GB Locational Pricing - A framework for analysis of benefits and some initial results

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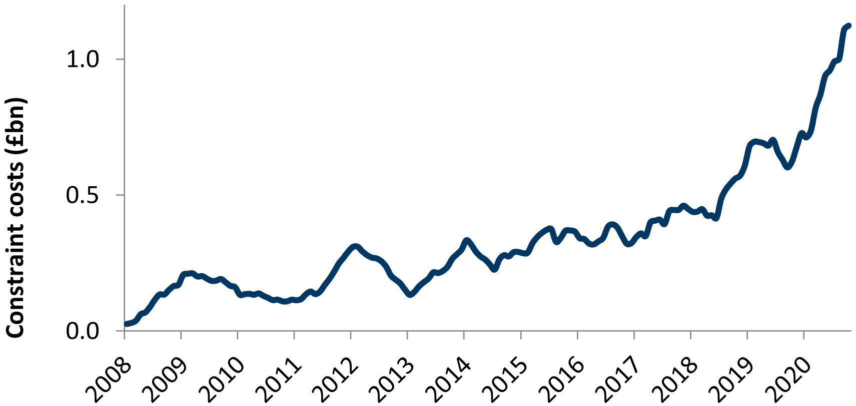
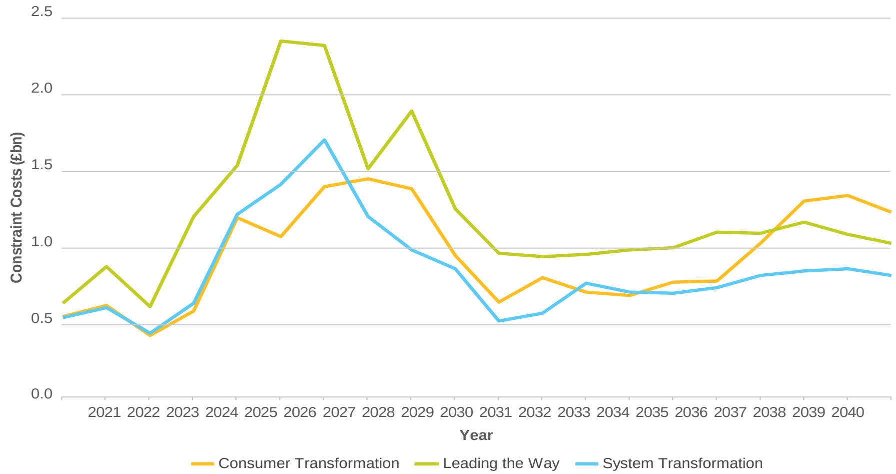
Context for considering locational pricing is that, according to the ESO, constraint costs are "*rising at a dramatic and accelerating rate*"

Congestion costs increased 8-fold since 2010 at a cost of £7bn to customers…



… anticipated to be sustained at high levels – at a cost of c.£13bn to £19bn to 2035



ESO identified three other issues with market design:

Balancing role	Balancing role increasingly challenging – system operator **no longer "residual"** in market
Interconnector and storage flows	Interconnectors and storage are important sources of flexibility but at times currently **exacerbate constraints**
Flexibility resources	Current market design **does not unlock full potential** of diverse ranges of flexibility resources

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Commissioned by Octopus Energy to understand, quantitatively, the potential benefits of more granular locational pricing and impact on consumers

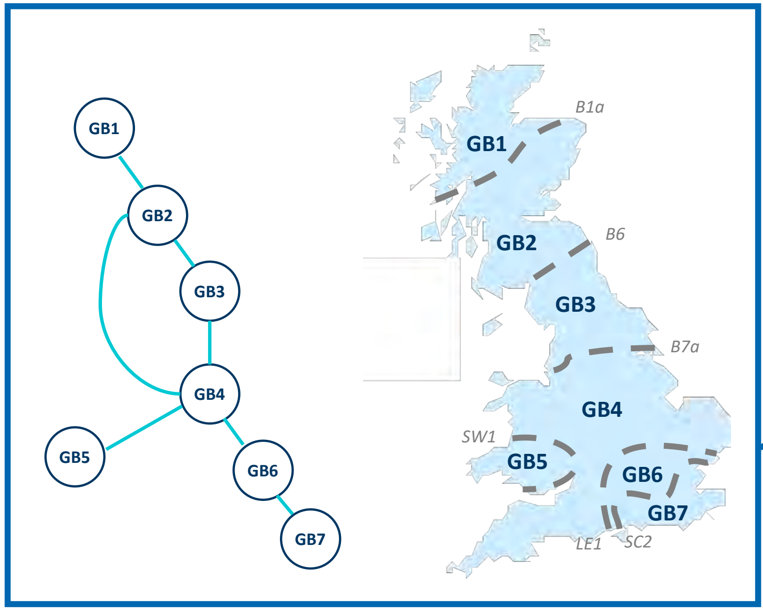
Type	Effect	Modelled
Short-run impact	Reduced cost of congestion	Yes
	More efficient dispatch – improved signals for interconnectors and storage	Yes
	Changes in wholesale prices	Yes
	Enhanced flexibility	Yes
	Enhanced operational benefits	No
Long-run impact	Improved siting decisions for generators and storage	Yes
	Improved siting decisions for demand	No
	Improved signals for transmission developments	No

- Modelling between 2022 and 2035.
- Assumed “overnight” implementation of LMPs – i.e. go-live 1 Jan 2022
- Costs not considered (e.g. implementation, cost of capital etc)
- *Note: All monetary values in euros.*

Framework for analysis of benefits

We divide GB market into seven zones, overlaid on our existing European market model to assess impact on GB prices and consumer welfare

Baseline geographical set-up of FTI-CL Energy's power market model

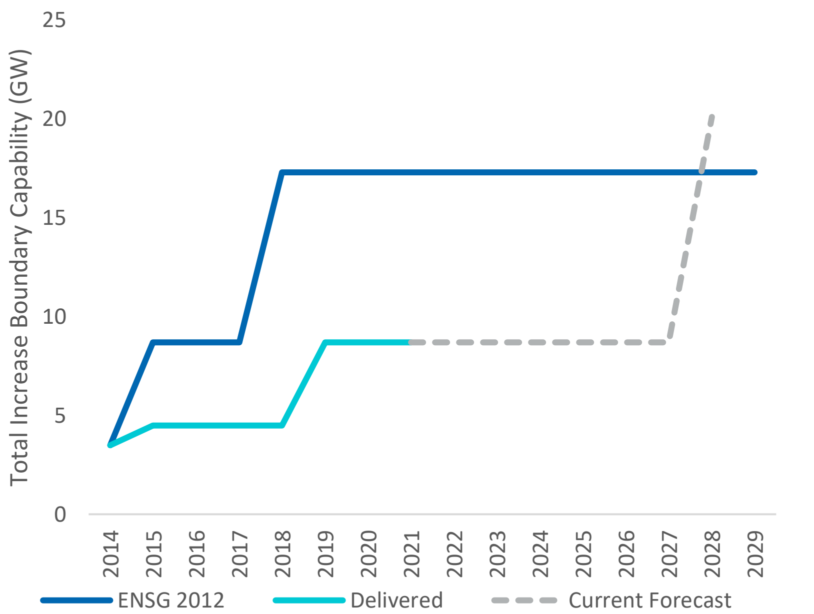


Split and define key assumptions for each zone and boundary over the modelling horizon

Step 1: Define transmission capacity between zones	Step 2: Define electricity demand (annual demand, profile and flexibility)	Step 3: Define and optimise generation capacity build-out	Step 4: Sense check compared to existing benchmarks

Step 1: Evolution of transmission network - We assume some delay relative to NOA plans given historical under delivery of transmission investment….

Reinforcements on major boundaries consistently delayed



***Sources**: ENSG Our Electricity Transmission Network: A Vision For 2020 (2012); FTI analysis.*

Assumed intra-GB transmission capacities, 2025 – 2035 (GW)

	2025	2030	2035
GB1 – GB2	4.9GW	5.1GW	5.3GW
GB2 – GB3	5.0GW	5.8GW	6.7GW
GB2 – GB4	2.3GW	2.3GW	4.3GW
GB3 – GB4	8.3GW	8.5GW	8.7GW
GB4 – GB5	2.9GW	2.9GW	2.9GW
GB4 – GB6	10.9GW	13.8GW	16.6GW
GB4 – GB7	-	-	-
GB6 – GB7	4.0GW	4.2GW	4.3GW

***Sources**: FTI-CL analysis and NG ESO: Network Options Assessment .*

Applied delays to NOA:
- **Increase in onshore GB Tx capacity assumed to be spread over 10 years, not 5**
- **Incremental bootstrap capacity delayed by 5 years**

Step 2: Define the evolution of demand levels, develop a split between zones and an hourly demand pattern for each zone

Part A: Define demand levels in each category for each zone

GB residual demand

Based on FES baseline demand

GB1 | GB2 | GB3 | GB4 | GB5 | GB6 | GB7

GB industry electrification demand

Based on industry demand

GB EV demand

Based on EV numbers

GB heat pump demand

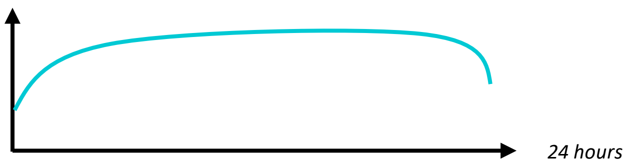
…

GB cooling demand

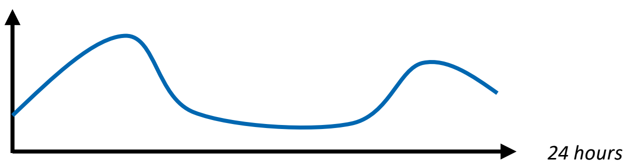
…

Part B: Define demand patterns in each zone

Typical Industrial demand



Typical GB residential demand



For other types of demand (e.g. EV), the same pattern is assumed in each zone and then optimised according to prices based on pre-defined flexibility assumptions.

GB1 residual demand

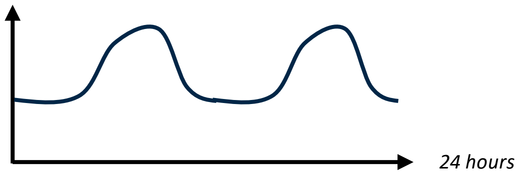
Residential (%)	Industrial (%)

GB2 residual demand

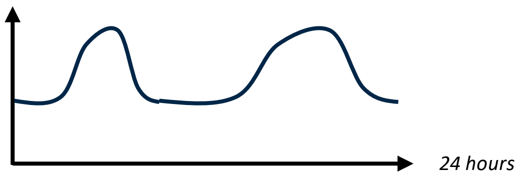
Residential (%)	Industrial (%)

…

GB1 residual hourly demand profile



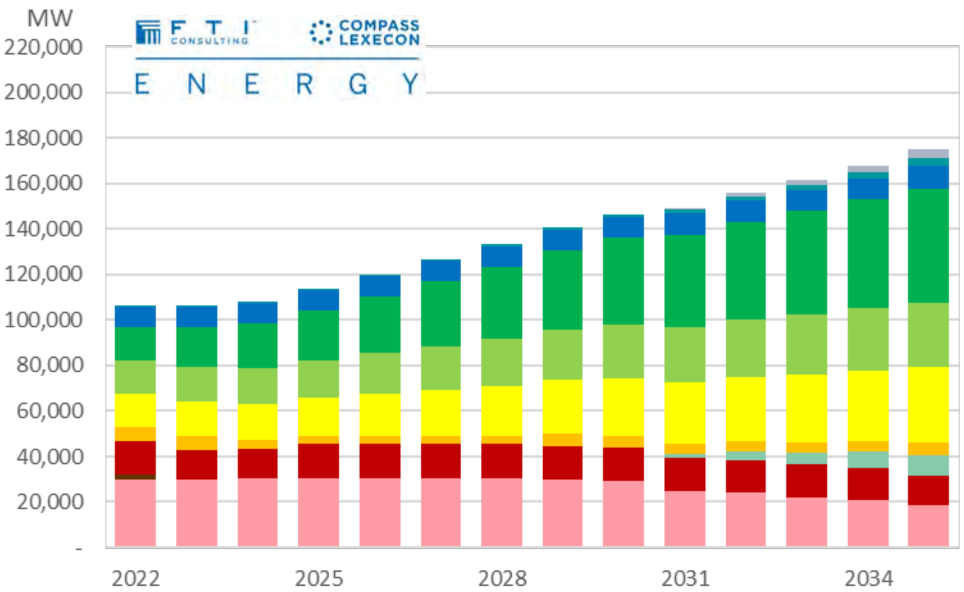
GB2 residual hourly demand profile



The same process is repeated for all zones

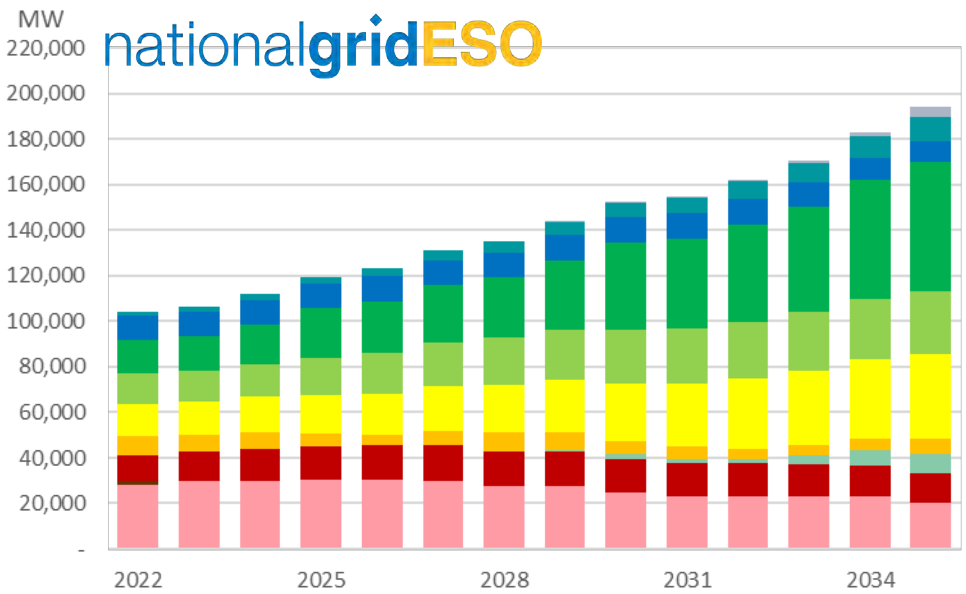
Step 3a: Develop scenario of generation evolution under current market design – our scenario is similar to the FES System Transformation scenario

Total GB capacity (MW), Single national price model



Source: *FTI analysis based on FES2021, DUKES, REPD, Crown Estate*

Total GB capacity (MW), FES System Transformation



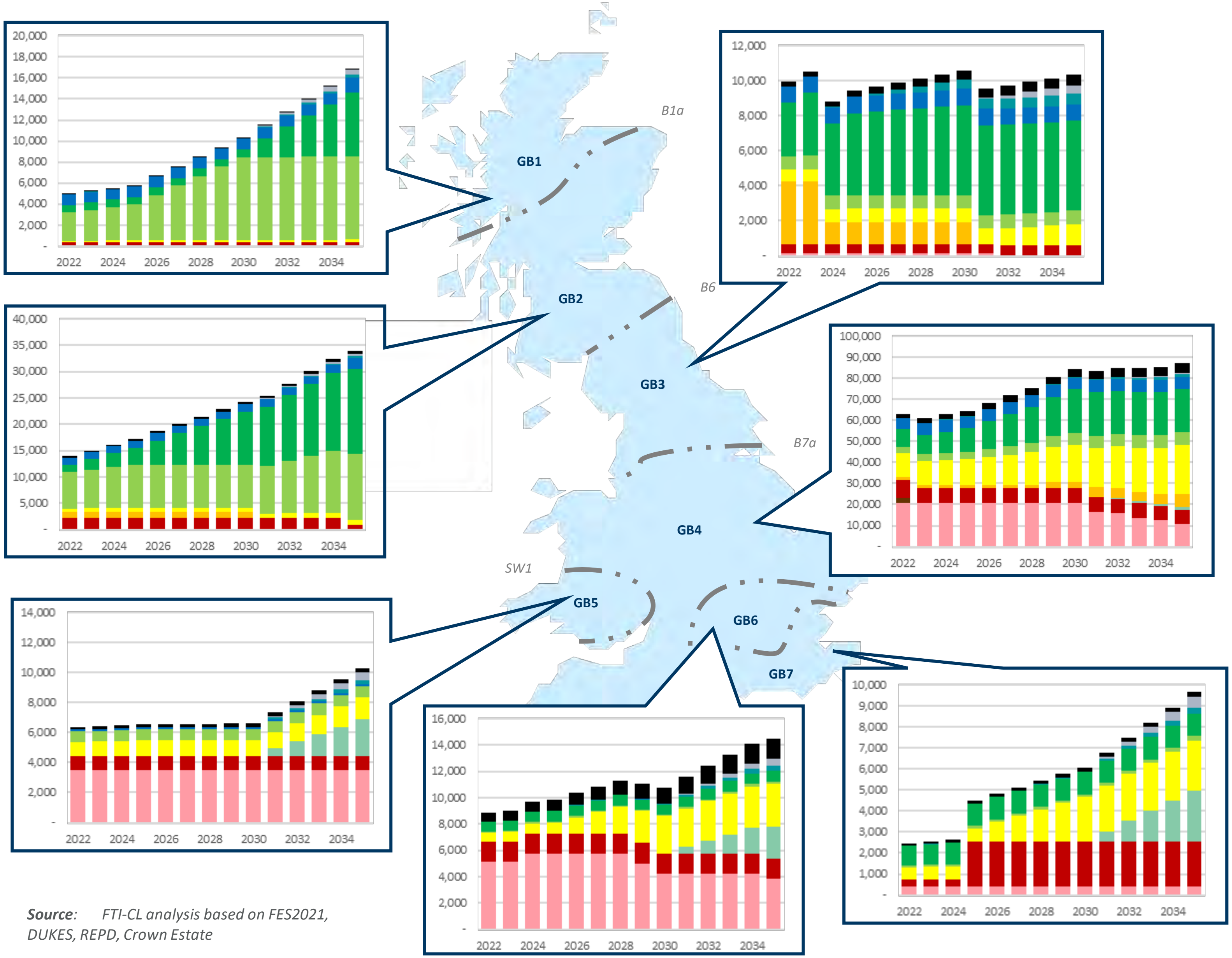
Source: *National Grid ESO: Future Energy Scenarios 2021*

CCGT Coal Other thermal CCS Nuclear Solar Wind (onshore) Wind (offshore) Other renewables Battery P2G

- Capacity evolution modelling (mostly) endogenous given assumptions on capital costs of technologies…
- …broadly consistent with reaching zero carbon electricity system by 2035 (very limited use of CCGT)

- Our results broadly in line with FES System Transformation scenario.
- FES has slightly faster offshore wind and solar roll-out after 2030 and higher battery capacity over the whole period

Step 3b: Allocate generation to each zone under single price market design



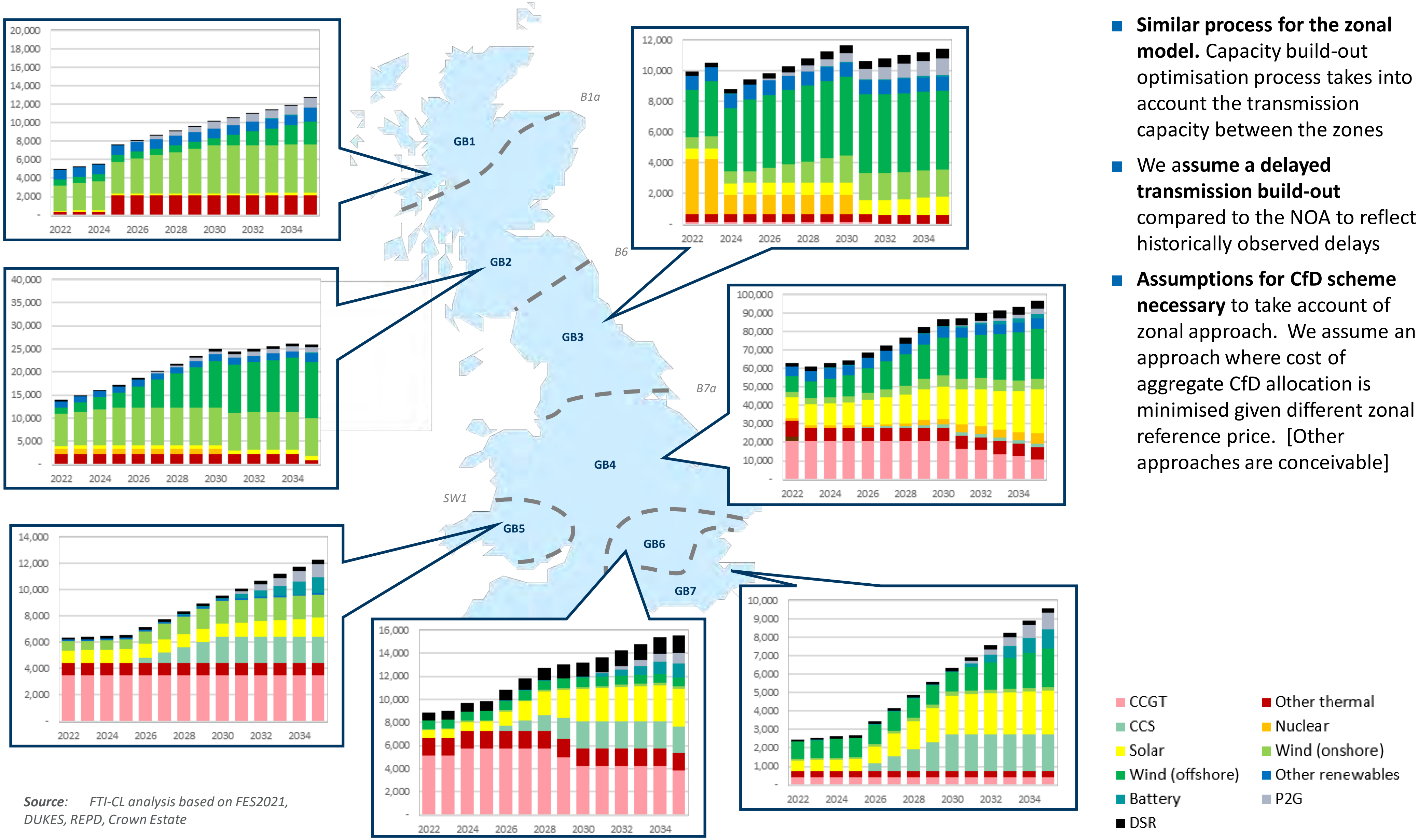
- **Initial allocation** of GB capacity, using public databases (FES, Dukes, Crown Estate, etc)
- **Beyond 2025**
  - build-out across system optimised given capex assumptions, local conditions (e.g. higher wind factors in Scotland, limits on onshore wind in England), and system-wide targets and limits.
  - 2025 - 2030: Build-out for offshore wind fixed - reflects long lead time
- TNUoS impact on siting decision not included….
- ..could refine in subsequent analysis.
- **Cross-checked** against consents and lease options for some technologies (offshore wind generation)

CCGT
Other thermal
CCS
Nuclear
Solar
Wind (onshore)
Wind (offshore)
Other renewables
Battery
P2G
DSR

Source: FTI-CL analysis based on FES2021, DUKES, REPD, Crown Estate

Step 3c: Repeat allocation given zonal pricing and therefore potentially influence on siting decisions…

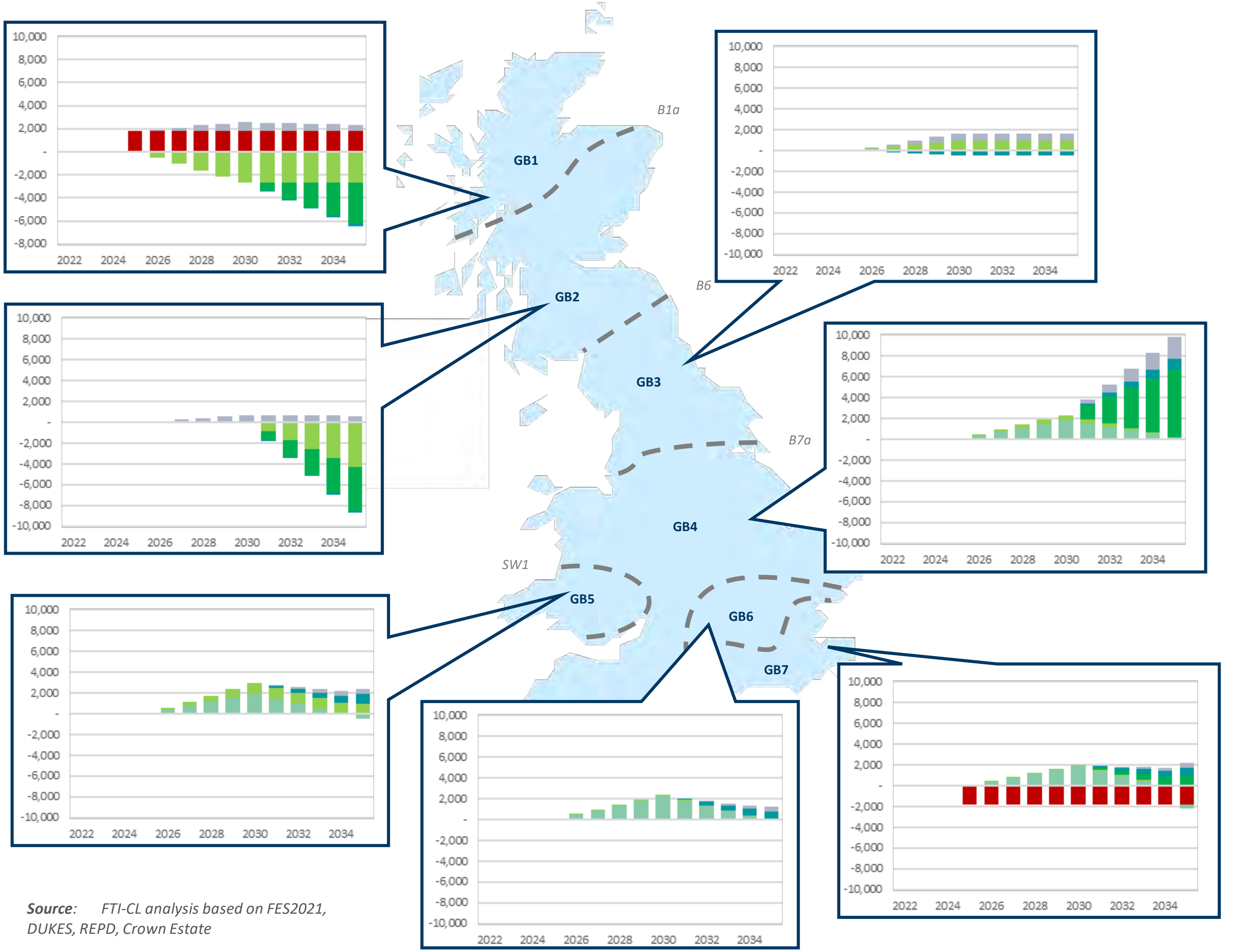
- **Similar process for the zonal model.** Capacity build-out optimisation process takes into account the transmission capacity between the zones
- We assume a **delayed transmission build-out** compared to the NOA to reflect historically observed delays
- **Assumptions for CfD scheme necessary** to take account of zonal approach. We assume an approach where cost of aggregate CfD allocation is minimised given different zonal reference price. [Other approaches are conceivable]



Source: FTI-CL analysis based on FES2021, DUKES, REPD, Crown Estate

Generation capacity

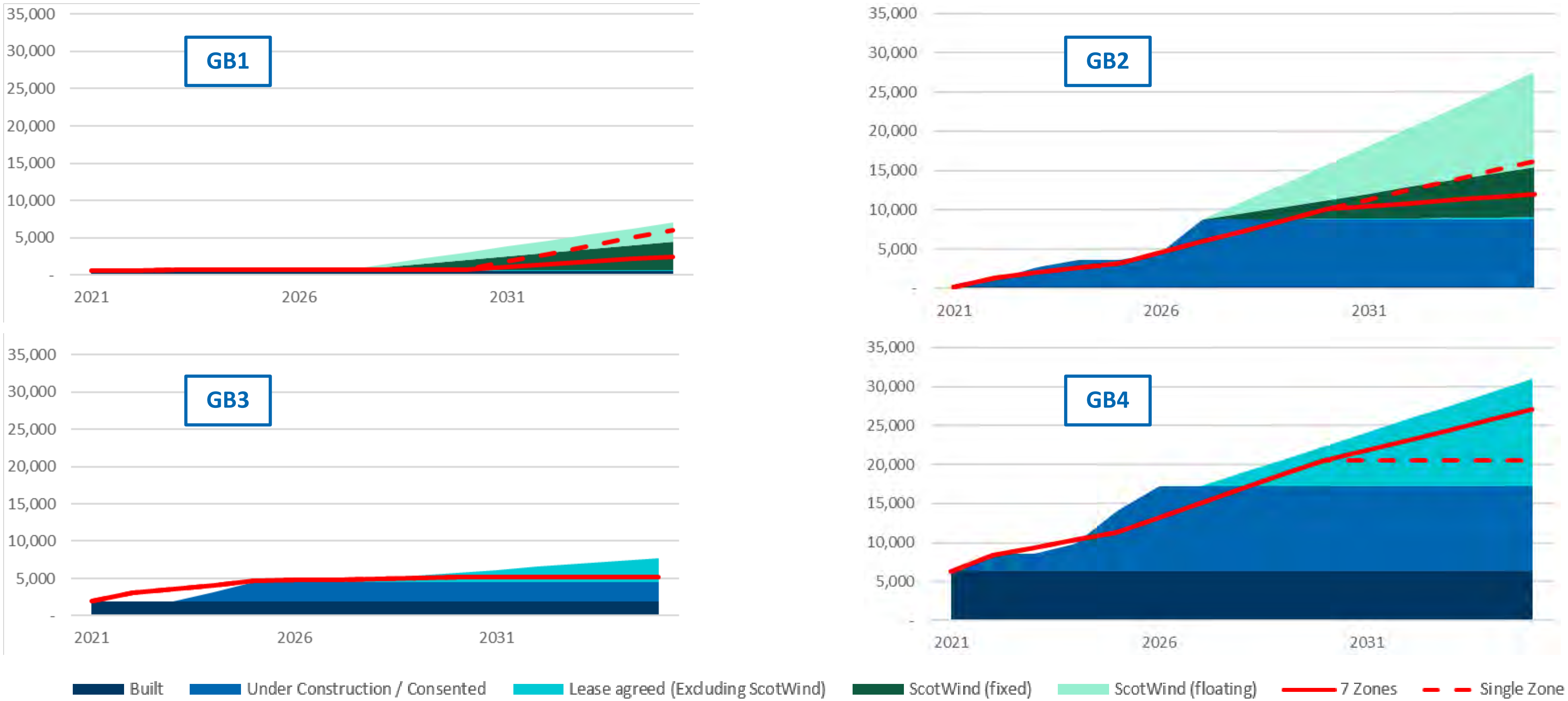
Zonal arrangements lead to relocation of offshore and onshore wind farms and more storage in south



- c7GW of offshore wind farms relocates from the Scottish zone (GB1 and GB2) to mostly GB4
- New onshore wind also lower in Scotland under the zonal scenario,…
- …some of this capacity relocates to GB3 and GB5
- Battery and P2G take-up is higher overall and in most zones in the zonal set-up
- New OCGTs are located in GB1 in the zonal-model instead of GB7 in the single price model

Source: *FTI-CL analysis based on FES2021, DUKES, REPD, Crown Estate*

Step 4: Modelled roll out of offshore wind generation by zone is consistent with policy goals, leasing agreements, lease option areas etc

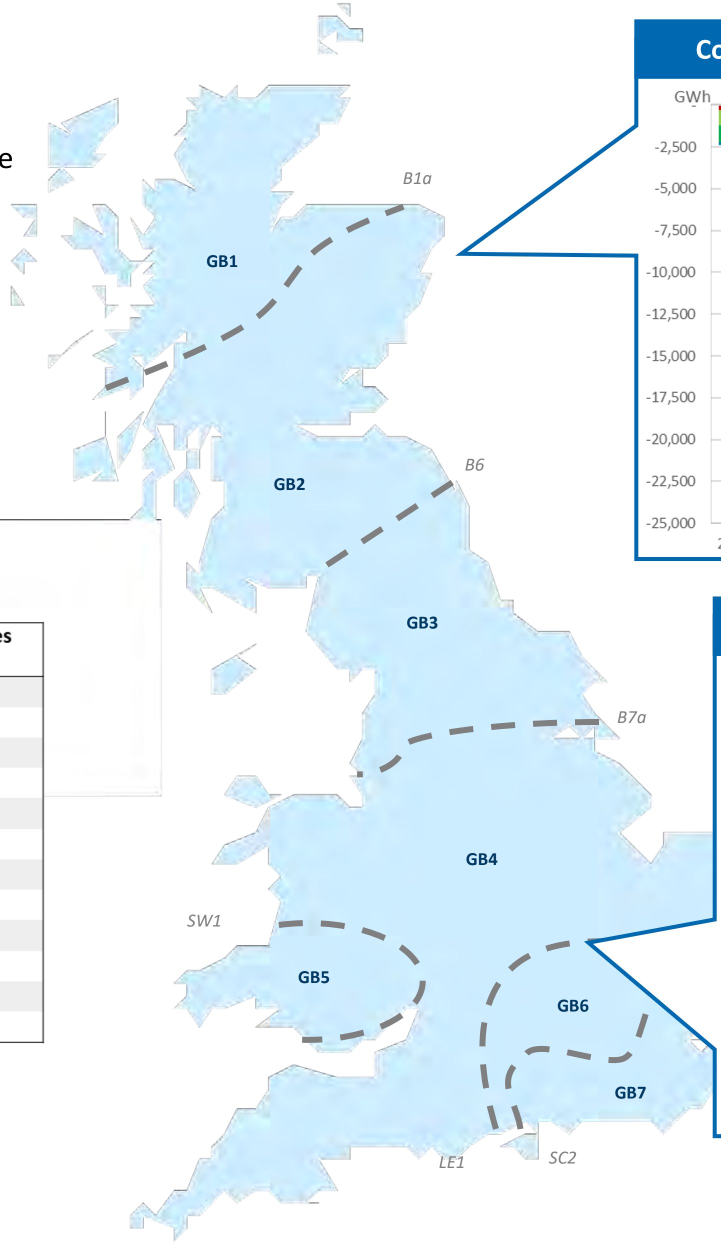


- Assumed wind capacities in consistent with with planned roll out and other commitments e.g ScotWind

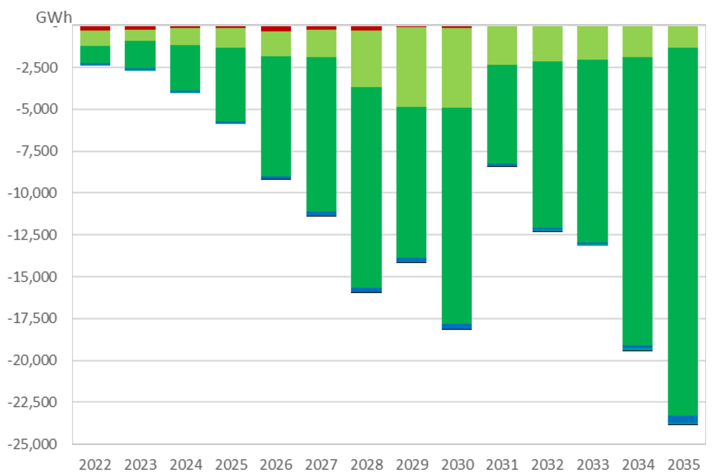
Our estimate of congestion is another cross-check

- Forecast congestion volumes and costs
- Our BM price estimates are based on the **average accepted bid/offer price for each technology in 2021**
- Bid and offer values are based on comparable technologies due to data limitations..
- …bid and offer prices are also likely to evolve over the period (e.g. in line with gas prices for some technologies)
- Potential refinement in further analysis

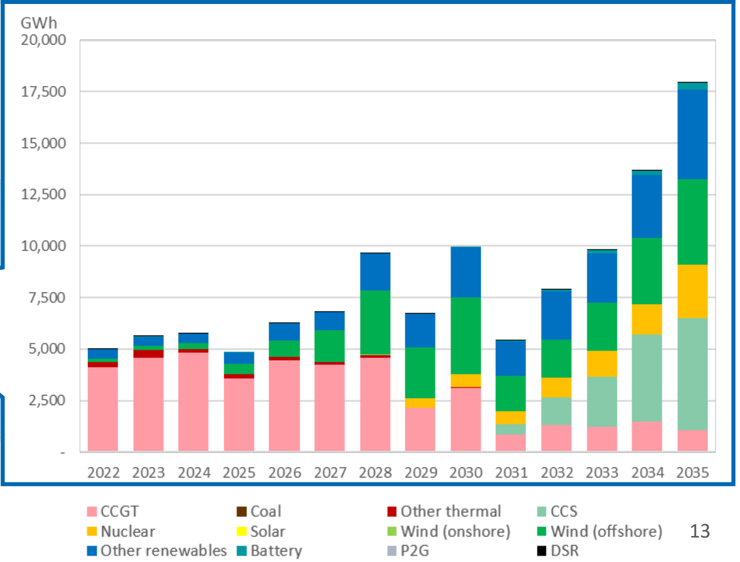
	BM bid prices(£/MWh)	BM offer prices (£/MWh)
CCGT	49	181
Coal	75	435
Other thermal	49	181
CCS	49	181
Nuclear	-50	0
Solar	-50	0
Wind (onshore)	-68	3
Wind (offshore)	-68	27
Other renewables	10	136
Battery	111	341
P2G	75	300
DSR	150	2000



Constrained-off generation in GB1 and GB2 (GWh)



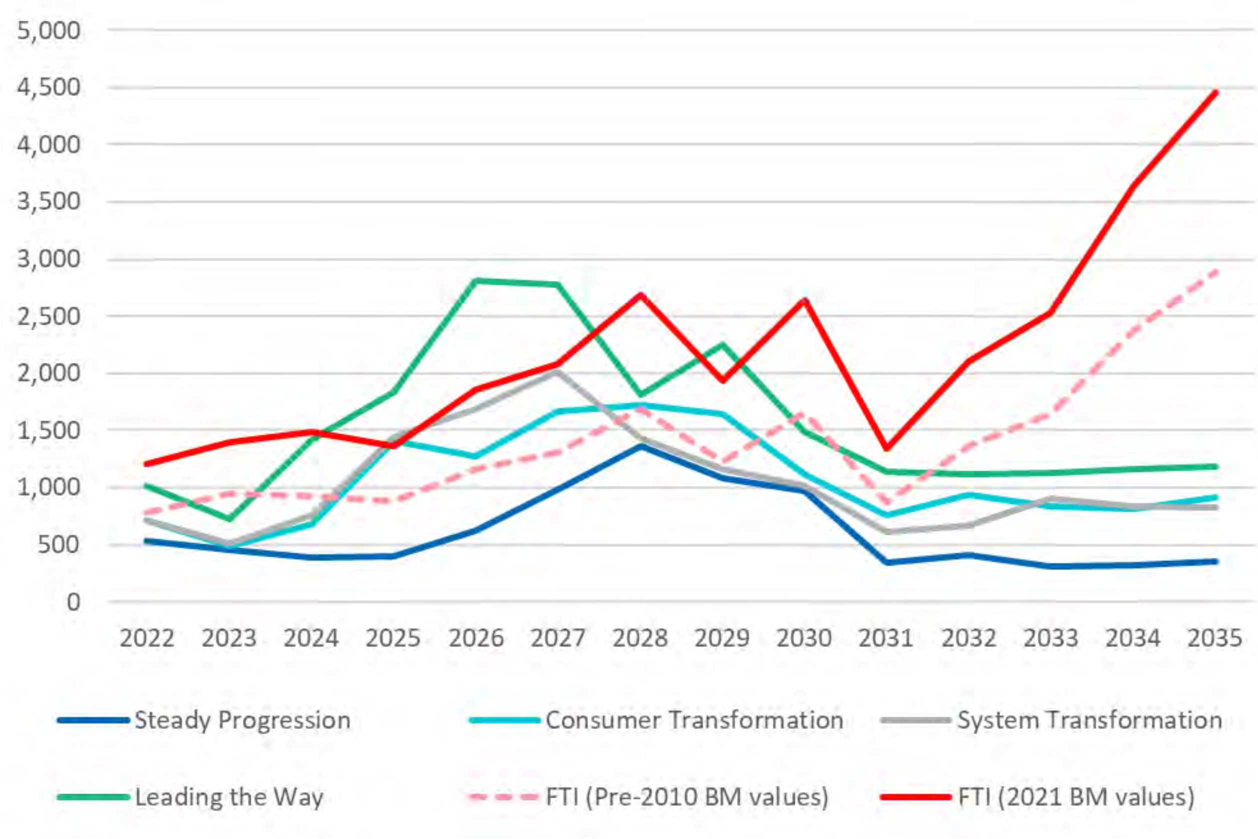
Constrained-on generation in GB3-GB7 (GWh)



Note: The difference between constrained-off and constrained-on generation shown reflects a different level of net imports into GB.

FTI constraint cost estimates are in line with NG ESO's FES scenarios until 2031 and exceeds it from 2032 onwards

Comparison of constraint costs scenarios (€ millions)



***Source**: National Gird ESO, NOA 6 and FTI-CL analysis*

- Our estimated constraint costs are **close to the higher end of the NOA 6 estimates between 2022- 2031 …**
- **….but exceed NOA 6 forecasts from 2032,**
- **Likely driven by higher volumes of wind generation in Scotland relative to volume anticipated a year ago**
- According to **public statements by ESO, NOA 7** congestion cost forecasts will likely be higher than NOA 6
- Our estimates are also sensitive to the BM prices used in the analysis. [Potential refinement]
- The overall constraint cost under the single zone model have an **NPV of €22.9bn at least based on estimates using 2021 BM bid/offer data.**

Modelling results: Detailed consumer impact analysis

We measured the total costs/benefits of locational pricing to the GB consumers using four components

Change in wholesale cost to consumers

- Difference in wholesale costs paid by consumers for electricity between the zonal and single price model
- Given, in each hour, by *wholesale price (€/MWh) x load (MWh)*

- Reduction in costs incurred by System Operator to manage congestion – but ultimately borne by consumers

Calculated for each zone separately

+

Intra-GB congestion rents

- Congestion rents earned on GB boundaries, retained by transmission owners, assumed to be returned to consumers via reduced bills

+

Change in CfD payments

- The difference in CfD payments to generators each year as a result of moving to a zonal price model

+

Change in the annualised costs of new transmission

- The change in the cost of new transmission built, annualised…
- …on a €/MW basis with reference to the cost of planned transmission projects published by NGET

Aggregate benefit, allocated pro-rata per total annual MWh demand

Pro-rating of change in transmission costs is an approximation. Given locational TNUoS on demand, the impact on GB consumers would actually vary slightly by region. For simplicity, we have not taken this regional effect into account at this stage

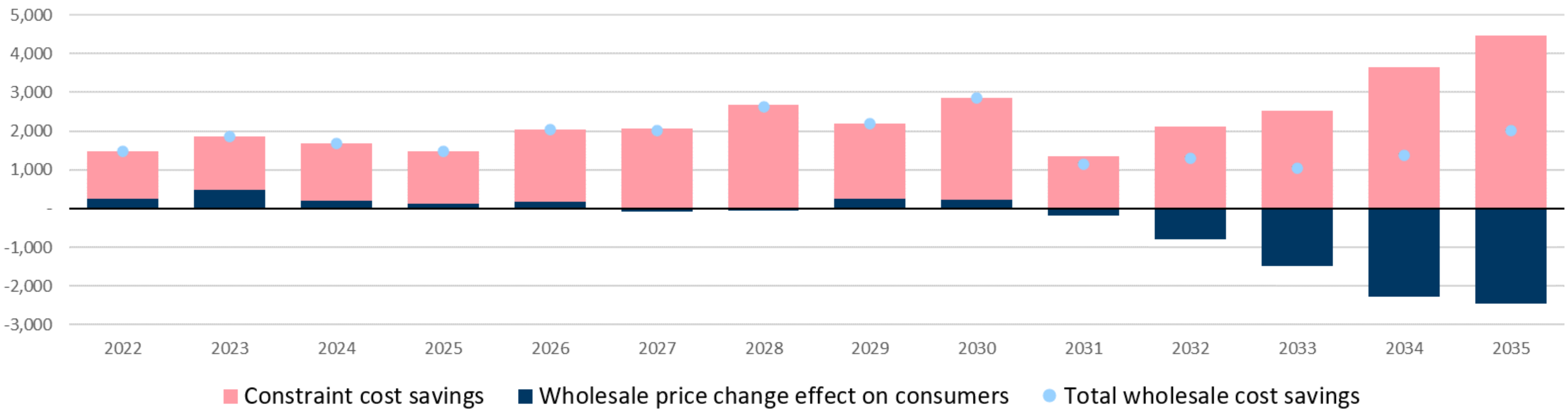
Under our input assumptions, price differentials between the zonal and national models persist in most zones into 2035

GB wholesale prices, Delayed bootstraps and onshore transmission scenario, 2025 – 2035 (€/MWh)

- In general, GB wholesale prices fall over time, likely due to an expected fall in gas prices and increased RES penetration
- In all modelled years, northern GB zones face a lower wholesale price under the zonal model, relative to the single price model (and vice versa for the southern GB zones)

In aggregate, consumers would, under this scenario, have reduced wholesale costs under a zonal model, as a result of savings on constraint costs

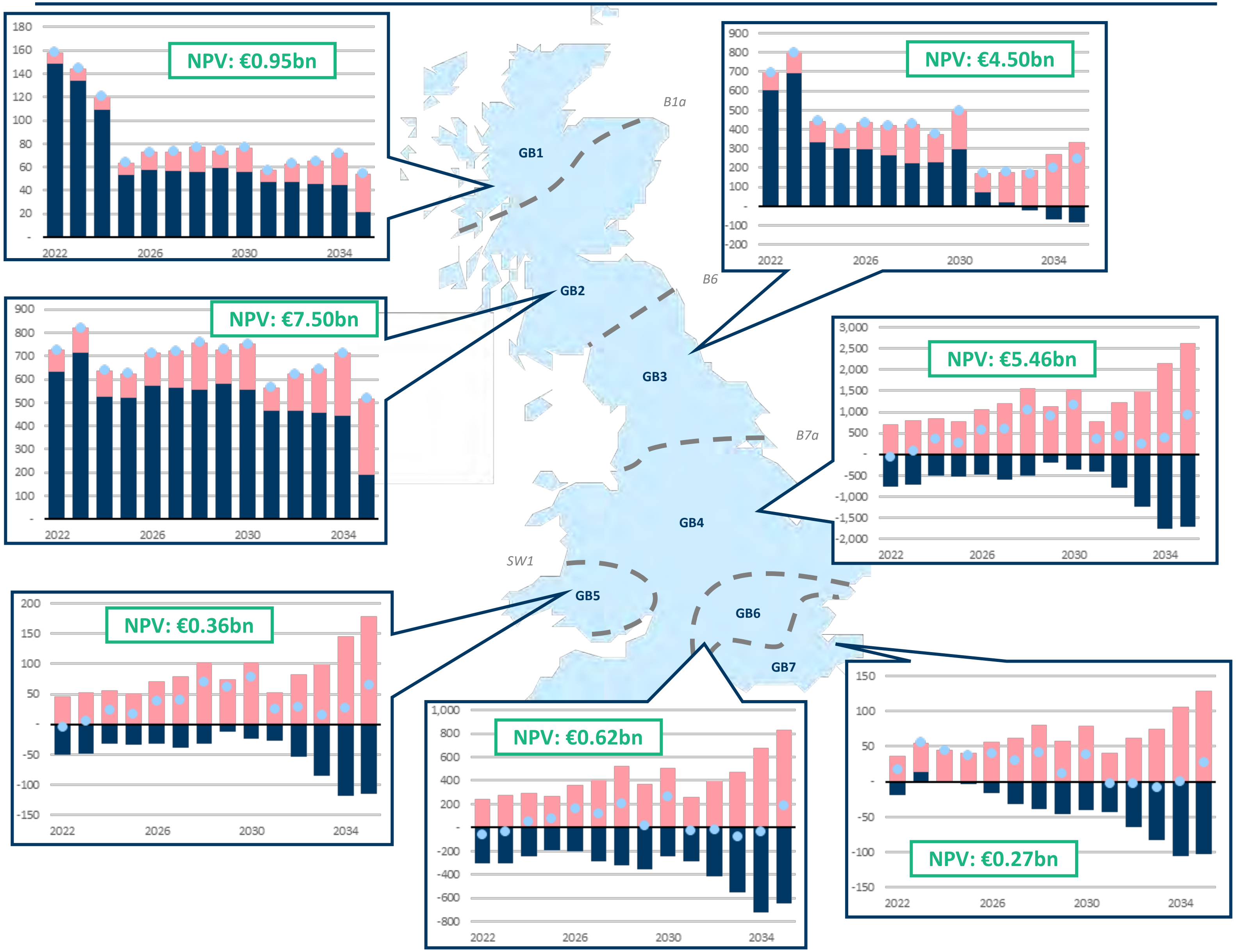
Wholesale savings for consumers – GB total, 2022 – 2035 (€ millions)



- **In the early years,** wholesale price effects broadly neutral in aggregate – northern price decreases offset by southern price increases (on volume weighted basis
- **From 2032**, the effect on southern zones starts to be larger than the effect on northern zones…
- ….as southern BM generators now reflected in wholesale market price
- But in aggregate**, consumer benefit from reduced congestion costs outweighs wholesale price effect**

Northern zones experience material wholesale costs savings over the modelling period, while the effect for southern zones is marginally beneficial

Effect on GB customers (€ millions)

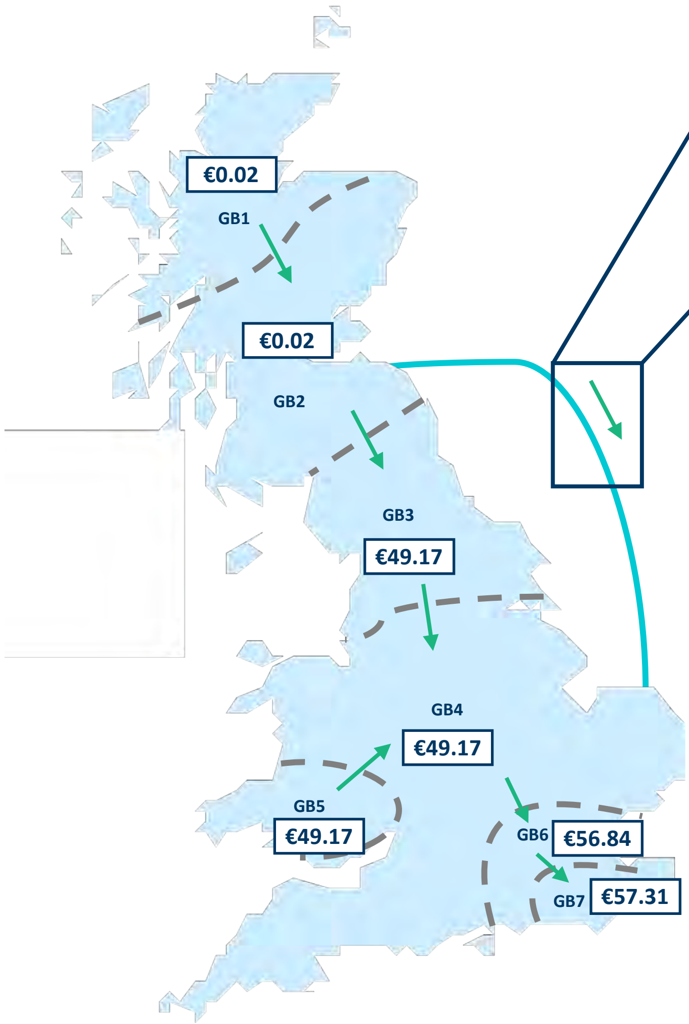


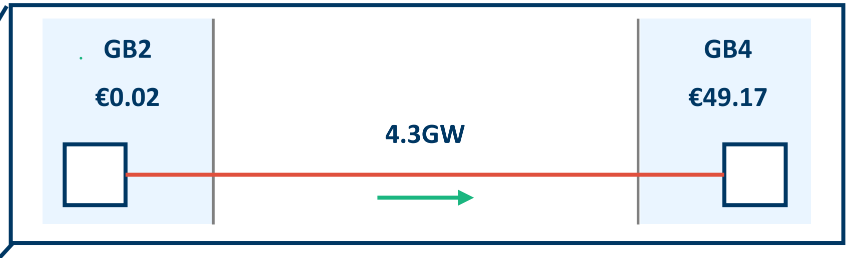
- **Customers in all zones experience wholesale cost savings from a move to zonal market design**
- In **northern zones,** the reduction in wholesale prices is the biggest driver behind net benefits to consumers
- In the **southern zones**, effect of increased wholesale prices is offset by corresponding reduction of constraint costs. Overall, consumers are better off in these regions as well.

Constraint cost savings
Wholesale price change effect on consumers
Total wholesale cost savings

Transmission owners would earn congestion rents, based on the wholesale electricity price differential between the two price zones they are connecting

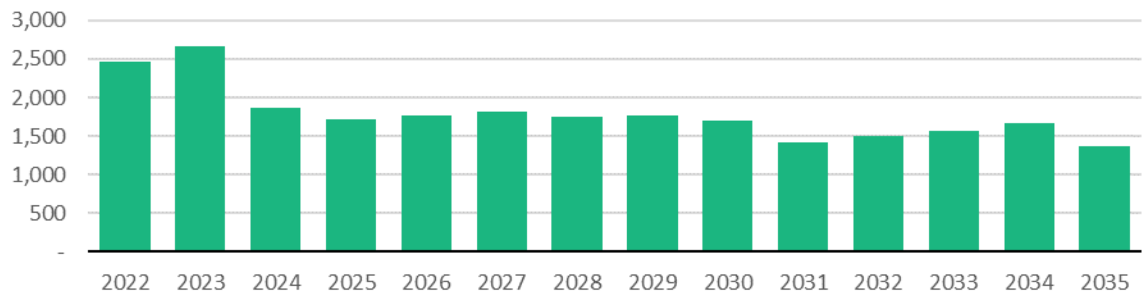
2035 December 6, 17:00





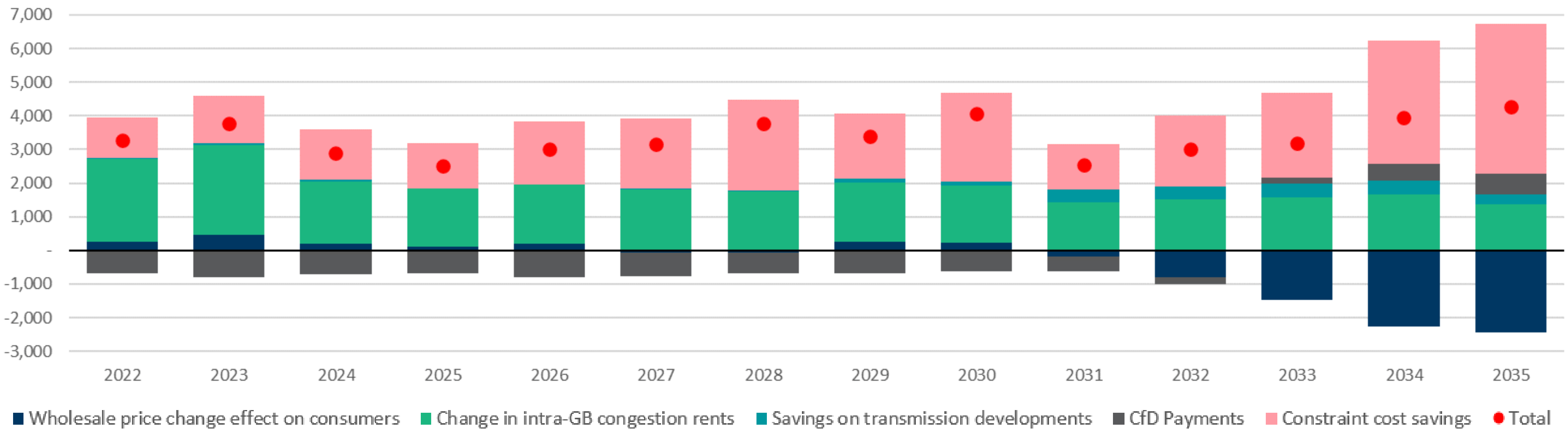
- Suppose, in a **given hour**:
  - The **wholesale price** of electricity in **GB2** is **€0.02/MWh**;
  - The **wholesale price** of electricity in **GB4** is **€49.17/MWh**; and
  - There exists **interconnection capacity** of **4.3GW** connecting GB2 and GB4.
- Assuming no losses, in settlement, this results in a rent of €211,345 (4.3GW*€49.15/MWh) in this hour.
- We refer to these revenues as **congestion rents and arise on all zone boundary.**
- The rights to these rents are so-called "financial transmission rights"....
- ....they are equivalent in concept to congestion rents in **interconnectors**
- For most of the modelling period, congestion rents are c. €1-1.5bn per year

Intra-GB congestion rents (€millions)



In aggregate, locational pricing has a positive effect on GB customers in all modelled years, due to intra-GB congestion rents and reduced constraint costs

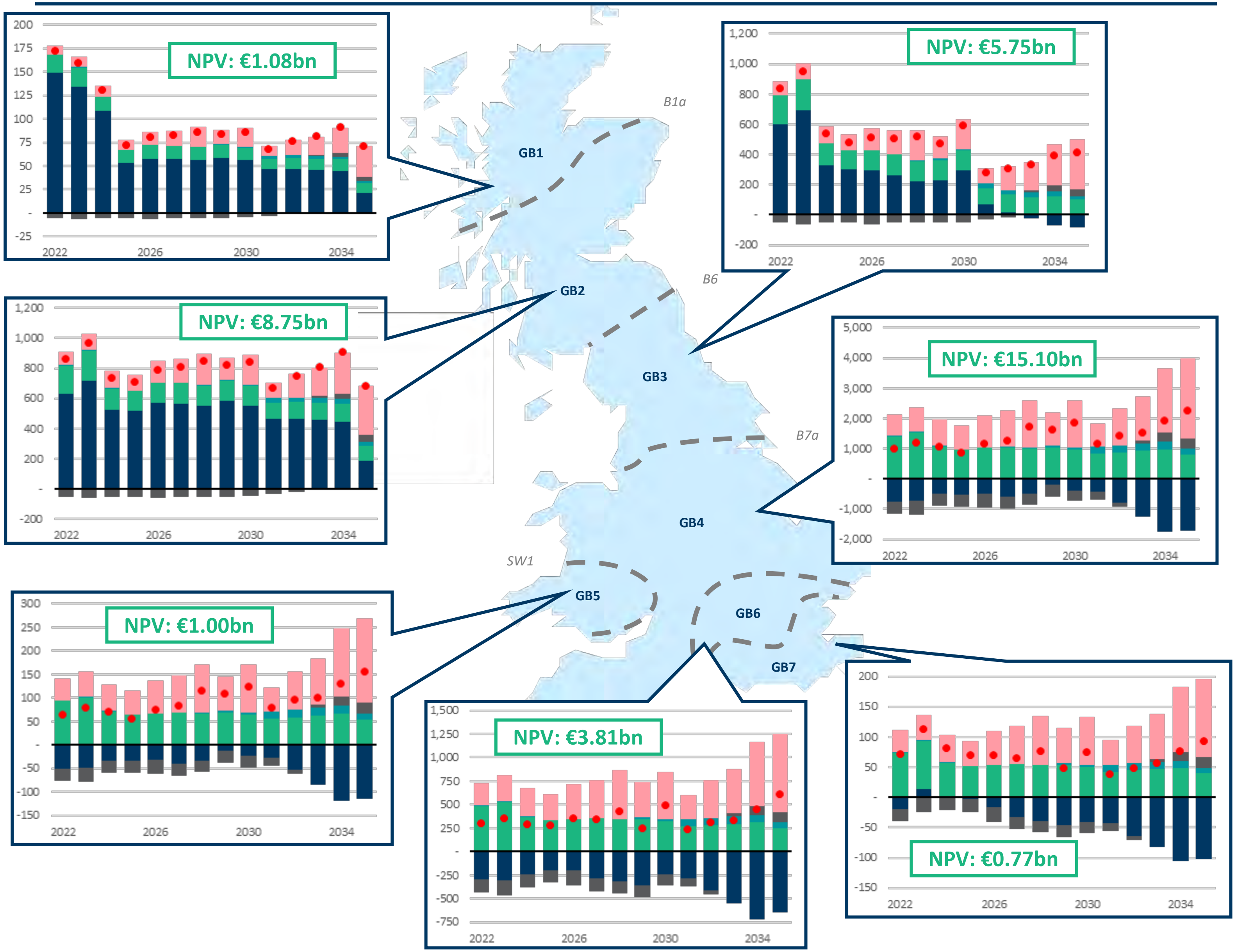
Total effect on GB consumers, 2022 – 2035 (€ millions)



- Also modelled resulting change in CfD payments as a result of change in wholesale prices [Net negative effect of €5bn]
- The overall effect on GB customers between 2022-2035 is positive and has an **NPV of €36.3bn.** The two main positive components of the effect are:
  - The **reduction in constraint costs (€22.9bn)**; and
  - The **creation of intra-GB congestion rents (€20.0bn)**
- Savings on the transmission developments also effect customers positively (€1.6bn)
- Fluctuations over time driven by timing of transmission investments reducing constraints for short periods

In aggregate, GB consumers save €36.3bn – although allocation of benefits varies by region

Effect on GB customers (€ millions)

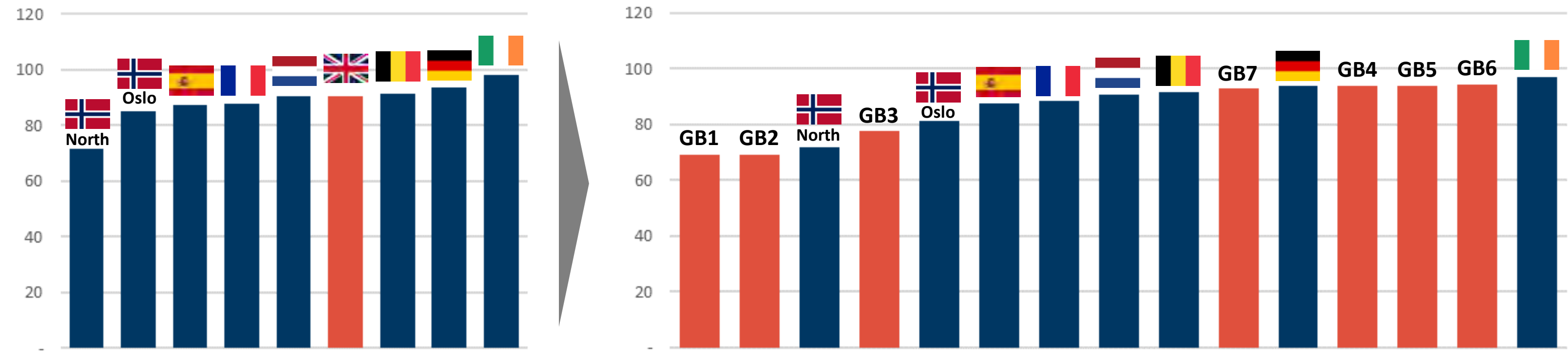


- Savings to GB consumers have been allocated to each zone **based on MWh demand**.
- **Customers in all zones can benefit from a move to zonal market design**
- In northern zones the reduction in wholesale prices is the biggest driver behind net benefits to consumers
- In the southern zones, the effect of increased wholesale prices is offset by intra-GB congestion rents and reduction of constraint costs. Overall, consumers are better off in these regions as well.

Constraint cost savings
CfD Payments
Savings on transmission developments
Change in intra-GB congestion rents
Wholesale price change effect on consumers
Total

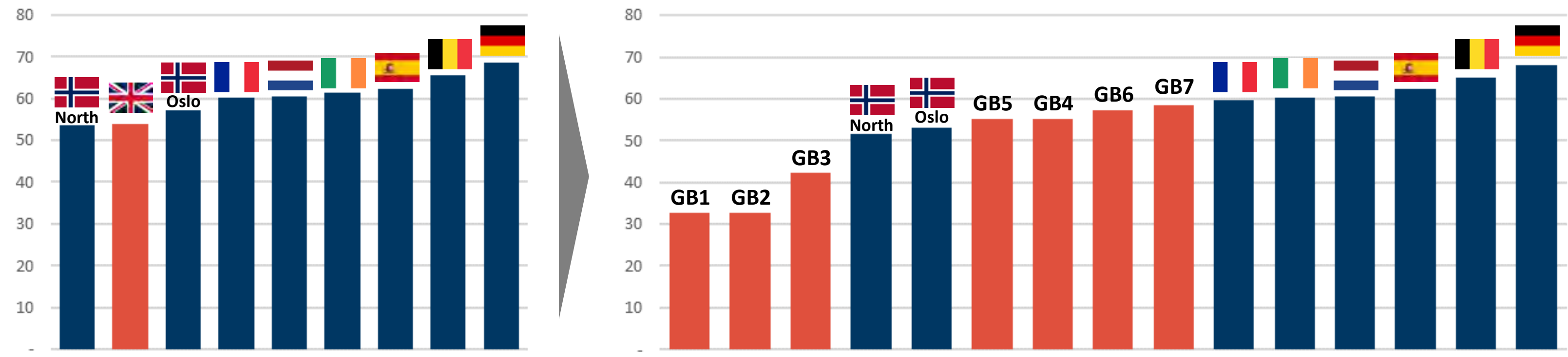
Under this scenario, moving to zonal market makes wholesale price in Scotland comparable with Northern Norway and cheapest in Western Europe by 2030

Annual average price under the single and the zonal model, 2025 (€/MWh)



- In 2025, the GB national price is around the average of comparable Western European prices
- By moving to a zonal model, prices in **GB1, GB2 decrease below prices in other countries**
- …while prices in other GB zones **remain similar to Western European prices**

Annual average price under the single and the zonal model, 2030 (€/MWh)

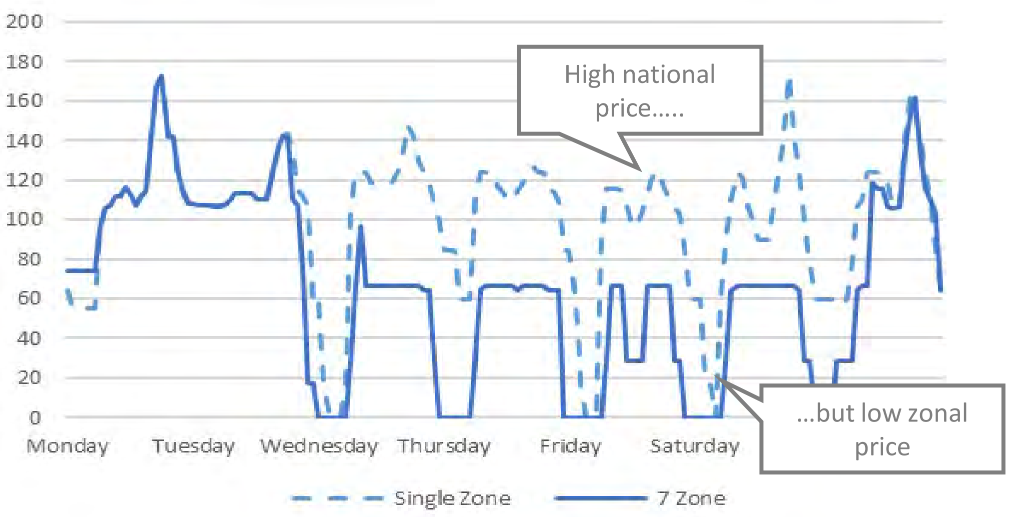


- By 2030, the GB national prices decreases to become as cheap as in North Norway due to major wind expansion
- Moving to a zonal **modal reduces prices in GB1, GB2 and GB3 further…**
- …while prices **in other GB zones remain among the cheapest in Western Europe**

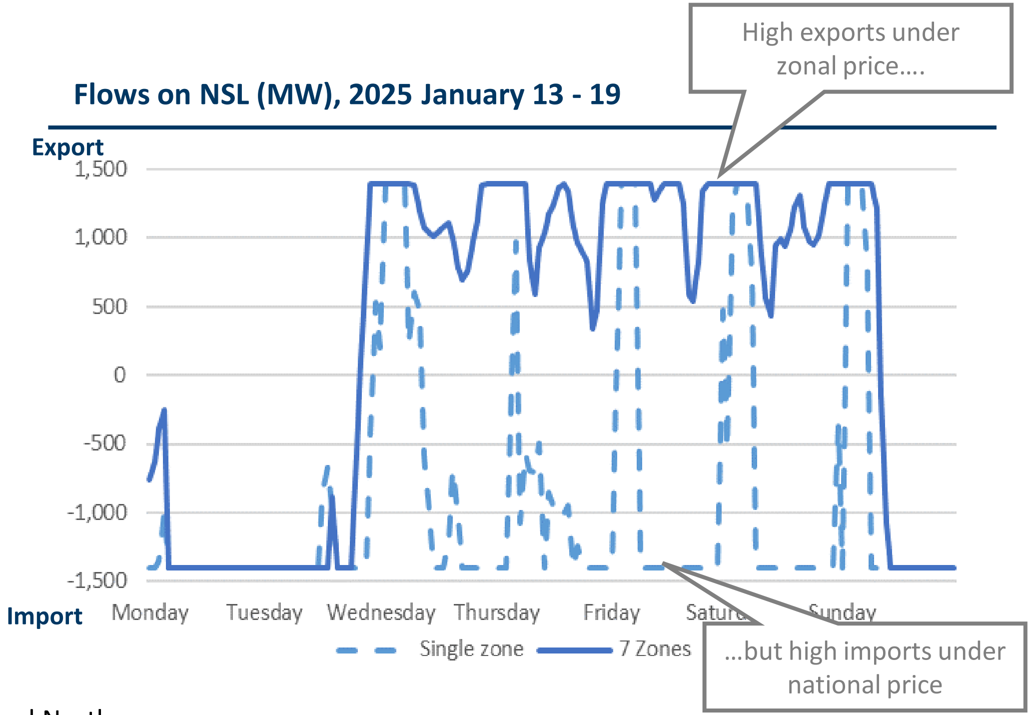
…. could be important in considering demand portability (e.g. siting decisions of data warehouses, hydrogen reformers etc) – not captured in analysis here

ESO concern regarding two ways assets (e.g. ICs) appears well placed and potentially mitigated by zonal pricing

GB3 prices (€/MWh), 2025 January 13 - 19



Flows on NSL (MW), 2025 January 13 - 19



- **Under the zonal model, NSL can export the excess wind generation** from Scotland and North England to Norway….
- **..whereas national price exacerbates congestion as NSL imports**
- Under this scenario, zonal pricing **leads to a 20% decrease in imports and 29 % increase in exports on NSL in 2025**

Annual imports and exports on NSL in 2025

	Import	Export
Single GB Price	6.96TWh	4.06TWh
Zonal Price	5.51TWh	5.23TWh
Difference	-1.45TWh	+1.17TWh

Full cost benefit analysis will require additional areas of analysis

Key areas still to be considered	• Other **benefits** (e.g. demand portability)… • Implementation costs (Central and participant) • **Potential impact on risk exposure for participants – e.g. Cost of capital** impacts…. • **…..relative to policy stance in other areas** (e.g. Capacity Market and CfDs) and **mitigation/transitional** measures
Model refinements….	• Analyse impact through a **full nodal market model** • Test model under **different scenarios and sensitivities** (amending supply, transmission and demand assumptions) • Other input assumptions (TNUoS impact)
Benefits to customers from two areas…	• **Efficiency benefits** from improved siting and despatch • **Transfers between stakeholders** as a result of changes in access rights (e.g. constrained off generators no longer compensated; some generator rents captured in congestion rents)
…but likely need to consider transitional / mitigation measures	• **Measures to mitigate transfers (**e.g allocation of congestion rents to some stakeholder cohorts rather than consumers) likely to need to be evaluated.. • …but will come at **cost of diluted consumer benefits**
Conscious that very contentious issue	• **Strongly held beliefs** on both sides of market design debate • **Possibility of material financial transfers** between stakeholders cohorts

In this context benefits and costs need to be assessed as <u>transparently and objectively</u> as possible

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