



Report for Octopus Energy

Impact of a Potential Zonal Market Design in Great Britain

Quantitative Assessment of GB Welfare Impacts

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Table of Contents

1	Executive Summary	4
2	Introduction	9
3	Modelling Approach and Assumptions	14
4	Welfare Impacts of Zonal Wholesale Electricity Market Design	25
	Base model	26
	Shock 1: Transmission Delays	37
	Shock 2: Nuclear Delay	45
	Shock 3: Offshore Wind Shock	51
	Summary of Results	56
A	Appendices	58



1. Executive Summary

Octopus has asked FTI Consulting to update our assessment of the benefits of zonal pricing given policy developments, and to reflect the latest NESO scenarios and transmission plans

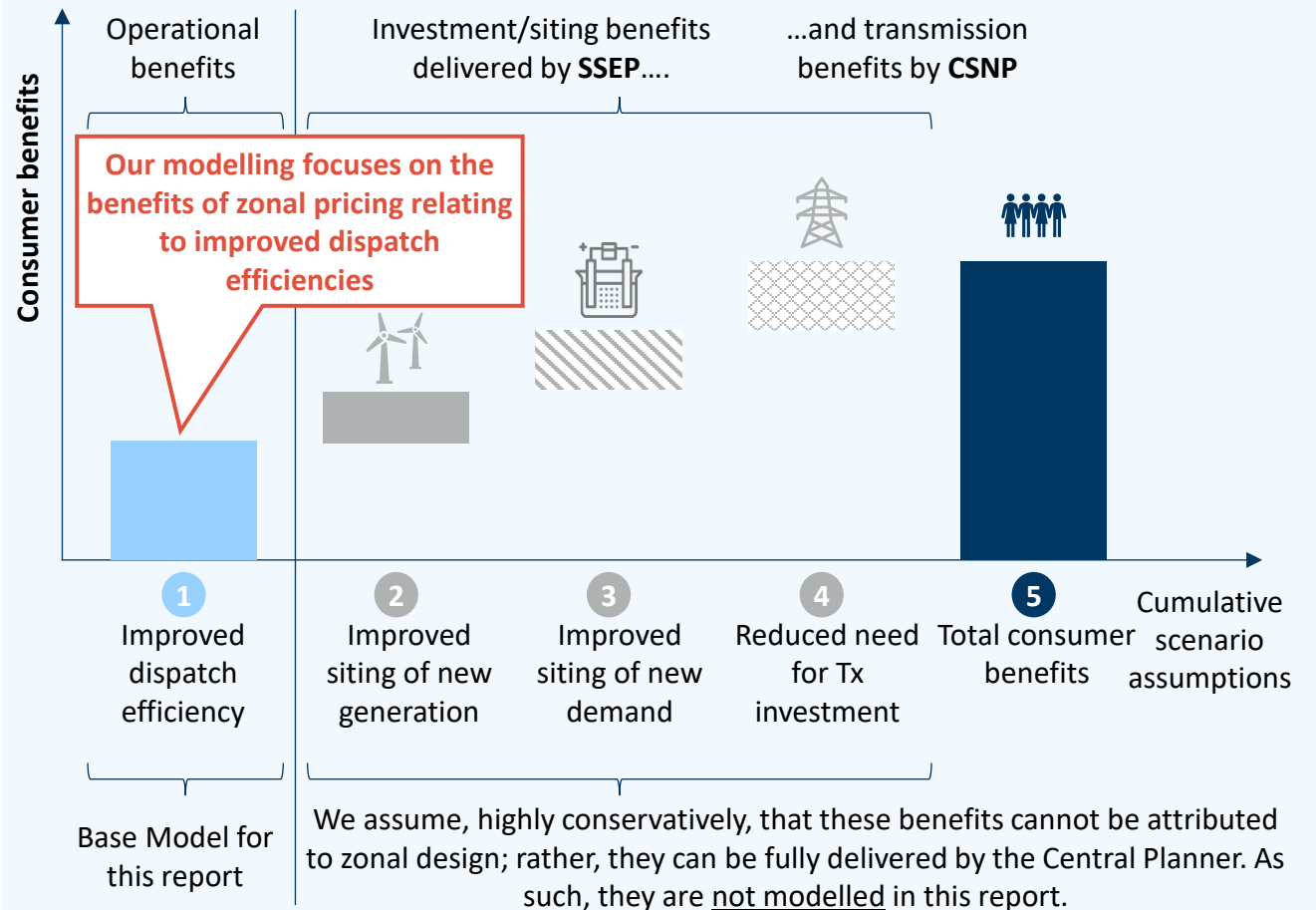
Energy markets and design in GB are under active development

- The UK Government is considering a potential shift to a locational (zonal) wholesale pricing design through its Review of Electricity Market Arrangements (“REMA”). In parallel, National Energy System Operator (“NESO”) published advice on the possible pathways for GB to achieve clean power by 2030 (“CP2030”).
- Additionally, there is a move towards centralised network planning of energy and transmission (“Tx”) infrastructure via NESO’s Strategic Spatial Energy Plan (“SSEP”) and Centralised Strategic Network Plan (“CSNP”).
- Octopus has been actively involved in the ongoing debate and has engaged FTI Consulting to assess the impact of zonal pricing on consumer and societal welfare across GB.

Benefits of locational pricing

- At a high level, the benefits of locational pricing arise from: (i) improved dispatch efficiency due to better operational signals; (ii) improved siting decisions of supply and demand; which then together lead to (iii) reduced need for transmission investment.
- Our previous work for Ofgem on the benefits of locational pricing examined (i) and (ii) and found that zonal pricing would deliver £15.2 billion to £30.7 billion in consumer benefits (NPV, 2025-2040).¹
- Since our original work for Ofgem, the context has shifted, with a new emphasis on central planning of electricity generation, storage and transmission. The ambition and objectives behind the SSEP and CSNP mean that – under the assumption of a perfect central plan – the benefits of zonal design would materialise only via improved dispatch efficiency (while other benefits would be delivered by SSEP/CSNP).
- Our analysis in this report therefore, highly conservatively, estimates only the benefits of improved dispatch efficiencies under zonal pricing.²

Illustrative benefits of zonal pricing



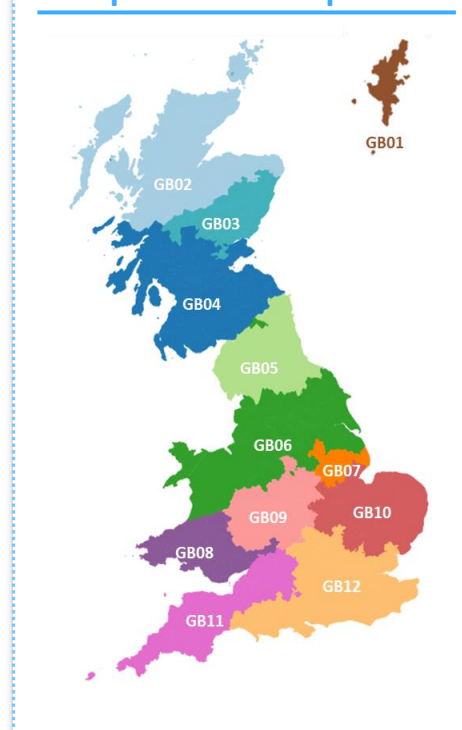
Notes: (1) £15.2 billion under FES 21 System Transformation (“SysTr”) (NOA7), £30.7 billion under FES 21 Leading the Way (“LtW”) (NOA7). ‘Assessment of locational wholesale electricity market design options in GB’, FTI Consulting, October 2023 ([link](#)); (2) This is a highly conservative assumption. As shown in our previous work, a zonal design could have a significant impact on the siting choices that new generation and demand might make, as well as on the needs case for new transmission.

Based on latest NESO forecasts, we estimate that zonal pricing delivers £54.9 billion in net GB consumer benefits and increases net GB societal welfare by £25.2 billion (PV, 2030-50)

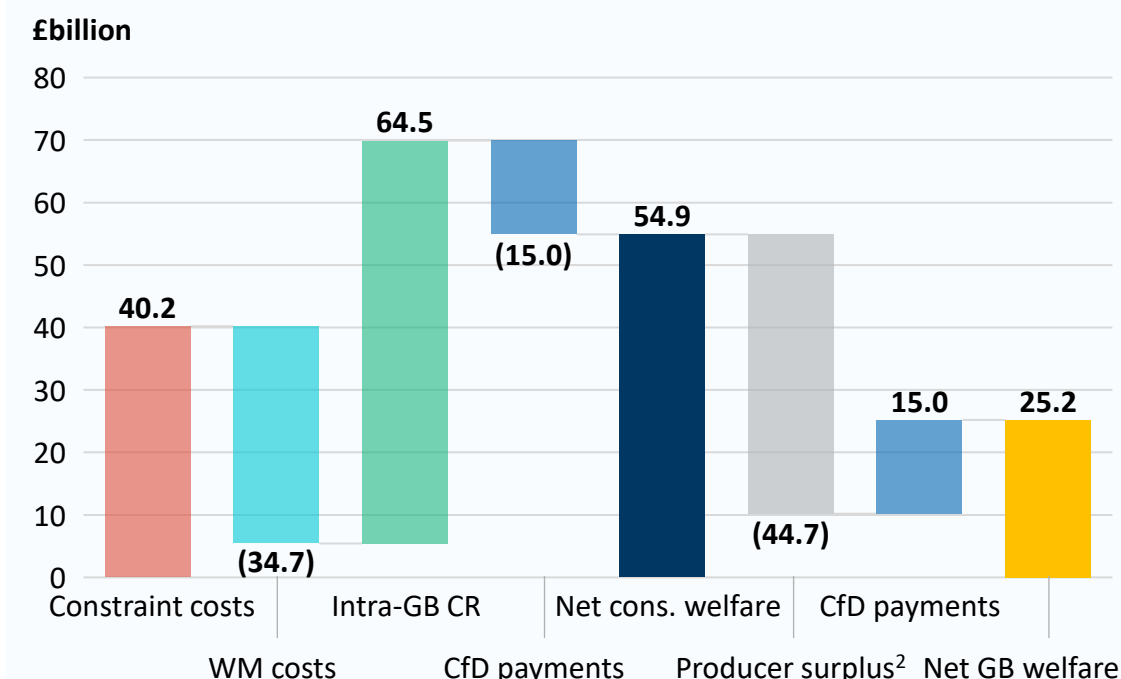
Approach and methodology

- The assessment was conducted using our in-house Plexos power market model, which has a representation of the GB transmission network with approximately 1,200 nodes.
- This is the same model used in our assessment for Ofgem on the benefits of locational pricing, but has been updated to reflect assumptions from the latest forecasts from NESO in GB:
 - GB generation capacity, demand and commodity prices are aligned to CP2030's Further Flex and RES pathway for 2030,¹ and the Future Energy Scenarios 2024 ("FES 24") Holistic Transition ("HT") pathway thereafter;² and
 - GB transmission network assumptions are aligned with CP2030 and Beyond 2030.³
- Our Europe assumptions are based on the Distributed Energy ("DE") scenario from European Network of Transmission System Operators for Electricity's ("ENTSO-E") Ten-Year Network Development Plan 2024 ("TYNDP 24").
- We deploy our GB nodal model for the years 2030, 2035, 2040, 2045 and 2050. We linearly interpolate between modelled years to derive values for intermediate years.
- We first run our model assuming a national market design, and then assuming a zonal market design using a 12-zone set up, delineated based on where we find the main persistent and enduring transmission constraints arise on the GB transmission network.

GB price zone map



Net GB welfare impact of zonal pricing (NPV 2030-50)



Modelling results

- We estimate that zonal pricing leads to £54.9 billion in net consumer benefits...
- ...comprising: (i) £40.2 billion lower constraint costs; (ii) £34.7 billion higher wholesale market costs; (iii) £64.5 billion in intra-GB congestion rents ("CR") that arise due to zonal price differentials; and (iv) £15.0 billion increase in CfD payments.¹
- These consumer benefits are partially offset by a £29.7 billion reduction in producer surplus. Overall net GB welfare increases by £25.2 billion as a result of zonal design.

Notes: (1) 'Clean Power 2030', November 2024, NESO ([link](#)). (2) 'Future Energy Scenarios', July 2024, NESO ([link](#)). (3) 'Beyond 2030', March 2024, NESO ([link](#)). (4) The categories considered in the analysis are the same as in previous published work for Ofgem, which were scrutinised by the industry. In this report we continue to assume there is no impact on market participants' cost of capital; however, we have not included implementation costs, which, based on previous analysis, were generally agreed to be materially lower relative to the other cost and benefits; (5) Producer surplus category aggregates change in producer surplus in wholesale market and balancing markets, and GB share of change in interconnector revenues.

Compared to our previous work for Ofgem, our latest estimate of the consumer benefits of zonal on an annualised basis is 21% higher (£3.7 billion vs £3.1 billion)

Comparison of key differences between FTI Consulting's latest assessment (for Octopus) and FTI Consulting's previous assessment (for Ofgem)

	Our latest assessment (for Octopus)	Our previous assessment (for Ofgem)
Modelling period	2030-2050	2025-2040
Generation and demand	FES 24 HT	FES 21 LtW, FES 21 SysTr
Transmission	CP2030 + Beyond 2030	NOA7, NOA7R + HND
Number of zones	12	7
Commodity prices	CP2030 and FES 24	FES 21
CfD strike price	AR6	AR4
Benefits related to siting of new generation	Not assessed	Assessed for some technologies

Welfare benefits of zonal pricing in our Base Model (£billion, real 2024)¹

	Welfare:	Consumer	Producer	Net GB
Our latest assessment (for Octopus)	NPV (2030-50)	54.9	(29.7)	25.2
	Annualised ²	3.7	(2.0)	1.7
Our previous assessment (for Ofgem)	NPV (2025-40)	37.5	(18.5)	19.0
	Annualised ²	3.1	(1.5)	1.6

Results

- Our current estimate of consumer benefits is higher compared to our previous estimate in our assessment for Ofgem. This is mainly driven by:
 - differences in the modelled periods in both assessments;
 - differences in the modelling assumptions, as our current assessment has been updated to reflect the latest available forecasts from NESO; and
 - refinements to our zonal set up such that it better reflects constraints identified in our model.
- Unlike our assessment for Ofgem, which optimised the siting of some new generation under locational pricing, our current assessment (conservatively) focuses only on the dispatch efficiencies of zonal pricing.³ As such, there is a larger producer welfare loss in a transition to a zonal market in which there is no associated change in siting decisions for new resources.
- Comparing our results on an annualised basis:
 - Our current estimates of annualised consumer benefits of zonal design are 21% higher than in our assessment for Ofgem (£3.7 billion vs £3.1 billion);⁴ and
 - Our current estimates of annualised GB welfare benefits of zonal are 9% higher than in our assessment for Ofgem (£1.7 billion vs £1.6 billion).⁴
- The fact that these results broadly accord with our findings from our earlier work for Ofgem despite using updated assumptions provides (in our view) further evidence to policy makers on the potential benefits to GB consumers of zonal pricing.

Notes: (1) Results from FTI Consulting's previous assessment presented here are from the zonal LtW and NOA7 scenario, as this is the most comparable to the modelling in this assessment. See Appendix 3 for comparison to other FTI Consulting scenarios for Ofgem. For comparability with our updated assessment, we have removed implementation costs from the previous assessment figures and inflated results from 2021 to 2024 prices. (2) Annualised results have been levelised over the respective modelling periods. These figures therefore represent the welfare impact which, if replicated in each year of the modelling period, would deliver the same NPV impact in the respective starting year of the modelling period; (3) In our assessment for Ofgem, we performed a dispatch-only sensitivity in our assessment of the benefits of nodal pricing under the FES 22 LtW NOA7 scenario. We found that this reduced the consumer benefits by 24% and the GB welfare benefits by 43%. (4) The two figures are calculated based on different modelling periods and only overlap over 2030 to 2040.

Our Base Model conservatively assumes the central plan is fully delivered, on time. If the plan is unexpectedly delayed, zonal benefits could increase to up to around £74 billion...

Unexpected shocks

- The ‘base’ operational benefits of £54.9 billion (PV, 2030-50) are based on a highly conservative (in our view) assumption that the SSEP and CSNP plans are delivered on time and in full to achieve CP2030 and Net Zero by 2050.
- This is highly challenging – as NESO notes, “[s]everal elements must deliver at the limit of what is feasible” to achieve CP2030.¹
- In reality, the central plan could be affected by factors that are outside of NESO’s and other policy makers’ control. We have therefore modelled (individually and cumulatively) the benefits of zonal pricing under three ‘exogenous shock’ scenarios, where the central plan is – due to external factors outside the direct control of NESO and other policymakers – not delivered in full.

Transmission delay shock

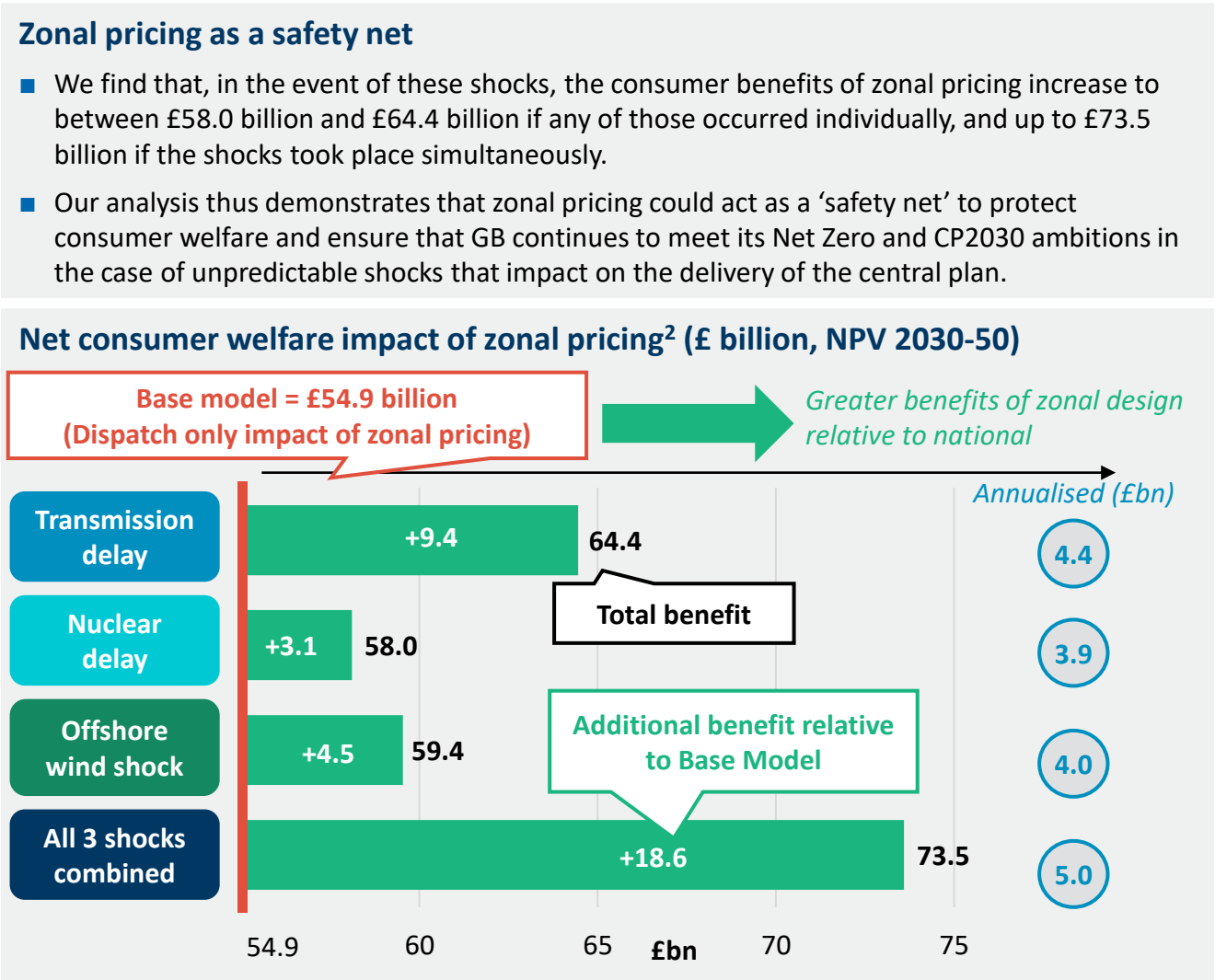
What if the delivery of nine “vital” transmission projects, including three that were identified in CP2030 as needing to be accelerated to 2030, were delayed (for example, due to supply chain constraints)?

Nuclear delay shock

What if the delivery of three new GW-scale nuclear plants and nine SMRs was delayed (for example, given uncertainty around SMR technology)?

Offshore wind shock

What if the relative pace of roll-out of offshore wind in England & Wales and Scotland is impacted (for example, by planning objections and project development timelines)?



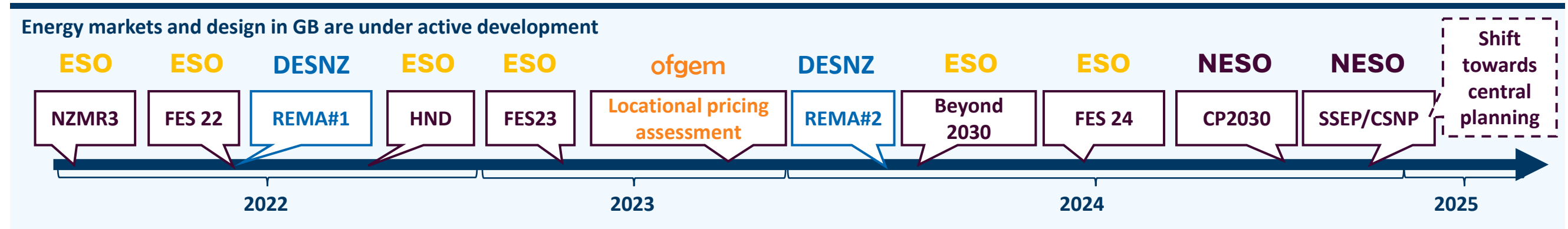
...which demonstrates how zonal pricing could act as a safety net to protect consumers

Notes: (1) ‘Clean Power 2030’, p4, NESO, November 2024 ([link](#)); (2) See slide 57 for results from other scenarios combining two shocks.



2. Introduction

Octopus Energy has commissioned FTI Consulting to examine the welfare impacts of a potential zonal wholesale electricity market design in GB



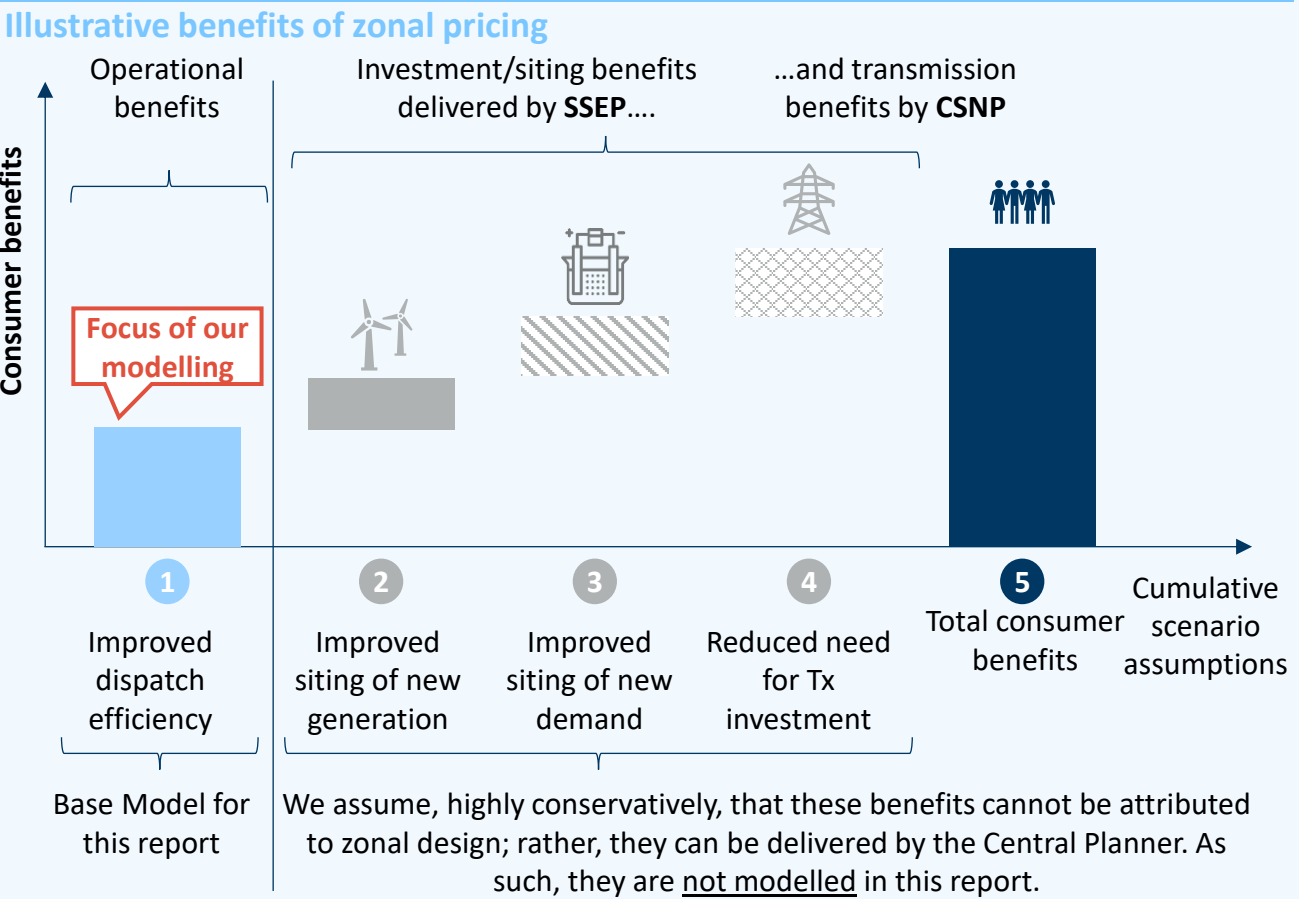
- Energy markets and design in GB are under active development:
 - **Electricity market design reform:** The UK Government is considering a potential shift to a locational (zonal) wholesale pricing design through its Review of Electricity Market Arrangements (“REMA”).
 - **Centralised network planning:** National Energy System Operator (“NESO”) is developing a Strategic Spatial Energy Plan (“SSEP”) to identify optimal locations, quantities and types of energy infrastructure, which will feed into the Centralised Strategic Network Plan (“CSNP”) for transmission (“Tx”) infrastructure.
 - **Clean Power 2030 (“CP2030”):** NESO published advice on the possible pathways for GB to achieve clean power by 2030.
- **Octopus Energy (“Octopus”) has been actively involved in the debate** on locational pricing and has engaged FTI Consulting to model the impact of a zonal market design in GB in light of latest policy developments and updated scenarios.
- This report builds on previously published FTI Consulting work for National Grid ESO (now NESO), Ofgem and Octopus which:
 1. Assessed locational market designs and national market design across against 10 qualitative assessment criteria;¹
 2. **Found significant consumer and societal benefits** of transitioning from a national to a locational wholesale price design (including from more efficient siting of new generation);²
 3. **Found significant savings for consumers** (for example, data centres and electrolyzers) who are incentivised to site in northern areas to take advantage of lower prices relative to southern areas. This also leads to lower prices in southern areas, which benefits other consumers located there;³ and
 4. **Found significant reductions in required transmission investments** under a zonal wholesale price design (not quantified in our previous assessment for Ofgem).²
- FTI Consulting is also currently undertaking work for NESO in relation to a quantitative assessment of self and central scheduling which includes a consideration of zonal design.⁴
- This report augments previous FTI Consulting analysis by providing an updated estimate of the dispatch benefits of zonal pricing using the latest NESO forecasts / plans and further demonstrates the value of zonal pricing as a ‘**safety net**’ even under central planning.

Notes: (1) Net Zero Market Reform: Phase 3, FTI Consulting, May 2022 ([link](#)); (2) ‘Assessment of locational wholesale electricity market design options in GB’, FTI Consulting, October 2023 ([link](#)); (3) ‘Impact of electricity market design on siting decisions of large consumers of electricity’, FTI Consulting, October 2023 ([link](#)); (4) Quantitative assessment of self and central scheduling, FTI Consulting, November 2024 ([link](#)).

As a starting point, we assess the benefits of zonal pricing assuming “perfect” central planning, delivered by SSEP and CSNP

- A zonal market design is generally considered to have up to three key benefits:
 - **Improved dispatch efficiency:** Asset scheduling based on zonal prices (which reflect local demand, supply and inter-zonal Tx constraints) is more efficient and requires less redispatch by NESO – for example, it allows better use of two-way assets such as interconnectors (“ICs”) and batteries to relieve rather than worsen constraints. Under the current market design the price signals sometimes mean that these assets exacerbate rather than alleviate constraints.
 - **Improved siting decisions of generation and demand:** Zonal price signals have the potential to incentivise generation and demand to site in a manner that could reduce system constraints – for example, higher zonal prices incentivise new generation to site in areas where existing generation is relatively scarce or costly. Conversely, new large users of electricity would be more strongly incentivised to consider siting in areas with lower prices where there tends to be lower cost and/or more plentiful electricity supply.
 - **Reduced need for transmission investment:** Improved dispatch and siting, all else being equal, would reduce the incremental need for transmission relative to national pricing.
- NESO has been commissioned by the UK, Scottish and Welsh governments to decide on the spatial distribution of future demand, supply and transmission. As such, the SSEP will assess the optimal location, quantities and types of electricity infrastructure, generation and storage. This will feed into the CSNP, which will in turn set out the network requirements needed.¹ From the demand siting perspective, NESO is, in principle, able to influence siting choices through the connection permitting process.
- In this report we do not consider the extent to which NESO is expected or able to identify an ‘optimal’ demand/generation/transmission plan for GB. Rather, we assume that NESO centrally plans perfectly, and therefore the benefits of optimal siting choices by demand, generation and transmission could be delivered fully and solely by the SSEP/CSNP.

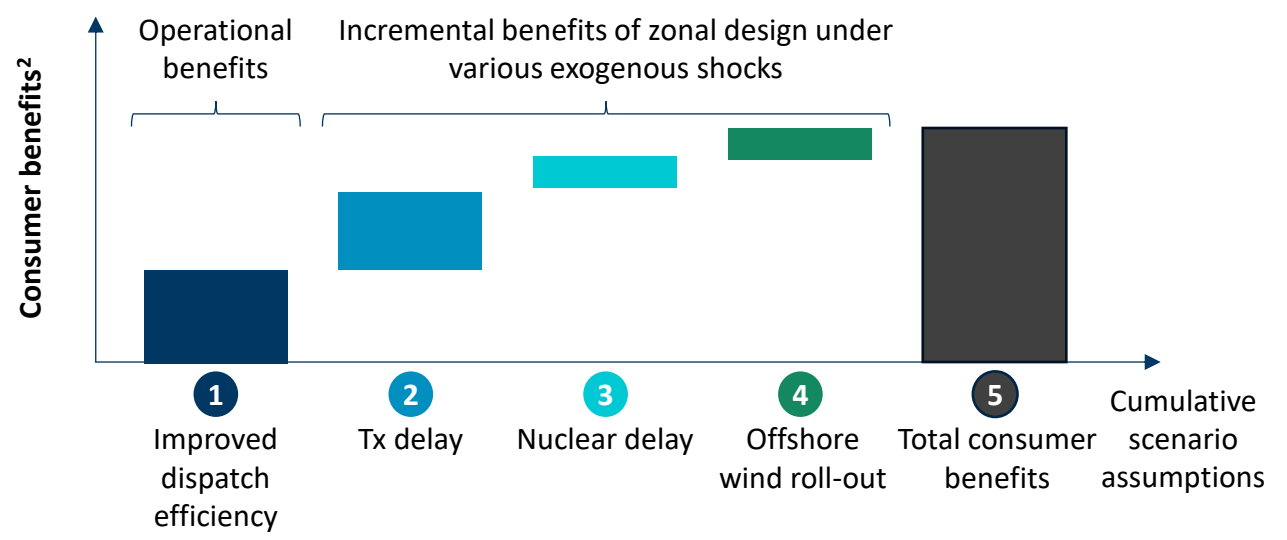
- As a starting point for our modelling, in our Base Model, we focused on capturing the ‘dispatch efficiency’ benefits of zonal pricing. This is shown as #1 in the chart and implicitly assumes a “perfect” central planner. As such, the Base Model benefits of zonal design do not include any benefits relating to improved siting due to zonal pricing (assumed to be delivered by the SSEP) or changes in Tx investment (assumed to be delivered by the CSNP).



Notes: (1) ‘Strategic Spatial Energy Plan’, DESNZ, October 2024 ([link](#)).

We quantify how the benefits of zonal design change when the central plan is impacted by exogenous factors outside of NESO’s control, and how zonal design acts as a ‘safety net’

- In the short term, CP2030 already has been described by NESO as being ‘at the outer edge of feasibility’, as ‘several elements must deliver at the limit of what is feasible’.¹ Going forward, central plans such as the SSEP could be affected by exogenous factors (that is, factors that are unforeseeable and outside of NESO’s control) and it therefore seems reasonable to us to consider what the outcomes would be if the central plan was not delivered in full and/or on time.
- In this report we have therefore assessed how zonal pricing could act as a ‘safety net’ to protect consumer welfare¹ and ensure that GB continues to meet its Net Zero and CP2030 ambitions in the case of certain exogenous shocks.
- This approach continues to make the highly conservative assumption that the benefits of optimal siting choices by demand, generation and transmission are delivered fully and solely by a central planner, but we introduce shocks to the system that – for reasons entirely outside of the planner’s control – make the original central plan not-fully-deliverable.



We have modelled the benefits of zonal pricing under the following scenarios:

	Base Model	Assumes perfect central planning where improved siting and transmission benefits are delivered by the SSEP and CSNP (and hence are not attributable to zonal design itself).
	Transmission delay shock	The latest transmission network plans are highly ambitious – for example, CP2030 identifies three ‘vital’ transmission projects that are ‘acceleration required’ and need to be delivered earlier by 2030. In this ‘shock’ scenario we test what would happen if the delivery of several projects is delayed (for example due to supply chain constraints or planning delays).
	Supply shock: Nuclear delay	FES HT assumes several new GW-scale nuclear plants and small modular reactors (“SMRs”) to be developed. However, delivery timelines appear optimistic (for example, SMRs are still immature) – in this ‘shock’ scenario we therefore test the impact of delays to the delivery of these projects.
	Supply shock: Offshore wind	In this ‘shock’ scenario we examine energy market outcomes if the relative pace of roll-out of offshore wind in England & Wales and Scotland is impacted by planning objections and project development timelines.

We model these scenarios both individually and cumulatively

Notes: (1) Strategic energy planning for the net zero transition, NESO ([link](#)), CP2030, NESO ([link](#)). (2) Our analysis focuses on consumer welfare, but also presents total GB welfare, both of which are significantly improved under zonal pricing.

Structure of report and report conventions

Structure of the report

The remainder of this report is structured as follows:

- **Section 3** sets out our modelling approach and assumptions.
- **Section 4** presents our modelling results, which quantify the consumer and GB welfare benefits of a zonal market design. In this section, we:
 - present our modelling results on prices, constraint costs and welfare impacts under the Baseline Scenario; and
 - present our modelling results under various sensitivity scenarios (including transmission delays, supply shocks, and cumulative scenarios).
- **Appendix 1** presents our modelling results on the impact of zonal pricing in GB on exports/imports and wholesale prices in connected countries.
- **Appendix 2** presents our modelling results on CO2 emissions under in our Base Model and exogenous shock scenarios.
- **Appendix 3** compares our current estimates of the benefits of zonal pricing to our previous modelling performed for Ofgem assessing the benefits of zonal pricing from 2022-23.

Report Conventions

Unless otherwise stated:

- Prices, revenues and costs are expressed in GBP and in 2024 real terms. As our model is run in real EUR terms, we convert these values to GBP at an exchange rate of 1 GBP = 1.20 EUR.¹
- All present values (“PVs”) are discounted to 2030, at a discount rate of 3.5%.
- We have linearly interpolated between modelled years to derive values for intermediate years (for example, 2031, 2032, etc).
- All results are presented for calendar years beginning 1 January.
- All annual average prices are time-weighted.

Notes: (1) Exchange rate on the 6th January 2025 (European Central Bank, [link](#)).



3. Modelling Approach and Assumptions

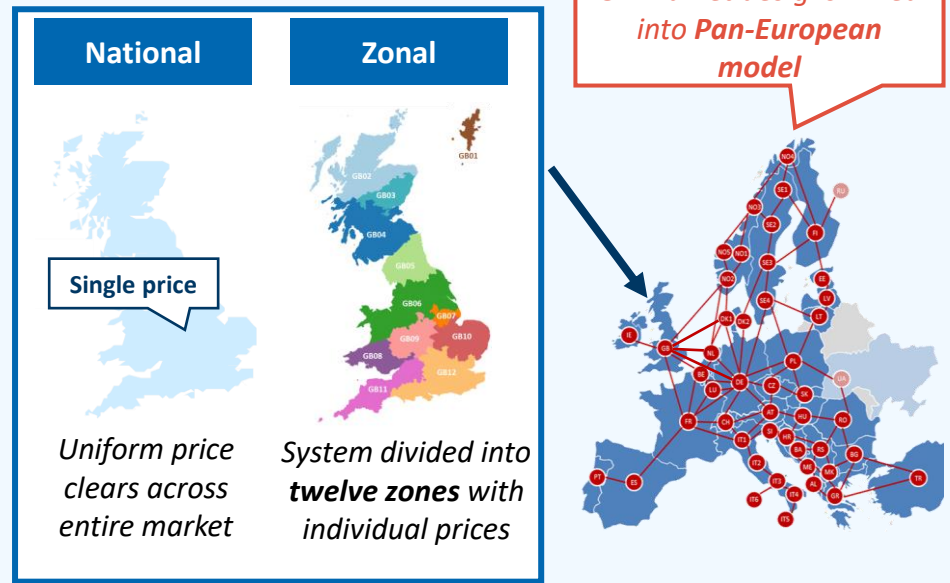
We use the Plexos Integrated Energy platform to model hourly dispatch under different scenarios

Key model inputs		
Transmission capacity		Current & future network topology, and seasonal availability assumptions
Demand		Annual demand, profile and flexibility assumptions by type and location
Generation capacity		Build-out assumptions, plant technical characteristics and renewable capacity profiles
Commodity prices		Price projections for a set of commodities (CO2, gas, etc.)
BM and CfD ¹ assumptions		BM bid and offer prices and capacity constraints, and projected CfD capacity and future regime design
Other baseline assumptions		
Modelled years		2030, 2035, 2040, 2045, 2050
Climate year ("CY")		CY2009

See slide 16 for input sources

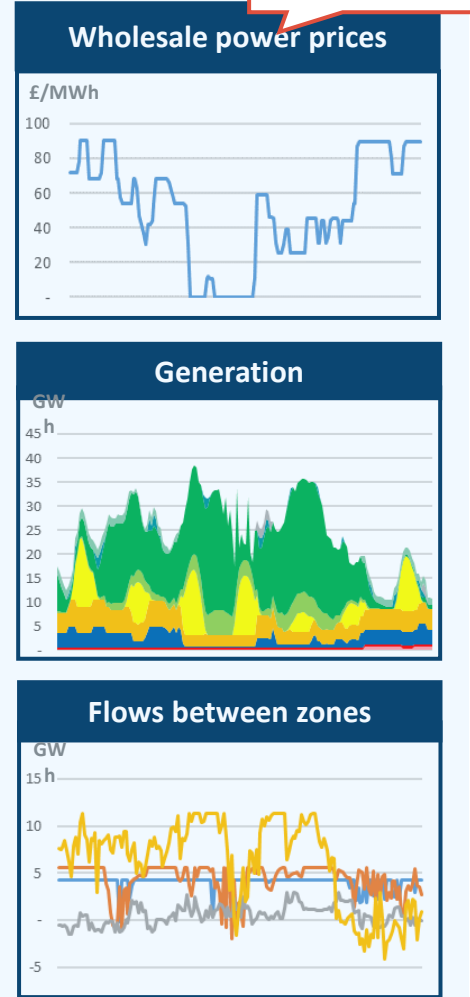
Based on capacity, demand, commodity, transmission and other assumptions, the model determines optimal dispatch of assets:

- The dispatch model finds the least-cost dispatch profile of generation that meets demand...
- ...on an hourly basis...
- ...for each generating plant...
- ...for each price zone...
- ...with intra-GB transmission constraints used to estimated Balancing Mechanism outcomes.



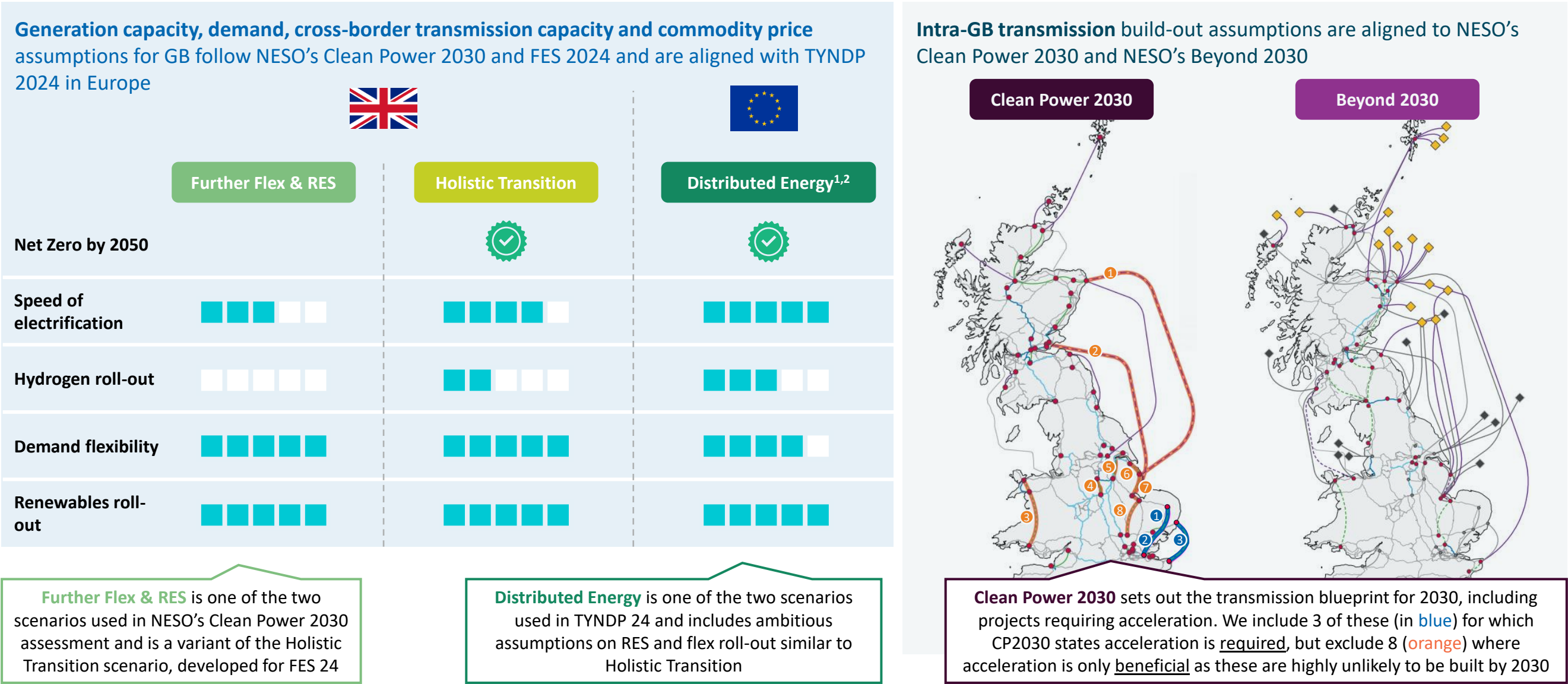
Hourly outputs for each modelled year

Illustrative



Notes: (1) BM: Balancing Mechanism. CfD: Contract for Difference.

Our GB assumptions for 2030 are aligned with NESO’s CP2030, and FES 24 HT/Beyond 2030 for 2035-2050, while our EU assumptions are aligned with TYNDP 24 DE



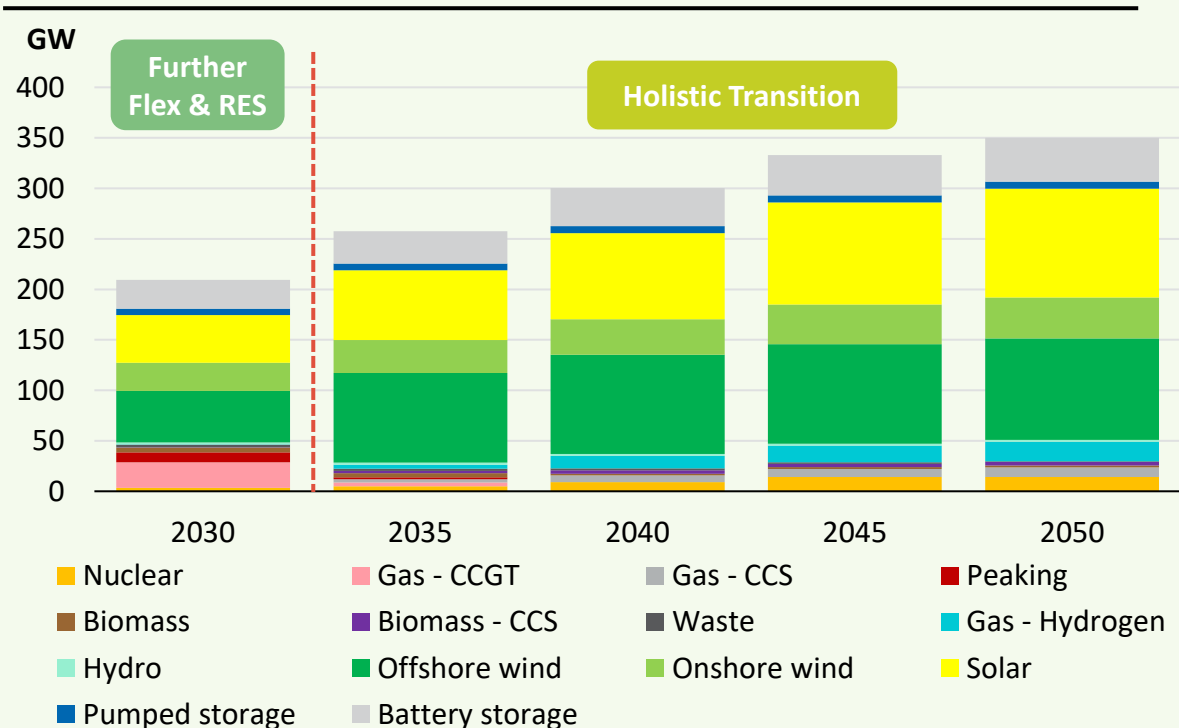
Notes: (1) As TYNDP 24 DE does not have forecasts for 2030, we rely on a mix of TYNDP 2024 National Trends (“NT”) and ERAA 2023 for 2030; (2) When calibrating our model, we identified several issues with the TYNDP data and have adjusted the assumptions where appropriate following discussion with ENTSO-E. We do not expect these adjustments to materially affect the conclusions of our modelling.

16

Our generation capacity assumptions include a steady roll-out of renewables to replace unabated gas generation and meet increased demand from electrification

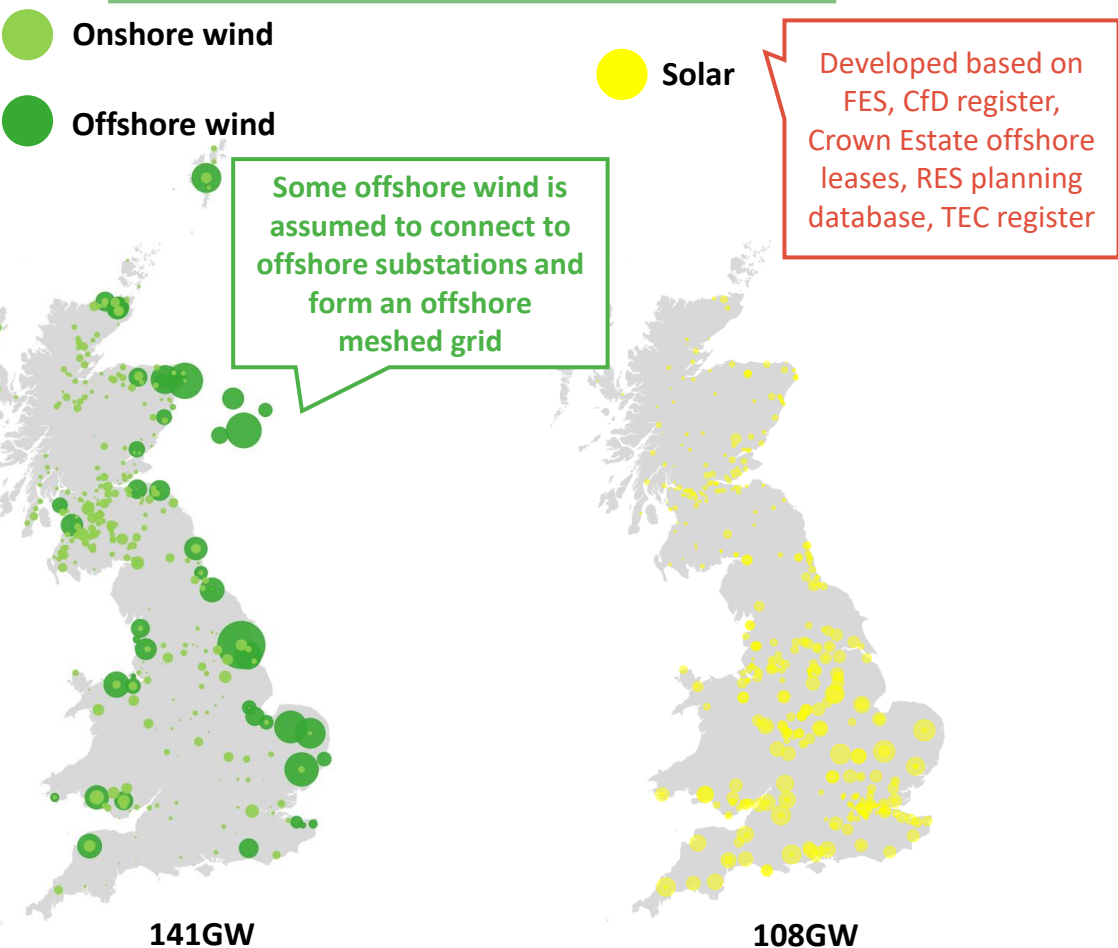
1. Core assumptions aligned to FES 24 HT scenario

Installed GB capacity, HT scenario, GW



- For 2030, based on Further Flex & Res, which assumes ambitious offshore wind roll-out and a limited reduction in unabated gas generation capacity compared to 2024.
- Post-2035, the scenario follows the FES 24 HT (Net Zero) scenario, which has a steady build-out of RES and total phase-out of unabated fossil fuels.

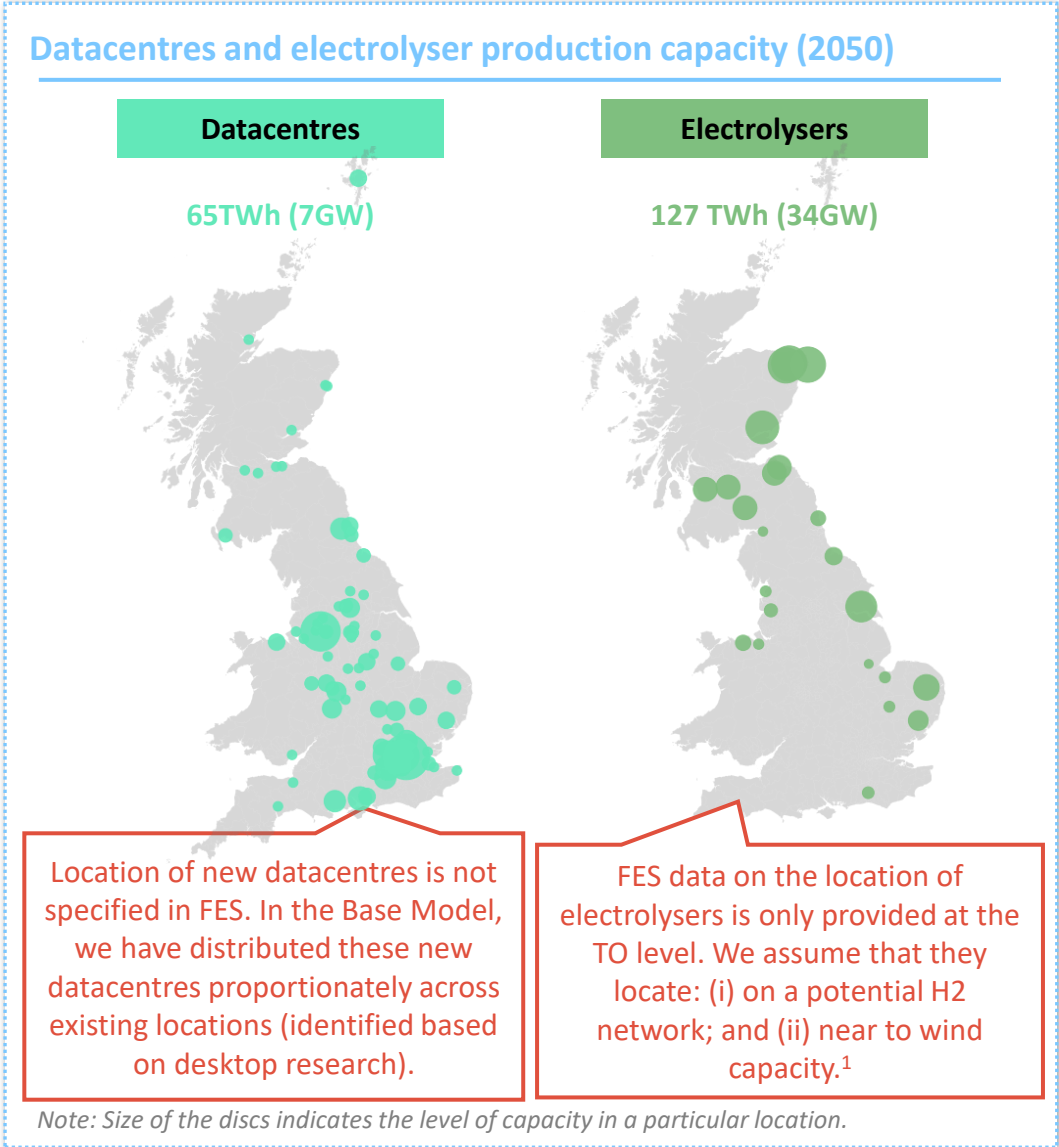
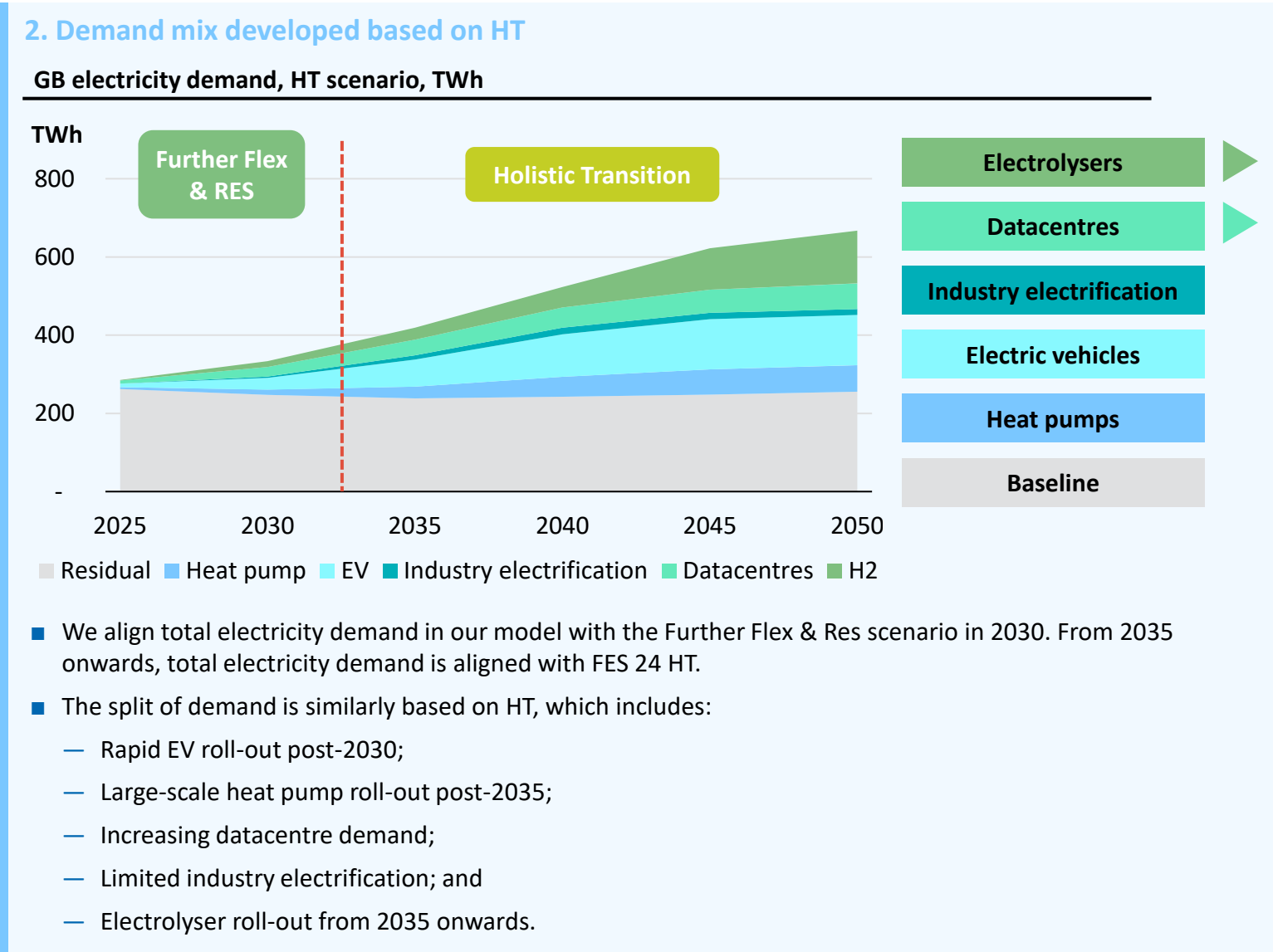
Location of RES capacity in our modelling, 2050¹



Note: Size of the discs indicates the level of capacity in a particular location.

Notes: (1) To develop locational assumptions for the siting of new generation, we follow the FES assumptions where possible. Distributed capacity assumptions are provided on the nodal level, while transmission connected generation assumptions are provided by transmission owner ("TO") areas, requiring further assumptions to develop nodal inputs. We do this by building a pipeline of projects for each technology in each TO area using the following sources: (i) Transmission Entry Connection ("TEC") register for operational and under construction generators; (ii) CfD auction results for committed RES capacity; (iii) Capacity Market ("CM") auction results for committed non-RES capacity, (iv) Renewable Energy Planning Database for consented RES projects, (v) Crown Estate lease data on non-consented offshore wind, (vi) CCUS clustering areas for CCS gas and biomass, (vii) Project specific Government plans for nuclear and (viii) TEC register for non-committed capacity for all other technologies. If locational data is not available in any of the sources, we develop them according to the technology (for example, future nuclear is restricted to nuclear sites, while H2P locates close to a potential H2 network).

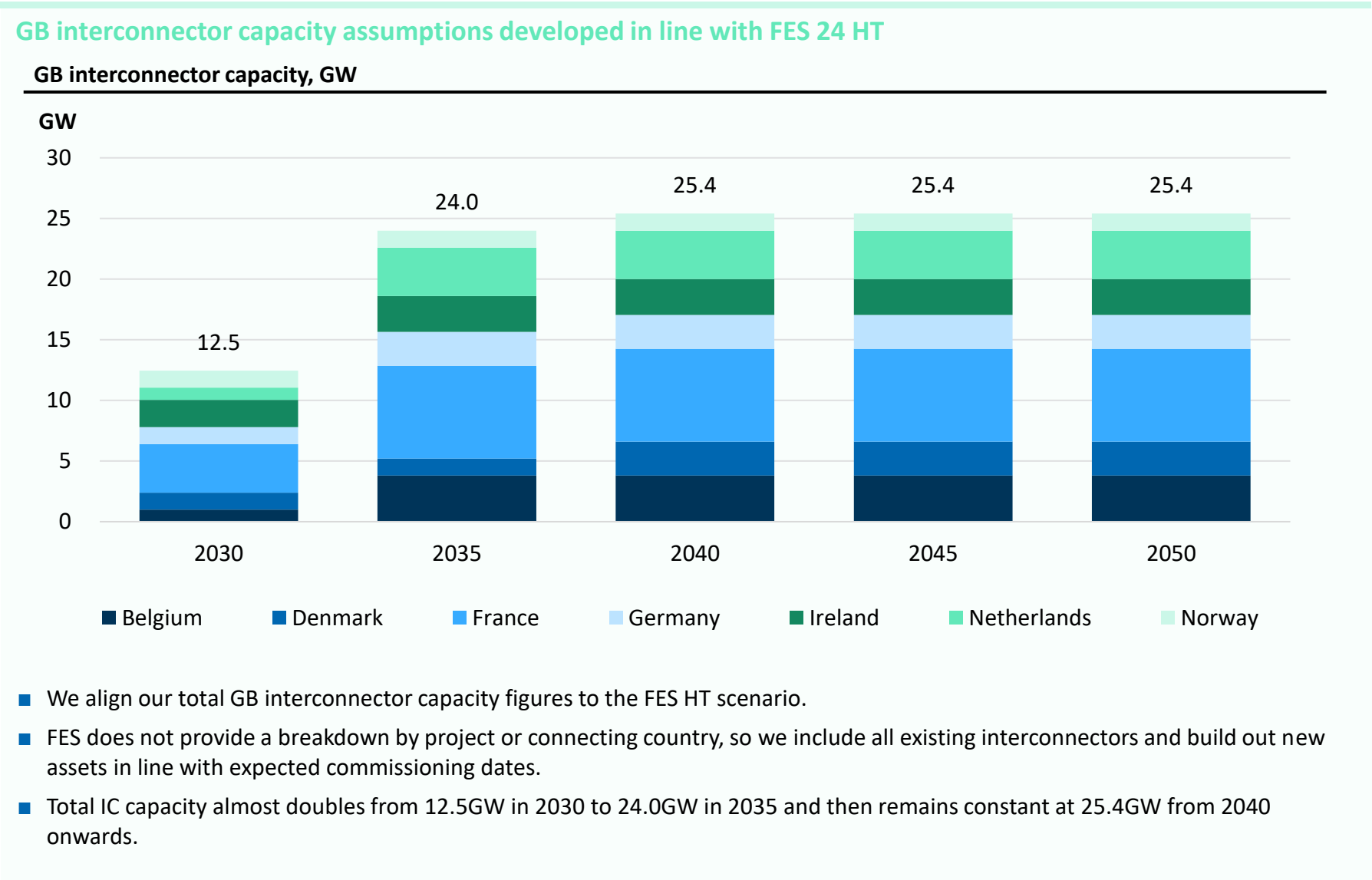
Demand grows to 667 TWh by 2050. Where FES does not provide nodal level projections, we follow the location of existing data centres and siting of wind capacity (electrolysers)



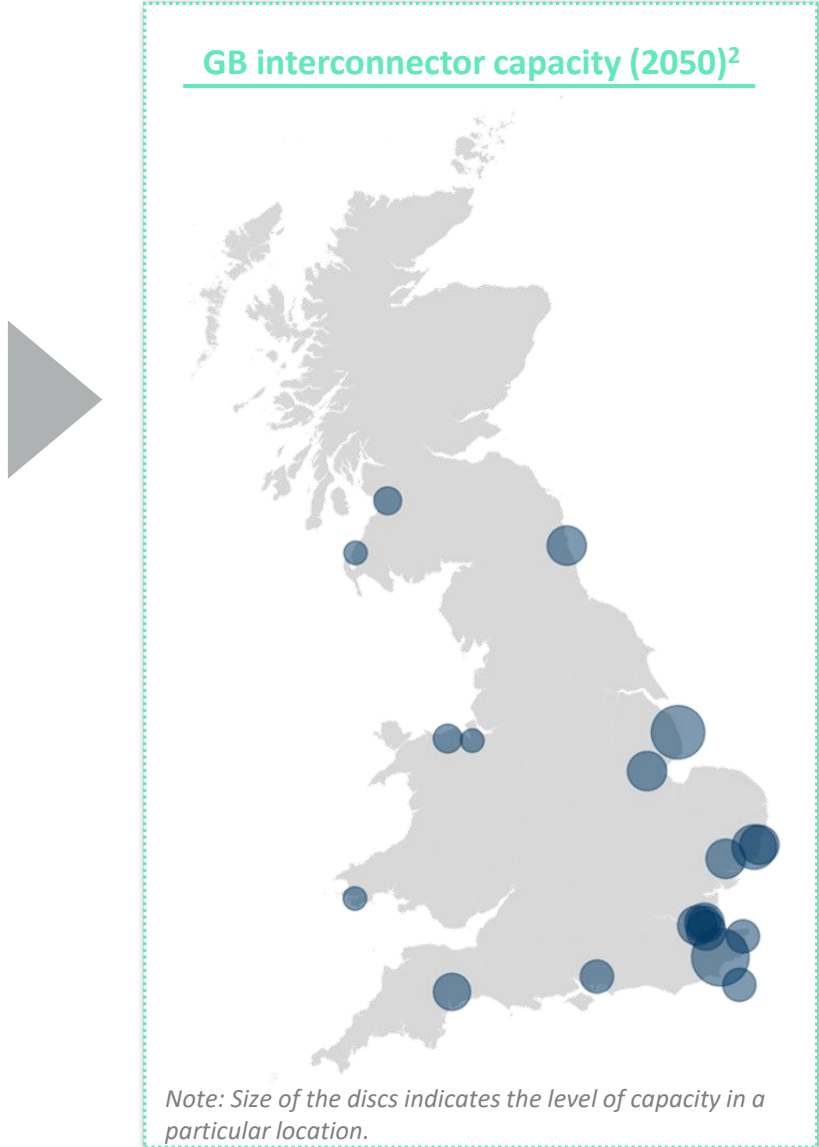
Notes: (1) Electrolyser assumptions in FES are only provided at the transmission owner level (NGET, SPTL, SHETL). We split electrolyser capacity between sub-regions (minor FLOP zones) according to wind capacity in the given sub-region, only considering sub-regions which both: (i) would be served by a potential H2 network; and (ii) have at least 1,000MW of wind capacity in 2050. Within each sub-region considered, we allocate electrolyser capacity to a single representative node, except for sub-regions with over 2GW of electrolyser capacity in 2050, where we spread this capacity across multiple nodes to prevent local constraints on the system.

18

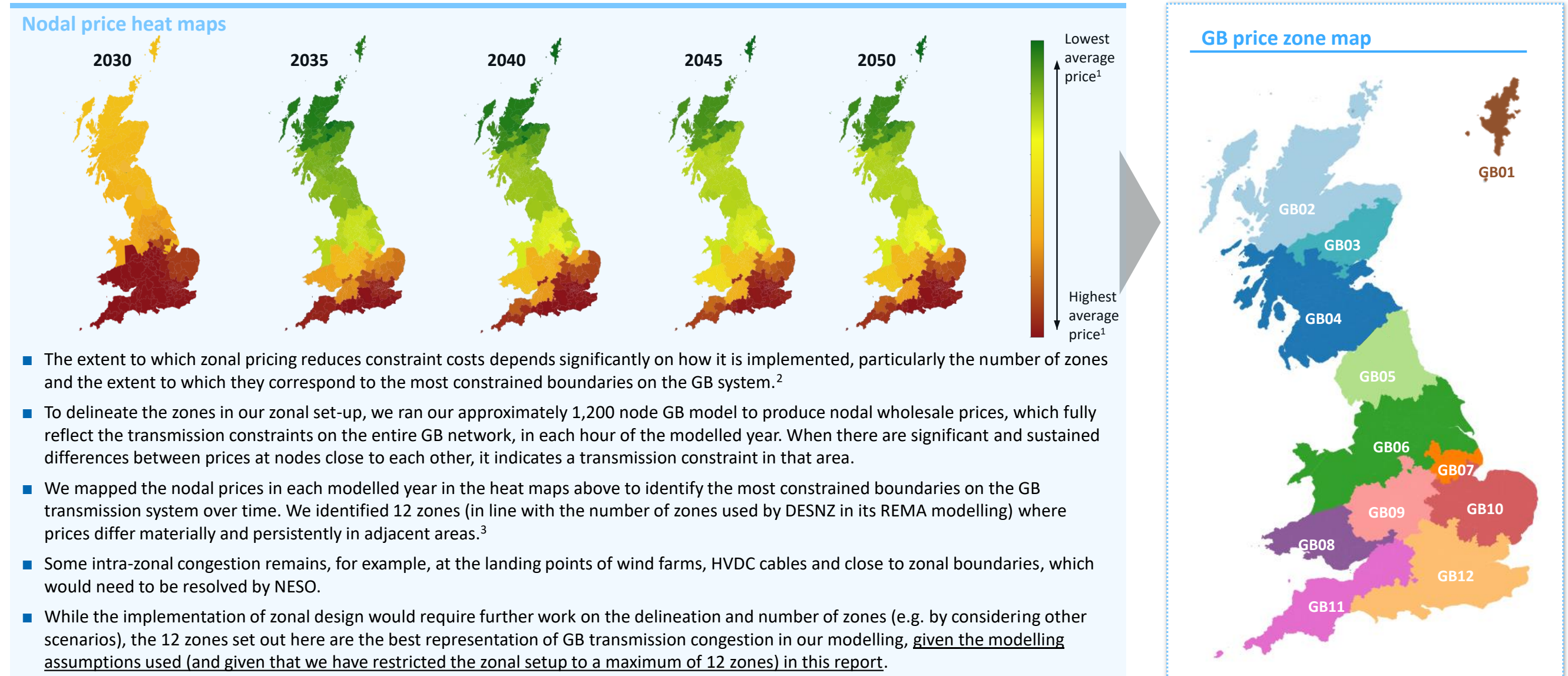
Interconnector capacity almost doubles from 2030 to 2035 and then remains constant from 2040 to 2050, in line with FES 24 HT assumptions



Notes: (1) Ireland refers to the Integrated Single Electricity Market, encompassing both Northern Ireland and the Republic of Ireland.



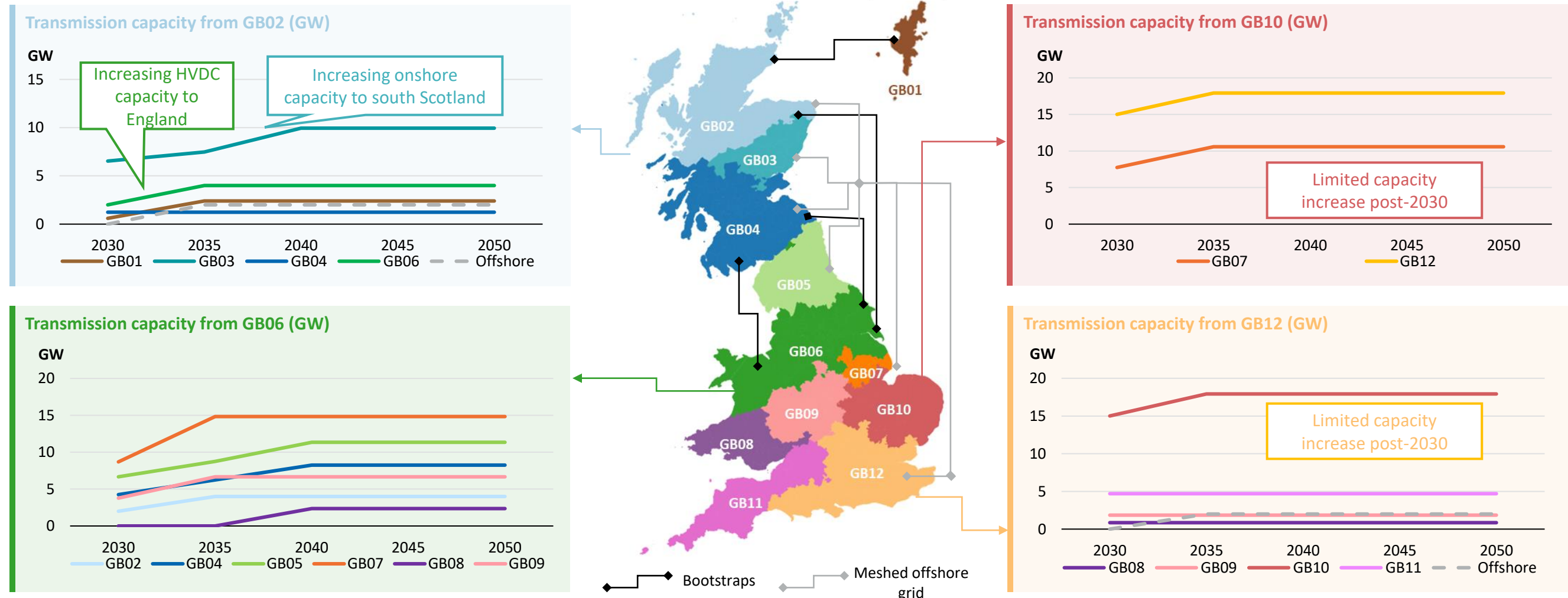
We have delineated 12 zones within GB based on observed price outcomes in modelling with a full nodal representation



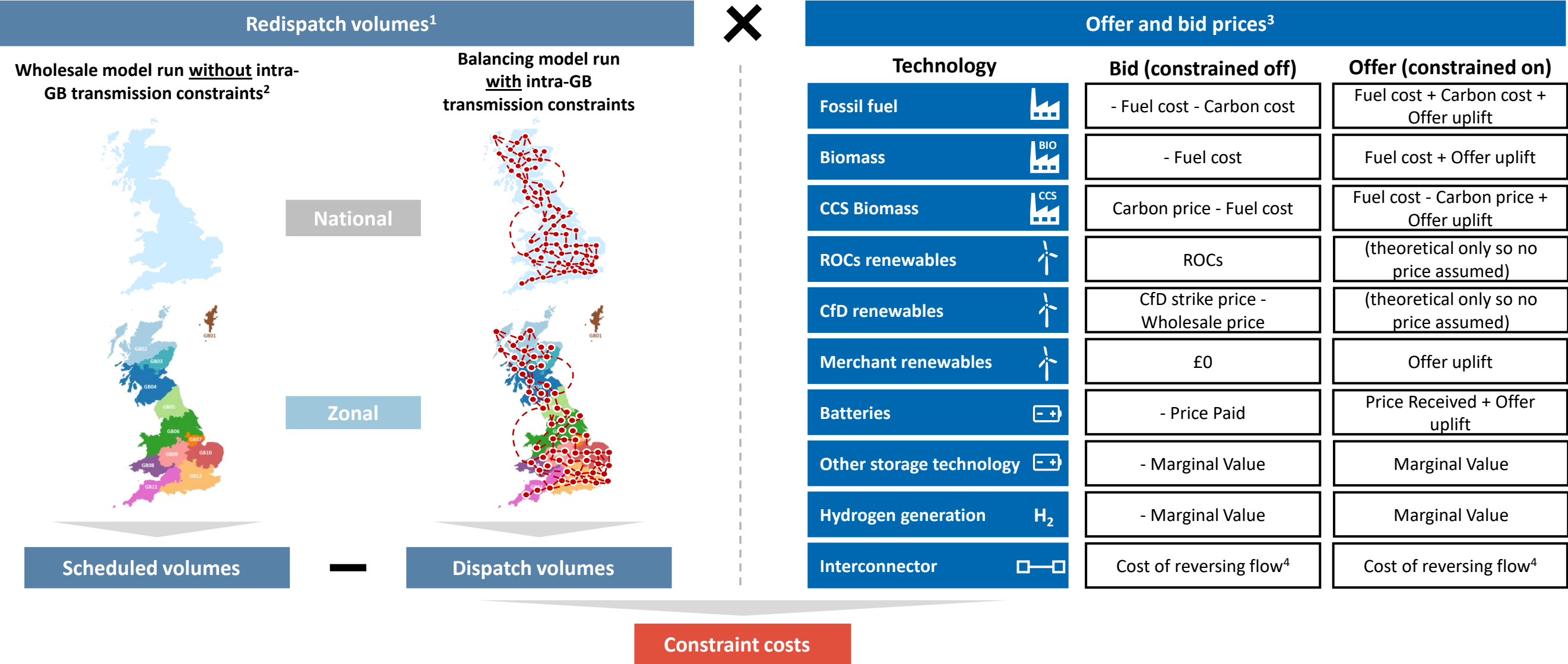
Notes: (1) The nodal price maps use a dynamic scale, which ranges between the lowest and the highest observed annual average price in each year to clearly illustrate the price difference in each individual year; (2) The impact of zonal pricing also depends on how assets are scheduled and dispatched (for example, central dispatch); (3) We have not relied on NESO projections regarding congestion on transmission boundaries, such as the ones in ETYS or NOA7 Refresh, as these only extend to the early 2030s and were all developed using different IC baseline/assumptions and would therefore reflect different constraints compared to our modelling. We also have not used DESNZ's 12-zone REMA set up as they were developed based on ETYS/BID3 and would similarly reflect different constraints compared to our modelling. 'System Benefits from Efficiency Locational Signals', p39, DESNZ ([link](#)).

Beyond 2030 plans for an increase in Tx capacity in north GB to accommodate wind capacity, but limited growth between the Midlands and north GB, despite growing south GB demand

- Our transmission network assumptions in our Base Model follow: (i) CP2030, which assumes that three projects that were originally planned to be delivered in 2031 are accelerated to 2030; and (ii) Beyond 2030, which recommends an additional £58 billion of direct investment in offshore and onshore network upgrades.¹
- In line with Beyond 2030, we assume that transmission capacity remains constant after 2040.

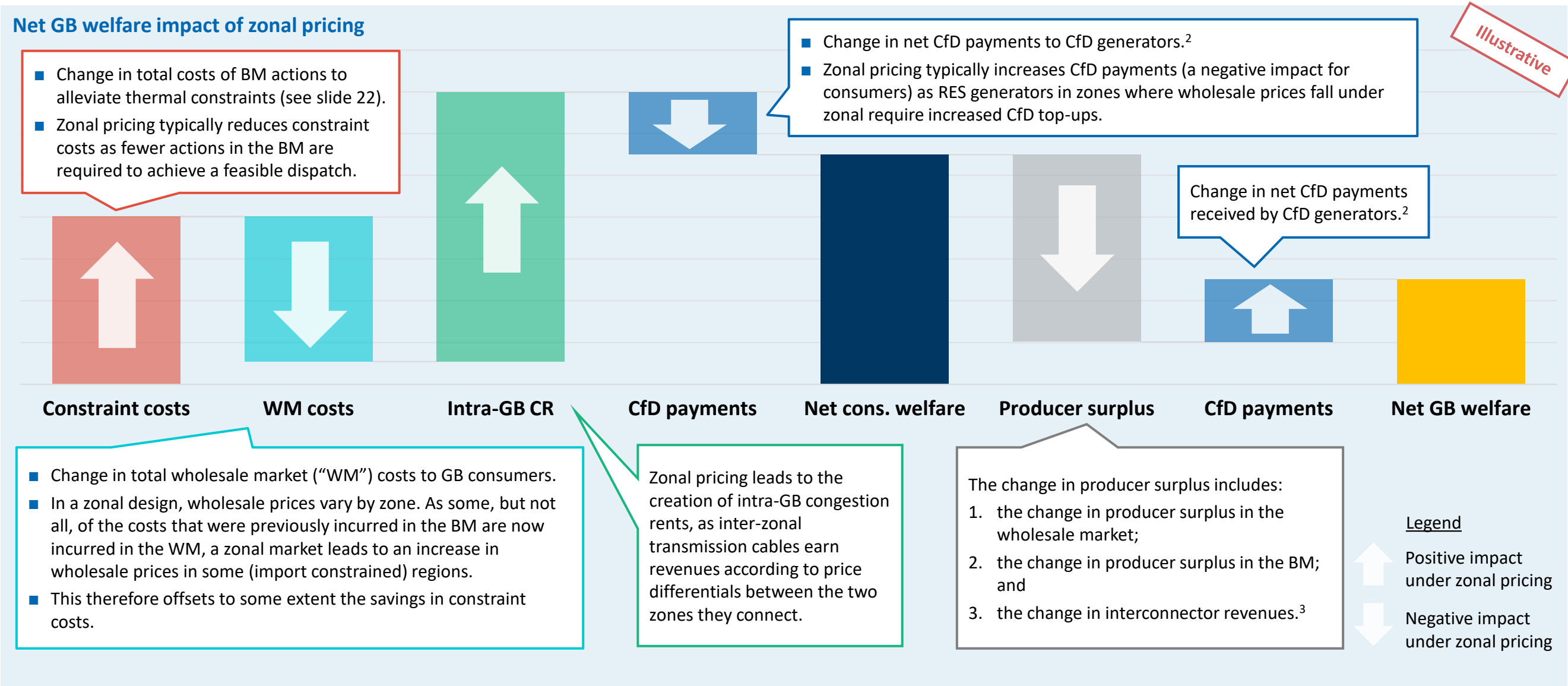


Modelled redispatch volumes are combined with Balancing Mechanism offer and bid price assumptions to calculate GB-wide constraint costs



Note: (1) Redispatch volumes are calculated on a weekly basis by generator; (2) Zonal wholesale model runs include inter-zonal transmission constraints; (3) We assume that any unserved energy in balancing model runs would be mitigated by DSR and hence we value it at the DSR price (approximately, £280-340/MWh); (4) Assumed to be €100/MWh. We do not explicitly model the balancing markets of neighbouring countries, which would be the basis of offers and bids in practice. However, as changing IC flows would likely require gas generators to be constrained on in a neighbouring country, we have set IC offers to a level slightly above the SRMC of Combined Cycle Gas Turbine (“CCGT”) plants. This assumption is also reflective of historical NESO actions to balance thermal constraints. Historically, most export constraints have been resolved by turning down wind generation behind the constraint and turning up gas generation in front of the constraint, rather than reversing IC flows. From 2020 to 2022, ICs were primarily used to resolve import constraints. See ESO Markets Roadmap, March 2023 ([link](#)).

The net GB welfare impact of zonal pricing is the sum of five components, calculated across our wholesale market and balancing market model runs

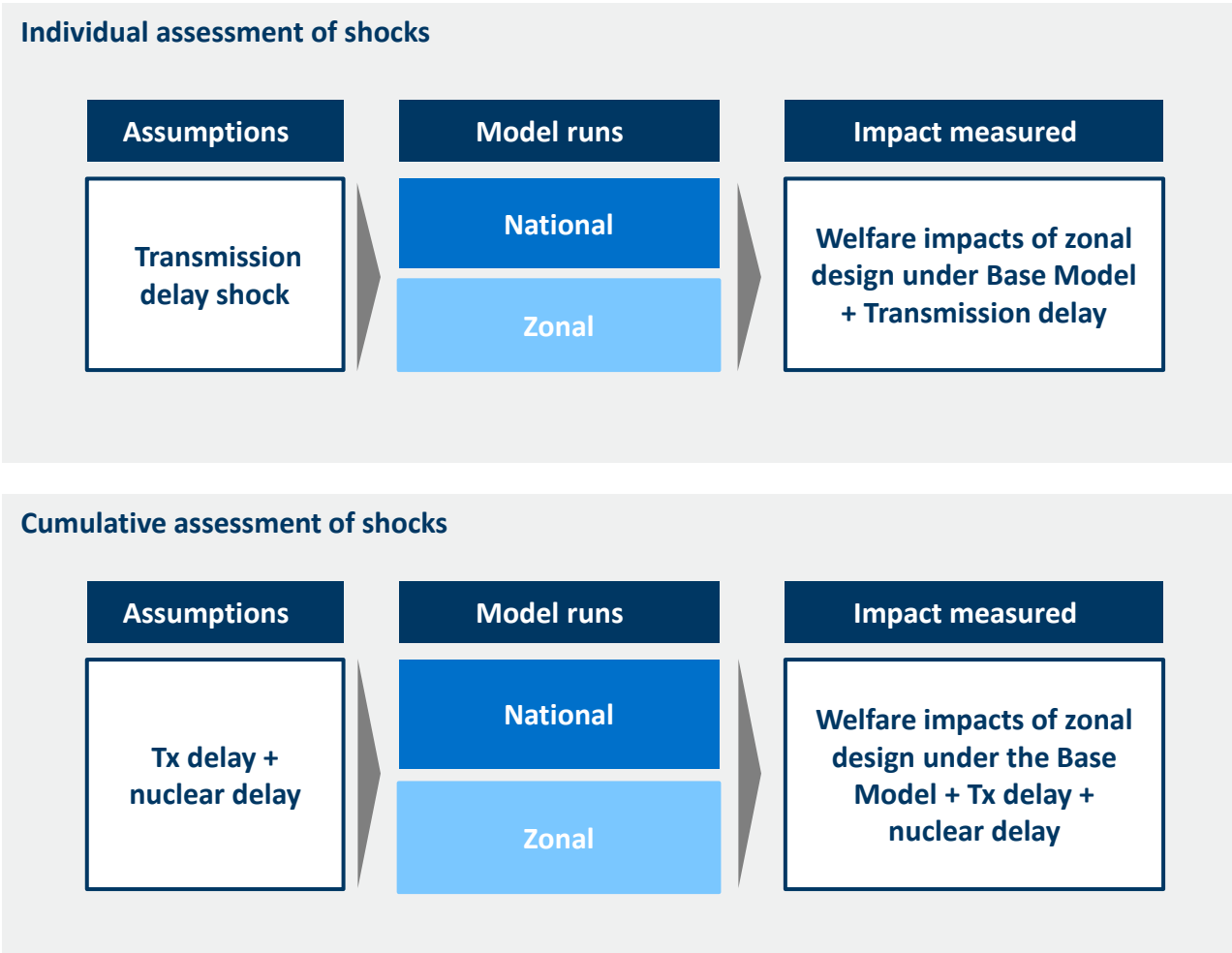


Notes: (1) Our analysis does not include the implementation costs of transitioning to a zonal design. However, we note from our assessment of locational marginal pricing for Ofgem that these costs are two orders of magnitude lower than the estimated benefits of zonal pricing. We also found limited evidence that moving to zonal pricing would increase investors’ cost of capital (see Appendix 3); (2) CfD payments calculated on a weekly basis as: CfD payment = (strike price – wholesale price received) * physically-dispatched generation. Strike prices from CfD Register and technology assumptions based on Levelised Cost estimates from DESNZ ([link](#)); (3) We allocate interconnector congestion rents 50/50 between GB and the connecting jurisdiction, except for EWIC and Moyle, which are wholly owned by parties in I-SEM and hence no revenues accrue to GB.

23

We assess the impact of exogenous shocks both individually and cumulatively. For each scenario, we run both national and zonal models to calculate welfare impacts

- To assess the welfare impact of zonal pricing in the Base Model, we compare outcomes between our national and zonal models (as explained on slide 23).
- For the shock scenarios, we again run national and zonal models under each set of scenario-specific assumptions. We assess shocks both individually and cumulatively, with a summary of our modelling approach below.



Exogenous shock included in scenario	 Tx delay	 Nuclear delays	 Wind shock
Base model	✗	✗	✗
Transmission delay shock	✓	✗	✗
Supply shock: Nuclear delay	✗	✓	✗
Supply shock: Offshore wind	✗	✗	✓
2 shocks: Wind shock + nuclear delay	✗	✓	✓
2 shocks: Tx delay + nuclear delay	✓	✓	✗
All three shocks combined	✓	✓	✓

Notes: (1) We were not instructed to model a cumulative scenario for wind shock + transmission delay. However, based on our analysis of the other combinations, we do not expect this combination to provide qualitatively different insights regarding the merits of zonal design.

24

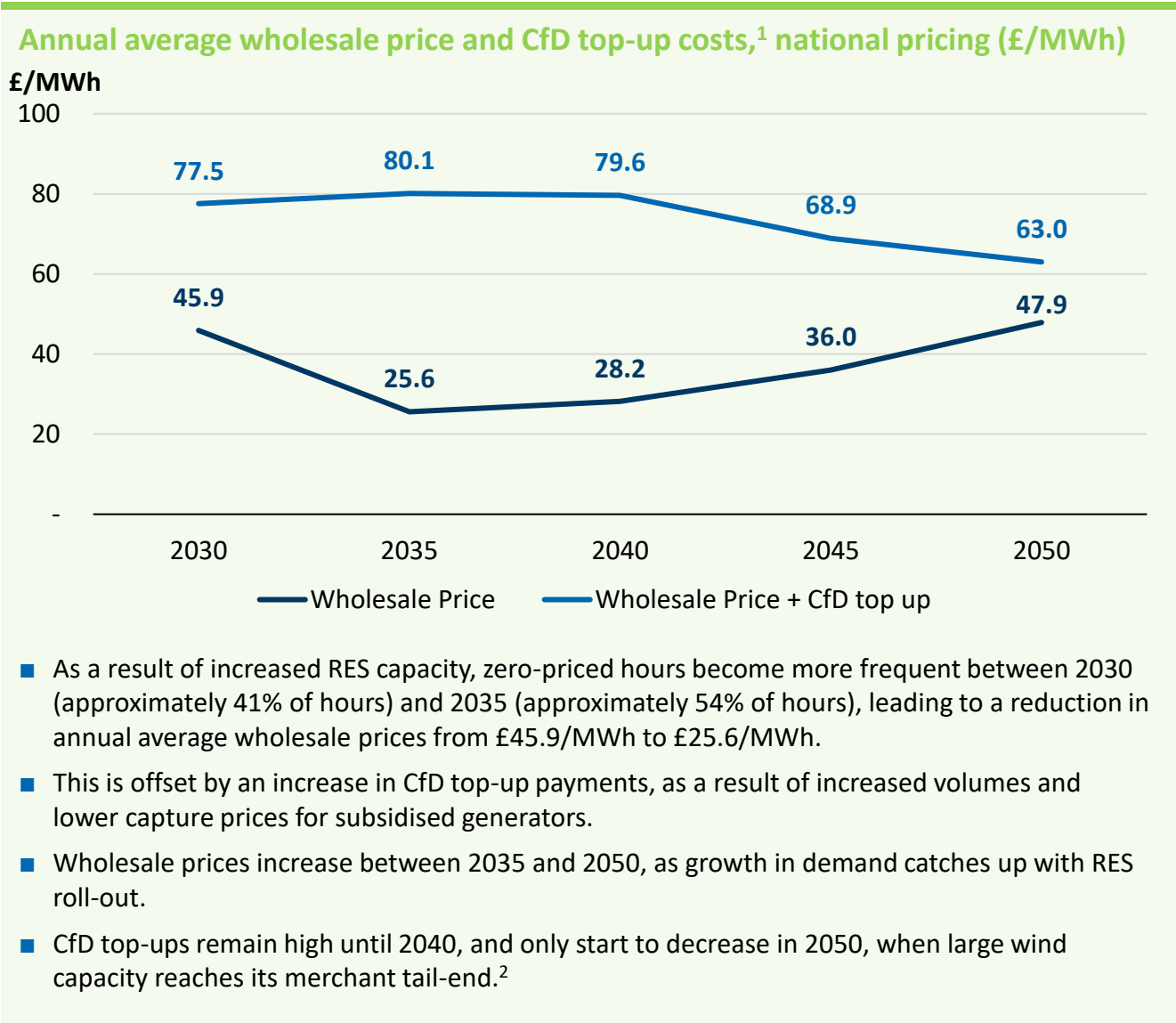
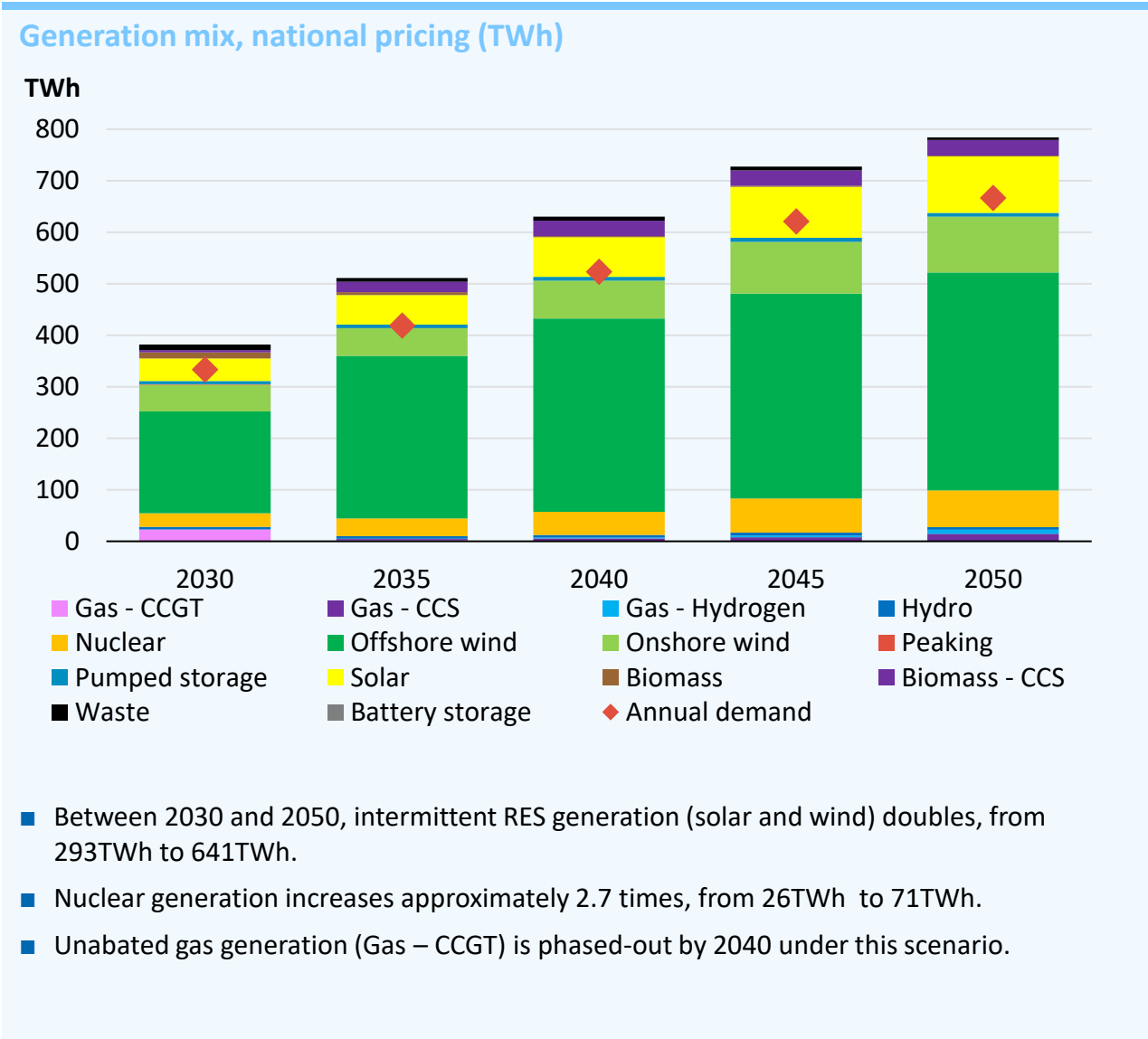


4. Modelling Results



Base Model

The share of RES generation increases over the modelling period, which leads to a reduction in wholesale prices and, in turn, an increase in CfD top-up costs

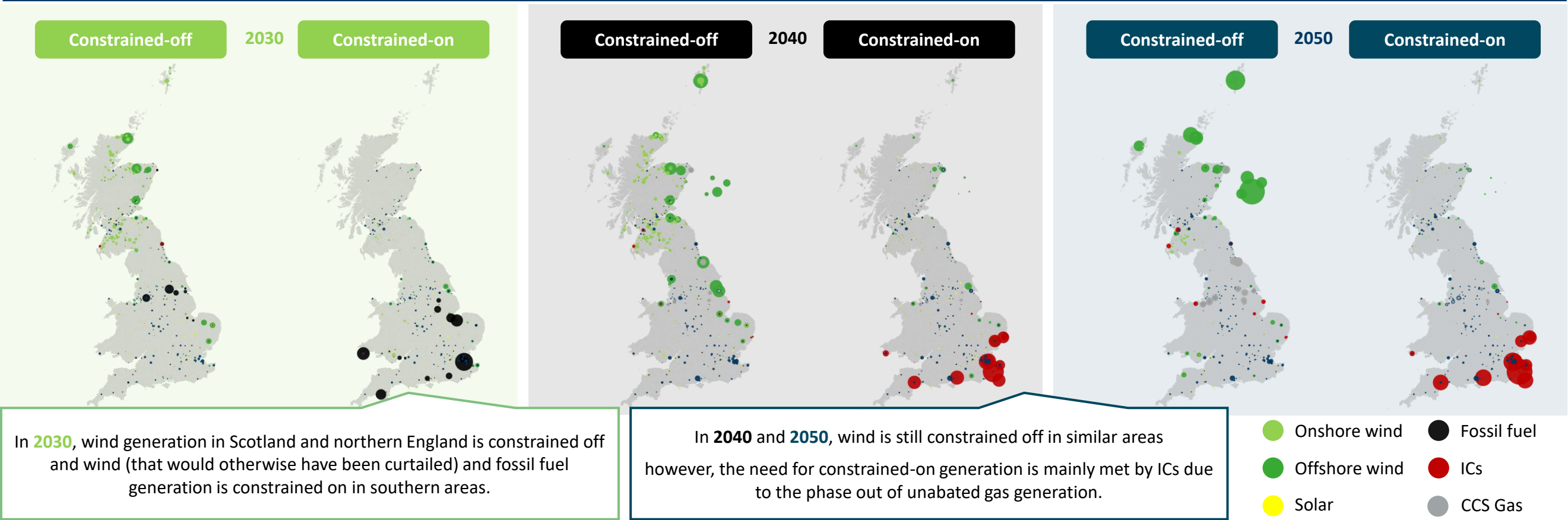


Notes: (1) WM prices are time-weighted average prices. CfD top-up costs are calculated as total CfD payments/total GB non-electrolyser demand, as we assume that electrolyzers are exempt from such charges. (2) We assume a 15-year length for CfD contracts, but a 25-year lifetime for onshore wind and solar assets and 30-year lifetime for offshore wind assets. At the end of the 30-year asset life for CfD and RO offshore wind farms, we assume these units are repowered at the AR6 strike price (£81.39/MWh, 2024 prices).

We find that significant volumes of wind are constrained off in northern areas, despite Tx investment. The need for constrained on generation is met by gas in 2030 and ICs in 2035+

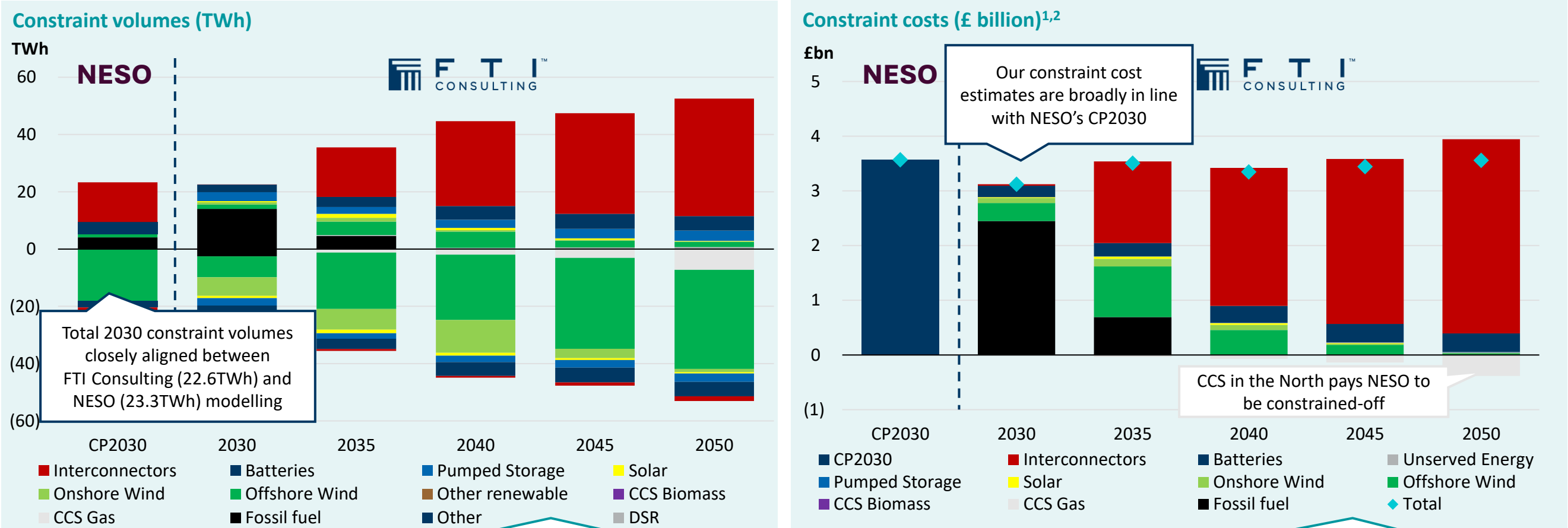
- The maps below illustrate the location and technology of constrained off and constrained on generation in each modelled year. We assume that technologies with the highest/lowest marginal cost are constrained off/on first. This is except for inflexible technologies (for example, large-scale nuclear) and generators with subsidy support.
- The order in which RES generators are constrained off depends on: (i) their subsidy support (for example, merchant is constrained off first); (ii) their technology¹ (for example, merchant offshore wind is constrained off ahead of merchant onshore wind); and (iii) location (for example, a merchant offshore wind generator located further north would be typically constrained off ahead of one further south).

Annual constrained generation by technology and location¹



Notes: (1) For RO generators, we assume that offshore wind is constrained off last as they receive more ROCs per unit of generation compared to onshore wind and solar. For merchant generators, we assume that offshore wind is constrained off first, followed by onshore wind and solar. (2) Size of the discs indicates the volume of constraints in a particular location in the modelled year.

We find that annual constraint costs remain between £3.1 billion and £3.6 billion across the modelled period, as constraint volumes grow and interconnectors are increasingly used

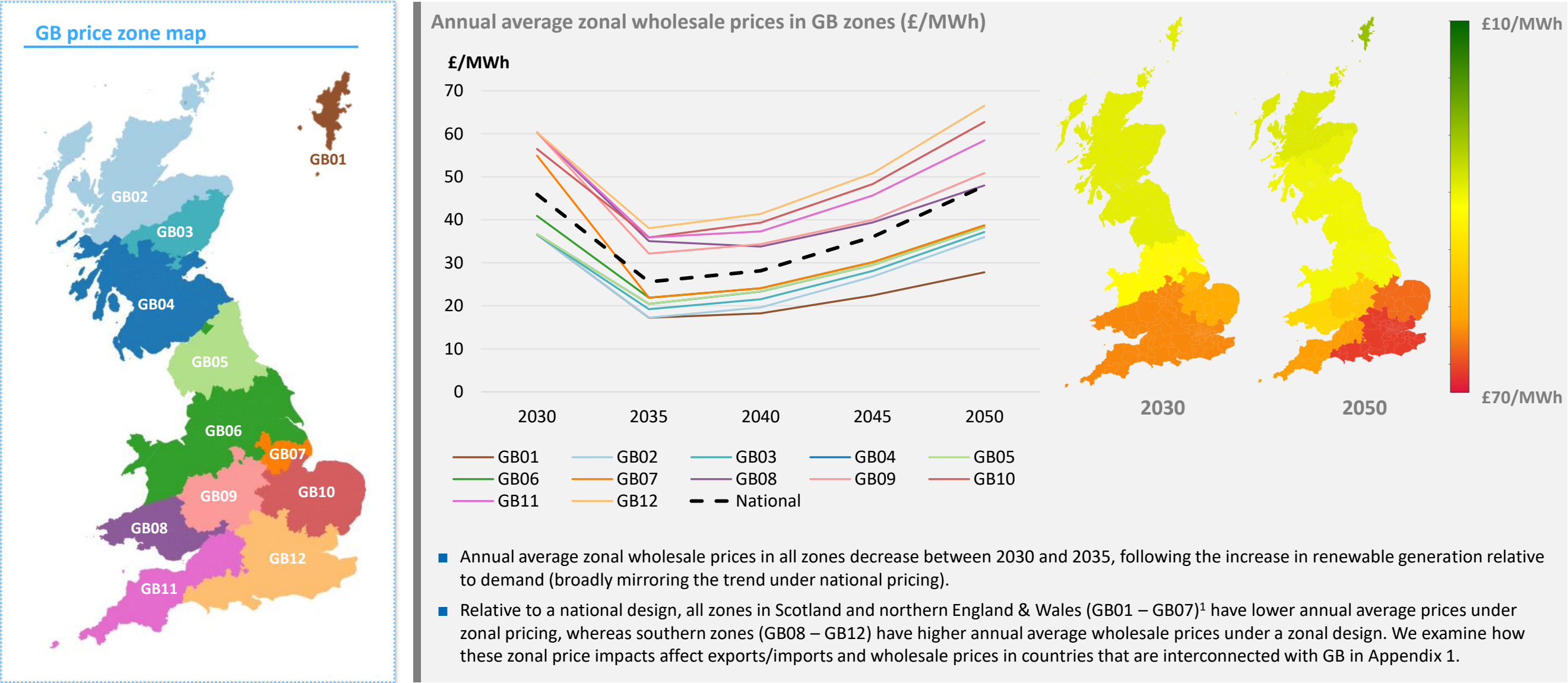


- We forecast similar level of congestion volume in the Base Model in 2030 as NESO in CP2030.
 - However, the mix of constrained-on generation is different in 2030, as NESO expects ICs to be used ahead of fossil fuel generators to resolve constraints.³
- Costs of constraining off wind decrease in later years, as the proportion of merchant capacity increases, allowing the BM to avoid turning down more costly CfD wind. This decrease is driven by differences in the lifetime assumption of offshore wind assets and length of CfDs.⁴
 - CCS gas constraint costs are negative in later years as the location of CCUS clusters in the north of England means they are often constrained off post-2040.

Note: (1) CP2030 does not provide a breakdown of constraint costs by technology; (2) Some of our redispatch model runs in the later years include small amounts of unserved energy. We assume that, in reality, this would be mitigated by DSR and hence we value it at the DSR price (approximately £280-340/MWh); (3) This is likely driven by the near-zero carbon emissions objective underpinning the CP2030 publication. We assume similar costs of constraining on ICs and fossil fuels (but slightly lower for fossil fuels), hence leading to a different technology mix compared to CP2030, and slightly lower total costs; (4) We assume a 15-year length for CfD contracts and 30-year lifetime for offshore wind assets. At the end of the 30-year asset life, we assume CfD and RO offshore wind farms are repowered at the AR6 strike price (£81.39/MWh, 2024 prices).

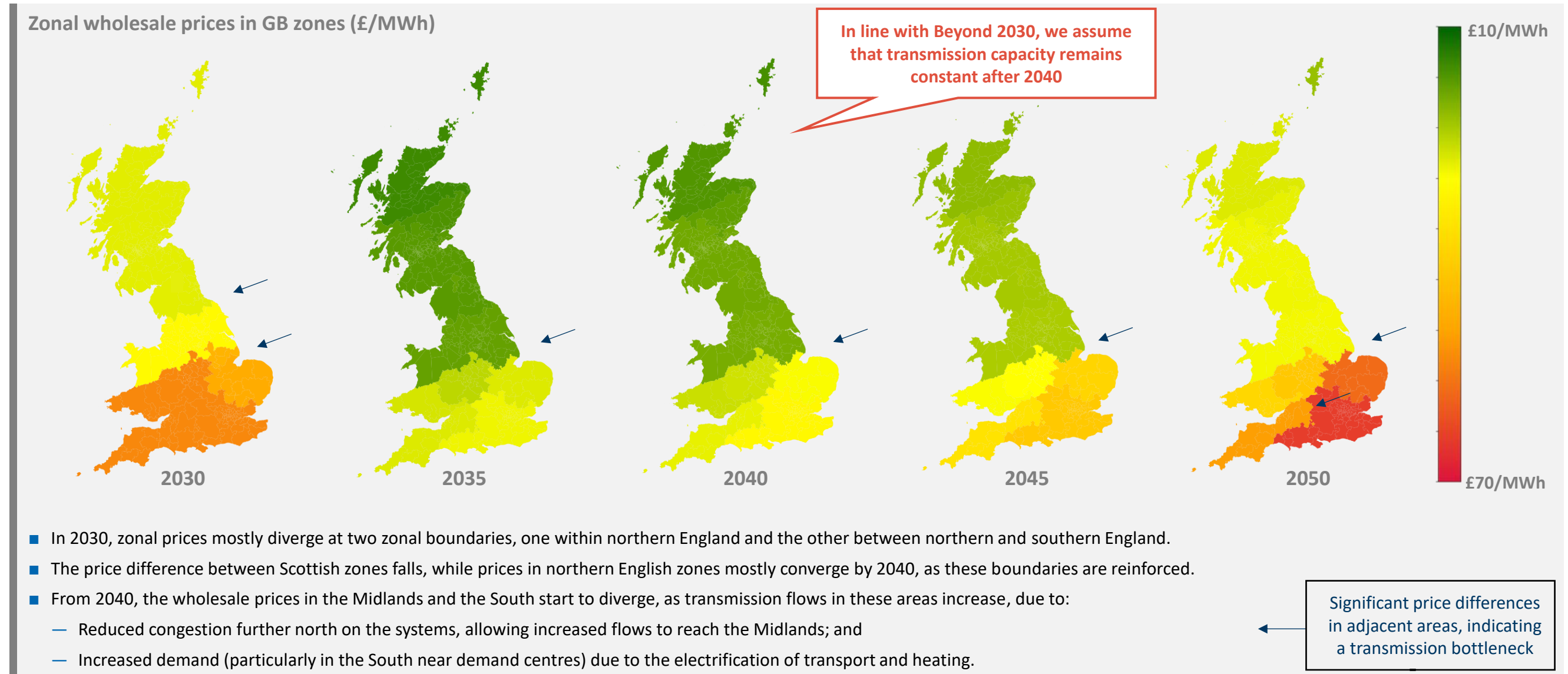
29

Relative to national prices, annual average zonal wholesale prices in the north of GB are lower, while annual average wholesale prices in the south of GB are higher

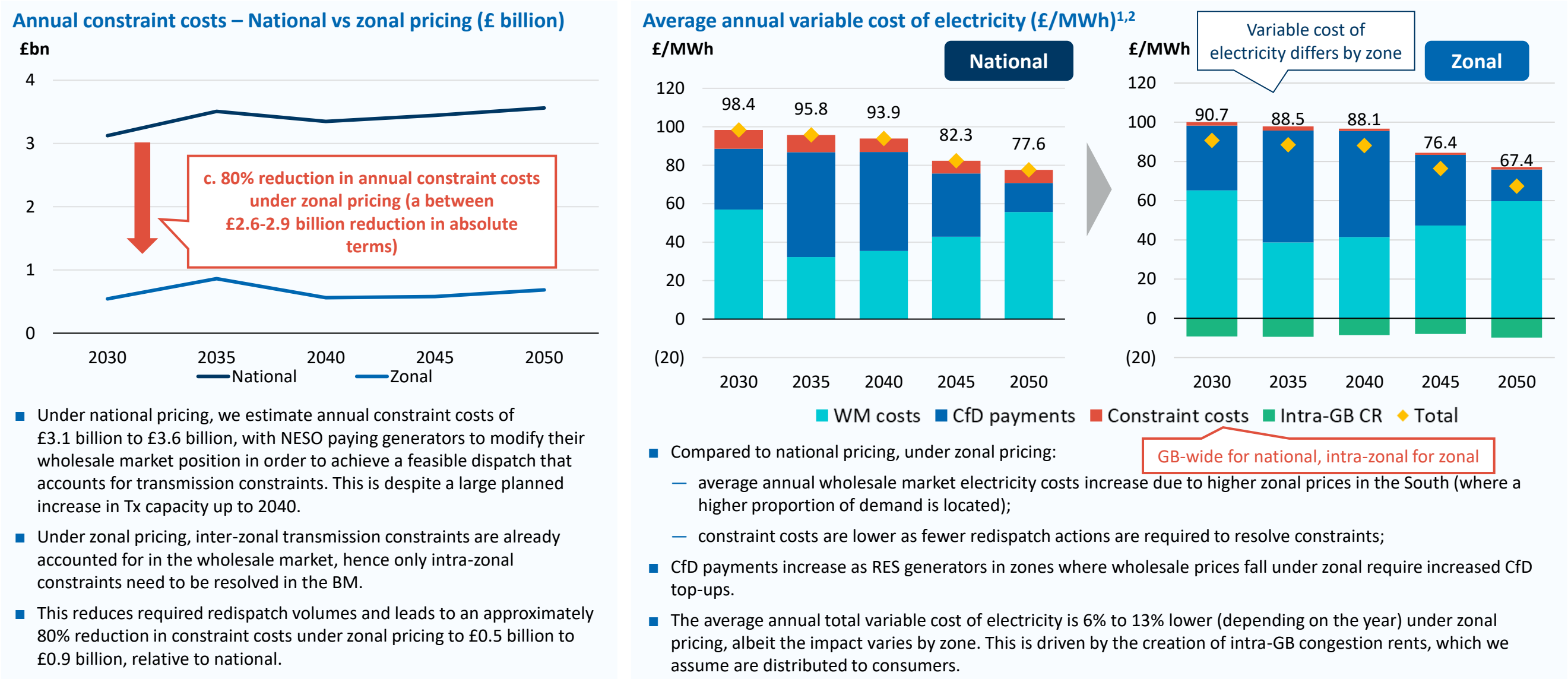


Note: (1) Only exception is GB07, which has a higher zonal price than the national price in 2030.

We find that the main transmission bottlenecks move south over the modelling period, from northern England to the Midlands, and later from the Midlands to the South



Constraint costs are 80% lower under zonal than under national pricing. The variable cost of electricity is 6% to 13% lower due to the creation of intra-GB congestion rents

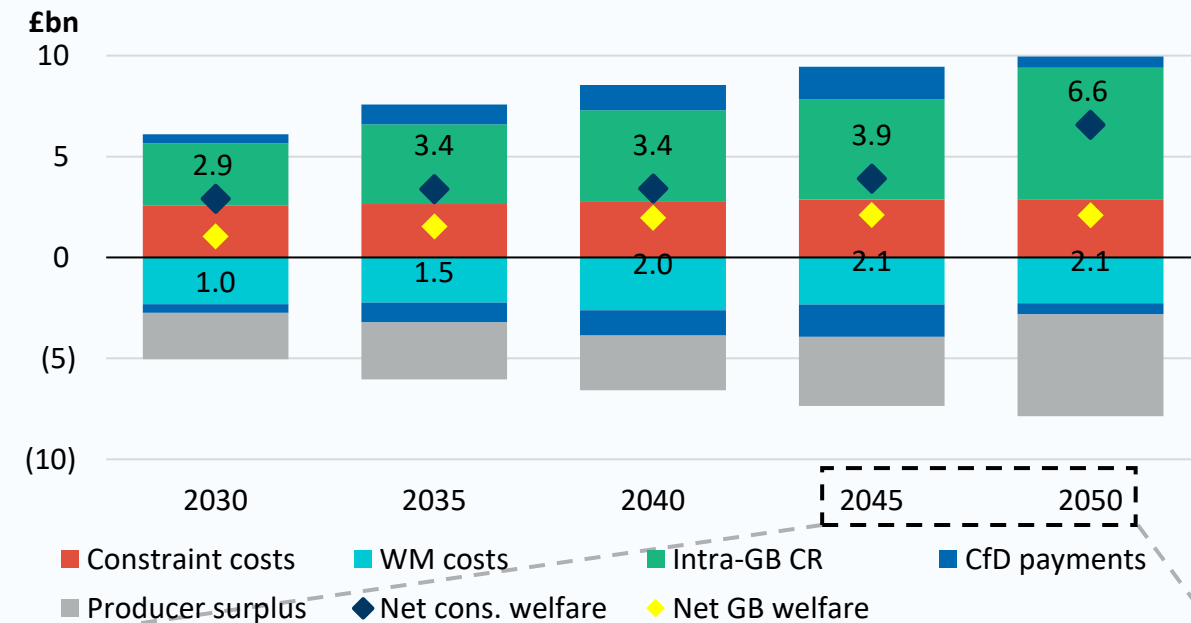


Note: (1) Variable cost of electricity = Total wholesale market costs/total GB demand + (Total GB constraint costs + total CfD payments - intra-GB congestion rents (zonal only)) / total GB non-electrolyser demand. (2) WM costs in this chart are load-weighted and therefore differ from the time-weighted WM prices presented on slide 27.

32

We find consistent annual consumer and GB welfare benefits of zonal pricing, driven by significant reductions in constraint costs (80%) and the creation of intra-GB congestion rents

Annual net GB welfare impact of zonal pricing (£ billion)



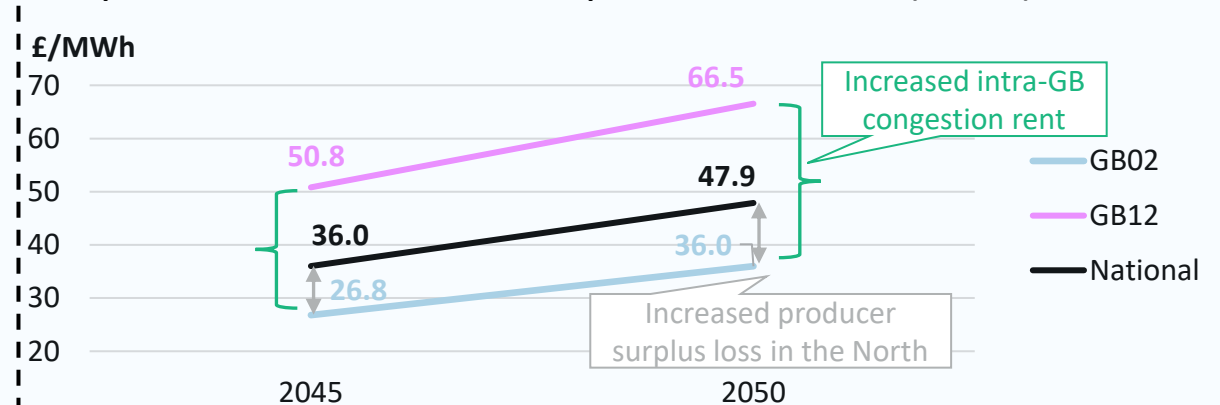
Consumer benefits in 2030-2045

- On top of the constraint cost savings under zonal, GB consumers benefit from the creation of intra-GB congestion rents, which more than offset the WM cost and CfD top-up increases.
- This leads to consistent annual consumer welfare benefits of £2.9 billion to £3.9 billion under zonal pricing.

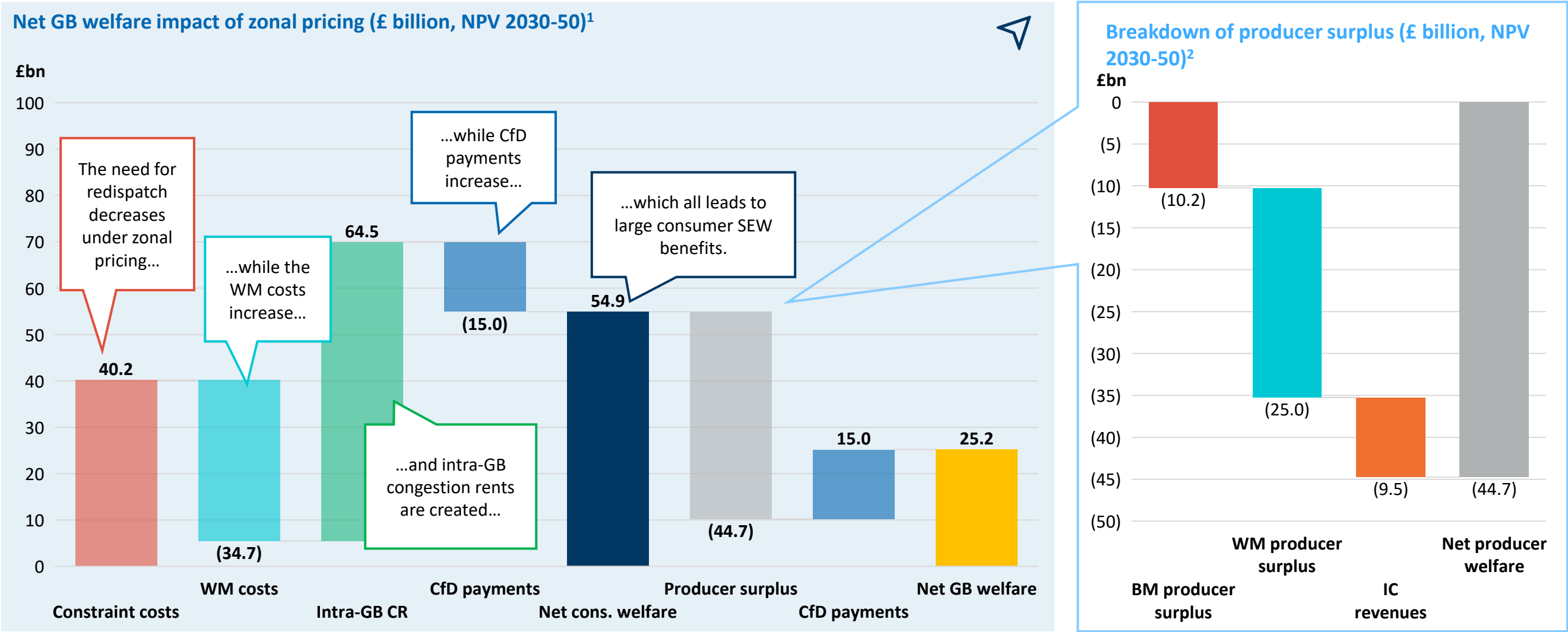
Consumer benefit increase in 2050

- The net consumer welfare gain in 2050 increases to £6.6 billion compared to £2.9-£3.9 billion in earlier modelled years. There are two main reasons for this.
- First, large volumes of CfD-supported capacity come online in the early 2030s, reaching their merchant tail-end before 2050. As such, the CfD payment transfer from consumers to producers under zonal is lower in 2050 than in earlier years (£0.6 billion in 2050 compared to £1.6 billion in 2045), leading to an improvement in consumer welfare under zonal.
- Second, as illustrated in the bottom figure, the 'wedge' between national price, North GB and South GB zonal prices increases between 2045 and 2050. This increases the loss of producer surplus for generators in the North, which is not offset by the improvement in producer surplus for South GB generators. As a result, there is an overall increase in the **loss of producer surplus** (grey bar in the top figure).
- At the same time, the 'wedge' between the North and South GB prices, under a zonal design, **increases intra-GB congestion rents**, and hence benefits to GB consumers.

Comparison of GB02, GB12 and National prices in 2045 and 2050 (£/MWh)



We find £55 billion of consumer benefits from a zonal market design and £25 billion of welfare benefits for GB as a whole (NPV, 2030-50)



Our analysis is based on external sources, and we have also examined, quantitatively and qualitatively, several sensitivities to key input assumptions

- As with any modelling, our results are inevitably a function of the input assumptions we have used. We have sought to transparently document these throughout this report.
- We are aware that some stakeholders have previously raised concerns that the benefits of locational pricing are sensitive to some key input assumptions. Below we describe some of our key assumptions and the extent to which they may impact our findings.

Legend: Increase net benefits Decrease net benefits Distributional impacts but no net impact No impact

LIKELY DIRECTIONAL IMPACT

ConsumerSocietal

	No new transmission post-2040 NESO transmission plans only extend to 2040. As such, we used the 2040 Tx plan for 2045 and 2050. We consider this assumption to be plausible given: 1. Wind roll-out in FES24 HT reaches nearly its peak in 2040 (95%), as such the 2040 Tx network is designed to accommodate nearly as much wind capacity as planned for 2045 and 2050, likely requiring limited additional reinforcements post-2040; 2. Indeed, the constraint cost increase post-2040 is modest (£3.3 billion in 2040 and £3.6 billion in 2050), signalling stable level of congestion on the system. Nonetheless, as a sensitivity, we have estimated how the <u>total</u> benefits of zonal design would change if <u>annual</u> benefits remained constant from 2040 onwards (at £3.4 billion per year, as shown in slide 33), for example as a result of additional transmission being built post-2040. In this sensitivity, the total GB consumer benefits would be reduced from £54.9 billion to £48.7 billion and the total SEW benefits would be reduced from £25.2 billion to £24.6 billion, highlighting the robustness of our zonal benefits estimate.	
	FTR auction revenues Historically, some stakeholders have questioned whether the full quantum of congestion rents will accrue to consumers (as we have assumed in our analysis). Financial Transmission Rights (“FTRs”) are financial products that enable market participants to hedge locational price risk by providing the FTR holder with the rights to the congestion revenues on a defined boundary. FTRs are auctioned ahead of real time and are likely to trade at either a discount or premium to the actual realised congestion rent.¹ To the extent that forward sales of FTRs trade at a discount to the actual congestion rents earned this would represent a transfer from consumers to producers, but would not affect the overall level of SEW benefits.	

There are further sensitivities that could be performed, but were not in the scope of this report. Some of them have been previously examined in other work by FTI Consulting.

We have run multiple meaningful sensitivities to test the robustness of our analysis. However, given the number of options and combinations available, we could not be exhaustive. We recognise that there are several other sensitivities that would enhance the understanding of the impacts of locational pricing, some of which have been covered in previous studies:

Legend: Increase net benefits Decrease net benefits Distributional impacts but no net impact No impact			LIKELY DIRECTIONAL IMPACT	
			Consumer	Societal
	Demand siting	Assumptions on the siting of new demand could significantly impact consumer and SEW benefits in both directions. While we have not quantified the possible impacts in this study (given the overarching assumption that siting would be centrally planned), we identified two key uncertainties that could impact results: 1. Datacentres: As not provided in FES, we assume new datacentres site in line with the existing siting. If datacentres were to respond to zonal price incentives and locate further North than assumed under national, this would likely increase the benefits of zonal pricing; 2. Electrolysers: Following FES assumptions, we have sited most electrolyser demand in Scotland, which implicitly assumes the construction of a hydrogen backbone (the costs of which have not been considered in this report). If the backbone is not built and electrolyser demand sites in England (or simply does not materialise), benefits of zonal pricing would increase (although costs of hydrogen may increase relative to electrolysers being sited in Scotland).		
	Grandfathering	In case DESNZ decides to grandfather elements of firm access rights of legacy and transitional assets, the consumer benefits case of zonal pricing could change. Our assessment already assumes that CfD generators are shielded from any price risk during the 15-year CfD period. If additional grandfathering would take place (e.g. in relation to volume risk during the CfD period) this would constitute a transfer from consumers to generators and would reduce consumer benefits but not impact SEW benefits (assuming a well-designed regime).		
	Distribution of consumer benefits	As part of this report, we have not performed a granular distributional analysis to determine how much of the benefit is attributed to different consumer groups (e.g. residential, industrial, datacentres), or across different locations. This will be driven to a large extent by future policy on levy exemptions (e.g. superchargers) and how congestion revenue is distributed among stakeholders. However, none of these will impact the overall consumer or SEW benefit figures. Ofgem previously performed a distributional analysis as part of its evaluation of locational pricing, finding that most consumer groups would benefit.¹		
	Load-shielding	As part of this report, we have not considered any load-shielding. However, we conducted a sensitivity for this in our previous analysis for Ofgem on nodal pricing, which indicated that the consumer and SEW benefits were 4% and 13% lower respectively, but remained robust to load-shielding.²		

Notes: (1) 'Assessment of Locational Wholesale Pricing for GB', Ofgem, October 2023 ([link](#)); (2) 'Assessment of locational wholesale electricity market design options in GB', FTI Consulting, October 2023 ([link](#)).



Shock 1: Transmission Delays

Our transmission delay scenario assumes that nine projects will be delayed between 2030 to 2040 relative to our Base Model

Transmission delay scenario

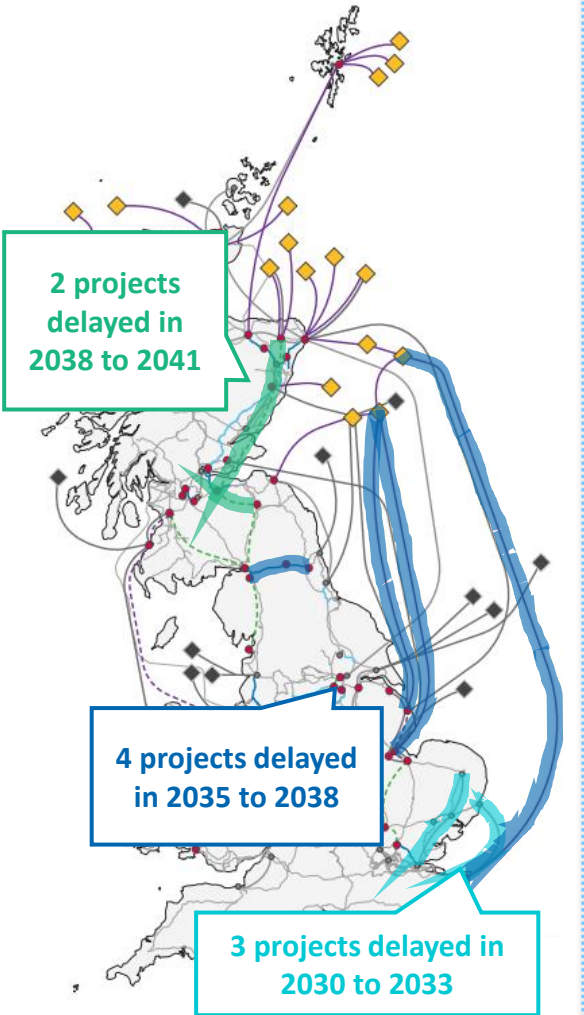
- The transmission network build programme to 2030 (published in Pathway to 2030 in 2022) requires up to £54 billion of cumulative investment to deliver 1,000km of onshore and 4,500km of offshore projects – more than double the total built in the last 10 years.¹
- CP2030 identifies that 80 of these projects need to be delivered by 2030 to achieve a clean power system, including three works that were originally planned to be delivered in 2031 that need to be accelerated to 2030.
- After 2030, NESO’s Beyond 2030 report recommends an additional £58 billion of direct investment in offshore and onshore network upgrades.²
- Our Base Model assumes that the transmission network will be developed in line with CP2030 ambitions by 2030 and Beyond 2030 thereafter.
- However, as this is an optimistic best-case scenario, we test what would happen if Tx projects experience unforeseen delays³, particularly given the large number of new transmission projects required and the historically high average lead time for Tx projects of 12 to 14 years.⁴ Therefore, for our Tx delay scenario:
 - In 2030, we assume a delay to the three ‘acceleration required’ projects that need to be delivered by 2030 to meet CP2030 targets.
 - In 2035 and 2040, we assume a delay to large-scale projects with unclear earliest in-service dates (“EISDs”) or expected operational dates within 2 years of the EISDs.

Delayed projects in transmission delay scenario

Tx line	Cost estimate ⁶	Operational date ⁵	
		Base	Tx delay
AENC	£100-500m	2030	2033
ATNC	£500m-1bn	2030	2033
SCD1	£1-1.5bn	2030	2033
FSU1	<£100m*	2035	2038
SW_E1c_1	£2-2.5bn*	2035	2038
SW_E1c_2	£2-2.5bn*	2035	2038
SW_E2a_2	£2-2.5bn*	2035	2038
HGNC	£500m-1bn*	2038	2041
NHNC	£2.5-3bn	2038	2041

We assume Tx build-out catches up with policy ambition by 2045 and generator roll-out plans are unchanged.

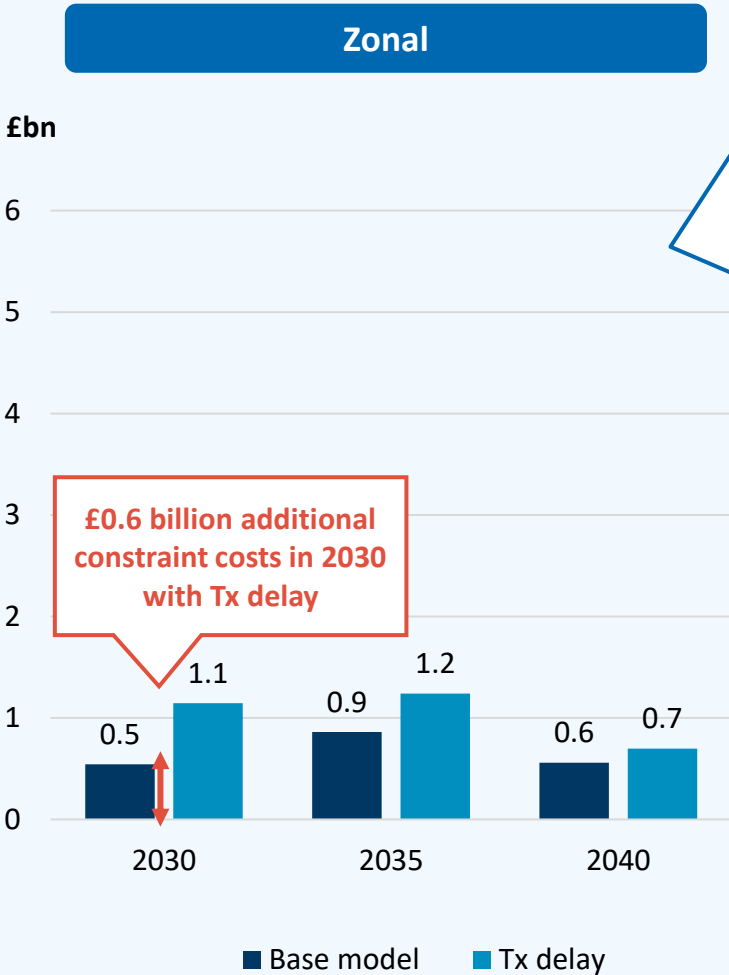
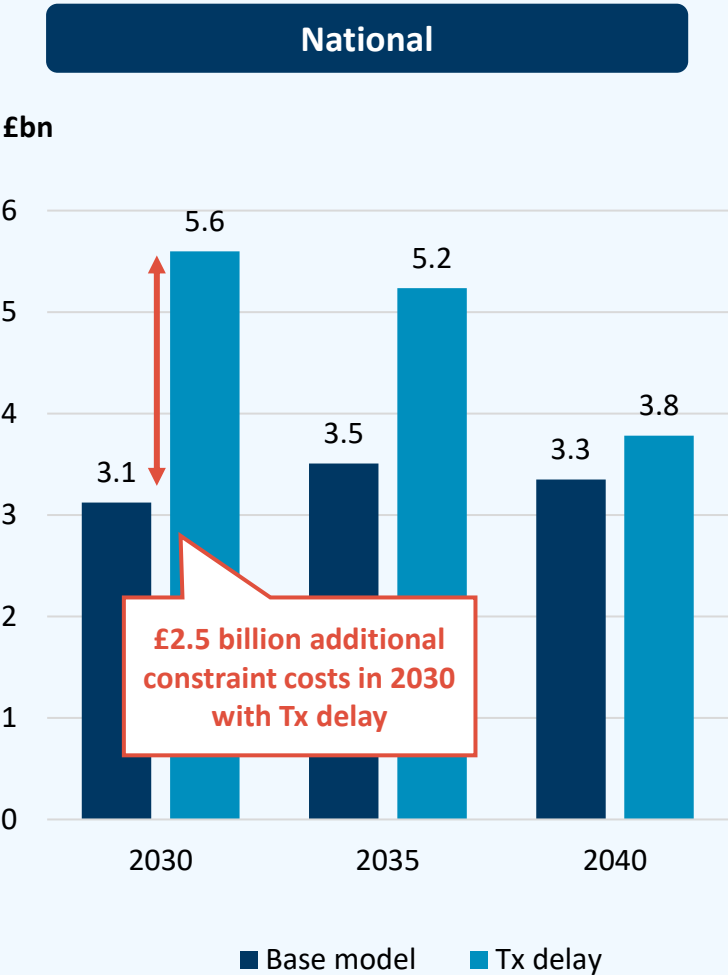
Transmission delays



Notes: (1) Clean Power 2030, NESO, December 2024 ([link](#)); (2) Beyond 2030, NESO, March 2024 ([link](#)); (3) For example, due to supply chain issues or planning delays; (4) Although we note that Ofgem and DESNZ are aiming to halve this lead time. Connections Action Plan, DESNZ and Ofgem, November 2023 ([link](#)); (5) Operational dates are for 1st January of the respective year. These are based on the optimal delivery dates of each line. (6) Cost estimates follow projections from NESO in NOA21/22 refresh. For projects not included in this (*), we have used the cost band of similar projects.

Zonal pricing helps to reduce the impact of transmission delays on consumers by £9.4 billion.
Delaying some transmission build saves consumers £1.6-£2.2 billion in transmission costs

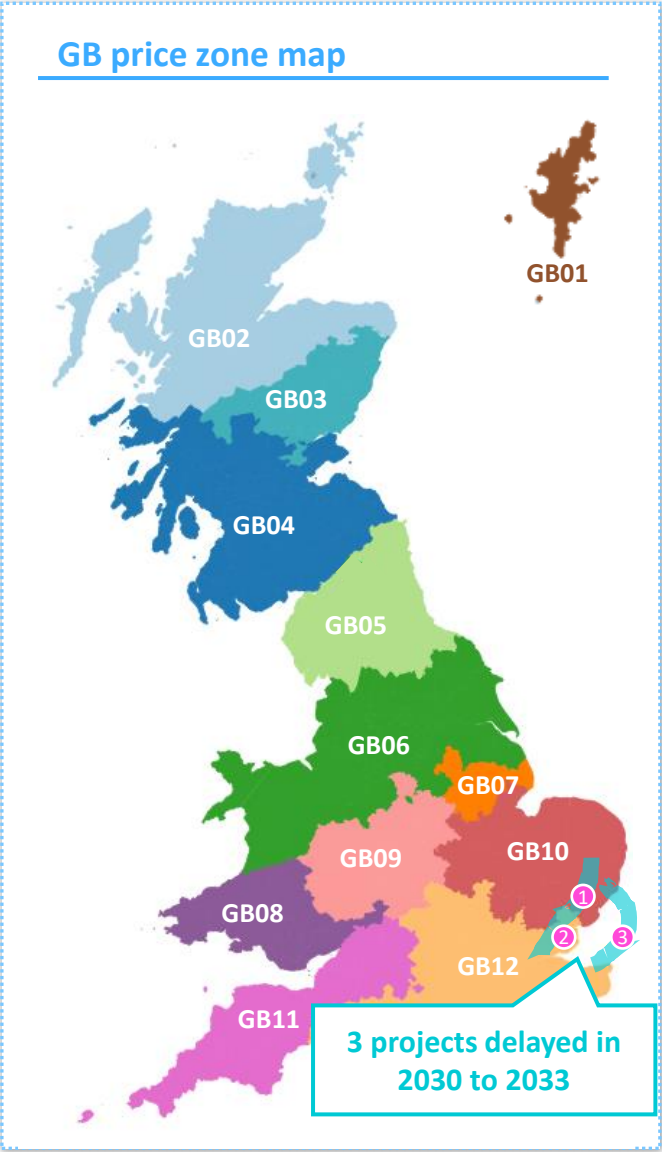
Total constraint costs under Base Model and Tx delay scenario 2030-40, £ billion



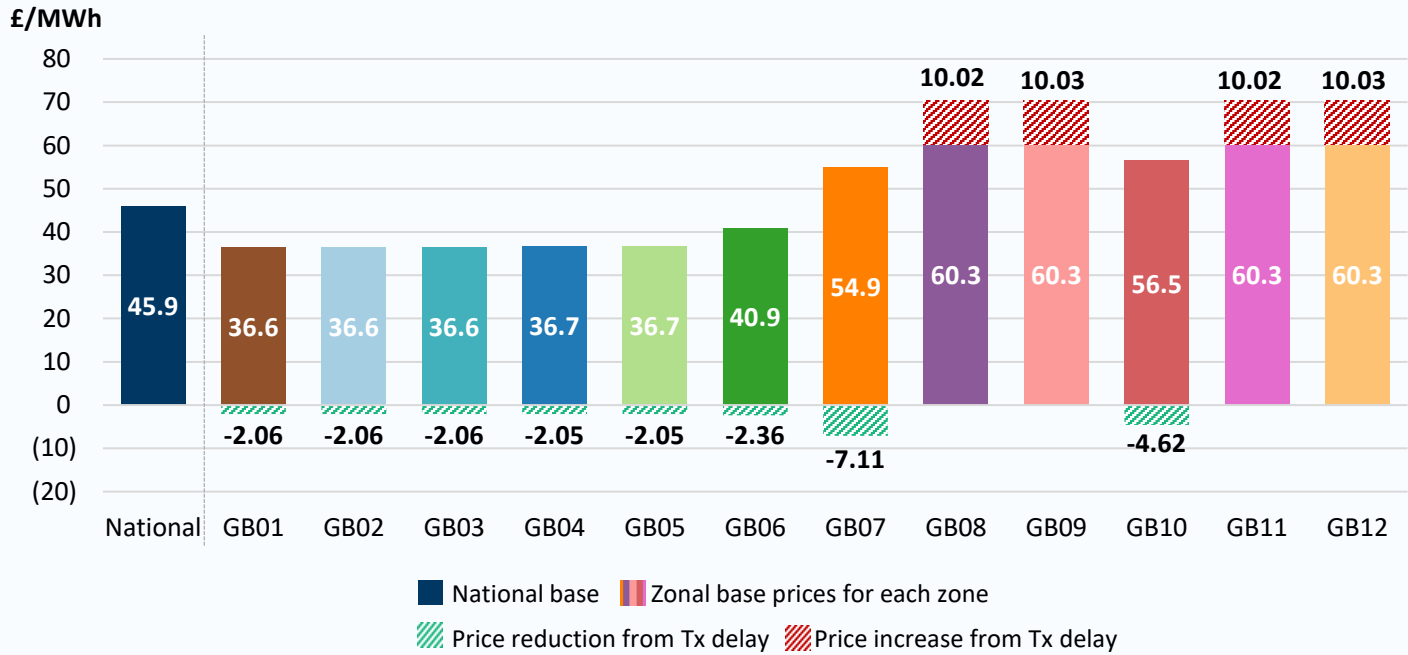
- As explained on slide 38, our transmission delay scenario assumes that nine projects will be delayed over 2030 to 2040 relative to our Base Model.
- Under a national market design, this leads to a £2.5 billion increase in constraint costs in 2030 (from £3.1 billion to £5.6 billion).
- Under a zonal market design, the impact of the transmission delay is much lower (£0.6 billion, from £0.5 billion to £1.1 billion).
- This is because a key benefit of zonal market design is improved dispatch efficiency; as asset scheduling is based on zonal prices that better reflect the physical realities of the network, it is more efficient and reduces the need for redispatch.
- Consumers also benefit (under both national and zonal designs) £1.6 billion to £2.2 billion from the delay in transmission costs (NPV 2030, assuming a 40-year asset life – see slide 41).²
- This demonstrates how zonal pricing can act as a ‘**safety net**’ for consumers to mitigate the negative impacts of transmission delays and that the benefits of transmission are lower under a zonal pricing regime.

Notes: (1) To estimate the time value of Tx delays for consumers, we calculate the annual consumer spending on transmission, assuming a three-year delay for all spending on the selected projects. We then determine the NPV as of 2030 for the entire lifetime of all assets, using the following assumptions: WACC of 4.0%, a discount rate of 3.5%, an economic asset life of 40 years, and straight-line depreciation. Project costs are based on the NOA7 Refresh or comparable projects if not included in the NOA 21/22 Refresh. (2) We have calculated the benefits of the delay over a 40-year asset life, which is more conservative than calculating it over the 2030-2050 modelling period.

Delays to transmission do not affect national prices but lead to higher prices in most southern zones. GB10 prices fall due to lower transmission capacity out of the zone

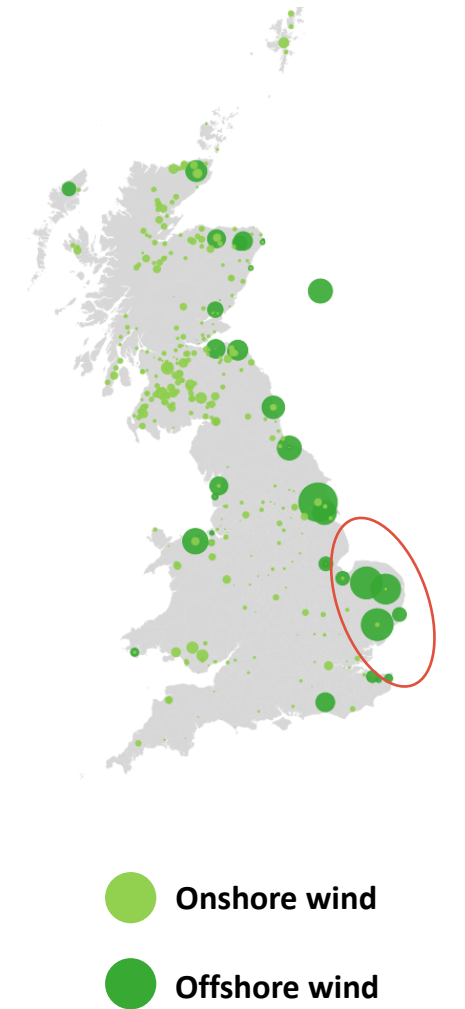


Impact of Tx delay on annual average wholesale market prices – 2030 (£/MWh)



- As the **national** wholesale price does not reflect transmission constraints, transmission delays do not affect the national price.
- Under **zonal**, the price impact is most significant in southern GB zones located close to the delayed projects.
- Zonal prices in GB07 and GB10 (where there is significant growth in wind capacity in 2030) decrease as there is less transmission capacity to transport wind generation out of these zones, which also results in higher prices in the other southern zones.

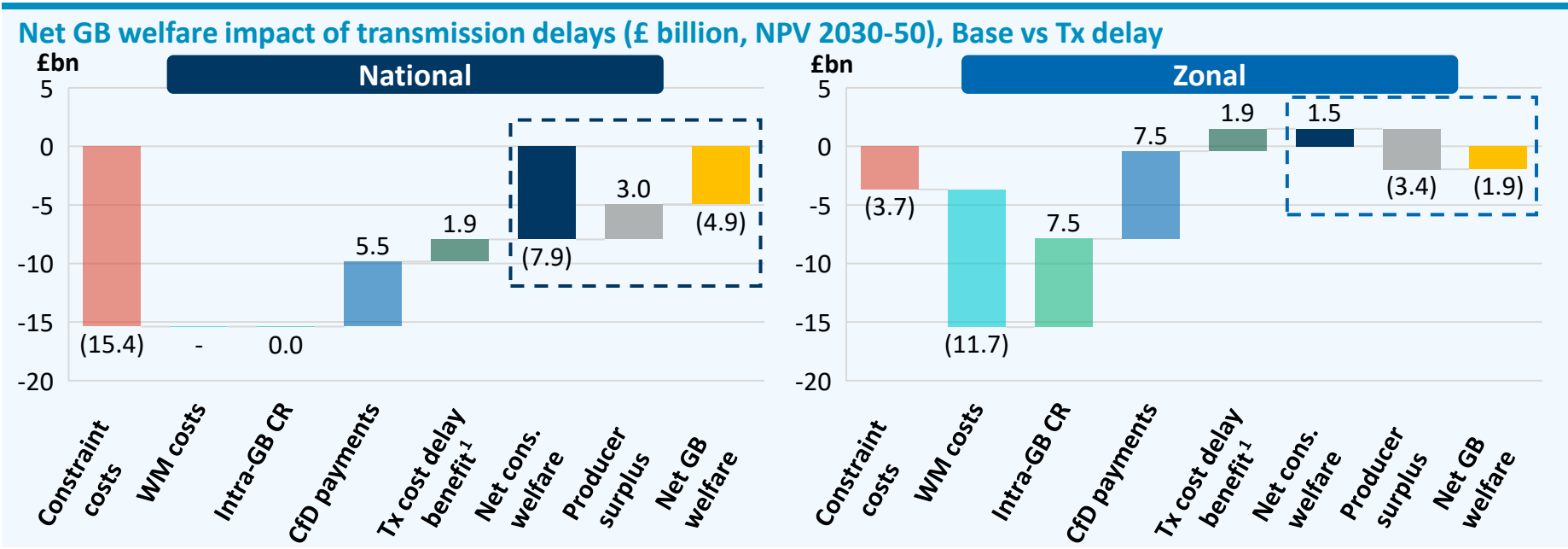
Wind capacity roll-out, 2030¹



Note: (1) Size of the discs indicates the level of capacity in a particular location.

A delay in Tx build-out reduces GB SEW. This welfare loss is partly mitigated under zonal (relative to national) but it is shifted to producers from consumers

- We have compared our modelling results with and without the transmission delay to illustrate how the impact of the transmission delay varies under different market designs.
- We find that there is a GB-wide welfare loss under both national and zonal designs, as GB's electricity demand is now met with higher cost resources. However, there are two distinct impacts:
 - **A quantum impact:** the GB-wide SEW cost of transmission delay is reduced under zonal (i.e. zonal design mitigates the total societal cost of a transmission delay);
 - **A distributional impact:** the stakeholders affected by transmission delay are different (with the burden shifting from consumers to producers).



Tx delay under national pricing

- The cost of the Tx delay described on slide 38 is £4.9 billion for GB as a whole.
- As shown in the figure on the left, under a national design, all of this cost is borne by GB consumers.
- On average generators earn higher margins on the BM, leading to a £3.0 billion increase in producer surplus with the Tx delay.
- Some of the impact on consumers is mitigated by the benefit from delayed spend on Tx and reduced CfD payments, with consumers facing an overall £7.9 billion cost as a result of Tx delay.

Tx delay under zonal pricing

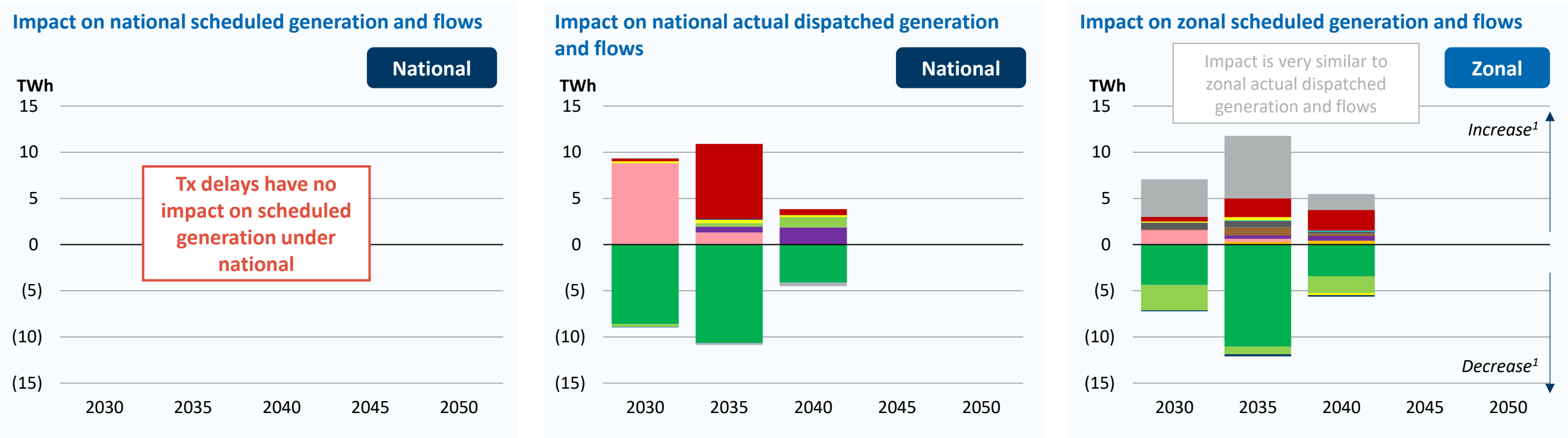
- The cost of the Tx delay described on slide 38 is reduced to £1.9 billion on an SEW basis under zonal.
- While WM prices and constraints increase, this is more than offset by reduced CfD payments, increased intra-GB congestion rents and savings through delayed spend on Tx.
- Instead, producer surplus decreases by £3.4bn as a result of the Tx delay.

Potential way forward to achieve a good balance of risks

- As we have modelled them, neither zonal nor national price regimes appear to achieve a good balance of risks among participants: producers benefit from transmission delays under national pricing, while consumers lose out, and *vice versa* under zonal pricing.
- Good regulatory design allocates risks to parties best placed to manage them. Using this principle, a potential approach to allocating the risks of a potential Tx delay could be (under a zonal design) to allocate a portion of this risk to Tx owners. One option to achieve this could be to require Tx owners to forward sell FTRs on a financially firm commitment basis to incentivise timely Tx delivery.

Note: (1) We assume that the delay in Tx commission date corresponds to the same delay in Tx spend, which in turn leads to a benefit for consumer through the time-value of money. To estimate this, we calculate the NPV of savings, if the spend on the asset was delayed by 3 years. We assume a WACC of 4% and straight-line depreciation; NPV figures are calculated for the 40-year economic life of the asset (which is more conservative compared to using only the modelled period) to avoid attributing benefits to shifting costs from consumers in the 2030-2050 period to consumers post-2050. £1.9bn is the midpoint of £1.6bn to £2.2bn.

Transmission delays exacerbate constraints under a national design, leading to increased dispatched thermal generation and reduced wind generation



- National**

 - The transmission delays do not affect national wholesale market outcomes and therefore have no impact on scheduled generation.
 - Actual dispatch of offshore wind is lower, as it has to be constrained off due to increased transmission constraints...
 - ...and the need for constrained on generation is met by fossil fuels and IC imports.
- Zonal**

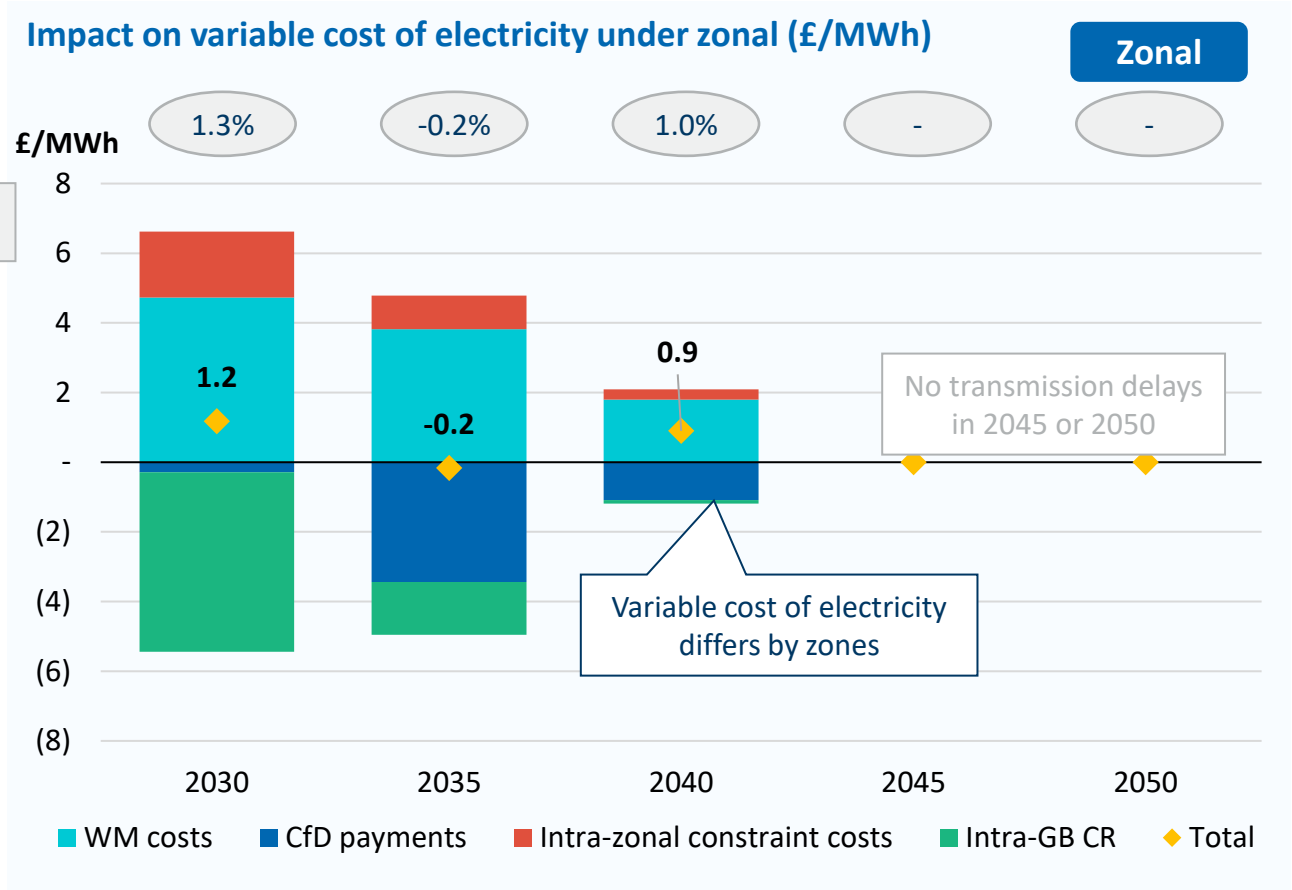
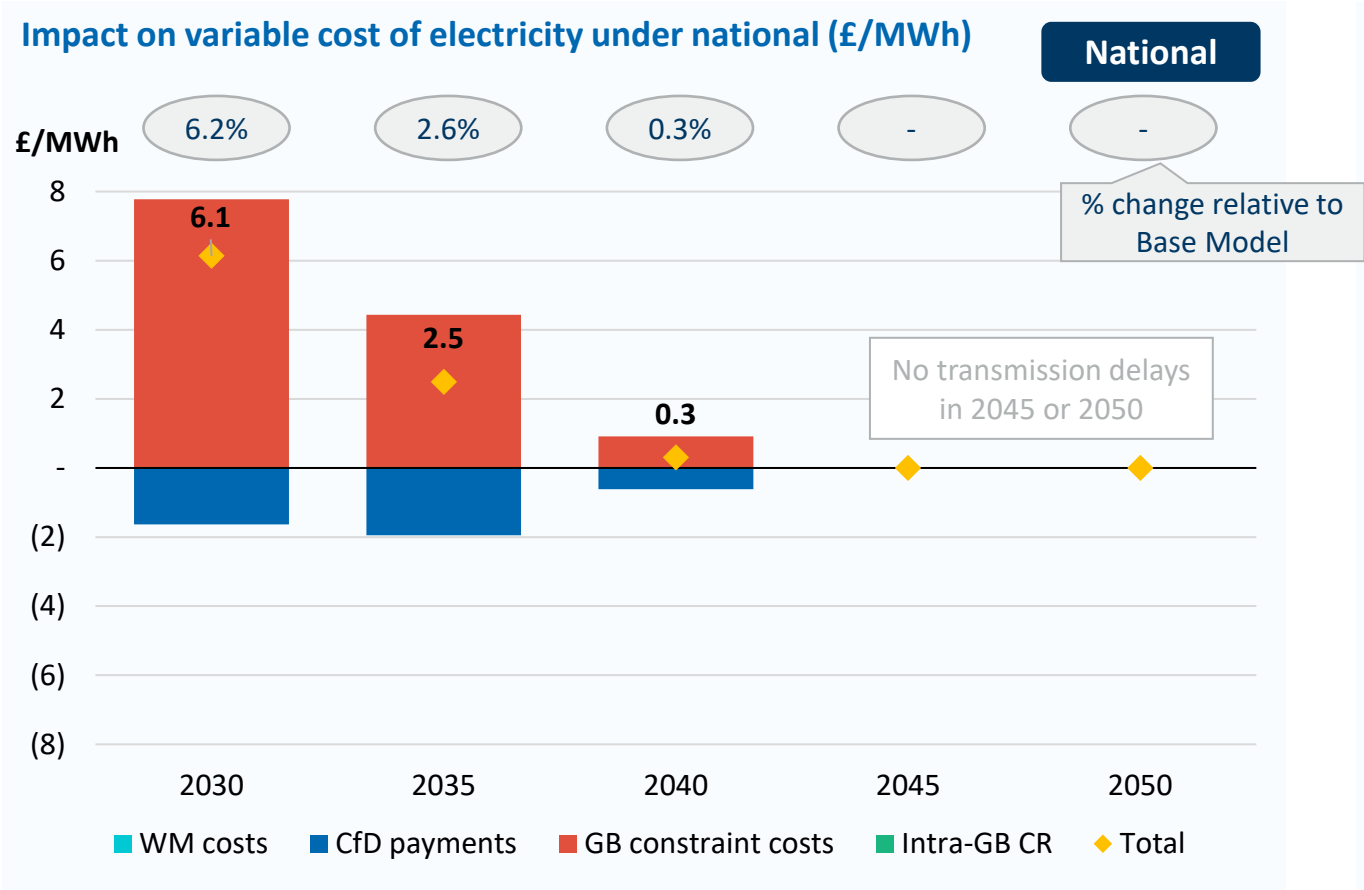
 - Zonal wholesale market outcomes are impacted by the transmission delays. Less wind is scheduled in the wholesale market, leading to lower prices in GB07 and GB10...
 - ...and higher prices in the other southern GB zones drive higher imports from and fewer exports to Europe.
- Nuclear ■ Gas - CCGT ■ Gas - CCS ■ Peaking ■ Biomass ■ Biomass - CCS

■ Waste ■ Gas - Hydrogen ■ Hydro ■ Offshore wind ■ Onshore wind ■ Solar

■ Pumped storage ■ Battery storage ■ DSR ■ Imports ■ Exports

Note: (1) This is except for exports (in grey) – bars above the x-axis indicate a decrease in exports and bars below the x-axis indicate an increase in exports.

The transmission delays lead to an increase in the variable cost of electricity of up to £6/MWh under national design, which is largely mitigated under zonal design

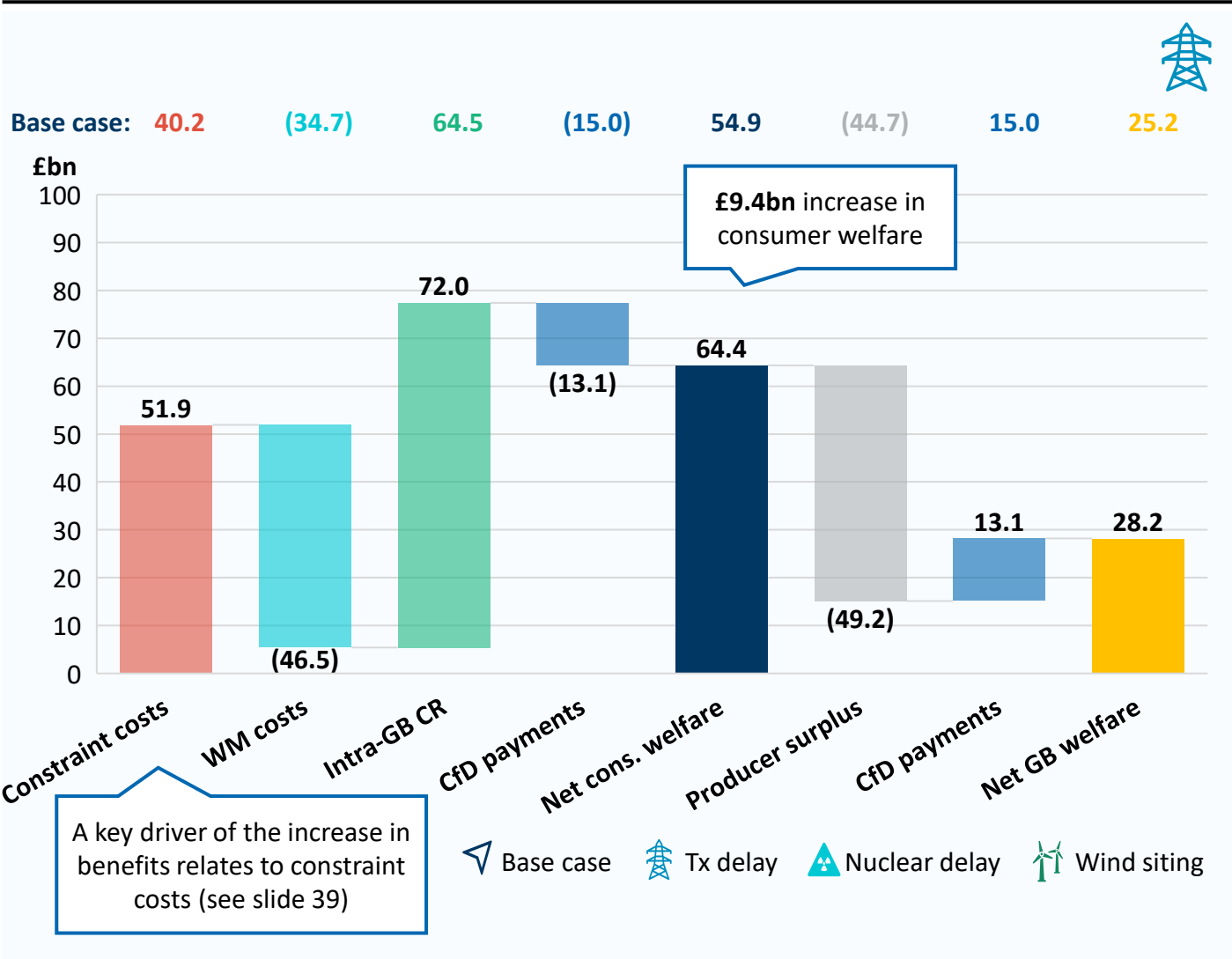


- Under national, the transmission delays do not impact wholesale market costs, but do lead to higher constraint costs.
- The transmission delays also lower CfD payments (which are paid out based on actual dispatched generation) as more CfD wind is constrained off.
- Overall, the variable cost of electricity increases by up to £6/MWh.

- Additional constraints arising from the transmission delays are resolved mainly via the WM under zonal, leading to higher prices in the southern zones and an increase in WM costs.
- This is offset by an increase in intra-GB congestion rents due to wider price differentials between zones and lower CfD payments.
- As a result, the increase in total variable cost of electricity under zonal is largely mitigated.

Under the Tx delay scenario, the consumer benefit from zonal pricing increases to £64 billion, highlighting the ability of zonal pricing to shield consumers from the impacts of delays

Net GB welfare impact of zonal pricing (£ billion, NPV 2030-50)



Compared to national pricing, consumers are less exposed to the negative impacts of transmission delays under zonal pricing.

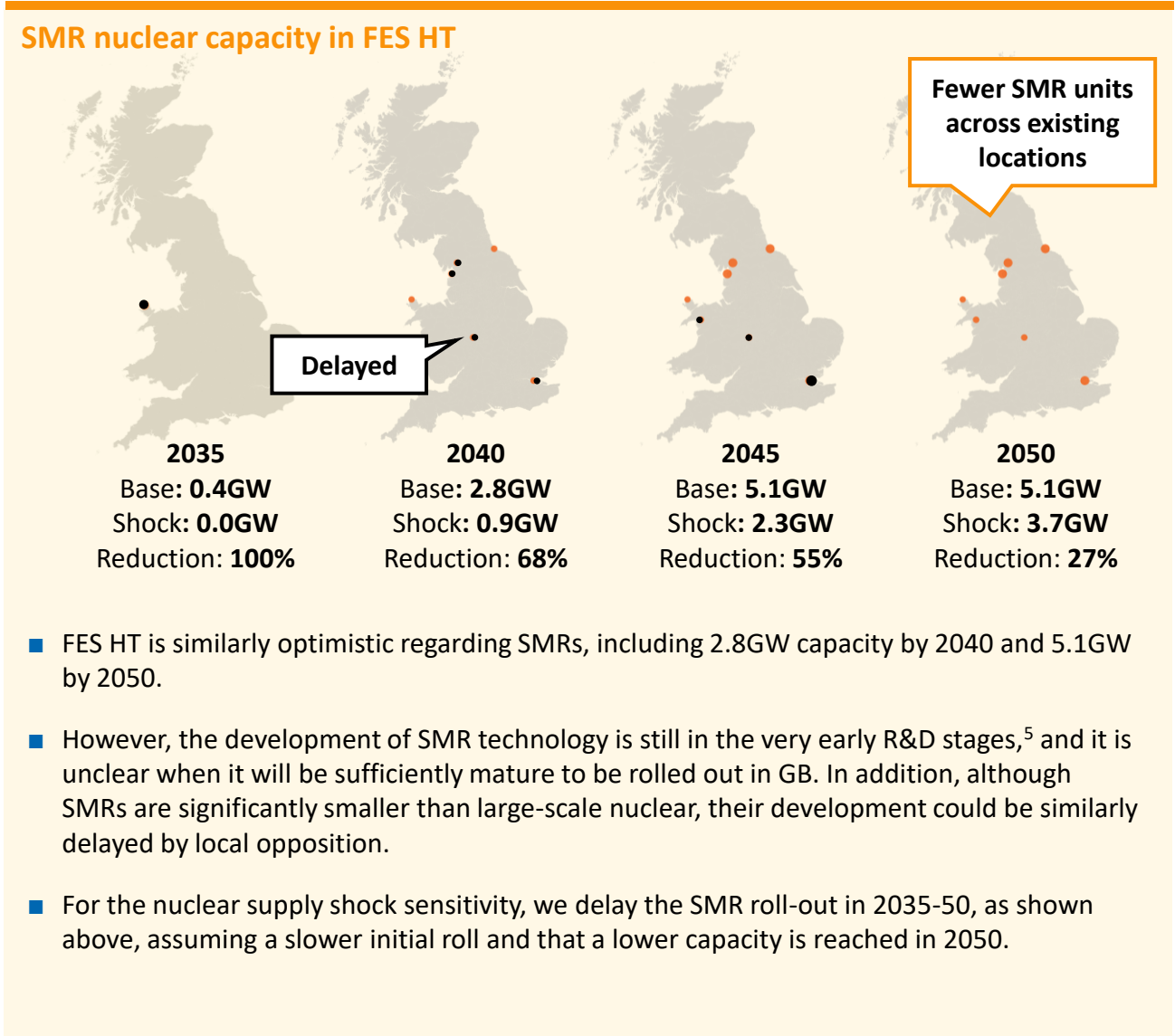
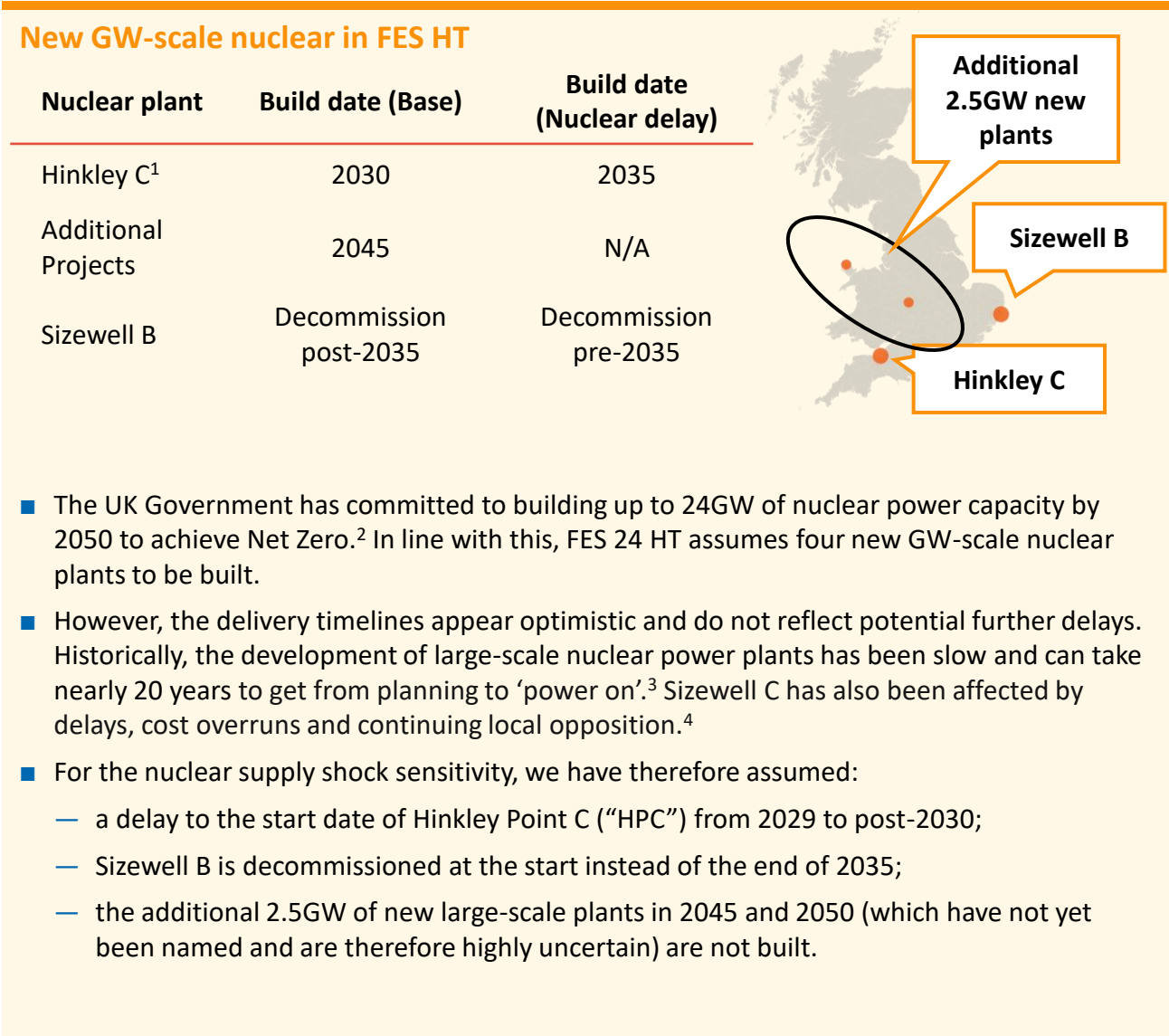
As a result, the benefits case of zonal pricing increases if key transmission infrastructure is delayed. Relative to our Base Model, in our Transmission Delay scenario:

- the consumer welfare benefit of zonal pricing is £9.4 billion higher and the GB welfare benefit is £3.0 billion higher;
- constraint costs savings are £11.7 billion higher. This is because the transmission delays result in £15.4 billion higher constraint costs under national pricing, but are largely mitigated under a zonal market design (only £3.6 billion increase); and
- intra-GB congestion rents are £7.5 billion higher, reflecting a wider price divergence between zones due to less transmission.



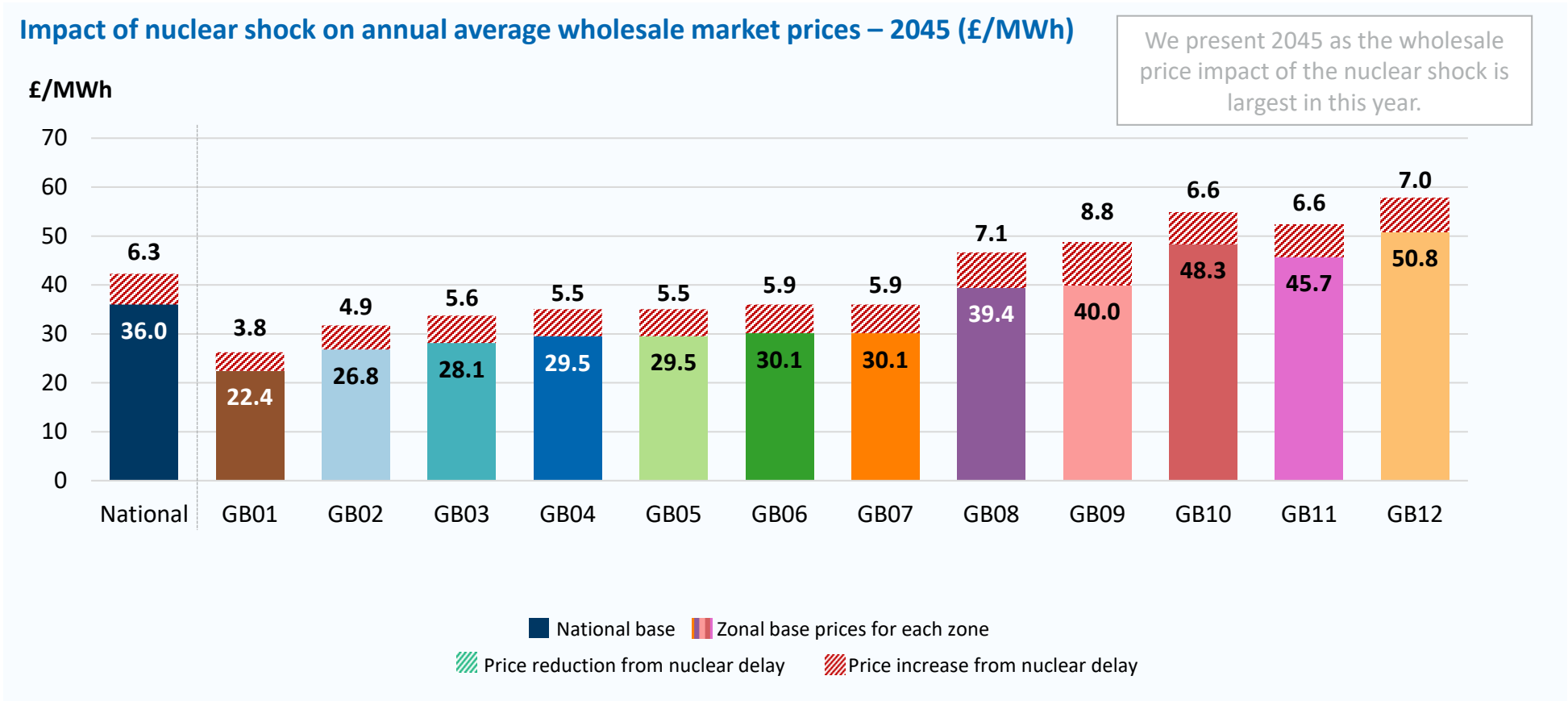
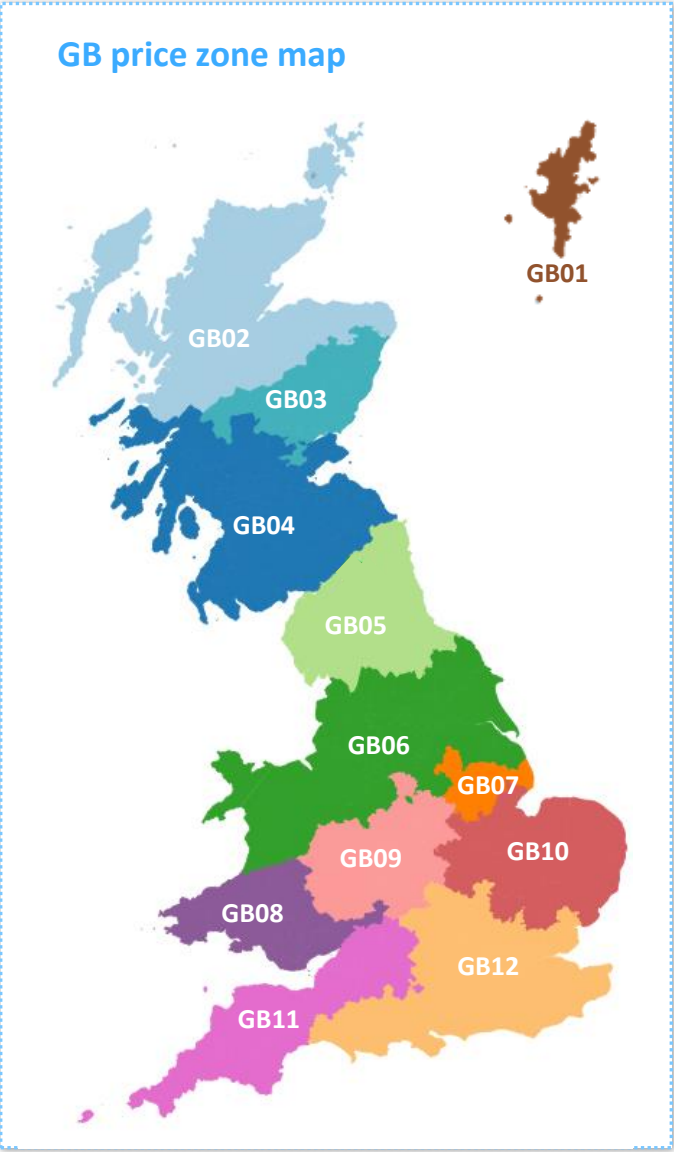
Shock 2: Nuclear Delay

For our nuclear supply shock scenario, we have delayed the commissioning of both GW-scale and SMR nuclear plants and assumed Sizewell B closes at the start of 2035



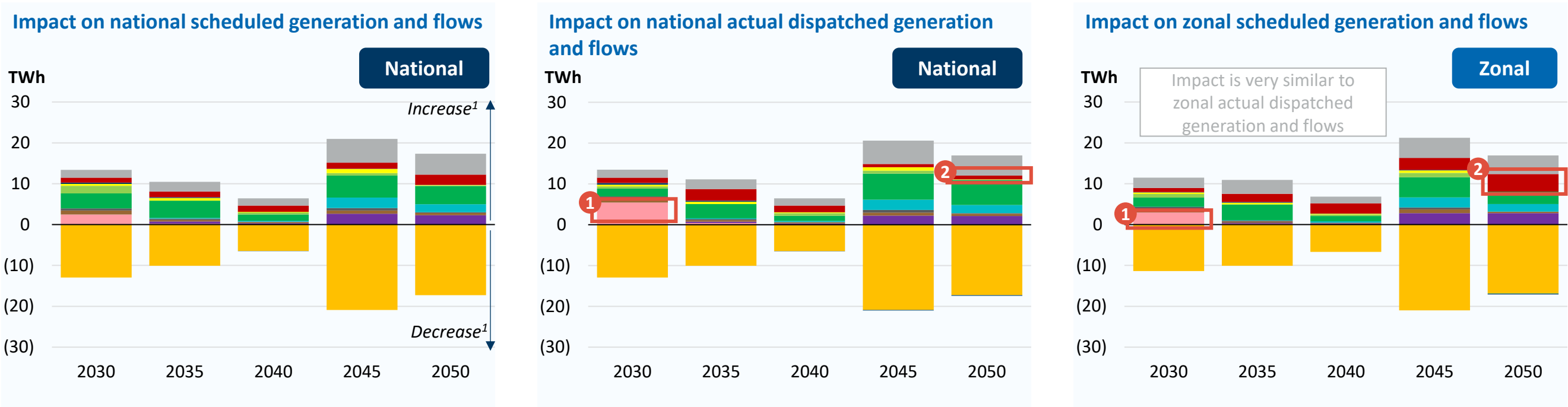
Notes: (1) In order to align with FES 24 HT’s assumption of 3.5GW of nuclear capacity in 2030, in the Base Model we assume only one of Hinkley Point C’s reactors is built by 2030 and hence only this unit (1.6GW) is delayed in the nuclear delay scenario. (2) UK Government, January 2024 ([link](#)); (3) Hinkley Point C submitted its initial planning application in 2011 (Somerset Council, [link](#)) and is now expected to come online 2029-31 (EDF, January 2024, [link](#)); (4) The Guardian, January 2025 ([link](#)) and BBC News, January 2024 ([link](#)). (5) DESNZ, December 2024 ([link](#)).

Delays to nuclear lead to higher wholesale prices under both market designs. Under zonal, the nuclear shock increases prices more in southern areas than in northern areas



- The nuclear delays result in higher wholesale prices under a national design as there is less capacity available to meet demand.
- Prices also increase under a zonal market design. The absolute price impact is greater in the southern zones (where most of the delayed nuclear is located) compared to the northern zones.
- The impact of the increase in prices would be partially offset by lower CfD payments to CfD generators under both market designs. This is quantified in the detailed breakdown of the welfare analysis in slide 50.

In 2030 and 2035, need for generation due to the nuclear delays is met by a lower cost mix of generation under zonal compared to under national



National

- Lower nuclear generation due to the assumed delays in nuclear build-out is replaced by a mix of other generation (for example, RES and higher marginal cost thermal) and an increase in net flows into GB, which drives higher national prices.
- The nuclear delays have a slightly larger impact on actual dispatch than on scheduled generation in 2030 and 2035, as nuclear capacity falls in southern areas, thereby increasing constraints that require more redispatch actions to resolve.

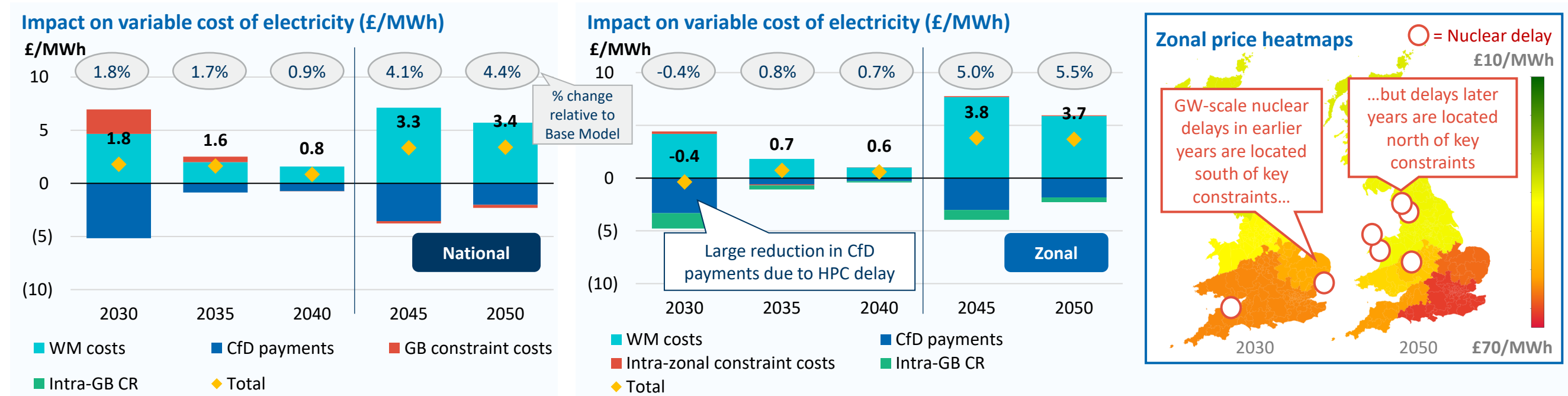
Zonal

- Compared to actual dispatched generation under national, in 2030 and 2035, a lower cost mix of generation (that is, a mix with fewer gas CCGTs- see 1) and imports are used in place of nuclear generation under zonal.
- From 2040 onwards, higher zonal prices (particularly in the southern zones) lead to higher imports into GB (see, for example, 2)



Note: (1) This is except for exports (in grey) – bars above the x-axis indicate a decrease in exports and bars below the x-axis indicate an increase in exports.

Zonal helps to mitigate the impact on the total variable cost of electricity arising from the nuclear delays in earlier modelled years



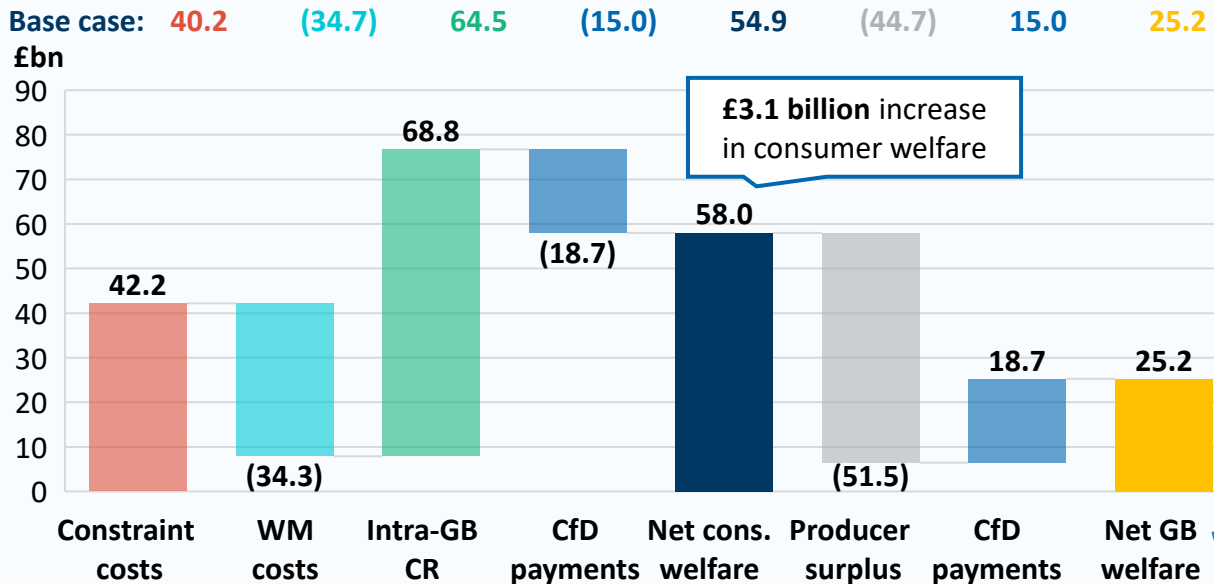
- Under national, the nuclear delays lead to higher variable cost of electricity of up to £3.4/MWh in all modelled years. The impact is the largest in 2045 and 2050 (in line with the volume of delayed capacity).
- The nuclear delay leads to higher constraint costs in the earlier years but slightly lower constraint costs in later years, as some of the delayed nuclear sits behind key transmission bottlenecks in the Midlands (see 2050 heat map above).
- Some of the increase in WM and constraint costs are offset by lower CfD payments (see slide 47).
- Under zonal, the impact of nuclear delays arises mainly in the WM (rather than the BM).
- The majority of the benefit of zonal design (relative to national) occurs in the early years where the impacts of nuclear delay are most pronounced.
- In 2030-35, the increase in constraints is resolved primarily via the WM, leading to higher zonal prices and WM costs. This is offset by an increase in intra-GB congestion rents due to wider price differentials between zones and lower CfD payments, helping to mitigate the increase in variable cost of electricity.
- By 2045-50, the delays in nuclear occur north of key transmission constraints, so the benefit of a zonal design (relative to national) is limited. In the charts above, the impact on variable cost of electricity is very slightly higher under zonal compared to national (£3.7-3.8/MWh v £3.3-3.4/MWh). This is in line with expectations – delays in the build-out of generation sited further north tend to reduce the marginal benefits of zonal design.

The consumer benefits of zonal pricing are £3.1 billion higher under the nuclear delay scenario, and further increase by £10.2 billion when combined with transmission delays

Net GB welfare impact of zonal pricing (£ billion, NPV 2030-50)

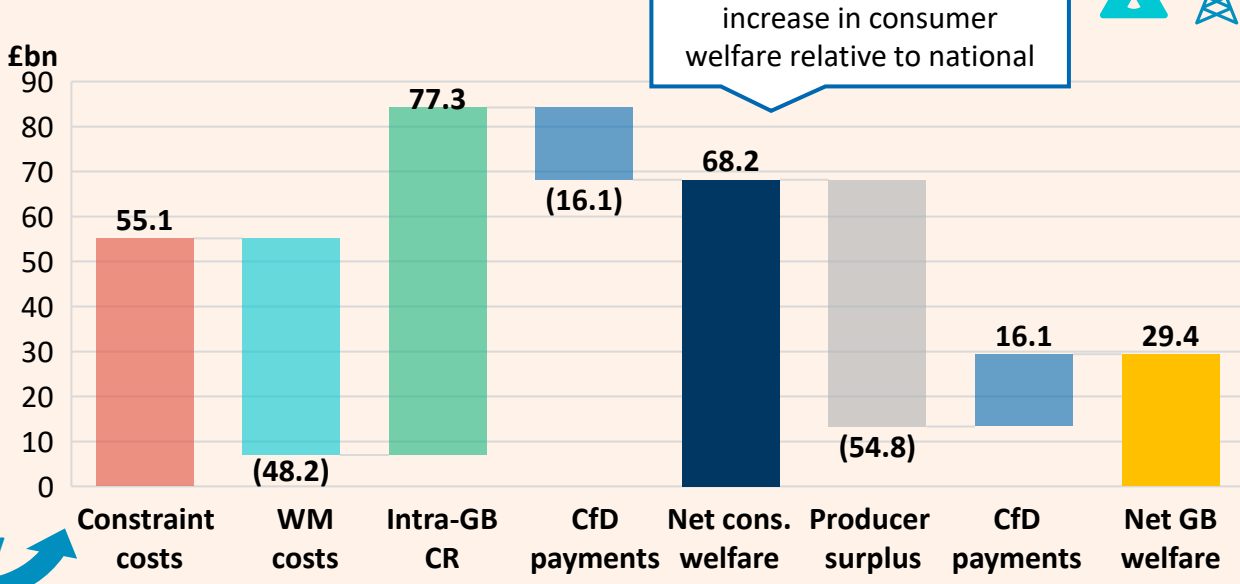
Base case Tx delay Nuclear delay Wind siting

Nuclear delay



- Our nuclear delay scenario increases the consumer welfare benefits of zonal pricing by £3.1 billion.
- Nuclear delays reduce baseload nuclear generation (which is predominantly located in the south of England and the Midlands). This increases constraint costs, but this increase is partially mitigated by zonal pricing.
- Net GB welfare remains broadly unchanged relative to the Base Model as the additional consumer welfare benefits of zonal pricing under the nuclear delay scenario are cancelled out by reduced producer surplus for nuclear generators in the wholesale market.

Nuclear delay + Tx delay

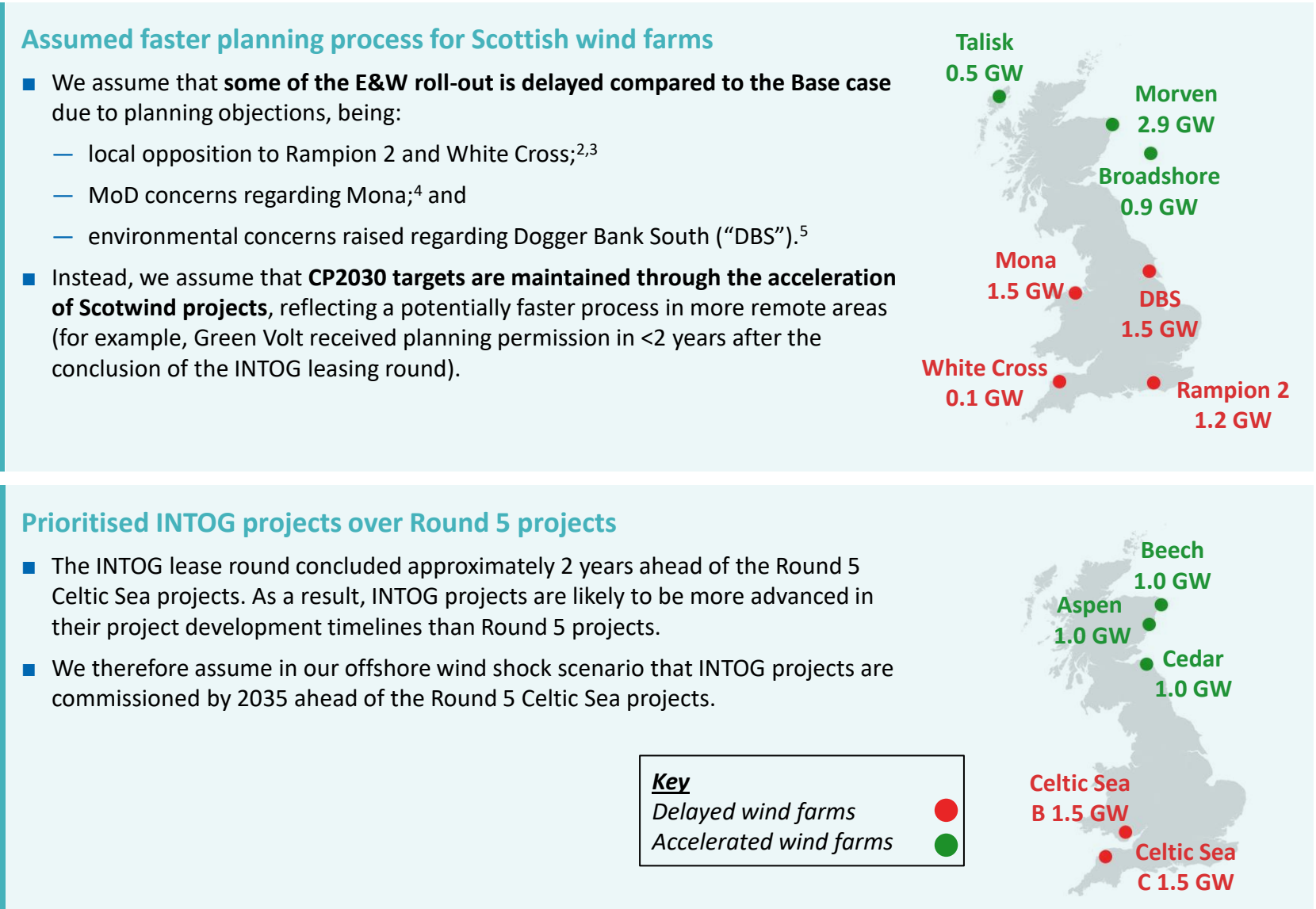
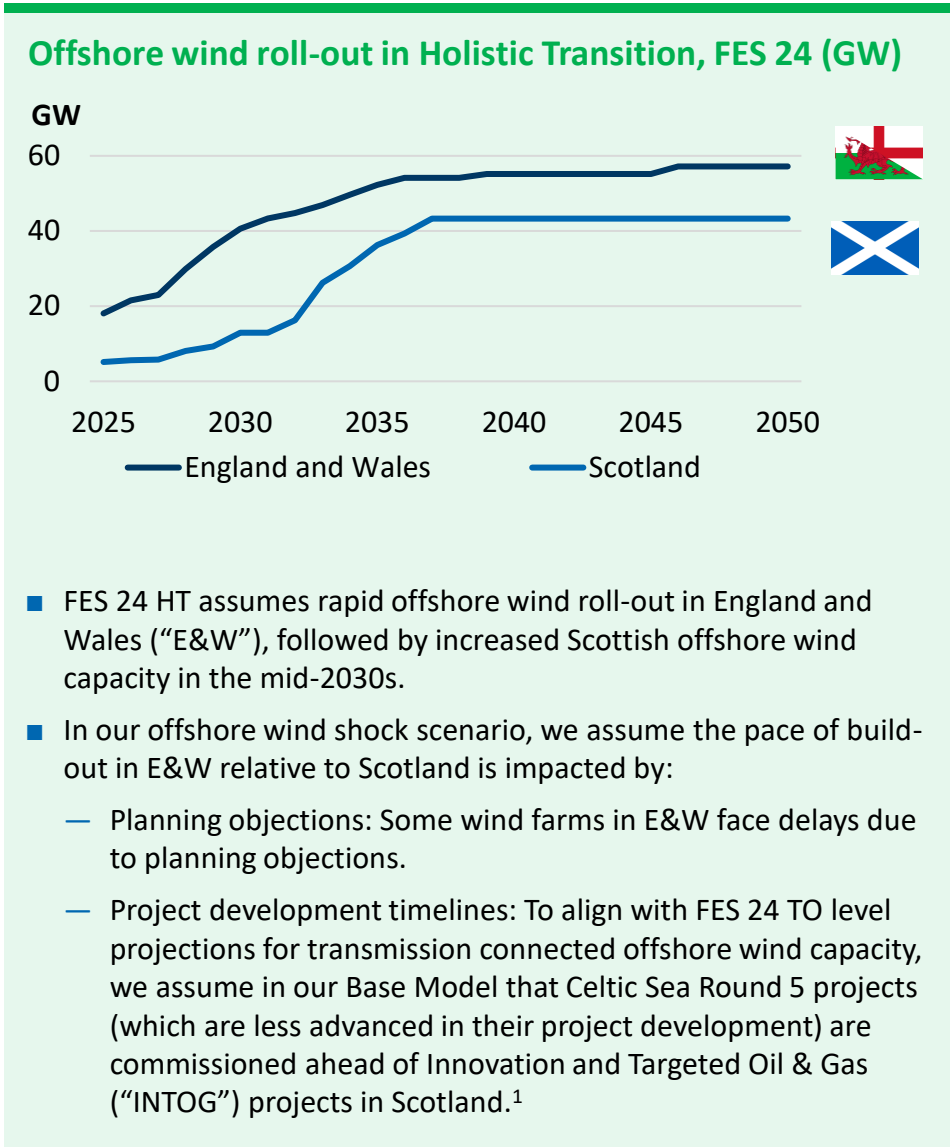


- Adding the Tx delay to our nuclear delay scenario, zonal pricing provides an additional £10.2 billion of consumer benefit. This is larger than the £9.4 billion benefit for consumers from the Tx delay scenario alone, as the cumulative negative impact of Tx and nuclear delays is worse for consumers compared to their individual impacts.
- With the delay in nuclear roll-out, delaying Tx build-out creates additional stress on the system. Under national pricing, these effects compound into higher constraint costs, as less efficient dispatch solutions have to be reached.
- Zonal pricing acts to mitigate this as wholesale prices adjust, which increases its consumer benefits relative to national pricing.



Shock 3: Offshore Wind Shock

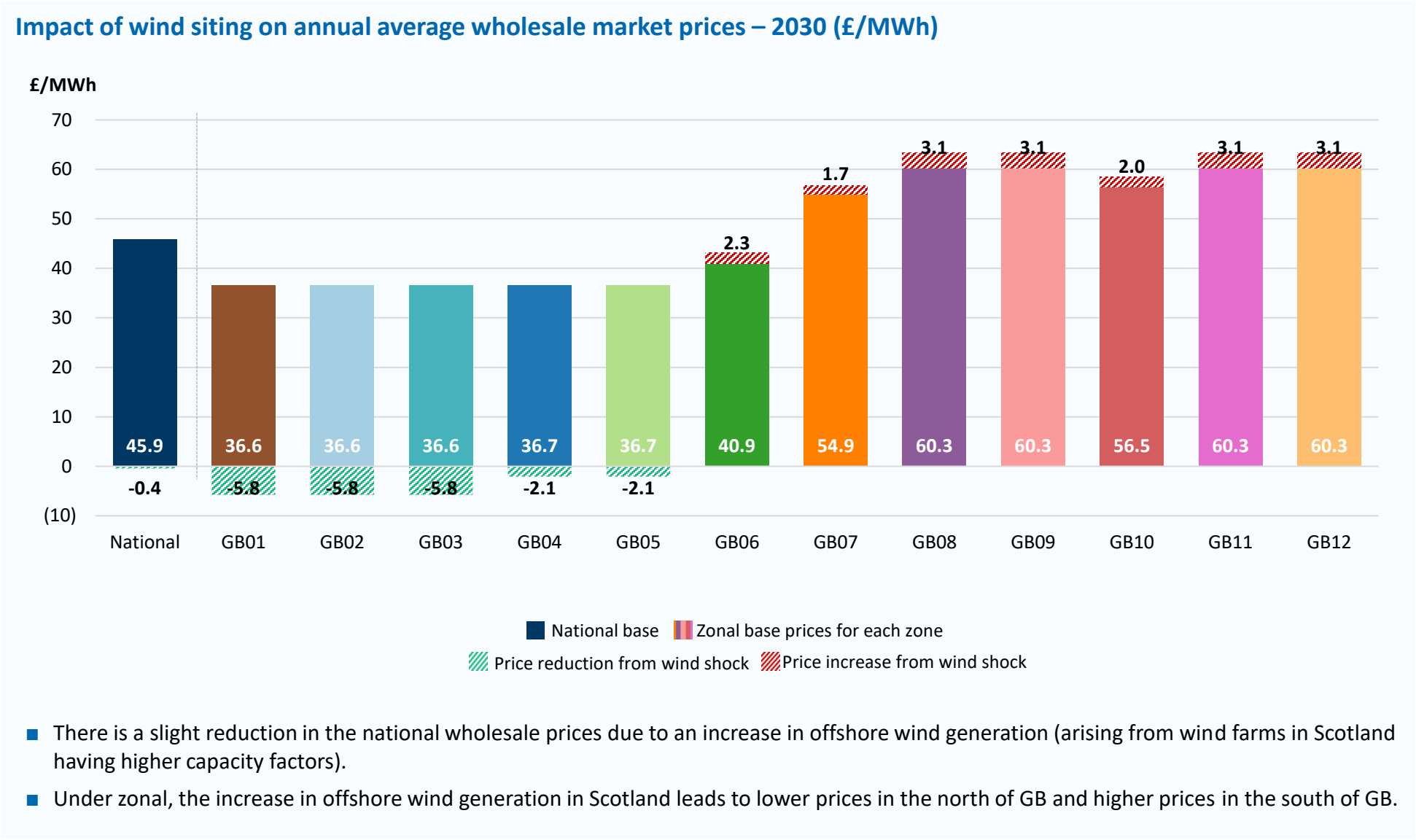
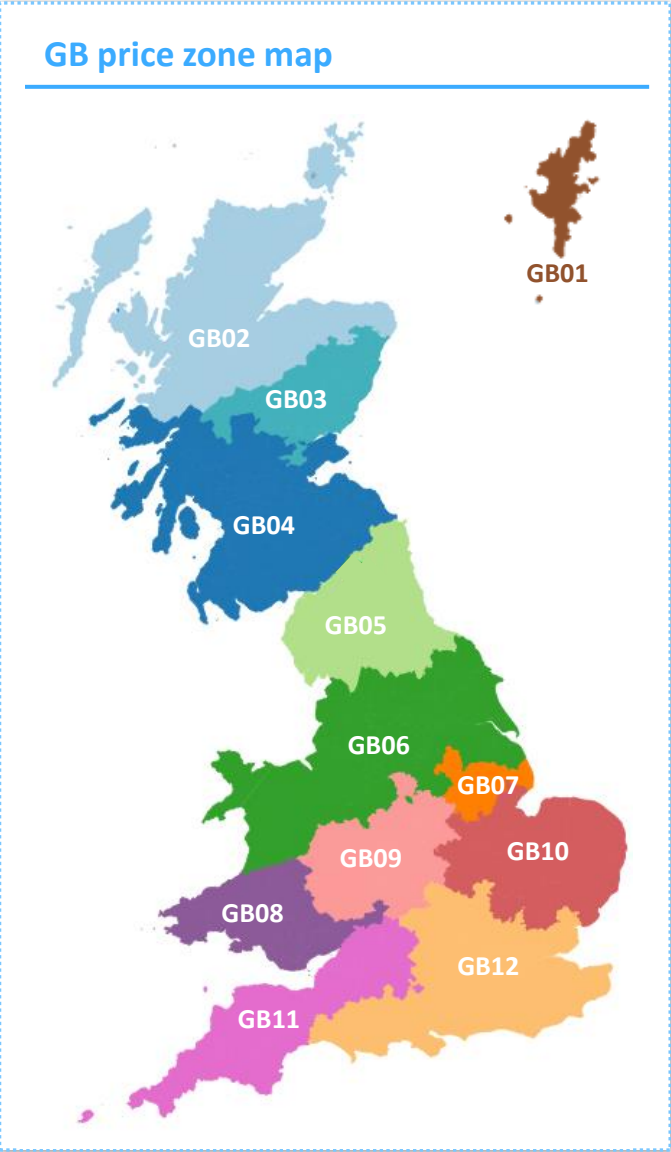
In our wind shock scenario, we assume a faster build-out of offshore wind in Scotland compared to E&W (due to factors such as planning and project development timelines)



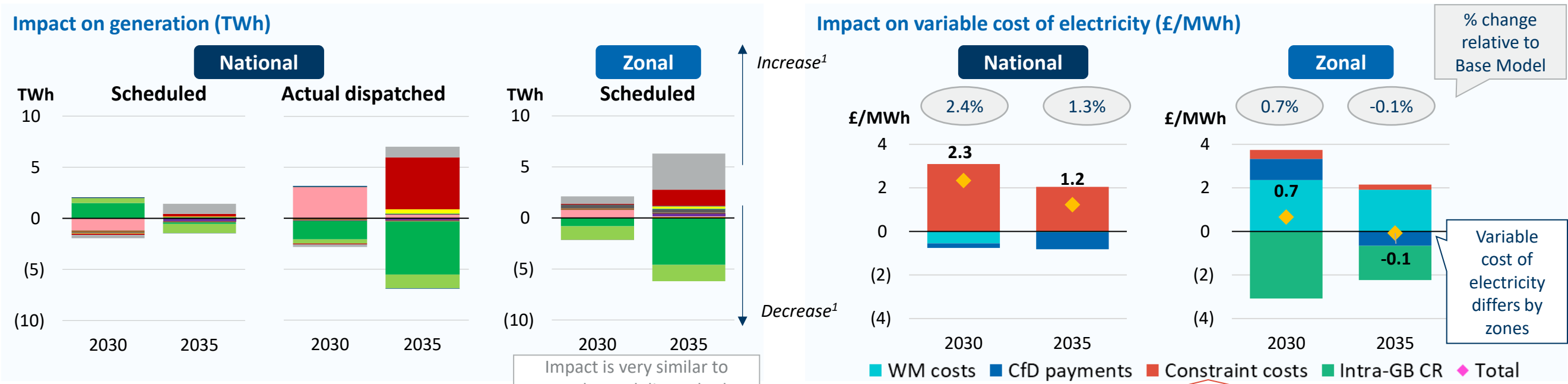
Notes: (1) FES 24 provides projections for transmission connected generation capacity at the TO rather than Grid Supply Point (“GSP”) level. To align with the 2035 projections for each TO, we assume in our Base Model that some projects in the NGET area (for example, Round 5 Celtic Sea projects) are commissioned ahead of projects in SHET and SPT (for example, INTOG projects) even though the former are less advanced in their project development. (2) ‘Wind farm expansion decision postponed’, 2025, BBC ([link](#)); ‘Campaigners oppose offshore windfarm substation plans’, 2024, BBC ([link](#)); (3) ‘Locals object to Devon wind farm cable plans’, 2024, BBC ([link](#)); (4) MoD Written Representation, 2024, DIO ([link](#)); MoD response to ExA questions, 2024, DIO ([link](#)); (5) ‘RWE lawyer ‘shocked’ at UK planning delay to \$9 billion Dogger Bank South wind farm over seabirds’, 2024, Recharge News ([link](#)).

52

Changing the relative pace of offshore wind build-out such that more comes online earlier in Scotland than E&W reduces prices in northern zones and increases them in southern zones



Increases in the variable cost of electricity are mitigated under a zonal market design due to an increase in intra-GB congestion rents arising from wider zonal price differentials



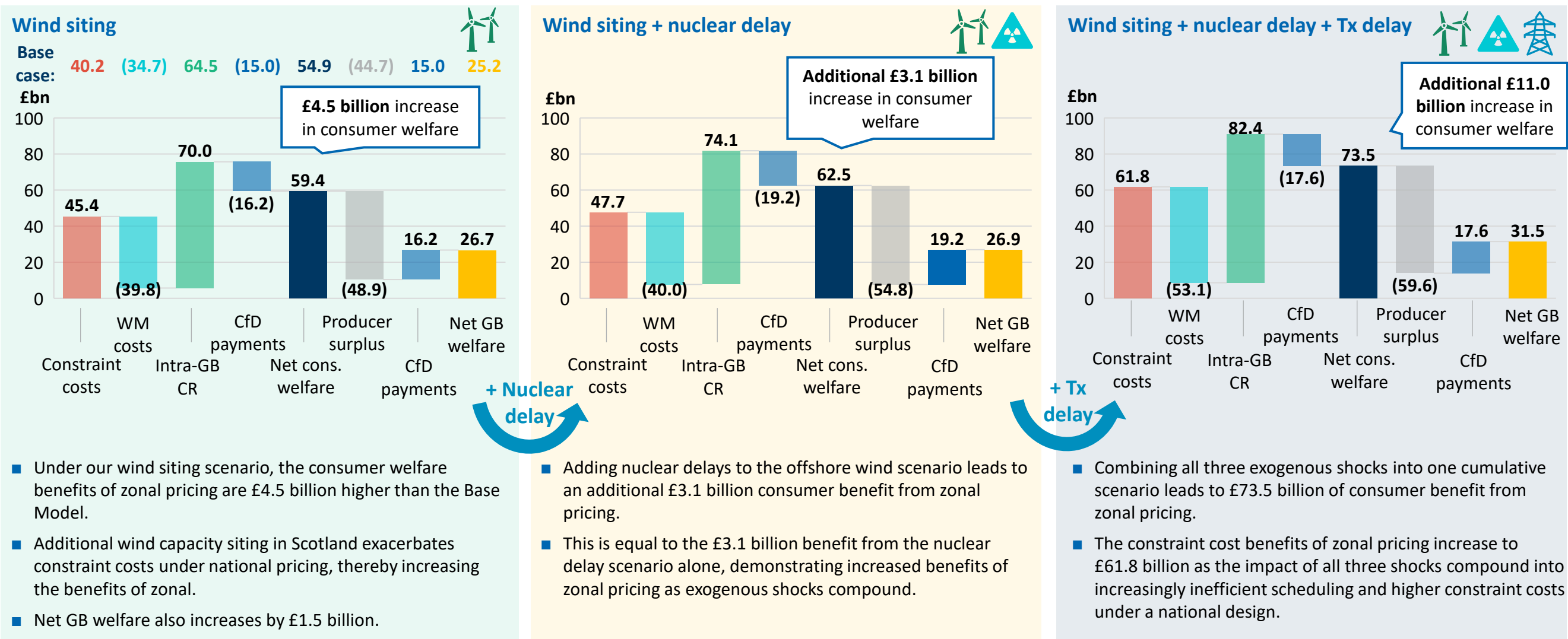
- National**
- The offshore wind shock has minor impacts on the wholesale market, as the different capacity factors of the different wind farms lead to differing levels of scheduled wind generation, with small impacts on prices and WM costs.
 - However, there is an overall increase in the variable cost of electricity by £1.2/MWh to £2.3/MWh due to higher constraint costs as more wind generation in the northern areas has to be constrained off in the BM.
 - CfD payments decrease due to the reduction in actual dispatched wind generation.
- Zonal**
- The change in the locational balance of offshore wind in GB is reflected in zonal wholesale outcomes. Less offshore wind is scheduled in the wholesale market, which minimises the need for additional redispatch actions to resolve constraints.
 - There is an increase in wholesale market costs due to higher zonal prices in the southern zones where most demand is located...
 - ...however, the increase in the variable cost of electricity is mitigated by an increase in intra-GB congestion rents due to wider zonal price differentials.
- GB-wide for national, intra-zonal for zonal
- Variable cost of electricity differs by zones
- Impact is very similar to zonal actual dispatched generation and flows
- Legend: Nuclear, Gas - CCGT, Gas - CCS, Peaking, Biomass, Biomass - CCS, Waste, Gas - Hydrogen, Hydro, Offshore wind, Onshore wind, Solar, Pumped storage, Battery storage, DSR, Imports, Exports

Note: (1) This is except for exports (in grey) – bars above the x-axis indicate a decrease in exports and bars below the x-axis indicate an increase in exports.

The consumer benefits of zonal pricing are £4.5 billion higher under the wind shock scenario and further increase by up to £14.1 billion when combined with the other exogenous shocks

Net GB welfare impact of zonal pricing (£ billion, NPV 2030-50)

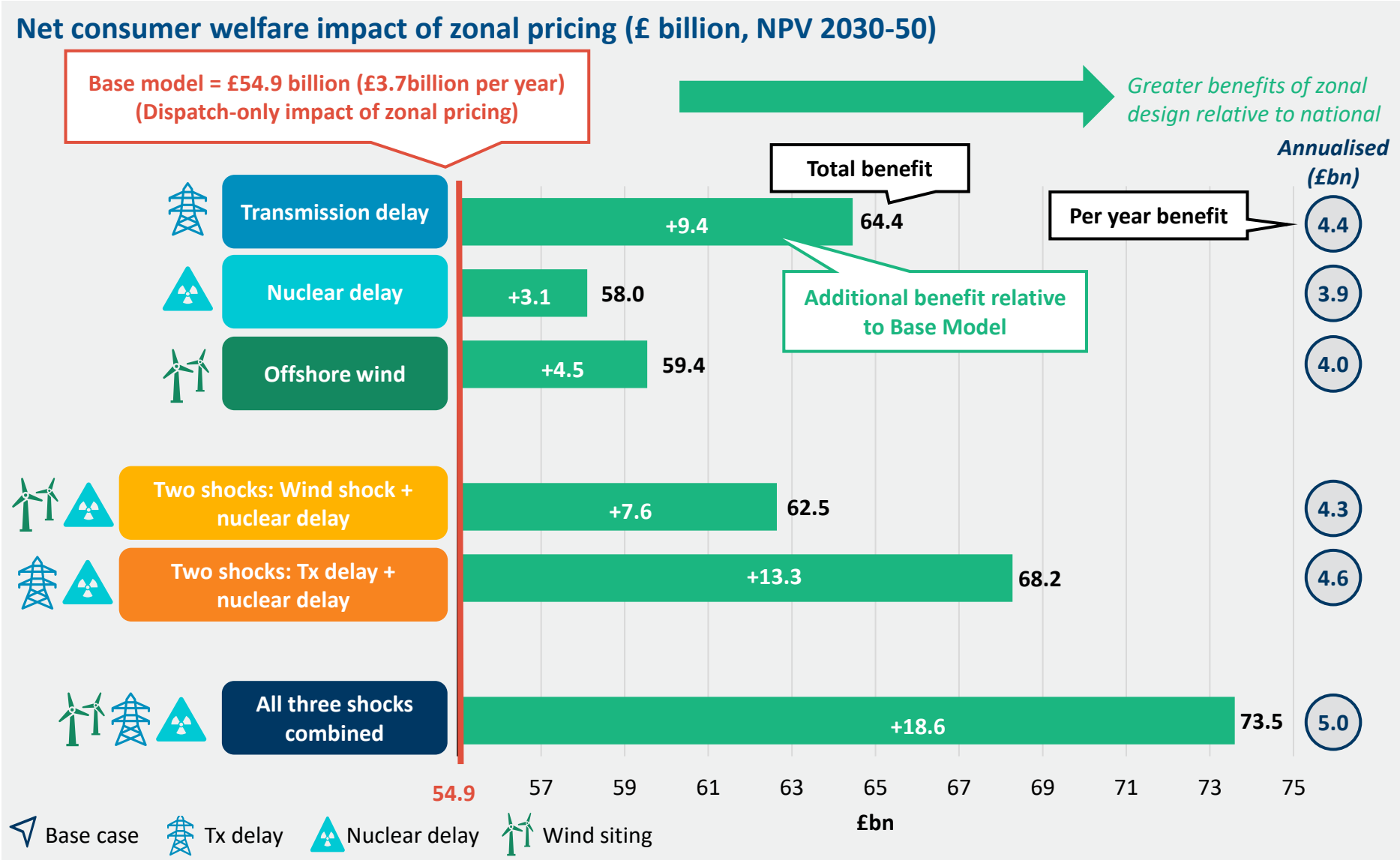
Base case Tx delay Nuclear delay Wind siting





Summary of Results

Transmission delays, wind siting and nuclear delays could all increase the benefits of zonal pricing, with even greater benefits when these scenarios are combined



Zonal pricing as a safety net

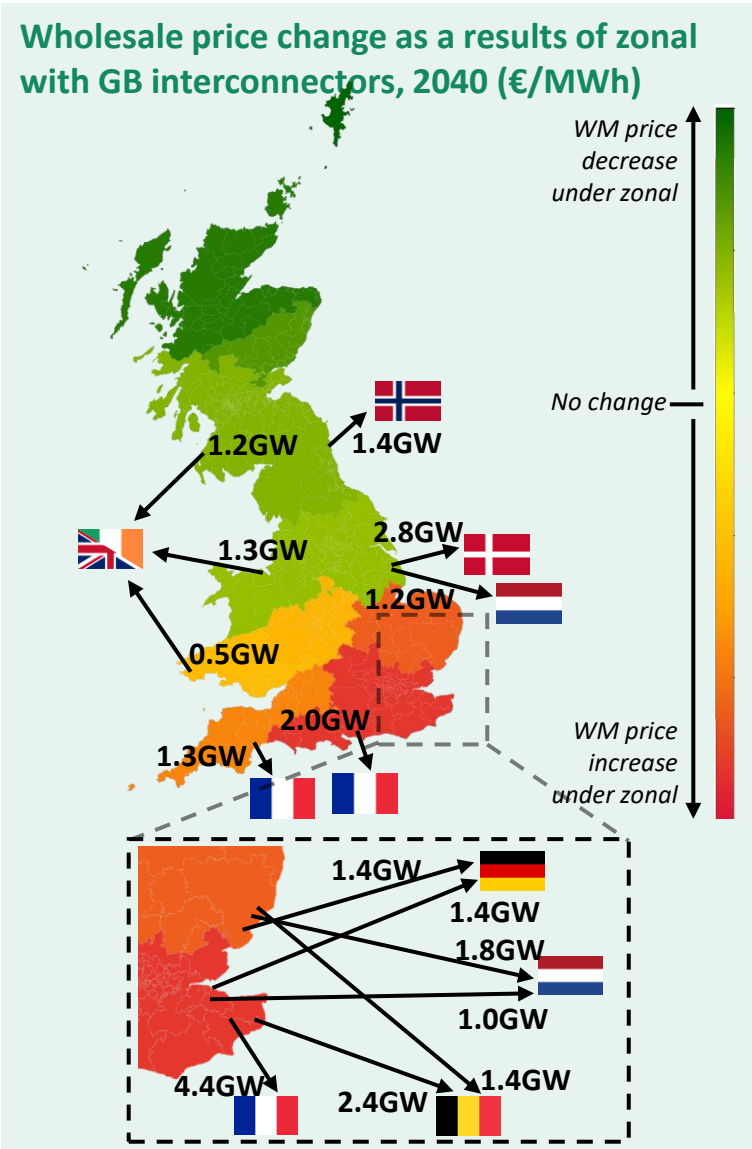
- The chart on the left sets out the net consumer welfare impacts of zonal pricing in each modelled scenario.
- The green bars indicate the consumer benefits of zonal pricing in each modelled scenario, expressed both in absolute terms (in black) and as additional benefits relative to the £54.9 billion benefits in the Base Model (in white).
- We find that the consumer benefits of zonal pricing increase to £58.0 billion and up to £64.4 billion if any of the exogenous shocks occurred individually, and up to £73.5 billion if the shocks took place simultaneously.

Our analysis thus demonstrates that zonal pricing could act as a 'safety net' to protect consumer welfare and ensures that GB continues to meet its Net Zero and CP2030 ambitions in the case of unpredictable shocks that jeopardise the central plan.



Appendix 1: Impact of Zonal Market Design on Connected Countries

In line with our earlier study, we find zonal pricing in GB would impact prices in neighbouring countries – with higher prices in Northwest Europe and lower prices in Norway and Ireland



■ In our previous assessment for Ofgem assessing the benefits of locational pricing,¹ we examined the WM price impact on connected countries due to zonal pricing.

■ We have undertaken a similar analysis for 2040, and find that the impacts remain directionally similar.

Flows (TWh) and WM price changes (€/MWh) in connected countries in 2040

Price zone	France	Belgium	Netherlands	Germany	Denmark (DK1)	Norway (NO2)	I-SEM	Total
Interconnector capacity in 2040 (GW)								
Capacity	7.7	3.8	4.0	2.8	2.8	1.4	3.0	25.5
Scheduled flows under national (TWh)								
Import to GB	21.7	3.0	3.9	3.5	7.9	4.9	2.5	47.4
Export from GB	36.3	25.0	26.4	16.6	11.2	5.0	18.9	139.4
Net flow	-14.6	-22.1	-22.5	-13.1	-3.3	-0.1	-16.4	-92.1
Change under zonal (TWh)								
Import to GB	+0.8	-0.1	+0.4	+0.3	-1.0	-0.8	-0.1	1.1
Export from GB	-9.0	-3.1	-2.5	-3.9	+1.5	+1.0	+0.4	-15.6
Net flow ²	+9.8	+3.0	+2.8	+4.2	-2.5	-1.8	-0.5	+15
Price change (€/MWh)								
WM price ³	+3.1 (8%)	+2.5 (5%)	+3.0 (6%)	+1.7 (3%)	+0.1 (0%)	-0.7 (-3%)	-1.5 (-3%)	

Higher zonal prices in the south of GB lead to lower exports to and higher net flows from France, Belgium, Netherlands and Germany...
...which increases wholesale prices in these countries.

Lower zonal prices in the North of GB lead to higher imports and net inflows from Norway and I-SEM...
...which drives lower prices in these connected markets.

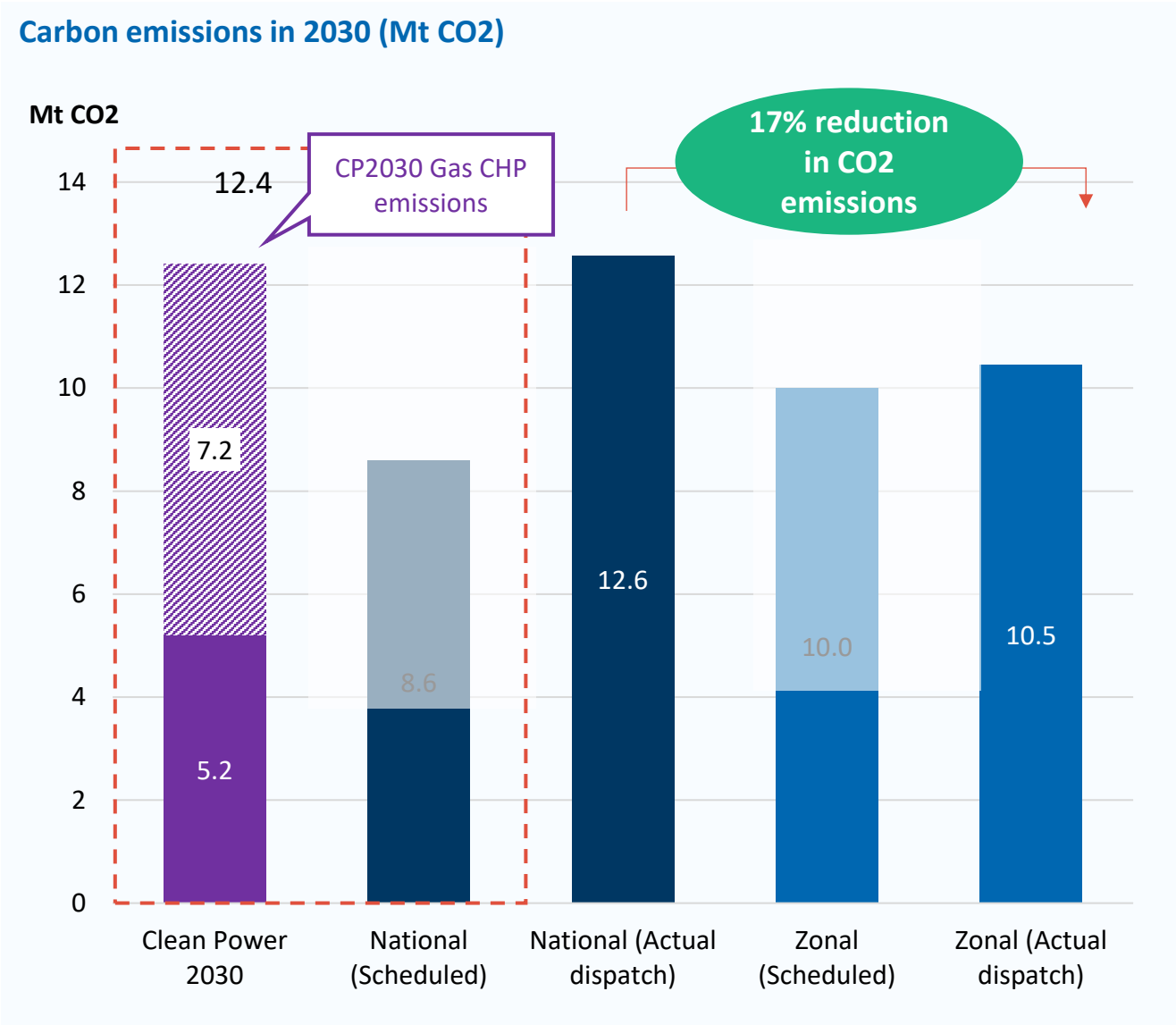
Notes: (1) 'Assessment of locational wholesale pricing for Great Britain', FTI Consulting and Ofgem, October 2023 ([link](#)), p.149-155. (2) Positive change in net flows represents more net flows into GB or reduced net outflows from GB, while negative values represent the opposite. (3) Positive numbers represent price increase in the connected price zone as a result of zonal pricing in GB.

59



Appendix 2: Emissions Impact

Compared to national, actual emissions are 17% lower under zonal in 2030 as the difference between scheduled and re-dispatched emissions under zonal is much smaller



CP2030 comparison

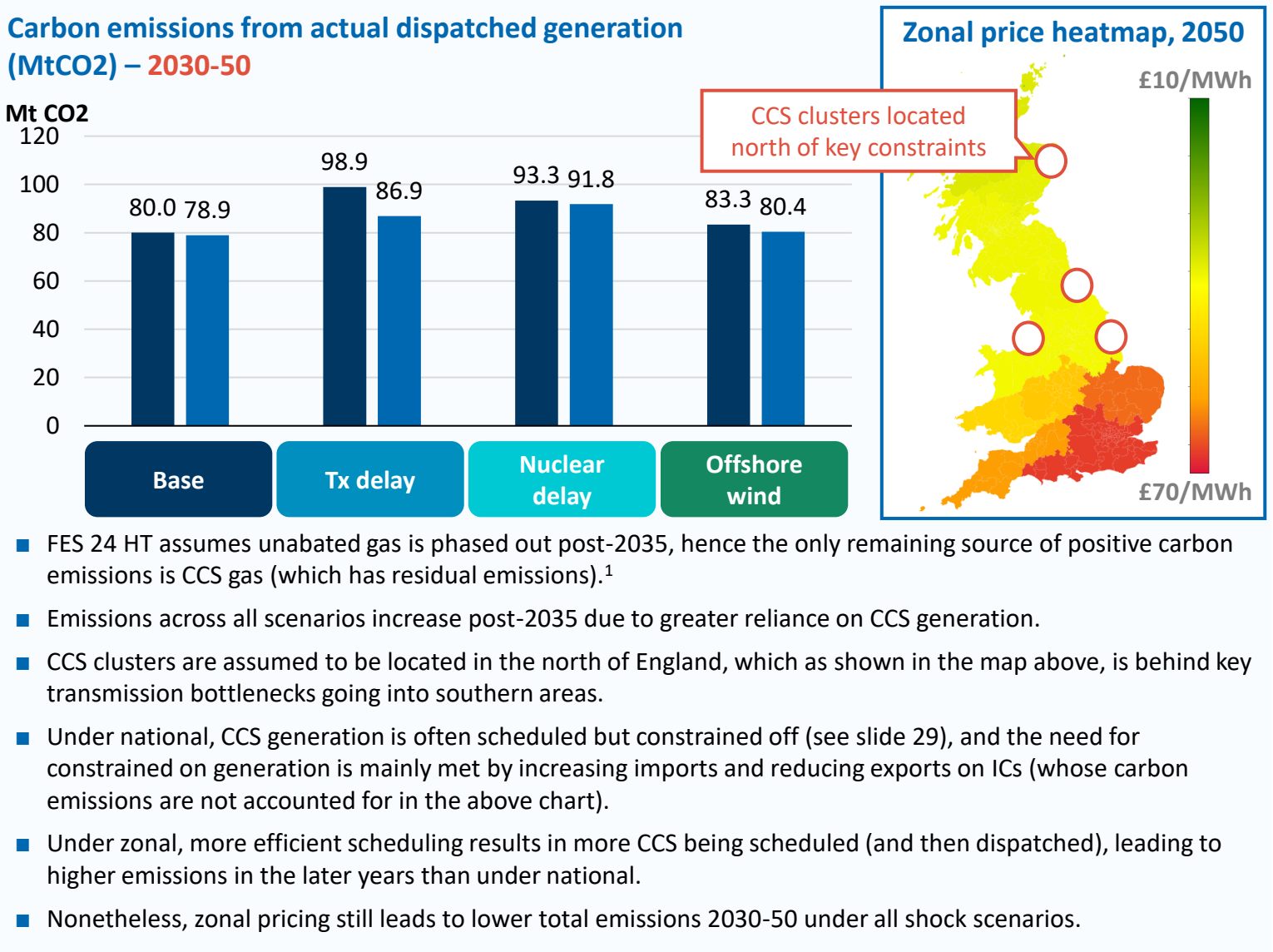
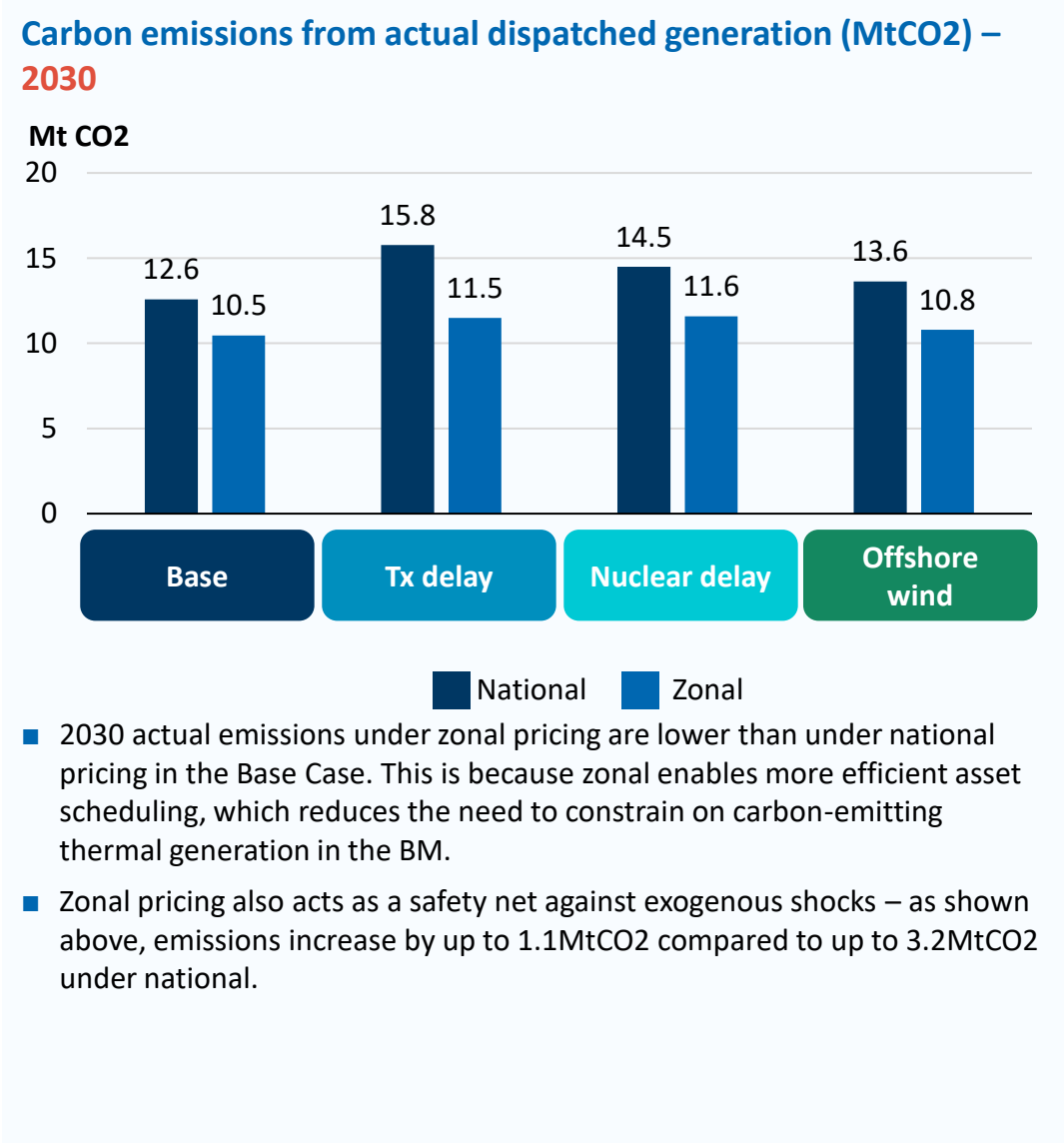
- CP2030's emissions figure is based on scheduled generation¹ and excludes emissions from combined heat and power ("CHP"), from waste to energy, and before removal of emissions from Bioenergy with Carbon Capture and Storage ("BECCS").^{2,3}
- There are differences in our modelled CHP generation in 2030 (FTI Consulting: 4.4TWh vs CP2030: 11.8TWh). For comparability, we therefore include CHP emissions in both the CP2030 figure and our modelled emissions.
- As shown, our 2030 estimate based on scheduled generation under national pricing is lower than CP2030 (8.6MtCO2 vs 12.4MtCO2).

National vs zonal

- Under national pricing, emissions after redispatch are higher than scheduled emissions as fossil fuel generators are constrained on to resolve transmission constraints (see slide 29). Emissions increase by 4.0MtCO2 from 8.6MtCO2 to 12.6MtCO2.
- Under zonal pricing, the difference between redispatch and scheduled emissions is much lower compared to national pricing (0.5MtCO2 under zonal vs 4.0MtCO2 under national). This is because fewer redispatch actions are required from thermal generators to resolve constraints (such that scheduled and actual dispatched generation is more similar).
- As less thermal generation (National: 36TWh vs Zonal: 30TWh) is physically dispatched under zonal pricing compared to national pricing, actual emissions are 17% lower under zonal market design.

Notes: (1) The CP2030 databook (ES1 tab) states: "Carbon intensity represent the case where no generation output is adjusted to overcome network or operability constraints. The real world values will be higher." (2)The CP2030 databook (CP.23 tab) states that this "aligns to the CCC's emissions accounting, which attributes these emissions to the industry and waste sectors respectively and identifies removals separately. In international emissions reporting, removals are attributed to the sector where they occur, with the net figure reported". (3) Emissions figures in both our modelling and CP2030 are positive emissions from GB generators, with no adjustments made for (i) negative emissions from CCS biomass generators; or (ii) the implied carbon emissions on imports/exports.

Overall, across the modelling period, zonal pricing helps to mitigate against increases in emissions due to the exogenous shock scenarios, particularly in 2030



Notes: (1) Emissions figures reported in charts are positive emissions from GB generators, with no adjustments made for: (i) negative emissions from CCS biomass generators; or (ii) the implied carbon emissions on imports/exports.



Appendix 3: Comparison of Results to Previous FTI Consulting Modelling for Ofgem

Compared to our previous assessment for Ofgem, our latest estimate of the consumer benefits of zonal are higher – reflecting updated FES projections and improved zonal set up

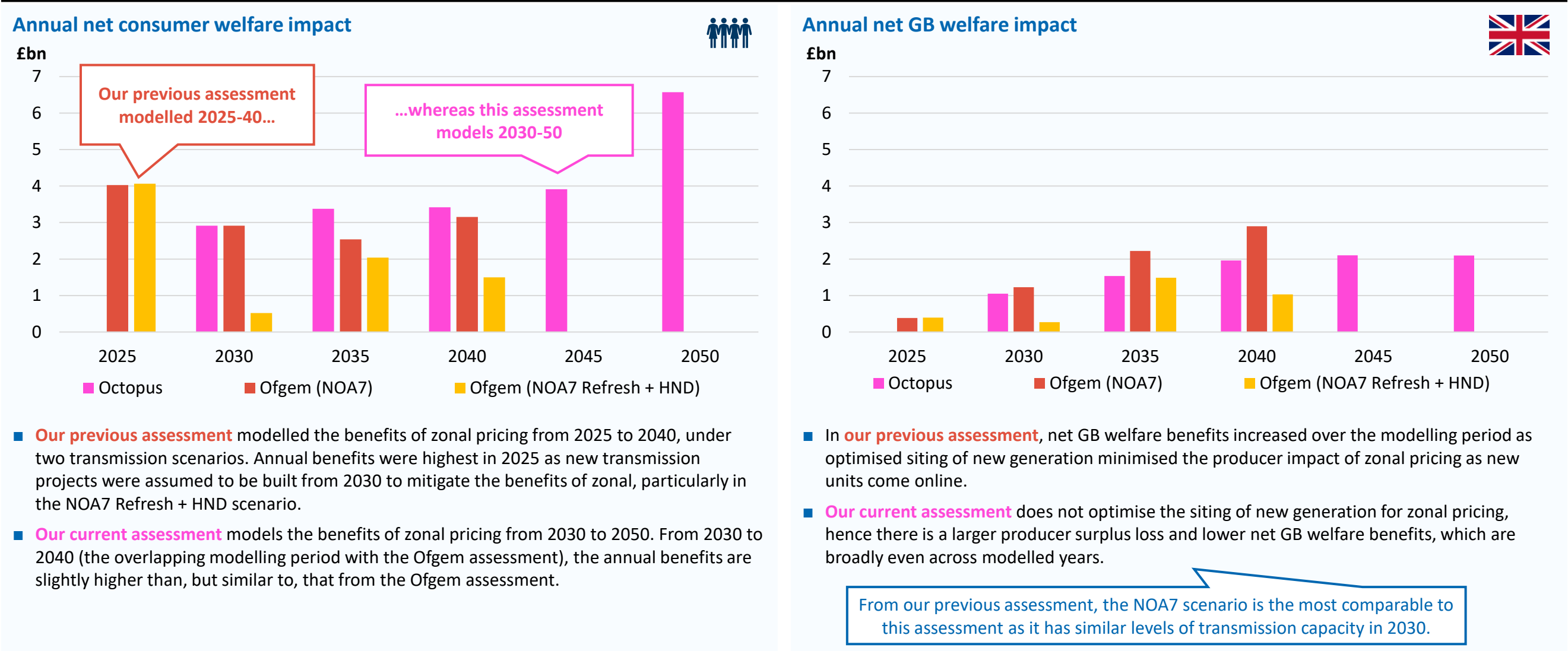
	New assessment 	Previous assessment ⁵	Likely impact of new assumption on the benefits of zonal
Market arrangements assessed	Only Zonal	Nodal and Zonal	-
Modelling period and length	2030-2050	2025-2040	↑ Longer modelling period (only affects total NPV) ↔ Different set of modelling years
Generation and demand assumptions	FES 24 HT	FES 21 LtW and FES 21 SysTr	↑ FES 24 HT includes more ambitious renewable roll-out ↔ Updated spatial distribution of demand and supply
Transmission assumption	CP2030 (central) + Beyond 2030	NOA7 and NOA7 Refresh + HND	↑ CP2030 assumes lower Tx in 2030 compared to HND ↓ Beyond 2030 forecasts more transmission from 2035 onwards
Number of zones	12	7	↑ Higher number of zones, which increases zonal benefits
Commodity prices	CP2030 and FES 24	FES 22	↑ Higher gas and carbon prices
CfD strike price assumptions	AR6	AR4	↑ Higher strike prices – BM costs are now higher for constrained off wind
Siting benefits of new generation	Not assessed quantitatively	Assessed quantitatively for some technologies ³	↓ Siting benefits of new generation assets would offer additional benefits due to zonal

Net GB welfare impact of zonal pricing across the full period					Key drivers of differences ■ Differences in modelled periods ■ Differences in modelling assumptions ■ Refinements of our zonal set up ■ Current assessment focuses on dispatch-only efficiencies of zonal pricing⁴
	NPV (£bn)		Annualised (£bn) ²		
	Consumer	SEW	Consumer	SEW	
Octopus (Zonal: CP2030, FES 24 HT and Beyond 2030)	54.9	25.2	3.7	1.7	
Ofgem (Zonal: FES 22 LtW and NOA7) ¹	37.5	19.0	3.1	1.6	
Ofgem (Zonal: FES 22 LtW and NOA7 Refresh + HND) ¹	23.1	9.2	1.9	0.8	

Notes: (1) For comparability with our updated assessment, we have removed implementation costs from the previous assessment figures and inflated results from 2021 to 2024 prices. (2) Annualised results have been levelised over the respective modelling periods. These figures therefore represent the welfare impact which, if replicated in each year of the modelling period, would deliver the same NPV impact in the respective starting year of the modelling period. The annualised figures are calculated based on different modelling periods and only overlap over 2030 to 2040; (3) In our assessment for Ofgem, we performed a dispatch-only sensitivity in our assessment of the benefits of nodal pricing under the FES 21 LtW NOA7 scenario. We found that this reduced the consumer benefits by 24% and the GB welfare benefits by 43%. (4) ‘Assessment of locational wholesale pricing for Great Britain’, FTI Consulting, October 2023 ([link](#)).

This assessment uses a longer modelling period than the Ofgem LMP assessment and has similar consumer welfare impacts as the NOA7 scenario in the overlapping years

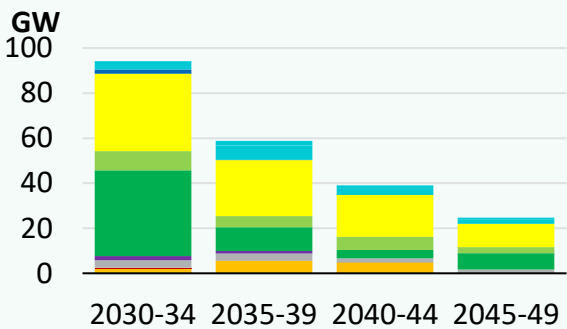
Welfare impacts of zonal pricing in our Base Model (£ billion) – FTI Consulting’s previous assessment (for Ofgem) vs our latest assessment (for Octopus)



To negate the benefits of zonal pricing, WACC would need to increase 4.59 percentage points (“pp”) under our Base case and by nearly 6pp under the Tx delay and supply shock scenario

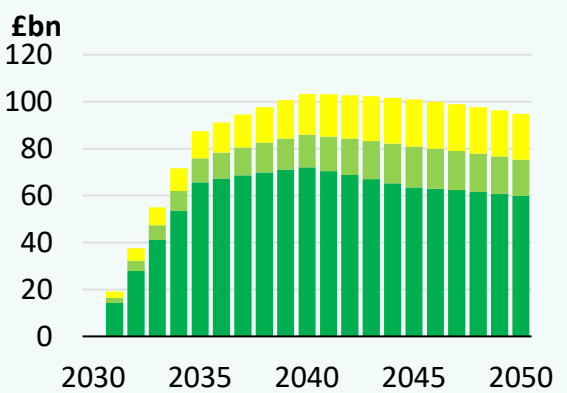
Some stakeholders have argued that moving to locational pricing would lead to greater investor risk and uncertainty increasing their cost of capital. We have not found evidence for this, nevertheless, in line with previous work for Ofgem, we perform an extreme sensitivity to estimate the level of WACC increase that would negate the benefits:⁴

Step 1: New capacity in each year



- To estimate the volume of capacity that could be impacted by a WACC increase, we calculate how much **new capacity** would be built in each year **between 2030-2049**^{1,2} for each technology:
 - Large-scale technologies (for example, nuclear) based on individual project commissioning and retirement dates; and
 - Other technologies (for example, solar) by assuming that a fixed % of capacity is retired in each year and replaced by new units.³

Step 2: Impacted CAPEX base in each year



- To estimate the CAPEX base that could be impacted by a WACC increase, we exclude technologies that are mostly shielded from WM price impact or are not expected to earn lower revenues:³
 - Nuclear, CCS (gas, biomass), H2P, Pumped storage and ICs: assumed to be shielded through subsidy mechanisms; and
 - Batteries: Not expected to be negatively affected by zonal.
- We then assume a straight-line depreciation for the remaining assets over the course of their economic lifetime.⁴

Hypothetical WACC increase needed to negate the benefit

- We find that under the Base case, **WACC would need to increase by 4.59pp** to negate the consumer benefits...
- ...and by **6.14pp in the cumulative scenario with all three shocks** (which has the highest zonal pricing benefits).
- In our assessment for Ofgem, we have found that WACC would need to increase by between 1.25-2.06pp to negate the benefits of zonal pricing. The necessary WACC increase has risen as a result of:
 - Our exclusion of capacity built up to 2030;¹
 - Our current assessment forecasting higher per-annum zonal benefits, for reasons described on slides 64-65;
 - Methodological change to reflect discounting more accurately.⁵
- As a result, under our refreshed modelling, the WACC increase that would negate the benefits of zonal is higher, and less plausible than previously.

Scenario	NPV of benefits	WACC increase that would negate benefits
Base	£54.9bn	4.59pp
Tx delay 	£64.4bn	5.37pp
Nuclear delay 	£58.0bn	4.84pp
Wind shock 	£59.4bn	4.96pp
Nuclear and tx delay  	£62.5bn	5.22pp
Wind shock and tx delay  	£68.2bn	5.69pp
All three shocks   	£73.5bn	6.14pp

Notes: (1) We assume that any capacity built ahead of 2030 would be classed as legacy asset and would see no impact to its cost of capital. This should not be interpreted as a policy recommendation on the transitional arrangements. (2) We assume that all capacity comes online on 1st January. As a result, any capacity built in 2050 would only be impacted in 2051, which is outside of the assessment period. (3) We have applied the same methodology as deployed in previous work for Ofgem, since this has been tested and validated with stakeholders. We recognise that the extent of specific technology impacts may have evolved but given that we have not had the opportunity to re-test these assumptions with the industry, we continued, for consistency and comparability of our modelling results, with the established methodology. (4) Lifetime assumptions of new assets are based on DESNZ's Electricity generation costs 2023 publication ([link](#)). (5) We discount the impact of the increase in WACC to 2030 using the Green Book rate of 3.5%. Our previous analysis for Ofgem did not account for the impact of discounting. All else equal, accounting for this impact increases the WACC uplift needed to negate the consumer benefits of zonal pricing.



Experts with ImpactTM