regen transforming energy

Improving locational signals in the GB electricity markets

Clear locational signals are vital for both long-term investment decisions and operational efficiency for generation, storage and flexible assets when participating in electricity markets. A holistic review of how locational signals could be enhanced to provide a more meaningful and valid signal is an essential outcome of the current market reform process.

In this insight paper, Regen's markets team provides a broader view of how locational signals operate today and how they could be enhanced, reformed and refined to meet the challenge of a net zero electricity system.

Our conclusion is that reform is certainly needed, but that there are several opportunities to deliver more effective locational signals within a relatively short delivery timeframe by implementing reforms that are largely within the existing market arrangements:

- Reforming network charging to give a transparent and dependable forward cost signal.
- Continuing reforms to network connection and queue management processes towards anticipatory investment and increasing alignment across locations.
- Improving and enhancing the operation of the Balancing Mechanism (BM).
- Continuing to develop operability, flexibility and local constraint management markets/services to enable the utilisation of a wider range of assets.
- Improving planning locational signals, aligned with infrastructure investment, at a national and local level, including strengthening the power of integrated net zero delivery plans, Regional System Plans (RSPs) and Local Area Energy Plans (LAEPs).
- Retaining the existing integrated GB wholesale market, with reforms to locational signals, rather than a shift to a radically new market design.

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1. Introduction

Locational factors have always played a central role in the development of our energy systems. In the 20th century, investment decisions around the development of transmission networks and power stations considered the location of coal mines and demand – the relative costs of building power stations near the cities and transporting coal to the power stations was compared with building the power stations near the mines and transporting the electricity. The result was the distribution of generation situated in the mining areas of the Midlands and north of England, and at sites to which coal could be shipped, and the development of the 275 kV transmission network in the 1950s, followed by the 400 kV network in the 1960s.

Figure 1: Yelland – site of an old coal fired power station in North Devon on the Taw estuary.
Not an obvious location for a power station but within easy reach for coal shipments from South Wales. Note the collier jetty in the background.

The current market reform discussion has put locational factors at its heart. The **Review of Electricity Market Arrangements** (REMA) consultation highlighted the need to provide efficient locational signals to minimise system cost as one of its four main challenges. So far, the focus within market reform discussions has been on creating new locational signals within the wholesale markets, delivered via a locational marginal price (LMP) based on either nodal or zonal pricing locations, coupled with a centralised dispatch process.

However, there are many other ways in which locational signals could be improved from within the existing market arrangements. These alternative signals would still require reform of today's model, but could be delivered more quickly and with less risk of an investment hiatus as part of an incremental reform package.

It is incorrect to suggest that project developers are blind to locational factors, such as consideration of network investment costs, constraints or charges, when siting generation projects. This myth has produced a false narrative that the cause of increased network constraint management costs has been the inappropriate siting of generation (mainly wind) projects in Scotland[1] and that a further increase in constraint costs will be the inevitable result of inappropriate project siting. In fact, there exist a wide range of locational signals that impact on the electricity system. Some are related to factors such as resource availability and planning consent, but others are directly related to the availability of network capacity, network charging and connection lead-times. There are also strong locational revenue signals (via price and asset utilisation) within the balancing mechanism, which could be enhanced and made more transparent.

1 The actual cause of increased constraint management costs has been the delay in network investment across several key boundaries such as the Scotland-England border, compounded by the very steep increase in gas prices which has led to an increase in the 'turn up' cost to run expensive and inflexible gas fired power stations to replace power from constrained renewables. This point is discussed further in our paper **Seven solutions to the rising costs of transmission constraint management**.

The purpose of this insight paper is to provide further input and a broader view of how locational signals operate today, and how they could be enhanced, reformed and refined to support a net zero energy system with very high levels of renewable energy and flexibility at its core.

BOX 1

What are locational signals?

REMA is mainly concerned with two types of locational signals:

- Siting or investment locational signals that encourage investors in new generation or storage assets, demand or sources of flexibility to favour one location over another. To be effective these must be long-term and dependable.
- Operational locational signals that, alongside temporal signals, may encourage network users (generation, demand or storage/flexibility providers) to flex demand or supply of electricity at a certain time and location. Operational signals could be forward signals – for example, day-ahead – or they could be short-term/real-time signals within the dispatch function.

Locational signals could originate from several sources, including:

- **Price:** where the wholesale price of electricity, or related services such as reserve provision or balancing services, differs by location – for example, locational wholesale prices or contract prices for flexibility services.
- **Cost:** where the costs faced by market participants are different in one location compared with another – for example, Transmission Network Use of System Charges.
- **Utilisation or dispatch revenue:** where the opportunities for revenue are higher in some locations compared with others – for example, the requirement for some ancillary services is limited to certain locations.
- **Resource:** where the availability of the underlying resource differs by location – for example, variations in the quantity and timing of wind and solar resources.
- **Land/seabed availability:** where the availability and cost of suitable land to build energy assets varies by location – for example, lack of land availability within large urban areas, competition for seabed rights with other marine activities and land designations.
- **Planning factors:** where the planning and consenting systems are more likely to grant permission to develop in one location compared to another or there is specific provision for certain investments within a plan – for example, treatment of onshore wind by planning processes in England compared with Scotland and Wales.
- **Other:** including policy signals, levelling up signals, community group activism, political, supply chain availability, clustering signals, skills availability, precedence and a variety of other things that attract investment.

2. Overview of existing and in development locational signals

In this section, we discuss the many locational signals – summarised in **Table 1** – that currently impact on project development and investment decisions, with a focus on national strategic locational signals that aim to influence the siting or locational operation of generation, flexible demand, and storage on the basis of the development of the national electricity system. There are other locational signals that focus on influencing local or micro-siting decisions or operation, e.g. relative local network constraints, particularly at the distribution level. These are important for an efficient electricity system, and often take precedence for project siting, but are not the focus of this paper.

National locational signals can be grouped into four themes:

- **Locational signals related to network capacity and connections**
- **Locational signals related to markets**
- **Locational signals related to spatial planning, land-use and energy resource**
- **Other policy mechanisms that could deliver a stronger locational signal**

Locational signals related to network capacity and connections

The ability to access the network is a pre-requisite for any participation in electricity markets. Places where it is easy and relatively cheap to connect and access the network benefit from a positive locational signal; those where it is difficult and expensive experience a negative locational signal.

Across much of the country, generators, flexibility providers and consumers may choose to connect to either the distribution or the transmission network. The decision depends both on physical factors – it is unlikely to be physically suitable to connect a large power station to the lower tiers of the distribution network – and economic factors – how much it costs to connect and then use the network.

Locational signals related to markets

The wholesale electricity market is the framework within which electricity is brought and sold in bulk across Great Britain (GB) and it is how traders will buy and sell electricity between GB and our neighbouring countries. The GB wholesale market is integrated but does not have a single unique clearing price. The current system brings together a diversity of trading options, which emerge from a decentralised system[2], and is a mix of marginal pricing (e.g. through day-ahead power exchanges), quasi-marginal (where bilateral trading for short-term contracts tend to approximate or reference the marginal price) and long-run pricing (for example, through seasonal trades and long-term Power Purchase Agreements).

While the locational signal within the wholesale market is weak, there are strong to very strong signals within other balancing and ancillary markets that currently operate within the GB electricity system, many of which are directed at managing network congestion, balancing and operability.

Locational signals related to spatial planning, land-use and energy resource

Planning policy impacts the way in which developments such as buildings and renewable generation projects are planned for, managed and controlled. The extent to which the planning environment is supportive of generation projects can have a significant impact on where projects are sited.

Additionally, for some technologies, there are specific planning policies and processes that can determine locations – marine spatial planning and leasing for offshore wind development licences, for example. Increasingly, local authorities, devolved governments and cities/regions are adopting a more deterministic approach to energy planning and infrastructure siting. This is being encouraged by the development of Local Area Energy Plans and, in the future, Regional System Plans.

Other policy mechanisms that could deliver a stronger locational signal

There are other policy mechanisms – specifically, the Contracts for Difference (CfD) scheme and the Capacity Market (CM), both established as part of the Electricity Markets Reform programme in the 2010s – which could be reformed to send stronger locational signals. While it is unlikely that these will provide sufficiently strong signals to be a primary driver of investment decisions, they are included within the scope of the government's REMA package of reforms and, while not explored in depth in this paper, are the subject of discussion elsewhere.

2 Contrary to some reports and analysis presented, the GB market does not have a single clearing price. Since the NETA and BETTA reforms introduced at the turn of the century, the GB market has been characterised by bilateral energy trading over multiple time horizons and a process of decentralised dispatch coupled with a balancing mechanism market.

Table 1: Summary of the most significant locational signals at a national level, including existing signals and those being explored by REMA.

	Signal	Signal type	Summary	Status	Recommendation
Network capacity, connections	Connection charges	Investment	Developers pay a charge for some of the infrastructure needed to connect new generator projects to the network, or to upgrade existing projects, creating a local locational signal depending on the cost of infrastructure required to connect. At the transmission level, connection costs are described as 'shallow', meaning they largely cover assets which will be for the sole use of the project. This creates a relatively local locational signal – for example, a wind farm that requires tens of miles of cable to connect is likely to face higher connection charges than one that can connect to a suitable substation next to the project.	Existing	
	Use of System charges (generation)	Investment	An ongoing charge that covers all other network cost elements that are not directly covered by connection charges, as well as funding the ongoing cost of maintenance and operation of the network. This changes by location and at transmission level is defined across 27 zones.	In need of reform	**Network charging (TNUoS) reform** 1
	Congestion location signalling	Investment	At the distribution level, detailed locational information on network congestion is provided by network companies, to give an indication of where is quickest and cheapest to connect. Other signals include the occurrence of Constraint Managed Zones and Active Network Management areas.	Existing	
	Connection lead times	Investment	The timescale for getting connected to the network provides a locational signal, with projects increasingly being offered connections for ten years' time in some locations.	Reform ongoing	**Network connection and queue management reform** 2
Markets	Balancing Mechanism (BM)	Investment and operational	The mechanism by which the ESO balances the system during the last hour before delivery. The utilisation of assets depends on their location. For example, those assets able to provide 'generation turn up' at relatively short notice will have significantly more opportunity when located in front of a network constraint.	In need of reform	**BM enhancements** 3
	Constraint and flexibility markets	Investment and operational	Regional constraint markets are beginning to develop as alternatives to the BM for management of network constraints. The ESO has recently introduced a constraint management market in Scotland to manage the B6 boundary. An alternative approach that is increasingly common on the distribution network, flexibility auctions could be expanded by the ESO to support investment in flexibility at locations that are constrained.	In development	**Strengthen locational flexibility signals and improve their coordination** 4

	Signal	Signal type	Summary	Status	Recommendation
Spatial factors	Planning environment	Investment	The extent to which the planning environment is supportive of renewable development. This varies between the different nations of GB and between different planning authorities.	In need of reform	**Align planning policy with net zero and empower greater local decision-making agency** 5
	Spatial Planning	Investment	Actions by local authorities, devolved governments and national policy to predetermine the preferred location of energy projects. The Crown Estate, for example, in consultation with marine stakeholders determines offshore wind, wave and tidal leasing areas	In development	**Align planning policy with net zero and empower greater local decision-making agency** 5
	Resource	Investment	A key locational signal is the availability of the underlying energy resource. High availability drives higher capacity factors and therefore lower levelised costs of energy. For example, solar resource is clearly higher in the south of GB and this is reflected in the distribution of solar PV capacity across the country. In addition to the absolute level of resource, there is also the distribution of that resource throughout the year.	Existing	
Other	Contracts for Difference (CfD)	Investment	There are a number of ways the CfD mechanism could evolve to better value other system benefits, such as those generated through geographic diversity, as we explored in our insight paper **Go West!**. More information on our work in the CfD space can be found **here**.	In development	**Regen's recommendations for CfD reform are discussed here**
	Capacity Market (CM)	Investment	As we discuss in our **insight paper** on Capacity Market reform, it is vital that the CM evolves to better recognise the system value of attributes such as flexibility and responsiveness, which will be critical to manage more diverse system events in the future. This could be achieved through the introduction of multipliers, to allow the CM to better value attributes such as flexibility and location, stimulating investment in certain areas.	In development	**Regen's recommendations for Capacity Market reform are discussed here**
Wholesale market reform	Locational pricing	Operational	In simple terms, a shift to an LMP-based wholesale power market would see GB split into a series of zones (or nodes), with electricity priced differently in each, to reflect the level of congestion and the incremental cost of meeting demand at each location. We do not believe this option should be taken forward.	Radical reform	**Retain an integrated GB wholesale market** 6

3. Regen's recommendations

Regen has developed six recommendations for improving locational signals through reform and innovation within existing market arrangements. These are discussed in more detail in the subsequent sections.

For Ofgem:

1. Reform network charging (TNUoS) to provide a long-term investment signal for generation that is cost-reflective, transparent, stable and consistent. A review of the signals directed at demand should be undertaken in tandem, ensuring that fairness is considered as a key criteria.

2. Continue to reform network connection and queue management processes so that there is a consistent and integrated process between locations and across network voltages. At the same time, continue the shift towards more strategic and anticipatory network and system planning and investment, to direct the market to invest where assets are needed.

For the Electricity System Operator (ESO):

3. Improve and enhance the operation of the Balancing Mechanism (BM), through digitalisation, IT investment, forecasting and market development, so that it becomes far more adept, efficient and competitive. The objective should be to reduce balancing and constraint management costs by making best use of low carbon generation and flexibility.

4. Alongside the BM, work with Ofgem and the Distribution Network Operators (DNOs) to continue to develop operability, flexibility and local constraint management markets/services that will enable the utilisation of a wider range of assets and resources and to pre-emptively manage constraints. This would allow markets to send a stronger locational signal for flex providers and investors.

For the government:

5. Harmonise planning policies to ensure alignment with the UK's net zero targets. Empower local authorities, city regions and devolved governments (e.g. through Local Area Energy Plans, Regional System Plans and other local strategic energy system planning) to have more decision-making agency to send stronger local and regional signals as to where infrastructure, low carbon technologies and system assets are required.

6. Retain the existing integrated GB wholesale market and seek ways to provide effective locational siting and operational signals via solutions and enhancements within the existing market structure, avoiding the risks associated with shifting to a radically new market design.

3.1 Network Charging (TNUoS) reform

Type of locational signal: Investment

In addition to connection charges, all users of the network face ongoing Use of System charges. These pay the costs of developing the strategic element of the distribution and transmission networks (all the elements that aren't directly covered by connection charges) and they also cover the ongoing cost of maintenance and operation. Very different methodologies are applied at distribution and transmission level. At the distribution level, costs are covered through a Distribution Use of System (DUoS) charge with each DNO region recovering costs from its own connected customers in order to ensure broad cost-reflectivity[3]. At the transmission level, the Transmission Network Use of System (TNUoS) charge applies to both consumers and generators through an approach that aims to broadly reflect the marginal cost of transmission network investment requirements at each location.

How the locational signal is delivered

The locational element of Use of System charges has been the subject of several reform initiatives over the past five years, and is currently part of the review of network access and charging, with a TNUoS Task Force already in place. There is also an **ongoing Ofgem project** looking at the potential to introduce stronger locational signals within the distribution network charges (DUoS).

There is a common perception that the locational elements of network charges are of too little consequence with insufficient weight and granularity. In reality TNUoS has an **extremely strong locational element** for generation, which is potentially even too strong, although the way it is delivered reduces its ability to drive well informed investment decisions.

Network charges are generally presented in terms of £ per kW of capacity per year. However, it is useful to convert these to £/MWh in order to compare with other costs of generation. The current 2022/23 charging tariff shows that there is around a £6-7 per MWh difference in TNUoS charges for 'as available' generation, such as wind, between high charge zones in the north of Scotland and lower charge zones in the south of England and Wales. Looking ahead, into the timeframe in which future investment decisions are made, and the differential between zones is expected to grow significantly.

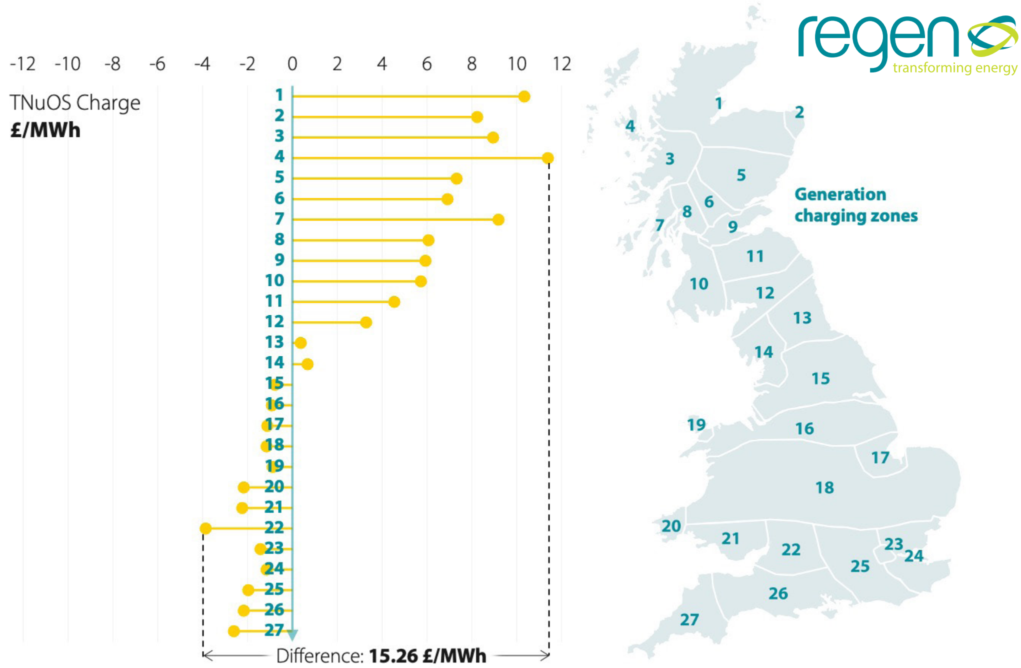
Figure 2 shows the current **Five-year forecast for TNUoS wider-network charges**[4] for the year 2028/29 as published by the ESO April 2023. It demonstrates that TNUoS locational price differences rise significantly across GB and could represent up to £15 per MWh differential between the highest and lowest charge areas, or up to a third of the Levelised Cost of Energy (LCoE) for onshore and offshore wind.

Unfortunately, because of the short-term nature of TNUoS forecasts, and their propensity for error and to change – including changes to methodology – developers are cautious and will typically include a signal of high TNUoS charges in their site selection, but not consider a signal of low or even negative charges. So TNUoS tends to delay projects in Scotland but not accelerate projects in south west England, for example.

3 The exception to this rule is the north of Scotland region where the Hydro Benefit Replacement Scheme subsidises some of the costs due to the materially higher distribution costs associated with such a large and relatively sparsely populated area. For more information see: Hydro Benefit Replacement Scheme and Common Tariff Obligation: statutory review 2022.

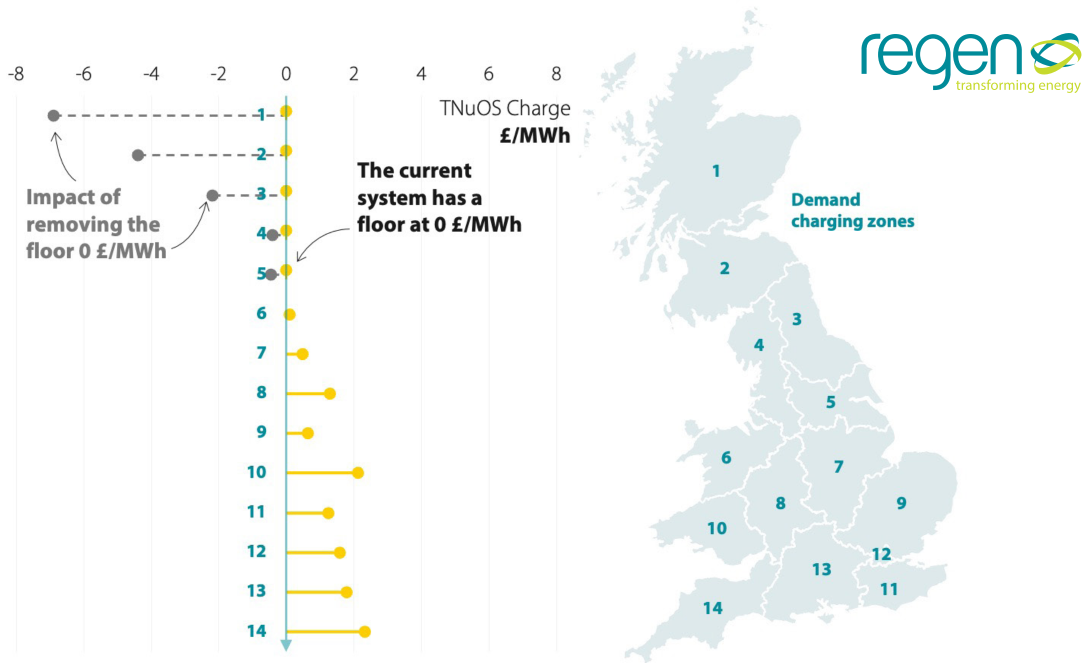
4 These are charges for intermittent generators with a 45% load factor which might be representative of an offshore wind farm, although the charges do not vary significantly (on a £/MWh basis) with load factor and so are likely to be illustrative of both onshore and offshore wind and solar.

Figure 2: Forecast 'wider generation' TNUoS costs for a variable generator with 45% load factor in 2028/29 converted into £/MWh. Source: National Grid ESO.



The TNUoS framework also delivers locational signals to demand that are largely the inverse of the generation signal, with larger costs for demand in the south and lower costs in the north. However, as Figure 3 shows, a key difference is that the demand signal is floored at zero, meaning that, where the TNUoS methodology calculates a negative demand charge, that value is then set to zero. This has been a deliberate policy decision to significantly reduce the demand cost differential between regions. However, this means that the signal to demand to locate in areas of high demand – which could become increasingly important in a high-renewable electricity system – has been significantly dampened. There is scope to look again at the demand locational charge signal, especially for commercial and industrial customers, to see whether there are opportunities to strengthen this without unfairly impacting those consumers who are less able to relocate.

Figure 3: Demand TNUoS costs in £/MWh based on a 50% load factor against its Triad demand, showing the current system that includes a floor at zero and the impact of removing that floor. Source: National Grid ESO.



How this signal is currently used

Developers are now very aware of the impact of network charges and will build this into their cost of energy calculation. In the case of CfD auctions, it means that generators in Scotland will likely bid in at a higher strike price, although their higher network charges may be slightly offset by better energy resource versus a project in England. Given that CfD auctions award strike prices to successful bidders on a pay-as-clear basis, an important implication that should be explored is the impact of TNUoS on CfD clearing prices. If Scottish projects are generally clearing the CfD auctions with bid prices reflecting significantly higher TNUoS, then the strike prices for all successful generators will be set based on these high TNUoS costs, raising the consumer payments.

Generators in Scotland have already highlighted that the TNUoS charges they face are too high and may be sending a locational signal that is too strong and not reflective of true costs. An SSE report has a good analysis of this showing that, in 2020/21, a wind farm in the North of Scotland would pay £5.54 per MWh compared to a windfarm in South Wales receiving £2.81 per MWh, a locational signal difference of £8.35 per MWh. The difference now, and in the future five-year forecast, is even greater.

How the locational signal could be improved

Improving the TNUoS signal does not mean increasing its magnitude; rather, it means making sure it can be used effectively, and is trusted to inform investment decisions. The five-year forecasts are useful, but there remains an issue with the long-term prediction of TNUoS charges, which are variable, non-transparent, difficult to forecast and can change quickly after investment decisions and throughout the life of the project, leading to potential unexpected gains and losses for the generator or their offtaker.

Some developers have called for a longer term TNUoS forecast of 10-15 years plus – as part of a more integrated and strategic net zero delivery plan – and greater transparency as to the TNUoS cost calculation and methodology. A reformed TNUoS has the potential to continue to deliver sufficiently strong locational price signals, but to do so in a way that is more predictable, less volatile and better reflects the underlying variation in locational costs. Such an approach can reduce un-mitigatable risk and can give better signals for flexibility, as well as considering wider objectives such as energy security that currently sit beyond the scope of locational network charging. It would also be of significant value to allow negative demand-side TNUoS signals, although it is important that any changes to demand charges and the associated embedded generator charges are carefully reviewed.

The TNUoS methodology needs to be properly examined. At the moment, there is some debate and challenge as to whether TNUoS charges are properly cost-reflective and on what basis that calculation has been made. Forward-looking TNUoS charge forecasts would have to consider network build as well as the growth of demand and generation over the period. This analysis should be aligned with net zero delivery plans and network investment plans, including the Regional System Planners.

However, if done properly, network charges could carry an economic signal that includes a fair and accurate estimation of the wider network investment and operational costs and benefits associated with delivering net zero energy and security for customers.

Regen's recommendation for Ofgem

Reform network charging (TNUoS) to provide a long-term investment signal for generation that is cost-reflective, transparent, stable and consistent. A review of the signals directed at demand should be undertaken in tandem, ensuring that fairness is considered as a key criteria.

3.2 Network connection and queue management reform

Type of locational signal: Investment

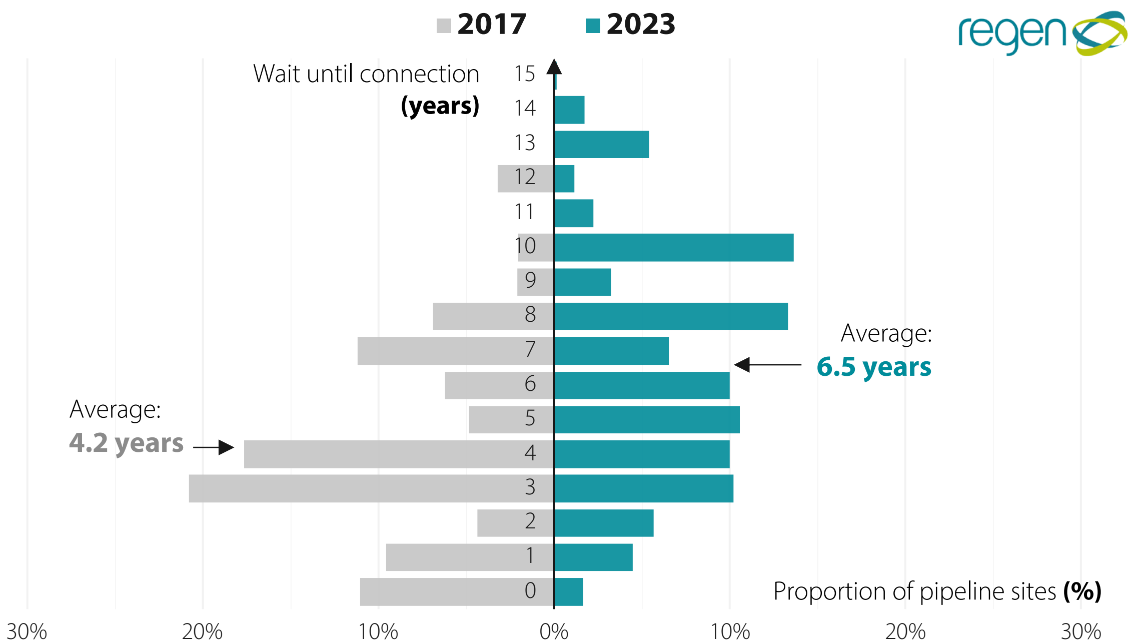
In addition to connection costs, the timescale for getting connected to the network provides a further locational signal. Connection offers given by the ESO increasingly require developers to wait ten years or more before connecting, due to significant and complex network reinforcement. These lead times are closing off renewable development in certain locations for the next few years.

How the locational signal is delivered

Transmission networks do not levy upfront connection charges (except for own use assets, i.e. the part of the transmission network that is built specifically for a particular project and not shared with others), but they do regularly give long lead times to connect.

At the moment, owing to an exceptionally high number of new connections, coupled with delays in building new capacity, connection lead times for new projects have now reached up to 15 years. As shown in Figure 4, in 2017 the average project had a wait time to connect of under 4 years. In 2023, this had increased to 6.5 years. Putting aside the issues that this causes in terms of delayed investment, loss of economic value and the risk to delivery of net zero, the connection queue and associated lead time now send a very strong locational signal for project developers.

Figure 4: Transmission connection lead times. Source: Regen analysis of ESO Transmission Entry Capacity (TEC) Register, 2023.



How this signal is currently used

Developers are now hyper-aware of the connection queue issue and are actively looking for new connections with grid capacity and a shorter lead time. This is especially true of battery and solar PV projects, which have more locational flexibility. Unfortunately, this process has now reached saturation, and there are almost no parts of the country that have significantly shorter queues.

There exists, therefore, a very strong locational signal resulting from the connection queue. Unfortunately, because the queue is so long in almost all areas, this is now sending a more general negative signal that the GB networks are too constrained for new generation investment.

The idea that there are parts of the grid with spare capacity that could be developed for want of a price signal is incorrect. Any LMP cost benefit analysis that suggests that there could be transmission network constraint savings if more solar would move from the north and midlands to the south of England ignores the fact that a) there is already a massive queue of projects wishing to connect in the south, b) the south is constrained at the distribution network level and c) the south is getting close to saturation point from a planning perspective for solar.

How the locational signal could be improved

The need to better plan and accelerate network investment and to reform the queue management processes has been highlighted at length elsewhere, and is now the subject of several reform initiatives[5].
In particular, there is likely to be value in better managing the transmission queue and ensuring that only viable projects that are actively in development are allowed to remain in the queue.

In terms of its effectiveness as a locational signal, even once the queue management issues have been addressed, the connection lead time will remain a very strong signal. To make sure that it is sending the right signal – and not just a "closed for business" sign – it is important that network planning is better aligned with future load growth and that future investment plans and capacity availability is made transparent to the market.

The barrier created by long lead times is an example of a negative locational signal working against locational opportunities: connection times are long in areas where resource and planning opportunities are high. A more strategic approach to network planning would entail the identification of future areas of likely renewable development and could begin to deliver networks that are capable of connecting those projects ahead of need. Although this involves an element of strategic investment and some (although, if well managed, minimal) risk to investment made with consumers' money, there are ways of mitigating this. The approach taken in Texas, where network capacity was built around 'Renewable Investment Zones' identified as particularly suitable for wind development, is an example of how this can be successfully managed (as discussed in our **Wild Texas Wind Paper**).

Regen's recommendation for Ofgem

Continue to reform network connection and queue management processes so that there is a consistent and integrated process between locations and across network voltages. At the same time, continue the shift towards more strategic and anticipatory network and system planning and investment, on which to base forward-looking locational signals – i.e. have a strategic plan, and tell the market where assets are needed.

5 Initiatives such as Ofgem's policy review as well as the National Grid's **TEC amnesty and queue management reform**.

BOX 2

What can be learnt from the locational signals sent by the DNOs?

DNOs produce connection heat maps indicating the parts of the network that are currently constrained. They highlight where available network capacity exists today and where network upgrades are expected in the near future. The value of DNO heat maps is that they provide information to developers about where it may be possible to connect to the network in the relatively near future. This has driven clear behaviour change, with developers focusing on areas where securing a connection is likely and balancing the timescale for connection with other factors, such as land costs and resource.

DNOs also use a range of other frameworks that encompass other spatial signals, such as the use of Constraint Management Zones (CMZ) or Active Network Management (ANM) areas. Both frameworks signal that there is limited network capacity available in an area and put in place systems to limit access to capacity. Along with improving forecasting of the access limitations that operators might face in ANM and CMZs, this means that the implications of limited network capacity at each location can be appropriately factored into developers' investment decisions, including, for example, the decision to invest in behind-the-meter flexibility, like battery storage.

Developers, local authorities and others in the industry have regularly called for networks to publish clearer data on the current status of distribution networks, and to provide a forward view of likely network constraints and investments over the longer term. DNOs have responded by making more data available – including innovation projects that would allow direct access to substation-level data – and presenting data using graphical tools.

There is an opportunity for innovations put in place by DNOs to be mirrored at the transmission level. For example, Transmission Operators (TOs) could provide clearer signposting of which network locations could accommodate quicker connections for different types of user: generation, storage or demand. There are also opportunities to extend the concept of non-firm connection arrangements that underpin ANM connections at the distribution level. This is being explored as part of the current review of transmission connection arrangements. Unlike a move to LMP, which involves a compulsory move to non-firm connections, transmission-level ANM would allow for additional options to be explored, where network users are encouraged to consider location and flexibility, with the potential benefit of earlier and cheaper connection offered alongside traditional firm access.

3.3 Balancing Mechanism (BM) enhancements

Type of locational signal: Operational

The BM is the mechanism by which the ESO balances the system during the last hour before delivery. It is used both to ensure an energy balance at the national level, matching supply and demand – actions to deliver this outcome are listed as 'energy balancing actions' – and to ensure the system remains operable, including that network limits are maintained – actions to deliver this outcome are listed as 'system balancing actions'.

The BM is already locational by nature. Asset owners submit bid and offer prices, to turn up or turn down generation and demand into a single mechanism, but the utilisation of assets will depend on their location and other factors. For energy balancing actions, assets can only be chosen if their bid or offer is consistent with network limits and other system constraints – for example, a generator behind a network boundary that is already at its limit cannot be used to meet a shortfall of generation at a national level. For system balancing and constraint management actions, assets are specifically chosen for their location relative to a constraint.

Investors in assets that plan to participate in the BM are becoming more aware of the geographical spread of BM actions and, through analysing BM data provided by the ESO, can begin to work out the best location for assets that wish to provide BM services. While historically this has tended to be generation assets, increasingly battery storage and demand response providers are a growing fraction of the BM actions.

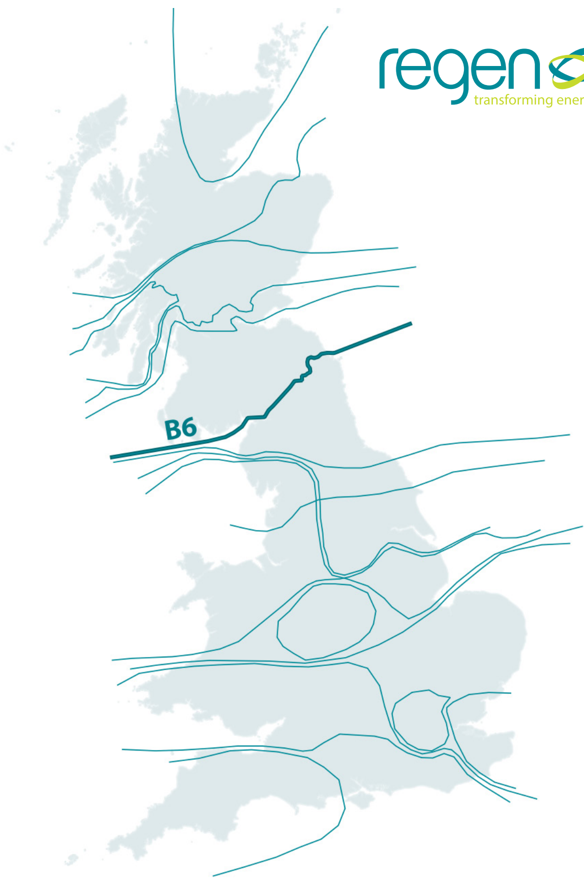
The BM has become especially important for battery storage developers who are now actively targeting this market.

Modo Energy has produced a useful summary of recent BM actions, suggesting modestly higher dispatch rates in the south of Scotland and south east of England, around boundaries which are constrained. This is also reflected in the location of new battery projects[6].

However, while the BM delivers a partial solution to managing constraints, there are at least three limits on its effectiveness:

- The number of actions needed to manage today's network constraints goes significantly beyond the capability of the BM and the ESO's control room processes and IT capability. The importance of solving this challenge is a key rationale for the current debate around wholesale market reform.

Figure 5: Transmission zones and constraints in the GB system. The B6 boundary is the focus of the recently developed local constraint market, as discussed in Section 3.4.1.



6 For more information, see MODO Energy BM analysis.

- The BM in its simple form operates during the last hour after gate closure and before delivery, meaning that only assets capable and willing to reschedule and respond in less than one hour can contribute to constraint management. In reality, there is no reason why the system operator could not take balancing actions earlier, and in fact this has been happening through 'trading' actions.

- There is limited ability in the BM to look over multiple settlement periods and consider constraints that run over multiple time periods. A critical example of this is energy storage, where the ability to charge at one time, for example, to reduce export from a generation constrained region, depends on it discharging during a previous period to free up storage capacity.

How the BM locational signal could be improved

At a broader level than the operation of the BM, there is a need for the ESO to provide more visibility around future need, particularly on investment timescales. This is closely connected to the importance of central strategic planning – there is a need for stronger signals to be sent around where flexibility will be required in the future, to stimulate investment in those areas. This is particularly the case for constraint management, which is now beginning to happen with initiatives like the ESO's **Local Constraint Market**, as discussed in the next section, and the new **EC5 Constraint Management Inter-trip Service (CMIS)**, also developed by the ESO and due to be in service from 2025. Combined with Holistic Network Design and the shift to strategic network planning, the ESO should now be able to produce a more forward-looking forecast of their flexibility requirements over timescale of up to several years in advance.

The ESO markets team is already embarking on a series of reforms and enhancements to the BM and associated markets. As a direction of travel, these are intended to open the BM to many more participants. However, the limitations of current IT systems and processes limit the ability of the ESO to identify and communicate locational signals through the BM and, ultimately, to dispatch assets. There is a need for substantial investment in digital infrastructure capable of managing the significantly increased volume of actions that will be needed for a range of operability issues.

While in the past BM actions were delivered by a relatively small number of large power stations, today it is more likely that a large number of small providers including batteries, demand-side response provision, aggregators and renewable generators will be dispatched to deliver the same volume of flexibility. Improved digital infrastructure including control room IT systems, communications, control systems and cyber security will ensure that the locational signals that BM related frameworks aim to deliver is not diluted by a technical inability to identify and dispatch the most economically efficient actions.

Regen's recommendation for the Electricity System Operator (ESO)

Improve and enhance the operation of the Balancing Mechanism (BM), through digitalisation, IT investment, forecasting and market development, so that it becomes far more adept, efficient and competitive. The objective should be to reduce balancing and constraint management costs by making best use of low carbon generation and flexibility.

Return to Regen's Recommendations

3.4 Strengthen locational flexibility signals and improve their coordination

Whilst reform of the BM may improve some signals to flexibility providers, both locational and non-locational, it is unlikely that the BM will be the appropriate vehicle for all forms of operational signals. For example, there is distinct value in providing signals at the day-ahead stage or even more in advance, allowing flexibility providers to plan their schedules against other commitments. There is also the question of spatial granularity – it is unlikely that the BM will be appropriate for managing very local distribution level network constraints.

Care needs to be taken to ensure that the full suite of flexibility signals developed are consistent and work effectively together. As an example – should one organisation, such as the ESO/FSO, be responsible for all flexibility signals at all voltage levels, or could responsibility be split between organisations, with sufficiently clear demarcation of responsibility?

3.4.1 Constraint markets

Type of locational signal: Operational

An option for improving the management of transmission constraints is the exploration of regional constraint markets, building on the local constraint market (LCM) **currently being introduced** in Scotland, and the various flexibility services and auctions that have been established to manage distribution network level constraints.

The approach being used in Scotland involves a daily day-ahead and within-day market for either generation turn-down or demand turn-up in Scotland. It will be used to access cheaper alternatives to BM actions for reducing scheduled exports across the B6 boundary – the boundary between Scotland and England, as shown in **Figure 5** – and specifically targets non-BMU registered assets that are distribution-connected or smaller, giving ESO more visibility and, to a certain extent, control over these assets. The market will operate whenever there is a forecast of constraints between Scotland and England, and an offer to reduce generation or increase demand will be accepted where these are expected to be cheaper than waiting until the BM to schedule actions. Currently the ESO is exploring the best trigger point for accepting trades, but has suggested that where they are at least circa 2% cheaper than expected BM equivalents that LCM actions could be used.

The Scottish LCM represents a useful example of the evolutionary development of operational locational price signals. It takes a relatively small but important step away from relying primarily on the BM to a system with the potential to work better for smaller providers, demand-side options and storage. It is also the first step in a process that could lead to a more extensive constraint management approach. Box 3 below lays out a summary of how such an approach could work. At this stage there are a wide range of issues that need to be explored in order to understand the potential of such a general constraint management market for GB. To date there has been little exploration of this option and, in order to make good decisions on market reform, it is critical that market reform discussions focus on exploring and developing options such as this in detail.

BOX 3

Outline of a constraint management market for GB

The Scottish LCM, whilst a useful first step, has a number of limitations in terms of its potential. It is a day-ahead/within-day market, which deals only with the exporting side of a constraint and focuses only on one constrained region. The table below highlights how a more general constraint management market could evolve out of the Scottish trial. An aspect of particular importance is that the majority of the costs of a constraint are related to the need to turn up generation (or turn down demand) in the importing area of the system 'in front' of the constraint and, as a result, are often set by the fuel and carbon costs associated with the need to turn up a flexible gas plant. The current Scottish LCM does not tackle these costs.

2023 Scottish local constraint market	Full scale regional constraint management market
Timescales: day-ahead and intraday.	A marketplace solution means there is flexibility to adapt to market need and respond to changing conditions. As such, timescales could expand up to several days ahead of delivery, or even further ahead, dependent on confidence of constraint forecasting, or deliver services closer to real time, if required.
Location: Operates behind the constraint only for generation turn-down and demand turn-up.	Could expand to include generation turn-up or demand turn-down in front of the constraint, to impact the current cost of turning up replacement generation in the BM.
Boundaries: Designed specifically for a single boundary (B6) but also considering constraints across the parallel boundary further north (B4).	Could operate across multiple constraints, using a more sophisticated optimisation approach for dispatch.
Participation: Distribution connected non-BM assets only.	Could be extended to include larger transmission-connected assets with contracts forming part of the final physical notification submitted at gate closure.

A market that covered multiple constraints across the whole of GB would require a significantly more complex methodology, reflecting the fact that certain actions could relieve multiple constraints at the same time, while others might relieve one constraint whilst exacerbating another. The development of such an optimisation framework has the potential to show significant parallels with the types of dispatch algorithm used in an LMP market, and may therefore provide the opportunity to harness the power of such algorithms for effective dispatch without the excessive disruption to existing wholesale arrangements that LMP would risk.

There are a number of areas that need to be explored in order to understand the most appropriate way to design such a market and the level of value it could deliver:

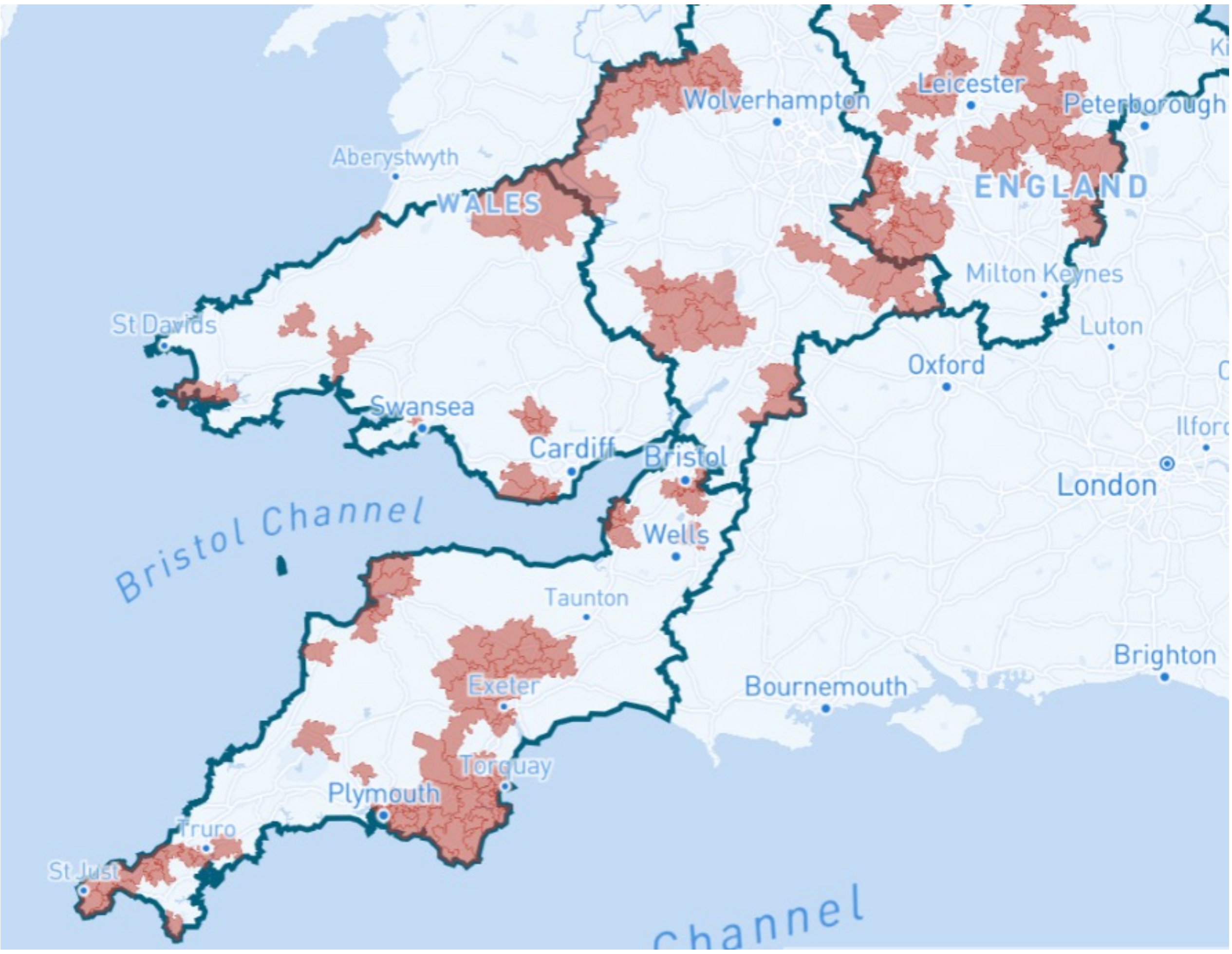
- **Constraint forecasting:** Constraint markets will be effective where they can be informed by meaningful forecasts of constraint levels. To understand the best design, we need to better understand the ability to forecast constraint levels over different time periods.
- **Interaction with the wholesale market:** A constraint management market will run alongside the wholesale market, meaning market participants may have the option of participating in either market – or both. There will be a need for rules to govern what market participants are allowed to do, and for the development of robust systems to monitor market activity to identify potential market manipulation.
- **Mechanisms for adding value:** The cost reduction of contracting constraint management actions ahead of time will vary between providers, and the markets developed need to cater for this. For example, it may be that for some peaking generator plants, there is little cost difference in scheduling their output a day ahead or an hour ahead. However, for others, there is likely to be significant differences. For industrial demand-side providers, it may not be possible to adjust their operation in order to reduce demand at short notice, but providing day-ahead (or longer) scheduling may open up a new group of potentially cheaper providers for constraint management.

3.4.2 Flexibility markets and auctions

Type of locational signal: Operational

The use of flexibility markets and auctions by the DNOs has become common practice. Flexibility markets begin with an analysis of flexibility requirements across the networks by location. NGED, for example, now publishes a regularly **updated flexibility map** with data provided as to the extent and duration of flexibility requirements. Network operators then deliver auctions to procure those flexibility services, with contracts most commonly ranging from **one to five years in length**.

Figure 6: An example of NGED's flexibility maps. Source: National Grid Electricity Distribution.



Flexibility auctions on the distribution network have now become **business as usual**, with over 12 GW tendered, and have attracted locational investment by battery and demand side response providers. The equivalent flexibility tenders on the transmission network, where constraint management costs are greatest, is beginning to happen – albeit at a relatively slow pace. For example, the ESO have recently implemented a **'MW dispatch Service'** for distributed generation and battery storage connected in south west England, allowing them to instruct those assets to reduce their export to the grid to zero.

How the locational signal could be improved

Flexibility providers have been encouraged by the development of flex markets and auctions. In common with other areas, the ask of transmission networks and the ESO is to:

- Increase the scale of flexibility procurement under a 'flex first' approach for both transmission and distribution constraints, providing strong locational signals for investment in, and operation of, flexibility in order to make efficient use of network infrastructure[7].
- Provide more long term forecasting and visibility of flex requirements on a locational basis. This should build on the evolving Regional Development Plan approach being taken at the transmission level.
- As far as is feasible, remove barriers preventing smaller assets from participating in all flexibility services including the Balancing Mechanism, and ensure that as new services evolve they are open to all sizes of providers.
- Increase the overall transparency of procurement processes and, where different mechanisms are used to procure flexibility, aim to harmonise the data provided to the market to allow easy comparison and reduce barriers for flexibility providers to operate in multiple markets.
- Remove barriers preventing assets from stacking revenue across several markets and auxiliary services.

Regen's recommendation for the Electricity System Operator (ESO)

Alongside the BM, continue to develop operability, flexibility and local constraint management markets/services that will enable the ESO to utilise a wider range of assets and resources and to pre-emptively manage constraints. This would allow markets to send a stronger locational signal for flex providers and investors.

7 This has been recognised in RIIO ED2, which includes incentives to encourage DNOs *"to deliver net zero at lowest cost to consumers, supporting a smarter, more flexible energy system"*. For more information, see Ofgem's **RIIO-ED2 Final Determinations Overview** document.

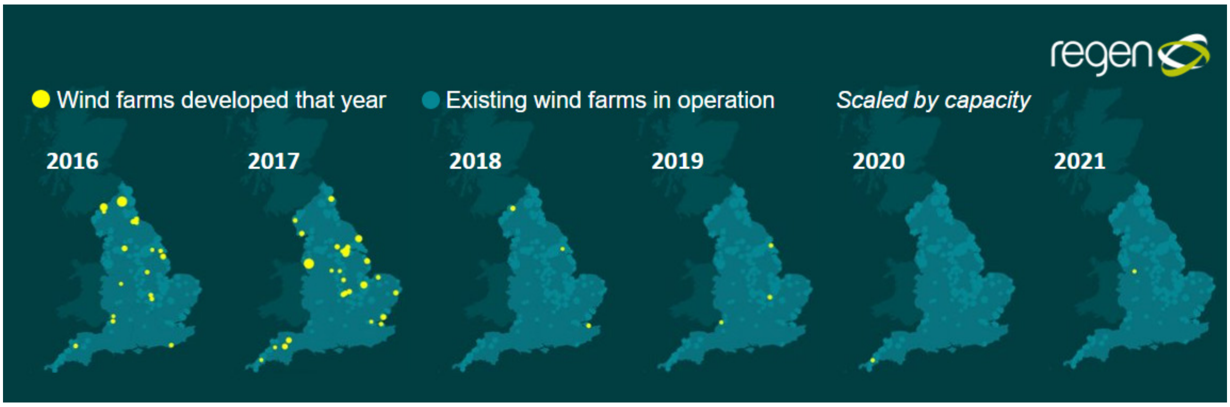
3.5 Align planning policy with net zero and empower greater local decision-making agency

Type of locational signal: Investment

It is clear that developers and investors respond strongly to locational signals given by various forms of spatial planning. The most obvious is the almost complete lack of planning applications for onshore wind in England since the introduction of **2015 Written Ministerial Statement** introduced by the current government that effectively banned onshore wind developments.

In contrast, the planning system in Scotland is highly supportive of onshore wind – the **National Planning Framework 4**, adopted in 2023, includes a policy intent to *"encourage, promote and facilitate all forms of renewable energy development onshore and offshore."* As a result, the Scottish onshore wind sector is highly active, with a **policy commitment** from Scottish Government to deliver 20 GW of operational onshore wind in Scotland by 2030 (up from around 8GW in 2023) and more than 10 GW currently in the planning system[8].

Figure 7: The stalled deployment of onshore wind in England. Regen analysis showing wind farms deployed in each year, to 2021. Since 2021, only one project in England has completed construction and become fully operational. Source: DESNZ REPD.

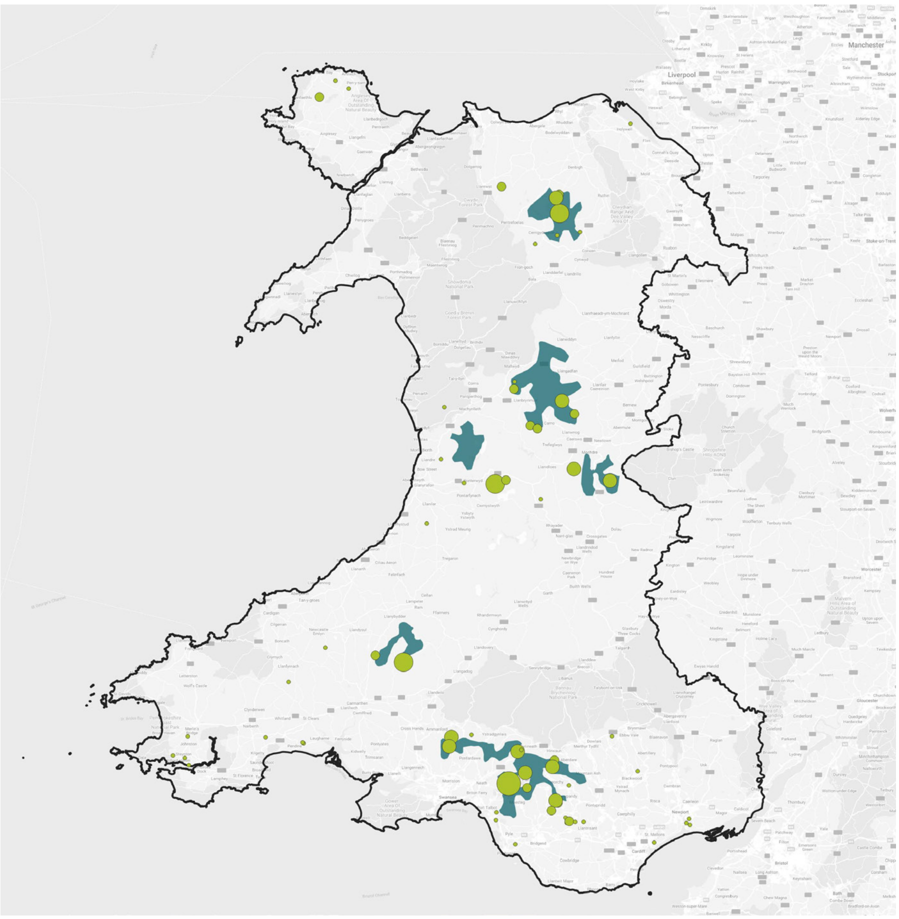


Offshore wind, tidal and wave energy developments are almost entirely driven by the spatial planning and leasing process led by the Crown Estate and Crown Estate Scotland. Only a handful of offshore projects have ever sought to develop outside the Crown Estate leasing process and those that have, Atlantic Array being a good example, were brought into the process at a later date.

Several regional initiatives have implemented forms of spatial planning for renewable technologies. The most notable has been the **TAN 7 & TAN 8** search areas that have been designated for renewable energy, including onshore wind, in Wales. As Figure 8 below shows, this has had a very significant impact on the location of onshore wind development in Wales. The Tan 7 and TAN 8 areas have now been replaced by a new set of 'priority areas' for renewable energy in Wales.

8 Based on analysis of the Renewable Energy Planning Database, April 2023 extract and includes all capacity listed as either 'Planning Application lodged', Planning Application Granted' or 'Appeal Lodged'.

Figure 8: Map of Welsh wind farms in relation to Wales' Strategic Search Areas.



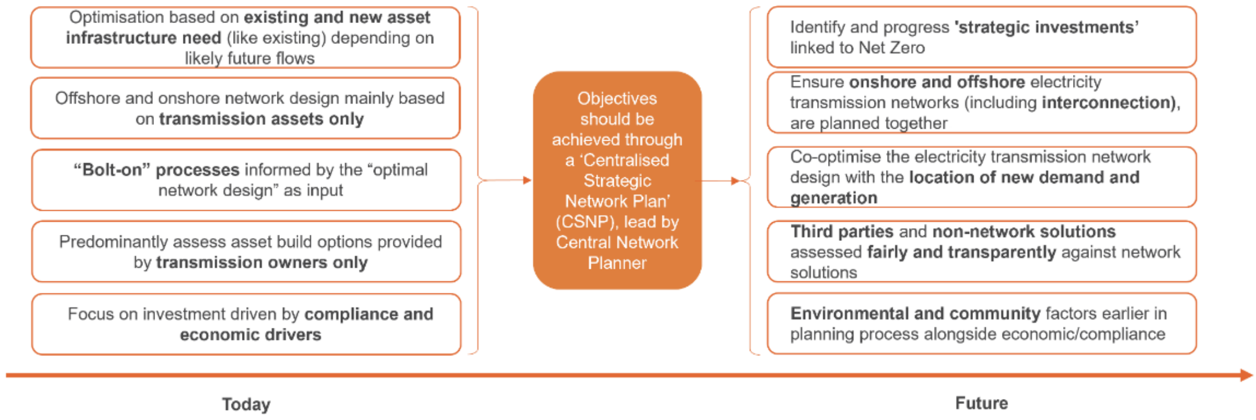
How the locational signal could be improved

Regen has, for some time, been calling for more strategic spatial planning at national, regional and local levels. At a most basic level, there needs to be consistency between policies to ensure alignment with the UK's net zero targets. The effective ban on onshore wind in England as a result of the **2015 Written Ministerial Statement**, for example, is fundamentally incompatible with achieving net zero.

Furthermore, there has long been a role for the government in setting overall ambitions, often in a technology-specific way. This is illustrated by specific targets for offshore wind and hydrogen production capacity. However, to date, there has been little action from the government or other national institutions to define where that capacity is best located, which has always been left to the market to shape. The exception is that devolved, regional and local governments have often made commitments or set targets for their areas – for example, the Scottish Government's objective for 20 GW of onshore wind in Scotland by 2030.

There could be significant value in developing a locational element to strategic energy system planning. The obligation recently placed on the ESO to develop a Centralised Strategic Network Plan (CSNP) is a good opportunity to explore and integrate strategic spatial planning of the electricity system, including generation, flexibility, demand and networks.

Figure 9: The ESO's ambition for the centralised Strategic Network Plan includes the co-optimisation of transmission network capacity with the location of new demand and generation, an approach that points towards a more strategic and planned approach to regional distribution of energy resources. Source: National Grid ESO.



At a local and regional level, the advent of local area energy planning and the development of Local Area Energy Plans (LAEPs) has created an opportunity for more local authorities to work with developers and network operators to determine the optimal location for renewable energy projects. However, it is vital that once LAEPs have been developed and adopted they then have some additional weight within the planning system, to provide regions with greater agency in determining where projects should be developed. This would then send a very strong locational signal to project developers, empowering them to prioritise developments in areas where this is supported in the planning system. Ofgem are currently considering the introduction of Regional System Planners as part of the institutional framework for strategic planning at a regional level[9]. In the foreword to its consultation. Ofgem highlights that it

> *is imperative and urgent that generation and network capacity are closely planned and coordinated to deliver the investment needed to meet net zero targets for 2035 (a net zero clean power system) and 2050 (a net zero economy) and ensure the system can become truly smart and flexible.*

Regen's recommendation for the government

Harmonise planning policies to ensure alignment with the UK's net zero targets. Empower local authorities, city regions and devolved governments (e.g. through Local Area Energy Plans, Regional System Plans and other local strategic energy system planning) to have more decision-making agency to send stronger local and regional signals as to where infrastructure, low carbon technologies and system assets are required.

9 For more information, see Ofgem's consultation on the future of local energy institutions and governance.

Return to Regen's Recommendations

3.6 Retain an integrated GB wholesale market

Locational Marginal Pricing (LMP) has been cited as a means to provide better locational signals to participants in the GB wholesale electricity market, with supporters suggesting that it would be capable of influencing both investment decision-making (including asset siting) and operational dispatch.

In common with many of our industry colleagues, Regen is doubtful about the claims that LMP would improve locational signals for future investment. However, it does seem clear that LMP would increase investment risk, especially for low carbon generation, and so in that sense it would send a strong negative signal: *'don't invest in this market'.*

Much emphasis has been placed on the ability of LMP to improve generation siting as a means to reduce constraints and improve network investment efficiency, such as in the modelling produced for Ofgem by FTI[10]. Within this business case modelling for LMP, it has been claimed that a shift to LMP could result in the re-siting of up to a third of wind generation capacity compared to an integrated wholesale market, as well as storage and solar PV.

In reality, we believe that this type of modelling analysis can be misleading because:

1. The base case distribution of assets, which results in high levels of constraints, is not the result of the operation of the integrated wholesale market but is the theoretical outcome of combining a build-out and distribution of assets under a hypothetical future energy scenario[11], with a given network investment plan[12], to which the scenario may not be aligned.

2. The re-siting of assets (mainly offshore wind, onshore wind, batteries and solar) are arguably not the result of an LMP price signal but are either:

   a) The result of other factors, such as offshore wind leasing aligned with a network investment plan;

   b) or would be very unlikely to happen in a real world energy system without an anticipatory investment in network capacity, such as a major shift in onshore wind and batteries to within constrained areas in the north of Scotland;

   c) or would happen in any market, if other locational factors were changed, such as an increase in solar PV in the south of England if there was capacity on the distribution network.

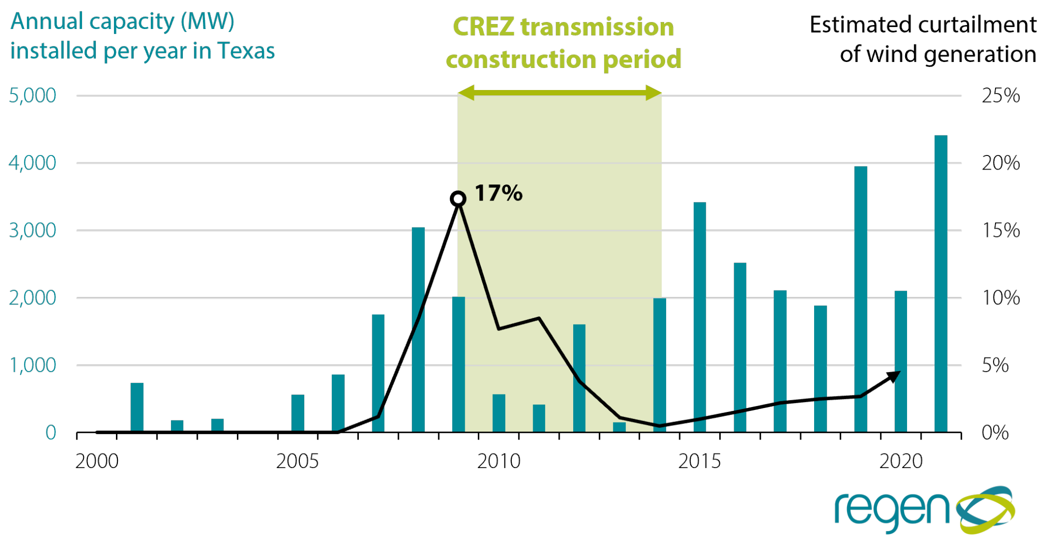
The danger of ascribing the location of assets to the action of the market is explored in our paper **Wild Texas Wind**, which looked at the operation of LMP markets in the US. In that paper, we came to the conclusion that the success of Texas at delivering new investment in onshore wind capacity in the last decade had far more to do with strategic planning, investment support and a commitment by the System Operator and state authorities to build network infrastructure to connect west Texas, and very little to do with prices that vary between location. In Texas, once the initial network capacity had been exhausted and constraints rose, wind farm investors did not move themselves to areas of demand and higher prices (although they may have liked to) – instead, they stopped investing.

10 See **www.linkedin.com/feed/update/urn:li:activity:7072868042820444160** for more information.

11 For example, the regional (GSP) view of the FES 2021 System Transformation or Leading the Way scenario.

12 For example the NOA 21/22 refresh, and Holistic Network Design 1 which runs only to 2030.

Figure 10: Buildout of Texan onshore wind installed capacity. $6.8 billion in transmission lines were constructed in the Competitive Renewable Energy Zone (CREZ) between 2009 to 2013, adding circa 18 GW to grid capacity in west Texas. Source: U.S. Energy information administration (EIA) Wind 2021 data, curtailment data 2007-2020.



The reasons for Regen's conclusion that LMP will be a significant barrier to delivering a decarbonised electricity system are as follows:

1. **LMP locational signals only capture short-run costs of generation and flexibility and ignore longer term investment costs and network costs.**

   An LMP price signal is by its nature based only on the short-run cost of generation (or flexibility). Short-run generation costs are largely those associated with fuel and carbon emissions and some elements of maintenance: they exclude any consideration of the cost or original investment, fixed operation and maintenance, and the costs and benefits of network and other elements of the system.

   Within the current debate around LMP there is often an erroneous assumption that sending such a short-run marginal price signal based on generation alone is the most appropriate way to encourage developers to build projects in less congested areas of the network. In fact, the LMP price signal takes no account of the economics of network investment but is based **only on a nodal supply/demand balance** and a price determined by the short-run costs of meeting demand at that node. Locational signals, therefore, reflect the current marginal cost of supplying demand and **do not reflect the costs or benefits of building additional generation and network capacity.**

   A more useful price signal would be based on a balance between operation and investment costs, including the costs associated with network development. A cost benefit analysis (CBA) of the economics of building additional network capacity versus the value to the customer would provide a more sensible approach than the use of LMP, and one that better reflects the total costs of supplying demand at a node, including short-term and long-term generation, flexibility and network costs. And, to be efficient, the CBA should consider not just an individual project but a holistic analysis of the investment required to support future projects and future changes in demand and supply. This is the basis under which Holistic Network Design (HND) and strategic network planning should be conducted and an approach which can be taken forward through the proposed Centralised Strategic Network Plan (CSNP).

2. **Under an LMP model, the price signal is likely to discourage investment in areas where, under a true CBA, adequate network investment and/or investment in flexibility would be the optimal outcome.**

The true cost to the network user should be reflected in network charges, which then provide an effective means by which network investment is recovered from the network customer, including the fair return on asset value. As discussed in **Section 3.1**, ideally the network charge methodology should give a forward view of ten years or more to give a true economic locational signal.

A map of how locational wholesale prices vary across the country at a given point in time is akin to looking at the current 'heat' maps produced by the networks, but such a map only tells you about the current variation of generation costs – it says nothing about the future. Since the main renewable and low carbon technologies take 5-10 years to develop, if we are to introduce locational signals, these need to provide a long term and reliable forward price/cost signal. LMP does not provide this[13].

Some generation technologies may be more amenable to a short term signal than others. Solar, for example, usually has a slightly shorter lead time than wind. But a) the location of solar is less of a structural issue in the GB market, b) solar investors are already responding to other more pertinent locational signals such as the availability of a connection, connection lead times and connection costs, and c) solar is heavily influenced by the available capacity on the distribution network.

Figure 11: Some generation technologies, such as solar, may be more amenable to a short term signal than others, due to shorter lead times.


Image credit: Lightsource

3. **LMP price signals would be extremely transitory and unpredictable.**

As well as being short term, LMP price signals would be subject to quite rapid change, as new network capacity is added, new generation is developed and demand patterns change. A location that seems attractive because of low congestion at present could flip as new generation capacity comes online. Given the current queue of projects wishing to connect, and the current levels of constraint, it would be realistic for any generator to assume that areas with network capacity today will be quickly cannibalised.

13 See University of Strathclyde's study **Exploring Market Change in the GB Electricity System: the Potential Impact of Locational Marginal Pricing** for more research in this area.

Some have argued that investors, or their consultants, would be able to model future LMP price movements and thus the drive for competitive advantage will deliver investment in areas that LMP prices would highlight. Our expectation, however, is that, during a period of very rapid transition, this modelling would be nearly impossible given the number of variables, and that any forecast would be subject to both commercial and extreme policy risk – and would certainly not be sufficient to secure investment. Such variables which may impact future LMP price movements include:

a) **Competing generation investment:** where new investment in generation leads to previously unconstrained areas of the network becoming constrained in one, five or ten years' time.

b) **Network development:** whether the System Operator or regulator decided to delay, or bring forward, a network investment; whether there are consenting and construction delays in the build out of new network; or whether network capacity is operated efficiently, maintained appropriately, or there are unexpected outages once operational.

c) **Development of new demand:** an argument put forward for the value of LMP to Scotland and northern England is that it could encourage new demand to come forward in those regions, potentially relieving constraints. The degree to which this happens could have a significant impact on prices in those regions.

These three examples show risks that are wholly outside the control of developers and would be challenging to forecast in advance, but they would have a significant impact on a project's revenue stream in an LMP system.

Some investors may have a different attitude to risk and be willing to accept higher risk for a much higher return (resulting in a higher cost of energy for the consumer). However, as a general observation, energy developers and their investors are typically risk adverse, hence their willingness to offer very low strike prices in CfD auctions in exchange for revenue certainty, and their focus on obtaining a firm grid connection.

On the basis that those best placed to understand and manage risk should bear risk, it makes far more sense for constraint risk to continue to sit with the system and network operators, except where generators or other asset owners choose to accept a non-firm connection agreement, e.g. in an Active Network Management scheme.

4. LMP locational signals for flexibility providers would be unreliable.

Some flexibility providers, including members of the Electricity Storage Network (ESN), have identified that the increased volatility produced by LMP – as locational prices flip from a higher marginal price to a zero or even negative price depending on constraint levels – could create an incentive for batteries or Demand Side Response (DSR) to locate within network-constrained areas, e.g. currently in the north of Scotland.

However, other flexibility providers have identified that such an LMP incentive may be short-lived and ineffective because:

a) Renewable generators would simply not build in network-constrained areas under an LMP model and would in fact be less likely to invest in the GB market. As one ESN member put it *"the driver for flexibility is renewable energy: if renewable energy projects face an investment hiatus then so would flexibility"*.

b) Any advantage for flexibility assets to locate in a constrained area would be dependent on the continuation of that constraint into the future. Revenues would be dependent on future network build-out, the development (or not) of new generation and demand, and exposure to cannibalisation by other flexibility providers. The result would be similar high levels of uncertainty to that experienced by generators (see description above).

c) Storage providers would themselves be curtailed in their ability to discharge, especially during periods of high wind. The model of charging storage behind a constraint and then waiting for a low wind period to discharge is not usually commercially viable, due to the potential length of time the storage asset would be sat waiting to discharge, and would lead to under-utilisation of storage assets.

d) Storage and flexible assets offer many services to the electricity system such as frequency response and reserve. Constraint management is only one such service and, as indicated in the previous point, the characteristics of congestion (the time-distribution and duration of congestion events) mean that it may be relatively low value compared with other services. As such, there is the risk that storage actually responds to signals from other, non-wholesale sources, signals such as contracts offered by DNOs for local and regional flexibility, or for services such as dynamic containment reserve from the ESO.

5. **Locational price signals in an LMP market would be unlikely to align with locational signals such as resource availability or signals from the planning system and future regional and local energy plans.**

For LMP to succeed in helping to better align locational investment decisions with network capacities, the LMP price signal would need to reduce investment in generation-heavy constrained regions whilst simultaneously increasing investment on the other side of network constraints. However, without the possibility of getting planning permission, the availability of seabed leases, access to a strong local supply chain, and – in the short to medium term at least – a well-developed pipeline of potential projects, there is simply no opportunity to build. LMP is likely to be successful in the first half of its aim – reducing investment in some parts of the country – but that lack of alignment between prices and other critical locational factors means that it will likely fail to deliver sufficient generation capacity on a national scale.

LMP may send a strong dispatch (operational) locational/temporal signal within a central dispatch process but, as discussed in **Section 3.3**, the benefits of better dispatch and co-optimisation could be achieved more quickly and more effectively by enhancing the current balancing mechanism, control room functions and constraint management processes. There is also a significant question around whether LMP and centralised dispatch would be more efficient in a very high renewable energy system which, until we have seen more detail on the LMP/central dispatch design, is very difficult to answer.

Regen's recommendation for the government

Retain the existing integrated GB wholesale market and seek ways to provide effective locational siting and operational signals via solutions and enhancements within the existing market structure, avoiding the risks associated with shifting to a radically new market design.

4. Concluding remarks and next steps

The market reform debate is currently in full swing, with several workstreams being established in tandem in the last two years. This includes the ESO's recently completed Net Zero Market Reform programme that was established in early 2021, with the ESO presenting their conclusions in **a webinar in July 2023**, and Ofgem's call for input on their Locational Pricing Assessment, established in June 2022, through which FTI was commissioned to undertake their modelling discussed in **Section 3.6**.

However, the publication of the government's Review of Electricity Market Arrangements (REMA) consultation in summer 2022 has arguably provided the greatest opportunity for discussion, with the need for market arrangements to send appropriate temporal and locational signals cited as a key factor in the case for change underpinning the original consultation.

Delivering an electricity system that can provide secure, affordable and zero carbon energy is critical to our future as a country. The hotly anticipated second REMA consultation – due in autumn 2023 – should provide a further, no less vital opportunity to explore the reform opportunities discussed in this paper, to strengthen the mechanisms required for the UK to achieve its decarbonisation targets and deliver a net zero electricity system by 2035.

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