Presentation to stakeholders – Workshop 2

Preliminary modelling results

FTI Consulting | Ofgem

FTI Consulting ENERGY | Compass Lexecon

ofgem

30 August 2022

Internal Only

Glossary

AR	Allocation Round
BEIS	Broad Measure of Customer Service
BM	Balancing Mechanism
CAISO	California Independent System Operator
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation and storage
CfD	Contract for Difference
CoC	Cost of Capital
DSR	Demand Side Response
DUKES	Digest of UK Energy Statistics
ENTSO-E	European Network of Transmission System Operators for Electricity
ERCOT	Electric Reliability Council of Texas
ESO	Electricity System Operator
ETYS	Electricity Ten Year Statement
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FES	Future Energy Scenarios
FiT	Feed-in-Tariff
FTR	Financial Transmission Right
GSP	Grid Supply Point

H2	Hydrogen
IC	Interconnector
IESO	Independent Electricity System Operator
IRENA	International Renewable Energy Agency
ISO-NE	Independent System Operator New England
LMP	Locational Marginal Price
LtW	Leading the way
MBIE NZ	Ministry of Business, Innovation and Employment New Zealand
MPs	Market Participants
NOA	Network Option Assessment
NYSO	New York System Operator
PEMMDB	Pan European Market Modelling database
REMA	Review of Electricity Market Arrangements
ROCs	Renewable Obligation Certificate
SPP	Southwest Power Pool
TGCs	Tradable green certificates
TNUoS	Transmission Network Use of System
SPP	Southwest Power Pool
WACC	Weighted Average Cost of Capital
WIP	Work In Progress
WPD	Western Power Distribution

Agenda for today's workshop

Welcome, purpose of session	13:00 – 13:05	5 mins	ofgem
Recap of project scope, objectives and wider context	13:05 – 13:15	10 mins	ofgem
Session 1: Methodology and assumptions update	13:15 –13:30	15 mins	FTI Consulting
Session 2: Preliminary capacity build-out results	13:30 –13:50	20 mins	FTI Consulting
Q&A	13:50 – 14:00	10 mins	FTI Consulting, ofgem
BREAK	14:00 – 14:10	10 mins	
Session 3: Preliminary price and consumer impacts	14:10 – 14:50	40 mins	FTI Consulting
Session 4: Cost of capital and liquidity	14:50 – 15:05	15 mins	FTI Consulting, Catapult Energy Systems
Q&A	15:05 – 15:20	15 mins	FTI Consulting, ofgem
Wrap up, thanks and next steps	15:20 – 15:25	5 mins	ofgem

Welcome

Re-cap on scope

Since our last session, the UK Government has published its first Review of Electricity Market Arrangements consultation. This considers a wide range of options for updating GB electricity market arrangements to meet our 2035 target – decarbonisation of our power sector by 2035.

Alongside providing advice on the case for change and full suite of options, we are undertaking an assessment of zonal and nodal market design for GB.

Approach

1. Identify (i) simplified market designs to model and (ii) how these markets could operate in GB
2. Economic modelling to provide a quantitative benefits analysis of different market designs
3. Assess likely implementation requirements and costs
4. Distributional impact assessment and potential mitigations (and impact on benefits)

Outcomes

System modelling and analysis:

1. Supports BEIS decision-making on whether zonal and nodal market design should be short-listed for further consideration
2. Advances sector-wide market reform debate and capability in considering reform options

Timeline

March: FTI / Catapult project kick-off with Ofgem

26 May: First stakeholder session on modelling methodology, assumptions, and policy interactions

01 June: Workshop summary and Call for Input published (closed 26 June)

07 July: Holistic Network Design published

18 July: REMA consultation published

18 July: FES 2022 published

25 Aug: FAQ published online

Today: update on the modelling methodology, interim results (based on NOA6), approach to cost of capital and liquidity

Planning for 2-3 further workshops ~ Oct-Nov covering:

- Zonal and nodal market designs and policy interactions
- Updated modelling results (based upon NOA7 refresh)
- Analysis on mitigations and transitional measures, distributional impacts and market participant risks

Decision to include HND as part of modelling exercise pushes original timeline to the right

Housekeeping

- Focus for today’s session is an **update on the modelling methodology, presentation of some preliminary results, the cost of capital** and **liquidity**
- **Different format to last session –** presentation and Q&A as opposed to small break-out groups and discussion
- Attendees are welcome to use the **chat function for clarification questions**– we don’t plan to respond to questions during the presentations but instead seek to address at the end of each session
- **Chatham House Rule** – if we publish an overview of key discussion points, views will not be attributed
- **Break** at 14:00 for 10 mins

Today’s workshop will be delivered by Ofgem’s Wholesale Market Reform Team supported by FTI Consulting and ES Catapult

Jason Mann
Project Director

Joe Perkins
GB policy expert

Martina Lindovska
Modelling expert

Ljubo Mitrasevic
Project manager

Scott Harvey
US market expert

Susan Pope
US market expert

George Day
Project Partner

Nicole Tan
Project team

Joe Proffitt
Project team

Methodology and assumptions update

In the May workshop, we discussed a range of options for locational granularity and the plausible range of modelling scenarios

Locational granularity

National market	Zonal market	Nodal market

Proposed Modelling scenarios

Scenario 1: Leading the Way

Scenario 2: System Transformation

In this workshop, we will be presenting our emerging results on the impact of locational wholesale pricing **across all three market designs.**

The results presented today **reflect one FES 21 scenario (Leading the Way)**, covering the period from **2025 to 2040**.

The assessment presented today does not include:

- 8 out of 44 NOA7 Projects are not in the model - awaiting data from the ESO
- Holistic Network Design assumptions;
- The System Transformation FES 21 scenario;
- The remainder of the modelling period (2041-2050); and
- Sensitivity analysis.

Key inputs

1 Transmission capacity

Includes current & future network topology, and seasonal availability assumptions

2 Demand

Includes annual demand, profile and flexibility assumptions by type and location

3 Generation capacity

Includes build-out assumptions, plant technical characteristics and renewable capacity profiles

4 Commodity prices

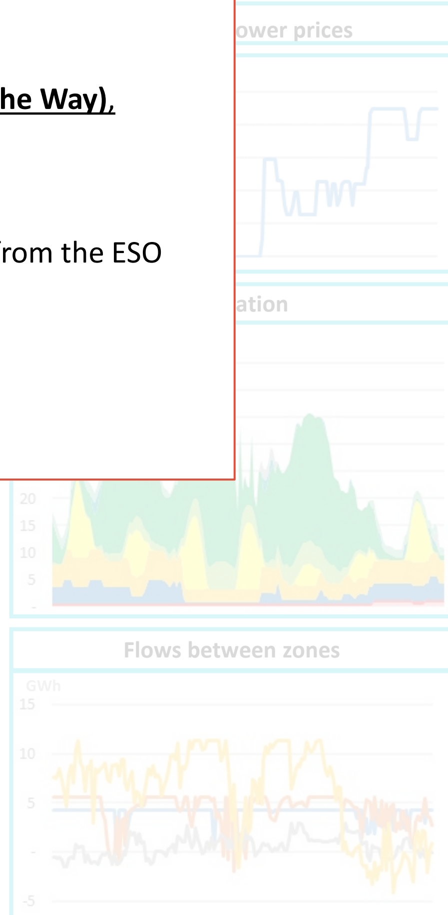
Includes price projections for a set of commodities (CO2, gas etc)

Short Term Dispatch Model

Takes capacity from the Long Term model as given and determines the optimal output of generation (GWh):

- Finds the least-cost dispatch profile of generation…
- …that meets demand…
- …on an hourly basis…
- …for each generating plant…
- …for each price zone

…ts for each …d year



5 *Additional quantitative analysis*

Internal Only

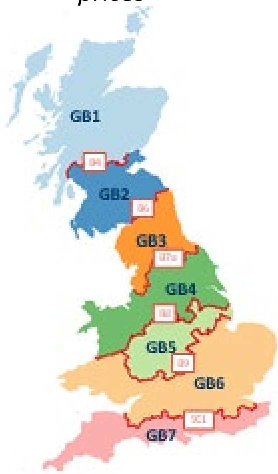
Today's presentation focuses on a subset of the full quantitative and qualitative impacts of more granular locational pricing

Type	Effect	Covered today
Short-run impact *(Operational)*	**Changes in wholesale prices** (lower in export-constrained areas and higher in import-constrained areas)	✓
	Reduced cost of congestion to be borne by consumers	✓
	More efficient dispatch across all resource types including **flexibility resources**	✓
	Surplus revenues from congestion rent (and losses)	✓
	Operational impacts from central dispatch system relative to the BM	
Long-run impact *(Investment)*	Greater price signals to incentivise **generation and storage to site** at more efficient locations	✓
	Greater price signals to incentivise **demand to site** at more efficient locations	
	Improved signals for **transmission development** (due to transparent wholesale prices between different nodes)	
Costs / Other	Changes to **CFD payments**	
	Other **policy interactions**	
	ESO system implementation costs	
	Market participant costs	
	Changing **risk profiles** of market participants including **financing cost**	✓ Qualitative

Recap: Overarching approach is to divide GB market into a number of zones or nodes, overlaid on European market model to assess relevant impacts

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

Single national price	Zonal pricing	Nodal pricing
Uniform price clears across entire market	*System divided into **seven** zones with individual prices*	*System divided into c **850** "nodes" with individual prices*



Weaker locational signals → *Stronger locational signals*

Since May we have updated and provided further detail on **(1) transmission, (2) demand, and (3) generation capacity** assumptions

Locational granularity

National market | Zonal market | Nodal market

Proposed Modelling scenarios

Scenario 1: Leading the Way

Scenario 2: System Transformation

Key inputs

1 Transmission capacity

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4 Commodity prices

Includes price projections for a set of commodities (CO2, gas etc)

Updates provided today

Power Market Model PLEXOS

Long Term Capacity Expansion model

For the zonal and nodal market designs only – the LT model determines the optimal evolution of generation capacity (GW):

- Finds the lowest-cost combination of generation plants (of all technologies)…
- …that meets the minimum capacity margin…
- …constraints on CO2 and other emissions…
- …for each price zone

For the national market design, we will align total capacity and location with the FES21 scenarios

Short Term Dispatch Model

(GWh):

- Finds the least-cost dispatch profile of generation…
- …that meets demand…
- …on an hourly basis…
- …for each generating plant…
- …for each price zone

PLEXOS

Asset Profitability module

Utility Strategic Decision

Power Market Dispatch model

Presented in the May workshop; not repeated today.

Hourly outputs for each modelled year

5 *Additional quantitative analysis*

Internal Only

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The evolution of the transmission network is an exogenous input based on ETYS and NOA, and is the same for all market design variants

Our model up to 2031 is currently based on ETYS 21 and incorporates NOA7 (Leading the Way) upgrades for the period 2031- 2041.

Currently in model

2022

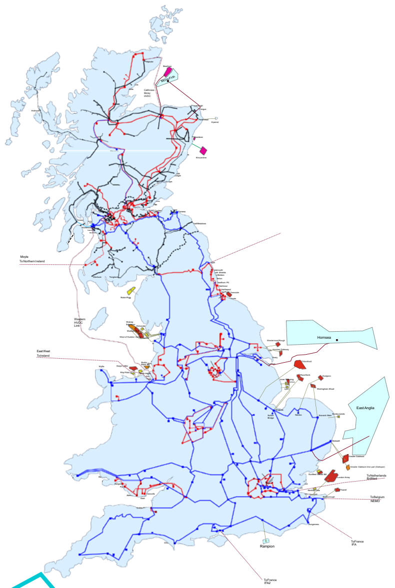
- **Current Network as defined in ETYS21**
- **112GW of capacity across 20 boundaries**

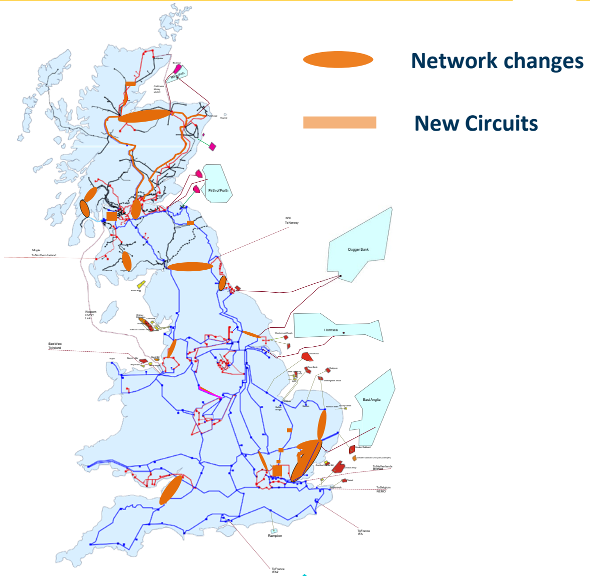
2031

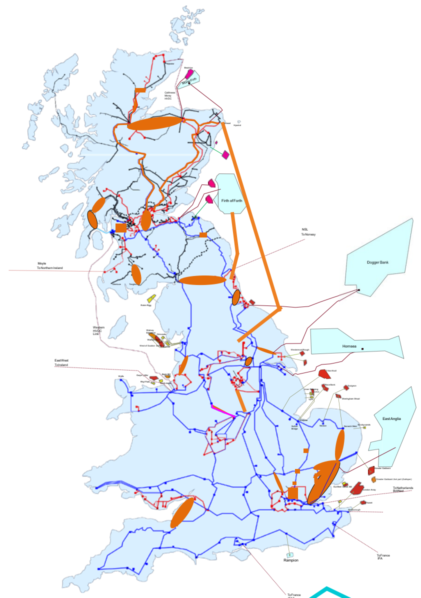
- **ETYS21** based on NOA6 (LtW)
- **c.160GW of capacity across 20 main boundaries**

2041

- **ETYS21** and **majority post-2031 NOA7-LtW** scenario recommendations
- **c.190GW of capacity across 20 main boundaries**







Planned updates

- None

- Update network to reflect pre-2031 NOA7 recommendations –
- HND recommendations – c21GW of new transmission capacity

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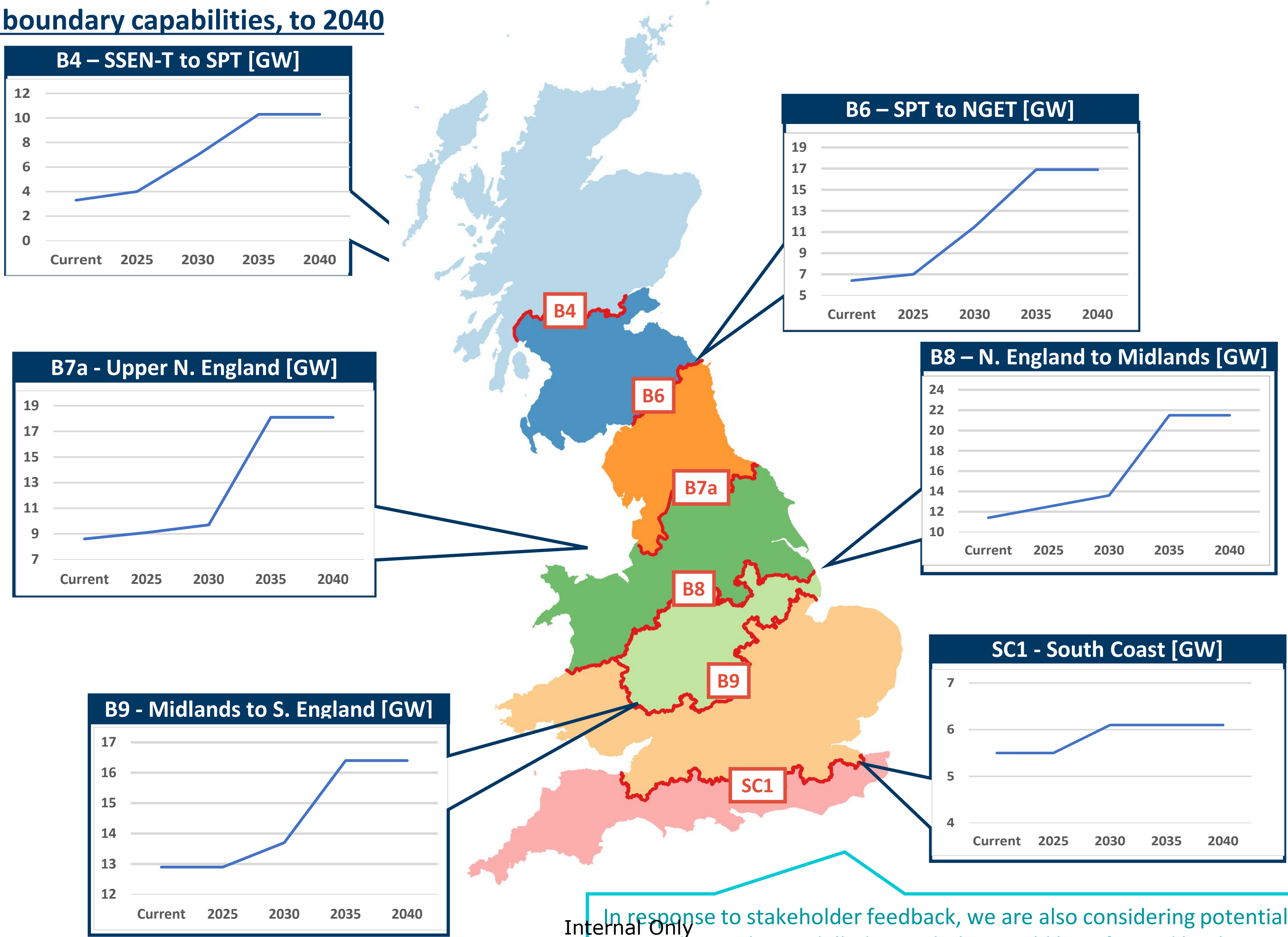
- Include NOA7 recommendations incl. non-public data (8 projects) – ongoing discussion with ESO
- HND recommendations – c21GW of new transmission capacity

Transmission capacity	Electricity demand	Generation capacity build-out

For the zonal model, we have identified appropriate boundaries based on a forward-looking view of future constraints by ESO

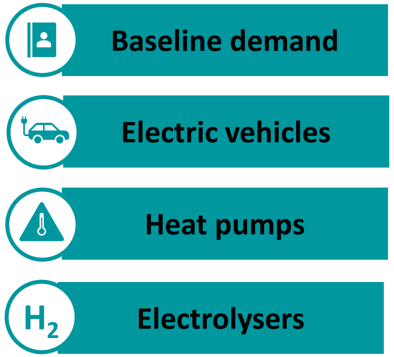
Projected GB boundary capabilities, to 2040



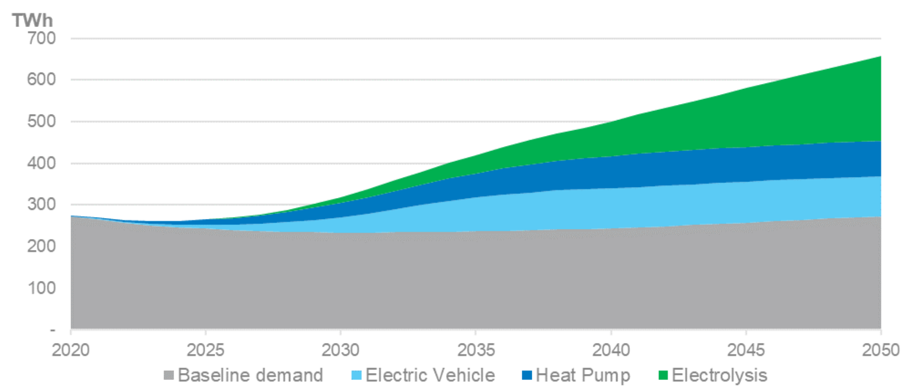
In response to stakeholder feedback, we are also considering potential re-zoning during the modelled period: this would be informed by the quantum of congestion observed over the period and an assumption regarding the frequency with which re-zoning could realistically occur.

Demand projections are based on FES21 LtW, including the flexibility behaviour of different technologies, excluding demand portability

A **We split customer demand[1] into four components. Total annual demand for each of these components, in each scenario, is set exogenously, using the local demand as defined in FES2021 (GSP demand level)**



FES21 Leading the Way - demand forecast (TWh)



B **Demand profiles for each of these components are based on the Pan European Market Modelling database (PEMMDB)[2]. These profiles are optimised by the model, using flexibility assumptions developed based on FES21**

DSR	▪ Two tier of DSR included in the model, each of them activated at different price levels ▪ Capacity of DSR and price levels are based on FES21
Electric vehicles	▪ A quarter of EVs optimise demand across ten hours a day day to minimise cost, consuming at times when power is cheapest ▪ Remaining 75% of EVs follow a fixed hourly demand profile peaking late at night (i.e. most charging happens overnight)
Heat pumps	▪ 50% of heat pumps optimise demand within each day to minimise cost, with climate profiles varying heating demand across the year ▪ The proportion of flexible units follows the proportion of flexible heat pumps units in use according to FES21
Electrolysers	▪ Electrolyser capacity and annual demand is fixed to FES21 (implying load factors of c.11-31%) ▪ The model optimises the demand profile within the year

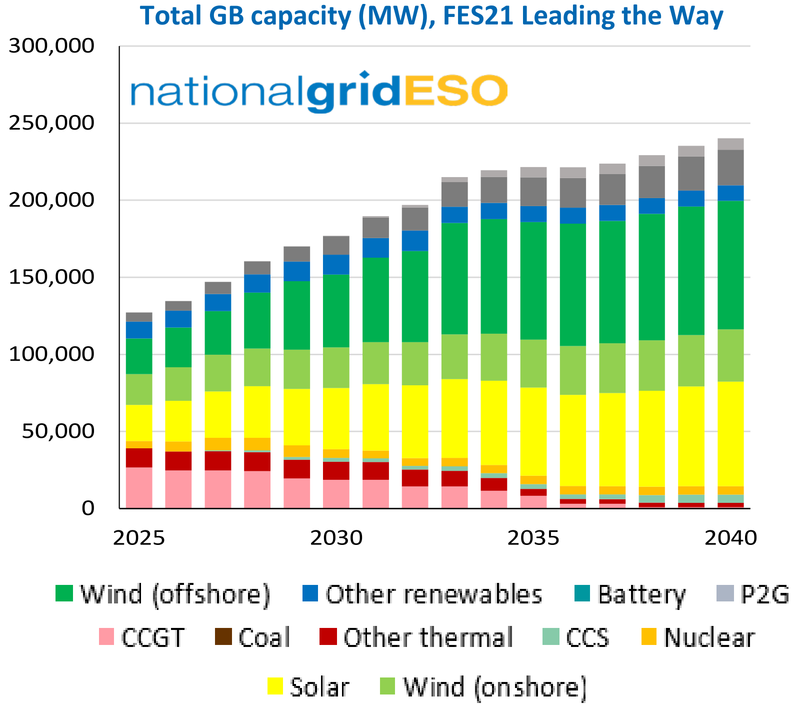
C **Demand from the power sector (e.g. battery and pumped storage) is optimised endogenously by the model. The installed capacity of these technologies is fixed to FES21**

1: Customer demand excludes demand from the power sector (e.g. power plant own consumption).

2: The PEMMDB is published by ENTSO-E and is the basis of the TYNNDP modelling

Generation capacity forecasts are based on FES21 Leading the Way scenario, and the mix stays the same across market designs

National model assumes capacity follows FES21



- Total generation capacity per technology is based on the FES21 data
- Siting is based on FES21 regional breakdown (at nodal granularity)

Capacity under nodal and zonal design also follows FES21[1], but we allow the following technologies[2] to re-site, subject to limits

Technology	Re-siting limits
Onshore Wind	• England: No new onshore wind • Wales and Scotland: New capacity can locate on any node/zone with onshore wind capacity in FES21 • Total capacity at any node can be max 2x FES21
Offshore Wind	• Offshore wind responds, but respects historical ARs and reflecting local resource availability (wind speeds)
Solar	• Total solar capacity at any node can be max 2x FES21
Battery	• New capacity can locate on any node with battery capacity in FES21
CCS Biomass (CCS BIO)	• New capacity can locate at nodes which are part of CCUS clusters
Hydrogen generation (H_2)	• New capacity can locate at nodes with Hydrogen CCGTs as specified in FES21 and nodes around H2 clusters

- Keeping the same capacity mix is a conservative assumption for alternative market design options, as more granular pricing could potentially trigger a change in the capacity mix
- This approach allows a direct comparison across the three locational designs under consideration
- Restricting new build to (mostly) locations with prior new build is arguably also conservative, as it limits the optimisation of siting

1: Small changes of <2% are allowed for Biomass, CCS biomass and Hydrogen generation, reflecting resource availability in line with FES21
2: All other technologies, including fossil fuel, biomass, nuclear, pumped hydro, hydro and interconnectors remain sited in identical locations across national, zonal and nodal designs.

Modelling results
Long-term model output: capacity

Location of generation capacity is based on FES21 under the national design, and we allow for a degree of re-siting under zonal and nodal designs

Locational granularity

National market | Zonal market | Nodal market

Proposed Modelling scenarios

Scenario 1: Leading the Way

Scenario 2: System Transformation

Key inputs

1 **Transmission capacity**

Includes current & future network topology, and seasonal availability assumptions

2 **Demand**

Includes annual demand, profile and flexibility assumptions by type and location

3 **Generation capacity**

Includes build-out assumptions, plant technical characteristics and renewable capacity profiles

4 **Commodity prices**

Includes price projections for a set of commodities (CO2, gas etc)

Power Market Model PLEXOS

Long Term Capacity Expansion model

For the zonal and nodal market designs only – the LT model determines the optimal evolution of generation capacity (GW):

- Finds the lowest-cost combination of generation plants (of all technologies)…
- …that meets the minimum capacity margin…
- …constraints on CO2 and other emissions…
- …for each price zone

For the national market design, we will align total capacity and location with the FES 21 scenarios

Short Term Dispatch Model

Takes capacity from the Long Term model as given and determines the optimal output of generation (GWh):

- Finds the least-cost dispatch profile of generation…
- …that meets demand…
- …on an hourly basis…
- …for each generating plant…
- …for each price zone

Internal Only

Hourly outputs for each modelled year

Wholesale power prices

Generation xsz

Flows between zones

5 *Additional quantitative analysis*

The national model sites generation as defined by FES21, and we assess the zonal and nodal re-siting relative to this

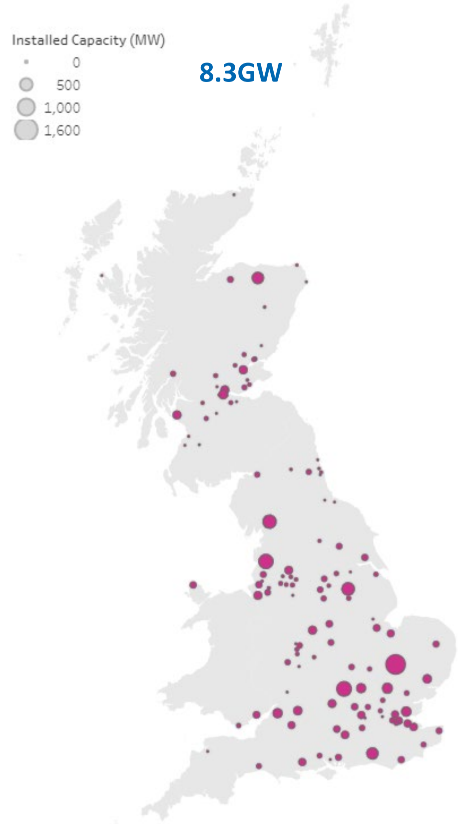
Wind Capacity 2030

Offshore wind   Onshore wind

Solar 2030

Solar

Battery 2030



Battery

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National design | Zonal design | **Nodal design**

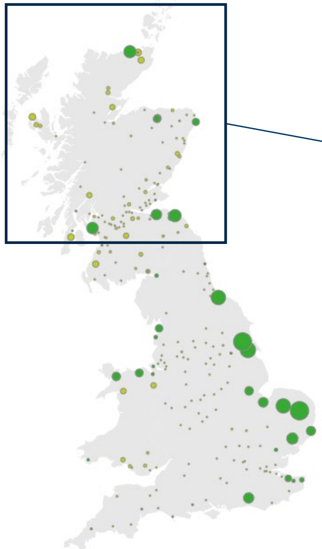
Introduction - Projected capacity results under the nodal market design

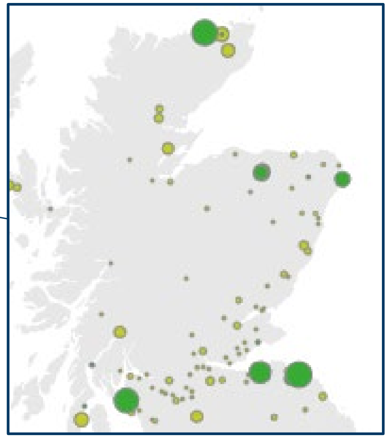
Modelling year

Installed Capacity

The total installed capacity in the modelling year

73.5GW



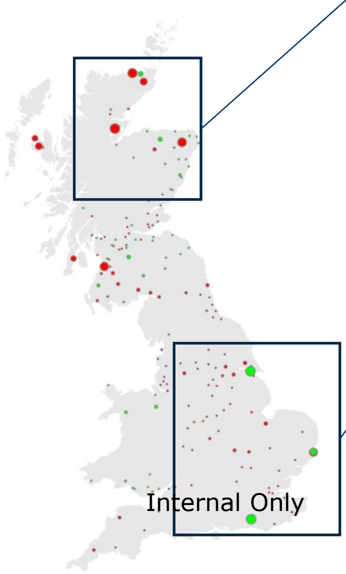


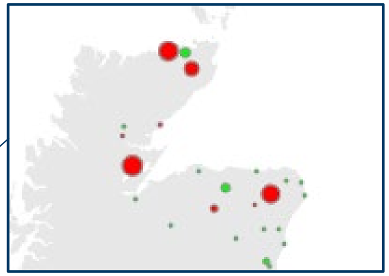
The circles represent installed capacity with different colours for each technology as indicated in legend

Cumulative capacity location change

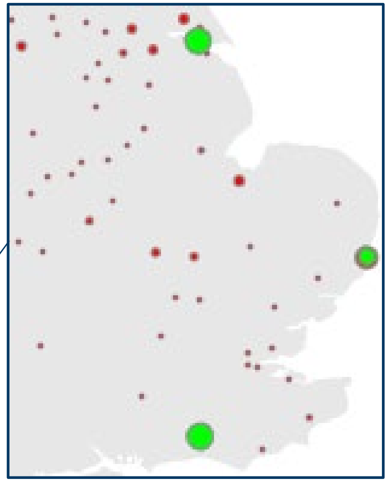
The capacity change represents the change in location of installed capacity between the national and nodal models

12.1 GW





Red circles represent a decrease in capacity at the node relative to the national model



Fluorescent green circles represent an increase in capacity at the node relative to the national model

The larger the circle, the greater the capacity or capacity change represented

Decrease relative to national model | **Increase relative to national model** | **Offshore wind** | **Onshore wind**

National design | Zonal design | **Nodal design**

Projected wind capacity under nodal market, and relative to national market

2025 | 2030 | 2035 | 2040

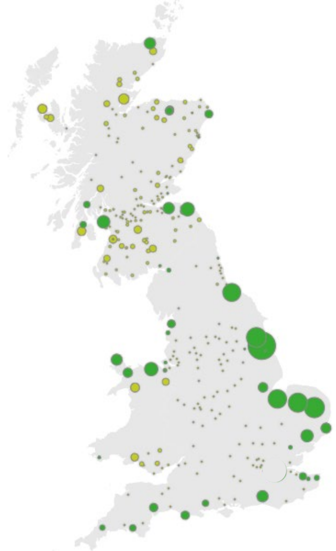
Installed Capacity

Increase in capacity of offshore wind in East Anglia and the South Coast

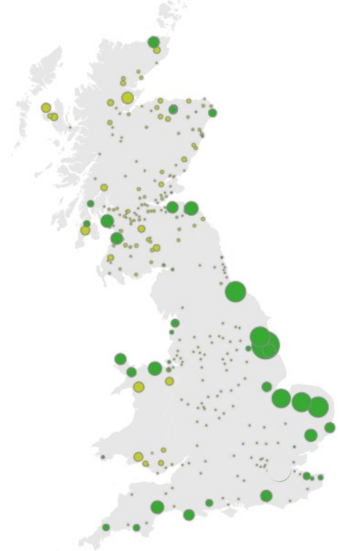
43GW

73.5GW

107GW



117GW



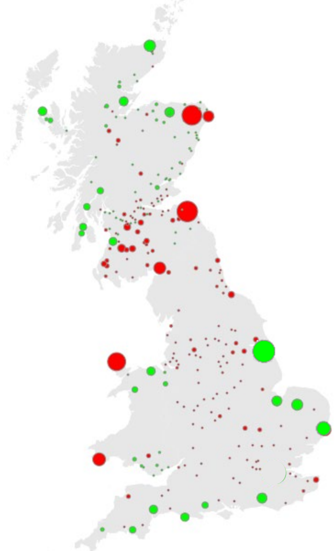
Cumulative capacity location change

In comparison to the national market, we can observe a reduction in installed wind capacity in Scotland, North West of England and North Wales

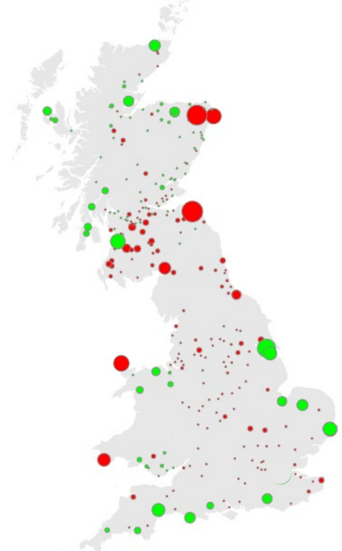
3.1GW

9.4GW

39.9GW



45.2GW



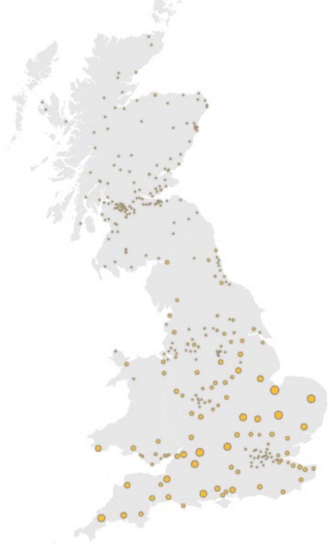
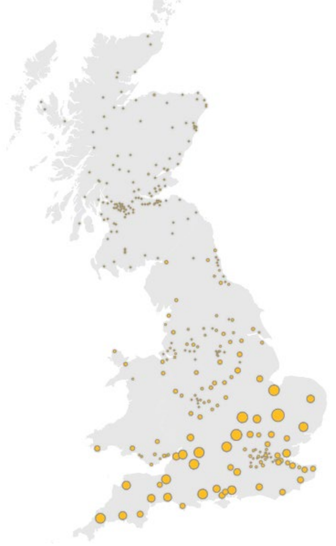
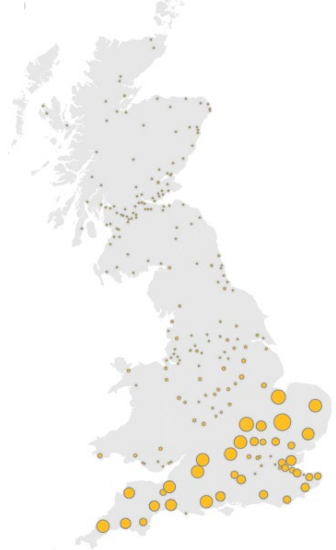
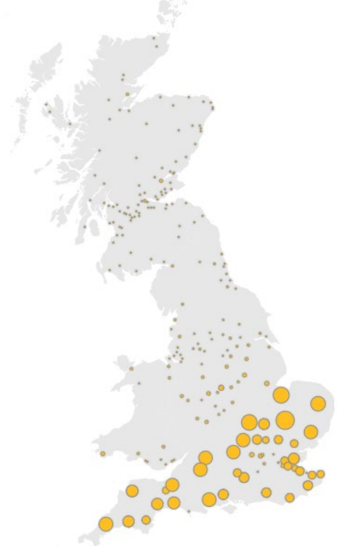
Decrease relative to national model · **Increase relative to national model** · **Offshore wind** · **Onshore wind**

National design | Zonal design | **Nodal design**

Projected solar capacity under nodal market, and relative to national market

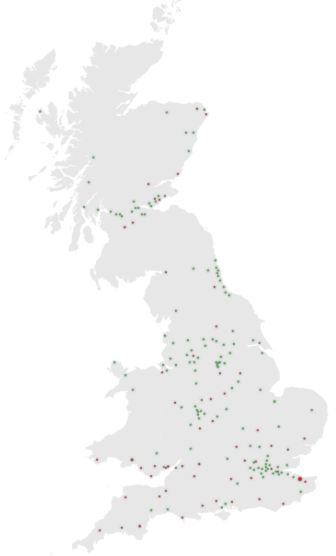
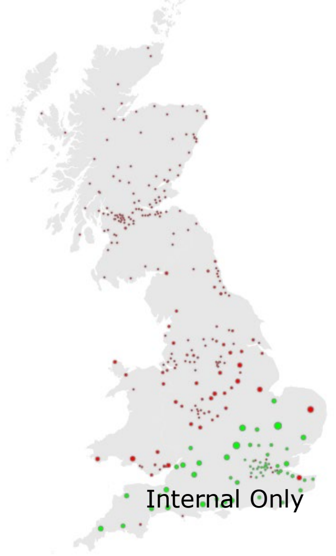
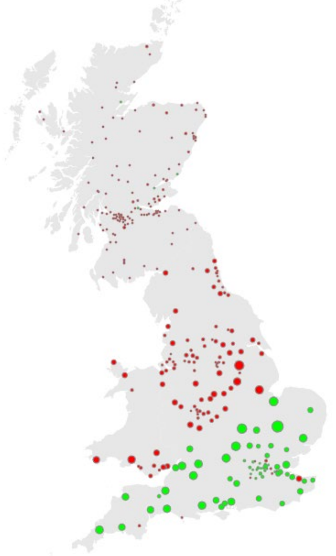
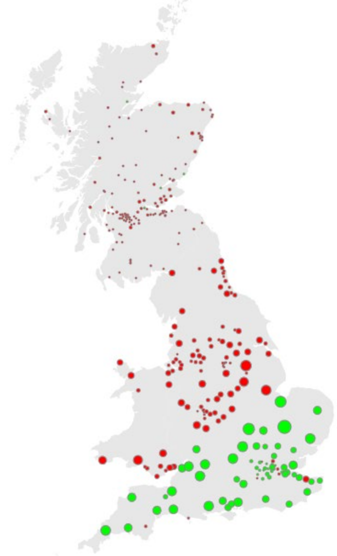
	2025	2030	2035	2040
Installed Capacity	**23GW**	**39.7GW**	**57.2GW**	**67.8GW**

In the nodal model we can observe a greater concentration of solar capacity in the South East

	2025	2030	2035	2040
Cumulative capacity location change	**0.7GW**	**8.2GW**	**20.9GW**	**27.5GW**

In comparison to the national market, we can observe a reduction in installed solar capacity in Midlands and South West

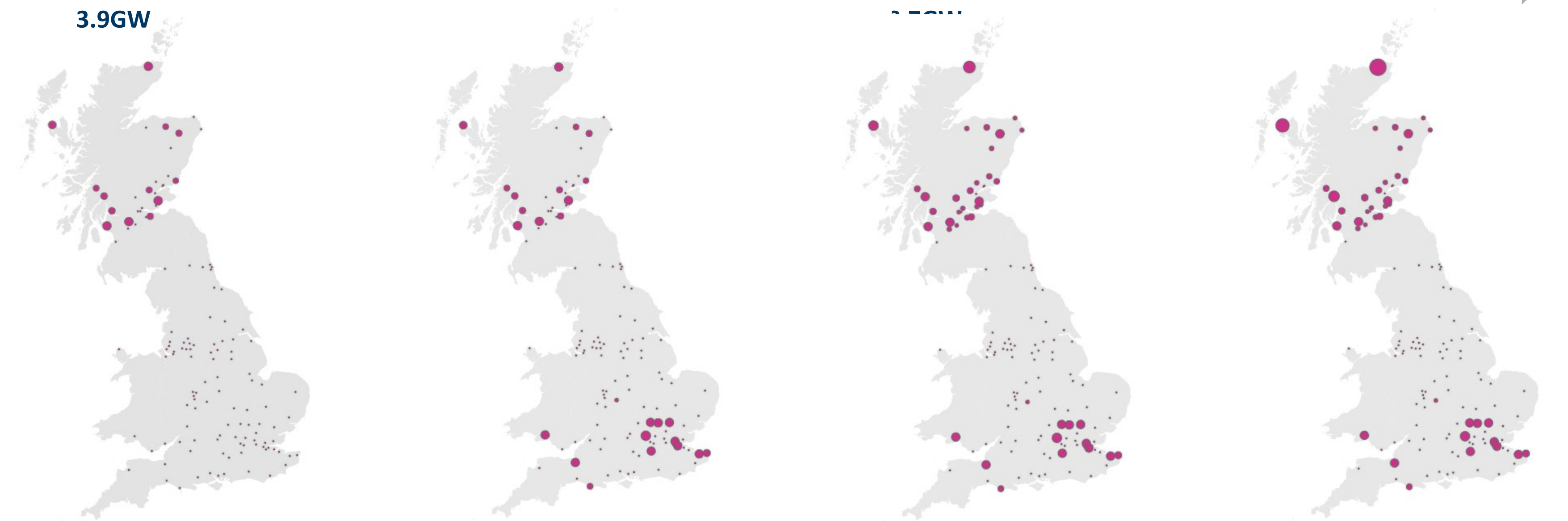
Decrease relative to national model **Increase relative to national model** **Solar**

Projected battery capacity under a nodal market, and relative to a national market

2025 | 2030 | 2035 | 2040

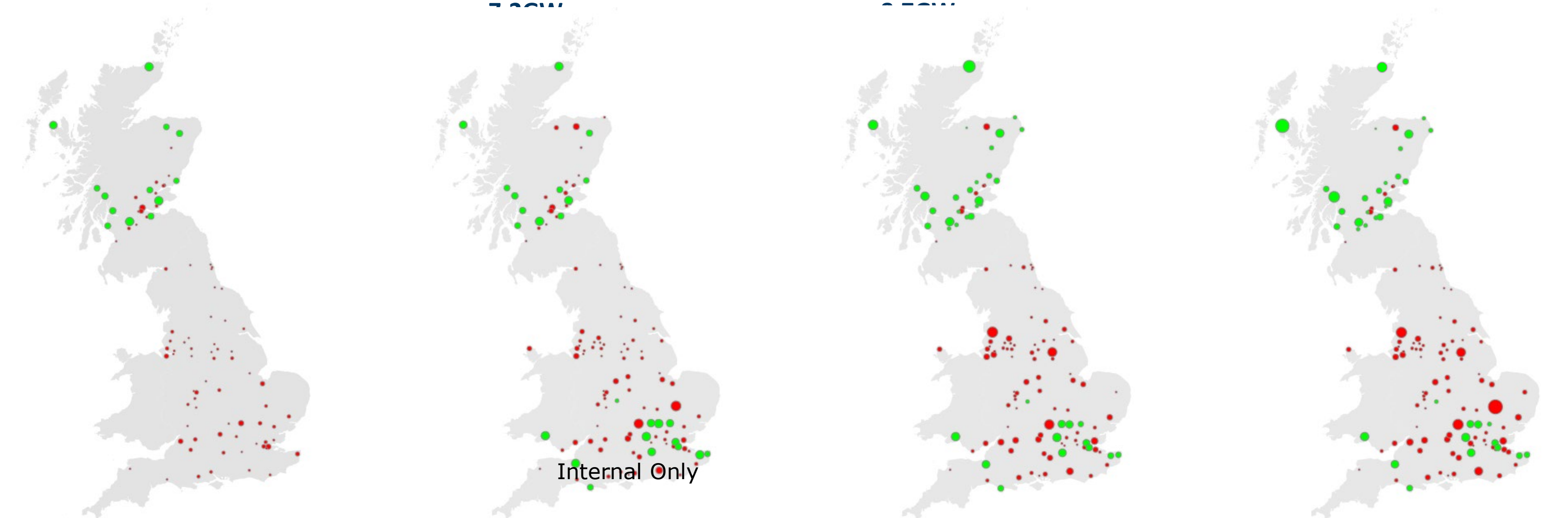
Installed Capacity

The nodal model estimates increasing build of batteries around London and in Scotland



Cumulative capacity location change

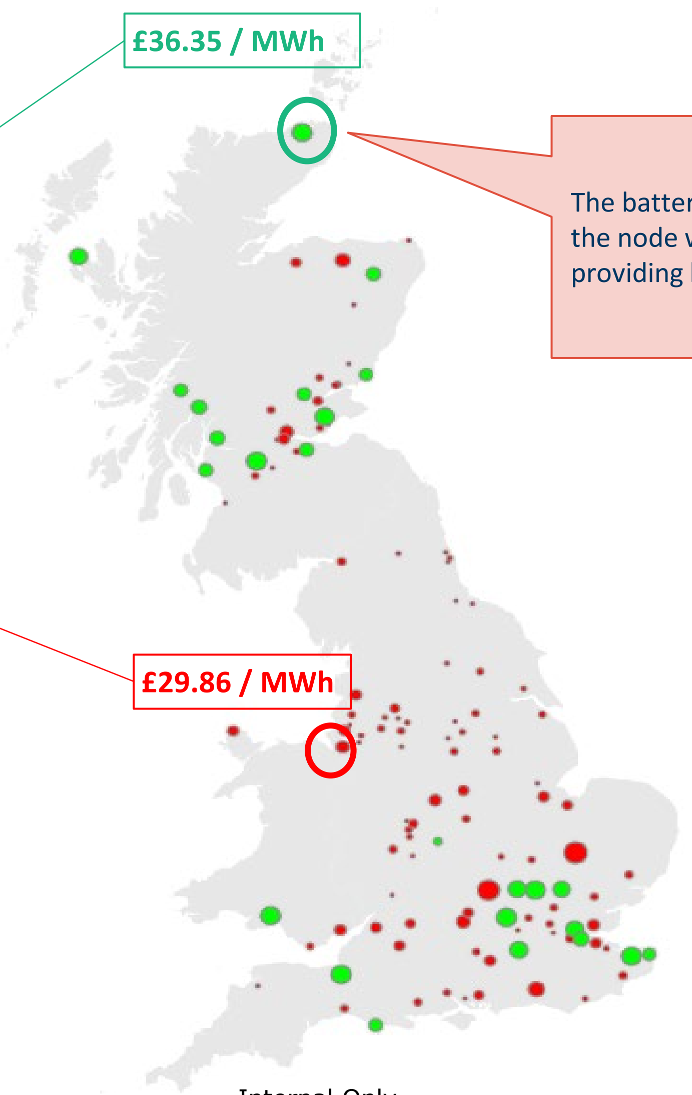
In comparison to the national market, we can observe a reduction in installed battery capacity in Midlands Anglia and South England



Decrease relative to national model · Increase relative to national model · Battery

National design | Zonal design | **Nodal design**

Under a nodal design, battery capacity chooses to re-site in response to the average price arbitrage opportunities



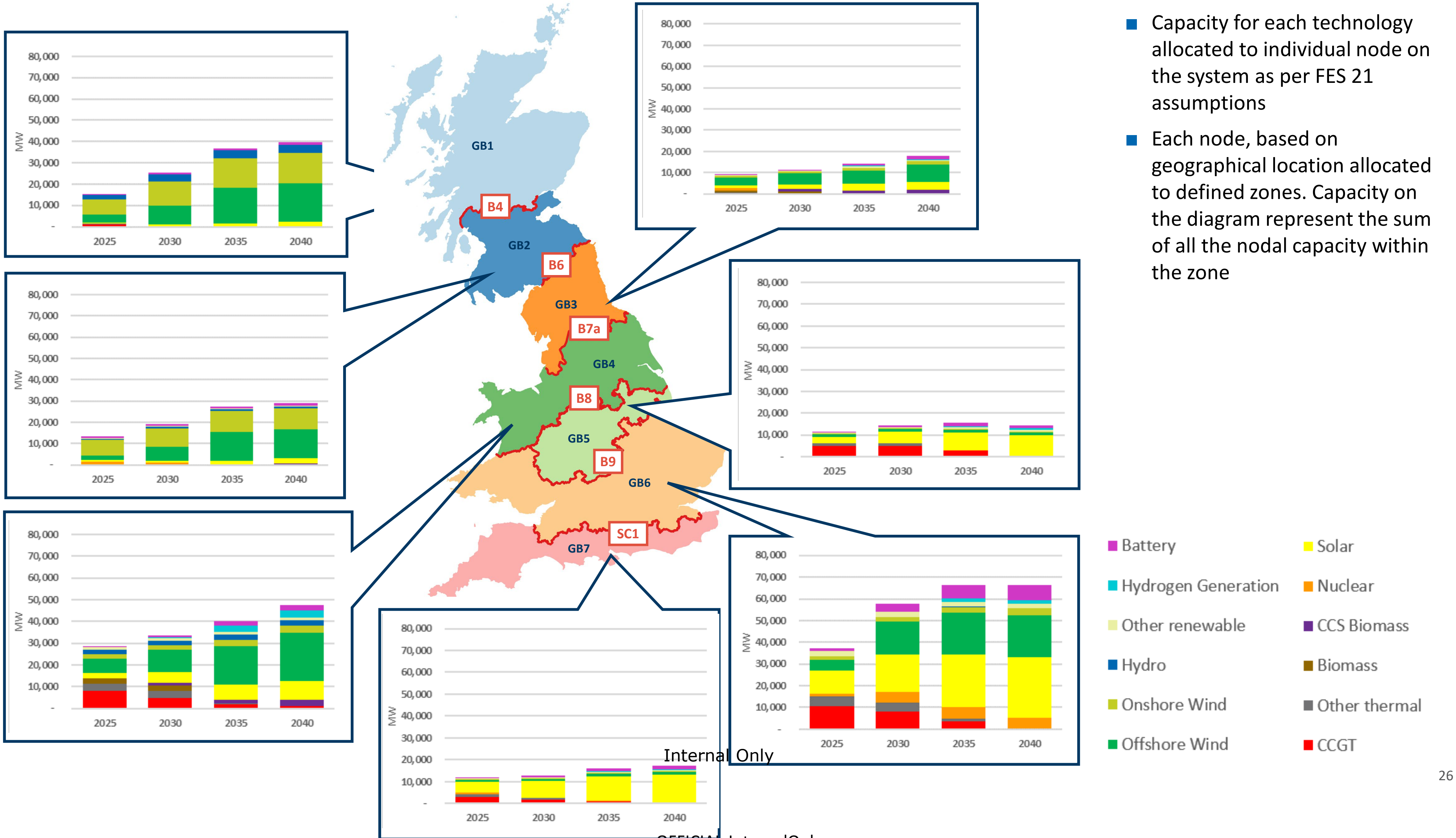
The battery capacity allocates to the node with greater spread, providing higher revenue potential.

Spread between the average price received (export) and the price paid (import) across the year.

Internal Only

● **Decrease relative to national model** ● **Increase relative to national model** ● **Battery**

Evolution of generation capacity under the National market design as per FES21 assumptions



- Capacity for each technology allocated to individual node on the system as per FES 21 assumptions
- Each node, based on geographical location allocated to defined zones. Capacity on the diagram represent the sum of all the nodal capacity within the zone

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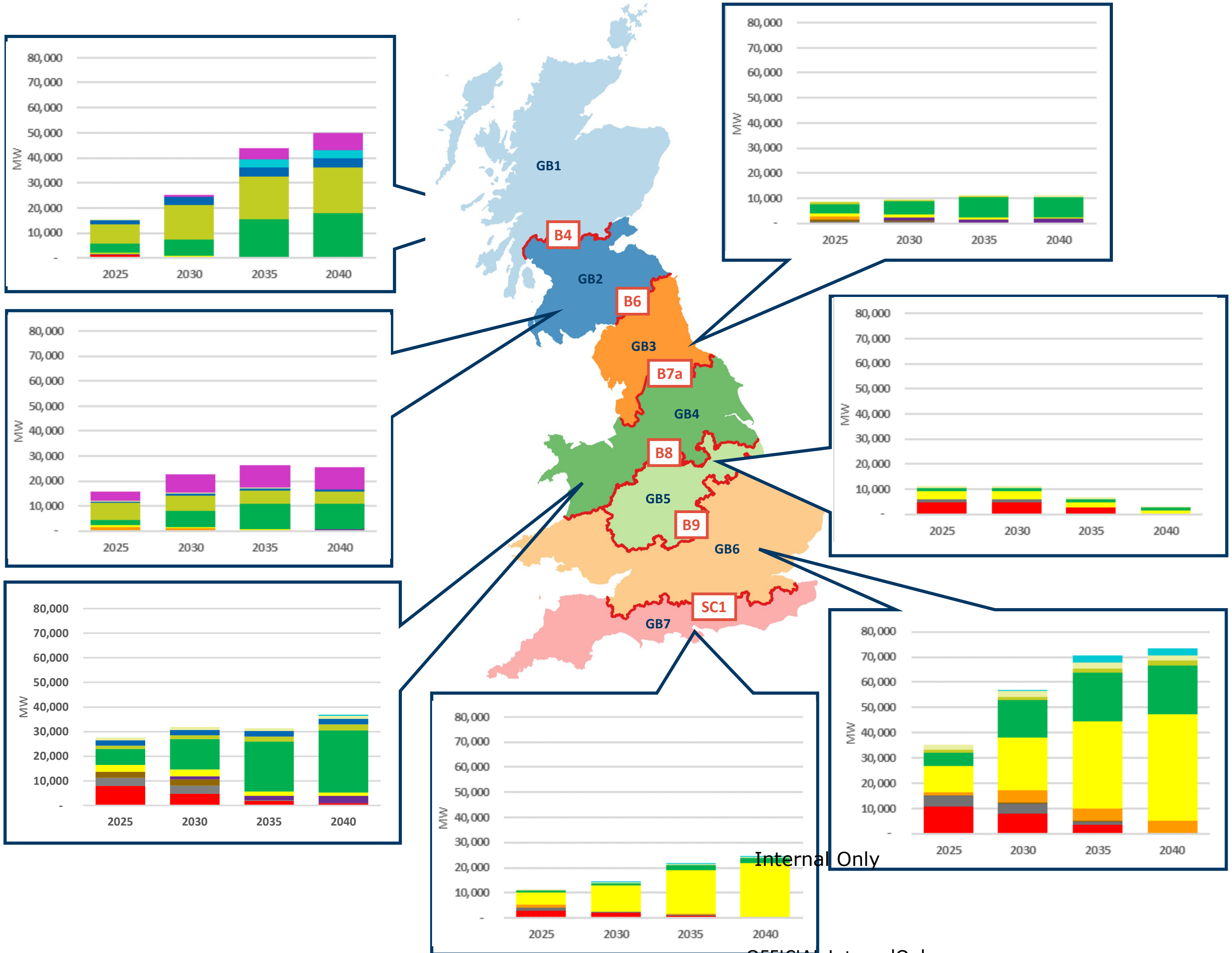
Similar to our nodal assessment, we have modelled the projected evolution of generation capacity in a zonal market design



- Zonal arrangements lead to a less build-out of offshore Scottish wind (GB1 & GB2) and less onshore wind in GB2 (but more onshore wind in GB1).
- Conversely, some additional new wind capacity (notably offshore) locates closer to demand centres in the South
- Majority of solar generation locates in GB6 & GB7

Battery
Solar
Hydrogen Generation
Nuclear
Other renewable
CCS Biomass
Hydro
Biomass
Onshore Wind
Other thermal
Offshore Wind
CCGT

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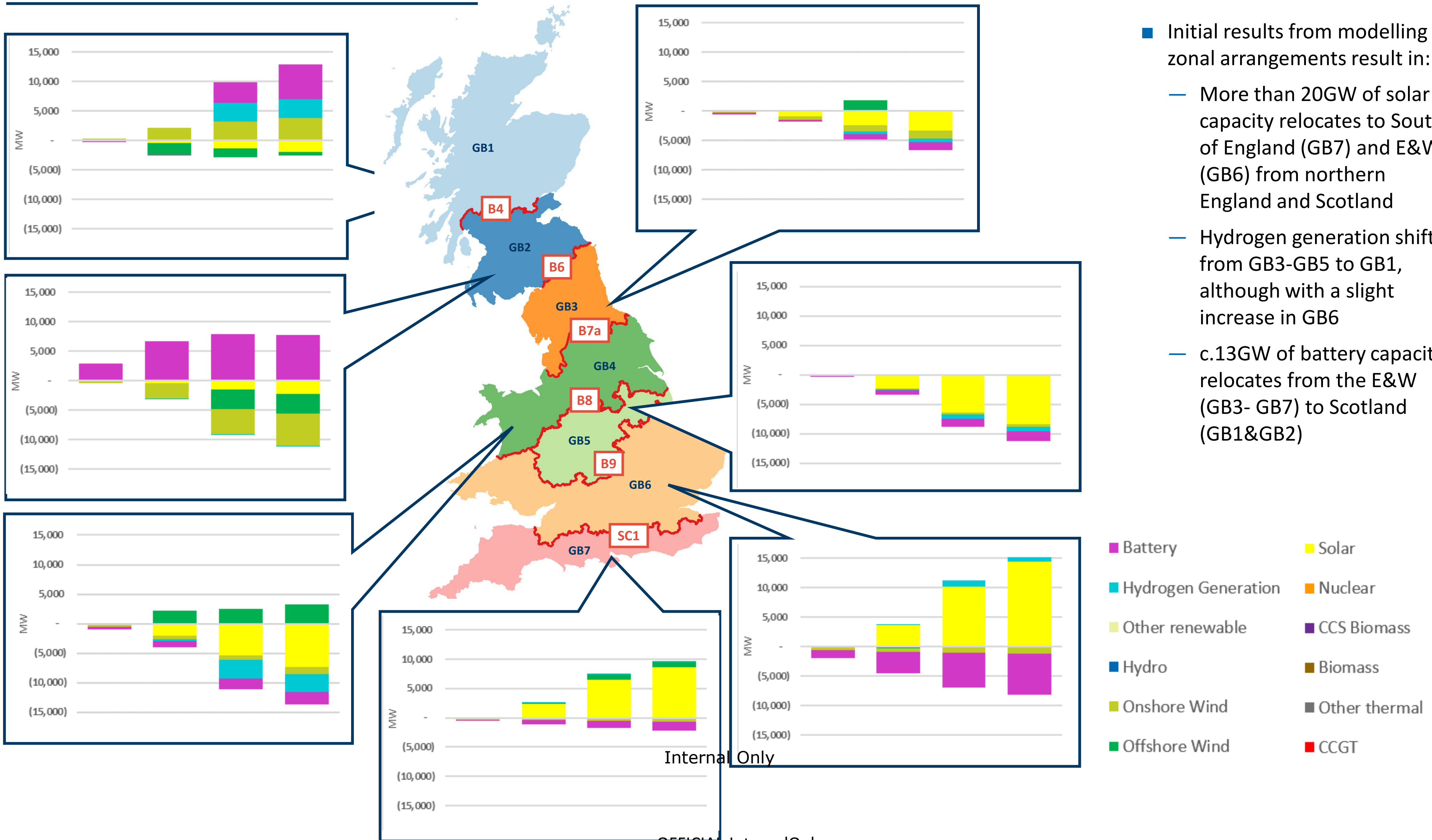
ENERGY

Under the zonal model, wind (onshore and offshore), hydrogen and solar capacities relocate across the GB zones

Difference in capacity relative to national model (MW)



- Initial results from modelling of zonal arrangements result in:
  - More than 20GW of solar capacity relocates to South of England (GB7) and E&W (GB6) from northern England and Scotland
  - Hydrogen generation shifts from GB3-GB5 to GB1, although with a slight increase in GB6
  - c.13GW of battery capacity relocates from the E&W (GB3- GB7) to Scotland (GB1&GB2)

Preliminary modelling results: Detailed price outcomes

Once transmission, demand and generation parameters are defined, we **(4) run the dispatch model** with **(5) additional analysis** on the outputs

Locational granularity

National market | Zonal market | Nodal market

Proposed Modelling scenarios

Scenario 1: Leading the Way

Scenario 2: System Transformation

Key inputs

1 **Transmission capacity**

Includes current & future network topology, and seasonal availability assumptions

2 **Demand**

Includes annual demand, profile and flexibility assumptions by type and location

3 **Generation capacity**

Includes build-out assumptions, plant technical characteristics and renewable capacity profiles

4 **Commodity prices**

Includes price projections for a set of commodities (CO_2, gas etc)

Power Market Model PLEXOS

Long Term Capacity Expansion model

For the zonal and nodal market designs only – the LT model determines the optimal evolution of generation capacity (GW):

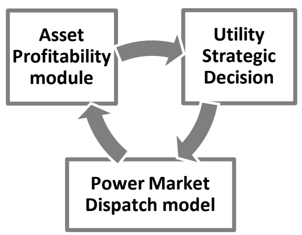
- Finds the lowest-cost combination of generation plants (of all technologies)…
- …that meets the minimum capacity margin,…
- …constraints on CO2 and other emissions…
- …for each price zone

For the national market design, we will align total capacity and location with the FES 21 scenarios

Short Term Dispatch Model

Takes capacity from the Long Term model as given and determines the optimal output of generation (GWh):

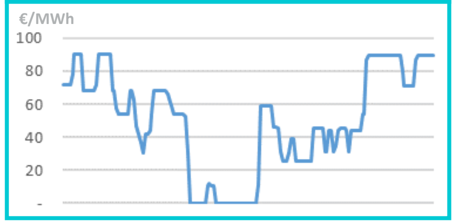
- Finds the least-cost dispatch profile of generation…
- …that meets demand…
- …on an hourly basis…
- …for each generating plant…
- …for each price zone



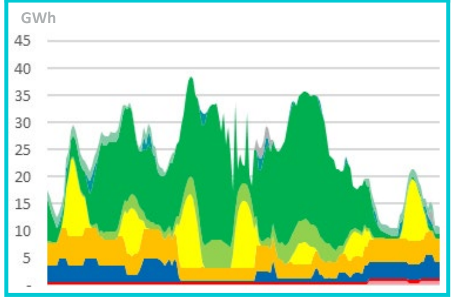
Internal Only

Hourly outputs for each modelled year

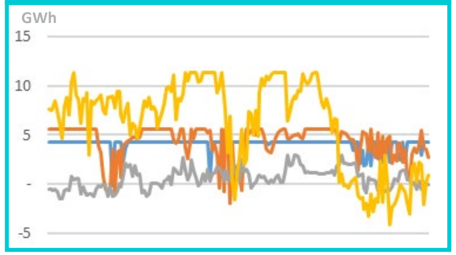
Wholesale power prices



Generation

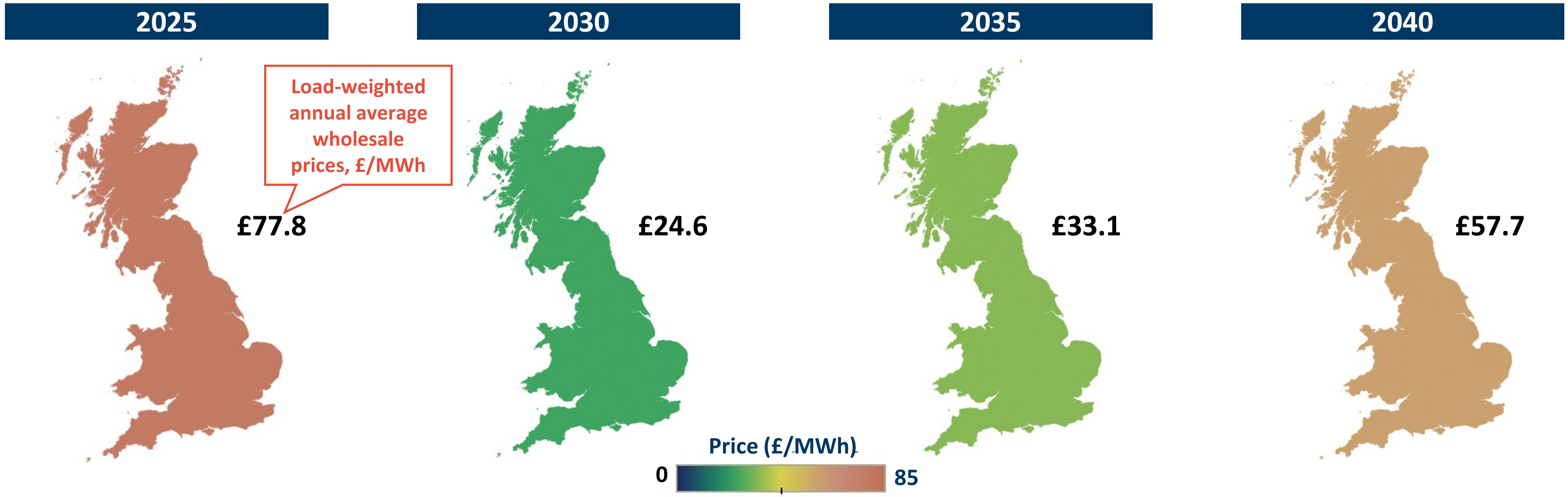


Flows between zones



5 ***Additional quantitative analysis***

Pressure on wholesale prices is expected to ease in 2030 but increase again due to increased electrification, limited flexibility options and high carbon prices



2025

Wholesale prices are **expected to be high** in 2025…

….reflecting **higher gas prices** in a system that is still **reliant on fossil fuels.**

2030

These are **expected to fall significantly** by 2030…

…as **pressure on gas prices** is **expected to ease** and **more renewable capacity** is built.

2035

Power prices **trend upward** again in 2035…

…as **increased electrification** drives electricity demand…

…and rising carbon prices increase the cost of some flexible generation.

2040

Wholesale prices continue to increase into 2040…

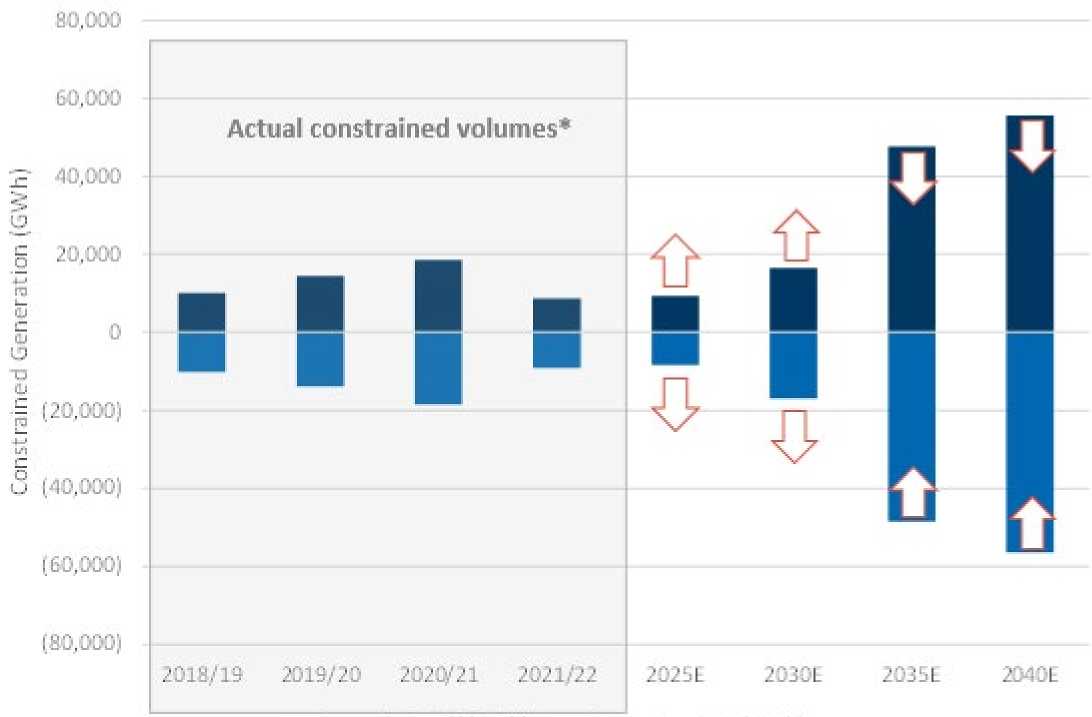
…reflecting **high carbon prices** and **fewer options for flexibility** as gas capacity becomes increasingly limited…

…with GB exposed to **higher prices in other countries** due to **increased reliance on ICs for flexibility**.

Preliminary modelling results: National Market- Constraint management costs

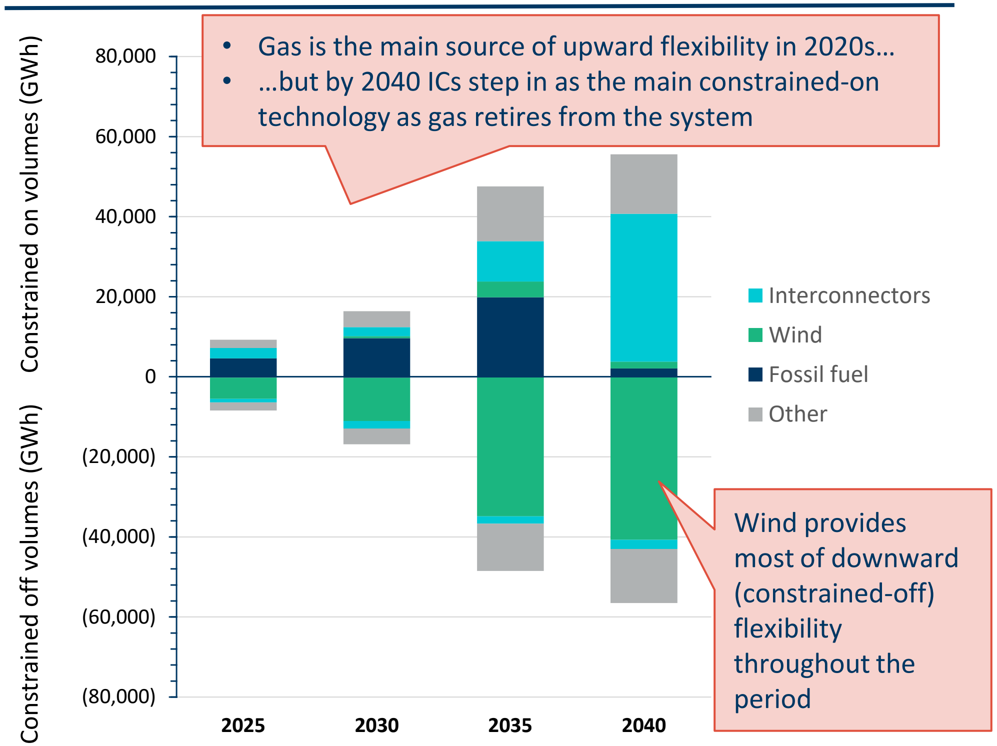
A comparison of the national design with and without transmission constraints allows us to calculate the generation that is constrained on and off

Actual and modelled constrained on/off volumes (National design, GWh/year)



*Source – ESO Data Portal.

Breakdown of constrained on/off volumes by technology (GWh/year)



We expect these changes to increase our volume estimates in 2025-30 and decrease our volume estimates in 2035-40

Key limitations:

Impact on volume estimates

- Only **thermal constraints** are reflected in our modelling. **Other constraints (e.g. voltage, stability) could also limit boundary capacities.** ↑
- **Planned and unplanned transmission outages are not reflected in our analysis.** ↑
- **Pre-2031 transmission** network based on NOA6 is **missing NOA 7 recommendations**. Circuit capacity for eight post-2031 NOA7 recommendation projects is **yet to be included** (ongoing discussion with ESO to ensure accurate network reinforcement representation) ↓

We calculate constraint costs by forecasting the underlying bid and offer prices used in the balancing market

Technology	Cost to ESO Bid	Cost to ESO Offer	Additional assumptions
Fossil fuel	- Fuel cost - carbon cost	Offer Uplift + Fuel cost + carbon cost	Multiplier uplift calculated using historical offer prices and historical commodity prices
Biomass	- Fuel cost	Offer Uplift + Fuel cost	50% of the Absolute fossil fuel offer uplift utilised as a proxy
CCS Biomass	Carbon price – Fuel cost	Offer Uplift + (Fuel cost – carbon price)	50% of the Absolute fossil fuel offer uplift utilised as a proxy
ROCs renewables	ROCs*	(theoretical only so no price assumed)	-
CfD renewables	CfD strike price – Wholesale price	(theoretical only so no price assumed)	-
Merchant renewables	£0	Offer Uplift	20% of the Absolute fossil fuel offer uplift utilised as a proxy
Storage technologies	- Marginal value	Marginal value	Marginal value calculated by Plexos
Hydrogen generation H_2	- Marginal value	Marginal value	Marginal value calculated by Plexos
Interconnector	Cost of reversing flow £130/£100**	Cost of reversing flow £130/£100**	Our final output will utilise an integrated pan-EU model to estimate interconnector flows

*- The number of ROCs will depend on technology. For simplicity, we assumed 1.9ROCs for OfW and 0.99ROCs for Onshore which is the average per technology from BEIS [link]
** - Cost of reversing flow of £130 assumed in 2025 and 2030

Technologies not participating in the BM	Demand side response	Nuclear	Hydro (run-of-river)	Small-scale thermal

The mix of technologies in the BM evolves significantly over time, highlighting bid/offer behaviours that have not been frequently observed in the past…

Technology	Cost to ESO Bid	Cost to ESO Offer	Additional assumptions
Fossil fuel	- Fuel cost - carbon cost	Offer Uplift + Fuel cost + carbon cost	Multiplier uplift calculated using historical offer prices and historical commodity prices
Biomass	- Fuel cost	Offer Uplift + Fuel cost	50% of the Absolute fossil fuel offer uplift [illegible]
[illegible]	[illegible] price – [illegible]	[illegible] bon price)	[illegible]
ROCs re[illegible]	ROCs*	(theoretical only so no price assumed)	[illegible]
CfD renewables	CfD strike price – Wholesale price	(theoretical only so no price assumed)	[illegible]
Merchant renewables	£0	Offer Uplift	[illegible] utilised as a proxy
Storage technologies	- Marginal value	Marginal value	Marginal value calculated by Plexos
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** - Cost of reversing flow of £130 assumed in 2025 and 2030

Technologies not participating in the BM: Demand side response | Nuclear | Hydro (run-of-river) | Small-scale thermal

1 The total constraint costs are driven by the assumption on the **share of the renewable capacity** developed under the **CfD regime or as a merchant plant**

2 When **wholesale prices exceed the strike price** (increasingly frequently over time), CfD holders are assumed to be **willing to pay ESO for being constrained off**.

3 The total constraint costs are also driven by the behaviour of storage and H2 technologies for which there is **no or very limited historic information**.
We use an approximation of their **opportunity costs**, which, for storage technologies, can mean **paying ESO for being constrained off** in anticipation of being able to discharge later.

4 We approximate interconnector BM behaviour by estimating the **cost to ESO of reversing the flow**.

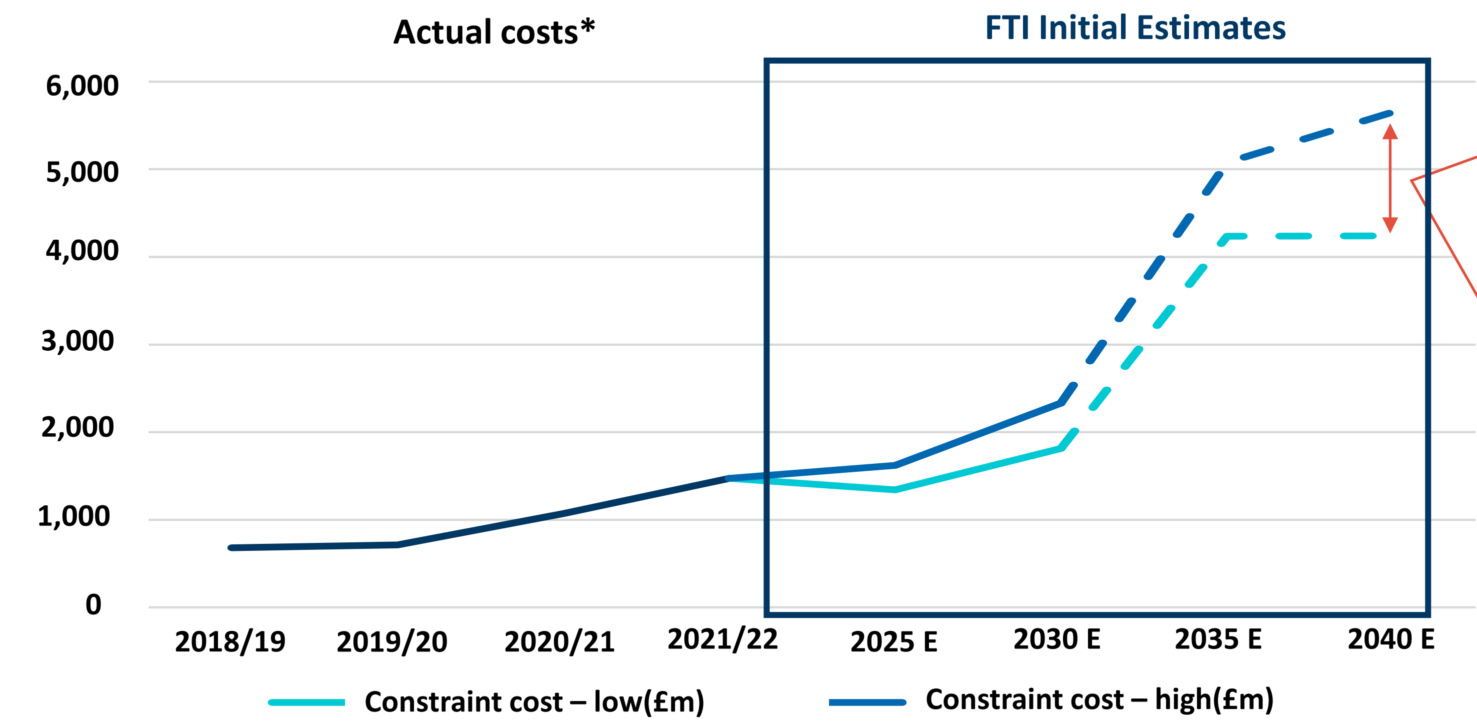
…and the assumptions on future policy and market participants behaviour in BM can have a material impact on the constraint cost estimates.

Constraint management costs

National design | Zonal design | Nodal design

Our preliminary estimate shows a significant increase in constraint costs post-2030, potentially over £5bn/year, given the assumptions in this scenario

Constraint cost estimates, Leading the Way, 2025-2040, £m



- **Higher constraint cost** estimates are based on assumptions **all new wind capacity will be developed under the CfD regime**, with 20% of the Marginal value assumed as an offer uplift for H2 and Battery assets
- **Lower constraint cost** estimate based on **all new wind capacity developed as a merchant** and no offer uplift for H2 and Storage assets

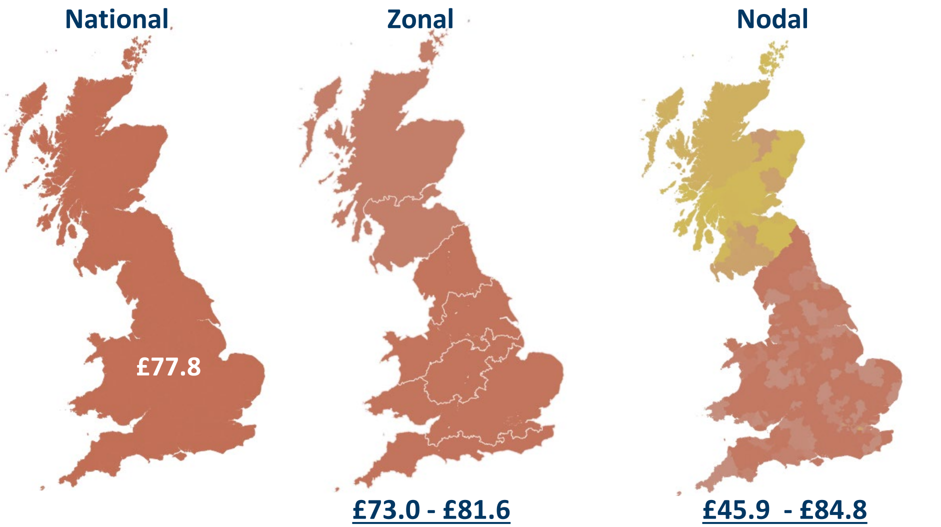
- Our **preliminary assessment** indicates that constraint cost under the national market design option **could exceed £5bn by 2035.**
- However, these estimates are likely to be over-estimated due to some **transmission reinforcements recommended by NOA7 currently missing**.
- Moreover, including **HND transmission projections** is likely to **reduce the forecasts** further.

Internal Only

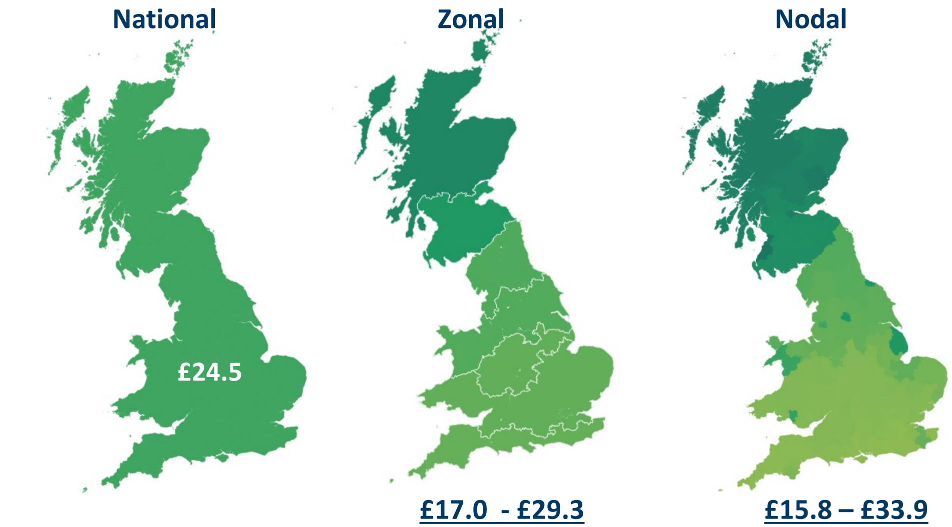
Outstanding refinements:
- Impact of additional **transmission reinforcements** (NOA 7 and NOA 7 Refresh - HND)
- Share of **merchant vs CfD**-supported new wind
- Pricing of **interconnectors** in the BM
- **Transmission outages**
- Estimate of constraint management costs in **zonal design**

Average wholesale power prices across the three market design options are influenced both by 'macro' trends and by the locational granularity

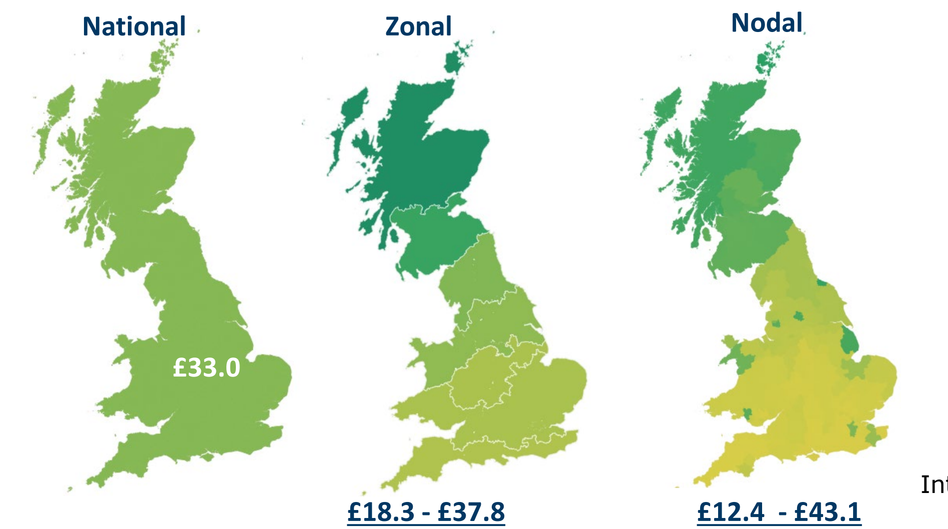
2025 - Annual average wholesale prices, £/MWh



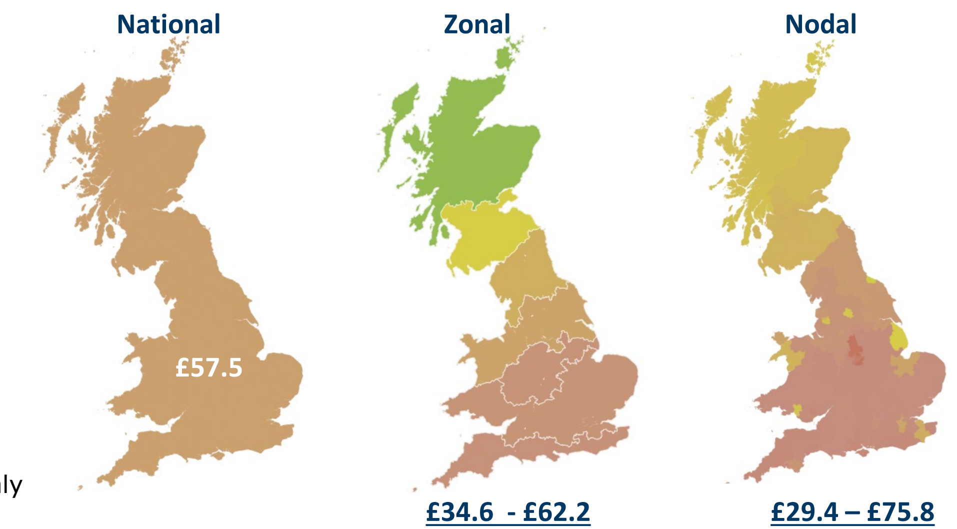
2030 - Annual average wholesale prices, £/MWh



2035 - Annual average wholesale prices, £/MWh



2040 - Annual average wholesale prices, £/MWh



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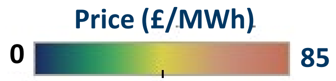
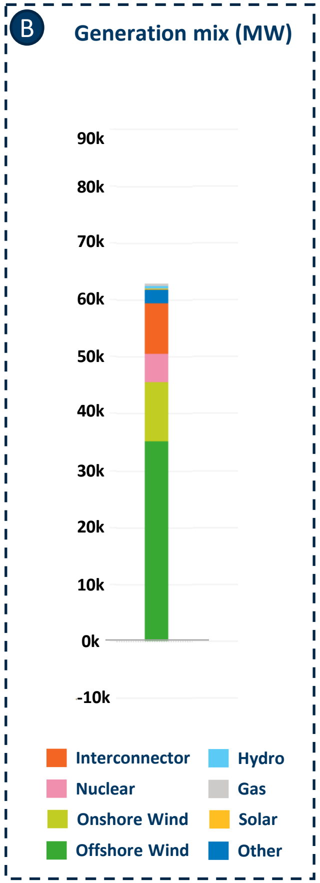
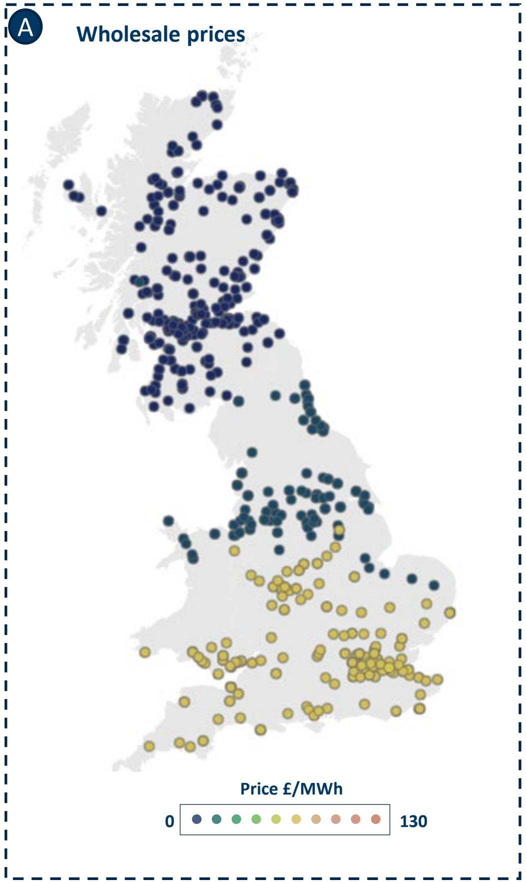


Preliminary modelling results: Nodal Market- Detailed nodal price outcomes

Introduction to detailed nodal price outcomes: Presentation of the wholesale prices, generation mix and congestion costs





A Wholesale prices

1. Each circle represents a node on the system
2. The colour of the circle represents the wholesale price in £/MWh

B Generation mix

1. Bar chart next to the map represents the generation mix in the same hour as the wholesale prices
2. Colour of the bar segment represent relevant technology as indicated in the generation mix legend
3. Height of the bar represents the capacity of the technology that generates at the time (negative figures reflecting IC exports)

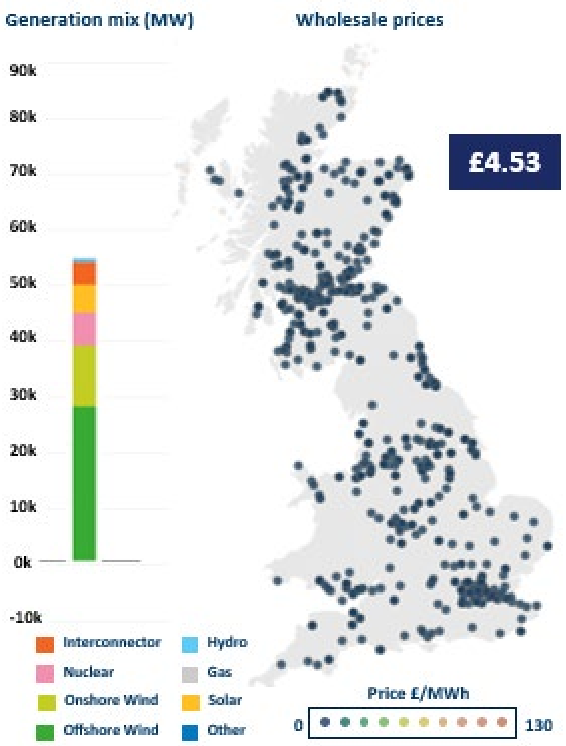
C Congestion cost

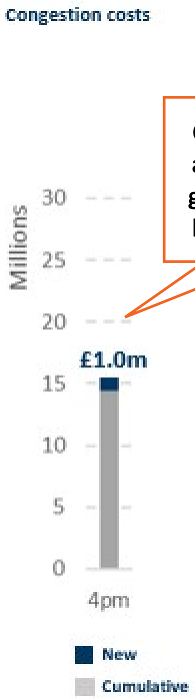
1. Bar chart next to the map represents the cumulative congestion costs on the day up to and including the hour shown
2. Colour of the bar segment differentiates between current hour (dark blue) and the cumulative prior hours on the same day (grey)

With high volumes of RES generation across GB, all of GB faces low wholesale prices, but the cost of meeting demand under national design is higher

4pm

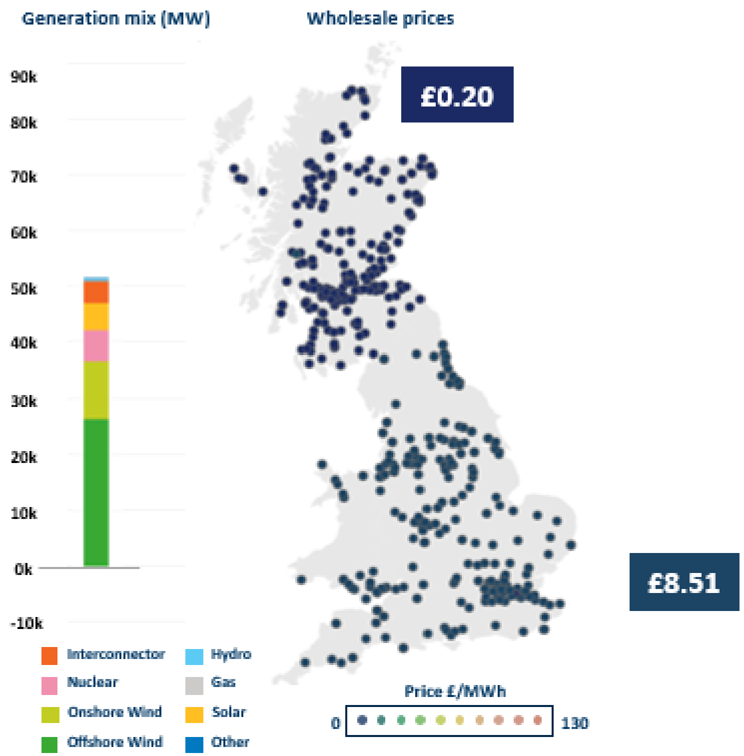
National





Congestion costs are £1m because generation has to be re-dispatched

Nodal



Prices under both national and nodal prices are close to zero….

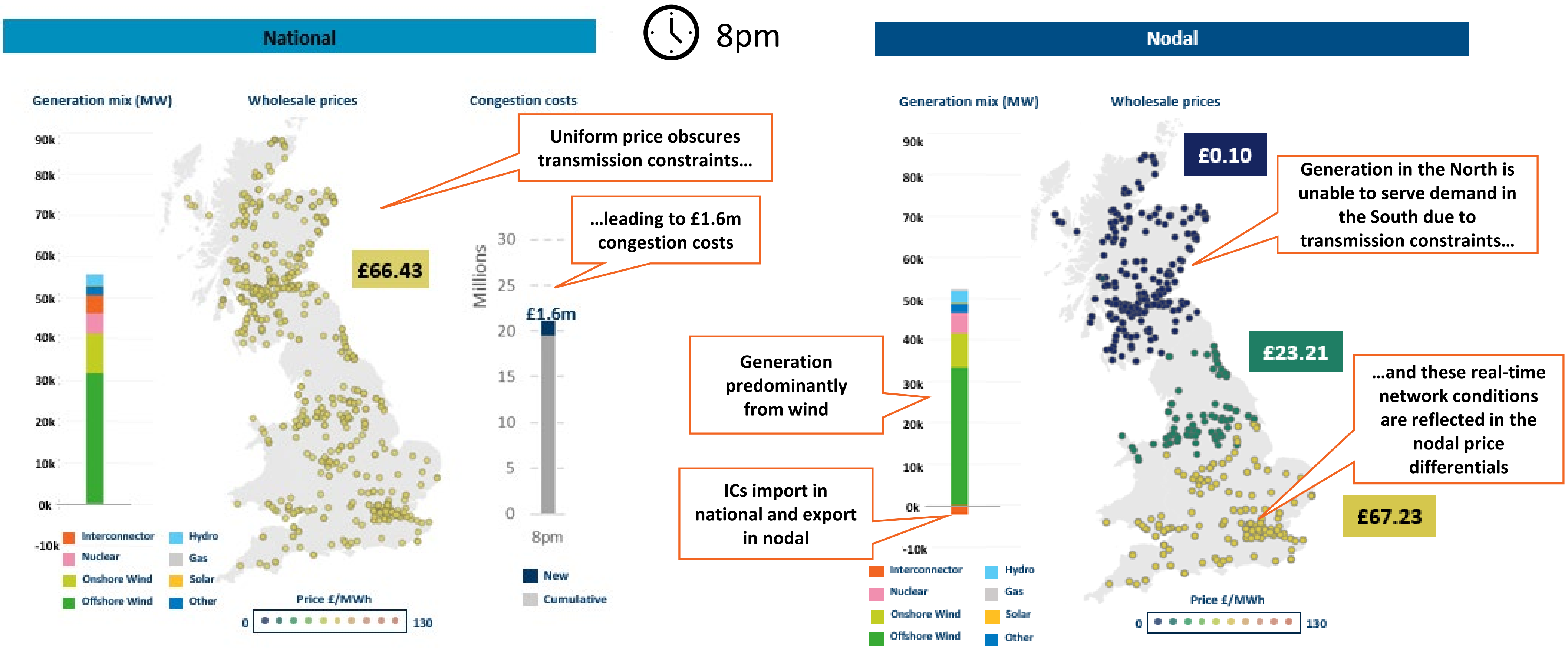
…because demand is mostly served by zero marginal cost generation, e.g. wind

Internal Only

Snapshot – 30/03/2030 @8pm

National design | Zonal design | Nodal design

Nodal prices reflect the real-time transmission network constraints, whereas these are obscured in a national price



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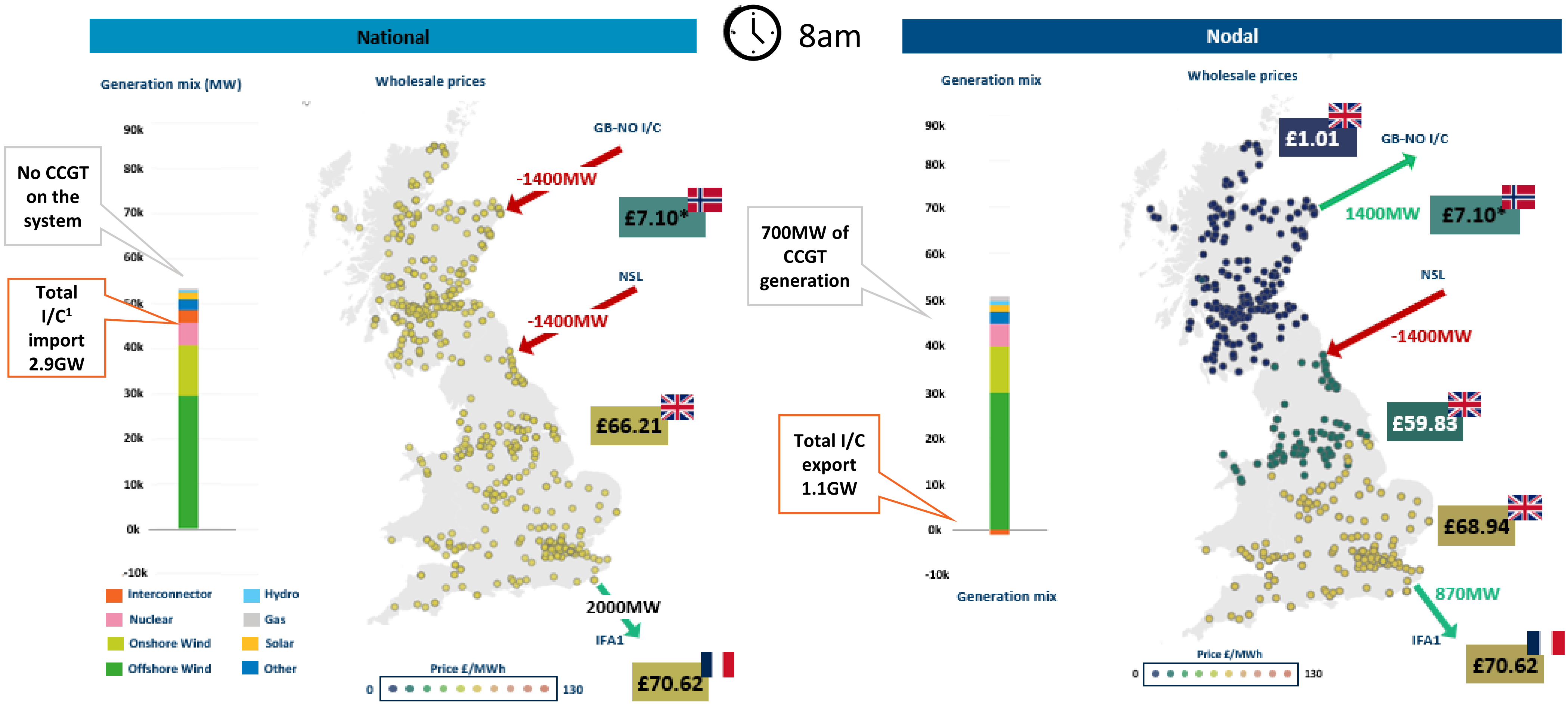
Under the national design, interconnector flows can exacerbate congestion, whereas under the nodal model, they can export excess renewable generation



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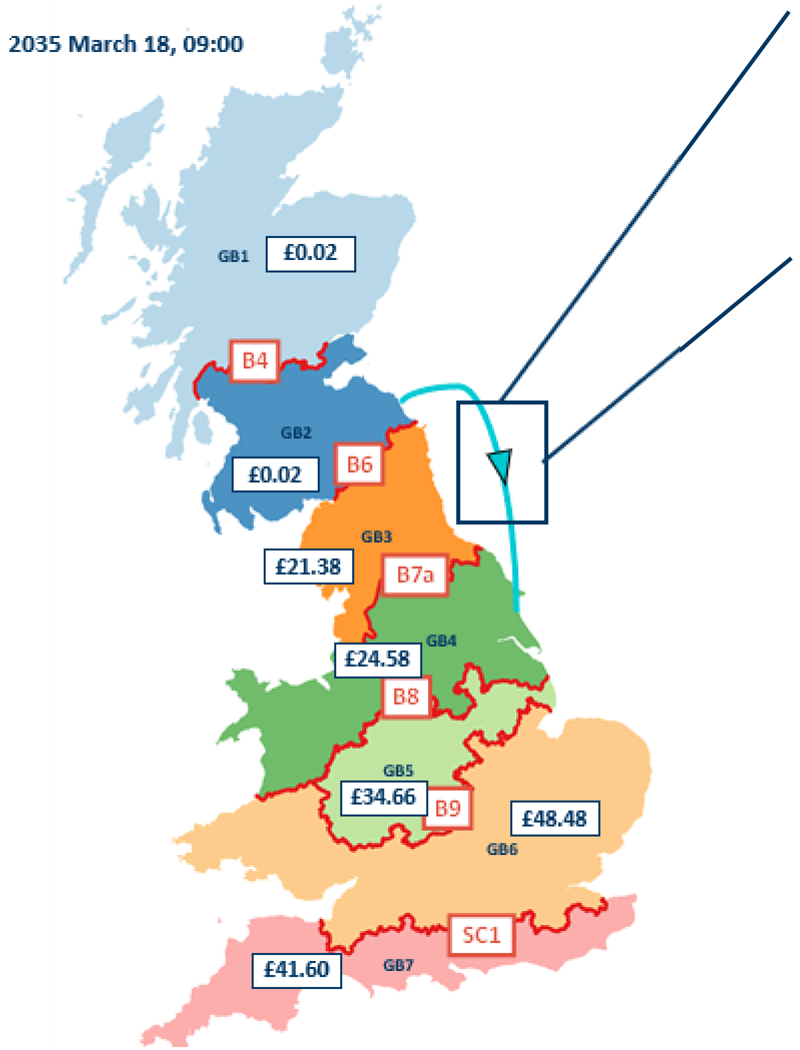
*Further refinement will update European prices to reflect changes in IC flows
Note: only a subset of interconnectors are shown in the map, for clarity.

Evolution of wholesale prices over day – National and Nodal market design

Modelling results: Intra GB-congestion rents

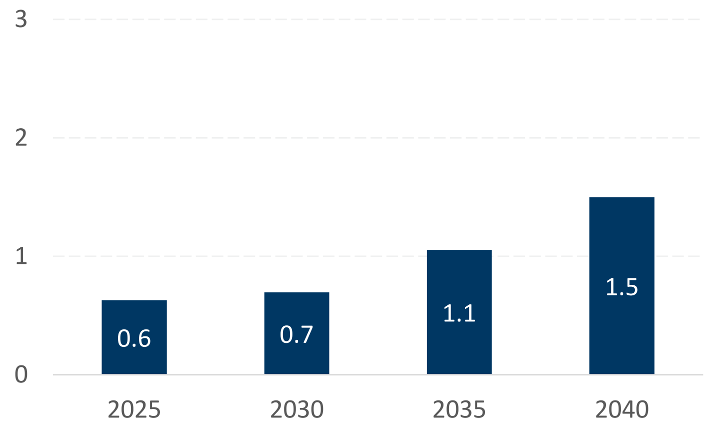
Transmission owners would earn congestion rents, based on the wholesale electricity price differential between the two price zones they are connecting



- Suppose, in a **given hour**:
  - The **wholesale price** of electricity in **GB2** is **£0.02/MWh**;
  - The **wholesale price** of electricity in **GB4** is **£24.58/MWh**; and
  - There exists **interconnection capacity** of **4.4GW** connecting GB2 and GB4.
- Assuming no losses, in settlement, this results in a rent of £108,064 (4.4GW*£24.56/MWh) in this hour.
- We refer to these revenues as **congestion rents, which arise on all zone boundaries** under a zonal market and **between all nodes on the network under a nodal model. Congestion rents do not exist under the national model.**
- The rights to these rents are so-called "financial transmission rights"....
- ....they are equivalent in concept to congestion rents in **interconnectors**

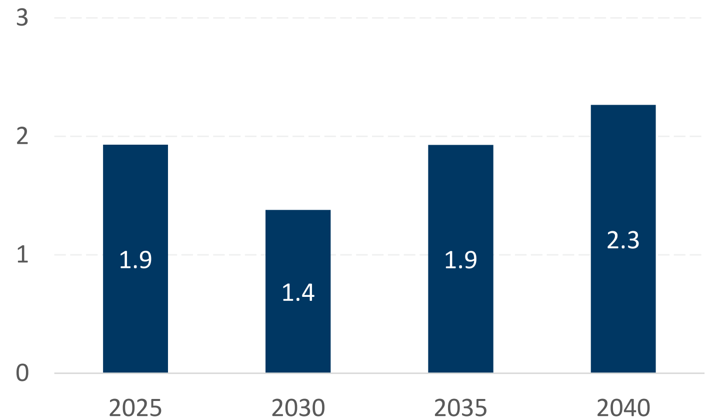
Transmission owners would earn congestion rents, based on the wholesale electricity price differential between connecting price zones or nodes

Intra-GB congestion rents (Zonal) (£bn/year)



- In **zonal design**, where congestion rents are only earned on inter-zone transmission lines, we estimate these revenues to be between £0.6bn and £1.5bn across the modelled years

Intra-GB congestion rents (Nodal) (£bn/year)



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- In **nodal design**, where congestion rents are earned on all transmission lines between pairs of nodes, we estimate these revenues to be between £1.4bn and £2.3bn across the modelled years

Transmission owners earn **congestion rents** when there is a **difference in wholesale price** between zones / across nodes.

Congestion rents **accrue to transmission owners** and we assume that they would, as a default option, be **used to reduce transmission costs** (ultimately borne by consumers).

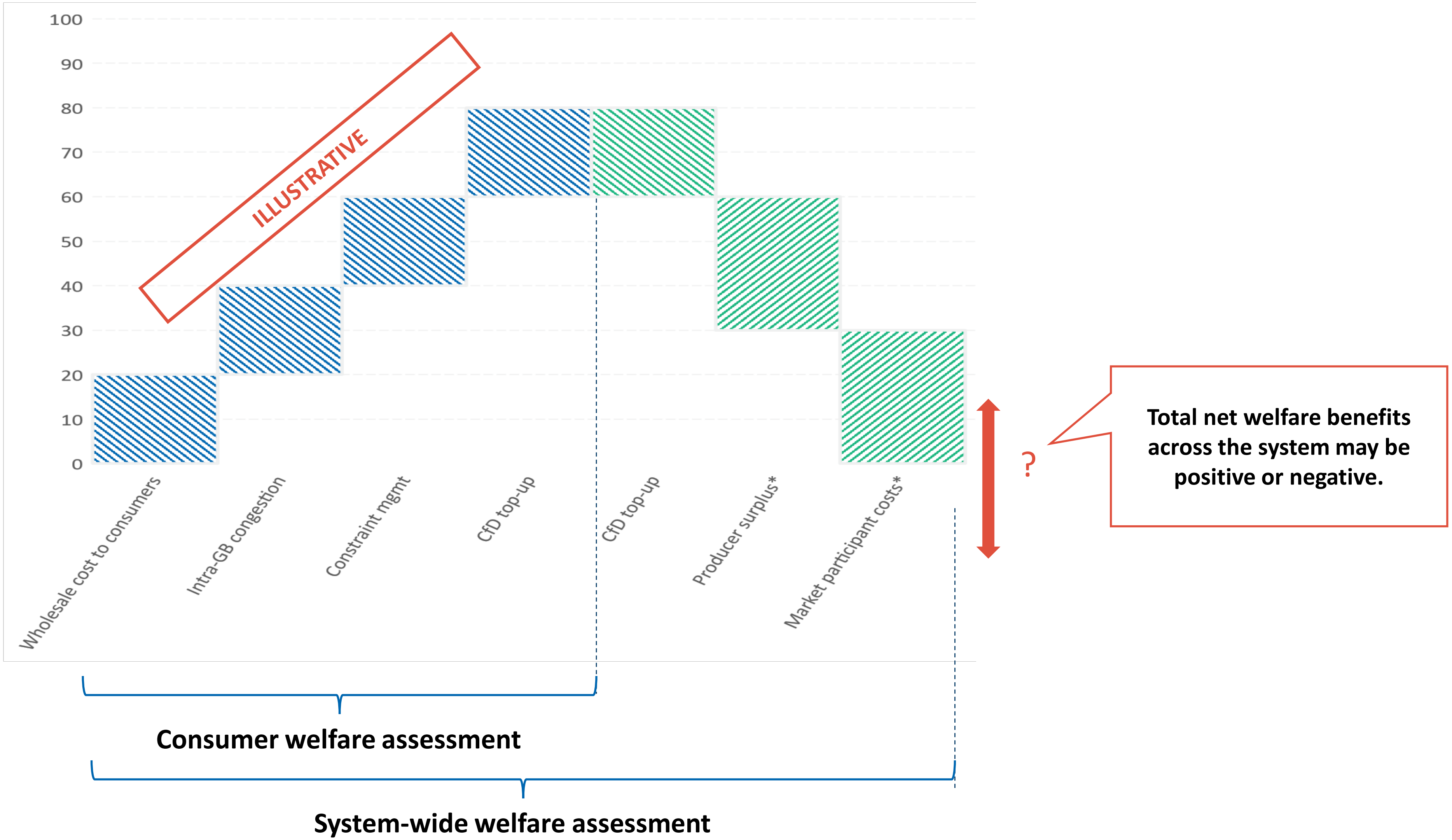
We therefore treat **congestion rents** as a **net benefit to GB consumers**.

Alternative options for distribution congestion rents are possible, e.g. by allocating FTRs to other stakeholders, which would represent a **welfare transfer**.

Preliminary modelling results: Aggregate impact assessment

Our final analysis will include both a consumer and a system-wide welfare assessment, in present value terms over the modelled period

Change in welfare impacts (£bn, Present Value over the modelled period)



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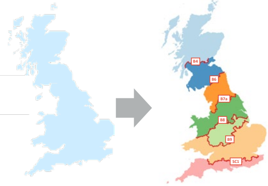
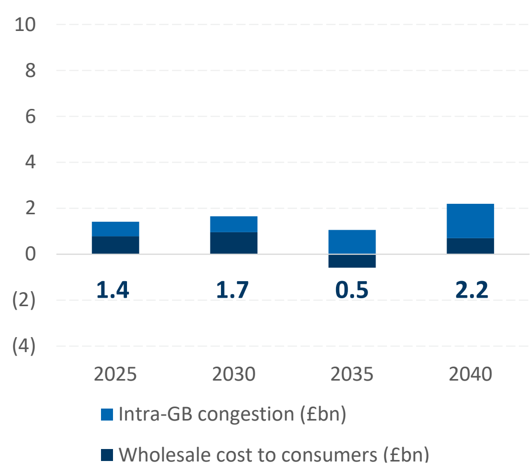
*Note: * Market participant costs include implementation costs to the ESO and industry participants, as well as any potential impacts on the cost of capital*
*** We will also include an estimate of the cross-border congestion rent change*

Preliminary results indicate significant consumer benefits from zonal/nodal designs, but we are yet to evaluate the full welfare impacts

National → Zonal design



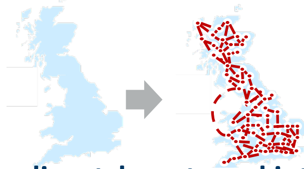
Change in wholesale prices and intra-GB congestion rents, Zonal (£bn/year)



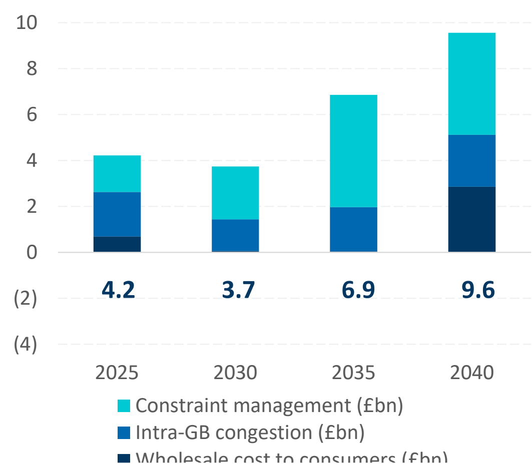
- On average across GB, in all modelled years, consumers benefits are estimated to be £0.5-2.2bn per year
- Constraint management savings are yet to be calculated, and are expected to be lower than in nodal design

Note: Positive figures represent consumer savings

National → Nodal design



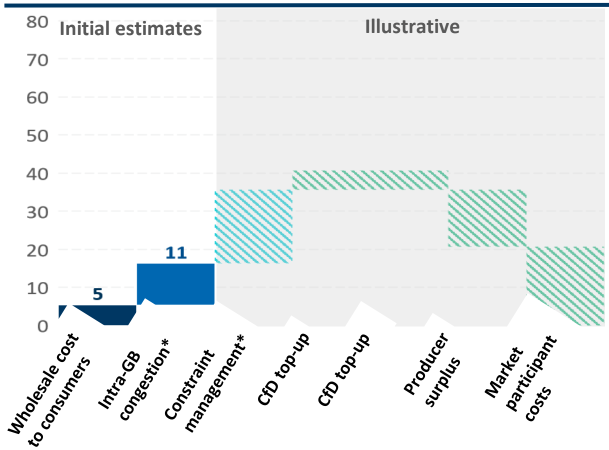
Change in wholesale prices, redispatch costs and intra-GB congestion rents, Nodal (£bn/year)



- On average across GB, in all modelled years, consumers benefits are estimated to be £3.7-9.6bn per year…
- …which includes an estimate of constraint management savings of £2-5bn

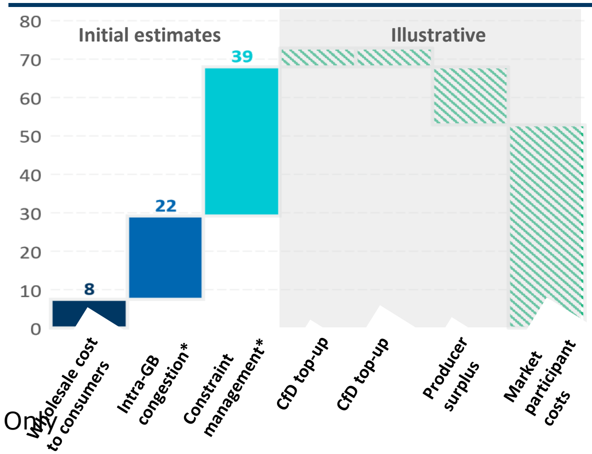
Note: Positive figures represent consumer savings

Change in welfare impacts, Zonal (£bn, Present Value 2025-40)



- Total system cost impact will include the elements above, plus changes in constraint management costs and producer surplus.
- Changes in CFD top-up payments, resulting from a change in wholesale prices, are a transfer between consumers and producers

Change in welfare impacts, Nodal (£bn, Present Value 2025-40)



- Preliminary results indicate that consumer benefit from moving from a national design to nodal design would, over 2025-40, be around £69bn
- Producer surplus will need to be considered to estimate the total system costs.

Internal Only

Note:
- *Intra-GB congestion refers to congestion rents on inter-zone transmission lines under the zonal market design and on all transmission lines under the nodal market design*
- *Constraint management refers to change in constraint management cost between national and zonal/nodal market design*

We will refine the preliminary results further and complete the assessment of consumer and system-wide welfare impacts

Key next steps to refine the assessment:

- Adjust the Leading the Way scenario outcomes (in relation to the transmission network updates and BM modelling)
- Undertake an analysis of the Leading the Way + HND scenario
- Complete the welfare assessment (CfD transfers, producer surplus, market participant costs, BM costs in zonal design)
- Consider potential transitional and implementation measures (with associated welfare transfer impacts)

Expected to increase avoided constraint costs in 2025-30 and reduce them in 2035-40 in zonal/nodal scenarios

Expected to reduce estimate consumer benefits of zonal/nodal designs (due to lower avoided constraint costs)

Locational granularity

National market

Zonal market

Proposed Modelli

Scenario 1: Leading

Scenario 2: System Tra

Key input

1 Transmission c

Includes current & future topology, and seasonal av assumptions

2 Demand

Includes annual demand, profile and flexibility assumptions by type and location

3 Generation capacity

Includes build-out assumptions, plant technical characteristics and renewable capacity profiles

4 Commodity prices

Includes price projections for a set of commodities (CO2, gas etc)

Power Market Model PLEXOS

Takes capacity from the Long Term model as given and determines the optimal output of generation (GWh):

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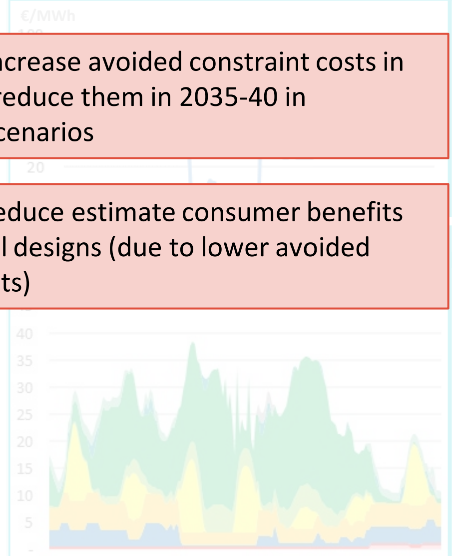
- …that meets demand…
- …on an hourly basis…
- …for each generating plant…
- …for each price zone

Hourly outputs for each modelled year

Wholesale power prices



Flows between zones

5 *Additional quantitative analysis*

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Changing **risk profiles** of market participants including **financing cost**

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We consider from three angles how moving to locational pricing may change the risks faced by market participants and the potential impacts on the CoC

Risk assessment	▪ Consider how the various risks faced by market participants might change following a change in market design from national pricing to locational pricing. ▪ Examine how the risks to market participants identified above may affect each component (taking into consideration any mitigation and transitional measures).
Stakeholder input	▪ Consider any evidence from stakeholders quantifying the impact on the cost of capital.
International evidence	▪ Examine direct and indirect international evidence on how implementing locational pricing has affected investment and the cost of capital

Risks may change for market participants depending on their location, but the magnitude and direction of the overall impact on risk is uncertain

Impact on risk depends on where MPs are located

We will focus on how these risks may impact WACC

		High demand relative to supply	Low demand relative to supply
Risks related to price variability	**Variability of wholesale revenues**	↑ **in price variability for some** but not all market participants (“**MPs**”), e.g. thermal or nuclear may have lower price volatility ↓ Higher prices likely, which **raises generator returns, stimulating investment**	↑ **in price variability** (some predictable, tools available to manage) ↑ Lower prices likely, which **reduces returns to generation built where it often cannot be dispatched**
	Variability of BM revenues	↓ BM will be smaller or no longer required, so **less volatile BM revenues**. Constraint costs are instead reflected in the locational price.	↔ Under both market designs, MPs (that would have been constrained down in a national market) **receive the national/ locational price**
Transmission network risk	**TNUoS charging risk**	↓ TNUoS charges, which are currently highly volatile, will likely be simplified leading to a **decrease in related risks**	
	Network build risk	↑ Future changes to transmission capacity can affect congestion in a zone/node and therefore prices, which may **increase risk for merchant MPs that do not take account of the timing of new transmission in their investment decisions**	
Other risks	**Transition risk**	↑ **Temporary increase** while MPs adjust to new market design, expected to dissipate over time	
	Regulatory risk	↔ **No change** as market design in GB is not fixed.	

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We are carrying out a high level assessment on how we might expect the identified risks to affect the various components of the cost of capital

Other components such as the risk free rate, market risk premium and tax rate are not affected by these risks

Components of the cost of capital that may be impacted		Beta	Cost of debt	Gearing
Risks related to price variability	Variability of wholesale revenues Variability of BM revenues	• Measure of systematic risk (that is, risk that cannot be diversified away). • Impacted by structural changes that affect the correlation between investment returns and market returns • We will assess the drivers of these risks and whether they are correlated with market return • If correlated, how does this correlation change with after moving to LMP?	• Measure of a company's credit risk • Primarily impacted by firm's probability of default • We will assess how these risks impact the probability of default.	• Measure of a company's financial leverage • There is an optimal level of gearing that minimises the WACC • We will assess how this may be affected by any changes to the cost of equity or cost of debt.
Transmission network risk	TNUoS charging risk Network build risk			

We will not be conducting a full analysis of the impact on the WACC as it is outside the scope of this project. Instead, we will perform a high level assessment of the expected impacts of each component above.

Some stakeholders have provided qualitative views on the likely impact on the cost of capital, but limited evidence quantifying their positions

Qualitative evidence

Stakeholders have raised concerns that locational pricing will increase the cost of capital, which could impact investment and hinder our Net Zero efforts. Some of the reasons cited include:

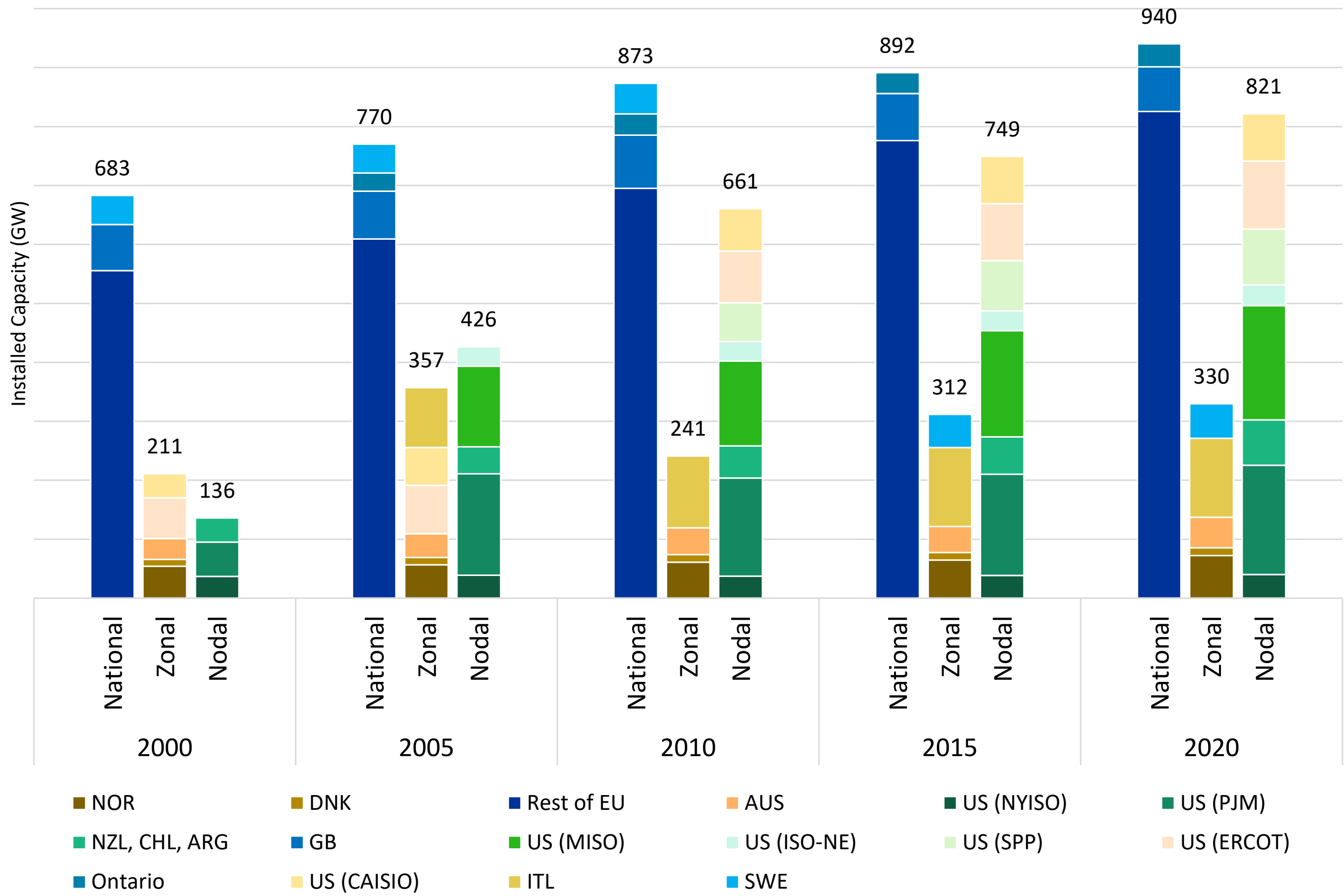
- greater uncertainty in forecast wholesale prices over the asset life at the point of investment;
- additional risks imposed on generators which they cannot manage;
- inability for generators to hedge exposure to lower wholesale prices;
- impact of a reducing number of generators and investors;
- temporary increase in cost of capital due to market disruption effects;
- investors will seek a premium for exposure to increased locational basis risk (which can lead to stranding of assets in particular locations);
- redistribution of congestion costs from consumers to generators; and
- volume risk as under LMPs wind farms will not be compensated for system curtailment

Quantitative evidence

- In Texas, one stakeholder's experience is that the premium required for a "station gate" contract over a "system contract" is 100-150bps

Q: Is there any further substantiated quantitative evidence from stakeholders?

Liberalised markets are increasingly moving towards more granular locational pricing

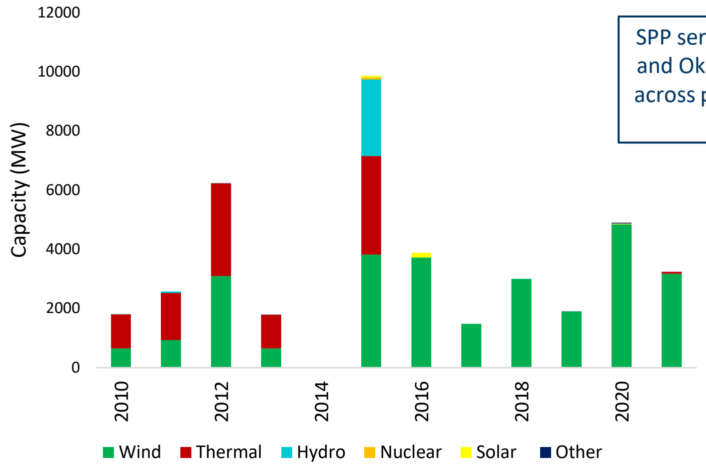


- Since 2000, capacity using **zonal and nodal pricing has grown by 56%** and **510%** respectively…
- This is partly driven by a **103% increase** in the **overall capacity** of all markets in the figure on the left.
- Capacity has also increased as various jurisdictions **switch toward more granular locational pricing**.
- As at 2020, **24%** of capacity using nodal pricing had **previously adopted zonal** (ERCOT and CAISO) pricing…
- … while **18%** of capacity using zonal pricing had **previously adopted national pricing** (Sweden).
- **Ontario**, which currently uses national pricing, is **planning to move to nodal pricing**.

In case study jurisdictions, investment in generation appears to be mainly influenced by policy incentives

Southwest Power Pool ("SPP")

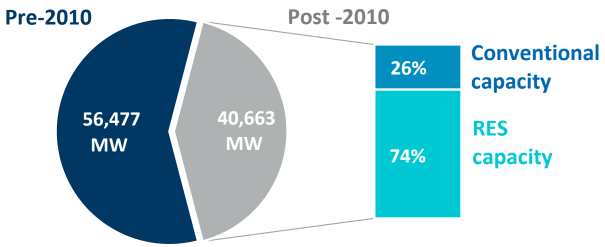
SPP capacity additions, 2010 - 2021



SPP serves all of Kansas and Oklahoma, and lies across portions of other states

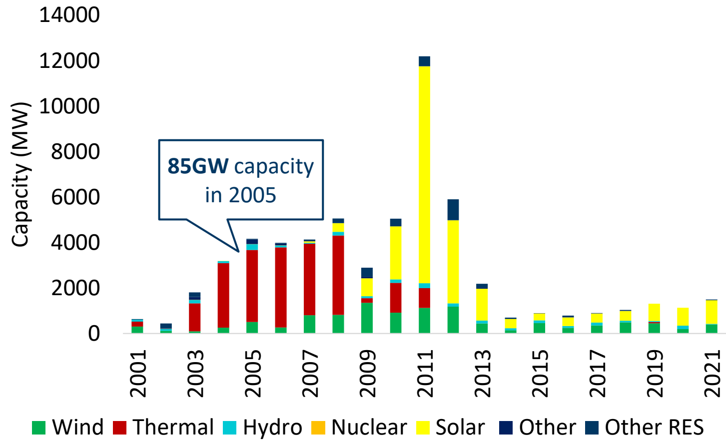
Note: 2014 and pre-2010 data unavailable.

- SPP moved to nodal pricing in 2007. There are a variety of RES investment schemes across the different states that make up SPP for example:
  - Oklahoma "promotion of wind development plan" in 2010, that aimed to facilitate further RES development and promote wind energy.[1]
  - State Renewable Energy Goals in Kansas (2009) and Oklahoma (2010), and Renewable Portfolio Standards other member states.[2]
- Of the capacity built from 2010 onwards, 74% of this comes from renewable sources. This is equivalent to over 30GW of RES, 27GW of which comes from additional wind capacity.

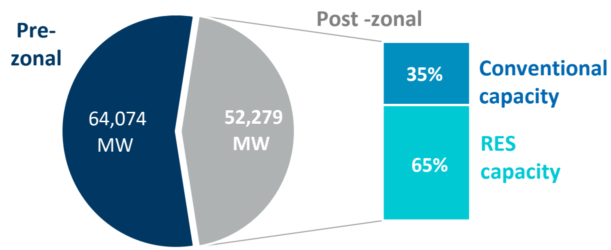


Italy

Italy capacity additions, 2001 - 2021



- Italy moved to zonal market design in 2005. At this time, there was an established Decree ("RES-E") that stated the minimum share of electricity from RES must increase by 0.35% per year. This was supported by Budget Laws outlining various incentives[3] e.g:
  - A new Feed-in-Tariff ("FiT") system introduced for Solar PV, leading to significant investment across Italy.[4] In 2011, the government announced it would reduce incentives due to falling prices of solar technology and lower electricity bills.
  - "Tradable green certificates (TGCs)", a cap-and-trade scheme to promote RES investment. From 2007 onwards these were extended to enable new RES plants to obtain TGCs for a total of 15 years (vs 12 before).
- Almost 50% of Italy's existing capacity has been developed since 2005. 65% of which is from renewable sources – this is driven by Solar PV, which has increased by >22GW.



Sources: 1) Southwest Power Pool update 2019 (link); 2) NCSL state renewable portfolio standards and goals (link); 3) IEA – Italy 2009 (link); 4) European Commission (link)

Due to the limited evidence found to date, we propose to assume no change in the cost of capital in our base case but will perform sensitivity analyses

Risk assessment

Risks may change for market participants depending on their location, but the magnitude and direction of the overall impact on risk is uncertain

Stakeholder input

Stakeholders have provided limited evidence quantifying the impact on cost of capital

International evidence

We expanded our review of capacity evolution in other jurisdictions. We found that RES capacity development was predominately influenced by policy incentives.

Proposed approach	
Base case	No change in the cost of capital
Sensitivity 1	Increase in cost of capital by **X** bps
Sensitivity 2	Decrease in cost of capital by **X** bps

Degree of change in the sensitivity analyses to be determined

- We have also considered assuming that the CoC will vary with **time, location or technology**…
- ….but have **not implemented** these due to the **limited evidence base**

Q: What are your views on degree of change that we should consider the sensitivity analysis?

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Liquidity

Comparison of liquidity across jurisdictions can be difficult due to different market characteristics (e.g. volume, structure, products) and metrics reported

What is liquidity?

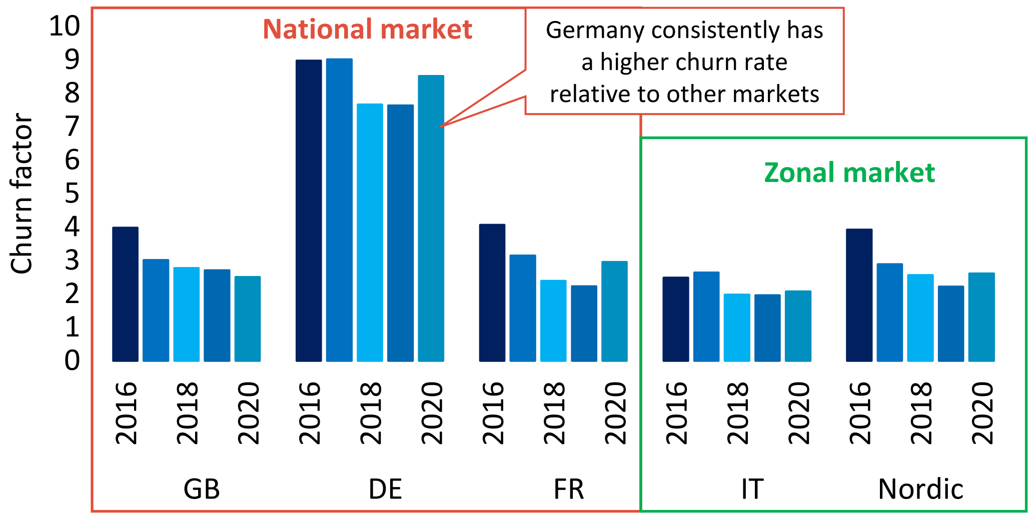
- Electricity markets are considered liquid if a **significant number of market participants** are able to sell and buy products in **large quantities quickly**…
- …**without significantly affecting prices** or incurring **significant transaction costs**.

Measures of liquidity

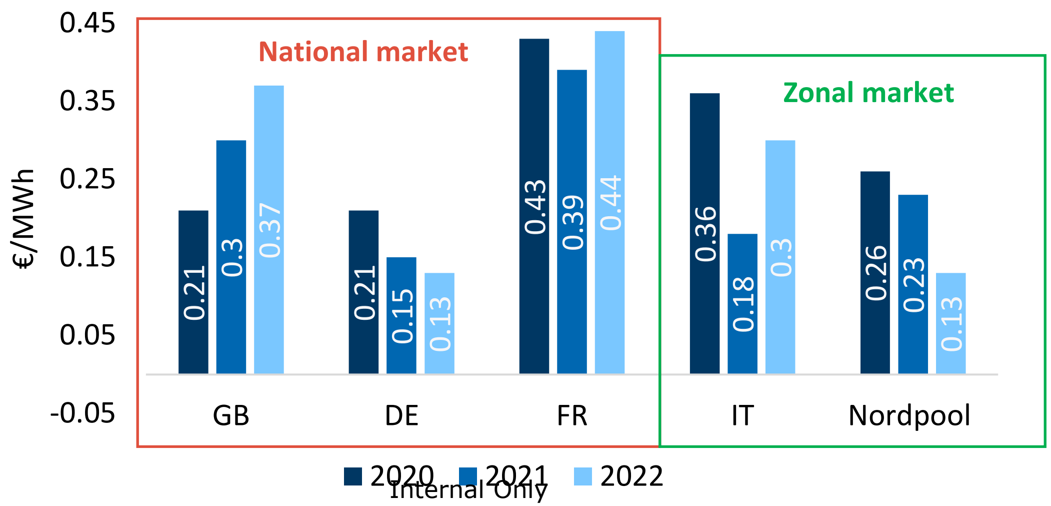
- There is **no universal measure of liquidity** in energy markets…
- …but the two most commonly used approaches are the **churn rate** and **bid ask spread**.

Churn ↑ / **Bid-ask spread** ↓ ▶ ↑ **Liquidity**

Forward market churn factors, international markets, 2016 - 2020



Average bid-ask spreads of OTC yearly products, 2020 – 2022



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Churn

- GB's churn rate has **fallen since 2016**
- Compared to other national pricing systems…
- …GB's forward market churn is **similar to that of France** but **lower than Germany**…
- … and is **comparable to Italy and Nordpool (zonal)**.

Bid-ask spread

- Average bid-ask spreads in GB have **risen since 2020**
- Compared to other national pricing systems…
- GB's average bid-ask spread is **lower than France** but **higher than Germany**…
- … and are **higher than Italy and Nordpool (zonal)**.

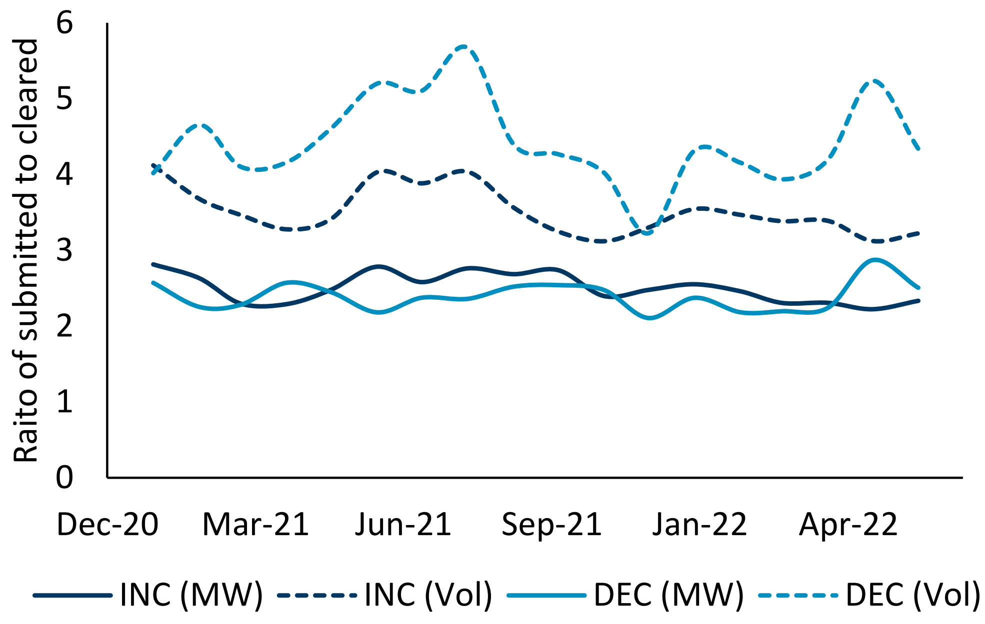
The evidence we have found indicates that nodal markets have evolved to form hubs and FTRs that support market liquidity

Concerns expressed by some stakeholders

- Some stakeholders have expressed concerns that **liquidity will be lower** under locational pricing because market participants will have to **trade at their node rather than across the whole market…**
- …resulting in **fewer trading counterparties and less efficient trading.**

- The evidence we have gathered so far indicates that **nodal markets have developed mechanisms** to support **market liquidity**.
- For example, nodal markets **in the US have evolved trading hubs** that are defined by ISOs and market participants.
- Trading at and between these hubs are **very liquid** in the forward exchanges as evidenced in papers by the Climate Policy Initiative (2011) and MIT Energy (2022).[1]
- This could a potential option for GB, where **trading is not constrained at a particular node**, but rather via **liquid hubs**…
- … and market participants will manage **price differentials** between the hub and their node **via FTRs**.

Cleared bids/offers as a % of submitted bids/offers, PJM, Jan 2021 to June 2022



In PJM, the no. of submitted increment ("**INC**") offers and decrement ("**DEC**") bids is typically **2x to 3x** the number of cleared bids (measured in MW) or **3x to 6x** (measured in volume)

Source: (1) Climate Policy Initiative (link), (2) Q2 2022 State of the Market, PJM, (3) Eicke and Schittekatte, MIT Energy (February 2022).

Wrap-up and next steps

Wrap up & next steps

Next few weeks

- Publish workshop materials and any other supportive materials
- Progress modelling (incl. limitations discussed today and HND)
- Incorporate additional stakeholder feedback

Later this year

- Planning for 2-3 further workshops ~ Oct-Nov covering:
  - Zonal and nodal market designs and policy interactions
  - Updated modelling results (based upon NOA7 refresh)
  - Analysis on mitigations and transitional measures, distributional impacts and market participant risks
- Report setting out our findings