Regen Insight Paper June 2022

"Wild Texas Wind"

A look at Locational Marginal Pricing (LMP) in the US, focusing on Texas, to better understand the potential implications of an LMP based market design for GB net zero investment.

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1. Introduction and summary findings

National Grid Electricity System Operator (SO) and Ofgem have launched reviews of **Locational Marginal Pricing** (LMP) as a potential basis for GB market reform. This focus on LMP has been prompted by the rise in balancing mechanism costs and a belief that constraint costs will continue to escalate in a high renewable energy, net zero scenario. A parallel Review of Electricity Market Arrangements (REMA) being carried out by the Department for Business, Energy and Industrial Strategy (BEIS) also plans to consider LMP, but is taking a broader view of potential market reform to deliver net zero electricity by 2035, ranging from radical change to a more incremental modification to existing arrangements.

This insight paper looks at existing LMP markets in the US to better understand: LMP working in practice; the impact that this type of market design may have on both low carbon generation and strategic network investment; and whether there are lessons that can be learned and applied to the reform of the GB market.

The analysis of US markets concludes that an LMP market design does not create a natural pathway to net zero and, without substantial state actions, increases investment risk for low carbon technologies to the point where investment would likely stall. The assumption that low carbon generation would relocate in response to locational price signals is not supported by the evidence, although there could be a case that solar energy (both grid connected and off-grid) is more locationally fluid than wind, hydro and nuclear.

The lessons from Texas' stop-start wind investment highlight the importance of having a long term plan and strategic commitment to support renewable energy deployment. In Texas, this included making **anticipatory strategic network investment** (especially through the Competitive Renewable Energy Zone (CREZ) investments made between 2009 and 2013) to ensure sufficient grid capacity was available to enable wind farm development in West and North West Texas. Without new network capacity, as constraint risk rises, investment in generation quickly stalls.

Having experienced a second period of renewable energy growth from 2014 to 2021, constraints are rising again, and so Texas energy authorities are considering another round of major grid investment to get to the next level in its net zero transition. There is a big question, however, whether the structure and governance arrangements of the energy market will enable their previous strategy to be repeated.

The western Texas case study has some similarities with the position of Scotland in the GB energy system; lots of potential energy resource, a high level of ambition and challenge of network constraints. Lessons from the Texas and US experience suggest that for the GB electricity system:

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- An LMP market design will increase investment risk for low carbon generation and would jeopardise progress towards a net zero electricity system.
- This risk could be mitigated by making anticipatory network investment, to guarantee capacity, or by providing another form of revenue guarantee. The Texas experience suggests that a "build and connect" strategy would be required for grid infrastructure.
- While GB's current 'connect and manage' approach has led to increasing constraint costs (almost all in Scotland), this could be reduced by making more timely network investment, modernising dispatch process and greater use of flexibility assets.
- Whether a LMP plus 'build and connect' approach would be more economical to deliver net zero is questionable. If generation investors require certainty that capacity is available before committing investment, it may in fact require more network investment, and result in less use of flexibility solutions. An outcome would indicate that the SO is better placed to manage the risk of curtailment, and the use of flexibility, than individual generators.
- Most renewable and nuclear technologies are unlikely to shift their location based on a marginal price signal. Part of the problem is that the LMP signal is transitory. Plus they are already responding to other stronger locational signals including resource, planning and access to grid. Locational signals could be better given through ongoing network charging and access (connection agreement) reform.
- Demand is similarly difficult to shift based on marginal price signals alone, although there are some outlier exceptions such as cryptocurrency mining.
- There is no evidence from US markets that LMP increases investment in flexibility such as storage and demand response for constraint management. Recent battery growth in Texas has been mainly in areas of high demand to provide network services and resilience after recent outages.

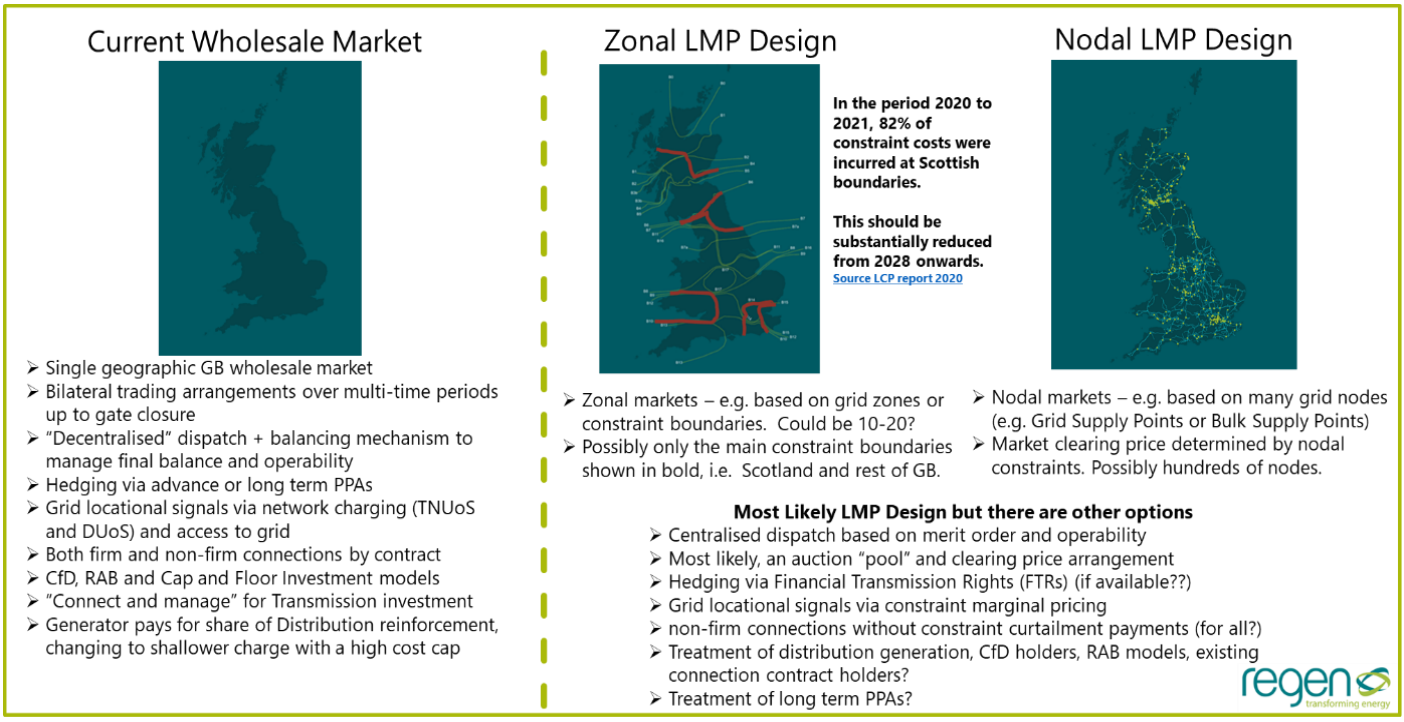
2. Locational Marginal Pricing – brief overview

Interest in the concept of LMP has grown because of the increased occurrence of network constraints which has in turn led to an increase in balancing mechanism charges[1] and the need for the SO to "re-dispatch" higher volumes of power. It currently does this by curtailing some generation assets while bringing others on-line to meet consumer demand.

In this context, LMP is viewed by some as an effective way to manage network constraints and, by centralisation of dispatch decision making, giving the SO control room greater ability to optimise the generation mix and, in particular, to more efficiently dispatch fossil generators.

There are many potential options and variations in LMP market design including: whether locations are defined as zones or at network nodes; the degree of centralisation of the dispatch function; and the extent to which LMP price signals are reflected in the end-consumer bill.

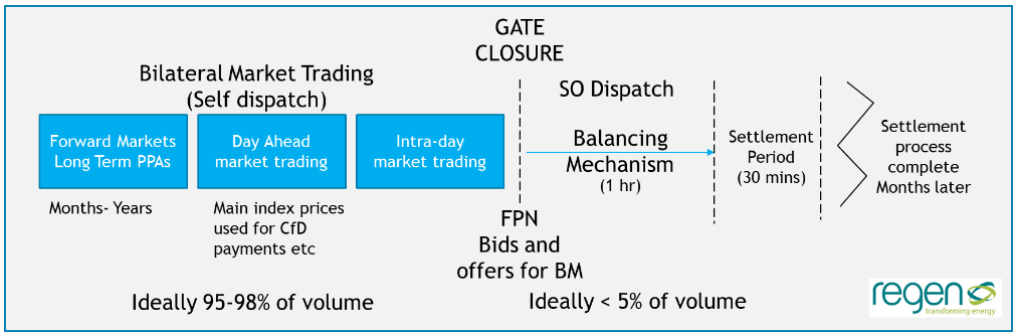
[1] Wind farms receive a small proportion of constraint management costs. The bulk of costs are incurred to turn up generation on the other side of boundary constraints to satisfy demand. A recent study by LCP identified that 85% of the consumer cost from constraint management was for turn-up payments, almost all of this (94%) was paid to large CCGT plants. 82% of constraint costs were at Scottish boundaries.



Current GB market arrangements

In theory, the current GB electricity trading market operates[2] under a system of decentralised self-dispatch with bilateral trading. In simple terms, the current market arrangements in GB are:

- Market participants (buyers and sellers) can bilaterally trade[3] energy with each other on the basis that that electricity will be dispatched.



- Wholesale trading (with long-term, day-ahead and intra-day trades) continues up to the point of 'gate closure' for each half-hourly settlement period. At this point, balancing market participants must submit their Final Physical Notification (FPN) to the SO for that period.

[2] New Electricity Trading Arrangements (NETA), introduced in early 2000s, created an integrated GB market, including Scotland, replaced previous Electricity Pool of England and Wales (the Power Pool), culminating in the Electricity Market Reform (EMR) in 2013.

[3] Trading can be via long term PPA, month(s) ahead, day ahead and intraday auctions. **Note: it is wrong to say that the GB market has one single market price or that the wholesale market 'clears' at a single price.**

- The FPN details their balance position i.e. intended volume of generation and demand, and their Offer and Bid prices[4] to increase or reduce demand/generation if required to do so by the SO.
- The SO then has a time window, from the point of gate closure[5], to make balancing and system based adjustments to ensure that electricity supply meets demand at all times and that the system is operable. This process includes action to turn up or down generation, and potentially demand.
- To manage constraints, the action(s) to turn down generation is often accompanied by parallel actions(s) to turn up generation (often fossil fuels) somewhere else on the system. This secondary turn-up is the biggest cost driver[18] and is subject to "bullwhip effects"[6] and market exploitation[18].
- New connections on the transmission network are managed on a 'Connect and Manage' basis – new customers do not contribute to network upgrades, Transmission Operators (and the SO) are expected to plan and manage new investments, and to optimise the use of flex solutions.
- On the distribution network, new customers do contribute to network upgrades as a condition of their connection agreement. The basis of this cost share is changing as a result of Ofgem's Network Charging and Access Significant Code Review.

Under these trading arrangements, the market is expected to be largely self-balancing with the SO left to manage a small residual imbalance, and to deal with system operability requirements. Increasingly, however, the SO's balancing actions, in certain periods, are amounting to a redispatch of a significant volume of energy[7], both for power balancing and to manage boundary constraints, especially with Scotland, and other operability issues.

LMP market arrangements

To simplify a very complex topic, we could think of a LMP market as having **four key features**:

i. **Locational pricing.** Assuming some degree of network constraint[8], electricity is priced separately at each node (or zone) of the electricity network in each trading period, through a bidding process. Assuming competition between generators, prices at each market location would, in theory at least, reflect the marginal value[9] of constrained electricity.

   Constrained locations with high levels of lower cost generation (relative to demand) would encourage highly competitive bidding to dispatch electricity which would drive locational prices down to the marginal cost of the marginal constrained generator. In locations dominated by near zero marginal cost renewables and nuclear, this would produce an extreme form of price

[4] Plus any asset level constraints of minimum power output levels and minimum run times. These are an important driver of constraint costs and carbon impact for gas fired power stations.
[5] The SO can take actions ahead of gate closure and this is increasingly happening e.g. the SO can already make its own forward trades to secure energy supply.
[6] An overreaction to supply chain imbalance – caused by imperfect information and inflexibility e.g. the minimum run-times and power output of inflexible gas fired power stations. A case for investment in flexible and responsive assets.
[7] Analysts have cited periods when re-dispatch amounts to over 50% of overall volume. That is rare, but occurrences of 10-30% of volume are quite common. An ideal level is somewhere less than 5%.
[8] In the absence of network grid constraints, nodal or zonal locations would in theory cascade into a single market. The degree of price variation between markets is driven by the degree of grid constraint/integration, plus level of competition and non-competitive market power within constrained markets.
[9] This is sometimes presented as "the value of local energy". This is not correct in the sense of valuing the true cost of local energy supply, local economic value or other local value measure. It is more properly described as the "marginal value of constrained energy" at a given location.

competition. Market locations with less generation relative to demand, and/or reliant on higher cost fossil fuel generation, would result in higher, less competitive, market prices. Following this logic, the north of Scotland may see lower energy prices, while parts of England may see higher prices. Prices could also vary considerably within regions down to the level of individual nodes or zones.

This would, in theory, send a very strong[10] locational price signal to generators and, if implemented fully, to demand consumers. In practice, price signals to most demand consumers may be dampened by averaging so as to avoid extreme consumer price volatility, and energy bill disparities based on the chance occurrence of network constraints.

The locational price signal to generators and customers is potentially offset by a loss of economic signal (or incentive) that new network investment is needed. The relationship between LMP and network investment is discussed further below.

ii. **Removal of export rights & curtailment payments.** A second key feature of LMP markets is that generators who have sold their energy to an off-taker/customer would no longer have a contractual right to export energy to the grid (or in other words a 'firm connection'[11] agreement) and the right therefore to expect curtailment payments. This would shift the risk of constraint curtailment from the Balancing Mechanism into the LMP market and onto individual constrained generators and customers.

The extent to which grid export rights are removed may vary depending on the detailed LMP design. There is an argument that distribution network connected generators should retain a firm connection or dispatch priority, since they may have contributed more towards the costs of network upgrades at the time of connection. Contracts for Difference (CfD) contract holders, and new nuclear under a Regulated Asset Base (RAB) investment model, may also require the equivalent of a firm connection. Differences in approach between generation will, however, distort the LMP market and greatly complicate the dispatch processes.

iii. **Secondary hedging – FTRs.** To mitigate the risk of curtailment and price volatility, LMP markets usually include some form of secondary market in **Financial Transmission Rights** (FTRs)[12] that would allow participants to hedge[13] the risk of transmission constraint, which can lead to significant variation in prices and curtailment at different locations. As a general point, however, financial hedging requires a willing counterparty, someone with a different business model and/or a different view of the market.

Whether a FTR market would develop with sufficient liquidity to provide the level of hedging that would be required in a net zero system with high levels of renewables and significant constraints, is a key question. It would be very difficult (and progressively more expensive) to sustain a secondary

[10] Current locational price signals are made through network charging tariffs (Transmission Network Use of System and Distribution Network use Of System) and the upfront cost and/or delay of obtaining a connection agreement. Network charging reform has been ongoing for years and has been difficult to implement for the very reason that locational signals are so politically and economically sensitive.

[11] There are examples of non-firm connection agreements, for example those associated with Active Network Management schemes. For the most part, however, the finance of energy projects requires a firm connection, or at least a firm timetable to obtain one. For further insight, see Regen's analysis of the Dunbar Active Network Management Scheme.

[12] Sometimes also called Congestion Revenue Rights (e.g. in Texas).

[13] FTR hedging does not mean booking physical network capacity – it is purely a financial instrument more like an insurance policy. Paid for with a premium.

FTR market with high levels of constraint where markets have access to the same power forecast and constraint data.

Critics of these arrangements have also highlighted that *"financial instruments may be used to hedge against such congestion costs, but some RTO market monitors have expressed concerns in recent years that these financial instruments are providing earnings for financial traders and not providing a sufficient a hedge for load-serving entities"*[14].

Vertically integrated energy companies who generate and supply (and/or consume) electricity have a form of natural hedge, and have been a feature of LMP markets.

iv. **A shift (back) to a centralised dispatch function.** Most LMP market designs are based on a centrally managed dispatch function. There are different options for this, but is likely to operate something like the older Power Pool auction arrangement. Under this market arrangement, generators and buyers of electricity submit their Offer and Bid prices to a central SO function, who would be tasked with dispatching generation to meet demand on a price merit order basis, with some adjustment to maintain system operability and the minimum run-times/capacity of assets.

In a nodal LMP model, this dispatch function would need to be highly automated, based on algorithms which would replace the bilateral market trading arrangements between buyers and sellers and would seek to minimise the marginal cost of energy on a node-by-node basis.

There is broad consensus that the current dispatch process and design of wider balancing service markets need to improve[15]. Whether a LMP driven centralised dispatch function would be more efficient than an alternative technically enhanced and modernised 'control room of the future' function[16] is a critical question. At a high level at least, the challenge of optimising a centralised dispatch model is not that different to the challenge of optimising the current balancing mechanism. SO controllers would still have to choose the lowest cost (and lowest carbon) generation to meet demand within the constraints of the network and the constraints of the generation assets. The centralised dispatch market would still be subject to the exploitation of scarcity rents, limitations on asset flexibility and whatever gaming of the system that is present in the balancing mechanism.

One argument put forward is that centralised dispatch would be more efficient because it would allow the SO control room more time, and visibility, to optimise dispatch. This argument rather assumes that LMP Bid/Offer notifications would be made earlier than the current FPN, which may not be the case and itself carries system cost inefficiency. There is an alternative view that the gate closure period should be reduced to allow the market to be more efficient.

LMP benefit modelling using marginal pricing also assumes generators would not use their market power (or gaming[17]) within the LMP dispatch process as they currently do in the balancing mechanism. This seems naïve. Even without exploiting market power, there is still good evidence that balancing mechanism costs are in part being driven by the relative inflexibility of legacy gas

[14] American Public Power Association: https://www.publicpower.org/policy/wholesale-electricity-markets-and-regional-transmission-organizations-0
[15] This area is currently subject to a wide range of innovation projects and market reforms.
[16] See for example The Day in the Life of the Electricity Network 2035 – National Grid ESO and Regen 2022
[17] Recent behaviour of dispatchable generators in the balancing mechanism has prompted the ESO and Ofgem to launch an investigation: https://www.nationalgrideso.com/news/national-grid-eso-announces-review-balancing-market

and coal fired plant[18]. This would not be solved by a new LMP model, but could be addressed by encouraging more investment in flexibility and high-response assets such as battery storage through, for example, reform of the Capacity Market.

How a return to centralised dispatch would impact storage and flex providers, affect the viability of long term Power Purchase Agreement (PPA) markets, and change the role of distributed customers are also open questions.

LMP and investment risk for net zero

The introduction of LMP into the GB electricity market would face a number of practical challenges, and would have significant implications for investors, at a time when an estimated £210 billion[19] of power sector investment is needed by 2037 to deliver the UK net zero commitments.

There are a lot of detailed questions to be addressed before an LMP market design could be implemented, including, for example: the degree to which locational price signals are reflected in consumer bills, the impact on long term PPAs, implications for CfDs and RAB investment models, impacts for the lower voltage distribution network, treatment of existing generators with a firm connection agreement, interactions with carbon prices and the REGO[20] market, and the impact on other system service markets.

At face value however, the implementation of LMP, **without significant mitigation policy measures**, would greatly increase the investment risk for new generation, especially for renewable energy and nuclear whose ability to respond to locational price signals is likely to be limited by other overriding factors. The fundamental change an LMP market would bring would be to shift the dual risks of constraint based marginal pricing and network curtailment to generators and their customers. Overall, this would increase investment risk and cost of capital leading to a reduction in investment in new generation capacity.

Critics of LMP would highlight that, whereas the SO is in a position to assess the economic trade-off between making network capacity investment and the cost of curtailment, generators are not in this position. Their choice could be to a) not invest thereby delaying net zero, b) to only invest in those parts of the network which has abundant capacity albeit at higher cost of energy or c) to seek another form of mitigation through, for example, a higher level of revenue guarantee such as a capacity guaranteed CfD or RAB business model.

So far, little analysis has been done to quantify, or otherwise address, these risks. Some could be resolved in the detailed design process. For now, however, it is difficult to imagine how developers in offshore wind, nuclear and a range of smaller scale generation and flexibility technologies would contemplate making an investment, or be able to raise finance, in a market that could feature high levels of curtailment and extreme price risk/volatility.

In answer to these concerns, proponents of LMP have pointed to existing LMP markets which have managed to achieve higher levels of renewables. Closer examination of these markets is, however, less convincing.

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[18] In a recent study by LCP, in 2021 85% of balancing mechanism costs are in fact paid to turn up generation to replace wind that had been curtailed. The overwhelming majority of this (94%) was paid to large CCGT plants. 82% of costs were incurred around Scottish constraint boundaries

[19] Treasury analysis for BEIS Net Zero Strategy "Build Back Greener 2021" Workbook. Does not include grid investment.

[20] Renewable Energy Guarantee of Origin (REGO) which are used to track the carbon intensity of electricity supply.

3. Current LMP markets around the world

Markets based on the principle of LMP , in the US, Europe, Scandinavia and Australia, have been around in various forms for almost a century. The oldest US LMP market, Pennsylvania, New Jersey and Maryland (PJM) was created in the 1920s and now also covers parts of 12 US states in a band from the east coast to Illinois and Michigan. Significantly the PJM market was created at a time when energy was delivered by vertically integrated utilities who generated, distributed and sold electricity, and it is still governed by a committee structure of market participants. This helps to explain some of the LMP design solutions and their treatment of curtailment and electricity price risk.

Other significant North American LMP markets now include Texas, most parts of California and a number of Canadian provinces. Separately, zonal LMP markets, with different design features, have been created in countries like Norway, Australia and Italy. The Norwegian and Australian markets are examples where geography and, in Norway's case, large scale (hydro) generation plants have led to a zonal market.

The degree to which LMP markets have been able to integrate low carbon generation varies considerably between LMP markets. PJM, the original LMP market, has very low levels of renewable generation at only 6-7%[23] of supply. Critics have suggested that the PJM market, and its governance structure, has allowed incumbent utilities and fossil generators to dominate the market and prevent new entrant renewables. In fact, even in the last decade, new generation build in PJM has continued to be dominated by fossil fuels.[21]

Compared to PJM, Texas has higher levels of onshore wind and California has higher levels of solar[25 29]. Although a long way from net zero, these markets are often cited as evidence that LMP markets can sustain higher levels of investment in renewable energy. Whether that assertion is justified will be discussed in more detail later in the sections below. Norway, which must be considered a special case because of its geography and early adoption of large scale hydropower, has the lowest carbon intensity power markets in Europe.

More important than the current levels of low carbon generation is the question of whether LMP based markets provide a pathway for renewable energy to get beyond a moderate 20-30% share of electricity to achieve a net zero outcome at, for example, 70-80% renewable share. Or whether the challenge to fully decarbonise the electricity sector will inevitably require a shift away from the LMP model and, if so, what will replace it. For UK policy makers, about to embark on a potentially radical and costly market redesign at a time when investment in low carbon generation is paramount, answering this question will be critical.

[21] " Fossil Fuels in PJM have pushed aside renewables" https://sustainableferc.org/transforming-pjm-is-the-key-to-a-clean-energy-grid/

Key questions

Marginal prices provide marginal signals - does this work at a time of major energy transformation?

If LMP isn't the right design for a net zero outcome, can the UK pioneer a better market design solution?

Looking at investment in the PJM and Californian LMP markets

PJM[22], the original LMP market, which covers 12 US states from the east cost to the mid-west, has a very low level of renewable energy generation at around 6.7%.[23] PJM has not, therefore, had to deal with high levels of variable renewable energy, nor is there a strategy in place as to how and when PJM will transition to a net zero electricity system in line with the Biden administration's stated goal of carbon free electricity by 2035[24].

By contrast, California's CAISO LMP market has managed to deploy a higher amount of non-hydro renewable energy capacity to meet 28% of electricity demand[25]. Of this renewable generation, 14% came from solar and around 8% from wind energy. Hydro and nuclear met a further 8% and 10% of demand respectively.

It is significant that, the California CAISO LMP features relatively high levels of solar compared to wind. California is year-round sunny of course, and has high summer demand for cooling, but it also suggests that solar energy may be better able to respond to locational price signals and, as we have also seen in the GB market, is better able to exploit available network capacity.

Critics of the California market would, however, highlight that until very recently renewable energy growth had stalled, and that the weighting towards solar has produced a lopsided energy mix with a day-night and seasonal imbalance. California also net-imports 21% of its electricity, a figure that has been increasing. Off-grid batteries are common, but grid connected battery storage had only reached 488 MW in 2020[25].

California's historic lack of investment in network infrastructure has also become a serious political issue and has been blamed amongst other things for blackouts, forest fires, economic decline and inequality in low income and rural neighbourhoods, increased off-gridding and for the failure of California to exploit its initial investment in green technologies.

[22] PJM About Us: https://www.pjm.com/about-pjm
[23] 2021 generation data by fuel type: https://dataminer2.pjm.com/feed/gen_by_fuel
[24] Biden Administration Clean Electricity Performance Programme
[25] 2020 CAISO Annual Report: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

Lack of investment, poor long term planning and especially poor inter-regional connectivity have been highlighted a as major weakness of US electricity markets[26]. While not confined to those markets based on LMP; PJM, Texas and CAISO have been criticised for a lack of planning especially to support new generation:

"The PJM Market Monitor acknowledges the uncertainty associated with transmission planning and accuracy of inputs and expresses concern with planning for anticipated new generation."

"The PJM Market Monitor claims that PJM incorrectly defines the benefits of proposed market efficiency transmission projects, resulting in uneconomic transmission upgrades. In particular, the PJM Market Monitor argues that PJM uses speculative transmission-related benefits over a 15-year period while limiting the analysis to the existing generation fleet and existing patterns of fuel costs and congestion, which eliminates the possibility that new generation could respond to market signals and meet the same needs."[26]

More research is needed to understand the relationship between LMP markets and network investment, and to address the question of whether LMP gives clear signals, to the SO and system regulator, that infrastructure investment is needed. There does appear to be a theme that marginal price signals, which can only ever reflect the current states of network constraint and current energy flows, are not a good basis to plan forward infrastructure investment at a time of major system transformation. Hence the adage, "marginal price signals promote marginal change, not major transformation".

In the case of California, the need for additional network capacity to support a new push for net zero has been identified as a major issue and is forcing CAISO and state authorities to rethink their approach to strategic investment.

"There is a critical need for more proactive, long-term transmission planning and coordination," said Elliot Mainzer, CEO of California ISO (CAISO)[27]

This renewed focus on strategic investment is forecast to require over $30 billion investment in high voltage bulk transmission infrastructure by 2040, along with over 120 GW of new renewable and energy storage capacity, according to state's first 20 Year Transmission Outlook report[28].

"California is working very diligently to ensure resource adequacy during this transition to a carbon-free system," In 2021, California brought 79 clean-energy projects onto the grid, the most it has ever added in a single year"[28].

"This improved transmission planning and coordination with regulatory agencies and other partners will help ensure that California can sustain and even exceed that pace and meet the challenge of achieving a reliable clean-energy grid"[28]

The lesson from PJM seems to be that, if there isn't the ambition, LMP isn't going to bring forward investment in low carbon technologies and may in fact be a barrier to entry that favours incumbents. While in California, the lesson is that, even with a net zero ambition, LMP may favour certain technologies

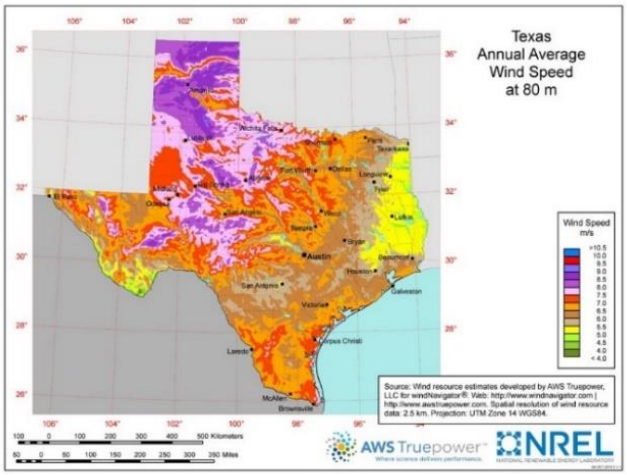
[26] Federal Register: https://www.federalregister.gov/documents/2022/05/04/2022-08973/building-for-the-future-through-electric-regional-transmission-planning-and-cost-allocation-and#citation-322-p26538
[27] ReCharge News, Feb 2022 : https://www.rechargenews.com/energy-transition/california-scopes-30bn-grid-plan-in-face-of-unprecedented-green-power-demand/2-1-1165980
[28] California Public Utilities Commission and CAISO – 20 Year Transmission Outlook Report Draft, Feb 2022: http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf

like solar (to a limited extent) and is no guarantee that states or SOs will deliver long term strategic infrastructure investment.

4. Texas Wind - learning from the ERCOT LMP market in Texas

While lessons can be learnt from the PJM and California, neither market is a particularly good comparator with the GB energy market. PJM has a very low level of renewables and a low level of ambition to achieve net zero; California has more ambition but is still some way behind GB and is dominated by solar, albeit with new plans for both onshore and offshore wind. Neither market exhibits good forward planning leading to strategic investment, neither market has high levels of flexibility (storage) or demand side response. California in particular has suffered from chronic underinvestment in network infrastructure.

The Texas ERCOT market is not an ideal match with the GB market - there is very little interconnection, for example - but is does have some interesting points of comparison especially with regard to the development of wind energy.



Growth of wind energy in Texas

Famous enough for Dolly Parton to write a song about it, the wild wind of west Texas has created a 'bonanza' for wind farm developers in the north west and Panhandle regions of Texas. In this respect, the north west Texas region is similar to North Scotland: plenty of wind resource, open spaces and probably even less indigenous energy demand.

Overall, wind development in Texas is on a similar scale to GB, although it should be noted that Texas has proportionally far less solar, hydro and biomass renewable energy and its overall progress towards net zero electricity is still behind the GB market. Data to the end of 2021, shows that Texas had wind capacity of just over 34 GW which provided around 24% of Texas electricity demand[29]. By comparison, GB wind (including offshore) totalled 25.8 GW and also provided energy equivalent to around a quarter of electricity demand.

The concentration of wind farms in the north west of Texas, and their absence from areas of relative high demand in the east (around Dallas, Houston and Austin) is striking. Texas is a huge state, 2.7 times as large as the UK, and the distances that wind energy is being transmitted from generator to consumer are therefore considerable.

[29] Summary of Texas State Profile and Energy Statistics: https://www.eia.gov/state/analysis.php?sid=TX

A first obvious conclusion is that even the very strong locational price signals in the Texas LMP market have not been sufficient to cause wind farm generators to locate near to demand centres.

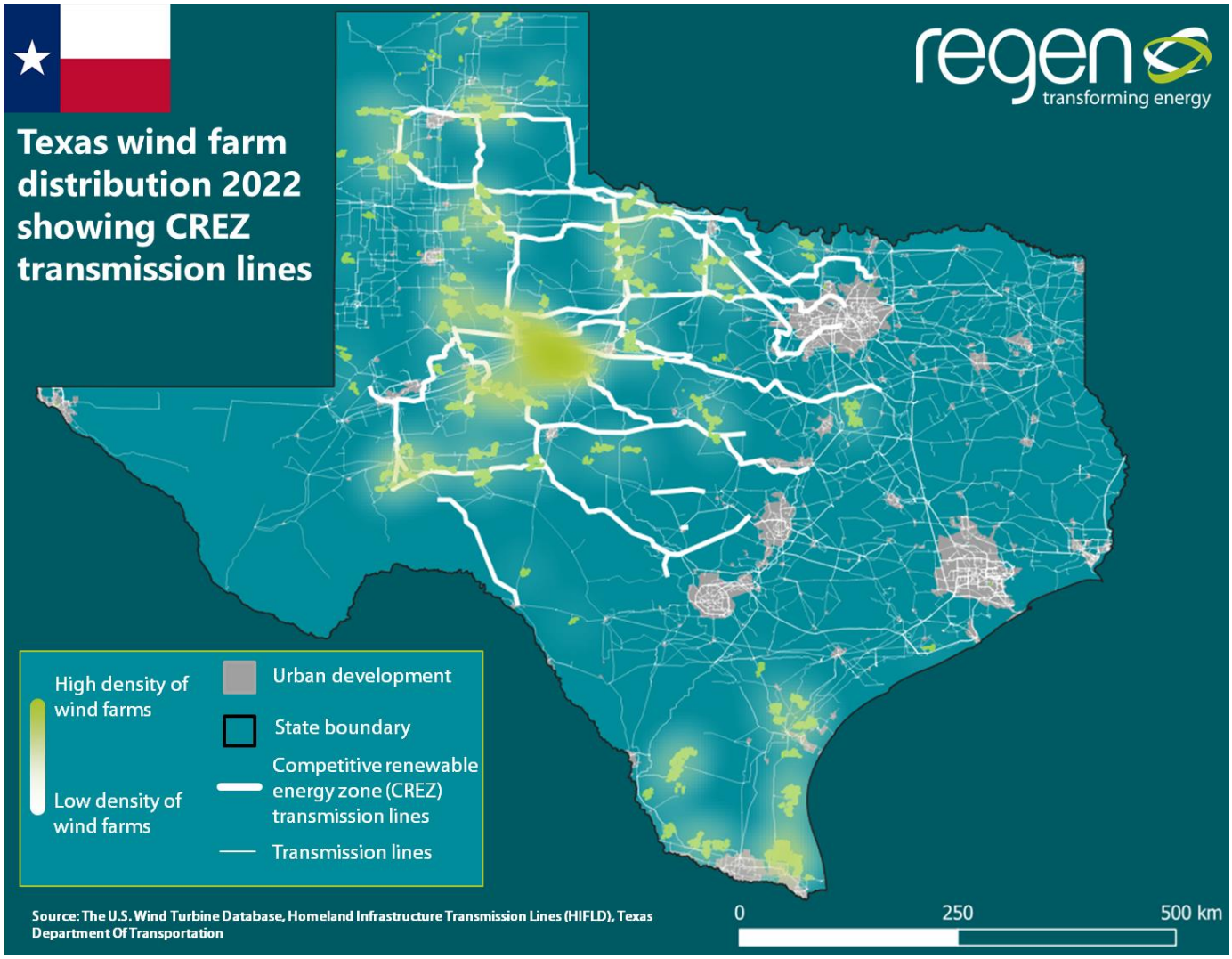


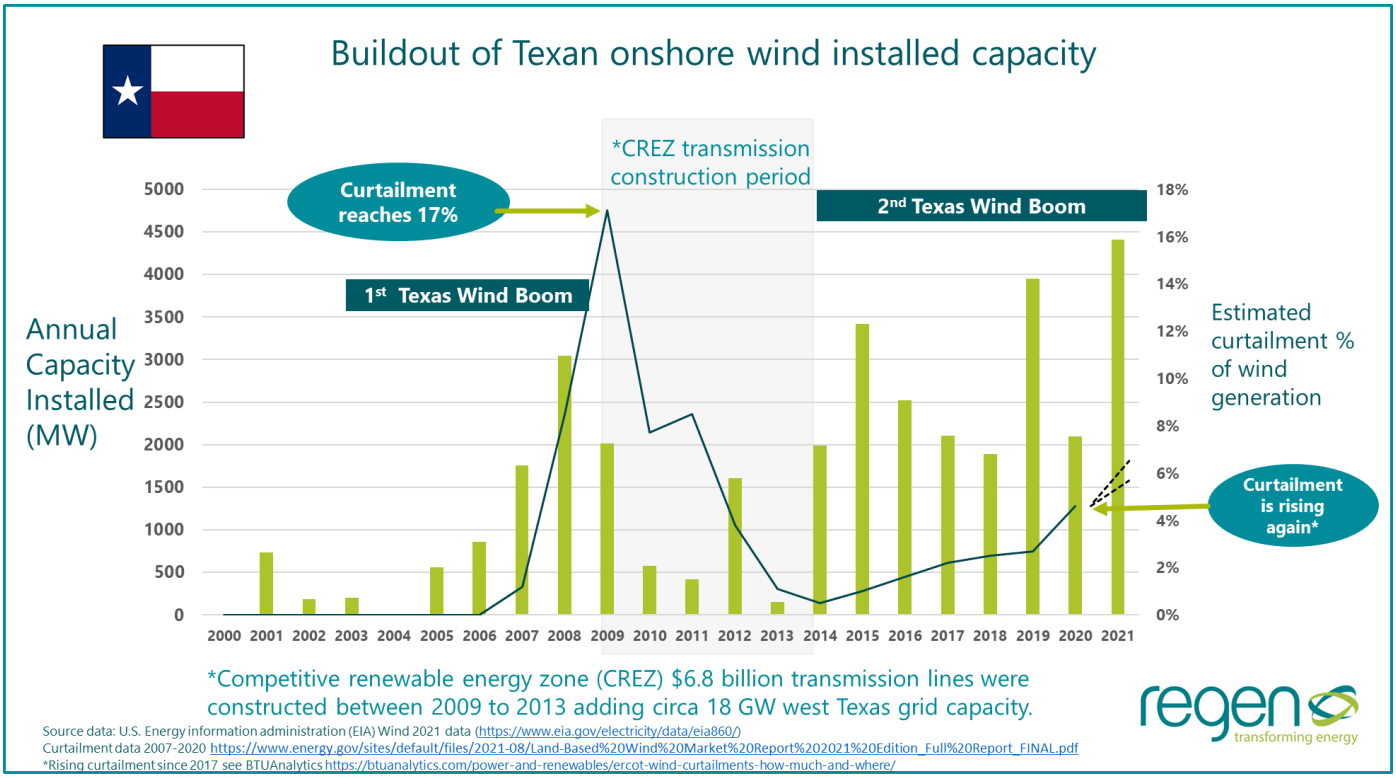
Figure 1 Distribution of wind energy in Texas, also showing main transmission lines, CREZ investment connectors and demand centres.

Network investment drives generation capacity growth

The story of wind farm development in Texas is not one of generation investment responding to market driven price signals, but instead is one of entrepreneurship, economic development, strategic infrastructure investment and a considerable amount of market intervention. It could be said that Texas wind was developed, not because of LMP but despite of it.

The early wind farm development in Texas which lasted from 2005 to 2009 was led by a number of billionaire investors, including for example oil tycoons such as T. Boone Pickens, and featured a number of very large installations of over 250 MW.

By 2009, the first phase of the Texas wind farm boom was over and installations dropped off significantly because of a lack of network capacity leading to constraints running at an estimated 17%[33] of wind output.



Anticipating rising wind constraint levels, the state authorities, working with the energy SO ERCOT, had already in 2005 determined a strategy to support increased wind farm development by making a strategic investment in new transmission capacity to link CREZ, which had been designated by the state legislature, to areas of demand in the east. These transmission lines are shown in Figure 1.

The programme of investment, which cost just under $7 billion, was carried out by nine different transmission service providers (TSPs) constructing 2,400 miles of transmission lines to carry 18.5 GW of west Texas wind eastwards[30]. Increased non-CREZ investment also continued in the period to 2019. Note: Texas has a more competitive market than GB for network investment.

As a result of the strategic investment made in the period from 2009 to 2013, constraint levels fell dramatically[31], and Texas was able to enjoy a second wind farm boom[32] which has added an additional 22 GW of capacity by 2021 (17 GW in north and west Texas, effectively using up the CREZ transmission capacity, plus circa 5 GW in South Texas).

The growth of wind has inevitably led to a return to higher levels of constraint. Analysis by BTUAnalytics shows that constraints rose again from near zero in 2017 to over 5 TWh in 2021[33]. Much of this constraint is from the West Texas and Panhandle regions[33] [34].

[30] Centre for Energy Studies Baker Institute: https://www.bakerinstitute.org/media/files/files/eb251d15/ces-pub-texascrez-111720.pdf
[31] Fewer Wind Curtailments and Negative Power Prices after Major Grid Upgrade – US EIA, June 2014: https://www.eia.gov/todayinenergy/detail.php?id=16831#
[32] Houston Chronicle, Jun 2014: https://www.houstonchronicle.com/business/energy/article/Transmission-line-project-boosted-Texas-wind-power-5580077.php
[33] BTUAnalytics: https://btuanalytics.com/power-and-renewables/ercot-wind-curtailments-how-much-and-where/
[34] Wind curtailment in 2020 was estimated at 4.1% of output, an increase on previous years but still less that the 17% experienced in 2009. US Department of Energy https://www.energy.gov/sites/default/files/2021-08/Land-Based%20Wind%20Market%20Report%202021%20Edition_Full%20Report_FINAL.pdf

With constraint levels for wind rising again[35 36], the big question for Texas renewables and its broader net zero agenda is what happens next. Without new capacity investment there is a clear risk that renewable energy deployment will stall[37 38]. ERCOT's own analysis has identified an **additional $7.5 billion** of planned transmission investment which will be deployed between 2022 and 2027 with a focus on the far West and South Texas regions.

There has also been a renewed effort to encourage demand growth in areas of high renewables in the west. To date, however, demand growth has focused on the development of the unconventional (fracking) oil and gas sector in West Texas Permian Basin, and the development of cryptocurrency data mining[39 35]. Other industries like data centres and manufacturing have been harder to shift.

Other support measures

The development of Texas wind is not just a story of strategic network investment. The wind sector has been supported by a number of other policy measures and market interventions. Firstly, at a federal level, wind has enjoyed significant federal production tax credit benefits as well as state level renewable portfolio standards and financial incentive schemes. This is one reason why LMP market prices can in fact turn negative as generators seek to maintain output to secure revenue support even when prices plummet.

In the context of market intervention, the Renewable Portfolio Standard is important since it mandates utility energy suppliers to supply a minimum and increasing amount of renewable energy within their energy mix. Initially, this helped to push renewable energy into the supply market and maintain wholesale prices, although the standard has not been renewed and extended in Texas as it has in other states[40].

Other measures implemented in Texas have included the designation of the CREZ areas, by the Public Utility Commission, which has influenced planning policy, and streamlined investment in infrastructure (as already described), as well as helping to focus state funds for supply chain and employment growth.

5. Applying the Texas experience to GB

There are several ways to read the Texas experience across to the GB market. The development of wind in West Texas is similar in terms of resource, system challenges and ambition to Scotland.

In a broader context, the Texas experience does have important lessons for policy makers contemplating market reform for GB and how best to achieve net zero electricity by 2035.

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[35] Report on Existing and Potential Electric System Constraints and Needs ERCOT Dec 2021
[36] Interesting that it is very difficult to get sight of actual constraint data from ERCOT. This says something about how commercially sensitive this is and the workings of the LMP and FTR market.
[37] Institute of Energy Economics and Financial Analysis https://ieefa.org/articles/texas-renewable-growth-risk-because-transmission-constraints
[38] Powering Texas "Wind and solar power is rapidly growing in Texas, but ERCOT limits how much goes to the grid" https://www.houstonchronicle.com/business/energy/article/Wind-solar-production-outstrips-transmission-in-16223706.php
[39] MIT Technology Review https://www.technologyreview.com/2020/02/27/905626/how-texass-wind-boom-has-spawned-a-bitcoin-mining-rush/
[40] https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx

a) A clear strategy and plan

The first lesson, which would probably be agreed across the UK industry, is that achieving an energy transition requires a plan and a clearly articulated strategy which can be formulated in policy. In many other respects, Texas's energy planning has been poor, as the storms of 2021 revealed. But in the case of wind in the west, the Texas legislature and Public Utility Commission, encouraged by major Texan investors, set out the ambition and put in place investment to jump-start the wind sector. The level of ambition and planning shouldn't be exaggerated, however Texas doesn't have a coherent net zero strategy, and much of the imperative to develop wind in the west was driven by regional economic and job objectives.

b) Investment risk – the need for anticipatory infrastructure investment to minimise network constraint risk

The second lesson is that, in the case of Texas, renewable energy generators and their investors would not accept any significant risk of constraint. In an LMP based market, strategic grid investment was required to assure generators that capacity was available, and only then was investment made. When constraint levels rose, investment stalled, and is likely to remain stalled until more grid capacity is added.

The Texas model could therefore be described as 'build and connect' as opposed to the current GB transmission network model of 'connect and manage'.

A key question is whether UK investors in renewable energy would respond in the same way by withholding investment until capacity is made available. The broad answer is almost certainly, yes.

There are some examples where UK renewable generators have been prepared to accept a 'non-firm' connection agreement which carries with it the risk of curtailment, for example, as part of an Active Network Management scheme. But, as our analysis of the Dunbar ANM[41] scheme highlights, the exception proves the rule. Generators will generally only accept an ANM type solutions, or other non-firm connections, so long as it clearly accelerates the timetable for deployment, has a clear end date at which time capacity will be available and there is some clear limit regarding the extent of constraint. Ofgem is itself reviewing the availability of non-firm connections to ensure that generation and storage customers are not given a bad deal.

There is very little evidence that large scale generators will accept the risk of an enduring constraint, and it is hard to imagine that investors in major generation assets, such as an offshore wind farm or a nuclear power station, would even contemplate building generation capacity ahead of network infrastructure. Hence the need for a holistic network design and an integrated offshore transmission strategy for offshore wind.

Bringing in LMP now, with current high levels of constraint, would very likely kill of investment until such time that generation investors are convinced that sufficient grid capacity will be available to remove the risk of constraint curtailment.

Is a LMP market with an 'build and connect' strategy a better model for GB net zero than the current 'connect and manage' approach? The failure of 'connect and manage' in GB has been caused by the delay in strategic network investment and a slowness to fully exploit sources of flexibility. However, if generators are unable or unwilling to take on constraint curtailment risk, a 'build and connect' approach may in fact lead to higher network investment costs, and less use of flexibility solutions, to

[41] Regen 2021 https://www.regen.co.uk/project/an-economic-evaluation-of-the-active-network-management-scheme-at-the-dunbar-gsp/

achieve net zero. This suggests a wider lesson that, in reality, the SO is in a far better position to manage curtailment risk, and optimise the use of flexibility assets, than individual generators or other energy system actors.

c) Wind generation in Texas did not locate on the basis of locational marginal price signals, nor will most types of low carbon generation in GB (see table on page 17)

There is little to no evidence of generators in Texas locating to areas of high energy demand on the basis of locational price signals. Wind farm location has instead been driven by resource availability, land space/planning and the strategic designation of areas for development.

There is some evidence, in California and beginning in Texas, that solar developers may be better able to locate near demand areas, but this is less to do with locational price signals and more to do with access to network capacity and behind the meter/off-grid opportunities.

There is a debate about what drives locational decision making for GB generators and it almost certainly depends on technology type and project development lead-time. Those technologies with shorter lead-times that are less resource dependent are better able to respond to locational signals.

A challenge for LMP price signals is that the marginal locational signal can only ever reflect current network constraints. This is of passing interest for an offshore wind farm, or nuclear development, that may take a decade to come to fruition. In an LMP market, investors would need to know the risk of future network constraint at the time their project is commissioned and for the lifetime of the asset. In an energy system undergoing transformation, this is incredibly difficult to glean from current market prices, hence the focus in GB on contractual commitments, and the confidence given by having a clear net zero plan and infrastructure strategy.

It is also worth highlighting that for many of the larger technologies, like offshore wind, nuclear and onshore wind, the choice of location is largely driven by policy decisions – either through planning, leasing of seabed rights or industrial strategy. This begs the question, if we can, by-and-large, already determine the locations of the main generation assets, and strategically build grid infrastructure[42] around those locations, why rely on marginal price signal?

[42] As we are doing now via the Offshore Transmission Network Review and Holistic Network Design process.

Factors driving locational choice for GB renewables		
Technology	**Major locational factors**	**Impact of LMP location signal**
Offshore Wind	Marine Spatial planning & designated leasing areas Wind resource Seabed conditions Access to grid infrastructure Ports and supply chain	**Very low** - Given long term development and that location is largely determined by UK policy and seabed leasing
Nuclear	UK new nuclear policy Existence of current nuclear sites Planning Site specific – land space, water, safety Grid infrastructure guaranteed	**Very low** - Given long term development and that location is largely determined by UK policy, planning and site conditions. Smaller modular reactors may have more locational flexibility but are likely to be driven by proximity to industrial demand and planning
Onshore wind	Wind resource Land space and designation Planning Designated areas for development e.g. Tan 8 areas in Wales Access to grid connection Cost of grid connection	**Very low** - planning and societal attitudes in England make it incredibly difficult for on-shore wind farms to locate near areas of high demand. There are almost no current projects in development in England. Location choice in Scotland and Wales is primarily based on resource and planning with access to grid and a low cost connection important secondary drivers.
Solar large scale	Low cost grid connection Land space Potential for behind the meter and private wire Co-location with battery storage Planning risk Solar resource irradiance	**Some potential but, apart from some temporary constraints, the location of solar isn't the same scale of issue.** Solar is more adaptable and could potentially be influenced by a locational price signal if it was likely to endure in the longer term. However solar developers are already heavily targeting sites with a low cost grid connection and proximate to demand areas in the south of the UK. In Scotland, solar development is concentrated in the central belt and east coast demand areas
Hydro, wave, tidal geothermal and other resource based technologies	Location is almost entirely driven by energy resource potential. Planning and access to grid are also important viability criteria	**Very Low** Network constraint risk would impact on project viability but choice of location is mainly driven by resource potential.