CATAPULT Energy Systems

Introducing nodal pricing to the GB power market to drive innovation for consumers' benefit

Why now and how?

Contents

About Energy Systems Catapult

Energy Systems Catapult was set up to accelerate the transformation of the UK's energy system and ensure UK businesses and consumers capture the opportunities of clean growth. The Catapult is an independent, not-for-profit centre of excellence that bridges the gap between industry, government, academia and research.

We take a whole systems view of the energy sector, helping us to identify and address innovation priorities and market barriers, in order to decarbonise the energy system at the lowest cost.

We have more than 200 staff based in Birmingham and Derby with a variety of technical, commercial and policy backgrounds. We work with innovators from companies of all sizes to develop, test and scale their ideas. We also collaborate with industry, academia and government to overcome the systemic barriers of the current energy market to help unleash the potential of new products, services and value chains required to achieve the UK's clean growth ambitions as set out in the Industrial Strategy

Rethinking Electricity Markets

Rethinking Electricity Markets is an Energy Systems Catapult initiative to develop proposals to reform electricity markets so that they best enable innovative, efficient, whole energy system decarbonisation. Key objectives underpinning the project are:

- identify and characterise key sources of value within electricity markets and how they are reflected in current GB arrangements,
- review approaches taken in other jurisdictions and identify the main strategic choices for GB electricity policy for improving market signals across time and space,
- consider how to strengthen the evidence base to inform decision-making about improving the coherence of the existing UK market framework.

Building on the insights from our Rethinking Electricity Markets initiative, this report explores locational energy pricing and is the latest of a number of reports that we have published, available on our website.

Acknowledgements

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We would like to thank external experts that provided feedback throughout developing this report. (Providing feedback does not imply endorsement and the content of the report remains solely that of Energy Systems Catapult.) In particular, thanks go to: CEPA and TNEI; Iacopo Savelli, University of Edinburgh; and Ed Birkett, Policy Exchange.

Executive Summary

This report aims to raise awareness of nodal pricing as the first best approach to signalling locational value in a more deeply decarbonised, decentralised, and digitised electricity system. **Our work suggests that adoption of nodal pricing in future GB power market design will be highly valuable in enabling an efficient transition to a net zero grid in Great Britain (GB).**

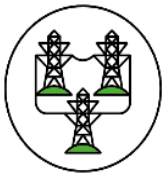
The key advantage of nodal pricing is that it encourages generators and providers of flexibility to locate and operate assets (e.g. generation or storage) efficiently, taking account of the real physical constraints in the network. Over time this is likely to lead to more efficient location of new resources and efficient expansion of the network. It will reward innovation and development of flexibility in locations where it is most valuable to the overall system.

Nodal pricing (also known as locational marginal pricing (LMP) involves determining market clearing prices for several locations on the transmission grid, called nodes. The price calculated for each node reflects the locational value of energy, which includes the cost of the energy and the full cost of delivering it including energy losses in networks and network congestion. Nodal prices are determined in real-time using an algorithm to calculate the incremental cost of serving one additional MW of load at each respective location subject to system constraints (e.g. transmission limits, maximal generation capacity).

Nodal pricing has been adopted in a number of jurisdictions around the world and enables the signalling of locational value mainly through short-term wholesale electricity prices (i.e. spot prices), instead of in network charges. **We propose that nodal pricing be introduced as part of a wider reform package, as detailed in ESC's recently published report *EMR2.0: a new phase of innovation-friendly and consumer-focused electricity market design reform* (Keay-Bright & Day, 2021).**

Recommendations

Recommendation 1: NGESO should be asked by BEIS and Ofgem to commission a detailed study of the introduction of nodal pricing in the GB power market, encompassing a detailed assessment of the cost benefit case and the implementation and transition practicalities.



Recommendation 2: Transition to nodal pricing at transmission level as soon as feasible as part of a wider reform package to drive innovation through open, competitive and high-performing markets. See ESC's recommendations for consumer-focused market design reforms.[1] The assessment of how to implement nodal pricing in GB should include consideration of shorter time frames for scheduling and settlement (e.g. 5 minutes), and the extent to which trading in short-term electricity markets should be mandated (i.e. mandatory pool).

Recommendation 3: Transition directly to nodal pricing, not via zonal pricing. Experience from other jurisdictions suggests that reforms to locational pricing are complex and disruptive, but worthwhile and that it makes sense to transition directly to full nodal pricing. The US switched early from zonal pricing to nodal pricing and hasn't looked back, while progress in implementing zonal pricing within EU countries has been slow and challenging.

Recommendation 4: Establish the independent future system operator (FSO) without delay and ensure it has the functions to efficiently implement nodal pricing. Options for integrating the roles of market operator and system operator within the FSO entity, as in US markets, should be considered.

Recommendation 5: An independent market monitor should be established to improve the performance of power markets in consumers' best interests. Ensure the market monitor is adequately resourced with necessary capabilities. If some locations exhibit market power, then enhanced market monitoring will be necessary. Continuous feedback through the market monitor, to the key decision-makers responsible for aspects of market performance (i.e. BEIS, Ofgem, FSO), will facilitate agile decision-making, swift action against market power and timely market development.[2] Strong independent market monitoring can also help to build investor confidence and public acceptance of market operation, reforms and consequent prices.

[1] https://es.catapult.org.uk/reports/rethinking-electricity-markets-the-case-for-emr-2/

[2] Further discussion of the need for and benefits of enhanced market monitoring can be found in ESC's recent market design report, 'Rethinking Electricity Markets – EMR2.0'.

Recommendation 6: Develop a roadmap for locational signals at distribution level and the institutional structure, role and responsibilities of DNOs, the FSO and any other future entities needed (e.g. DSO, regional entities). Many innovators are basing their business models on the current market arrangements including the latest TCR decision and upcoming NAFLC decision. A roadmap and clarity on the target model for locational signals at distribution level and possible pathways would help innovators manage regulatory risk and develop more robust business models.

Recommendation 7: Reform planning arrangements to complement nodal pricing to cost-effectively develop and fund the network we need. Optimising locational investment decisions will require changes to the planning permissions rules and processes, the responsibility for which sits with national and local governments. Strategic planning/coordination needs to be improved at national and local level (e.g. Local Area Energy Planning (LAEP)[3]) interfacing with, and being informed by, more market signals that reflect locational value.

Recommendation 8: Evolve reliability arrangements to work with the emerging digitalised and distributed energy system under nodal pricing. Nodal pricing is likely to improve the market's ability to address physical reliability, but it is likely that the policy mechanisms for reliability and resource adequacy will also need to evolve. This evolution should be designed to mesh with much more developed locational market signals.

Recommendation 9: Combine nodal pricing with robust time and location-specific tracking of carbon (content or intensity) through the electricity system and settlement process ESC proposes combining more granular market signals, by location and nearer to real-time (e.g. 5 minute scheduling and settlement), with an outcome-based carbon policy mandate on retailers/offtakers of electricity. Such a policy framework would require arrangements to track carbon accurately through electricity trading and settlement systems.

Recommendation 10: Design targeted provisions to ensure fairness and address impacts on low-income consumers. Transitional arrangements to dampen distributional impacts may be necessary, such as options for combining nodal prices and flat prices for flexible and non-flexible users/resources, introducing nodal pricing on an opt-in basis with levelling up of bills using credits/charges or targeted support for vulnerable consumers in adopting low/zero carbon solutions.

[3] https://es.catapult.org.uk/reports/local-area-energy-planning/

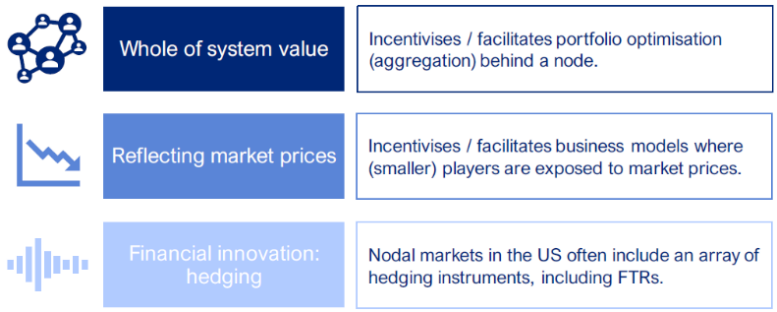
Recommendation 11: Provide temporary support to incumbents during the transition to nodal pricing. The definition of access rights may need to be redefined if locational energy pricing is introduced. Under uniform pricing, generators implicitly have access (at least in terms of pricing) to the entire network, whereas under nodal pricing generators are only guaranteed unconstrained access to their node (and the respective price). Temporary mitigation measures of compensation arrangements have been employed in other jurisdictions to facilitate the transition.

A move to nodal pricing has previously been considered and rejected in GB several times. A key reason why nodal pricing was not adopted during the Transmission Access Review (TAR) from 2008 to 2010, was because of fear that it might hold back development of renewable energy generation. The GB power market, however, is in a very different place now. The Electricity Market Reforms (EMR) implemented a decade ago have successfully driven down the cost of renewable energy and enabled deployment at scale, particularly for offshore wind. We conclude that now it is time to adapt GB power market design for Net Zero, including the introduction of nodal pricing.

Available evidence presented in this report suggests that locational value could be more efficiently revealed in GB's power market signals. Sharper locational incentives for both generators and consumers could significantly reduce total system costs by ensuring users invest in the right places and consume or produce at the right times. Locational efficiency could be improved in a range of different ways including reforms to connection charges, network charges, or to the Contracts for Differences and Capacity Market schemes, as well as broader improvements to arrangements for strategic planning. The focus in this report is on nodal pricing because it can simultaneously influence decision-making in operational and investment timeframes.

Nodal pricing makes it possible for the energy market to co-optimise energy and reserves nearer real-time taking into account network constraints, reducing the need for redispatch of energy resources to balance the system and address network congestion. This would reduce the role of the system operator, while sharpening incentives for market participants to address locational constraints. This would drive significant savings in system operation costs and more efficient development of the network, delivering major costs savings for consumers and wider system benefits through **greater innovation and a more diverse and resilient power mix**, as illustrated below.

How nodal pricing could support innovation in GB energy markets



Source: (CEPA & TNEI, 2021)

The increasing reliance on renewable and distributed resources as we transition to Net Zero strengthens the case for nodal pricing to incentivise efficient location, investment and operational decisions in a more variable and decentralised system. Continuing with our current approach of a uniform energy price while improving network charges will tend to increase the need to rely on redispatch and constraint management by the system operator – and experience suggests an ongoing need to review and revise the detail of network charging methodologies.

Costs could be much lower for consumers

Fully decarbonising the electricity system to help meet Britain's net zero emissions target will require significant investment in generation, networks and flexible energy resources. NG ESO's estimates for the total cost (final Net Present Value) of transforming the energy system for Net Zero by 2050 are in the range of £2,820-£3,020 bn.

Net balancing costs have risen from £506m in 2015 to £1.3bn in 2020, with a large share of this being 'constraint costs' resulting from NGESO having to redispatch resources following gate closure to manage network congestion. These constraint costs were around 0.5 bn/year in 2020 but NGESO's Network Options Assessment 2020/21 (NOA6) modelling shows these costs will rise to a maximum of between £1bn/yr to £2.5bn/yr before they reduce again around 2030 when new major transmission investments come online.[4]

The most recent modelling for locational energy pricing in the GB market, conducted by Aurora and commissioned by Policy Exchange, estimated savings of £2.1bn p.a. from 2030 to 2050, and this was under a zonal approach involving just three zones. Savings would almost certainly be higher under nodal pricing but modelling is expensive and existing models of the GB market would need significant investment to model LMP. It's worth noting that studies of US markets with LMP reveal significant net benefits and US Independent System Operators (ISOs) typically recovered the one-off implementation costs within just one year of operation (Neuhoff & Boyd, 2011).

It would be logical for NGESO to explore an LMP scenario and the extent it could reduce these high costs, as many studies reveal considerable net benefits for implementing LMP (see section 5.5). NGESO, however, is developing the future system assuming incremental improvements to current market arrangements. Ofgem's proposals for a Future System Operator (FSO) foresee NGESO taking more initiative in future as an expert, independent system operator that puts consumers' interests first. Establishing the FSO, however, will take time.

There is no time to waste as decisions for building transmission network infrastructure in 15 years' time are being made today. **Therefore, we believe there is a strong case for NGESO, supported by Ofgem and BEIS, to move ahead with commissioning a thorough analysis of the case for, and practicalities of, introducing nodal pricing in the GB**

[4] https://www.nationalgrideso.com/document/194436/download

electricity market. Given the urgency of progressing reforms to enable full decarbonisation of the system by 2035, this should be initiated in parallel with other related workstreams.[5]

Some trade-offs and impacts must be managed

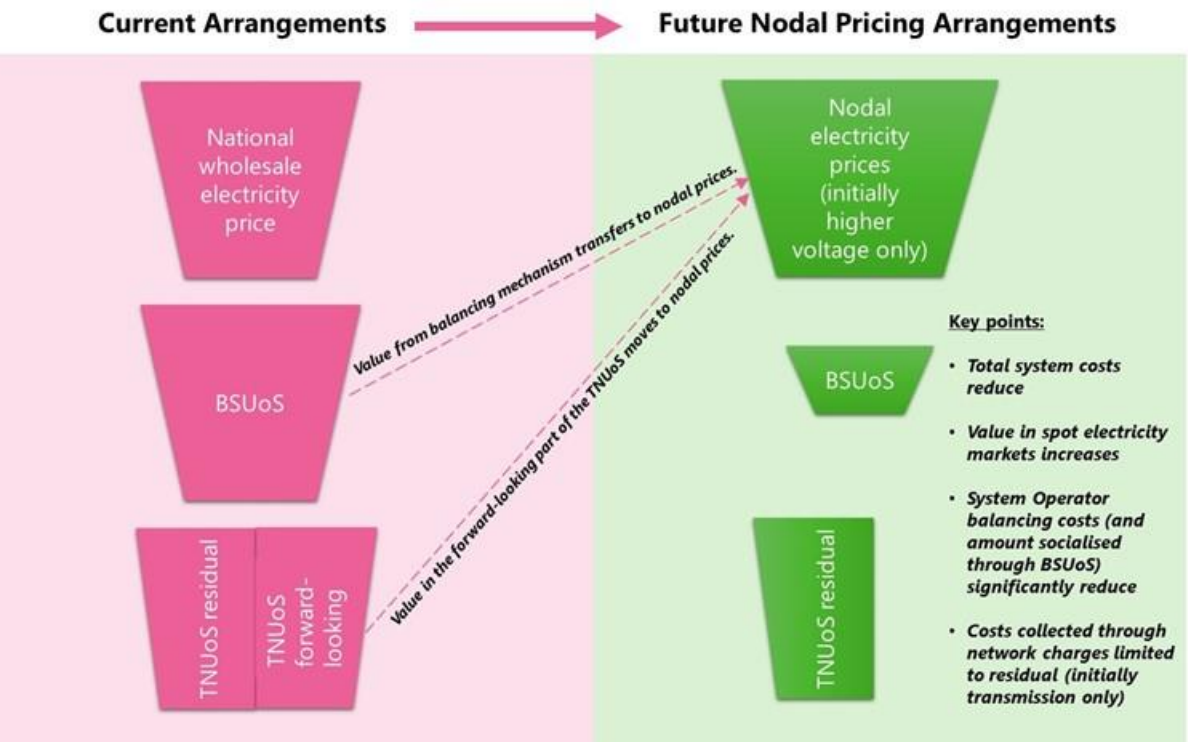
In reducing total system costs, nodal pricing impacts allocation of costs across the system. Sources of value will shift between markets and mechanisms, as illustrated in the Figure below.

Under nodal pricing, risk will also shift. The risk associated with being "constrained off" will shift from the consumer to the generator and will therefore lie with the market actor best able to mitigate the particular risk. Consequently, negatively impacted generators might either close plant earlier or be more reluctant to invest. Given the long lead-times in getting new generation capacity onto the system, some form of transitional policy is likely to be required. Market design and the overlying policy and regulatory framework, however, should ensure efficient exit and entry of capacity aligned with Net Zero requirements for the power sector, as recommended in ESC's recent report on market design reforms (Keay-Bright & Day, 2021).

Similarly, there may be incidence effects for suppliers which would need to be managed during a transition to nodal pricing. Over time we would expect to see upward pressure on prices in more congested areas, improving the business case for demand response, storage, energy efficiency or local low carbon generation.

Distributional impacts on residential consumers and small businesses, particularly impacts on vulnerable consumers, would also need to be managed as part of wider retail market reforms. Various solutions exist to facilitate the transition for these consumers, such as averaging prices across geographic areas as has been implemented in other jurisdictions. New ideas include using both nodal pricing and flat energy prices at distribution level to enable co-existence of flexible and non-flexible consumers and resources (Savelli & Morstyn, 2021), or introducing nodal pricing to residential consumers and small business on an opt-in basis with levelling up of energy bills using credits and charges (Birkett, 2020). The implementation and phasing-in of nodal pricing must therefore be carefully managed, with appropriate and targeted complementary policies that are aligned with Net Zero. The introduction of nodal pricing should therefore be considered alongside retail market reforms.

[5] Ofgem's Strategic Code Review on Network Access and Forward-Looking Charges review and Full Chain Flexibility programme; the BEIS/Ofgem Smart Systems Flexibility Plan programme of work; and the BEIS Alternative Energy Markets programme.



Nodal pricing will cause costs to shift across markets and mechanisms. Note: The size of the 'buckets' are not reflective of actual value – it is the change in their sizes from left to right that serve to illustrate changes in sources of value. Source: Sarah Keay-Bright, ESC.

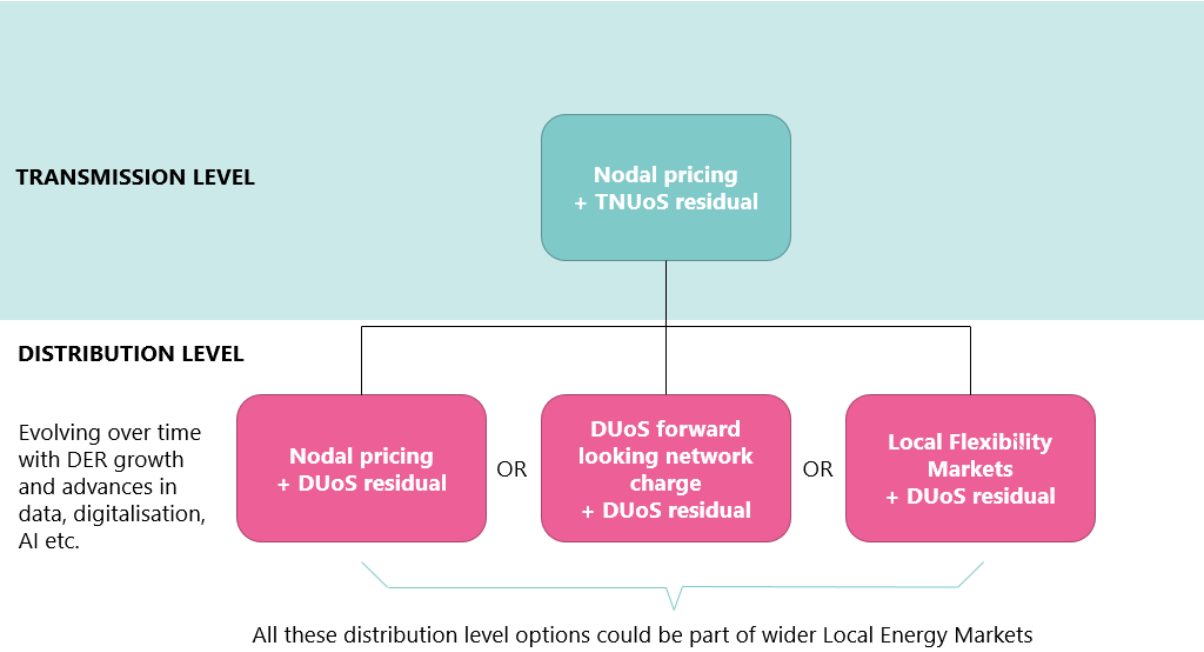
At the distribution level, strategic and flexible approach needed

Nodal pricing would initially be implemented at the transmission level and would create a local market behind each node. Behind the node, two options are currently possible:

a) designing more highly granular distribution network charges by space and time; or
b) sending locationally-specific dynamic price signals to consumers via flexibility platforms / marketplaces (in this case, the distribution network tariffs would need to be simple (e.g. flat tariffs).

In future, however, there are three options as LMP could be extended to lower voltages with DER growth and with improvements at the distribution level in relation to network monitoring, digitalisation and availability of data and ICT, as illustrated below. This would change the role of flexibility markets, if introduced, over time as LMP is extended.

Options behind the node, at the distribution level



Source: Sarah Keay-Bright, ESC.

The potential of flexibility markets and LMP at lower voltages is currently being examined under several innovation projects, particularly through Innovate UK's Prospering from the Energy Revolution (PFER) programme[6]. Uncertainty at the distribution level, however, should not hold back moves to introduce nodal pricing at the transmission level.

[6] https://www.ukri.org/our-work/our-main-funds/industrial-strategy-challenge-fund/clean-growth/prospering-from-the-energy-revolution-challenge/

1. Introduction

This report aims to raise awareness of locational energy pricing as an option of high potential for future power market design in Great Britain (GB). This is a form of locational energy pricing whereby locational value is mainly signalled in short-term wholesale electricity prices (i.e. spot prices), instead of in network charges. We propose that nodal pricing be introduced as part of a wider reform package, as detailed in ESC's recently published report *EMR2.0: a new phase of innovation-friendly and consumer-focused electricity market design reform* (Keay-Bright & Day, 2021).

There are signs that the GB power system is struggling to cope efficiently with the rapid growth in variable renewables, yet much greater pressure is to come as the power sector needs to:

a) decarbonise more quickly, and potentially further, than other sectors; and
b) accommodate huge growth in electricity consumption with the electrification of heat and mobility.

Available evidence presented in this report suggests that locational value could be more efficiently revealed in GB's power market signals and that sharper locational incentives for both generators and consumers could significantly reduce total system costs.

The aim of locational price signals is to ensure network users internalise the impacts of their behaviour/decisions on the costs of the total system. This will then ensure users:

a) invest in the right places; and
b) consume or produce at the right times.

In GB today, network charges based on long-run marginal costs (LRMC) are used to influence point a), and the spot prices of the wholesale energy market based on short-run marginal costs (SRMC) are used to influence b). In effect **our current system is designed to send investment and dispatch signals separately.**

An alternative approach, which **simultaneously** sends short-run and long-run signals to influence both a) and b), is for wholesale electricity spot prices to vary by location. This is referred to as **locational energy pricing (LEP),** which requires varying prices based on either:

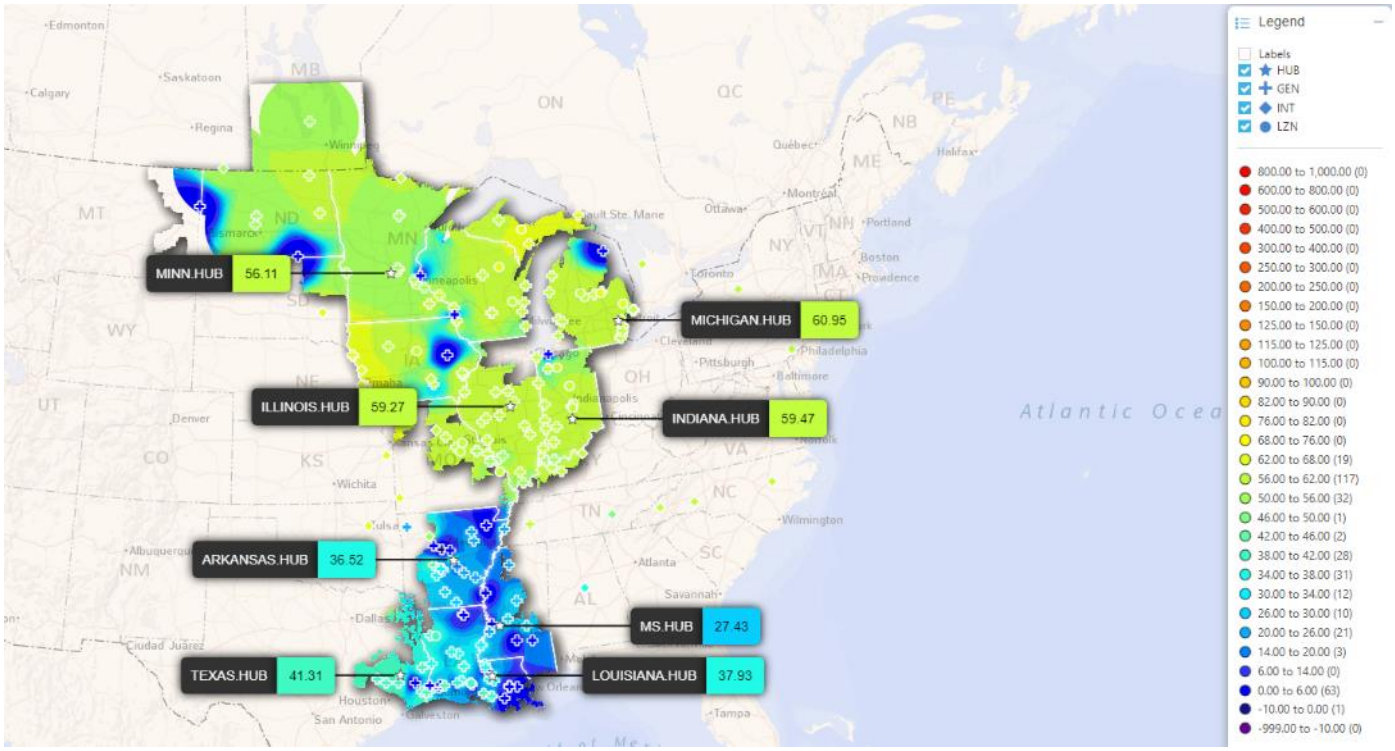
- nodes or points on the network (i.e. nodal pricing); or
- areas or zones with defined boundaries that reflect congestion (i.e. zonal pricing).

Locational energy pricing has previously been considered and rejected for the GB market several times. It would be a major change for GB's power market design, but the net benefits would likely be considerable and trade-offs and risks can be managed. A key reason why nodal pricing was not adopted during the Transmission Access Review (TAR) from 2008 to 2010, was because it might hold back development of renewable energy generation. The GB power market, however, is in a very different place now as EMR has successfully driven down the cost of renewable energy and enabled deployment at scale, particularly for offshore wind. We conclude that now it is time to adapt GB power market design for Net Zero, looking to the future and working back rather than taking an incremental approach that risks path dependency.

2. What is nodal pricing?

Nodal pricing (also referred to as Locational Marginal Price (LMP)) is a method of determining prices in which market clearing prices are calculated for several locations on the transmission grid, called nodes (Schweppe, Caramanis, Tabors, & Bohn, 1988). The price at each node reflects the locational value of energy, which includes the cost of the energy and the full cost of delivering it including energy losses in networks and network congestion. Nodal prices are determined in real-time using an algorithm to calculate the incremental cost of serving one additional MW of load at each respective location subject to system constraints (e.g. transmission limits, maximal generation capacity). Nodal pricing has been implemented in several jurisdictions including the US (ISONE; MISO (see Figure 1); ERCOT; NYISO; PJM), New Zealand and Singapore. Australia currently considers moving from zonal pricing to nodal pricing.

Figure 1 Midwest ISO LMP contour map



Source: https://api.misoenergy.org/MISORTWD/lmpcontourmap.html Screenshot 30th August 2021, 9:30pm.

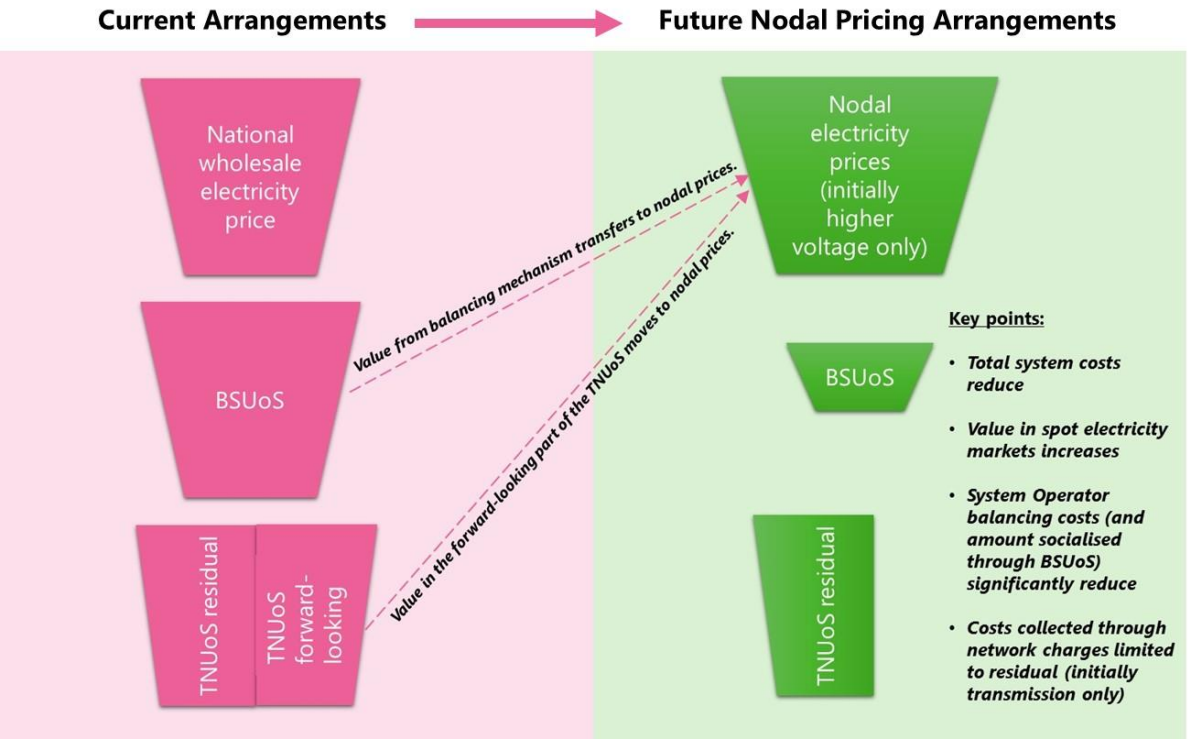
Nodal pricing represents a considerable departure from current arrangements in the GB electricity market. In principle, there should be no or minimal out-of-market actions by the system operator (SO) in nodal markets since the nodal pricing algorithm accounts for security constraints on the system. Resources would be dispatched by the SO – or if self-dispatching, resources must follow dispatch instructions and accept possible intervention. Typically, the SO would only intervene if the market fails to clear or deliver.

Nodal pricing also requires unit-specific bidding – that is, a supplier would be able to optimise its portfolio within the nodal market (i.e. *behind* a node), but not *between* nodal markets. Nodal pricing would also drive optimisation behind the node, potentially through local flexibility/energy markets.

When the output of variable renewables is high, the system's marginal costs can also be high and bids should reflect the opportunity costs of providing reserves or system services. Nodal pricing causes market participants to internalise the choices between providing energy, reserves or storage and so market participants' offers based on their short run marginal cost (SRMC) will include the *opportunity costs* of providing different power system products and services or other potential uses for their energy resources (e.g. storage, conversion to another energy vector etc).

While introduction of nodal pricing would remove the need for a balancing mechanism and increase the value in the short-term wholesale electricity markets, it would reduce total system costs due to efficiency gains (see Figure 2). If LMPs are introduced, then the forward-looking part of the network tariff must be removed to avoid double-counting, leaving just the residual of the network charge (i.e. for the higher voltage network in front of the node).

Figure 2 - Change in 'buckets' of value with move to nodal pricing at transmission level



Note: The size of the 'buckets' are not reflective of actual value – it is the change in their sizes from left to right that serve to illustrate changes in sources of value. Source: Sarah Keay-Bright, ESC.

Retail suppliers and generators would need to hedge their exposure to pricing differences between nodes. The most commonly used form of hedging in nodal markets is financial transmission rights (FTRs; also known by other names in different US markets). There are many forms of FTRs, but a common feature is that they are created by the market making entity (i.e. the System Operator (SO)/Market Operator (MO)) and funded through the difference between the charges on withdrawals and the payment for injections, so there is a natural limit to the amount of FTRs that can exist at a point in time.

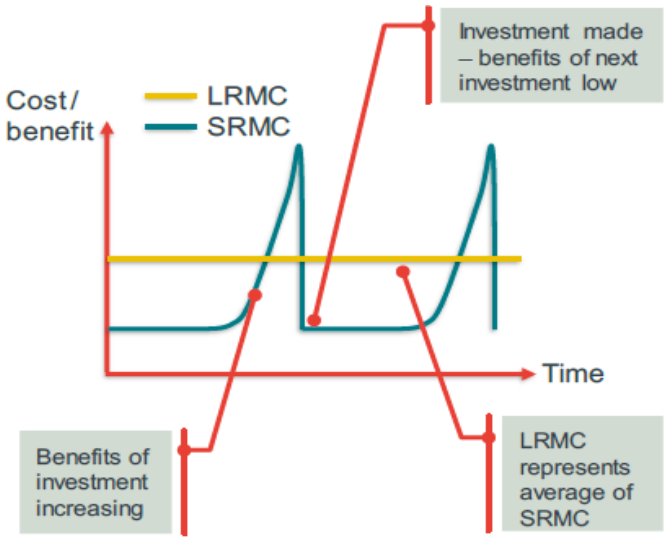
The GB network is owned by different merchant entities. In a meshed network, the overall merchandising surplus is equal to the total congestion rent and covers exactly the network investment costs. This is not true for a single line, however, where the congestion rent can be negative in the case of counter-economic flows. The GB market making entity would therefore need to develop a sufficiently sophisticated methodology and take care with splitting any merchandising surplus to renumerate network investors.

LMPs in competitive energy markets reflect the locational differences in participants' marginal costs, creating 'spreads' between prices in different locations. Differences between LMPs that are forecast to sustain under a range of credible future scenarios would signal a constraint that may need to be addressed through reinforcement, thus improving the robustness of decisions about major lumpy transmission investments. Response to higher prices in particular locations, however, if generation is developed or demand reduced in such locations, may mean the new investment is not needed or is delayed.

Reinforcement should only be undertaken using regulated revenues when the cost of congestion exceeds the cost of reinforcement to provide a positive cost-benefit ratio. Any such cost-benefit analysis would need to account for the very long lives of network investment and apply appropriate valuation methodologies for decision making under uncertainty.

Once network reinforcement or replacement has taken place, the price difference will reduce, reflecting greater network capacity. A system based on LMPs therefore results in a 'saw-tooth' pricing pattern over time (see Figure 3), but the time-averaged locational signal should equal the long-run marginal cost (LRMC) of new network capacity[7], which is the basis of current network charges.

Figure 3: The 'saw-tooth' pricing pattern of LMPs



Source: Frontier Economics

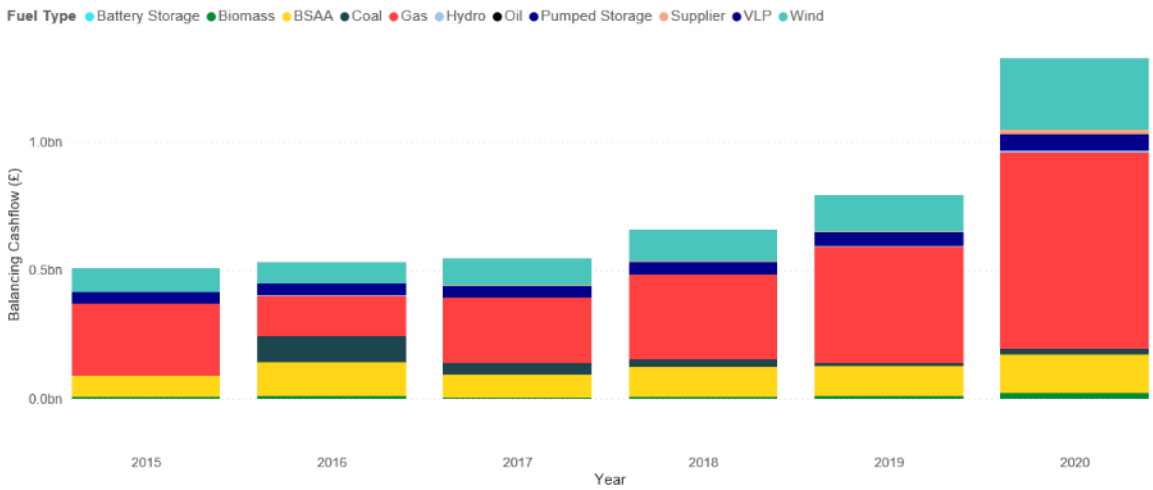
[7] Though this depends on the efficiency of the body deciding on or delivering network reinforcement.

3. GB network investment and system operation – opportunity for huge savings

Already there is evidence that the GB power system is struggling to cope with the growth in generation capacity based on variable renewables. The share of intermittent renewables - wind and solar - in the power mix has rocketed from 3% in 2010 to 28% in 2020 (TWh). System balancing costs are increasing and while this can be expected with growth in weather dependent renewables, the rate of increase is impacted by market design. Under the current market arrangements, NG ESO has to rebalance the system following gate closure through considerable redispatching of energy resources in order to manage network congestion. In some cases, NGESO is having to redispatch the majority of the stack.

Net balancing costs have risen from £506m in 2015 to £1.3bn in 2020 (see Figure 4), with the recent surge in 2020 explained by the extraordinary circumstances resulting from the lockdown driven by the COVID-19 pandemic.

Figure 4 GB power market balancing costs 2015-2020

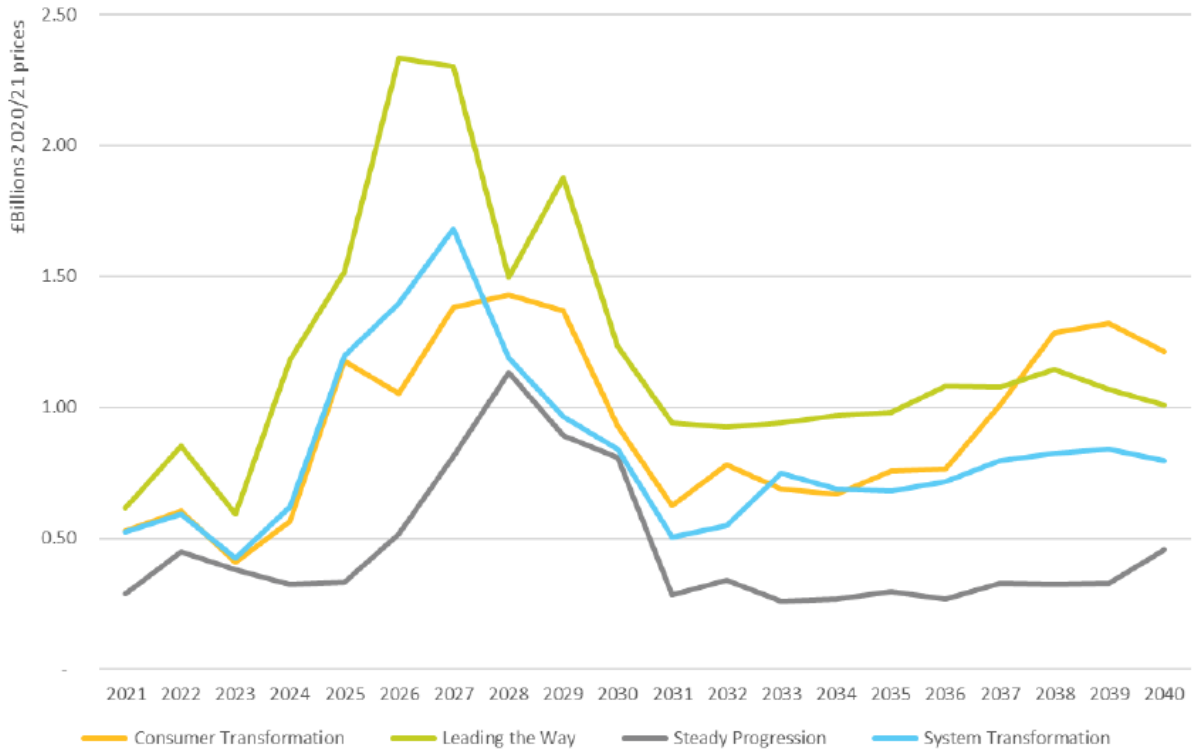


Source: Elexon (note: not including availability fees or start-up costs)

A very large share of the balancing costs are constraint costs relating to redispatching. At present, the constraint costs are around £0.5 bn/year but NGESO's NOA6 analysis shows modelled constraint costs increasing to between £1bn/yr to £2.5bn/yr at a maximum before they reduce again at the end of the decade when new major transmission investments come online (see

Figure 5) (NGESO, 2021a). This rise and fall reflect the disparity in timescales for building renewable generation and large transmission projects.

Figure 5 Modelled constraint costs after NOA6 optimal reinforcements



Source: (NGESO, 2021a)

The lead-times for planning and delivering major reinforcements and newbuild of grid infrastructure are long and decisions for network infrastructure to be built in 15 years time are already being made now (see Figure 6). Huge sums of money are involved and considerable risk and uncertainty must be managed.

Figure 6: NG ESO's recommended reinforcements for Scotland and the north of England region

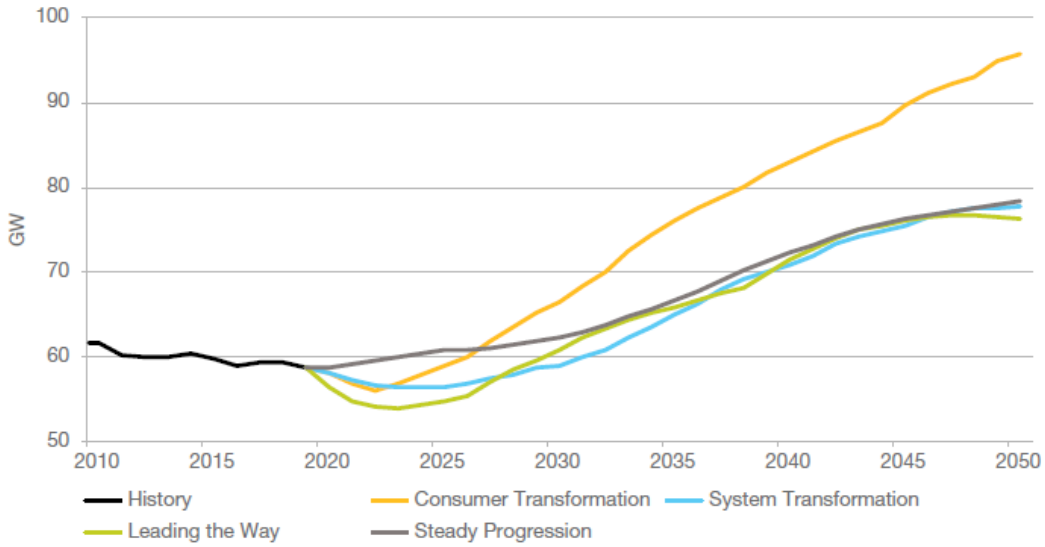
Code	Option description	To meet its EISD of:
MRP2	Additional power control devices at both Harker and Penwortham	2021
WHTI	Tee-in of the West Boldon to Hartlepool circuit at Hawthorn Pit	2021
CDHW	Cellarhead to Drakelow circuits thermal uprating	2023
HAEU	Harker supergrid transformer 5 and supergrid transformer 9A banking arrangement	2022
WLTI	Windyhill–Lambhill–Longannet 275kV circuit turn-in to Denny North 275kV substation	2022
CS05	Commercial solution for Scotland and the north of England - stage 1	2023
CS06	Commercial solution for Scotland and the north of England - stage 2	2023
ECU2	East Coast onshore 275kV upgrade	2023
HAE2	Harker supergrid transformer 6 replacement	2023
HNNO	Hunterston East–Neilston 400kV reinforcement	2023
THS1	Installation of a single series reactor at Thornton substation	2023
CTP2	Alternative power control device along Creyke Beck to Thornton	2024
DWUP	Establish Denny North-Clydesmill-Wishaw single 400kV circuit from existing 275kV circuits	2026
ECUP	East Coast onshore 400kV incremental reinforcement	2026

Code	Option description	To meet its EISD of:
ECVC	Eccles hybrid synchronous compensators and real-time rating system	2026
E2DC	Eastern subsea HVDC link from Torness to Hawthorn Pit	2027
OPN2	A new 400kV double circuit between the existing Norton to Osbaldwick circuit and Poppleton and relevant 275kV upgrades	2027
DWNO	Denny to Wishaw 400kV reinforcement	2028
E4D3	Eastern Scotland to England link: Peterhead to Drax offshore HVDC	2029
BBNC	Beauly to Blackhillock 400kV double circuit addition	2030
BLN2	Beauly to Loch Buidhe 275kV reinforcement	2030
CGNC	A new 400kV double circuit between Creyke Beck and south Humber	2031
E4L5	Eastern Scotland to England 3rd link: Peterhead to the south Humber offshore HVDC	2031
GWNC	A new 400kV double circuit between south Humber and south Lincolnshire	2031
SHNS	Upgrade substation in the south Humber area	2031
TGDC	Eastern subsea HVDC link from south East Scotland to south Humber	2031
CMNC	South east Scotland to north west England AC onshore reinforcement	2033
EDNC	Uprate Brinsworth and Chesterfield to double circuit to 400kV and a new 400kV double circuit between Ratcliffe and Chesterfield	2033

Source: p. 41 (NGESO, 2021b)

The impact of electrifying mobility and heat, which is still in relative infancy, will cause electricity (net) peak demand to dramatically increase well into the 2040s (see Figure 7) with consequences for the variability of network flows and the capabilities of the networks to handle this. The role that hydrogen will play is a major uncertainty impacting electricity demand projections.

Figure 7 Projected electricity peak demand including losses



Source: (NGESO, 2021b)

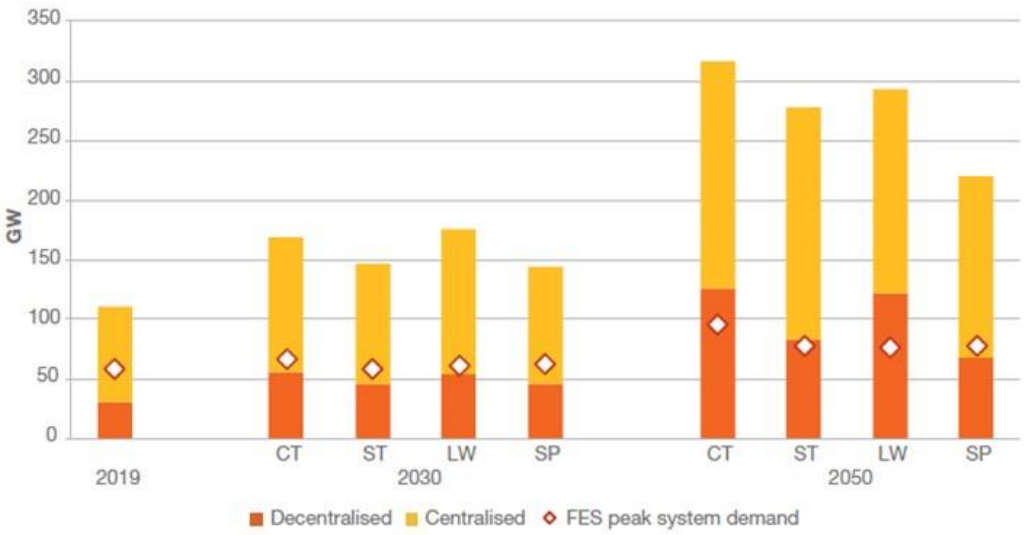
Figure 7 notes:
NG ESO Future Energy Scenarios: SP Steady progression - slowest credible decarbonisation, minimal behaviour change, decarbonisation in power and transport but not heat; CT Consumer transformation - electrified heating, consumers willing to change behaviour, high energy efficiency, demand-side flexibility; ST System transformation - hydrogen for heating, consumers less inclined to change behaviour, lower energy efficiency, supply side flexibility; LW Leading the way - fastest credible decarbonisation, significant lifestyle change, mixture of hydrogen and electrification for heating.

The increase in the total costs of the electricity system will be extremely large under any scenario, inviting opportunities to cut costs and reduce bills for energy consumers. NG ESO's estimates of the total cost (final Net Present Value) of transforming the energy system by 2050 under each of its scenarios are: Leading the Way £2,820bn; Steady Progression £2,930bn; System Transformation £3,020bn; and Consumer Transformation £3,020bn.

All NGESO's Future Energy Scenarios are based on high shares of weather dependent renewables in the power mix and show higher levels of decentralisation compared to today, with up to around 42% of generation capacity decentralised by 2050 (see Figure 8 - Connection location of installed generation capacities and peak demand (excluding vehicle-to-grid)). By 2050, the level of decentralisation in all ESO's scenarios suggests the role of the transmission system may often be to transport electricity from one distribution network to

another, rather than delivering from transmission connected generation to distribution networks. This will be or should be shaped, however, by the price signals resulting from the GB's market design, which ESC argues need reform (Keay-Bright & Day, 2021).

Figure 8 - Connection location of installed generation capacities and peak demand (excluding vehicle-to-grid)



Transmission-connected offshore wind is the energy resource with the largest increase in all FES scenarios, as might be expected given its cost reductions and the Offshore Wind Sector Deal, including 40GW of targeted capacity by 2030. NGESO states that the increase in offshore wind, however, will tend to limit the maximum contribution of decentralised generation as a proportion. While offshore wind will likely dominate the future power mix, the extent to which it does so and how it is complemented by other energy resources should be shaped by a more efficient market design combined with strategic planning and an outcome-based policy framework (Keay-Bright & Day, 2021).

Market signals that can accurately reflect system value, indicating where to invest in new generation or demand reduction, and when to dispatch generation or demand, have the potential to play a **key role** in reducing the total system costs of a fully decarbonised electricity system (and optimising its future configuration as the backbone of the wider net zero energy system). **It would be logical for NGESO to estimate total system costs under an LMP scenario.**

Establishing a more efficient power system and markets, however, will require institutional reforms. Ofgem and other stakeholders believe there may be a potential asset ownership bias in NGESO's current arrangements – this may also introduce bias in relation to market design, procurement of ancillary services and policy options, potentially leading to overspend on transmission assets.

4. Locational value in the GB power system today

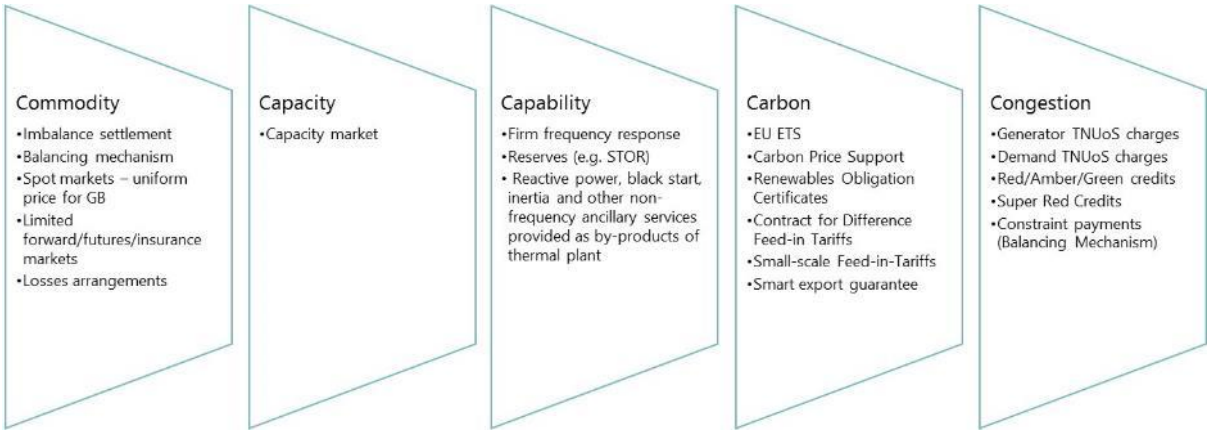
Analysis by ESC and AFRY (previously Poyry) mapped sources of value across the '5Cs' of the GB power system: commodity, capacity, capability, carbon and congestion, summarised in Figure 9 (Poyry, 2019b). In the GB power market, locational value is highly fragmented and price signals are relatively static and inefficient.

The spatial dimension has relatively limited prominence in the current GB arrangements. In the wholesale market and the capacity market, which are the primary origins of commodity and capacity value streams respectively, the location of resource is not particularly important, with pricing and associated signals national in nature. The CfD scheme, driving investment in large-scale renewables, does not encourage system-efficient siting of generation (Newbery, 2021) and is a key area of investigation under a recent Call for Evidence.[8] Some balancing services, such as constraint resolution, voltage support and Black Start, do attach importance to location.

At present, the main source of locational differentiation in GB's market signals is via network charging arrangements, which seek to provide signals of the value of congestion alleviation and avoidance. GB's network charges are currently undergoing reforms.

Figure 9: The 5C framework for sources of value in the GB electricity markets

Commodity	Capacity	Capability	Carbon	Congestion
Value of MWh energy delivered to the system	Value of reliability of availability in support of security of supply	Value of supporting system operability in operational timescales	Value of carbon emissions	Value of easing network congestion or offsetting network build



Source: Based on (Poyry, 2019b)

[8] https://www.gov.uk/government/consultations/enabling-a-high-renewable-net-zero-electricity-system-call-for-evidence

Ofgem is currently undertaking and implementing network charging reforms, which have been separated into two parts:

- The **Targeted Charging Review (TCR): Significant Code Review (SCR)**[9] has examined the 'residual charges' which recover the fixed costs of providing existing pylons and cables, and the differences in charges faced by smaller distributed generators and larger generators (known as Embedded Benefits); and
- The **Network Access and Forward-Looking Charges (NAFLC)** review[10] is looking at the 'forward-looking charges' which sends signals to users through connection charges and use-of-system charges about the effect of their behaviour on the networks. The charges can be designed to encourage efficient siting of new generation or demand and to incentivise users to use the networks in a particular way.

Ofgem took a final decision on TCR in December 2019 and implementation details are now being developed through multiple codes[11]. Key elements of these reforms include:

- Residual charges will be levied in the form of fixed charges for all households and businesses that will not be avoidable; previously they were linked to energy consumption and for transmission, the charges could be avoided by shifting demand as they were based on the three highest half hour periods of demand during the winter months (i.e. Triads).
- The liability for the Transmission Generation Residual will be removed from generators in line with EU law.
- Balancing services charges 'embedded benefits' received by smaller distributed generators are being removed in order to remove market distortions and ensure a level-playing field.
- Balancing services charges will now be allocated to gross final demand, rather than net demand as was previously the case.

Ofgem recently conducted a consultation on its 'minded-to' decisions concerning the NAFLC review. The minded-to positions cover connection charges and access rights only, with a view to implement these reforms by April 2023. On use-of-system charges, the minded-to decision on DUoS charges, based on the short-listed options[12] presented in March 2020[13], is delayed and Ofgem will shortly consult on splitting the NAFLC so that these reforms can be implemented post 2023[14]. This might give more time to assess some more sophisticated charging options.

On TNUoS charges, Ofgem is minded to ensure small distributed generators face wider TNUoS charges but implementation will be delayed while Ofgem conducts a Call for Evidence regarding a broader review of TNUoS charges, which could lead to the launch of a **new** Significant Code Review (SCR).[15] This could provide an opportunity to align reforms with Ofgem's ongoing Full Chain Flexibility Work and the recently updated Ofgem/BEIS Smart Systems Flexibility Plan. **It is therefore an opportune moment to assess nodal pricing implemented at transmission level as an alternative to TNUoS options.**

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[9] See https://www.ofgem.gov.uk/electricity/transmission-networks/charging/targeted-charging-review-significantcode-Review
[10] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/reform-network-access-and-forward-looking-charges
[11] For example: CMP264/265/308/333/334/335/336/340/353; DCP 358/359/360/361 and P402.
[12] https://www.ofgem.gov.uk/publications-and-updates/electricity-network-access-and-forward-looking-charging-review-open-letter-our-shortlisted-policy-options
[13] https://www.ofgem.gov.uk/system/files/docs/2020/03/access_scr_open_letter_march_2020_0.pdf
[14] http://www.chargingfutures.com/about-charging-futures/charging-futures-forum/22-september-2021-forum-webinar/
[15] Ibid.

Ofgem ran the TCR and the NAFLC processes as separate processes based on different timeframes creating much regulatory uncertainty for innovators and investors. With TCR decision being taken earlier than the NAFLC decision, innovators and providers of flexibility are aware that their revenues will be negatively impacted (e.g. Triads; embedded benefits) but they do not know how this value might be replaced by NAFLC or alternatives.

The challenge for the regulator is whether to invest in designing more sophisticated UoS charges, incrementally improving them over time, or whether to and when to pursue alternatives to network charges, such as nodal pricing and local flexibility markets. Looking ahead, the energy system is expected to dramatically change with, for example:

- growth in weather dependent renewable generation at transmission and distribution levels;
- growth in electric vehicles and heat pumps at distribution level, introducing potentially flexible load to the system;
- advances in delivering demand response due to implementation of the Smart Systems and Flexibility Plan and with aggregators gaining experience and expanding their portfolios of flexibility resources;
- investment in data/digitalisation and monitoring;
- NG ESO potentially transforming to FSO, DNOs potentially separating out their DSO functions, with new coordination arrangements between DNOs/DSOs and the ESO/FSO.

Many innovators are basing their business models on the **current** market arrangements including the latest TCR decision and upcoming NAFLC decision. It is certain, however, that further reforms will be necessary given the Net Zero ambition and the rapidly changing power mix with system consequences. **A roadmap and clarity on the target model and possible pathways would help innovators manage regulatory risk and develop more robust business models.**

5. The case for nodal pricing/LMP

5.1. Comparison of options

ESC commissioned CEPA and TNEI to explore a number of issues and questions in relation to locational energy pricing in order to inform policy debate on the question of which policies and market design the GB energy market should adopt in order to achieve the net zero target. The study explored four sets of issues:

What role network charging should play in providing locational signals in the future energy system, and what limitations may be on the ability of network charging to signal locational value.	What reforms may be necessary to market design and governance in order to enable locational signals through wholesale energy pricing.	How locational energy pricing in the wholesale market may interact with network charging, policy instruments that signal the value of capacity and carbon emissions, the procurement of local flexibility by DNOs, and long-term strategic planning of the energy system.	To what extent is locational pricing in wholesale markets consistent with more centralised or decentralised generation mixes; with post-Brexit market developments and with greater autonomy for the GB devolved administrations.

Through a series of workshops and case studies, the study explored these issues by developing three potential approaches (i.e. 'straw-persons') to energy market design that could be developed over time to provide more targeted signals of locational value in operational timeframes compared to current arrangements:

Straw-person 1: Locational network tariffs	Straw-person 2: EU model 'plus'	Straw-person 3: Nodal pricing
Locationally granular and dynamic network tariffs. Uniform pricing in wholesale markets	Zonal day-ahead market; zonal or nodal balancing market. Some locational signals in network tariffs	US-style nodal market in day-ahead and real time. Simple network tariffs only recover 'residual' costs

More detailed descriptions of the straw persons are set out in Appendix 1. In principle, each of the straw-persons is capable of enabling a net zero electricity system, but they each offer different costs and benefits. In particular, each straw-person may introduce inefficiencies that result from its impact on:

- generator and consumer behaviour;
- the generation mix, including the extent to which consumers take up DER; and
- system planning (including investment in network capacity), coordination and operation.

Various aspects of the different arrangements were explored including the likely market behaviours and outcomes within each straw-person and between the straw persons. The findings are referred to throughout this paper and pros/cons/issues are summarised in Appendix 2 - Summary of commonly cited discussion points for different approaches to locational pricing. For further information, see the full report (CEPA & TNEI, 2021).

5.2. Pure network charging approach not best choice for digitalised future

One option to improve locational price signals in operational timeframes is to develop network charges as far as possible, beyond the options being discussed under Ofgem's current network charging reforms and assuming the necessary data and monitoring capabilities will be in place. This scenario (i.e. Straw Person 1 – see section 5.1) would be a continuation of the current GB market ideology. The result is high locational and temporal granularity in the network tariffs, reflecting the short run marginal cost (SRMC) of using the network at particular times and locations. All other aspects of this model are unchanged from the current GB arrangements: uniform pricing in the day-ahead electricity market and in the balancing mechanism; a locational dimension to the charging for transmission losses; and some ancillary services being procured at a specific location (e.g. voltage support).

This approach will always be second best as it seeks to mimic the locational and dynamic nature of nodal prices. The key difference is that the level of network charges under different system conditions would have to be announced well in advance (e.g. annual, months), while LMPs are computed near to real time.

This model would rely on the ability of Transmission Owners (TOs) and DNOs to offer locational network tariff hedges (this may necessitate that the TO collects more revenue from the tariffs than is necessary to cover its costs). If such hedges are not sufficiently accessible, it could result in sub-optimal participant behaviour from a system perspective, resulting in higher overall system costs.

A potential advantage of this model compared to nodal pricing, however, is the ability to signal locational value at very granular levels (potentially down to the low voltage network) without the risk of local generators exerting market power. Generators would have a lesser ability to influence their local network tariff than they would to influence their LMP in the wholesale market, particularly if there exists low liquidity in the market. This is why, under any scenario (e.g. zonal pricing, nodal pricing), locationally differentiated UoS network charges may still be needed at the distribution level until the point at which, due to changing conditions, they could be replaced by local flexibility markets or LMPs at low voltages.

5.3. Nodal vs Zonal: zonal pricing 2nd best but better than network charges

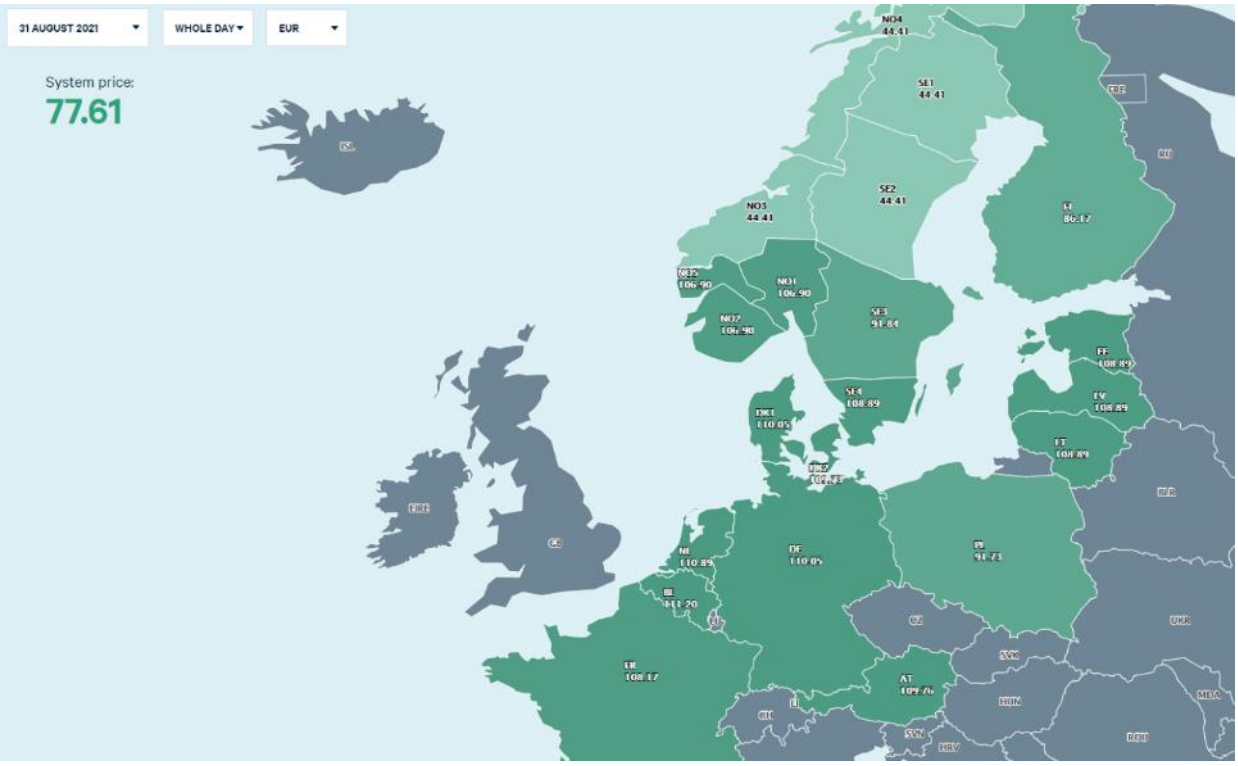
The European electricity Internal Energy Market is based on zonal markets. The boundaries of zones should reflect network constraints. Prices within the zone are uniform, reflecting an assumption that there exists no structural congestion internally. A supplier would pay and recover the same price for any amount of energy that it purchases and supplies within the same zone. If the prices diverge between two zones, the supplier would effectively be charged the price differential between the zone in which it contracted for generation and the zone in which it serves consumers. This differential is the cost of congestion *between* the two zones, but not *within* either zone. Retail suppliers and generators would seek to hedge their exposure to zonal pricing differences. So zonal markets are often accompanied by trading of (financial) contracts for difference for zonal prices.

Trading and market clearing in a zonal market can be achieved while maintaining the current separation between the SO and MO. The model also requires a market clearing algorithm that covers the relevant zones – similar to the market coupling algorithm used in Europe.

Once the SO notifies the available capacities between each zone, offers and bids are placed with zonal power exchanges and are cleared in accordance with a common algorithm (Antonopoulos, Vitiello, Fulli, & Masera, 2020).

The rules governing EU markets are laid down in eight Commission Regulations, commonly referred to as Network Codes. The *Regulation 2015/1222 on establishing a guideline on Capacity Allocation and Congestion Management (CACM)* coordinates the transmission capacity calculation and addresses the definition of bidding zones for the day-ahead and the intraday market time frame. The CACM provides guidelines on how congestion is to be managed, in order to implement single day-ahead and intraday coupling.

Figure 10 Market splitting in Nordpool



Source: https://www.nordpoolgroup.com/Market-data1/#/nordic/map

The zonal market approach is typically based on strong simplifications of the physical characteristics of the electricity grid, which requires countertrading and out-of-market re-dispatch measures to align with the physical characteristics of the grid. As previously mentioned, considerable out-of-market re-dispatch is already occurring. Looking forward to Net Zero and a power system based on a very high share of weather dependent renewables and DER, it would be important that the market design is efficient and minimises such out-of-market interventions. For zonal pricing, this would depend on how well the zone definitions reflect the physical reality of the network under constraint conditions. Zone definitions would need to be updated in a timely manner to reflect changing congestion conditions. Nordpool is the most advanced European power market in terms of implementing zonal pricing (see Figure 10).

The CEPA/TNEI study explored a variant to the zonal pricing model, with nodal pricing in the balancing mechanism. Such an approach could result in an inefficient divergence between

the two markets (day-ahead, balancing) and possibly result in some gaming, especially if day-ahead zones experience internal congestion (CEPA & TNEI, 2021).

Another source of potential inefficiencies could come from the risk that network tariffs could give conflicting locational signals to those provided from energy markets. Nodal markets tend to be free of this problem because relatively simple network tariffs (i.e. residual only) are often applied and they are not designed to offer locational signals. The main sources of divergence between network charges and zonal prices are (CEPA & TNEI, 2021):

- locational granularity (network tariffs would be more locationally specific than the zonal day-ahead prices and zonal/nodal balancing prices); and
- temporal granularity (the lower frequency at which network tariffs are set in this model means that they may not accurately reflect system costs in operational timeframes).

A staged approach to nodal pricing via zonal pricing has been undertaken in some jurisdictions but the evidence suggests this is not a recommended approach, especially if the objective is to transition markets quickly to accommodate rapid growth in VRE and DER.

All markets in the US began with zonal congestion management with physical transmission rights (PTRs). In 1997, the limits of a zonal approach proposed by PECO (Philadelphia Electric Company, now an Exelon company) were identified causing the Federal Energy Regulatory Commission (FERC) to approve the nodal pricing system that became operational in Pennsylvania-New Jersey-Maryland (PJM) regional transmission organization in 1998 (Antonopoulos, Vitiello, Fulli, & Masera, 2020). FERC later made nodal pricing part of its standard market design proposal and all restructured electricity markets in the US moved to nodal congestion management.

A staged transition could result in a greater disruption to market participants, as well as in additional costs incurred in transition to the relevant systems, as indicated by the experience in the Australia's NEM. As an indicator of disruption and controversy, since the NEM commenced as a zonal market in 1998, there have been at least thirteen major reports and reviews related to congestion management and generation access (AEMC, 2019). The primary concern has related to high levels of generation investment inefficiently locating in weaker parts of the system, prompting reinforcements to address the resulting congestion. The authorities are now seeking a more efficient enduring solution and the options under consideration include a blended and complementary approach that brings together strategic/coordinated planning and higher quality price signals through nodal pricing (see Box 1).

Box 1: Market-led and centralised approaches to facilitating a low-cost decarbonised energy system in Australia's National Electricity Market (NEM)

(Source: CEPA/TNEI, 2021)

Australia's NEM operates a real-time only, wholesale electricity market with five pricing zones. Within each zone, there is a single market price, defined as the marginal cost of supply (effectively, the LMP) at a defined zonal reference node. Zonal prices may diverge if there a binding constraint on flows across interconnectors between the zones.

The NEM has been engaged, over many years, in a debate around the adequacy of existing locational signals in the wholesale market, in both operational and investment timescales. **Regulatory bodies – in particular, the Energy Security Board (ESB) and the Australian Energy Market Commission (AEMC) - are of the view that the current zonal pricing model does not encourage new market entrants – including renewable generation and energy storage – to make efficient siting decisions.** This is because although the value of electricity at different locations varies when there is congestion, under the current market design all market participants within a zone are settled at the same price regardless of their location (adjusted for marginal loss factors, which do vary locationally and are set each year by the Australian Energy Market Operator (AEMO)). The primary concern is that this leads to inefficiently high levels of generation investment in weaker parts of the system, which prompts reinforcements to address the resulting congestion (ESB, Post-2025 Market Design, Directions Paper, 2021a).

In previous transmission access reviews, a distinction has been made between solutions that rely on 'centralised transmission system planning' as distinct from 'market based solutions' (involving variants of LMP/FTR models). However, in more recent developments, **a complementary role for both planning and market signals has been articulated.** In particular:

- **Reforms have been introduced to the transmission planning process, including a central role for AEMO in identifying strategically important investments in the transmission system through an Integrated System Plan (ISP).** Regional transmission and distribution network service providers retain a strong role in planning and developing the transmission system, including the final decision to undertake ISP investments identified by AEMO.
- The Energy Security Board (ESB) and Australian Energy Market Commission (AEMC) are further proposing:
    - **As an enduring solution, an LMP/FTR based model** (with both similarities and differences to arrangements in New Zealand and US nodal markets).
    - Interim access arrangements for '**renewable energy zones'** (REZ), which are still to be determined.

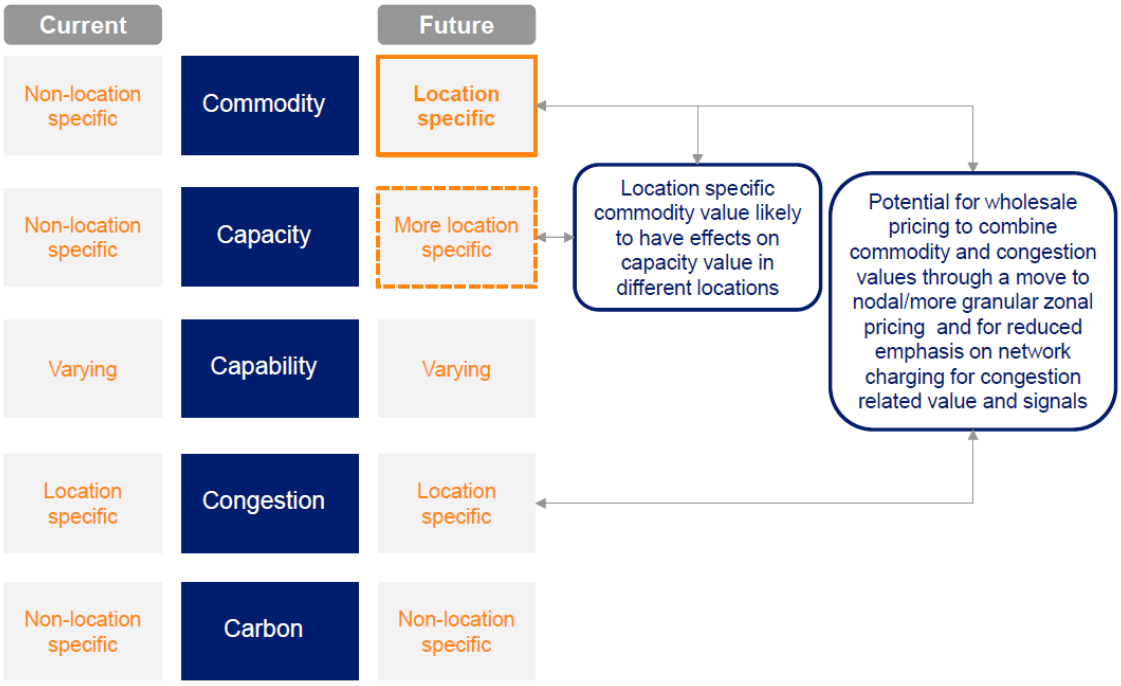
The AEMC and ESB have argued that in order to achieve this outcome in practice, **nodal pricing is required to send appropriate locational signals to new entrant generation and storage facilities (i.e. to prevent future iterations of the ISP diverging from the least-cost development pathway due to inefficient siting decisions).** The AEMC and ESB are exploring a range of design issues, including (ESB, 2021a):

- How to make FTRs as useful as possible for market participants (duration, granularity) while balancing implementation practicalities. For example, market participants have both expressed a desire for an FTR design that meets the hedging requirements of renewable generators (e.g. time-of-use products or variable volume products), while also expressing concern around the overall complexity of FTR procurement.
- How to best manage the transition to nodal pricing, including grandfathering arrangements for existing market participants, without disadvantaging new participants.
- The design of interim REZ access arrangements that are consistent with the proposed enduring model (ESB, Rnewable Energy Zones, Consultation Paper, 2021b).

5.4. Markets based on marginal pricing – prices should reflect all marginal costs

ESC and AFRY's analyses concluded that value for the 5Cs could be much more efficiently revealed through market design reforms, in particular by incorporating more of the 5C value into wholesale energy prices (see Figure 11). Greater locational differentiation in wholesale pricing will also impact capacity value e.g. capacity value may be greater in a demand heavy pricing area.

Figure 11 Locational value in the 5C framework – present and potential future



Source: (Poyry, 2019b)

The current GB power market model is based on marginal pricing. **Wholesale electricity prices are supposed to reflect the full marginal costs of providing electrical energy and reserves to a consumer at a certain moment in time, in a certain location.** Energy prices should therefore reflect the marginal costs relating to network constraints and losses. When all marginal costs are incorporated in wholesale electricity prices, the markets can perform as designed and price formation is efficient – consequently, the need for interventions (i.e. SO redispatch/reserves; Government policies) is much reduced (Keay-Bright & Day, 2021, p. Appendix 2). The current GB model, however, is implementing economic dispatch, ignoring network constraints and sorting them out later through the balancing mechanism. **To reflect the full marginal costs in wholesale electricity prices, <u>security-constrained</u> economic dispatch (SCED) is necessary and this is best implemented through nodal pricing.**

5.5. Clear net benefits where nodal pricing implemented

Studies comparing the costs and benefits of locational energy pricing to network charges always show higher net benefits for locational energy pricing due to increased competition and net economic welfare associated with greater accuracy in locational pricing.

Given their complexity, cost/benefit analysis (CBA) studies for LMP are expensive and time-consuming to carry out though some CBA data are available for the GB market, as presented in Table 1.

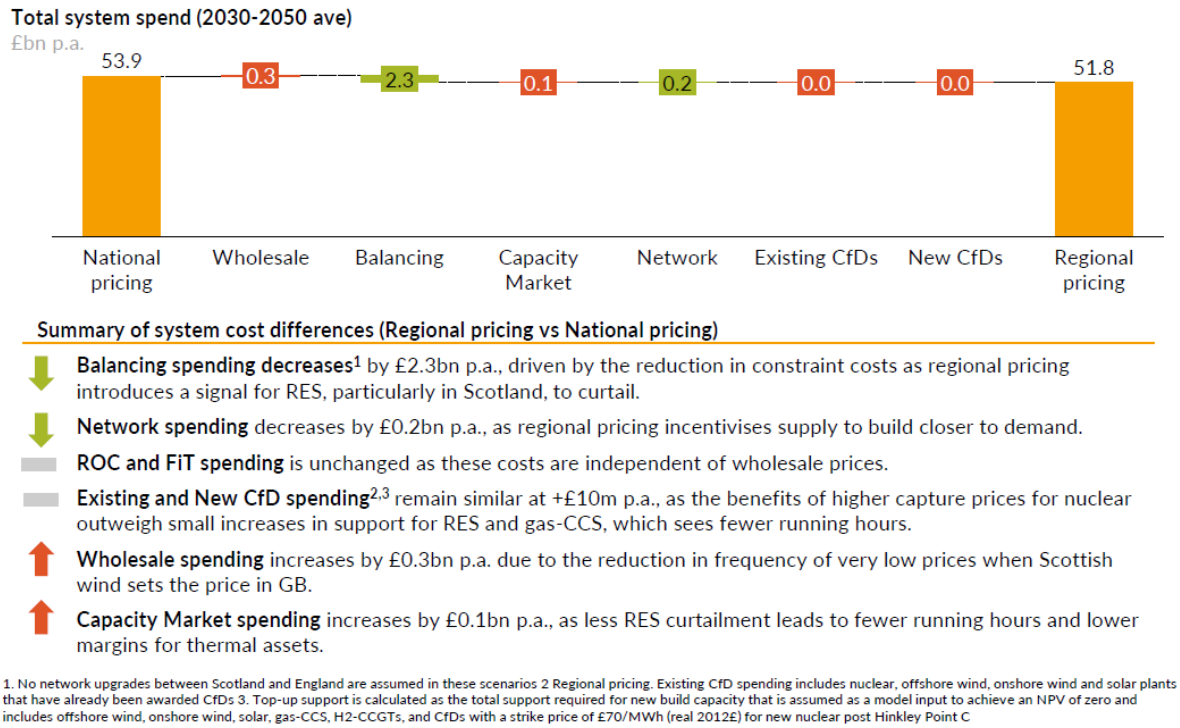
Table 1 Studies into the net benefits of locational pricing in GB electricity market

Study name	Date	Findings
Green, R. Nodal pricing of electricity: how much does it cost to get it wrong? *Journal of Regulatory Economics,* Vol: 31, 125–149.	2007	- The study was based on implementation of a zonal pricing scheme with market splitting based on 12 zones. While published in 2007, it was based on 1997 data and limited to England & Wales. - The combined annual benefit of congestion and losses pricing was estimated to be £73m.*
Staffell, I. and Green, R. Electricity markets in Great Britain: better together?	2014	- The authors found that on average domestic consumers in Scotland would benefit by an estimated £64 off their annual energy bills. - Generators in Scotland would have lower revenues, and consumers in energy-importing areas (such as south-east England) would face higher prices (an estimated average increase in annual energy bills of up to £14 - this estimate does not take account of benefits that would be passed back to consumers from the elimination of congestion costs in BSUoS charge) while generators there would enjoy higher revenues. - While this study looked at distributional effects it did not try to estimate a net benefit figure.*
Aurora, Policy Exchange. Impact of locational energy pricing on Great Britain.	2020	The study, which modelled zonal pricing, found: - reduces total system spending by £50bn cumulative from 2025 to 2050; - lowers household bills in all zones and 33% lower in most northern zone; - provides £37 p.a. savings/household (2030-2050 average); - reduces annual CO_2 emissions by 1 $MtCO_2e$ p.a. (2030-2050 average)

*Quoted in: Appendix 5.2, CMA Energy Market Investigation, 2015.

The **most recent modelling carried out for the GB power market was conducted by Aurora for the Policy Exchange, which involved three bidding zones realising savings of £2.1bn p.a. from 2030 to 2050** (see Figure 12). The largest source of cost savings is the Balancing Market, with balancing costs reducing by £2.3bn p.a. over the two decade time period. Net benefits would be even higher if nodal markets would be simulated for GB; while more granular nodal pricing was promoted by the study, modelling LMPs was out of scope due to resource limitations. It should also be noted that the study did not consider transmission reinforcement.

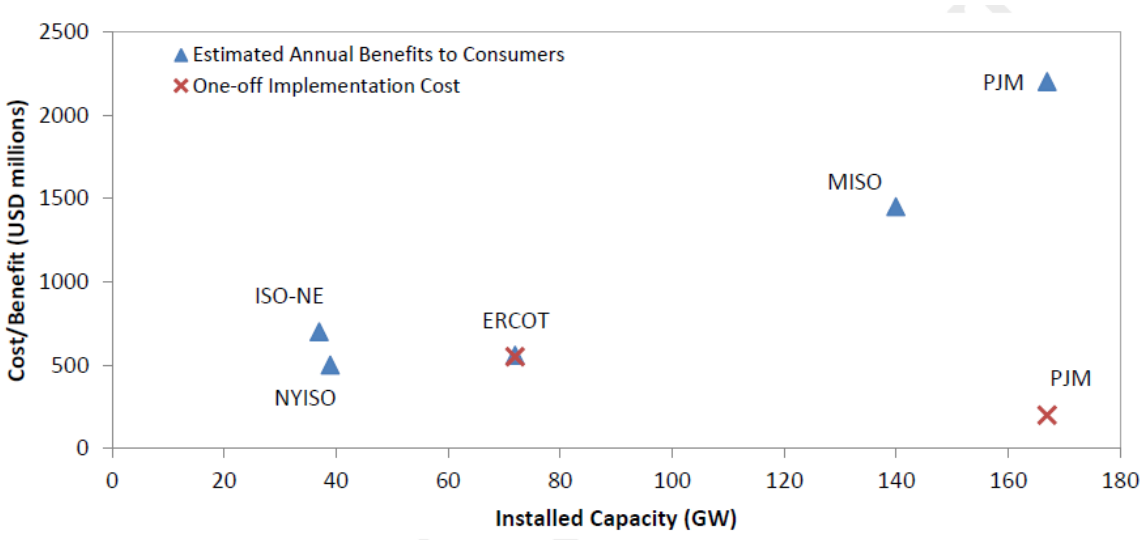
Figure 12 Total system spend comparing national and regional pricing scenarios



Source: (Aurora, 2020).

The US provides valuable experience for the GB market to draw upon as nodal pricing has been in successful operation in the US since the late nineties. **Figure 13 illustrates that the US ISOs typically recovered the one-off implementation costs within a year of operation.** The largest cost components are stated to be the additional need for specialised information technology software and hardware and personnel costs such as training (Neuhoff & Boyd, 2011). **Ofgem and NG ESO should facilitate knowledge exchange with US nodal markets as the US ISOs and regulators have many years of experience in developing the IT systems and training personnel.**

Figure 13: Annual benefits and one-off implementation costs vs. installed capacity



Source: (Neuhoff & Boyd, 2011)

Multiple studies have tried to evaluate the costs and benefits for the different US ISOs moving from the zonal model to the nodal model, and for improving market design. Many of these studies conclude that significant net benefits have been realised - see Table 2.

Table 2 Various cost benefit studies of US ISOs

US ISO	Study/source	Modelled	Observed	Aspects covered in the study
ALL ISOs	Eto, J. H., Lesieutre, B. C. & Hale, D. R., (2005) "A Review of Recent RTO Benefit-Cost Studies: Toward More Comprehensive Assessments of FERC Electricity Restructuring Policies".	-	Yes	Better congestion management, improved grid reliability, increased retail access and competition, reduced transaction costs, improved planning, and better coordination with regulatory agencies.
ERCOT	CRA International and Resero Consulting (2008), "Update on the ERCOT Nodal Market Cost-Benefit Analysis." Prepared for Public Utility Commission of Texas.	Yes	-	Congestion management improvements, reduced costs of ancillary services, reduced gaming, improved competition.
ERCOT	Zarnikau, J., Woo, C.K. & Baldick, R. (2014) Did the introduction of a nodal market structure impact wholesale electricity prices in the Texas (ERCOT) market? Journal of Regulatory Economics 45, 194–208.		Yes	Zonal averages of LMPs under the new nodal market were about 2% lower than the balancing energy prices that would have occurred under the previous zonal market structure.
MISO	MISO, 2009: *Start up and first year of operation*, MISO Value Proposition 2010.	-	Yes	Improved system reliability, competition and management of assets. Reduced ancillary services. Annual benefits of $1.3-$1.6 bn include deferred investment.
ISO New England	RTO, 2005: *Value of Independent ISOs*	-	Yes	Reduced wholesale market power price, improved dispatch.
NYISO	Analysis Group, 2007: *A CBA of NYISO Initial Years*	Yes	-	Benefits to O&M, improved market performance, improved generator dispatch.
PJM	Ott, A. 2010: *Personal communication*, PJM Value Proposition 2010.	-	Yes	Reliability, congestion improvements. Generation investment savings, grid services savings (reduced ancillary and regulatory costs). Energy cost savings.
CAISO	Wolak, F. A. (2011) "Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets." *American Economic Review*, 101(3): 247-52.		Yes	The total hourly energy consumed and total hourly operating costs for all natural gas-fired generation units fell by more than 2% after the implementation of LMP.

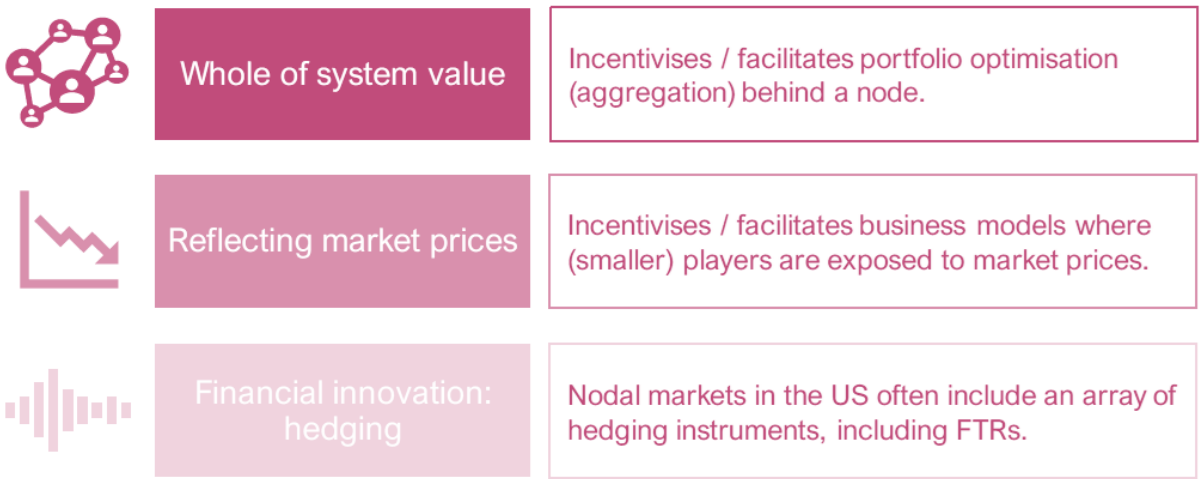
Source: (Neuhoff & Boyd, 2011)

5.6. Nodal pricing positive for innovation

The vision for future modern energy systems envisages unlocking the potential of the demand-side through business model innovation that can exploit digitalisation, big data, artificial intelligence, the Internet of Things, automation, advanced control, blockchain and so on, and translate this into products and services that meet the needs and preferences of consumers (Borowski, 2020; IRENA, 2019; Keay-Bright & Day, 2021). Such business model innovation, however, requires highly accurate system-reflective prices.

The introduction of nodal pricing is expected to drive innovation in multiple ways. Locational differentiation in prices at different nodes across the transmission network would encourage co-location of generation and storage, the siting of generation or demand reduction investment near centres of high energy demand, portfolio optimisation behind a node, greater flexibility, more efficient dispatch and use of market-led risk mitigation tools (e.g. financial transmission rights) (see Figure 14 How nodal pricing could support innovation in GB energy markets).

Figure 14 How nodal pricing could support innovation in GB energy markets



Source: (CEPA & TNEI, 2021)

5.6.1. Innovation in financial markets

All nodal markets and many zonal markets have developed to enable participants to hedge their exposure to nodal/zonal prices. PJM offers an example of a market with highly liquid forward trading at the Western hubs (the most liquid of the 20 hubs in the PJM system), with FTRs being used to hedge price difference between the hubs. In Europe's zonal markets, Electricity Price Area Differentials (EPADs) are used to hedge differences between the system price and bidding zones prices.

The experience from market participants and regulators suggests that existing contracting strategies of market participants, and how these might evolve in a market with stronger locational market signals, are a relevant consideration in the design of appropriate congestion hedging instruments (CEPA & TNEI, 2021).

5.6.2. Nodal pricing, complex bids and DER

The nodal pricing model can involve unit-based bidding from all market participants and submission of 'complex bids'[16]. These bids incorporate variable costs, start-up and no-load costs, and information on operational parameters, such as ramping rates, minimum load levels and start-up times.

In designing the new market design, close attention would need to be given to ensure the SO sets up the centralised system in a way that maximises participants' access by ensuring market rules, administrative and procurement requirements, and evaluation of bids and offers are fair and reasonable.

Intermediaries may play a role in bridging the gap between the market's requirements and smaller participants' ability to meet those requirements. For example, reforms in the state of New York offer a recent example of the additional changes to regulation and market design that may be required to enable local flexibility solutions in nodal markets – see Box 2.

[16] This should not be confused with another form of complex bids used in European power exchanges – known also as block bids because the bidder can stipulate a number of consecutive hours and required revenue from the period – are less compatible with nodal pricing because they are a less accurate representation of generators' technical parameters.

Box 2: Case study – Integration of DER into a system with locational energy prices in New York

NYISO is currently undertaking reforms to open their wholesale energy, ancillary services and capacity markets to a wider set of DER. These reforms started in 2017 with full implementation of new DER rules scheduled for 2021. In preparing for these reforms, NYISO found that DER mostly participated through demand response programs. In addition, participation was predominantly through reliability-based programs including the emergency demand response program (EDRP) and the special case resource (SCR) program. Other demand response programs include the day-ahead demand response program and the demand side ancillary services program.

NYISO concluded that **achieving integration of DER across all markets required ensuring that DER are dispatchable** and follow many of the rules applying to traditional generation resources. NYISO currently operates nodal pricing for generation, while load prices are set for 11 zones based on the load weighted average of nodal prices. Ensuring granular pricing at the nodal level for DER was seen as a way to ensure more economically efficient DER benefits, as well as encouraging investments at the most economically efficient transmission location.

Under the current demand response programs, aggregators are permitted to aggregate resources at the zonal level, while **under the proposed reforms DER will only be allowed to aggregate at the transmission node level.** This was seen not only as a way of ensuring appropriate nodal pricing but also ensuring that system constraints were modelled appropriately and by extension helping to achieve reliability. Aggregations behind a single transmission node should appropriately recognise intra-zonal congestion and achieve localised price formation.

A key part of the DER reforms will be reducing the minimum bid size from 1MW to 100kW, with the ability to meet the 100kW requirement using aggregation. NYISO identified a potential problem with allowing the number of entities to increase. As the number of entities increase, the processing time required by NYISO's Security Constrained Economic Dispatch (SCED) also increases. **To minimise negative impacts on the SCED, NYISO is proposing to 'Super Aggregate' offers of less than 1 MW behind the same transmission node.** Once offers are super aggregated, they will be considered by SCED as a single resource. If a super aggregation is awarded a schedule, NYSIO will then disaggregate and distribute this in increments based on the individual offers.

Source: (CEPA & TNEI, 2021)

5.6.3. Centralised system/market operation, mandatory pool and algorithms

As nodal pricing is intended to ensure a balanced supply-demand position at each node while ensuring transmission constraints are respected, central dispatch and use of an algorithm to determine clearing prices is necessary.

The need for a centralised market clearing algorithm is not unique to nodal pricing markets as algorithms are also applied in the EU to allocate transmission capacity between pricing zones in the context of market coupling. In this case, Nominated Electricity Market Operators (NEMOs) act as the interface between self-dispatch and the need for optimised market clearing.

Despite the need for central dispatch, most nodal markets allow bilateral contracting and self-supply/scheduling in both day-ahead and balancing markets – enabling innovation in managing participants' financial exposure to locational price risk and potentially supporting innovative business models.

Generators can choose to self-dispatch but need to provide a notice (FPN) at the injection node and the consumer needs to do so at the withdrawal node. The two parties to the bilateral contract can agree any price for this (as with CfDs) but they have to pay the transmission charge between the nodes, based on the LMP differences. Generators must follow the SO's dispatch instructions (and accept charges for losses and congestion) if they wish to inject/withdraw power into/from the system as is currently the case with the GB balancing market.

The distinction between centralised and decentralised models may be more nuanced in practice. In particular, the PJM market contains strong elements of a decentralised model, including self-scheduling and voluntary participation in the day-ahead market for some market participants (CEPA & TNEI, 2021, pp. 25, Case Study 2)

While there is no theoretical issue with self-supply in a nodal price market, there is a practical issue caused by the need to centrally calculate the LMPs. If at least some of the self-schedules or FPNs do not give offer prices, there would be no obvious way to set the LMPs or determine who could generate, and hence the key points of locational signals and the benefit of minimising system cost would be lost (CEPA & TNEI, 2021). The question is, therefore, what fraction of bids would need to be price-elastic to deliver meaningful prices.

Given the benefits of a pool compared to self-scheduling (see Table 3), however, **mandating participation in a pool should be considered.**

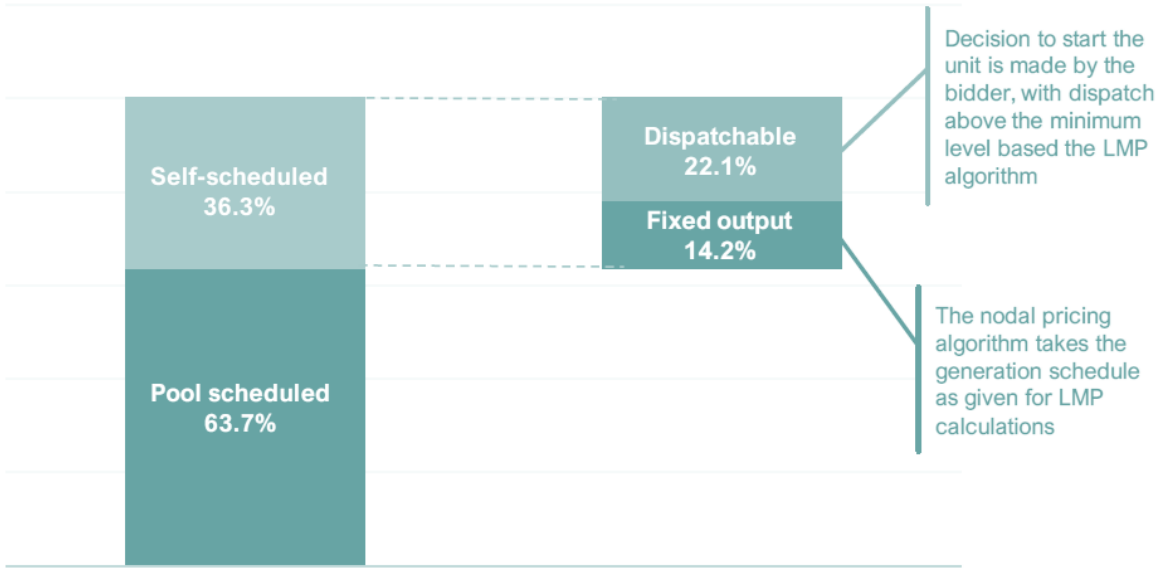
Table 3 The rationale for selecting a pool market as opposed to only self-dispatching

Structure	Pool
Suitability for variable renewable energy	• Reduced risk of facing imbalance charges as a result of a central market which pools liquidity. • This promotes the ability for renewable energy generators to procure, or sell, depending upon the environmental conditions which may result in deviations from contracted positions.
	• Due to standardised products, trades can operate on a faster timescale allowing them to occur closer to real time compared to continuous trading. • This also allows renewable energy generation to react to fluctuations in output due to environmental conditions and mitigate imbalance charges.
Transparency	• Uniform price auction provides transparency and ensures that the least expensive and most efficient generating unit or service is dispatched.
	• Market prices are visible to buyers/traders/sellers.
Reducing trading costs	• Typically lower transaction costs than continuous trading.
	• Safe counterparty risk, often provided by the central exchange.

Source: (Pownall, Soutar, & Mitchell, 2021)

A significant share of demand in established nodal markets is self-dispatched/self-scheduled. Figure 15 shows that self-scheduling made up a sizable share of generator offers into the PJM real-time market during the first nine months of 2020. There is no evidence as yet that the level of self-scheduling seen in PJM has had an adverse impact on LMP formation.

Figure 15 Self-scheduling in PJM (January – September 2020)



Source: Presented in (CEPA & TNEI, 2021) *based on Monitoring Analytics (2020), Quarterly State of the Market Report for PJM: January through September, p.101.*

There could be various reasons why resources choose to self-schedule. For example, depending on the market price floor and other factors (such as out of market payments), resources with low or zero marginal cost may opt for self-scheduling on the basis that their LMP is unlikely to fall below their marginal cost of production (Orvis & Aggarwal, 2018). Contractual arrangements may also play a role. However, some commentators have expressed concerns regarding the implications of high-levels of self-scheduling for the efficiency of day-ahead market outcomes.[17]

Most US markets tend to be dominated by incumbent suppliers that are vertically integrated utilities, and retail competition in most states is limited. **The ability to generate meaningful LMPs may be different in the GB market, which is characterised by retail competition but with vertical integration of generators and suppliers. This merits closer investigation.**

5.6.4. Market and regulatory innovation at distribution level – GB as pioneer?

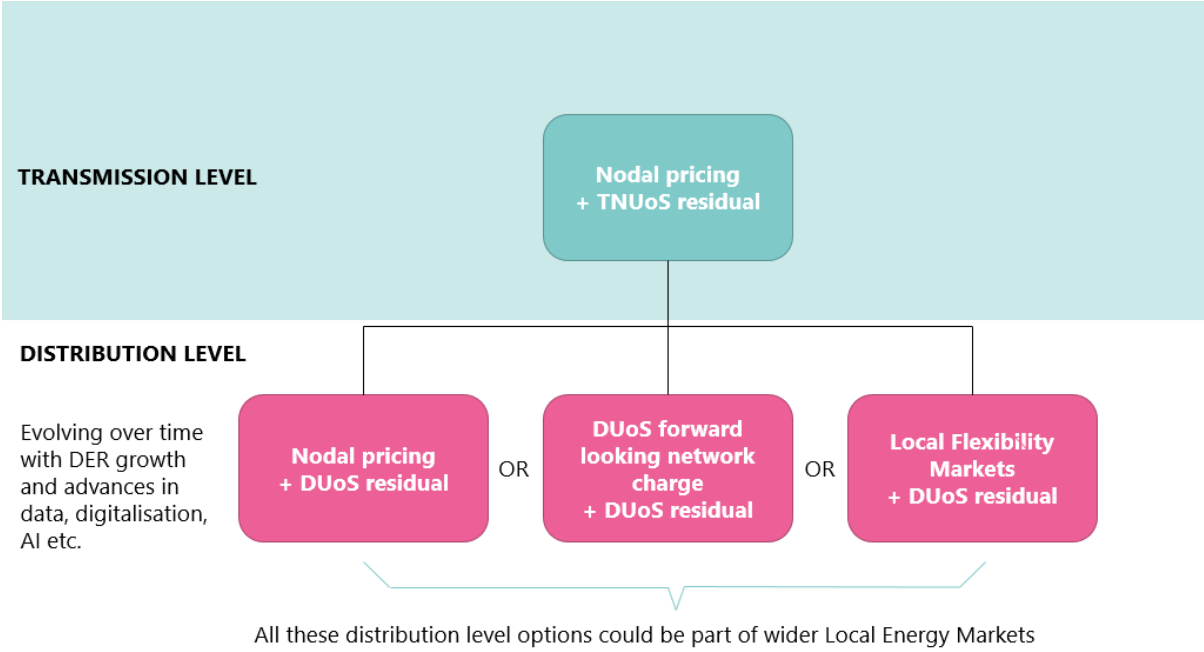
Data availability and monitoring capability at the distribution level is typically inadequate for implementation of LMP but also the need for locational signals at distribution level has until now been weak though will change with DER growth.

There will be practical limitations to how low down the voltage levels nodal pricing could be applied.[18] For nodal pricing to result in efficient outcomes across all voltage levels in operational timeframes there would need to be alignment between system-wide signals

[17] See for example, Wolak, F.A. (2010) Presentation - The Economics of Self-Scheduling, CAISO. http://www.caiso.com/Documents/Presentation-Economics-Self-Scheduling-MSCPresentation.pdf
[18] See detail of straw-person 3 in Appendix 1 - Detail of the three straw-persons for examining locational signals in operational timeframes.

provided at the higher voltage level through nodal pricing and price signals provided at lower voltage levels, which could be through various options – LMP, distribution network charges or local flexibility markets – as illustrated in Figure 16.

Figure 16 - Locational signal options for the distribution level



Source: Sarah Keay-Bright, ESC

Nodal pricing implemented at the transmission level would create a local market behind each node. Instead of designing highly granular distribution network charges by space and time, locationally-specific dynamic price signals could be sent via flexibility platforms/marketplaces[19]. In this case, the distribution network tariffs would need to be simple (e.g. flat tariffs). Various designs for flexibility markets are possible (CEPA & TNEI, 2021). For example:

- network tariffs being set at a level that reflects peak conditions, with the marketplace offering payments for flexibility actions, thus reducing the effective tariff for participants; or
- the marketplace applying mandatory charges for non-participation.

From the SO's perspective, the LMP algorithm treats aggregated generation behind a node (net of aggregated demand behind the same node) the same way it would treat a single generator or load of the same capacity if it were located at the same node. From a supplier's perspective (or a DNO/DSO's perspective), it can minimise its exposure to the nodal price by

[19] In the absence of nodal pricing at the higher voltage level, such marketplaces would need to cover both the distribution and transmission levels. This approach could be seen as analogous to 'World B: Coordinated DSO-ESO Procurement and Dispatch', which was explored by the Energy Networks Association in its Open Networks project. See: ENA (2018), Open Networks Future Worlds, Developing change options to facilitate energy decarbonisation, digitisation and decentralisation.

reflecting it in charges to consumers to drive consumption/distributed generation behaviour. Effectively, the supplier (or DNO/DSO) is incentivised to optimise their portfolio of local DER behind the node. These could then be aggregated – facilitated through a Local Flexibility Market - and offered into the wholesale markets in addition to being used to manage the distribution network.

Market participants will likely need to hedge their exposure. Consistency of locational signals for investment (e.g. from connection charges, network charges) across voltage levels is particularly important for avoiding inefficient outcomes.

In future, LMP could be gradually extended to lower voltages with DER growth and with improvements at the distribution level in relation to network monitoring, digitalisation and availability of data and ICT. This could be facilitated through a mixture of flat and nodal prices (Savelli & Morstyn, 2021). This would change the role of flexibility markets over time, if LMPs extend to lower voltages in time.

Considerable research is underway in the UK – with several projects supported under the Prospering From the Energy Revolution (PFER) programme[20] - to explore and prove the value, impact, and routes to investment in Smart Local Energy Systems (SLES) in order that they can support the transition to Net Zero. Several of these research projects explore LMP applied to the distribution level, including:

- The design of a new framework that uses both nodal and flat energy prices at distribution level to enable the coexistence of flexible and non-flexible users/resources in a local distribution area. Flexible users will pay nodal prices, whereas non-flexible consumers will be charged a flat energy price derived from the underlying nodal prices. The developed approach shows how a distribution system operator should manage the local grid by optimally determining the lines to be expanded, and the collected network tariff levied on grid users, while accounting for both congestion rent and investment costs (Savelli & Morstyn, 2021);
- Modelling of an organised distribution LMP market structure for each of the nodes within a distribution network as a means to aid in coordinating actions taken between the DSO/DNO and TSO/ESO (Papalexopoulos, Frowd, & Birbas, 2020);
- Modelling of a new local energy market within the distribution systems to integrate peer-to-peer (P2P) trading and probabilistic distribution LMP pricing (Morstyn, Teytelboym, Hepburn, & McCulloch, 2020)
- Incorporation of distributed LMP as part of a modular market design proposal to realise DER value (Pownall, Soutar, & Mitchell, 2021)
- Development of a concept for a Multi-Vector Energy Exchange for the Liverpool area[21] that will enable trade of local energy (e.g. P2P, electricity, hydrogen) and flexibility (e.g. provision of balancing and network services to DNOs and ESO), potentially using locational marginal pricing within the local market.

[20] https://www.ukri.org/our-work/our-main-funds/industrial-strategy-challenge-fund/clean-growth/prospering-from-the-energy-revolution-challenge/
[21] https://www.essex.ac.uk/research-projects/lmex

5.6.5. Nodal pricing as part of wider market design reform package

The current approach to developing the GB power system reflected in the Government's Energy White Paper and Ten Point Plan is to "get stuff built" – that is, large-scale generation and transmission networks - to meet growing energy demand. The Government has set a target of 40GW for offshore wind to be built by 2030 and current policy is to procure the zero carbon capacity needed through Contracts for Difference (CfDs).

It is not yet clear for how long the Government will continue to determine the power mix and secure its targeted carbon emissions reductions using CfDs. Through CfDs the Government determines the volume of capacity to be built and strongly influences the power mix. Furthermore, the design of the CfD scheme distorts bidding behaviour in the short-term wholesale electricity markets (i.e. spot markets) and distorts siting decisions for the capacity.

In its recent publication – Rethinking Electricity Markets (Keay-Bright & Day, 2021) - ESC identified a number of issues and risks in continuing with the current market and policy arrangements, including hampered innovation and failure to unlock the potential of the demand-side and DER. ESC proposes to develop the policy framework in a way that helps improve the performance of the wholesale, retail and financial markets to deliver efficient outcomes for consumers. This requires improving market signals so they are free of distortions and much more granular by space and time, ensuring key enablers and safeguards are in place (e.g. consumer protection, market monitoring, data, interoperability, governance).

ESC proposes replacing the Electricity Market Reform (EMR) policy with an outcome-based policy framework that would be applied to the retail market (e.g. decarbonisation obligation on electricity suppliers; decentralised reliability mechanism), so that retailers and consumers drive markets to deliver affordable, decarbonised and reliable power and energy services. This approach would provide greater opportunity for innovation to unlock the system value of demand-side resources while better meeting the needs and preferences of consumers.

The current governance arrangements of the power system also set back progress in driving greater innovation and realising consumer benefits. Highly relevant to the discussion on nodal pricing is the conflict of interest with system operators owning networks, due to real or perceived biased that asset owners may have towards solutions and activities that build out the network, potentially costing more for consumers than is necessary. It also means they can be potentially biased towards certain market design and policy arrangements and Ofgem is aware of this, citing the example of nodal pricing in its paper supporting the proposal for establishing an independent Future System Operator (see Box 3 below).

Box 3: Importance of removing bias from the system operator - case study of LMP as presented verbatim in Ofgem, *Review of GB energy system operation*, January 2021.

Locational signals are arguably more important in a decarbonising world. Locational marginal pricing is a way for wholesale energy prices to reflect the value of electric energy at different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system. It can mitigate the potential negative impacts of uniform national pricing, such as:

- **Congestion rents** – additional revenue earned by parties that transfer energy over a constraint as a result of that constraint, being diverted away from consumers.

- **Inefficient investment signals to locate for supply sources and storage** - resulting in higher capital costs, for example, as more transmission network investments are required. The variable costs of electricity generation may also be higher (relative to a scenario with locational marginal pricing), as a result of poorly-located sources of supply.

The benefits of locational marginal pricing could be billions of pounds in net present value terms depending on factors such as congestion levels, the generation mix and network access arrangements in the region. For example, benefits arise from lower balancing costs and lower investment costs as investors take fewer but better located supply and storage investments and fewer transmission network investments are required through better use of the existing network infrastructure.

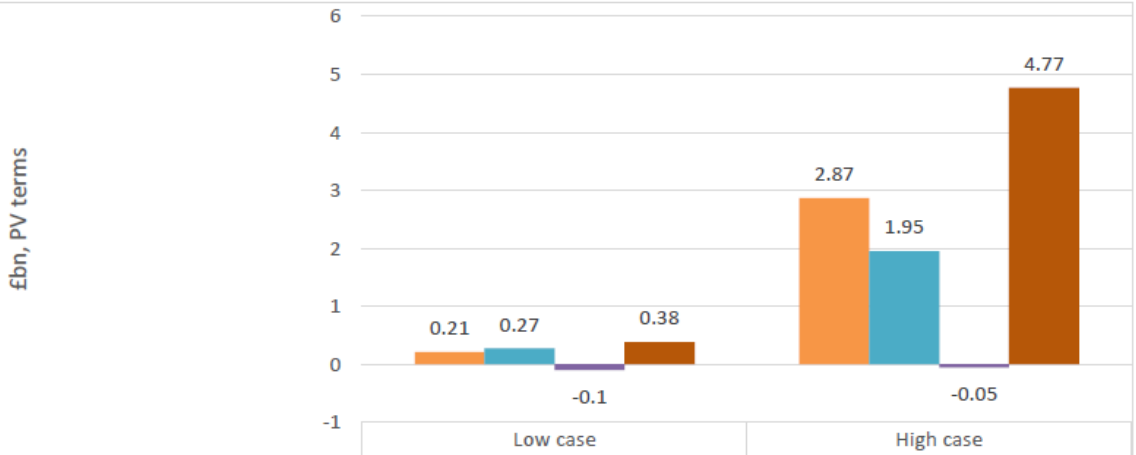
Ownership relationships with transmission network owners may create real or perceived bias in any views the SOs provide on the merits of such market design options because they can reduce the need for transmission network assets.

While it is difficult to determine the proportion of forecast total expenditure that may theoretically be 'overspend' with any degree of confidence, consultants have estimated it could be between 1% and 10% for the GB system based on discussions with Ofgem (FTI Consulting, 2021). This gives an estimated theoretical benefit of between £0.2 billion and £2.9 billion (in present value terms) for removing the potential NG ESO asset ownership bias (see Figure 17).

Ofgem proposes to remove this conflict of interest through governance reforms and is currently consulting on the form of a Future System Operator (FSO)[22]. Depending on the effectiveness of the objectives, funding and governance arrangements established, this could present a significant opportunity to develop much more efficient system operation, coordinated and strategic planning and much better functioning electricity markets. This move could also facilitate implementation of nodal pricing.

[22] https://www.ofgem.gov.uk/publications/consultation-proposals-future-system-operator-role

Figure 17 Estimated impacts of removing asset ownership conflicts in electricity system operation arrangements (2022-2050)



	Low case	High case
Avoided over-investment in the transmission network	0.21	2.87
More effective competition in delivery of transmission network assets	0.27	1.95
Implementation costs	-0.1	-0.05
Net	0.38	4.77

Source: (FTI Consulting, 2021)

For the GB market, implementing nodal pricing may mean combining the role of power exchanges and system operator within the single system operator (SO) entity, as in US markets. That said, the functions of SO and market operator (MO) could remain separated as in the electricity markets of Singapore and New Zealand where the SO is not responsible for generating LMPs. However, a review of these markets by CEPA/TNEI suggests that primary responsibility for price formation does in practice rest with the SO, reflecting the data and modelling requirements for the calculation of nodal prices and both jurisdictions operate a real-time only energy market (CEPA & TNEI, 2021)[23].

[23] CEPA/TNEI did not identify examples where the division of MO and SO responsibilities has been tested internationally in the context of a nodal day-ahead market.

6. The backstory of locational energy pricing in GB

In GB, locational energy pricing has been considered and rejected several times. Below we set out several of these key events over the last decade with the reasoning for the rejections.

From 2008 to 2010, the Government undertook the Transmission Access Review (TAR) and Project TransmiT - an independent and open review of transmission charging and associated connection arrangements. Ofgem commissioned three academic teams in December 2010 (Newbery[24], EPRG, the University of Cambridge; Bell et al, Strathclyde and Birmingham Universities[25]; and Baldick et al, from a number of American universities[26]) and asked them to provide their views on the optimal approach to transmission charging for Great Britain given the new challenges networks face. The experts were asked to consider several objectives, including value for money and a timely move to the low carbon energy sector. A summary of their favoured options is set out in Table 4 below.

The experts foresaw some of the issues the GB market experiences today such as self-dispatch resulting in generators being paid to resolve congestion they have caused, giving rise to perverse incentives to increase congestion. As shown in Table 4, LMP received greater support compared with market splitting (i.e. zonal pricing) though there was suport for adopting a zonal approach as an interim step towards nodal pricing, which reflected the influence of the EU at the time.

Ofgem then asked the Energy Policy Group (EPG) of the University of Exeter to provide a critique of the three original reports, including whether the experts struck an appropriate balance in key areas of trade-off between potentially conflicting objectives. EPG concluded that potential trade-offs had not been adequately considered, particularly between cost efficiency and increased low carbon deployment. This critique, combined with the Energy White Paper published in 2007 (that later led to the Electricity Market Reform policy and Energy Act 2013), which had identified that wind farms were having difficulty connecting to the grid, resulted in the Government rejecting locational energy pricing in favour of 'Connect and Manage' and Investment Cost Related Pricing. While there was consensus that locational energy pricing would be the lowest cost option, it was concluded that it might hold back development of renewable energy generation due to factors such as lower prices, additional volatility and uncertainty.

Locational energy pricing came up again in 2015 during the energy market investigation carried out by the Competition & Markets Authority (CMA), which issued a paper on locational pricing in the GB electricity market. It concluded, *"There is a wide consensus that in principle a well-functioning market would have spot prices that include an element reflecting short-run locational costs. The impact on competition – on the technical efficiency of production; on the competition between fuels and other goods in consumption; and on the competition between locations for siting generation and supply – would be positive."*

[24] https://www.ofgem.gov.uk/publications-and-updates/high-level-principles-guiding-gb-transmission-charging-and-some-practical-problems-transition-enduring-regime-david-newbery

[25] https://pure.strath.ac.uk/ws/portalfiles/portal/67589703/Bell_etal_TransmiT_2011_academic_review_of_transmission_charging_arrangements.pdf

[26] https://www.ofgem.gov.uk/sites/default/files/docs/2011/05/ofgemreport_usteam_revised_2011_05_01_0.pdf

Table 4 Evaluation of transmission charging arrangements by the three original Project TransmiT expert reports and their critical review

Range of charging options	D Newbery, EPRG, University of Cambridge	Bell et al, Universities of Strathclyde and Birmingham	Baldick et al, various US universities
Full LMP with flat charging		++	+++
Full LMP with deep connection charging	+++		
Market splitting	+	+	+
Locational TNUoS – enhanced			++

+=possibly implies; ++=implies and considers in a positive light; +++=argues for
Source: Mitchell, 2011[27].

This conclusion was based on evidence presented in the paper, including various studies estimating costs and benefits. It also set out the history of failed attempts to introduce locational energy pricing in GB, the arguments for and against put forward by different market actors with attention to welfare and distributional impacts and transitional costs. In the end, CMA instructed National Grid to implement locational charging for transmission losses but not congestion. The final design adopted included the use of semi-marginal transmission loss factors.

The most recent rejection was when Ofgem issued a discussion note as part of the SCR NAFLC review[28]. While Ofgem concluded that LMP would be the best way to send short run charging type signals as it allows market-based price discovery, it rejected the option because of the practical challenges that would mean it is not viable in the nearer-term for the *distribution level* and therefore could not be within scope of this particular SCR.

The practical issues highlighted by Ofgem include those set out in Table 5 below, along with ESC's response to those challenges. While it is the case that the data quality and monitoring are currently inadequate at distribution level to introduce LMP at the distribution level for the timeframe of this SCR, the reasons stated do not justify ruling out implementation of LMP at the transmission level now. However, Ofgem has recently announced it will be launching a Call for Evidence regarding the undertaking of a broader review of TNUoS charges, which could present the opportunity to consider nodal pricing.[29]

[27] https://www.ofgem.gov.uk/publications-and-updates/academic-review-transmission-charging-arrangements-university-exeter
[28] https://www.ofgem.gov.uk/sites/default/files/docs/2019/09/000_-_working_paper_-_summer_2019_-_locational_charges_note_final.pdf
[29] http://www.chargingfutures.com/about-charging-futures/charging-futures-forum/22-september-2021-forum-webinar/

Table 5 Reasons set out in Ofgem's SCR NAFLC review for rejection of locational energy pricing

Ofgem reason for rejection	ESC response
• **The framework to allow for hedging is very complex.**	• **Hedging is an essential feature of any market where market actors need to manage risk.** • GB can draw from the extensive experience of various other jurisdictions that successfully use nodal pricing – complex hedging arrangements have not been a block to introducing nodal pricing in other jurisdictions. • **GB does not need to tread new ground in this area.**
• **It would involve a fundamental redesign of the wholesale electricity market.** ○ Particularly, most LMP models involve market clearing and dispatch decisions being centralised and determined through an algorithm, which would be a major change from our current system of self-dispatch.	• It would indeed involve a **fundamental redesign** of the market but this is **necessary given the growing evidence that the current system/market is already having considerable difficulty** to efficiently integrate variable renewables. • While centralised dispatch, a transparent pool and use of algorithms are necessary, the **benefits resulting for consumers from improved market performance are considerable and far outweigh the costs**. • Algorithms are already in use in the GB electricity market for management of cross-border trade through interconnectors.
• **Network models and monitoring – LMP is highly dependent on highly granular, rich network data that is kept well maintained.** ○ This is necessary to determine how hedges are defined and manage network constraints in operational timescales.	• **The state of data quality and monitoring in networks (particularly at distribution level) is not fit for Net Zero** given the rapid and high growth in variable renewables and DER that we can expect. • **This needs to be dramatically improved** under any market design scenario.
• **We are not aware of any examples where LMP has been introduced at a distribution-level on a national basis.** ○ This is largely due to the very significant practicality issues. The possibility to extend LMP to distribution networks ("D-LMP") is possible in theory and is an area of active research and investigation. ○ However, this significantly increases the complexity of arrangements and degree of feasibility challenges. This includes both challenges with sufficient network data and computational power, and potentially increased difficulties in establishing an effective hedging market which could need to include smaller users (including consumers). ○ There is the additional risk that there could be insufficient liquidity in hedging markets for very localised distribution network constraints, with a low number of market participants behind them.	• LMP has not been introduced at distribution level yet, but **the case for it strengthens with growth in DER and advances in digitalisation, monitoring and ICT**. The UK is far ahead of most other countries in terms of its progress and commitment to Net Zero. • **The GB electricity market will have the need for more granular locational price signals at the distribution level ahead of other markets, including those that already have LMP. GB could therefore be a pioneer in introducing LMP at the distribution level.** • LMP at the transmission level, however, could be rolled out now yielding considerable benefits for consumers. • In time - with experience from implementation at the transmission level, improvement in data, network monitoring and ICT at the distribution level and with growth in DER (and therefore liquidity) - LMP could potentially be extended into lower voltage levels. • In the meantime more temporally and spatially granular distribution use-of-system tariffs or local flexibility markets should be introduced alongside nodal pricing at transmission level.

7. The timing is right for nodal pricing in GB

7.1. Variable renewables have become the new baseload

A key reason why nodal pricing was not adopted during the Transmission Access Review (TAR), mentioned in the previous section, was because it might hold back development of renewable energy generation. The GB power market is in a very different place now as EMR has successfully driven down the cost of renewable energy and enabled deployment at scale, particularly for offshore wind. Several key renewable technologies have matured.

The challenge now is to continue driving investment while enabling innovation across the entire energy system to ensure efficient integration of VRE/DER and activation of the demand-side. Section 3 highlighted that balancing costs are higher than they need to be and the situation is likely to worsen. If issues become increasingly visible – particularly with rising costs but potentially worsening reliability (operational stability) - consumers and market actors will become increasingly aware of and frustrated by GB's sub-optimal market arrangements.

Market design and policy reforms must simultaneously address multiple challenges – ESC has identified five challenges relating to: consumer focus, zero carbon resource investment, network investment, system integration, and policy governance (Keay-Bright & Day, 2021). Reforms to market design, the complementary policy framework and governance arrangements must reorientate towards consumers and the whole energy system.

7.2. Digitalisation and electrification of demand underway and coming fast

The digitisation and automation of the energy system makes it possible to efficiently integrate variable renewable energy generation and distributed energy resources but it needs to be complemented by highly granular prices by time and location as successful business models will depend on market signals being able to reflect full system value. Reforms, such as nodal pricing, which can improve the quality of price signals in the short-term energy markets will improve the business case for and the participation of the resources that are most able to contribute to system efficiency.

Progress in digitalising the system is progressing at pace, with for example, recommendations of the Energy Data Taskforce[30] (Energy Systems Catapult, 2019) being implemented. The barriers to demand response are being systematically identified and addressed through the Ofgem/BEIS Smart Systems Flexibility Plan (SSFP)[31] though the scope of this plan is constrained to the current market design. Many of the measures to enable demand response will be in place by 2025. It will take several years to implement nodal pricing but started now, would have the best chance of coordinating with the current reforms underway.

The UK is one of the most ambitious countries in the world with regards to reducing carbon emissions given its commitment to Net Zero by 2050, which is enshrined in law and the carbon budget process of the independent Climate Change Committee. Given the rapid

[30] https://www.gov.uk/government/groups/energy-data-taskforce
[31] https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021

deployment of variable renewable generation in the UK to date and the needed growth in variable renewable generation and DER to match its ambition, it is ironic that the UK has not yet implemented locational energy pricing when the need for it is growing, while other jurisdictions with nodal markets are far behind the UK in decarbonising their power systems. Once the ambition of such jurisdictions with nodal pricing increases, LMPs could potentially facilitate rapid and efficient decarbonisation of their energy systems.

There are signs of growth in participation of DER in nodal markets of some jurisdictions. As of March 2021, there was nearly 9GW of demand response active in the PJM electricity market based in the US, operating out of more than 15,000 locations on the system (PJM, 2021). Of this, just under 1.4GW was 'economic demand response', which is treated as equivalent to generation capacity in the LMP calculations. Over the last five years DER has made up around 15% of demand-response capacity offered in the PJM market, with over 1.2GW of DER capacity offered on average annually during this time (PJM, 2021).

Nodal prices, however, may be perceived to be unfair or undesirable because prices can vary from one location to another, even within a small neighbourhood, and they can also fluctuate significantly from one time period to another and consumers are not equipped to manage this. There are also consumers who are not willing or able to provide flexibility. Many consumers do not have electric vehicles or heat pumps, though this will change with time. Furthermore, only part of a consumer's load profile may be flexible.

Consumers would unlikely be directly exposed to nodal prices, however, as retailers mediate retail prices/tariffs. Some consumers may prefer a dynamic contract for all or part of their load, as they prefer to set the automated control of their asset(s). Other consumers may prefer flat rates (e.g. monthly) incorporating incentives or discounts in exchange for their willingness to offer flexibility enabled by automation and a service provider that would stack value for flexibility from various sources and manage risk on their behalf.[32] Many consumers not able or willing to offer flexibility would also want a flat tariff.

Pricing frameworks can be designed to encourage flexibility while accommodating or safeguarding consumers that have limited flexibility or may be vulnerable. For example, Savelli and Morstyn (2021) propose a new framework based on both nodal pricing and fixed prices at the distribution level that enables co-existence of flexible and non-flexible consumers and resources (Savelli & Morstyn, 2021). Policy Exchange propose that residential and small businesses be charged a regional or zonal price for a transitional period unless they opt-in to nodal pricing, with Government offsetting differences between electricity prices in different GB regions using fixed credits and charges on customers' bills (Birkett, 2020).

When considering the distributional impacts of nodal pricing on residential consumers, particularly the impact of price increases for low income or vulnerable consumers, wider and deeper consideration should be given to electricity pricing and equity issues for the transition to Net Zero. For example, the Cost of Energy Review proposed a Universal Service Obligation, which is like an essential services tariff that provides a basic block of energy to all

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See https://es.catapult.org.uk/reports/smarttalking-overcoming-barriers-to-demand-side-reponse/ ; This would not only make it possible to extract greater value for the participating consumer but would also have a more direct downward impact on price formation in wholesale electricity markets for the benefit of all electricity consumers (Keay-Bright & Day, 2021, p. 159).[32]

households with exemption from legacy costs and a discount on fixed elements, with these costs passed through to consumption above this basic level (Helm, 2017). Citizen's Advice propose various tariffs for vulnerable consumers (Bridgeman, White, Asher, & Redgrove, 2015). Many organisations are also calling on Government to shift the policy costs on electricity bills to general taxation and/or to gas bills which could significantly reduce electricity bills (Rhys, 2019; Public First, 2021), which can be done as part of a strategy to achieve coherent effective carbon prices across different energy vectors and sectors of the economy (Energy Systems Catapult, 2020).

7.3. Changing situation with the EU

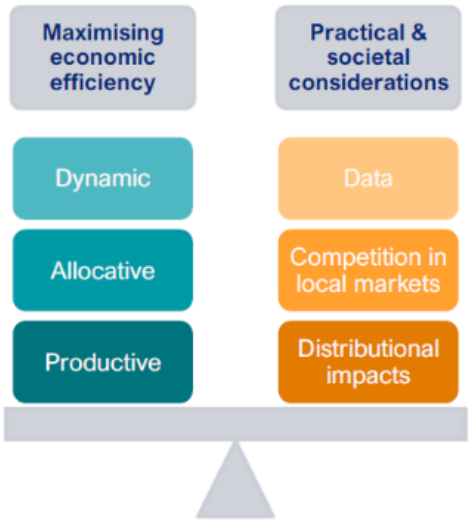
There is growing interest within the EU for nodal pricing as EU countries face similar challenges to the UK in relation to cost-efficiently integrating variable renewables and DER. A recent study by the European Commission Joint Research Centre on the potential to transition the European internal electricity market to nodal pricing concluded that "*the current European market design principles theoretically do not exclude the possibility to apply nodal pricing*" (Antonopoulos, Vitiello, Fulli, & Masera, 2020).

This report acknowledged that nodal pricing is theoretically superior to zonal pricing when it comes to both short- and long-term efficiency. However, the report suggests that a number of practical hurdles would need to be passed if nodal pricing were to be implemented in the European internal electricity market:

- The balancing market would have to replace day-ahead markets as the reference price. This would have a knock-on impact on contracts and policy instruments.
- Changes to institutional arrangements, particularly with regard to balancing markets.
- Changes in the interactions between TSOs and DNOs/DSOs, including with regard to the potential application of nodal pricing at the distribution level

The UK has left the EU and new electricity trading arrangements have been established and continue to evolve. The UK now has a greater degree of freedom in relation to how it develops its market rules and supporting policies.

8. Recommendations to phase-in nodal pricing and manage impacts

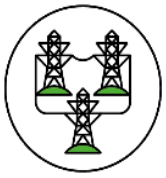


Source: (CEPA & TNEI, 2021)

All approaches to improving locational market signals involve trade-offs between maximising economic efficiency and considerations that might offset the benefits of any increase in economic efficiency.[33] ESC explored these trade-offs with CEPA and TNEI for different options and has discussed some of trade-offs in earlier sections of paper. While we conclude that the nodal pricing would be the preferred option for the GB market, we recognise the need to mitigate or manage some impacts and trade-offs and this is reflected in our recommendations that follow.

Recommendations:

Recommendation 1: NGESO should be asked by BEIS and Ofgem to commission a detailed study of the introduction of nodal pricing in the GB power market, encompassing a detailed assessment of the cost benefit case and the implementation and transition practicalities.



Recommendation 2: Transition to nodal pricing at transmission level as soon as feasible as part of a wider reform package to drive innovation through open, competitive and high-performing markets. See ESC's recommendations for consumer-focused market design reforms.[34] The assessment of how to implement nodal pricing in GB should include consideration of shorter time frames for scheduling and settlement (e.g. 5 minutes), and the extent to which trading in short-term electricity markets should be mandated (i.e. mandatory pool).

Recommendation 3: Transition directly to nodal pricing, not via zonal pricing. Experience from other jurisdictions suggests that reforms to locational pricing are complex and disruptive, but worthwhile and that it makes sense to transition directly to full nodal pricing. The US switched early from zonal pricing to nodal pricing and hasn't looked back, while progress in implementing zonal pricing within EU countries has been slow and challenging.

[33] Note: Productive efficiency means that energy is sold at the lowest cost of production; Allocative efficiency means that the prevailing price satisfies all demand that is willing to pay that price, and that the price is equal to the marginal social cost of production; and Dynamic efficiency means that prices signal the least social cost location for investment.
[34] https://es.catapult.org.uk/reports/rethinking-electricity-markets-the-case-for-emr-2/

Recommendation 4: Establish the independent future system operator (FSO) without delay and ensure it has the functions to efficiently implement nodal pricing. Options for integrating the roles of market operator and system operator within the FSO entity, as in US markets, should be considered.

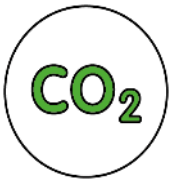
Recommendation 5: An independent market monitor should be established to improve the performance of power markets in consumers' best interests. Ensure the market monitor is adequately resourced with necessary capabilities. If some locations exhibit market power, then enhanced market monitoring will be necessary. Continuous feedback through the market monitor, to the key decision-makers responsible for aspects of market performance (i.e. BEIS, Ofgem, FSO), will facilitate agile decision-making, swift action against market power and timely market development.[35] Strong independent market monitoring can also help to build investor confidence and public acceptance of market operation, reforms and consequent prices.

Recommendation 6: Develop a roadmap for locational signals at distribution level and the institutional structure, role and responsibilities of DNOs, the FSO and any other future entities needed (e.g. DSO, regional entities). Many innovators are basing their business models on the current market arrangements including the latest TCR decision and upcoming NAFLC decision. A roadmap and clarity on the target model for locational signals at distribution level and possible pathways would help innovators manage regulatory risk and develop more robust business models.

Recommendation 7: Reform planning arrangements to complement nodal pricing to cost-effectively develop and fund the network we need. Optimising locational investment decisions will require changes to the planning permissions rules and processes, the responsibility for which sits with national and local governments. Strategic planning/coordination needs to be improved at national and local level (e.g. Local Area Energy Planning (LAEP)[36]) interfacing with, and being informed by, more market signals that reflect locational value.

Recommendation 8: Evolve reliability arrangements to work with the emerging digitalised and distributed energy system under nodal pricing. Nodal pricing is likely to improve the market's ability to address physical reliability, but it is likely that the policy mechanisms for reliability and resource adequacy will also need to evolve. This evolution should be designed to mesh with much more developed locational market signals.

[35] Further discussion of the need for and benefits of enhanced market monitoring can be found in ESC's recent market design report, 'Rethinking Electricity Markets – EMR2.0'.
[36] https://es.catapult.org.uk/reports/local-area-energy-planning/



Recommendation 9: Combine nodal pricing with robust time and location-specific tracking of carbon (content or intensity) through the electricity system and settlement process ESC proposes combining more granular market signals, by location and nearer to real-time (e.g. 5 minute scheduling and settlement), with an outcome-based carbon policy mandate on retailers/offtakers of electricity. Such a policy framework would require arrangements to track carbon accurately through electricity trading and settlement systems.

Recommendation 10: Design targeted provisions to ensure fairness and address impacts on low-income consumers. Transitional arrangements to dampen distributional impacts may be necessary, such as options for combining nodal prices and flat prices for flexible and non-flexible users/resources, introducing nodal pricing on an opt-in basis with levelling up of bills using credits/charges or targeted support for vulnerable consumers in adopting low/zero carbon solutions.

Recommendation 11: Provide temporary support to incumbents during the transition to nodal pricing. The definition of access rights may need to be redefined if locational energy pricing is introduced. Under uniform pricing, generators implicitly have access (at least in terms of pricing) to the entire network, whereas under nodal pricing generators are only guaranteed unconstrained access to their node (and the respective price). Temporary mitigation measures of compensation arrangements have been employed in other jurisdictions to facilitate the transition.

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Appendix 1 - Detail of the three straw-persons for examining locational signals in operational timeframes

	Straw-person 1) Network tariffs only	Straw-person 2) Zonal pricing/market splitting	Straw-person 3) Nodal/locational marginal pricing
Locational signals	• Uniform national energy price in electricity spot markets (DAM, ID) • Pay-as-bid balancing market – uniform or zonal prices • Locationally granular and dynamic transmission network tariffs (TNUoS) (e.g. locationally-specific critical peak pricing) • Transmission losses allocated through output scaling via Transmission Loss Multipliers (TLMs). **At the distribution level:** • Locationally granular and dynamic network tariffs (DUoS) potentially down to LV (depending on metering, etc.); OR • Flexibility platforms (e.g. ENA World B) with flat/residual network charges – various options possible e.g. network tariffs set at peak conditions with payments from marketplace for flexibility; marketplace applies charges for non-participation re. flexibility.	• Zonal day-ahead market • Zonal pricing in balancing markets • Transmission network tariffs (TNUoS) more locationally granular than currently • Transmission losses allocated through output scaling via Transmission Loss Multipliers (TLMs). **At the distribution level:** • Locationally granular and dynamic network tariffs (DUoS) as per straw-person 1 • Flexibility platforms as per straw-person 1.	• Nodal day-ahead and balancing markets (prices incorporate energy + network congestion + losses). Adequate market monitoring needed. • Simple transmission network tariffs (TNUoS) only recover 'residual' costs **At the distribution level:** • Nodal pricing down to the voltage level that is practically possible and efficient – in time this could extend down to LV with growth in DER and improved data/monitoring. Adequate market monitoring needed. Below that: • Locationally granular and dynamic network tariffs (DUoS) as per straw-person 1 • Flexibility platform behind the node as per straw-person 1
Setting of prices/charges	• Network tariffs set in advance with info on how they change depending on conditions - ESO/DSOs provide tariff forecasts	• Zone boundaries determined in advance, reflecting congestion • Zonal prices computed in real-time through algorithms	• Nodal/LMP prices computed in real-time through algorithms

Dispatch & system operation	• Bilateral trading and through power exchanges • Self-dispatch and SO redispatch (resulting in BSUoS) or with flexibility platform, self-dispatch and DSO-ESO coordinated procurement and dispatch/redispatch (resulting in BSUoS)	• Bilateral trading and through power exchanges • Self-dispatch and SO redispatch (resulting in BSUoS)	• Centralised optimisation to calculate nodal prices – SO/MO may need to be merged • Centralised dispatch with no redispatch – much reduced out-of-market role for SOs (no/minimal BSUoS) • Self-dispatch possible, but some bids need to be price-sensitive (mandatory trading pool could be an option)
Contracting & hedging	• Financial hedges available for locational network tariffs (via TOs/DNOs)	• Financial hedges available for zonal price differences in day-ahead market, and for zonal price differences in the balancing mechanism	• Financial hedges available for nodal price differences
Network investment	• Planning standard, responsibility and regulation same as current arrangements	• Planning standard and responsibility same as currently • Reinforcement between zones signalled by price difference	• Requires changes to planning standard • Reinforcement subject to cost-benefit test vs. cost of congestion

Source: (CEPA & TNEI, 2021)

Appendix 2 - Summary of commonly cited discussion points for different approaches to locational pricing

Feature	Uniform national energy price + locational network tariffs OR local flex platform	Zonal energy price + locational network tariffs OR local flex platform	Nodal/LMP energy prices, with LMP at distribution level OR locational network tariffs OR local flex platform
Efficient use of existing grid in general.	Moderate if re-dispatch process is effective	Moderate if re-dispatch process is effective and zone definition is appropriate	Good if well implemented
Consistent and coherent price signals	Potential for **consistent** locational price signals across all voltage levels, without the risk of greater generator market power	Potential **conflict** between locational signals in energy markets and locational signals in network tariffs	Potential for **consistent** locational price signals across all voltage levels, without the risk of greater generator market power if sufficient liquidity or administered prices used where necessary
Efficient price signals, in operational timeframes (SRMC) and in investment timeframes (LRMC)	Network UoS tariffs play limited role in providing locational signals for generators in the operational timeframe because they cannot accurately reflect the SRMC of energy supply. Tariffs can signal the binary SRMC of networks through some tariff designs (e.g. critical peak pricing) but this introduces the need to hedge against price spikes. Network UoS tariffs offer more useful locational signals in investment timeframes. Lumpy nature of investments and long delivery timeframes lend themselves to tariffs based on LRMC.	Potential **inefficiencies** as a result of zone definition	**Practical and technical limitations** on the extent to which nodal prices could be used to send locational signals in the distribution network. This could change over time with DER growth. Nodal pricing at transmission level can be coupled with granular (temporal and locational) network charges at lower voltage levels or flexibility markets. Nodal pricing can be complemented with strategic planning at local and national levels to ensure efficient and timely investment.
Incentives for efficient resource dispatch.	No incentives linked to location within zone	Mixed, depending on number of zones	Strong locational incentives but could constrain innovation in context of complex bidding
Re-dispatch volume (i.e. extent of ESO/DSO revision to market positions).	High if network expansion delayed	Lower than national	No re-dispatch
Risk of market power abuse on pricing.	Lower risk because of broad price setting geography	In between	High in absence of regulation because of local scarcity potential. Enhanced market monitoring needed. LMP should extend down to appropriate voltage level and be coupled with UoS network charges and or flexibility markets. Prices can be administered.
Market power abuse on re-dispatch.[37]	Potentially high in absence of regulation	In between	Low due to central dispatch

[37] This relates to potential for the requirements for re-dispatch actions to be influenced by market participants and/or the available range of bids/offers for re-dispatch purposes to be limited in instances of market power.

Incentives for locationally efficient resource investment.	None from energy prices	Moderate, effectiveness depends on credibility and stability of zonal price signals	Stronger, effectiveness depends on credibility and stability of local price signals
Credibility of prices as incentives for investment.	High, linked to price stability across broad geography	In between	Reduced if local prices are difficult to predict/unstable
Impact on consumers as a whole	Lower net benefits compared to locational energy charging (i.e. zonal or nodal)	Higher net benefits compared to pure network charging approach if well implemented	Higher net benefits compared to approaches based on pure network charges or zonal pricing if well implemented
Distributional impacts on consumers	Potentially socially unacceptable incidence of charges on certain consumers, particularly if hedging of locational network tariffs is not possible.	Consumers in different zonal markets will be exposed to different energy prices. This may be seen as unfair – mitigating actions could include: averaging prices across an area on a temporary basis; introduce targeted policies e.g. demand reduction.	Consumers in different nodal markets will be exposed to different energy prices. This may be seen as unfair - mitigating actions could include: averaging prices across an area on a temporary basis; introduce a price framework that uses both nodal prices and flat prices, to enable co-existence of flex/non-flex consumers/resources; introduce targeted policies e.g. demand reduction.

Source: (Poyry, 2019b; CEPA & TNEI, 2021)

Energy Systems Catapult supports innovators in unleashing opportunities from the transition to a clean, intelligent energy system.

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