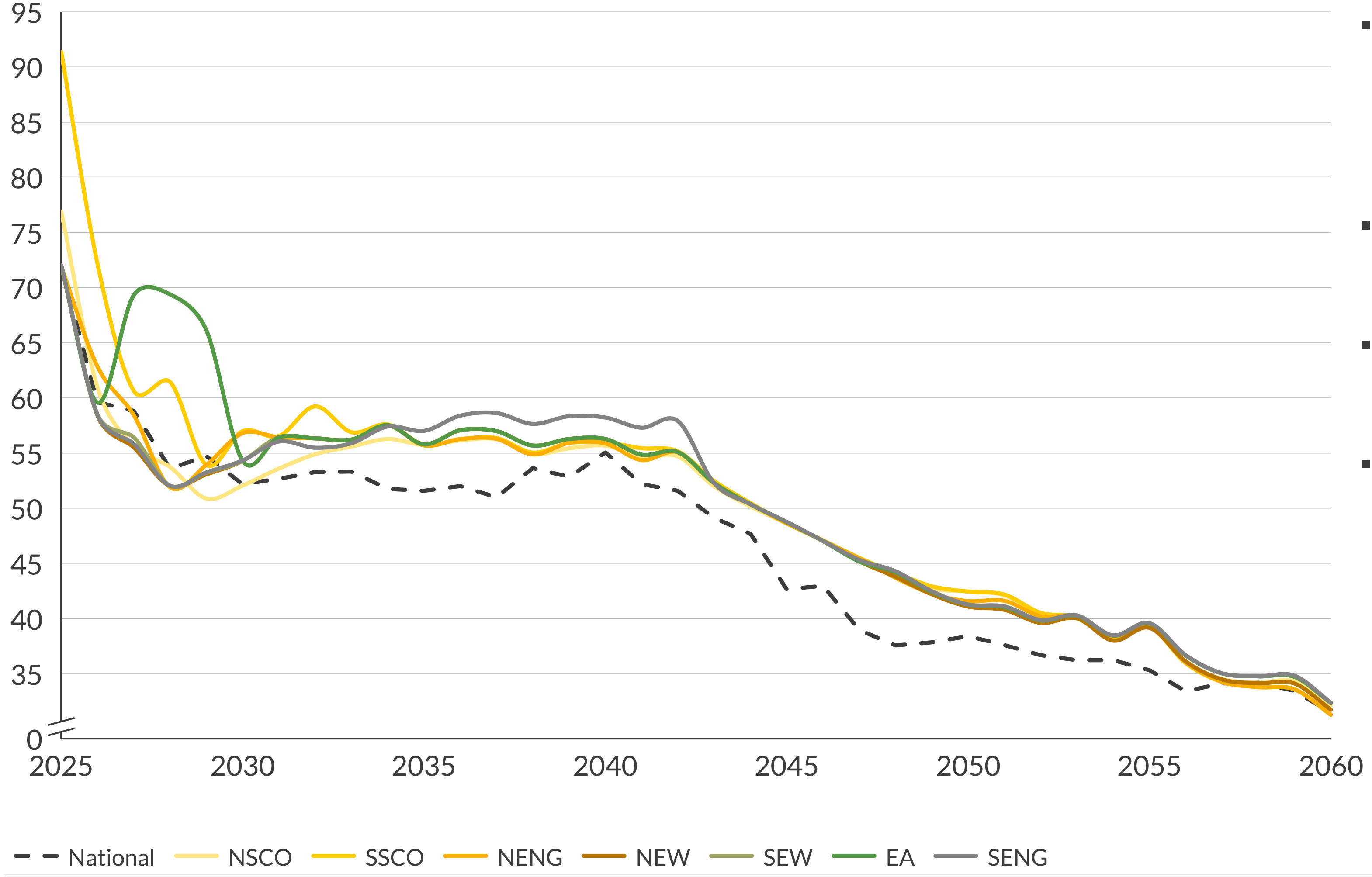
Zonal Pricing

Average Daily 2-hour Wholesale Price Spread
£/MWh (real 2021)



- Price spreads indicate the difference between the top and bottom prices within a day. The 2h price spread takes the two highest prices within a day less the lowest two settlement prices in the same day.
  - Note that these periods are not necessarily sequential
- As wholesale prices decrease and move towards equilibrium with easing of congestion, so too do zonal spreads
- Removing congestion constraints drives the zones towards converging spreads as zones are freely able to trade across boundaries
- Aurora's national model reflects lower 2h spreads, driven by less system congestion and therefore less price variance overall

Source(s): Aurora Energy Research

Under zonal pricing, 95th and 5th percentile prices generally increase, except for in oversupplied zones when boundaries are congested

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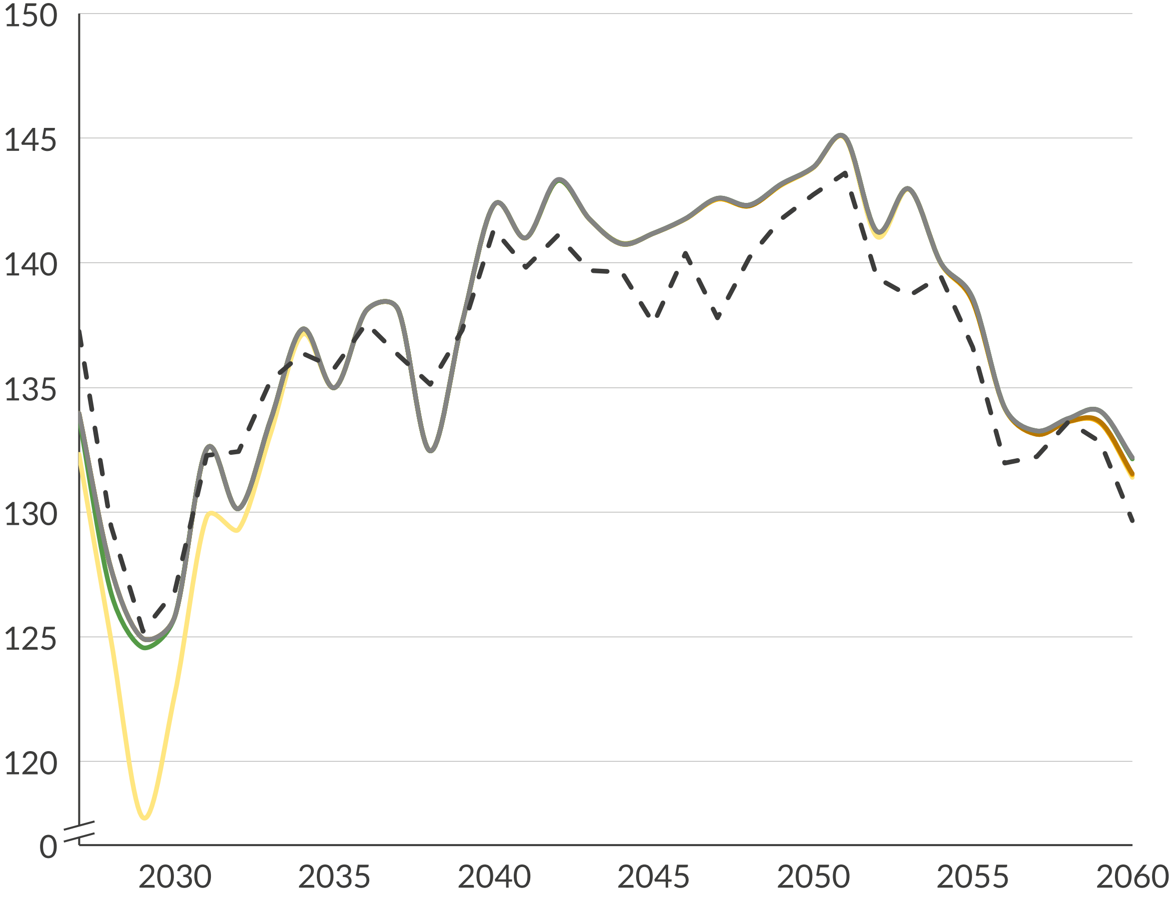
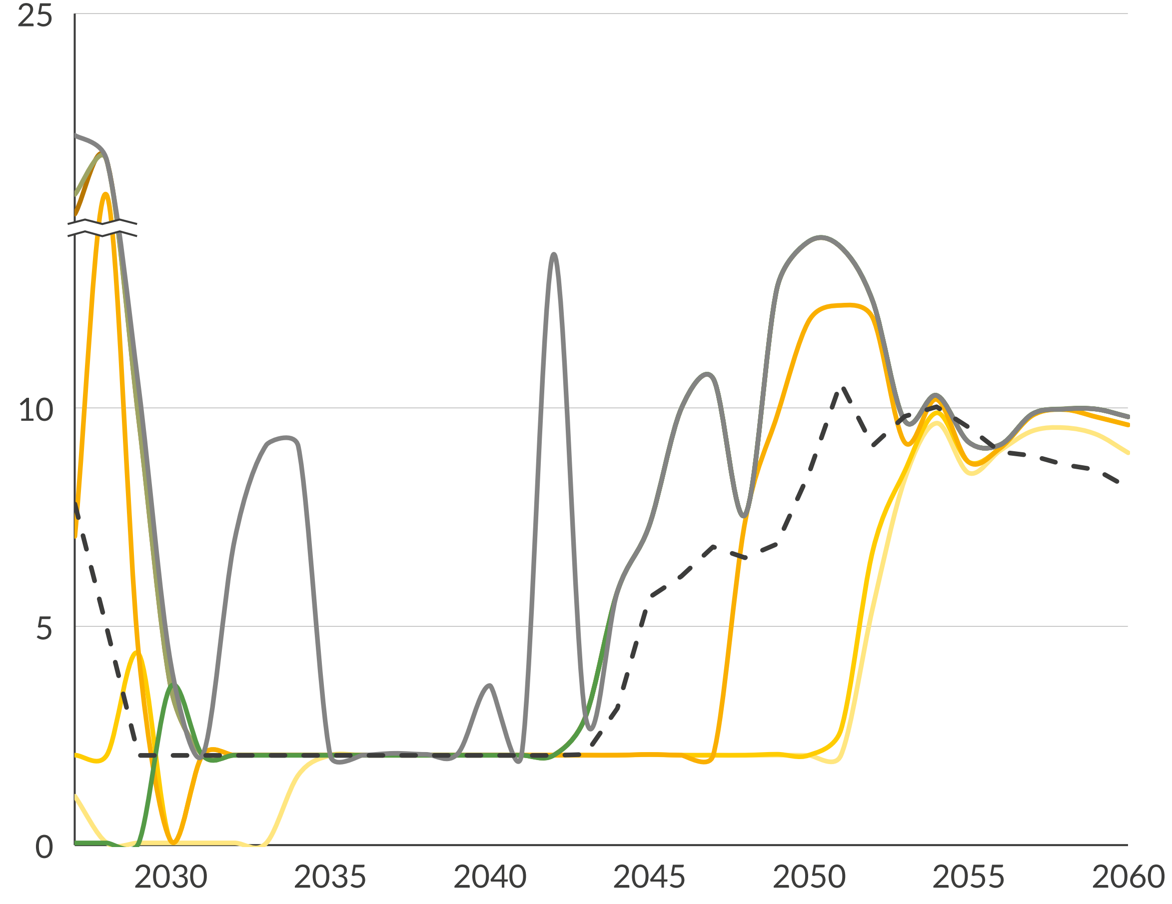
95th Percentile Wholesale Price
£/MWh (real 2021)



5th Percentile Wholesale Price
£/MWh (real 2021)



NSCO SSCO NENG NEW SEW EA SENG National

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Similarly to Net Zero, average nodal prices decrease over time, with easing congestion, while price differences across GB remain high

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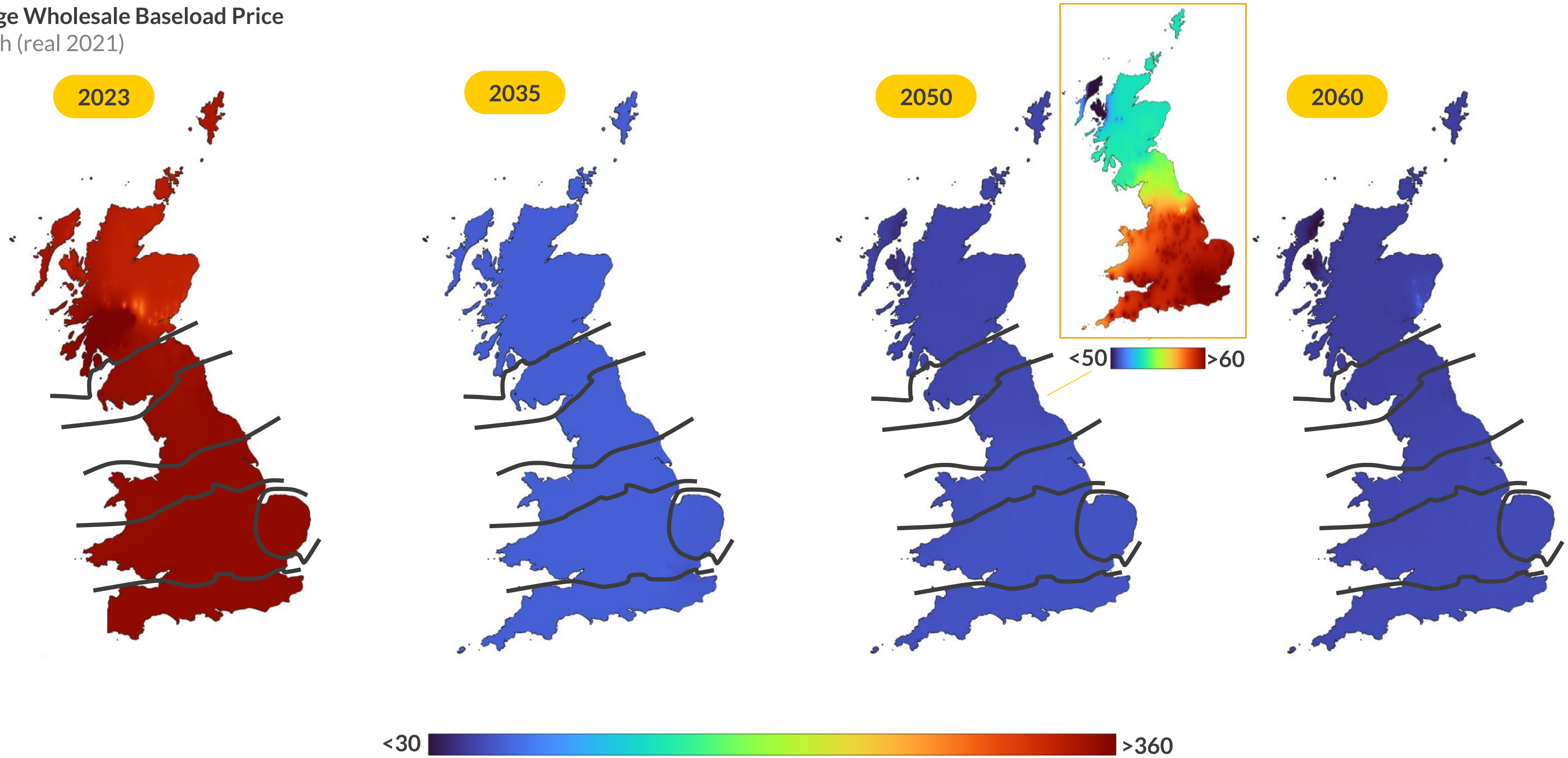
Nodal Pricing

Average Wholesale Baseload Price
£/MWh (real 2021)



Source(s): Aurora Energy Research

Relative to the national case, nodal Central sees a greater frequency of prices at high and low extremes, reflecting congestion

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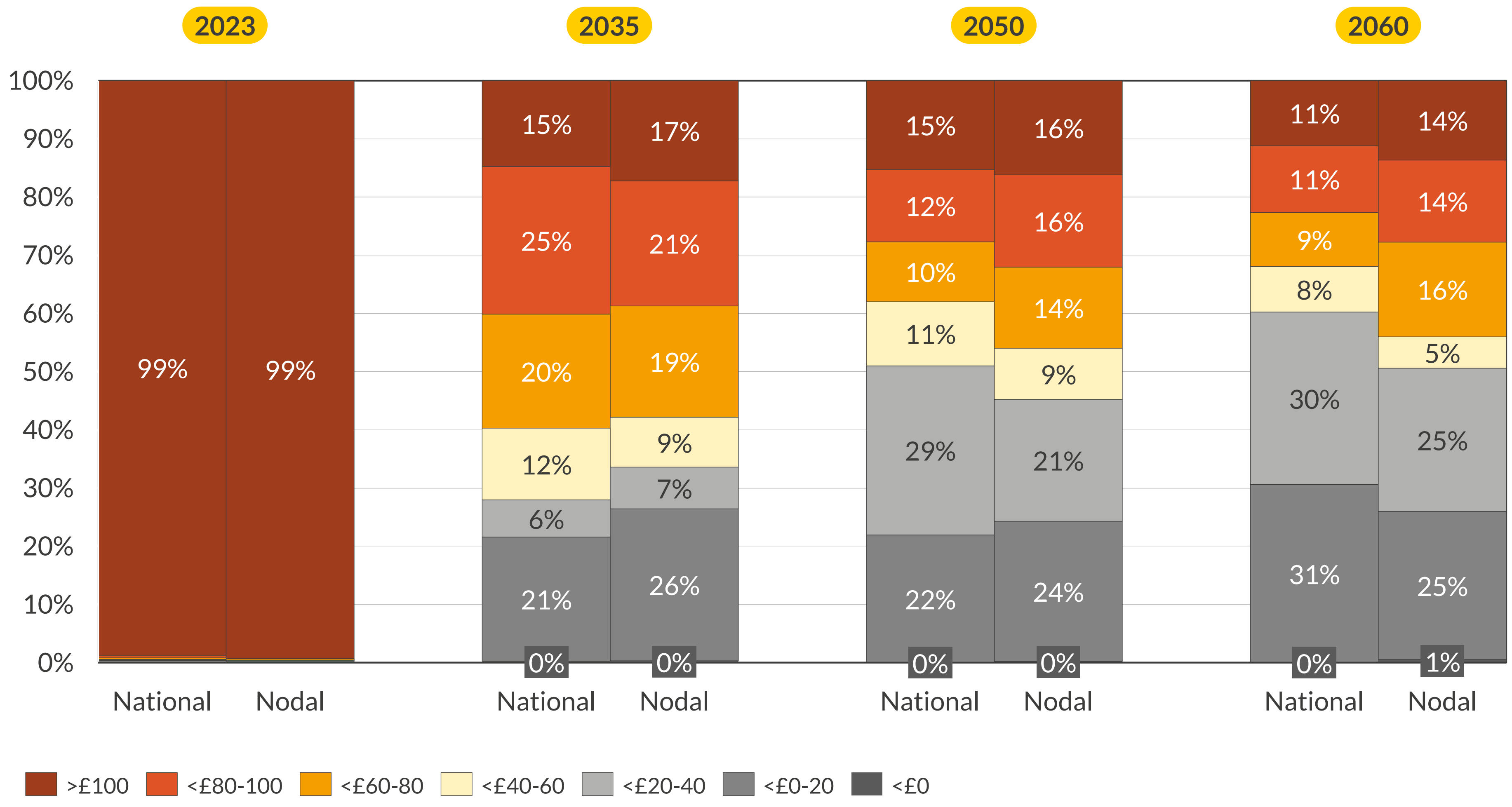
Nodal Pricing

Frequency Distribution of Demand-Weighted Wholesale Prices
%



- In 2023, prices are nearly always above £100/MWh in both the National and Nodal model due to high gas prices
- As gas prices fall and the penetration of RES increases, we see baseload prices fall and price variability increase, with low-SRMC RES increasingly setting low bottom prices, whilst more expensive peaking assets set top prices
- In the nodal model, we generally see prices more frequently at the high and low extremes compared to the national model. This reflects the consideration of congestion in nodal wholesale prices, which causes more variability both geographically and from one hour to the next

Source(s): Aurora Energy Research

Changes in nodal congestion generate a system of low persistence across highest and lowest price percentiles

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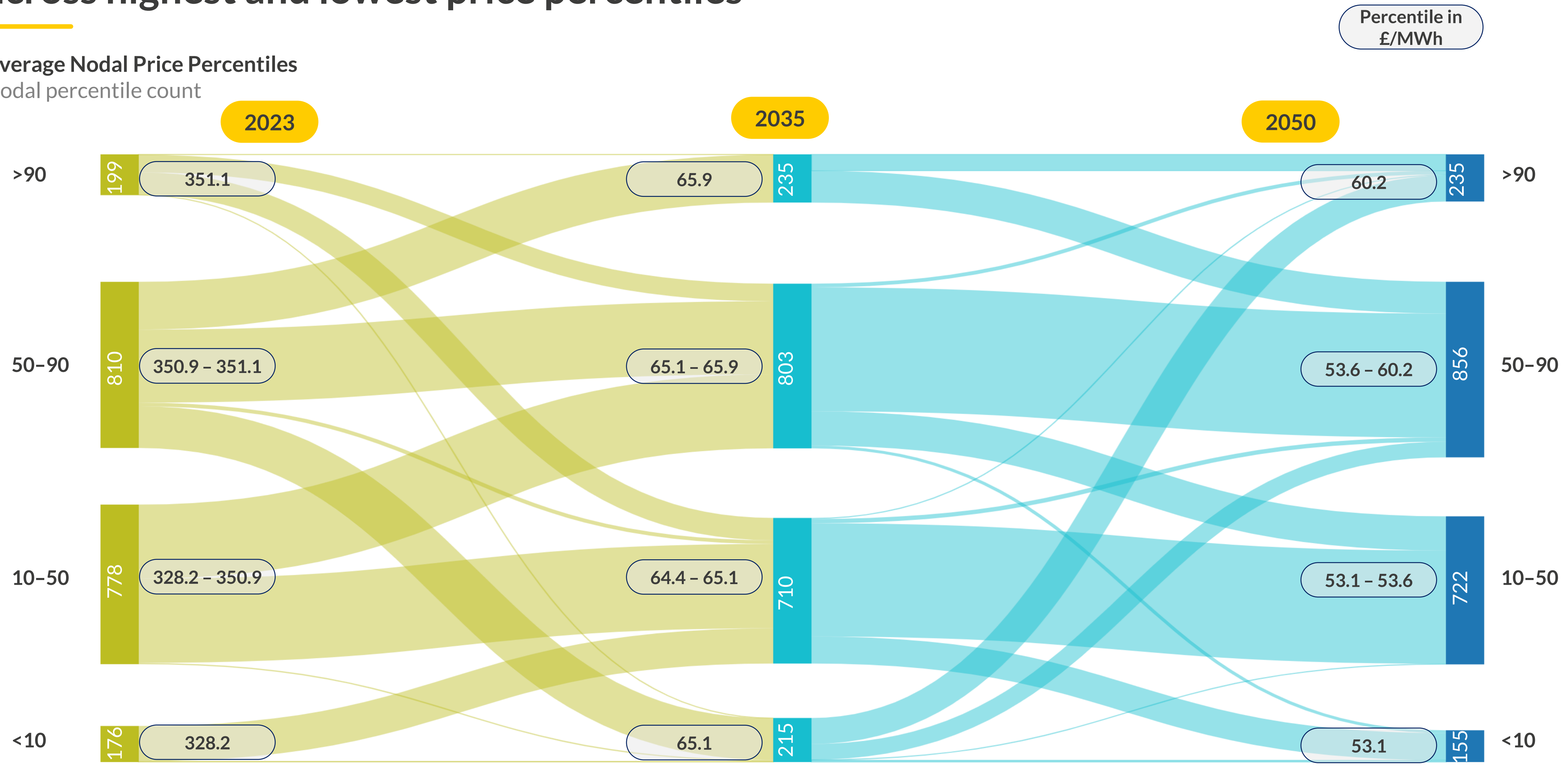
Average Nodal Price Percentiles

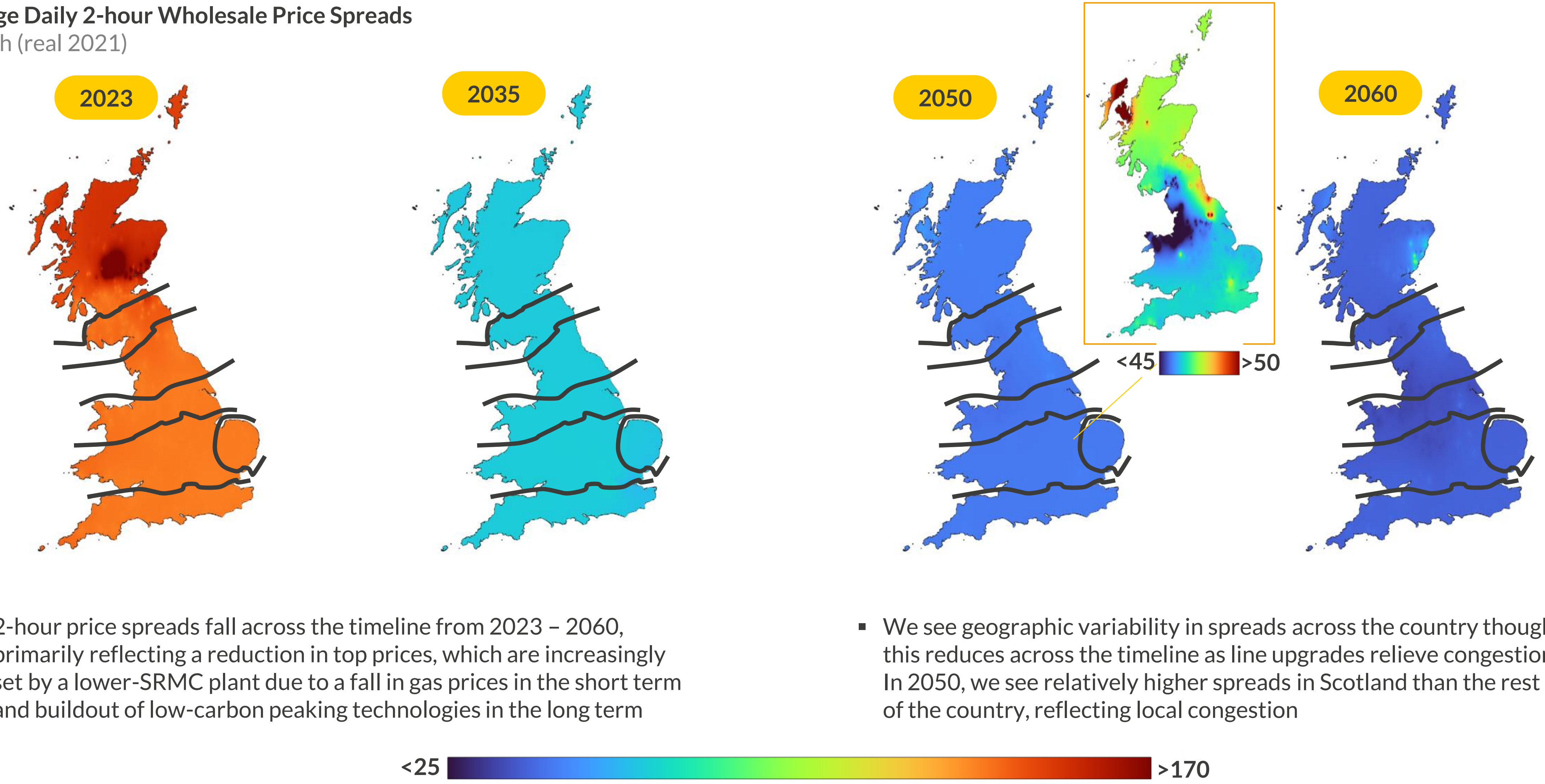
Nodal percentile count



A similar story holds as 2h price spreads decrease on average over time, with some persistence of higher spreads in Scotland

Nodal Pricing

Average Daily 2-hour Wholesale Price Spreads
£/MWh (real 2021)



- 2-hour price spreads fall across the timeline from 2023 – 2060, primarily reflecting a reduction in top prices, which are increasingly set by a lower-SRMC plant due to a fall in gas prices in the short term and buildout of low-carbon peaking technologies in the long term
- We see geographic variability in spreads across the country though this reduces across the timeline as line upgrades relieve congestion. In 2050, we see relatively higher spreads in Scotland than the rest of the country, reflecting local congestion

Source(s): Aurora Energy Research

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A change to LMP will affect several components of the cost of the energy system in Great Britain

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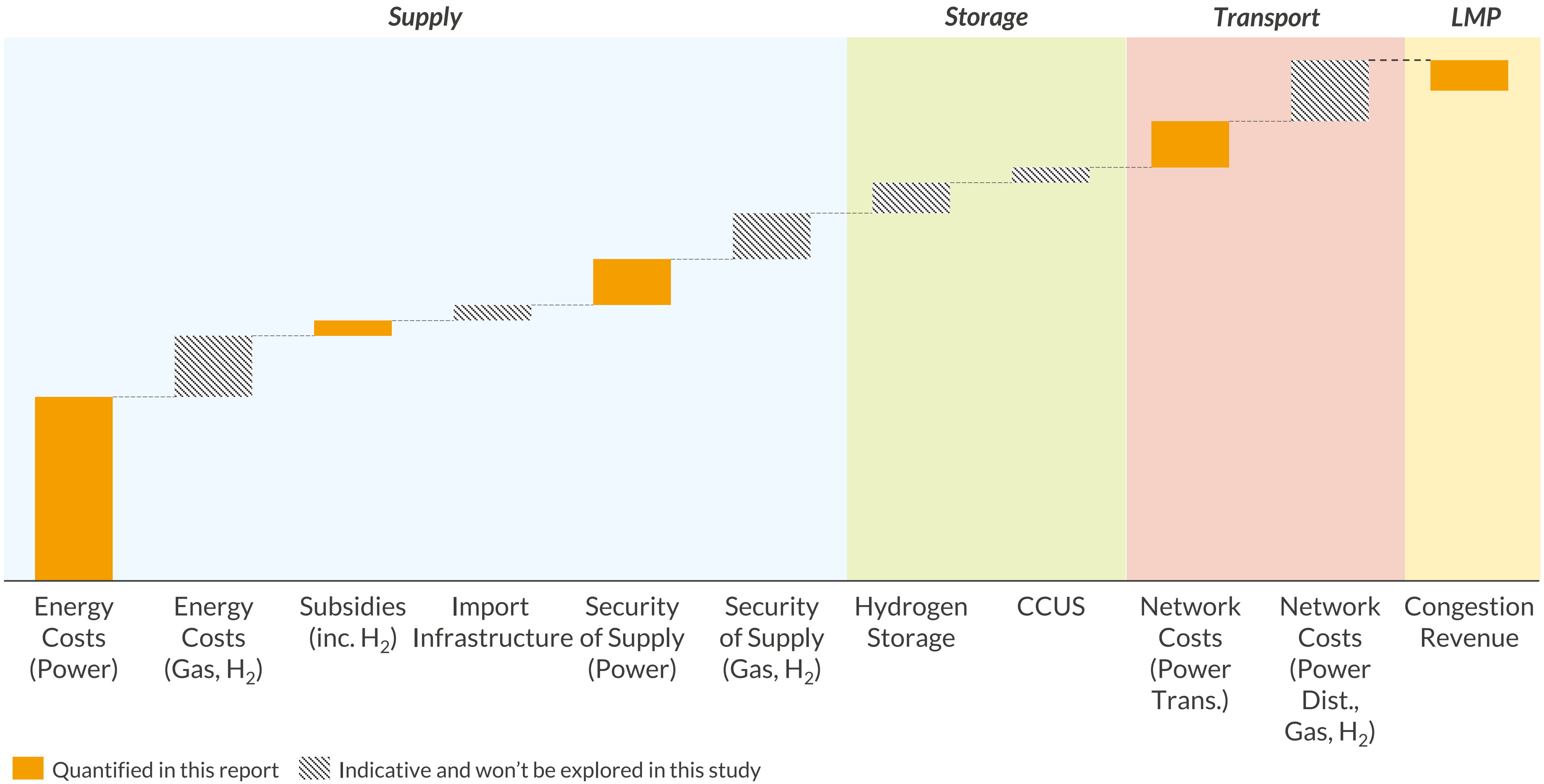
Illustrative Diagram of System Cost Components



- Aurora previously assessed system cost stacks for our study on hydrogen in 2020
- Excluding the "indicative" parts of the stack, we found that **energy costs** and **network costs** were the largest parts
- We evaluated the NPV of 2020–60 costs for each of the models

Source(s): Aurora Energy Research

We've taken a whole system approach to determine the trade-offs associated with each of the market pricing models

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Cost Component	Methodology
Wholesale Cost	The cost of demand where it was consumed, assuming that demand is fully exposed to it's local price
BM System Cost	Dispatch actions of plants in our nodal model with and without constraints informs the volume of system actions in our national model[1]. For zonal, we subtract the power flow deltas across boundaries to arrive at intrazonal system costs. We assume no system actions in nodal.
BM Energy Cost	Energy actions are assumed to be resolved at the national level across all models, with no locational price differences
Subsidy Cost	Legacy subsidy schemes coupled with national strike prices with zonal reference prices for existing cfd RES assets. Subsidies for other technologies forced onto the system are such that their NPV is zero. Zonal subsidy costs are used as a proxy for nodal subsidy costs.
Security of Supply Cost	The cost of the Capacity Market when considering the "missing money" problem across the models
Network Cost	The CAPEX cost associated with upgrading transmission infrastructure
Congestion Revenue	The cost recovered by the grid by buying power cheaply in one location and selling it at a higher price in another

1) Note that this methodology is not flexible to include in our national pricing model results elsewhere

Source(s): Aurora Energy Research

Under our models, benefits of removing costly BM system actions are countered with rises in wholesale and security of supply costs

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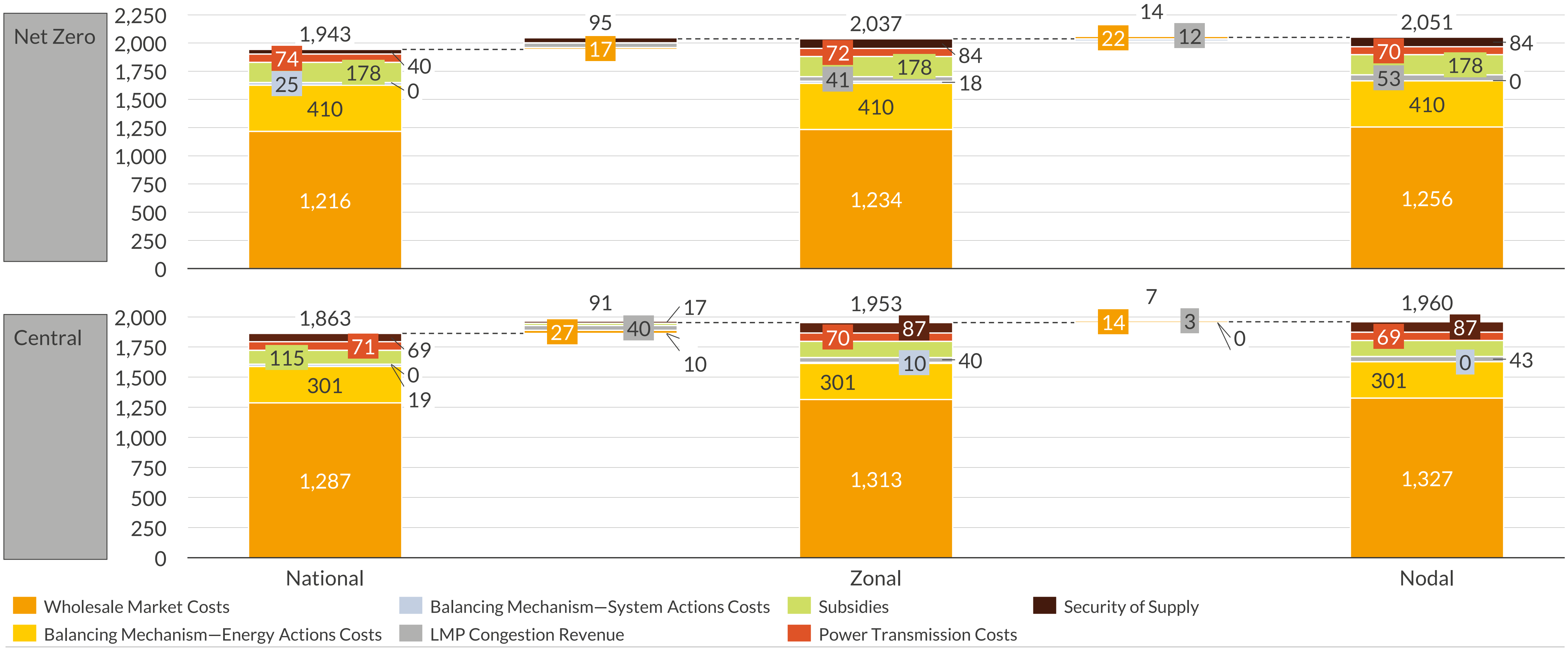
Total System Costs (2023–2060)
£bn (real 2021)



Source(s): Aurora Energy Research

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Aurora has assessed two alternative transmissions scenarios with lower transmission capacity than the study's base case

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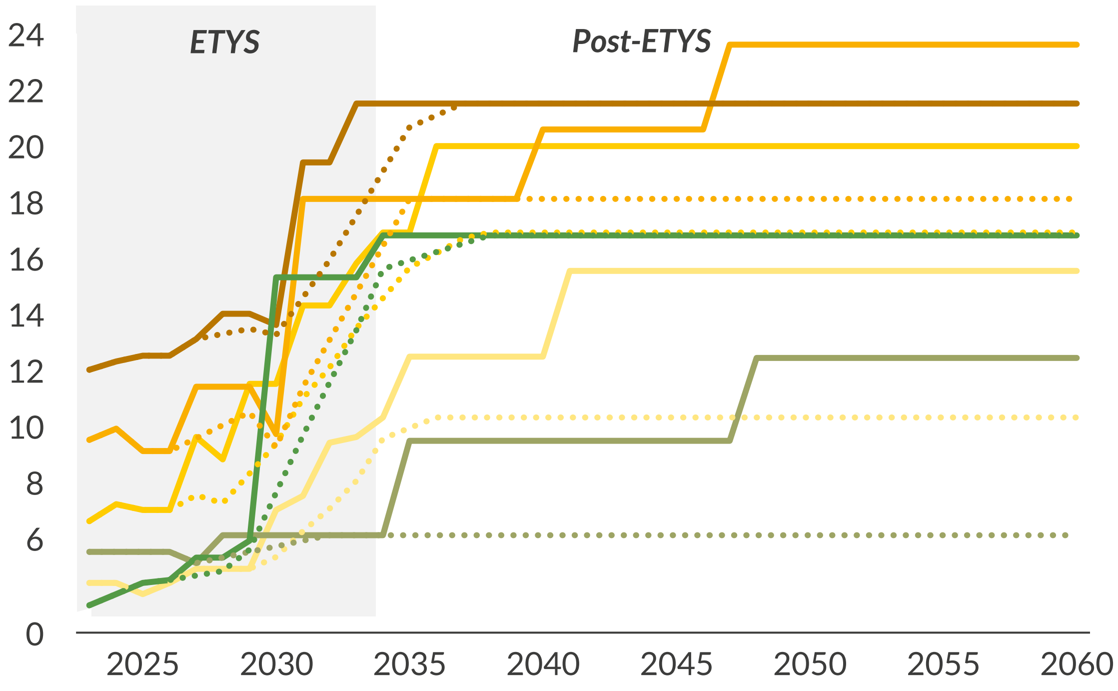
Zonal Pricing

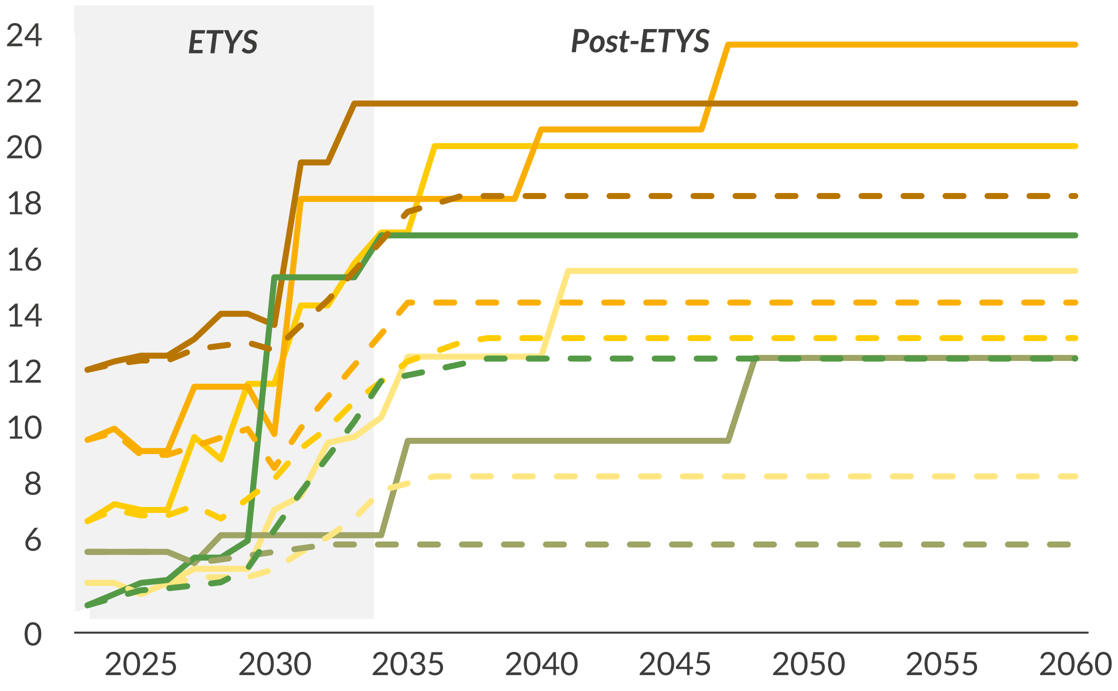
Transfer Capacity — Low 1 (Slow ETYS only)
GW



- Low scenario 1 represents a situation where only the ETYS line upgrades are implemented, with no additional build out, but with a slower implementation than the ESO timeline
- As a further downside, low scenario 2 reflects a slower implementation of ETYS but assuming that only 66% of total build is achieved

B4 B6 B7a B8 SC1 EC5 Base Case Low 1

Transfer Capacity – Low 2 (Slow & fall short of ETYS)
GW

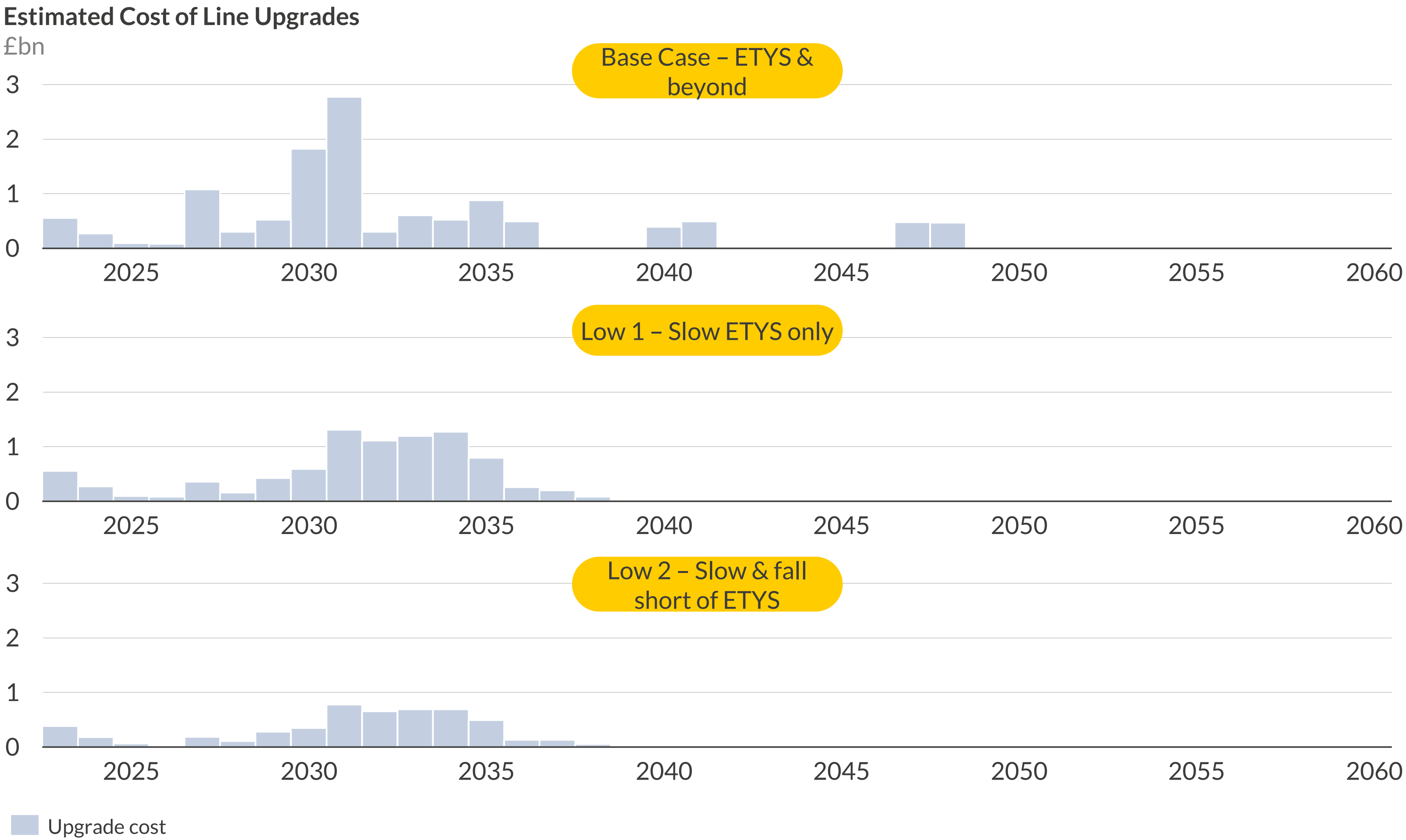


- The scenarios focus on downside transmission build risk due to historic shortfall in line build relative to ESO planned upgrades, and lower maximum annual build than current projections
- The three scenarios together allow assessment of LMP across a range of possible short-term and long-term situations

B4 B6 B7a B8 SC1 EC5 Base Case Low 2

Source(s): Aurora Energy Research

The Low 1 and 2 scenarios reduce total line upgrade costs by £3.2bn and £6.9bn respectively vs the Base Case



Total Line Upgrades Spend

£12.1bn

£8.9bn

£5.2bn

Source(s): Aurora Energy Research

With slower and lower total transmission capacity built in the model, dispatch switches to less wind generation and increased imports

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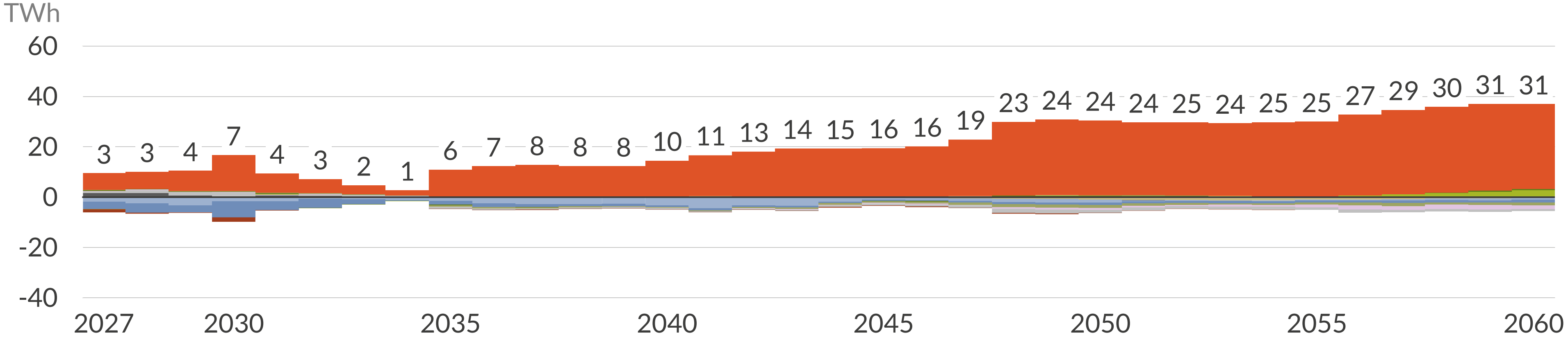
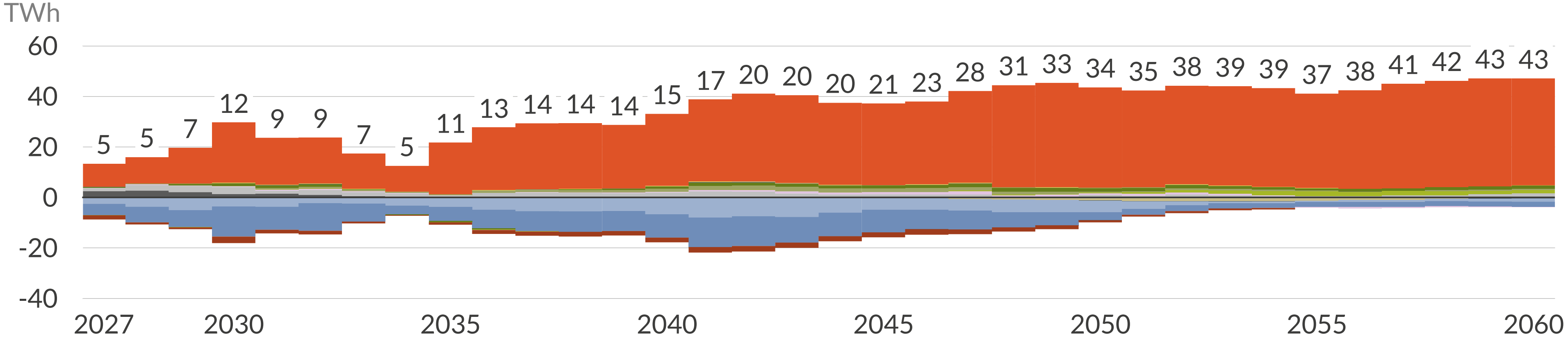
Generation Delta for Low 1 vs Base Case[1]



Generation delta for Low 2 vs Base Case[1]



Interconnectors, Battery storage, Peaking, Onshore wind, Other RES, Solar, Hydrogen CCGT, Gas CCGT, Nuclear, DSR, Hydrogen peakers, Pumped storage, Offshore wind, BECCS, Other thermal, Gas CCS, Coal

- Changes to net endogenous capacity built under the two transmission line scenarios remain below 1% relative to the total capacity under the zonal Net Zero base case
- Generation changes under the first low scenario – slow ETYS build out – ranges from around 1% to 4% change from the base case
- While under lower upgrade assumptions for scenario 2 – falling short of ETYS targets – generation reaches 6% higher than the base case by the end of the time horizon
- With more restricted capacity build in the years up to 2035, there is more curtailment of wind assets and an increased reliance on imports

1) Generation including net interconnector flows.

Source(s): Aurora Energy Research

Under the first low scenario, more peaking and battery capacity builds in the tightest southern zones

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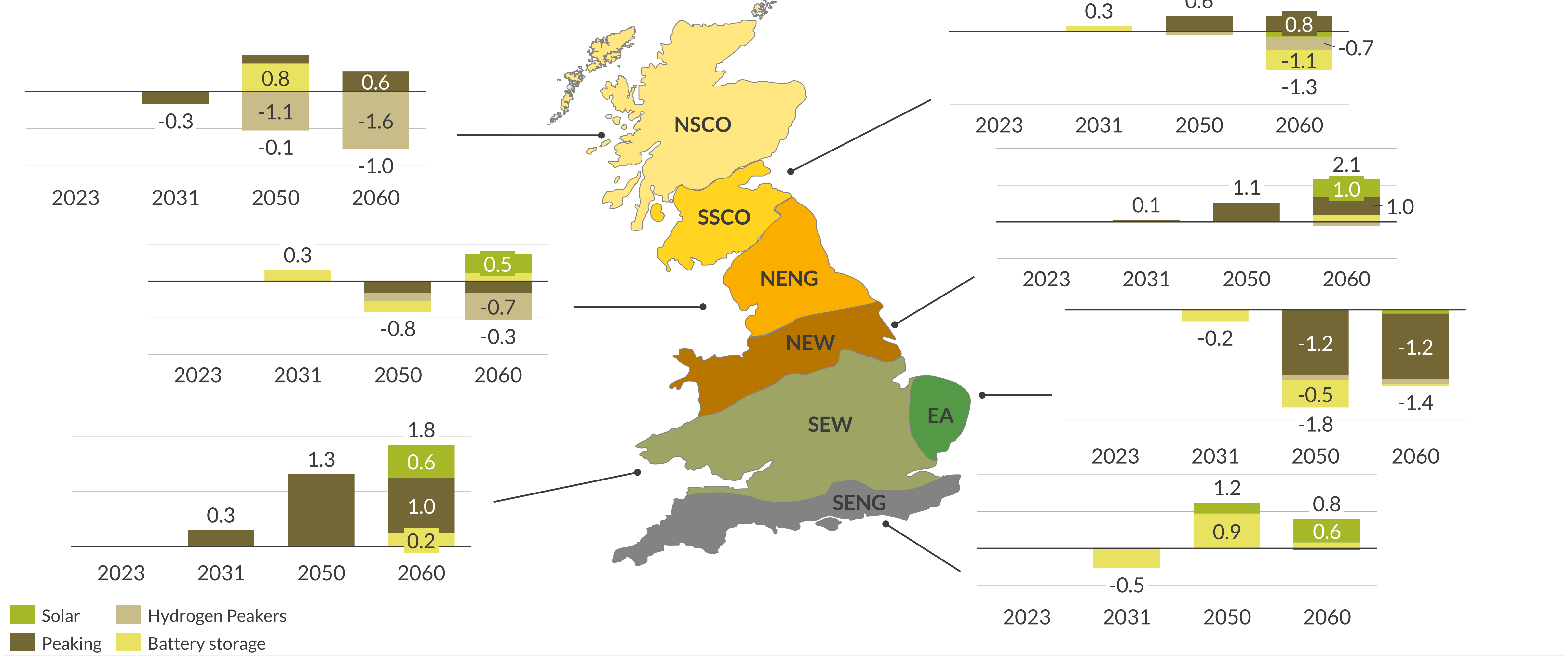
Low 1

Net Capacity Delta with Low 1 vs Zonal Net Zero
GW

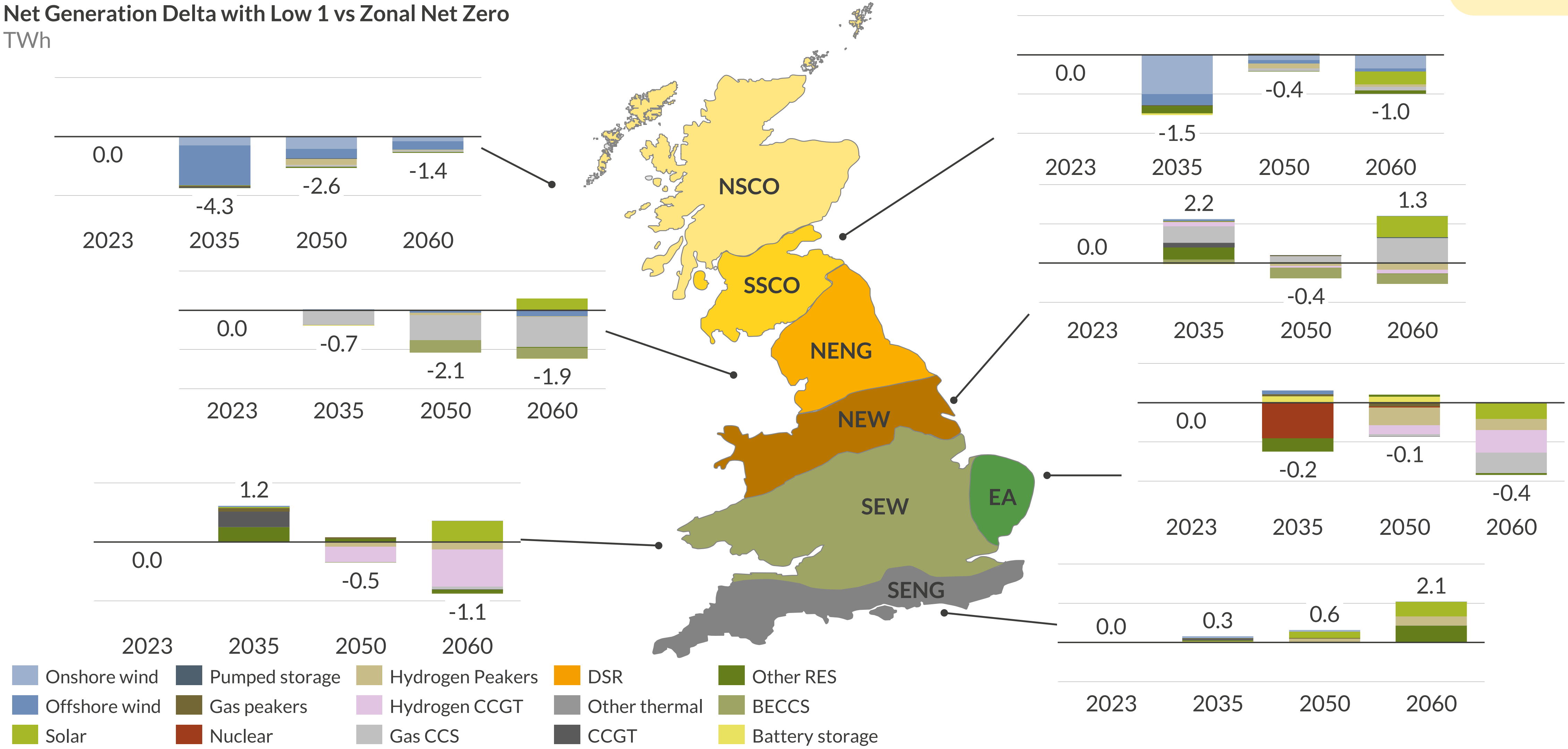


Source(s): Aurora Energy Research

With less transmission capacity between zones there is more curtailment of wind in northern zones

Low 1

Net Generation Delta with Low 1 vs Zonal Net Zero
TWh



Source(s): Aurora Energy Research

With the system falling short of ETYS transmission line upgrades under Low 2, southern zones build out more unabated peaking capacity

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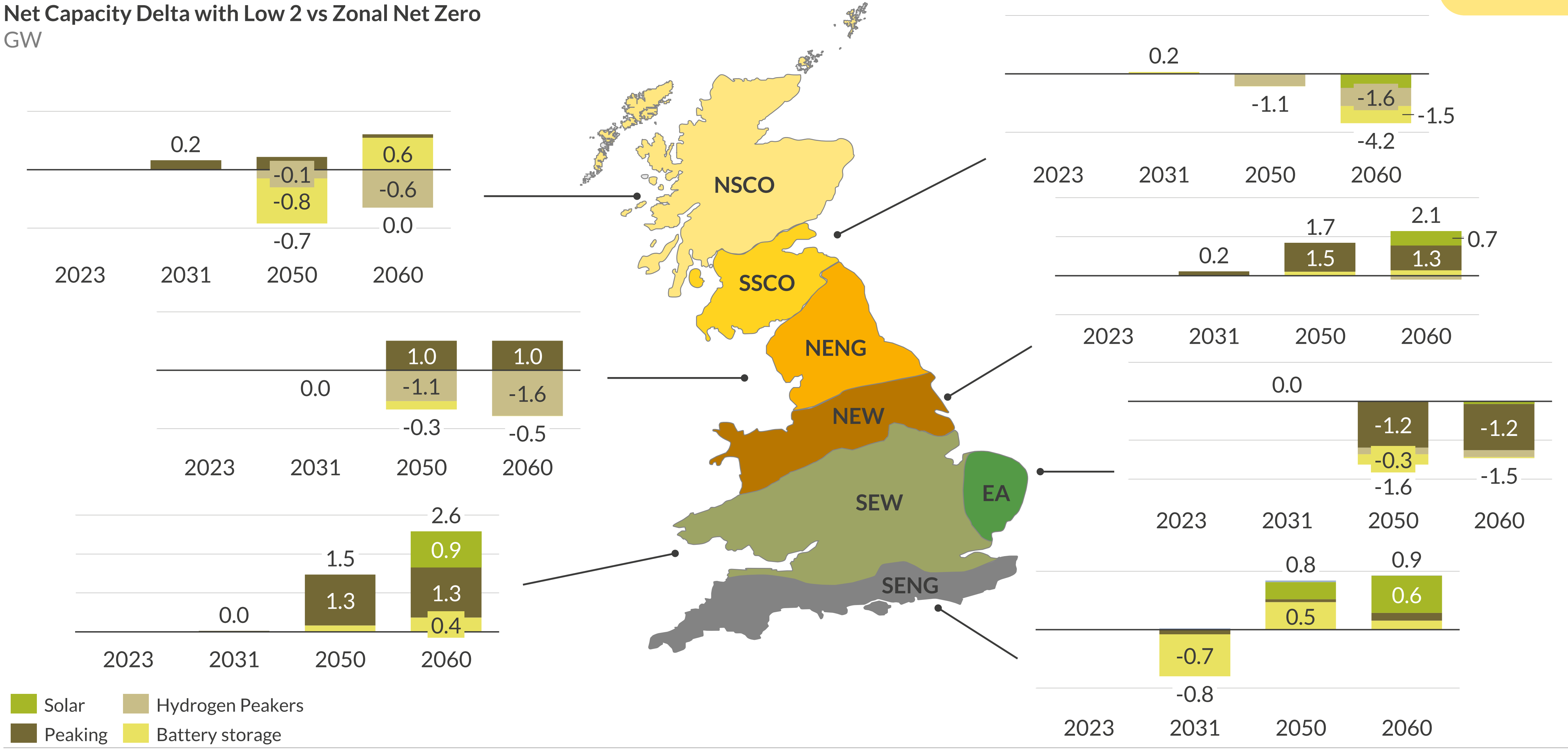
Low 2

Net Capacity Delta with Low 2 vs Zonal Net Zero
GW



Source(s): Aurora Energy Research

Changes to dispatch remain in line with the first low scenario, highlighting the efficiencies of faster transmission line build

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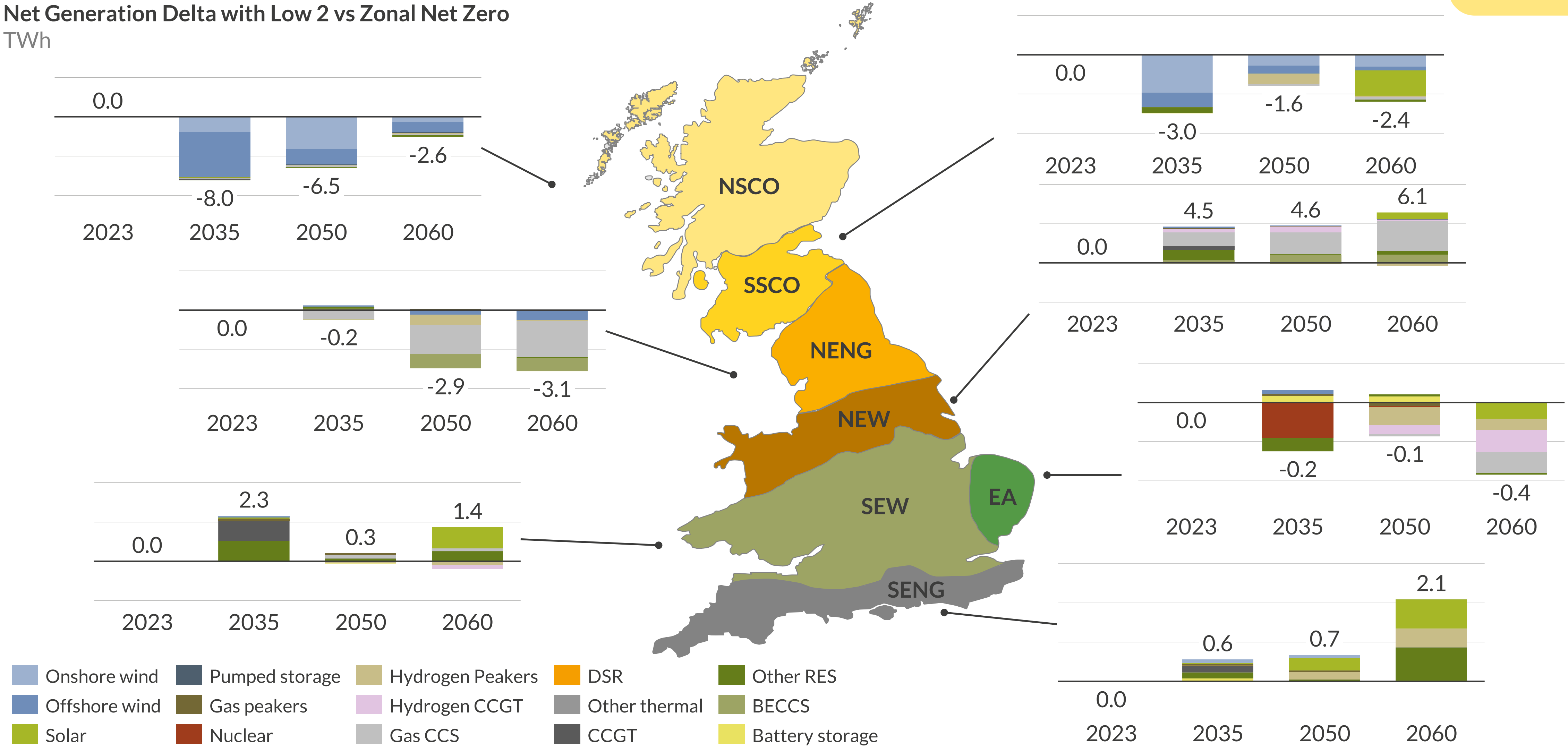
Low 2

Net Generation Delta with Low 2 vs Zonal Net Zero
TWh



Source(s): Aurora Energy Research

With slower build of line upgrades, wholesale prices remain more volatile than the base case and do not reach an equilibrium state

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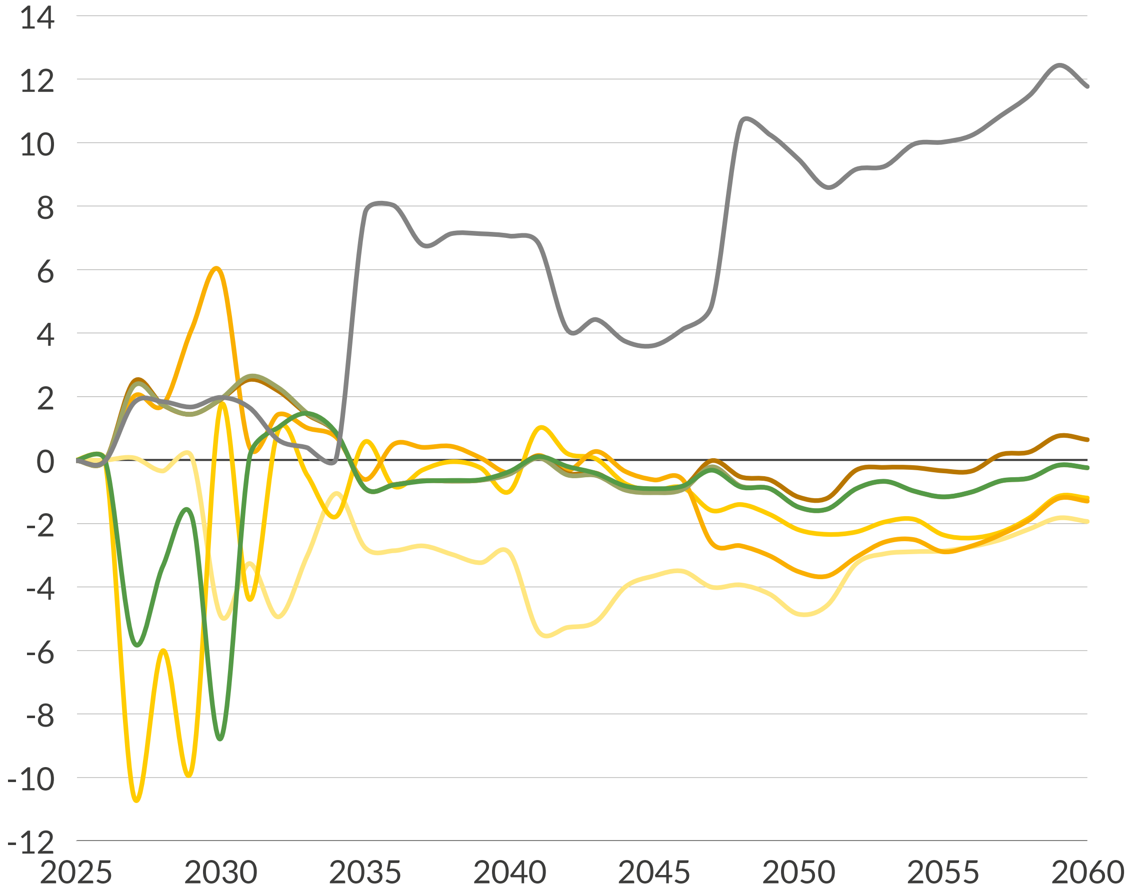
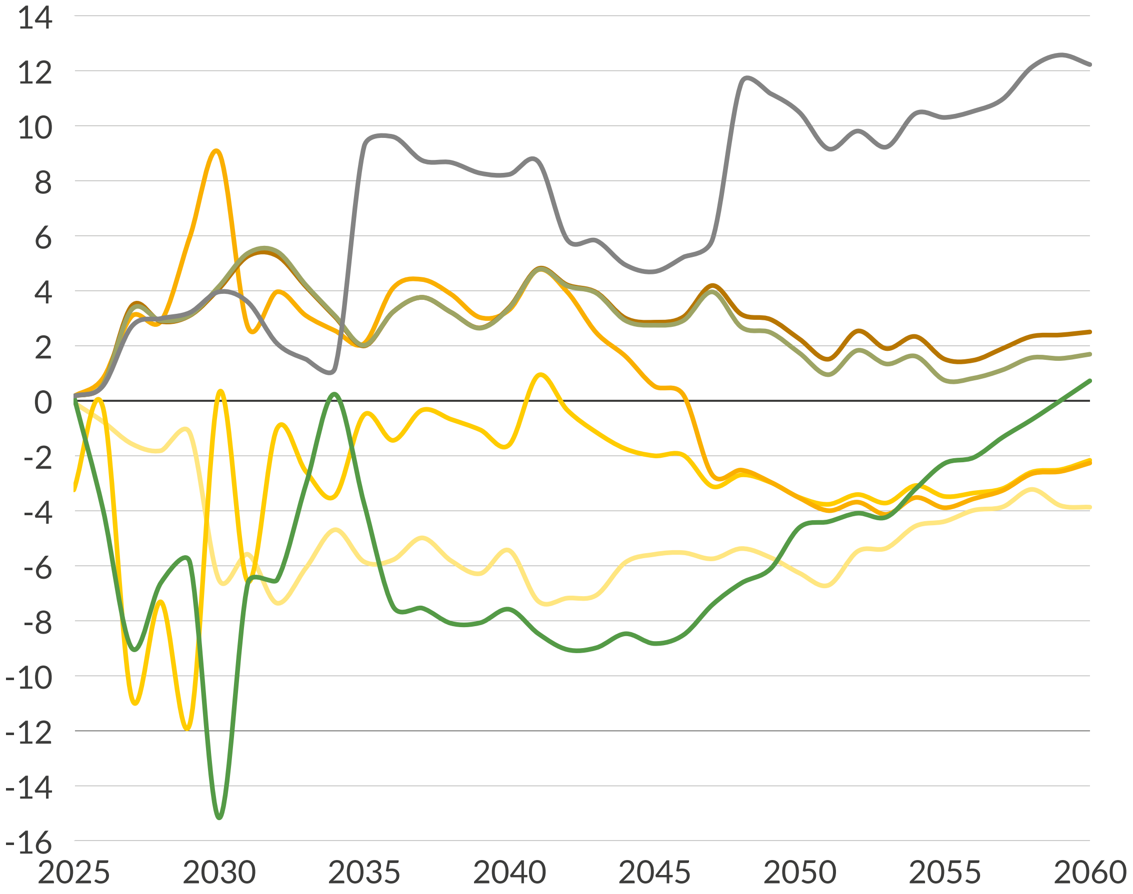
Baseload Wholesale Electricity Price Deltas in Low 1 vs Zonal Net Zero
£/MWh (real 2021)



Baseload Wholesale Electricity Price Deltas in Low 2 vs Zonal Net Zero
£/MWh (real 2021)



NSCO SSCO NENG NEW SEW EA SENG

Source(s): Aurora Energy Research

Top percentile prices under scenario Low 1 remain higher than the base case during the delayed ETYS build period

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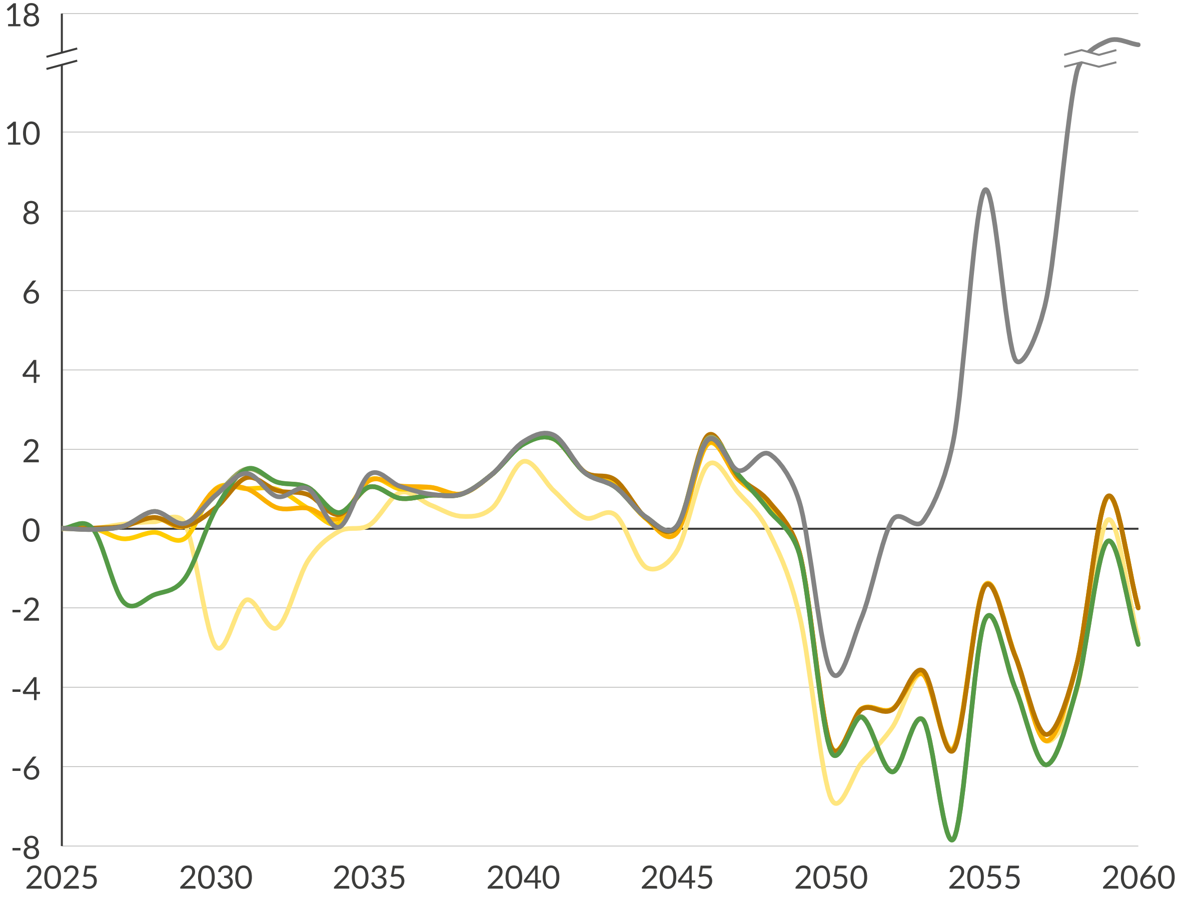
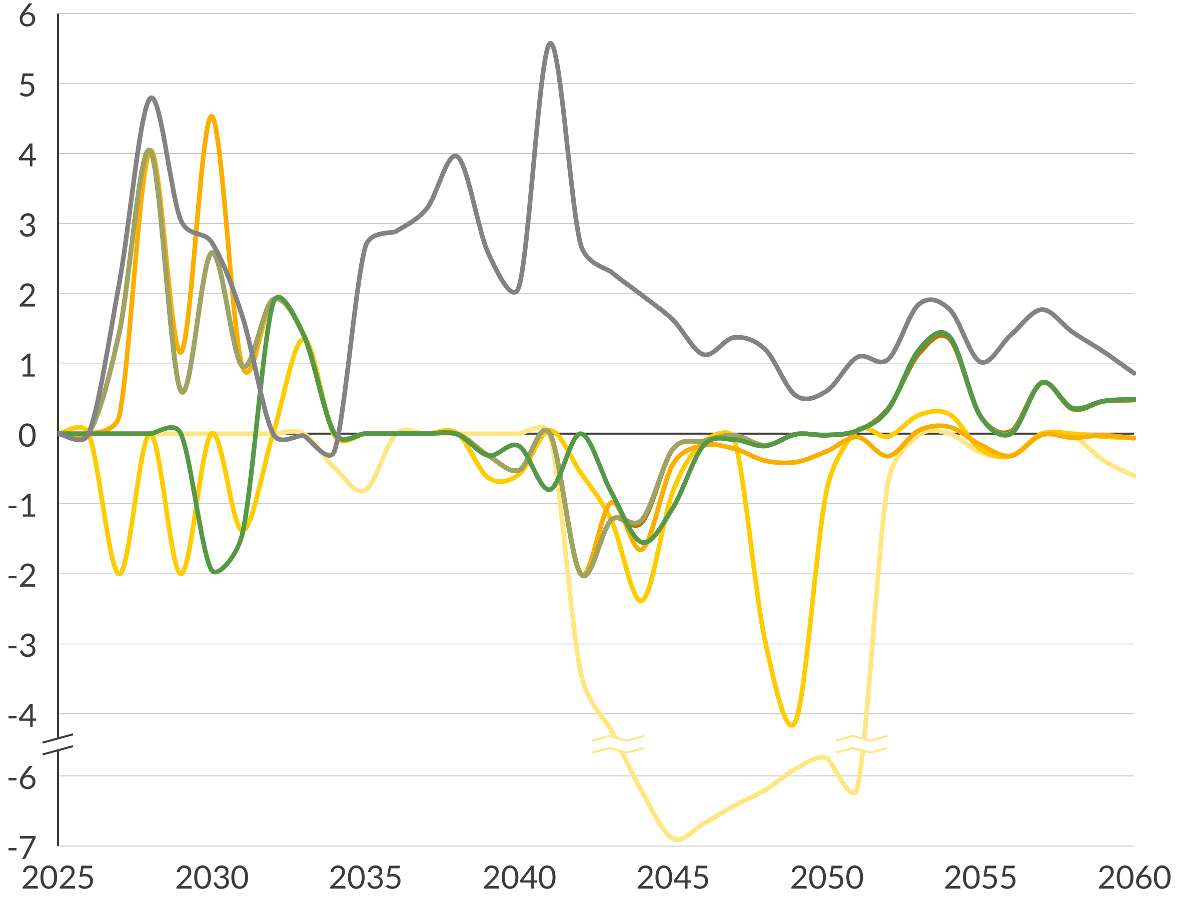
Low 1

95th Percentile Wholesale Price – Delta in Low 1 vs Zonal Net Zero
£/MWh (real 2021)



5th Percentile Wholesale Price – Delta in Low 1 vs zonal Net Zero
£/MWh (real 2021)



NSCO SSCO NENG NEW SEW EA SENG

Under Low 2, the top percentile prices remain persistently higher than the base case, while bottom percentiles increase in the tighter zones

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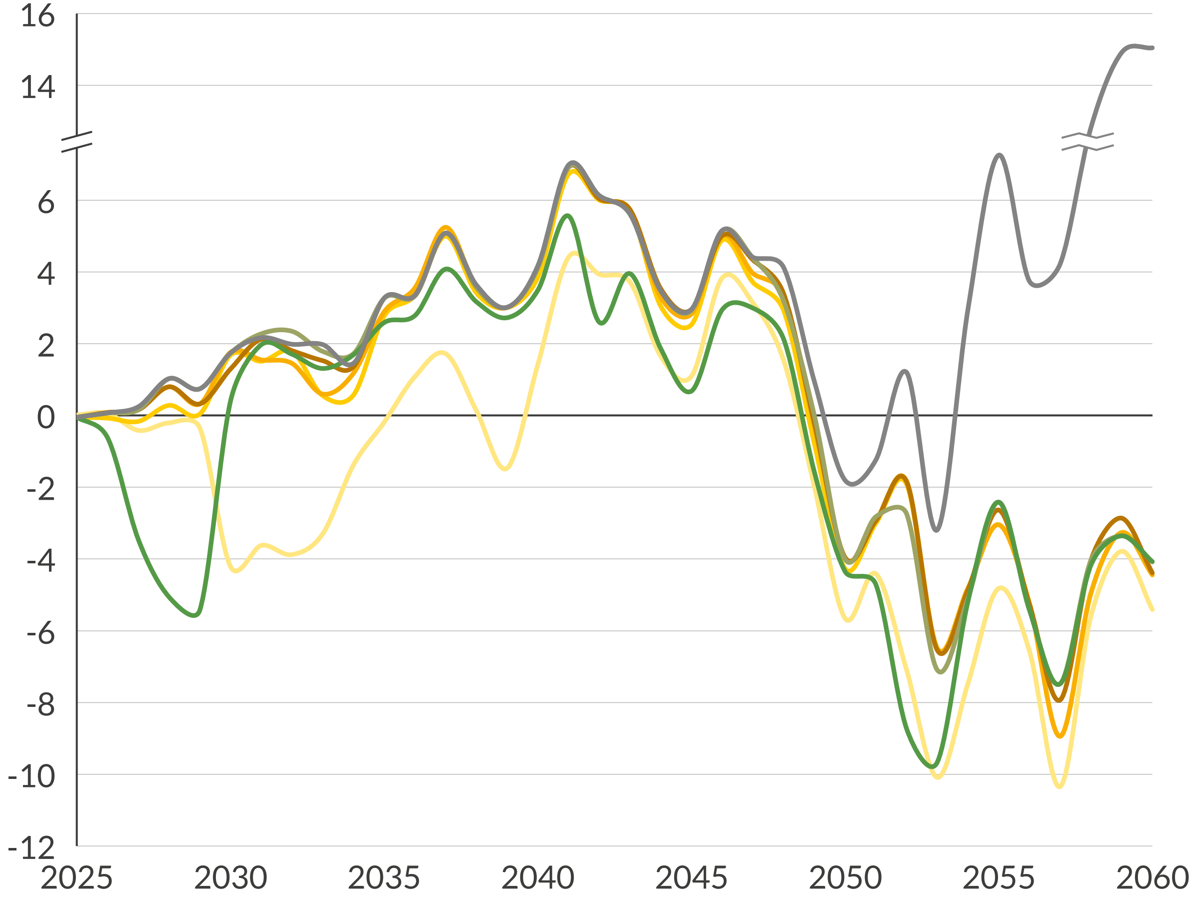
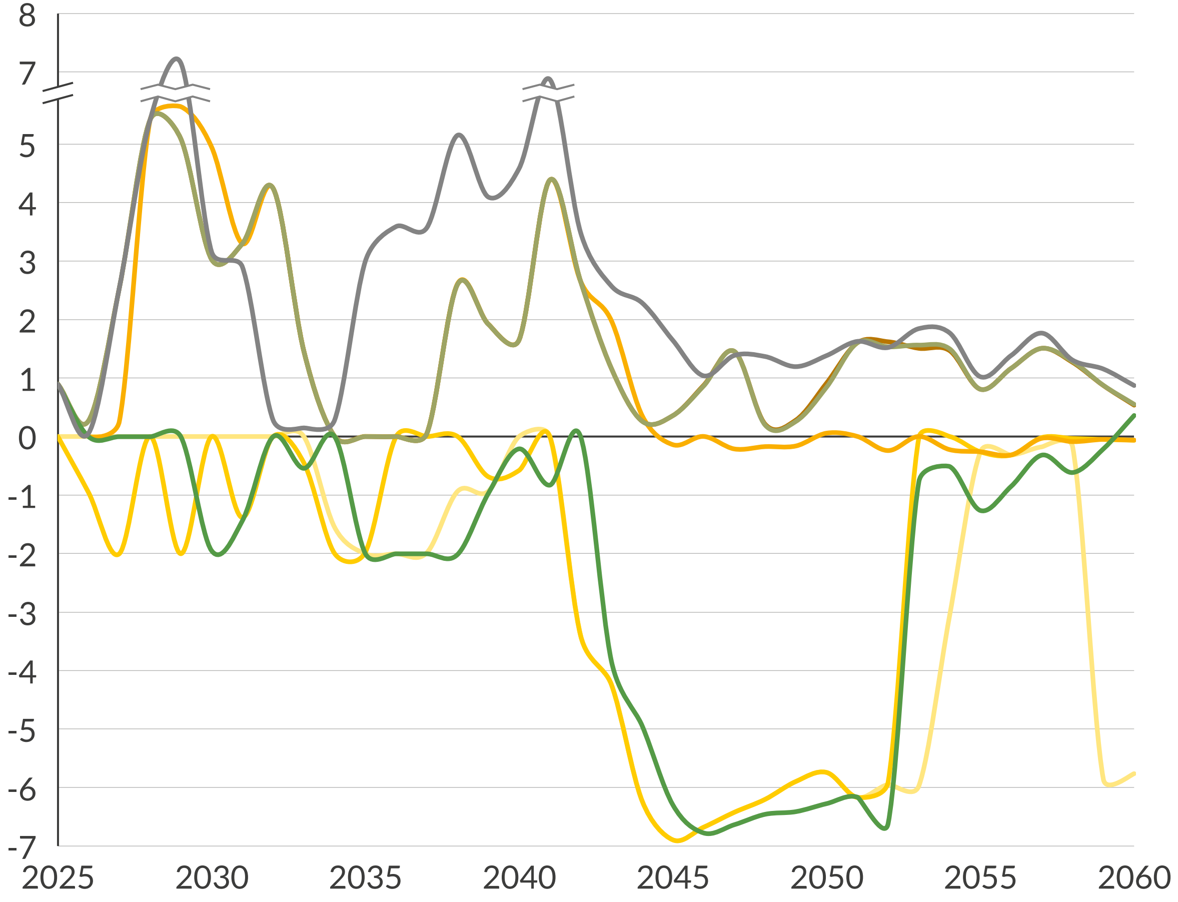
Low 2

95th Percentile Wholesale Price – Delta in Low 2 vs Zonal Net Zero
£/MWh (real 2021)



5th Percentile Wholesale Price – Delta in Low 2 vs Zonal Net Zero
£/MWh (real 2021)



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2h Spreads track the base case more closely in the Low 1, while congestion in Low 2 drives up spreads in the tightest zones

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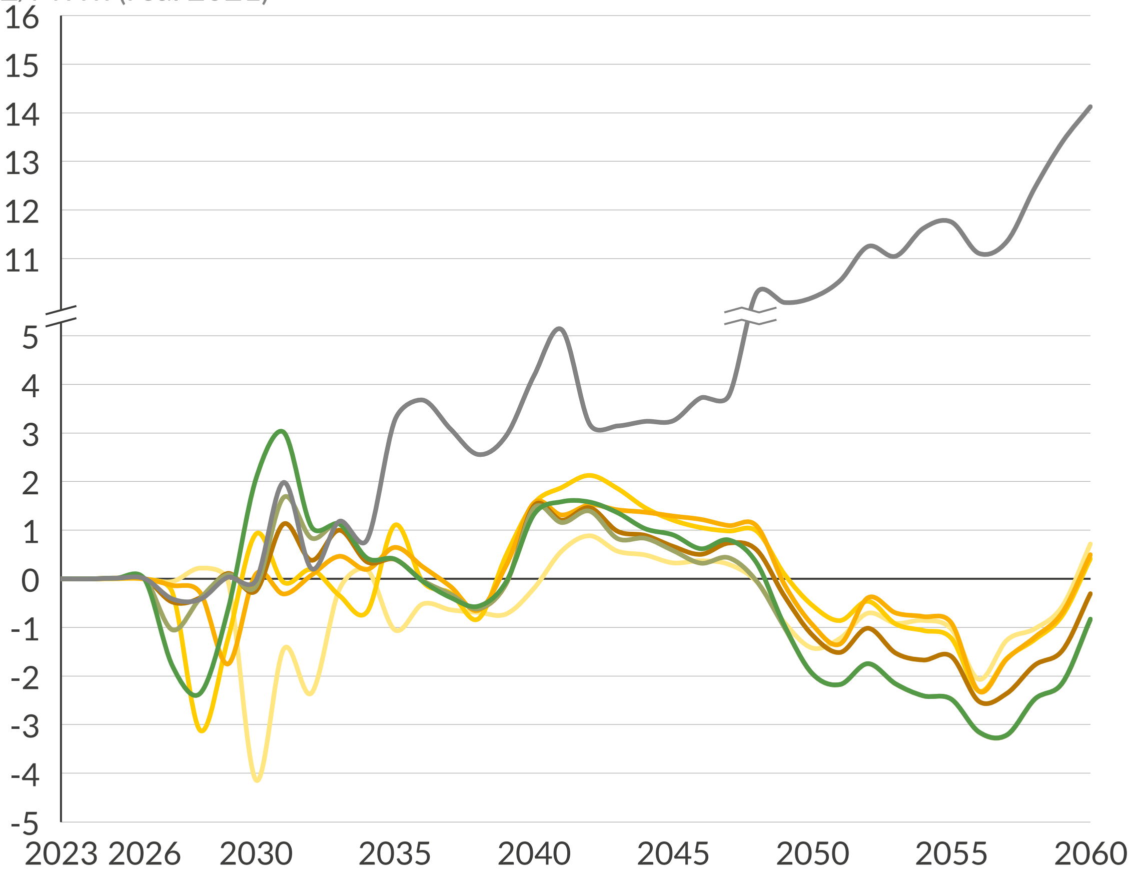
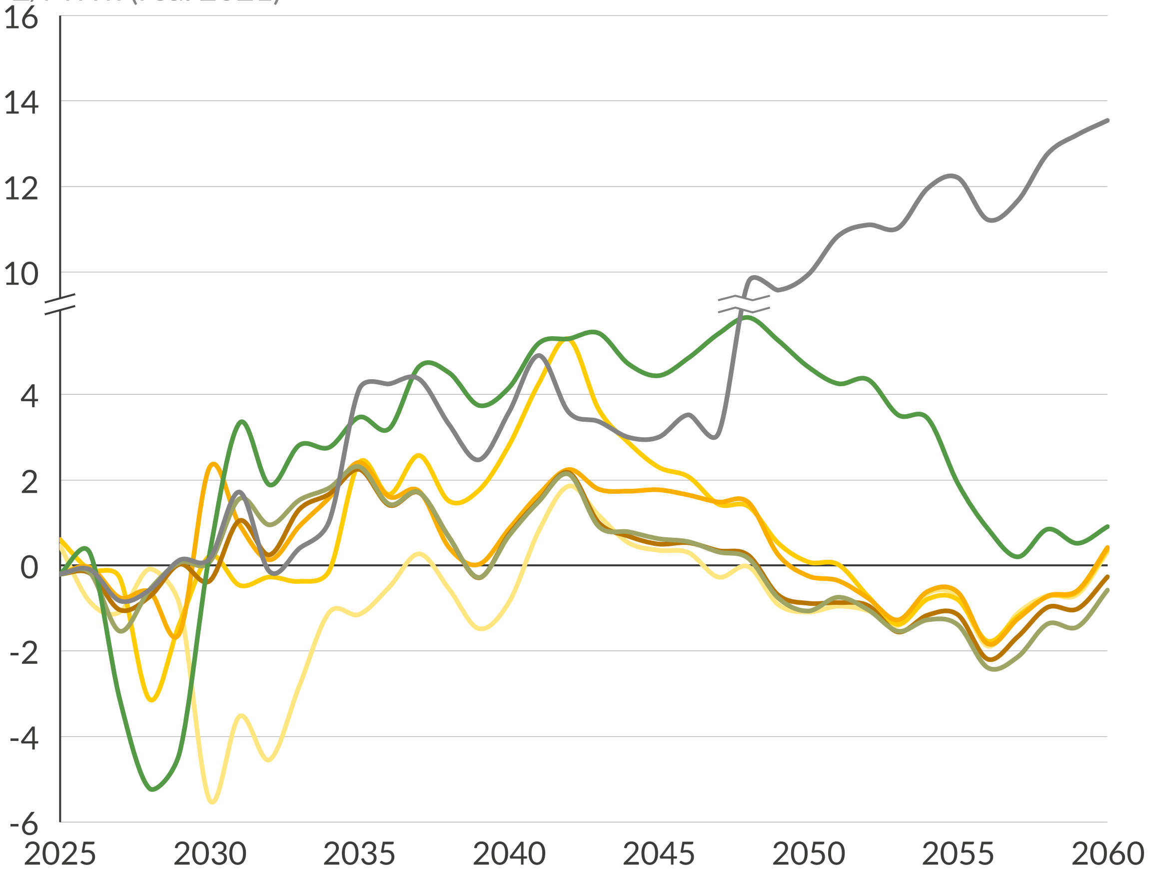
Average Daily 2-hour Wholesale Price Spread – Delta in Low 1 vs Zonal Net Zero

£/MWh (real 2021)



Average Daily 2-hour Wholesale Price Spread – Delta in Low 2 vs Zonal Net Zero

£/MWh (real 2021)



NSCO SSCO NENG NEW SEW EA SENG

In today's session we will focus on central model results, system costs and scenario analysis

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I. Aurora Central Market Scenario Results

- How do central scenario LMP results compare to National?
- How do central LMP results compare to Net Zero LMP?
- Zonal results deep-dive
- Nodal results deep-dive

II. System Costs

- How do system costs vary under Central and Net Zero scenarios?

III. Scenario Analysis

- How do LMP results change when considered with different transmission line upgrades?
- How do LMP results change when we expose demand to locational signals?

Meeting the target for a Net Zero economy by 2050 is expected to necessitate a significant role for hydrogen, with 252 TWh by 2050

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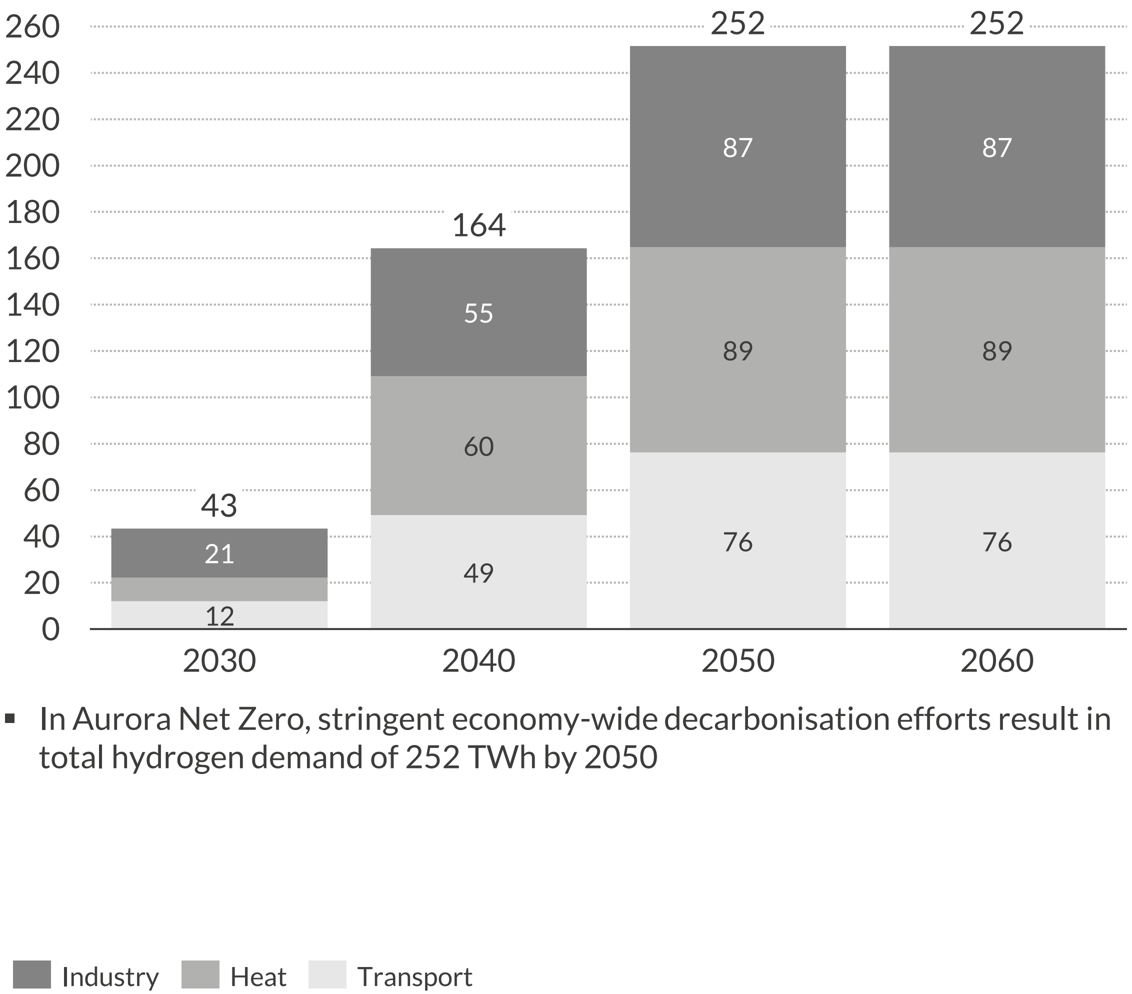
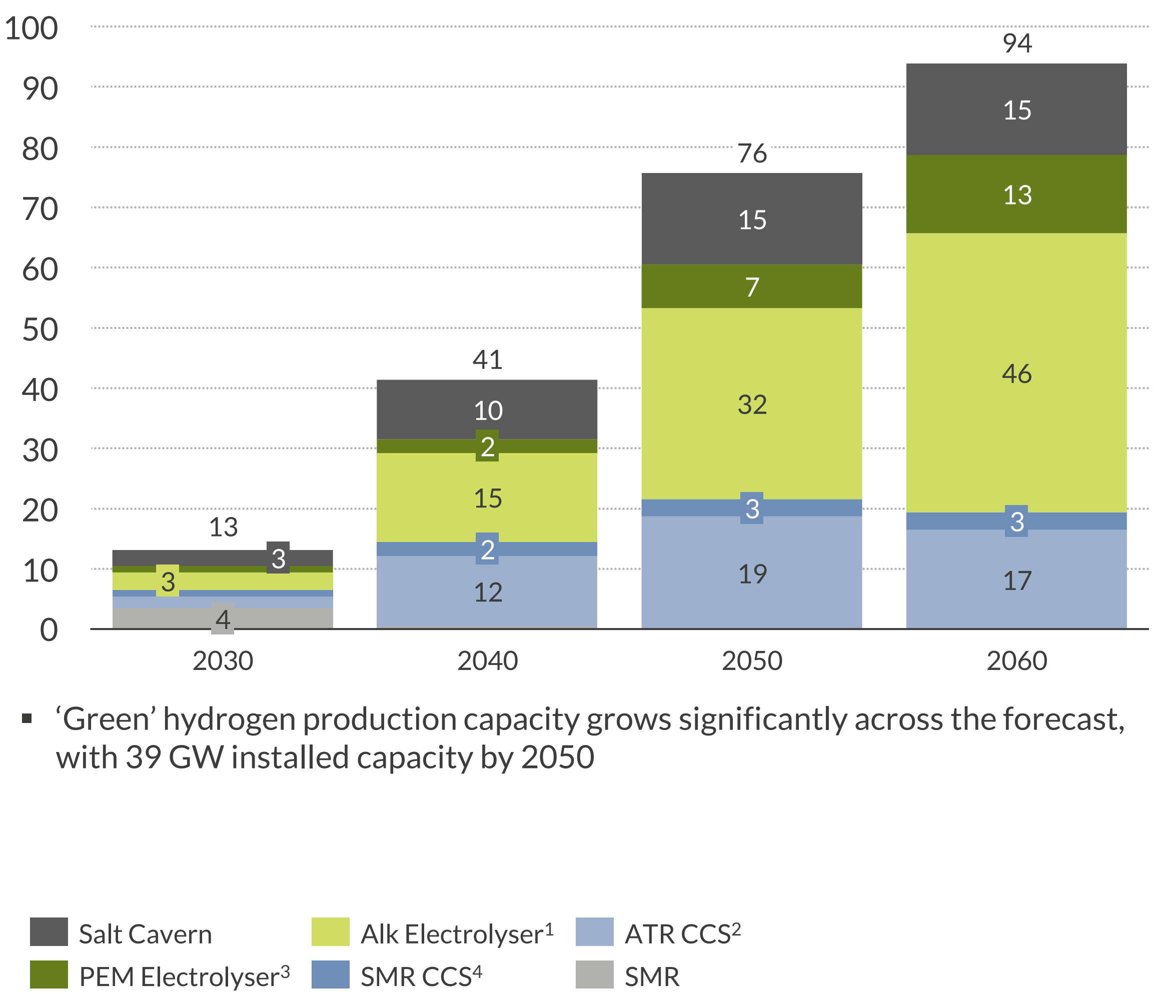
Total Hydrogen Demand
TWh



- In Aurora Net Zero, stringent economy-wide decarbonisation efforts result in total hydrogen demand of 252 TWh by 2050

Hydrogen Supply Capacity
GW



- 'Green' hydrogen production capacity grows significantly across the forecast, with 39 GW installed capacity by 2050

1) Alkaline water electrolyser; 2) Autothermal reformer with carbon capture and storage; 3) Polymer electrolyte membrane electrolyser; 4) Steam-methane reformer with carbon capture and storage.

Source(s): Aurora Energy Research

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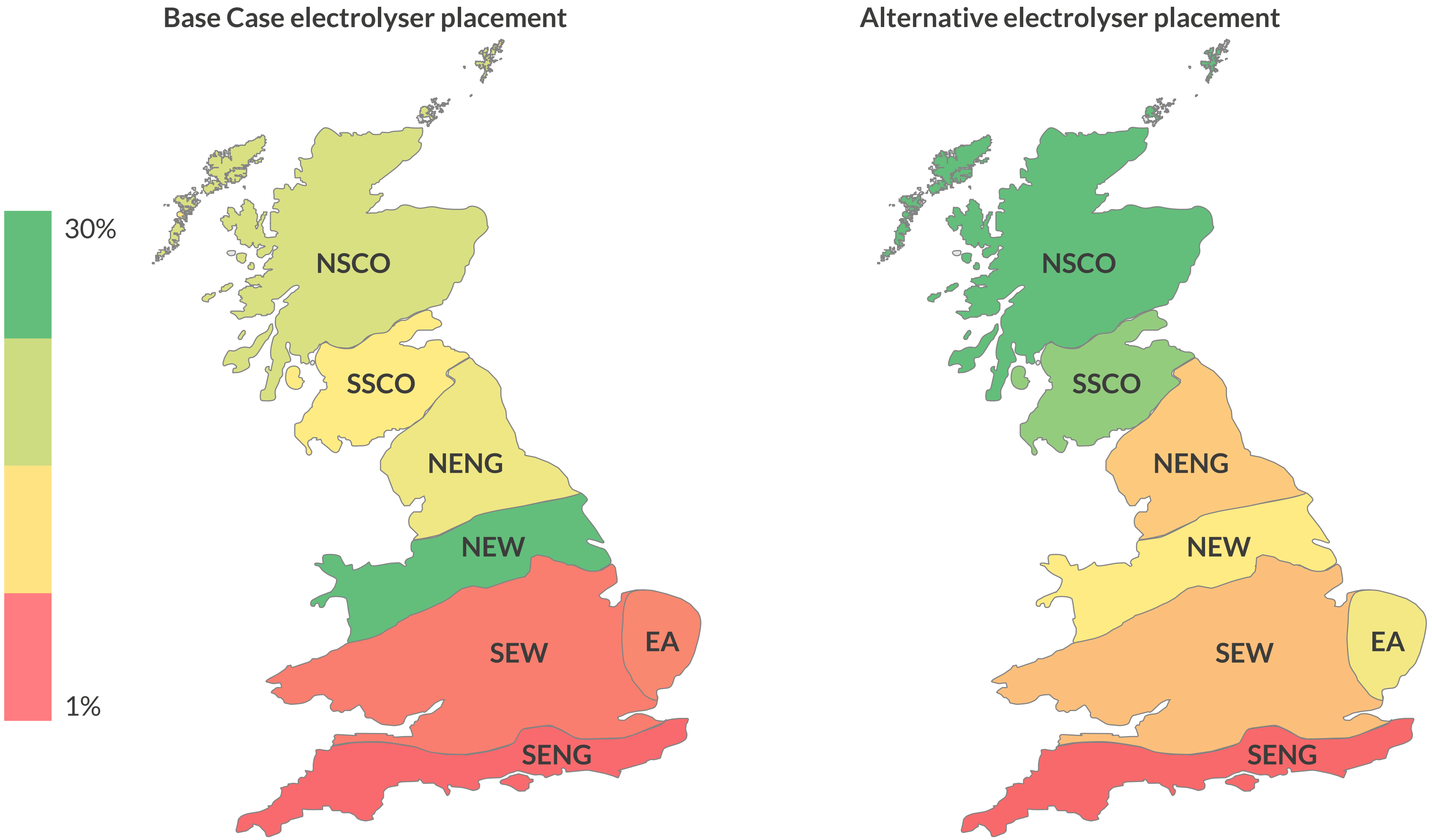
Concentration of demand is moved around GB by placing electrolysers in zones with most wind generation and lowest prices

Average Percentage of Total Electrolyser Demand by Zone

%



- Under the Base Case, electrolyser capacities are distributed across zones based on a combination of Aurora's view on the project pipeline, stated policy, and buildout of renewables. This results in most electrolyser demand in North England and Wales.
- Under the alternative placement, electrolyser buildout is directly correlated with the buildout of onshore and offshore wind, reflecting the likely colocation of green hydrogen production and high RES generation. This concentrates electrolyser demand in Scotland and East Anglia, taking advantage of low prices in these zones

Source(s): Aurora Energy Research

In the short term, higher wind generation is driven by electrolysers capturing spill while the boundaries remain constrained

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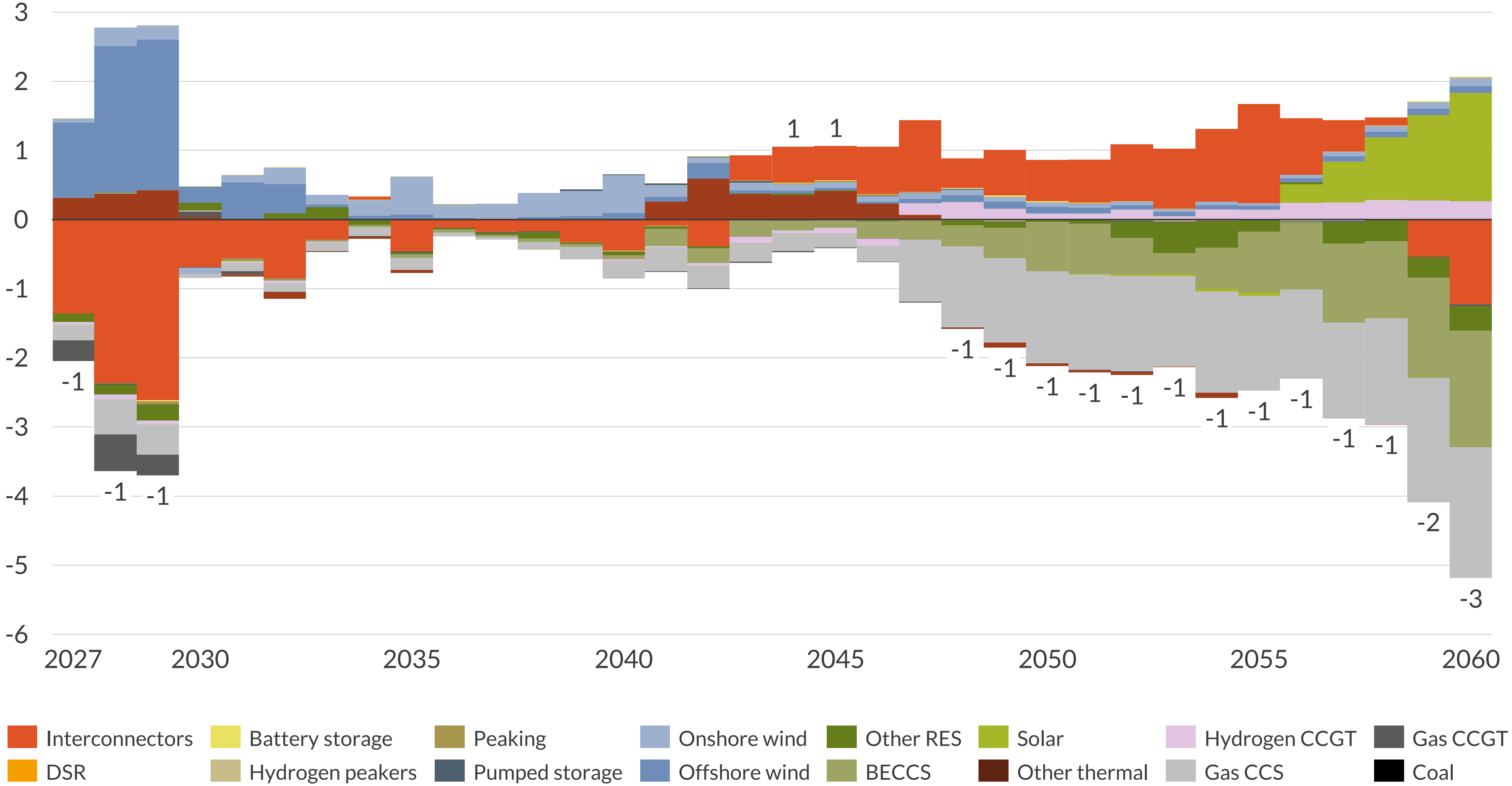
Generation delta in Alternative Demand Scenario vs vs base case[1]
TWh



- Increased electrolyser demand in zones with large amounts of offshore wind (North Scotland and East Anglia) acts to reduce curtailment of off- and onshore wind in the 2020s and 2030s relative to the base case
- In the long term, the effect of moving demand is reduced since line upgrades relieve boundary congestion and reduce curtailment in the base case
- We see slightly less generation from BECCS and CCGT+CCS in North England post-2045 since reduced electrolyser capacity reduces total demand in these zones

1) Generation including net interconnector flows.

Source(s): Aurora Energy Research

Co-locating electrolyser demand with wind buildout reduces RES curtailment by up to 15% vs the base case

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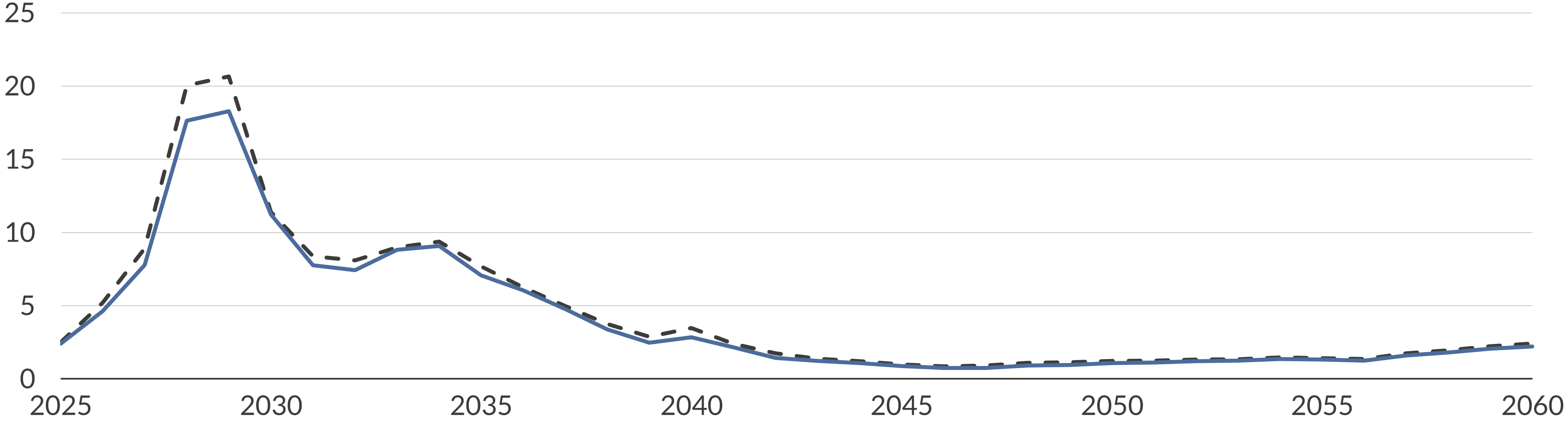
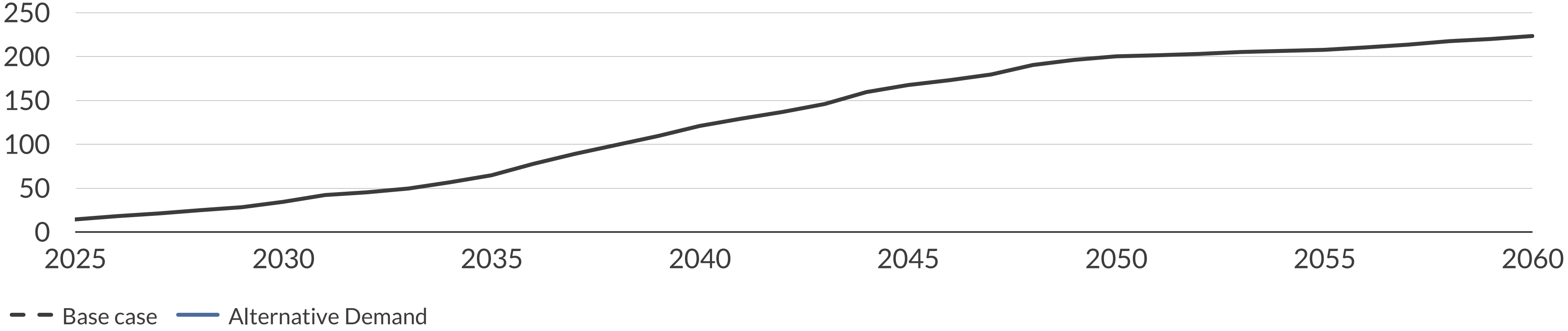
Curtailment of RES Assets
TWh



Electricity Demand from Electrolysis
TWh



- Under the alternative electrolyser placement, RES curtailment is reduced relative to the Base Case since electrolysers have greater ability to soak up excess wind generation in oversupplied zones such as North Scotland
- This effect is strongest when there is congestion on the system, since this results in turn down of wind in these oversupplied zones. However, as congestion is resolved via line upgrades, the gains from moving electrolysers fall since curtailment in the Base Case falls
- Since electrolyser demand is less significant in the short term when congestion is highest, the curtailment reduction in this scenario is limited

Relative to the Base Case, baseload prices increase in zones which have seen a rise in electrolyser capacity, namely EA and NSCO

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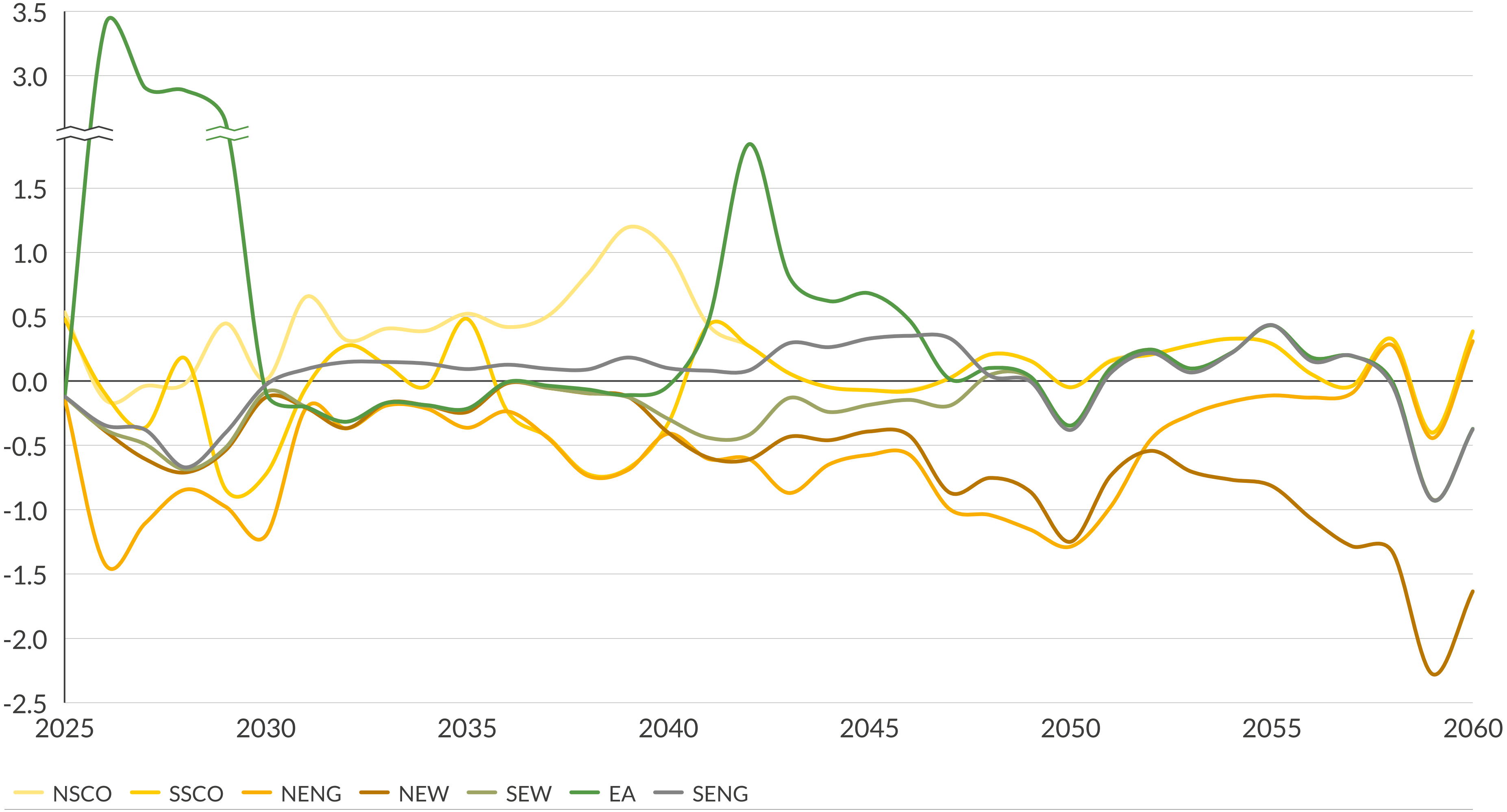
Zonal Baseload Wholesale Electricity Price – Delta in Alternative Demand Scenario vs Base Case
£/MWh (real 2021)



- Overall, under the alternative electrolyser placement, baseload prices increase in East Anglia and North and South Scotland relative to the Base Case. This reflects greater electrolyser capacity in these zones, which increases total demand and places upward pressure on bottom prices.
- In contrast, zones which have seen a fall in electrolyser capacity, mainly North England and North England & Wales, see a drop in baseload prices as they see lower total demand

Source(s): Aurora Energy Research

95th percentile prices fall in NEW, which has lost a lot of electrolyser capacity, while 5th percentile prices rise in NSCO, SSCO and EA

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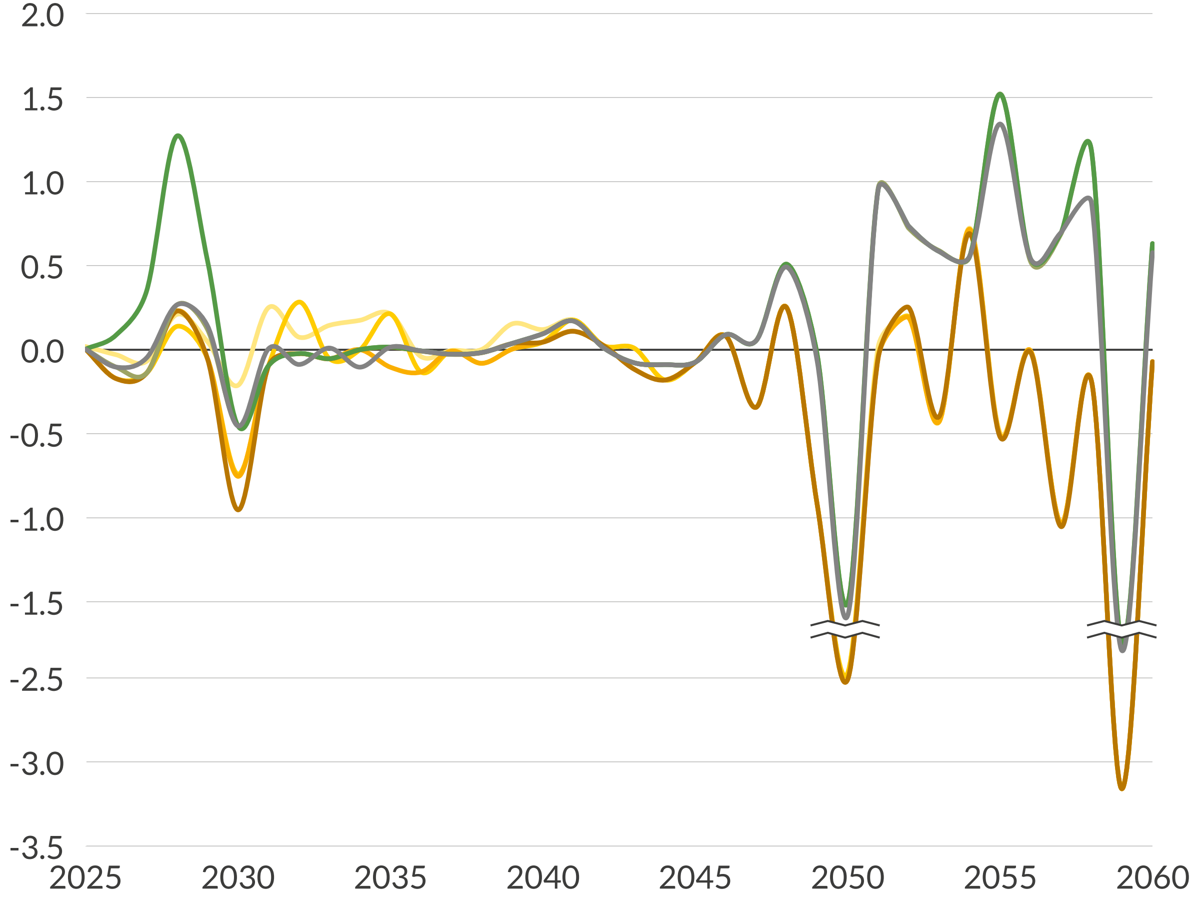
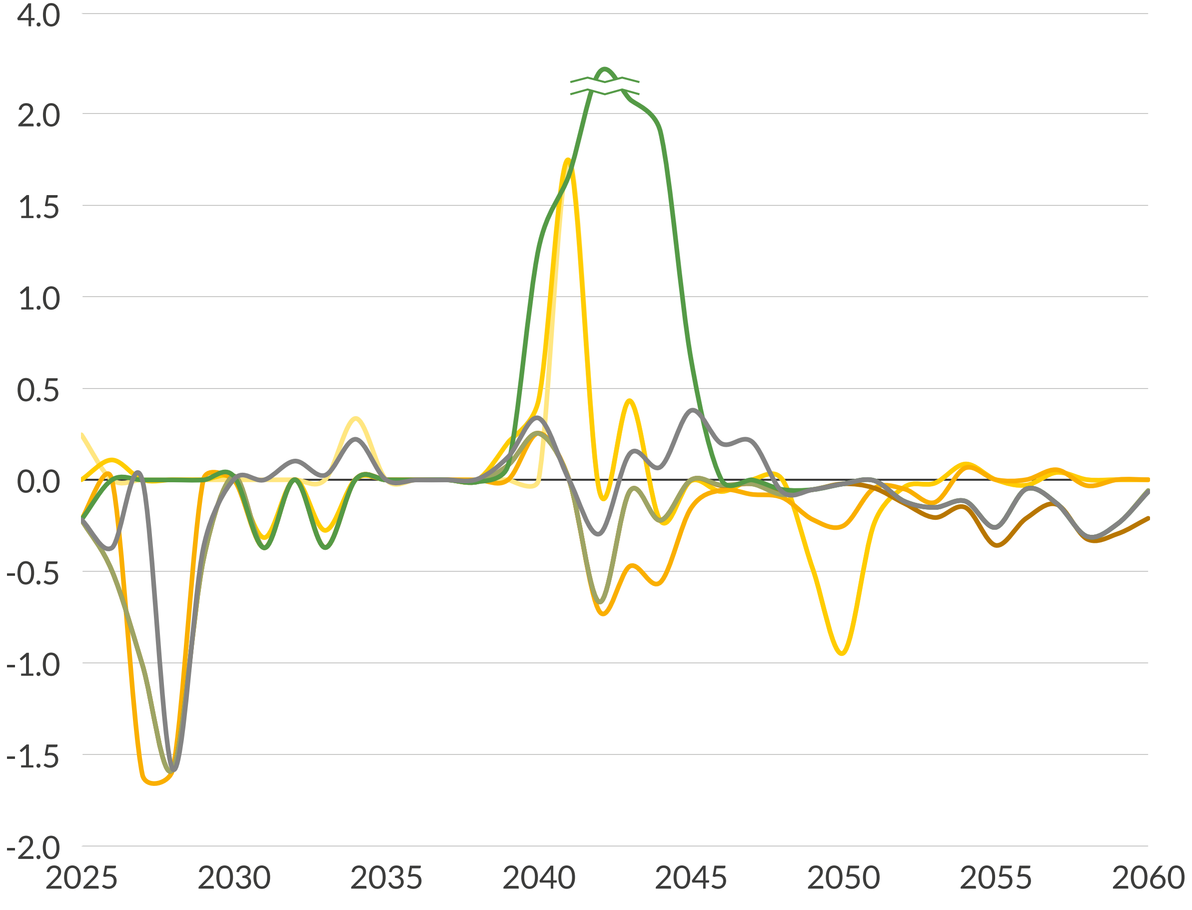
95th Percentile Wholesale Price – Delta in Electrolyser Scenario vs Base Case

£/MWh (real 2021)



5th Percentile Wholesale Price – Delta in Electrolyser Scenario vs Base Case

£/MWh (real 2021)



NSCO SSCO NENG NEW SEW EA SENG

2h Spreads fall most in East Anglia, where electrolyser capacity almost doubles

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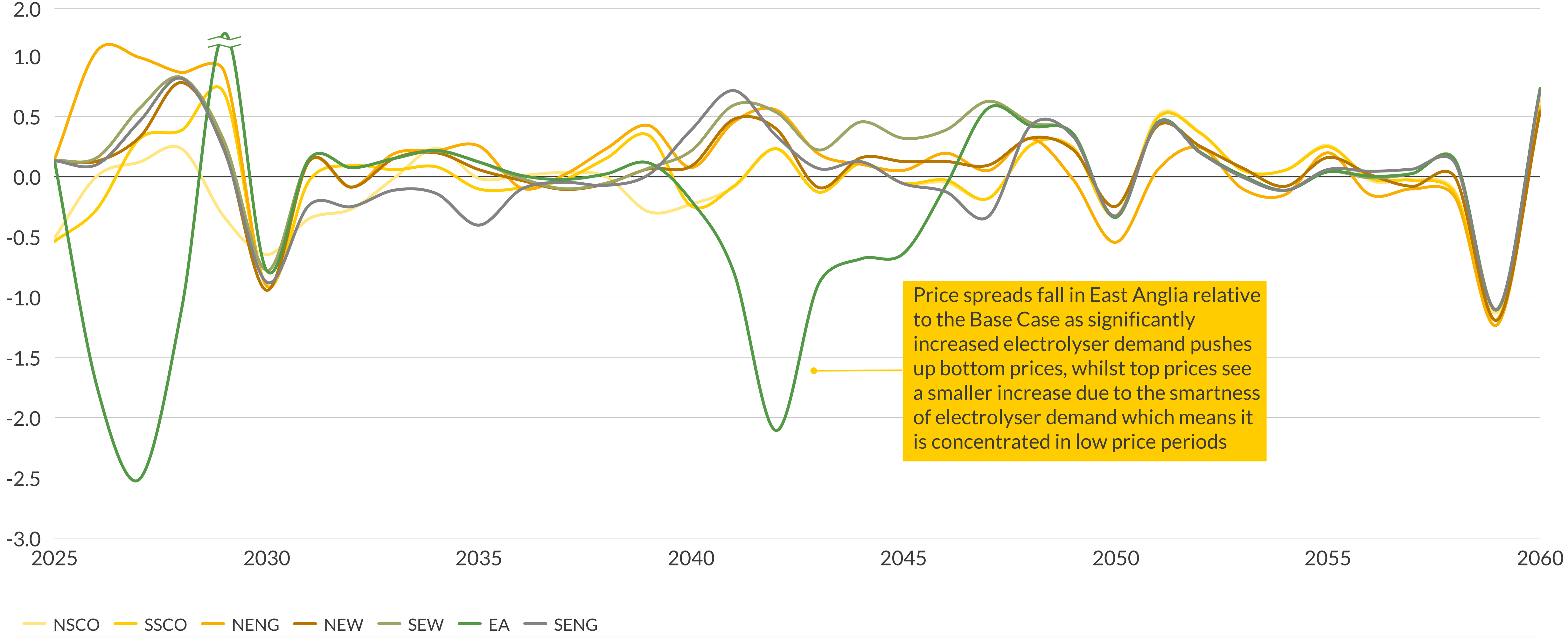
Average Daily 2-hour Wholesale Price Spread – Delta in Electrolyser Scenario vs Base Case
£/MWh (real 2021)



Any Questions?

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Report

- Aurora will circulate a draft of the final report and results by May 16th, we would request feedback and comments by the 23rd May
- The final report and public version will aim to be circulated by the end of the month

Bilateral discussions

- We have held several bilateral discussions already with various participants, where requested. Please reach out if you would like further discussions on any elements of the study.
- Reach out to Christian (christian.miller@auroraer.com) or Alex (alexandra.houston@auroraer.com)

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