

Net Zero Market Reform Phase 3 Conclusions

A futuristic, brightly lit tunnel with glowing blue lines on the walls and floor, with people walking through it. The tunnel has a curved, ribbed structure and is illuminated with a cool blue light. Several people are walking away from the camera towards the end of the tunnel. The overall atmosphere is clean, modern, and high-tech.

Markets Forum
22nd March 2022

Detailed slides

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- The case for market reform
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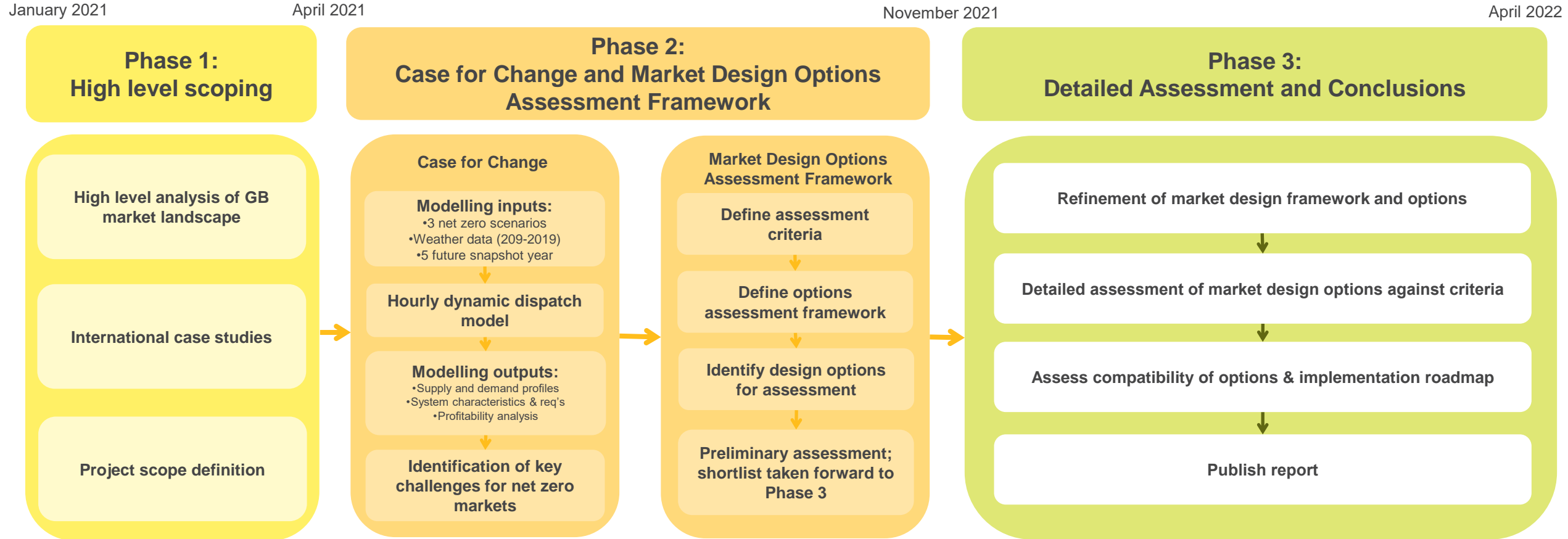


Overview



NZMR Project Timeline

Recap



We need to achieve net zero at lowest whole system cost. The current market was not designed for net zero and left unchanged will impose excessive costs to consumers.

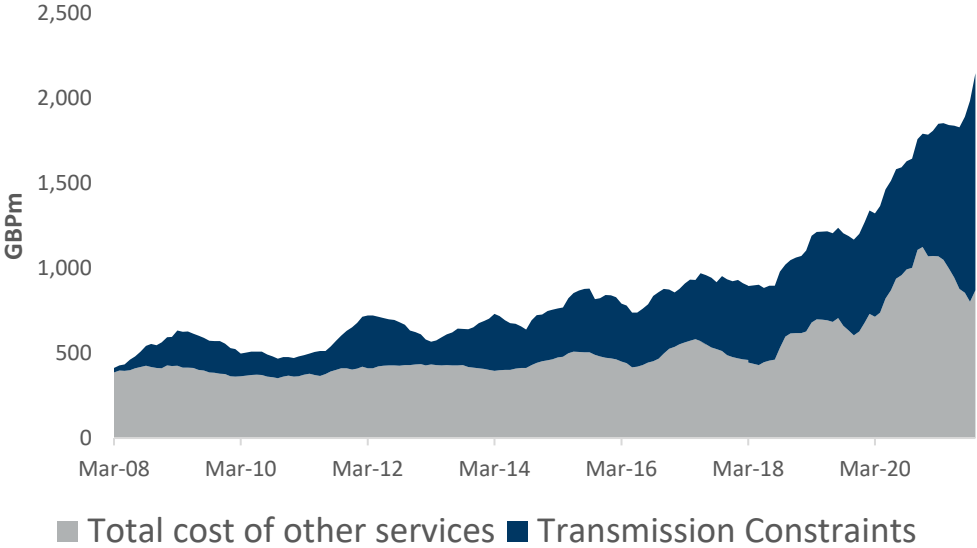
From our position as Electricity System Operator, our analysis has provided some key insights that support the argument for reform:

1. Even with significant transmission investment, constraint costs are **rising at a dramatic and accelerating rate**
2. **Balancing** the network is becoming **more challenging** and requires increasing levels of inefficient redispatch
3. **Interconnectors and storage** are an important source of supply and flexibility but current market signals mean they are at times flowing in a direction that **exacerbates constraints**
4. Current market design does not provide the signals required to **unlock the full potential of the diverse range of sources of flexibility** needed to facilitate net zero

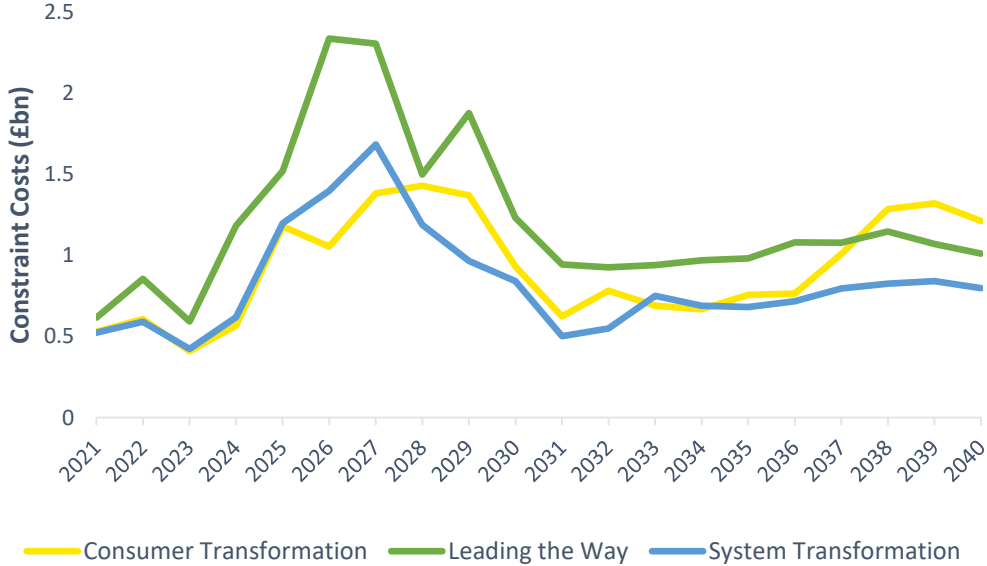
These issues are arising because the wholesale market price is missing a key component: dynamic real-time locational signals

Our most recent NOA process indicates constraint costs may continue to rise at an extreme rate, despite network reinforcement, through the 2030s

ESO balancing services costs, 12-month rolling (£m)



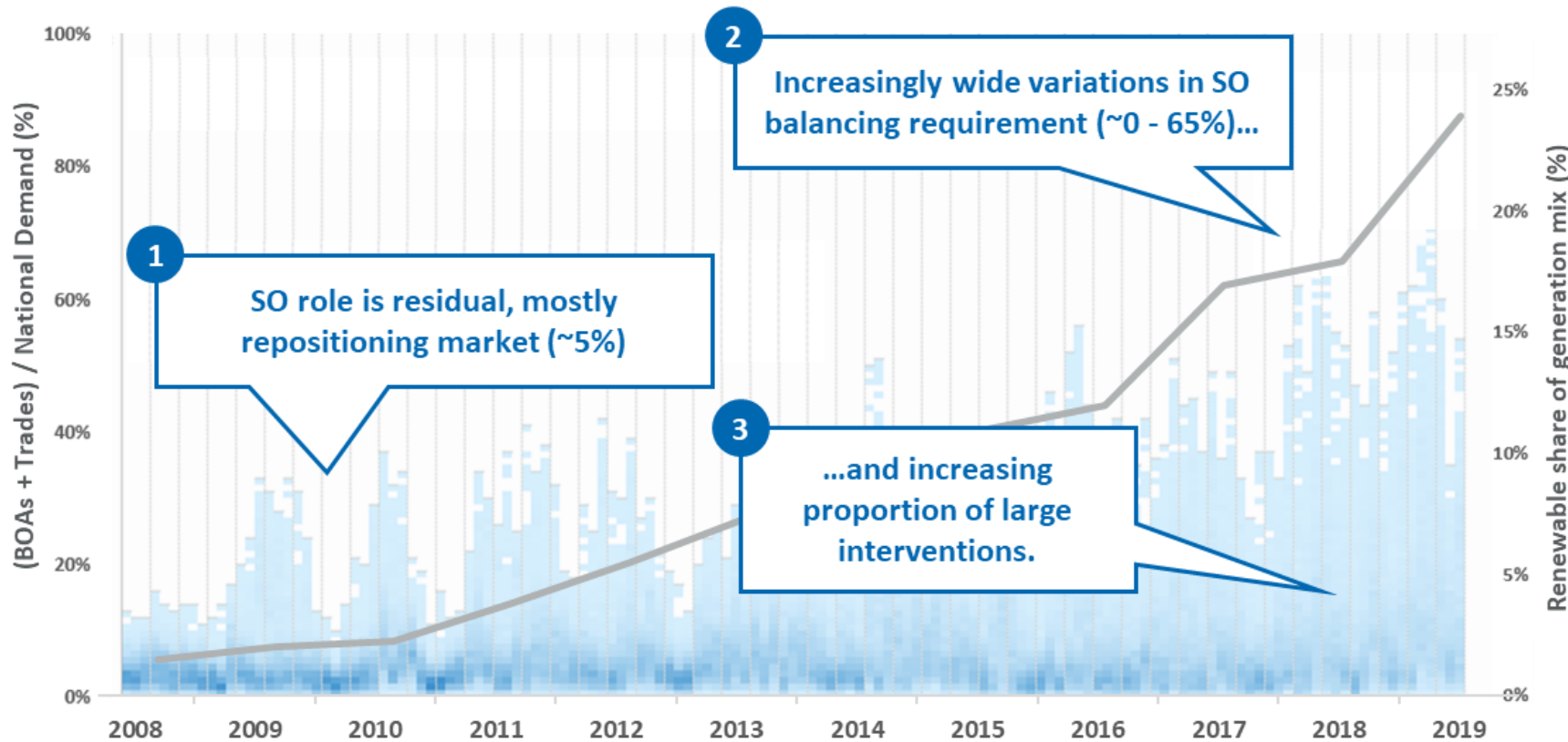
Modelled constraint costs after NOA6 Optimal Reinforcement (£bn)



- **Congestion costs** have already **increased 8-fold since 2010**
- Latest NOA projections for the Leading the Way and Consumer Transformation FES scenarios indicate **continued dramatic growth in constraint costs this decade**
- Constraint costs **could reach £2.3bn p.a. by 2026**, with potential renewed growth in the late 2030s after a reduction due to network upgrades in the early 2030s

With higher renewables penetration, the need for ESO redispatch has markedly outgrown the residual balancer role envisaged at NETA

SO balancing as proportion of national demand¹ (%) vs renewable share of generation

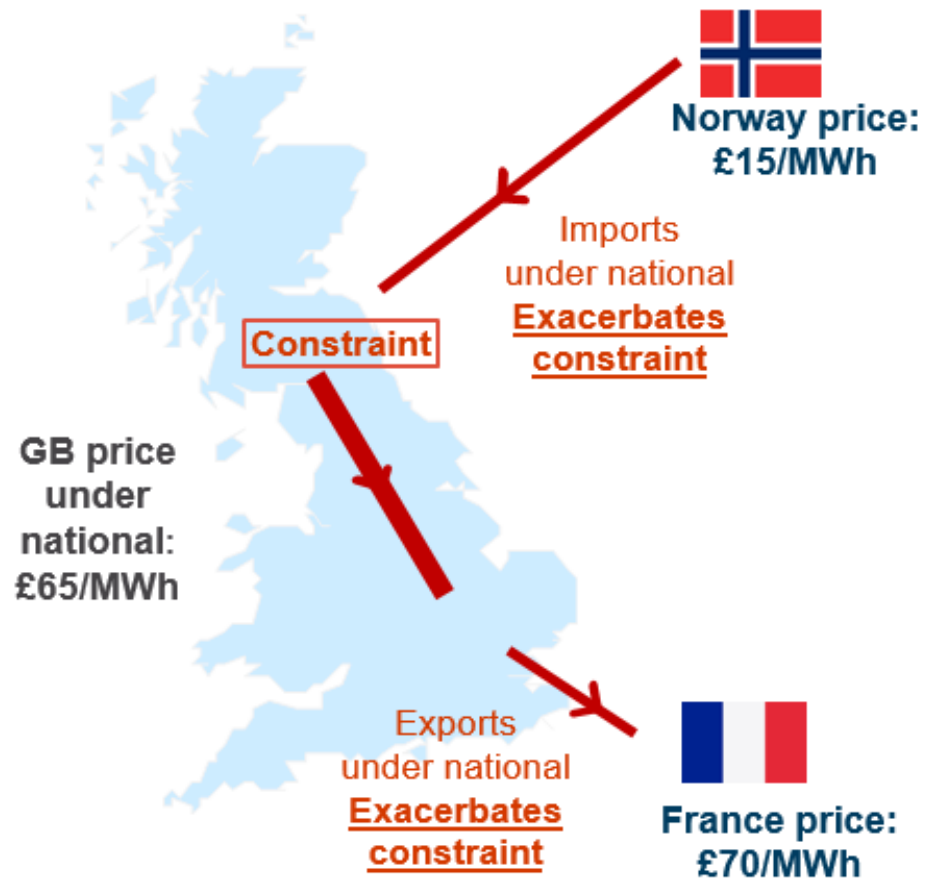


- A rapid change in **how** and **where** electricity is generated has **shifted the requirements of the ESO**.
- Undermining the **residual role** envisaged at NETA inception, the level of ESO activity has increased significantly...
- ...with balancing actions now **regularly exceeding 50% of national demand**
- At times the GB system now **operates close to central dispatch** (though under very condensed timescales post-gate closure).

1) ESO balancing actions shown as a heatmap, with darker areas representing a higher frequency of actions of a given size.

The single national price is creating perverse incentives for flexible assets crucial to net zero

Interconnector flows under status quo national pricing

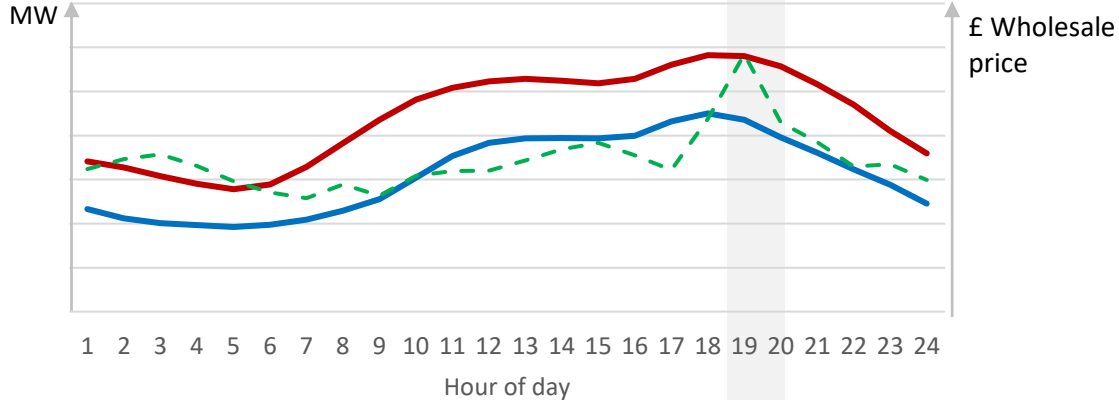


Status quo market design is causing storage and interconnector behaviour that aggravates grid constraints

- When the cross-border market price falls between the true local price at GB point of interconnection and the national GB price, an I/C can import / export counter to system needs
- A similar dynamic occurs for battery storage
- Projected capacity increase to 2035 (Leading the Way, FES 2021):
 - Interconnectors: 7.1 GW → 26.8 GW
 - Battery Storage: 4.6 GW → 23.4 GW

The single national price is also creating inaccurate signals for demand to respond

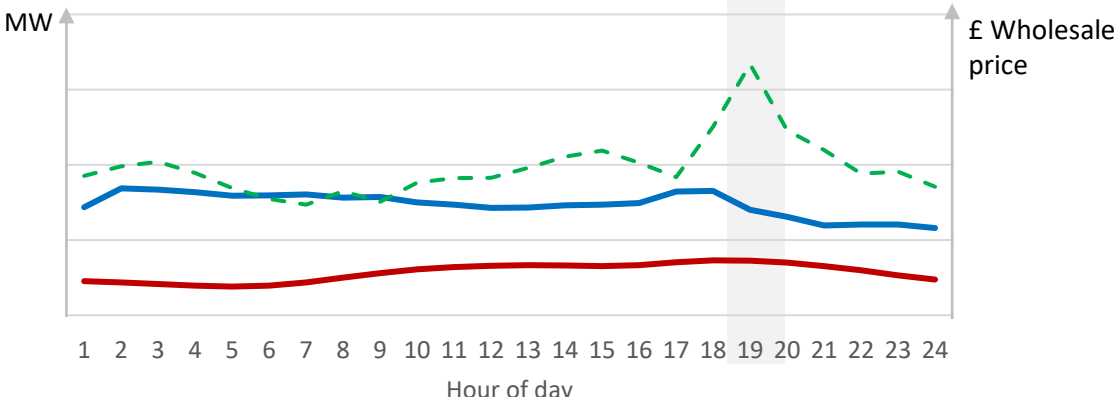
Location in South (illustrative)



Demand is incentivised to reduce load to address scarcity... (although not as much as it could be)

— Local supply — Local demand - - - Wholesale price

Location in North (illustrative)



...but low demand location is also incentivised to reduce demand despite no scarcity issue

...and at times exacerbates constraints

These issues are arising because the wholesale market price is missing a key component: near real-time, dynamic, locational signals

- The wholesale electricity price should reflect the full marginal cost of meeting demand
 - At a certain **time**
 - At a certain **location**
- So long as the real time **wholesale price cannot communicate the locational value of energy**, both generation and demand side assets will respond to inaccurate price signals
- The consequence is a **steep and accelerating rise in costs**, as assets are dispatched inefficiently

We have assessed three options for improving locational signals in the GB electricity market

Weaker locational signals

Stronger locational signals

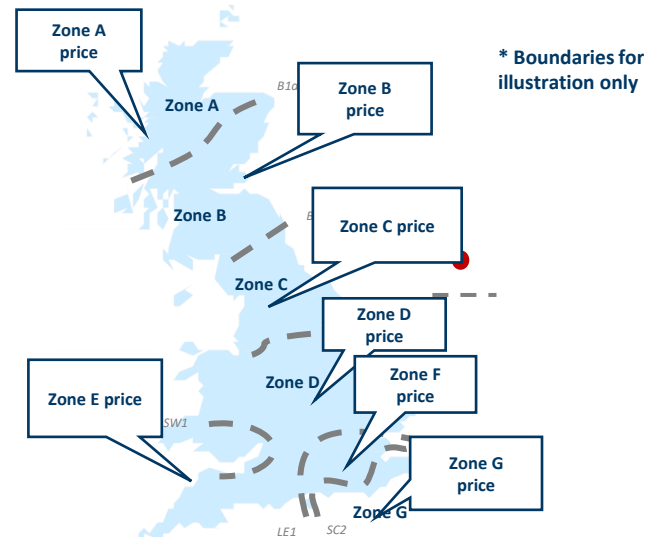
Single national price and locational network charges

Uniform price clears across entire market



Zonal pricing

System divided into a small number of zones with individual prices



Nodal pricing

System divided into many "nodes" with individual prices



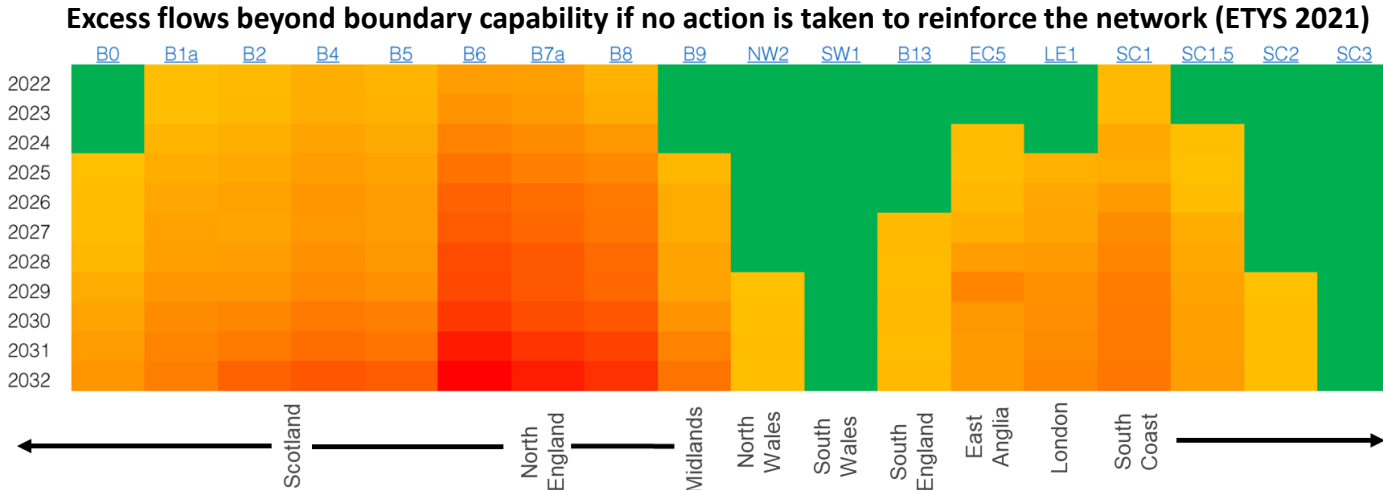
Neither national nor zonal pricing can provide a full and enduring solution to inefficient real-time dispatch

Incremental reform to existing locational network charges cannot provide signals that reflect real-time system needs

- As an ex-ante capacity based charge, **TNUoS cannot provide a short-run locational signal** to market participants that **reflects real-time system needs**
- BSUoS Taskforce (2019) assessed the feasibility of four potential options for BSUoS reform, concluding:
 - “the implementation of each of these would not or could not provide a cost reflective and forward-looking signal that would drive efficient and effective market behaviour”
- Only a subset of the market is exposed to locational signals via BM bid / offer acceptances

Zonal pricing provides only a partial and temporary solution

- Intra-zonal congestion would remain unresolved
- The **need to re-zone** to capture congestion costs effectively is **inevitable**:
 - ETYS 2021 illustrates the rapid evolution of boundary transfers over the next decade – a trend that is likely to continue
- Ongoing regulatory risk** from debate on whether and where to redraw zonal boundaries



Nodal pricing would address critical issues in the current design, and sets up an enduring foundation for net zero

Nodal pricing scored most highly against our assessment criteria

		National wholesale market	Zonal wholesale market	Nodal wholesale market
1	Decarbonisation			
2	Security of supply			
3	Value for money			
4	Investor confidence			
5	Deliverability			
6	Whole system			
7	Consumer fairness	/	/	/
8	Competition			
9	Adaptability			
10	Full chain flexibility			

Analysis to be published in April

Additionally, we believe it is the optimal solution for resolving the critical operational issues we have identified

1. Efficient dispatch **reduces balancing costs**
2. Provides **correct signals** to interconnectors and storage
3. Delivers accurate locational price signals (dispatch and siting) needed to **realise demand side value**
4. More **adaptable and resilient** to changes in electricity market conditions

We assessed two types of Dispatch mechanism: self-dispatch (the status quo) and central dispatch with the option for self-commitment

The choice of Locational market design largely determines the choice of Dispatch mechanism:

National/ zonal pricing

Self-dispatch (status quo)

- Participants self-schedule and commit their output
- Market Operator issues dispatch instructions to balance generation and demand and to resolve constraints



Nodal pricing

Central dispatch with self-commitment

- Participants submit their availability and price (unless self-scheduling, when just availability is required)
- Market operator schedules assets and may commit additional units within day
- Actions complemented by bilateral markets with over-the-counter trades
- In most jurisdictions, trades are financially binding not physically binding



Central dispatch with the option for self-commitment gives the System Operator the tools and visibility needed to balance a highly volatile market

Central dispatch with the option for self-commitment scored most highly against our assessment criteria

		Central dispatch: Centralised commitment	Central dispatch: Self-commitment	Self-dispatch
1	Decarbonisation	Analysis to be published in April	●	●
2	Security of supply		●	●
3	Value for money		◐	◑
4	Investor confidence		◐	◐
5	Deliverability		◑	●
6	Whole system		●	●
7	Consumer fairness		●	●
8	Competition		◐	◑
9	Adaptability		◐	◑
10	Full chain flexibility		◐	◑

System Operator would have better information, greater diversity of tools and more time to balance the system

- In representative markets, SO pre-schedules units at 24 hours, giving it more time to balance the system
- SO would have access to a wider diversity of assets for balancing with visibility of more assets and their capabilities

Enables co-optimisation of energy and reserves

- Near real-time, single procurement process drives efficiencies: System Operator could choose whether to allocate the same capacity to producing energy or reserves

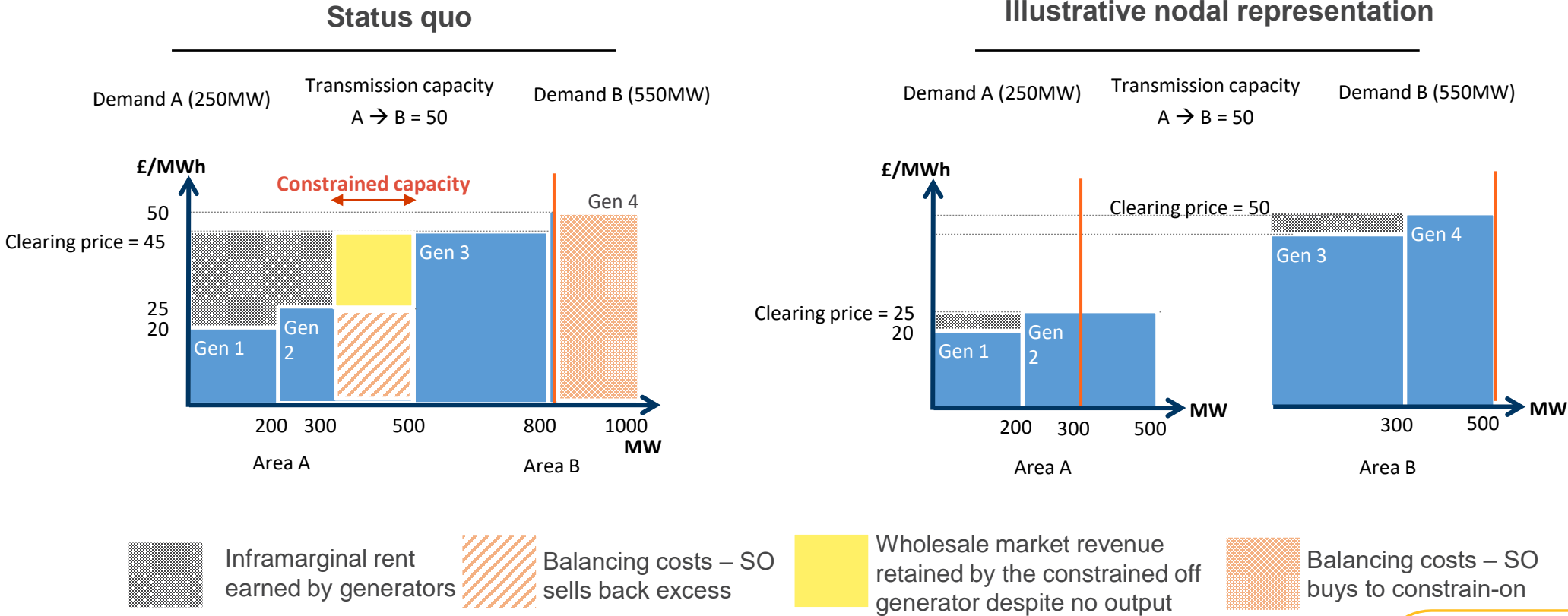
Level playing field for smaller assets & new entrants

- Single counterparty for wholesale market transactions would reduce administrative burden for new entrants
- System Operator would publish key price data, increasing price transparency and lowering barriers to entry



Nodal pricing: key benefits

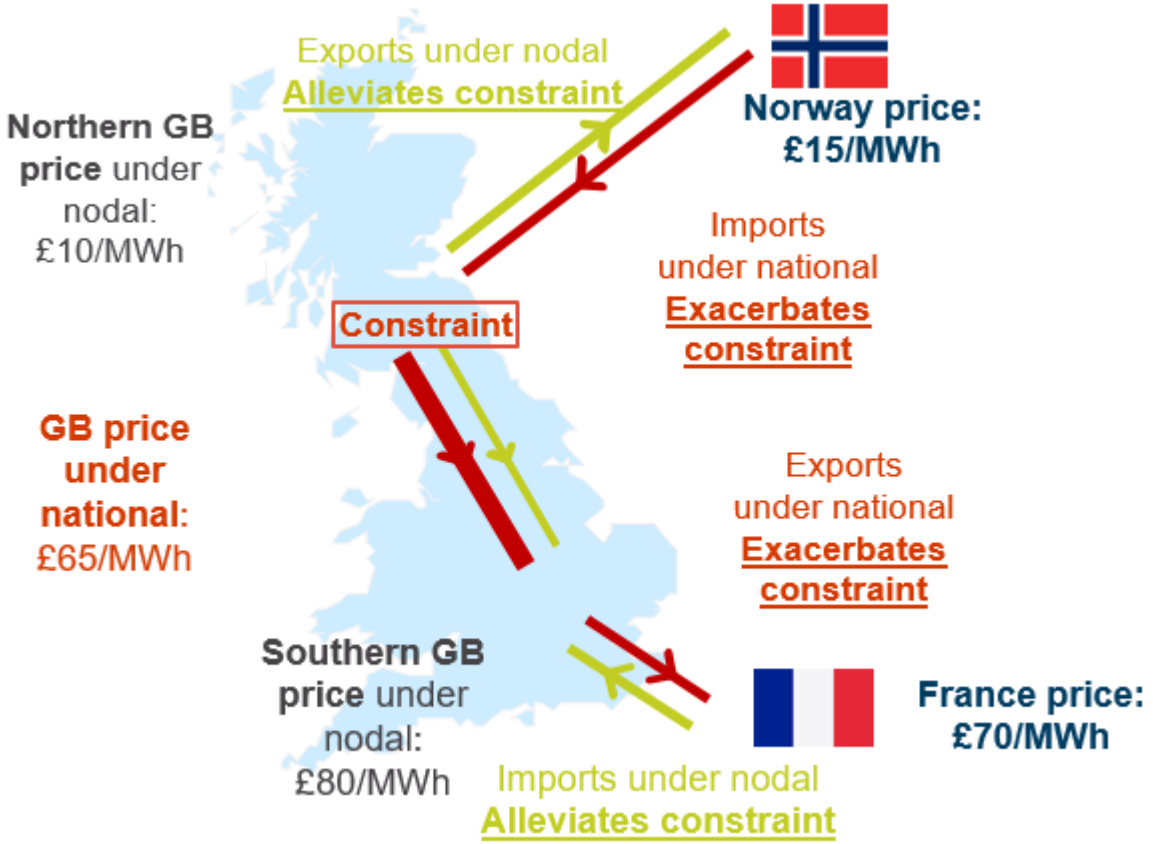
1. Nodal pricing would incorporate congestion value into the wholesale price, removing the need for constrained off payments



Nodal pricing: key benefits

2. By incorporating a dynamic locational signal into the wholesale price, interconnector and storage flows would align with system needs

Illustrative comparison of interconnector flows under status quo and nodal pricing



- With a **national price**, transmission constraints **can create inefficient price signals for interconnectors and storage assets**, increasing BM costs...
- ... Whereas with **zonal/nodal pricing**, as **transmission constraints are recognised in price formation**, correct price signals would be provided.

Nodal pricing: key benefits

Evidence

3. Nodal pricing would facilitate sharper and more accurate price signals that would help the demand side to realise its full value



Nodal pricing would facilitate locationally accurate signals needed by demand side assets to respond effectively. This includes dispatch signals, but importantly also siting signals, for example hydrogen electrolysers and energy-intensive industries.



Greater within-day price variations with nodal pricing would greatly **increase the incentive on consumers to shift demand** to times of greatest local renewable output, reducing the peaking capacity requirements



Other fundamental demand-side enablers, including smart metering and time of use tariffs, are already available (and must become universal to maximise potential).

Key questions: investment



Our analysis of jurisdictions that have implemented nodal pricing and central dispatch has not identified any adverse impact on investment

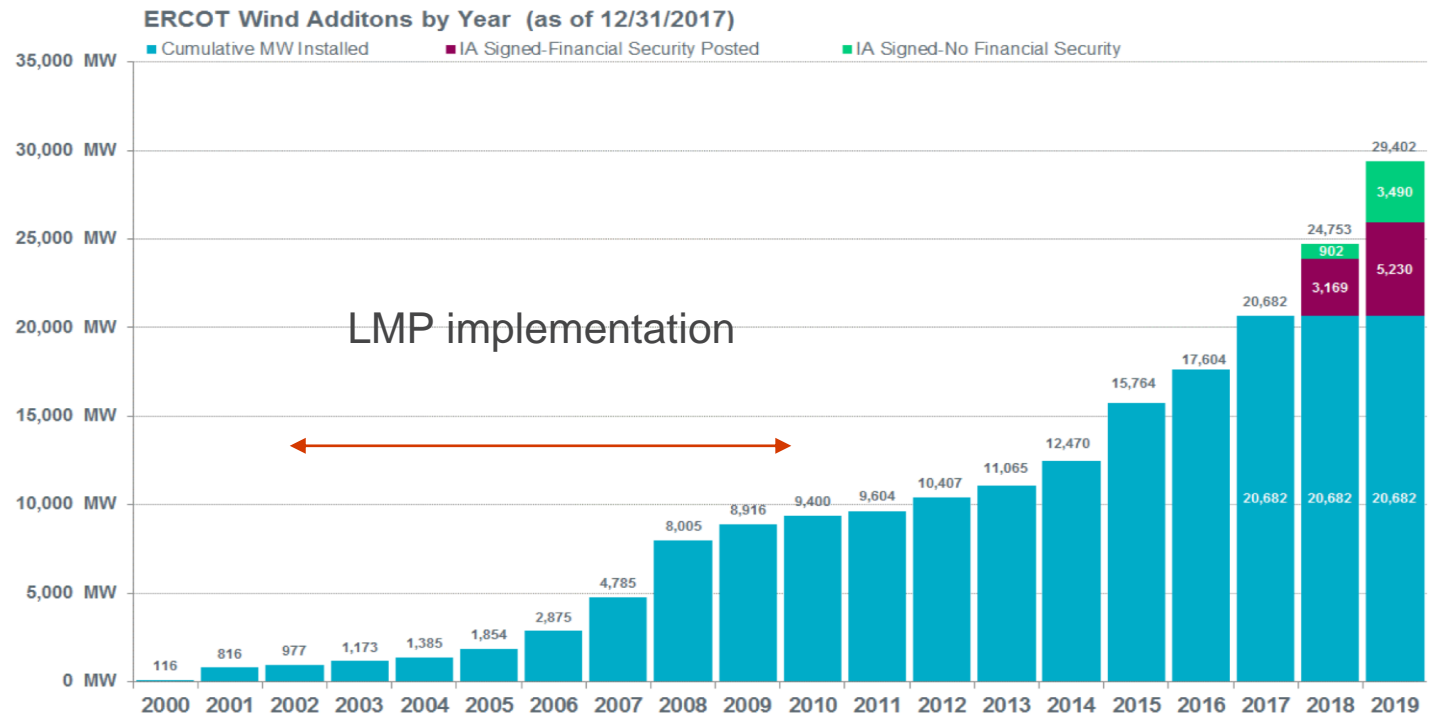
In ERCOT wind capacity built at scale during and after implementation of nodal pricing

- From 2005, Texas developed Competitive Renewable Energy Zones and a transmission plan alongside implementation of nodal pricing
- Texas installed wind capacity is now c.35GW, around double original target

Other nodal markets have seen sustained wind capacity growth following nodal pricing implementation

Market	Nodal intro	Wind build (1998-2020)	Wind build (pre-nodal)	Wind build (post-nodal)
MISO	2005	26.3GW	1.7GW (6%)	24.7GW (94%)
CAISO	2009	5.5GW	1.3GW (24%)	4.2GW (76%)

Texas (ERCOT) wind capacity growth (2000 – 2019)



Source: ERCOT (2018)

Key questions: consumers



Our analysis shows that a nodal pricing market with central dispatch could deliver significant consumer benefits

1. Removes compensatory payments from consumers to generators who are constrained off
2. Ensures most efficient resources are dispatched, taking into account network constraints
3. Increases demand side flexibility
4. Incentivises more efficient siting of assets

Key questions: consumers



Consumer exposure to locational prices can be modified by choice of design

Consumers less exposed to nodal prices



Consumers more exposed to nodal prices

Ontario (IESO)

- At implementation go live (2023) all load will be default charged the average Ontario price
- Consumers can opt-in to nodal prices

California (CAISO)

- Consumers pay one of 3 prices corresponding to the state's 3 distribution utilities
- Price derived from nodal weighted average price in that region

PJM / MISO

- Allows designation of custom load zones for particular customers
- Remaining load pays residual
- Annual revision of new load zones to incorporate changes

Texas (ERCOT)

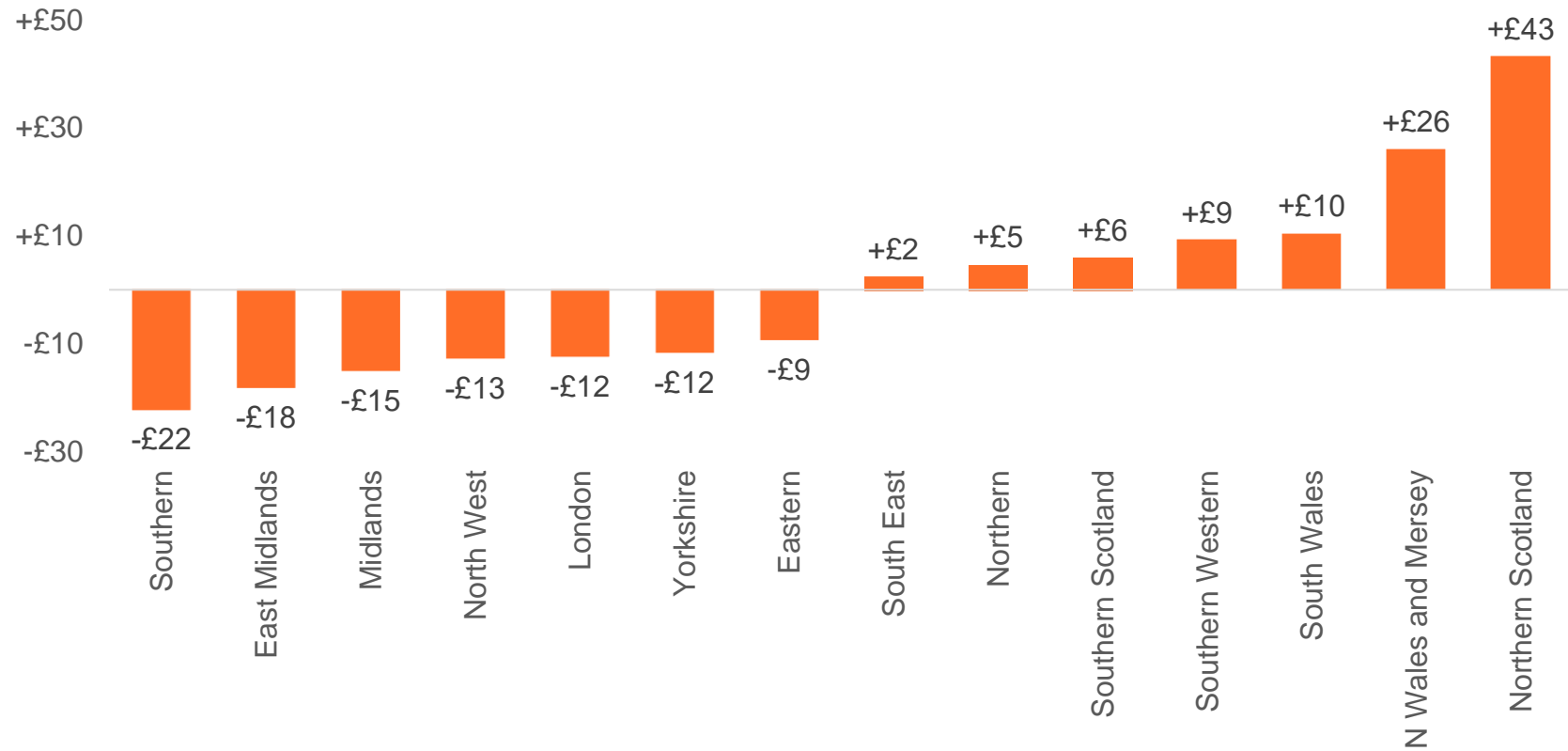
- All consumers in deregulated regions are served at nodal prices

Key questions: consumers



Consumer tariffs are already unequal due to locational variations in network charges passed through to consumers

Average impact on annual consumer bill due to regional DUoS charges



Variance against average DUoS charge for all regions for 2020/2021.

- Consumers are **exposed to DUoS tariffs reflecting the higher cost** of serving more dispersed areas
- Similarly, TNUoS tariffs reflect the incremental transmission infrastructure cost of supplying consumers at different locations
- £90m p.a. cross-subsidy in place to reduce Northern Scotland tariffs



It is credible to implement nodal pricing and central dispatch within 5 years



Implementations in other jurisdictions indicate 3 key phases of work, and an overall delivery of ~5 years

Assessment concluding with decision by Gov't

Design & software development phase

Testing & implementation phase



Conclusions

- Our analysis shows that the status quo will not deliver net zero cost effectively, as current market design creates inefficient behaviours, particularly in dispatch, resulting in dramatic and rising costs for consumers.
- The most efficient solution to this is real-time dynamic locational signals, and our assessment of the three locational market design options finds that neither national nor zonal pricing can deliver these effectively.
- Our analysis shows that a nodal pricing market with central dispatch has the potential to deliver significant consumer benefits through facilitating efficient dispatch of generation, demand and flexible assets; and optimising siting decisions across the whole electricity system.
- It creates the opportunity for consumers and industry to access low-cost, low-carbon electricity when and where it is abundant.
- We think it is credible to implement nodal pricing and central dispatch within 5 years. There are some key questions that need to be answered, such as what are the additional market reforms required to complement nodal pricing, and to what extent should consumers be exposed to locational price signals.

ESO Next Steps

Publication (mid-April)

Detailed assessment of locational and dispatch design option against assessment criteria (with supporting evidence)

Next Phase of Analysis

Support OFGEM's Technical assessment of locational pricing options

Further explore implementation considerations and impact on different market participants and consumers

Assessment of other market design elements in a nodal world

We will continue engagement with industry stakeholders and policymakers

Investment design elements assessment



The required policy interventions to support investment are fundamentally linked to the price signals delivered through wholesale market design. We will therefore assess options for investment market design elements in the context of nodal pricing and central dispatch.

