climate change
Scotland's centre of expertise connecting climate change research and policy

GB wholesale electricity market reform: impacts and opportunities for Scotland

Freddie Barnes, Fabian Bräuer, Foaad Tahir
ERM
July 2024

DOI: http://dx.doi.org/10.7488/era/4431

1 Executive summary

1.1 Introduction

This study assesses the likely impact of an electricity pricing model known as locational marginal pricing (LMP), as well as its potential alternatives, in the context of the Scottish Government's Draft Energy Strategy and Just Transition Plan ambitions. LMP is a component of the UK Government's ongoing Review of Electricity Market Arrangements (REMA) and could significantly impact Scotland's energy landscape.

The assessment is based on a literature review and engagement with an expert advisory panel, including members from across the energy industry. The study was conducted between September 2023 and January 2024 and the assessment is based on the literature available at the time.

Under LMP, the national wholesale electricity market would be split into several smaller areas. This creates the opportunity to provide different local price signals that incentivise the optimal siting of generation, demand, and flexibility across the areas. Such incentives can improve the utilisation of renewable energy, reduce the need for network build and reduce costs. Additionally, variations in price provide flexible assets with locationally specific dispatch signals. This encourages these assets to adjust their consumption or generation to match local grid requirements, further reducing system costs. However, LMP creates significant uncertainty for market participants and could discourage investment in some low-carbon technologies in different parts of GB.

1.2 Findings

Based on the Scottish Government's energy transition ambitions, we have categorised the impacts of LMP into the following four categories:

1. The scale up of **low-cost renewable energy**

   Without insulating mechanisms, LMP would heighten price risk (£/MWh sold) and volume risk (MWh sold) for Scottish renewable generators. Delays to transmission network build would exacerbate this. Elevated risk could increase the cost of capital for new developments, potentially negating the modelled system benefit of LMP. Renewables support mechanisms could help mitigate disruption to Scotland's renewables pipeline, reducing UK decarbonisation risks. Wider benefits of the green economy in Scotland are closely tied to the continued buildout of renewables.

2. Adhere to the principles of a **fair and just transition.**

   Studies suggest that, due to the significant existing capacity of renewables, Scottish consumers could benefit from some of the lowest wholesale power prices in Europe under LMP. Conversely, as LMP creates regional differences in price, some GB regions would see increases in prices. The extent to which this materialises depends on policy design and the pace at which LMP is implemented. The impact of LMP is reduced the later it is implemented as the network is reinforced to 2035, reducing transmission constraints.

3. Support **accelerated decarbonisation.**

   LMP is unlikely to accelerate the decarbonisation of the power sector. LMP could even slow decarbonisation down by causing a hiatus in investment if implemented without sufficient mitigations demonstrating that renewable support can be maintained. However, the potential to improve system efficiency could decrease the cost of the UK power system between £0.2bn-1.6bn annually (AFRY 2023, Aurora 2023). In Scotland, lower wholesale prices could reduce the cost of electrification of sectors such as transport, heat and industry, and could play a part in attracting new industries and green hydrogen production.

4. Enable a **secure and flexible net zero energy system.**

   LMP has the potential to encourage the efficient location and operation of assets that provide flexibility to the electricity system. Due to significant capacity of renewables in Scotland, LMP could attract further investment in flexible assets. This would help to reduce network congestion in Scotland, allowing for greater penetration of renewable generation. However, strategic planning is necessary to ensure that Scotland receives the network capacity required for further development of renewables.

1.3 Conclusions

The authors have critiqued quantitative and qualitative studies on the possible impact of LMP, assessing the strength of assumptions used in the studies. This overview of the conclusions is based on this literature review as well as evidence gained through the expert advisory panel.

1. Scotland must prioritise and coordinate a **strategic plan for renewable generation and network reinforcement** with the UK Government.

   If LMP is to be introduced, mechanisms to support renewables need to be feasible. Long-term locational signals for strategically siting renewables are vital for achieving a low-cost net zero power system by 2035. Support mechanisms like a reformed Contracts for Difference scheme that protect against revenue and volume risk, are essential to maintaining investor confidence in Scottish renewables. Alternatively, reformed Transmission Network Use of System charges could offer locational investment signals in a national market, although they lack the same operational signals created by LMP.

2. LMP would provide the **clearest dispatch signal for flexibility**, delivering efficient investment and operation of flexibility.

   Maximising the use of renewables can only be done with significant flexibility. LMP can provide effective investment signals for the development of flexibility in Scotland. Of the options evaluated, LMP can also provide the clearest operational dispatch signals to optimise the use of flexibility. Local constraint markets are a potential alternative to LMP, although they may introduce further market complexity and are unlikely to fully replicate the effects of LMP.

3. The **potential benefits of LMP for consumers are greater the earlier it is introduced.**

   A quick implementation of LMP would create the most significant benefit for Scottish consumers. As the transmission network is upgraded to 2035, the benefits of LMP are reduced. However, LMP will likely take four to eight years to implement and must be done with care, providing support for existing and future renewable generation.

4. **Careful implementation** of LMP is required to address **regional differences in price across GB**.

   LMP will create regional differences in price across GB that need to be carefully considered. Scottish consumers would likely be a key winner of LMP, benefiting from lower wholesale prices. However, support for renewables needs to be secured to ensure that investment stays in Scotland, jobs are realised, and the wider benefits of net zero can be delivered. Future renewables support needs to be designed and communicated ahead of a transition to LMP.

Contents

Abbreviations table

CfD	Contracts for Difference
BAU	Business-as-usual
BM	Balancing Mechanism
CCUS	Carbon capture, utilisation, and storage
EAP	Expert advisory panel
EV	Electric vehicle
FES	Future Energy Scenarios
FTR	Financial transmission right
H2	Hydrogen
HDV	Heavy duty vehicle
HND	Holistic Network Design
HP	Heat pump
LCM	Local constraint market
LCOH	Levelised cost of hydrogen
LMP	Locational marginal pricing
MO	Market operator
NGESO	National Grid Electricity System Operator
NOA	Network Options Assessment
PPA	Power purchase agreement
REMA	Review of Electricity Market Arrangements
SO	System operator
SWOT	Strengths, weaknesses, opportunities, and threats
TCO	Total cost of ownership
TNUoS	Transmission Network Use of System
WACC	Weighted average cost of capital
VAT	Value Added Tax

Glossary

Assets	In the context of this report, assets include any source of power demand or generation on the electricity system. This includes generating assets, demand-side assets, energy storage, and interconnectors.
Balancing	The continuous adjustment of generation and consumption of electricity to maintain a stable grid. As generation and demand need to be matched in real-time, National Grid ESO performs balancing actions to do so. The primary mechanism for this is the Balancing Mechanism.
Capacity	Maximum amount of instantaneous power an asset can provide (usually measured in MW).
Capacity Market	A mechanism from the UK Government to ensure there is enough generating capacity to enable security of supply. The Capacity Market provides payments for the availability of reliable sources of power.
Congestion	When there is insufficient network capacity to transport electricity from generators to consumers.
Congestion rent	Additional revenue collected by the Market Operator under LMP markets when the network is congested. Areas with an oversupply will see generators receiving lower prices. Areas with an undersupply will see consumers paying higher prices. The difference between these is collected as congestion rent.
Contracts for Difference	The main mechanism through which renewable generation is supported in the UK. Enables stable revenues by auctioning “strike prices” for generators. When wholesale prices fall below the strike price, generators receive a top-up. When wholesale prices exceed the strike price, generators must pay back excess revenues.
Curtailment	The intentional reduction of electricity generation, primarily due to excess generation (e.g. during high wind periods), or grid constraints.
Demand-side response	Demand-side response is a form of flexibility by shifting electricity consumption according to grid requirements or market signals. This can achieve an equal but opposite effect of flexing generation.
Dispatch	The process of determining which generating units will supply electricity to meet demand at any given moment. In the UK generators “self-dispatch,” choosing when to provide electricity, while National Grid ESO can then proceed to redispatch electricity according to real-time balancing requirements.
Dispatchable generation	Generating assets that can be controlled and scheduled, such as gas power plants or hydro-electric plants.

Distribution network	The network that transports electricity from the transmission network to consumers. Some new intermittent renewable energy sources are also directly connected to the distribution network.
Electrolyser	A device that uses electricity to split water into its constituent parts: hydrogen and oxygen.
Embedded generation or storage	Any assets that can deliver power and are connected to the distribution, rather than transmission system. In the UK, most solar generation is connected to the distribution system.
Firm access rights	The guaranteed access to the network for certain types of assets. In the GB national wholesale market, this means generators can sell electricity without considering the impact on network constraints.
Flexibility	The ability to adjust the generation/consumption of electricity to meet grid requirements. This is essential to provide a reliable and stable grid in an electricity system with growing intermittent renewable generation. Includes dispatchable generation, energy storage, interconnectors, and demand-side response.
Flexibility market	Markets operated by NGESO or distribution network operators that procure flexibility to ensure the needs of the grid are met. Flexibility providers are typically paid on either an availability (£/MW/h) and/or utilisation (£/MWh) basis.
Interconnector	High-voltage power cables that connect the grid in GB with other countries e.g. France and the Netherlands, allowing for power trading across markets.
Liquidity / illiquidity	The degree to which electricity can be bought and sold easily, quickly, and with minimal impact on prices.
Locational element / signal	Incentives to invest and/or operate assets in ways that reflect local grid requirements i.e. generation, demand, network constraints.
Locational marginal pricing	A wholesale electricity market reform that divides a single national market into smaller markets.
Market Operator	In an LMP market, the Market Operator is responsible for the operation of the wholesale market and administering the pricing mechanism of the market. If introduced in the UK, this task would likely fall to National Grid ESO.
Network constraints	Physical bottlenecks on the electricity network that occur when the amount of electricity that needs to be transmitted from generating assets to demand exceeds the maximum possible flows of the network. In this study, network constraints generally refer to constraints on the transmission network.

Operational efficiency	In the context of wholesale markets, the ability for assets to appropriately schedule generation or consumption to best match grid requirements, enabling a cost-effective system.
Peaker plant	A type of generating plant that is designed to operate intermittently during periods of high electricity demand (peak demand).
Power purchase agreement	Bilateral agreements between generators and suppliers or consumers that allow generators to reduce wholesale market price risk by selling electricity at a pre-agreed price.
Redispatch	A change in the operating schedule of a generating asset to balance supply and demand or resolve network constraints. National Grid ESO may pay generators to redispatch.
Settlement period	Half-hourly period in which electricity is traded in UK markets.
Transmission losses	The electricity dissipated as heat when transmitted across the network.
Transmission network	High-voltage network that transports bulk electricity from large generating assets to distribution networks. Most large-scale generation is connected to the transmission network.
Variable renewable energy / generation	Renewable energy sources that generate intermittently based on variable resources like wind or solar, as opposed to dispatchable generation that can be actively adjusted.
Wholesale electricity market	The main market for electricity to be sold between generators and suppliers on day-ahead or intra-day time scales. Electricity not sold in bilateral trades will be sold in the wholesale market.

2 Introduction

In this section we will introduce the context of this literature review and the concept of locational marginal pricing (LMP). This is followed by a brief introduction on the ambitions of the Scottish Government regarding the climate transition, how this relates to electricity market reform, and what the key limitations of this review are.

2.1 Context

This study has been commissioned by ClimateXChange, acting on behalf of the Scottish Government, to explore the likely impact that LMP, as an approach to wholesale electricity market reform, could have in Scotland. LMP is currently being explored as part of the Review of Electricity Market Arrangements (REMA), the UK Government's consultation on the reforms required to make electricity markets fit for a net zero energy system. REMA's scope of potential reform is very wide, looking at almost all aspects of electricity markets. As LMP has the potential to significantly impact Scotland's energy landscape, it is of particular interest.

This is an independent review of LMP and its alternatives and does not represent the view of the Scottish Government. The authors have critiqued quantitative and qualitative studies on the possible impact of LMP, assessing the strength of assumptions used in the studies. The study was conducted between September 2023 and January 2024 and the assessment is based on the literature available at the time. The conclusions are based on this evidence as well as evidence gained through an expert advisory panel (EAP). The EAP was invited to contribute and comment on the interim findings of the study. Members of this panel include various stakeholders across government, energy research centres, renewables developers, flexibility aggregators, industry, community, consumer and business representatives, energy suppliers, and large consumers of electricity in Scotland. This panel was invited to two 2-hour presentations and roundtable discussions. The panel's views have been considered in our analysis, and certain commentary has been highlighted in this report. In addition, the study team responded to additional engagement requests for bilateral discussions with members of the panel representing industry and energy system representatives. One of these was followed by detailed letters setting out the members' views on the interim findings.

The review has been structured into three sections. Firstly, a literature review of LMP and its alternatives, including an assessment of recently published cost-benefit assessments. Secondly, an analysis of how LMP may impact – positively and negatively – the Scottish Government's key ambitions outlined in the Energy Strategy and Just Transition Plan, amongst others. Thirdly, the study presents a set of conclusions and suggested next steps.

2.2 Locational marginal pricing

Electricity that is not traded under bilateral agreements between generators and suppliers/consumers is sold in the wholesale market. The current GB electricity wholesale market is a national market with marginal pricing[1]. This means that across the market, electricity can be bought or sold regardless of the location of the consumer or generator and the resulting grid conditions this creates. As the price is set by the cost of the marginal generator, the revenue or cost seen by all generators or consumers is the same price across GB for each settlement period. A settlement period is the 30-minute period in which volumes of electricity are traded.

Under LMP, the wholesale market would be split up into several zones (zonal pricing), or many (multiples of) nodes (nodal pricing), see Figure 1. With zonal pricing, the boundaries between zones reflect network constraints (bottlenecks) on the transmission network. These network constraints occur when power flow is limited by the capacity of the physical network. With nodal pricing, each location where demand or generation is connected to the transmission network is known as a node. For each settlement period, consumers and generators in different zones/nodes can experience different wholesale prices, depending on the local level of generation, demand, and network constraint.

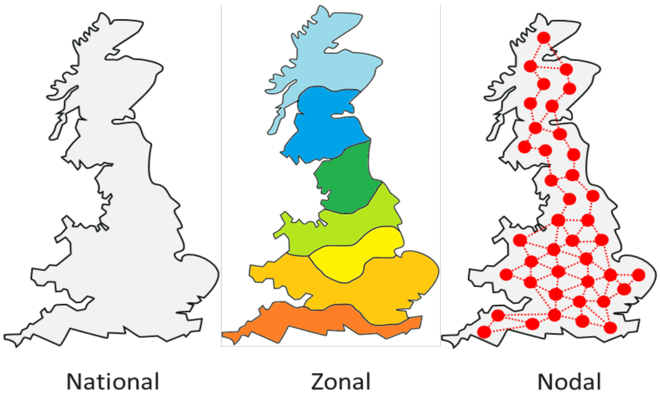

Figure 1: Illustrative diagram of national, zonal, and nodal wholesale market arrangements.

LMP is being proposed in REMA as a potential mechanism to tackle the drawbacks of a national market in a net zero power system. A key drawback of a national wholesale market is that transmission losses and network constraints are not considered in the wholesale price of electricity. Therefore, national pricing does not incentivise efficient investment decisions for generation, demand and flexibility to locate where it is most helpful for the system. On a constrained network with a national market, generation often needs to be re-dispatched to resolve constraints, creating additional costs. The annual cost of this transmission constraints has been growing in recent years (£170m in 2010, £1.3bn in 2022), and will likely increase with a higher proportion of renewable generation outpacing transmission capacity (National Grid ESO, 2022a).

The main theoretical benefits of LMP are improved locational signals for investment, as well as improved operational efficiency. This improves whole system efficiency, thus reducing cost. Different prices across zones or nodes set by local generation, demand, and network constraint, create new investment incentives for assets and consumers to locate where it is most economical. In the long-term this should create a more efficient system, reducing the need for network reinforcement. Additionally, as locational pricing reflects the current level of demand and supply in the region, price signals incentivise optimal dispatch of generation, demand and flexibility, improving operational efficiency. However, operationally, there are

[1] Marginal pricing means that one price, the price set by the most expensive selected electricity generation offer to meet demand is received by every successful participant in the electricity generation auction.

also non-price factors which influence investment decisions – including Government policy, planning, natural resources, access to skills, supply chains and connectivity.

2.3 Objectives of the Scottish Government

The Scottish Government has outlined its ambitions relating to the energy transition in its Draft Energy Strategy and Just Transition Plan (ESJTP) (2023). The ambitions of the Scottish Government have been further detailed in the Heat in Buildings Strategy (2021), the Hydrogen Action Plan (2022), and the National Transport Strategy 2 (2020). This study aims to discuss how LMP will impact the Scottish Government in achieving these ambitions. The ambitions can be summarised into the following four broad categories:

1. Support ambitions to **scale up low-cost renewable energy**.
2. Adhere to the principles of a **fair and just transition**.
3. Support accelerated **decarbonisation of heat, transport, and industry**, including through **CCUS and hydrogen**.
4. Enable a **secure and flexible net zero energy system** which is not dependent on fossil fuels.

In Section 4 of this report, we detail which ambitions are sensitive to the impact of LMP and summarise the key strengths, weaknesses, opportunities, and threats (SWOT) of LMP relating to Scotland's ambitions.

2.4 Key outcomes for wholesale market reform

Wholesale market reform will have widespread impacts on Scotland's ESJTP, as well as wider economic implications. By reviewing Sottish Government strategy papers and assessing where wholesale market reform has significant impact, we have developed key outcomes that need to be prioritised for electricity market reform to align with Scotland's ambitions:

1. **Strategic coordination** of renewable development and network investment is required to ensure that renewables continue to be deployed in Scotland and net zero is achieved.
   - UK decarbonisation relies on significant capacity of renewables being built in Scotland.
   - Strategic planning of renewable development is required to place generation where it is most suitable, whilst considering existing and future network capacity and the pace required for decarbonisation.

2. **More efficient locational dispatch signals** are necessary to encourage flexibility and enable greater renewable penetration.
   - Granular locational dispatch signals that provide the right signals for flexibility, in the right places, are essential for a power system with a high penetration of renewables and significant network constraints.

3. Mechanisms that allow demand, including industry, businesses, and domestic consumers to **benefit from the lower cost of renewable generation** are required.
    - GB already generates significant electricity from renewable sources, yet consumers still pay prices largely defined by national gas generation.

4. **Benefits and costs** of a green transition need to be **shared fairly**.
    - Changes in market arrangements need to consider the winners and losers of reform, as well as the status quo, to ensure that costs and benefits are distributed fairly.
    - Market arrangements need to ensure that investment is incentivised at pace yet is also cost efficient, minimising energy bills for consumers.
    - Wider economic benefits, skills, fair work, and quality jobs need to be maintained and created for local communities.

2.5 Key limitations in the quantitative modelling of LMP

This review is based on a qualitative assessment of existing published literature. As such, it does not include any further detailed modelling. The main limitation of the assessment of LMP in the Scottish and GB context is the uncertainty of quantitative outcomes published in reports by Aurora (2023), FTI (2023), and AFRY (2023). These constituted the main published economic cost-benefit analysis of LMP in GB at the time of writing, between October 2023 and February 2024.

It needs to be noted that significant assumptions are made within the existing modelling that can materially impact any outcomes. Firstly, the benefits of the studies are compared to a counterfactual of the existing national market arrangements. Regardless of whether LMP is implemented, the market will likely see significant reform. As alternative reform is not predictable, comparing LMP to the existing market arrangements provides a baseline to assess wider reforms and alternative measures against in future studies. We acknowledge the limitations with this approach; however, this reflects the nature of existing studies and literature. This will likely lead to an overestimation of the benefits of LMP compared to a future reformed national market. On the contrary, some negative impacts may be overstated due to the mitigations that wider reforms – particularly to investment policy – could deliver.

Indeed, additional reforms introduced alongside LMP are equally uncertain. The design of investment policy (e.g. the reform of Contracts for Difference, CfD) will have a significant impact on scale of the benefits of LMP. The modelled benefits of LMP are also significantly impacted by the level of transmission network buildout. National Grid ESO are proposing substantial levels of network build. Each study includes various scenarios which make assumptions about the level of network buildout expected over the modelled period. Finally, the timing of when LMP is introduced will have a significant impact on the potential scale of benefits. The benefits will likely reduce the later LMP is introduced, as network build progresses and alleviates constraints costs. However, the rate of required buildout is unprecedented[1] (National Grid, 2023) and may see delays.

Due to these limitations, the absolute values of the outcomes in these studies will have significant levels of uncertainty. Therefore, while we have used absolute values for subsequent analysis, in general, we have conveyed the general trends of the outcomes of the studies.

3 A literature review of the impacts of LMP and alternatives

This section comprises of a literature review of the impacts of LMP and its alternatives. We have included both quantitative and qualitative studies in the GB context, with some additional insight from international markets. This section has been split into the following themes to guide the review:

1. Consumers and end users
2. Investment and decarbonisation
3. Market arrangements

Furthermore, this section provides a critique of the modelling assumptions taken in the literature and a high-level review of the alternative reforms to LMP explored in the literature.

3.1 Consumers and end users

3.1.1. System cost/net economic benefit

The net economic benefit of introducing LMP, both zonal and nodal pricing, has been most extensively modelled by Aurora (2023), FTI Consulting (2023), and AFRY (2023) in recent studies. These assess the impact that LMP will have on the whole system cost of the power system. Whole system cost includes wholesale cost, balancing costs, CfD cost, and congestion rent. Overall, these cost benefit analyses suggest that, in the broad terms, LMP would improve market efficiency and reduce net costs to the consumer (Table 1), i.e. reduce whole system cost. However, the total reduction in whole system cost remains relatively small (% change in whole system cost, Table 1). The modelled periods in these studies are not all the same, making direct comparison of total net savings difficult.

[1] National Grid suggest that to meet the Government's target of 50GW of offshore wind by 2030, more than five times the amount of transmission infrastructure must be delivered in the next seven years, than has been built in the past 30 years.

Table 1: Modelled net economic benefit of LMP in GB. Whole system cost and net benefits for AFRY and Aurora are presented in 2021 base year. FTI values are converted from 2024 to 2021 using CPI inflation and 2.2% assumption for 2024[1].

		AFRY (2023)	FTI (2023)	Aurora (2023)
Period		2028-2050	2025-2040	2025-2060
Scenario		Consumer Transformation	System Transformation – Leading the Way NOA7	Net zero 2035
Base case whole system cost		£466bn	N/A	£1310bn
Zonal	Net benefit	4.2bn	5.2 – 12.8bn	23bn
	% change in whole system cost	-0.9%	N/A[2]	-1.8%
Nodal	Net benefit	4.5bn	11.0 – 20.5bn	35bn
	% change in whole system cost	-1.0%	N/A	-2.7%

On an annual basis, the modelled benefit on the overall cost of the system varies greatly, ranging from £0.2bn to £1.3bn for a nodal arrangement (see Figure 2). These differences show the significant impact that different inputs and scenarios can have on the modelling outcome and indicate uncertainty in the modelling.

The components of where these benefits come from broadly align in the studies. In both Aurora and FTI modelling, average wholesale prices increase for consumers across GB, however this is balanced out by reduced balancing costs and congestion rent revenues. Modelled CfD costs are expected to increase. However, these will largely depend on the assumptions made as to how CfDs will be reformed alongside the wholesale market.

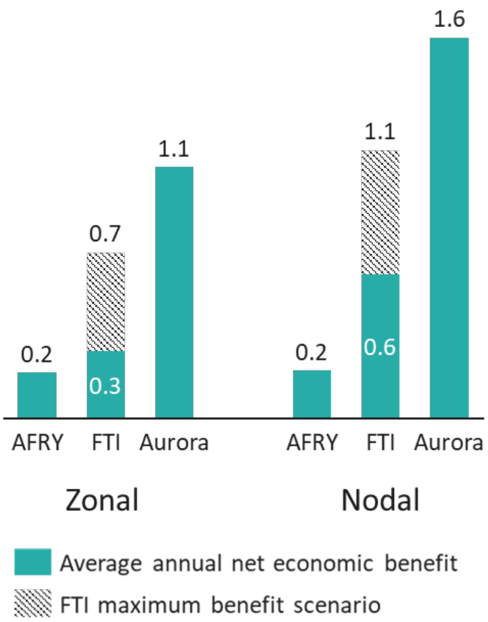

Figure 2: Average annual net economic benefit of zonal and nodal markets (£b).

Congestion rent is a new source of income for the Market Operator (MO) that is created under LMP. The role of the MO is to optimise dispatch and calculate prices under LMP markets. The System Operator (National Grid ESO in the UK) could take this role. Congestion rent is the revenue gained by the MO by moving electricity between zones/nodes with different prices and is generally assumed to be passed to the consumer.

A concern highlighted by one member of the EAP is that without understanding the full package of market reform that will be undertaken, it is difficult to model the impact that LMP will have as a standalone change. Additionally, there has been concern that radical

[1] Historical CPI inflation data from ONS (2024), and 2024 forecast from OBR (2024).
[2] No whole system cost estimate provided, only relative changes.

market reform would create increases in the cost of capital or an investment hiatus, which could reduce or eliminate any benefits seen. This will be discussed later.

3.1.2. Wholesale power prices

LMP would introduce regional wholesale electricity markets, leading to regional differences in prices. These differences are created when network constraints between two different zones or nodes limit the amount of power that can be transferred at a given moment. Across the UK, consumers in areas with an oversupply of renewable generation, such as Scotland, stand to benefit the most from reduced wholesale prices due to LMP. Areas such as the south of England, which have high demand, are expected to see wholesale prices increase when compared to a national wholesale market.

Across the three reviewed studies, the most detailed analysis on prices is in the FTI report. AFRY modelling is generally at the national level, while Aurora reporting focuses on whole system costs and spreads of capacity and generation.

In FTI's modelling, price projections in oversupplied areas such as Scotland decrease more compared to the national wholesale price, than price increases in undersupplied areas (see Figure 3). The north of Scotland could even benefit from the lowest prices in all of GB.

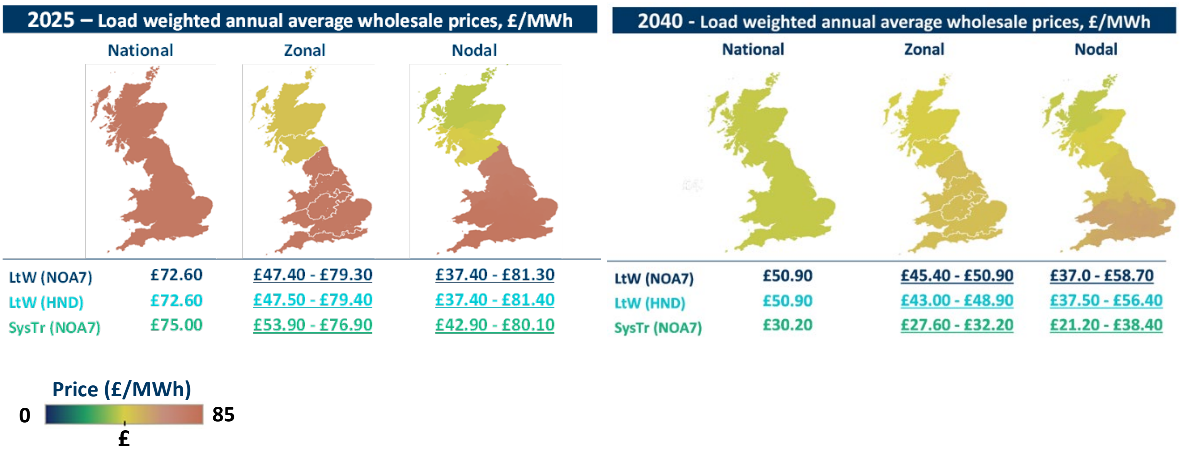

Figure 3: Changes in average wholesale prices across GB in 2025 and 2040. Scotland stands to benefit the most under all scenarios, whereas southern regions show smaller increases in price. These differences diminish to 2040 (FTI Consulting, 2023).

The extent to which differences in wholesale prices between different regions are maintained will depend on the location and scale of future demand and generation, as well as network build. These differences will diminish over time as generation is built closer to demand, new demand re-sites to where prices are lowest (to an extent), and importantly new network build reduces constraint.

3.1.3. Electricity bills for residential consumers and shielding of demand

Currently, the average domestic electricity bill in Scotland is one of the highest in the UK (DESNZ, 2023c). A significant factor that causes regional differences in bills are unevenly distributed network charges, which make up approximately 23% of the average electricity bill (Ofgem, 2024). Network charges include distribution, transmission, and balancing components. The other main components of a domestic electricity bill in the UK are wholesale costs (29%), supplier operating costs (16%), environmental/social obligation costs (25%), and VAT (5%). In Scotland, transmission network charges are generally lower, as demand is located closer to generation. Distribution network charges make up the greatest difference between regions and are particularly high in Northern Scotland. Overall, this means that the average domestic direct debit bill in Scotland is £1,282, compared to £1,252 in England and Wales, and £1,152 in Northern Ireland, based on fixed consumption levels (DESNZ, 2023c). The introduction of LMP could reduce the wholesale cost contribution to Scottish electricity bills.

LMP would likely create different regional inequalities in the cost of electricity across GB. Particularly in a nodal arrangement, some regions could see significant changes due to significant oversupply or undersupply of generation in the area. This can be mitigated by shielding demand from wholesale market price exposure (see Table 2) and could be done to protect consumers at risk of fuel poverty. Shielding would reduce the benefit Scottish consumers would see from lower wholesale prices. The greater the extent that demand is shielded from differences in wholesale price, the less effective LMP would be in providing a locational signal to improve market efficiency on the demand side. FTI consulting has completed a demand shielding sensitivity, showing net economic benefits of LMP reduce (FTI Consulting, 2023). This reduces the net benefit from £13.1bn to £11.4bn (Nodal, System Transformation NOA7 Scenario). The reporting does not show the regional impact of demand shielding, however, does indicate that average wholesale prices for GB would be higher than without load shielding.

Table 2: Citizen's Advice (2023) has summarised different options for shielding demand from price exposure under LMP.

Type	Description	Effect	Example
National average	Consumers pay a weighted average national price.	Eliminates all price differences and reduces price volatility.	Italy
Adjust for regional variations	Consumers pay national average wholesale price, but regions preserve different time of use profiles.	Socialises differences in average cost between regions, but still sends local dispatch signals.	None – hypothetical scenario
Zonal average	Consumers pay a regional (zonal) average price in a nodal market.	Reduces, but does not eliminate regional differences in price. Reduces price volatility.	California, New York
Minimal intervention	Up to suppliers to offer range of tariffs, with varying exposure, for consumers to choose from.	Variable. Will likely send strongest price signal through to consumers.	Denmark, New Zealand
Opt-in	Choice between exposure to locational price, or national/regional price.	Provides consumers the choice to be exposed to a potentially more volatile price.	Ontario, PJM (USA)
Shield by type of user	Expose some users (e.g. commercial and industrial) but shield other consumers (e.g. residential).	Considers the ability of different types of users to respond to locational prices. Still exposes large consumers to price signals.	Most jurisdictions (e.g. Ontario)
Phased exposure	Expose some types of large and flexible demand first, before expanding to other types.	Incentivise uptake of technologies to improve grid flexibility, before domestic consumers are exposed.	New York

3.2 Investment & decarbonisation

3.2.1. Changes in location of renewable development

One intended outcome of LMP is that locational wholesale prices provide incentives for generation and demand to be built where it is most efficient. In theory, where there is oversupply, prices fall and there is an incentive for demand to co-locate. High demand leads to higher prices, incentivising new generation capacity to co-locate. This should incentivise a more efficient system in which generation is located closer to demand, reducing the need for network build, as well as reduced re-dispatch.

The modelling of capacity siting decisions in Aurora and FTI Consulting generally allows new capacity to re-site within certain limitations. The limitations and assumptions made significantly affect the outcome, e.g. FTI assumes no new onshore wind in England, with offshore wind re-siting being limited by seabed leasing. Aurora assumes that most capacity in their net zero scenario requires some form of subsidy support, thus will have limited ability to respond to locational signals. AFRY suggests that the sharpness of the locational signal under LMP is stronger before 2030, but then becomes weaker than the national base case after 2035. As current locational network charges will be largely integrated into the wholesale market under LMP, once transmission constraint is relieved in the medium-term, after 2035, the overall locational investment signal will be reduced. This analysis is aligned with the trend of wholesale prices across GB converging over time under LMP and reflects a system with less constraint.

In Aurora and FTI modelling, the overall patterns seen for capacity siting in Scotland are a general increase in battery storage capacity[1], as well as a reduction in solar generation capacity[2], as compared to the national base case (see Table 3). Changes in wind capacity are contested. FTI assumes that offshore wind will generally re-site away from Scotland[3], Northwest England and Northern Wales to the Humber and East Anglia. Onshore wind is limited by not being able to re-site in England, showing increased capacity in the Northern Scotland[4]. FTI also assumes there is no change in locations of pumped hydro for any scenario. Aurora shows limited changes in wind capacity locations.

A significant limitation of the modelling is that it assumes capacity buildout will continue at the same rates, simply responding to locational signals. Several members of the EAP relay the concern that the impact of unmitigated LMP on general investment levels in renewable energy could be severe. As renewable energy is very capital intensive, changes in the risk profile, and thus the cost of capital can have significant negative consequences.

[1] 6.8GW and 3.7GW increase in battery capacity by 2035 in N and S Scotland respectively, compared to 13GW total GB capacity. FTI Consulting (2023) LtW NOA7 Scenario. Values estimated from report charts.
[2] -1.2GW and -1.4GW reduction of solar capacity by 2035 in N and S Scotland respectively, compared to 58GW total GB capacity. FTI Consulting (2023) LtW NOA7 Scenario. Values estimated from report charts.
[3] -1.5GW and -4.3GW reduction in offshore wind capacity by 2035 in N and S Scotland respectively, compared to 76GW total GB capacity. FTI Consulting (2023) LtW NOA7 Scenario. Values estimated from report charts.
[4] 6.5GW increase in onshore wind capacity by 2035 in N Scotland, compared to 31GW total GB capacity. FTI Consulting (2023) LtW NOA7 Scenario. Values estimated from report charts.

Table 3: Changes in generation and storage capacities under LMP, as compared to the national base case.

Area	Aurora Zonal	FTI Zonal	FTI Nodal
Northern Scotland (above B4 boundary[1])	• Short-term[2] increase in fossil peaker capacity • Long-term[3] increase in hydrogen peaker capacity • Long-term decrease in solar capacity • Onshore and offshore wind capacity unchanged	• Long-term increase in onshore wind and battery capacity • Long-term decrease in solar capacity	• Long-term increase in onshore wind and battery capacity • Long-term decrease in offshore wind and solar capacity
Southern Scotland (between B4 and B6 boundary)	• Short-term increase in fossil peaker capacity • Long-term increase in battery capacity and hydrogen peakers	• Long-term increase in battery capacity • Long-term decrease in onshore wind, offshore wind, and solar	• Long-term increase in battery and onshore wind capacity • Long-term decrease in offshore wind and solar
England & Wales	• Short-term increase in peaker capacity across GB • Long-term decrease in overall battery buildout • Southern shift in capacity growth of solar • Widespread growth of hydrogen peaker capacity	• Southern shift in capacity growth of solar • Long-term increase in offshore wind on the south English coast • Little change in fossil peaker capacity across all regions	• Southern shift in capacity growth of solar • Long-term increase in offshore wind on the south English coast • Little change in fossil peaker capacity across all regions

The table above shows general trends in the re-siting of generation caused by LMP. These general trends are read from charts in the studies. Detailed data on exact capacity changes in specific regions is generally not reported. Large uncertainties in absolute modelling outputs mean general trends are more useful to assess.

[1] The boundaries for Scotland and Southern Scotland in the models are generally defined by the B4 and B6 transmission constraints. The B4 constraint separates the transmission network between the SP Transmission and SSEN Transmission interface, from the Firth of Tay in the east to the north of the Isle of Arran in the West. The B6 boundary runs roughly along the border between Scotland and England, on the SP Transmission and NG Electricity Transmission interface.
[2] Up to 2035.
[3] Beyond 2035.

3.2.2. Impact on renewable development

A significant change that would be introduced under LMP, particularly affecting generators, is the loss of firm access rights. Under a national market, generators have “firm access” to the grid. This means generators can sell electricity on the wholesale market without consideration of network constraints. Therefore, generation can act independently of network buildout, and future scenarios for generation inform network build out plans.

In an LMP market, generators lose firm access to the market outside of their respective zone. This means generators lose the right for compensation when the lack of network capacity means they cannot export onto the network, requiring a change to business models and investment approaches.

Scotland is currently in an oversupplied region behind an export constraint, meaning more electricity is generated than consumed locally (National Grid ESO, 2022b). The B6 boundary between Scotland and England limits the power that can be exported such that generators in Scotland are often curtailed off. There is currently significant network buildout planning to increase the capacity across the B6 boundary, which would reduce this risk for Scottish generators. However, excess flows across the B6 boundary are still maintained, even with these upgrades (National Grid ESO, 2023b). The loss of firm access under LMP is a significant new risk for generators in Scotland, as they will lose volume certainty when the network is constrained.

Existing generators could lose out on revenue from markets or CfD payments as they lose firm access rights to sell electricity to wholesale market. This would make many projects (especially in Scotland) unviable. Projects that are in development face similar risks. Should no new CfD scheme be implemented, new renewable development in areas behind constraints with high existing renewables (like Scotland), will have to compete for already very low wholesale prices during times of wind output, likely making projects unviable. For planned projects, lack of revenue certainty would either drive up the cost of capital (due to sizeable increase in risk) or lead to an investment exodus to markets in other parts of GB/Europe with more certain/lucrative revenue streams.

However, overall renewable curtailment across GB is projected to decrease under LMP, though this may not be the same in oversupplied Scotland. FTI’s modelling shows less renewable curtailment in both zonal (510-636 TWh between 2025-2040) and nodal markets (426-502 TWh), with the difference to the national base case (591-812 TWh) increasing to 2040 (National Grid, 2022b). This is due to improved dispatch, interconnector use, flexible demand, and the re-location of generation closer to demand. Aurora’s modelling suggests Scottish wind generation will face slightly higher curtailment in a zonal market, 3% more than in the national base case in 2035.

The risks to generators are further increased because under LMP, particularly in a nodal market, wholesale electricity markets are split into small areas. Aurora suggests that, particularly in smaller, more illiquid zones or in a nodal system, revenues can become less predictable for generators as price volatility increases. This is because local demand and supply become harder to predict. This could increase the cost of capital and reduce investment. FTI suggests that liquidity problems that may arise from smaller markets in a nodal system could be solved using trading hubs (as in USA), reducing liquidity problems.

3.2.3. Pace of power market decarbonisation

As electrification of transport, heat, and industry are key components of decarbonisation, a decarbonised power sector is a key step towards net zero. Under LMP, the modelled pace of GB power sector decarbonisation does not show a significant change. In a scenario where a net zero power sector is achieved by 2035, Aurora modelling shows emissions tracking the national base case closely. FTI modelling show an emissions reduction of 25-100MtCO2 between 2025-2040. This equates to 2-7 MtCO2 per year, or 2-7% of 2022 power sector emissions. This reduction is due to modelled improvements in dispatch, siting efficiency, and interconnector use, reducing the requirement for fossil fuel peakers. Overall, there is little difference in power sector decarbonisation as FTI and Aurora generally model continued buildout of generation at a similar pace.

A major limitation of LMP is the significant time it will take to implement. AFRY argue that the earliest implementation date would be 2028, meaning the window for investment decisions to impact emissions by 2035 (UK Government ambition for power sector decarbonisation) is limited. Additionally, the detrimental risk of causing an investment hiatus could threaten power sector decarbonisation in GB. This has not been properly captured in the modelling.

Scotland’s decarbonisation efforts will require an increased focus on flexibility alongside continued deployment of renewables. Scotland already has significant renewable generation, and thus a significantly decarbonised power sector. Under a constrained network with significant variable renewable generation, greater volatility in local wholesale prices can attract the deployment of flexibility (i.e. storage and demand side response), which enables a more efficient use of said generation.

3.2.4. Interconnector use

A significant potential benefit of LMP is the improved use of interconnectors. Interconnector flows are largely determined by price differentials between markets (Ofgem, 2014). This means that interconnectors can exacerbate network constraints under current market conditions.

The example in Figure 4 shows how a national market allows for import from Norway to Scotland and export from England to France, exacerbating the constraint between England and Scotland. This is a hypothetical example developed by National Grid ESO, as no interconnector between Norway and Scotland currently exists. When there is high wind in Scotland in an LMP market, Scottish prices would be lower than in the south, due to the oversupply of renewable generation. Interconnector flows would reflect price differentials between markets, allowing electricity generated in Scotland to be exported through the hypothetical GB interconnector to Norway, alleviating the constraint to England. Overall, this would enable greater export of Scottish renewable generation.

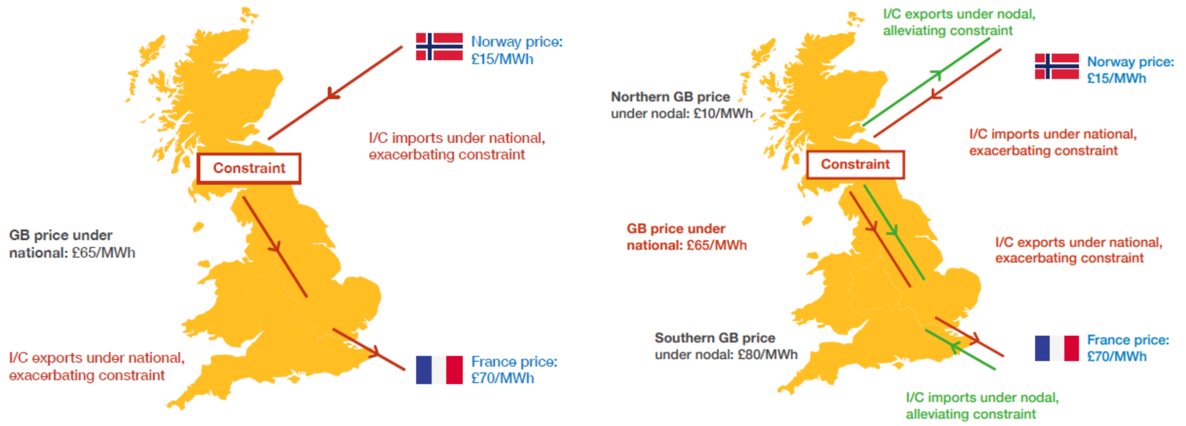

Figure 4: Example of interconnector flows exacerbating congestion on the English Scottish constraint in a national market (left), and how an LMP market could instead alleviate this constraint (right) (National Grid ESO, 2022a).

There has been overwhelming agreement of this benefit of LMP in the EAP sessions. Some members suggest that LMP is the best way to enable improved interconnector use, stating there has been a significant lack of alternative options tabled by industry that could solve this issue.

3.2.5. Energy storage and demand response

LMP markets would create locationally granular dispatch signals that enable the efficient use of flexibility. Price differentials in the wholesale market create an opportunity for assets that can be used flexibly to generate value, including BESS (battery energy storage system), pumped hydro, long duration energy storage, and demand response. Under a national market, wholesale price signals do not consider local constraints, so there is no incentive to place flexible assets in particular locations (National Grid ESO, 2022a). This means that flexible assets, placed in the wrong location, do not necessarily contribute to alleviating constraints.

In an LMP market, prices reflect local constraints on the network. As such, the dispatch signal created by the wholesale market will more accurately reflect the current needs of the network. For example, local oversupply is reflected in the wholesale market and incentivises charging of local storage assets, reducing export constraint. In a national market, the price signal will not only be weaker, but also not send specific signals to assets that are ideally located.

Increased price volatility increases revenues for battery and other energy storage projects, incentivising investment. Scottish price volatility is expected to be higher due to the significant capacity of variable renewable generation. Aurora and FTI modelling suggest Scotland will therefore likely see increased buildout of battery storage, making use of more volatile local nodal and zonal prices. Pumped hydro is likely to also benefit from this, however reporting on this technology is limited in the literature. According to Aurora modelling, overall GB market volatility is expected to decrease over time, but will persist in Scotland.

For this reason, improved locational dispatch signals provided by the wholesale market under LMP could help reduce congestion in Scotland and reduce curtailment by incentivising storage assets and demand response to respond in an efficient way.

Stakeholders in the Expert Advisory Panel agree that improved flexibility is a significant benefit of LMP for GB and Scotland. Improved flexibility allows for the more efficient use of renewable generation, and LMP provides the locationally granular price signal that otherwise needs to be created in separate flexibility markets.

3.3 Market arrangements

3.3.1. Additional market complexity under nodal arrangement

The introduction of LMP necessitates a decision between adopting a nodal or zonal market arrangement. FTI and Aurora modelling show that nodal markets can achieve greater power system cost benefit than zonal markets, however, increase complexity significantly.

Nodal markets would require radical change that increase the barriers to entry in the electricity market. International nodal markets have generally required central dispatch, forcing generators to participate in wholesale markets, and therefore require generators to develop new mechanisms to hedge against price risk. This is to enable the MO to run a clearing algorithm that allows for the most optimal cost-efficient dispatch at hundreds of nodes. Zonal markets exist with both centralised dispatch, and self-dispatch internationally.

For Scotland and GB, the benefits of an LMP market could be enabled in a zonal market, reducing the risk of increased complexity and radical reform required in a nodal market. With increased market complexity and associated uncertainty in a nodal market, there is heightened risk for investors.

3.3.2. Market arrangements to allow for bilateral trading

Generators in LMP markets can only directly access their specific nodal/zonal price. This increases risk as any local changes in network build, demand, and generation can have a significant impact on the price. To reduce such risk some international nodal markets have introduced Financial Transmission Rights (FTR) to allow for price risk hedging.

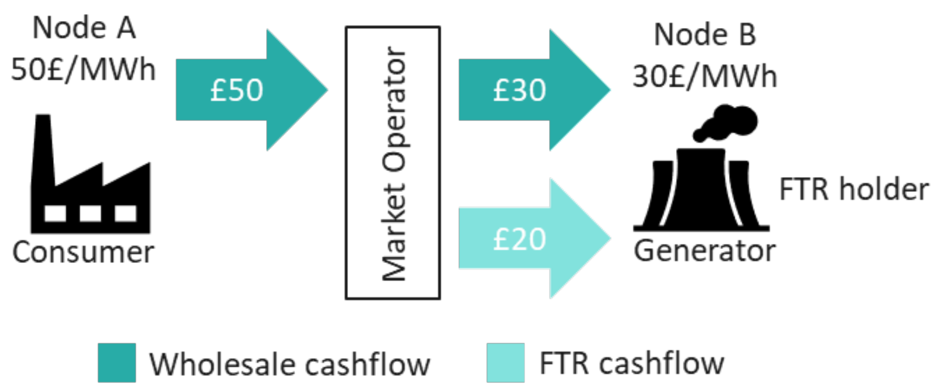

Figure 5: Example cashflows between a generator and consumer for 1MWh of electricity. The generator in Node B holds an FTR that gives them access to the market price of Node A.

An FTR gives the holder the right to cash flows relative to the difference in price across nodes, thus allowing generators in oversupplied areas to potentially access higher prices (see Figure 5). They are funded by congestion rent, accrued by the MO. The MO may assign FTRs to electricity suppliers, with the intention that congestion rent is passed as a saving to consumers.

As all market actors need to participate in the wholesale market in a nodal system (as they are centrally dispatched), FTRs are also necessary to enable Power Purchase Agreements, (PPA). PPAs are a mechanism that allow generators to reduce price risk of the wholesale market by directly selling electricity to an electricity supplier or consumer at an agreed price. In a nodal market, the consumer and generator within a PPA still need to buy and sell electricity on the wholesale market. The prices bought and sold at will not necessarily be the same when they are not on the same node. An FTR between the nodes allows for some of the price difference to be compensated, though additional cashflow may be required if the value of the FTR is not equal to the agreed upon PPA price (Gill et. al, 2023).

As greater volumes of FTRs are created by the MO, the impact of nodal pricing on generators will be reduced, as fewer are exposed to local prices. It is therefore unlikely that enough FTRs are created that all generation can be hedged.

3.3.3. Implementation of a CfD scheme

Creating a CfD scheme under a locational market would be a novel development, with associated risks in implementation. Designing a CfD scheme under LMP faces significant new complexities, however, would be important to support the mass buildout of renewable generation in Scotland. Currently, CfDs provide generators top-up revenue calculated by the difference between their reference price (wholesale market price), and the auctioned strike price (price to which uplift is calculated, ensuring revenue certainty). When wholesale prices are higher than their strike price, generators also need to pay back excess revenues. A key decision for a CfD scheme under LMP is the extent to which generators will be shielded from local prices. A CfD scheme that completely protects generators from locational signals could be seen as counterproductive, as it would reduce the benefit of signalling where generation should be built.

Choosing a strike price, to which uplift is calculated, can be done either nationally or at the zone/node. Auctioning strike prices nationally, would provide similar support to all generators, and auctions would tend to minimise cost. Alternatively, a zonal/nodal strike price would support generators across regions differently, and the cost to the consumer would vary across regions. An auction that minimises CfD cost would minimise the average cost of uplift, rather than minimise the strike price, which is the current mechanism. Such an auction would require significant modelling to assess which generators will require the least uplift. In our view, regionally auctioned strike prices would favour generators located in areas with favourable conditions such as high-capacity factors and lower grid costs, yet still reduce the locational signal of the wholesale market.

The way the reference price is chosen in an LMP market impacts the strength of the locational signal and the cost of support (Figure 6). A zonal/nodal reference price completely shields the generator from the locational wholesale market. A national reference price provides equal uplift for all generators (given the strike price is the same). Generators in low price regions are still exposed to the lower wholesale price, so earn less revenues unless hedged. This allows for some exposure to locational wholesale prices.

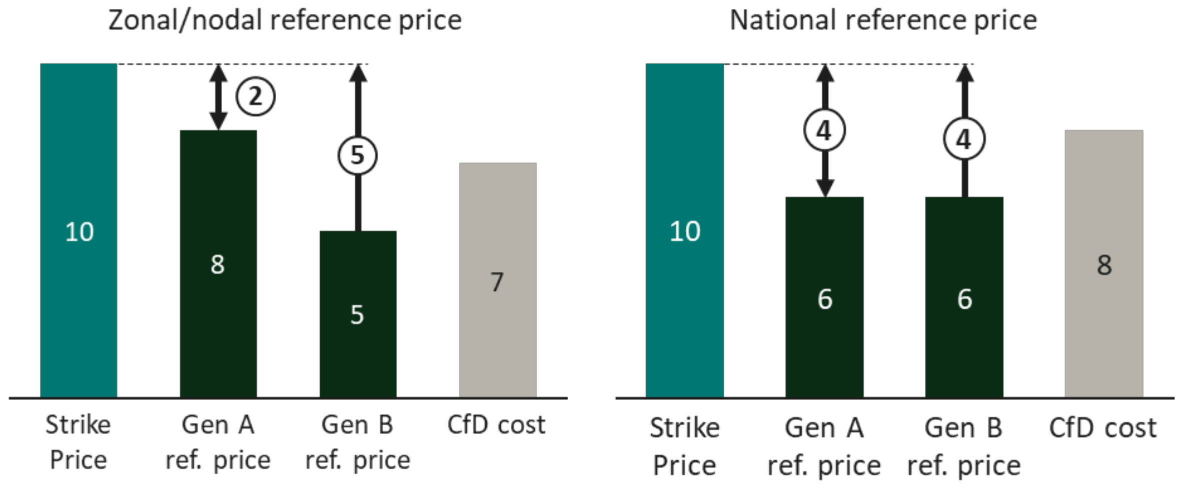

Figure 6: Hypothetical illustration of the impact of local and national reference prices on CfD payments.

Some members of the EAP see the continuation of a reformed CfD scheme under LMP as potentially difficult to implement. Many choices need to be made that will significantly affect the extent of the impact that LMP can have, whilst also introducing additional complexity in CfD administration, auctioning, and cost. Other EAP members have stated that to ensure continued investor confidence, existing CfD schemes will likely need to be grandfathered. This means existing CfD generator revenues are secured such that they remain unchanged, regardless of market reform.

3.4 Critique of LMP modelling assumptions

3.4.1. Introduction (description of modelling approaches)

The two key studies that have been used in this literature review to assess the economic and system benefit of LMP are Aurora (2023) and FTI Consulting (2023). To date, these are the only cost-benefit analyses that have published a significant level of detail, with AFRY (2023) only publishing overall results. The key modelling approaches can be seen in Table 4.

Table 4: Key configurations of Aurora and FTI Consulting's modelling of LMP.

	FTI Consulting	Aurora
Zones	7	7
Nodes	850	Not stated
Period	2025 – 2040	2025 – 2060
Scenarios	3 scenarios each with different network build assumptions, including Network Options Assessment 7 (NOA7) and Holistic Network Design (HND), as well as decarbonisation pathways Leading the Way (LtW) and System Transformation (ST).	2 scenarios of a net zero power system by 2035 and by 2050. HND is included in network build assumptions.
Sensitivities	Dispatch only, load shielding, increased cost of capital.	Increased cost of capital, delayed network build, dispatch only.

3.4.2. Impact of network build assumptions

Network buildout has a large effect on the impacts of LMP, and how they are distributed geographically. It is therefore a core assumption that determines the benefits of LMP. In an unconstrained network, LMP will have no benefit over a national wholesale market. If the modelling underestimates the level of network build, it will overestimate the impact of LMP.

NGESO identify which parts of the network require reinforcement and assess the cost-effectiveness over other possible measures. The Network Option Assessment 7 (NOA7) sets out the requirements for new infrastructure out to 2030. However, NOA7 has been supplemented by the new Holistic Network Design (HND), which accounts for additional upgrades required to support offshore wind (National Grid ESO, 2022b).

FTI Consulting only uses NOA7 as its central network buildout scenario, with a second scenario exploring HND. However, as HND has already been approved, only the HND scenario should be considered. This reduces the FTI net benefit of LMP by 40%. Aurora accounts for HND in its net zero scenario, then models further grid reinforcement after 2035 using their own network congestion/revenue algorithm. Sensitivities of delayed network build in Aurora modelling also show that this increases whole system cost in both national and LMP markets. LMP markets, however, can partially mitigate this impact.

3.4.3. Wholesale price projections

Wholesale price projections in the national base case will affect the absolute magnitude of the modelled net impact of LMP. Comparing to DESNZ national wholesale price projections (DESNZ, 2023a), Figure 7 illustrates that Aurora projects higher prices than DESNZ before 2030, then lower prices afterwards. FTI projects significantly lower prices than DESNZ in the short- and long-term. Therefore, the counterfactual national wholesale cost is not consistent between the two studies, leading to different net benefit calculations. When comparing equivalent scenarios, this could partially explain the greater benefits of the Aurora modelling (£1.40Bn/a) compared to FTI (£0.77Bn/a).

When assessing the modelled wholesale prices in Scotland under LMP, both Aurora and FTI prices are similar to (in fact slightly greater than) DESNZ projections for the levelised cost of energy (LCOE) of offshore wind (DESNZ, 2023b). This provides confidence that with LMP, the wholesale prices in Scotland will be closely tied to the levelised cost of wind. As a greater proportion of electricity is supplied by unsubsidised wind in Scotland, the levelised cost of wind will to a greater extent determine wholesale prices in Scotland. The higher projections reflect that additional dispatchable generation/storage is required during periods of low wind output.

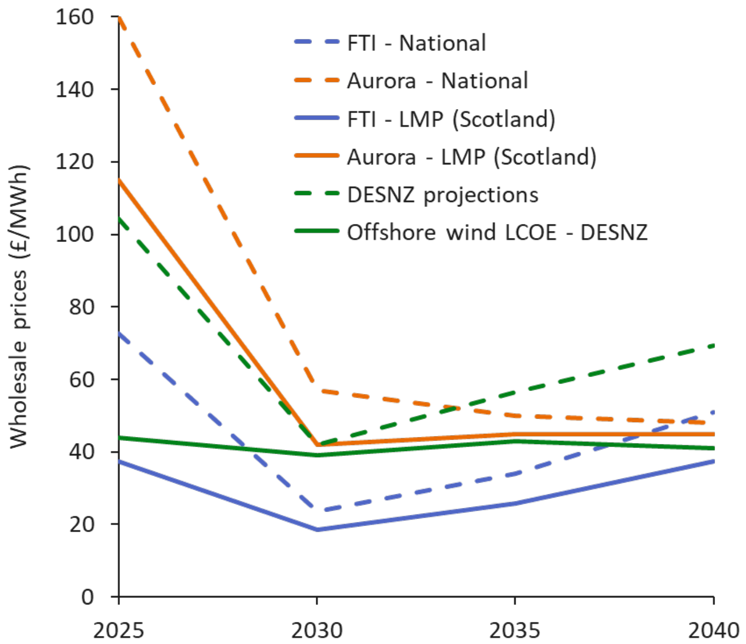

Figure 7: FTI and Aurora national and LMP wholesale price projections compared to DESNZ wholesale price and LCOE for offshore wind projections.

3.4.4. Cost of capital for renewable generation

A transition to LMP could have a significant impact on the cost of capital of generation. There is a consensus amongst the literature, as well as from modelling from AFRY, Aurora and FTI Consulting, that even small changes in the cost of capital would eliminate the net benefits of LMP.

A transition to LMP would be a radical market reform, with reduced volume and price certainty and transition uncertainty leading to a potential increase in the cost of capital. A study assessing the impact on introducing a zonal market in Australia, showed the weighted average cost of capital (WACC) increased by 15-20%, which is equivalent to 1-2pp (Rai et al., 2021). Frontier Economics (2022) suggests that price volatility in the GB market under LMP would increase the WACC of wind farms by 1.8-4pp.

AFRY, Aurora, and FTI have modelled sensitivities to estimate the impact that increases of the cost of capital can have on the modelled net benefit of LMP.

- Aurora models that a 3pp (percentage point) increase in the WACC would increase the cost to consumers by up to 5% compared to the national base case.
- FTI models that an expected 0.5pp increase in the cost of capital of renewables would reduce the net economic benefit of the base case by £7.5bn across the modelled period. Further analysis shows a 1.3-3.4pp increase would be enough to eliminate any consumer benefit in their base case.
- AFRY modelling suggests that a 0.56pp increase in the cost of capital would eliminate the net modelled benefit of LMP.

The wider literature suggests it is likely for there to be an increase in the cost of capital upon the implementation of LMP. Modelling of this scenario shows that even small increases could eliminate the net modelled benefit of LMP. The base cases presented by Aurora and FTI consulting therefore likely overestimate benefits as they do not consider this factor. The potential impact of an increased cost of capital on the level of investment, as well as the cost of electricity, is one of the major factors to consider when choosing to implement LMP.

3.4.4.1. Volatility

Average price volatility, which is a contributing factor to revenue risk and increasing the cost of capital, is unlikely to significantly increase in a locational market. Both FTI and Aurora argue there is not a significant increase in average wholesale price volatility in LMP markets over a national market. FTI does suggest that volatility will increase over time, likely due to increasing renewables, but this would also occur without LMP. However, it is worth noting that in specific nodes/zones where variable renewable generation is high, such as Scotland, volatility may significantly increase. While this provides opportunities for flexibility and energy storage, it could increase risk for generators participating directly in the wholesale market and would likely require continued/reformed CfD support to mitigate against it.

3.4.5. Re-siting of generation and demand

With lower wholesale prices under LMP, some re-siting of renewables away from Scotland should be expected. While Scotland has the highest load factors for both offshore and onshore wind in the UK (DESNZ, 2023d), the greater load factors may not be sufficient to offset lower wholesale prices. However, the extent to which new renewable generation will re-site away from Scotland is limited by several factors. This includes planning, sea-bed leasing, and network availability. Furthermore, short-term changes in the location of advanced development pipelines are unlikely, given the level of planning and permitting required. Development timelines for large generation projects are often very long and so the window for changes to 2035 is limited. At worst, existing pipelines could be cancelled due to lacking investor confidence, which could cause delays in overall GB investment levels as new areas need to be scoped. Consequently, a bigger impact might be expected in the siting of future generation, rather than that which is already planned.

The re-location of some renewable generation in the modelling by Aurora and FTI is a sensible assumption. However, this will be moderated by other non-price factors that could reduce the benefits modelled in the studies.

While significant existing demand is unlikely to re-site according to locational wholesale signals, new forms of demand could re-site within GB or enter the UK market to take advantage of the lower electricity prices in Scotland. Residential demand, constituting 35% of national demand (DESNZ, 2023e), is unlikely to significantly re-site, with most change in this sector likely to be seen in demand response to wholesale price profiles.

Early electrolysers are likely to be developed near centres of demand such as industrial clusters. This is the assumption in both Aurora and FTI studies. FTI allows hydrogen electrolysers to locate on any node with hydrogen gas turbines (as specified in NGESO's Future Energy Scenarios 2021). Aurora's main approach is to model new electrolyser locations based on existing pipelines. As electrolyser capacities increase, the siting of their new demand could be an additional benefit of LMP (McIver et al., 2023).

New sources of demand could also be an unmodelled benefit of LMP. Existing industry is less likely to shift locations in the short- and medium-term, however could benefit from lower wholesale costs to drive electrification. New sources of demand such as data centres and green steel could re-locate to Scotland to take advantage of lower electricity prices. Precedence for this is the choice of northern Sweden for the first commercial green steel plant (H2Green Steel, 2023).

3.4.6. Impact of timescales

The period when LMP is introduced has a significant impact on the modelled cost-benefit. The literature agrees that the earlier it is introduced, the more significant the benefits of LMP will be. The more constrained the network is, the greater the benefit that LMP can have on the system. Based on the NOA 2021/22 Refresh (National Grid ESO, 2022b), significant transmission build is planned to 2030. This will relieve the network constraints and reduce the potential benefit of implementing LMP. It will still take a significant amount of time between deciding to implement an LMP market and its delivery. REMA timelines do not allow the implementation of LMP to begin by 2025 (Ofgem, 2023), and National Grid assumes implementing a nodal market would take 4-8 years (National Grid ESO, 2022a). As such, the modelled benefit of LMP is likely overestimated by FTI and Aurora, both models start in 2025. The modelling by AFRY would still overestimate benefits, with a start year of 2028. As such, the realisation of wholesale cost benefits for Scotland are likely more limited than presented. However, any delays to grid build will improve the case for LMP, as seen in sensitivities completed by Aurora (2023). The volume of additional grid required is unprecedented and it could be likely that some is delayed.

3.5 Alternatives to LMP

There are alternative options to LMP to further locational signals in the electricity system. Some of the most prominent options, as agreed by the project steering group, will be discussed at a high level in this section.

3.5.1. Transmission Network Use of System reform

Locational signals already exist in the GB electricity system within Transmission Network Use of System (TNUoS) charges, which are paid by generators, embedded generators, suppliers, and directly connected transmission demand. TNUoS covers the cost of installing and maintaining the transmission network. This is passed down to consumer's electricity bills. TNUoS reform could provide an alternative to LMP investment signals, creating an equivalent benefit to LMP by influencing investment siting. It will however be unlikely to enable benefits seen by improved dispatch under LMP. Currently, the method for calculating TNUoS limits its impact on investment decisions for generation/demand build. Energy UK (2023) have published reforms that would be required to make TNUoS reflective of a modern system to provide an alternative to LMP, summarised in Table 5.

Table 5: A summary of Energy UK (2023) requirements for TNUoS reform.

Reform	Current TNUoS	Reformed TNUoS
Transparency	Methodology for calculating TNUoS is not transparent on locational inputs.	Transparent methodology would help investors forecast TNUoS charges.
Modelling assumptions	Assumptions underpinning TNUoS are based on an outdated fossil-based power system.	Reformed TNUoS would reflect a decarbonised system with increasing generation and demand.
Predictability	TNUoS varies yearly, often with volatile price signals, increasing uncertainty for investors, hence the cost of new generation.	Long-term TNUoS charges (e.g. fixed for 10 years at point of connection) have been proposed to provide certainty to investors.
Locational charges	Currently, locational signals in TNUoS are small.	Signals would need to increase for both generation and demand to reproduce the effects of LMP.
Treatment of storage	Storage is currently treated as a "conventional carbon generator", despite being both generation and demand.	Storage could be given specific treatment to encourage siting areas with net supply.

Aurora and Frontier Economics (2023) agree that a reformed TNUoS charge could create an equivalent benefit to LMP for the optimal siting of generation/demand. Aurora's modelling shows that in some locations in Scotland, TNUoS reform would need to increase charges on some renewables to have the same impact as LMP, causing some renewables to re-site away from Scotland. However, their modelling assumes sufficient grid build to incentivise new offshore wind in northern Scotland. Across the whole of Scotland, Aurora model increasing incentives to build flexible generation and storage. As a whole, Frontier Economics argues TNUoS reform could improve investor confidence by providing long-term location signals to influence generation/demand siting. This would mean that the risk of increases in the cost of capital for renewable generation introduced by LMP could be avoided by TNUoS reform.

3.5.2. CfD reform

CfD reform could also provide locational signals in renewable investment. CfDs are the main mechanism through which renewable generation is supported in the UK. They enable stable revenues by auctioning “strike prices” for generators. When wholesale prices fall below the strike price, generators receive a top-up. When wholesale prices exceed the strike price, generators must pay back excess revenues.

This study has identified two main approaches to introducing a locational signal to CfDs, deemed generation (discussed by AFRY, 2023) or non-price factors (discussed by Regen, 2023a).

Table 6: Description of reformed CfD mechanisms.

Mechanism	Actual generation CfD	Deemed generation CfD	CfD – non-price factors
Source	Current mechanism	AFRY	Regen
Description	Revenue top-up based on generation (MWh) based on a fixed £/MWh strike price.	Revenue top-up based on capacity at a fixed £/kW/yr. Contracts awarded by the lowest deemed £/MWh, rather than the actual MWh produced.	Introduce non-price factors into the auction that reflect various additional considerations of CfD, including locational and other whole systems benefits.
Benefits	Ensures best value (£/MWh generated) projects win contracts, reducing wholesale prices in national market.	Contracts awarded based on forecasts of MWh delivered, accounting for locational factors (e.g. expected load factor and hours constrained). Guarantees revenue at point of contract award.	Non-price factors reflect various additional considerations of CfD, e.g. location & other whole systems benefits. Recognises projects that provide wider socio-economic benefits.
Limitations	Generators still topped-up if constrained, so no consideration of network constraints. Generators do not receive revenue during periods of national curtailment.	Does not necessarily provide best £/MWh generated for consumers. Requires CfD awarder to produce generation and constraint forecasts, increasing mechanism complexity.	Does not necessarily provide best £/MWh generated for consumers. Increase complexity of mechanism for CfD awarder and developers to introduce/quantify additional benefits.

3.5.3. Balancing Mechanism reform

The Balancing Mechanism is the main energy balancing market NGESO uses to ensure that demand and supply are matched, as well as to solve constraints on the network. A reformed BM could both influence investment siting decisions, as well as improve dispatch signals, though it is unlikely to fully replicate the benefits of LMP. Note that under a national market with a reformed BM, dispatch is still done through the wholesale market, meaning BM reform would only aim to reduce the cost of redispatch.

Investment siting decisions could be improved under a reformed BM, influenced by the potential revenue offered by the BM. However, currently this is difficult to forecast. Improvements to forecasting could include increasing the transparency of BM dispatch. Reform could go further by introducing/increasing long-term contractual agreements between NGESO and flexibility operators.

Reducing the cost of redispatch could be achieved by BM Wider Access, which will enable participation from aggregation of demand side assets and embedded generation storage. This would increase the number of assets in the BM and increase competition. Increasing the visibility and dispatch of storage assets could increase participation. National Grid is currently working to improve battery storage participation with the Open Balancing Platform, allowing bulk dispatch of batteries. Another potential reform in the BM to increase operational efficiency of the market is to enable interconnectors to participate. This could allow for the redispatch of significant interconnector capacity to resolve constraints on the network.

3.5.4. Local constraint markets

Local constraint markets (LCM) are newly developing flexibility markets that aim to enable wider access of assets to solve constraints on the network. These could go some way to improving locational dispatch and investment signals in a national market.

GB’s first local constraint market (LCM) came into operation in Scotland in 2023, seeking to manage the constraint between England and Scotland. Participants above the B6 export constraint in Scotland turn up demand during periods of high renewable generation. The aim is to provide a service that can solve the constraint at lower cost than the Balancing Mechanism, and simultaneously increase the number and types of assets that can participate in electricity markets by allowing households to participate.

Regen’s Insight Paper (2023b) suggests NGESO should procure flexibility in LCMs over a variety of timescales (intraday, day-ahead, and long-term) to help the optimal locational dispatch of demand in a national price market. If LCMs are guaranteed in certain locations in the long-term, Regen also comment that they could provide investment signals in areas of constraint for the development of flexibility. It is important that such markets provide constraint management at a lower cost than currently through the BM, otherwise they will increase the system cost of resolving constraints.

While LCMs are unlikely able to replicate the granular benefits of LMP, they are a useful addition to national pricing to add a locational signal, and, if the trial in Scotland is successful, could be rolled out in the intermediary period ahead of market reform. A possible downside, also raised in the EAP, is that many separate markets will need to be developed, possibly leading to increased complexity.

4 Assessment of the opportunities, threats, costs and benefits to the Scottish Government's objectives

In this section we assess the impact that LMP and its alternatives could have on the objectives of the Scottish government, as outlined in the Draft Energy Strategy and Just Transition Plan amongst other strategy papers. The assessment is split into four main categories:

1. The scale up of low-cost renewable energy.
2. The fair and just transition.
3. The decarbonisation of heat, transport, and industry.
4. Enabling a secure and flexible net zero energy system.

We have proceeded to summarise the main findings in a SWOT diagram (Strengths, Weaknesses, Opportunities, Threats).

4.1 Scale up of low-cost renewable energy

The development of renewable energy will be significantly affected by any wholesale market reform. This section outlines how Scottish renewables ambitions could be affected by LMP.

4.1.1. Description of Scottish ambitions

Scotland has strong ambitions for the scale up of renewable energy, largely focusing on the scale up of onshore and offshore wind, but also on increasing contributions from solar, hydro, and marine energy. The Scottish Government also has an ambition for an installed capacity of 5GW of renewable and low-carbon hydrogen production by 2030, and 25GW by 2045.

Scotland's wind capacity ambitions largely align with UK goals and NGESO Future Energy Scenarios (FES) 2023 modelling. The UK Government goal of 50GW offshore wind by 2030 is supported by significant ambitions for 20GW of offshore wind development in Scotland. To reach net zero by 2050, FES 2023 also forecasts 45% of offshore wind to be located in Scotland. In addition to offshore wind, Scotland's ambition for onshore wind is to develop 8-11GW by 2030.

Scotland's current wind pipeline is extensive, with 12.7GW of onshore wind projects under construction, awaiting construction, or in planning (Scot Gov, 2023a). 8.3GW of projects stand to deliver the bulk of the offshore wind ambition in Scotland. Additionally, the ScotWind and Innovation and Targeted Oil & Gas (INTOG) leasing rounds reflect very significant market ambitions for offshore wind in Scottish waters. For Scotland, and wider UK decarbonisation, it is key that these projects are not risked by market reform. Renewables development is a significant pillar in the energy strategy of Scotland and underpins other socio-economic and decarbonisation ambitions.

4.1.2. Impact of continued constraint and network delays on Scottish generators

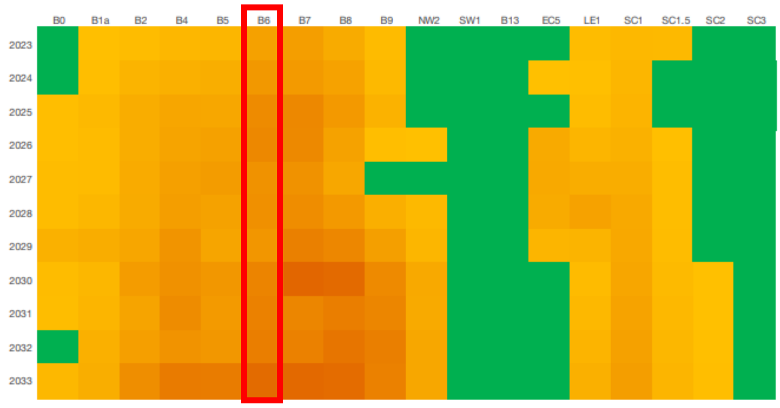

Figure 8: Heatmap of excess flows beyond boundary capability. The Anglo-Scottish boundary (B6, marked in red) will continue to see excess flows after new transmission is built (NG, 2023b). Green means unconstrained flows, with yellow to darker orange indicating increasing times of constraint.

A significant challenge in the development of renewables in Scotland from a power system perspective is the export constraint to England. In FY22/23, export constraints in Scotland resulted in 4.4TWh of balancing actions at a cost of £908 million to the consumer (National Grid ESO, 2023e). To address this, National Grid has proposed transmission build between Scotland and England to allow for flows of 20GW by 2030, and 30GW by 2035 (NOA 2021/22 Refresh). Even with this additional transmission build, the boundary will still likely see excess flows resulting in constraints (National Grid ESO, 2023b). Any delays in this network build would further exacerbate the constraint.

Under LMP, Scottish generators would lose firm access rights to the wholesale market. This means they would be acutely impacted by export constraints and delays to network build, which would limit the market they could sell to, generating a significant volume risk for investors. Excess renewable generation and export constraints in Scotland would drive down wholesale prices, and while this benefits consumers, it would generate further risk for renewable investors' revenue opportunities. Continued low wholesale prices for consumers in Scotland would still rely on further development of renewables. This risk could be partially mitigated by new opportunities for renewable generators to sell electricity to new sources of demand in Scotland or to Europe, via interconnectors, taking advantage of the lower wholesale prices in Scotland. However, this would unlikely fully outweigh the current opportunity to sell to England under a national market.

Some members of the EAP highlighted that Scotland still is the best location for renewable generation in the UK with the load factors and existing pipelines and supply chains, despite the inability of some of the generation to reach demand. However, another member of the EAP suggested that planning to build more generation in Scotland, when there is not the physical grid to support it is unsustainable. Especially when accounting for a history of slow network build, with required transmission build exceeding current rates significantly. These views set out by EAP members must be assessed on the basis that decarbonisation at the lowest cost to the consumer should be prioritised, however within the timeframe to achieve a net zero power system by 2035.

4.1.3. Market arrangements for mass renewables in Scotland

A long-term strategic plan for renewable generation and network upgrades could be implemented in a future market design to achieve a decarbonised power system at the lowest cost to the consumer, within the timeframe set by the UK Government's decarbonisation targets. Such a plan would need to coordinate the location of generation and network upgrades (and flexibility) to send a clear signal to investors about where generation is required to de-risk investment and ensure confidence in mass renewable buildout. The establishment of the Strategic Spatial Energy Plan (SSEP) by 2025 could provide the framework to achieve this. This will be a UK Government led strategy that outlines where, when, and what energy infrastructure needs to be built to enable a net zero system.

Under LMP, it is most efficient and profitable to place generating capacity near demand, reducing the cost of transmission. This is a short-term market signal that does not consider the future location of new generation and network build. It places all the risk on investors to forecast how local grid conditions will evolve when developing their business case. The necessity of the Scottish pipeline for broader GB decarbonisation efforts should be considered before implementing reform that could risk development, considering the limited time for action. Market arrangements are needed that ensure the development of renewables in strategic locations but protect generators.

Support mechanisms such as CfDs would provide revenue certainty whether LMP is introduced or not. However, under the current CfD mechanism, the awarding of CfD does not consider locational factors (past planning and renewable resource) and places all volume risk on consumers (there is no top-up payment if the reference price falls below £0/MWh for recent CfDs). CfD reform could encompass locational considerations when awarding contracts. Such considerations should locate low-cost renewable generation where it minimises cost for consumers, considering the constraints on the network, planned upgrades, and centres of demand. Furthermore, under LMP, CfD reform would need to consider how it could protect renewables from volume risk to improve investor confidence in renewable development in the UK. We discuss this in more detail in section 5.2. Regardless of LMP, CfD reform should consider the increasing periods of national curtailment of renewables as capacity increases and the additional volume risk for investors this will bring.

An alternative method to LMP and reformed CfDs to provide long-term investment signals for the location of renewables is a reform to TNUoS charges. Depending on the timeframe of the investment signal, TNUoS charges could be used to both incentivise or disincentivise the development of renewables in Scotland. The potential benefit of TNUoS reform is that radical market reform is not required. TNUoS reform could be rapidly adopted under a national price market, with fewer of the associated transition risks. However, TNUoS charges would be unlikely to provide regular and accurate locational dispatch signals and so would have to be combined with additional reforms to replicate the full potential benefits of LMP.

4.1.4. Cost of capital

A significant risk that is presented throughout the literature, as well as the modelling, is the impact of an increase in the cost of capital. As renewables development is very capital intensive, changes in the cost of capital will have significant effects on the levels of investment and the final cost of electricity. A small increase in the cost of capital can significantly affect the total cost of a project, impacting its financial viability.

The cost-benefit modelling sensitivities simulated by Aurora, FTI, and AFRY, show that small increases in the cost of capital can easily wipe out the net modelled benefits of implementing LMP. Therefore, well-planned implementation of LMP is essential to limit the increases in the cost of capital for renewables. Furthermore, supporting policies such as CfDs, could work to derisk renewable development, if reformed for a LMP market, reducing the impact of market reform on the cost of capital of renewables.

4.1.5. Strengths, Weaknesses, Opportunities & Threats

Table 7: Strengths, Weaknesses, Opportunities & Threats of LMP regarding renewables development in Scotland.

Strengths	**Opportunities**
• High load factors in Scotland enable renewables development at lower cost to the consumer, if benefit is passed on to the consumer and not retained by developers. • Scotland's targets for renewables capacities align with UK government targets, as well as NGESO forecasts for net zero. • There is an existing strong pipeline of renewable projects in Scotland.	• Lower wholesale prices provide an opportunity for renewables generators to sell more electricity to new demand and Europe via interconnectors.
Weaknesses	**Threats**
• Existing and continued constraints on the network, in combination with the loss of firm access rights, means generators would have increased revenue risk in Scotland. • Implementation uncertainty and potential increases in the cost of capital.	• Without government support, the development of renewables in Scotland is at risk, due to increased costs and risks. • This risks the UK's and Scotland's decarbonisation efforts. • The conditions for continued low wholesale prices are at risk, given reduced development of renewables.

4.2 Fair and just transition

This section outlines how LMP may affect Scotland's ambitions to achieve a fair and just transition, as outlined in the draft ESJTP (Scottish Government, 2023c). This is of particular significance, as LMP will create regional differences across GB.

4.2.1. Description of Scottish ambitions

A fair and just transition is the cornerstone of Scotland's energy strategy and aims to ensure that benefits and risks of the energy transition are distributed fairly. This means delivering affordable energy to Scottish consumers which is not subject to global fossil fuel price volatility. It also includes the wider economic developments of the energy transition. Scotland aims to maintain or increase employment in the energy production sector, amongst the backdrop of a historically strong oil and gas sector. Further growth in the energy sector should also come alongside boosting the skills base and local supply chains, ensuring technology, manufacturing, and know-how remain in Scotland. The benefits of market reform need to be spread out across all regions of Scotland, and not leave anyone behind. This is of particular concern for those at risk of fuel poverty. Additionally, Scotland aims to grow the community energy sector to 2GW by 2030.

4.2.2. Lower wholesale prices for consumers

LMP could see Scotland's consumers benefitting from the lowest wholesale prices in GB, and possibly Europe (FTI Consulting, 2023). This is due to the significant capacity of renewable generation that is behind an export constraint, so prices will largely be set by wind generation. Compared to southern England, prices will converge in the long-term, as network build reduces constraint and generation is built closer to demand. However, Scotland is expected to maintain the cheapest prices in GB. It should be noted that there is limited reporting on the finer regional differences on price in the modelling.

As LMP creates regional differences in wholesale prices across GB, some areas will see electricity prices increase. It should be noted that the increase in electricity prices in some areas will not be equal, but less than the decrease in prices in Scotland. Because the current market arrangements are a national marginal price, every consumer in GB pays the price of the most expensive generator across the country. Under LMP, the marginal price of generation may increase in some locations (e.g. due to generation scarcity within the zone/node). However, on average this will only be a small increase on the national marginal price compared to the decrease in locations such as Scotland. In 2025, FTI project average wholesale prices in the most expensive zone and node to increase by 9% and 12% respectively compared to national pricing. This reduces to -4%[1] and 11% in 2040 respectively (FTI, LtW (HND) Scenario). It should be noted that zonal prices can help mitigate some of the most extreme regional inequalities that nodal LMP could create.

Despite this, it is possible given examples of LMP in other markets (see section 3.1) that, at least initially, domestic consumers could be shielded from some wholesale price signals under LMP, to reduce the negative impact on consumer bills where prices go up and protect consumers at risk of fuel poverty. In the reverse this would reduce the benefits on Scottish domestic electricity bills. A concern raised in the EAP is that it may be politically difficult or unpalatable for the UK Government to implement a new policy that disadvantages domestic consumers in specific areas.

Electricity suppliers may also decide not to pass on the whole benefit of reduced wholesale prices in Scotland to Scottish consumers. Increased costs in other areas mean suppliers may decide to effectively average out wholesale cost across their customer base. Additionally,

[1] A decrease in the average wholesale price in the most expensive zone by 2040 due to system savings under LMP.

ERM analysis projects that wholesale costs will make up 44% of domestic consumer bills in 2025. Any reduction in wholesale cost will thus be buffered by other components of the electricity bill including distribution network charges, green levies, and supplier costs. This would lead to a 21% reduction in Scottish electricity bills under LMP in 2025, based on a 35% reduction in wholesale cost (FTI Consulting, 2023). This would still be a significant reduction for Scottish consumers, which could result in a wide range of benefits and further a fair and just transition.

4.2.3. Employment, skills, and economic opportunities

A key ambition for a fair and just transition is to encourage economic growth and employment opportunities. The growth of the renewables sector poses a significant opportunity for this. New job opportunities will be needed to offset the decline of the oil and gas industry in Scotland. In 2021, there were around 82,400 direct and indirect jobs in the oil and gas sector (OEUK, 2022). Employment growth in the renewables and green energy sector could be used to offset this. The Fraser of Allander Institute (FAI) study shows that the renewable energy sector supported more than 42,000 jobs across the Scottish economy and generated over £10.1 billion of output in 2021 (FAI, 2023). With Scottish Government ambitions for increased generation capacity across a range of technologies by 2030, the wider employment benefits of renewables development are large. As discussed in section 4.1, LMP without mitigation could see future investment in renewables leave Scotland. This would risk the wider economic and employment benefits associated with renewables development.

However, if implemented successfully, lower wholesale prices could incentivise new industries such as electrolysers and data centres as well as other decarbonised industry with high electricity demand to locate in Scotland. This is a significant opportunity that could bring economic growth and employment to Scotland. An important factor is that the continued development of renewables in Scotland is necessary to provide sustained low electricity prices to attract new demand, as well as provide the actual power required for demand growth. Several members of the EAP supported this view, noting that reductions in electricity bills could be a key driver for new industry to locate in Scotland, especially if paired with additional Scottish Government backed incentives for industrial growth. However, others have stated that lower wholesale prices alone may not be sufficient to encourage new demand in certain industries.

4.2.4. Community energy

Without further support, community owned energy renewable generation is likely to become less attractive under LMP in Scotland. Renewables support mechanisms are likely to target larger scale projects, potentially leaving smaller community projects behind. Without support, lower wholesale prices are expected to make renewable energy projects less profitable in Scotland, reducing incentives for investment. Demand-side community energy projects will not be directly affected by wholesale market reform, other than the effect of lower and more volatile prices in Scotland. Members of the EAP noted that community energy projects are already lacking access to finance. Additional market reforms would be required to ensure the growth of community energy and enable easier routes to market, which is needed for a net zero system. Overall, there is not much literature on the impact of LMP on community energy, both regarding generation and demand-side projects.

4.2.1. Strengths, Weaknesses, Opportunities & Threats

Table 8: Strengths, Weaknesses, Opportunities & Threats regarding a fair and just transition under LMP in Scotland.

Strengths	Opportunities
• High existing penetration of renewables provides Scottish consumers with lower wholesale prices. • For greater periods the price of Scottish electricity will be defined by low-cost renewables.	• Lower wholesale prices for consumers in Scotland, and overall reduced system cost should reduce average bills across GB. • Lower wholesale costs could incentivise new demand industries like data centres, green-steel, hydrogen, etc., providing economic growth and employment.
Weaknesses	**Threats**
• Uneven geographic distribution of wholesale prices means some consumers (mostly in England) could face higher costs. • Potential shielding of demand from locational wholesale prices would diminish benefits for Scottish consumers. • Possible re-siting of renewable development away from Scotland.	• Without support, re-siting of renewables away from Scotland would risk renewables industry jobs. • Lack of renewables development reduces conditions for continued low wholesale prices and opportunities in new demand sectors. • Fuel poverty for vulnerable consumers where prices increase could be exacerbated without shielding.

4.3 Decarbonisation of heat, transport, & industry

Wider decarbonisation efforts are often closely linked to electrification. In this section we will outline how regional changes in electricity prices that LMP creates could affect heat, transport, and industrial decarbonisation in Scotland.

4.3.1. Description of Scottish ambitions

Scotland’s ambitions for decarbonisation extend beyond the power sector to include heat, transport, and industry. Scotland aims to decarbonise heat and transport using renewable electricity or hydrogen. This includes the delivery of 6TWh of heat through heat networks (13% of 2021 heat demand). Electrolysis to produce green hydrogen is a significant opportunity, as Scotland already has a significant capacity of renewable generation, with ambitions for significant growth. This would not only use excess generation, store energy, and decarbonise industrial processes domestically, but also enable export of hydrogen to other countries. As such, Scotland aims to develop 5GW of renewable and low carbon hydrogen generation capacity by 2030 and 25GW by 2045. To further enable industrial decarbonisation, Scotland aims to accelerate the development of carbon capture utilisation and storage (CCUS).

4.3.2. Transport decarbonisation

Increasingly the decarbonisation of road transport looks to be dominated by electrification (Element Energy, an ERM Company, 2021). A reduction in electricity prices in Scotland under LMP could result in a decrease in the costs of electric vehicle (EV) charging. Despite this, the implementation of LMP is unlikely to significantly accelerate the uptake of EVs.

An Element Energy (an ERM Company) study in 2022 shows that electricity costs only make up around 9% of the total cost of ownership (TCO) of an EV car for a first owner (typically 1-4 years). Therefore, a 21% reduction in electricity cost for the consumer under LMP (see section 4.2) would only reduce the total cost of ownership by 2%. This highlights that the key cost consideration for an EV is the upfront purchase cost (and the associated depreciation for a first owner). Note that the potential savings attributed to electricity cost increases as a proportion of the TCO for second and third owners as the upfront purchase cost decreases. However, as with new EVs, operational costs are not a barrier to the uptake of second hand EVs. Additional considerations for EV ownership include access to public EV infrastructure and EV performance. So, while LMP could provide valuable benefits for consumers with EVs by reducing running costs, it is unlikely to significantly accelerate EV car adoption.

The impact is similar for other forms of road transport, such as vans and heavy-duty vehicles (HDVs). While fuel/energy cost can be a greater proportion of the TCO for high mileage vans and HDVs, capital expenditure is still the key consideration for electrification (ICCT, 2023). Access to public EV infrastructure is also essential for the uptake of electric vans and HDVs. Nevertheless, reduced wholesale electricity costs would lead to more favourable TCOs for these EVs, leading to earlier price parity with diesel equivalents and a more rapid uptake.

4.3.3. Heat decarbonisation

As with EVs, electrification will play a key role in the decarbonisation of heat in Scotland. The electrification of heat will focus on heat pumps (HP) and heat networks, with some role for other electric heating technologies including storage heaters and direct electric heating. For the average consumer, electric heating (with a HP) is more energy intensive than an EV, with annual consumptions of 3,000kWh and 1,800kWh respectively (ERM analysis). Therefore, lower electricity prices would have a greater impact on the running costs of a HP than an EV, so could incentivise uptake to a greater extent.

For the same reduction in prices detailed in section 4.2, ERM analysis on the TCO of a domestic HP shows a 10% reduction. For other forms of electrified heat (e.g. storage heaters and direct electric), LMP could similarly reduce running costs in Scotland. However, in the case of HPs, upfront costs can currently be prohibitive for many households. Continuation of Government support schemes to reduce upfront costs will be crucial to drive uptake, even with electricity market reform, particularly amongst lower income households. An example of this is the Home Energy Scotland Scheme, which offers homeowners grants of £7,500 to install a HP, and up to £9,000 in rural areas. A stakeholder in the EAP suggested that the introduction of lower prices in Scotland through electricity market reform could come at a critical moment as the uptake of HPs and EVs accelerates among the majority of consumers.

4.3.4. Hydrogen

A significant opportunity for Scotland under LMP is the development of hydrogen electrolysis capacity for the production of green hydrogen. Electricity cost is the largest contributor to the levelised cost of hydrogen (LCOH) via electrolysis, making it an important factor that contributes to the location of electrolysers (BEIS, 2021). Under LMP, Scotland could benefit from some of the lowest wholesale prices in Europe (FTI Consulting, 2023) which would attract electrolyser growth. This would enable a hydrogen export industry, but also contribute to the decarbonisation of industry by enabling some industries to decarbonise where it is more cost effective to use hydrogen. It can also help to enable a high renewables power system by absorbing excess variable generation. The wider economic benefits of employment and industry are also an opportunity for Scotland. An EAP member stated that the levels of electrolyser capacity in Scotland required for a net zero energy system are already very ambitious in FES 2023. Without market reform it will be very difficult to deliver this.

The main risk is that LMP leads to reduced development of renewables in Scotland, which is required for the significant demand that electrolysers, as well as wider electrification, will create. This could mean that supply may not grow in-line with growing demand, reducing the ability to provide electricity at low cost. Mechanisms to retain renewable development in Scotland are therefore essential for a thriving green hydrogen industry in Scotland.

4.3.5. Carbon capture, utilisation, and storage

Carbon capture can be used to reduce emissions of difficult to decarbonise industrial processes. Carbon capture generally involves three processes: carbon capture, conditioning and compression, and transport and storage. The main drivers for successful carbon capture are the need to mitigate large industrial emissions of CO_2, as well as good transport and storage options. The main energy requirement for carbon capture is heat, not electricity, which is usually procured using natural gas. Some electricity is required for processes such as compression. As such, lower wholesale electricity prices would only minimally benefit the cost of carbon capture in Scotland.

Other types of carbon capture, including Direct Air Capture, also predominantly require heat. The solid sorbent DAC process requires lower thermal energy (80-100°C), which can be delivered using waste industrial heat or industrial heat pumps. The liquid solvent process requires temperatures of 900°C, which are usually delivered using natural gas (McQueen et al., 2021). Thus, DAC could benefit from lower wholesale electricity prices when using lower-temperature processes coupled with heat-pumps, maximising the use of electricity as the main energy requirement.

4.3.6. Strengths, Weaknesses, Opportunities & Threats

Table 9: Strengths, Weaknesses, Opportunities & Threats regarding the decarbonisation of heat, transport, and industry, including CCUS and hydrogen.

Strengths	Opportunities
• High load factors and existing penetration of renewables. • Renewable electricity generation exceeds demand. • Ambitious hydrogen capacity goals that align with NGESO forecasts for a net zero system.	• Lower wholesale prices and excess renewable electricity allow for cheaper electrification of heat, transport, and industry. • Electric heating and new demand, like electrolysis, are most likely going to benefit from lower wholesale prices.
Weaknesses	**Threats**
• Some re-siting of renewable generation away from Scotland. • Wholesale benefits in Scotland may not be passed entirely to consumers. • EV uptake not significantly influenced by electricity prices. • Implementation of carbon capture unlikely to be significantly impacted by LMP.	• Reduced renewable development means supply may not grow in-line with electrification of demand. • Less renewable build reduces ability to decarbonise demand and develop hydrogen electrolysis at reduced cost. • Electrification of demand not significantly accelerated by LMP.

4.4 Enabling a secure and flexible net zero energy system

A future electricity system must be resilient to the fluctuations in variable renewable generation and demand. Flexibility is a significant aspect of enabling a secure electricity system. In this section we outline how LMP could affect Scotland's ambitions to achieve this.

4.4.1. Description of Scottish ambitions

The Scottish Government aims to enable a secure and flexible net zero energy system which is not dependent on fossil fuels. As Scotland continues to expand its growing renewable energy capacity, increasing its role as a net exporter of electricity to the rest of the UK, the need to maximise the penetration of renewables will become increasingly important. There are several key factors that can contribute to this. Firstly, the development of energy storage and flexibility. This will enable the efficient use of variable renewable generation. Secondly, investment in grid infrastructure is essential, so that generators are not curtailed to mitigate constraints and electricity can flow where it is needed. Finally, dispatchable low carbon generation, such as hydrogen generation or gas with carbon capture, will be an important component of a secure decarbonised power system during periods of low renewable output. LMP provides a significant opportunity in Scotland for locational price signals to incentivise flexibility, as well as to incentivise efficient dispatch profiles to reduce constraints.

4.4.2. Energy storage and flexibility

The introduction of LMP would incentivise energy storage and flexibility to locate in Scotland due to volatile electricity prices, driven by generation from the high variable renewable capacity in Scotland that at times exceeds demand. Storage and flexibility benefit most when there is greater variation in electricity prices. Under LMP, this will occur in zones where intermittent renewable capacity or peak demand is greatest. Given that Scotland has significant wind capacity, prices will be more volatile than in other regions of GB. FTI find that the standard deviation in electricity prices in N. Scotland in 2025 under LMP would be similar to 2023 national prices, despite average prices being 71% lower. This is greater than in other areas in the country, even those with high demand (e.g. SE England). Such volatility would provide the best environment in the UK for wholesale arbitrage, likely attracting the relocation of battery investment to Scotland. Whilst this opportunity would decrease in magnitude as the transmission network is upgraded between England and Scotland, FTI notes that Scotland would still be among the most attractive locations to locate energy storage within the modelling timeframe to 2040. It should be noted that the implementation of LMP will likely take 4-8 years (National Grid ESO, 2022a), so the opportunity is overestimated when including years that LMP can not actually be realised. Overall, increasing flexibility in Scotland will not only reduce the need for expensive network build, but also improve security of supply.

This view was largely confirmed by the EAP. However, it was raised that the strongest signal to provide certainty for the investment in flexibility in Scotland would be a long-term contract, similar to the Capacity Market. Despite this, the clear signal sent by LMP would be stark in comparison to the weak signals from current locational mechanisms such as TNUoS charges and the Balancing Mechanism.

Furthermore, LMP would introduce locational dispatch signals improving the operational dispatch of flexibility to respond to generation and grid conditions at the node/zone that the flexibility is located. This would improve the efficiency of energy storage and flexibility (including interconnectors). The result of this would be to reduce the flexible capacity requirement and hence the cost of developing a secure and flexible net zero system.

4.4.3. Alignment of investment signals with network upgrades, at correct timescales

LMP provides short-term price signals that identify where the grid is constrained the most, given that it is designed around network bottlenecks. As such, it can be used to identify which zone/node boundaries require network reinforcement. Incentives for generation and demand to relocate should also reduce the need for network reinforcement itself.

However, to build an optimal net zero power system by 2035, rapid transmission build needs to be strategic, and in-line with plans for generation capacity build. This means that network build-out will not always be optimal, but the goal of strategic planning is to deliver electricity to consumers at the lowest cost achievable within the timescale for decarbonisation. This means co-optimising the development of generation, flexibility, and transmission network within these constraints. Such an approach has begun with NGESO proposing the HND, planned around offshore wind seabed leasing, providing more capacity to transport electricity out of Scotland.

Market reforms need to ensure that strategic planning of investment is prioritised. LMP can only send short-term price signals that dictate where network reinforcement is required for the current power system, it does not take into account future developments. Under LMP, this could be achieved through investment mechanisms (e.g. reformed CfDs and the Capacity Market) to ensure generation is developed in locations with a long-term system benefit.

4.4.4. Dispatchable low-carbon generation

Firm dispatchable low-carbon generation is a requirement for a future energy system that relies on variable renewable generation, to ensure security of supply. Dispatchable low-carbon generation is required for longer periods of limited renewable generation, when battery storage is not able to provide power over extended periods of time. This includes gas generation with carbon capture, hydrogen generation, or biomass generation (with carbon capture).

Such generation will be dispatched based on periods of high electricity prices, balancing actions, and Capacity Market instructions. LMP would improve locational signals for this generation, improving the efficiency of dispatch. Therefore, under LMP, dispatchable generation would be incentivised to locate in locations with high renewable generation or where peak demand is greatest. As with flexibility, such conditions would make Scotland an attractive location for dispatchable generation under LMP.

As with renewables, LMP creates additional risks for the investment in low carbon dispatchable generation. In an optimal market, LMP should incentivise investment in low carbon dispatchable generation where it is most required (locations with the highest prices). However, LMP introduces new risks for investors over the certainty of revenue as this will be significantly impacted by when and where network is upgraded. Mechanisms could be implemented alongside LMP to incentivise investment where it is most required while reducing risk for investors e.g. adding a locational element to the Capacity Market. This could be implemented without LMP, but with reduced dispatch efficiency.

4.4.5. Strengths, Weaknesses, Opportunities, Threats

Table 10: Strengths, Weaknesses, Opportunities and Threats for a secure and flexible net zero energy system.

Strengths	Opportunities
• More efficient dispatch signals from the wholesale market under LMP. • High renewable capacity and existing constraints would lead to favourable conditions for flexibility in Scotland under LMP. • Large wind capacity and pipeline in Scotland has led to HND to upgrade network in Scotland.	• Under LMP, Scotland would be among the most attractive locations for flexibility in GB. • Encouraging investment in flexibility would enable increased renewable penetration and improve security of supply. • LMP could provide efficient price signals highlighting locations which require network reinforcement.
Weaknesses	**Threats**
• Loss of firm access rights makes areas behind a constraint (such as Scotland) less attractive for future investment for renewable generation. • In addition to renewable generators, this could provide a level of uncertainty for dispatchable generation.	• Lack of a strategic plan for renewable generation and network build-out could weaken revenue certainty for dispatchable generation in Scotland.

5 Conclusions

5.1 Summary of findings

In this study we have reviewed the literature to understand the potential impacts of electricity market reform in Scotland. Based on the ambitions of the Scottish Government in their Draft Energy Strategy and Just Transition Plan, we have applied these impacts to explore how market reform and LMP could help further or risk these ambitions. The key conclusions of this assessment are summarised in Table 11.

Table 11: Key conclusions on the extent that LMP in electricity market reform could aid the Scottish Government's ambitions in their Draft Energy Strategy and Just Transition Plan.

Ambition	Conclusions
Support the scale up of low-cost renewable energy	**On its own, LMP would create new risks for renewable generators and increase the cost of capital of new developments.** • Existing and continued constraints in Scotland mean that under LMP, greater price and volume risk would be placed on generators, as they lose their firm access rights. This would be exacerbated by any delays to network buildout. • Without support, the renewables pipeline in Scotland could be disrupted, impacting UK power system decarbonisation goals.
Adhere to the principles of a fair and just transition	**LMP could provide Scottish consumers with some of the lowest wholesale prices in Europe.** • Scottish consumers could benefit from the existing high renewable generation in Scotland, significantly reducing electricity bills. • However, the benefits would not be distributed evenly across the UK, with some customers (mostly in the south of England) seeing their bills slightly increase, unless some form of demand shielding occurs. • The relative benefit in wholesale prices compared to the rest of GB will decline to 2040. The largest benefit occurs when networks are most constrained. Considering the time it will take to implement LMP (4-8 years), modelled benefits may be overestimated. • To ensure the wider economic benefits of the energy transition are felt in Scotland, the continued buildout of renewables must be ensured.
Support accelerated decarbonisation	**LMP could reduce the cost of electrification and incentivise power intensive industry and H2 production to locate in Scotland.** • It is unlikely that LMP would significantly increase the pace of power sector decarbonisation (and could slow it down if implementation leads to an investment hiatus).

	• The potential benefit of LMP would be to reduce the cost associated with decarbonisation. • Lower wholesale prices would reduce the cost of electrifying demand and attracting new industry and green hydrogen production to Scotland. • Other non-price factors still act as blockers to wider decarbonisation such as government policy, planning, access to skills etc. • While lower wholesale prices would benefit the electrification of heat and transport, these sectors still face the barriers of high upfront costs for consumers. Support in these areas would also be needed.
Enable a secure and flexible net zero energy system	**LMP is the most effective reform to provide locational signals for flexibility.** • LMP could encourage the efficient location and operation of energy storage and dispatchable generation to help reduce investment for security of supply. • However, strategic oversight to reinforce the network is essential to ensure that Scotland receives the network capacity it needs to maintain a thriving renewables industry.

Overall LMP provides theoretical benefits to consumers of electricity and flexibility in Scotland, reducing wholesale prices and improving dispatch signals. If executed optimally, LMP could reduce the whole system cost associated with decarbonisation. However, LMP only provides short-term market signals and removes firm access rights for generators. Therefore, LMP would be ineffective at providing the long-term investment signals for renewables, which could create risks for the industry in Scotland, nullifying the potential benefits. Nevertheless, if additional market reform, alongside LMP, could protect renewable investment in Scotland, the potential benefits for Scottish consumers of electricity are sufficient to explore such a set of reforms.

5.2 Future market arrangements

In this section, we will explore the arrangement in which LMP could be successfully implemented and two counterfactuals, business-as-usual (BAU) with incremental reform, and LMP without further support. This will illustrate how reform could deliver benefits for consumers while protecting renewable generators.

These have been created based on what we believe possible market arrangements could be. First, business-as-usual arrangement identifies the flaws of continuing as usual. We identify the key reforms that would be required if national pricing is maintained to create a market with more effective locational signals. Second, LMP without supporting measures is described to identify the risk to Scottish renewables this arrangement could have. Finally, we explore LMP with mitigating measures as a final arrangement that we believe has the most potential to be successful.

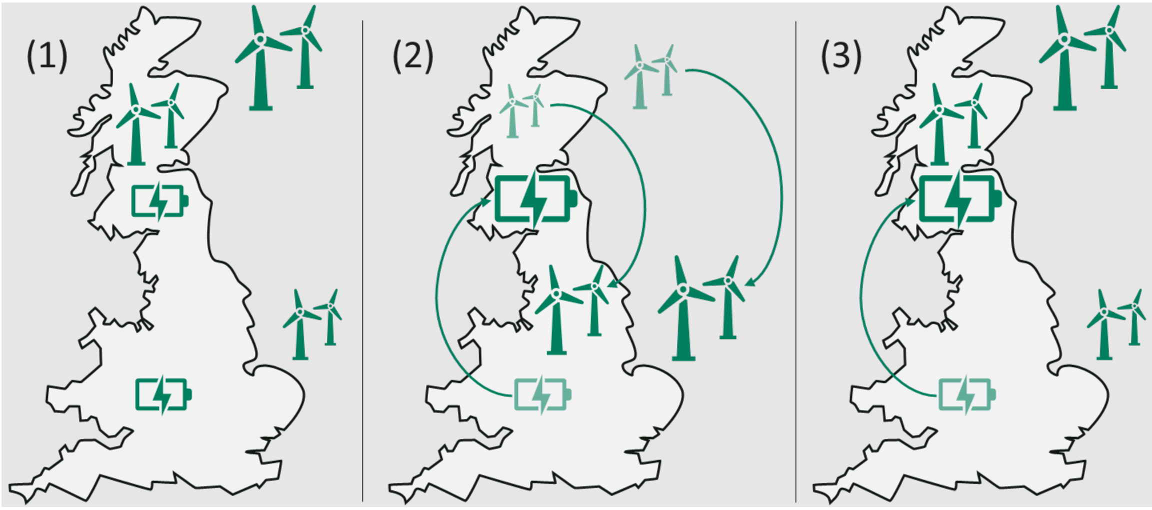

Figure 9: ERM developed illustration of the relocation of renewable capacity and energy storage under (1) business-as-usual [left], (2) LMP without further support [centre], and (3) LMP with support mechanisms to insulate renewables (e.g. CfDs) [right].

Arrangement 1: Business-as-usual with incremental reform

Firm access to the entire GB electricity market will see renewable generators continue to locate in Scotland. Revenues would be secured by CfDs (regardless of exacerbated constraints, but not national curtailment). Without additional reform, TNUoS charges would be the only locational price driver for investment in renewables and flexibility. Although, non-price factors such as planning and renewable resource would also influence the location of renewables. As such, flexibility would not have a significant incentive to locate near renewables or behind import constraints in centres of demand. Local constraint markets could go some way to provide such signals, however, not without risks of its own (complicated market arrangements and perverse interactions of constraint and wholesale markets). Therefore, without reform, a BAU electricity market will not be optimal to encourage efficient investment in generation, flexibility, or networks for power system decarbonisation.

For consumers, the entire country would pay the marginal price of electricity regardless of the local generation mix. Therefore, wholesale prices will remain uniform across GB and would not provide a signal for demand to relocate to take advantage of areas with surplus renewable generation. As such, Scottish demand sectors would not be able to benefit from the renewable resources present in the country.

As indicated by the current REMA consultation, existing BAU electricity market arrangements are not fit for net zero. Regardless of the introduction of LMP, the electricity market will require reforms to enable a decarbonised energy system. Any reforms will create uncertainty so maintaining confidence for investors and consumers will be essential in any next steps. A combination of alternative reforms could achieve some the LMP’s potential benefits. These could include reforms to TNUoS, CfDs, the Balancing Mechanism, as well as developing local constraint markets. These alternatives could see less disruption, as they would be evolutions of existing arrangements. However, they would be unlikely to fully replicate the benefits of a successfully implemented LMP market.

Arrangement 2: LMP without further renewables support

Under LMP, the loss of firm access rights to markets outside of immediate zones/nodes would greatly increase revenue risk to generators located behind export constraints (such as in Scotland). With the additional prospect of low wholesale prices, due to a surplus in renewable generation in Scotland, LMP would create a significant investment risk in Scotland. This could lead to some renewable generation re-locating to other parts of the UK, or investment leaving for other markets entirely. This would pose further risks to whole system decarbonisation, potentially leading to delays in renewable roll-out in the UK as supply chains move from Scotland to other areas. Likely increases in the cost of capital due to elevated risks for generators would also lead to reduced investment in renewables. This alone could wipe out the power system cost-benefit of introducing LMP.

Flexibility would be incentivised to relocate to Scotland under LMP, where volatile locational prices would provide operational profiles that could see flexibility generate the highest revenue across the UK. Furthermore, consumers would be set to benefit in Scotland. Given Scotland is already a net exporter of electricity, LMP would see a reduction in wholesale prices and hence a reduction in retail prices if passed through to consumers. Note that some consumer groups could be shielded from locational variations in wholesale prices.

Nevertheless, despite the potential benefits for consumers, the risk to the renewables industry in Scotland and the wider economic benefits that it brings means that LMP alone will be unable to deliver on the ambitions of the Scottish Government. Further reform would be needed to insulate renewable generators from the adverse effects of LMP on their investment case.

Arrangement 3: LMP with reformed support mechanisms to insulate renewables

LMP can provide strong incentives for the optimal location and dispatch of flexibility and demand as well as offering Scottish consumers the lowest wholesale prices in the UK. The extent to which Scottish demand could benefit from lower wholesale prices will depend on several factors, including potential shielding of demand and long-term effects on the cost of electricity if cost of capital increases materialise. However, in Scotland it leaves an oversupplied generation market with limited case for further investment until the transmission network is reinforced. A thriving Scottish renewables sector is required to meet the UK Government's target of a net zero power system by 2035. Therefore, it is vital that renewables continue to be developed in Scotland ahead of planned network capacity upgrades that enable generation to be transmitted to centres of demand across the UK. Should a support mechanism for investment in renewables be implemented on this basis alongside LMP then such electricity market reforms could deliver for all players in the power system: generators, flexibility, and consumers.

While it is out of the scope of this study to fully consider the design of such a support mechanism, it would likely take the form of a reformed CfD. Already, the current CfD mechanism completely insulates renewable generation from market price to de-risk investment. Under LMP, the further reform that would be required to de-risk renewables would be to insulate renewables from market volume. Essentially, this would protect renewables from the loss of firm access rights under LMP. An example of this reform could be moving to a deemed CfD, however other options should be considered.

The argument for such a reform is that renewable generation is inflexible, with no control over when and how much it generates. Given that vast additional renewable capacity is required to reach net zero, renewable energy should not be penalised based on these limitations. The result of this would put additional onus on the UK Government to consider the long-term system benefits when awarding CfDs based on current and future constraint forecasts and network upgrades. It would also likely increase the cost of CfDs for the UK Government. However, given the rapid pace of decarbonisation required to reach net zero, it could be argued that such additional risk and cost should sit with the UK Government rather than investors. This is because, overall, the mechanism should still provide whole system investment and operational savings, which will be passed down to consumers via electricity bills.

5.3 Conclusions

The authors conclusions are based on the work presented in this report. They form an assessment of the opportunities and threats that LMP and wider electricity market reform poses to the Scottish Government's ambitions as per their Draft Energy Strategy and Just Transition Plan. Based on the findings of this study, the Scottish Government should consider supporting the implementation of LMP alongside a GB-wide strategic plan for renewable and network investment through further electricity market reform. The following conclusions are in order of importance and are sequential:

1. Scotland must prioritise and coordinate a **strategic plan for renewable generation and network reinforcement** with the UK Government.
    - Alone, LMP poses a significant risk for renewable development in Scotland, threatening the green economy in Scotland, the wider economic benefits it may bring, and a net zero power system by 2035.
    - Long-term locational signals to strategically locate investment of renewables are essential to achieve a cost-efficient net zero power system by 2035.
    - Due to its existing renewable pipeline, renewable resources, and existing industry, Scotland should be prioritised as a location for renewable investment and network reinforcement.
    - Introducing support mechanisms, such as a reformed CfD, which protects against revenue and volume risk in the wholesale market, is essential to the successful implementation of LMP to maintain investor confidence in Scottish renewables.
    - Alternatively, improved TNUoS charges, with long-term locational signals, could provide similar locational investment signals in a national market, however without creating the efficient dispatch signals LMP could.

- The Scottish Government has the opportunity to work with the UK Government to implement reform, as the responsibility for these mechanisms lie with the UK Government.

2. LMP would provide the **clearest dispatch signal for flexibility**, delivering efficient investment and operation of flexibility.
    - To maximise renewable penetration, net zero will require clear dispatch signals for flexibility to improve siting and operation. These signals under LMP would incentivise the relocation of flexibility to Scotland.
    - If implemented effectively, these features of LMP should reduce the whole system investment and operational cost associated with decarbonisation, benefiting consumers.
    - Should consumers be exposed to locational prices, Scottish consumers would benefit directly from reduced wholesale prices because of existing renewable generation in Scotland. This would send a clear signal to site new demand in Scotland.
    - A zonal market would enable most of the system benefits of LMP, without the complexity and disruption of implementing a nodal market.
    - However, should LMP be deemed too disruptive, local constraint markets could serve as an alternative dispatch signal for flexibility. However, this is unlikely to be able to replicate the granular benefits of LMP and could result in complex market arrangements with consequences that should be explored in detail before it is recommended as a complete solution to locational dispatch signals.

3. The Scottish Government should account for the **potential benefits of LMP for consumers being greater the earlier it is introduced**.
    - Scottish consumers stand to benefit more from LMP the earlier it is introduced ahead of planned network reinforcement by 2035 and onwards.
    - While the priority must be to have a clear and well communicated plan for the implementation of market reform, the earlier LMP could be implemented, the greater the benefits to Scottish consumers.
    - The first step would need to be the development of reformed support mechanisms and the grandfathering of existing support mechanisms which protect both existing and developing renewable generation.
    - If alternative market reforms are pursued, a similar approach to prioritising confidence in renewables should be adopted.

4. Locational market reform would need to be **carefully implemented as it would inevitably create winners and losers**.
    - While Scottish consumers could be a key winner of LMP, the Scottish Government would have to consider how the rest of GB may be impacted.
    - Support to protect the future Scottish renewables industry is essential to deliver net zero, while ensuring that the industry remains in Scotland and jobs are realised.

- Future renewables support, also including the grandfathering of current arrangements, should be designed, communicated and implemented ahead of a transition to LMP.
- Zonal pricing could help to remove the most extreme regional inequalities from LMP under a nodal market, reducing the risk of LMP to a just transition.

5.4 Next steps

Based on our conclusions, we suggest the Scottish Government takes the following next steps to fully explore whether LMP could be implemented with the appropriate support mechanisms to provide benefits to generation and demand across the whole system:

- Work with the UK Government to develop a long-term strategic plan, such as the SSEP, to achieve a decarbonised power system by 2035 and net zero by 2050. This includes the planning of a cost-effective level of network infrastructure investment, renewables development, and short- and long-duration storage. This would improve the penetration of renewables, reduce constraints, and lead to whole system savings.
- Fully explore the risks and opportunities of reforming CfDs to insulate renewables against price risk and volume risk, and the suitability of implementing such a support mechanism alongside LMP.
- Develop wider support mechanisms to support the benefits of LMP in Scotland, such as new demand sectors, to ensure that Scotland can take full advantage of electricity market reform.
- LMP will take 4-8 years to implement if selected, Scotland should support alternative reforms in the interim to encourage the early development of locational benefits ahead of LMP (e.g. extending the NGESO Local Constraint Market in Scotland).

Scotland has a significant opportunity to benefit from a decarbonised power system by taking advantage of its renewable resources and distributing those benefits to consumers in a decarbonised economy. Proposed changes to wholesale electricity markets could improve system-wide efficiency and offer cheaper electricity in Scotland. However, it could increase risk associated with investment in Scottish renewables, increasing costs. The Scottish Government needs to engage carefully with the electricity market reform process to ensure that prospective benefits are realised, and that potential disbenefits are avoided or mitigated.

6 References

AFRY (2023) *Review of electricity market design in Great Britain*. Available at: https://afry.com/sites/default/files/2023-12/gb_electricitymarketdesign_phase2_publicsummaryreport_v500.pdf

Aurora (2023) *Locational marginal pricing in Great Britain*. Available at: https://auroraer.com/wp-content/uploads/2023/09/Locational-Marginal-Pricing-GB-Aurora-Public-Report.pdf

Baringa (2023) *Net Zero Market Reform - Phase 4*. Available at: https://www.nationalgrideso.com/document/276841/download

Carbon Tracker (2023) *Gone with the Wind? Grid congestion and wind integration in GB*. Available at: https://carbontracker.org/reports/gone-with-the-wind/

Citizens Advice (2023) *It's all about location: Will changing the way we price electricity deliver for consumers?*. Available at: https://assets.ctfassets.net/mfz4nbgura3g/2esOmp5ZjvBnxChIV7sjd4/8d1a042a8c1e406b189a2491144b9e01/For_20publication_20-_20It_s_20all_20about_20location.pdf

ClimateXChange (2022) *Expanding Scottish energy data – heat.* Available at: https://www.climatexchange.org.uk/media/5157/cxc-expanding-scottish-energy-data-heat-february-22.pdf

Department for Business, Energy & Industrial Strategy (2021) *Hydrogen Production Costs 2021.* Available at: https://assets.publishing.service.gov.uk/media/611b710e8fa8f53dc994e59d/Hydrogen_Production_Costs_2021.pdf

Department for Energy Security and Net Zero (2023a) *Energy and emissions projections: 2022 to 2040.* Available at: https://www.gov.uk/government/publications/energy-and-emissions-projections-2022-to-2040

Department for Energy Security and Net Zero (2023b) *Electricity generation costs 2023.* Available at: https://www.gov.uk/government/publications/electricity-generation-costs-2023

Department for Energy Security and Net Zero (2023c) *Average annual domestic electricity bills by countries in the United Kingdom.* Available at: https://www.gov.uk/government/statistical-data-sets/annual-domestic-energy-price-statistics

Department for Energy Security and Net Zero (2023d) *Regional Statistics 2009-2022: Standard Load Factors.* Available at: https://www.gov.uk/government/statistics/regional-renewable-statistics

Department for Energy Security and Net Zero (2023e) *ECUK 2023: Primary energy consumption data tables.* Available at: https://www.gov.uk/government/statistics/energy-consumption-in-the-uk-2023

Element Energy (an ERM Company) (2021) *Decarbonising the Scottish Transport Sector.* Available at: https://www.transport.gov.scot/media/50354/decarbonising-the-scottish-transport-sector-summary-report-september-2021.pdf

Element Energy (an ERM Company) (2022) *TCO and tax scenarios for passenger cars in the UK.*

Energy UK (2023) *Energy UK high-level views on Locational Marginal Pricing.* Available at: https://www.energy-uk.org.uk/publications/energy-uk-high-level-views-on-locational-marginal-pricing/

ES Catapult (2021) *Introducing nodal pricing to the GB power market to drive innovation for consumers' benefit: Why now and how?* Available at: https://es.catapult.org.uk/report/locational-energy-pricing-in-the-gb-power-market/

ES Catapult (2021) *Locational Energy Pricing in the GB Power Market.* Available at: https://es.catapult.org.uk/report/locational-energy-pricing-in-the-gb-power-market/

ES Catapult (2022) *Informing the REMA debate. International Learnings on Investment Support for Clean Electricity*. Available at: https://es.catapult.org.uk/report/rema-international-learnings-on-investment-support-for-clean-electricity/

ES Catapult (2022) *Location, Location, Location. Reforming wholesale electricity markets to meet Net-Zero*. Available at: https://es.catapult.org.uk/report/location-location-location-reforming-wholesale-electricity-markets-to-meet-net-zero/

Fraser of Allander Institute (2023) *The Economic Impact of Scotland's Renewable Energy Sector – 2023 Update*. Available at: https://fraserofallander.org/wp-content/uploads/2023/12/FINAL-The-Economic-Impact-of-Scotlands-Renewable-Energy-Sector-1.pdf

Frontier Economics (2022) *Locational marginal pricing – Implications for cost of capital*. Available at: https://www.frontier-economics.com/uk/en/news-and-insights/news/news-article-i20310-locational-marginal-pricing-implications-for-the-cost-of-capital/#

Frontier Economics (2023) *The benefits of locational marginal pricing in the GB electricity system – A review of FTI's assessment of the benefits.* Available at: https://www.frontier-economics.com/uk/en/news-and-insights/news/news-article-i20234-locational-marginal-pricing-assessing-the-benefits/

FTI Consulting (2023) *Locational pricing assessment in GB: Final modelling results*. Available at: https://www.ofgem.gov.uk/sites/default/files/2023-

10/Key%20findings%20from%20FTI%20Consulting%20presentation%20June%202023%20.pdf

FTI Consulting (2022) *Net Zero Market Reform: Phase 3. Assessment of market design options.* Available at: https://www.nationalgrideso.com/document/258876/download

Gill et al. (2023) *Exploring market change in the GB electricity system: the potential impact of Locational Marginal Pricing.* Available at: https://pureportal.strath.ac.uk/en/publications/exploring-market-change-in-the-gb-electricity-system-the-potentia-2

Gill, S. (2023) *Review of Electricity Market Arrangements: A Vision for Scotland.* Available at: https://www.scottishfuturestrust.org.uk/publications/documents/sft-rema-report-a-vision-for-scotland-november-2023

H2Green Steel (2023) *Questions and answers about our establishment in Boden*. Available at: https://www.h2greensteel.com/questions-and-answers-about-our-establishment-in-boden#:~:text=We%20chose%20to%20locate%20our,the%20region%20%E2%80%93%20an%20ideal%20environment

ICCT (2023) *A total cost of ownership comparison of truck decarbonisation pathways in Europe*. Available at: https://theicct.org/publication/total-cost-ownership-trucks-europe-nov23/

MacIver et al. (2023) *Exploring market change in the GB electricity system: the potential impact of Locational Marginal Pricing – stakeholder insight report.* Available at: https://pureportal.strath.ac.uk/en/publications/exploring-market-change-in-the-gb-electricity-system-the-potentia

McQueen et al. (2021) *A review of direct air capture (DAC): scaling up commercial technologies and innovating for the future.* Available at: https://iopscience.iop.org/article/10.1088/2516-1083/abf1ce/pdf

National Grid (2023) *We're engaging on our early pans to transform our network for net zero.* Available at: https://www.nationalgrid.com/electricity-transmission/were-engaging-our-early-plans-transform-our-network-net-zero

National Grid ESO (2022a) *Net Zero Market Reform: Phase 3 Assessment and Conclusions.* Available at: https://www.nationalgrideso.com/document/258871/download

National Grid ESO (2022b) *Network Options Assessment 2021/22 Refresh.* Available at: https://www.nationalgrideso.com/document/262981/download

National Grid ESO (2023a) *Monthly Balancing Services Summary.* Available at: https://www.nationalgrideso.com/data-portal/mbss

National Grid ESO (2023b) *Markets Roadmap.* Available at: https://www.nationalgrideso.com/document/278306/download

National Grid ESO (2023c) *Future Energy Scenarios 2023 Data Workbook.* Available at: https://www.nationalgrideso.com/future-energy/future-energy-scenarios-fes

National Grid ESO (2023d) *NZMR Phase 4 Webinar Q&A*. Available at: https://www.nationalgrideso.com/document/283516/download

National Grid ESO (2023e) *Monthly Balancing Services Summary (MBSS) Mar-2023.* Available at: https://www.nationalgrideso.com/data-portal/mbss

OEUK (2022) *Workforce Insight 2022+.* Available at: https://oeuk.org.uk/wp-content/uploads/2022/11/OEUK-Workforce-Insight-2022.pdf

Office for Budget Responsibility (2024) *Economic and fiscal outlook – March 2024.* Available at: https://obr.uk/efo/economic-and-fiscal-outlook-march-2024/

Office for National Statistics (2024) *Consumer price inflation time series (MM23).* Available at: https://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/d7bt/mm23

Offshore Wind Scotland (2023) *Offshore Wind Market in Scotland.* Available at: https://www.offshorewindscotland.org.uk/the-offshore-wind-market-in-scotland/

Ofgem (2014) *Electricity Interconnectors factsheet.* Available at: https://www.ofgem.gov.uk/sites/default/files/docs/2014/05/electricity_interconnectors_factsheet.pdf

Ofgem (2023) *Assessment of Locational Wholesale Pricing for GB*. Available at: https://www.ofgem.gov.uk/sites/default/files/2023-10/Ofgem%20Report%20-%20Assessment%20of%20Locational%20Pricing%20in%20GB%20%28final%29.pdf

Ofgem (2024) *Breakdown of an electricity bill.* Available at: https://www.ofgem.gov.uk/energy-data-and-research/data-portal/all-available-charts?keyword=bills&fuel_type=1606&sort=relevance

Pollitt, M. (2023) *Locational Marginal Prices (LMPs) for Electricity in Europe? The Untold Story.* Available at: https://www.eprg.group.cam.ac.uk/wp-content/uploads/2023/07/text-2318-revised-180723.pdf

Rai et al. (2021) *Financing costs and barriers to entry in Australia's electricity market.* Available at: https://www.researchgate.net/publication/350358213_Financing_costs_and_barriers_to_entry_in_Australia's_electricity_market

Regen (2023a) *Call for evidence on introducing non-price factors into the Contracts for Difference scheme.* Available at: https://www.regen.co.uk/wp-content/uploads/CfE-non-price-factors-CfD-Regen-response.pdf

Regen (2023b) *Improving locational signals in the GB electricity markets.* Available at: https://www.regen.co.uk/insight-paper-improving-locational-signals-in-the-gb-electricity-market/

Scottish Government (2021) *Heat in Buildings Strategy.* Available at: https://www.gov.scot/publications/heat-buildings-strategy-achieving-net-zero-emissions-scotlands-buildings/documents/

Scottish Government (2022) *Hydrogen Action Plan.* Available at: https://www.gov.scot/publications/hydrogen-action-plan/

Scottish Government (2023a) *Scottish Energy Statistics HubEnergy Statistics for Scotland - Q2 2023.* Available at: https://scotland.shinyapps.io/sg-scottish-energy-statistics/?Section=RenLowCarbon&Subsection=RenElec&Chart=RenElecPipeline https://www.gov.scot/publications/energy-statistics-for-scotland-q2-2023/pages/renewable-electricity-capacity/

Scottish Government (2023b) *Just Transition: Grangemouth.* Available at: https://www.gov.scot/binaries/content/documents/govscot/publications/strategy-plan/2023/09/discussion-paper-transition-grangemouth-industrial-cluster/documents/discussion-paper-transition-grangemouth-industrial-cluster/discussion-paper-transition-grangemouth-industrial-cluster/govscot%3Adocument/discussion-paper-transition-grangemouth-industrial-cluster.pdf

Scottish Government (2023c) *Draft Energy Strategy and Just Transition Plan.* Available at: https://www.gov.scot/publications/draft-energy-strategy-transition-plan/documents/

The Crown Estate (2023) *The Crown Estate Offshore Wind Leasing Round 4 Selected Projects.* Available at: https://www.thecrownestate.co.uk/media/3721/the-crown-estate-offshore-wind-leasing-round-4-selected-projects.pdf

Transport Scotland (2020) *National Transport Strategy 2.* Available at: https://www.transport.gov.scot/publication/national-transport-strategy-2/

climate change

Scotland's centre of expertise connecting climate change research and policy

info@climatexchange.org.uk
+44 (0) 131 651 4783
@climatexchange_
www.climatexchange.org.uk

ClimateXChange, Edinburgh Climate Change Institute, High School Yards, Edinburgh EH1 1LZ

If you require the report in an alternative format such as a Word document, please contact info@climatexchange.org.uk or 0131 651 4783.