Report

Assessment of Locational Wholesale Pricing for GB

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This report sets out the key findings from Ofgem's assessment of the potential impacts of introducing locational pricing in GB. It aims to provide analysis and insight into how these market designs could operate in GB and what they could mean for GB electricity consumers, producers and our electricity system. This work is intended to support the UK Government's consideration of these market design options as part of its Review of Electricity Market Arrangements.

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Executive summary

This report sets out the key findings from our assessment of locational wholesale pricing for GB.[1] Our principal finding is that improving the accuracy and effectiveness of locational signals can produce material benefits for consumers. These benefits would partly flow from improving the co-ordination of generation, storage, demand, and network infrastructure, reducing the amount of new infrastructure needed; and partly from reducing the costs of managing the system, in particular dealing with residual network constraints (even after the network has been upgraded in line with current system plans).

We find that locational pricing is likely to produce significant benefits for society compared to current arrangements, ie doing nothing to improve locational signals in existing market arrangements. The scale of these benefits will be shaped by several important policy choices. Ofgem has already set in train a series of improvements in how network and generation infrastructure is co-ordinated and delivered through centralised system plans and anticipatory network investment.

Further work is underway to develop a more realistic counterfactual of improving locational signals under current market arrangements. This could be done through a combination of better spatial planning, reforms to Contracts for Difference (CfD) scheme design, network charges, access arrangements and balancing markets. This "reformed national market" should serve as a future counterfactual to locational pricing in determining whether or not the latter would be a desirable policy.

We intend to continue working with the government to develop this counterfactual, and in the next phase of work, examine the implementation requirements of locational pricing in more detail if this option is taken forward as part of its Review of Electricity Market Arrangements.

[1] For this report, the term 'locational wholesale pricing' is used interchangeably with 'locational pricing' to collectively refer to zonal and nodal wholesale market designs. This is distinct from use of the term 'locational signals', which can be sent through a range of policies and mechanisms.

Our future energy system will look very different to the one our current market arrangements were designed to support.

Decarbonisation of our energy system is fundamentally changing how we produce and use electricity and re-shaping the physical structure of the system and how consumers and market participants interact with the networks and markets that underpin its operation.

These changes create challenges to manage and opportunities to capture if we are to deliver and operate a renewables-based power system securely and at low cost. Key system changes include:

- **Physical system changes as renewable generation grows to become the backbone of a larger future power system**, supported by substantial investment in a broad range of generation capacity and flexible assets needed to support a fully decarbonised power system. Many large generation assets, particularly offshore wind farms, will be located in parts of the network with relatively low levels of electricity demand, such as along the Scottish coastline. A significant expansion of the transmission network is planned for the next two decades[2] to accommodate this geographically dispersed generation. New approaches to system planning and network regulation can work to better enable an efficient siting of new assets and reduce an anticipated increase in network constraints, which otherwise create cost and operability challenges. However, even with significant network expansion, our networks will continue to have some level of constraint under certain conditions and in particular locations. New market-based approaches to constraint management have the potential to reduce costs and balancing issues for the Electricity System Operator (ESO) and the overall amount of network expansion required.

- As we move further away from adjusting supply up/down as the principal way to meet demand, the **number and type of market participants will expand**. Substantial changes to how generation, flexibility and demand assets behave in response to a less predictable, more weather dependent and regionally concentrated electricity supply is required to ensure the system can be balanced securely and at low cost. A low-cost transition to net zero means making best use

[2] The Pathway to 2030 Holistic Network Design | ESO (nationalgrideso.com)

of all existing and future assets, with accurate market signals able to play a key role in more closely matching demand to available cheap renewable power.

- **Future consumers' retail market experience will be different from today,** with innovation already changing how some consumers use energy and low carbon technologies. Government, with support from Ofgem, recently published a vision for the future retail market that sees the role of suppliers and nature of competition evolving, with consumers having access to a far greater range of products and services, better tailored to their individual needs. This can support broader system transformation by providing incentives for customers to shift consumption, reduce energy use and support adoption of low carbon technologies.

Reforming Great Britain's electricity market is a critical step in delivering and operating a renewables-based power system securely and at low cost.

The UK Government's Review of Electricity Market Arrangements (REMA) provides the opportunity to enhance energy security and cut costs for consumers in the long-term. REMA aims to identify and implement reforms to GB electricity markets to unlock the necessary investment in and drive efficient operation of a secure, low carbon electricity system, ensuring that our electricity markets are fit for purpose over the period to 2035 and beyond. This includes improving locational signals for both investment and operational decisions.

How our electricity markets are organised will have a critical impact on how we decarbonise our energy system and our ability to operate an increasingly complex system securely and at low cost. As set out in the government's case for change,[3] without reform, we can expect a higher cost and slower decarbonisation if we over-build infrastructure and over-pay for generation that is unable to reach consumers.

Ofgem is working closely with government to build the evidence base around a broad range of market reform options being considered by REMA and the interdependencies between them.[4] As part of this, in April 2022 Ofgem began an assessment of the potential impacts of implementing locational pricing in GB. Our aim is to provide insight into what this kind of

[3] Review of electricity market arrangements - GOV.UK (www.gov.uk)
[4] This includes consideration of reform to transmission charging and access rights, which fall under Ofgem's remit. Open letter on strategic transmission charging reform | Ofgem

reform could mean for GB electricity consumers, producers and the energy system. This report sets out key findings from this assessment.

Locational pricing is a well-established market design used in many jurisdictions, including across North America, Europe and New Zealand. It can in theory provide locational signals in both investment and operational timescales to improve the siting of assets and how they are used in real-time. However, there are challenges with implementing locational pricing in the GB market. It would fundamentally change how electricity is traded and, depending on design, how assets are scheduled for dispatch. Some of these changes will come at a cost and may disrupt existing business models and could impact the flow of investment in the sector. That is why we are also exploring alternatives that could, to a greater or lesser extent, deliver many of the benefits of locational pricing with potentially less disruption to existing market arrangements. Alternatives include a possible combination of spatial planning and reforms to CfD design, network charges, access rights for new and existing assets and balancing markets.

Locational pricing is likely to produce significant benefits for consumers compared to doing nothing to improve locational signals.

Under locational pricing, wholesale prices reflect the locational value of energy at different points across the network. Wholesale electricity prices would reflect the marginal cost of generating the electricity, the losses incurred in transmission, and the cost of any network congestion. This would mean the price of wholesale power would be different, for instance, in Glasgow compared to London (whereas it is the same in the existing market arrangements). Including losses and congestion in wholesale power prices could create incentives for new generation, storage and demand assets to locate where they can provide overall benefits to consumers.

The real-time operational signals provided by locational pricing could also encourage market participants to behave in ways that reduce constraints on the network, reduce peak electricity flows and make best use of cheap, renewable electricity when it is available. Consumer cost savings could be expected to flow from incentives for assets, including interconnectors, to avoid scheduling use of the network at times when it is most constrained, reducing the costs consumers pay when excess wind needs to be turned-off and reducing the amount of network capacity that needs to be upgraded.

Flexible demand could also be encouraged to consume when prices are low, which can deliver benefits for all consumers by reducing total system costs. In the absence of such incentives, assets such as smart charging electric vehicles could, by following national price signals, add to network constraints – with locational pricing they would be more likely to mitigate those constraints.

Our assessment suggests that – compared to doing nothing to improve locational signals -– introducing locational pricing would deliver material benefits to GB electricity consumers. The scale of the benefits will be shaped by several important policy choices that would influence the breadth of reform. This includes the extent to which some or all market participants and consumers are shielded from the effects of locational pricing.

Analysis commissioned by Ofgem indicates that, based on network plans approved by Ofgem under the Accelerated Strategic Transmission Investment (ASTI) framework, locational pricing could deliver significant net socio-economic benefits of up to £14bn (NPV, 2025-2040).[5] The benefits to consumers could be larger as locational pricing could result in an additional transfer from generators to consumers in the form of congestion rents, with consumer benefits as high as £34bn. From the domestic consumer viewpoint, this would be equivalent to an average £38 a year saving.[6] However, further work will be needed to assess how such consumer benefits could be allocated without disrupting investment.

The exact scale of benefits realised will depend on several factors – although we have not identified any realistic scenarios where locational pricing would not deliver significant benefits for both consumers and the GB economy, compared to current arrangements.[7] In combination, three sensitivities (full load-shielding, no change in generator locations and network build in anticipation) have a cumulative effect of reducing the upper-end of the socio-economic net benefits to £7.2bn.[8]

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[5] REMA timelines and the implementation requirements for locational pricing mean these market reform options cannot be implemented from 2025. All else being equal, a later introduction of locational pricing would reduce the potential benefits out to 2040. Modelling performed by Aurora Energy Research to assess the potential benefits of locational pricing in GB over 2025 – 2060 considered the impact of a later implementation date. This found that while the consumer benefits of locational pricing reduce, they remain positive. A 2035 start date (under their net zero scenario) indicated consumer benefits of £16bn (2035-2060) for zonal design and up to £35bn (2035-2060) for nodal design. This sensitivity was only presented for their "net zero" scenario and was not presented for the modelled "central" scenario. https://auroraer.com/insight/locational-marginal-pricing-in-great-britain/

[6] We note the magnitude of this is considerable when compared to other, recent GB power market interventions. See Market-wide Half Hourly Settlement, https://www.mhhsprogramme.co.uk/, projected to result in a benefit of £11/HH/annum maximum.

[7] Subject to any potential increase in cost of capital being keeping within a plausible threshold.

[8] These sensitivities were run on different scenarios and so are not immediately comparable, but if load-shielding reduced consumer benefits by 4%, as it did under the System Transformation scenario, and dispatch represented 71% of consumer benefits, as under the NOA7 Leading the Way sensitivity, then consumer benefits would fall by a combined 32%. However, we note that since more generation re-sites in locational markets under Leading the Way than in other scenarios, there is reason to believe that dispatch benefits may be a larger proportion in other scenarios.

Equally, since we have not modelled any transmission capacity enhancements beyond the existing ASTI projects approved by Ofgem, the benefits from locational pricing will likely be impacted by further transmission upgrades that arise as a consequence of future system plans. Simply put, the more the transmission network is upgraded to reduce network constraints, the lower the net benefits from locational pricing.

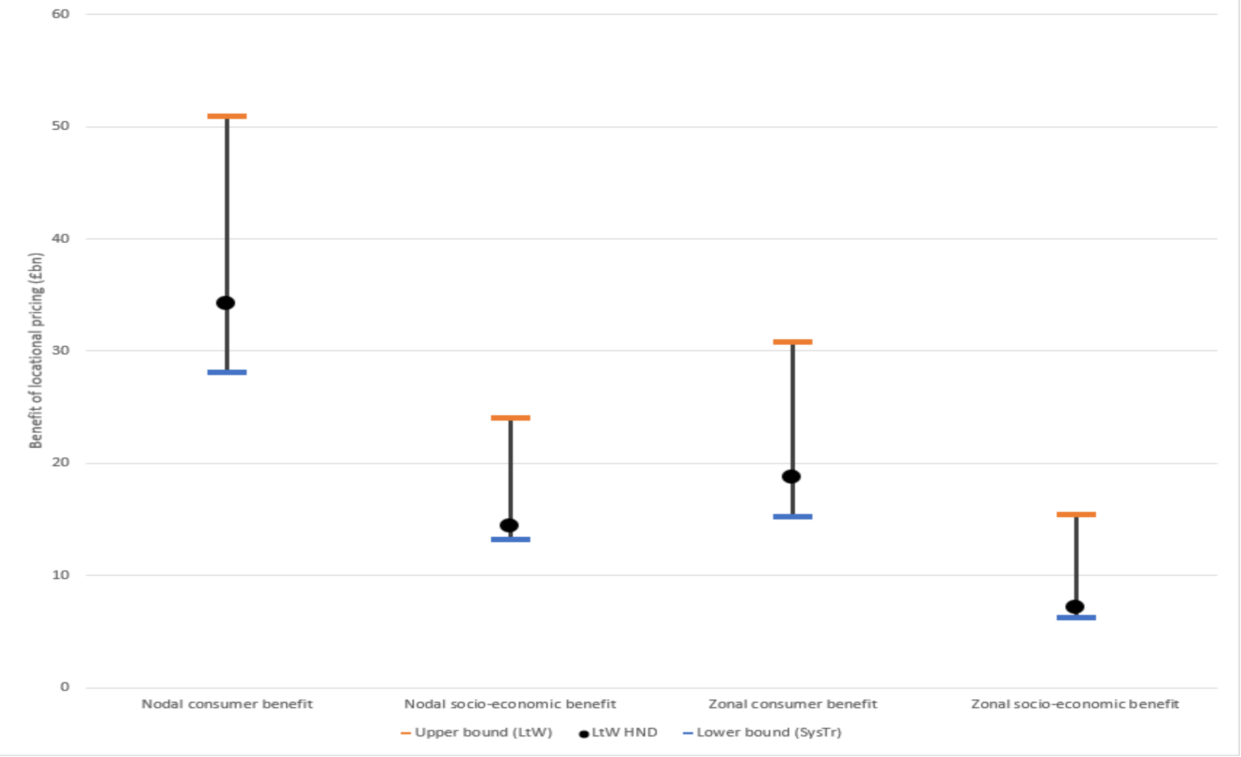

Figure 1. Modelled range of socio-economic and consumer benefits from locational pricing

Several potential benefits sources have not been quantified which could increase the consumer and socio-economic benefits of locational pricing, such as different capacity configurations to achieve net zero; reduced need for further investment in the distribution and transmission networks in the future; and new demand (such as hydrogen electrolysers and some industrial demand) and low carbon technologies (such as electric vehicles and heat pumps) locating in response to locational price signals.

The scale of the benefits realised from locational pricing would also be shaped by implementation choices.

The case for locational pricing versus other reform options will depend upon a complex evidence base and interactions between a locational wholesale market and wider policies. A range of market design choices would play a key role in shaping the magnitude of benefits that could be realised in GB from locational pricing, and whether (and in what form) this would be preferable to alternative reform options.

Below we consider three of the most significant policy choices – demand-side exposure, balancing consumer and producer exposure to risk, and implementation requirements - that could be expected to materially shape the benefits of locational pricing in GB.

Demand-side exposure: A broad range of options exists for how suppliers (and, therefore, different types of demand) could be shielded from or exposed to locational wholesale prices.

Whether, and how, suppliers are exposed to locationally varying wholesale prices and the future of retail market design and consumer protections would materially shape the impact of locational pricing on the retail market, total consumer and system benefits and the distributional impacts between consumer groups. A key finding from this assessment is that implementing locational pricing whilst **shielding certain types of demand from locational prices could still deliver material system cost reductions and consumer benefits compared to current arrangements**, albeit they would be lower.

Shielding households and businesses from locational prices could represent a missed opportunity. A distributional analysis of how exposure to locational wholesale prices could affect different types of consumers (ie, flexible and inflexible, domestic and industrial) finds that **all or most consumers would be better off under locational pricing when compared to current arrangements**, with consumers in northern GB benefitting more than their southern counterparts.

However, there may be distributional consequences for consumers (including for vulnerable consumers in import-constrained locations) that will need to be examined more carefully. For instance, it is inevitable that consumers in some parts of the country would end up paying higher wholesale prices compared to consumers in other parts of the country under locational pricing, but their total bill could still be lower when compared to current arrangements. Distributional impacts could be offset by transfers from gaining regions to losing regions, or targeted support for vulnerable consumers, which could leave everyone better off than without locational pricing. Such transfers would require careful consideration.

If government continue to consider locational pricing as part of REMA, further consideration will need to be given to the distributional consequences and the protection of vulnerable consumers from outcomes that may be perceived as unfair. In addition, further analysis would be needed to consider the impacts of locational pricing on the retail market and the financial resilience of different types of suppliers.

Investment risk: Locational pricing could increase the risks certain market participants face – any resulting impact on low carbon investment will be shaped by how change is managed and broader policies that balance risks and costs between consumers and producers.

Challenges with integrating low carbon generation, in particular large volumes of offshore wind, require difficult decisions to be made on the balance of market risks that generators should be exposed to. These decisions will be required regardless of market design, but reform options such as locational pricing can change the allocation of risks between market participants and consumers. For example, locational pricing seeks to increase generator risk exposure to transmission network constraints in order to produce more cost-efficient system outcomes, on the notion that generators are better able to manage this risk than consumers.

However, the scale of investment needed for net zero is immense. There is therefore a large consumer interest in keeping the cost of capital low and the flow of investment as smooth as possible. Increasing the risk exposure of certain market participants such as renewable generators could disrupt investment and/or increase the cost of capital for new investment. It would therefore be important to examine ways of mitigating these risks (for instance, through the treatment of legacy contracts and design of the CfD scheme) in order to keep the overall costs to consumers as low as possible.

These measures would need to be carefully designed for the GB energy system. They would increase implementation requirements, and the extent to which market participants were shielded from or compensated for the effects of locational pricing would have an impact on the consumer and system benefits realised from market reform.

Implementation requirements and challenges will influence the final costs and benefits of locational pricing.

Locational pricing would represent a significant implementation challenge. We expect it to require changes to the current legislative and regulatory architecture and significant change to current market design principles and market rules.

As many jurisdictions have successfully transitioned to greater locational wholesale pricing, there is diverse experience for GB to draw upon. However, we have identified certain implementation challenges that could be difficult and/or expensive to address, notably compatibility with currently unknown future European Union-United Kingdom (EU-UK) trading arrangements, amending existing CfD contracts, any compensation arrangements for legacy contracts, and potential changes to metering.

Detailed requirements and timelines for locational pricing are currently uncertain as they are linked to a range of market design choices, in particular whether locational pricing would be implemented alongside a move to centralised scheduling and dispatch, as well as changes to dispatch and settlement periods.

Next steps

Our view is that GB consumers would benefit from improved locational signals. Given the range of market design options and mitigation measures available, locational pricing could deliver material consumer and system benefits compared to doing nothing.

However, this kind of market reform comes with potential risks to investment and distributional impacts on consumers. It is therefore important to explore the counterfactual of improving locational signals under the current single price model through a possible combination of better spatial planning, anticipatory network investment and reforms to CfD design, network charges, access arrangements and balancing markets. This "reformed national market" should serve as the counterfactual to locational pricing options in determining whether or not the latter would be a desirable policy.

We intend to continue working with the government to develop this counterfactual, and in the next phase of work, to examine the implementation requirements of locational pricing in more detail if this option is taken forward under REMA.

1 Introduction

Background

1.1 Great Britain's transition to a low carbon energy system is well underway. Changes in how we produce and use electricity are re-shaping the physical structure of our electricity system and how consumers and market participants interact with the networks and markets that underpin its operation. While significant progress has been made to date,[9] delivering and operating an electricity system that will be very different from today's requires radical change to how, when and where electricity is produced and consumed.

1.2 As part of the British Energy Security Strategy, the UK Government launched the Review of Electricity Market Arrangements (REMA) programme in April 2022. REMA aims to identify and implement reforms to GB electricity markets to unlock the necessary investment in and drive efficient operation of a secure, low carbon electricity system, ensuring our electricity markets are fit for purpose over the period to 2035 and beyond. The first consultation, published on 18 July 2022, identified a strong case for change to current arrangements, with this broadly supported by consultation responses.[10]

1.3 In Powering Up Britain, the government committed to a further REMA consultation in autumn 2023. A key focus for REMA is improving locational signals, for both investment and operational decisions, to efficiently deliver a decarbonised power system and balance an increasingly complex system securely and at low cost. Through the REMA programme, the government is considering a wide range of options to achieve this including a combination of potential reforms to wholesale markets, CfD design, electricity network charges and balancing markets.[11]

1.4 Ofgem is working closely with the UK Government on this opportunity to reform the electricity market to enhance energy security and cut the costs of electricity for consumers in the long-term. As the regulator, we aim to facilitate a path to net zero at the lowest cost to consumers within the context of government policy. As set out in our paper 'Net Zero

[9] Greenhouse gas emissions from electricity generation in 2019 were 71% lower than 1990 levels. Plans unveiled to decarbonise UK power system by 2035 - GOV.UK (www.gov.uk)
[10] Review of electricity market arrangements - GOV.UK (www.gov.uk)
[11] Constraint management measures includes options such as storage based ancillary services and local constraint markets.

Britain: developing an energy system fit for the future', published on 8 July 2022, reform is required to how we plan, operate and regulate our energy market.

1.5 How our electricity markets are organised will have a critical impact on how we decarbonise our energy system and our ability to operate a decarbonised power system efficiently and securely. Electricity markets serve as a way of financially recognising what is happening on the physical system and should create signals for what we ultimately want to be physically delivered on the system. This means that electricity market design and the price signals sent to an increasingly diverse range of market participants can have a significant impact on broad energy system outcomes and consumer costs.

1.6 Ofgem is supporting the government in its consideration of market reform options by helping to build the evidence base around a broad range of market reform options being considered as part of REMA and the interdependencies between them. This includes options related to transmission charging and access reform,[12] which fall under Ofgem's remit, and wholesale and balancing market reform options. As part of this broad package of work, in April 2022, Ofgem began a detailed study into locational pricing in April 2022. This report sets out the key finding from this assessment.

Purpose and scope

1.7 This assessment considers the potential benefits, costs and distributive impacts associated with introducing locational pricing in GB.[13] Locational pricing would split the current single GB wholesale electricity price zone into either multiple-zones ("zonal pricing") or potentially hundreds of nodes ("nodal pricing"), with participants competing to set the price at each zone or node in a way that takes into account constraints on the flow of power. Locational pricing is a well-established market design used in many jurisdictions, including across North America, Europe and New Zealand.

1.8 This assessment aims to provide insight into what this kind of market reform could mean for GB consumers, producers and the energy system to support consideration of

[12] Open letter on strategic transmission charging reform | Ofgem
[13] For this report, we use the term 'locational pricing' to collectively refer to zonal and nodal wholesale market design. It is used interchangeably with locational wholesale pricing.

these options by government. The UK Government will make decisions on GB electricity market reform that may involve legislative change.

1.9 Several recent studies have considered the potential impacts of moving to locational wholesale pricing in GB.[14] This assessment seeks to build upon the existing evidence base by: (i) undertaking detailed system modelling and considering the market design options at a high degree of spatial granularity; (ii) assessing the potential costs and distributional impacts of such change; and (iii) considering the changes required to facilitate locational pricing in GB.

1.10 This scope of the assessment covers:

- how a zonal or nodal wholesale market could operate in GB;
- detailed economic modelling of the potential quantitative benefits of moving to zonal or nodal pricing in GB;
- potential implementation requirements and costs; and
- potential distributional impacts and mitigation measures.

1.11 This assessment is 'transmission-first' in scope. While distribution-level locational pricing is theoretically possible, it has not been applied in practice and would likely represent a much greater implementation challenge. However, as noted in Section 3, it is important to understand the potential impact of a transmission-level zonal or nodal pricing on the distribution network.[15]

1.12 In line with the approach recommended by HM Treasury's Green Book guidance for the appraisal of policies, programmes and projects, the costs and benefits of locational

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[14] Including but not limited to: Citizens Advice, 'It's all about location', June 2023; Simon Gill, Callum MacIver, Keith Bell (University of Strathclyde), 'Exploring Market Change in the GB Electricity System: the Potential Impact of Locational Marginal Pricing', February 2023; Energy Systems Catapult, 'Informing the REMA Debate: International Learnings on Investment Support for Clean Electricity', November 2022; Energy Systems Catapult, 'Location Location Location', May 2022; National Grid ESO, 'Net Zero Market Reform programme', March 2021 – present; Energy Systems Catapult, 'Introducing nodal pricing to the GB power market to drive innovation for consumers' benefit: why now and how?', March 2021; Policy Exchange/Aurora Energy Research, 'Impact of locational pricing in Great Britain', December 2020; Policy Exchange, 'Powering Net Zero: Why local electricity pricing holds the key to a New Zero energy system', December 2020; Competition Markets Authority, Energy Market Investigation (2014 – 2016); Ofgem, Project TransmiT (2010 – 2015). Since we began this work, several other studies funded by industry have been undertaken to assess the potential impacts of locational pricing in GB, notably Aurora Energy Research and Afry.

[15] In this report, 'distributed generation' is used to refer to electricity generation and storage assets connected to a distribution network. Distribution voltages are 132 kV and lower in England and Wales, and less than 132 kV in Scotland.

pricing are assessed against the counterfactual of a national price market, as per current arrangements in GB. This assessment does not provide a comparative evaluation of the costs and benefits of locational pricing with other REMA options, nor does it seek to identify a preferred package of market reform options.

1.13 However, as noted in our recent open letter on strategic transmission charging reform, the implementation of other reform options being considered by REMA (such as the design of transmission network charging) will impact the expected benefits from locational pricing, and vice-versa. Consideration of locational pricing against viable alternatives is part of a broader programme of work and is out of scope of this report. Further work is underway to explore the counterfactual of improving locational signals under the current single price model through a possible combination of better spatial planning and reforms to CfD design, network charges, access arrangements and balancing markets.

1.14 This report provides an overview of the key findings from our assessment of the potential implications of introducing zonal and nodal pricing in GB. It is structured as follows:

- How locational pricing could work in GB – Section 2 provides an overview of how a zonal or nodal market could be organised in GB.
- Interactions with market policies – Section 3 considers how a wider suite of market policies and regulatory arrangements could interact with and be impacted by the introduction of locational pricing.
- Monetised costs and benefits – Section 4 provides an overview of the key findings from analysis commissioned from FTI Consulting to assess the potential costs and benefits of introducing locational pricing in GB.
- Wider market and system impacts – Section 5 considers a range of wider potential impacts that could shape the scale of benefits from introducing locational pricing in GB.
- Distributional analysis – Section 6 provides a snapshot analysis of how different consumer groups could be impacted by exposure to more granular price signals.

Approach

1.15 We identified a range of feasible market designs that vary according to the locational granularity of the wholesale electricity price (eg zonal and nodal). A non-exhaustive review of jurisdictions that have introduced zonal or nodal pricing, or are currently implementing these market designs, was used to identify key market design features, understand how these markets operate and have evolved over time, and how changes have been implemented.[16]

1.16 We commissioned FTI Consulting (FTI) to assess the potential benefits and costs of operating a national, zonal or nodal wholesale electricity market in GB between 2025 and 2040. This used 2021 National Grid Electricity System Operator's (ESO) Future Energy Scenarios (FES), Networks Options Assessment (NOA) and Holistic Network Design (HND) data, as well as other reputable sources. A full list of assumptions, including the detailed methodology and approach to the modelling, is included in FTI's final report, which is published alongside this document.

1.17 We commissioned three academics to provide an independent review of FTI's assessment of locational pricing. The scope of the reviews was to consider the assumptions, methodology and limitations identified by FTI and provide a view on whether the key findings should be considered conservative or optimistic.

1.18 The FTI modelling results formed the basis of our exploration of the distributional impact of locational pricing on different consumer groups.

1.19 A high-level assessment of the changes likely required to implement locational pricing has been informed by discussions with key bodies that would likely be responsible for implementing such market changes. This includes, but is not limited to, ESO, Elexon, the Energy Networks Association, Low Carbon Contracts Company and the Power Exchanges.

1.20 Regular stakeholder engagement, primarily via three workshops with a wide range of interests, and a Call for Input was used to shape and inform the progression of this assessment. Stakeholder input has been used to: (i) identify opportunities, risks and challenges associated with locational pricing; (ii) test and refine the modelling methodology, assumptions and interim modelling results; and (iii) inform our consideration of potential stakeholder and policy impacts and implementation requirements. Final FTI modelling results were shared and discussed with stakeholders at two events in June 2023. Materials from all events can be found on our website.[17]

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[16] This included a desk-based study and interviews with representatives from energy regulators and system operators from Norway, Italy, Canada, New Zealand, and the US.
[17] Locational Pricing Assessment | Ofgem

Your feedback

1.21 We believe that feedback is at the heart of good policy development. We are keen to receive your comments about this report. We would also like to get your answers to these questions:

1. Do you have any comments about the overall process of this report?
2. Do you have any comments about its tone and content?
3. Was it easy to read and understand? Or could it have been better written?
4. Are its conclusions balanced?
5. Did it make reasoned recommendations for improvement?
6. Any further comments?

1.22 Please send any general feedback comments to WMReform@ofgem.gov.uk.

2 How locational pricing could work in GB

Section summary

This section aims to:

- provide an overview of locational pricing market designs, and
- identify high-level changes to current market arrangements likely required to facilitate locational pricing in GB.

It finds that:

- Reforming the GB electricity wholesale market[18] to introduce more granular locational pricing would represent a significant change to current market arrangements.
- Locational pricing would fundamentally change how electricity in GB is traded and, depending on design, scheduled ahead of dispatch, thereby changing how market participants and the System Operator (SO)[19] interact with electricity markets and networks.
- Introducing locational pricing would represent a significant implementation challenge. We expect it to require changes to the current legislative and regulatory architecture and significant change to current market design principles and market rules, with the detail of this dependent upon a series of market design choices.

Introduction

2.1 Our assessment of locational pricing for GB is informed by the identification of high-level design options for how these markets could be organised in GB.[20] Using these high-level designs, this section considers the changes to current GB market arrangements that may be required to facilitate locational pricing. This has been informed by a review of the operation of locational pricing in other jurisdictions, our experience of regulating and facilitating change to GB market arrangements, and discussions with several relevant

[18] For the purpose of this report, we use the term 'electricity wholesale market' to cover both electricity commodity markets and derivative markets and includes, inter alia, regulated markets (such as the Balancing Mechanism) multilateral trading facilities (such as Power Exchanges), over-the-counter ("OTC") transactions and bilateral contracts, direct or through brokers. This aligns with the definition of electricity wholesale markets in Recital 5 of REMIT.
[19] For the purpose of this report, we refer to the System Operator or 'SO' when considering alternative and/or future arrangements, and the ESO when referring to the current roles, functions and responsibilities the GB SO undertakes.
[20] These design options are based upon how zonal and nodal markets are arranged in other jurisdictions. They do not represent an Ofgem proposal for future market design.

organisations from the electricity sector and electricity market design experts. Stakeholder workshops and bilateral engagements have been used to test and refine initial thinking.

Overview of locational pricing

2.2 Locational pricing is an electricity wholesale market design that aims to reflect the locational value of electricity within the electricity wholesale price and align market outcomes with the physical realities of the electricity system (see Box 2.1).

Box 2.1. Physical realities of electricity system operation

While electricity can be traded like any other commodity, it has certain characteristics that require specific trading arrangements:

- Electricity supply and demand needs to be balanced in real time across the whole system. Any deviation between supply and demand results in fluctuations away from the nominal system frequency (50 Hz in GB). Significant deviations of system frequency can result in a partial or full black-out.
- Electricity follows the path of least resistance across a network (according to Kirchhoff's law). Electricity flows across all possible paths via transmission lines according to their respective resistances.

The objective of electricity system operation includes ensuring, as a minimum, an operable, reliable and efficient dispatch of resources:[21]

- Operability: The pattern of injections and withdrawals within the network, and resulting power flows, must be within operational limits, ie, the system must be balanced, and transmission constraints must not be exceeded (see Box 2.2).
- System reliability: The dispatch must ensure that the system can handle contingencies, such as sudden losses of resources, within a sufficiently short time.
- Efficiency: Resources are dispatched at least cost subject to the technical requirements of the system and providers.

2.3 The location of electricity production and consumption can have a fundamental impact on the overall efficiency and operability of an electricity system. As electricity cannot be transported or stored for free and the cheapest available electricity cannot always be used to serve demand, the real value of a unit of electricity can vary significantly depending on where and when it is consumed relative to produced.[22] With locational pricing, wholesale

[21] The objectives for electricity system operation in GB are defined in the transmission licence conditions that apply to the ESO: Licences and licence conditions | Ofgem

[22] Typically, a unit of electricity will be cheaper if it is consumed closer to where it is produced. This is because there are costs associated with transporting electricity from where it is produced to where it is consumed. These costs include: (i) building and maintaining the physical network that transports electricity between producers and consumers, (ii) managing network constraints and balancing the system in real-time and (iii) electricity losses

prices vary by location as constraint costs (see Box 2.2 below) and, in some cases, losses are considered in the price formation process.

Box 2.2. Transmission constraints

Transmission capacity on the network is scarce and subject to the physical limits of transmission lines ("transmission constraints").

'Transmission constraints' include thermal constraints, ie, the maximum power that can be transmitted through a line[23], and voltage and stability limits[24]. Some local voltage constraints are typically managed through specific ancillary services and are generally not considered for locational pricing.

Transmission constraints mean that the most economically efficient output by market participants, established through the merit order in a national market, cannot be physically accommodated. Under locational pricing, these constraints are considered as part of the wholesale market. The impact of this is that the 'economically efficient' outcome established through the wholesale market, is closer to what can be physically accommodated.

The nature of transmission network constraints and generator locations in any system dictates how a move to a locational wholesale market would impact prices. In theory, for an unconstrained network, introducing locational pricing would have limited impact as all wholesale prices would be approximately the same. In contrast, the more constrained the transmission network, the greater the divergence in pricing between any nodes or zones.

Currently, thermal constraints are managed by ESO using the Balancing Mechanism and other tools ("re-dispatch"). Thermal constraint management is an essential aspect of system operation. Constraint management costs in GB (which are borne by consumers) have increased significantly. Annual transmission thermal constraint costs have increased 8-fold from £170mn in 2010 to £1.3bn in 2022.[25] These costs are modelled to rise further, potentially reaching to more than £3bn p.a. by 2028.[26]

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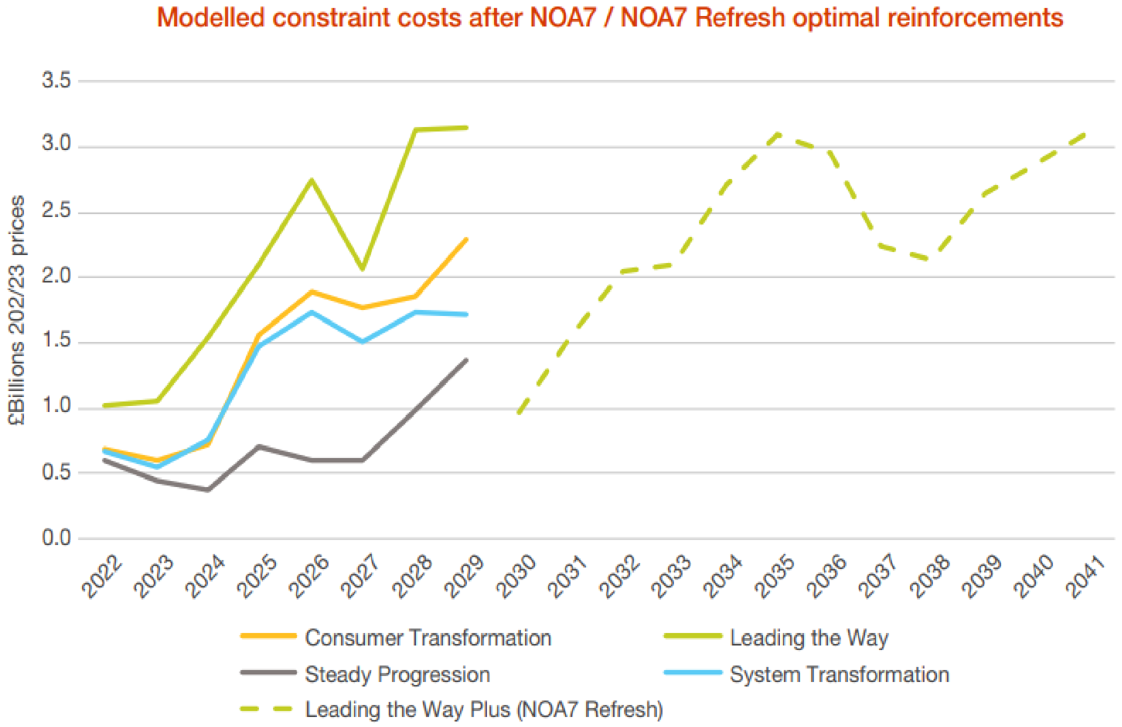
created during transmission due to electrical resistance on transmission lines, with losses generally increasing with distance.

[23] Thermal limits include normal pre-contingency flow limits, short-term post-contingency limits and long-term post- contingency limits.

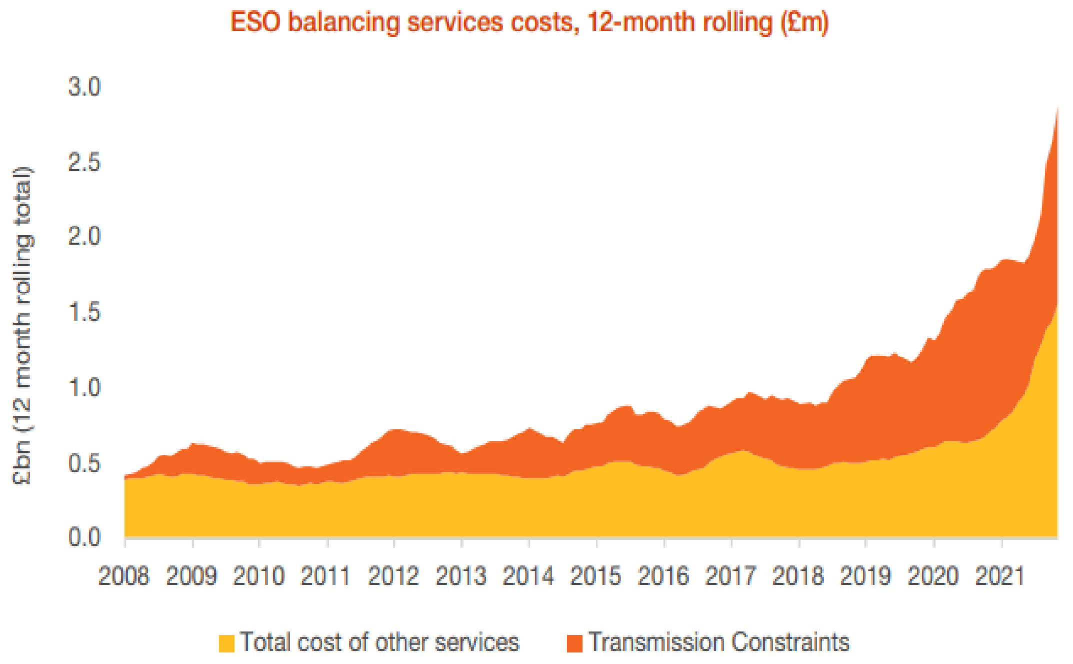
[24] For example, Central East, the most important transmission constraint in New York, is a combined voltage and stability limit that is studied offline and represented as a nomogram in both the day-ahead market and the real-time dispatch.

[25] Net Zero Market Reform Phase 3 Assessment and Conclusions

[26] ESO Markets Roadmap March 2023

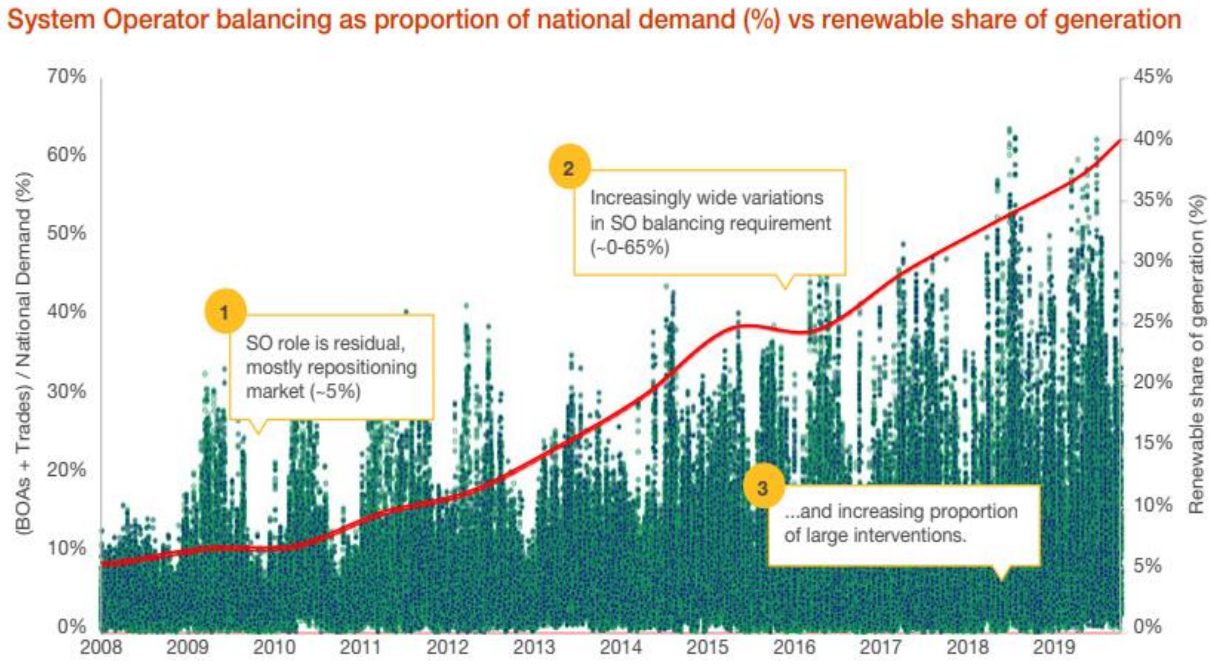


Source: ESO, [ESO Markets Roadmap March 2023]



Source: ESO, [Net Zero Market Reform Phase 3 – Assess operational element and share conclusion], May 2022.

In recent years, the ESO has had to re-dispatch an increasing proportion of the market to resolve transmission constraints. A rapid change in how and where electricity is generated means the ESO now redispatches more than 65% of demand, in certain Settlement Periods, up from around 10% in 2008.[27] Much of this is to solve locational constraints arising from renewable energy that cannot be transported to demand centres.



Source: ESO, Net Zero Market Reform – Phase 3 Assessment and Conclusions, May 2022.

2.4 There are two broad designs for locational pricing that are principally distinguished by the level of spatial granularity:

- **Zonal pricing** – this splits the electricity network into defined geographical zones that typically reflect major recurring transmission network constraints, with wholesale electricity prices (£/MWh) calculated for individual zones. One type of zonal pricing is based on a security constrained economic dispatch and calculates the zonal price as the load (or potentially generation) weighted average of the nodal prices within the zone.[28] This type of zonal pricing continues to be widely used in US markets for setting prices for at least some load. Another type of zonal pricing is based on modelling of transmission constraints, where structural congestion within zones is minimised and they reflect the transmission system's technical limits.[29]

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27 REMA: ESO Response ESO, Net Zero Market Reform – Phase 3 Assessment and Conclusions, May 2022.
28 Security-constrained refers to the algorithm considering wider reliability criteria for the system, such as N-1/N-2 contingencies, and is not limited to transmission capacity constraints.
29 This type of zonal pricing has been used in the US (notably in California and ERCOT) and is currently used to define bidding zones in the European Internal Energy Market.

- **Nodal pricing** (also known as locational marginal pricing or "LMP") – in which the price in each network location (also known as a node[30]) represents the locational value of electricity.

2.5 These market designs are well-established and well-regarded in jurisdictions around the world. Some jurisdictions introduced locational pricing at the time of liberalisation or, in the US, at the time open access to the transmissions system and competitive wholesale power markets were implemented. Other jurisdictions have evolved towards greater locational granularity to address system challenges, in particular increases in constraint costs. A recent comparison of OECD countries indicates that the amount of capacity under locational pricing market designs now exceeds capacity under national pricing systems.[31]

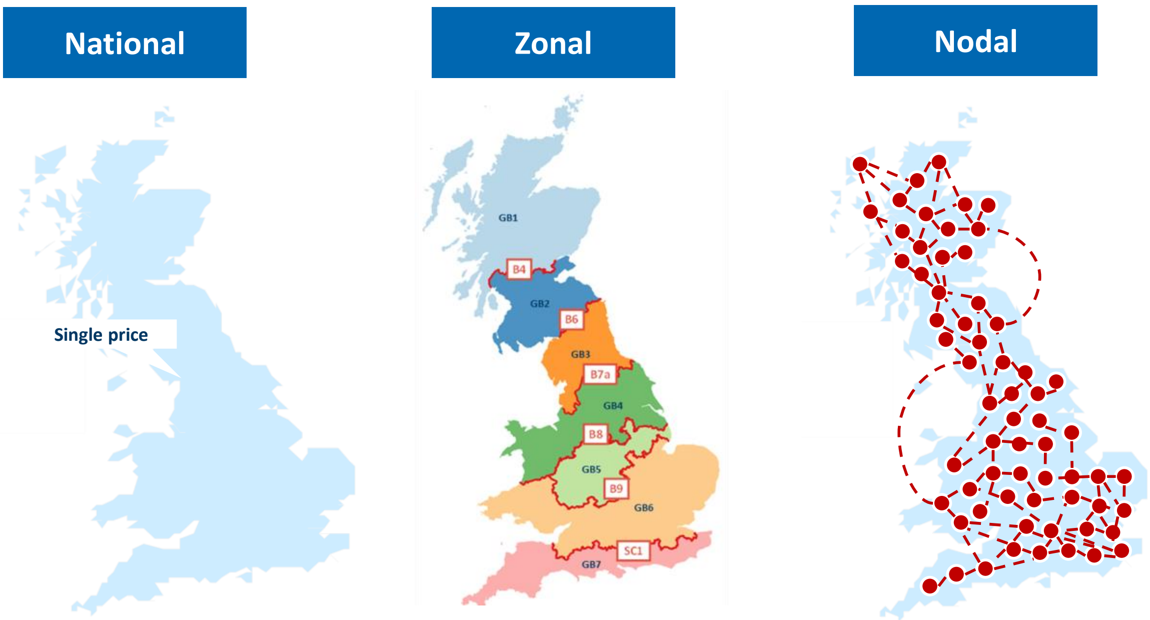

Figure 2.1: Illustrative representation of locational wholesale pricing (national, zonal and nodal). Source: FTI Consulting.

2.6 Electricity market design in the European Union (EU) - the European Internal Energy Market (IEM) - is based on zonal pricing.[32] Nodal pricing is used in several electricity

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[30] A transmission network is often simplified into nodes and lines. Nodes are individual end-points in the network (eg, substations or Grid Supply Points), which are connected by lines. In theory, nodes could be even more granular, and include the distribution networks as well.
[31] Alongside this report we are publishing the work of the consultants that have supported this study. See Section 3 of their report '*Assessment of locational wholesale electricity market design options in GB*', FTI Consulting and Energy Systems Catapult, October 2023. Hereafter, referred to as "the FTI report" or "FTI analysis".
[32] The locational granularity of the IEM varies between jurisdictions. Some have a single price zone (ie France and Germany) while others have multiple price zones within their jurisdiction (eg, Norway, Italy and Sweden).

markets including, but not limited to, the USA, New Zealand, Singapore and is currently being implemented in Ontario, Canada.[33] The design of zonal and nodal markets in operation today varies significantly across jurisdictions.

2.7 The current GB wholesale market operates as a national market or single-price zone (see Figure 2.1 above). This means the location of electricity production and consumption is generally not considered when it is traded and scheduled for dispatch ahead of Gate Closure.[34,35] In theory, decisions made by, and competition between, market participants to produce energy at least cost take place independently of whether the system can physically accommodate their generated energy at any time.[36]

2.8 It is the role as GB System Operator (SO), ESO changes the market outcome ("re-dispatch") to ensure transmission constraints are respected. The Balancing Mechanism is the primary market tool through which this is done. ESO should be working to encourage the market to solve the issue itself where appropriate, to minimise its own role in balancing, as set out by the principles of the New Electricity Trading Arrangements.[37]

Zonal pricing

2.9 Zonal pricing introduces locational variability into electricity prices by splitting the transmission network into clearly defined geographical areas (zones).[38] There are various types of zonal markets which could be implemented in GB, the specific design of which would need to be the subject of further work. Here we briefly introduce some of the main concepts related to zonal markets, and highlight some typical features of these markets. The boundaries of the zones are typically drawn to reflect where major recurring

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[33] Informing the REMA Debate: International Learnings on Investment Support for Clean Electricity - Energy Systems Catapult

[34] Gate Closure is the point in time by which market participants have to inform the System Operator about their planned electricity production or consumption. Gate Closure is currently 1 hour ahead of the time of delivery, and market participants have to notify their plans for 30-minute periods (a Settlement Period).

[35] In practice, prices set by market participants have a locational component through the locationally dependent Transmission Network Use of System ("TNUoS") Charges.

[36] The GB system with national pricing is sometimes referred to as a "copper plate", ie it is assumed that there is unlimited physical transmission capacity for electricity between market participants.

[37] The new electricity trading arrangements of England and Wales, Dec 2003

[38] In countries (or jurisdictions), in which zonal pricing has been implemented, zonal boundaries are typically defined by the SO through consultation with stakeholders.

transmission network constraints occur and may be re-defined over time as the transmission network evolves and new generation and demand connect to the system.[39]

2.10 If zonal prices are calculated based on the nodal prices in a security constrained economic dispatch, they would be calculated by the SO as part of the central scheduling and dispatch process. Zonal wholesale electricity prices (£/MWh) may also be calculated for each zone individually via a market operator (eg the Power Exchanges[40]) or the SO, based on a zonal representation of the underlying transmission constraints.[41] Prices typically vary between zones as the cost of managing constraints between zones ("inter-zonal constraints") are considered in the market clearing process. Price formation for individual zonal prices assumes no network constraints within the zone ("intra-zonal constraints").[42] The zonal price is paid to generators and other energy assets for energy they inject into the zone and is paid by demand (eg suppliers) for electricity consumed in the zone.

2.11 In zonal pricing, and as above depending on the design and scheduling arrangements, market participants typically have firm access rights (see Box 2.3) within their zone, independent of volumes or time and also independent of the loop-flow impact of injections on constraints outside the zone. Access rights outside of the zone are only granted for specific times and volumes by a system or market operator that allocates inter-zonal transmission capacity. This means there is a need for the SO to somehow approximate the actual transmission constraints with zonal constraints, as well as a need for the SO to manage intra-zonal constraints (ie through re-dispatch) to change the market outcome so that intra-zonal constraint limits are respected, and to provide compensation for participants that are curtailed, as occurs today on a GB-wide level primarily via the Balancing Mechanism. Further assessment is required to assess potential other designs.

[39] Some zonal markets, eg Norway and Italy, have re-drawn zonal boundaries in response to evolving transmission network constraints. Norway began with two bidding zones in the 1990s and gradually increased the number of zones over time, with a fifth zone created in 2015. In Italy, the number of bidding zones has also changed over time, decreasing from seven to six zones in 2006 and returning to seven zones in 2021.
[40] Power Exchanges are entities who offer trading platforms to their members who conduct energy trades via such exchanges/platforms. Members submit orders for buying and/or selling power, which are registered in an orderbook - the parties stay anonymous so that they do not know who they have been trading with. Orders placed by the members reflect supply and demand for a specific market area at a certain moment in time. Based on the orderbook, Power Exchanges calculate a market price. There are many different auctions and many different products offered by various Power Exchanges in GB, Europe and around the world.
[41] In locational markets, typically the Market Operator is responsible for operating dispatch optimisation to identify the dispatch schedule and the SO supplies operational data and issues instructions. They can be the same or distinct entities.
[42] This type of zonal pricing therefore assumes that there are no intra-zonal transmission constraints, and that each zone behaves as a "copper plate". If the zones are created based on the most commonly occurring transmission constraints in the system, there is less significant constraints or losses within zones. Several factors will influence the level of intra-zonal constraints, such as where capacity locates within a zone.

Nodal pricing

2.12 Nodal pricing uses a more granular spatial model of the transmission network, enabling it to more accurately reflect the different costs of electricity and transmission constraints at locations across the network. Compared to zonal pricing, nodal pricing increases the number of defined points or 'nodes' on the network where individual wholesale prices (£/MWh) are formed. The number of nodes can vary from a few hundred to a few thousand, with this typically influenced by network size. Defined points or nodes are often substations or Grid Supply Points (GSP).

2.13 Under nodal pricing, the access rights of market participants to other nodes in the network are only granted for specific times and volumes. This means, in theory, there is no need for transmission constraint management by the SO, as the market schedule respects all relevant transmission constraints. In reality, some re-dispatch would be required as the SO fine tunes the schedule, eg when dealing with outages.

Box 2.3. Electricity market arrangements and network access rights

Background

Electricity market arrangements refer to the rules and processes that facilitate the trading, scheduling, dispatch, and settlement of electricity – they are applicable to all wholesale electricity market participants. Network access rights are a fundamental building block of electricity market design. Access rights determine the nature of a market participant's access to the electricity network and the network capacity they can use – how much they can import or export, when and for how long, whether their access can be interrupted and what happens if it is.

Market arrangements should work to efficiently communicate available access rights to market participants, eg through price signals. Clearly defined and communicated access rights can provide market participants with greater certainty over potential revenues as participants cannot schedule if they do not hold the relevant access rights.

Current GB arrangements

A wide range of access rights exist in theory and practice – options vary between and within jurisdictions. In GB, transmission-connected market participants generally have financially firm access rights to the entire transmission network. Subject to compliance with applicable rules, this means that such market participants are able to submit any position, irrespective of whether this position is physically feasible for the transmission system, and are eligible to receive compensation should their access rights be curtailed. The ESO redispatches submitted positions in the Balancing Mechanism, so that the final outcome respects the relevant transmission constraints.

Transmission access rights are set out in the Connection and Use of System Code (CUSC), which specifies generators as having the right to export up to an agreed limit known as the Transmission Entry Capacity (TEC). A generator's TEC is specified in their

Bilateral Connection Agreement. There is no equivalent for consumers of power, whether they're connected to the transmission system directly, or to the distribution system.

In 2010, the UK Government introduced the 'Connect and Manage' network access regime to improve access for generators to the electricity transmission network. As set out in Box 2.2, this appears to have contributed to a significant increase in constraint payments.

Network access rights in locational wholesale markets

Markets with locational pricing could have different transmission access rights. With zonal pricing, market participants could retain financially firm access rights (akin to the existing arrangements in GB) within their zone, while a form of nodal pricing with a central dispatch usually requires non-firm access rights. Access to other zones or nodes is only granted for specific times and volumes, eg by having an energy offer accepted through a competitive market that allocates the available relevant transmission capacity in a way that minimises total system cost. Power flows between zones or nodes is still considerable, but price differentials will be formed in response to network constraints.

In theory, the impact on market participants of changing access rights under locational pricing is likely to correlate with the frequency and magnitude of transmission constraints in the network. This would likely depend on their location relative to transmission network linking major generation and demand hubs.

Access rights are a critical commercial factor for generators located in parts of the transmission network that are typically export constrained as they can provide greater revenue certainty and financially shield generators from exposure to the consequences of transmission constraints. Typically, jurisdictions with locational markets employ some mechanisms to allow market participants to compete and use what transmission capacity is available between zones or nodes. One such mechanism is Financial Transmission Rights (FTRs). We discuss these in Box 2.6.

Additional locational pricing market design features and adaptations

2.14 As with all international electricity markets, zonal and nodal markets have evolved in response to challenges and opportunities associated with the energy transition. This includes changing the locational granularity of their markets by re-defining zones or moving from zonal to nodal,[43] introducing new ancillary services to reward flexibility and new market products to accommodate new technologies, and updating to the optimisation algorithm that is used for market clearing and dispatch to account for the variability of renewable generation.[44]

[43] Norway introduced zonal markets in the 1990s and gradually increased the number of zones over time, from 2 zones to 5 in 2015. The Texas ("ERCOT") and Californian ("CAISO") zonal markets transitioned to nodal pricing.
[44] New Elspot/Elbas bidding area in Norway | Nord Pool, Day-ahead Market Enhancements - Final Proposal | California ISO

2.15 When there are constraints on the transmission network, then charging all load the nodal (or zonal) price at their location (including charging them a zonal price based on the load-weighted average of the nodal prices if demand is shielded from nodal prices) and paying all generation the nodal (or zonal) price at their location, will result in the SO collecting a residual (commonly referred to as "congestion rent").[45] The congestion rent is the difference between selling power to consumers in high priced regions at a higher price than paid to generation outside the region.[46]

2.16 Zonal and nodal markets are also often accompanied by additional market design features that enable market participants to hedge against price differences between zones and nodes. This includes:

- **Regional trading hubs** – typically in locational pricing markets, most constraints are not binding all the time. Therefore in a nodal market, for example, there is often price convergence between nodes (ie the prices in any two locations tend towards the same value, excluding any price difference arising due to losses). Regional trading hubs often overlay nodal markets to pool liquidity within regions and help manage the risk of lower liquidity in forward markets from having a large number of nodes.

- **Financial Transmission Rights** (FTRs) – a financial product that can provide a means to return congestion rent to consumers, and/or help market participants to hedge against volatility in the price differentials between zones or nodes (amongst other functions).

2.17 These features are explained in more detail from paragraph 2.25. Zonal and nodal markets also often use market mitigation measures to limit the ability of market participants to exercise locational market power. These additional features are considered below.

[45] In this document, the term congestion rent refers to the financial surplus arising from the difference between the price paid for electricity by demand at a given location, and that paid to generators at another location. We note that the term 'congestion' and related terms such as 'congestion income' or 'congestion rent' may have different definitions under EU law.
[46] Including the cost of marginal losses in LMP prices will also result in the SO collecting a loss residual which is equal to the difference between the cost of marginal and average/actual losses.

Box 2.4. Electricity system operation, scheduling and dispatch

Electricity system operation is a continuously repeated process to ensure that unplanned changes from forecasted conditions, such as changes in demand (eg as temperatures rise and fall), generation (eg as cloud-cover and wind speeds shift impacting renewable generation output, or as unit availability changes), and transmission network availability can be taken into account as they emerge.

The commitment, scheduling and dispatch of system assets is a key part of electricity system operation:

- **Unit commitment** (ie which units will be available) – a decision process where specific assets/market participants are financially committed to generating power. It involves deciding which asset to turn on (or off) and at what levels, considering start-up/shutdown costs, ramping capabilities, minimum run times, and other constraints.
- **Scheduling** (ie how available assets will be used to meet demand) **–** sets out the plan for how much power each asset/market participant should produce at every time interval to meet forecast demand and relevant contingencies, while minimising cost.
- **Dispatch** (ie real-time adjustment of the plan to real-time conditions) **–** the real-time implementation of the schedule, with adjustments made to the output of online assets/market participants to meet actual demand and manage unforeseen changes in generation or consumption, while maintaining system stability and reliability.

There are two broad ways in which an electricity system can be scheduled, both of which are used internationally:

- **Central scheduling** refers to a system in which the SO coordinates the organisation of assets and determines a schedule that specifies which assets should operate at which times given economic/market conditions and expectations of, eg, demand, transmission availability, generator availability, self-schedules, and expected output of renewable generators. Market participants submit bids and offers to the SO or a Market Operator ("MO"), indicating the price at which they are willing to supply or consume electricity. These offers can include self-schedules, which are typically used for resources such as nuclear plants, run-of-river hydro, and the minimum operating level of thermal generation. These self-schedules could include just the minimum operating output of the plant or the full output of the plant. Market participants also submit the technical characteristics which the SO needs to respect, eg, their maximum injection/withdrawal power, ramp rates, and minimum operating level[47]. The MO/SO accepts bids and offers in a way that ensures physical feasibility and system reliability, whilst minimising overall cost and meeting other relevant technical constraints, creating a schedule, and issuing operating instructions to market participants. This scheduling tends to occur in the first instance at the day-ahead stage and is refined from that point in time as expectations about the forthcoming delivery period's demand and supply conditions are updated.
- **Self-scheduling** refers to a system in which market participants submit their intended positions and running profiles to the SO. Market participants usually

[47] Storage resources are sometimes able to submit additional parameters such as end of period state of charge constraints, as well as their current state of charge if not directly monitored by the SO.

contract trading of electricity bilaterally or via Power Exchanges.[48] Respecting the intended positions and maintaining a balance between supply and demand can be incentivised, eg, by imbalance pricing. Close to real-time (in GB after Gate Closure), the SO takes control of the system and re-dispatches some of the intended positions to meet the physical requirements of the system. The objective of the SO here is to minimise the cost required to move the intended positions to a physically feasible dispatch while maintaining security of supply.[49] The current GB system can be characterised as a self-scheduling market – see the section below for a summary of the current GB market arrangements.

Changes to facilitate locational pricing in GB

2.18 This section identifies high-level changes to current GB wholesale electricity markets that would likely be required to facilitate locational pricing in GB. It identifies changes to: (i) forward markets; (ii) day-ahead and intraday markets; (iii) the real-time market (or Balancing Mechanism); and (iv) settlement.

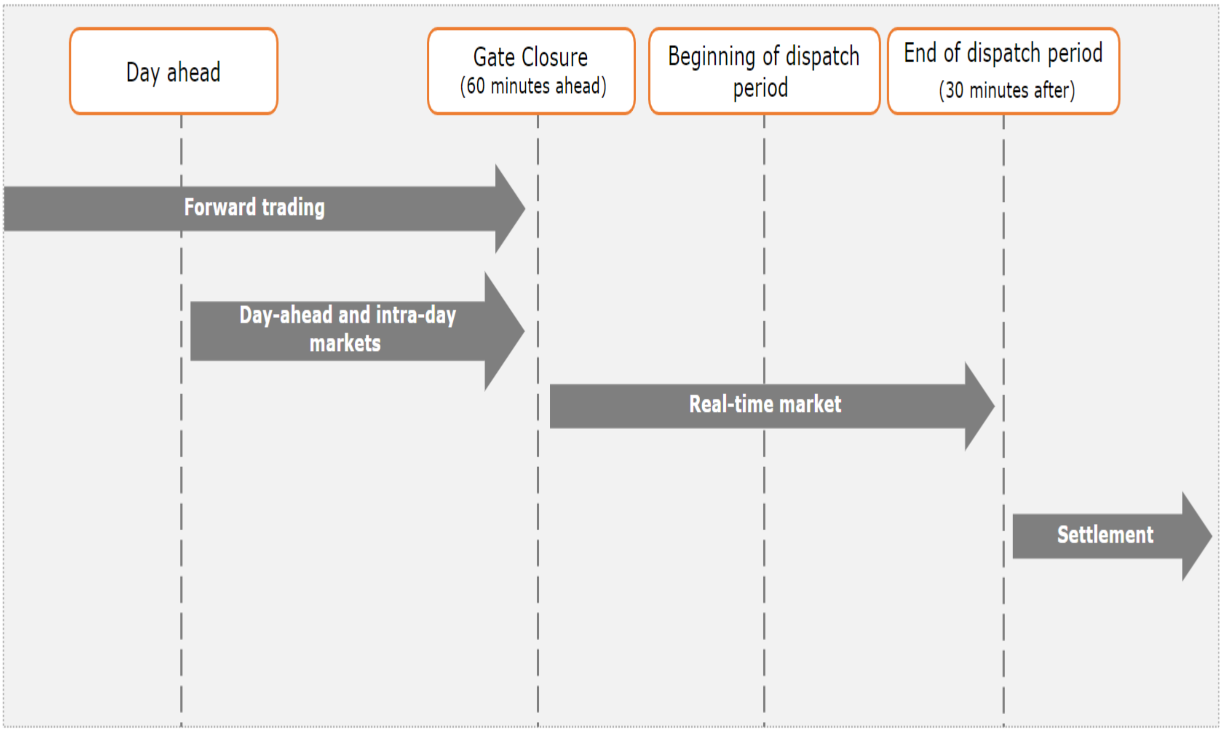

Figure 2.2: Illustrative example of timescale of current market arrangements. Source: Ofgem.

[48] Market participants also have forward contracts, either bilateral or exchange traded, in centrally scheduled markets but these contracts are generally financial and settled at spot market prices in centrally scheduled markets.
[49] Further reading: [Ahlqvist, Holmberg, Tangeras: Central- versus Self-Dispatch in Electricity Markets (cam.ac.uk)]

2.19 Electricity market arrangements are usually split across different timescales, with different marketplaces and platforms available at different points in time (see Figure 2.2Figure). Market participants choose which markets to participate in, depending on their hedging strategy, requirement to obtain long-term revenue certainty, or ability to forecast their positions and provide flexibility. Whilst the transmission of electricity is continuous, for the purpose of trading and settlement it is considered under current GB market arrangements to be generated, transported, and consumed in discrete 30-minute dispatch periods, commonly referred to as Settlement Periods.

Forward markets

2.20 Forward electricity markets serve to enable market participants to hedge against short-term price risks and uncertainties. Various financial products exist, and a variety of standardised products are available that cater for the individual needs and risk appetite of the trading parties.[50] In GB, forward trading occurs through over-the-counter (OTC) trading (ie bilateral trading) or through Power Exchanges.

2.21 Trading in GB forward markets, similarly to day-ahead and intraday markets, does not consider location, therefore trading parties do not carry risk associated with the traded position not being physically feasible as a consequence of constraints on the transmission network (volume risk). Market participants are required to inform the ESO of their intended physical output position via Initial Physical Notifications (IPNs) at day-ahead. Trades must be submitted to the Settlement Body for settlement purposes in the form of Energy Contract Volume Notifications, but those are not considered for the purpose of system operation.

Anticipated changes to current arrangements

2.22 Forward trading remains an important feature of both zonal and nodal markets. Unlike current GB arrangements, forward traded products in locational markets need to reflect the locational value of electricity, with both trading parties typically agreeing a delivery zone, node or trading hub. As discussed, market participants in jurisdictions with locational pricing do not have financially firm access rights to the entire transmission network. This

[50] Financial products include forwards, futures, options, swaps, and contracts for differences. Standardised products include e.g. baseload and peakload, and for different timeframes, e.g., daily, monthly, quarterly or seasons.

means certain market participants' risks may increase when compared to current arrangements. This includes volume risk (as the SO would no longer be paying for generation that cannot be dispatched because of transmission constraints) and price risk (in that the price market participants pay or receive may differ between locations. We consider these risks further in Section 5.

2.23 There are ways in which increased risk due to uncertainty can be mitigated, such as through FTRs. However, it is likely that generation located where it cannot be dispatched will have lower returns under a locational design than under a design in which it receives constrained-off payments. Hedging any resulting locational risk associated with a bilateral contract with an FTR requires market participants to agree a delivery zone, node or trading hub if trading parties do not inject and withdraw energy at the same zone (or node). If a zone (or node) is not agreed, the parties will be exposed to the zonal (or nodal) price difference between the inject and withdraw zone (or node).[51] The level of price difference between nodes depends on whether network flows between them are constrained at that time. When there are no network constraints binding, the prices between any two nodes should converge to the cost of marginal losses.

2.24 The application of additional locational market design features (highlighted in paragraph 2.14) would also have implications for forward trading, specifically for any method of acquiring and trading transmission rights (such as FTRs) and regional trading hubs. While these tools are used in multiple jurisdictions around the world, they would add further implementation complexity and cost, and have their own advantages and disadvantages.

Regional trading hubs

2.25 A market with hundreds or potentially thousands of nodes could increase the complexity for market participants in finding counterparties for bilateral forward trading. This is due to the need to agree on a delivery node, as discussed above. Several

[51] Even if a particular zone or node is agreed, typically one of the parties will be exposed to the price difference, e.g. a wind turbine in North Scotland selling to a supplier in a London delivery zone would be exposed to the price difference between North Scotland and London.

stakeholders and studies have noted that this increased complexity could, among other reasons, reduce liquidity in forward markets.[52]

2.26 To mitigate this risk, a number of US markets with nodal pricing (eg PJM, ISO-NE, NYISO, MISO, CAISO and ERCOT) facilitate the use of regional trading hubs for forward trading. A hub is an aggregation of nodes in a geographic region and serves to create a common point for electricity trading and the pooling of liquidity. This could also be a feature of a zonal market, depending on the number of zones.

2.27 For each hub, reference prices are calculated for both day-ahead and real-time markets based on a pre-defined set of nodes. These reference prices can be used for forward trades, such as OTC trading.[53] Hub reference prices are typically calculated through some form of weighted average of the locational prices of the nodes belonging to the hub. Node weights could be equal, depend on historical metered volumes, vary dynamically, and/or only include a specific subset of nodes.

2.28 Hubs typically have no relevance for system operation, market clearing or settlement of day-ahead and real-time markets. Participants with physical positions that trade at hubs still need to participate in the nodal wholesale market, which remains the sole source of dispatch instructions and provides the basis for settlement. Bilateral and exchange trade contracts are typically structured as contracts for differences which settle against either the day-ahead or real-time spot price at the trading hub or other location. In US markets, the methodology to determine hub designs and calculate reference price tends to be subject to stakeholder consultation. The SO generally agrees not to change the definition of a trading hub without stakeholder agreement.[54] This ensures that the hub design is most effective to cater for market participants' needs and minimises any risks resulting from poor hub design.

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[52] Day-ahead and real time markets are less affected by this as they can be run centrally, thereby removing the need for market participants to find counterparties for bilateral trading.
[53] Long-term bilateral contracts are often defined relative to established trading hubs to facilitate the parties trading in and out of their position.
[54] Transmission expansion projects can occasionally result in a node included in a trading hub being eliminated or split and the SO and stakeholders will agree on using one of the new nodes as a replacement.

Box 2.5. Common features of trading hub design and operation

Common features associated with the effective design and operation of trading hubs have been identified from a review of regional trading hubs in US jurisdictions:

- To produce robust and predictable hub prices**, locational price variations between nodes should be limited and rare**, though it is possible for constraints to arise within hubs (for example the PJM western hub can be impacted by transmission constraints). It is generally desirable to include a **substantial number of nodes in a trading hub** definition to reduce the impact on the trading hub price of particular nodes or high or low prices at particular nodes due to a transmission outage impacting a particular node or a few nodes.
- The implementation of trading hubs and reference price calculation is typically the **responsibility of the SO**. The decision to use a trading hub for forward trading is typically made by Power Exchanges and market participants.
- Hubs can contain several hundred nodes but size and design vary significantly. **Some US hubs contain a mixture of generation and load nodes, while others contain generation-only or load-only**.
- As consistency in hub definition is important, **changes to hub definition are typically minimised** and when necessary are discussed with market participants. Poor hub design can result in limited active trading.
- **Market participants play a key role in hub design** as they are the principal beneficiaries. Stakeholder consultation is used to determine the methodology to determine hub design and calculate reference prices.
- The **methodology to determine the nodes belonging to a hub is sometimes done via an optimisation algorithm**, such as clustering of nodes that respond in a similar way to transmission constraints. Many hubs also correspond to load zones that are defined as the weighted average of the nodal prices within the zone.
- Hubs should be designed so that the **loss of a node or individual transmission outage should not substantially affect the reference price.**

Financial transmission rights

2.29 The FTR is a financial product used in the energy industry to help market participants hedge the differential between two zones, or nodes, and reduce their exposure to any potential price difference for a given capacity in a given Settlement Period, amongst other reasons.[55] They are typically funded by the congestion rents.

2.30 When a participant holds an FTR, they have the right to receive a financial settlement based on the price difference between the two locations. In theory, market participants do

[55] We note that there are alternative tools to FTRs that are designed to enable market participants to hedge price differentials between zones or nodes. For example, Electricity Price Area Differences (EPADs) are used in the Norwegian zonal market and Physical Transmission Rights (PTRs) are used over some borders within the IEM and over some borders between GB and the IEM. The application and use of locational hedging tools would be a key consideration in designing and implementing a zonal or nodal market in GB.

not require an FTR to trade outside their zone or node, however, typically an FTR will provide a useful hedge for market participants against price differentials between two locations due to binding network constraints when forward trading.[56] FTRs can be obligations ("two-way") or options ("one-way").[57]

2.31 FTRs were used to provide market participants with the opportunity to hedge against price differences between the Integrated-Single Electricity Market and GB electricity markets, namely as products available on the Moyle[58] and East West[59] interconnectors.

2.32 As FTRs are a financial, and not a physical, product, it is not necessary for an FTR holder to either physically inject or withdraw from the system to be paid the price difference between two locations.[60] As a result, in markets where they are used, FTRs can typically be purchased by anyone interested in obtaining such a product. In general, FTRs will be most valuable between nodes where the network is frequently constrained. This high value can provide a signal to system planners about the potential benefits of increasing network capacity in those locations.

2.33 Where FTRs are allocated to market participants competitively[61] at a premium to the expected FTR payout, this premium represents a cost to market participants based on their willingness to pay for future certainty in the price that they will buy energy for, or sell at, at a given location.

Box 2.6. FTR governance, design and allocation

The use of FTRs (or alternative locational hedging tools) in GB would require careful consideration. Below we consider some important issues related to governance, product design and allocation.

Governance

An FTR regime would require an organisation to take on key functions and responsibilities including, but not limited to:

- identifying the physical transmission capacity available between each location,

[56] Parties can also trade via day-ahead and intraday markets where FTRs are not required.
[57] An obligation means that the holder of the FTR is required to pay (or receive) the difference between the price at two locations. If the FTR is an option, then it will only have a value if electricity flow is in the direction assumed under the FTR (ie if the FTR is held counter to the direction of flow the value becomes zero).
[58] See FTRs_01.pdf (mutual-energy.com) for more information.
[59] See Interconnection (eirgridgroup.com) for more information.
[60] This is different from PTRs which are necessary in order for the holder to be able to nominate and physically transfer electricity across the relevant interconnector (or not nominate and receive financial compensation).
[61] For example, via an auction, where proceeds can be allocated to consumers.

- ensuring revenue adequacy (ie via a simultaneous feasibility test[62]), and
- allocating and/or auctioning FTRs.

In US markets, this tends to be the responsibility of the Regional Transmission Organisation (RTO)/Independent System Operator (ISO). An equivalent party in the GB market could be the Future System Operator (FSO), however there may be other new or existing bodies that could fulfil the functions above.

Product design

If FTRs were to be used to complement locational pricing in GB, product design (ie the type of FTRs available) would be a critical consideration. Several key product design features have been identified based on the design and operation of FTRs in international jurisdictions:

- **Product granularity**, ie. whether products would be baseload, peak, off-peak[63] and covering delivery periods of months, quarters or seasons, with a need to balance complexity, the number of products available and the usefulness of the FTR regime as a hedging tool.
- **Location**, ie the zones and nodes between which FTRs would be offered. Some jurisdictions began with FTRs only between main trading hubs before introducing more offerings over time.
- **Timeframe** over which FTRs are available. Typically, auctions are held as far ahead as 3 years from the relevant Settlement Period. There could be opportunities for shorter or longer time periods, based on anticipated demand for long-term hedging in GB (ie auction liquidity), as well as the degree of certainty in available, future network capacity.
- The **reference price that the FTR is settled against**. Generally in locational markets, the price in any one node or zone changes through time as the market gets closer to real-time. As such, it is necessary to specify the timeframe at which the prices are taken for the purpose of settling the FTR. In US markets, FTRs are typically settled against the day-ahead scheduled price. There may be other options to consider for use in GB, such as the real-time price.

In addition to the above, we note that there are concerns around the usefulness of FTRs as a hedging tool for non-dispatchable forms of generation. For example, wind generators may have less certainty of their specific level of output in a given dispatch period, arguably making it harder to judge the capacity of FTR required compared to dispatchable generation. This would need to be considered within GB FTR design.

Allocation

FTRs can be allocated in a number of ways. For illustrative purposes, a simple, auction-based method could involve:

- The SO holding an auction for all FTRs simultaneously[64] for a given dispatch period. Auctions could be split by granularity of products (see above).

[62] A simultaneous feasibility test is used to ensure revenue adequacy (ie. that no more FTRs can be offered than the physical transmission capacity between two locations). This helps to ensure that there is always sufficient congestion rent to pay out on the FTRs.
[63] These are the current definitions used in US FTR markets but there is discussion of defining FTRs for different periods, such as the solar day. GB stakeholders could choose to define FTRs covering different sets of hours than has been the case historically in the US.
[64] Identifying the volume of rights available via a simultaneous feasibility test.

- Interested parties (who do not have to hold physical positions on the network) provide competitive bids to secure the right to hold an FTR for said dispatch period. Individual bids reflect how much market participants are willing to pay to secure an FTR for a given volume between two locations on the network.
- FTRs are priced on a market clearing basis in all US jurisdictions. FTR prices are not determined path-by-path but overall paths simultaneously with FTR auction prices determined by the impact of each FTR on binding transmission constraints in the auction.
- Auction revenues collected by the SO are allocated in a pre-determined manner, eg to final demand either directly (eg via suppliers) or indirectly (eg as a reduction to network charges).
- FTRs can be traded amongst market participants via a secondary market. This trading is allowed by all US jurisdictions but is typically relatively rare because market participants using FTRs for hedging will typically not be interested in holding FTRs with exactly the same source and sink.

In some jurisdictions, such as PJM ISO and Midcontinent ISO (MISO), access to the revenue stream generated by FTR auctions, sometimes conferred via Auction Revenue Rights ("ARRs"), is provided to market participants. ARRs are typically viewed as a tool to provide long-term certainty to market participants. They are typically allocated by an independent authority, such as a regulator or SO, for a set period of time.

ARR holders normally have at least two options:

1. Convert the ARR into an FTR on the same path (ie. equivalent to being handed an FTR, for a set capacity, for free). This would mean that the income arising to the party would be based on the constraints on the path to which the ARR applied; or
2. Retain the ARR and earn an income solely based on the revenue arising from the auction for the FTRs of the equivalent path.

ARRs could be used in GB to provide some market participants (eg suppliers, on behalf of consumers) certainty over access to congestion rent. Such access could be beneficial for two reasons:

1. Consumers are not faced with an additional cost of securing certainty over future prices (as they would be if suppliers had to compete for FTRs in an auction); and
2. A market for long-term FTRs may not appear (eg typically US markets do not auction FTRs any further out than three years before the relevant Settlement Period).

Day-ahead and intraday markets

2.34 Day-ahead and intraday markets are organised marketplaces for short-term delivery. Today in GB, these marketplaces are operated by independently operating Power Exchanges (in addition to direct bilateral transactions, ie OTC trading).[65] The day-ahead and intraday markets in GB facilitate the trading of electricity via auctions in hourly or half-

[65] EPEX Spot and Nord Pool currently operate day-ahead and intraday markets in GB.

hourly blocks for the next day and for the day of delivery (with some of the auctions being ‘coupled’ for the purpose of cross-border trading).

2.35 Some of the intraday markets in GB are continuous markets with first-come/first-served principles (trades are executed as soon as buy and sell orders are matched). Day-ahead and intraday markets also help facilitate trading with the IEM.

2.36 Like forward trades, current day-ahead and intraday markets do not consider the available transmission capacity within GB as part of the market clearing process, as GB forms a single pricing zone (although the price may differ for each Power Exchange). This reflects current GB transmission access rights (see Box 2.3). As a consequence, the day-ahead and intraday outcome often needs to be subsequently re-dispatched by the SO in order to resolve violations of transmission constraints (see section on real-time market and Box 2.2).

Anticipated changes to current arrangements

2.37 Participation in day-ahead and intraday markets under locational pricing would differ compared to participation in current day-ahead and intraday markets. In particular:

- **Under a potential nodal pricing design**, current self-scheduling arrangements (ie, market participants having the right to export up to their TEC and submitting Physical Notifications[66]) would be replaced by a central scheduling process through which market participants submit offers to the day-ahead and intraday markets for each delivery period of the relevant delivery day.[67] Subject to market design, market participants who want to ensure that they are dispatched, eg because of plant economics, could choose to self-schedule (essentially by submitting a very low or negative price), meaning they become price takers and would not participate in the market clearing.

- **Under one of the potential zonal pricing designs**, current self-scheduling arrangements could be maintained for intra-zonal trading (with intra-zonal constraint management remaining a responsibility of the SO through a revised

[66] See Box 2.3 for more detail.
[67] Markets with nodal pricing require central scheduling, albeit with the opportunity for self-schedules, given the need for the SO or MO to run the SCED to determine the optimal dispatch profile taking into account transmission constraints and to calculate nodal prices.

balancing market). Alternatively, intra-zonal trading could also be facilitated through coordinated day-ahead and intraday markets and central scheduling, as under nodal pricing.

- **Under nodal and zonal pricing, subject to the exact design,** the day-ahead and intraday market outcome could be financially binding. Market participants who deviate from their awarded position at time of delivery would have to pay (or receive) the real-time price for any deviations.

2.38 Introducing locational pricing would likely require significant changes to current intraday trading arrangements, such as potentially moving from continuous trading to auctions to provide locational intraday prices. The use of intraday markets with a locational GB wholesale market could therefore add further complexity to central settlement processes, as these markets would theoretically create further locational prices to be considered in addition to the day-ahead prices.

Market power mitigation

2.39 Market power that provides the ability to profitably raise prices above competitive levels – exists within all offer-based short-term electricity markets (ie day-ahead, intraday and real-time and within national, zonal and nodal markets) as assets can exercise market power by virtue of a unique position on the network and/or unique capabilities. Higher prices resulting from the exercise of market power typically result in a wealth transfer from consumers to producers.

2.40 All US markets with nodal pricing have now implemented automatic market power mitigations (see Box 2.7 below). Once an offer is submitted to the day-ahead, intraday or real-time market, but before it is accepted, the offer is subject to a predetermined ex-ante market power test. If the offer fails the test, the price is replaced by a typically regulator-determined reference price. Market power mitigation can also include an ex-post mechanism to provide an opportunity for market participants to challenge a mitigation measure.

Box 2.7. Market power

US markets with nodal pricing use one of the following two tests to determine whether an offer is to be mitigated via market power mitigation:

1. The **"Conduct and Impact"** test: First, following a trigger (eg, transmission constraints arising in a particular area), this test determines whether the offer price of resources within the triggered region exceeds a specific threshold (the generator's reference level, the "Conduct"). Secondly, the test determines whether the offer price has an impact on the clearing price when it is replaced by the reference level (the "Impact"). The "Conduct and Impact" test is implemented in the ISO-NE, MISO and NYISO markets.
2. The **"Pivotal supplier"** test (aka "Structural" test): This test measures the degree to which the supply from a group of generators is required to meet demand in an area that has a constraint limitation. In contrast to the "Conduct and Impact" test, this test does not consider actual offers of market participants. The "Pivotal supplier" test is implemented in the CAISO, Western Energy Imbalance Market and PJM markets.

2.41 In some jurisdictions with zonal pricing, market power mitigation is undertaken manually. For example, in Italy, market participants that can exert market power under certain conditions are identified in an annual simulation exercise. During the year, units identified as part of this process can then be kept out of the market for specific times and paid a reference price.

2.42 Determining the reference price is critical for the effectiveness of the market power mechanism and must be reflective of the competitive offer price of a market participant to avoid inefficient outcomes. Different methodologies for determining the reference price are applied in US markets, eg, based on a unit's estimated marginal cost, historical offer prices of a unit, or historical but fuel-corrected offer prices of the market in general. Challenges for estimating reference prices include, eg, energy limited resources such as hydro generation or batteries, and volatile fuel prices.

2.43 Market power mitigation measures are not a requirement of locational pricing but evidence from US markets indicates they are a desirable 'day-1' feature. The design of any form of market power mitigation would require careful consideration of the specifics of the GB electricity system, however many international designs have been in operation with few changes for 10 years or more, thereby providing well-tested mechanisms to inform GB policy-making. Across jurisdictions, market power mitigation responsibilities can sit with the regulator, the SO, or with another independent body.

Co-optimisation between energy and ancillary services

2.44 An optional market design feature for zonal or nodal markets with central scheduling is the co-optimisation of energy and ancillary services needs.[68] On top of system actions in the Balancing Mechanism, ancillary services that provide for the non-energy needs of the electricity system are currently procured by the ESO outside of the wholesale market, usually via auctions or tenders.[69]

2.45 With locational pricing, market participants could offer ancillary services provision[70] alongside energy offers in the day-ahead market, with these offers cleared in a single market clearing process. This would reduce the number of ancillary services procured outside of the wholesale market via separate markets, helping enhance the standardisation of different balancing products (eg procurement timelines and requirements) and improving the liquidity of all involved markets.

2.46 This is expected to be more efficient than current energy and ancillary service markets, as market participants could make themselves available in both markets with the SO deciding (based on system needs) whether to accept an energy or an ancillary service offer. This would remove the need for market participants to include estimated opportunity costs in their offers, as these opportunities would be determined in the market and be reflected in market clearing prices.

2.47 With co-optimisation, the central clearing algorithm would accept ancillary service offers alongside energy offers from ancillary service providers in a way that: (i) balances demand and supply, (ii) ensures the relevant ancillary service needs of the system are met in each delivery period, and (iii) minimises the combined production cost of meeting energy and ancillary service requirements. Changes to the procurement of ancillary services should not affect the mechanism for ancillary service cost recovery (currently through Balancing Services Use of System (BSUoS)), as they would remain non-energy products. Certain ancillary service products (eg, restoration services) would continue to be procured as today.

[68] This option would be unlikely to apply to market arrangements with multiple MOs, as the additional reserve constraints would likely increase the complexity of the market clearing mechanism.
[69] Balancing services include the provision of frequency response, reserve, voltage stability, system restoration, thermal constraints and balancing mechanism.
[70] Frequency response and reserve services are typically co-optimised in most US markets with nodal pricing. Voltage and stability services are not yet co-optimised but could potentially be in the future.

Real-time market

2.48 Real-time markets are organised marketplaces for immediate and/or short-notice delivery (in GB up to 60 minutes ahead of the beginning of the relevant Settlement Period) to account for short-term variations in demand or generation. They are required to ensure the electricity system is balanced at all times and to meet physical network capabilities and requirements (see Box 2.1). The latter is of particular importance in markets where trading ahead of real-time does not consider network constraints, as is currently the case in GB. All electricity markets implement a real-time market that pays or charges market participants for adjusting their intended (under self-scheduling) or agreed (under central scheduling) positions to ensure supply and demand is balanced (the dispatch).

2.49 In GB, the ESO uses the Balancing Mechanism as the key tool to balance supply and demand and ensure security of supply in real-time. The ESO has access to a range of dynamic and commercial data submitted by different market participants. Normally, generators can access the Balancing Mechanism via Bilateral Connection Agreement (BCA), Bilateral Embedded Generation Agreement (BEGA), and Bilateral Embedded Licence Exemptible Large Power Station Allowance (BELLA) routes. Energy suppliers can also register Balancing Market Units (BMUs). Recently, a new route has been developed to widen access to the Balancing Mechanism. Via Virtual Lead Party (VLP), parties could register Secondary BMUs with ESO and Elexon for the minimum size of 1MW.

2.50 From Gate Closure onwards, the ESO is responsible for identifying the need for balancing actions and accepting bids and offers from market participants for two reasons:

- to manage imbalances between the sum of participants' contracted and actual positions (energy balancing), or
- to manage system constraints or other non-energy needs (system balancing).

2.51 Participants who have a bid or offer accepted by the ESO receive or pay their bid or offer price (pay-as-bid).

2.52 Under some forms of locational pricing with central scheduling, the current Balancing Mechanism would likely be superseded by a new real-time market. The key difference from the current Balancing Mechanism is that it would be pay-as-clear (the locational real-time prices) and that real-time prices, which are relevant for imbalance settlement and substitute the Single Imbalance Price (SIP), would be locational (nodal or zonal).[71] Also, under central scheduling the MO/SO would use both dynamic and economic parameters of units to issue instructions to manage the system real-time.[72] Market power mitigation measures, as discussed previously for day-ahead and intraday markets, would likely need to apply to the real-time market.

2.53 Under locational pricing, particularly nodal with central scheduling, consideration would need to be given to reducing the current dispatch and Settlement Period from 30 minutes. As an example, US jurisdictions with locational pricing typically use 5-minute dispatch periods. Within these dispatch periods, system balancing is typically performed via ancillary services, eg, frequency response. US ISOs have also implemented Automatic Generation Control (AGC) that sends frequency control signals to generators to maintain frequency. AGC is currently not implemented in GB but might be required or desirable under zonal or nodal pricing under a more automated dispatch process.

2.54 Under zonal pricing with self-scheduling based on managing constraints intra-zone, we expect that current Balancing Mechanism arrangements could largely be maintained. However, this zonal Balancing Mechanism could produce a SIP for each zone and market participants' imbalance positions could be settled based on these.

Settlement

2.55 Settlement refers to a number of post-delivery processes that account for imbalances between intended and actual positions of market participants and facilitate relevant transactions. The process is generally comprised of:

- Metering, ie, the measurement of electricity flows within, to and from the electricity system.
- Volume allocation (in some jurisdictions also referred to as reconciliation), ie, the process of determining how much electricity is consumed or generated in a given Settlement Period.[73]

[71] In the GB market, the term 'Single Imbalance Price' is interchangeable with 'System Sell Price (SSP)', 'System Buy Price (SBP)' and 'cash-out price'.
[72] Otherwise complex bids and offers.
[73] This process is particularly important for customers that do not have real-time meters to measure consumption.

- Financial settlement, ie, calculation of imbalances and facilitating financial transactions taken to charge/pay market participants for any imbalances.
- Data reporting, ie, publication of market data for the purpose of transparency.

2.56 Changes to the existing settlement processes would likely be required to facilitate locational pricing. Below we consider the relevant processes and likely changes in more detail.

Metering

2.57 Depending on whether locational pricing was implemented concurrently with changes to the temporal granularity of dispatch and settlement, existing meters and metering arrangements could be maintained. Settling demand at more temporally granular intervals could result in more significant implementation impacts and investment related to the relevant IT systems, metering data management, and billing procedures.

Volume allocation

2.58 Locational pricing would require changes to the volume allocation of distribution-connected customers (both generation and demand) to reflect the potential for pricing zones/nodes not matching the current aggregation of supplier volumes by GSP groups. This is because GSP groups match historical DNO licence areas, but not necessarily transmission constraints. In theory, to fully expose distribution-connected customers to locational pricing, each electricity meter (represented by a Meter Point Administration Number or MPAN) would need to be assigned to a pricing zone/node. This assignment is likely to be complex due to the following reasons:

- The distribution network below a GSP can be meshed and only tends to become radial from the primary substation (33/11 kV level) downwards. A customer can thus be connected to multiple GSPs (and consequently pricing zones/nodes) simultaneously.
- Power flows on the distribution network change, eg, depending on consumption and reconfiguration of the distribution network. The assignment of meters to pricing zones/nodes could therefore change over time.

2.59 Further complexities could arise from:

- Electricity flows between DNOs that do not go through a GSP or the transmission system might need to be accounted for separately.

- The current processes for socialisation of unallocated energy might need to be adapted.
- The methodology for treating losses in the distribution network between customer meters and GSP meters might need to be reconsidered.

2.60 There is likely to be a trade-off between cost of accurate mapping and the value of accuracy. Potential simplifications could include:

- Mapping MPANs to a single zone/node which (on average, across the period analysed) would be most affected by a marginal increase in demand at that point.
- Mapping MPANs to one or more nodes or zones, using a percentage allocation reflecting the extent to which (across the period analysed) each zone/node would be affected by a marginal increase in demand at that point.
- Shielding some or all distribution-connected customers from locational prices.

Financial settlement

2.61 Settlement processes would need to be adapted to consider locational prices and different prices stemming from day-ahead, intraday and real-time markets.

2.62 In a zonal and nodal market with centralised day-ahead and intraday markets, central settlement of the day-ahead and intraday markets would be required in addition to the current imbalance settlement. The body responsible for calculating locational prices would provide nodal/zonal day-ahead and intraday prices for each SP based on the outcome of the day-ahead and intraday markets.

2.63 In a zonal market without central day-ahead and intraday markets, settlement of day-ahead and intraday trades could remain a responsibility of the individual MOs (currently the Power Exchanges).

2.64 Deviations from day-ahead and intraday positions would be settled at the nodal/zonal real-time price, replacing the current national SBP/SSP (ie those market participants that are exposed to locational prices and are deviating would receive or pay the relevant real-time price depending on whether they are over- or under- delivering).

Identified system implementation gaps

2.65 Table 2.1 provides a summary of system implementation gaps that follow from the above analysis of the current market arrangements in GB. We note that further gaps may exist that would depend on the actual market design chosen should locational pricing be taken forward, and that this would need to be the subject of further work. We also note that the table contains both necessary changes and changes that would be subject to policy decisions.

Table 2.1: Summary of potential system implementation gaps identified to date. Source: Ofgem.

	Element	Current	Gap	Responsible party
Forward trading	Forward product design	Forward products exist with agreement on volume and time	Forward product would need to agree on delivery zone/node	Power Exchanges, brokers
	Trading hubs	Not existing	Implementation of trading hubs to establish common markets across groups of nodes with similar prices	MO/SO/other party
	FTRs[74]	Not existing	Implementation of mechanism to allocate/auction FTRs and pay/collect FTR revenue	MO/SO/other party
Day-ahead and intraday markets	Day-ahead and intraday markets	Independently operating Power Exchanges with day-ahead and intraday auctions and continuous intraday trading as well as OTC trading	Coupling of day-ahead and intraday markets or implementation of central markets. Potentially new intraday auctions to replace/be used alongside continuous trading	MO
	Day-ahead and intraday price calculation	Day-ahead and intraday prices calculated by Power Exchanges	Calculation and publication of locational day-ahead and intraday prices	MO/Settlement body/other party
	Co-optimisation	Ancillary services are procured	Integration of energy and ancillary services	MO/SO

[74] Or alternative locational hedging tool.

	Element	Current	Gap	Responsible party
	of Ancillary Services	outside of the market		
	Market power mitigation	See footnote [75]	Automatic, ex-ante market power mitigation measures	MO/SO/Ofgem/other party
Real-time markets Real-time operation	Real-time market	In the Balancing Mechanism, bids/offers are submitted for each Settlement Period but accepted on a continual basis within each Settlement Period	Under central scheduling, ability to submit, assess and accept complex real-time bids/offers for discrete dispatch periods.	MO/SO/Market participants
	Real-time price calculation	Ex-post system-wide imbalance prices (SSP, SBP)	Calculation and publication of locational real-time prices	MO/Settlement body/other party
	Market power mitigation	See footnote 75	Automatic, ex-ante market power mitigation measures	MO/SO/Ofgem/other party
	Real-time optimisation	ESO Security-Constrained Economic Dispatch ("SCED") algorithm	Likely changes to SCED algorithm required	SO
	Real-time control of generation assets	Frequency response via Ancillary Services and Balancing Mechanism	Automatic Generator Control (AGC) likely to be required for balancing system between dispatch runs and to automatically manage frequency.	SO
Settlement	Metering	Half hourly and non-half hourly meters	Depending on design, existing meters, IT system, metering data management, and billing procedures could be maintained, or additional	Suppliers/market participants

[75] Ofgem has powers under both REMIT, which specifically prohibits market manipulation in the wholesale energy market, and the Competition Act to prevent trading parties from engaging in abusive practices. There are also generation licence conditions (TCLC and IOLC) specifically covering bids and offers in the BM. Within REMIT they are responsibilities on 'persons professionally arranging transactions' (marketplace operators) to monitor for breaches and inform the regulator. Currently this includes the ESO for the BM and power exchanges for DA markets. If the SO's role were expanded to cover intraday and day-ahead markets then we envisage their surveillance role as a Person Professionally Arranging Transactions would expand accordingly.

	Element	Current	Gap	Responsible party
			investment may be required.	
	Volume allocation	MPANs only mapped to GSP groups	MPAN mapping to pricing nodes/zones	DNOs
	Day-ahead and intraday settlement	Responsibility of Power Exchanges, system-wide price	Enhanced settlement processes needed for integration of locational day-ahead, intraday and real-time settlement should there be a single MO	MO/Settlement body
	Real-time settlement	30-minute SP, system-wide price	Enhanced settlement processes for locational prices, potentially shorter SP or averaged SP over multiple Dispatch Periods	MO/Settlement body
	Reporting	System-wide imbalance prices per SP	Reporting of locational prices and other system conditions	MO/SO/Settlement body

3 Implications for market policies

Section summary

This section considers how a broad suite of market policies and regulatory arrangements could interact with and be impacted by the introduction of locational pricing in GB.

This section aims to:

- provide an overview of a wide range of existing or planned market policies likely to interact with or be impacted by the introduction of locational pricing; and
- provide further insight into select policies likely to be materially impacted.

Introduction

3.1 This section considers how a broad suite of market policies and regulatory arrangements (hereafter referred to as “market policies”) could interact with and be impacted by the introduction of locational pricing. The market policies considered and the impacts and implications are not exhaustive, with the ability to consider interactions limited by factors including uncertainty over the future design of a locational wholesale markets and whether policies may be subject to change as an outcome of REMA or wider reform programmes. Market policies which we consider more likely to be materially impacted by the introduction of locational pricing are considered in further detail.

Approach and overview

3.2 A list of market policies to consider and prioritise was tested with stakeholders.[76] Each market policy was then considered in terms of: (i) likely degree of interaction with a locational wholesale market and potential materiality of any changes required to facilitate locational pricing; and (ii) degree of uncertainty and/or risk associated with how said policy could operate in a locational wholesale market.

3.3 Tables 3.1-3.3 below provide a high-level summary of potential impacts and interactions identified to date, with policies grouped into three key themes: (i) current

[76] Stakeholder workshop #1: 26 May 2022. Materials: Design options for nodal pricing in GB (ofgem.gov.uk)

investment support schemes,[77] (ii) network and connections, and (iii) wider electricity system markets and infrastructure.

3.4 We then discuss four policies which this initial assessment indicates are likely to be significantly affected[78] by the introduction of locational pricing and/or where there is significant uncertainty over potential interactions, and where the absence of a workable solution could pose a material barrier to market reform. These four market policies are: (i) the Contracts for Difference (CfD) regime, (ii) transmission network charging, (iii) cross-border market arrangements, and (iv) decentralised energy resources, demand flexibility and consumers.

Table 3.1: Current investment support schemes - summary of potential impacts and interactions with a locational wholesale market. Source: Ofgem.

Policy area	Potential impacts and interactions
Capacity Market	• Relatively minor changes to existing Capacity Market Rules and Regulations are likely to be required to ensure ongoing operability and compatibility with locational pricing. However, material changes to current design features (eg a move from national to 'local' Capacity Market auctions) could be considered to facilitate greater compatibility with wholesale market design. • Capacity Market costs (which are ultimately borne by consumers) are likely to be affected by changes in market participants' wholesale market revenues relative to the status quo but materiality and direction of impact on scheme costs is uncertain.[79]
Contracts for Difference	• Several current CfD design features are likely to be materially impacted including, but not limited to, the reference price methodology and design of negative pricing rules. We note

[77] This section considers the potential impact and interaction of locational pricing with current government support schemes only. The REMA programme is considering a range of options for reforming how investment in low carbon, adequacy and flexibility is supported by government. We do not consider the potential interaction of locational pricing with the range of investment reform options set out in the REMA consultation.
[78] Note that this is a relative assessment, and that it does not mean that we consider that there could not be significant implementation challenges with other market policies.
[79] We note that analysis undertaken by Aurora Energy Research on 'Locational Marginal Pricing in Greater Britain' (September 2023) modelled differences in Capacity Market costs under national, zonal and nodal pricing between 2025 and 2060 and found the differences to be negligible. Locational Marginal Pricing in Great Britain | Aurora Energy Research (auroraer.com)

Policy area	Potential impacts and interactions
	government are considering CfD re-design as part of the REMA programme. • In aggregate, support costs for existing and future CfD holders (borne by consumers) are expected to be greater compared to those which would be incurred under the status quo. Across GB, support costs would likely be higher in the north and lower in the south. This is due to changes in average wholesale prices (which would reflect network conditions) altering the top-up payments CfD-generators receive (eg, a lower average wholesale price in the north requiring a larger top up for generators in this region). • Consideration would need to be given to the operability of existing CfD contracts and remedies developed for addressing identified issues. • Any CfD re-design would need to ensure coherency with the locational and operational signals sent through locational pricing. This should include the potential role for CfDs (and other mechanisms that provide a degree of price stability) in helping market participants manage certain market risks associated with locational pricing.[80]
Interconnector Cap and Floor regime and current and future interconnectors (including offshore hybrid assets)	• The business cases for existing (and future) interconnectors and offshore hybrid assets could expect to be impacted by the introduction of locational pricing. • There may be some instances where price differentials between a locational GB market and the European bidding zone price it is connected to could converge. This is unlikely to occur to the same extent under the current GB single price design. As the underlying business case for the development of interconnectors is driven by the capture of the price differential between the two connecting points (congestion rent), some interconnectors could face reduced revenues, while some could face increased revenues. For interconnectors with a cap and floor regime in place, changes

[80] As discussed in Section 5, measures to reduce or shield market participants from certain price signals can be expected to reduce the consumer benefits associated with locational pricing.

Policy area	Potential impacts and interactions
	in revenues could alter consumer support payments. For example, reduced revenues for interconnectors could increase the risk of consumers having to top-up revenues to the floor level. For merchant interconnectors, the interconnector owner, and not consumers, would bear this risk associated with reduced revenues. • Changes to current market design (including alternatives to locational pricing) could create uncertainty that could act as a barrier to achieving the government's ambition for 18GW of interconnection by 2030. This could impact new investment or require re-consideration of the regulated route for interconnector investment. • In future, connection locations will play a more significant role in the siting of new interconnectors and will likely be more centrally planned than developer-led. The Third Cap and Floor Application Window indicates the direction of travel for future application windows. Consideration of location in the application process would need to take into account price signals from a locational wholesale market.
Regulated Asset Base ("RAB") for Nuclear	• As the RAB model is designed to be resilient to price volatility and guaranteed revenue is not directly linked to the wholesale price, our current expectation is that there is unlikely to be a material impact on the operability or functionality of the RAB model. • However, levy payments could be impacted if the size of allowed revenue components adjust in response to changing wholesale prices and increased volatility compared to status quo.
Dispatchable Power Agreement for Carbon Capture, Usage (CCUS DPA), and Storage	• The variability payment mechanism in the CCUS DPA aims to put unabated Combined Cycle Gas Turbine (CCGT) below CCUS in the merit order. Locational pricing could change the merit order compared to the status quo. This could lead to instances where the variable payment is insufficient to ensure CCUS displaces CCGT at every zone or node.
Renewables Obligation (RO)	• No direct impact on the RO scheme has been identified to date as there is no direct reference to wholesale electricity

Policy area	Potential impacts and interactions
	prices in the RO, Renewable Obligation Certificates ("ROC") or the buy-out price.
Feed-in Tariffs (FiT)	• The methodology for calculating the costs and export payments of the FIT scheme would need to be amended, which could increase the complexity of processing scheme costs.

Table 3.2 Network charging and connections - summary of potential impacts and interactions with a locational wholesale market. Source: Ofgem.

Policy area	Potential impacts and interactions
Transmission Network Use of System (TNUoS)	• Material changes could be required to current transmission network charging arrangements to accommodate locational signals being sent via wholesale prices.
Distribution Use of System (DUoS)	• Based on the 'transmission-first' scope of this assessment, locational pricing is anticipated to have limited impact on DUoS.
Balancing Services Use of System (BSUoS)	• Impact on BSUoS costs would depend on design. For example, under locational pricing with central dispatch, some of the costs currently in the Balancing Mechanism would flow through the wholesale market. A reduction in constraint costs associated with optimal location of the assets would likely reduce BSUoS costs.
Connections arrangements and charges	• No required changes to current transmission connection arrangements have been identified to date but there may be opportunities to optimise connection arrangements against wholesale market design and transmission network charges to ensure market participants receive appropriate long-run locational signals.

Table 3.3 Wider electricity system infrastructure and markets - summary of potential impacts and interactions with a locational wholesale market. Source: Ofgem.

Policy area	Potential impacts and interactions
Distribution System Operation (DSO)	• Ofgem recently consulted on reforms to roles and responsibilities for key distribution system operation activities – energy system planning; flexibility market

Policy area	Potential impacts and interactions
	facilitation and real-time operations of the network.[81] That is separate to the consideration of locational pricing, but we would consider the impact of market reform outcomes on the relevant arrangements at the relevant time. • There may be some areas where the introduction of locational pricing could impact DSO activities, such as increasing the efficiency of local flexibility markets as more granular prices at each GSP could facilitate more economically-efficient dispatch of flexibility services.
Cross-border market arrangements including multi-purpose interconnectors	• The electricity market design of the EU is based on a zonal structure and several IEM members use zonal pricing.[82] The IEM is not currently interconnected with any nodal market, therefore, there is no existing example for how such a cross-border set-up could work in the European context but we note there is international precedence.[83] • Ongoing development and design of the new cross-border trading arrangements (as required under the Trade and Cooperation Agreement (TCA)) would require further consideration and assessment in terms of compatibility with locational pricing in GB (in particular nodal pricing). • As set out in the first REMA consultation,[84] the government would need to take into account the UK's international agreements and obligations for energy trading and cooperation, and consider the role and interactions of both current and future interconnection with both zonal and nodal pricing. • Compatibility of locational pricing with future market arrangements for multi-purpose interconnectors, including bidding zone configuration for these assets, would also need to be considered in more detail.

[81] Consultation: Future of local energy institutions and governance | Ofgem
[82] The EU market is based on a zonal structure insofar as each Member State represents a price 'zone' or, in some cases, multiple zones such as in Italy, Sweden, Norway and Denmark.
[83] An international example of interconnection between zonal and nodal jurisdiction is previous arrangements between ERCOT (a nodal market) and the Southwest Power Pool (when it operated a zonal market before transitioning to nodal).
[84] Review of electricity market arrangements - GOV.UK (www.gov.uk)

Policy area	Potential impacts and interactions
Distributed energy resources, demand-side flexibility and consumers.	• The impact of locational pricing on Distributed Generation (DG) is likely to vary depending on the type of asset, its location on the distribution network and whether and how it participates in the wholesale market. • Locational pricing could play a key role in increasing the system value of demand flexibility by more closely aligning flexible behaviour (in time and location) with real-time system needs. • Further work is required to understand the costs and benefits of moving to centralised scheduling (under any wholesale market design) and the potential impacts this could have on flexibility and demand side response (DSR). • A key market design choice if locational pricing is taken forward is whether suppliers should be exposed to locational prices. While this is associated with a range of consumer and system benefits, exposing suppliers (and by extension different types of consumers) to locationally varying prices could be subject to a range of technical, economic and socio-political challenges, including the potential for differential treatment amongst consumers. However, we note many of these challenges exist regardless of a move to locational pricing. Regardless of demand exposure, there are likely to be significant implications for how suppliers buy and sell electricity. • If a Price Cap was retained for the period in which locational pricing could be implemented for GB, further consideration would need to be given to the compatibility of design with a locational wholesale market.

Market policy deep dives

3.5 This section considers the market policies identified so far as likely to be materially impacted in further detail. This includes: (i) the CfD scheme, (ii) transmission network charging, (iii) cross-border arrangements; and (iv) decentralised energy resources, demand flexibility and consumers.

(i) Contract for Difference scheme

3.6 The CfD scheme is the government's main mechanism for supporting investment in low-carbon electricity generation.[85] The current CfD scheme is closely integrated into the wholesale market, more so than other investment support mechanisms. As identified by other studies[86], the introduction of locational pricing would interact with several key features of the current CfD scheme. This includes the reference price methodology, design of any negative pricing rules, and the design of Allocation Rounds. The use and design of locational pricing market features, such as the potential use of FTRs, would also need to be taken into account if locational pricing was introduced. Consideration would also need to be given to the operability of existing CfD contracts, with remedies developed for addressing identified issues.

3.7 As locational pricing would impact both average and hourly wholesale prices (eg long-term wholesale average prices and spot market prices), the costs borne by consumers in supporting existing and future CfD assets would be different compared to those realised with retention of the status quo. The impact on the costs of supporting individual CfD holders would typically depend upon their location. Generators in export-constrained regions generally receiving lower wholesale prices under locational pricing can be expected to seek compensation through higher CfD support payments. In contrast, generators in import-constrained regions (ie solar and nuclear assets located close to demand centres in the south) would generally receive a higher wholesale price, so support payments could fall. Overall, we anticipate a net increase in CfD support payments under both zonal and nodal pricing, which FTI has sought to calculate (see Section 4 and its final report).

3.8 The current CfD scheme is designed to reduce a CfD-generator's exposure to fluctuations in wholesale prices to reduce revenue uncertainty. If a CfD-generators "strike price" is higher than the market price, the generator will be paid the difference between the two.[87] CfD generators expect to receive their CfD strike price through their CfD contract or

[85] The current scheme has successfully supported a significant increase in low-carbon generation, awarding contracts to nearly 27GW of new renewable capacity since 2014. Contracts for Difference and Capacity Market Scheme Update 2022 (publishing.service.gov.uk)
[86] Simon Gill, Callum MacIver, Keith Bell (University of Strathclyde), 'Exploring Market Change in the GB Electricity System: the Potential Impact of Locational Marginal Pricing', February 2023; National Grid ESO, 'ESO- Baringa Assessment of Investment Policy and Market Design Packages ', February 2023
[87] Conversely, if the market price is higher than the agreed "strike price" then the generator must pay back the difference. In each allocation round, the strike price is set through a competitive auction and contracts are typically awarded for 15 years. Recent rule changes mean generators do not receive top-up payments when the reference price is negative.

equivalent curtailment revenues in the Balancing Mechanism, meaning that consumers ultimately pay for reducing generator risk either through the wholesale, green levy,[88] or network cost component of their bill. Broadly, it is possible for the objective of de-risking renewable investment risk via the CfD scheme to continue with locational pricing, although scheme reform would most likely be required to ensure this did not result in a significant increase in cost for consumers.

3.9 A REMA reform package that includes changes to the existing CfD scheme along with locational pricing would need to consider how CfD design (and other mechanisms that provide a degree of price stability) would impact the consumer benefits of locational pricing, as while shielding market participants from the effects of locational pricing can help market participants manage certain market risks, it is likely to reduce the consumer benefits of reform.

(ii) Transmission Network Use of System Charges

3.10 Transmission Network Use of System (TNUoS) charges recover the costs incurred by the network companies in providing, maintaining, and developing the electricity transmission system. They will recover the costs of the significant onshore and offshore network expansion needed to deliver net zero. Transmission network charges also play an important role in delivering an efficient net zero system, by sending investment and siting signals to electricity network users that support the efficient use and design of the electricity network.

3.11 As set out in our recent open letter on strategic transmission network charging reform, work is underway to improve the current TNUoS methodology through the TNUoS Task Force and Ofgem is considering the case for more fundamental reform to the long-term role and design of transmission charges. Long-term reform to transmission charging design is being considered within the context of fundamental system change and policy reform, such as the market reforms being considered as part of REMA.

3.12 Locational pricing would have implications for the future design of transmission charging, with it highly likely that changes would be required to transmission charging design to promote compatibility between the signals sent through wholesale prices and

[88] Green levies are taxes imposed by a government on contributors to climate change, such as pollution or carbon emissions. They are applied to dual bills for electricity and gas, which are common in the UK.

charges. The open letter sets out initial considerations that would need to be taken into account when designing transmission charges for a locational wholesale market, and how the benefits of different TNUoS design option would differ depending on whether a zonal or nodal design was progressed.

3.13 Jurisdictions with locational pricing use a variety of charging arrangements to recover the costs of the transmission network and send supplemental locational investment signals[89]. Under a nodal market design, the locational element of TNUoS could be removed altogether and a purely cost recovery approach to transmission charges could be used alongside a nodal market, provided there was sufficient evidence to the consumer benefits. Alternatively, TNUoS could be designed so as to retain a locational investment signal that worked coherently with the locational operational signals sent by the wholesale market.

3.14 Similarly, there are a wide range of options for how TNUoS could be designed for a GB zonal market, including a role for TNUoS in delivering additional benefits in the form of intra-zonal locational price signals to incentivise capacity to locate more efficiently within zones. Any work that Ofgem progresses on strategic charging reform will be aligned temporally with the governments work on REMA, to facilitate effective decision-making.

(iii) Cross-border market arrangements

3.15 We anticipate locational pricing (both zonal and nodal designs) likely having different implications for implicit and explicit cross-border trading arrangements (and vice versa).[90] Following the UK's exit from the EU, electricity is no longer traded implicitly through the EU day-ahead market coupling regime (Single Day Ahead Coupling - SDAC).[91] As a result, current trading arrangements between GB and continental Europe are explicit across all timeframes (long-term via Physical Transmission Rights (PTRs), day-ahead and intraday via

[89] In Norway and Italy, the costs of transmission network (investment, maintenance, and operation) are recovered equally from all participants irrespective of their location. New Zealand recovers transmission network costs via a hybrid charging arrangement. New infrastructure will be paid through a "beneficiary pays" regime, with charges paid by load and generation customers that benefit from the upgrade. All costs not recovered by the beneficiary pays regime are recouped with a postage stamp charge on load.

[90] Trading across interconnectors can be implicit or explicit. Implicit trading means that interconnector capacity and energy are allocated in the same process - transmission capacity is included implicitly in the auctions of electrical energy as one product. Explicit trading is when the transmission capacity on an interconnector is auctioned separately and independently from electrical energy. Explicit trading is less efficient as the two commodities, transmission capacity and electrical energy, are traded separately, resulting in a lack of information about the price of the other commodity. This lack of information can result in an inefficient use of interconnectors compared with implicit trading, with more frequent adverse flows (ie flows against price difference).

[91] The EU day-ahead market coupling regime was established through Capacity Allocation and Congestion Management (CACM) regulation: COMMISSION REGULATION (EU) 2015/ 1222.

explicit capacity-only auctions held by individual interconnectors). Trading between GB and the Integrated Single Electricity Market (I-SEM)[92] is in a form of implicit price coupling in intraday via two GB intraday auctions (without other timeframes currently being available). Trading between GB and Norway is facilitated via an implicit price coupling day-ahead solution (without other timeframes currently being available).[93]

3.16 As the electricity market design in the EU is based on a zonal structure, it is likely that cross-border trading arrangements (implicit or explicit) with a zonal GB market would be relatively easier to implement than with a nodal GB market. However, this initial view requires further analysis and more work is required to fully understand how locational pricing (both zonal and nodal) could work with the current and any envisaged future cross-border trading arrangements.

3.17 On 24 December 2020, the UK and the EU agreed the Trade and Cooperation Agreement (TCA), which took effect provisionally from 1 January 2021 and came into force on 1 May 2021.[94] The TCA imposes a duty, delegated to the UK and EU Transmission System Operators (TSOs), to deliver a new day-ahead electricity trading model based on the concept of implicit multi-region loose volume coupling (MRLVC).[95] As set out in the UK Government's July 2022 REMA consultation document, the government will need to take into account the UK's international agreements and obligations for energy trading and co-operation when considering REMA.

3.18 Whilst the TCA sets out the high-level principles and requirements of the MRLVC solution, uncertainty remains over how MRLVC arrangements would operate in detail. To date, high-level MRLVC options have been designed on the basis of a single GB bidding zone and a single GB price within that zone. Were locational pricing to be pursued in GB, further assessment would be required to understand the compatibility of the MRLVC design with both potential zonal or nodal arrangements in GB.

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[92] I-SEM is the wholesale electricity market for the island of Ireland.
[93] NSL has a bespoke implicit day-ahead trading solution as Norway, although being part of the IEM, is not a member of the European Union and therefore is not a party to the TCA - thus the requirements of the TCA do not apply to that border.
[94] Trade and Cooperation Agreement between the United Kingdom of Great Britain and Northern Ireland, of the one part, and the European Union and the European Atomic Energy Community, of the other part - GOV.UK.
[95] Volume coupling is an implicit allocation mechanism; but unlike price coupling it only determines cross-border flows, with prices determined in a subsequent step. To date, the UK and EU TSOs have conducted a cost-benefit analysis of possible ways of developing MRLVC. The CBA was consulted upon between 26 April 2021 and 16 May 2021. Both analytical results and a summary report are available here: Cost Benefit Analysis of Multi-Region Loose Volume Coupling (MRLVC) arrangements.

(iv) Decentralised energy resources, demand flexibility and consumers

3.19 The effective integration and use of distributed energy resources (DER) and demand flexibility is vital to the rapid development of a smart, more integrated, low carbon energy system.[96] While the scope of this assessment is 'transmission-first'[97] and the evolution of the energy retail market is being carried out alongside but separate to REMA,[98] this section considers the potential impact of locational pricing on distributed energy assets, including demand-side flexibility and consumers.

3.20 Given the anticipated timescales for implementing locational pricing, it is important to consider the likely characteristics of the future retail market and consumer experience in the 2030s. Regardless of whether locational pricing is introduced in GB, we anticipate:

- The participation of distributed energy resources in both local and national markets to increase as commercial opportunities for small-scale flexible assets and consumption to obtain the value of their flexibility grow.

- Domestic and non-domestic consumers to have greater visibility and ability to respond to dynamic price signals, facilitated by a broader range of energy services, tariffs and broader market reforms, such as the implementation of Market-wide Half Hourly Settlement (MHHS).

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[96] Decentralised generation current constitutes ~30% of total GB generation capacity, with this potentially increasing to 41% by 2050. Source: NG ESO Future Energy Scenarios Source: NG ESO Future Energy Scenarios

[97] While distribution-level nodal pricing is theoretically possible, it has not been applied in practice and would likely represent a much greater implementation challenge. For example, optimised market clearing would be significantly more complex at distribution than transmission, as it would require more sophisticated software to compute hundreds of thousands of data points and communication nodal prices at regular intervals. Accurately modelling and monitoring distribution-nodal pricing would require a significant improvement in the availability and quality of distribution-level data. Any potential evolution or extension of locational pricing to distribution voltages could be considered in the future. Ofgem previously considered locational pricing at a distribution level in 2017 to address distribution constraints. Ofgem has since implemented other measures to improve our understanding of distribution network constraints, including improvements to the monitoring of network constraint levels and flexible connection offers. Smart optimisation – a cross-cutting initiative within RIIO-ED2 to drive investment in network monitoring, data, digital processes and new DSO functionalities – will help to address many of these implementation challenges which may enable this option to be considered in the future. RIIO-ED2 Final Determinations | Ofgem.

[98] Delivering a better energy retail market: a vision for the future and package of targeted reforms (HTML) - GOV.UK (www.gov.uk) Broadly, REMA will consider the impact of options on consumers and suppliers, while retail market reform will consider how the retail market can support the decarbonisation of the electricity system, as well as continue to protect consumers.

- The value of greater responsiveness amongst smaller commercial and domestic customers to increase in line with the system's need for flexibility, especially as domestic consumers often consume electricity in high-price periods.

Distributed Generation

3.21 In this section, Distributed Generation (DG) refers to electricity generation or storage assets connected to a distribution network rather than the transmission network. In principle, more granular wholesale prices would enable the services provided by DG assets to be more accurately priced, which could facilitate greater wholesale market participation and whole-system optimisation, and improve our understanding of the value of different behaviours to the whole energy system.

3.22 In practice, the impact and implications of locational pricing for DG are likely to vary depending on the asset and where it is located on the distribution network. To consider how existing and future DG assets could be impacted by more granular and dynamic wholesale prices, we have distinguished DG market participants between those assets that compete in current wholesale, balancing and ancillary service markets (direct market participating DG) and those that do not (non-market participating DG).

(i) Direct market participating DG

3.23 DG assets that compete directly in national markets (wholesale, real-time or ancillary services) would see and be able to respond to the zonal or nodal price. DG assets that have TEC and firm access rights to the transmission network could expect to be impacted by locational pricing in the same way as assets connected to the transmission network. Similar to transmission-connected assets, they would be exposed to congestion risk (ie they would not be financially compensated if they were constrained-off). We would expect that all DG assets would have the same ability to access wholesale market products as transmission-connected assets (dependent on policy design), including any locational hedging tools such as FTRs. Typically, DG is located closer to demand centres, and therefore there may be a reduced requirement for DG to access these tools.

3.24 As set out in Box 2.4 in Section 2, a key assumption is that introducing nodal pricing in GB would need to be accompanied by a move to central dispatch with day-ahead scheduling, with this an optional design choice for a zonal market. Participation in the central scheduling process could create benefits and challenges for these assets. When participating, DG assets would have two options: to be a price taker, and agree to dispatch whatever the price,[99] or to submit offers to the SO with the potential to not be scheduled as part of the optimisation process. Not all DG assets may have this choice, eg inflexible process linked plants where electricity is produced as a product of an industrial process, would likely have to accept the going price.

3.25 To participate in both day ahead and real-time markets, DG assets could self-dispatch and take the price at that node (eg, if the market participant wants its asset to run regardless of market need).[100] The real-time market changes would be different to day-ahead and could offer more choice for DG in that, from the point of view of a DG asset, they could choose to either self-dispatch and have a contract to do so, or, acting through an aggregator, they may offer their price, providing offers, and be dispatched if that is efficient from a system perspective.

3.26 The ability for DG assets to change their schedule after Gate Closure could create balancing problems for the SO to manage if smaller DG is not incentivised to keep the system balanced.[101] In a nodal market, the SO's day-ahead schedule would be based on a forecast that would not include DG. This forecast could be affected by DG assets responding to the real-time nodal price (by spilling or falling short) to take advantage of the locational price, requiring the SO to take action to balance the system. There would likely need to be rules in place to manage their participation.

(ii) Non-market participating DG

3.27 These assets are more likely to operate behind a node than across nodes or zones. They are largely invisible to the ESO[102] – in that the ESO are unable to view the real-time actions of these assets - and can choose how they participate in markets. Given these features, these assets would largely have a choice as to the extent to which they were exposed to zonal or nodal prices.

[99] A price-taker must accept the prevailing prices in the market of its products, its own transactions being unable to affect the market price. The alternative would be a price-maker, who is able to set the market price. If DG agreed to be a price-taker, it could increase the risk they would face as they would need to find a way to hedge against the locational price.
[100] As part of the implementation process, it would have to be made clear who needed to participate in central scheduling.
[101] Currently, smaller DG is not party to the BSC and therefore is not incentivised to keep the system balanced.
[102] Operational visibility is defined as the ability to access real-time information on the MW and MVAr positions to inform both operational and planning purposes.

3.28 Alternatively, assets could continue to operate outside the market by relying on a Power Purchase Agreement (PPA) contract, if available to them. Existing PPA prices could be impacted by a move to locational pricing as prices are generally set from a forecasted wholesale price, with this creating a higher cost compared to the status quo, due to the potential for increased complexity in forecasting zonal or nodal prices.

Demand-side flexibility

3.29 Demand-side flexibility is demand that can be reduced, increased or shifted to a different time period to support cost-effective system balancing.[103] It is a growing feature of our energy system that can take many forms (see Box 3.1) and will increase in importance under a range of energy scenarios (see Figure 3.1).[104]

3.30 Demand flexibility has the potential to facilitate cost-savings for a wide range of consumers, not just those who reduce or flex their demand. Even modest changes to demand in certain periods and in certain locations can play a critical role in supporting the effective integration of a greater volume of renewables by shifting consumption to when renewable supply is available (ie sunny and windy hours and days when prices are lower) and reducing the need to balance the system with more expensive and higher carbon generation.

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[103] Demand side flexibility for power sector transformation (irena.org).

[104] A range of current and planned changes to policy and regulatory frameworks aim to facilitate increased use of demand-side flexibility including: actions to remove barriers to the use of smart appliances (Delivering a smart and secure electricity system: the interoperability and cyber security of energy smart appliances and remote load control - GOV.UK (www.gov.uk); updating of regulatory arrangements to account for Third-Party Intermediaries and regulated parties that control load, such as aggregators; implementation of Market-Wide Half-Hourly Settlement ("MHHS") which, when combined with smarter metering, will send more accurate signals to suppliers about the costs of serving their customers throughout the day. The costs of supplying consumers in each half hour will be more accurately reflected in suppliers' costs, thereby creating an incentive for suppliers to offer more cost-reflective tariffs (Electricity settlement reform | Ofgem).

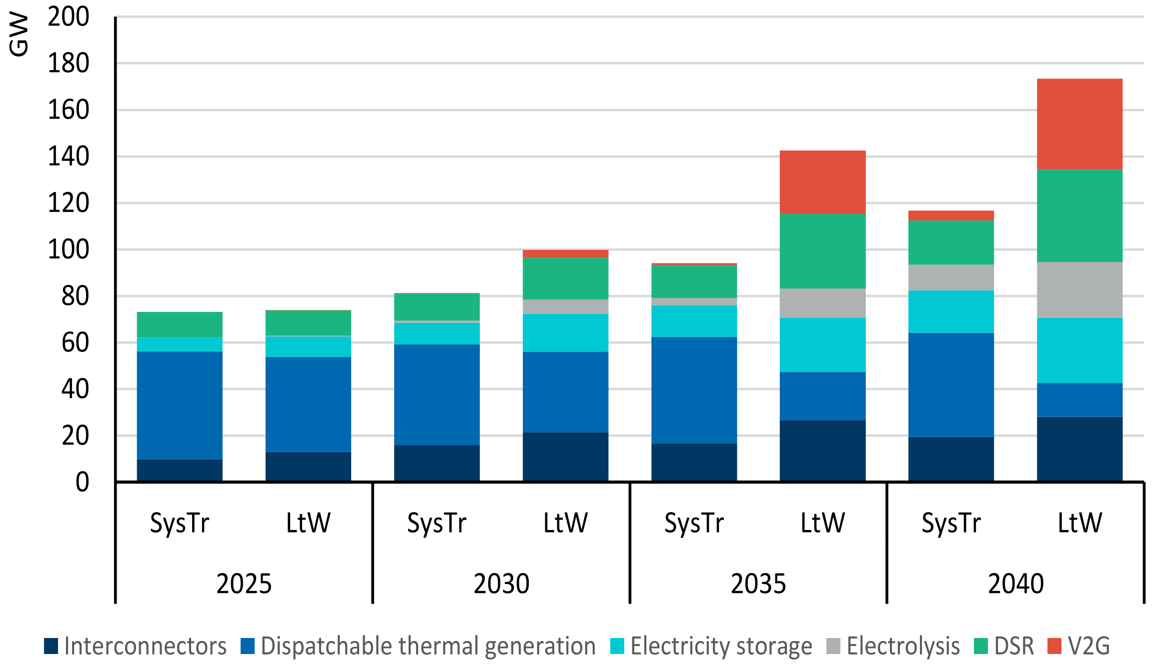

Figure 3.1 – Supply and demand flexibility in Leading the Way and System Transformation Future Energy Scenarios 2025-2040 (GW). Source: National Grid ESO, Future Energy Scenarios 2021

3.31 Individual domestic and non-domestic consumers can benefit from lower energy costs if they consume, and are billed for consuming, in lower priced periods. For example, a household moving their EV charging away from a typical system peak high-cost hour to a lower-priced hour could reduce its energy bills. More generally, effective load-shifting at-scale has the potential to benefit both flexible and non-flexible consumers by flattening peak demand and reducing market clearing prices. This can deliver genuine social benefit and lower energy bills for all consumers by:

- minimising the need for infrastructure investment by reducing the amount of generation (and higher carbon generation[105]) and network capacity needed to meet peak demand,

- reducing average annual wholesale prices paid by consumers, and

[105] Consumer flexibility can be a cost-effective way of reducing carbon emissions as it will often be lower cost than building additional generation and provides large benefits to the energy system (http://www.challenging-ideas.com/wp-content/uploads/2021/01/ReCosting-Energy-Powering-for-the-Future.pdf page 40). Similarly, recent modelling by the Carbon Trust and Imperial College London showed that a system that deployed flexibility, but without demand side flexibility, could cost around £5bn more per annum in 2050 (https://publications.carbontrust.com/flex-gb/analysis/ page 106).

- making best use of all existing assets and integrating renewable assets more efficiently by using renewable generation when it is available and reducing flexible demand when it is not.

Box. 3.1. Recent innovations in demand-side flexibility

Consumers are increasingly engaging in flexibility opportunities and capturing savings from adjusting their consumption in response to market signals. For example:

- The **ESO's Demand Flexibility Service** (DFS') was developed to reward energy users for reducing their energy consumption during peak times when energy supplies are low. The service aims to spread winter demand for electricity to avoid using more expensive and polluting forms of generation. The ESO ran 12 DFS trials over winter 22-23, with participating consumers voluntarily reducing their consumption during short-term events (typically 1 hour) in response to information sent by the ESO and participating suppliers. Over 5 DFS events, one participating supplier, E.ON, saw customer demand reduce by 78MWh and paid out over £240,000 to customers. Overall, 1.6 million households and businesses delivered 3.3GWh of electricity savings across 22 events.[106]

- **Smart EV charging** – Electric Vehicles (EVs) have the potential to provide significant demand-side response and energy storage in response to electricity system needs. This flexibility can be accessed via smart charging technologies that match electricity demand for EV charging to when there is cheaper and often cleaner power available. It is estimated that up to 70% of EV drivers with access to off-street parking have a dedicated charge point at home, most with some degree of 'smartness'. The joint UK Government-Ofgem Electric Vehicle Smart Charging Plan aims to unlock the potential of smart electric vehicle charging, which could enable high milage EV motorists to save up to £1,000 a year through smarter charging.

- **In-home automation**: Several GB-based companies are pioneering innovative digital platforms and services that enable domestic consumers to participate in markets and provide flexibility through automation, while retaining consumer choice and control over what happens in their homes. One example is AMP X's behind-the-meter ALICE (Agent for Lifestyle-based Intelligent Control of Energy) technology, a home-energy management system which allows domestic consumers to optimise electricity consumption against dynamic time-of-use-tariffs.[107] A 7-month trial over 2021-22 with 60 households in the Energy Systems Catapult's Living Lab, provided participants with an in-home hub and a mobile phone interface to schedule the household's energy use during periods with the cheapest and/or lowest carbon electricity, according to the user's choice. The trial saw ALICE schedule and communicate over 4000 actions for EVs, washing machines, dishwaters and tumble driers with EV owners saving 33% and non-EV owners saving 25% compared to a standard "flat" tariff.

[106] National Grid ESO Household Engagement with DFS 2022/2023
[107] Amp X Testing Digital Energy | Energy Systems Catapult

3.32 Realising the system and consumer benefits of demand-side responses requires assets to be exposed to effective and accurate operational signals. Locational pricing, which would provide more granular, accurate wholesale market prices that consider time and location, could play a key role in increasing the system value of demand flexibility by more closely aligning flexible behaviour (in time and location) with real-time system needs. This could increase the opportunities for consumers (as a whole) to benefit from increasing demand-side flexibility, eg due to reductions in wholesale prices and infrastructure investment needs.

3.33 Locational pricing could incentivise suppliers and third-party participants to optimise assets behind a node[108], thereby providing greater opportunities for small-scale flexible assets to obtain value from their flexibility via indirect market participation. For example, a supplier or Virtual Lead Parties[109] of a certain size could take advantage of a low nodal price by optimising a group of EV charging points behind a node to turn on demand. It could also provide third-party intermediaries facilitating broader market participation with the price signals needed to optimise asset portfolio behaviour against wider system needs.

3.34 Locational pricing could also improve the effectiveness and accuracy of time-of-use (ToU) tariffs, which are an existing form of dynamic pricing. Dynamic pricing varies electricity across time and location to reflect the costs of providing electricity to consumers under specific market and network conditions.[110] ToU tariffs based on current national average wholesale prices can help shift flexible consumption to certain periods, eg signalling flexible consumption such as EVs to consume when the national price is lowest, such as during the night or periods of high renewable output.

3.35 However, our energy system is undergoing major changes in how and where we use and produce electricity, and our networks will continue to be constrained under certain conditions and in particular locations, even with significant network expansion. These physical system changes reduce the likelihood of a national average price accurately reflecting increasingly diverse regional and local system conditions. A national average

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[108] From an SO perspective, aggregated generation behind a node is treated the same way as a single generator if it were located in the same node.
[109] Virtual Lead Parties are used to facilitate the participation of Independent Aggregators in the Balancing markets.
[110] ToU tariffs can charge consumers a price per kWh, with the price determined by the time when electricity is consumed, with the day often split into several predefined periods such as day/night and on-peak/off-peak. This differs from fixed-price tariffs which typically provide a predefine price for energy for defined periods of time, with this often independent from actual changes in wholesale prices. Time-of-use tariffs – Innovation Landscape Brief (irena.org)

price can even incentivise consumption patterns that exacerbate local system constraints in certain periods and, from a system-wide perspective, create inefficiencies and additional costs. For example, areas with high penetrations of solar may benefit from EV's charging-up in the sunniest hours of the day, which may not align with when the national average price is lowest (such as overnight). Spot year analysis in 2035 by FTI also shows that under national pricing, flexible EV load could charge in ways that exacerbate system constraints up to 28% of the time and heat pumps sub-optimally charge up to 17% of the time.

3.36 ToU tariffs based on zonal average or nodal wholesale prices can provide a more accurate locational signal to influence demand behaviour and shift flexible consumption to certain periods of time, at certain locations. For example, signalling flexible consumption, such as EVs, in areas with lots of wind or solar relative to demand to turn-up consumption during windy and/or sunny periods when the price is low. Moreover, while locationally varying energy prices are unlikely to become a key factor influencing where domestic network users choose to live, they could play a key role in influencing broader household energy choices. This could include the installation of flexible demand assets or solar panels, where these investments could lead to long-term bill reductions. This could become a key route for engaging residential DER in flexibility provision.

3.37 The optimisation of sub-nodal flexibility could play a vital role in reducing the costs of serving demand in a decarbonised energy system.[111] However, this will represent a step-change in market participation that would need to be accompanied by new regulatory arrangements to provide required protections. This work is ongoing, with the government publishing their response and decisions to deliver a smart and secure electricity system in March 2023.[112] The development of new tariff offerings and/or third-party market actors (eg, Virtual Lead Parties) would require a suitable policy and regulatory framework covering the activity of aggregators across multiple zones or nodes.[113]

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[111] 2021 FES indicates that smart charging and Vehicle-to-Grid could together reduce peak demand by 32GW by 2050, equivalent to the generation capacity of ten Hinkley Point C power stations.
[112] Delivering a smart and secure electricity system: Government response to the 2022 consultation on interoperability and cyber security of energy smart appliances and remote load control (publishing.service.gov.uk)
[113] This could mean, for example, that automated behavioural changes for smart technology-use in response to a price change could be accommodated by local network conditions and wider systems stability is protected by robust cyber-security measures.

Consumer impacts

3.38 The UK Government, with support from Ofgem, recently published a vision for the future retail market that sees the role of suppliers and nature of competition evolving, with consumers having access to a far greater range of products and services, better tailored to their individual needs.

3.39 Exposing suppliers to locational signals and incentivising them to pass signals through to their consumers could enhance competition and stimulate the development of more sophisticated retail offerings, which are a key component of consumers gaining more control over and reward for how they use energy. This could help the retail market become a positive force in achieving net zero by providing incentives for customers to shift consumption, reduce energy use and support adoption of low carbon technologies which can support broader system transformation. If a Price Cap was retained for the period in which locational pricing could be implemented for GB, further consideration would need to be given to the compatibility of design with a locational wholesale market.

3.40 While we anticipate consumer participation and the opportunities to benefit from new services to increase overtime,[114] a range of technical, economic and socio-political challenges exist when exposing consumers to dynamic prices (temporal or locational) that are relevant to the consideration of locational pricing. It should be noted that these challenges and risks broadly exist regardless of a move to locational pricing, in that they may need to be addressed within a national pricing design to support increased temporal granularity of prices, with locational pricing anticipated to create an incremental challenge largely related to geographical fairness considerations. A range of options are available to manage key challenges and protect those who need it.

Challenges of exposing consumers to dynamic prices

3.41 This section briefly considers four key challenges that could affect the retail market and consumer impact of locational pricing: (i) additional complexity and costs that prohibit uptake of new products and services, (ii) the ability of consumers to respond to price

[114] The full range of services that might emerge or how domestic and non-domestic consumers will respond and engage with these is uncertain. While trials in GB and internationally have shown appetite from consumers to engage in flexibility there remain challenges for some, including concerns about giving up control of appliances to third parties. See e.g. Applying behavioural insights to forward-looking charging reform | Ofgem for a review of flexibility behaviour in time-of-use tariff trials in GB and internationally and Ofgem's 2021 Consumer Survey.

signals, (iii) additional risks for energy service providers and (iv) delivery of critical, enabling infrastructure. As noted, many of these challenges need to be addressed, regardless of a move to locational pricing.

(i) Additional consumer complexity and costs that prohibit uptake of new products and services

3.42 Dynamic tariffs that incentivise consumers to respond to price signals come with additional risk and complexity which many businesses and households may find unappealing and could increase costs for some. Attracting and retaining interest in such tariffs would be critical and potentially difficult as individual financial savings (especially amongst individual household and small commercial customers) may be relatively limited, despite the potential scale of overall system benefits.[115]

3.43 The growing use of digital technology is expected to play a key role in making this much simpler and more user-friendly. Advancements in automation and innovation in household technology, including the development of consumer-focused algorithms that adjust consumption to price signals throughout the day, will be critical in making dynamic tariffs more attractive to end-users, or in increasing end-users' opportunities to reduce their costs by becoming an automated flexible resource. While a range of innovative companies are already offering energy services based on automated processes, wider scale adoption of these services has the potential to better enable consumers to capture savings while reducing the complexity of monitoring use and responding to price changes. However, many consumers are not yet comfortable with the concept of third-party control/ automation.

3.44 Designing a range of tariffs that, to varying degrees,[116] provide customers with price signals that reflect system conditions while supporting consumer preferences, lifestyles and business models will be a challenge for some suppliers. Suppliers will need to develop a greater understanding of their customers' ability and willingness to respond to signals and the lifestyle and business models that facilitate greater flexibility. Improved use of data analytics will be a useful tool for suppliers in better understanding customers' preferences,

[115] Studies have indicated that savings from flexible use of whitegoods, such as dish washers and washing machines, are relatively minor due to these representing a small share of electricity consumption in the total bill, with main benefit being for those using smart energy technologies such as EVs and heat pumps. New report on dynamic electricity prices: a potential opportunity for some consumers but be aware of the risks | BEUC

[116] Demand for less flexible or fixed tariffs will still exist in the 2030s, with suppliers likely to offer a range of tariffs with varying degrees of flexibility, based on customer needs and preferences.

needs and demand patterns and ensuring customer demand-shifting does not cut across essential energy needs.[117]

(ii) Ability of consumers to respond to price signals

3.45 Not all consumers can or will respond to dynamic tariffs and price signals, which can result in a negative impact on certain consumer groups (eg through higher prices or rationing energy use) or some consumers benefiting more than others. Today, early adopters of low carbon technologies, who may be more affluent consumers, are typically more open to engaging with smart products and services, and may stand to benefit the most from further advancements in this area. Increased use of dynamic tariffs (whether temporal or locational) could lead to some customers who are unable (eg, due to lack of smart devices) or unwilling to engage in dynamic pricing being 'left behind' and potentially paying higher prices. Specific consideration would need to be given to ensure adequate protections were in place for consumers in vulnerable circumstances[118] who may be unable to engage and respond.

3.46 For locational pricing specifically, there are important socio-economic concerns with consumers in different regions paying different wholesale unit prices. As current market design produces a national average price for wholesale electricity, locational price variations in consumer bills predominantly comes from transmission and distribution network charges.[119]. Under certain arrangements, locational pricing would alter this, with consumers in different locations paying different wholesale unit prices, with consumers in the north expected to see lower wholesale costs than consumers in the south.[120] This could have significant distributional impacts (which we consider in more detail in Section 6) and raises important questions regarding fairness.

3.47 Different levels of price volatility within regions could also influence the types of tariffs and products that suppliers offer in certain areas. Price volatility within a region will be influenced by generation availability within the area, ie areas with high penetration of

[117] For example, studies into customer preferences regarding EV charging indicate that EV owners are likely to reject supplier managed charging for flexibility purposes if it prevents them from using their car as they want to. FRED-Insight-Smarttalking-FINAL.pdf (esc-production-2021.s3.eu-west-2.amazonaws.com)
[118] As defined in Section 3A(3) of the Electricity Act 1989.
[119] Network costs can vary by up to £75 annually. Although there is a national price, there may be some variations depending on how much electricity is lost through the wires as it's transported to different regions of GB (of up to £25). Citizens Advice 'It's all about location'.
[120] This is due to high levels of cheaper renewables generation and less demand in the north and physical limitations on how much power can be transferred south.

renewables are likely to see greater price volatility, while zones/nodes with more consistent prices could see less volatility. Suppliers operating in areas with high price volatility may need to account for associated risks when designing products and offering rates to consumers, and this could lead to greater distributional impacts, as products that could effectively manage price volatility may not be suitable or available to all consumers, resulting in higher costs for some.

(iii) Additional risks for energy service providers

3.48 Exposing suppliers to locational wholesale pricing would alter the market and regulatory risks suppliers face, with additional risks and costs likely to be passed on to their customers. Different supplier business models are likely to be affected in different ways. In general, suppliers could see the benefit of demand response through a reduction in the cost of energy they need to buy for all their consumers.

3.49 Depending on how locational pricing was implemented, there would be key changes to the ways in which suppliers buy and value energy, with suppliers likely to be exposed to greater price volatility and complexity in forecasting and managing their customers' demand. This may require suppliers to adopt new hedging strategies and new regulatory safeguards.

(iv) Delivery of critical enabling infrastructure

3.50 One of the key challenges we face as our system evolves that could, by extension, reduce or delay the consumer benefits of locational pricing is slow progress, complication and prohibitive costs incurred in rolling out the substantial physical and digital infrastructure necessary to facilitate greater visibility and responsiveness to price signals. This challenge, and potential impact on the consumer benefits from system transformation, exists regardless of wholesale market design.

3.51 The uptake of smart meters, electrical heat pumps, electric vehicles, and smart technologies will be critical for realising the potential of flexible load at scale. However, these physical assets may need to integrate with complex communications networks and data management systems to record consumption in shorter intervals than current arrangements, develop targeted consumer tariffs, and provide easy-to-use portals that allow consumers to analyse their use.[121] This will require improved data sharing and analytics and new cyber security standards and data protections.

Potential mitigations and protections

3.52 As discussed, many of the challenges we currently face with introducing greater temporal price granularity to end-users could reduce or delay the benefits associated with introducing locational pricing. In addition, exposing suppliers to locational wholesale prices could lead to differential treatment amongst consumers and increase the difficulty of portfolio management by suppliers. This section considers options that could be used to manage these concerns. The design and application of potential mitigation measures would require careful consideration, both in terms of the likely impact on the benefits case for locational pricing and the distributional impacts of funding mitigation measures through consumers' bills and/or taxpayers.

(i) Supply-side exposure as a key market design choice

3.53 Whether and how suppliers (and, therefore, different types of demand) would be exposed to locationally varying prices would be a key market design choice that would materially shape the impact of locational pricing on the retail market, the total consumer benefits of locational pricing and the distributional impacts between consumer groups.

3.54 In theory, the greater the degree of demand exposure to locational signals, the greater the potential consumer and system benefits. This is because providing accurate and sufficiently granular price signals to flexible consumers would enable them to consume in lower-priced hours relative to their location, with this delivering individual savings and wider system benefits that inflexible consumers could benefit from.

3.55 However, as previously discussed, there are likely to be limitations on how consumers respond in practice. There may also be pragmatic reasons for retaining a national price for all or certain types of demand, such as from a transitional perspective (e.g., adopting a phased approach to exposing certain demand types).

[121] For example, on-going developments, such as the implementation of MHHS, require significant changes to many of the internal systems and processes operated by energy suppliers, and to their external systems and processes that interact with the settlement system and with the Data Communications Company.

3.56 In June 2023, Citizens Advice published a discussion paper outlining its emerging views on the case for implementing locational pricing, and the risks that would need to be addressed if it was implemented.[122] This included the identification of a range of options for shielding consumers from locational pricing (see Table 3.4 below) and a conclusion that concerns for a 'post-code lottery' should not constitute a reason to avoid locational pricing.

Table 3.4 Citizen's Advice options for shielding consumers. Source: Citizen's Advice, 'It's all about location – will changing the way we price electricity deliver for consumers?', June 2023.

Option	Detail	Effect	Example
Average nationally	Consumers settled on a weighted average national price	No difference in average cost, shape of profiles or the volatility of price signals between regions	Italy (zonal)
Adjust for regional variations	Adjust for differences in average annual bills between regions but preserve different time of use profiles	Maintains differences in shape of profile and volatility of signal between regions. Eliminates difference in average cost between regions	Not currently implemented

[122] Citizen's Advice, 'It's all about location – will changing the way we price electricity deliver for consumers?', June 2023.

Option	Detail	Effect	Example
Average across larger areas	Consumers settled on a regional basis that averages across multiple nodes or zones	Reduces volatility of price signal, reduces difference in the average cost between regions	California, New York
Minimal intervention	Up to suppliers to offer a range of tariffs for people to choose from (eg, flat tariff, load management, dynamic ToU, fixed ToU)	Uncertain	Denmark (zonal), New Zealand, ERCOT
Opt-in	Consumers can choose to be settled on a locational basis if they want to, otherwise settled on a national or regional basis	Guarantees access to a less volatile wholesale price for consumers who don't opt in – although this could still be a higher overall cost	Ontario, PJM (North America)
Shield by type of user	Expose some users (eg, industrial) to more granular locational price signals while other consumers are	Accounts for that fact that different types of consumers may be able to respond in different ways	Most jurisdictions

Option	Detail	Effect	Example
	settled on a national or regional basis		
Phased exposure to more granular signals	Shield some types of flexible resources at first before considering more granular exposure to locational price signals	Could allow for greater uptake of smart and flexible technologies before domestic consumers are exposed to locational signals	New York

3.57 Analysis conducted as part of this assessment indicates that retaining a national average price for key demand cohorts (eg, non-flexible domestic demand) could still deliver significant net consumer and socio-economic benefits (see Section 4).[123] However, benefits reduce when demand is shielded from the locational price, which could represent an opportunity cost from an energy system and consumer savings perspective.[124]

3.58 For options that expose demand to locational prices, an area for further consideration is the potential consumer and retail impacts of price volatility within regions. While our distributional analysis (Section 6) indicates that all or most consumers across GB could benefit from exposure to locational pricing, different levels of price volatility within regions could create regional differences between those able to flex their usage and those who

[123] FTI's load shielding sensitivity shows that locational pricing, in particular nodal pricing, could deliver significant benefit if a national average wholesale price was retained for certain types of demand. This modelling sensitivity, in which at least 95% of end-consumer demand shielded from locationally varying prices, reduces the consumer benefits of nodal pricing (compared to full demand exposure) from £28bn to £26.8bn and socio-economic benefits from £13.5bn to £12bn over the modelling period.

[124] In particular, our distributional analysis in section 6, which provides a snapshot of how different consumer groups could be impacted by exposure to locational wholesale prices, indicates that most, and often all, consumers across GB benefit even when unable to respond to price signals, ie, consumers are unable or unwilling to change their consumption patterns in response to price signals. This analysis also indicated the potential for key groups to benefit from exposure to locational pricing such as those in fuel poverty across England, Wales and Scotland and those utilising low carbon technologies, such as EVs and heat pumps. These benefits are greater under nodal pricing than zonal pricing.

cannot. Further work is required to facilitate a better understanding of how consumers could be affected by price volatility within regions, associated distributional impacts and what consumer safeguards and protections may be required.

(ii) Re-distribution of benefits across consumer groups

3.59 An option which could be used alongside various demand exposure options is to use congestion rents or revenues from FTR auctions to narrow the distributional spread of benefits from locational pricing across consumer groups, ie consumers in high-priced areas either being worse-off or benefiting less than consumers in low-priced areas. The allocation of congestion rents is a critical welfare allocation decision when designing a zonal or nodal market as it represents a welfare transfer between consumers and producers.[125]

3.60 There are two broad options:

- Congestion rents could be allocated directly to all consumers and be used, for example, to pay for the transmission network (thereby reducing network charges),
- Congestion rents could be allocated to some consumers (ie those worse-off or benefitting less than others under locational pricing) to mitigate wholesale price differences between consumers in different regions.

3.61 Alternatively, an out-of-market lump-sum transfer between consumers in high- and low-priced areas could facilitate a more even distribution of wholesale costs across consumers. Similar schemes exist today, such as the Hydro Benefit Replacement Scheme,[126] which provided £95m in 2022/23 to consumers in the north of Scotland to reduce the disproportional higher electricity network costs consumers in the region face.

[125] As noted previously, the allocation of congestion rents to consumer would come at the expense of using these revenues to sustain an FTR regime to help producers and suppliers manage locational risk. Use of FTR auction revenues to offset distributional impacts on consumers may, therefore be preferable.
[126] Hydro Benefit Replacement Scheme and Common Tariff Obligation. Three-yearly review of statutory schemes: response to consultation (publishing.service.gov.uk) In addition, the Government's Common Tariff Obligation prevents electricity suppliers in the North of Scotland from charging comparable domestic consumers different prices solely on the basis of their location within the region.

(iii) Policy and regulatory protections

3.62 As the supply of energy is an essential service, the interests of all consumers need to be protected, regardless of how they choose to engage with the market or which services they receive. Exposing consumers to more dynamic price signals, regardless of a move to locational pricing, will likely require a wide range of new policies and regulations to safeguard consumer interests as the consumer experience and supplier landscape evolve. These enablers and protections sit outside the scope of REMA but are intrinsically linked, and represent a key area for alignment between wholesale and retail market strategies.

3.63 Government policies that better enable all consumers to receive and respond to price signals (eg through the continued roll-out of smart meters and grants for the adoption of smart technologies amongst low-income households) can help more consumers take control of their energy use and financially benefit from improved price signals. Targeted support could also help to minimise the likelihood of some consumers being left behind. In July 2023, the UK Government launched a Call for Evidence on how the current regulatory framework needs to evolve to support new ways of offering energy to consumers in order to unlock greater innovation in the retail market.[127]

3.64 Customer protections will be essential to mitigate any potential harm from a lack of engagement, with consumer safeguarding maintained as new products and services are developed. The regulatory framework will need to evolve and account for increased complexity in the market and the diversity of domestic and non-domestic customer needs.

3.65 Consumer protections could be facilitated in a number of ways:

- Measures, such as caps on unit prices or providing ex-post rebates and rules on the tariffs that can be offered to less engaged consumers, could be used to protect consumers from extreme surges in wholesale prices, with regulatory pressures (where necessary) working alongside competition to ensure that consumers receive the value of their flexibility in the form of cost savings.

[127] UK Government, Towards a more innovative energy retail market: a call for evidence, July 2023
UK Government, Powering Up Britain: Energy Security Plan, March 2023

- Changes to the supplier licence: Ofgem has the ability to introduce consumer protections that balance supporting, for example, low-income and vulnerable households with fostering competition and innovation.

- Derogations, supplier licences for specific geographic areas or premises types, or new supplier obligations: Ofgem could introduce measures to support consumer participation, such as consumers being equipped with the information required to behave flexibly and to only be exposed to locational signals that they are able to respond to.

3.66 Tariffs will need to be well designed and easy to use, with consumers supported in making informed decisions on which offerings best match their flexibility potential and risk appetite. Information and awareness campaigns will be critical in:

- Enabling individual businesses and households to assess their flexibility potential and empowering interested consumers to make the most of new tariffs and automated and direct-participation services.

- Ensuring transparency on the risks associated with choosing tariffs more closely linked to price fluctuations in the wholesale market, especially those who may want to opt-in to direct exposure to spot prices.[128]

- Increasing use of demand flexibility and its role in balancing a high-renewables energy system to increase consumer engagement, with the potential to target this at the types of demand and consumption behaviours that can provide the most valuable response from a system-perspective.

3.67 Any move to implement and phase-in locational pricing would need to carefully align with the evolution of the retail market to ensure appropriate and targeted policies and protections are in place to promote the consumer benefits from such change and offset any potential harms.

[128] Ofgem, Engaging domestic consumers in energy flexibility | Ofgem , August 2023

4 Quantitative analysis: monetised costs and benefits

Section summary

This section summarises the key quantitative findings from FTI's analysis of the costs and benefits of implementing locational pricing in GB. It describes some of the main features of FTI's approach, highlights key findings from the assessment and discusses certain limitations of the analysis. This section also briefly summarises the conclusions of three independent academic reviews commissioned to inform our understanding of the key findings. A full description of the methodology employed for the modelling and the results of the analysis presented here are set out within the FTI report, published as a subsidiary document to this report.

FTI's analysis indicates that:

- Locational pricing in GB could deliver significant benefits for GB electricity consumers, the economy and carbon emissions compared to the status quo.
- Compared to current arrangements, the net consumer benefits of locational pricing over the modelled 16-year period could range from £15bn - £51bn.[129] Net socio-economic benefits of locational pricing, over the same period, could range from £6bn to £24bn.
- Across all modelled scenarios, nodal pricing delivers greater benefits than zonal pricing. Over 2025-2040, net consumer benefits from nodal pricing range from: £28bn - £51bn, compared to £15bn - £31bn for zonal pricing.
- Carbon emissions are modelled to fall more quickly in both zonal and nodal markets, relative to the status quo.
- While sensitivities (dispatch-only, load-shielding and cost of capital) reduce the benefits, locational pricing remains beneficial under the scenarios assessed.
- Locational pricing has the potential to result in significantly different interconnector flows scheduled in the wholesale market compared to the status quo, as it facilitates the more effective use of interconnectors thus lowering total system costs and reducing GB constraints.
- Over time, the optimal amount and location of network reinforcement could be significantly different under a market based on locational pricing.

The academic reviews we commissioned generally conclude that the quantitative estimates from FTI's study are likely to over-estimate the potential consumer and socio-economic benefits, with one reviewer considering certain dispatch benefits to be conservative. We agree with the overall conclusions from the academic reviews, in that it is likely the result overestimates the precise impact of some mechanisms. However, we consider that there is little reason to think the quantified benefits case could be reversed under a different set of reasonable assumptions or inputs and note that the modelling does not quantitatively assess several theorised benefits of locational pricing.

129 Unless stated otherwise, all CBA figures quoted in this chapter are Net Present Values ("NPVs") calculated using

Introduction

4.1 We commissioned FTI to perform a cost-benefit analysis (CBA) of introducing locational pricing into the GB wholesale electricity market. This scope did not include consideration of alternative market reforms that may have the potential to deliver equivalent benefits. This section provides a brief overview of FTI's approach to quantitative elements of the analysis, key findings from the analysis, and certain limitations. A full description of the methodology employed by FTI, including assumptions and results, are set out in FTI's report which is published alongside this document.[130] We encourage all interested stakeholders to familiarise themselves with the FTI report.

4.2 FTI's analysis estimates that introducing locational pricing in GB could result in significant benefits for GB electricity consumers, the economy and carbon emissions when compared to current arrangements. These benefits occur under a wide range of future energy scenarios, although we note that the magnitude of benefits reduces by approximately half under certain scenarios.

4.3 Compared to current market arrangements, FTI estimate that for the scenarios modelled, locational pricing could deliver net consumer benefits[131] ranging from between £15.2bn and £50.8bn over the 16-year period 2025 to 2040 and net socio-economic welfare benefits[132] ranging from between £6.2bn and £24.0bn. Whilst these figures are indicative, and rely on various assumptions and some modelling limitations, we note that the magnitude of potential net consumer benefits are considerable when compared to other, recent GB power market interventions.[133]

4.4 As with any modelling, particularly modelling of a complex nature looking at multi-year impacts, there is a need to use caution when drawing conclusions. The uncertain nature of

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2024 as the base year. Economic costs and benefits are in 2022 calendar year prices covering the period from 2025 to 2040 inclusive.

130 FTI's report is published on this webpage: https://www.ofgem.gov.uk/publications/assessment-locational-wholesale-pricing-great-britain

131 FTI estimate consumer benefits by considering the impact of the following: reduction in the costs of resolving transmission network constraints, changes in wholesale price, creation of intra-GB transmission congestion rents, changes to CfD support payments and implementation costs. See paragraph 4.15.

132 FTI estimate socio-economic welfare benefits by adjusting net consumer benefits for the additional impact on producers, specifically the change in producer surplus and changes to CfD payments. See paragraph 4.16.

133 From the domestic consumer viewpoint, the net consumer benefits of the nodal model under the Leading the Way HND scenario (see later in this section) would be equivalent to an average £38 a year saving. For a comparison see Market-wide Half Hourly Settlement, https://www.mhhsprogramme.co.uk/, projected to result in a benefit of £11/HH/annum maximum.

assumptions and scenario input data means that modelling outputs should be treated as indicative. This analysis provides valuable insight as to the anticipated magnitude and direction of impacts from introducing locational pricing in GB. It has helped to inform our assessment of these market reform options and to identify some of the key factors which are likely to influence the extent to which these benefits could be realised in practice.

4.5 To support our understanding of FTI's analysis, over summer 2023, we commissioned three academics to provide an independent view of FTI's assessment of locational pricing (the "academic reviews"). The scope of the academic reviews was to consider the assumptions, methodology and limitations identified by FTI and provide a view on whether the key findings should be considered conservative or optimistic. We reflect on the conclusions of these reviews at the end of this chapter.

Approach

4.6 This section describes some of the main features of FTI's approach to modelling the potential benefits of locational pricing against a Business as Usual (BAU), or status quo, counterfactual of a national price market, as currently used in GB. It covers the market designs, scenarios and sensitivities modelled.[134] We also describe the impacts FTI have quantified to calculate net consumer and net socio-economic welfare benefits.

4.7 FTI has developed an in-house power market model using leading industry software to model the GB electricity market under three different market designs (national, zonal and nodal) over the period 2025 – 2040 (inclusive).[135] These three designs have been modelled across two of the ESO's industry respected Future Energy Scenarios[136] (FES), reflecting Network Options Assessment (NOA) reinforcement recommendations and proposals under the Holistic Network Design (HND).[137] The software has allowed FTI to model all major circuits on the transmission network, as informed by extensive bilateral engagement with

[134] A full description of the methodology employed by FTI, including assumptions and results, are set out in FTI's report.
[135] Plexos is a dispatch optimisation software, which aims to determine the least cost development and dispatch of generation and demand-side resources to meet demand, whilst respecting various constraints (for example, technical characteristics of the transmission network).
[136] ESO's Future Energy Scenarios represent a range of credible pathways to decarbonise the energy system. The FES are a well understood data set, the creation of which follows a similar process year on year. The FES are used to inform other ESO outputs, such as the NOA and the Electricity Ten Year Statement (ETYS), and hence, taken together, these sources represent a coherent data set to use as the basis for modelling the future power system.
[137] The NOA provides ESO's latest view of projects to reinforce the transmission network.

ESO, so that under all three market designs FTI has been able to simulate economic dispatches that meet security of supply criteria.

Market designs and counterfactual

4.8 Following stakeholder engagement, FTI has modelled a seven-zone GB zonal market with boundary definitions informed by ESO's view of the main forecasted constraints and a GB nodal market consisting of approximately 850 nodes largely based on transmission substations. Figure 4.1 below provides an illustration of the locational granularity of the three wholesale market designs used.

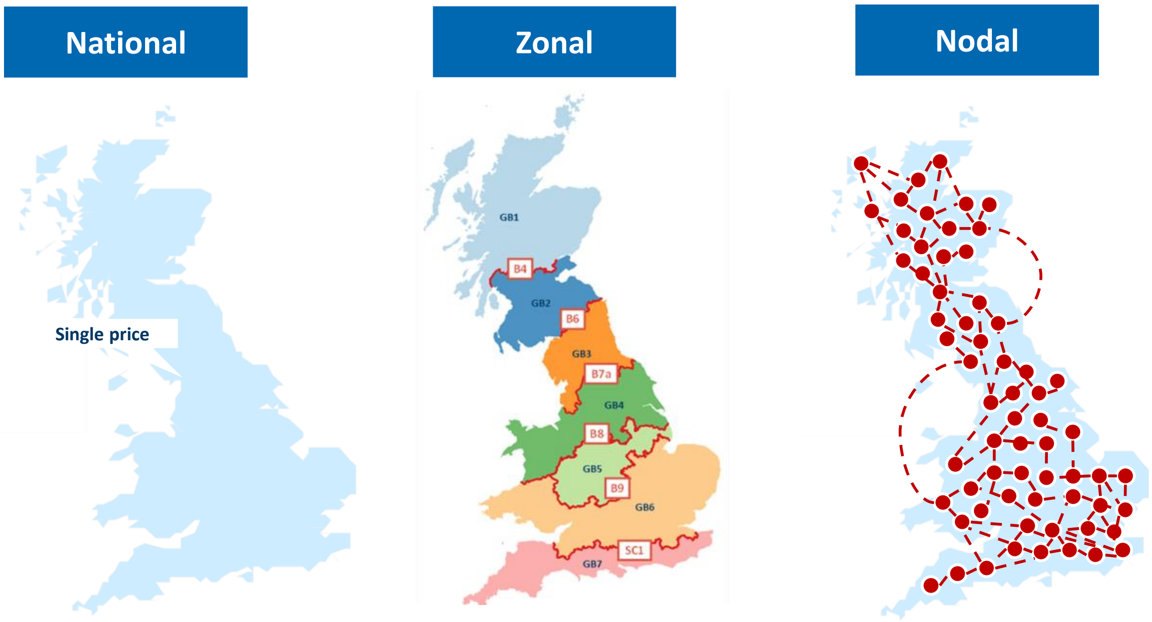

Figure 4.1: Geographical set-up of FTI's three locational market models. Source: FTI.[138]

4.9 The zonal and nodal markets have been assessed against the counterfactual of a national price market, as per current arrangements in GB. This is in line with the approach recommended by HM Treasury's Green Book guidance for the appraisal of policies, programmes and projects.[139] During the assessment, alternative counterfactuals were proposed by stakeholders and, subsequently, within the academic reviews. While some of these alternatives to locational pricing may merit separate assessment, they are considered

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[138] Note that the nodal image is illustrative – it does not show all of the ca. 850 nodes modelled.
[139] This guidance suggests that economic analysis of policies should be undertaken relative to a BAU case. [The Green Book (2022) - GOV.UK (www.gov.uk)](https://www.gov.uk)

outside of the scope of this assessment. Further work is underway to explore the counterfactual of improving locational signals under the current single price model through a possible combination of better spatial planning and reforms to CfD design, network charges, access arrangements and balancing markets.

Scenarios and sensitivities

4.10 The modelling compares the impact of the zonal and nodal market designs against the counterfactual across two of the FES 2021 scenarios for the future GB power system.[140] Scenarios refer to a set of supply, demand and transmission input assumptions that reflect a different view on the future evolution of the GB energy market. Leading the Way[141] (LTW) and System Transformation (ST) were chosen as the upper and lower bounds for forecast transmission network constraints (see figure 4.2, below).[142,143]

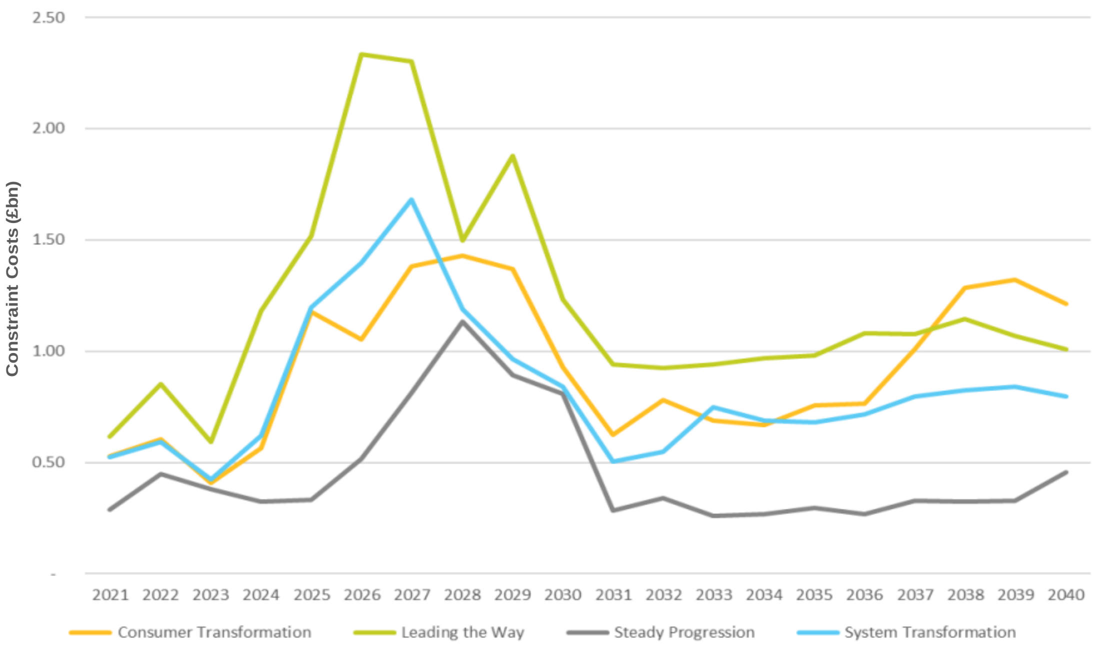

Figure 4.2: ESO modelled constraint costs in FES 2021. Source: NOA 2020/21

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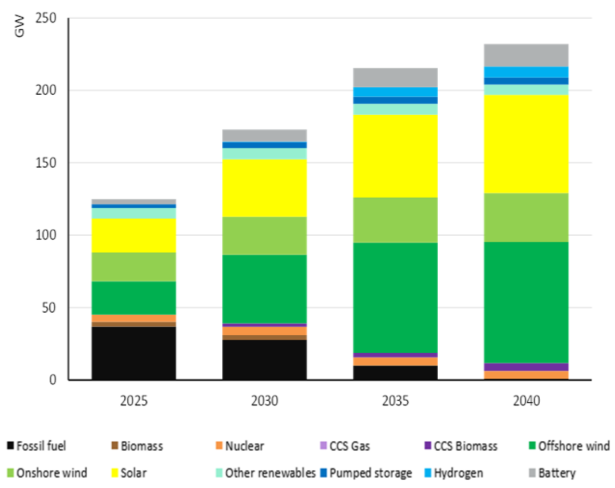
[140] We note that FES 2023 and 2022 have subsequently been published. FES 2021 was the latest version available at the start of this project.
[141] Leading the Way is also closest to current government plans for Offshore Wind generation capacity.
[142] Estimate of possible future constraint costs from [Modelled Constraint Costs, NOA 2020/21](). We note that a later view is available, published after the modelling exercise had begun, and based on updated NOA 2021/22 Refresh ([Modelled Constraint Costs after NOA7/NOA7 Refresh Optimal Reinforcements]()).
[143] Whilst Steady Progression has the lowest forecast of transmission constraint costs in FES 2021, we excluded it from this study on the basis that it did not meet the government's net zero mandate.

4.11 Figures 4.3 and 4.4 below show the main differences in capacity mix and flexible resources between the LTW and ST scenarios. Relative to ST, LTW represents a high demand scenario, with a higher capacity of installed renewable generation.



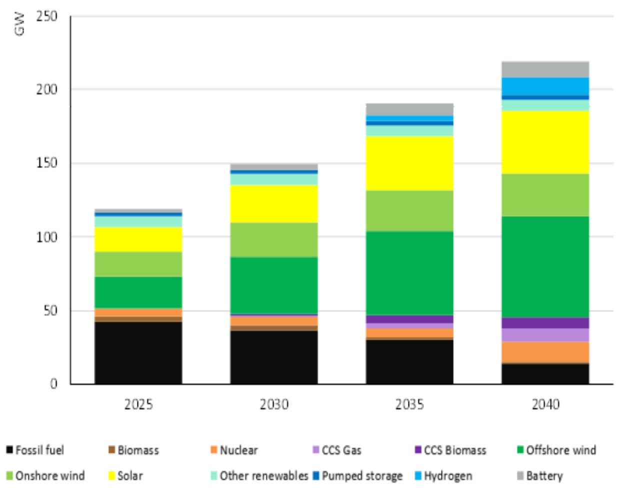


Figure 4.3: GB generation capacity mix, LTW *left* and ST *right*, 2025 – 2040. Source: FTI.

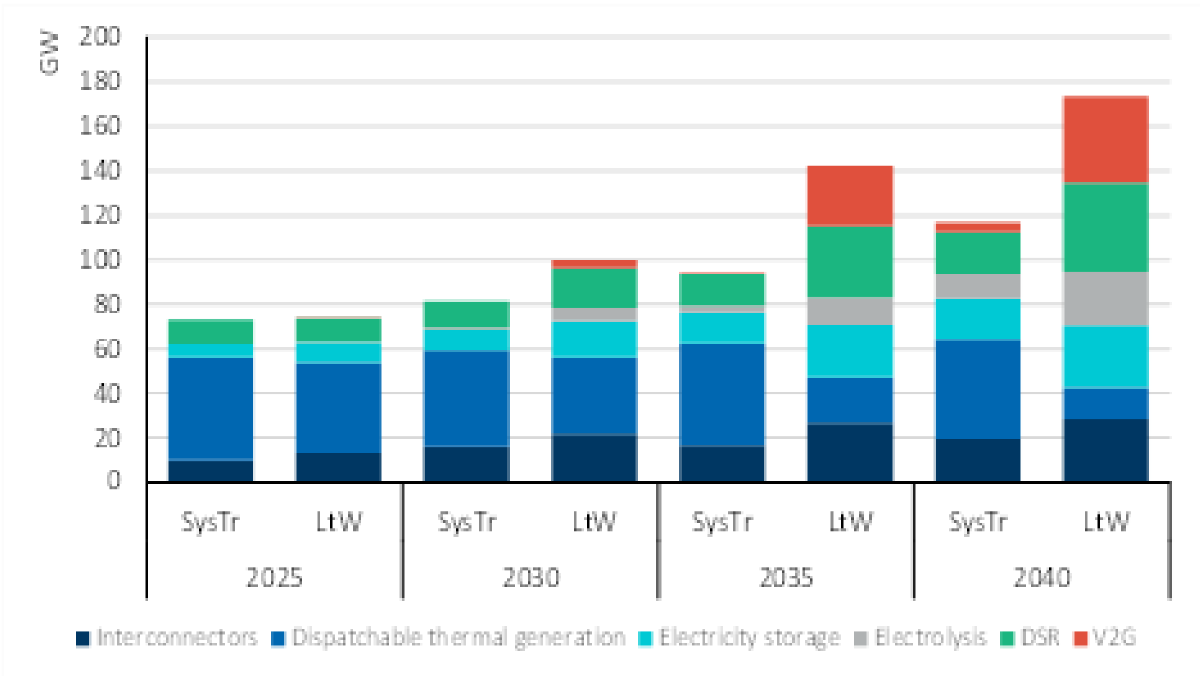


Figure 4.4: Showing the forecast of supply and demand flexible resources under ST (SysTr) and LTW (LtW). Source: National Grid, FES 2021.[144]

[144] See FTI report, figure 11-7.

4.12 Given that transmission network takes many years to build, the modelling used the most recent transmission network development plans developed by the ESO. A third modelling scenario was created by combining the LTW scenario with the transmission build-out from ESO's approved HND investment plans (published July 2022).[145] This provided the most up-to-date view from the ESO on which network reinforcements should receive investment, and when, in order to meet the government's target of 50GW of offshore wind by 2030 to be included in the assessment.[146] The FTI analysis therefore resulted in nine different models of the future GB power system, one for each of the three market designs (national, zonal and nodal), and for the three scenarios set out below:

1. Leading the Way NOA7 – **LTW** (generation and demand) **NOA7** (transmission build)

2. Leading the Way HND – **LTW** (generation and demand) **HND** (transmission build)

3. System Transformation – **ST** (generation and demand) **NOA7** (transmission build)

4.13 FTI also modelled two different sensitivities:[147]

i. A **dispatch-only sensitivity** to test the relative contribution of locational operational signals and locational investment signals to the overall benefits case.

ii. A **load-shielding sensitivity** to test how the benefits of locational pricing change if demand is shielded from locational prices.

4.14 In addition, FTI performed an analysis to assess how an increase in the **cost of capital** could affect the results.

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[145] The Pathway to 2030 Holistic Network Design | ESO (nationalgrideso.com)
[146] In the ESO's FES scenarios, compared to LTW NOA, the LTW HND scenario includes several GW of additional offshore wind capacity. A Holistic Network Design for Offshore Wind | ESO (nationalgrideso.com)
[147] Sensitivities represent amendments to specific assumptions within a scenario to test a hypothesis, for example, to account for a policy design choice, or to isolate a specific impact of locational pricing.

Assessed impacts

4.15 FTI's CBA uses the outputs of the modelling, together with additional quantitative analysis, to assess the following consumer impacts:

i. **Cost of managing thermal constraints on the transmission network**[148] – the model estimates the cost of actions under the status quo model to resolve transmission constraints, and therefore the relative saving under the zonal and nodal markets (where the value of transmission constraints across the node or zone are reflected in the relevant locational wholesale price).

ii. **Wholesale prices**[149] – an estimate of the difference in costs paid by consumers to meet demand, based on output hourly wholesale market prices from the model and the predicted level of demand.

iii. **Intra-GB congestion rent**[150,151] – the value arising from price differences between two nodes, or zones.

iv. **CfD payments to producers**[152] – as per point (ii) above, locational pricing will lead to different wholesale prices in zones or at nodes, relative to the counterfactual of a national price. FTI estimates the change in payments to producers with CfDs, as a result of these differences, under an assumption that the current CfD scheme remains in place (albeit with some changes to ensure compatibility of the scheme with locational pricing).

v. **Implementation costs**[153] – FTI estimates the cost of implementing locational pricing, for market participants and ESO (across both zonal and nodal), to be £500m.

4.16 FTI sums the above impacts to provide an estimate of the overall net consumer benefits of locational pricing. The following impacts have also been quantified and, when

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[148] See FTI report, chapter 7, section B
[149] See FTI report, chapter 7, section A
[150] See FTI report, chapter 7, section D.
[151] See also discussion on congestion rent in section 2, paragraph 2.15 of this report.
[152] See FTI report, chapter 7, section C
[153] See FTI report, chapter 8, section A

combined with the net consumer benefits, provide an estimate of the net socio-economic welfare benefits:

i. **Producer surplus**[154] – aggregate change in revenue earned by producers, due to changing wholesale prices and infra-marginal rent under locational pricing.

ii. **CfD payments to producers** – as above (see paragraph 4.15 iv), though equal and opposite noting that this is a transfer from consumers to producers (or vice-versa).

4.17 Engagement with a broad range of stakeholders was used to inform the development of the modelling methodology, assumptions and initial outputs. This was primarily facilitated by three stakeholder workshops, as well as a Call for Input published in June 2022 and bilaterals with interested parties[155,156]. Where applicable, stakeholder feedback has been used to refine assumptions and the analysis, however given the range of competing views raised by stakeholders not all feedback has been accommodated into the final assumptions and approach.

Headline results

4.18 FTI's analysis estimates that, compared to current arrangements, locational pricing could deliver significant net socio-economic benefits of up to £24bn (NPV, 2025-2040).[157] The benefits to consumers are calculated to be higher – as much as £51bn over 2025 to 2040 (inclusive) in an upside scenario. Tables 4.2 and 4.3 below summarise the consolidated CBA results from the three scenarios modelled.[158] These benefits do not

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[154] See FTI report, chapter 7, Section E

[155] We received 43 responses from a broad range of industry stakeholders including generators, traders, suppliers, interconnectors, developers, power exchanges, public entities (including local government), think tanks and trade associations. See: https://www.ofgem.gov.uk/sites/default/files/2022-08/CfI%20June%202022-%20Responses.zip.

[156] Locational Pricing Assessment | Ofgem

[157] Unless stated otherwise, all cost-benefit analysis figures quoted are Net Present Values calculated using 2024 as the base year. Economic costs and benefits are in 2022 calendar year prices covering the period from 2025 to 2040 inclusive. REMA timelines and the implementation requirements for locational pricing mean these market reform options cannot be implemented from 2025. All else being equal, a later introduction of locational pricing would reduce the potential benefits. Modelling performed by Aurora to assess the potential benefits of locational pricing in GB over 2025 – 2060 considered the impact of a later implementation date. This found that while the consumer benefits of locational pricing reduce, they remain positive. A 2035 start date (under their net zero scenario) indicated consumer benefits of £16bn (2035-2060) for zonal design and up to £35bn (2035-2060) for nodal design. This sensitivity was only presented for their "net zero" scenario and was not presented for the modelled "central" scenario. https://auroraer.com/insight/locational-marginal-pricing-in-great-britain/

[158] Note that six results are reported (two for each modelled scenario), and not nine, given that results are calculated as the difference relative to the national model (ie, the status quo for each scenario).

include FTI's modelled estimates of savings from lower carbon emissions (see paragraphs 4.24 and 4.25, below).

Table 4.2: FTI's consolidated CBA results for the zonal market. Note: Covering the modelling period of 2025 to 2040. Source: FTI.

Scenario	Consumer benefit, £bn	Socio-economic welfare, £bn
LTW NOA7	30.7	15.3
LTW HND	18.7	7.1
ST NOA7	15.2	6.2

Table 4.3: FTI's consolidated CBA results for the nodal market. Note: Covering the modelling period of 2025 to 2040. Source: FTI.

Scenario	Consumer benefit, £bn	Socio-economic welfare, £bn
LTW NOA7	50.8	24.0
LTW HND	34.2	14.4
ST NOA7	28.0	13.1

4.19 The rest of this section provides an overview of the key findings from FTI's analysis which include:

i. The nodal market produces greater benefits than the zonal market across all modelled scenarios. The LTW NOA7 scenario produces the highest benefits of all modelled scenarios, with the LTW HND[159] and ST NOA7 scenarios delivering lower benefits.

ii. Across all three scenarios, carbon emissions are modelled to fall more quickly in both zonal and nodal markets, relative to the status quo.

[159] To note; FTI analysis does not include consideration of the cost of HND. That said, the benefits numbers presented are relative to the national counterfactual. This means that in the LTW HND case, the cost of the transmission network is the same under the national, zonal and nodal markets.

iii. While sensitivities reduce the benefits, locational pricing remains beneficial under the scenarios assessed.

iv. Locational pricing results in scheduled interconnector flows that are significantly different than under the status quo, as it facilitates the more effective use of interconnectors thus lowering total system costs and reducing GB constraints.

v. Over time, the optimal amount and location of network reinforcement could be significantly different under a market based on locational pricing.

vi. Implementation costs are estimated to be between one to two orders of magnitude lower than the estimated net consumer benefits.

Key findings

The nodal market produces higher benefits than the zonal market across all scenarios

4.20 The modelling indicates that, across all scenarios, the benefits of a nodal market are higher than a zonal market from both a consumer benefit and socio-economic welfare benefit perspective. This is influenced by three key factors:

i. The modelled nodal market does not produce any transmission constraint management costs.[160] In contrast, the **zonal market continues to have significant constraint management costs** *within* the zones (estimated to range between approximately £12bn - £18bn in total across the scenarios, see Tables 4.4 - 4.6 below).[161] We note that the model forecasts intra-zonal

[160] In FTI's report, it discusses that redispatch actions in a national market (such as the GB market) involve the constraining on and off of resources to resolve a mismatch between the scheduled market outcome and the physical capabilities of the network. This arises in a national market as a consequence of the omission of network constraints when clearing the wholesale electricity market with a single price, and also arises in a zonal market, albeit to a lesser extent. In theory, no such transmission constraint related redispatch actions are required in a nodal market – nodal prices are typically determined in a 5-minute dispatch which takes into account both network constraints, as well as changes to load and the output of intermittent resources, leading to a schedule that balances net demand and is consistent with the capabilities of the transmission network. The modelling does not account for re-dispatch that may be required to deal with real-world fluctuations in, for example, demand/generation/transmission availability within each dispatch period, with this true for all market designs.

[161] Under the zonal models, whilst the network capacity between the seven zones is, ex-ante, factored into wholesale prices, intra-zonal constraints remain which are assumed to be solved via a zonal specific BM. Note that the model assumes no rezoning. If relaxed, the likely result would be lower constraint management costs under the zonal markets.

constraint costs to rise throughout the modelling period, as the geographical zonal boundaries become less representative of future constraint boundaries.

ii. The modelling estimates **a smaller reduction in producer surplus under the zonal market** relative to the nodal market (with the incremental surplus ranging from approximately £6bn - £19bn over the nodal markets, see Tables 4.4 - 4.6 below). This is because it is more likely that generation with low short-run marginal costs (SRMC) are able to access a higher wholesale market clearing price more of the time in a zonal market compared to a nodal market.

iii. The **zonal market produces lower intra-GB congestion rent** as this revenue is only earned on transmission capacity between the seven zones modelled (as opposed to the whole transmission network in the nodal markets). Over the modelling period, total intra-GB congestion revenue under a zonal market ranges from £12bn - £18bn compared to £16bn - £27bn under a nodal market.

Table 4.4: Summary of FTI's CBA for the LTW NOA7 scenario (£bn). Source: FTI.

Quantified impact	**Zonal**	**Nodal**
Reduced constraint management costs	31.15	48.78
Change in wholesale costs	-13.18	-12.65
Intra-GB congestion rents	18.00	27.09
Change in CfD payments (from consumers)	-4.78	-11.94
Implementation costs	-0.50	-0.50
Net consumer benefits	**30.68**	**50.78**
Producer surplus	-20.19	-38.76
Change in CfD payments (to producers)	4.78	11.94
Total GB socio-economic benefits	**15.27**	**23.96**

Table 4.5: Summary of FTI's CBA for the LTW HND scenario (£bn). Source: FTI.

Quantified impact	**Zonal**	**Nodal**
Reduced constraint management costs	15.56	28.41
Change in wholesale costs	-5.55	-9.75
Intra-GB congestion rents	15.45	25.55
Change in CfD payments (from consumers)	-6.25	-9.54
Implementation costs	-0.50	-0.50
Net consumer benefits	**18.70**	**34.17**
Producer surplus	-17.82	-29.35
Change in CfD payments (to producers)	6.25	9.54
Total GB socio-economic benefits	**7.14**	**14.37**

Table 4.6: Summary of FTI's CBA for the ST NOA7 scenario (£bn). Source: FTI.

Quantified impact	Zonal	Nodal
Reduced constraint management costs	13.22	24.87
Change in wholesale costs	-5.62	-8.72
Intra-GB congestion rents	12.05	16.45
Change in CfD payments (from consumers)	-3.92	-4.08
Implementation costs	-0.50	-0.50
Net consumer benefits	**15.24**	**28.02**
Producer surplus	-12.97	-18.96
Change in CfD payments (to producers)	3.92	4.08
Total GB socio-economic benefits	**6.18**	**13.13**

The LTW NOA7 scenario produces the highest benefits of all modelled scenarios, with the LTW HND and ST NOA7 scenarios producing similar benefits to each other.

4.21 If the GB net zero transition aligned with the LTW NOA7 scenario, ie HND network build-out was delayed, then the benefits of a transition to nodal or zonal pricing would be higher than under the other scenarios modelled. As indicated in Tables 4.4 – 4.6, the net consumer benefits in this scenario (on average, across the zonal and nodal markets) are approximately 40% greater than in the other scenarios. This is largely driven by significant constraint management savings (£48.8bn in the LTW NOA7 nodal case) as the scenario has a higher demand (relative to ST NOA7) and less transmission network capacity (relative to LTW HND).

4.22 The LTW NOA7 scenario sees higher wholesale costs across both market designs which results in higher producer surpluses. The nodal case also results in higher CfD payments. This is because there are lower wholesale prices on average in areas with high CfD-supported generation, meaning that required top-up payments are on average higher. However, the combined magnitude of these two impacts (higher wholesale costs and higher CfD payments) is lower than the impact of the constraint management costs mentioned above, resulting in the LTW NOA7 scenario producing the highest net consumer and socio-economic welfare benefits.

4.23 As indicated in Tables 4.4 - 4.6, the net consumer benefits in the scenario with the HND investment plans (LTW HND) are lower, but still significant. On average, across the zonal and nodal markets the consumer benefits are approximately 35% lower than in the LTW NOA7 scenario. Moving to a zonal or nodal market design is less beneficial with the additional transmission build-out under the HND, but still significant and the incremental cost of the HND proposal over NOA7 is not incorporated into this study. The reduction in benefits is largely due to increased network capacity between offshore wind locations and demand centres in the south of GB reducing constraint management costs in the national market. This reduces the benefits of both zonal and nodal markets, relative to the national market.

Across all three scenarios, carbon emissions in GB are modelled to fall more quickly in both zonal and nodal markets, relative to the status quo

4.24 FTI's analysis identifies that locational pricing could produce additional socio-economic welfare benefits of between £4.3bn and £17.9bn over the modelling period from carbon emissions savings.[162] Although emissions under all market arrangements are modelled to reach the same levels in 2040, across all three scenarios, nodal and zonal markets have lower emissions in all other years relative to the national market. This result is largely due to a reduction in the curtailment of low carbon generation from the re-siting of generation technologies observed in the modelling, as well as more efficient utilisation of interconnectors.[163]

4.25 As the modelling assumes an implementation date of 2025, the socio-economic welfare benefits of the carbon savings identified could represent an overestimate of what could be achieved in practice by 2040. However, this does indicate that, all else being equal, the longer it takes to implement locational pricing (should any such decision be taken), the lower the potential to reduce carbon emissions (and capture the associated socio-economic value), compared to the status quo. This is because the carbon emissions are expected to reduce over time under status quo arrangements.

While modelled sensitivities indicate a reduction in the benefits, locational pricing remains beneficial under the scenarios assessed

4.26 FTI performed two modelling sensitivities (referred to as dispatch-only and load shielding), and also assessed the impact to the results from changes to the cost of capital.[164] These sensitivities were chosen to assess the potential for the benefits in the three main scenarios to be reversed. These sensitivities found that while the benefits reduce, locational pricing remains beneficial under the scenarios assessed.

[162] Discounted to 2024, and following the methodology in HMT's Green Book, and supplementary guidance. See FTI report section 9C for further details.
[163] The modelling does not assess the impact to carbon emissions outside of GB.
[164] The cost of capital is the minimum expected return required for investing in a company or project.

Table 4.7: A summary of the dispatch-only modelled sensitivity in FTI's work. Source: FTI analysis.

Generation and demand	Transmission build-out	Locational granularity	Sensitivity description
LTW	NOA7	National	Takes generation siting from nodal LTW NOA7 as an input to the national model.

Table 4.8: A summary of the load shielding modelled sensitivity in FTI's work. Source: FTI analysis.

Generation and demand	Transmission build-out	Locational granularity	Sensitivity description
ST	NOA7	Nodal	Estimate benefits if demand is exposed to a national price instead of the local nodal price.

(i) Dispatch-only sensitivity

4.27 In FTI's work, the estimated benefits of locational pricing accrue mainly due to two factors:

- A more efficient dispatch of the available flexible resources to meet demand (arising from locational operational signals), and;
- Re-siting of certain generation capacity (arising from locational investment signals).

4.28 The dispatch-only sensitivity was used to test how the benefits of nodal pricing change (relative to the national market) if an alternative mechanism (eg strategic system planning or some form of TNUoS charge) was able to perfectly incentivise new generation to site in the locations identified within the nodal market model.[165] Put another way, the sensitivity aimed to answer the question: how much of the estimated benefits accrue due to locational operational signals versus locational investment signals?

4.29 The dispatch-only sensitivity was performed by taking the location of generation capacity from the LTW NOA7 *nodal* run (where some generation technologies are allowed to re-site in response to locational prices, within certain limitations), and using these

[165] See FTI report, section 11 A for a full explanation.

generation locations as an alternative input to the LTW NOA7 model run with *national* pricing.

4.30 Under the central case (ie, comparing nodal pricing to national pricing with status quo generation siting, under LTW NOA7) the **net consumer benefits** are estimated to be £50.8bn. Under the dispatch-only sensitivity (ie comparing nodal pricing to national pricing with optimised generation re-siting, under LTW NOA7) this reduces to £38.7bn.

4.31 Under the central case (ie, comparing nodal pricing to national pricing with status quo generation siting, under LTW NOA7) the **net socio-economic benefits** are estimated to be £24.0bn. Under the dispatch-only sensitivity (ie, comparing nodal pricing to national pricing with optimised generation re-siting, under LTW NOA7) this reduces to £13.7bn.

4.32 This sensitivity reduces the net consumer benefits of nodal pricing by 24% and net socio-economic welfare benefits by 43%.[166] It can be inferred from these results that the consumer benefits of a national pricing market with optimised generation re-siting, compared to the status quo and in the LTW NOA7 scenario, would be ~£12.1bn. These results further suggest that, under the LTW NOA7 scenario modelled, more than 75% of the net consumer benefits of nodal pricing are estimated to come from the operational signals, which also provide approximately half of the socio-economic welfare benefits.[167]

4.33 This suggests that the net socio-economic benefits of nodal pricing, in particular, could materially reduce if it is assumed that there is no re-siting effect on generation. That said, it also suggests that there is the potential for nodal pricing to deliver significant benefits in the event that optimal locational investment signals are provided via some other means (eg, TNUoS or strategic system planning).

4.34 In summary, this sensitivity demonstrates that optimising the location of generation capacity in a national market would result in benefits over the status quo. It further indicates that nodal pricing could work alongside other mechanisms, such as TNUoS and/or strategic system planning, which could theoretically facilitate optimised asset siting, to deliver significant additional system and consumer benefits.

[166] We note that these values exclude any quantification of the impact on carbon emissions.
[167] We note that this sensitivity could have been run by modelling the nodal market with no generator re-siting, and that under such a scenario the proportion of benefits arising from operational signals would likely be different.

(ii) Load shielding sensitivity

4.35 As set out in the previous chapter, whether (and how) suppliers and, in turn, demand is exposed to locationally varying prices is a critical design choice that will impact the net benefits of these market designs. To help inform any potential future policy decision, a load shielding sensitivity has been used to provide insight into how the benefits of nodal pricing could be impacted if certain types of demand remain exposed to a national average wholesale price, instead of a zonal or nodal price which is the base case across all scenarios.[168] This sensitivity assumes that all household and industrial and commercial demand (apart from electrolysers, batteries and vehicle-to-grid (V2G)) pay a national average price in each modelled hour in the ST scenario. This means that smart charging of EVs and heat pumps are the only forms of flexible demand shielded from the nodal price (ie, pay the national price) in this sensitivity.

4.36 Under the central case (ie, comparing nodal pricing to national pricing with no load shielding, under ST NOA7), the **net consumer benefits** are estimated to be £28bn. Under the load shielding sensitivity (ie, comparing nodal pricing to national pricing with load shielding, under ST NOA7) the benefits reduce by £1.2bn to £26.8bn.

4.37 Under the central case (ie, comparing nodal pricing to national pricing with no load shielding, under ST NOA7) the **net socio-economic benefits** are estimated to be £13.1bn. Under the load shielding sensitivity (ie, comparing nodal pricing to national pricing with load shielding, under ST NOA7), the benefits reduce by £1.7bn to £11.4bn.

4.38 Therefore, the load shielding sensitivity reduces the net consumer benefits of nodal pricing by 4% and net socio-economic welfare benefits by 13%. The benefits of nodal pricing in this scenario remain significant as the net impact of load shielding is a £1.2bn reduction in the consumer and a £1.7bn reduction in total socio-economic welfare benefits, over the modelling period.

4.39 This reduction in benefits is largely influenced by an increase in the wholesale prices (£3.2bn, 2025-2040) relative to the nodal ST NOA7 scenario, as shielded demand does not respond to local price signals. This results in more demand being consumed in more expensive periods than would be the case with full demand exposure. The total impact of

[168] See FTI report, section 11 B for a full explanation of the approach to this sensitivity.

increased wholesale costs on total consumer benefits is slightly tempered by a £1.3bn increase in intra-GB congestion rents (as load shielding increases the system price at points on the network, there is an increased divergence of local prices between connected nodes, which increases the congestion rents).

4.40 While there are several limitations with this sensitivity,[169] it indicates that the introduction of nodal pricing with a national average price retained for key demand cohorts could still deliver significant consumer and socio-economic welfare benefit. However, this may not be the case for scenarios which rely more significantly on consumer participation or flexible, behind-the-meter assets.

(iii) Cost of capital

4.41 A key stakeholder concern is that locational pricing could increase investor risks and uncertainties which could lead to them demanding a higher return on new investments. If this increase in *risk premia* was to be recovered from consumers, eg through higher wholesale prices or CfD auction clearing prices, this additional cost could reduce the net benefits of locational pricing. To provide insight, FTI considered the potential impact of an increase in the cost of capital on the benefits of locational pricing.[170] These represent post-modelling calculations, as opposed to modelled sensitivities, and indicate that:

- Under FTI's '**plausible uplift sensitivity'**, FTI find that:
    - the expected net consumer benefits for the nodal LTW NOA7 scenario reduces by £7.45bn, from £50.8bn to £43.4bn between 2025 and 2040 (inclusive).
    - the expected net consumer benefits for the nodal ST NOA7 scenario reduce by £5.46bn from £28.0bn to £22.5bn between 2025 and 2040 (inclusive).

[169] FTI assumes V2G would not be shielded, in line with batteries. Given the high proportion of V2G in the LTW scenario, FTI has tested that the load shielding sensitivity in the LTW scenario has a smaller effect and hence be less informative than the ST scenario. We note that this result would be different if V2G (or a proportion thereof) was shielded.
[170] See FTI report, Appendix 4 'Cost of Capital' for a full discussion on the method and results.

- FTI also calculated the required increase in Weighted Average Cost of Capital (WACC) to **negate any of the potential consumer benefits** as per Table 4.9, below.[171] FTI finds that the WACC would have to increase (on average **across all technologies in all locations**) by between 1.3-2.1% (zonal), and 2.3-3.4% (nodal) to negate any consumer benefit.[172]

Table 4.9: WACC increase required to negate consumer benefits for zonal and nodal markets. Source: FTI.

Scenario	Zonal market	Nodal market
Leading the Way	206 bps	341 bps
Leading the Way (HND)	125 bps	229 bps
System Transformation	139 bps	256 bps

4.42 For the purposes of estimating how this might affect the quantitative CBA, we would expect that any increase in cost of capital would be passed through to consumers and result in a reduction in consumer benefits. A cost of capital increase would affect socio-economic benefits therefore we have calculated the WACC increase necessary to erode any socio-economic benefits, see Table 4.10 below.[173] We discuss the potential impact on cost of capital further in the next chapter.

Table 4.10: WACC increase required to negate socio-economic benefits for zonal and nodal markets. Source: Ofgem.

Scenario	Zonal market	Nodal market
Leading the Way	103 bps	161 bps
Leading the Way (HND)	47 bps	96 bps
System Transformation	57 bps	120 bps

[171] Cost of capital represents the return a company needs to achieve in order to justify the cost of a capital project, such as purchasing new equipment or building infrastructure. It includes both equity and debt, weighted according to the company's preferred or existing capital structure. This is known as the Weighted Average Cost of Capital (WACC).
[172] To contextualise the size of this increase, Ofgem had previously estimated the small company equity premium to be 80 bps to 263 bps. Small Business Cost of Capital, October 2010.
[173] We note that consumers currently hold the risk of generation being unable to reach demand, ie they are exposed to BSUoS. As such, any potential cost of capital increase may be partially composed of a transfer of risk from consumers to producers, as well as a creation of risk, and so the estimated breakeven WACC increases would be a lower bound.

Locational pricing has the potential to significantly change how the market schedules interconnector flows

4.43 A key finding from FTI's modelling is that locational pricing results in notably different scheduled interconnector flows compared to the national market design, under the LTW NOA7 scenario.[174] This produces significant consumer benefit as accurate price signals facilitate the more effective use of interconnectors in dispatching generation at least cost and resolving GB constraints ahead of Gate Closure.[175] By contrast, in the national market design, scheduled interconnector flows are expected to exacerbate constraints more of the time, since they are responding to national rather than local price signals.

4.44 As shown by Figure 4.5 below, in general, the modelling indicates that, under nodal pricing and in the LTW NOA7 scenario, interconnectors in southern GB are scheduled to import more of the time, and those in the north scheduled to export more of the time, relative to the counterfactual. The trend is less clear in the zonal market under LTW NOA7, though there are clear changes in the scheduling of flows, as shown in Figure 4.5 below.

Figure 4.5: Percentage change in scheduled interconnector flows, grouped by landing point region. Zonal relative to national (left) and nodal relative to national (right). LTW NOA7. Source: FTI.

[174] We note that FTI provide detailed interconnector scheduling outcomes under one scenario, only. We would expect to see a similar effect under the other two modelled scenarios, albeit to a lesser extent given that the LTW NOA7 scenario has the highest constraint management costs.
[175] However, we should note that while nodal prices will send more efficient schedules, trades would typically take place before the nodal price is known, and the markets may differ from the optimal schedule.

4.45 Figure 4.6 below provides a snapshot of the modelled impact of nodal pricing on interconnector flows from hour-by-hour modelling in a high-renewables/high-flexibility scenario (LTW NOA7), in 2030. This shows an approximate 14GW swing from export to import across the French interconnectors, between the national and nodal markets. This is a large change, equivalent to roughly a third of current average demand or four Hinkley Point Cs. The figure shows a snapshot forecast of 8am 9 March 2030 under both the national and nodal wholesale market designs, highlighting net interconnector flows to each connected country and the prevailing wholesale market price in each market.

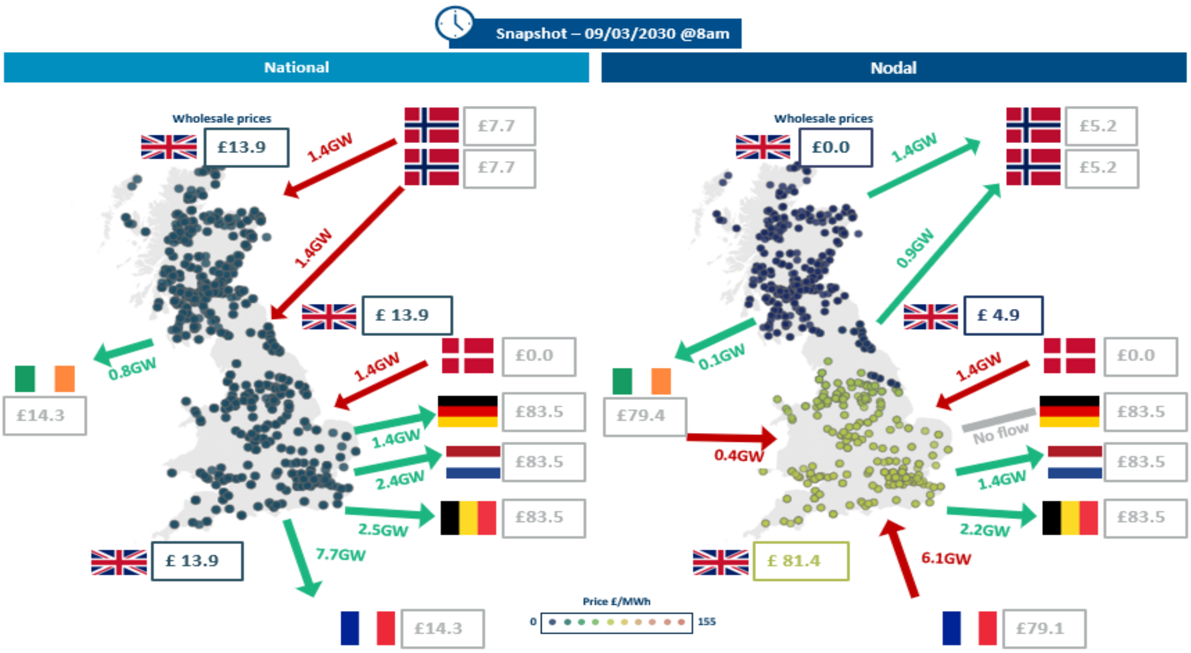

Figure 4.6: Illustrative view of the impact of nodal pricing vs. national pricing in a particular hour of FTI's modelling. Source: FTI.

4.46 This provides some evidence to support a major theorised benefit of more accurate operational locational signals, namely that interconnector flows between GB and connected countries would likely be better optimised, improving system efficiency by lowering total system costs and alleviating GB transmission constraints more of the time. Zonal pricing, and to a greater extent nodal pricing, allows flows on interconnectors to be scheduled more efficiently in the wholesale market, facilitating exports where the marginal source of generation is cheaper than in the relevant neighbouring market, and importing when the marginal source of generation is more expensive.

4.47 National pricing on the other hand schedules interconnectors based on the marginal cost of generation nationally, irrespective of network conditions. In order to reconcile the schedule to network conditions, in some cases expensive actions must be taken by the ESO via countertrades or SO-SO trades. Zonal, and to a greater extent nodal, thereby avoid the need for the ESO to pay to reverse the interconnectors or to pay other generators to turn up or down, when the interconnectors are initially scheduled to flow in 'the wrong way', against the marginal cost of generation. Given the potential for up to 18GW of interconnectors by 2030, and the key role interconnectors will play in system balancing, the more effective use of these assets could deliver significant consumer and system benefits.[176]

Over time, the optimal amount and location of network reinforcement could be significantly different under a market based on locational pricing.

4.48 A subsidiary finding of FTI's analysis is that the optimal level of network expansion would likely be much lower with locational pricing. FTI's modelling did not calculate optimal network reinforcement under the different market regimes so this outcome does not feature in the benefits reported above.

4.49 By comparing the outcomes of the *national* market under LTW NOA7 and LTW HND, FTI were able to compare the forecasted constraint management cost under the two network configurations. This leads to FTI finding that the consumer benefits of the HND versus the transmission network plans under NOA7 are approximately £28bn[177]. This benefit arises from savings due to increased efficiency and a reduction in the transfer from consumers to producers. We note that this analysis is a subsidiary finding of the modelling work and does not take account of any non-monetised benefits of the proposals under HND.

4.50 Similarly, by comparing the outcomes of the *nodal* market under LTW NOA7 and LTW HND, FTI was able to calculate both the consumer benefits and socio-economic welfare benefits of HND vs NOA7 under *nodal* pricing. It finds that the consumer benefit is estimated to be £1.7bn under the LTW scenario, with socio-economic benefits of £3bn.

4.51 FTI therefore find that the consumer benefits of the HND network reinforcements under a *nodal* market, in the LTW scenario, are approximately 10% of the consumer

[176] Energy white paper: Powering our net zero future (accessible HTML version) - GOV.UK (www.gov.uk)
[177] This number has not been discounted. Further, a comparison of socio-economic welfare is not possible between the two national markets, as all results are quoted relative to the status quo. See FTI report, section 10 for a full explanation of the method used by FTI to find these results.

benefits under a *national* market. This result is thought to be due to two effects: i) re-siting of generation in the nodal markets, meaning better use is made of the existing transmission capacity and ii) given that scheduling of assets in a nodal market is more consistent with the physical demands of the network (see discussion on interconnectors, above), the need for additional transmission network is reduced. This result suggests that:

i. The economically optimal level of transmission network under locational pricing may be less than under the status quo.

ii. That, under locational pricing, transmission network reinforcements would need to be assessed on a case-by-case basis to ensure that any reinforcement leads to a lower total system cost.

4.52 In summary, this investigation implies that locational pricing could significantly reduce the consumer costs associated with facilitating net zero through a significant expansion in wind capacity out to 2050. This is considered further in section 5.

Implementation costs are estimated to be between one to two orders of magnitude lower than the estimated benefits.

4.53 In estimating the potential economic benefits of locational pricing, FTI has sought to provide a view on the possible costs involved. At this time, there are too many uncertainties regarding the design of a GB-specific locational wholesale market to construct a 'bottom-up' cost estimate. FTI has therefore gathered information from three different sources to provide an initial estimate of the cost of introducing (and operating) locational pricing in GB. These three sources are:

- Cost information (incurred or estimated) from CBAs in other jurisdictions that have considered, or implemented, locational pricing.
- Direct conversations with system vendors and market participants.
- Discussions with ESO to understand the steps required for implementation.

4.54 This work has enabled FTI to estimate that the total cost to SO and market participants could be £500m. We note that the costs for market participants, in particular, are likely to vary across companies given differing requirements. We view this figure as an indication of the costs of implementing locational pricing in GB.

Key assumptions and limitations of the monetised costs and benefits

4.55 In this section we discuss the key modelling assumptions and inputs, and the potential impact this could have on the range of benefits estimated by FTI. This includes a summary of views from FTI and the academic reviews.

FTI view on key assumptions

4.56 FTI's report highlights some of the limitations inherent in power market modelling, which are likely to limit the ability to estimate the actual impacts of any market reform.[178] Further, FTI outline 11 key assumptions which could affect the results (see Table 4.8, below) and its view on the likely direction and magnitude of impact from changing these assumptions. Some of these key assumptions relate to potential non-monetised costs and benefits (eg, operational benefits of centralised scheduling over self-scheduling), which we discuss further in section 5. Some of these relate to modelling inputs or assumptions.

Table 4.11 FTI's view of key assumptions affecting the results of the CBA. Source: FTI.[179]

Key assumptions	Likely impact on results if assumption relaxed
Fixed transmission build: Based on ETYS, NOA7 and information provided by ESO. Does not vary across market designs. FTI provide an assessment of why less transmission is likely to be required in locational markets due to improved locational and operational price signals for market participants.	Increase benefits
Fixed capacity mix: Overall generation capacity and technology mix is fixed to FES 21. Allowing the capacity mix across technologies to change between national and locational market designs could increase consumer and socio-economic benefits and reduce the costs of achieving Net Zero.	Increase benefits
No demand re-siting: FTI fixed the location of demand across each market design assessed. Locational market designs could incentivise demand to site in different locations and/or attract	Increase benefits

[178] See FTI report, section 5.
[179] See FTI report, section 12. Note that this is a copy of table 12-2 in FTIs report, and therefore any reference to 'We' in this table means 'FTI'. Further, any references to different chapters etc refers to FTI's report, not this report.

Key assumptions	Likely impact on results if assumption relaxed
further investments by energy-intensive companies which could lead to further benefits beyond those assessed.	
Operational benefits: Modelling does not account for operational benefits from centralised scheduling as well as other potential benefits from using a security-constrained economic dispatch. For example, FTI do not consider the impact of the ability to co-optimise energy and reserves more effectively in a nodal market.	Increase benefits
Consumer exposure: Modelling assumes all consumers are fully exposed to locational pricing. Shielding consumers (or specific consumer types) from locational prices would reduce the estimated benefits to consumers.	Decrease benefits
Further policy support for existing generation: Compensating the investments of some cohorts of existing generation for reduced revenues would lead to a reduction in consumer benefits (offset by higher producer revenues). This would not lead to changes to socio-economic welfare unless interventions distort market incentives.	Increase or decrease benefits
FTRs confer full congestion rent benefits to consumers: FTI assume that all FTRs are auctioned at efficient prices (ie, with perfect foresight). Any differences between FTR auction revenues and congestion rent collected in the settlement processes would affect consumer benefits (in the form of a direct transfer with FTR holders). There would be no change in socio-economic welfare unless there is an inefficient risk transfer.	Increase or decrease benefits
No change in cost of capital: FTI assume no change in cost of capital due to lack of evidence, but an increase would reduce the estimated benefits, and a decrease would increase the estimated benefits.	Increase or decrease benefits
New generation capacity re-siting assumptions: Assumptions on technology siting were developed in discussion with stakeholders. Any changes to these assumptions could impact the overall benefits in either direction.	Increase or decrease benefits
No other reforms assumed: The status quo assessment is based on the current market structure and policy landscape. Further changes (eg, network charging, Capacity Market reforms) could change the overall benefits.	Increase or decrease benefits
Choice and design of zones: The seven-zone model is based on the six most constrained boundaries which is fixed in the modelling period. Alternative zonal boundaries would change the benefits of our zonal pricing assessment, while periodic rezoning, if assumed in our assessment, would be expected to increase the benefits.	Increase or decrease benefits
Modelling year: Delaying the start of the modelling period, while keeping the length of the modelling period the same, could lead to multiple effects in either direction. Overall, the net benefits are uncertain as they would depend on the energy system beyond 2040 – and in particular whether the benefits in later years would exceed the foregone benefits in early years.	Increase or decrease benefits

Summary of the academic reviews

4.57 We commissioned three academics to provide an independent view of FTI's assessment of locational pricing. The scope was to consider the assumptions, methodology and limitations identified by FTI and provide a view on whether the key findings should be considered conservative or optimistic. Academics were provided draft copies of the FTI report, as well as the annexes to support their reviews.

4.58 The reviews represent a thorough consideration of the FTI assessment and, as such, it is not feasible to summarise all the points made in these reports. We have therefore published these documents alongside this report.[180] Below, we provide a high-level summary of some key findings from these reviews, focussing on key areas of agreement between the reviewers.

4.59 In general, there is agreement amongst the reviewers that the overall results presented by FTI are likely to represent an over-estimate of the net socio-economic benefits and net consumer benefits of introducing locational pricing in GB, with one reviewer considering certain dispatch benefits to be conservative. Two key reasons are highlighted by all three reviewers:

- **Extent of generator re-siting benefits under locational markets:** The reviews concluded that the benefits associated with generation re-siting under locational market designs were likely to be overestimated. The reviewers had varying reasons for reaching this conclusion but included i) scepticism over the ability of generation to re-site in response to wholesale market signals, eg due to real-world limitations, ii) concerns regarding the extent to which FES accurately captures asset investment location decisions and generator economics and so a belief that original FES generation locations may be sub-optimal, iii) concerns that generators may not be economically viable even in optimised locations (and therefore that costs may be higher than FTI have estimated), and iv) a view that alternative locational signals, eg TNUoS reform, could achieve similar results and should be a part of the status quo.[181]

[180] The academic reviews are published on this webpage: https://www.ofgem.gov.uk/publications/assessment-locational-wholesale-pricing-great-britain
[181] Although, we note that the status quo is a reasonable counterfactual whilst TNUoS reform is ongoing.

- **Overestimation of consumer benefits due to congestion rents accruing exclusively to consumers.** This was typically discussed in relation to reviewers' views regarding: i) the potential need for producers to be 'kept whole' or recoup some of the modelled loss in producer surplus (noting that FTI do not assess the financial viability of new build generation[182]) and ii) the potential introduction of an FTR market, and the likelihood of this leading to a transfer of consumer benefits back to producers.

Further discussion of limitations

4.60 Further to FTI's table of key assumptions and limitations highlighted above, we note and elaborate on the following:

1. The modelled period starts in 2025, and four spot years are modelled across the 16-year period.[183] Interpolation between these years is used to estimate the cumulative impact over the 16-year period. We note that it is unrealistic to expect that locational pricing could be implemented by 2025, and therefore that the **quantified impact of locational pricing over the first 16-year period of operation would be different from that modelled**. Further, that the modelling period does **not extend beyond 2041.**[184] We note that further costs and benefits would arise were the model to be run for a longer period.

2. The use of specific scenarios to run the load shielding and dispatch-only sensitivities mean that these **provide an indication of the possible impact of these mechanisms** to the overall results rather than a range, as would be the case if multiple scenarios were studied.

3. As discussed by both FTI and the academic reviews, **congestion rent accrues to consumers in all scenarios**. This would be a critical market design decision for government. As discussed in section 2, several policy options exist

[182] We note that FTI do assess the potential impact to CfD supported generators.
[183] REMA timelines and the implementation requirements for locational pricing mean these market reform options cannot be implemented from 2025. Given the desire to, as far as possible, base this assessment on external sources of input, the modelling period chosen was 2025 to 2040 (inclusive). This aligned with the availability of information from the ESO regarding optimal network reinforcements.
[184] We agree with FTI that it was preferable to base the assessment in externally validated information sets, wherever possible. This meant that, at the time of undertaking the modelling work, there was no information available regarding transmission network reinforcement beyond 2041.

that could represent transitional or more permanent market design features. This includes passing congestion rent through to consumers (eg, by using this to pay for transmission network upgrades) to using the revenue to compensate existing generators who may lose financially firm access rights to the entire transmission network. The impact on estimated consumer benefits from this revenue accruing to producers instead of consumers can be crudely estimated. Under this scenario, the consumer benefits would reduce to between £3bn and £13bn (zonal), and to between £9bn and £24bn (nodal) (relative to the figures in tables 4.4 to 4.6, above). In theory, the total socio-economic welfare benefits would remain the same, as using the congestion rent in this way would be a transfer from consumers to producers. However, in reality we may expect the socio-economic welfare benefits to change as mitigating volume and price risk for producers would likely impact behaviour, eg through different bidding strategies, or closure/repowering decisions.

4. Some stakeholders have suggested that **network build beyond that in the HND** should be considered as a sensitivity, particularly given the ESO's work on the Holistic Network Design Follow-up Exercise (HNDFUE).[185] All else equal, and as shown by the LTW HND scenario, we would expect that the more transmission network there is in the model, the lower the benefits of locational pricing are likely to be. At the time of creating the model, there was no information on transmission network build beyond the plans under the HND. We note that the model continues to build out transmission network under the respective NOA7 or NOA7 refresh plans, through to 2041.

5. As noted by FTI in row 2 of table 4.11 above, the long-term model (which FTI uses to identify the location of generation under zonal and nodal pricing) **assumes that the capacity will come forward at the point in the future implied by the FES data**, and in such a way that minimises the cost of meeting system demand.[186] As such, this does not consider the individual financial viability of new build generation. The impact to the Capacity Market is not included in the analysis, although CfD top-ups are.

[185] https://www.nationalgrideso.com/document/270851/download
[186] See FTI report, section 5. The least cost optimisation applies only to the zonal and nodal markets subject to pre-agreed limits on the extent new generation can site differently to the FES. The national market follows the generation build out under the relevant FES scenario.

6. That the **bidding strategy of market participants could be different** to that assumed, particularly for generators with subsidy support.

7. That the **costs are passed directly through to consumers** (ie, the retail market is not modelled explicitly).

8. That it is assumed that a **smooth migration of all industry systems and contract**s to a new market structure.

9. The assumption that **trading is efficient across borders.**

10. Plexos, like many dispatch models of its kind, **uses perfect foresight when optimising.** This was a common assumption across all wholesale market configurations studied. However, perfect foresight has different effects across each market configuration. For example, in zonal and nodal scenarios generation re-sites in anticipation of higher profitability by predicting future power prices. In reality generators would have an imperfect ability to predict nodal power prices and so their location decisions may in turn be sub-optimal.

Summary

4.61 As with all modelling exercises, FTI's approach and methodology uses a number of simplifications and assumptions. The uncertain nature of assumptions and scenario input data means that modelling outputs should be treated as indicative and are most useful in informing the anticipated magnitude and direction of impacts.

4.62 The FTI modelling exercise, and accompanying analysis, has demonstrated that there are potentially material benefits to consumers, and society as a whole, via a market based on locational pricing. Through the modelling, FTI has been able to estimate the impact of specific mechanisms inherent in locational pricing, and has shown them to be significant.

4.63 We agree with the overall conclusions from the academic reviews, in that it is likely that the results overestimate the precise impact of some of these mechanisms. Specifically, we note that the magnitude of generation capacity re-siting is, in some cases, significant in relation to the total capacity predicted under the FES scenarios.[187] and that detailed work to understand the extent to which real-world limitations may prevent the volume of this relocation has not been undertaken.[188] Further, we agree that the consumer benefits estimated via the mechanisms assessed are likely overstated, given the potential for some consumer benefit to be transferred back to producers via policy mechanisms that could be used to support investment or due to the treatment of legacy contracts.

4.64 That said, we consider that there is little reason to think the quantified benefits case could be reversed under a different set of reasonable assumptions or inputs. Further, there are several theorised benefits of locational pricing which have not been quantitatively assessed under FTI's work. These include the potential for: new sources of demand to re-site in response to price signals; more efficient generation mix to outturn than the FES scenario used in the model; that less, or different, transmission network reinforcement may be required; and the benefits that may arise from co-optimisation of ancillary services. We consider some of these in the next section.

[187] Eg, and based on a read across of figure 6-8 in the FTI report - ca. one third of new solar capacity and ca. one half of new battery capacity under the LTW NOA7 scenario.
[188] We note that FTI restricted the generation technologies which could relocate, and placed limitations on the extent to which these technologies could relocate. FTI only allow new generation that is not in development to relocate.

5 Wider market and system impacts

Section summary

This section considers a broad range of market and system impacts associated with introducing locational pricing in GB that are either unquantified in the FTI analysis and/or merit further consideration. The impacts are grouped into three themes: (i) impact on market operation and participation, (ii) impact on investments by energy market participants, and (iii) impact on network and system planning and investment.

It finds that while locational pricing is likely to produce significant benefits for consumers, the scale of these benefits will be shaped (both positively and negatively) by design and implementation decisions, and how a locational market interacts with a range of other key policies.

For example:

- Implementing locational pricing with centralised scheduling and dispatch could deliver broader system cost savings and security benefits than those quantified by FTI. Further work is required to understand the net benefits associated with introducing centralised scheduling and dispatch under various wholesale market designs.
- The impact on market liquidity and access is currently uncertain, while the impact on market power and gaming is likely to be beneficial.
- Several potential benefit sources not captured by the FTI figures could increase the consumer and socio-economic benefits of locational pricing, such as different capacity configurations to achieve net zero, reduced future network build, and new demand (such as hydrogen electrolysers and some industrial demand) and low carbon technologies (such as EVs and heat pumps) locating in response to locational price signals.
- Market reform as a process can disrupt or delay investment and cause potential risks for existing assets, which can reduce the total benefits of any reform package. Policy responses to shield market participants (notably generators) from increased risk exposure and price signals can be expected to reduce the benefits of locational pricing, with the extent of this dependent on design.
- Network build could reduce the benefits of locational pricing – but locational pricing could reduce the need for future transmission investment and reduce risks associated with challenging build targets.
- Potential synergies between locational wholesale prices and an increasingly planned and coordinated approach to infrastructure build could improve the effectiveness of future system and network planning decisions, but system planning could also reduce some of the re-siting benefits of locational pricing.
- Compared to a 'fit-and-forget' nodal design, additional costs and disruption can be associated with a zonal design given the need to re-draw zonal boundaries over time.

Introduction

5.1 The scale of the benefits likely to be realised from introducing locational pricing in GB would be shaped by a wide range of impacts that this market design would have on market and system operation, network use and planning, energy system investments, and interactions between the power system and wider energy system. While many of these impacts are inherently uncertain or hard-to-quantify, they are important to consider as part of a complex and evolving evidence base.[189]

5.2 Below we consider a selection of potential impacts likely to have a material impact in shaping the realised benefits of locational pricing which we group into three themes: (i) market operation and participation, (ii) investments by energy market participants, and (iii) network and system planning and investment.[190]

Impact on market operation and participation

Scheduling and dispatch arrangements

5.3 . If locational pricing was to be implemented in GB, a key design choice that would shape the overall benefits of a market reform package would be the accompanying scheduling and dispatch arrangements. Drawing upon experiences from international jurisdictions with locational pricing, below we consider some options and identify areas where certain design choices could deliver broader system cost-efficiencies and security savings. We focus on options for central dispatch arrangements, as this is being considered as a stand-alone option within the REMA programme, but note where similar outcomes could be delivered by a zonal market with self-dispatch.

5.4 The design of central dispatch in jurisdictions with locational pricing varies. For example, New Zealand operates a nodal real-time market, whereas in the US, financially-firm day-ahead markets are common. In the US, a day-ahead schedule is created by market participants submitting offers that would be financially firm at unit level (reflecting the price they are willing to supply or consume electricity in a given period) and providing technical information to the Market Operator (MO). The MO then accepts bids and offers in a way that optimises the operation of the whole system. Depending on design, eg whether

[189] Uncertainty in this type of assessment can take many forms. It can include an inability to quantify or monetise an impact (either at this stage or at all), uncertainty over whether the impact would be realised, and the magnitude and nature of the impact, and uncertainty over future policy or market design and implementation that means it is difficult to assess the impact of certain impacts and risks.
[190] This section does not provide an exhaustive list of likely impacts. It considers some of the key and most commonly discussed impacts that we have identified through stakeholder engagement (bilateral, workshops and a Call for Input), desk-based research and a review of wider literature, discussions with several relevant organisations and electricity market designers, and our own experiencing in regulating and facilitating change to GB market arrangements.

central dispatch uses centralised-commitment or self-commitment, the MO might run an intraday unit commitment.

5.5 This would be different from current GB arrangements, in which market participants submit their intended positions and running profiles to the ESO, which do not need to be physically feasible and are not a financially-firm commitment, otherwise when called on in the Balancing Mechanism. The ESO then re-dispatches some intended positions after Gate Closure to meet the physical requirements of the system. Much of this redispatch is to solve locational constraints arising from renewable energy being transported to demand centres.

5.6 Typically, the MO will be responsible for operating dispatch optimisation to identify the dispatch schedule and the SO supplies operational data and issues instructions. As discussed in section 2, a key decision would be the allocation of MO roles and responsibilities. In US nodal markets, this role is typically undertaken by the ISO/RTO. This provides the ISOs with a central role in coordinating and organising assets by using physically feasible market outcomes to publish regular prices that vary by location, and develop and publish an optimised schedule which would determine how assets should operate given real-time system conditions.[191]

5.7 Similar arrangements could be designed for GB, eg to improve the information and tools available to the FSO in managing a more complex power system and reduce system costs. As occurs in other markets (ie the Irish system), the MO role could be undertaken by other bodies. For example, Power Exchanges could take on this role with the FSO providing network data to facilitate market clearing and acting as residual balancer.

5.8 Below we consider benefits that could be realised from central dispatch:

- **Improved visibility and certainty for the SO:** With some central dispatch designs, market participants would be financially committed to deliver positions set out in the optimised central schedule. This would give the SO much greater certainty on how a large share of assets are likely to operate, much earlier on. Also, by combining the SO/MO role, the schedule would respect transmission

[191] The day-ahead schedule would be determined by day-ahead market outcomes based on offers and technical information supplied by market participants. The schedule would be continually refined up until real-time as the SO received improved information and flexible and intermittent assets adjust their positions, often in response to published hourly locational prices.

constraints, therefore, the SO would only perform a minimal amount of asset re-dispatch in order to fine tune the schedule and deal with outages. This could also be the case with zonal pricing and self-dispatch, provided the zones are accurately defined (ie that there are no transmission constraints within zones).

- **Ability to combine energy and ancillary services:** This is an optional market design feature that could increase the efficiency of the energy and ancillary services markets.[192] Under current arrangements (see Section 2), the ESO procures ancillary services outside of the wholesale market over different time horizons, and (depending on the service) without a clear view of the constraints on the transmission network in the relevant Settlement Period. This can produce additional system costs, for example by reducing liquidity in the spot market for the relevant Settlement Period. ESO are working to co-optimise existing services within the national market to ensure that there is greater value to consumers, for example progressing with the Enduring Auction Capability (EAC).[193] Co-optimising energy and ancillary services would enable market participants to offer a range of ancillary services alongside energy offers to the SO. This has the potential to further reduce system costs as the SO would have access to a wider pool of resources, including flexibility, at day-ahead stage and in real-time and could automatically determine whether to accept the energy or ancillary service offer, based on which leads to the lower cost market outcome. As market participants would submit different bids and offers for different markets in a single pass to the SO, this would reduce the scope for bids to price-in the opportunity cost[194] of clearing in one market over the other, potentially removing this cost element and reducing overall balancing costs. While some stakeholders have raised concerns about computational complexity, we note all US nodal markets and other jurisdictions with central dispatch (such as Australia) co-optimise in this way.

- **Improved facilitation of distribution-connected demand and generation:** If implemented with central dispatch (with closer to real-time markets, ie intraday markets), locational pricing could streamline the participation of distributed energy resources and DSR in the wholesale market given the

[192] Today in GB, there is a wide range of ancillary services, with total balancing costs (including the Balancing Mechanism) reaching over £3bn in 2022. https://www.nationalgrideso.com/data-portal/mbss
[193] Enduring Auction Capability (EAC) | ESO (nationalgrideso.com)
[194] There might be some opportunity costs of holding back capacity for the Balancing Mechanism.

introduction of a single counterparty and/or co-optimisation. Under current arrangements, there are various markets for flexibility, including DNO flexibility tenders and a wide range of Balancing Services (including the Balancing Mechanism). A market with centralised scheduling, and co-optimisation of ancillary services could, therefore, result in long-term efficiencies for the operation and investment in the distribution network. Further, locational pricing (and nodal, in particular) has the potential to provide DNOs with greater visibility of likely dispatch, which may make it easier to operate their distribution networks.

5.9 REMA is considering central dispatch as a stand-alone reform option as it can be used with a national, zonal or nodal wholesale market to enable more cost-efficient dispatch decisions from better co-ordinated system actions and more efficient use of low carbon flexible assets to mitigate operability challenges.

5.10 Central dispatch is likely to have complex implementation requirements, such as requiring changes to IT infrastructure for both the SO and market participants and changes to market clearing, bidding, settlement and metering processes. As part of their Business Planning 2 investments, the ESO is revamping its internal digital infrastructure. This modernisation opens the door to the possibility of introducing central dispatch, likely reducing the overall costs to implement such a tool in the future.

5.11 Some market participants have also argued that central dispatch could reduce their ability to resolve issues and optimise at a portfolio level and could impact decisions on the co-location of assets. Current self-dispatch arrangements allow market participants to continuously trade intraday on the Power Exchanges, allowing them to continuously update their financial positions in response to changing forecasts. This can, arguably, provide a more transparent view of system needs in the run up to real-time.

5.12 Depending on design, central dispatch could limit the ability of market participants to update their positions and arbitrage intraday prices. Another requirement for central dispatch is very granular unit-level information and models to ensure a level-playing field, however, this is arguably required to support effective outcomes in GB balancing markets.

5.13 Further work is required to understand the costs and benefits associated with introducing central dispatch under different wholesale market designs to understand whether implementation with locational pricing would deliver additional benefits compared to central dispatch with national pricing. ESO is currently undertaking analysis to provide insight into the effectiveness of current scheduling and dispatch arrangements and to quantify potential benefits from centralised scheduling (notably the co-optimisation of energy and ancillary services) considered but not monetised within this work.

Market liquidity and access

5.14 The impact of locational pricing on GB forward market liquidity is currently uncertain as it is likely to be influenced by wider market design decisions and the optional use of mitigations designed to manage potential liquidity risks. A common perception is that locational pricing (both zonal and nodal[195]) could reduce liquidity in forward markets and increase the cost and complexity of hedging as market participants would be required to trade with a reduced number of counter-parties within their zone or at their node, as opposed to across the whole market.[196]

5.15 Effective forward trading in a locational market is important in helping market participants hedge future price uncertainty. To facilitate this, jurisdictions with locational pricing (particularly those in the US) have taken steps to mitigate against associated risk and complexity by introducing trading hubs.[197] As discussed in section 2, trading hubs are an aggregation of nodes in a geographic region to create a common point for electricity trading and the pooling of liquidity. This means market participants wanting to hedge do not necessarily need to find a counter-party at their node.

5.16 Trading hubs can be combined with other products (such as FTRs) to help market participants mitigate basis risk and encourage trading between locations.[198] We are not

[195] While liquidity concerns are most often attributed to nodal pricing, they also apply to zonal markets. A recent ACER report proposed improvements to the IEM's electricity forward market, in part to resolve issues arising from insufficient liquidity. See: Electricity_Forward_Market_PolicyPaper.pdf (europa.eu)
[196] As discussed in section 2, increased complexity is partly due to the need to agree on a delivery node (where the energy will physically be injected/withdrawn from the transmission network). Under a national market or a market with large zones, market participants can buy and sell electricity with limited consideration to the physical constraints of the transmission network. In theory, this enables a greater number of market participants to aid price discovery and reduce price volatility.
[197] A trading hub is a subset of nodes over which a price index is calculated as the weighted average nodal price. Liquidity in some US nodal forward markets is reportedly much higher than in most EU member states, except for Germany. See: Eicke A. and Schittekatte T. (2022). Fighting the wrong battle? A critical assessment of arguments against nodal electricity prices in the European debate. An MIT Energy Initiative Working Paper. Cambridge. February 2022.
[198] Market participants with long-term contracts settled at a trading hub remain exposed to the basis price risk, ie the price difference between the contract node and the hub. Financial instruments are commonly used to allow this basis risk to be hedge, with FTRs the most common as they can be designed to pay-out the price difference between two-defined nodes.

aware of any reason why trading via liquid hubs (and market participants managing price differentials between a hub and node via FTRs) could not be used alongside a locational GB market. However, the use of hubs and FTRs would create additional design and implementation requirements and costs and potentially increase some ongoing trading costs.

5.17 Locational pricing with central dispatch could lead to greater competition in the wholesale market by improving market access for smaller participants. With central dispatch, the SO could act as the counterparty for all centralised market trades, which would in theory reduce barriers to entry for smaller parties by providing a simpler route to market. On the other hand, depending on the design, in a central dispatch with self-commitment, the liquidity may reduce as the participation would split between central- and self-commitments.

5.18 The use of the wholesale price as a more accurate reference price for the value of flexibility could also make flexibility-focused bilateral contracts and investing in flexible assets easier. More generally, locational pricing could increase the participation of DSR and DER assets by sending enhanced and accessible price signals to all market participants, rather than only participants that are able to contract with the ESO in the Balancing Mechanism or through ancillary services.

5.19 Some market participants have raised concerns that a perceived increase in complexity with locational pricing (eg when developing or commissioning wholesale market price forecasts) and cost (eg via more granular data exchange with the SO) could create additional barriers to entry.

Market power and gaming

5.20 Implementation of locational pricing could facilitate the use of additional market power mitigation mechanisms to those currently used in the GB pay-as-bid Balancing Mechanism and reduce market participants’ ability to exercise market power and benefit disproportionately from market design. Nodal pricing is likely to deliver greater consumer benefits by significantly reducing the need for re-dispatch and required changes to bidding formats (from centralised scheduling) which could create greater transparency.

5.21 Market power that provides the ability to profitably raise prices above competitive levels exists within national, zonal and nodal markets as assets can exercise market power by virtue of a unique position on the network and/or unique capabilities. Current GB market arrangements incentivise and create opportunities for market participants to operate in ways that are less efficient for the system via:

i. Under existing market rules, generators can choose whether to self-dispatch or make themselves available in the Balancing Mechanism. At times, last minute changes have meant the ESO has had to make the decision to instruct a unit to generate at short notice, further limiting its ability to explore alternatives. Such action contributed to very sharp rises in balancing costs, such as those seen over Winter 2021-22, and Ofgem introducing changes to the generation licence, which will take effect from October 2023.[199]

ii. Increase-decrease ("inc-dec") gaming in which assets profit from network constraints.[200] This can involve generators (and storage assets) located in an import constrained region holding back capacity on the wholesale market and increasing their Balancing Mechanism offers in the knowledge they will be dispatched in the Balancing Mechanism, and generators in front of a constraint decreasing their wholesale bids to ensure they will be compensated for downward dispatch.[201] It can also involve generators inflating their position so the ESO has to decrease it (and compensate the asset) later.[202]

5.22 "Inc-dec" gaming can still take place in a zonal market, primarily within zones rather than between them, reducing the possibility for gaming. Inc-dec gaming can be a serious issue for zonal markets with market gaming, with this a key reason for the transition from zonal to nodal pricing in PJM in 1998[203] and CAISO in 2009[204].

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[199] Winter 21021/22 saw a large increase in balancing costs, with this primarily driven by increased offer prices in the Balancing Mechanism rather than increased volumes having to be purchase by the ESO. Following observations of concerning generators behaviour, Ofgem is in the process of introducing changes to the generation licence to prevent higher than necessary bills for consumers by prohibiting companies from obtaining excessive benefits as a result of their plant inflexibilities. Introduction of SLC20B, the Inflexible Offers Licence Condition | Ofgem

[200] EconStor: Market-Based Redispatch in Zonal Electricity Markets: Inc-Dec Gaming as a Consequence of Inconsistent Power Market Design (not Market Power)

[201] This type of behaviour led to the introduction of the Transmission Constraint Licence Condition ("TCLC") as a standard condition of the generation licence in 2017. The objective of the TCLC is to protect against the exploitation of market power by generators operating behind transmission constraints. Ofgem has recently closed two compliance engagements in relation to a breach of the TCLC.

[202] Strategic behaviour by wind generators: An empirical investigation (warwick.ac.uk)

[203] David Newbery (2011). `Reforming Competitive Electricity Markets to Meet Environmental Targets', Economics of Energy & Environmental Policy, 1(1): 69-82, and William W. Hogan (April 1999),'Restructuring the electricity market: institutions for network systems', John F Kennedy School of Government, Harvard University, hjp0499.pdf (harvard.edu).

[204]Ziad Alaywan et al., 'Transitioning the California Market from a Zonal or a Nodal Framework: An Operational

5.23 A key benefit of nodal pricing (relative to zonal and national pricing) is an intrinsic lack of gaming opportunities as the possibility of inc-dec gaming is removed entirely as constraints are accounted for in market clearing (ie the redispatch stage is limited).[205] Introducing locational pricing with central dispatch could further reduce gaming opportunities as changes to bidding formats (ie move to pay-as-clear and bidding formats differentiating various cost components) offers greater transparency and is easier to monitor.[206]

5.24 A common concern is that locational pricing would provide market participants with greater visibility of constraints, thereby enabling strategically-located market participants to exert a stronger influence on more granular electricity prices. Evidence from jurisdictions with locational pricing indicates that greater transparency of constraints can also make market power easier to observe and any unusual bidding actions easier to regulate. This could be the case, for example, where the presence of locational prices makes it easier to observe whether apparently high prices submitted by certain market participants are being driven by locational or other factors. As discussed in section 2, all US nodal markets have implemented automatic market power mitigations. Were such mitigations to be used in the GB market, this would require the development of new rules, and an associated monitoring framework.

Impact on investments by energy market participants

5.25 Decarbonising the power system will require substantial investment in generation capacity and flexible assets at all voltage levels. REMA is examining the investment challenges associated with transitioning away from an unabated gas-based system to a renewables-based, flexible and resilient decarbonised electricity system. This includes consideration of a range of market and policy interventions that could help ensure we get the scale and variety of investment needed, while maintaining security of supply in the face

Perspective', Available: Microsoft Word - Transitioning the California Market from a Zonal to a Nodal Framework An Operational Perspective (eccointl.com)

[205] For a more detailed discussion see: Graf, Christoph, Federico Quaglia, and Frank A. Wolak. *Simplified electricity market models with significant intermittent renewable capacity: Evidence from Italy*. No. w27262. National Bureau of Economic Research, 2020. Simplified Electricity Market Models with Significant Intermittent Renewable Capacity: Evidence from Italy (nber.org). Gill et all (2023) note the potential for nodal pricing to give rise to new market power opportunities with the example of a generator bidding low in the wholesale market in order to increase the value of their linked FTR Exploring market change in the GB electricity system: the potential impact of Locational Marginal Pricing (strath.ac.uk).

[206] In markets with simple price-quantity bids, deviations from marginal cost can be justified by (undisclosed) start-up and minimum-energy running costs.

of new system challenges and driving competition between technologies to support affordability.

5.26 Market reform as a process could, however, disrupt, delay or increase the costs of planned investments given reduced investor certainty over the future design of market arrangements and what new arrangements could mean for future returns. It could also create potential risks for the financial resilience of existing assets (assuming no arrangements are put in place to limit changes to expected cash flows) as billions of pounds worth of investments have been made with high levels of bank leverage (ie debt-funded by banks) on the basis of current arrangements and an anticipated level of return. Associated risks will need to be managed, regardless of the final REMA outcome, with the potential extent of disruption and investment risk likely to be proportionate to the degree of change adopted.

5.27 The quantitative consumer benefits identified within FTI's assessment can, in part, be attributed to a reduction in producer revenues. This transfer arises from changes to market arrangements that re-balance certain risks away from consumers and towards producers.

5.28 Below we consider further how market participant risk profiles and commercial opportunities could change with the introduction of locational pricing and implications this could have for investment in electricity generation, demand and low carbon technologies. We find that the risk to low carbon investment (and extent to which this increases consumer costs) will primarily be a function of how any transition to new arrangements is managed and broader policies that balance risks and costs between consumers and producers. We note that policies that seek to shield certain market participants from certain risks and price signals can be expected to reduce the consumer benefits of locational pricing.

Locational pricing would change the commercial risks and opportunities market participants face with this influenced by a range of factors

5.29 In any electricity market, risks are typically allocated between consumers and producers. Re-allocating risk (such as increasing market participant risk) can be used to drive certain behavioural changes that can deliver more socially desirable and efficient system outcomes.[207] These efficient outcomes can include improvements (from a consumer value perspective) in the location, scale, sequencing and type of investments coming forward, with this extending beyond the power sector into transport, heat and industry.

5.30 Compared to current arrangements, locational pricing would change the commercial risks and opportunities faced by most market participants. Behavioural changes (in operational and investment timescales) would flow from changes to market arrangements that would alter market participants' exposure to price variability and volume risks, compared to the status quo:

i. Price variability risk – By definition, locational pricing would increase the variability of prices between different locations on the GB network. However, variability at a particular location is likely to be of most interest to individual investors which could rise or fall under locational pricing.[208]

ii. Volume risk – Locational pricing could increase a generator's uncertainty regarding whether they will be scheduled, and what their place in the now-constrained merit order would be. This could reduce certainty over future output and returns. Further, the removal of generators' firm access rights to the entire transmission network (to either a zonal or nodal level) would either reduce or remove the extent to which they are automatically compensated if they are behind a constraint and do not generate.

5.31 The extent to which an individual market participant's risk exposure would increase or decrease would depend upon several factors, including the type of participant (ie generator or supplier), the type of assets they operate (eg wind farm, battery etc) and the location of

[207] An increase in risk for market participants is not necessarily an undesirable outcome as market reform and re-design often uses a re-allocation of risk between parties to drive certain behavioural changes and, in turn, socially desirable outcomes. Risk Allocation and Pricing Approaches (publishing.service.gov.uk). Common risks energy market participants face typically fall into three categories. 1. Market risk, which relates to losses arising from movements in market variables, such as prices or volatility. This risk occurs in all market designs. 2. Regulatory risk, which is the risk that a change in laws and regulations will materiality impact a market. Some degree of regulatory risk is inherent in electricity markets regardless of market design, as the structure of the market is not fixed and may be altered in the future. 3. Implementation risk, which relates to costs and uncertainty directly linked to the process of transitioning from one market design to another. Outcomes could include a delay in new investment, with potential short or long-run impacts on decarbonisation targets and security of supply, and inefficient actions by market participants and initial reductions in liquidity.

[208] For instance, under a nodal design, if prices at a particular node were always expected to be determined by one generation technology, price variability at that location could fall.

their assets (eg whether they are located in an export or import constrained area and the local level of zonal/nodal price volatility).

5.32 The impact of any increase in existing market participants' risk exposure would depend upon factors such as their current capital structure, the flexibility to adapt that structure and the extent to which the capital structures have been tailored to pricing under the current approach. The potential impact on financial resilience of assets would depend on the extent to which cashflows would change under a locational-based system, and the ability of assets to adapt their behaviour to this change without causing financial distress.[209]

Market design decisions will play a key role in shaping the risks market participants are exposed to (or shielded from) and their ability to manage additional risk

5.33 The design of a locational wholesale market, its implementation and how it interacted with wider market policies would shape the extent to which market participants would be exposed to or shielded from certain price signals and risks.

Table 5.1. Common risk mitigation tools in locational markets

Mitigation	Impact
Risk category: price variability	
Financial Transmission Rights (FTR)[210]	- FTRs are a financial product that can help parties hedge against the price differential risks between locations, and reduce their exposure to any potential price difference for a given capacity in a given Settlement Period. This can provide a useful (but often imperfect) hedge against price differentials between two areas when forward trading. - FTRS are commonly used across jurisdictions with nodal pricing, however conventional FTR design in other countries may not be suitable for GB and require further development. - How FTRs are allocated could have a material bearing on the consumer benefits of locational pricing. For example, allocating FTRs to market participants (eg as part of a transition from the current market), as opposed to auctioning, would reduce auction proceeds and shift congestion rents from consumers to the recipient of the free FTRs.

[209] If cashflows under locational pricing methodologies can be expected to vary by more than the current headroom built into the financing approach, and if the capital structure underpinning an asset cannot viably change during the life of the asset, assets may be pushed into a position of financial distress where they cannot meet their debt servicing commitments.
[210] See Section 2 para 2.16 for a more detailed description of FTRs.

Mitigation	Impact
Regional trading hubs[211]	- Regional trading hubs create a reference price from a weighted averaged between several nodes. This can reduce the volatility of prices at more extreme nodes. - Trading hubs can improve liquidity and balance the risk of locational price differences for both generation and demand.
Central scheduling and dispatch design	- With nodal pricing, current self-scheduling arrangements would be replaced by a central scheduling process through which market participants submit offers to the day-ahead and intraday markets for each delivery period of the relevant delivery day. There is greater optionality for zonal pricing (depending on the number of zones), as current self-scheduling arrangements could be maintained for intra-zonal trading if there was a small number of zones. - A well-designed central scheduling process would provide transparency on merit order for dispatch, providing more clarity than the existing Balancing Mechanism, which many market participants often find highly opaque. - This could provide certainty for future investments and clarity on optimal bidding strategy for existing assets.
Risk category: Volume risk	
Legacy rights	- Measures that shield existing investment from the effect of a policy change can range from relatively light-touch measures, eg maintaining existing contracts, to more extreme measures, such as guaranteeing expected revenue streams from previous market designs. - The provision of legacy network access rights could be used as a transition feature to allow existing generators with firm access to the entire transmission network to mitigate increased volume risk. This type of arrangement could be used to reduce risks for existing assets (ie to reduce volatility of cash flows). - Legacy rights arrangements could have significant impact on the consumer benefits of these market reforms as the transfer from producers to consumers would be reduced. A longer-term impact of shielding sections of the market from price signals could also reduce dispatch benefits from locational pricing.

5.34 Jurisdictions with locational pricing often use a range of tools and arrangements (see Table 5.1 above) to help market participants manage market risks on a permanent or transitional basis. As discussed in Section 2, many of these would represent optional design features for a GB locational market. If used, consideration would need to be given to the specifics of the GB energy system, the full suite of options that are feasible, and all would represent additional implementation requirements. Certain options would also be likely to reduce the benefits of market reform.

[211] Section 2 para 2.16 provides an overview of how regional trading hubs can work in locational wholesale markets.

Increasing market participant risk exposure could deliver consumer benefits and costs

5.35 All else being equal, greater risk exposure should incentivise market participants to behave in ways that lead to greater system and consumer value. As set out in Section 4, FTI's analysis has sought to quantify the potential benefits associated with such behaviour change.

5.36 FTI's analysis does not consider how locational pricing could incentivise different capacity mixes to be deployed to reach net zero, which could deliver additional benefits.[212] More cost-efficient decision-making (with regard to the future capacity mix and sequencing of new investment) could arise from strengthening the role of the wholesale market in reflecting complex information important for long-term build (as well as operational) decisions.[213] The scale and range of investment required in capacity assets creates scope for relatively minor efficiencies to deliver material additional consumer savings.[214]

5.37 However, a common feature of the debate on locational pricing in GB is the extent to which increased risk exposure for investors in renewable generation[215] could reduce the total benefits of reform by increasing investment costs, specifically the cost of capital. As the scale of investment in low carbon generation is significant, there is considerable consumer interest in keeping the cost of this as low as possible and the flow of investment as smooth as possible.

5.38 If steps were taken to introduce locational pricing, it would be important to consider ways in which this risk could be mitigated. In practice, several market and policy

[212] The potential impact of this is typically not considered within FTI's analysis as future electricity capacity mix is an exogenous input into the modelling, with the overall generation capacity and technology mix across all three market designs fixed to the relevant FES 2021 scenarios. While FTI's analysis models how the siting decisions of new assets may vary depending on the market design, it does not quantify the potential for different outcomes in terms of the types of assets coming forward and differences in capacity mix under the relative market designs.
[213] FTI note this as a limitation of their analysis that could increase modelled benefits. See Section 4.
[214] In 2021, it was estimated that total public and private investment of £280-400billion is needed in generation and flexible assets out to 2050. https://www.gov.uk/government/publications/net-zero-strategy
[215] Renewables generation (current and future merchant and CfD) is often the focus as: (i) relative to other generation assets, renewables (notably offshore wind) can be viewed as more constrained in where they can site due to planning and seabed leasing assets, (ii) generation assets subject to RAB financing (non-Hinkley Point C nuclear and CCUS) are guaranteed a return on investment and therefore unlikely to be affected by potential changes in price or volume risks, and (iii) interconnectors and batteries could benefit from greater arbitrage opportunities due to additional price and volume risks, with interconnectors floor arrangements providing revenues certainty for debt financing for the first 25 years. However, greater uncertainty over future wholesale prices may be an issue for all generators as locational pricing could increase the complexity of forecasting future wholesale prices due to the increased granularity of wholesale prices and because project prices could be driven by local system changes outside of their control. Some existing risks could also reduce under locational pricing, such as in the case of regulatory risk, which may reduce further under nodal pricing as less intervention is required to balance supply and demand.

mechanisms (see Box 5.1. and Table 5.1.) could be used to define an appropriate balance of risk between producers and consumers and, if required, re-balance risks back towards consumers (eg compared to assumptions in the FTI modelling).

Box 5.1. Potential impact on investment in wind generation in certain locations

Challenges with integrating low carbon generation, in particular large volumes of offshore wind, require difficult decisions to be made (regardless of market design) on the balance of market risks renewable generators should be exposed to and how they compete. Many large new generation assets, particularly offshore wind farms, will locate in parts of the network with relatively low levels of electricity demand. A significant expansion of the transmission network is planned for the next two decades to accommodate this geographically dispersed generation.[216]

Even with significant network expansion, system costs and operability challenges are anticipated to increase. These costs will largely arise from the need to curtail these assets as it would be inherently inefficient and impractical to reinforce the network to enable zero curtailment of those generators, which are likely to schedule for dispatch at very similar times. Locational pricing provides an efficient way to help manage these growing system challenges. However, a prominent concern is that increased price uncertainty for renewable investors could delay wind investment in certain regions and/or increase the cost of these investments, which could impact the ability of government/GB to reach its net zero targets and increase costs for consumers.

The market risks these types of assets should be exposed to is actively being considered as part of REMA. The CfD scheme is the principal mechanism used to reduce or eliminate the market risks investors in low carbon generation can face. Based on current proposals, we expect a large proportion of new, large generators to be supported by CfD-type mechanisms. If locational pricing was introduced in GB, policy and regulatory mechanisms would need to balance reducing investor risk (to encourage sufficient capacity to come forward) against increasing exposure to certain risks and competitive pressures to address the rapidly rising costs of operating a renewables-based system.[217] The impact on merchant renewables investment will depend on where they are/choose to connect to the network.

There is scope for investment policy and market design to work together to bring forward the government's ambitions for renewables investment, while supporting cost-efficient operation and organisation of a renewables-based system. Locational pricing, CfD design, wider investment conditions (eg levels of tax) and increasing coordination and planning of infrastructure build[218] could be designed to work together to appropriately balance risk allocation between investors and consumers.

[216] The Pathway to 2030 Holistic Network Design | ESO (nationalgrideso.com)
[217] Over 2020/21- 2021/22, system balancing costs almost doubled, from £2.6bn in 2021 to £4.6bn in 2022 (12-month rolling period). Transmission constraint management costs represented a significant share of total balancing costs. Constraint costs alone are anticipated to reach approx. £3bn by 2035, even with substantial network investment through the HND. ESO Operability Strategy Report 2023
[218] Reforms to how new infrastructure is planned and built to enable the transition to net zero are discussed in our open letter on strategic transmission charging reform. There are several important interactions between strategic

5.39 It is also important to note that increasing generators' risk exposure would not result in an automatic increase in the cost of capital.[219] As noted by FTI, it is feasible that some of the increased risk producers would face could be mitigated through diversification at a portfolio level.[220] As UK infrastructure is typically funded through capital provided by large, widely diversified global investors, it is reasonable to expect many investors to be sufficiently well diversified either across GB or globally, such that locational pricing would not increase their aggregate risk exposure and, in particular, the systematic risk of any given sub-set of renewable assets (eg offshore windfarms).

5.40 Given the potential for risk mitigation measures (see Table 5.1) and diversification, we see no obvious risk of a significant increase in the cost of capital from locational pricing at a GB-wide level.[221] However, we do acknowledge that a low/negligible impact at a GB-wide level could mask potentially material impacts on certain technologies, financing structures and/or locations. For example, projects that are financed on a project- as opposed to portfolio-basis or any specialist developers that focus on a certain asset type (ie storage) in specific locations.

5.41 Changes to cash flows could also create a risk for existing projects that have invested based on current market arrangements and which have been developed under targeted financing structures. If cashflow profile changes are greater than can be absorbed within the current capital structure, assets may be unable to service their debt costs and be pushed into financial distress. Debt impairments for certain assets may lead to broader risk contagion and so a higher cost of capital in the sector. In addition, higher volatility of cashflow would generally be associated with lower gearing (a higher proportion of equity) within asset financing structures. As debt interest costs can be tax deductible, lower gearing would generally increase the cost of capital within the sector.[222]

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system planning and locational price signals, including: (i) long-term transparent planning of network investment helping investors understand how costs and revenues could evolve, (ii) locational wholesale price signals being used as an input into strategic spatial system planning to help identify areas for asset siting and network reinforcement, (iii) a robust governance structure and methodological approach to re-zoning can support greater investor certainty.

[219] Some market participants, notably storage providers, may actively seek out greater volatility, suggesting that their cost of capital could fall under locational pricing.

[220] See FTI report, section 8 'Impact of changes in risk on the cost of capital'.

[221] We note that FTI's analysis indicates that locational pricing could still deliver material benefits, even assuming for a plausible cost of capital impact.

[222] This follows from the Modigliani-Miller theorems of cost of capital, that in the absence of taxation an investor is indifferent between holding equity in a geared company and holding equity in an ungeared company but with a personal borrowing against those shares. In a world with corporate taxation however the tax deduction on corporate interest payments increases the value of the company. A company with higher gearing will have a greater value for investors because it will pay less tax than if it was ungeared.

5.42 While there is scope for GB to introduce locational pricing in a way that facilitates broader UK energy ambitions, in particular for renewables deployment, this would require careful consideration as risk mitigation measures would most likely reduce consumer benefits. It should also be noted that there is international experience of significant investment in low-carbon generation occurring in jurisdictions transitioning to locational pricing (or increasing granularity), which could help inform this process.

Impact on location of electricity demand and low carbon technologies

5.43 Additional benefits could be realised from new demand and low carbon technologies locating in response to locational price signals. GB electricity demand is anticipated to double by 2050[223], with an increasing proportion of demand coming from flexible sources such as electrolysis, EVs and heat pumps, and energy intensive industries (see Figure 3.1.).

5.44 FTI's modelling assumes no difference in the location of new demand in response to locational price signals. However, electricity costs can be a key factor that new demand customers, such as energy intensive industries, take into account when deciding between locations.

5.45 If wholesale prices were to vary across GB, we can expect new demand customers with sufficient price elasticity and portability to consider options that would see them site in a part of the network with typically lower wholesale prices. This could deliver individual financial savings (via lower annual wholesale costs) and wider system-benefits, eg through lower constraint management costs and reduced need for transmission build in the long-term as lower prices would occur in import-constrained regions[224].

5.46 The potential gains from demand re-siting are more closely associated with large industrial demand for manufacturing and data centres, as opposed to domestic demand, which we might assume is highly unlikely to re-locate based on wholesale electricity prices. A market with locational prices may also give rise to new business opportunities that would be unprofitable at present.

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[223] Delivering a reliable decarbonised power system - Climate Change Committee (theccc.org.uk)

[224] We note Octopus Energy have recently undertaken analysis to consider how large, industrial energy users could save money by locating their operations to make the most of locational prices. Case Study: how locational pricing could save businesses (and everyone) on bills | Octopus Energy

5.47 There are several international examples of demand locating in response to locational price signals, eg in Sweden where access to low-cost renewables in the north of Sweden have led to datacentres choosing to site there preferentially, due to both lower costs and emissions considerations.[225]

5.48 A re-location of new, portable demand assets could also occur on a larger scale if average wholesale prices in parts of GB were lower than in other countries (as indicated by FTI's analysis). This could provide an incentive for new industrial and commercial demand to locate to GB, with any resulting increase in economic activity having the potential to provide wider socio-economic benefits for certain regions in GB, including Scotland, northern Wales and northern England.

5.49 More broadly, locational pricing could influence investment in heat and transport electrification. This could occur at a regional-level (eg strategic decisions on whether to connect a large transport charging hub within a network area) and at an individual house-hold level (eg households in areas with cheaper electricity installing heat-pumps more willingly). Locational pricing could also be a key enabler of efficient investment in electrolytic hydrogen production, enabling this potentially significant source of flexible demand to come forward in a way that maximises system benefits.

5.50 Locational pricing could incentivise hydrogen hubs to locate in export-constrained areas of the network which could reduce the levelized cost of hydrogen produced (via lower wholesale prices). This outcome could also deliver wider system benefits by making best use of electricity which would otherwise be constrained or curtailed in these regions and providing stable baseload demand that could reduce volume risk for nearby renewable generators.

Impact on network and system planning and investment

5.51 The government and Ofgem are reforming the approach to how new infrastructure is planned and built to enable the transition to net zero. The introduction of the FSO will enable a more strategically planned transmission network by taking on an increasingly significant role in strategic network planning and facilitating competition. This includes responsibility for the new Centralised Strategic Network Plan (CSNP) which sets out load-

[225] CBRA, Data centres in Sweden, March 2022. Available: PowerPoint Presentation (hubspotusercontent-na1.net).

related transmission network investment plans to achieve net zero, and also includes advice to government to inform the planning of the wider energy system.

5.52 The recent Electricity Network Commissioner report[226] also contained a list of recommendations, which included a Strategic Spatial Energy Plan, building upon Ofgem's work with government and industry to establish strategic national and regional planning as detailed above. This also included recommendations to unlock and accelerate infrastructure investment; implement reforms to the consenting process; and end delays in network connections to homes, businesses and public services.

Network build could reduce the benefits of locational pricing – but locational pricing could reduce the need for future transmission investment and reduce risks associated with challenging build targets

5.53 Our understanding of future transmission network build-out has progressed since the scenarios described in section 4 were first developed.[227] The ESO will be making further plans for transmission build later this year through the transition to the CSNP to facilitate additional generation, which will need to be taken into account as work on market reform progresses.

5.54 The realised benefits of locational pricing would be shaped by the capacity and design of the future transmission network. All else being equal, and as demonstrated by FTI's LTW (HND) scenario, reinforcing the network to reduce constraints would reduce the benefits of locational pricing.

5.55 The interplay between future network build and the benefit of locational pricing is, however, complex. Locational pricing - largely by making more effective use of existing assets to resolve constraints - could reduce the optimal size of the future transmission and distribution network. Given the scale of investment associated with planned HND and

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[226] Accelerating electricity transmission network deployment: Electricity Networks Commissioner's recommendations - GOV.UK (www.gov.uk)

[227] At the time of creating the model, there was no information on transmission network build beyond the plans under the HND. We note that the model continues to build out transmission network under the respective NOA7 or NOA7 refresh plans, through to 2041.

HNDFUE network upgrades, even a proportionally small reduction in optimal network build could deliver potentially significant additional consumer savings.[228]

5.56 There is also scope for locational pricing to help manage and reduce risks associated with challenging network build targets, both because less new build may be required overall and because wholesale prices would incentivise behaviours that help manage constraints until they can be alleviated, eg storage will be used more efficiently by flowing according to local marginal costs rather than national marginal costs.

Locational pricing could facilitate more efficient system and network planning – but system planning could also reduce some of the re-siting benefits of locational pricing

5.57 As set out in our open letter on strategic transmission charging reform, a more strategic approach to network and system planning could impact the benefits of locational investment signals being sent through locational wholesale pricing and transmission charges. Where system planning approaches and policy interventions become highly prescriptive with respect to location, the less beneficial the locational investment signals sent by locational wholesale electricity prices. This could reduce the potential re-siting benefits often associated with locational pricing. However, even with greater strategic system planning, many assets (in particular smaller flexibility assets) will still have choices about where to locate and incorporate expected locational wholesale electricity prices into siting decisions.

5.58 Locational price signals could play a key role in enabling a system planner to make more transparent, cost-effective and efficient decisions on the siting of new assets and network build, for example by providing new information and increased visibility of constraints.

5.59 Wholesale price differentials between locations, and the frequency and volume of the congestion rent they produce, could provide a more specific signal to build transmission capacity which could be used as part of network development and planning processes to identify the most effective investments at the right time in the right locations.

[228] Changes in asset utilisation driven by operational locational signals could have a material impact on future network investment decisions, and overall a reduction in total network build can be anticipated. However, across GB, some regions could see network reinforcement requirements decrease while network reinforcement requirements in other regions increase.

5.60 These signals could be used to complement existing and new approaches to network planning by incorporating this additional information into decision-making methodologies.[229] The use of wholesale market signals in this way could complement the increasingly dynamic nature of network constraints. Depending on the generation and demand background and level of investment over time, the frequency, volume, and distribution of constrained and non-constrained periods on different parts of the network could change over time. With locational pricing, the wholesale electricity price would reflect these constraints and changing conditions.

5.61 Over time, the aggregate of these signals in the wholesale market could help direct investment in transmission network to manage transmission more optimally, especially in regions with more flexible resources, such as the South Coast which has a high level of interconnection with mainland Europe.

5.62 Electrification of heat and transport is anticipated to make the characteristics of network constraints even more dynamic. In a zonal market, this would most likely create a need to revisit the boundaries of specific zones or all zones to ensure they accurately and efficiently reflect the dynamic nature of network constraints. Based upon international experience, the re-drawing of zonal boundaries (as has happened in almost all zonal markets) can represent a difficult and potentially disruptive process as it creates new winners and losers. Application of zonal pricing in GB would benefit from a robust institutional and governance framework for re-zoning that would create clarity on roles, responsibilities, process and the likely frequency of this process. In comparison, nodal pricing can be largely regarded as a 'fit-and-forget' market style, unless it is expanded to lower voltages which is being considered in some jurisdictions.

[229] Although wholesale price differentials are not sufficient to guide network investment due to the Braess Paradox, where increasing network size can paradoxically reduce performance.

6 Distributional analysis of the potential impact of locational pricing on consumers

Section summary

This section considers how a total pass through of locational prices could impact domestic and industrial electricity consumers across GB.

This section aims to provide an illustrative overview of:

- How consumer response to price changes could impact behavioural patterns and how this may impact consumer bills.
- How different categories of consumers (eg inflexible users, household with low carbon technologies, consumers in fuel poverty, inflexible commercial demand and price responsive demand) could be impacted by locational pricing.
- How the consumer cost savings associated with locational pricing could be distributed between local authority regions.

This analysis, for the spot year of 2035 and against a uniform national price counterfactual, indicates that:

- In most scenarios, the average consumer would be better off compared to the status quo, but more so in the north of GB than in the south of GB.
- For nodal pricing with HND network build-out, some consumers in certain regions could pay £10 a year (in £2021 terms) more for the wholesale component of their bill. This is due to additional network capacity reducing the constraint management savings of nodal pricing, which in other scenarios offset any wholesale price increases.
- Key groups could benefit from exposure to locational pricing such as those in fuel poverty across England, Wales and Scotland and those utilising low carbon technologies, such as EVs and heat pumps. These benefits are greater under nodal pricing than zonal pricing.
- From the domestic consumer viewpoint, the net consumer benefits could be equivalent to an average £56 a year saving (approximately 6% of the electricity proportion of a typical bill based on the current default price cap tariff). We note the magnitude of this £56 a year consumer saving is considerable when compared to other, recent GB power market interventions and reforms.[230]

Introduction

6.1 Ofgem's principal objective is to protect gas and electricity consumers, including having regard to the interests of vulnerable people, by ensuring (for example) that they are treated fairly and benefit from a cleaner, greener environment. While economic modelling commissioned by Ofgem from FTI indicates that locational pricing could deliver very

[230] See Market-wide Half Hourly Settlement, https://www.mhhsprogramme.co.uk/, projected to result in a benefit of £11/HH/annum maximum.

significant aggregate consumer welfare benefits, understanding the potential impact of locational price differentiation on different consumers' energy bills across GB is an important factor in considering feasibility of these market designs and the additional protections and policies that may need to be put in place.

6.2 Locational wholesale prices need not be passed through to consumers under zonal and nodal designs and consumers may only ever be subject to them on an opt-in basis. However, we intend this analysis to study the edge case where consumers are fully exposed to locational prices and so distributional outcomes are of most concern. We have therefore undertaken a distributional analysis, using outputs from the FTI modelling, to gain insight into the potential impacts of locational pricing on different types of consumers.[231]

6.3 For this analysis, we have assumed the illustrative scenario of total pass through of both the zonal and the nodal prices to all consumers. This means that consumers within each zone or at each node would be directly exposed to the price in that zone or node, with no aggregation or consumer protection in place and with no response factored into the results. It therefore represents an extreme version of price pass through that may be impractical or undesirable in practice.

6.4 This section sets out the different approaches and methodologies we have used to assess the distributional impact for GB consumers and the key findings. We also consider the limitations of our approach, and areas where it could be developed further in future.

6.5 FTI modelling assesses the impact of locational pricing on wholesale market pricing, constraint costs, congestion rents and Contract for Difference payments.[232] This can be shown in the waterfall chart below (Figure 6.1). These results were used as the basis for our analysis.

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[231] All assumptions made within the FTI modelling are reflected in the distributional impacts presented.

[232] Constraints management refers to the reduced cost of congestion management due to the reduction or removal of balancing costs in zonal or nodal pricing. Wholesale costs accounts for the higher wholesale costs faced by GB consumers, due to the inclusion of costs which had previously came through the balancing payments (notably constraints and losses). Congestion rents refer to the arbitrage revenues between nodes, and CfD payments accounts for the increase in consumer payments towards CfD to account for the higher top up costs caused by a lower wholesale cost in Scotland.

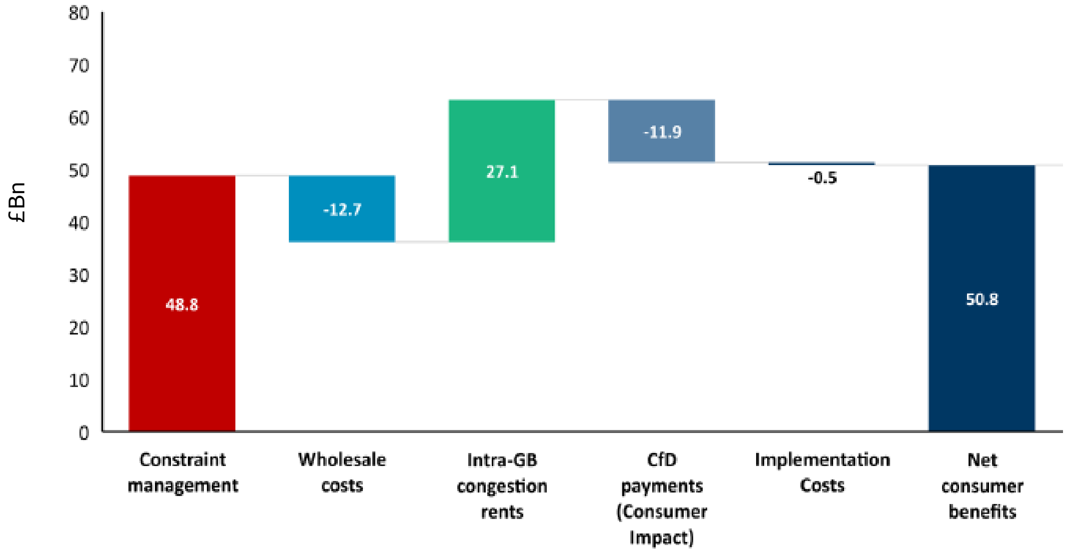

Figure 6.1: Breakdown of consumer benefits for Leading the Way NOA7 Nodal scenario. Source: FTI.

Approach

6.6 The FTI assessment used flexibility assumptions in line with ESO FES assumption for the LtW and ST scenarios. With regard to EV and heat pumps, a proportion of the units optimise demand within each day to minimise cost, consuming when power is cheapest (the share of these is as specified FES 21). Other units follow a fixed hourly demand profile.

6.7 The key feature of our approach is that we have estimated a reference case of what changes to wholesale market arrangements could mean for inflexible consumers (consumers who are less able to change their consumption pattern) which as outlined above will include some adopters of heat pumps and electric vehicles that follow a fixed demand profile. This group must pay the hourly charge that applies at a specific time on their usual consumption volume at that time.

6.8 Our reference case is based on prices being set to the model's hourly prices (ie Real Time Pricing[233]). Any alternatives (eg, static time of use, variable peak pricing, critical peak pricing) would require additional assumptions. By price, we mean the combination of

[233] Time-of-use tariffs – Innovation Landscape Brief (irena.org)

wholesale and constraint costs and not the total unit fixed pence per kwh that would appear in an electricity bill.[234]

6.9 Wholesale prices change hour by hour, as assumed in FTI's model. Box 2.2 highlights the past relationship between constraint costs and balancing costs, how balancing costs have increased in recent years, and what constraint costs are assumed by the ESO in the NOA7 update. As today, any constraint costs in our national and zonal analysis (FTI do not model constraints in the nodal market) will vary between Settlement Periods (half-hourly in practice, hourly in the model) but would be charged on an averaged fixed basis (£/kwh of demand). This is currently set every 6 months based on forecasts and incorporated in BSUoS.[235] In our calculations, the constraint value is the modelled constraint cost for 2035 for the national or zonal model divided by demand. Any reduction in the annual constraint relative to the counterfactual (national) constraint reduces the cost to consumers.

6.10 Our distributional analysis uses three approaches to scope the potential level and distribution of changes to wholesale costs and constraint management within consumers' bills. The first two approaches deal with locational issues, the third approach is based purely on Ofgem's distributional analysis framework. Approach 1 and 2 relate only to wholesale market price ("WMP") impacts and constraint savings, as we assume these impacts would be passed onto consumers.[236]

6.11 To date, the debate on the potential impact on consumers across GB has focused on the potential bill impacts of wholesale prices varying across GB. There is a natural concern that should consumers be exposed, varying wholesale prices across GB will lead to some consumers being worse-off when compared to the status quo. We found that, when considering the potential impact of these market reform options on different consumers, it is important to consider the impact on both wholesale prices and constraint costs. As constraint costs are a hidden element of energy bills, they often do not get as much attention as wholesale electricity prices.[237]

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[234] This is comprised of wholesale costs, network costs (including balancing costs), social and environmental obligations, other direct costs supplier operating costs and margin and taxes, like VAT.
[235] For our analysis we have assumed perfect foresight of these forecasts.
[236] We acknowledge that this is a purely illustrative scenario; in actuality, total and immediate pass through may not be possible as in practice, the retail market settlement would likely prevent the full nodal price being passed onto consumers.
[237] This is particularly the case during an energy crisis that has seen an immense change in wholesale costs, with the wholesale cost component of the Ofgem Price Cap increasing from £373 to £1077 between summer 2021 and summer 2022.

6.12 A reduction in constraint management costs, as highlighted in Figure 6.1 above, represents a major consumer benefit within the aggregate consumer benefits of locational pricing. As discussed in earlier sections, a reduction in constraint management costs is influenced by several factors including market design and network capacity.[238]

6.13 Importantly, to be conservative, we have not included the impact of intra-GB congestion rents or CfD payments in these analyses. Whether and how these are passed through to consumers would be a policy and commercial decision as to how these costs or savings are allocated between consumers and producers. Based on the FTI analysis, passing through congestion rents would represent a further saving to consumers. Like constraint costs, they are volumetric, and could be used to smooth distributional consequences. The additional CfD costs would reduce consumer benefits, but as demonstrated in the FTI results, should not outweigh the intra-GB congestion rents.

Box 6.1 Approach to the distributional analysis

Approach 1. Impact on inflexible users - no price response

This approach uses DESNZ consumption data by Local Authority District ("LAD") and Elexon profile information to help identify whether inflexible users will save under locational pricing. We consider the consumer as a passive recipient of the real-time zonal or nodal price combined with the constraint saving, ie, the consumer receives the cost signal but does not change their behaviour in response. Results are for specific consumer types in each LAD. The benefit of this approach is that it establishes a clear initial reference case for potential consumer impacts.

Approach 1 considers the impact on inflexible users, households with low carbon technologies, commercial demand and the overall impact on fuel poverty in England and Scotland.

Approach 2. Building in price response

This approach uses the same domestic user groups as Approach 1 but builds in a consumer response to costs to investigate if, all else being equal, the change in costs within an area might lead to increased or decreased consumption in a specific period. In allowing for some response to price, this is much closer to a real-time pricing model that has often been discussed in electricity pricing academic literature and implemented in some European countries (eg, Estonia, Latvia, Spain, Slovakia, Slovenia and Bulgaria).

[238] In the FTI modelling, constraint management savings over the indicative 15-year modelling period (2025-2040) range from £13.2-48.8bn. While network investment is regarded as a way to reduce constraint costs to consumers, the cost of network build is recovered from consumers via network charges. Technically, but not considered in this analysis, any reduction in transmission network build associated with the introduction of locational pricing would also represent a consumer benefit over and above those identified to date in the FTI modelling.

Approach 3. Ofgem-specific Distributional Assessment Framework

Ofgem has developed a distributional tool to investigate the impact of policies on vulnerable groups and 13 existing consumer archetypes, thereby allowing Ofgem to compare policies using the same framework. It assumes that there is a fixed level of annual consumption which is a limitation when a fundamental part of the aggregate modelling is changing profiles in response to locational signals.

6.14 For this analysis, Approach 1 and 2 assume the illustrative scenario of total pass through of both the zonal and the nodal prices to consumers. This means that consumers within each zone or at each node would be directly exposed to the price in that zone or node, with no aggregation, shielding, or consumer protection in place. It therefore represents an extreme version of price pass through that may be undesirable in practice.[239]

6.15 In practice, any differentiations in wholesale prices between different areas can be reduced through market design or through suppliers themselves choosing to apply hedging strategies that would enable them to offer a single WMP tariff across the country. Alternatively, in jurisdictions like Ontario, inflexible load receives a zonal (weighted average) price and the option to 'opt-in' to a nodal price. There are also currently untested approaches that could be designed where consumers could choose to be exposed to the marginal half hourly cost of electricity (which is desirable for economic efficiency) while maintaining a uniform national price over the year (which may be desirable in equity terms). These different approaches would change the overall consumer impact.

Method underlying Approach 1 and 2

6.16 For a single spot year (2035) hour by hour price data was extracted from the FTI model for the national WMP, zonal WMP and nodal WMP. The year 2035 was selected as it is the current target year for electricity system decarbonisation.

6.17 Our counterfactual is the WMP and constraint per unit in the National model. In LTW NOA7, the national constraint cost is circa £12/MWh and in LTW HND it is £8/MWh. Our tested factual scenarios are the zonal[240] wholesale market prices plus the associated intra-

[239] Our review of international practice found that there is a wide range of ways in which locational prices could be passed through to different consumers. Alternative options have not been modelled. Further work would be required determine the optimal level of potential pass through.
[240] The FTI model is based on transmission sub-stations. Just over half are demand nodes (associated with Grid Supply Points and a Grid Supply Point Area (GSPA)). A set of Grid Supply Point Area between significant transmission boundaries constitute a zone used within zonal analysis.

zonal constraint costs (circa £6/MWh in LTW NOA7 and £4/MWh in LTW HND), and the nodal wholesale market prices, which does not have any constraint costs.

6.18 DESNZ provide a time series of electricity consumption in each of the 360 Local Authority Districts (LADs) by profile class (PC1, PC2 and non-domestic[241]). Demand nodes and Grid Supply Point Areas (GSPAs) were mapped onto LADs. In LADs with several nodes (eg, Highlands) an average was taken of WMP in each hour. In a GSPA covering several LADs, nodal results were scaled by LAD consumption to get an area estimate.

6.19 For PC 1 and 2, we mapped LADs to an associated GSPA node. Impacts were then measured, by multiplying the consumption at the LAD[242] by the cost associated with the node or zone. The National Cost is used as a counterfactual so the difference between the national and nodal/zonal outcome is calculated.

Key Findings

6.20 Our results can be summarised as indicating that the average consumer in the majority of scenarios would be better off compared to the status quo:

- When compared to the counterfactual of national pricing, all typical consumers under NOA7 network build-out potentially save under both zonal and nodal pricing. This is also the case for zonal pricing with HND network build. This is because constraint management costs decrease more than any potential increases in wholesale prices. The amount consumers save is dependent on location – those in areas where supply outweighs demand (eg, North Scotland) would be on average around £60 a year better off under nodal pricing, whilst those in more Southern areas around London could be around £10 better off.

- For nodal pricing with HND network build-out, most consumers benefit, with some consumers (using storage heaters) in certain regions potentially paying £10 a year more for the wholesale component of their bill. This is due to additional network capacity reducing the constraint management savings of nodal pricing, which otherwise off-sets wholesale price increases. Our analysis does not consider the

[241] PC1 – Domestic Unrestricted Consumers. PC2 – Domestic Economy 7 Consumers.
[242] Stacked electricity consumption statistics data - GOV.UK (www.gov.uk),

consumer bill impact of the additional network build, ie increase in network charges.[243]

- As most consumers are better off[244], the analysis indicates that most inflexible or disengaged consumers (both domestic and non-domestic) would be able to benefit from nodal or zonal pricing. Further, if consumers do respond to prices, as predicted by economic theory, consumption may increase and, with it, welfare. However, those who typically use more electricity (eg, those with heat pumps or electric vehicles) stand to save more due to the volumetric nature of the benefits. Evidence also indicates that nodal pricing could be beneficial to English and Scottish households in fuel poverty, relative to the status quo of national pricing. An equivalent calculation for Wales could not be completed because of data limitations at the time of analysis.

- Depending upon the scenario, our results show potential savings for all or most consumers, relative to the counterfactual of national pricing. This should, however, not be interpreted as indicating that complete exposure is the optimal outcome for either zonal or nodal pricing. There are multiple options for passing through costs from the wholesale to the retail level, and further work is needed to determine what would lead to the highest consumer or socio-economic outcome.

Limitations

6.21 Below we highlight some limitations of our analysis:

- The approach concentrates on inflexible users. This means that we are not capturing the impact on many future consumers. No behind-the-meter generation is accounted for in this analysis, as such users are flexible.
- Our analysis does not consider the potential consumer bill impacts of incremental network investment, either a potential reduction in network investment (and, therefore, the network charging component of the bill) from these market designs or the increases in network charges from additional investment spend

[243] Network costs typically represent about 20% of an electricity bill. Ofgem Breakdown of an electricity bill, available at: Data portal | Ofgem
[244] Meaning all consumers in the nodal and zonal LTW NOA7 and zonal LTW HND scenarios.

under the HND scenario. Should locational pricing reduce the need for network investment, this would ultimately lower consumer bills further.

- The use of the counterfactual (national pricing) will influence perceptions of the level of potential savings. There could have been counterfactuals where total pass through of zonal or nodal pricing would lead to negative outcomes in comparison, such as if we allowed for partial pass through or aggregated price signals.
- Our analysis focusses on the FES 21 LTW scenario. In 2035, this assumes that the bulk of consumers will be in a position where they are optimising their electricity use. No insight is provided into the ST scenario, also used by FTI in their model, which might have different benefits in their distributional consequences.
- We assume that any impacts will be reflected at the LAD level. The choice to analyse at the LAD level was a reflection of data availability. An analysis at higher or lower granularity would present a different picture but create additional challenges.
- In using the average consumption figures for local authorities, we do not reflect the significant variations in income level. As an example, certainly within London Boroughs there can be significant variations that this will not capture.
- We have used the assumed Elexon profiles of demand for EVs and heat pumps.

6.22 Our results provide insight into the potential impact from an illustrative scenario based on inputs from FTI's modelling. These results do not provide a definitive view on the likely impact of fully exposing consumers to locational prices as they only show the results from a specific FTI modelled scenario in 2035.

Results - Approach 1: Impact on Inflexible Users

6.23 This section considers the potential impact of locational pricing on consumers (Profile Classes 1 and 2[245]) that are unable or unwilling to change their demand profile in response to locational prices, including domestic households that continue to follow current usage patterns. We also analyse business consumers that are in Profile Classes 3-8.[246] For all

[245] Broadly, those on Domestic Standard meters would continue to have morning and evening peak consumption (Profile Class 1) and households using electric storage heating (Profile Class 2) have a similar day-time pattern but with high overnight consumption. Profile Data was sourced from Elexon.

[246] An electricity profile class refers to the category of energy consumption that your business falls into. Domestic

Profile Classes, we assume that there is no increase in the volume demanded, eg, if a household consumes 2,700kWh before any policy change, it will consume the same amount afterwards.

6.24 We firstly consider PC1 and PC 2 consumers across a set of 8 results.[247] Our analysis shows that:

- Across all NOA7 results and zonal HND, **all consumers (PC1 and2) benefit compared to the status quo**. This is because, in all local areas, the savings from a reduction in constraint management costs outweigh any potential increases to wholesale costs.
- **There is not an even distribution of benefits across consumers, with the extent to which consumers benefit varying by location**. Figures 6.2, 6.3 and 6.4 below show the range of savings across GB for a range of consumers. For presentational reasons, these Figures show the range of extremes for the distribution of savings experienced across GB (nodal LTW NOA7/Figure 6.2 vs zonal HND/Figure 6.3 vs nodal HND/Figure 6.4[248]):
    - In Figure 6.2, the yellow/orange areas save only slightly from nodal pricing, at around £3/HH annually. In Northern mainland Scotland annual savings could be as much as £68/HH. In contrast, under zonal there is a narrower range of savings in England and Wales of as low as £1.70/HH, but again stronger savings in Scotland of around £27/HH.

6.25 It has been pointed out earlier that direct pass though is a strong assumption. Nevertheless, if it occurs, policy consideration would have to be given to the potential variation in savings and whether, for example, they are counter-balancing network charges.

maximum demand consumers fall into the categories of 05-08; businesses of a certain size need to measure their energy load and their usage at peak times. Businesses that sit in this profile class can measure their maximum demand through the peak load factor (LF). Profile classes 3 and 4 (E7) refer to small businesses with low energy usage.

[247] A set of 8 results is created by two possible locational pricing variants – zonal and nodal pricing - and two background scenarios (LTW with NOA7 and HND network-build out).

[248] To note, for Figure 6.4 (Nodal NOA7 + HND) the scale changes slightly to reflect that some consumers will now face a cost instead of a benefit.

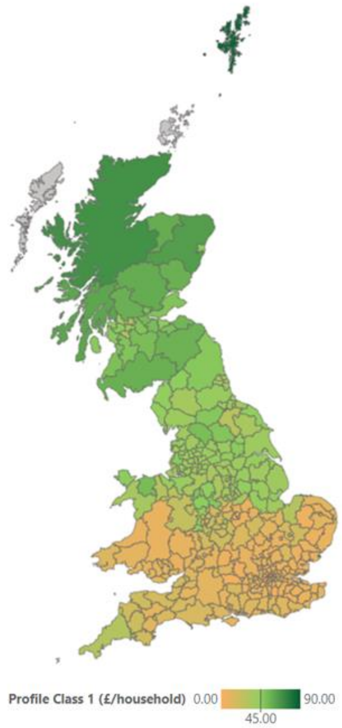

Figure 6.2: Map of average savings by Local Authority- Nodal LTW NOA7 (PC1). Source: Ofgem distributional analysis.

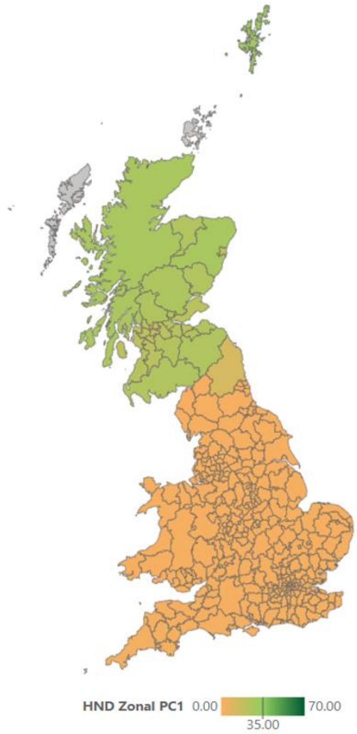

Figure 6.3: Map of average savings by Local Authority- Zonal LTW HND (PC1). Source: Ofgem distributional analysis.

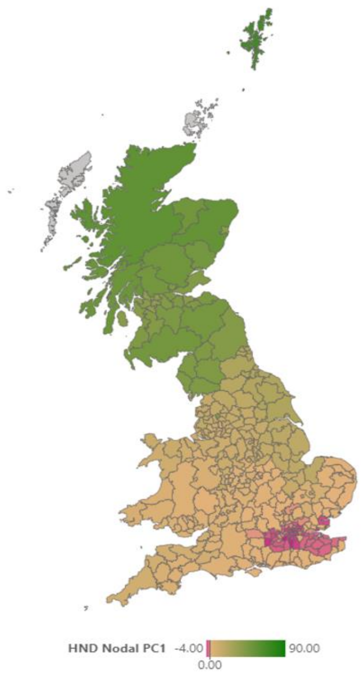

Figure 6.4: Map of average savings by Local Authority- Nodal LTW HND (PC1). Source: Ofgem Distributional Analysis

6.26 The results of different scenarios on potential savings are presented below in stock diagrams. The green spot is average LAD result (potential saving per household), top and bottom of the bars are consumer savings for the typical consumer in the LAD with the maximum potential saving and minimum saving respectively.[249] Below we show a range of results for 3 of our scenarios. We have used different vertical axes for PC1 and PC2.

6.27 Figures 6.2 and 6.3 show positive impacts for all areas for PC 1 and 2, although by varying amounts:

- The potential savings for zonal pricing in particular, compared to the national counterfactual, are relatively low for a number of zones.
- Annual savings from nodal pricing in the LTW NOA7 scenario and zonal pricing with HND buildout are lower in the southern regions. This is because these regions face an increase in wholesale costs which reduces the constraint management savings; in northern regions, reductions in the wholesale price are added to constraint management savings to deliver greater consumer savings.

6.28 The exception to all consumers benefiting is the LTW HND scenario. Figure 6.7 shows that the potential benefits of nodal pricing reduce for all consumers in the event of greater network buildout as the constraint management savings of nodal pricing are lower. Whilst the average consumer in all zones would experience a small benefit, some consumers in specific LADs within the Midlands(GB5), the Central zone (GB6) and the South Coast zone (GB7) could potentially pay more. For instance, consumers with legacy storage heating systems (PC2) and the same consumption profile as today, paying up to £10 p.a. in Westminster, Southwark, and Windsor and Maidenhead. However, as noted in previous sections, if network build-out was optimised to locational pricing, we would expect there to be additional savings in network costs with nodal pricing.

6.29 The charts show the range between the maximum nodal/zonal saving and the minimum nodal/zonal saving in each area. In chart 6.6, the range within zones is due to the differing levels of consumption between LADs.

[249] Under a Zonal System it is assumed each opting in consumer within a LAD will face the same zonal price. However, each LAD within a zone will have a different level of consumption, which is why the chart shows a range of results.

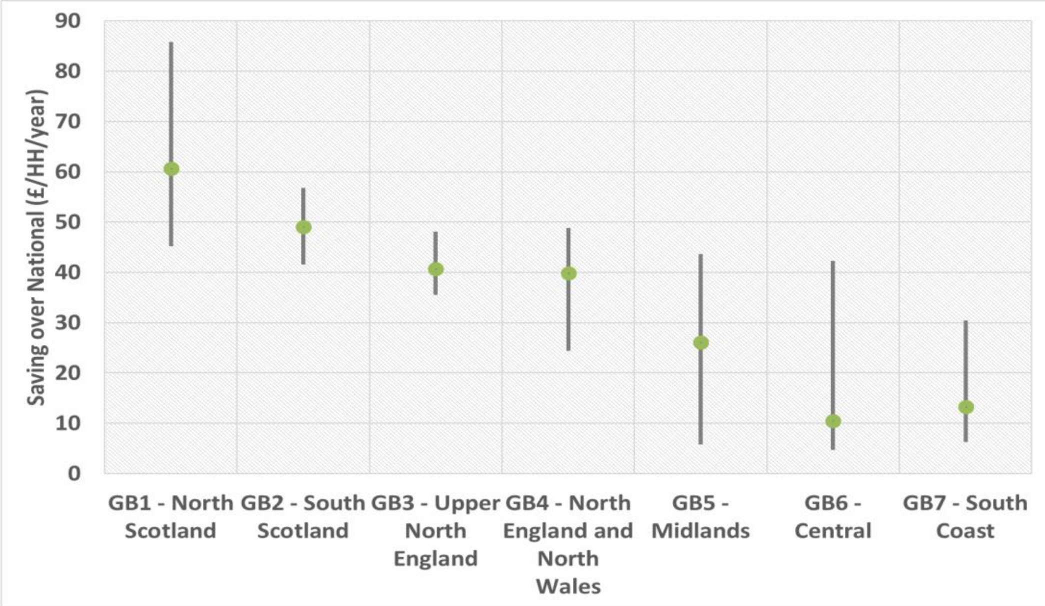

Figure 6. 5 Nodal LTW NOA7 PC 1 (equivalent to Figure 6.2). Source: Ofgem distributional analysis.

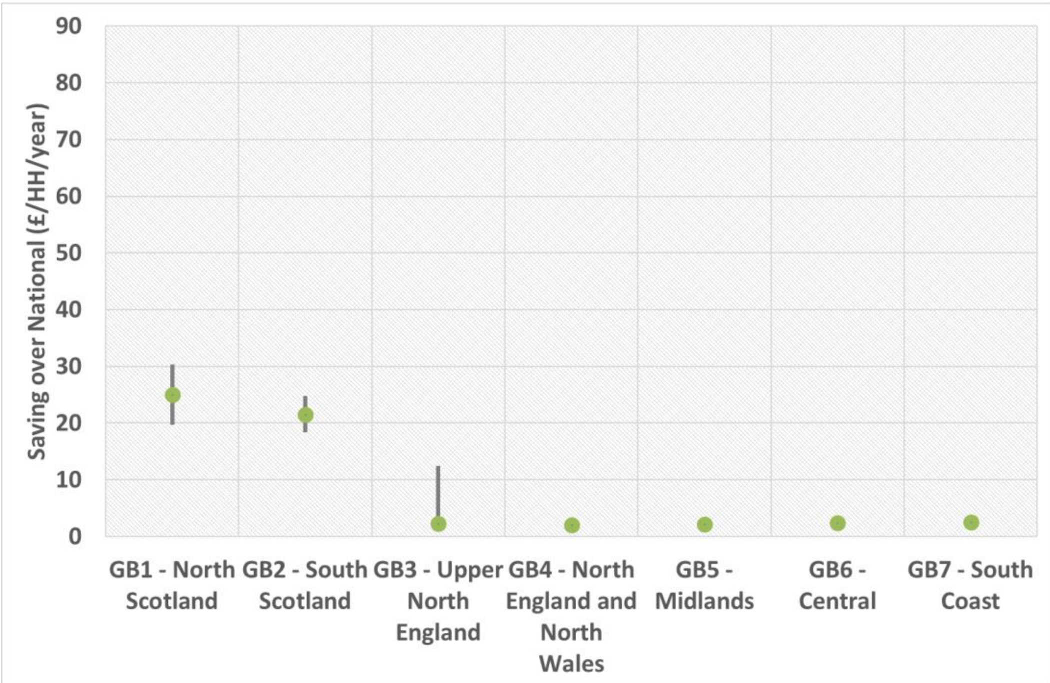

Figure 6.6 Zonal LTW HND PCI (equivalent to Figure 6.3). Source: Ofgem distributional analysis.

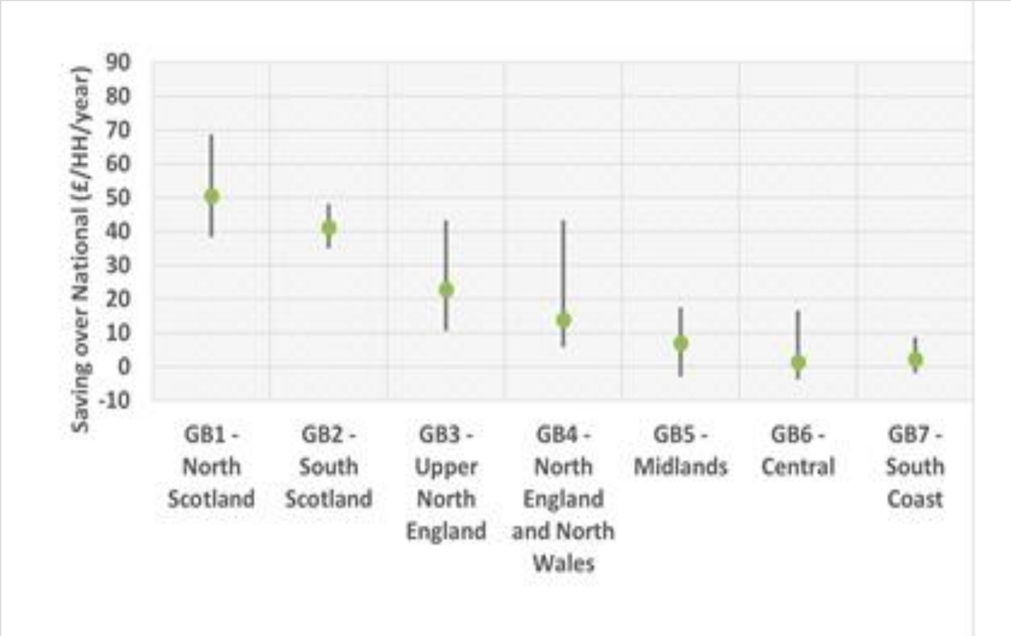

Figure 6.7. Nodal LTW HND PC1 (equivalent to Figure 6.4). Source: Ofgem distributional analysis.

Households with low carbon technologies

6.30 This section examines the potential impact on households with low carbon technologies, such as electric vehicles and air source heat pumps, but that do not use them in a flexible way. With locational pricing, we would expect the system benefits of flexibility to increase (as flexibility would no longer work against system needs). If these benefits were passed through to consumers, we could expect inflexible consumers to benefit less or sometimes lose out.

6.31 For PC1, we have added the electricity demand of electric vehicles (non-smart charged) and an air source heat pump profile. To PC2, we have added an electric vehicle with non-smart charging. As the savings of locational pricing are volumetric – meaning that the more electricity you use, the greater benefits you will receive – the results show that these high-load households could save more than average if they opt-in to nodal pricing, as shown in Figure 6.8. A similar pattern is found in the zonal analysis, but the average savings are about half those shown below.

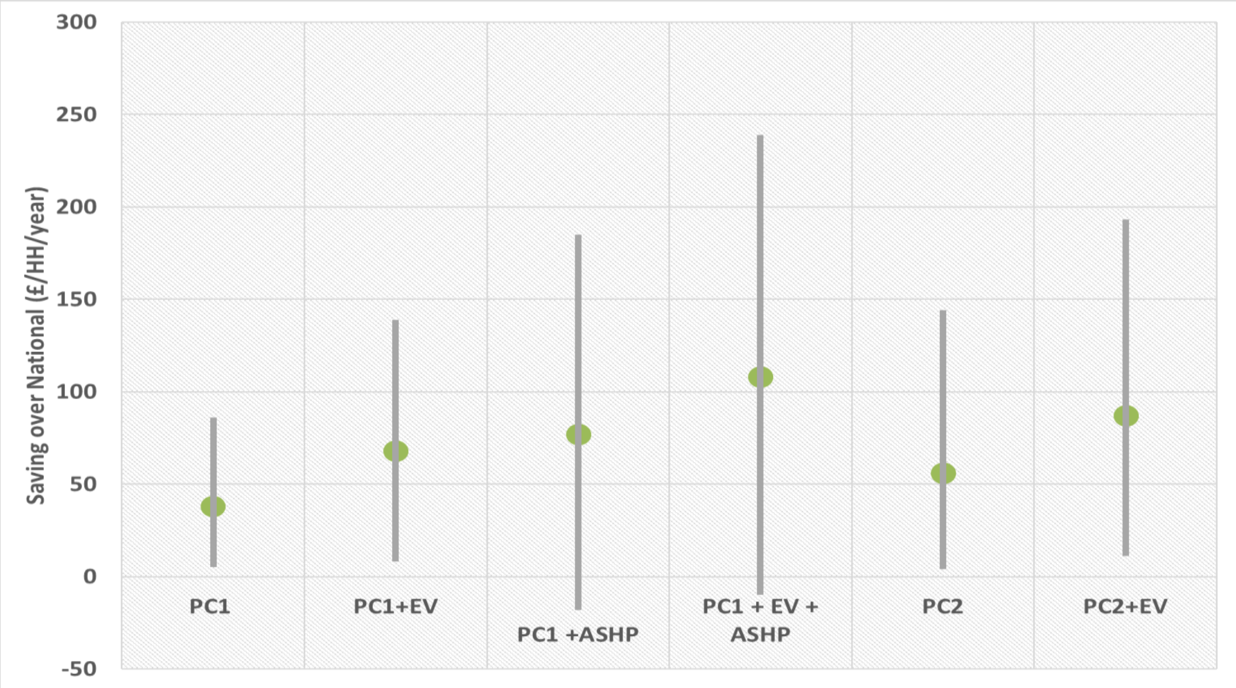

Figure 6.8: Range of Savings for Nodal Consumers with Low Carbon Technologies in LTW NOA7. Source: Ofgem distributional analysis.

6.32 If a household has a fixed hourly demand profile for heat pumps this gives rise to a slight negative impact in the Midlands, Central England and the South Coast. This indicates that without flexible charging – or consumer response to a price signal sent by the wholesale price – some consumers hypothetically face higher costs from the use of certain low carbon technologies.

Fuel Poverty

6.33 Our analysis includes consideration of the potential implications of full exposure to locational pricing for households that must spend a high proportion of their household income to keep their home at a reasonable temperature. Recent data on fuel poverty highlights the change that occurred between summer 2022 and summer 2023, with a significant growth in fuel poverty in some areas due to the energy prices crisis (Figure 6.10 below).[250] Visual comparison of Figures 6.9 and 6.10 shows some correlation between areas which save the most in our nodal LTW NOA7 results and areas that are particularly impacted by fuel poverty.

[250] Public First, Energy Bills and Fuel Poverty, Sept 22.

6.34 This indicates that direct pass through of locational signals in a nodal market has the potential to be beneficial to English households in fuel poverty, relative to the status quo. This relationship is shown in Figure 6.11 below for English consumers; the chart can be interpreted as showing a weak correlation, or as two clusters of results, but both show more positive benefits for consumers than negative. Similar analysis was conducted for Scotland and the same relationship was found under nodal pricing. This suggests that if nodal pricing was fully passed through, it could help to reduce fuel poverty, and would contribute to rather than work against fuel poverty goals.[251]

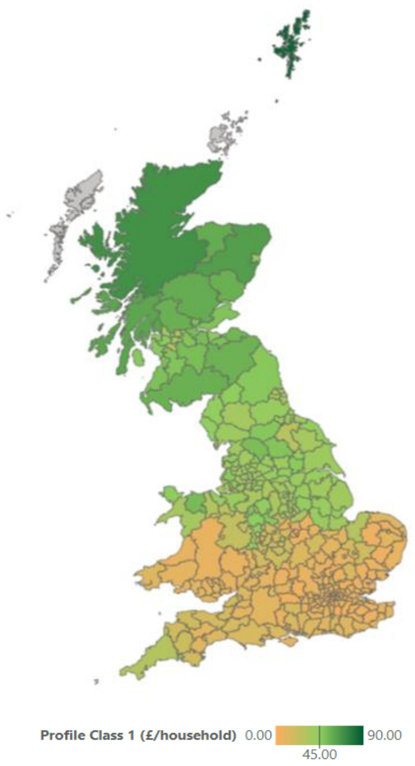

Figure 6.9: Map of Prices by Local Authority – Nodal LTW NOA7 (PC1). Source: Ofgem distributional analysis.

[251] Fuel poverty is defined differently across the UK. Definitions of fuel poverty can be found here: [How fuel poverty is measured in the UK - Office for National Statistics (ons.gov.uk)]

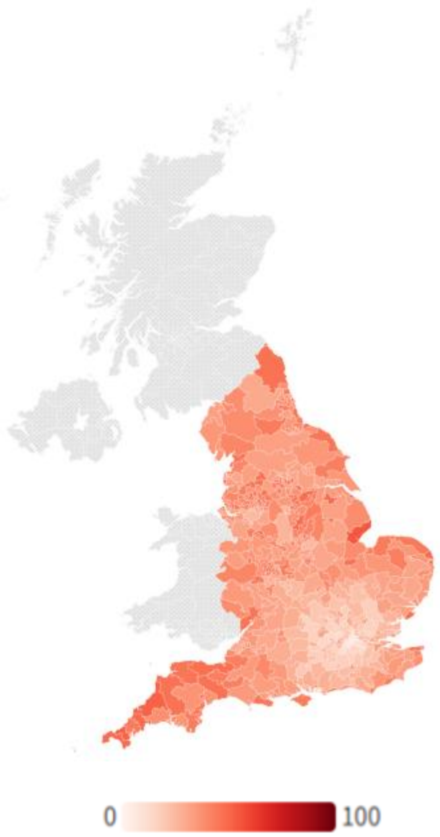

Figure 6.10: Distribution of households in England in Fuel Poverty (%, Public First)

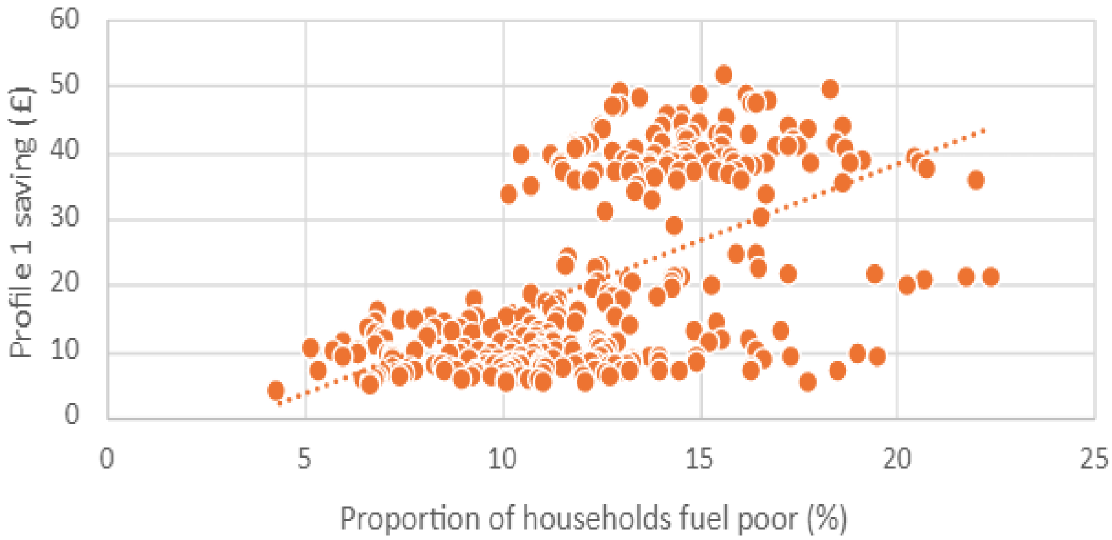

Figure 6.11: Relationship between fuel poor and PC1 in Nodal LTW NOA7. Source: Ofgem distributional analysis.

6.35 There is a similar correlation for the LTW HND nodal scenario, but savings are lower. A weak relationship was found between savings under zonal pricing and fuel poverty for either England or Scotland. In effect, as all locations within a zone face the same price, the only variation is driven by consumption differences and for the dataset the differences between zones are small.

Inflexible commercial demand

6.36 Our analysis also tests the potential impact on non-domestic demand, again assuming no price response. Table 6.1 shows the impact of nodal pricing on specific areas selected to include important regional centres and some East/West variation within the range of GB zones on different profile classes. To note, Profile Class 3, associated with microbusinesses, shops and small commercial premises, has not been included in the table, but has pro-rata results to Profile Class 4 (which is the same description with E7 meters). A load of 25MWh would be associated with a high use commercial site and 5,000MWh would be associated with an industrial site. In these terms, savings in GB5, 6 and 7 are unlikely to be consequential.

Table 6.1: £ Savings relative to the national counterfactual for different loads under Nodal LTW NOA7. Source: Ofgem Distributional Analysis.

Area	Zone	Load (MWh)				
		25	5000	5000	5000	5000
		PC 4	*PC5*	*PC6*	*PC7*	*PC8*
Dundee City	GB1	417	80,660	80,408	79,723	80,081
City of Edinburgh	GB2	414	80,180	79,932	79,254	79,614
Blackpool	GB3	324	63,741	63,921	63,716	64,294
Hartlepool	GB3	332	65,035	65,223	64,966	65,545
Liverpool	GB4	302	59,620	59,802	59,606	60,105
Telford and Wrekin	GB5	140	30,878	32,497	33,122	33,993
North Lincolnshire	GB4	324	63,906	64,049	63,866	64,370
Birmingham	GB5	134	29,639	31,290	31,935	32,821
Cardiff	GB6	67	18,067	19,170	20,067	19,962
Exeter	GB7	94	24,330	25,288	26,203	25,741
Ealing	GB6	18	8,797	10,086	11,106	11,050
Medway	GB6	37	12,729	13,863	14,778	14,473
Portsmouth	GB7	64	18,577	19,654	20,653	20,229

6.37 The results for nodal LTW NOA7 show that non-domestic demand in all areas would save, although by varying amounts. Compared to the status quo of national pricing, Table 6.1 indicates that industries in some locations could save significantly if they were exposed to nodal pricing, even if they had inflexible demand patterns. Depending on their location, non-domestic energy users could see a significant reduction in electricity costs due to the impact of nodal pricing on constraint management payments and wholesale prices. This analysis and the FTI analysis do not consider the potential additional benefits associated with exposure to locational prices incentivising industry to locate where they could take advantage of lower wholesale prices.

6.38 This pattern of benefits and costs for non-domestic users match the pattern for domestic users in all scenarios; however, the range of benefits differs. For example, in LTW HND scenario with zonal pricing, the pattern that exists for domestic consumers also occurs, ie, all non-domestic consumers benefit but there are minimal savings in England and Wales). For LTW HND with nodal pricing, there are some who could face slightly higher bills.

Results - Approach 2: Impact with Price Response

6.39 The FTI analysis models demand side response ("DSR") as a technology participating in the wholesale market. For both heat pumps and electric vehicles, a proportion of demand optimises and the remainder has the appropriate fixed hourly demand profile. The proportions are defined within the relevant 2021 FES scenario.[252]

6.40 An alternative view of consumer behaviour we are considering is that they deliver a conventional response to price, ie, they will use less when energy costs more. In further calculations we include and use a conservative elasticity estimate of −0.1,[253] which assumes that an increase (or decrease) in price would lead to a small reduction (or increase) in demand.

[252] Under the FES21 LTW Scenario, by 2040 residential and industrial demand side response becomes the largest source of flexibility, providing up to 59 GW.

[253] See Pellini, E. (2021). Estimating income and price elasticities of residential electricity demand with Autometrics. Energy Economics, 101. https://doi.org/10.1016/j.eneco.2021.105411

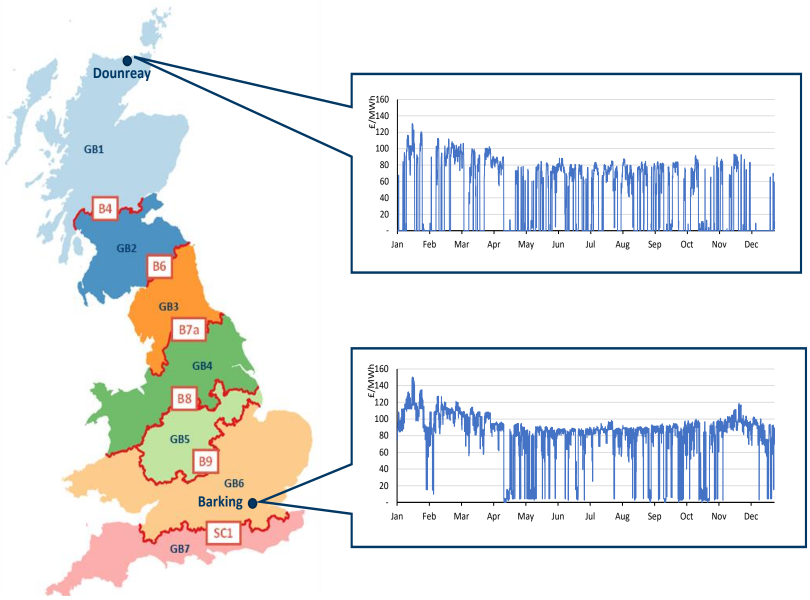

Figure 6.12: FTI's Hourly Price Profiles at Selected Nodes in 2025 (LTW NOA7 Scenario). Source: FTI.

6.41 As hourly nodal or zonal prices will deviate from the national price, demand in the hour will decrease if the nodal/zonal price is above the national and increase if it is below. Some of the wholesale price movements can be quite large at specific times as highlighted in Figure 6.12 from FTI's report and each price-series will be frequently moving relative to the others (ie, the hourly price profiles across different regions may reflect different consumption patterns).

6.42 Our analysis included consideration of whether this would increase consumption or decrease it. Using Ayr in Scotland as an example, electricity prices would decrease in a nodal market design and in many time periods would be virtually free. In this case, consumption increases from 3,200kWh to 4,600kWh per household over the year based on the demand function characteristics. This is a large percentage increase in demand. However, when we prevent any further demand response below 1p per kWh, ie, assuming that for consumers such a saving would be indiscernible and so would not elicit any further demand response, consumption increases by a more modest 247kWh over the year.

6.43 All nodes across GB could see a potential increase in consumption ranging from 94kWh to 387kWh per household in nodal LTW NOA7. This is because all areas are obtaining cheaper electricity, thereby enabling more electricity to be consumed for greater comfort and utility. This could lead to better outcomes for consumers in terms of supporting greater use of electricity for domestic heat and transport demand. For some consumers, lower prices could lead to a greater incentive to invest in technologies that would use more electricity, such as electric vehicles or heat pumps, encouraging decarbonisation and the switch to electricity. For example, a United States study has found, amongst other factors, that there was greater adoption of heat pumps in areas with low electricity prices.[254]

Results - Approach 3: Ofgem Distributional Analysis Framework

6.44 The Ofgem Distributional framework[255] is often applied to policies that are more immediate in impact than the introduction of locational pricing. The results below show the likely impact when the savings are simply divided equally across GB households – this does not require locational prices to be passed through to consumers and so we do not assume any geographic differences in standing charges or variable rates.

6.45 The consumer benefits figure as presented by FTI's modelling results was converted into Equivalent Annual Net Benefits (EANB) using the stated 16-year period (2025-2040 inclusive) and a discount rate of 3.5%.[256] This saving was then spread across household consumers (roughly 40% of all final consumption) and divided by the number of households (26.4 million). This gave the equivalent saving per household per year. We are not counting any indirect benefits from consumer goods and services that might be produced more cheaply in other sectors.

Table 6.2 : Ofgem Distributional Analysis Framework Results. Source: Ofgem Distributional Analysis.

Scenario	Consumer Welfare, £bn	EANB, £bn	Domestic share, £bn	£ per HH per year (mean)
Nodal LTW NOA7	50.8	4.20	1.65	56
Nodal LTW NOA7 (Constraint management & wholesale price only)	36.1	2.98	1.17	40

254 The Economic Determinants of Heat Pump Adoption | NBER

255 Impact Assessment Guidance | Ofgem

256 The Green Book applies a standard discount rate of 3.5% per annum to future benefits and costs. The Green Book (2022) - GOV.UK (www.gov.uk)

Scenario	Consumer Welfare, £bn	EANB , £bn	Domestic share, £bn	£ per HH per year (mean)
Nodal LTW HND	34.2	2.83	1.11	38
Nodal ST NOA7	28.0	2.32	0.91	31
Zonal LTW NOA7	30.7	2.52	1.00	34
Zonal LTW HND	18.7	1.55	0.61	21
Zonal ST NOA7	15.2	1.26	0.49	17

6.46 The above results are all based on uniform and complete pass through of consumer costs and benefits. Table 6.2 shows there to be material consumer benefits associated with locational pricing, regardless of granularity of locational pricing, network build or FES scenario. As expected, savings are greatest for nodal LTW NOA7, with total pass through of congestion rents and CfD additional payments leading to an average of a £56 reduction in annual household bills. When congestion rents and CfD payments are not passed through, to provide a degree of consistency with the earlier approaches, the mean household bill is reduced by £40 per annum.

6.47 Distributional weighting was also applied to the above results. The basis for distributional weights is the economic principle of the diminishing marginal utility of income. It states that the value of an additional pound of income is higher for a low-income recipient and lower for a high-income recipient. When equity weighting is applied, some poorer households could have savings approximately five times as high.

6.48 Ofgem's Distributional Framework also includes consumer archetypes. Again, as savings are related to volumes, the archetypes with the highest electricity consumption (including several off-gas archetypes) have the potential to gain the most. The results in Table 6.3 do not take into account the geographical spread of these archetypes.

Table 6.3: Ofgem Consumer Archetypes – Impact of nodal LTW NOA7 (Constraint Management and Wholesale Impact). Source: Ofgem Distributional Analysis.

Archetype	Description	Average Savings per household (£)	No. Households (m)	Total Savings (in £m)
A1	High incomes, owner occupied, working age families, low consumption	37	2.8	103
A2	High incomes, very high consumption, solar PV, environmental concerns.	57	2.9	165
B3	Average incomes, retired, no mortgage, electric vehicles, environmental concerns, late adopters.	42	3.7	155
B4	High incomes, part-time, high consumers, flexible, environmental concerns.	47	2.3	109

Archetype	Description	Average Savings per household (£)	No. Households (m)	Total Savings (in £m)
C5	Very low incomes, single pensioners, prepayment meters, disconnected	30	1.9	57
D6	Low income, disability, fuel debt, prepayment meter, disengaged, social housing, BME households, single parents.	45	1.5	70
D7	Middle aged/pensioners, disability, above average incomes, high consumers.	48	1.2	57
E8	Low income, younger, part-time or unemployed, renters	42	2.4	98
E9	High income, young renters, full time, early adopters, smart phones.	37	3.1	114
F10	Middle aged/ pensioners, higher incomes, oil heating, rural, environmental, RHI, late adopters.	66	1.9	127
G11	Renters, electric heating, average incomes, early adopters, BME backgrounds, low engagement.	60	1.5	91
H12	Elderly adults, v. low income, medium consumers, disconnected, debt.	46	0.6	30
H13	Off gas, low income, high consumption, disability benefits, low energy market engagement, late adopters	62	0.5	32

Conclusion

6.49 This assessment indicates that all or most consumers could be better off under full exposure to locational pricing compared to the status quo. Based upon a distributional analysis of the LTW NOA7 (nodal and zonal), and zonal LTW HND scenarios, our assessment indicates that the introduction of zonal or nodal pricing in GB could have a positive impact on all inflexible consumers (ie, regardless of location) relative to the status quo. However, under the nodal LTW HND scenario, some consumers in certain regions could lose out and potentially pay around £10 a year more for the wholesale component of their bill. This indicates that greater network build could lead to a reduction in benefits for consumers in a nodal market design. However, our analysis does not take into account the impact of different market designs (and network builds) on the network cost component of consumer bills, as greater network buildout will require higher costs for all consumers.

6.50 The positive impact for most consumers in these results is primarily driven by constraint savings outweighing wholesale price impacts. This accounts for why some consumers lose out under the nodal LTW HND scenario as constraint management savings from nodal pricing relative to the national are lower. Potential impacts from congestion rents and the increased costs for CfD were not included but overall, if these were included, the saving of congestion rents would outweigh the increased CfD costs, leading to further favourable bill impacts for all consumers.

6.51 Our analysis also identified potentially material savings to non-domestics depending on location, with those in Scotland and Northern England standing to gain more from exposure to locational prices.

6.52 There is evidence to suggest that direct pass through of locational signals in a NOA7 nodal market could be beneficial to English and Scottish households in fuel poverty, relative to the status quo of national pricing. This suggests that if nodal pricing was fully passed through, it could help to reduce fuel poverty, and would contribute to rather than work against fuel poverty goals. A weaker and less material relationship was found for NOA7 zonal pricing and HND nodal pricing. HND zonal pricing provided no benefit in this regard.

6.53 For Ofgem's internal distributional analysis framework, the standard distributional framework has been applied to the NPV results from FTI's modelling. In the current context, this is largely a reframing of FTI's aggregate results. As all scenarios and options have positive NPVs, and benefits are volumetric, all household's save by varying amounts, depending largely on usage.

6.54 While in this analysis most consumers are better-off compared to the status quo, in some scenarios there is a relatively wide distribution of the benefits between consumers in different locations. Typically, consumers in the north benefit more, while consumers in southern regions benefit less, with the most extreme distribution representing a spread of around £70 in annual household savings. Whether this represents a 'fair' outcome is open to debate. It should be noted that energy bills already contain a strong distributional element with the current spread of costs between highest and lowest price regions of £130 per annum, with this largely due to network costs[257] There is some evidence that nodal savings would counteract this differentiation.[258]

6.55 Our analysis also does not show the impact of price volatility in different regions. As mentioned in Section 3, the way that prices vary between regions, depending on generation make up or availability of flexible resources, could create regional inequalities between those able to flex their usage and those who cannot.

[257] As found in the current Ofgem Default Price Cap
[258] Current TNUoS Charges are typically higher in Scottish zones. Under locational pricing, these areas would face lower wholesale market costs.

6.56 The results of these analyses are purely illustrative. They are based on FTI's modelling which included many assumptions, although used external sources where possible. Further work would be required to address how any positive rewards for flexible consumers that stand to benefit by optimising consumption profiles or factoring in electricity costs in locational choice could impact those unable or unwilling to be exposed to locational prices.

7 Glossary

AS – Ancillary Services

AGC - Automatic Generator Control

BAU – Business as Usual

BCA – Bilateral Connection Agreement

BM – Balancing Mechanism

Bn – Billion

BSUoS – Balancing Services Use of System

CASIO – California system independent operator

CCGT – Combined cycle gas turbine

CCUS – Carbon capture, utilisation and storage

CSNP – Centralised Strategic Network Plan

CUSC – Connection and Use of System Code

DER – Distributed Energy Resources

DFS – Demand Flexibility Service

DG – Distributed Generation

DPA – Dispatchable Power Agreements

DSR – Demand Side Response

DUoS – Distribution Use of System

EANB – Equivalent Annual Net Benefits

EIM – Energy Imbalance Market

ERCOT – Electric Reliability Council of Texas

ESO – Electricity System Operator for Great Britain

ETYS – Electricity Ten Year Statement

EU – European Union

EV – Electric Vehicle

FES – National Grid Future Energy Scenarios

FSO – Future system Operator

FTI – FTI Consulting

FTR – Financial Transmission Right

GB – Great Britain

GSP – Grid Supply Point

GSPA – Grid Supply Point Area

GW – Gigawatt

HND – Holistic Network Development

HNDFUE – Holistic Network Development Follow-Up Exercise

HZ – Hertz

IEM – Internal Energy Market

ISO – Independent System Operator

ISO-NE – Independent System Operator New England

kV - Kilovolts

LAD – Local Authority District

LMP – Locational Marginal Pricing

LTW – Leading the Way Future Energy Scenario

MISO – Midcontinent independent system operator

Mn – Million

MHHS- Market-wide Half-Hourly Settlement

MO – Market Operator

MPAN – Meter Point Administration Number

MPI – Multi-purpose interconnector

MW – Megawatt

MWh – Megawatt hour

NPV – Net Present Value

NOA – Network Options Assessment

NYISO – New York Independent System Operator

OECD – Organisation for Economic Co-operation and Development

p.a. – per annum

PJM – Pennsylvania-New Jersey-Maryland Interconnection

PPA – Power Purchase Agreement

RAB – Regulated asset base

REMA – UK Government Review of Electricity Market Arrangements

REMIT – Regulation on Wholesale Energy Market Integrity and Transparency

RO – Renewables Obligation

ROC – Renewables Obligation Certificate

RTO – Regional Transmission Operator

SBP - System Buy Price

SCED – Security-Constrained Economic Dispatch

SO – System Operator

SRMC – Short Run Marginal Costs

SSP - System Sell Price

ST – System Transformation Future Energy Scenario

TCA – The EU-UK Trade and Cooperation Agreement

TCLC – Transmission Constraint Licence Condition

TEC – Transmission Entry Capacity

TNUoS – Transmission Network Use of System

ToU – Time of Use

TPI – Third Party Intermediaries

UK – United Kingdom

US – United States

V2G – Vehicle-to-Grid

WMP – Wholesale Market Price