Review of electricity market design in Great Britain

Phase 2 Report – Public Summary

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1 Key Messages

1. Evolutionary change is advised to maintain investment momentum

The first phase of our work concluded that although change is required in GB electricity market arrangements, an evolutionary rather than a revolutionary approach is advisory in order to maintain investment momentum in the Net Zero Transition.

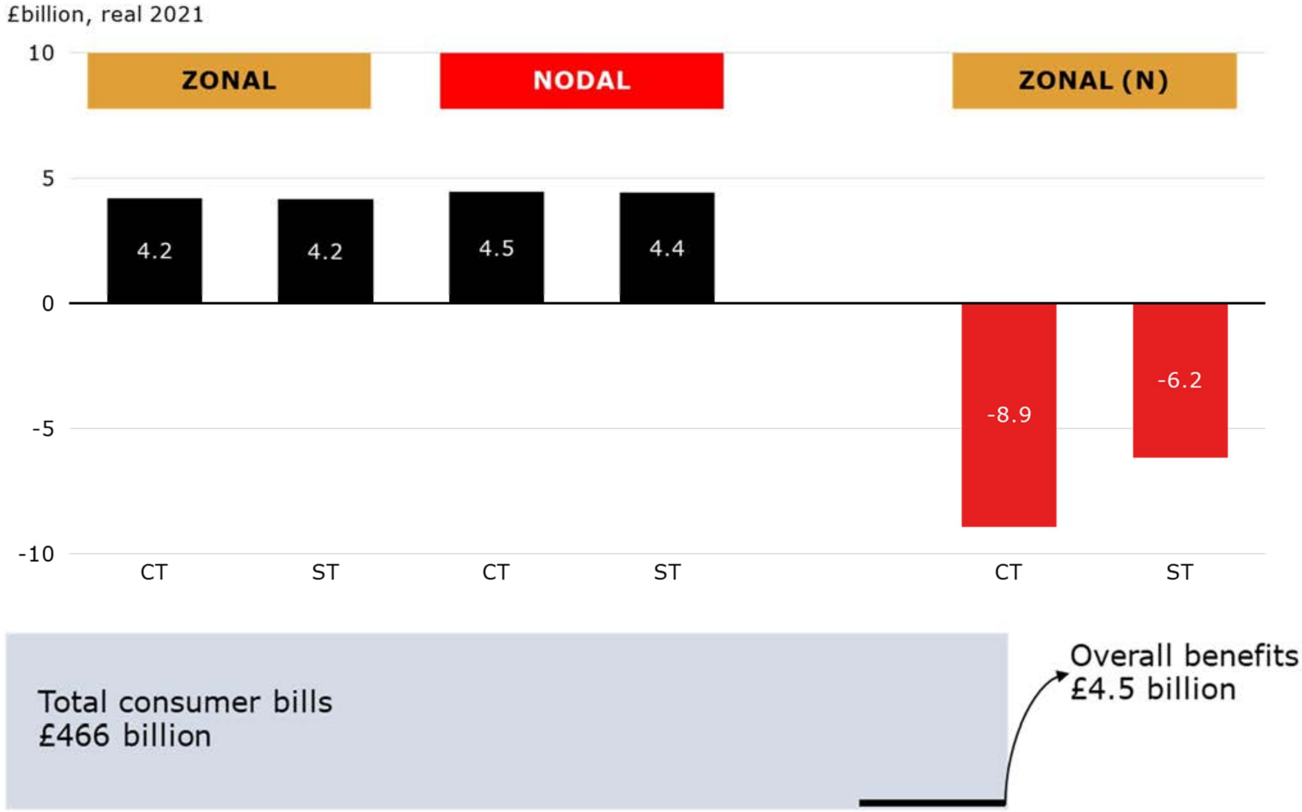
In this second phase of our work, we find that there are some merits of moving to a locational energy market. However, the potential benefits of a significant change to market design are fraught with risks to investment, making risk management the central challenge. Maintaining a national energy market poses fewer risks to investment, with maximising operational efficiency the central challenge. Given the current need for investment in the near term, any implementation of locational markets would need to be accompanied by a very robust risk management framework, which could in turn reduce the benefits from increased locational signals.

2. There is only a small economic welfare benefit of changing to a locational energy market

In this second phase of our work, we modelled alternative locational market arrangements, against two decarbonisation scenarios (Consumer Transformation and System Transformation from the NGESO's Future Energy Scenarios). We find that adopting our Zonal market case could achieve a small overall economic welfare benefit relative to current arrangements of £4.2 billion (NPV 2028-2050, 3.5% discount rate), while the Nodal case could achieve a further benefit of between £0.2 billion and £0.3 billion. If achieved, this would represent a saving of around 1% against consumer bills over the same period (£4.5 billion versus £466 billion, or £4.4 billion versus £397 billion, in the Consumer Transformation and System Transformation scenarios respectively, excluding costs of implementation). Any move to a locational market runs the risk that the small overall welfare gains are overshadowed by the scale of wealth transfers between parties and the myriad of other uncertainties between now and 2035.

The Exhibit shows that the economic benefits of locational markets are small in absolute and relative terms, and (as detailed in Key Message 6 below) could become negative under alternative assumptions about the risks to investors.

Total economic welfare benefit, Zonal and Nodal cases versus National BAU by scenario, and compared with consumer bills (Net Present Value 2028 to 2050, £billion real 2021)



Notes: All figures are based on Net Present Value over the period 2028 to 2050, with a 3.5% discount rate.
Zonal (N) = the Zonal case with a +100bps hurdle rate increase for CfD-supported new-build renewable capacity, to reflect the addition of basis risk between national and zonal prices
CT = Consumer Transformation, ST = System Transformation, both based on NGESO's Future Energy Scenarios 2022.

3. Locational markets give better dispatch incentives, particularly for interconnection

The challenge ESO faces in redispatch is well documented. In particular, the integration of interconnection to the market is currently poor, with some interconnectors not flexible after the day-ahead schedule. Locational markets can provide operational efficiency benefits compared with a national market.

4. Locational markets might not strengthen locational investment signals compared to current national market arrangements

For investment, we find that for many technologies, locational signals under a zonal or nodal market design may be stronger in 2030 but weaker by 2035. Longer term, and contrary to conventional wisdom, today's national market with locational transmission network charging would provide a stronger and more robust locational investment signal. Note this is under the assumption that where the level of congestion justifies it, reinforcements can be built in a timely matter. At any location, hedging and risk management options may not be available for the production profile or duration needed to support investment.

5. Risks to investor confidence are larger in a locational market

Our investment methodology assumes perfect foresight and therefore does not truly reflect the uncertainties investors face. We have run a sensitivity test assuming an unanticipated delay to grid build, which reduces economic welfare overall under all market designs. In terms of total economic welfare, locational markets are more resilient to transmission delays. However, the cost of delays would be unevenly felt – with winners and losers depending on location. The impact of delayed grid build is severely negative for generators who end up being held behind an export constraint for longer, with the risk of some generators going out of business because they happen to be in the wrong place. This effect is especially harsh if generation investments proceed in expectation of grid build which does not materialise. We have not modelled any secondary impacts to overall welfare changes or consequential transfers between consumers and producers that might need to follow in managing such an infrastructure shock.

6. The potential economic welfare benefits of changing to locational energy markets disappear if investment risk in generation increases

The small positive benefits in the base Zonal and Nodal cases were achieved assuming no increase in the cost of capital for renewable and nuclear generators (renewables are assumed to have 15-year CfD contracts). The cost of capital was assumed to increase by 50 to 100 bps for other new generation. We have found that modest increases in the cost of capital for new renewable generation of +52 bps in Consumer Transformation, and +56 bps in System Transformation would eliminate all welfare benefits in each of the respective scenarios before any consideration of implementation costs.

7. The increased complexity of locational markets may create barriers to entry

The complexity of the energy market will increase with the number of locations, creating additional challenges for predictability and decision making. Exposure to unforeseen events would increase for generators in a locational market, with an associated cost in time and resources devoted to understanding and managing them. Furthermore, the number of active market participants is likely to decrease if the market is segmented into locations. Fewer buyers and sellers could have an adverse impact on market liquidity. For smaller or less sophisticated developers, the complexity and cost of working out if a location is a good one in a locational market may be a significant barrier to entry.

8. With simple changes to locational grid charges, we were able to replicate some but not all of the benefits of locational markets

Great Britain already has locational incentives. We have explored ways of enhancing these locational incentives, to avoid the disruption of moving to a locational energy market. We were able to replicate most of the locational investment signals by modelling simple changes to locational grid charges within an enhanced national market framework. However, this approach would not provide the operational efficiency benefits of an 11-zone zonal market. We believe tariff reform would result in less risk to investment and be easier to implement than changing to locational markets. The addition of time-of-use transmission tariffs and reformed network charges for interconnectors would be likely to bring further operational efficiency benefits within an enhanced national market, but were not modelled as part of this study.

9. The window for reform to support the transition to a net zero power sector by 2035 is limited

Locational markets are being considered as part of an electricity market reform programme to achieve a fully decarbonised power system by 2035. We assume the very earliest a locational market could be implemented is 2028. This leaves a short window of seven years or less where a change to a locational market could potentially support net zero power system goals.

Our recommendations reflect the difficulty of changing market arrangements during a period of required investment

We recommend – based on the evidence available to us – that:

- Nodal pricing should not be progressed further. The practical aspects of centrally dispatching a set of decentralised resources under within-day uncertainty would need to be addressed. AFRY considers that it is – at best – unproven whether such a market design would be workable in the context of a decarbonised system, with heavy reliance on decentralised resources for system balancing, or whether such a design is deliverable in a timeframe which supports the 2035 investment challenge. The trade-off between the additional welfare benefit we have modelled and the increased complexity of the market arrangements appears unfavourable.
- Any further exploration of a zonal market design should be accompanied by a programme of work to explore ways in which the risks – and wealth transfers – could be mitigated. More evidence is needed on the implications of locational markets for cost of capital. Such a programme of work may have its own delivery challenges and create a period of uncertainty for investment.
- If the existing national market is retained, effort is required to provide more targeted investment and operational dispatch incentives, particularly for interconnectors and for resources behind transmission constraints. Further work should also be undertaken to improve stability, incentives, and information flows under the existing national market design.

2 Executive Summary

The electricity market arrangements in Great Britain are under review as we aim for delivery of a net zero power system by 2035. There is a strong case for change from existing market arrangements, but significant debate over the nature and extent of that change.

One of the most divisive topics is whether the current national wholesale energy market should be subdivided into zones or nodes, in which energy wholesale prices would vary by location. This change would result in a locational energy market.

AFRY has conducted a two-part study on the market reform programme. The first phase of our work concluded that although change is required, an evolutionary rather than a revolutionary approach is advisory in order to maintain investment momentum.

Irrespective of the locational market design, we advocate the use of a 'deemed generation' CfD as the basis for support for future renewable projects. We also recommend a more targeted capacity support mechanism to deliver investment in forms of generation and long duration storage which are consistent with a net zero power system.

There is only a small economic welfare benefit from changing to a locational energy market

In this second phase of our work, we modelled alternative locational market arrangements, against two decarbonisation scenarios (Consumer Transformation and System Transformation from the NGESO's Future Energy Scenarios).

We find that adopting our Zonal market case could achieve a small overall economic welfare benefit relative to current arrangements of £4.2 billion (NPV 2028-2050, 3.5% discount rate), while the Nodal case could achieve a further benefit of between £0.2 billion and £0.3 billion. As illustrated in Exhibit 2.1, if achieved this would represent a saving of around 1% against consumer bills over the same period (£4.5 billion versus £466 billion, or £4.4 billion versus £397 billion, in the Consumer Transformation and System Transformation scenarios respectively, based on the Nodal case excluding costs of implementation). Any move to a locational market runs the risk that the small overall welfare gains are overshadowed by the scale of wealth transfers between parties.

Exhibit 2.1 – Total economic welfare benefit compared with consumer bills (Net Present Value 2028-2050, £billion real 2021)

Notes: All figures are based on Net Present Value over the period 2028 to 2050, with a 3.5% discount rate. The comparison shown is based on the Nodal case in the Consumer Transformation scenario.

The potential economic welfare benefits of locational energy markets are very sensitive to changes in cost of capital

The small positive benefits in the Zonal and Nodal cases come at a price: market participants face risks and exposure to circumstances outside their control which cannot readily be hedged. These risks could materially increase the cost of capital for new projects, more than wiping out any welfare gains associated with a locational market.

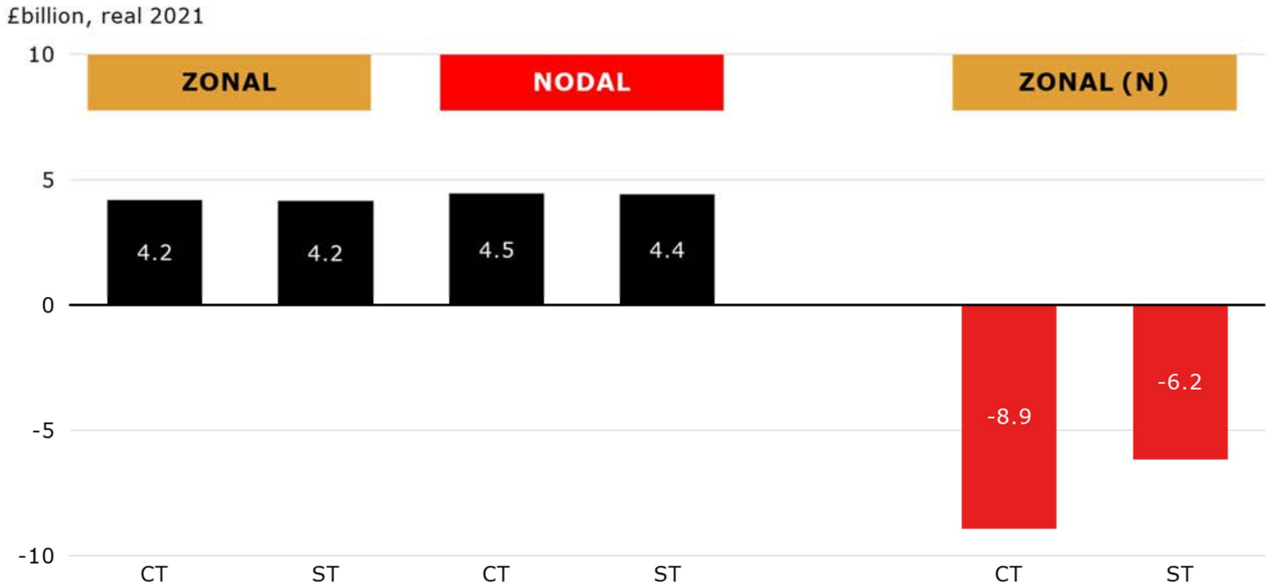
The benefits in the base Zonal and Nodal cases were achieved assuming increased levels of cost of capital for some generators (+100 bps for non-CfD supported capacity, +50 bps if OCGT capacity) but no increase for new renewable capacity (all of which is assumed to have 15-year CfD contract). This has been done in a partial way; we have not assumed any cost to existing capacity.

However, a variant on the Zonal case (Zonal (N)) in which CfD-supported capacity was also exposed to the basis risk between national and zonal prices[1] with a 1% increase in hurdle rate assumed, showed (after the generation mix had been re-optimised for both capacity type and location) a relatively large disbenefit (between -£6.2 billion and -£8.9 billion).

Total economic welfare benefits achieved in the Zonal and Nodal cases against an appropriate scenario-specific baseline are summarised in Exhibit 2.2.

[1] More specifically, in this scenario CfD supported capacity is exposed to the (hourly) spreads between the zonal price and a national weighted average price.

Exhibit 2.2 – Total economic welfare benefit, Zonal and Nodal cases versus National BAU by scenario (Net Present Value, £billion real 2021)



Notes: All figures are based on Net Present Value over the period 2028 to 2050, with a 3.5% discount rate.
Zonal (N) = the Zonal case with a +100bps hurdle rate increase for CfD-supported new-build renewable capacity to reflect the addition of basis risk between national and zonal prices.
Total economic welfare benefits shown are based on the differences between welfare in the scenario-specific case, versus the scenario specific National BAU baseline.
CT = Consumer Transformation, ST = System Transformation, both based on NGESO's Future Energy Scenarios 2022.

In addition, we have found that limited further increases in cost of capital over those already within the base Zonal cases would eliminate all welfare benefit relative to the National BAU baselines in each of the respective scenarios, as illustrated in Exhibit 2.3.

We have found that modest increases in cost of capital for new renewable capacity supported with a 15-year CfD contract duration (which we assume for all renewable capacity in all cases) would eliminate all welfare benefit in each of the respective scenarios (+52 bps in Consumer Transformation, +56 bps in System Transformation).

The replacement of the Renewables Obligation with the current CfD arrangements during the previous Electricity Market Reform programme removed some of the revenue volatility from around 50% of supported renewable plant revenues, and this was assumed to result in hurdle rate reductions of 120 bps for onshore wind and 100 bps for large-scale solar. Locational prices would increase the risk in the merchant tail. While the merchant tail would typically be discounted compared to the initial CfD period[2], it can still have a very material effect on project returns. Within the merchant tail itself, the additional risk depends on the view of the risks associated with locational prices and how these compare to risks also present in a national market, such as commodity prices, economic/political factors

[2] For example, with a 35-year asset lifetime and a 6% hurdle rate, assuming flat revenues years 16-35 would represent half the value of years 1-15, on a discounted basis.

and technology cost evolution, as well as the reduced risk of not being exposed to wider TNUoS tariffs. When surveying study members on the relative risks, they had a variety of views on these.

Exhibit 2.3 – Combinations of hurdle rate increases in the Zonal case that eliminate all economic welfare benefit relative to National BAU

	CfD capacity	OCGT capacity	Other non-OCGT capacity
CONSUMER TRANSFORMATION	+0.25%	+0.60%	+1.20%
	+0.50%	+0.04%	+0.08%
	+0.52%	+0.00%	+0.00%

	CfD capacity	OCGT capacity	Other non-OCGT capacity
SYSTEM TRANSFORMATION	+0.25%	+1.00%	+2.00%
	+0.50%	+0.18%	+0.36%
	+0.56%	+0.00%	+0.00%

Notes: +1% = +100 bps. The increases shown are over and above the increases that are already present in the Zonal case relative to National BAU i.e. +0% for CfD capacity; +0.5% for OCGT capacity and +1% for other non-OCGT capacity. Total hurdle rate increases relative to National BAU to eliminate all economic benefit would then be e.g. CfD capacity: +0.52%, OCGT capacity +0.5%, other non-OCGT capacity +1%.

Locational markets might not strengthen locational investment signals compared to current national market arrangements

Great Britain already has locational incentives in the form of transmission charges and locational transmission losses. The economics of location are pervasive: the introduction of a locational energy market would at least require changes to grid charges, and to future renewable support arrangements (including the contract award mechanism). In a locational market, we would also need to consider awarding grandfathered rights for existing projects.

Locational energy markets can provide more targeted incentives than grid charges, yielding potential economic benefits in both investment and efficiency of operation.

As one of the main objectives of locational energy markets is to provide signals for generation and demand to locate optimally, we have examined the variation in locational strength that could result in a move from a national to a locational market. A stronger or sharper locational signal is defined as one that provides larger incentives for generation to locate closer to demand (typically meaning further south), or alternatively for demand to locate nearer generation (to the extent demand is moveable, such as electrolysis when there is a hydrogen network).

As the existing National BAU market already has a significant locational signal in the form of locational grid charges, which we expect would be removed in locational energy markets, the effect of both locational energy prices and the removal of locational grid charges was considered. We have examined a metric based on wholesale energy market gross margins to compare changes in overall locational signal between cases.

We find that for many technologies including onshore wind, offshore wind and gas plants (with CCS), locational signals under a zonal or nodal market design are sharper until 2030 but weaker by 2035. Longer term, and contrary to conventional wisdom, today's national market with locational transmission network charging would provide a stronger signal. This reflects our assumption that network congestion will reduce over time as network build is progressed. We note this would require an acceleration in the level of grid build historically achieved, but this is consistent with the net-zero goal by 2035.

Solar PV has weaker locational signals in a zonal market even in 2030[3], due to locational signals in a zonal market correlating with wind generation rather than solar generation.

For hydrogen technologies (hydrogen CCGTs, hydrogen GTs and electrolysis), the locational signal based on energy market revenues and grid charges is obscured by other locational drivers such as the presence of hydrogen clusters and how interconnected these are, whether long-duration hydrogen storage is present in a location, and the influence of these factors on hydrogen prices. In a future with more coupling of the power sector to other sectors such as hydrogen, a whole energy system approach is required, as electricity market design alone will not be sufficient to achieve efficient locational outcomes.

Exhibit 2.4 summarises the locational signal strengths by technology in the National BAU and Zonal cases. The patterns shown were quite consistent for both the Consumer Transformation and System Transformations scenarios, so a composite score across both scenarios is shown.

[3] This could be seen as an advantage to a locational market – it models network sharing and different effects on different types of generators more naturally than TNUoS, which is based on a set of rules; however, simple rules plus just two charging backgrounds can only get so far, though there is scope for further reform of TNUoS.

Exhibit 2.4 – Locational signal strength by technology based on energy market gross margin less locational grid charges – National BAU and Zonal cases

		2030	2035	2040	2050
Onshore wind	Zonal	●●●	●●	●●	●●
	National BAU	●●	●●●	●●●	●●●
Solar PV	Zonal	●	●	●	●
	National BAU	●●●	●●●	●●●	●●●
Offshore wind	Zonal	●●●	●●	●●	●●
	National BAU	●●	●●●	●●●	●●●
Gas CCS	Zonal	●●●	●●	●●	●●
	National BAU	●●●	●●●	●●●	●●●
Batteries	Zonal	●◐	●◐	●◐	●◐
	National BAU	●	●	●	●

Notes: A larger number of balls indicates a stronger signal between cases for that technology. Scores are a qualitative composite over both the Consumer Transformation and System Transformation scenarios. Offshore wind is shown in grey due to its more limited capacity to move location, although some locational optimisation between lease areas correlating with the change in signal was still observed. A half circle indicates half the additional signal strength of a full circle.

In our National BAU case we found no additional economic build of onshore wind in northern England or Scotland would occur by 2050. In contrast, the locational cases (which showed small improvements in overall economic welfare) did have economic build. The implication of this is that from 2035, the existing TNUoS arrangements provide a signal that is too strong for some technologies. Given the other economic[4] benefits that generation in more remote regions may be able to provide, the current regime may result in sub-optimal investment patterns.

Locational markets give better dynamic dispatch incentives, particularly for interconnection

The integration of interconnection to the market is currently poor, with some interconnectors not flexible after the day-ahead schedule. The challenge ESO faces in redispatch is well documented. The Zonal and Nodal cases both showed an increase in net interconnector imports into the south of the country, and an increase in net exports from Scotland, consistent with avoiding the need to turn southern thermal generation up and wind in Scotland down to resolve transmission constraints in the National BAU case. The additional improvement in the Nodal case relative to the Zonal case is small.

We have also found that in overall economic welfare terms, locational markets have the potential to be more resilient to unanticipated shocks in

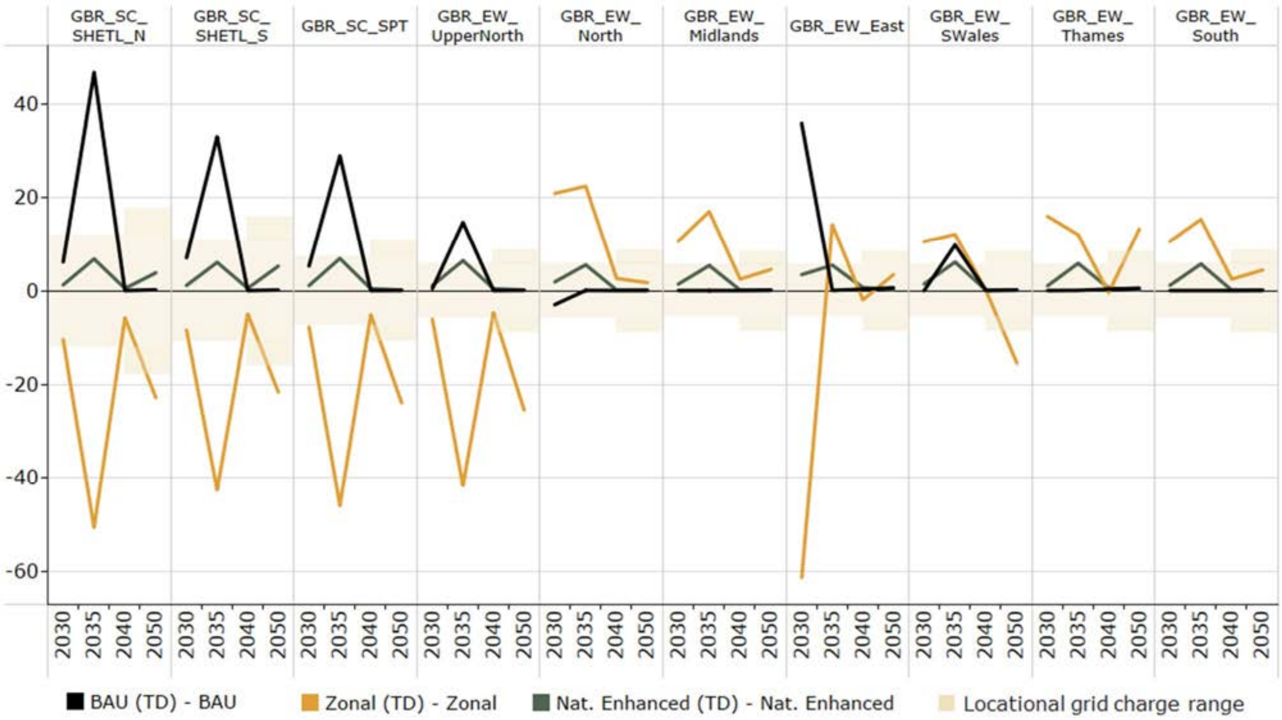
[4] These benefits include increased diversity of generation build, both within Great Britain and with respect to distance from wind sources in other interconnected markets. Northern Scotland also has some of the highest wind speeds in Great Britain.

infrastructure delivery (e.g. a 5-year delay in transmission reinforcement); greater operational efficiency enables the reduction in welfare that results to be managed better in a Zonal rather than a National market. However, the distributional impacts of transmission delay in the Zonal case are much worse for producers than in the National case, and the likely increases in producer risk premium in such a scenario would limit how much of this potential benefit from operational efficiency could be realised in practice. Conversely, one way of limiting risks in a zonal market is to provide confidence that reinforcements would be built where justified by price spreads and/or an economic welfare assessment. Particularly in the short term, any decisions around grandfathering of rights for existing assets will also impact distribution.

Risks to investor confidence are larger in a locational market

On allocation of cost, risk and reward, we find that locational markets have the potential to cause large risks to unhedged generators (including existing generators that are unhedged after any long-term support contract ends). We have run a sensitivity assuming an unanticipated delay to grid build. Exhibit 2.5 shows that in a zonal market, the impact of delayed grid build is severely negative for generators who end up being held behind an export constraint for longer, with the risk of some generators going out of business because they happen to be in the wrong place. This effect is especially harsh if generation investments proceed in expectation of grid build which does not materialise. We have not modelled any secondary impacts to overall welfare changes or consequential transfers between consumers and producers that might need to follow in managing such an infrastructure shock.

Exhibit 2.5 – Energy market plus redispatch gross margins for merchant onshore wind, impact of transmission delay (TD) on Zonal and National BAU cases compared, Consumer Transformation (£/kW)



Notes: For each market design case, the line on the chart represents the wholesale energy plus redispatch gross margin in the transmission delay sensitivity minus the equivalent gross margin in the base case. The redispatch element is based on zonal redispatch in the national market; nodal redispatch is not included. The locational grid charge range indicates the year-on-year volatility in the wider tariff component of TNUoS that has been observed historically.

Any move to a locational market runs the risk that the small overall welfare gains are overshadowed by the scale of wealth transfers between parties. These would be very dependent on the nature of any specific mitigation measures such as grandfathering of rights for existing parties. This is a complex issue: transmission rights to existing generators come in return for paying (locational) TNUoS and there are no simple solutions. The history of locational transmission loss charging in Britain suggests that this could result in a protracted legal process.

Overall, any move to a locational market design would need to be accompanied by mechanisms that limit the risks faced by individual connectees. This is a weakness in locational market designs generally, whether nodal or zonal in nature.

With simple changes to locational grid charges, we were able to replicate some but not all of the benefits of locational markets

The aim of the National Enhanced scenario has been to replicate the locational signals of the Zonal energy market case within a national energy market framework. If successful, this would have the advantage of reducing implementation cost and lowering the risk faced by market participants.

By defining locational grid tariffs to mimic the locational variations in gross margin by plant type from the Zonal case, we were able to achieve close matches between the National Enhanced and Zonal cases on overall locational signal strength for renewable and gas CCS plants, and obtain similar patterns of generation build by location. This approach was less successful for hydrogen-linked technologies, given the other drivers related to hydrogen infrastructure that influence those technologies.

We consider that this merits further work, and could be extended to a review of time of use tariffs, the application of network charges and potentially dynamic loss factors to interconnection, providing greater predictability of network charges to make them a more effective signal, and the development constraint markets.

Within the modelling we have carried out, a nodal market shows only small additional benefits relative to an 11-zone market

Many of the challenges in locational markets – especially fully centralised nodal designs – relate to the coordination of within-day real time dispatch and incentives for flexibility. These topics are beyond the scope of this modelling analysis but merit further consideration.

Conversely, many of the detailed flaws in the existing arrangements are dynamic in nature, including the difficulties to the TSO in coordinating redispatch from a national wholesale market, and the exercise of locational market power.

Within the modelling we have carried out, the Nodal case has shown only a small additional total welfare benefit above that achievable within the 11-zone Zonal case (with an additional NPV £0.2 billion over the discount period 2028-2050). We also found slight improvements in interconnector dispatch efficiency relative to the Zonal case.

A zonal market design (assuming a small number of zones) could continue as a decentralised market, consistent with today’s balancing arrangements and the markets elsewhere in Europe. However, many European zonal markets deploy (or are planning to deploy) flow-based market coupling which embeds many of the challenges of a nodal market within the decentralised processes. The zone boundary reviews are themselves a cause of significant market uncertainty.

A nodal market would be centralised, with central dispatch and co-optimisation of energy, ancillary services and network capacity. The design would need to consider how decentralised assets could be included in the arrangements and also how within-day flexibility would be dispatched and rewarded. A further problem with a nodal market is the potential for future re-integration to the European Internal Market for energy. We have not evaluated any of the dynamic or practical aspects of this type of centralised market design.

The complexity of modelling nodal outcomes should not be underestimated. There are many degrees of freedom including the location of new generation, demand and networks, and in turn the location of offshore connections, CCS and hydrogen infrastructure.

The increased complexity of locational markets may create barriers to entry

The complexity of the energy market will increase with the number of locations, creating additional challenges for predictability and decision making. Exposure to unforeseen events would increase for generators in a locational market, with an associated cost in time and resources devoted to understanding and managing them. Furthermore, the number of active market participants is likely to decrease if the market is segmented into locations. Fewer buyers and sellers could have an adverse impact on market liquidity. For smaller or less sophisticated developers the complexity and cost of working out if a location is a good one in a locational market may be a significant barrier to entry.

Modelling a 511-node grid representation of the GB transmission network at hourly resolution proved to be very challenging computationally, something we believe would pose an additional practical challenge to market participants and operators alike in the event a nodal market were introduced. Obtaining robust information to deliver the “accurate” price/revenue forecasts that locational pricing theory relies on is therefore a challenge.

Our investment methodology assumes perfect foresight[5]: investment decisions are made based on perfect foresight of the modelled future revenues and costs. In reality, investors have limited foresight of future market developments, and have to make decisions based on incomplete information. Perfect foresight modelling does not capture the value of predictability of market outcomes, and the reduction in this that locational markets bring compared to a national market.

We have also not modelled within-day changes in information in this analysis. The overall benefits of a locational market will also be affected by how optimal within-day interconnector trading is, ideally giving similar results to market coupling (which is being done in much of Europe via XBID[6]).

The window for reform to support the transition to a net zero power sector by 2035 is limited

Locational markets are being considered as part of an electricity market reform programme to achieve a fully decarbonised power system by 2035, which coincides with the period over which we have found that they have a stronger locational signal. We have assumed that the earliest a locational market could be implemented is 2028; this leaves a very short window for locational markets to have an impact on investment in time to influence outcomes in 2035. If investors face a period of uncertainty during which it is unclear whether there will be change to a locational market (or what the

[5] Though in the nodal market we have not assumed generators can predict the spreads between the price at individual nodes and that in wider regions (corresponding to zones in the zonal market).
[6] https://www.amprion.net/Energy-Market/Congestion-Management/Multi-Regional-Coupling-(MRC)-and-Cross-Border-Intraday-(XBID)/Content-Page.html

basic structure of that market will be), then some investors may conclude that they are unable to assess the risks adequately and will choose not to invest until the situation is clearer, leading to an investment hiatus[7]. No investment hiatus is factored into our overall welfare assessments, but the impact on investment timing of any market changes would be expected to be negative.

Our analysis shows that these conclusions are robust to the scenarios tested

Across the scenarios modelled (Consumer Transformation and System Transformation), we have found broadly similar outcomes.

The level of overall economic welfare benefit achieved in the Zonal and Nodal cases is similar in both the Consumer Transformation and System Transformation scenarios; despite quite different levels of overall hydrogen demand in the two scenarios, the greater freedom in System Transformation to optimise how hydrogen demand is met results in a similar level of electrolysis build and hence coupling with the power sector in both scenarios, resulting in limited impact from the hydrogen economy.

We also found a similar pattern of locational signal strength change in moving from a national to a zonal market, and comparable improvements in interconnector dispatch in both scenarios.

We modelled two different decarbonisation scenarios, therefore capturing only a subset of all possible market outcomes. In addition, the sensitivities modelled did not cover all possible uncertainties that could have been explored, focusing only on transmission grid build delay and cost of capital.

Recommendations

We recommend – based on the evidence available to us – that nodal pricing should not be progressed further

The trade-off between the additional welfare benefit we have modelled and the increased complexity of the market arrangements appears unfavourable even compared with a zonal market.

Many of the issues are not covered by our analysis. The practical aspects of centrally dispatching a set of decentralised resources under within-day uncertainty would need to be addressed. AFRY considers that it is – at best – unproven whether such a market design would be workable in the context of a decarbonised system, with heavy reliance on decentralised resources for system balancing, or whether such a design is deliverable in a timeframe which supports the 2035 investment challenge.

[7] Though this is a possibility in any case, for example see recent commentary on offshore wind costs.

Further work should be undertaken to improve incentives and information flows under the existing national market design

If the existing national market is retained, effort is required to provide more targeted investment and also operational dispatch incentives, particularly for interconnectors and for resources behind transmission constraints.

Any further exploration of a zonal market design should be accompanied by a programme of work to explore ways in which the risks – and wealth transfers – could be mitigated

The mechanisms to determine transfer capacity and zone boundaries would also require examination. We consider that this would require substantial effort and should be a precondition for taking a zonal market design further without risking delays to investment. There would need to be a parallel programme of work relating to network charging, and the payment structure and award mechanism for future renewable support arrangements.

The risk management frameworks associated with locational risks would be complex, and designing and delivering them would be a significant policy challenge with its own delivery issues.

Further exploration of a zonal market could also lead to delays in investment as it also creates uncertainty in itself. This needs to be taken into account when considering zonal markets. Policy makers may need to commit to mitigations against the uncertainties and risks for investors associated with a change to a zonal market (for example, committing to grandfathering of some rights for existing assets and for new projects taking final investment decisions in the near future) to minimise the risk of an investment hiatus in the near term.

More evidence is needed on the implications of locational markets for cost of capital.

The next steps should build on the analysis of Phase 1 of our work, including the development of ‘deemed generation’ CfDs (possibly including ‘evergreen’ CfDs with appropriate cost controls to protect consumers) to support new renewables, and a more targeted capacity support mechanism to deliver investment in forms of generation and long duration storage, consistent with a net zero power system.

3 Background

AFRY has conducted a study on the appropriate market design for a net zero power system in Great Britain (GB), in the context of the government's Reform of Electricity Market Arrangements (REMA) and National Grid ESO's Net Zero Market Reform programme. The overriding context is the government's aim to achieve a net zero power system by 2035.

The work has been financially supported by 12 industry members, and had the benefit of observers from 4 key stakeholder organisations[8].

This report is the work of AFRY and presents our own views on the ways forward. We are grateful to the clients who have supported the work, both financially and through their active participation in the debate. We also extend thanks to observers who have – to varying degrees – joined actively in the discussions of the group. Despite these contributions, this report represents the independent opinion of AFRY, and the opinions may not be attributed to any of the parties who supported the process.

The recommendations are based on the overall welfare of consumers and producers over time, not any particular interest group.

Phase 1 of the study concluded in 2022 and was entirely qualitative in nature, evaluating a set of reform options which spanned the broad scope of the REMA consultation. AFRY's then conclusions[9] were – in summary – that an evolutionary rather than a revolutionary approach would be advisable, given the need to maintain investment without any delay to meet the power system 2035 net zero ambition.

Phase 2 of the work has focused on one of the most contentious aspects of the reforms: the possible move from a national to a locational wholesale energy market.

Great Britain already has locational investment incentives in the form of zonal Transmission Network Use of System (TNUoS) charges, which are levied on generation and demand[10].

The economics of location are pervasive: in the cases modelled, we have had to analyse the patterns of wholesale pricing, transmission charging, the nature of future support regimes for renewables and (separately) the award mechanism for renewable support. The modelling dynamically allocates

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[8] Funding study members included EDF, Drax, Greencoat, Octopus, RES, RWE, Shell and SSE; our clients and observers are under no obligation to be identified, although they may choose to be so.

[9] https://afry.com/en/afry-publishes-report-great-britain-electricity-market-reform

[10] Great Britain market participants also face locational transmission loss adjustment factors, which we reflect in the modelling but hold unchanged between the cases. Locational losses may form part of a centralised nodal pricing market and if so we might expect them to be calculated more dynamically than the existing (seasonal, zonal) factors used in Great Britain today. This issue is not explored further in this study.

investment for generation, storage, transmission networks and electrolysis which means that any results need careful interpretation: like for like comparisons are not straightforward.

The analysis is conducted against the backdrop of two of the 2022 Future Energy Scenarios (Consumer Transformation and System Transformation), each of which is consistent with power sector decarbonisation by 2035 and economy-wide decarbonisation by 2050. The scenarios differ in the degree of consumer electrification and participation and the extent to which the economy relies on supply side transformation including extensive use of hydrogen. Although not reflected in the FES 2022 scenarios, we have also imposed an additional requirement in our modelling that the target of achieving 50GW of installed offshore wind capacity by 2030 is achieved in 2035 in both scenarios.

Some key assumptions such as technology costs assumptions and sources were decided based on discussions with study members and do not always align with AFRY internal views[11]. Interconnection with neighbouring markets is modelled, though assumptions such as the generation mix in those markets are fixed based on previous AFRY analysis.

The national market relies on redispatch (principally within the Balancing Mechanism) for ESO to resolve transmission congestion and other system constraints. In each of the national and zonal cases, we have modelled both the wholesale market outcome and the final dispatch allowing for balancing actions to resolve zonal transmission constraints[12]. To allow comparison between the zonal and the nodal cases, we have also modelled the additional intra-zonal redispatch for the zonal market.

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[11] To aid transparency, for some assumptions sources that are available publicly have been used in place of AFRY's proprietary assumptions.
[12] Our modelling of the Balancing Mechanism has not extended to ancillary services or resolving system constraints other than transmission constraints.

4 Objectives of Phase 2 locational analysis

The primary objective of this phase of analysis is to assess the implications of moving from a national to a locational (zonal or nodal) wholesale energy market, considering supporting changes to network charges and the support regime for renewables.

In our modelling, we consider the implications of the alternative locational market designs, in terms of total economic welfare[13] and the allocation to different participants; and the degree of volatility and risk exposure associated with the different regimes. Although our modelling generally assumes equilibrium modelling with a high degree of foresight, we have conducted sensitivity tests both on the cost of capital and possible delays to network capacity to explore some of the implications of uncertainty in a change to a locational market regime.

A particular concern expressed by some study members was the extent to which a move to locational pricing (whether zonal or nodal) would cannibalise revenue streams for existing capacity once it falls out of contract – though we note that those hardest hit by a move to zonal prices could receive the greatest benefit from the removal of (wider tariff) generator TNUoS. We have considered this issue within the results.

The drivers of locational incentives vary between the existing national market and the locational market designs. In the national market, TNUoS locational differentials (simplistically) reflect the distance[14] of generation from demand and vice versa[15]. Conversely, price differentials in locational energy markets reflect not distance but congestion, and in locational energy markets we would expect the locational aspect of TNUoS to be levelled[16]. There are other differences – TNUoS has various rules on sharing which feed into the calculations, whereas the degree of network sharing which takes

[13] Or more specifically total economic welfare for Great Britain – there are changes to welfare in other markets, but these are not discussed in this report. Calculating Great Britain economic welfare while also modelling a wider region requires some assumptions to be made: we have assumed 50% of interconnector revenues accrue to Great Britain and that profits associated with interconnector redispatch largely go to the other market.
[14] This is a little bit of a simplification – as the tariffs also depend on the type of line the power is flowing on, as well as the MWkm of flow and their relative expansion multipliers (essentially costs) which are higher for some types of lines (including lower voltage AC and HVDC lines).
[15] Generators in Scotland pay high levels of TNUoS and demand in Scotland pays low (zero) TNUoS; whereas generators in southern and south-western areas faces negative TNUoS charges (i.e. they are paid to export at key times) while demand in those areas faces the highest TNUoS charges. These values change over time.
[16] To compare the economics of location between the cases, we need to look at a composite financial indicator covering energy market gross margin for generation minus TNUoS costs. These metrics vary by generation technology; together they reflect the strength of locational incentives in the market (aside from transmission losses).

place falls out naturally in a locational market. As an example, this leads to very different effects on solar PV. We see this complexity revealed in the results.

Noting the conclusions of our Phase 1 work – that evolutionary rather than revolutionary solutions are generally preferable given the need to accelerate the pace of investment – we have also explored a design for an enhanced national market which attempts to capture the advantages of a locational market design within a less radical market overhaul.

5 Phase 2 study questions

In support of the primary objective, our analysis within Phase 2 has been directed towards answering the following questions:

Question 1 – Do locational energy markets improve or worsen market outcomes (in terms of operational efficiency, investment effectiveness and allocation of cost risk and reward) compared to national markets?

Question 2 – How robust are comparisons of the benefits and disbenefits of different locational market designs to uncertainty on future decarbonisation pathways?

Question 3 – How robust are comparisons of the benefits and disbenefits of different locational market designs to uncertainty on future infrastructure development, for example transmission network build?

Question 4 – How robust are comparisons of the benefits and disbenefits of different locational market designs to changes in investor risk appetite and costs of capital?

Question 5 – To what extent can any improvements in market outcomes from locational energy markets be replicated in a national market framework?

Question 6 – Are there significant differences in market outcomes between zonal and nodal markets?

6 Modelled market design cases

We have modelled three main market design cases (based on national business-as-usual arrangements, a zonal market and a nodal market) and an alternative ‘enhanced’ national case in which the advantages of a locational market are combined with the advantages of retaining the existing national wholesale energy market.

The selection of the market design cases to model was based on the locational focus of the analysis. Our market design cases model different combinations of the following locational elements, which are combined in each case to form an internally consistent market design:

- wholesale market granularity: national, zonal (11 zones) or nodal (511 nodes)
- market redispatch to respect transmission constraints (national and zonal cases only)
  - in National BAU, plants bid into the Balancing Mechanism based on historical levels of bid and offers, with falling bids and offers over time in cases where competition in the BM is expected to increase (e.g. between onshore wind farms). In the National Enhanced case, plants under the deemed generation CfD are preventing from bidding negatively as an assumed condition of their contract.
- locational transmission charges[17] (national cases only, zero in zonal and nodal cases)
- renewable support arrangements: National BAU CfD arrangements (National BAU case only) or deemed generation CfD arrangements (all cases except National BAU)
  - National BAU CfD arrangements comprise award of a 15-year contract based on lowest price, and payment based on metered output except in any hour when the reference price is below zero. Supported plants are assumed to bid into the energy market at very low prices.[18]
  - deemed generation CfD arrangements comprise award of a 15-year contract based on the lowest cost of top-up payments from a market reference price to a strike price, and payment based on deemed output (e.g. based on the predicted day-ahead generation profile) rather than actual metered output; in the main Zonal and Nodal cases the reference price is the price in the local zone or node (although we have also modelled a zonal variant based on a proxy national

[17] This refers to the wider tariff element only – i.e. we are not assuming a change on local circuit changes or offshore local generation tariffs, which would proceed as in the status quo.
[18] Onshore wind: £0.03/MWh; offshore wind: £0.02/MWh; solar PV: £0.01/MWh.

reference price). Supported plants are assumed to bid into the energy market based on their true variable costs[19].

We concluded that in locational markets, modification of the CfD award mechanism to a least-cost of top-up approach[20] was required to give a locational investment signal to new CfD-supported plants without causing undue investment risk; the current arrangements are not influenced by reference price expectations[21], so with indexation to a zonal or nodal reference price there would be no locational signal for investment under the National BAU CfD. The alternative of a National BAU CfD indexed to proxy national price, so that supported plants were exposed to the basis risk between their locational price and the reference price was considered to introduce significant investment risk, so was not adopted in the main zonal or nodal cases. Once awarded a 15-year deemed generation CfD contract, the supported plant is topped-up to its strike price from the reference price achieved in the market, based on the deemed output profile, independent of actual generation; this incentivises the supported plant to self-curtail if market prices fall below its variable costs.

We have modelled congestion rent in all zonal and nodal cases; however locational losses have been modelled as flat constant values by zone in all cases (rather than dynamically). The three modelled cases and National Enhanced variant are summarised in Exhibit 6.1.

[19] Based on BEIS Electricity Generation Costs (2020): onshore wind: £6/MWh; offshore wind: £3/MWh; solar PV: £0/MWh (all real 2018 money).
[20] In the case of CfDs awarded under a least cost of top-up approach, but indexed to the zonal price (with rules around zone boundary changes that we have not considered) the awarding body would need to develop assumed reference prices (i.e. capture prices) by technology and zone, as it does currently by technology. To the extent that it gets these prices wrong (in such a way that it leads to different build), this risk is essentially borne by consumers.
[21] Though there are different expected reference prices for different technologies in the same pot – in practice, these are only used to determine when the auction closes, with award still based on lowest price rather than lowest expected top-up.

Exhibit 6.1 – Summary of modelled market cases

NATIONAL BAU

- No change to current market arrangements:
- Grid charges based on current TNUoS methodology
- BAU CfD arrangements:
  - award based on lowest price (within pot)
  - payment based on metered output (when reference price is > 0)

ZONAL

- Enhanced market arrangements within an 11 zone market.
- No locational generator grid charges
- Deemed generation CfDs:
  - award based on lowest cost of top-up payments
  - payment based on deemed output

NODAL

- Enhanced market arrangements within a 511 node market.
- No locational generator grid charges
- Deemed generation CfDs:
  - award based on lowest cost of top-up payments
  - payment based on deemed output

NATIONAL ENHANCED

- Enhanced locational market arrangements within a national market.
- Locational generator grid charges set based on locational signals in a zonal market
- Deemed generation CfDs :
  - award based on lowest cost of top-up payments
  - payment based on deemed output

In the Zonal case, CfD-supported plants are assumed indexed to the zonal price, and no increase in hurdle rate relative to National BAU is assumed; this is also the case for the Nodal cases. As we have assumed 15-year CfD support contracts followed by a merchant tail for the remainder of the economic lifetime, this does not reflect any increase in hurdle rate as a result exposure to zonal or nodal prices after the CfD-contract has ended, and so is a conservative assumption. In reality, a windfarm with a 30-year economic lifetime and a 15-year support contract would face locational price exposure which investors would pro-rate, with the effect that the CfD contract would reduce but not eliminate any increases to cost of capital. For simplicity of comparison between cases we have not modelled the ‘evergreen deemed generation CfD’ based on an initial 15-year contract period, followed by auctions for further rolling contracts of shorter duration, which would be a way of addressing the issue of merchant tail risk while retaining cost control for consumers.

We have modelled a variant of the Zonal case which assumes both least cost of top-up award and indexation to a proxy national price (based on a generation weighted average zonal price)[22]. To reflect the basis risk this introduces, we have assumed a 1% increase in hurdle rates for CfD supported plants in this case, relative to the National BAU case. Both the Zonal and Nodal cases assume a 1% increase in hurdle rates for non-CfD supported capacity, reduced to 0.5% for OCGT capacity reflecting its lower exposure to the energy market as a share of its total revenue (including from the Capacity Market). There is no change in hurdle rates for any technology in the National Enhanced variant.

Note that we have not considered the effect of a higher risk for existing plants in this analysis. While this does not, by definition (since they are existing) affect plant build (and existing renewable plants are still likely to make enough money to recover their annual fixed costs and so would not

[22] The Zonal (N) case. Under this scenario generators are exposed to the spread between the zonal price and the reference price based on a proxy national price.

decommission early), there would be impacts on existing plants; including potentially higher costs for refinancing and a lower price if trying to sell the asset.

As a primary metric of the success of each market design, we evaluate the aggregate economic welfare to Great Britain actors (which should be the primary focus of policy makers), and then its distribution (which should be of secondary importance, given a larger total economic welfare can be reallocated between producers and consumers once obtained, but not otherwise). Note that our modelling is based on equilibrium and perfect foresight, which smooths the results of any market regime. To round out our results, we also apply sensitivity tests to some of the cases considering variation to the cost of capital for new investments (reflecting increased volatility in a locational market) and also the sensitivity to (unforeseen) network delays.

7 Modelled scenarios

To compare the benefits and disbenefits of the different market design cases, we have modelled two different scenarios which achieve a net zero power grid by 2035.

These are based on the Consumer Transformation (CT) and System Transformation (ST) scenarios from NGESO's Future Energy Scenarios (FES) 2022. These were selected as they both achieve a net zero power grid by 2035 (and a net zero economy by 2050), but under different decarbonisation pathways.

- Achievement of the 50GW of offshore wind by 2035 was not a feature of the FES 2022 scenarios, but was added into our modelling of both of the scenarios.
- We modelled each scenario to 2050, with modelled years 2025, 2030, 2035, 2040 and 2050. As we assume a revised market design (whether Zonal, Nodal or National Enhanced) would not be implemented until 2028, all modelled results for 2025 are based on the National BAU baseline; results comparing cases are therefore generally shown from 2030 onwards.

7.1 Demand

The Consumer Transformation (CT) scenario is characterised by high levels of consumer participation, electrification of heat and transport and correspondingly high levels of power demand, with more modest growth in hydrogen demand. Power demand excluding electrolysis has a compound annual growth rate of 2.9% between 2025 and 2050, reaching 435 TWh in 2035 and 572 TWh in 2050. Hydrogen demand is confined to isolated clusters, and all hydrogen production is constrained to come from electrolysis.

System Transformation (ST) reflects greater reliance on hydrogen – including use of 'blue hydrogen' from reformed natural gas with CCUS and development of hydrogen networks between clusters – and lower levels of electrification and native power demand. Power demand excluding electrolysis has a compound annual growth rate of 1.9% between 2025 and 2050, reaching 357 TWh in 2035 and 461 TWh in 2050. In the ST scenario, with its options for 'blue hydrogen' and for transportation and storage between clusters, there is greater freedom for electrolysers in terms of total capacity, choice of location, and flexibility of operation.

In the National market cases, we assume that electrolysis does not face locational TNUoS charges whereas in the locational (zonal and nodal) cases, electrolysis is exposed to the locational energy prices.

In terms of the location of power demand, in both scenarios we have assumed that the regional distribution of power demand in future years remains as projected in the Energy Ten Year Statement (ETYS), with zonal demand scaling with total demand.

7.2 Generation

For both scenarios, modelled generation capacity expansion is based on a combination of:

- Pre-defined exogeneous input assumptions from the FES 2022, with locations based on the Energy Ten Year Statement (ETYS) 2022.
- Achievement of the offshore wind 50GW target by 2035 as an exogeneous input (for capacity entering after AR6 we assume a degree of locational optimisation between different lease areas is possible and this capacity is distributed between lease areas based on assessment of the costs in these locations).
- Additional economic capacity built endogenously within the model, subject to:
    - all large-scale renewable capacity is assumed to be CfD-supported (either under the National BAU CfD arrangements or the deemed generation CfD arrangements under all cases other than National BAU)
    - a long-term budget allocation of zero for total CfD payments (in other words, over the course of their lifetimes, supported plants eventually pay back as much as they receive)
    - a minimum level of renewable generation procurement each year from onshore wind and/or solar PV (3TWh in CT, 2TWh in ST) reflective of the likely reality of annual CfD auctions going forward
    - caps on the rate of renewable capacity build by location

7.3 Interconnection

Interconnector capacity is an exogenous assumption taken from the FES 2022 scenarios. This includes some interconnectors that are expected to commission in the next few years, for example Greenlink connecting Ireland and Great Britain, and GridLink[23] connecting France and Great Britain. For interconnector capacity commissioning in the longer term, assumptions have been made about which market this connects to. Total interconnector capacity is significantly higher post-2030 in the CT, reaching 19GW in 2035 and 22GW in 2050 (compared with 13GW in 2035 and 16GW in 2050 in ST). For the interconnected markets we modelled with fixed capacity assumptions, based on previous analysis carried out by AFRY, optimising dispatch and interconnector flows.

[23] There are a number of proposed interconnectors between Great Britain and France – AFRY would normally model generically and not state which one is more likely – but this is not possible with nodal modelling, so we have selected one of them for inclusion.

7.4 Network build

Our network expansion methodology is based on exogeneous assumptions from the ETYS 2022 and NOA7 until 2030, plus economic assessment of options under the Holistic Network Development plan (HND). Our exogeneous network build capacity assumptions are the same across all modelled cases and scenarios.

From 2035 onwards there is additional endogenous network expansion, taking into account locational patterns of generation and demand, which in turn is determined by the impact of the locational signals on generation and on electrolysis. In the first instance this is based on a least cost approach using the BID3 Auto Build module in the national and zonal cases, and then subsequently refined to reflect:

- the cost of an additional 1MW of line capacity compared with the congestion cost (or, in the national cases, redispatch costs) that it would relieve
- the lumpy nature of network build in practice (particularly for HVDC lines)

A simpler approach is used in the nodal runs for the expansion of the nodal grid. Multi-line constraints are applied in the nodal cases, in order to reflect the same zonal boundary capabilities as the zonal cases[24].

[24] This is a modelling simplification – ideally the cross-zonal capabilities would follow from a nodal grid representation of the zonal cases, however, we have modelled the zonal cases at zonal granularity only, and have then built up the nodal grid to reflect the outcome of the zonal grid build (including endogenous reinforcement by the model). The zonal boundary capabilities are therefore included in the nodal cases to ensure the nodal grid does not allow more cross zonal flows than the zonal cases. Boundary capabilities can take account of a range of factors, including N-1 constraints not considered in the nodal simulations.

8 Results

8.1 Market outcomes

Question 1 – Do locational energy markets improve or worsen market outcomes (in terms of operational efficiency, investment effectiveness and allocation of cost risk and reward) compared to national markets?

There are already locational incentives in the form of transmission charges and locational transmission losses in Great Britain. The economics of location are pervasive: the introduction of a locational energy market would at least require changes to grid charges, and to future renewable support arrangements (including the contract award mechanism). In a locational market, we would also need to consider awarding grandfathered rights for existing projects.

Locational energy markets can provide more targeted incentives than grid charges, yielding potential economic benefits in both investment and efficiency of operation.

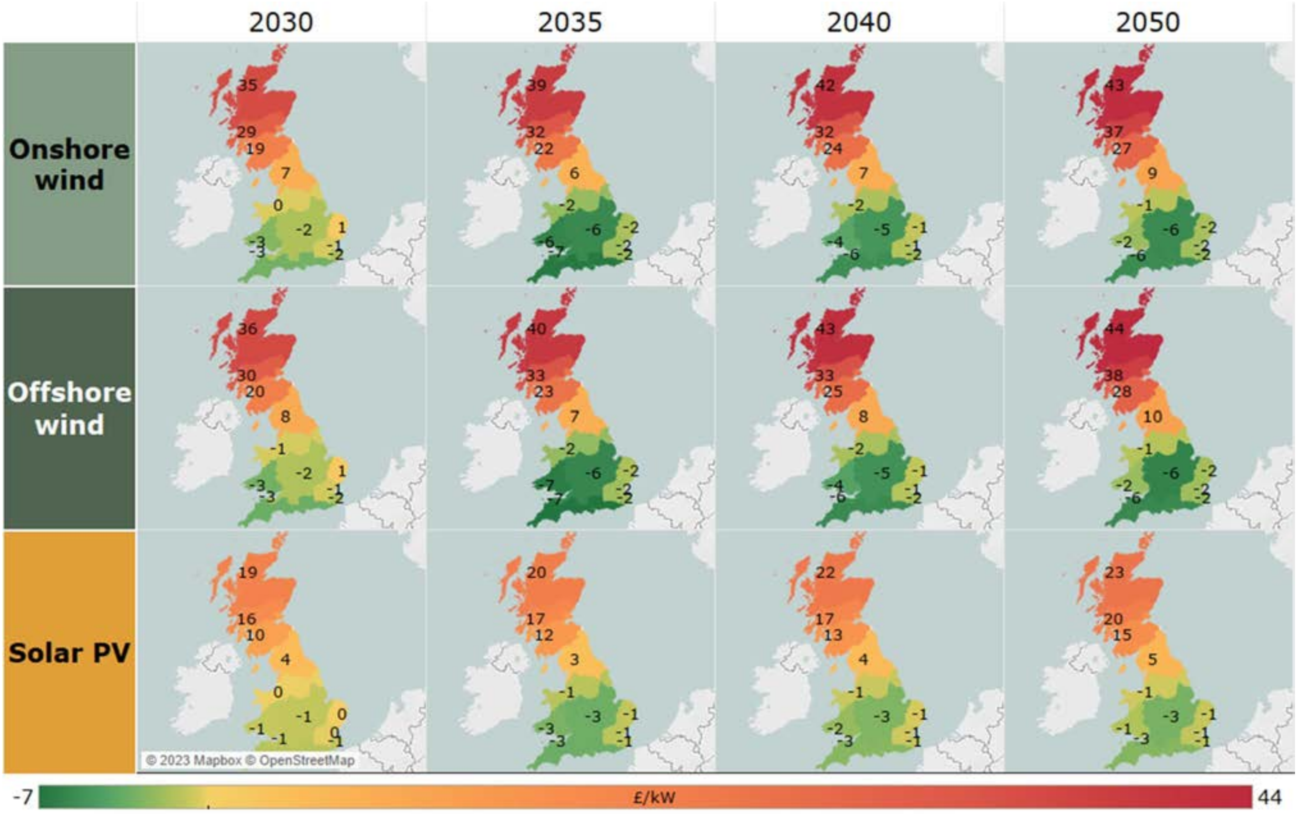
Locational signal strength in zonal versus national BAU

Across the modelled cases, we have captured the overall locational signal strength faced by market participants by modelling both locational energy prices (present in the zonal and nodal cases, and absent in the national cases), as well as locational grid charges (absent in the zonal and nodal cases, present in the national cases).

The locational grid charges in the National BAU are based on the existing TNUoS methodology for the wider tariff (locational) component of TNUoS. Exhibit 8.1 shows the results of our locational grid charge modelling in the Consumer Transformation scenario in the National BAU case for onshore wind, offshore wind and solar PV respectively.

Across all the maps within the Exhibit, darker red represents a more positive generator grid charge, and darker green a more negative generator grid charge. A map with both dark red and dark green represents a very sharp locational signal, while a map in the same Exhibit with less contrast in colours between different regions represents less variation in the locational signal. The pattern across all the generation technologies reflects high grid charges in Scotland and negative charges in the south of England, particularly for wind given its higher load factor compared to solar PV. The strength of the locational signal also increases over time, with the range between Scotland and southern England growing over time.

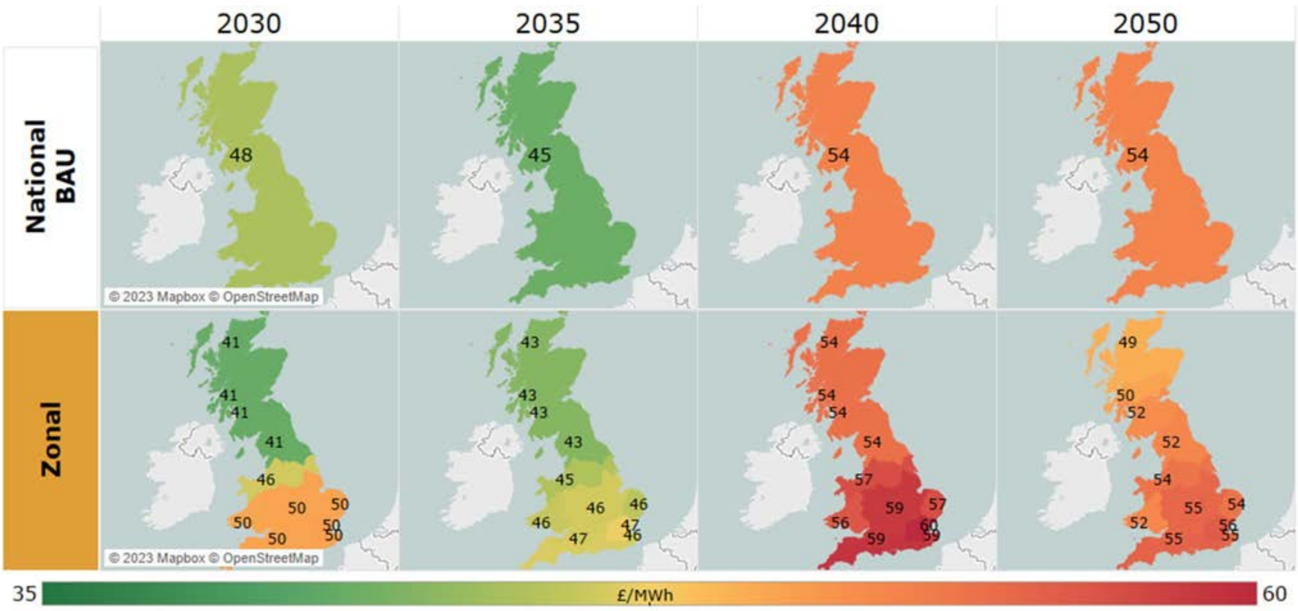
Exhibit 8.1 – Locational grid charges for renewable technologies in National BAU, Consumer Transformation (£/kW, real 2021)



Note: For offshore wind, the grid charge reflects the locational tariff for the onshore connection point.

In contrast to the National BAU case, the Zonal case does not have locational grid charges and locational signals arise from wholesale price variations. These are compared to wholesale prices in the National BAU case in Exhibit 8.2.

Exhibit 8.2 – Wholesale power prices, Consumer Transformation (£/MWh, real 2021)



The national average price in both cases dips between 2030 and 2035, driven by the large volume of renewable capacity entering over that period, notably offshore wind which achieves the 50GW deployment target in 2035. National average prices are then on a rising trend between 2030 and 2050, driven by rapidly growing power demand and rising carbon prices.

Zonal prices show the widest divergence in 2030, reflecting the highest level of network congestion occurring in that year. In the longer term, zonal price differentials generally moderate as network build catches up with renewable deployment and investment decisions respond to the new locational signals.

On a year average basis, the wholesale price in the National BAU case is broadly aligned with the Midlands price in the Zonal runs to within £1-2/MWh. The year 2040 is an exception; prices in the National BAU in this year are at the level of Scottish prices in the Zonal runs, driven partly by higher renewable capacity. This is due to the negative TNUoS in some southern locations[25,29] and our approach to modelling the BAU CfD driving extra solar build[26]. This price differential has a follow-on impact on the economic welfare which is partially offset by differences in capacity market and CfD costs.

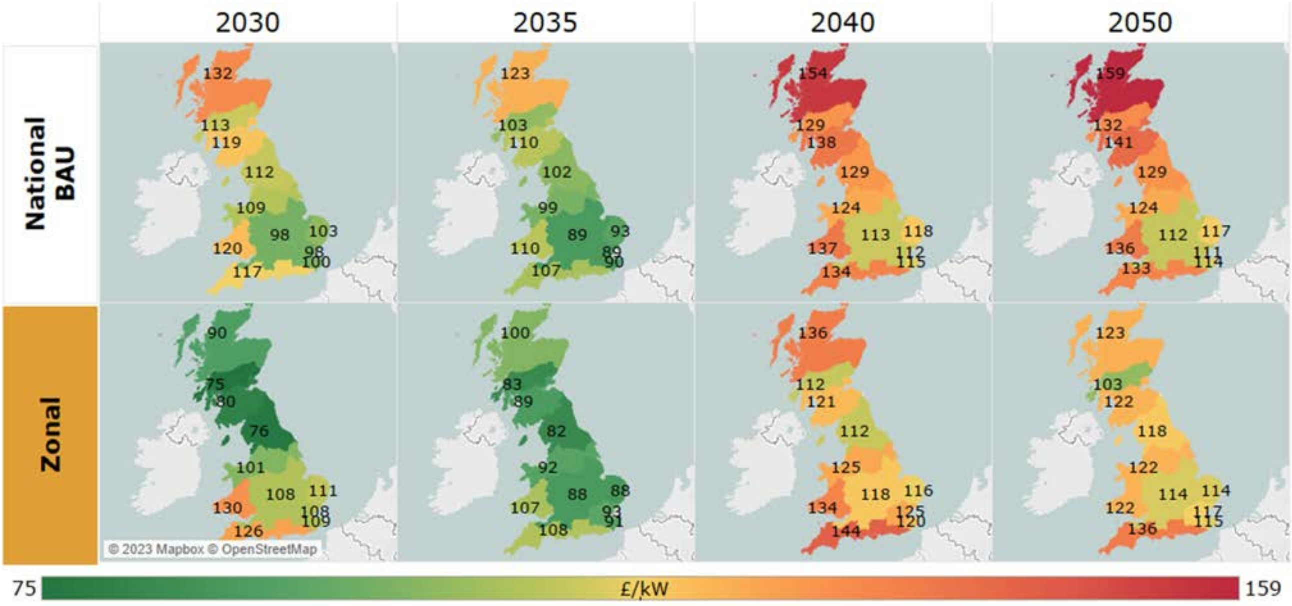
The change between the scenarios in wholesale market prices is an important influence on revenues earned from the energy market, with unhedged merchant renewable plants fully exposed to changes. Exhibit 8.3 shows the locational variation in energy market gross margin for a merchant onshore wind farm, before factoring in any support payments or locational grid charges.

In National BAU, energy market gross margins by region show a variation which largely follows load factor (though there are also differences in wholesale capture rate and price), with the higher load factor regions of Northern Scotland, Southern Scotland (SPT) and South Wales the highest across the timeframe. In the Zonal case in contrast, onshore wind gross margins in Scotland and northern England are initially below the national average as a result of depressed wholesale prices caused by transmission constraints; a situation which resolves in later years.

[25] A £/kW variation in costs has a much greater effect on plant economics for solar PV compared with wind, due to its much lower load factor. Very roughly, solar generates 1MWh/kW/yr, so a charge of -£5/kW is like lowering the LCOE by £5/MWh. The BAU scenario does not include any changes to the TNUoS regime other than a larger charging base, with distributed generation assumed to pay TNUoS. It is unclear whether TNUoS would remain unchanged if a lot of solar PV capacity was receiving negative TNUoS.

[26] Our approach is to build until the net top up is zero. Although onshore wind requires a higher strike price than solar PV, for the locations where it is built it actually requires less top up – in fact it would pay back. Since the award mechanism is based on lowest strike price this effectively subsidies some of the solar PV, though there would be a different outcome if solar and onshore wind were in different pots.

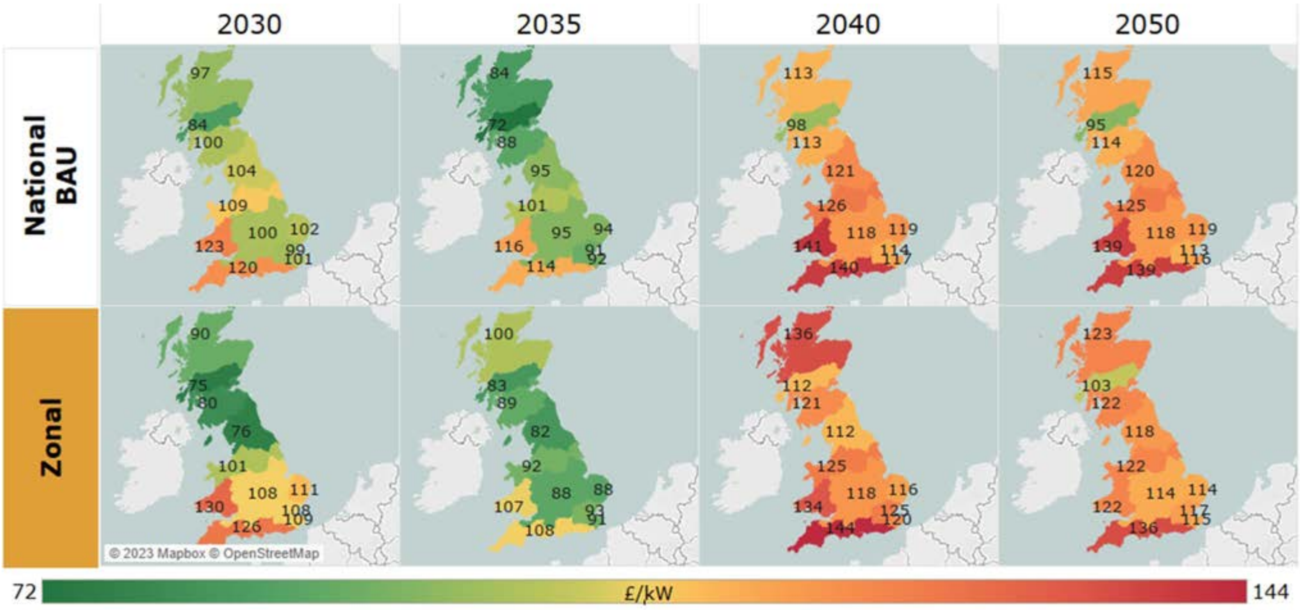
Exhibit 8.3 – Average wholesale energy market gross margin – merchant onshore wind, Consumer Transformation (£/kW, real 2021)



Note: Values shown are before any payments under a CfD or other support payment. All large-scale new build renewable capacity in our modelled scenarios is assumed to have a CfD (either BAU in National BAU, or deemed generation in all other cases). Figure does not include grid charges.

Subtracting locational grid charges from energy market gross margins provides a useful metric for the overall financial impact of a change from the National BAU market to the Zonal market; this is shown for onshore wind in Exhibit 8.4.

Exhibit 8.4 – Average wholesale energy market gross margin minus locational grid charges – merchant onshore wind, Consumer Transformation (£/kW, real 2021)



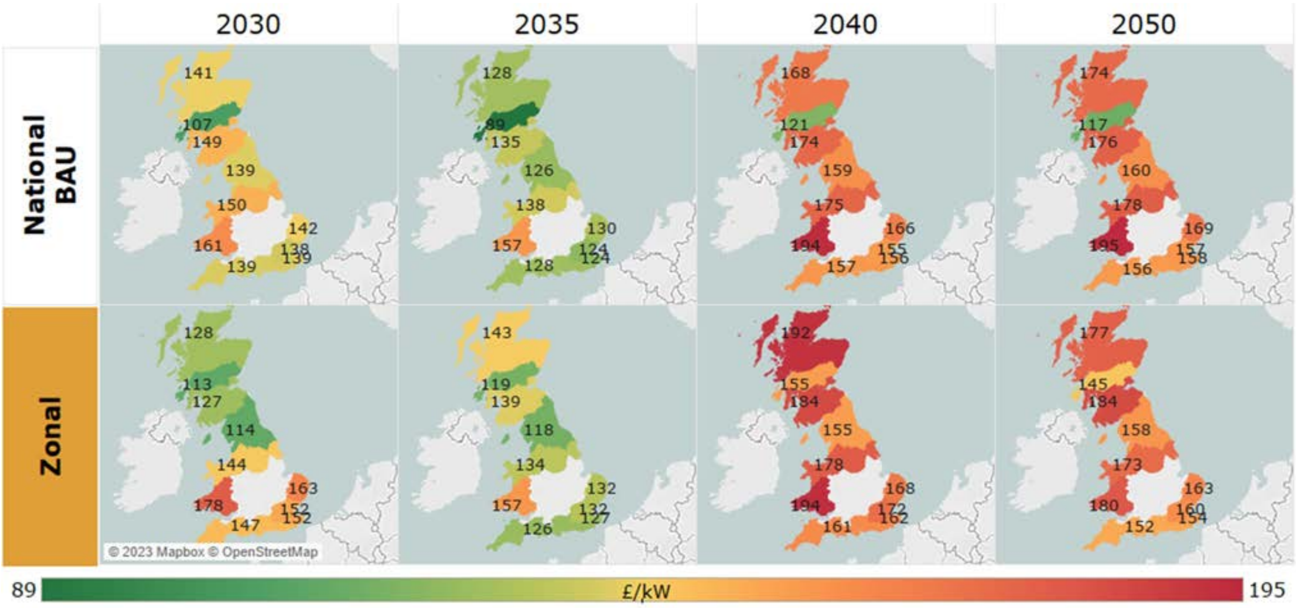
The effect of the locational grid charges in National BAU is to lower the cash flow for onshore wind assets in Scotland, sometimes to lower than the Zonal case, while South Wales and the South zone of England retain their status as (financially) more favourable locations.

Comparing Zonal with National BAU, the strength of the locational signal measured as the difference between the highest and lowest zones is sharper in the Zonal than in the National BAU case in 2030 (£55/kW and £39/kW, respectively). However, the locational signal of the Zonal market becomes weaker after 2030 as a consequence of reduced grid congestion, reaching £33/kW in 2050 in comparison to £44/kW in the National BAU. In contrast, signal sharpness remains relatively stable in the National BAU case. This is an important finding as it challenges the conventional wisdom that locational pricing would yield more extreme outcomes than the current market design. We find that after 2035 (assuming that grid build matches the NOA7 plans), the overall locational signal in today's national market with locational transmission network charging provides a stronger signal for generation (in this case onshore wind) and demand centres to locate closer to each other than would be seen in a locational energy market without locational network charges.

In both cases, starting in 2030, the South zone of England together with South Wales are the most favourable zones for onshore wind, and they generally remain so over the period to 2050. This effect is partly driven by scenario assumptions on build caps limiting build in these regions.

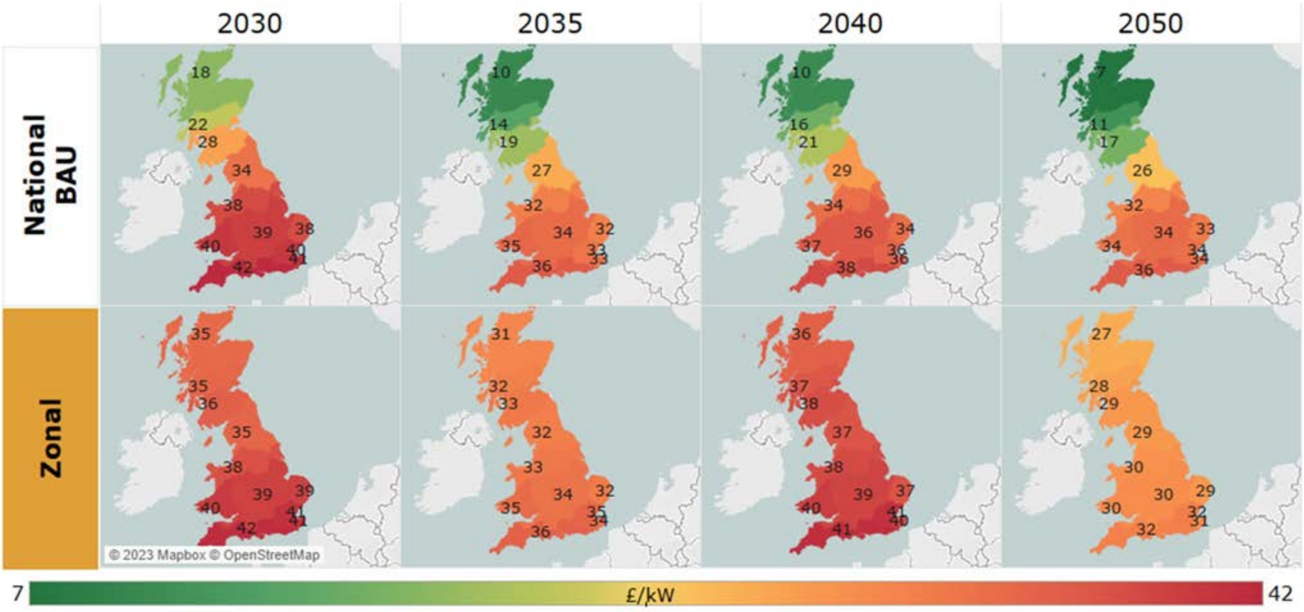
A similar process for offshore wind and solar PV results in the comparisons shown in Exhibit 8.5 and Exhibit 8.6

Exhibit 8.5 – Average wholesale energy market gross margin minus locational grid charges – merchant offshore wind, Consumer Transformation (£/kW, real 2021)



As variation in capex and opex by location is greater for offshore wind[27], the correlation between the gross margin less grid charge metric and new build location is weaker than for onshore wind and solar PV. For example, no build which connects to South Wales occurs as the relevant lease area is suitable for floating offshore wind only[28], which (based on the study assumptions) has much higher investment costs and so is not economic to deploy despite higher revenues. Build connecting to South, East Anglia and North is limited to respective build caps of 0.4GW, 0.9GW and 1.5GW. Nevertheless, the general pattern of a stronger locational signal in the Zonal case than in the National BAU case in 2030 becoming weaker in the subsequent years is discernible.

Exhibit 8.6 – Average wholesale energy market gross margin minus locational grid charges – merchant solar PV, Consumer Transformation (£/kW, real 2021)



For solar PV, the sharpness of the locational signal indicated by the energy market gross market less grid charge metric is stronger in the National BAU case than in the Zonal case in all years. Common to both cases is a lower load factor for solar PV the further north it is located; this is the main driver for the locational variation observed in the Zonal case. In the National BAU case, higher grid charges in Scotland (up to £20/kW in northern Scotland) compared with generally slightly negative charges in England (for example -£3/kW in the Midlands zone from 2035 onwards) drive the additional locational sharpness in the National BAU[29]. In the Zonal case, the network congestion that drives price separation between zones (particularly in 2030) is mainly driven by wind and tends to occur at times of low solar PV output.

[27] Capex and opex for offshore wind are dependent on lease area.
[28] In our assumptions the spread in costs between fixed and floating wind is generally bigger than any locational benefits that may be offered by some floating sites.
[29] Solar has low costs per kW, offset by also having low load factors compared to wind. Consequently, the same per kW TNUoS charge makes a bigger difference to the LCOE, in both absolute and percentage terms, than is the case for wind.

Consequently, energy market returns for solar PV are largely unaffected by network congestion, leading to a weak locational signal for solar PV in the Zonal case.

In the National BAU case, new build solar PV is completely suppressed in all zones north of the B7a boundary due to the heavy grid charges, although relatively low load factors also suppress build in the two northern-most zones of Scotland in the Zonal case. In the National BAU, negative grid charges for solar PV in most of England help drive additional solar PV expansion in England compared with the Zonal case.

The results of our analysis of energy market gross margin less grid charges for renewable technologies across the National BAU and Zonal cases show that:

- For onshore wind and offshore wind, locational signals are sharper – that is provide greater incentives to locate nearer demand – in National BAU than in Zonal in all years except 2030.
- For solar PV, locational grid charges are much stronger in National BAU than in Zonal in all years – the locational signal in the Zonal case is very weak for solar PV, even in 2030. Network congestion in Zonal is primarily correlated with wind generation and does not provide a financial signal for solar to relocate.
- The starting hypothesis that locational diversity of energy market revenues less grid charges will be greater in a zonal market is therefore partially (i.e. after 2030) disproved in our modelling of the Consumer Transformation scenario, and all the effects of sharper locational signals expected from the zonal market when compared with a national market are reversed.

Investment effectiveness

For investment, we find that the strength of the locational signal is not generally stronger under a locational energy market compared to today's national market arrangements. For most technologies, we find that locational signals under a zonal or nodal market design are sharper until 2030 but weaker by 2035.

A summary of the overall differences in renewable capacity locations between the National BAU and Zonal cases is provided in Exhibit 8.7. Reflecting the weaker locational signal overall once both energy market revenues and locational grid charges are considered, new renewable capacity is further from demand centres in the Zonal case than in the National BAU. Exhibit 8.7 shows the equivalent shift in generation from new build renewables, and the increased generation in Scotland.

There is little variation in capacity location for electrolysis between the National BAU and Zonal cases. This is to be expected, since without a hydrogen network in the CT scenario the locations of electrolysis units are mainly dictated by the regional hydrogen demands. As the FES assumptions for new build battery capacity were taken as an exogeneous input, and there is limited additional need for further economic build of capacity, capacity locations for battery storage are similar between the National BAU and Zonal cases. However, the pattern of energy market gross margin less grid charges broadly correlates with the location of the new battery capacity, being weighted towards the south of the country.

Exhibit 8.9 shows the overall change in location for new build thermal technologies. Overall differences are small, since we assume a capacity market would deliver broadly the same security standard in both scenarios; some differences will remain due to the renewables mix having a slightly different capacity credit in the two scenarios.

Exhibit 8.7 – Change in renewable generation capacity location – National BAU to Zonal, Consumer Transformation (cumulative GW)

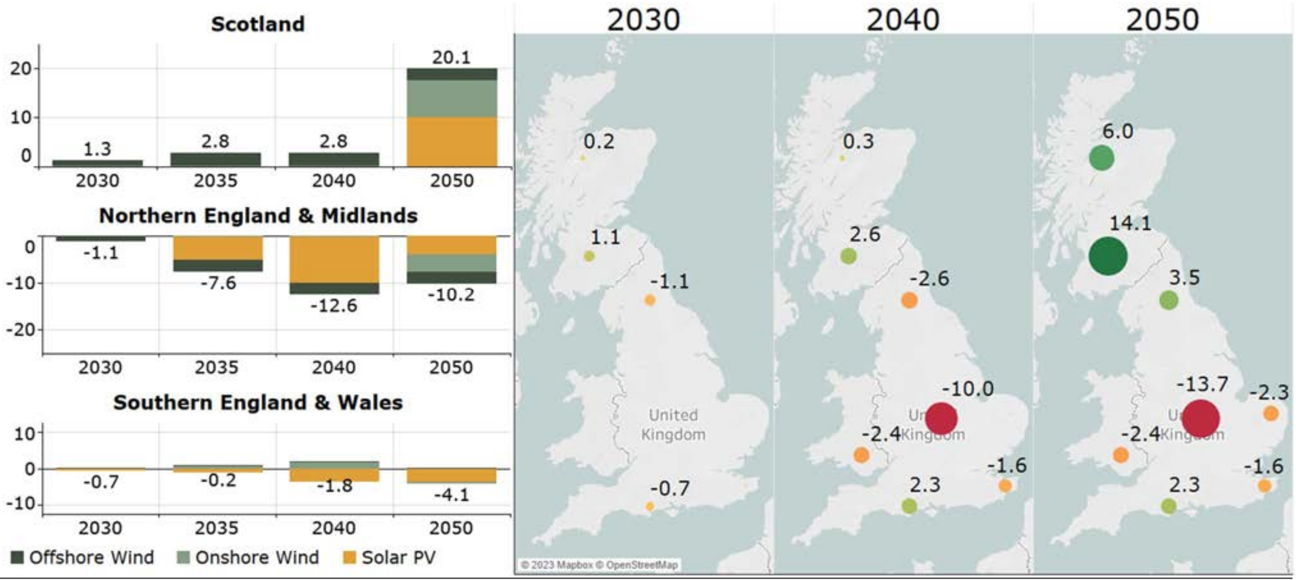


Exhibit 8.8 – Change in location of renewable generation – National BAU to Zonal, Consumer Transformation (TWh)

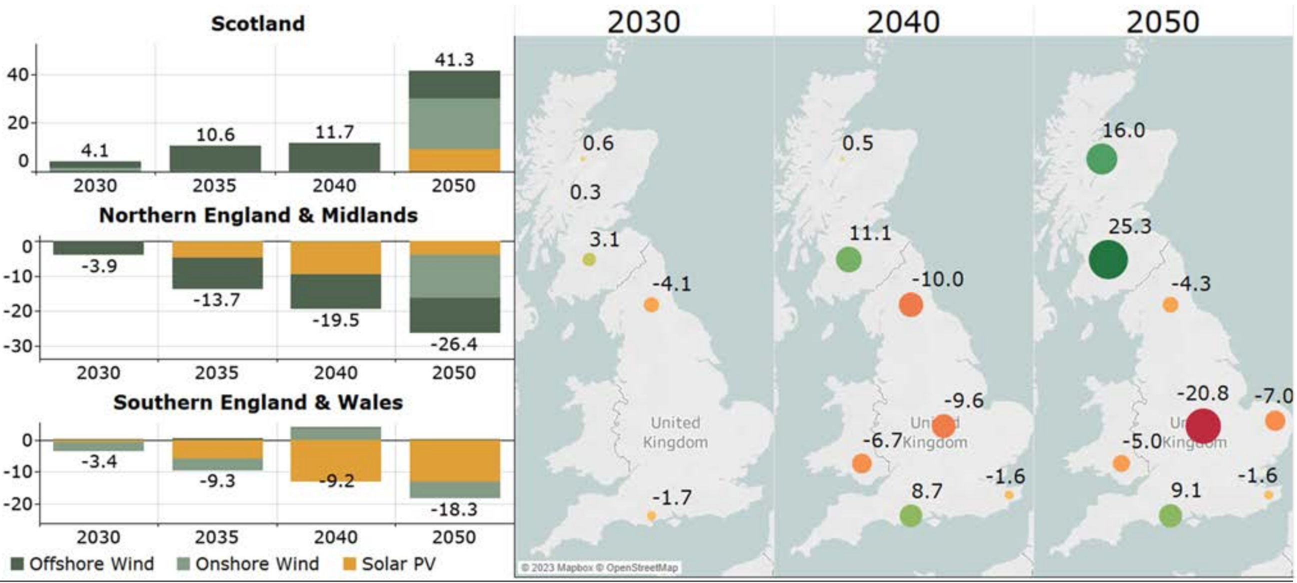
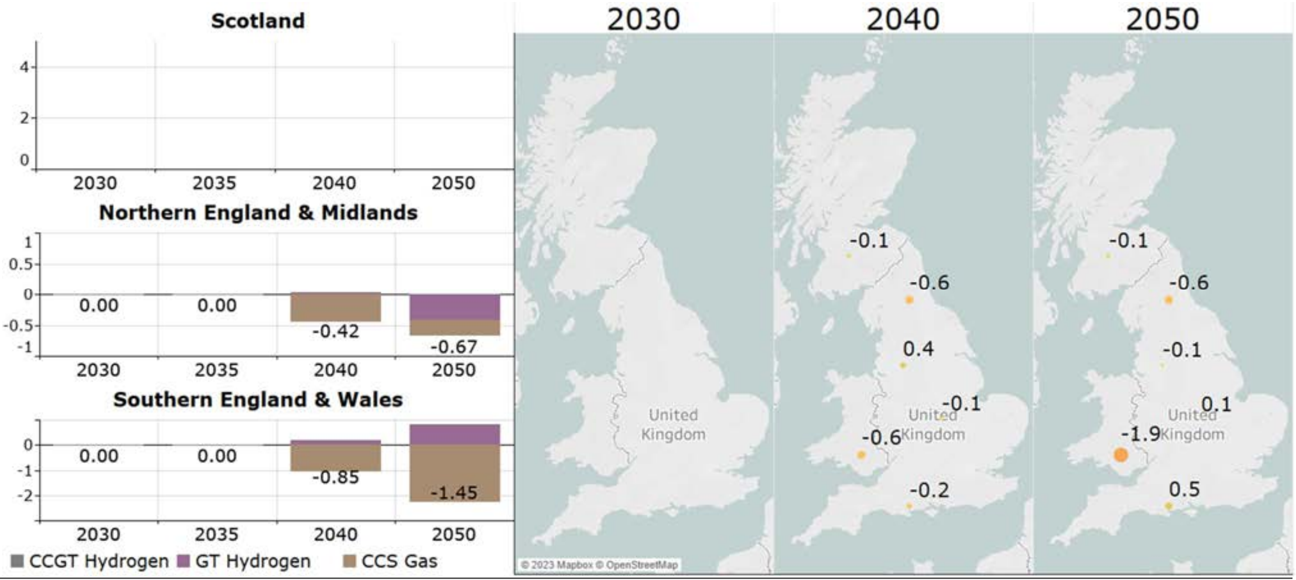


Exhibit 8.9 – Change in thermal generation capacity location – National BAU to Zonal, Consumer Transformation (cumulative GW)



Operational efficiency

The changed pattern of capacity build in the Zonal compared with the National BAU case results in several effects related to maintaining operational efficiency.

Overall levels of renewable curtailment are higher in the Zonal case, particularly in 2050, which might be expected, given the weaker locational signal in the Zonal simulations causing greater volumes of wind to locate further from demand. Exhibit 8.10 shows how total renewable curtailment volumes are spread across the different zones in both the National BAU and Zonal cases, alongside the differences between these cases.

Self-curtailment of onshore wind in the Zonal case will start at a price of £6/MWh in the Zonal case (and £3/MWh for offshore), due to the influence of the deemed generation CfD on the bidding behaviour of supported capacity (supported plants are incentivised to bid at their variable costs of generation). In the National BAU case, which assumes a continuation of the current CfD arrangements, market-self curtailment starts at the lower price levels of £0.03/MWh and £0.02/MWh for onshore and offshore wind[30]. In addition, as we have assumed the introduction of the deemed generation CfD in Great Britain only, rather than across the whole of Europe, there are some hours when it is less expensive to curtail wind in Britain and import power from Europe in the Zonal case compared to the National BAU case, also contributing to higher overall curtailment volumes.

[30] For the latest CfDs (e.g. AR4), CfD top ups are not paid if the day-ahead price goes negative, so generators are incentivised to bid at or near zero – though there are subtleties about portfolios having a preference for curtailing generators with a lower strike price.

Exhibit 8.10 – Renewable curtailment by technology by zone, Consumer Transformation (TWh)

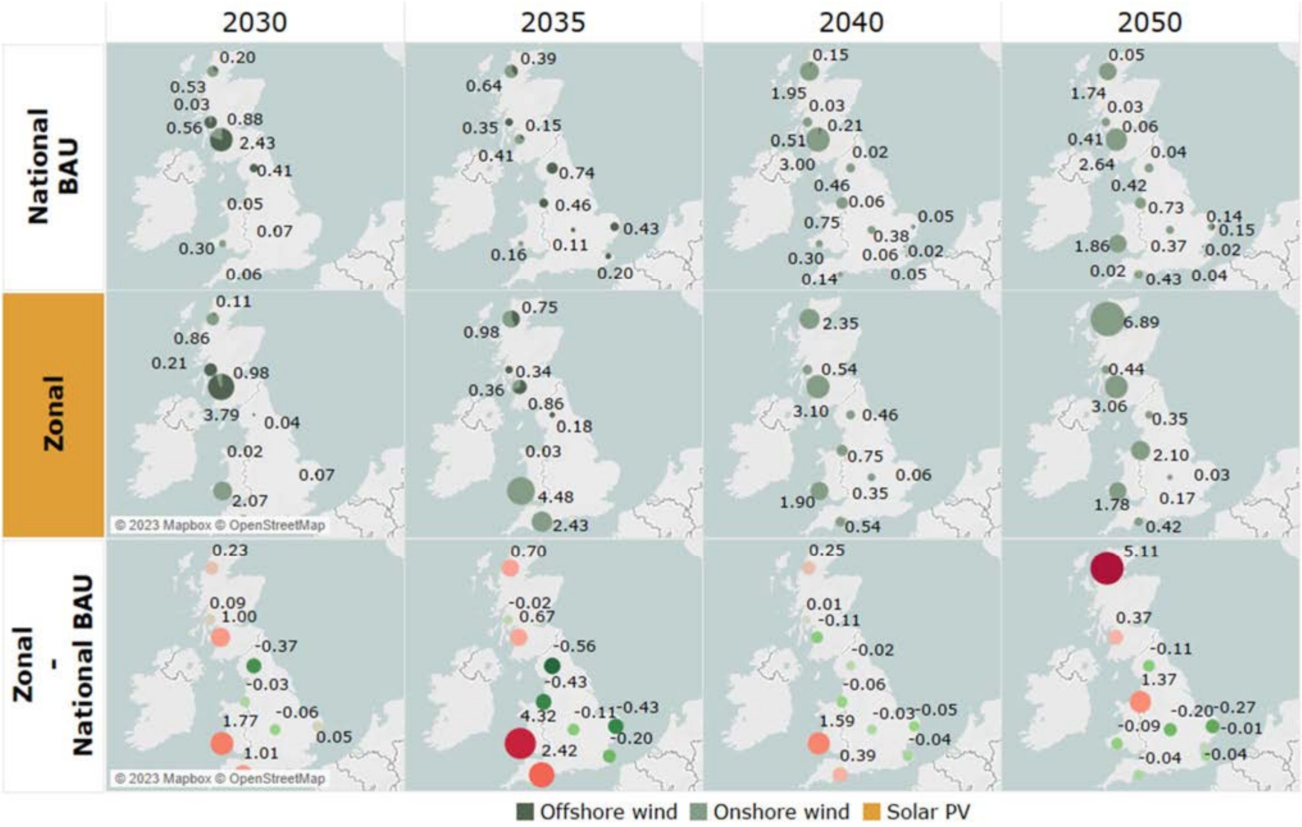
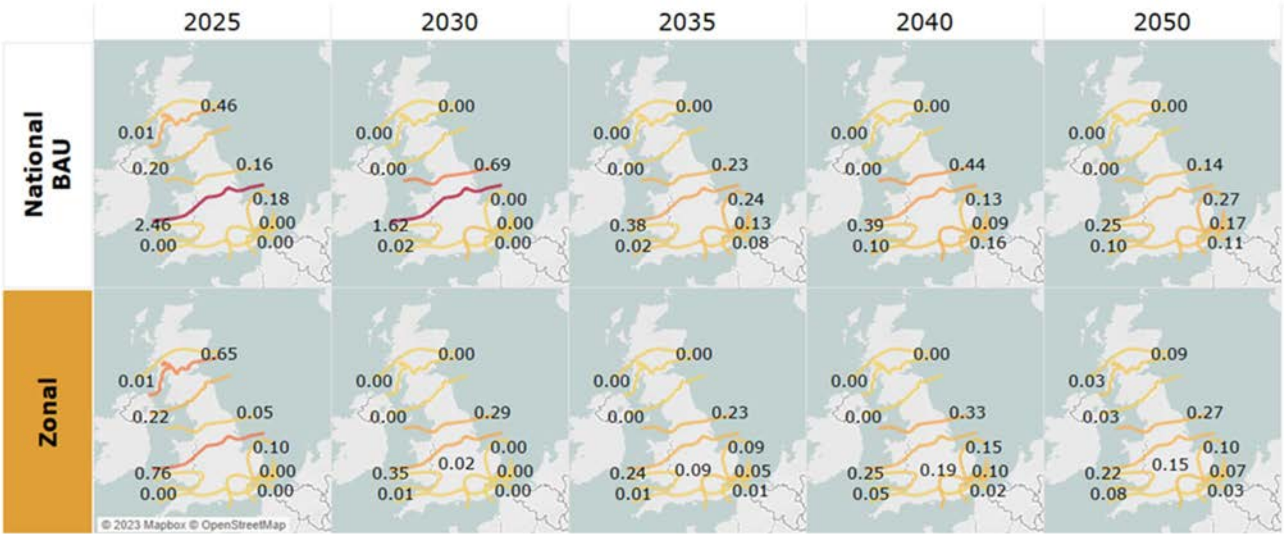


Exhibit 8.11 shows a metric intended to represent network congestion rent by boundary, although this is not a direct comparison due to the differences in market design. For Zonal, the figures reflect the power flows across the boundary multiplied by the price difference that is the intra-GB congestion rent broken down by boundary. There is no direct equivalent to congestion rent in a national market. For comparison purposes, the power flow multiplied by the effective marginal price differences in the Balancing Mechanism (meaning the offer price below a constraint minus bid price above) are shown for National BAU, though the actual costs are just on the redispatched volumes. In both cases, additional network build within the model is based on whether a marginal increase in boundary capability would reduce these congestion costs, either based on reductions in congestion rent (in the Zonal case) or reductions in accepted bid and offer volumes (in the National BAU).

As bids and offers in the National BAU Balancing Mechanism include significant bid and offer uplifts in addition to a cost reflective element, congestion rents are invariably higher in the National BAU case than Zonal, even for the same congestion volume. The effect of this is most noticeable in 2030 when network build is identical and generation capacity build is similar: additions in both cases of 4.1GW of offshore wind connected to the SHETL_S and/or SPT zones, and 0.9GW off East Anglia result in network constraints on the north to south flow on B7a and B8 and on LE1, although the congestion rent[31] associated with this is four times higher in the National BAU case. In later years much of the difference resolves as network build catches up with generation build.

Exhibit 8.11 – Network congestion rent by boundary, Consumer Transformation (£billion/year, real 2021)



Notes: In the National BAU case, figures are based on the difference in hourly marginal Balancing Mechanism prices on each side of the boundary, multiplied by the hourly flow across the boundary. The equivalent congestion rent for HVDC lines is also included and split across each boundary it crosses in proportion to the AC congestion rent for the boundary. In the Zonal case, data is based on the hourly difference in wholesale prices on each side of the boundary, multiplied by the flows across the boundary, with HVDC congestion rent split across boundaries as for the National BAU case.

Total AC transmission capacity by boundary is shown in Exhibit 8.12. The same 2030 starting point is used for boundary capabilities in both cases. From 2035 onwards the higher proxy congestion rent per unit of congestion volume in National BAU tends to incentivise greater build of network capacity in the National BAU case than in the Zonal, with the result that in nearly all cases network build is lower in the Zonal case. The exceptions are the Scottish boundaries B2, B4 and B6, which have higher levels of reinforcement in the Zonal than in the National BAU case in both 2040 and 2050, although these are small compared to reductions in grid build on the other boundaries. From 2035, SW1 is the boundary with the largest relative shortfall in boundary reinforcement, correlating with the high level of renewable curtailment in South Wales in Zonal compared with National BAU (despite the lower renewable capacity in South Wales).

[31] As above, defined through flows and marginal prices in the Balancing Mechanism.

Exhibit 8.12 – AC transmission capability by boundary, Consumer Transformation (cumulative '000 GWkm)

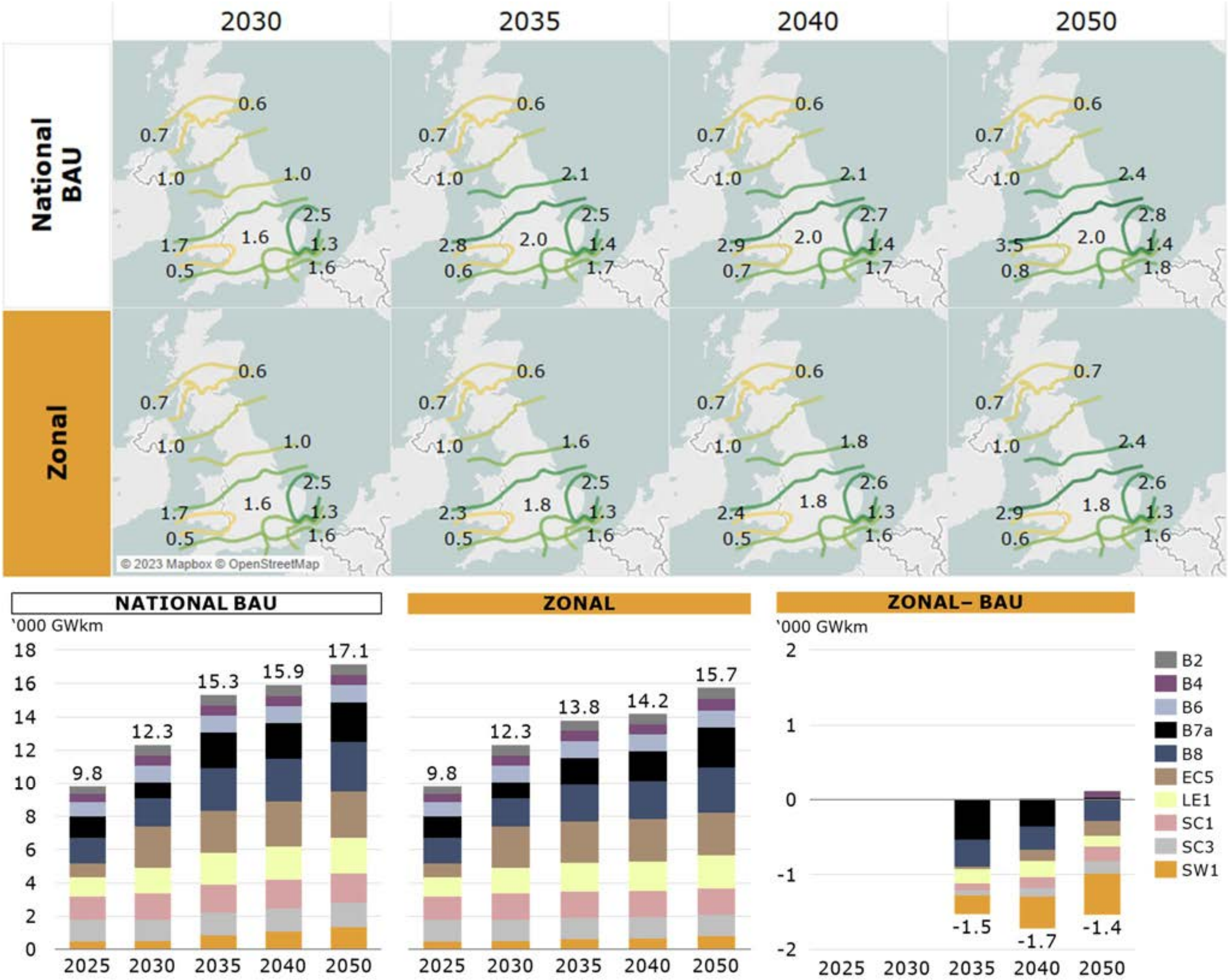
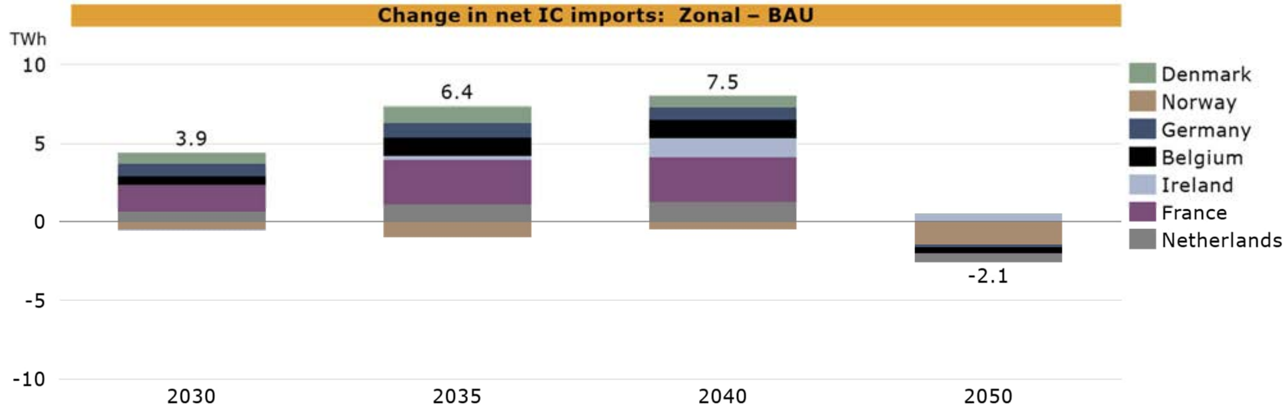


Exhibit 8.13 shows the change in net interconnector imports from other European countries in the Zonal compared with the National BAU case. Imports from most European countries interconnected to the southern zones of GB increase to 2040, while exports to Norway increase slightly. In 2050, the level of imports to the South of the country is similar in both National BAU and Zonal, reflecting the convergence in GB prices between the two cases over time. However, exports to Norway continue to increase in the Zonal case as more wind continues to deploy in Scotland, resulting in some price divergence from the rest of GB, and more periods when exporting to Norway is economic. The difference renewable bidding behaviour in the National BAU and Zonal cases is one factor driving the difference in interconnector flows.

Greater imports to meet demand in the South and higher levels of exports to Norway indicate greater alleviation of constraints through more efficient interconnector dispatch, with greater utilisation of wind generation in Scotland and reduced use of thermal generation in the South.

Exhibit 8.13 – Change in net interconnector imports, National BAU to Zonal – Consumer Transformation (TWh)



Allocation of risk, cost and reward

Exhibit 8.14 shows price duration curves in National BAU and for three zones (SHETL_N, North and South) in Zonal. The price separation in SHETL_N in 2030 is evident, with around 35% of hours being at very low prices. After 2030 the curves tend to converge, except that SHETL_N partially splits out again in 2050, reflecting increased wind build in Scotland in the Zonal case in 2050. The variability in exposure to low priced periods can be more variable in zonal markets, even in the long run when generation and grid build are more likely to be balanced. We do not observe any negative priced periods in 2030 or later years, significant transmission build being assumed to occur by 2030 based on the exogeneous assumptions from the ETYS and NOA7.

Exhibit 8.14 – Price duration curves, National BAU and Zonal, Consumer Transformation (£/MWh, real 2021)

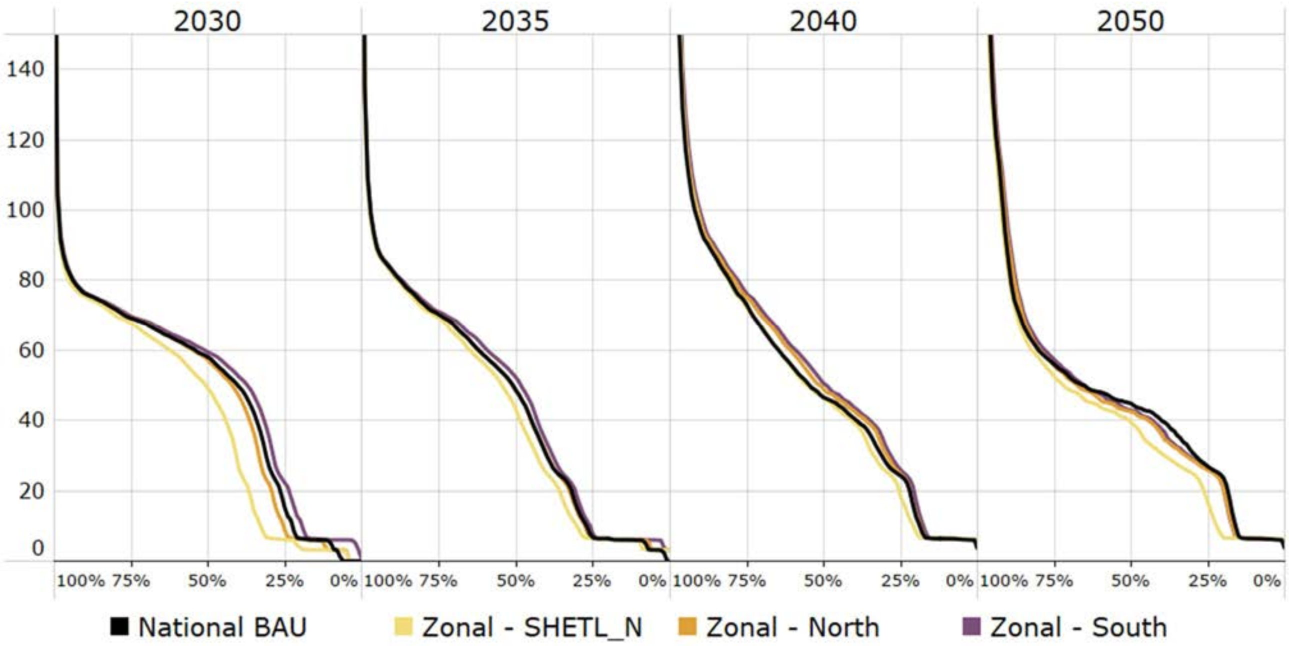
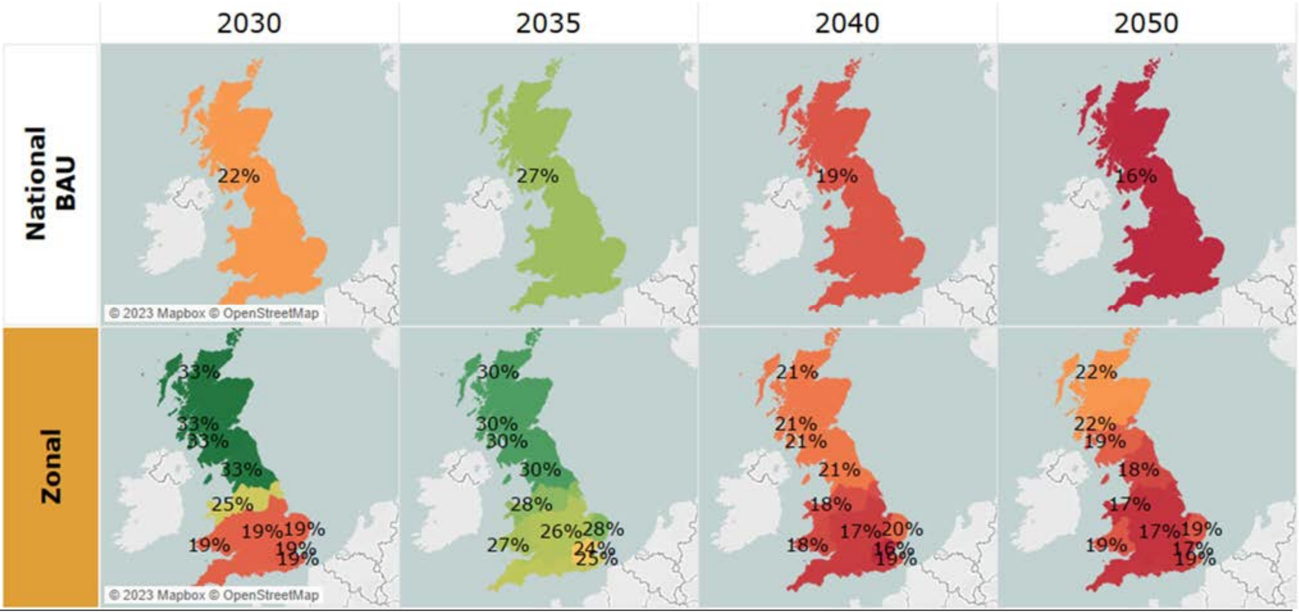


Exhibit 8.15 shows the percentage of hours annually when market prices are at or below £10/MWh in the Zonal and National BAU cases.

Exhibit 8.15 – Percentage of hours when wholesale prices are below £10/MWh, Consumer Transformation (%)



In 2030, the number of low-priced hours set by wind or other low variable cost technologies is 50% higher in Scotland and northern England in the Zonal than it is in National BAU (33% versus 22%, a difference of around 960 hours). This is to be expected since transmission constraints mean there are more hours where wind or other low marginal cost technologies set the price in these regions. By 2040 the difference has fallen to 2% (around 175 hours), but it rises again to 6% in northern Scotland by 2050. Without significant mitigation measures to compensate, merchant renewable plants in Scotland would experience a significant revenue impact to 2035. The potential longer-term persistence of smaller differences would also be an additional locational risk factor for generation investment, even for plants with 15-year support CfD contracts.

Economic welfare comparison

Net Present Values (NPV) of economic welfare provided in this report are calculated over an appraisal period from 2028 to 2050 inclusive, assuming a 3.5% discount rate. Modelled years were 2025, 2030, 2035, 2040 and 2050, with values for the non-modelled years in between based on interpolation between modelled years. Each future year is given a discounted value, starting with 2028 indexed to a value of 1. This includes all years, both modelled years and years in between. Final system costs included direct capex values from the modelled years[32]. Variable and annual fixed costs from each modelled year are counted for each of the years the modelled year represents. On this basis, the NPV values are therefore 2028 values for a 23-year period. We then further discount these values in order to bring them to a 2021 indexed value.

[32] The capex is included in the NPV using the Spackman approach.

The differences in economic welfare in the Zonal case compared with a National BAU baseline are shown in Exhibit 8.16. The Zonal case shows a total GB economic welfare benefit of £4.2 billion over the period 2028-2050, with electricity consumers and producers better off by £1.9 and £2.8 billion respectively, with the balance made up by reduced congestion rent (on transmission between GB and other markets) and changes in hydrogen sector welfare. Note that capacity payments are quite sensitive to minor changes in inputs: if the NPV capacity payment difference were £0.5 billion lower, consumers would be gaining more than producers. Apart from capacity payments, another factor in the increase in producer welfare is that some (mainly Northern) generators gain more from not facing TNUoS than they lose from zonal prices[33].

The main downside for consumers is the higher wholesale costs in the Zonal case. Higher costs in some zones would be expected in a zonal market (for example London would be expected to have higher prices). The main systematic driver of the lower wholesale prices in the National BAU case in 2040 compared to the Zonal case is driven, in part, by a higher renewable capacity. It should be noted that wholesale price differences might be somewhat offset by changes to capacity payments and CfD costs in any case.

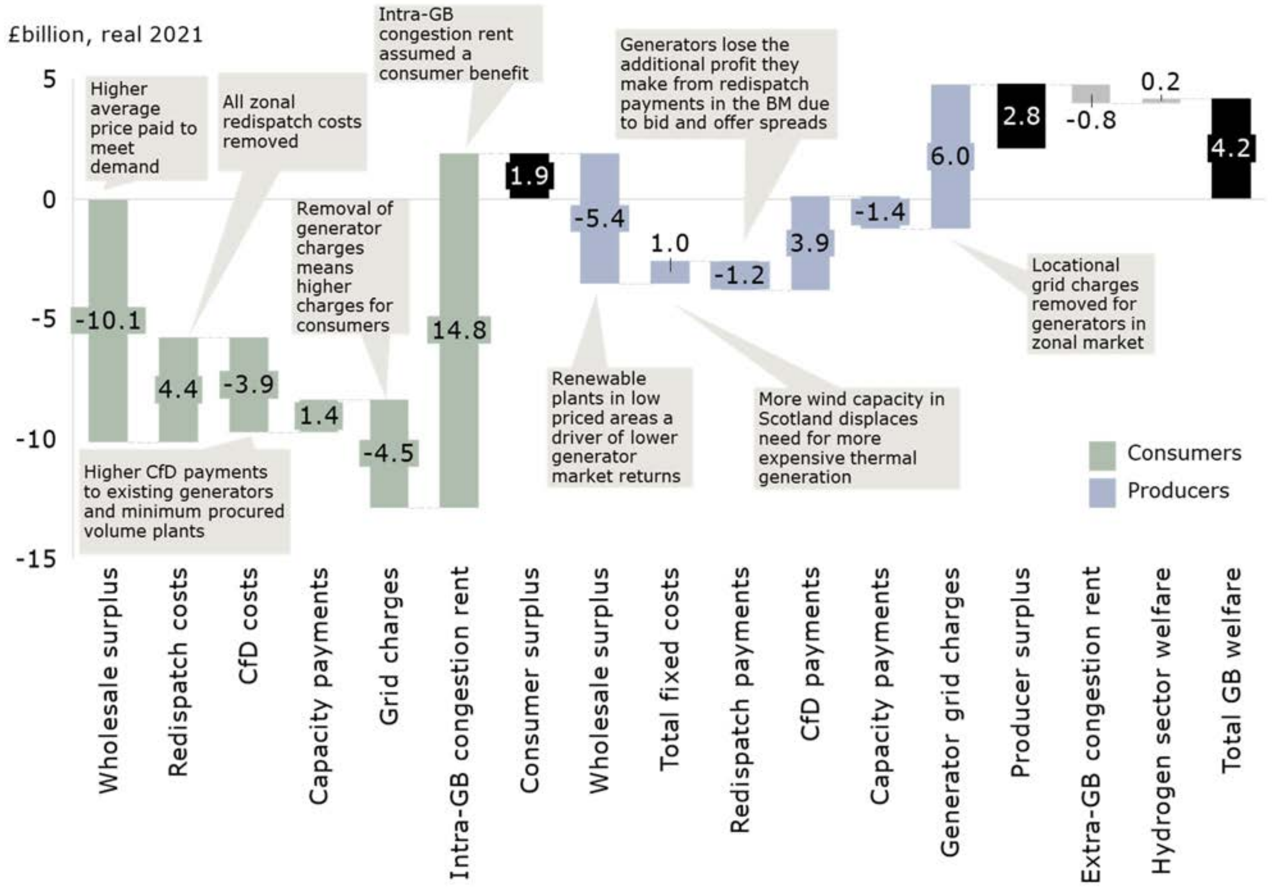
Overall benefits are small compared to the total system costs over the discounting period.

In terms of overall system costs, the overall benefit of £4.2 billion is primarily made up of the following cost savings in the Zonal case[34]:

- More efficient transmission network use (including reduced build): £1.5 billion.
- Reduced costs of generation investment: £1 billion.
- More efficient market operation: £1.2 billion.

[33] We have prevented generators with an existing CfD (including assumed AR5 and AR6 plants) indexed to zonal prices gaining from not paying TNUoS while also not losing from zonal prices by assuming they keep on paying TNUoS for the duration of the CfD. There are alternatives such as indexing to a national price for these CfD plants. However, for other generators such as merchant, post-RO and post-CfD generators, in some cases the gain from not paying TNUoS will exceed any drop in gross margins due to zonal prices.
[34] This split should be regarded as very approximate – for example, typically building some additional network or generation is of some benefit to the system – just less than its costs.

Exhibit 8.16 – Total economic welfare benefit breakdown, Zonal versus National BAU, Consumer Transformation (Net Present Value 2028-50 at 3.5% discount rate, £billion real 2021)



The split between generators and consumers is impacted by a number of factors (without impacting the overall economic welfare, neglecting any consequential change in build) including:

- Any transitional arrangements for existing generators (beyond existing CfD generators).
- Details of exactly how CfDs are awarded.
- TNUoS charging arrangements, including where any intra-GB congestion rent is allocated[35].

In addition, though we show a welfare split between consumers, producers, congestion rent and hydrogen sector welfare, there are likely to be differences between different generators (location, new/existing, technology,

[35] By intra-GB congestion rent we mean congestion rent arising in a locational market (zonal or nodal). While the details would be dependent on the specifics of a market design, the resulting cash flow collected by the transmission owners could be used to either lower TNUoS costs for consumers or producers, or possibly subsidise further network build. We have assumed it is used to lower costs for consumers (though generators also benefit from the removal of wider generation TNUoS).

support scheme, if any) and different consumers (location and pattern of demand). Indeed, some locational markets still charge a uniform price to some or all consumers, whereas others pass cost variation through[36].

8.2 Decarbonisation pathways

Question 2 – How robust are comparisons of the benefits and disbenefits of different locational market designs to uncertainty on future decarbonisation pathways?

Across the scenarios modelled (Consumer Transformation and System Transformation), we have found broadly similar outcomes.

The level of overall economic welfare benefit achieved in by the Zonal and Nodal cases is similar in both the Consumer Transformation and System Transformation scenarios; despite quite different levels of overall hydrogen demand in the two scenarios, the greater freedom in System Transformation to optimise how hydrogen demand is met results in a similar level of electrolysis build and hence coupling with the power sector in both scenarios, resulting in limited impact from the hydrogen economy.

We have also found a similar pattern of locational signal strength change in moving in from a national to a zonal market, and also similar improvements in interconnector dispatch from in both scenarios.

Locational signal strength

As for the Consumer Transformation scenario, we have carried out an exercise to establish the overall change in locational signal sharpness when moving from a national market with locational grid charges to a zonal one without in the System Transformation scenario. The outcome was similar to the Consumer Transformation scenario, with the National BAU market having sharper locational signals (i.e. stronger incentives on demand and generation to locate in proximity to each other) than the Zonal case.

Exhibit 8.17 shows the results of our locational grid charge modelling in the System Transformation scenario in the National BAU case for onshore wind, offshore wind and solar PV respectively. The locational grid charges in the National BAU are based on the existing TNUoS methodology for the wider tariff (locational) component of TNUoS, extended to 2050 and combined with modelled scenario outputs for the location of generation and demand. Compared with Consumer Transformation, the general pattern of charges is similar with high charges in Scotland, and somewhat negative charges in the south, particularly for wind. In addition, the charges in System Transformation are generally sharper, particularly in 2035, driven by similar levels of renewable deployment (particularly offshore wind in Scotland) combined with lower demand, with the result that less of the generation can be used nearby, resulting in more flows on the transmission network.

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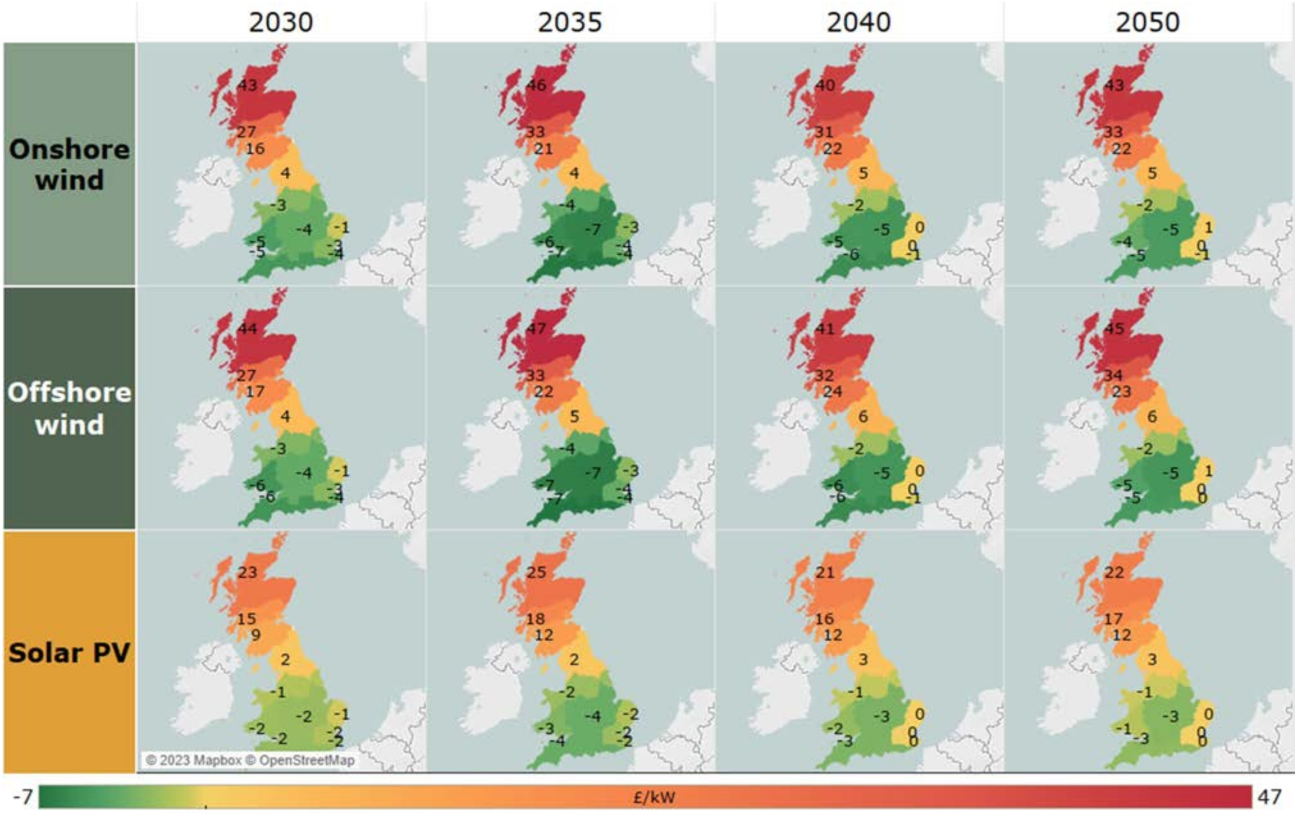
[36] Currently there are small differences in retail prices for electricity for different parts of GB – around +/- 1p/kWh for residential consumers, in part due to differences in distribution network costs, though demand TNUoS also varies.

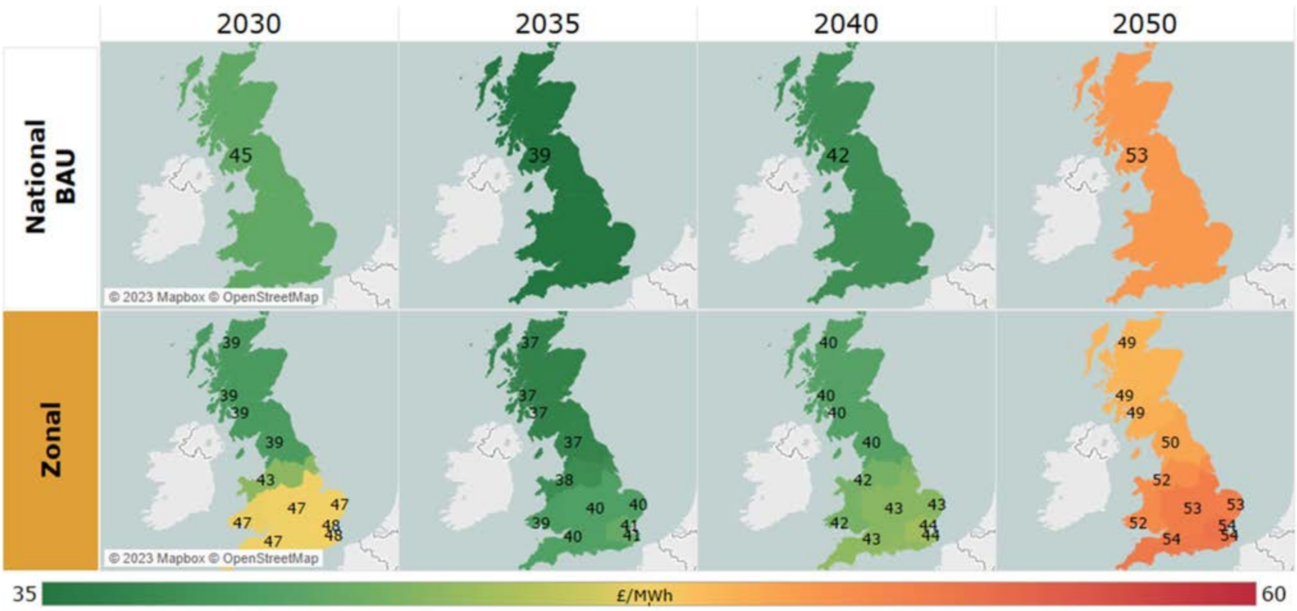
Exhibit 8.17 – Locational grid charges for renewable technologies in National BAU, System Transformation (£/kW, real 2021)



Note: For offshore wind, the grid charge reflects the locational tariff for the onshore connection point.

Exhibit 8.18 compares wholesale prices under both the National BAU and Zonal cases.

Exhibit 8.18 – Wholesale power prices, System Transformation (£/MWh, real 2021)



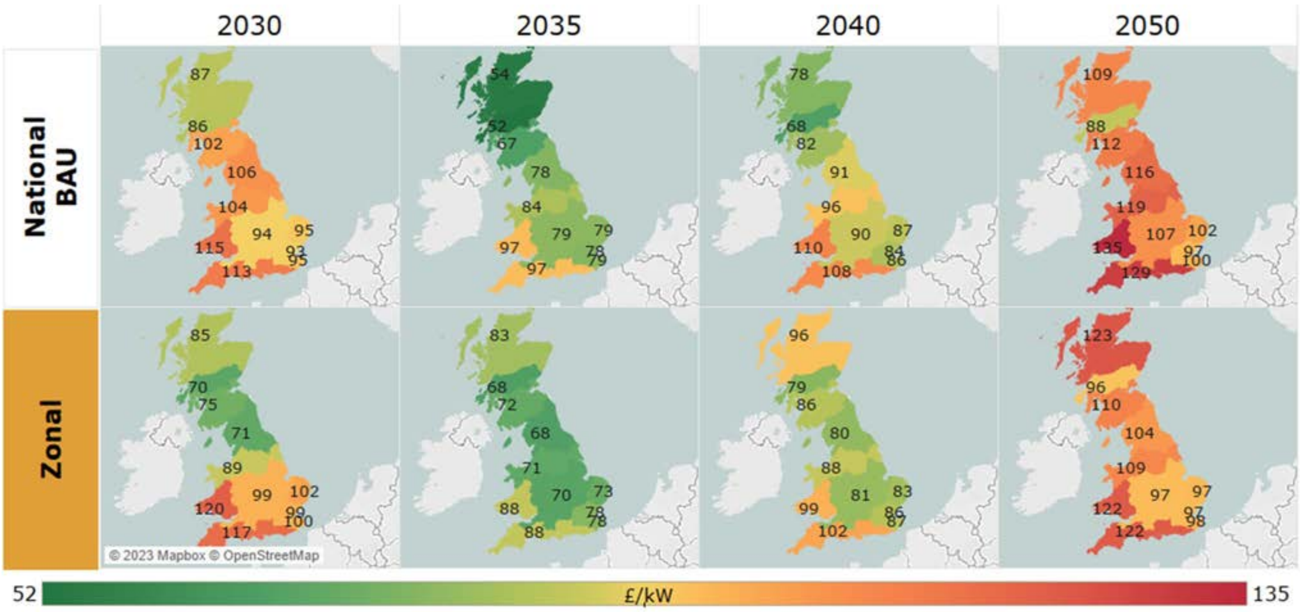
In System Transformation, average power price levels fall between 2030 and 2035 and do not recover fully until after 2040. The meeting of the same offshore wind target of 50GW by 2035 in both CT and ST has a greater downward impact on prices in System Transformation, given the lower level of demand in the scenario, although by 2050 both CT and ST have similar average prices.

Similarly to the Consumer Transformation scenario, Zonal prices show the widest divergence in 2030, reflecting the highest level of network congestion occurring in that year. In the longer term, zonal price differentials generally moderate as network build catches up with renewable deployment and investment decisions respond to the new locational signals.

The National BAU price is similar to the Zonal price in the Midlands for all years in the ST scenario – though the demand weighted average price is actually lower in 2050 in the Zonal scenario than in the BAU scenario.

Subtracting locational grid charges from energy market gross margins gives a useful metric for the overall financial impact of a change from the National BAU market to the Zonal market; this is shown for onshore wind in Exhibit 8.19 (this is equivalent to the exposure of a merchant wind farm, although in our scenarios all new build onshore, offshore and solar PV is assumed to be supported with a CfD).

Exhibit 8.19 – Average wholesale energy market gross margin minus locational grid charges – merchant onshore wind, System Transformation (£/kW, real 2021)



Note: Values shown are before any payments under a CfD or other support payment. All new build renewable capacity in our modelled scenarios is assumed to have a CfD (either BAU in National BAU, or deemed generation in all other cases).

As for Consumer Transformation, the strength of the locational signal (the difference between the best zone and the worst zone) is sharper in Zonal than National BAU in 2030 (which is reflected in the deeper contrast in colours), but weaker after 2030.

Investment effectiveness

Renewable technologies

The overall shifts in location for renewable capacity and generation in the System Transformation scenario are shown in Exhibit 8.20 and Exhibit 8.21. As for Consumer Transformation, the overall locational shift is generally from England towards Scotland, in line with the general locational signal strength. There is also a significant change in the type of capacity, with reductions in solar PV capacity being replaced by additional wind capacity in Scotland. However, for offshore wind the total capacity in 2035 is still around 50GW – so the offshore wind increase is mainly due to locations with higher load factors (even post curtailment) being more profitable in the Zonal case. The change from CfD award based on lowest strike price in National BAU to least cost of top-up in the Zonal case tends to favour onshore wind in Scotland, where capture prices are closer to required strike prices, and require a lower top-up than solar PV in the South.

Exhibit 8.20 – Change in renewable generation capacity location – National BAU to Zonal, System Transformation (cumulative GW)

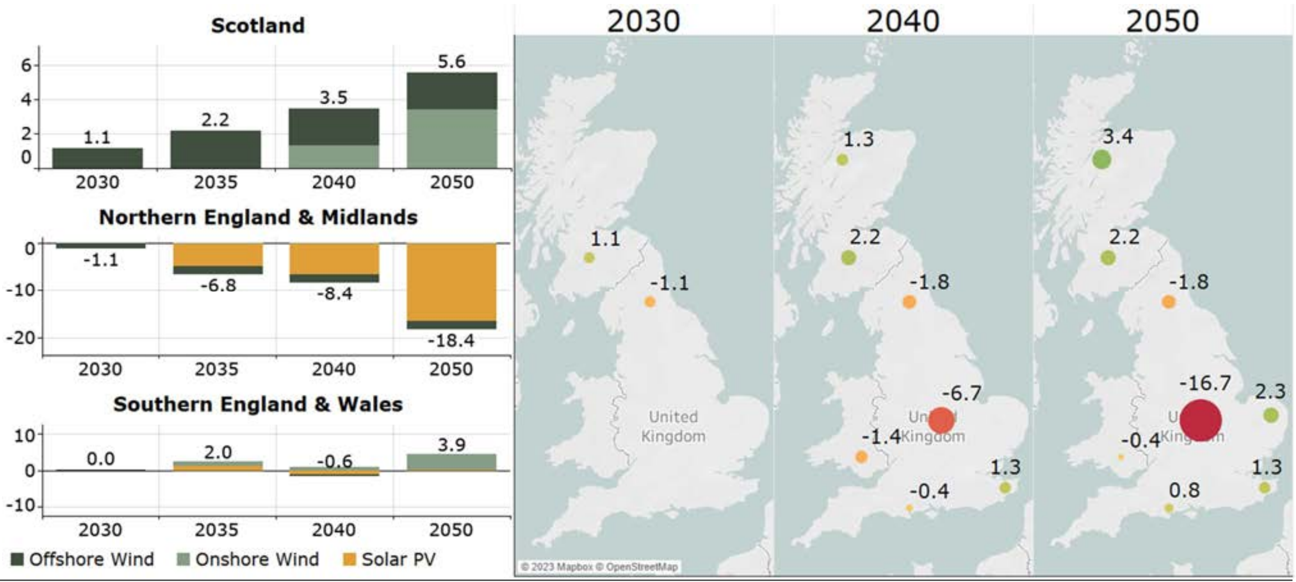
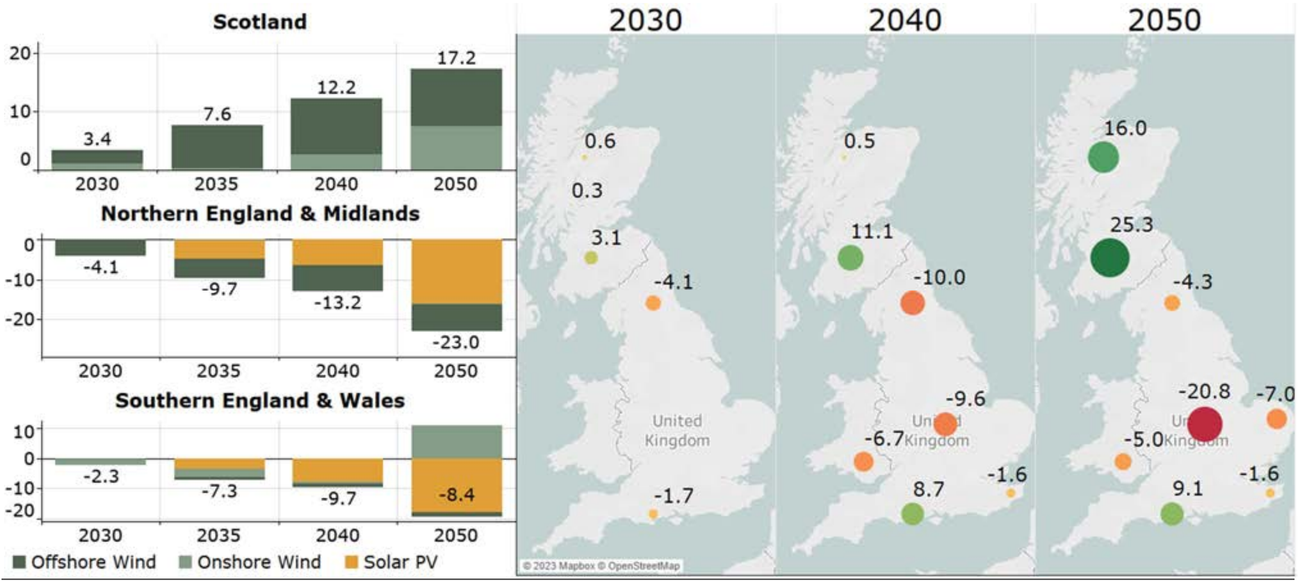


Exhibit 8.21 – Change in location of renewable generation – National BAU to Zonal, System Transformation (TWh)



Hydrogen production and hydrogen power generation technologies

In the exogeneous FES scenario input assumptions, relative to the Consumer Transformation scenario, the System Transformation scenario has very high hydrogen demand in the long term, and lower power demand. Following our modelling of the scenarios, which has allowed for build of both hydrogen production technologies and hydrogen fuelled power generation as part of the economic co-optimisation of the power and hydrogen sectors, this has remained the case, as shown for power demand in the National BAU case in Exhibit 8.22 and for hydrogen demand in Exhibit 8.23.

Exhibit 8.22 – Total annual power demand, National BAU – Consumer Transformation and System Transformation scenarios (TWh)

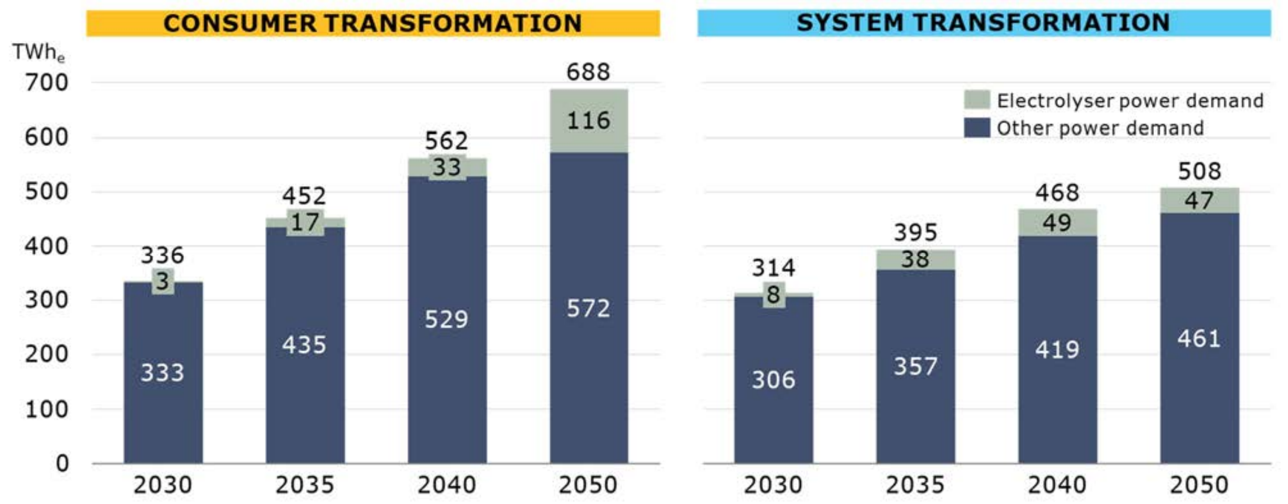
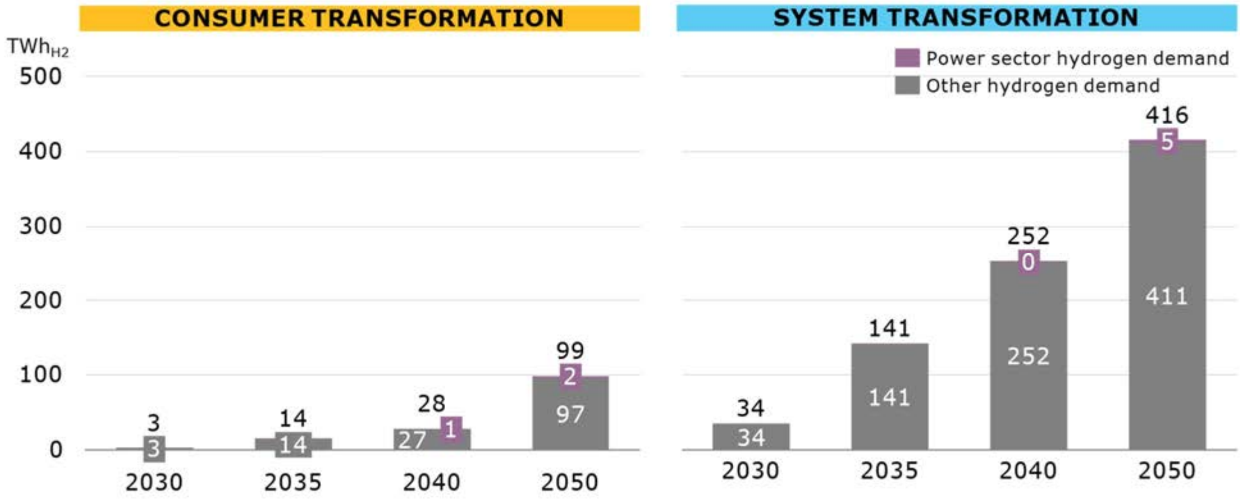


Exhibit 8.23 – Total annual hydrogen demand, National BAU – Consumer Transformation and System Transformation scenarios (TWh)



In System Transformation, there is freedom over the type of hydrogen production (either from electrolysis or Steam Methane Reformation[37] (SMR) with CCS). SMR with CCS is the dominant technology for hydrogen production in the System Transformation scenario, with around 50GW of hydrogen production capacity deploying by 2050, compared with around 11GW of electrolysers. Based on AFRY's wider experience modelling the interaction with the power system, the split between electrolysis and blue hydrogen is quite sensitive to gas prices, technology costs (both on the hydrogen and electrical side) and the volume of hydrogen demand.

Deployment of electrolysis by location is shown in Exhibit 8.24, while deployment of SMR with CCS is shown in Exhibit 8.25. In the System Transformation scenario there is a hydrogen network and so freedom for electrolysis to be moved to new locations. In the National BAU case, electrolysers do not face locational grid charges, and so the locational signal change between the Zonal and National BAU cases is limited to energy price changes. Under the Zonal case, we see that electrolysers respond to the locational signals and relocate northwards (compared with National BAU), taking advantage of lower prices, though this may be sensitive to assumptions on the bidding behaviour of electrolysis in the Balancing Market in the National BAU (and National Enhanced) market cases.

[37] For the purpose of this report, unless otherwise stated SMR should be taken to be a generic term for 'blue hydrogen' and also encompass ATR (Autothermal Reforming)

Exhibit 8.24 – Cumulative new build electrolysis capacity, System Transformation (GW)

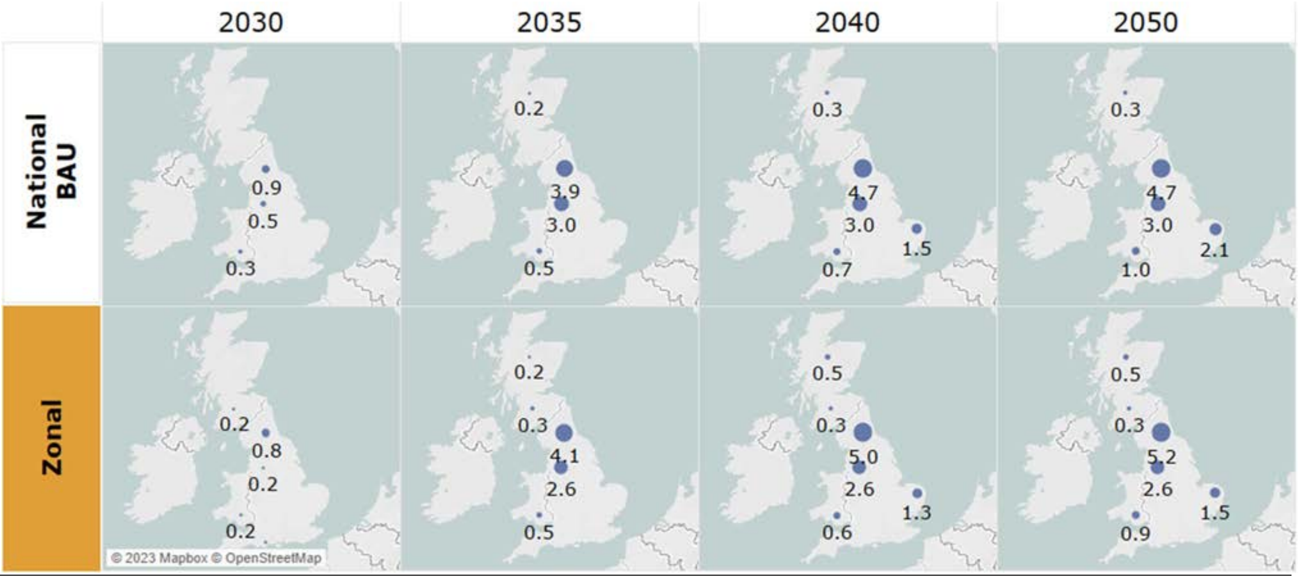
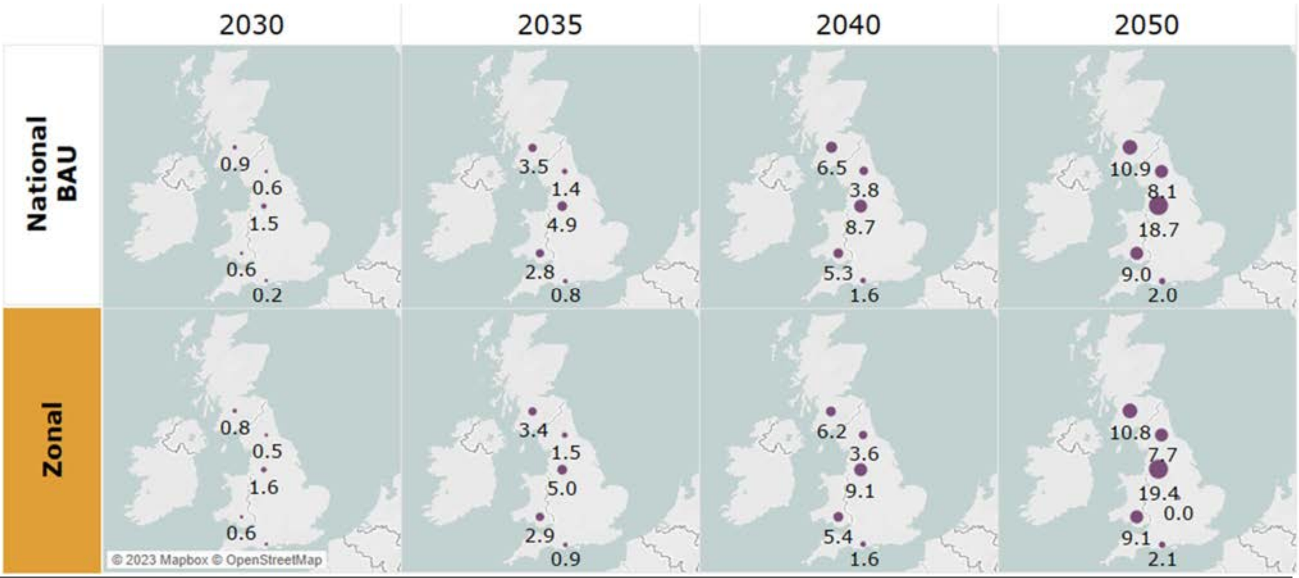


Exhibit 8.25 – Cumulative new build SMR with CCS capacity, System Transformation (GW)



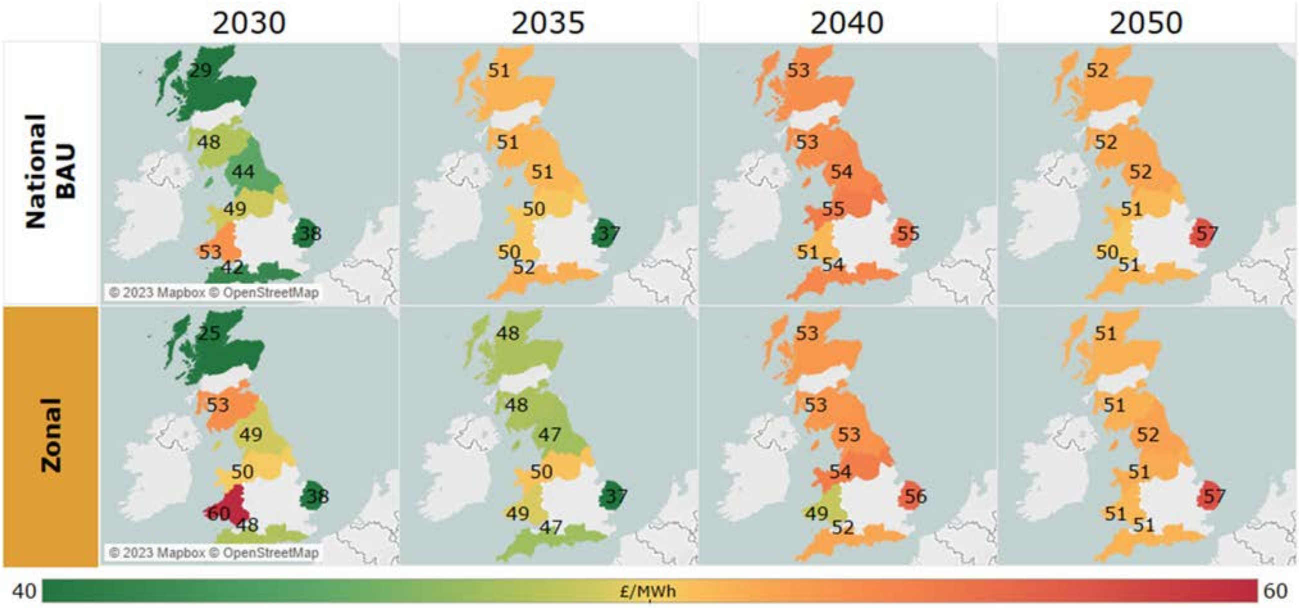
The build of electrolysis in System Transformation differs compared with Consumer Transformation:

- Total electrolyser capacity is higher in the System Transformation scenario to 2040, partly driven by more rapidly rising hydrogen demand. Lower power demand in System Transformation combined with the same deployment of c.50GW of offshore wind by 2035 in both scenarios leads to more low-priced hours in the System Transformation scenario, which helps to favours electrolysis.
- Despite much lower hydrogen demand in the Consumer Transformation scenario in 2050, the constraint that all demand must be met from electrolysis results in higher electrolysis capacity in Consumer

Transformation. Once the rate of renewable deployment slows post-2035 in System Transformation, electrolysis becomes less competitive relative to SMR with CCS, and deployment of electrolysis slows.

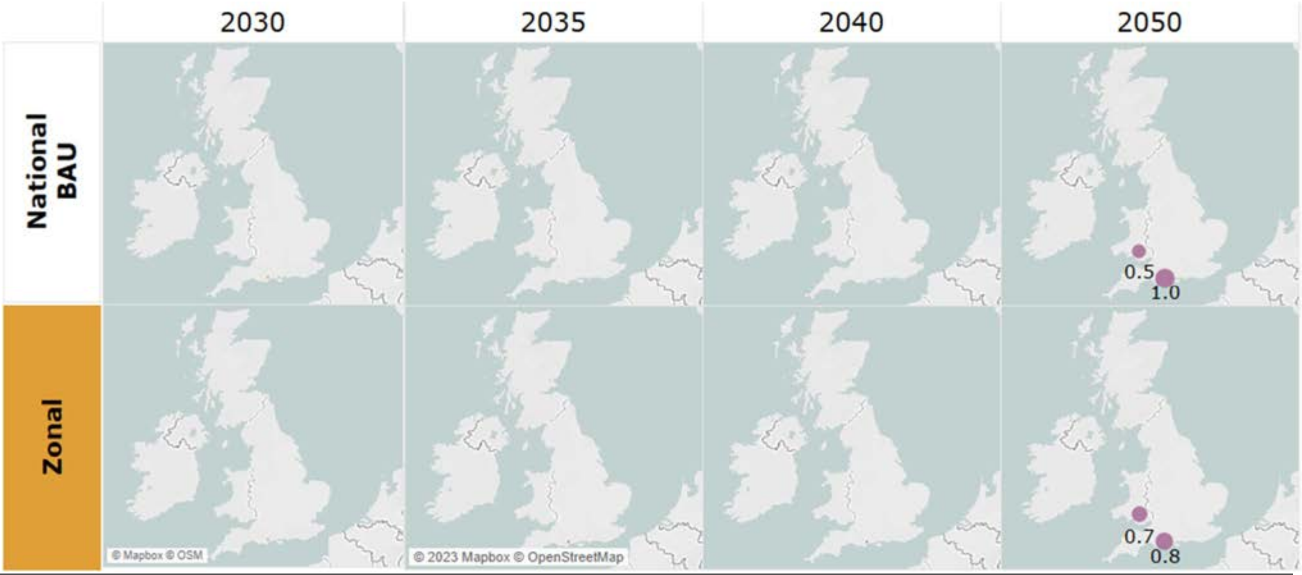
Hydrogen prices are generally lower in the System Transformation scenario compared to the Consumer Transformation scenario, enabled by lower power prices for electrolysers, and alternative production from SMR, together with having a hydrogen network, which makes electrolysis build more economic in areas that do not have the potential for salt cavern storage. Locational variation in hydrogen prices is also lower, particularly by 2050, also enabled by the development of the hydrogen network.

Exhibit 8.26 – Wholesale hydrogen prices, System Transformation (£/MWh, real 2021)



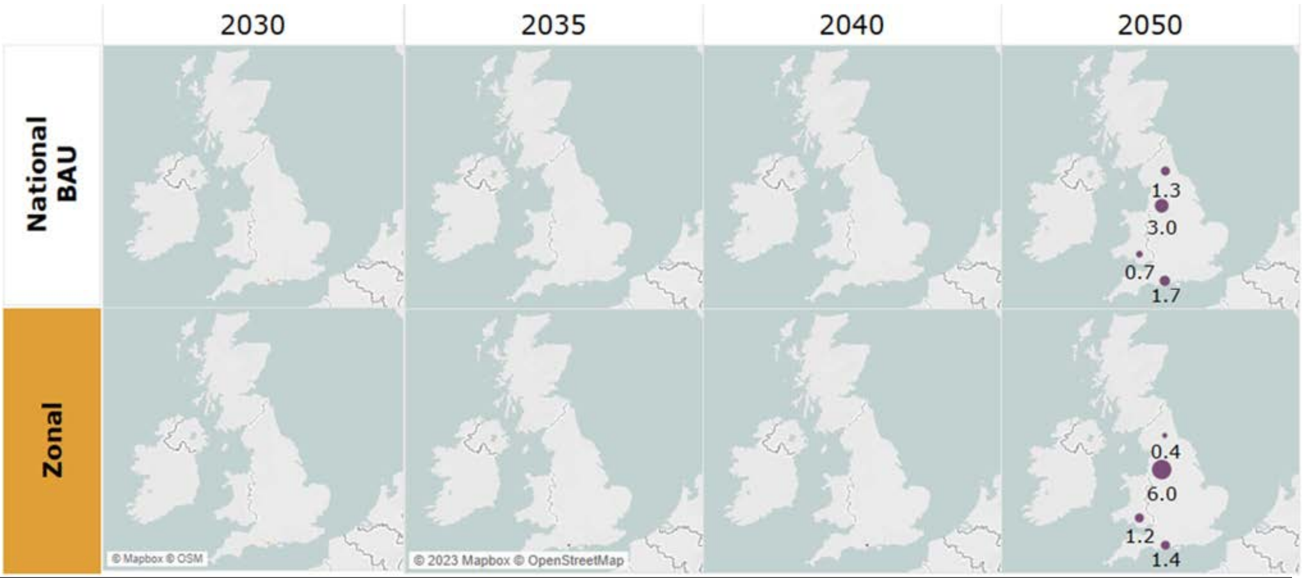
Unlike in the Consumer Transformation scenario, hydrogen CCGTs become economic to build in System Transformation, although only at the end of the timeframe. There is small shift of capacity northwards between two zones with very similar hydrogen prices, reflecting the general change that power market locational signals are less sharp in the zonal case.

Exhibit 8.27 – Cumulative new build hydrogen CCGT capacity, System Transformation (GW)



In System Transformation there is around 9GW of hydrogen GT capacity, compared with about 4GW in Consumer Transformation. A higher penetration of renewables in a lower power demand scenario and lower hydrogen prices help drive this difference.

Exhibit 8.28 – Cumulative new build hydrogen GT capacity, System Transformation (GW)



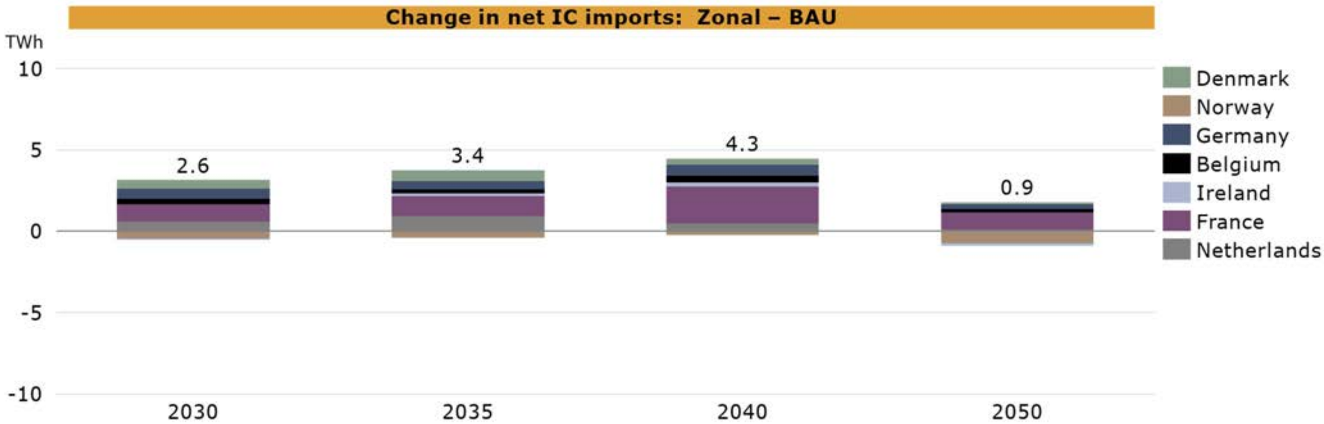
Operational efficiency

Exhibit 8.29 shows the change in net interconnector imports to other European countries in the Zonal case compared with the National BAU. As in the Consumer Transformation scenario, imports from most European countries interconnected with the south of the country increase including in 2050, while exports to Norway increase slightly. In 2050, the level of imports from the South of the country converges between the National BAU and

Zonal cases, reflecting the convergence in GB prices between the two cases over time. However, exports to Norway continue to increase in the Zonal case as more wind continues to deploy in Scotland, resulting in some price divergence from the rest of the UK, and more periods when exporting to Norway is economic. The overall size of the changes between cases is smaller in System Transformation compared with Consumer Transformation, given lower demand and lower price levels in System Transformation.

Greater imports to meet demand in the South and higher levels of exports to Norway indicate greater alleviation of constraints through more efficient interconnector dispatch, with greater utilisation of wind generation in Scotland and reduced use of thermal generation in the South.

Exhibit 8.29 – Change in net interconnector imports, National BAU to Zonal – System Transformation (TWh)



Allocation of risk, cost and reward

Exhibit 8.30 shows price duration curves in National BAU and for three zones (SHETL_N, North and South) in Zonal. As for the Consumer Transformation scenario, the price separation in SHETL_N in 2030 is evident, with around 35% of hours being at very low prices. A difference with Consumer Transformation is the plateau in the curves at £25/MWh, which grows in extent to 2050. This is due to the electrolysers setting a price in the power market consistent with competing with the alternative cost of hydrogen production from SMR with CCS[38], an interaction that occurs in the System Transformation scenario but not the Consumer Transformation scenario. After 2030 the curves tend to converge, except that SHETL_N partially splits out again in 2050, reflecting increased wind build in Scotland in Zonal in 2040 and 2050. As in the Consumer Transformation scenario, the variability in exposure to low priced periods can be greater in a zonal market, even in the long run, when generation and grid build are more likely to be balanced.

[38] On the whole both electrolysis and SMR do recover their capex via the hydrogen price – but cost recovery is not even, so at some times the hydrogen price will reflect short run costs, and at other times it will be higher.

Exhibit 8.30 – Price duration curves, National BAU and Zonal, System Transformation (£/MWh, real 2021)

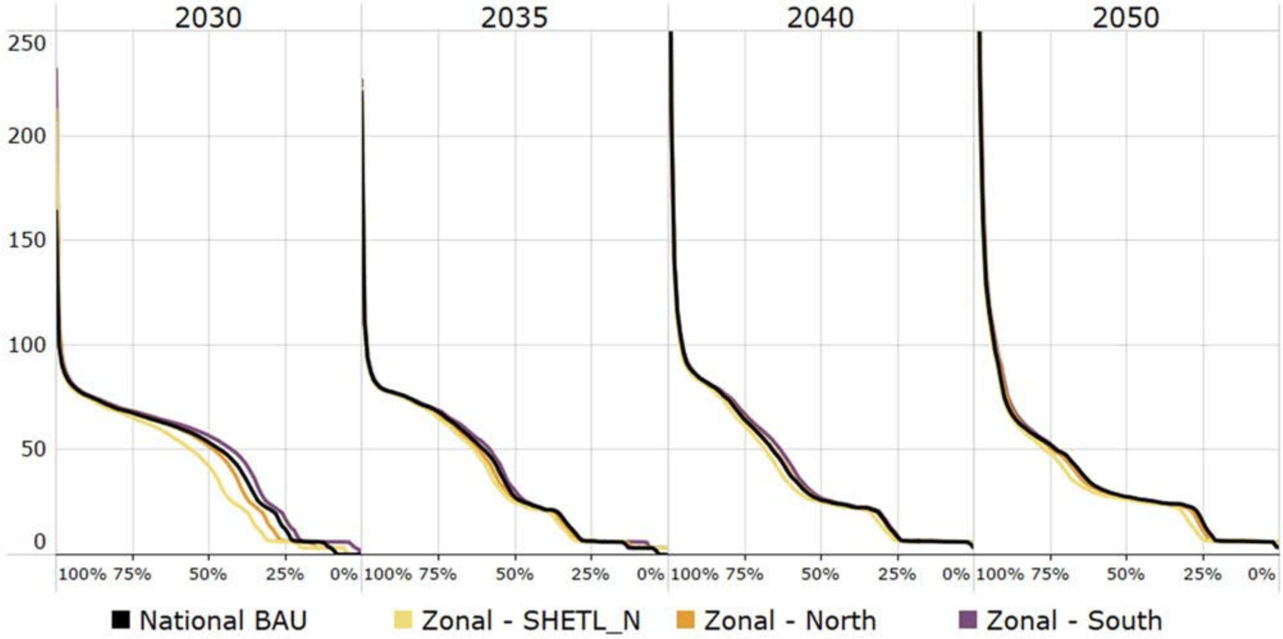
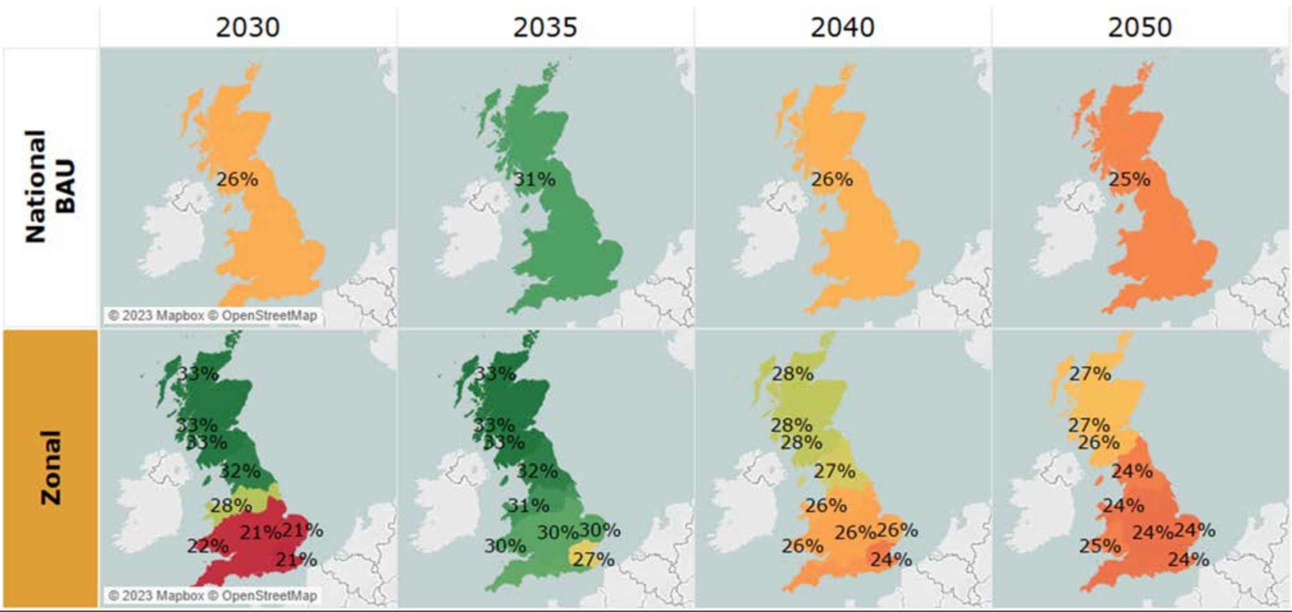


Exhibit 8.31 shows the percentage of hours annually when market prices are at or below £10/MWh in the Zonal and National BAU cases.

Exhibit 8.31 – Percentage of hours when wholesale prices are below £10/MWh, System Transformation (%)



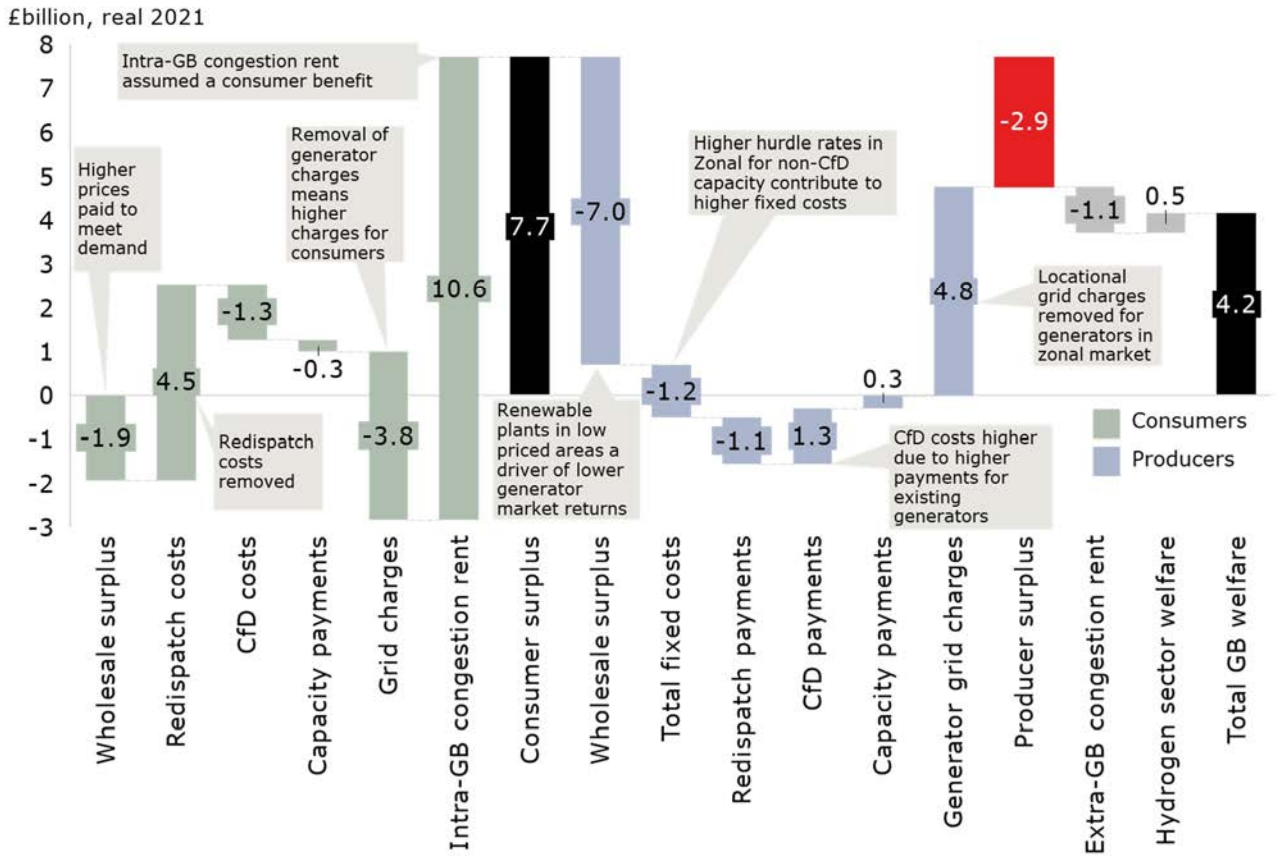
Similarly to Consumer Transformation, in 2030, the number low priced hours set by wind or other low variable cost technologies is somewhat higher in Scotland and northern England in Zonal than it is in National BAU (33% versus 26%, or around 1140 more low priced hours). Some differences across the country persist until 2050, despite network build catching up with generation build in the long run, again indicating some persistent additional locational risk for unhedged generators.

Economic welfare comparisons

Exhibit 8.32 summarises the total GB economic welfare benefits of the Zonal case against a National BAU baseline in the System Transformation scenario. Overall economic welfare benefits over the National BAU baseline in each case are similar in magnitude to those in the Consumer Transformation scenario. As for the Consumer Transformation scenario, overall net benefits are smaller than many of the individual components. The split between components is slightly different to the CT scenario. In this scenario the benefits accrue to consumers, with producers (overall) actually worse off – though this will vary for different producers. This is primarily due to the much lower reduction in wholesale surplus in the Zonal case – the ST does not include a year where the National BAU has significantly lower wholesale prices (such as 2040 in the CT scenario), and prices are the opposite way round in 2050. Again, there may be winners and losers among different types or locations of generators and consumers.

The disbenefit in Zonal (N) for the System Transformation scenario versus Consumer Transformation scenario (Exhibit 2.2) is somewhat smaller due to the lower levels of renewable build.

Exhibit 8.32 – Total economic welfare benefit breakdown, Zonal versus National BAU, System Transformation (Net Present Value 2028-50, £billion real 2021)



8.3 Uncertainties in future infrastructure development

Question 3 – How robust are comparisons of the benefits and disbenefits of different locational market designs to uncertainty on future infrastructure development, for example transmission network build?

In terms of total economic welfare, locational markets are more resilient to transmission delays. However, cost of delays would be unevenly felt – with winners and losers depending on location. The impact of delayed grid build is severely negative for generators who end up being held behind an export constraint for longer.

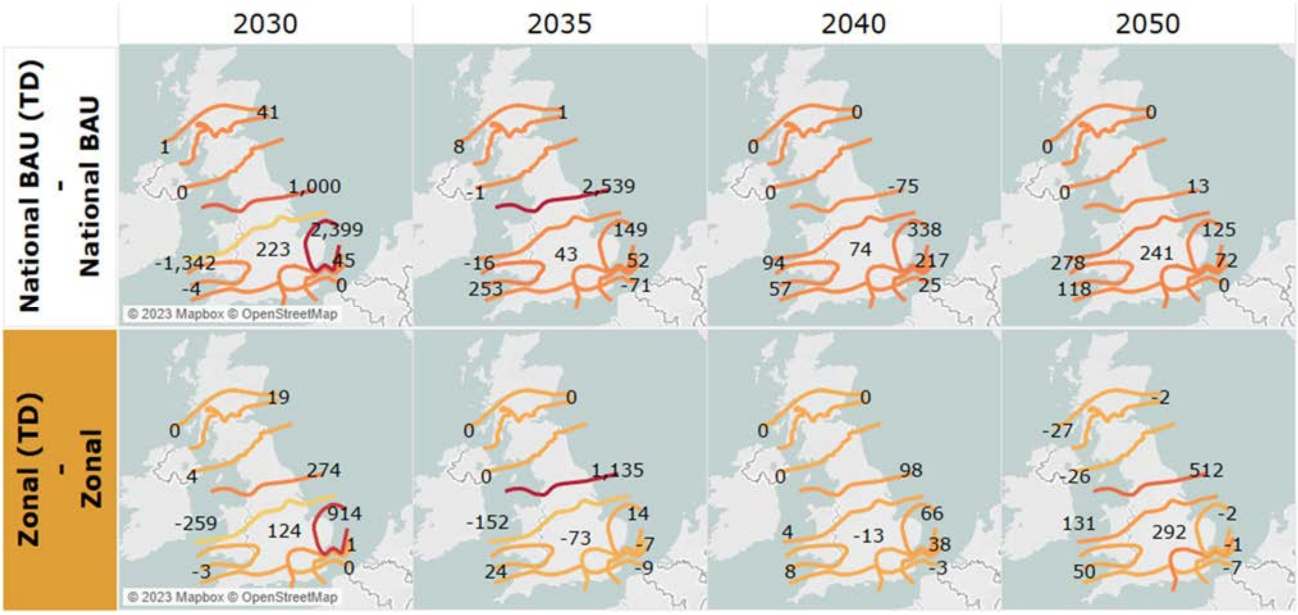
We carried out a sensitivity on the National BAU and Zonal cases in the Consumer Transformation scenario, based on a systematic 5-year delay to all network reinforcement occurring over the timeframe to 2050 (resulting in the National BAU TD and Zonal TD modelled cases). The 5-year delay was imposed exogenously on the National BAU and Zonal modelled cases without any other adjustments, including any re-adjustment of the mix or location of the capacity the model had built optimally based on the previous, on time, network infrastructure.

To account for the fact we model only every fifth year, the following approach to implementing the sensitivity was applied:

- Network reinforcements in place prior to 2028 were assumed to still go ahead (as already committed).
- Networks reinforcements coming in in 2028 and 2029 were delayed as follows:
  - HVDCs
    - 2GW entering in 2028 delayed until 2030
    - 2GW entering in 2029 delayed until 2035
  - AC boundary capabilities
    - Boundary capability increases between 2027 and 2028 delayed 50% to 2030 and 50% to 2035
    - Boundary capability increases between 2028 and 2029 delayed to 2035
- Network reinforcements in 2030 and all later years assumed to be delayed by 5 years.

The resulting impact on network congestion rent (taking a proxy for this from the Balancing Mechanism for National BAU) is shown in Exhibit 8.33. The values show the differences in congestion rent by boundary in the transmission delay case compared with the equivalent base simulations with no transmission delay. Delayed grid build will influence boundary capabilities differently depending on when reinforcements occur on individual boundaries, and the pattern of flows and congestion will alter accordingly. In 2030, delays to the EC1 boundary reinforcement cause a severe constraint to offshore wind generation increasing congestion on that boundary, although this enables some greater flows of onshore wind generation out of South Wales, reducing congestion on that boundary. In 2035 there is a major constraint between the North and Upper North zones, coinciding with meeting the offshore wind target of 50GW. In subsequent years, increases in congestion are less severe, as growth in renewable capacity slows and the delayed network build catches up.

Exhibit 8.33 – Network congestion rent by boundary, impact of transmission delay (TD) on National BAU and Zonal compared, Consumer Transformation (£million/year, real 2021)



Notes: For National BAU, this is based on the difference in hourly marginal Balancing Mechanism prices on each side of the boundary, multiplied by the hourly flow across the boundary. The equivalent congestion rent for HVDC lines is also included and split across each boundary it crosses in proportion to the AC congestion rent for the boundary. For Zonal, it is based on the hourly difference in wholesale prices on each side of the boundary, multiplied by the flows across the boundary, with HVDC congestion rent split across boundaries as for the National BAU case.

Exhibit 8.34 illustrates the impact of transmission build delay on energy market revenues (plus any redispatch revenues in the national market) for a wind farm with merchant exposure[39].

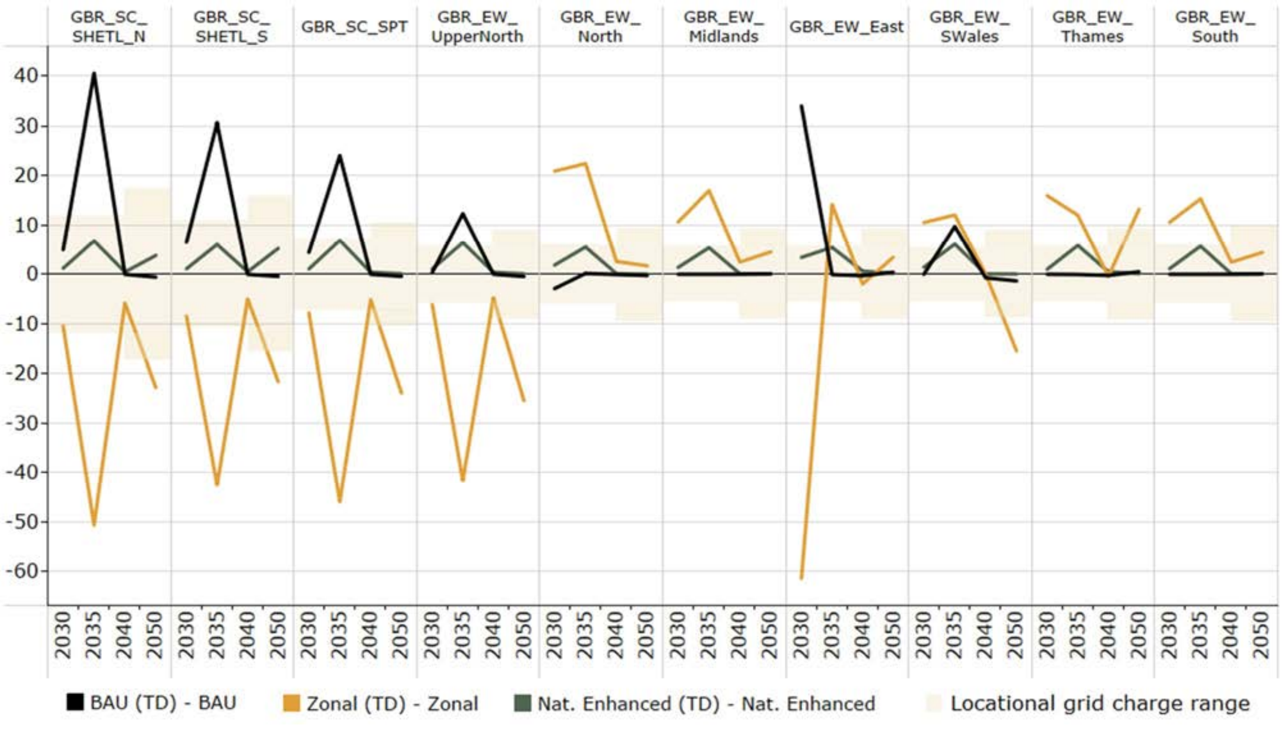
In the zonal case, energy market revenues are severely impacted for merchant wind farms in 2030 in the East zone, and in 2035 in all zones north of the B7a boundary when transmission delay occurs. Wind farms located in front of transmission constraints (e.g. in North in 2030 and 2035) benefit from higher prices during congested periods. However, in the National BAU case, wind farms behind a constraint (e.g. in Scotland in before 2035) do better as a result of additional profits made in the Balancing Mechanism from constrained off payments. This is a flaw in the existing arrangements, as it tends to incentivise wind to locate in perverse locations (other things being equal). In the National Enhanced case we have tackled this issue by preventing plants supported by deemed generation CfDs from bidding negatively in the Balancing Mechanism, a change which could be

[39] A merchant wind farm is one with no support contract; all our new build plants are assumed to be supported by CfDs for the first 15 years of their economic life.

implemented as a condition of the CfD contract (although they could still make a profit nearly equal to their variable costs of around £6/MWh for onshore wind in the modelled scenario). In the National Enhanced case, these small profits are discernible but the incentive to locate in a perverse location is greatly reduced.

Exhibit 8.35 illustrates the impact on transmission delay on the occurrence of low-priced periods in the National BAU and Zonal cases. The impact in East in 2030 is extreme, with an extra 38% of hours at low prices in the Zonal (TD) case compared with the National BAU (TD) case. In Scotland the Zonal (TD) case shows an increase of 2,100 hours in 2035, indicating quite severe impacts for merchant onshore wind farms. Although plants still within their CfD contract period would probably be hedged (subject to the design), the potential merchant tail impact post the assumed 15-year contract duration is likely to have some influence on investor appetite (unless also hedged via a type of “evergreen CfD” arrangement).

Exhibit 8.34 – Energy market plus redispatch gross margins for merchant onshore wind, impact of transmission delay (TD) on Zonal and National BAU compared, Consumer Transformation (£/kW)



Notes: For each market design case, the line on the chart represents the wholesale energy plus redispatch gross margin in the transmission delay sensitivity minus the equivalent gross margin in the base case. The redispatch element is based on zonal redispatch in the national market; nodal redispatch is not included. The locational grid charge range indicates the year-on-year volatility in the wider tariff component of TNUoS that has been observed historically.

Exhibit 8.35 – Percentage of hours when wholesale prices are below £10/MWh, impact of transmission delay (TD) on National BAU and Zonal compared, Consumer Transformation (%)

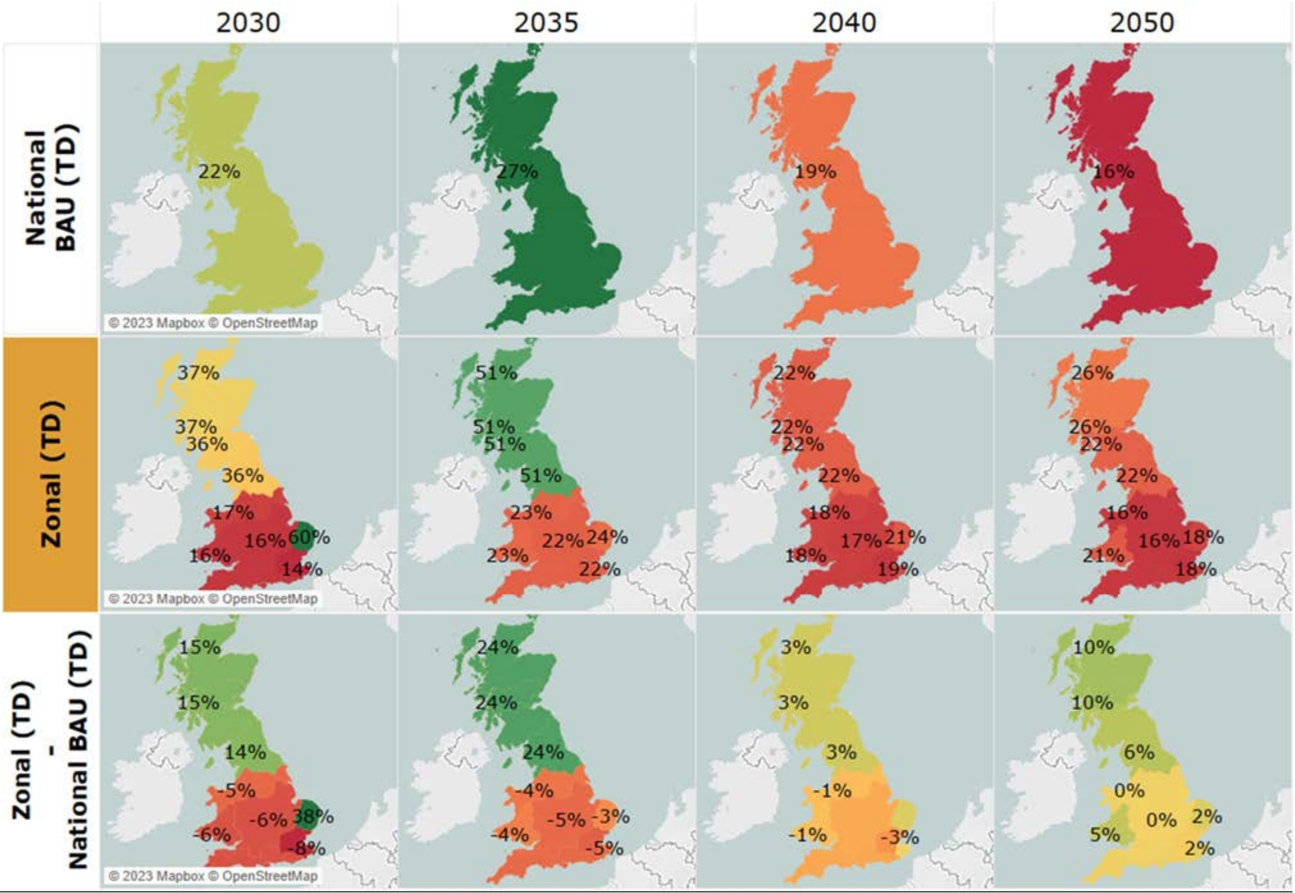


Exhibit 8.36 shows the impact on wholesale power prices as a result of transmission delay: zero in the national market, and up to £12/MWh lower in Scotland and Northern England. Consumers in the southern half of the country could potentially pay wholesale costs up to £5/MWh more in 2035.

Exhibit 8.36 – Wholesale power prices, impact of transmission delay (TD) on National BAU and Zonal compared, Consumer Transformation (£/MWh, real 2021)

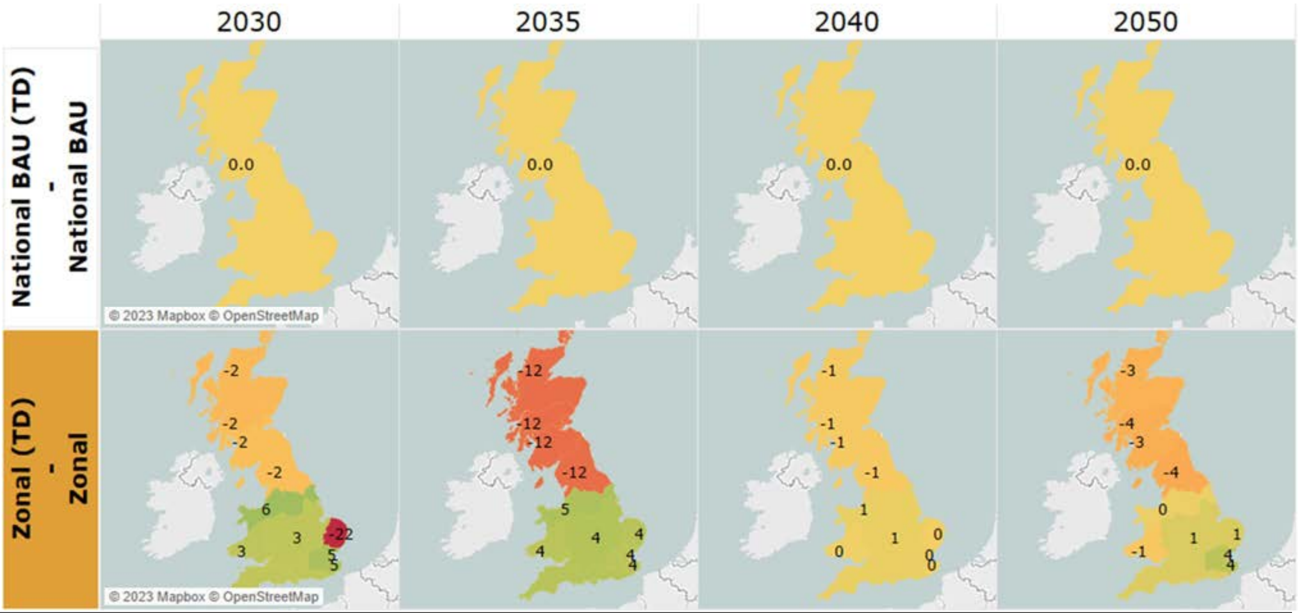


Exhibit 8.37 summarises the changes in economic welfare resulting from transmission delay in the National BAU case. The overall change is for a strong reduction in welfare relative to other cases examined in the study (a disbenefit of £9.8 billion over the 2028 to 2050 discounting period).

High costs of redispatch of £18.5 billion are borne by consumers, who are £15 billion worse off overall. Electricity producers are better off by £5.8 billion, mostly due to higher redispatch payments (this represents the profit made by domestic generators in the Balancing Mechanism, whereas total costs paid by consumers also reflect any fuel and carbon costs incurred in redispatch, as well as interconnector redispatch).

CfD payments to generators are lower under the transmission delay scenarios. With more curtailment there is a lower CfD volume, though the magnitude of the value of top ups depends on whether the price was above or below the strike price in these periods. However, such generators gain from redispatch, with margins from redispatch outweighing the change in CfD top up income.

Some economic welfare is also transferred to generators in other markets by interconnector redispatch.

The outcome that electricity producers are better off by £5.8 billion, with the corresponding cost to consumers, is subject to uncertain assumptions about the long-term ability of generators to earn extra margins in the Balancing Mechanism relative to the wholesale market, which could reduce over time, lessening the impact of the increased redispatch volumes.

Exhibit 8.37 – Total economic welfare benefit breakdown, National BAU (TD) versus National BAU, Consumer Transformation (Net Present Value 2028-50, £billion real 2021)

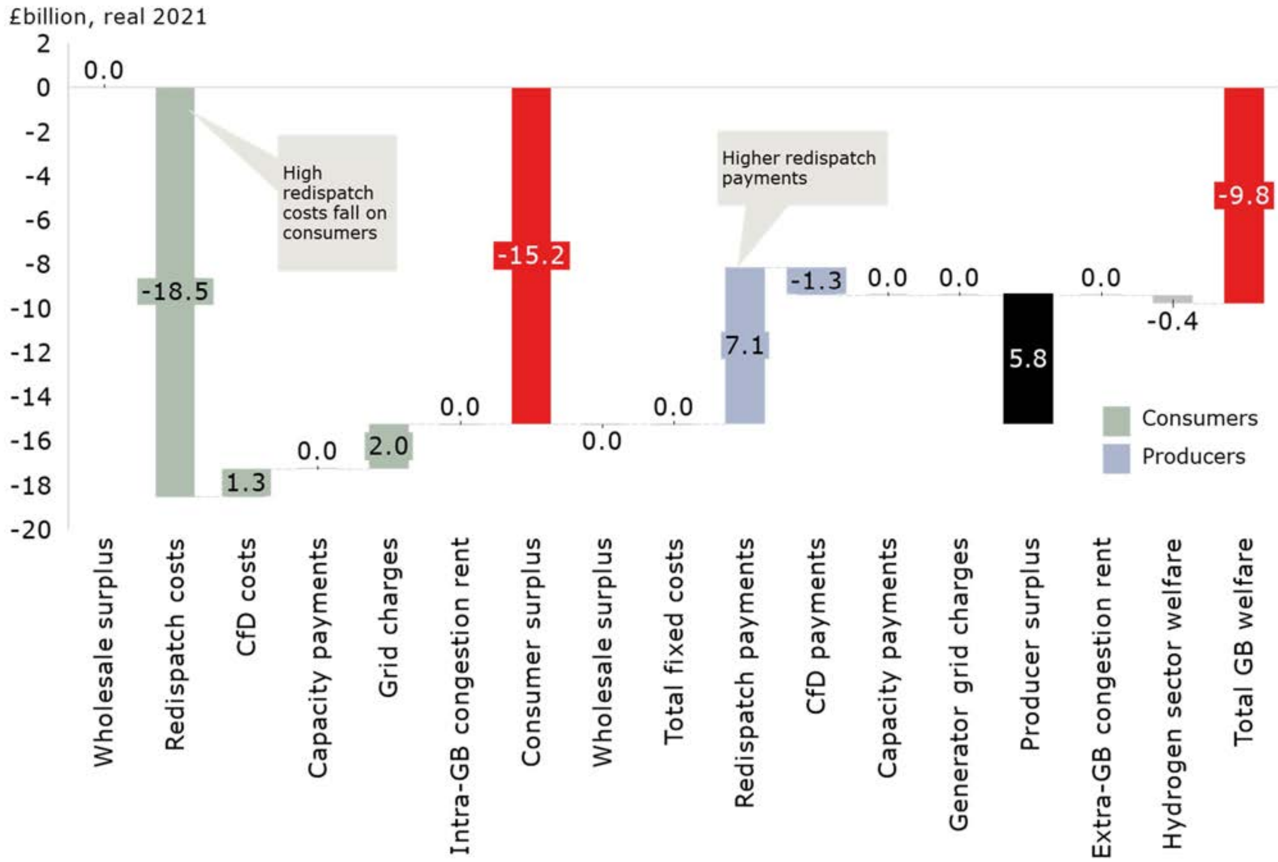
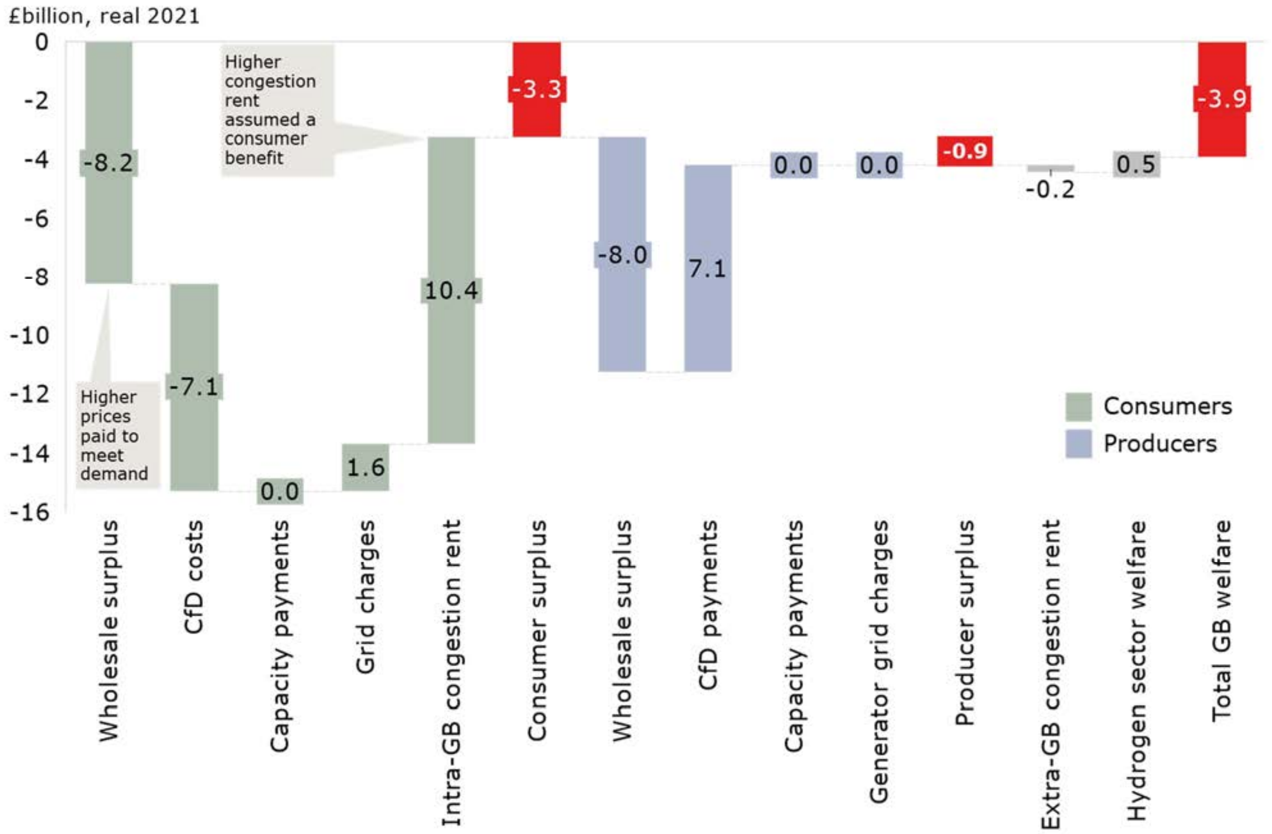


Exhibit 8.38 shows the equivalent breakdown of economic welfare in the Zonal (TD) case compared with the base Zonal case. The overall fall in economic welfare going from the Zonal to Zonal (TD) case is a lot smaller than for the National BAU versus National BAU (TD) case. In total economic welfare terms, zonal markets are more resilient to transmission delays than national markets, increased operational efficiency helping to mitigate the sub-optimal mix of capacity and grid build.

Exhibit 8.38 – Total economic welfare benefit breakdown, Zonal (TD) versus Zonal, Consumer Transformation (Net Present Value 2028-50, £billion real 2021)



Within the welfare breakdowns shown in Exhibit 8.37 and Exhibit 8.38 above, there are essentially three major features:

- The drop in overall welfare is more severe when an unexpected transmission delay occurs in the National BAU market (a drop of £9.8 billion) compared to when it occurs in the Zonal case (a drop of £3.9 billion).
- A zonal market primarily puts the risks on generators (particularly those without CfDs), though the overall loss of welfare is relatively small, with CfD payments offsetting much of the wholesale difference. Consumers also do significantly worse in the Zonal (TD) than in the Zonal case. Due to the offsetting nature of the CfD and a lot of renewable generators being on a CfD, the chart does not fully demonstrate the larger effect on merchant generators, which do not have the protection of a CfD.
- Within our modelling of the Balancing Mechanism, we assume bid/offer spreads in addition to actual variable costs incurred, so generators benefit from the extra redispatch required in the National BAU (TD). However, this additional profit in itself would just be a transfer between consumers and generators.

The biggest driver for the overall welfare impact being smaller in a zonal market than in the National BAU relates to interconnector redispatch, and to which market the profits associated with interconnector redispatch are assigned, since we also assume bid/offer spreads for interconnector redispatch. We effectively assume that the profits go to the underlying power plants in the interconnected market; alternatively a share could go to the interconnector itself. For congestion rent we have allocated half the congestion rent to GB. The additional interconnector redispatch margins therefore represent a transfer of around £6 billion of welfare out of GB, compared to around £1 billion in the case without the transmission delay. Note that this would still represent a transfer out of GB of £3 billion (TD) / £0.5 billion (base) even if it was assumed all the profit went to the interconnector, which we assess as unlikely.

In the transmission delay sensitivities, we have not modelled any secondary impacts to overall welfare changes (e.g. resulting from plant closures), or the consequential transfers between consumers and producers that might need to follow in managing such an infrastructure shock.

8.4 Investor risk appetite and cost of capital

Question 4 – How robust are comparisons of the benefits and disbenefits of different locational market designs to changes in investor risk appetite and costs of capital?

We find that adopting a zonal market could achieve a small overall economic welfare benefit[40] relative to current arrangements of £4.2 billion (NPV 2028-2050, 3.5% discount rate), while a nodal market could achieve a further benefit of between £0.2 billion and £0.3 billion. If achieved in practice, this would represent a saving of around 1% against consumer bills over the same period (£4.5 billion versus £466 billion, or £4.4 billion versus £397 billion, dependent on scenario).

The small positive benefits in the zonal and nodal markets come at a price: market participants face risks and exposure to circumstances outside their control which cannot readily be hedged. These risks could materially increase the cost of capital for new projects, more than wiping out any welfare gains associated with a locational market.

For the zonal market, we modelled two variants, based on deemed generation CfDs for new plants having a reference price indexed to the local (zonal) price (our main Zonal case), or indexed to a proxy national price (based on demand-weighting of the zonal prices) (referred to as Zonal (N)). The resulting basis risk between the zonal and national prices would increase investment risk; we consequently assumed a 1 percentage point increase in hurdle rates in the Zonal (N) case relative to the Zonal case (and the national market cases).

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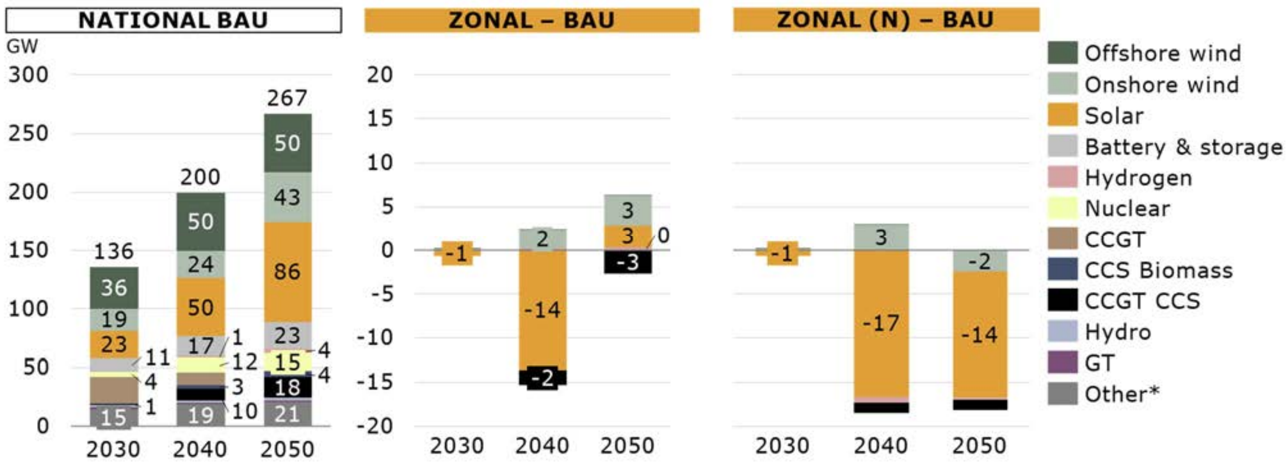
[40] We have focused on the overall change in overall economic welfare as the key metric in comparing market design cases, the split between producers and consumers being a secondary consideration once an overall gain has been achieved. The split between producers and consumers is in principle alterable through further policy and regulation (although potentially at some complexity and cost), options for which we have not considered in this study.

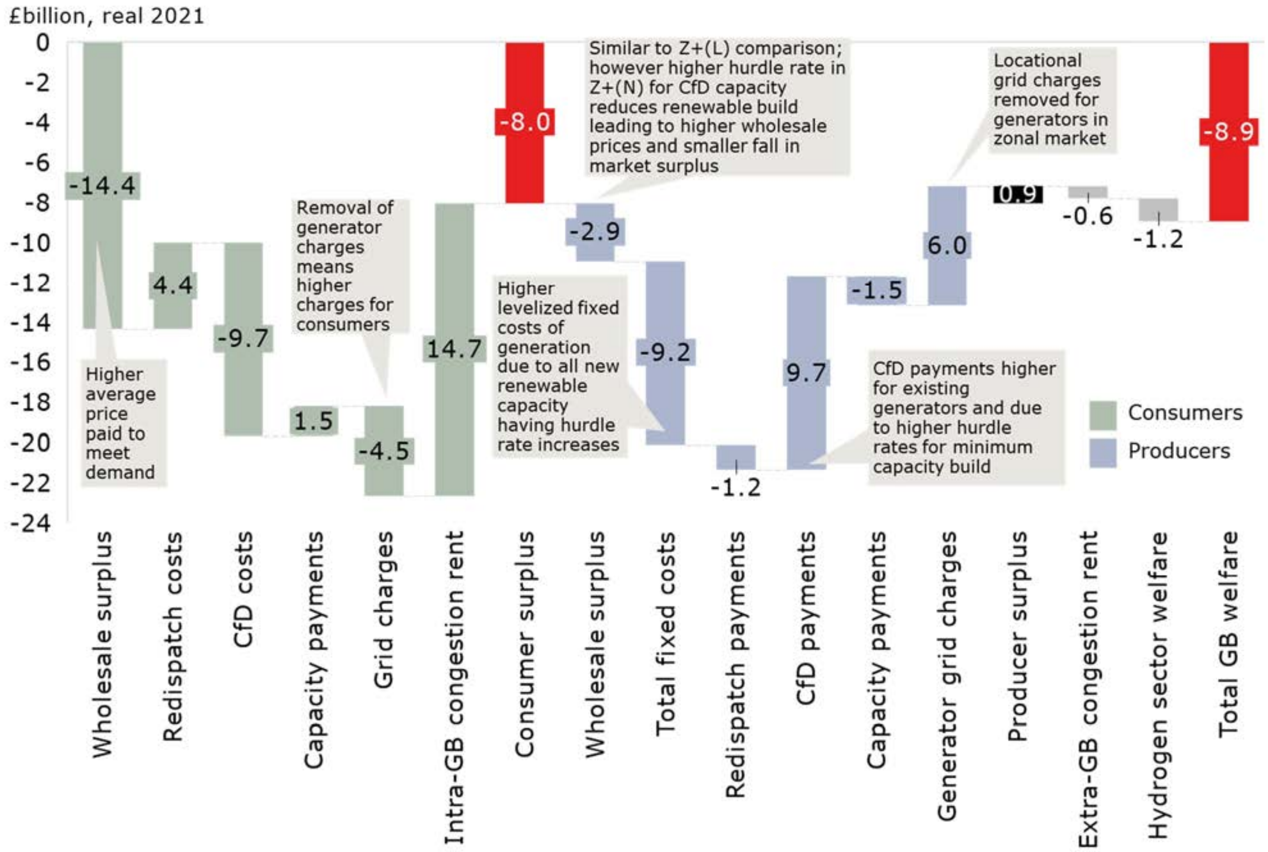
The increase in hurdle rate is the dominant effect when comparing the Zonal (N) with Zonal, resulting in significantly less total renewable capacity build, as shown in Exhibit 8.39.

Exhibit 8.39 – Differences in total capacity build in the Zonal and Zonal (N) cases



The overall economic welfare benefit over National BAU in the Zonal case is more than eliminated in the Zonal (N) case, resulting as shown in Exhibit 8.40 in a net disbenefit of £8.9 billion versus the BAU. Beyond the difference in the hurdle rate, other differences are not captured well by perfect foresight modelling. In the Zonal case the CfD award mechanism (least expected top up) is based on projections of wind and solar capture prices. With this methodology, to the extent these projections are wrong (specifically the spread between locations and technologies rather than absolute levels) the effect of this error in the projections would fall on the consumer.

Exhibit 8.40 – Total economic welfare benefit breakdown, Zonal (N) versus National BAU, Consumer Transformation (Net Present Value 2028-50, £billion real 2021)



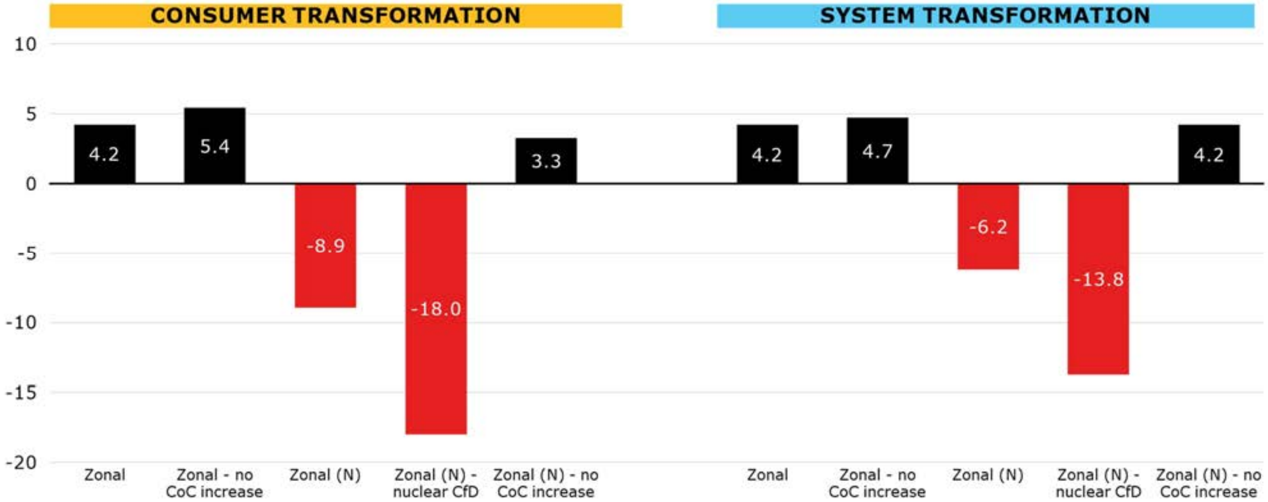
Cost of capital sensitivities

In addition to the Zonal (N) case which was modelled as a fully internally consistent scenario, we have also carried out a number of cost of capital sensitivities on the Zonal and Zonal (N) cases in both CT and ST, as described below:

- Zonal – no cost of capital increase: In the main Zonal case, we have assumed a 1% (+100 bps) increase in hurdle rates for non-CfD supported capacity (0.5% for OCGT capacity); this sensitivity examines the impact of no cost of capital increases for any technology.
- Zonal (N) – nuclear CfD sensitivity: in the Zonal (N) case we have assumed that Hinkley Point C is the only new nuclear capacity under a CfD and so exposed to the basis risk between its zonal price and the proxy national reference price, as for other CfD capacity. All other new nuclear capacity is assumed to be supported via a Regulated Asset Base type arrangement. In this sensitivity, all new nuclear capacity is assumed to benefit from CfD support arrangements and so is also exposed to the 1% increase in hurdle rates for CfD capacity generally.
- Zonal (N) – no cost of capital increase: as for the equivalent sensitivity on the main Zonal case.

The results of these sensitivities are summarised in Exhibit 8.41 below.

Exhibit 8.41 – Changes in total economic welfare relative to National BAU in the cost of capital sensitivities (Net Present Value 2028-50, £billion real 2021)



Notes: The National BAU baseline is the National BAU case from the same scenario (CT or ST) as the case being compared.

Overall the Zonal (N) case and related sensitivities illustrate that exposure of plants with high fixed costs to market price basis risk which increases their cost of capital is not a recommended approach, with Regulated Asset Base (RAB) type arrangements more likely to be appropriate for nuclear plants.

In addition, we examined combinations of increases in hurdle rates in the Zonal case that eliminated all economic benefit relative to the National BAU, either spread across all technology types, or applied just to CfD-supported capacity. The results of this analysis are summarised in Exhibit 8.42.

Exhibit 8.42 – Combinations of hurdle rate increases in the Zonal case that eliminate all economic welfare benefit relative to National BAU

CONSUMER TRANSFORMATION	CfD capacity	OCGT capacity	Other non-OCGT capacity
	+0.25%	+0.60%	+1.20%
	+0.50%	+0.04%	+0.08%
	+0.52%	+0.00%	+0.00%

SYSTEM TRANSFORMATION	CfD capacity	OCGT capacity	Other non-OCGT capacity
	+0.25%	+1.00%	+2.00%
	+0.50%	+0.18%	+0.36%
	+0.56%	+0.00%	+0.00%

Notes: +1% = +100 bps. The increases shown are over and above the increases that are already present in the Zonal case relative to National BAU i.e. +0% for CfD capacity; +0.5% for OCGT capacity and +1% for other non-OCGT capacity. Total hurdle rate increases relative to National BAU to eliminate all economic would then be e.g. CfD capacity: +0.52%, OCGT capacity +0.5%, other non-OCGT capacity +1%.

In addition, we found that for CT:

- An increase of +1% applied only to CfD-supported non-nuclear capacity resulted in an overall economic welfare disbenefit of £4.6 billion for Zonal relative to National BAU in CT; in ST the same change resulted in £3.8 billion overall net disbenefit.
- Overall, we have found that overall economic welfare benefits in the Zonal cases are sensitive to quite small changes in hurdle rates, with hurdle rate increases of around +0.5% (50 bps) on non-nuclear CfD supported capacity sufficient to eliminate all economic welfare benefits over National BAU.

We have found that modest increases in cost of capital for new renewable capacity supported with a 15-year CfD contract duration (which we assume for all renewable capacity in all cases) would eliminate all welfare benefit in each of the respective scenarios (+52 bps in Consumer Transformation, +56 bps in System Transformation).

Given the merchant tail of such plants, exposure to the unpredictable and large variations in project revenues that could arise in locational markets (especially with unforeseen delay of grid build) might be expected to have some impact on cost of capital unless mitigated in some other way.

The replacement of the Renewables Obligation with current CfD arrangements during the previous Electricity Market Reform removed some of the revenue volatility from around 50% from supported renewable plant revenues, and this was assumed to result in a hurdle rate reduction of 120 bps for onshore wind and 100 bps for large scale solar. Locational prices would increase the risk in the merchant tail. While the merchant tail would typically be discounted compared to the initial CfD period, it can still have a very material effect on project returns. Within the merchant tail itself the additional risk depends on the view of the risks associated with locational prices and how these compare to risks also present in a national market such as commodity prices, economic/political factors and technology cost evolution, as well as the reduced risk of not being exposed to wider TNUoS tariffs. A survey of study members on the relative risks demonstrated that they had a variety of views on these.

8.5 Alternatives to changing to a locational market

Question 5 – To what extent can any improvements in market outcomes from locational energy markets be replicated in a national market framework?

The aim of the National Enhanced scenario has been to replicate the locational signals of a zonal energy market within a national energy market framework. If successful, this would have the advantage of reducing implementation cost and lowering the risk faced by market participants.

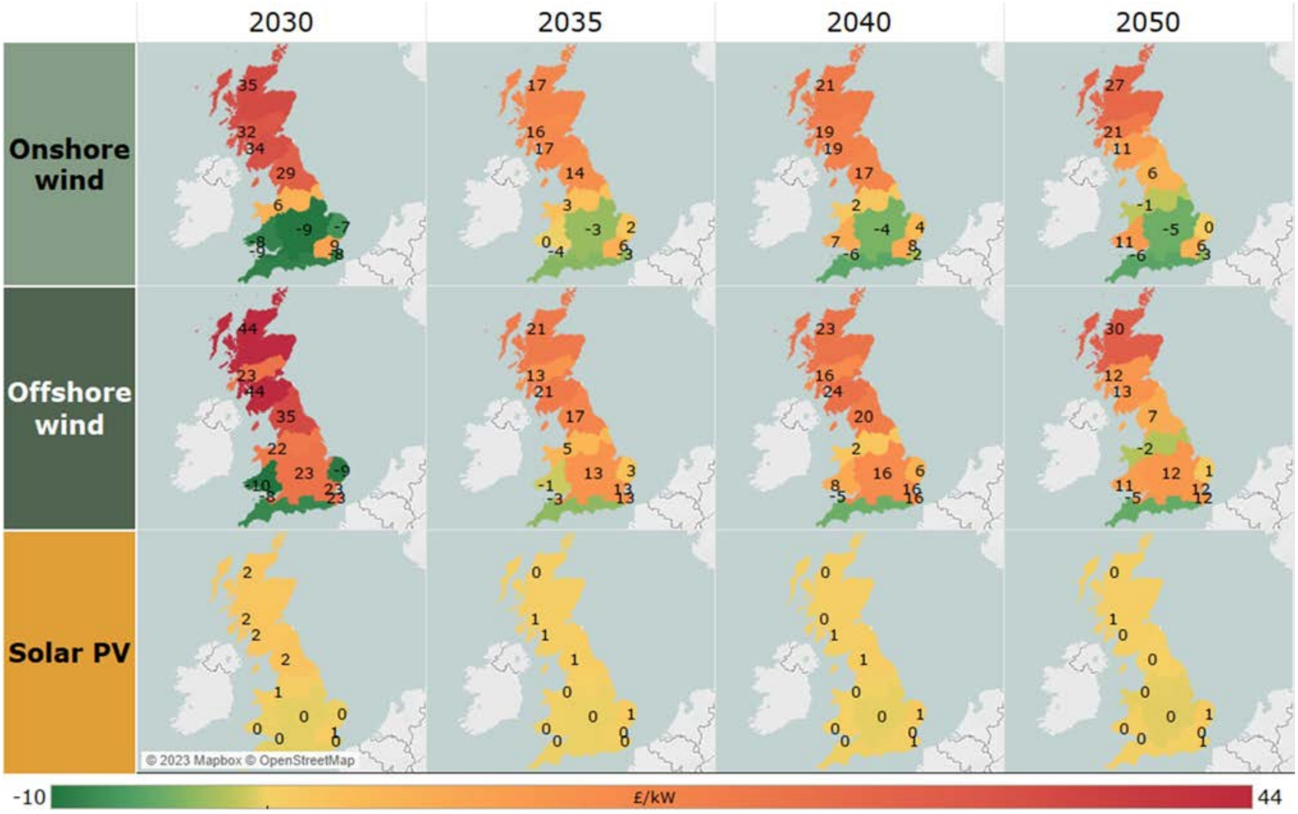
By defining locational grid tariffs to mimic the locational variations in gross margin by plant type from the Zonal cases, we were able to achieve close matches between the National Enhanced and Zonal cases on overall locational signal strength for renewable and gas CCS plants, and obtain similar patterns of generation build by location. This approach was less successful for hydrogen-linked technologies, given the other drivers related to hydrogen infrastructure that influence those technologies.

In total economic welfare terms, we were only able to capture a relatively small share (10-20%) of the total economic benefits of the Zonal market.

We consider that this merits further work and could be extended to a review of time of use tariffs, the application of network charges and potentially dynamic loss factors to interconnection, providing greater predictability of network charges to make them a more effective signal, and the development constraint markets.

A key element of assessing Question 5 is to develop a set of locational grid charges which reflect the locational signals on market participants from a zonal energy market and defining grid tariffs to mimic locational variations in gross margin by plant type from the Zonal case. The locational grid charges for main renewable technologies in the National Enhanced case that result from this approach are shown in Exhibit 8.43.

Exhibit 8.43 – Locational grid charges for renewable technologies in National Enhanced, Consumer Transformation (£/kW, real 2021)



As a result of the methodology for setting the grid charges in the National Enhanced case, the energy market gross margin less grid charge metric (Exhibit 8.44 and Exhibit 8.45) shows a similar pattern of locational signal sharpness between the Zonal and National Enhanced cases.

Exhibit 8.44 – Average wholesale energy market gross margin minus locational grid charges – merchant onshore wind, Consumer Transformation (£/kW, real 2021)

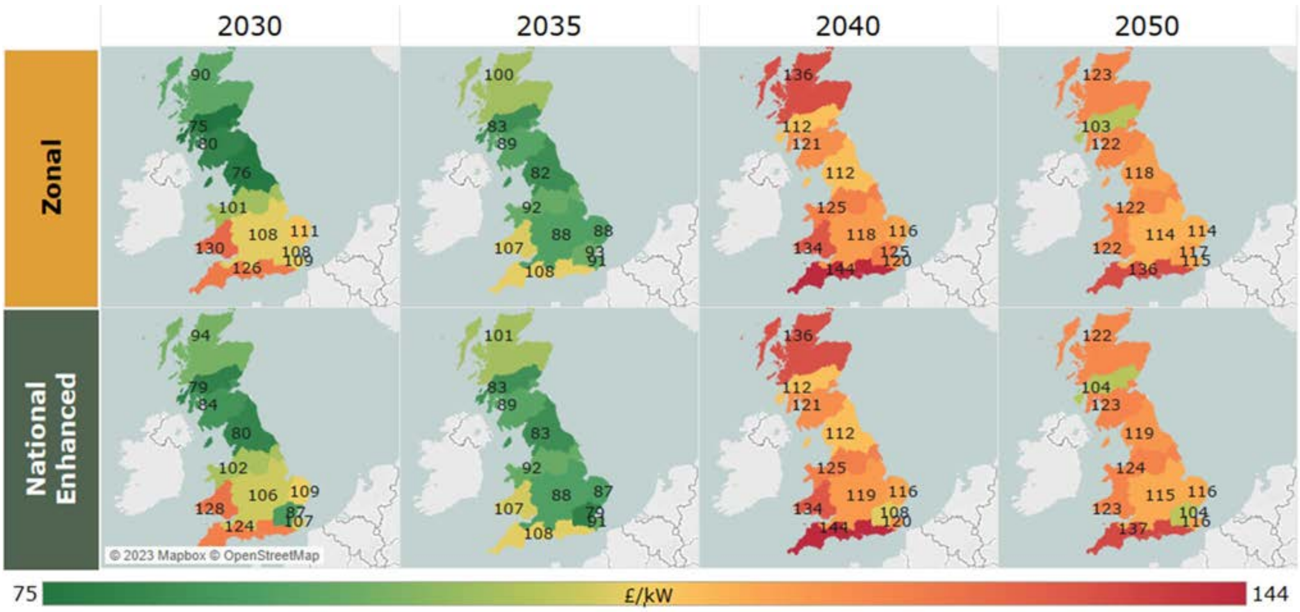
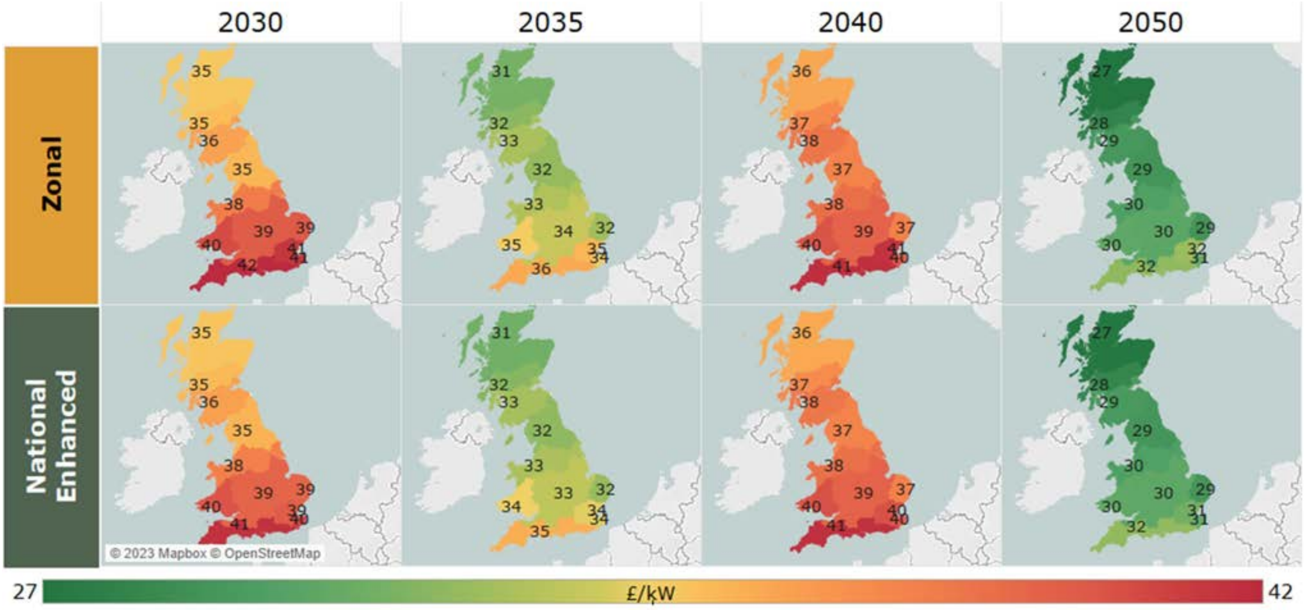


Exhibit 8.45 – Average wholesale energy market gross margin minus locational grid charges – merchant solar PV, Consumer Transformation (£/kW, real 2021)



Overall renewable capacity build is similar in the National Enhanced and Zonal cases, with the main difference being a switch in 2050 between 3.6GW of solar PV in the zones south of the B4 boundary, in favour of 3.6GW of onshore wind in SHETL_N (Exhibit 8.46). Slightly lower wholesale prices in the National Enhanced (Exhibit 8.47) in the zones south of the B6 boundary reduce solar PV capture prices and increase the top-up required under the least cost of top-up award mechanism present in both the National Enhanced and Zonal cases. The converse is true for wind in SHETL_N, resulting in different CfD allocation outcomes and the changed build pattern observed.

Exhibit 8.46 – Change in renewable generation capacity location – Zonal to National Enhanced, Consumer Transformation (cumulative GW)

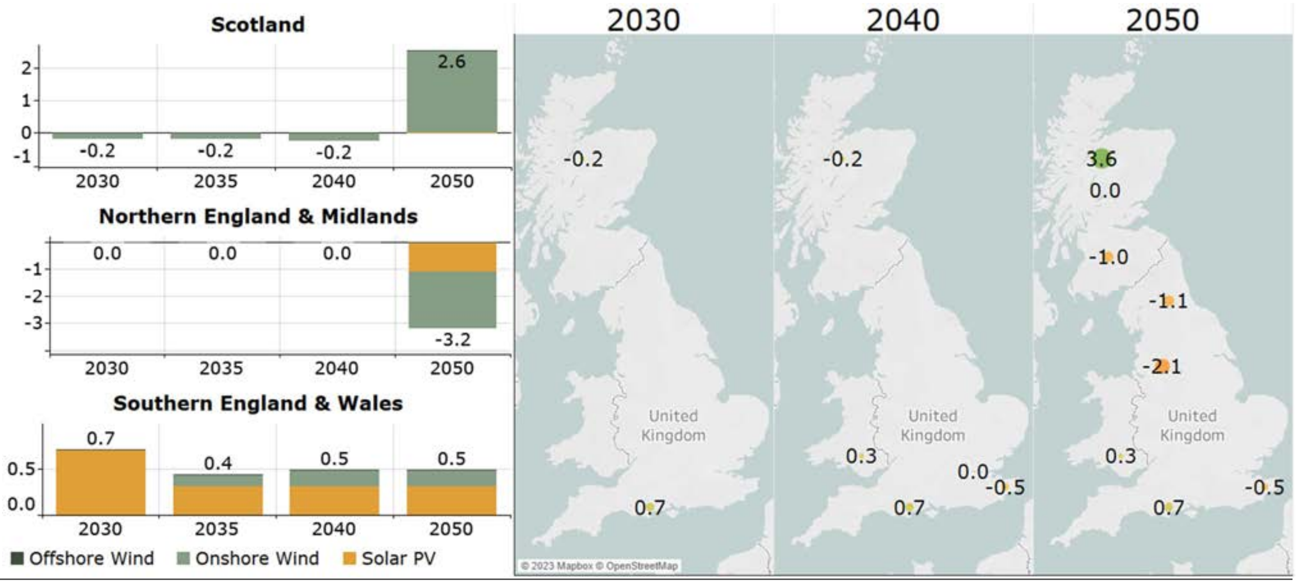
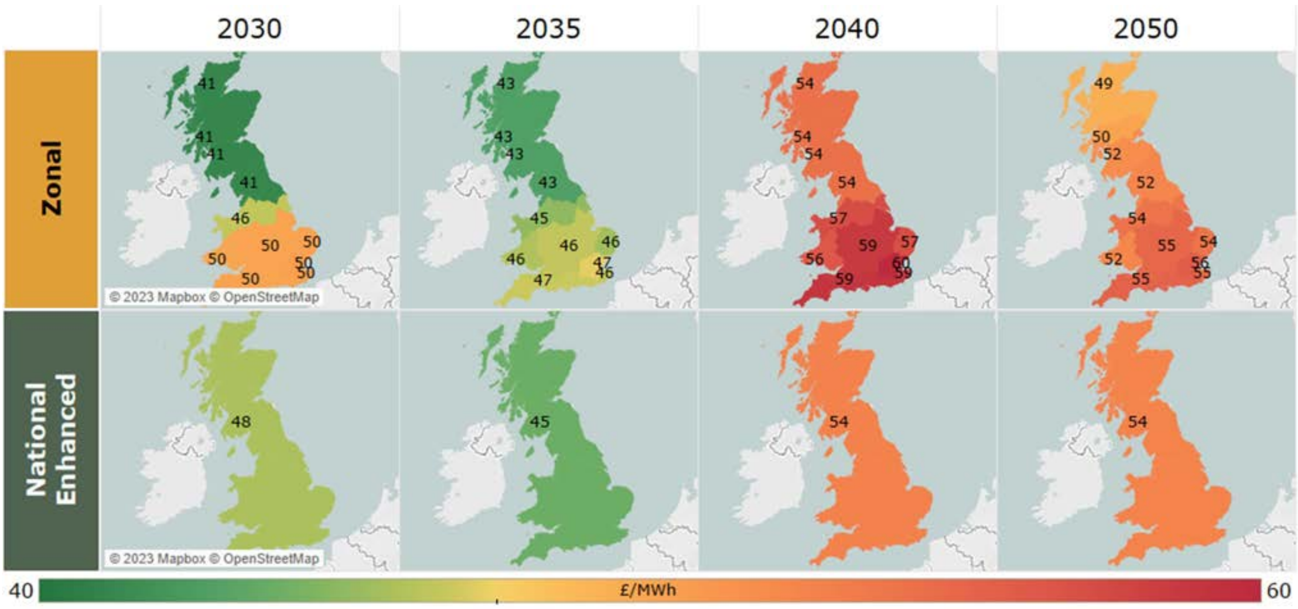


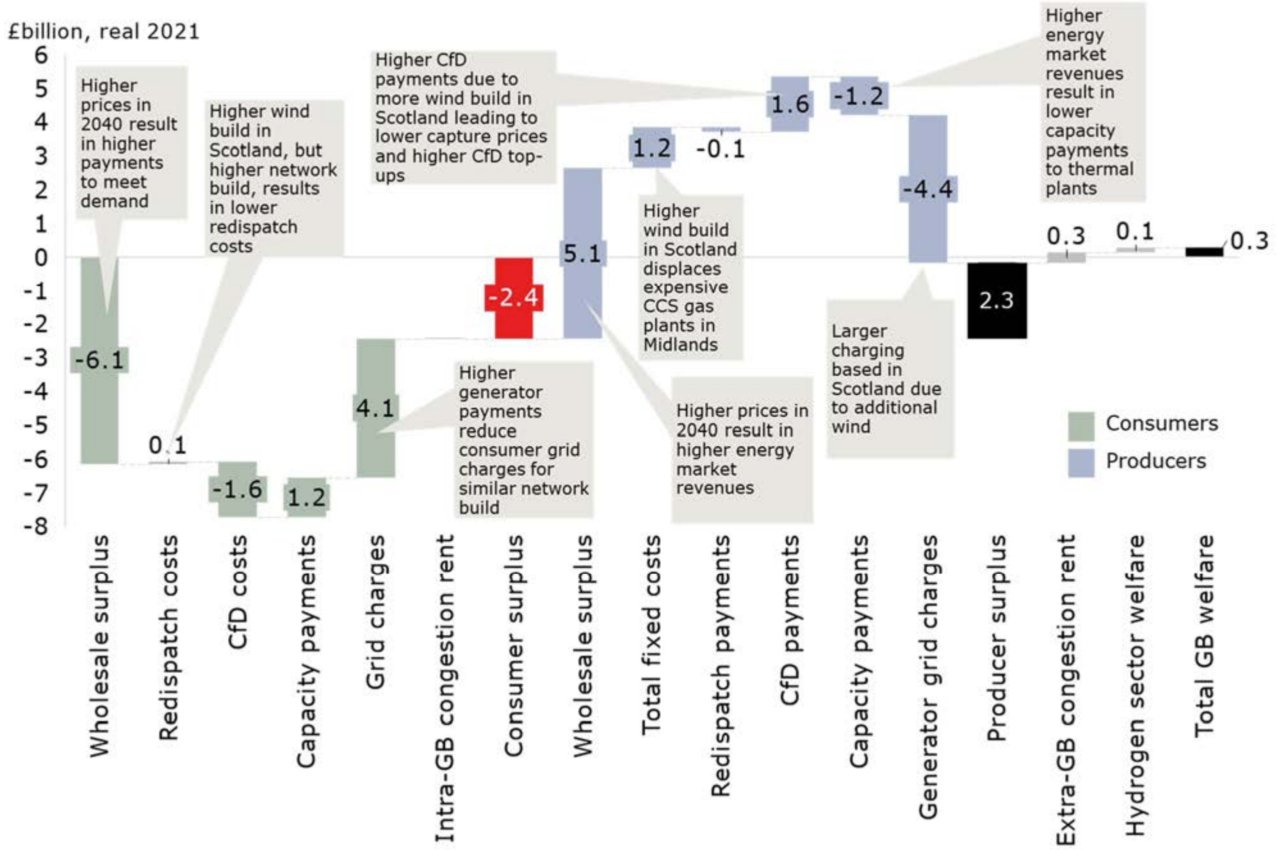
Exhibit 8.47 – Wholesale power prices, Consumer Transformation (£/MWh, real 2021)



Economic welfare comparison

The differences in economic welfare in the National Enhanced case compared with a National BAU baseline are shown in Exhibit 8.48. National Enhanced shows a total GB economic welfare benefit of £0.3 billion over the period 2028-2050, with a small benefit for producers and a small disbenefit for consumers, with the balance made up by reduced costs of interconnector imports and changes in hydrogen sector welfare. The split between the consumers and producers is mainly driven by the assumptions on grid charges. Overall benefits are small compared to the total system costs over the discounting period.

Exhibit 8.48 – Total economic welfare benefit breakdown, National Enhanced versus National BAU, Consumer Transformation (Net Present Value 2028-50, £billion real 2021)



8.6 Zonal compared to nodal markets

Question 6 – Are there significant differences in market outcomes between zonal and nodal markets?

Many of the challenges in locational markets – especially fully centralised nodal designs – relate to the coordination of within-day real time dispatch and incentives for flexibility. These topics are beyond the scope of this modelling analysis but merit further consideration.

Conversely, many of the detailed flaws in the existing arrangements are dynamic in nature, including the difficulties to the TSO in coordinating redispatch from a national wholesale market, and the exercise of locational market power.

Within the modelling we have carried out, nodal markets have shown only small additional total welfare benefits above those achievable within an 11-zone zonal market (with an additional NPV of £0.2 to £0.3 billion over the discount period 2028-2050). We also found slight improvements in interconnector dispatch efficiency relative to the Zonal case.

A zonal market design (assuming a small number of zones) could continue as a decentralised market, consistent with today's balancing arrangements and the markets elsewhere in Europe. However, many European zonal markets deploy (or plan to employ) flow-based market coupling, which embeds many of the challenges of a nodal market within the decentralised processes, though this is also true for many national markets. The zone boundary reviews are themselves a cause of significant market uncertainty.

A nodal market would be centralised, with central dispatch and co-optimisation of energy, ancillary services and network capacity. The design would need to consider how decentralised assets could be included in the arrangements and also how within-day flexibility would be dispatched and rewarded. A further problem with a nodal market is the potential for future re-integration to the European Internal Market for Energy. We have not evaluated any of the dynamic or practical aspects of this type of centralised market design.

The complexity of modelling nodal outcomes should not be underestimated. There are many degrees of freedom including the location of new generation, demand and networks, and in turn the location of offshore connections, CCS and hydrogen infrastructure.

Modelling a 511-node grid representation of the GB transmission network at hourly resolution for an extended foresight window proved computationally challenging, something we believe would be an additional practical challenge to market participants in the event a nodal market was introduced. Locational risk and exposure to additional impacts due to events such as unforeseen delays to transmission build or development of new generation capacity which increases exposure to local congestion risk would increase in importance for investment in new capacity, with an associated time and resource cost devoted to understanding and managing them.

Our results for nodal wholesale prices in the Consumer Transformation scenario are illustrated in Exhibit 8.49 which shows average annual wholesale prices at all nodes within a zone (based on colour scale), with the price label based on a typical node within a zone. Average zonal prices in the Zonal case are also shown by way of comparison. Exhibit 8.50 shows the nodal prices for the System Transformation scenario on the same basis. The prices across the typical nodes within a zone generally show good agreement with average zonal prices, with a few exceptions with local congestion at the nodal level present.

Exhibit 8.49 – Wholesale power prices, Consumer Transformation (£/MWh, real 2021)

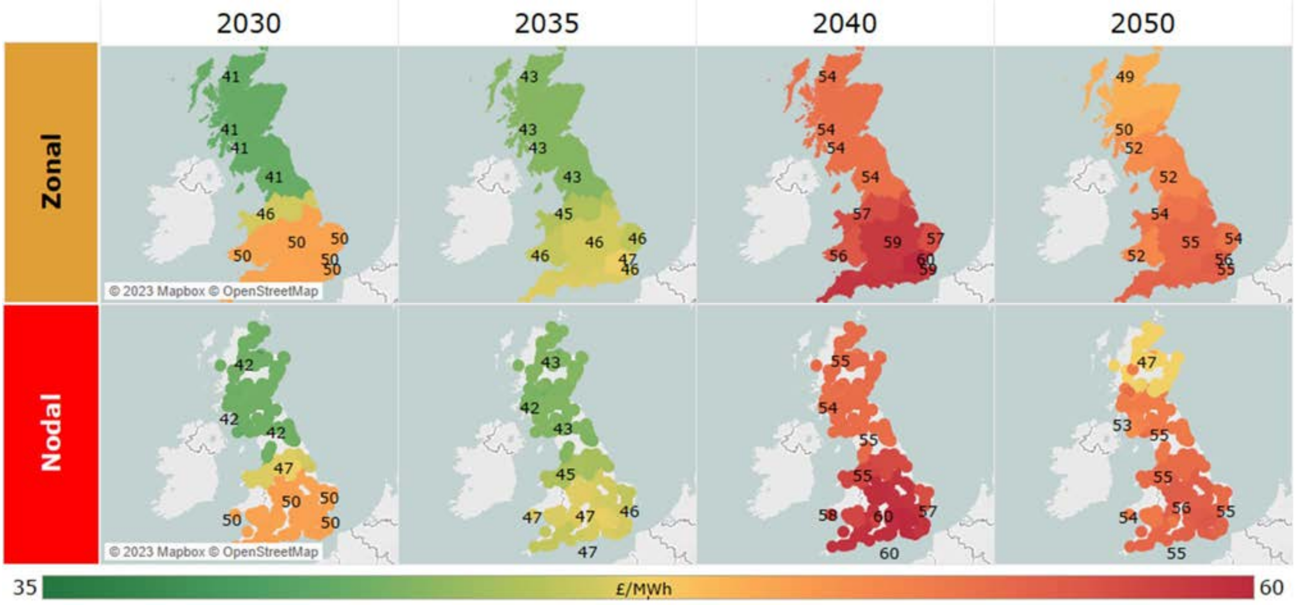
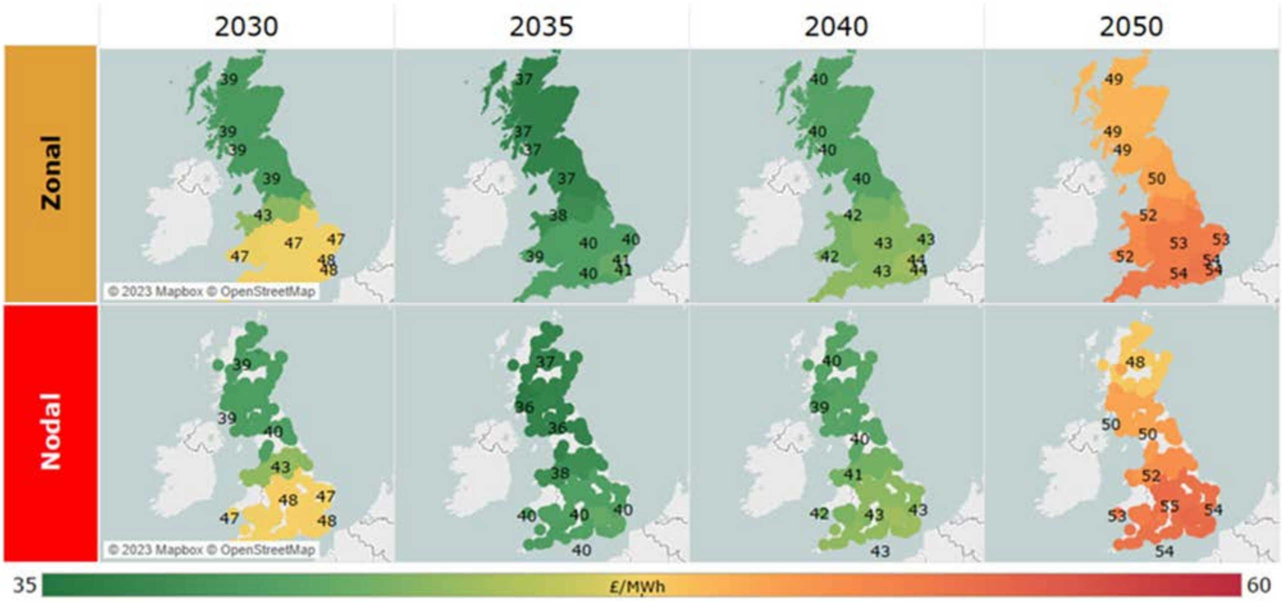


Exhibit 8.50 – Wholesale power prices, System Transformation (£/MWh, real 2021)



Operational efficiency

On operational efficiency, Exhibit 8.51 illustrates the change in post-redispatch net interconnector flows in the Nodal case, compared with the changes observed in the Zonal case, both relative to National BAU. The overall patterns of changes in net interconnector flows are similar, with increased imports on the interconnectors linking to the south of the country before 2050, and increased exports to Norway from Scotland, indicating improved use of interconnection in both cases. Nodal has the largest difference with Zonal in 2040, with a further increase in imports to the south. Exhibit 8.52 shows a very similar pattern in the System Transformation scenario.

Exhibit 8.51 – Change in net interconnector flows post redispatch, Nodal and Zonal vs National BAU, Consumer Transformation (TWh)

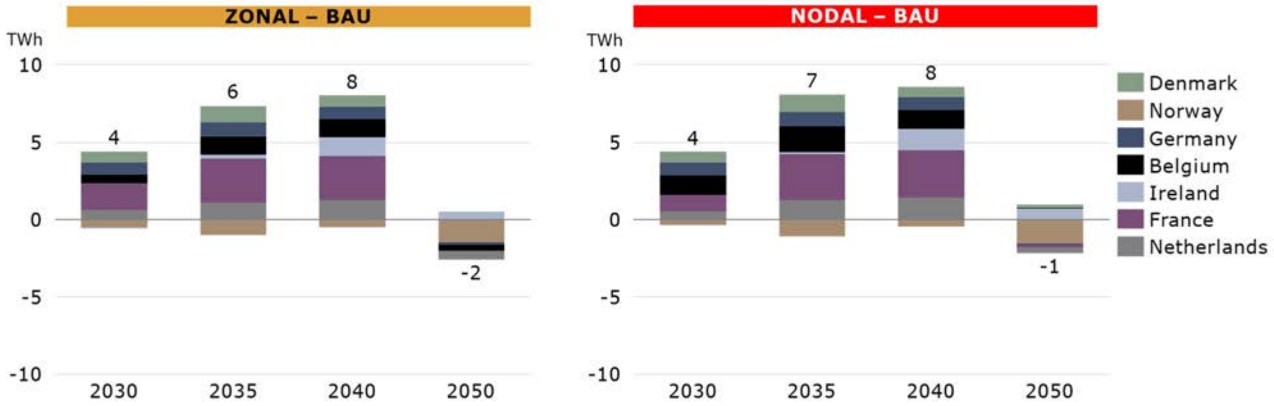
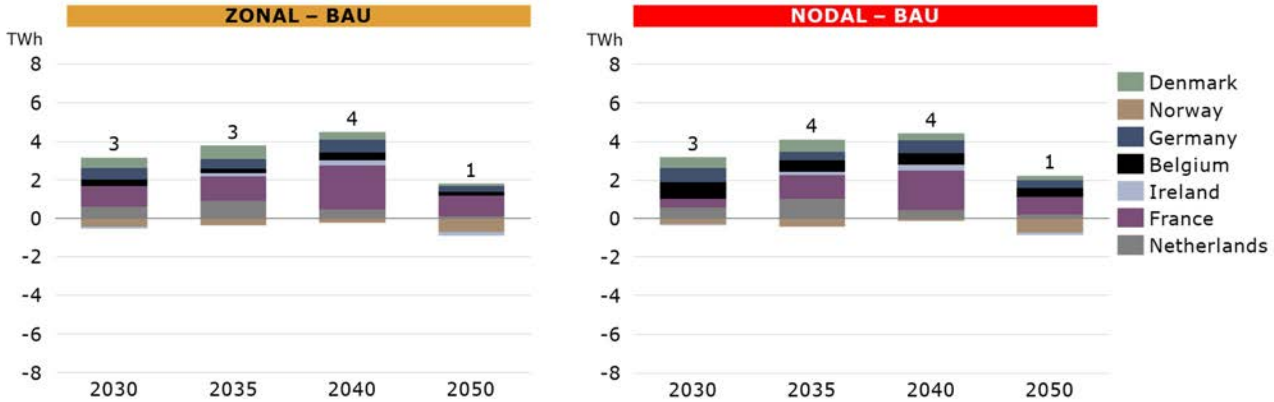


Exhibit 8.52 – Change in net interconnector flows, Nodal and Zonal vs National BAU, System Transformation (TWh)



Overall this indicates a slight improvement in the efficiency of interconnector use in the Nodal case, compared with the Zonal.

Allocation of cost, risk and reward

The difference in congestion levels between Zonal and Nodal runs are small, and this difference is independent of the market scenario, as shown in Exhibit 8.53 and Exhibit 8.54.

Exhibit 8.53 – Percentage of hours when wholesale prices are below £10/MWh, Consumer Transformation (%)

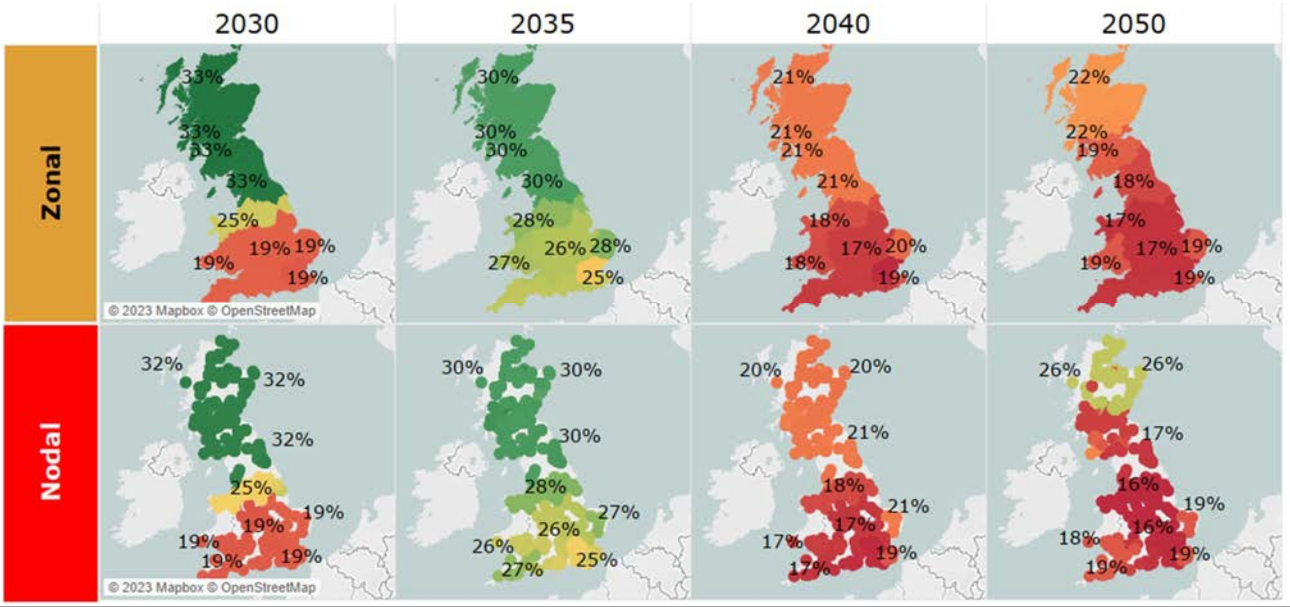


Exhibit 8.54 – Percentage of hours when wholesale prices are below £10/MWh, System Transformation (%)

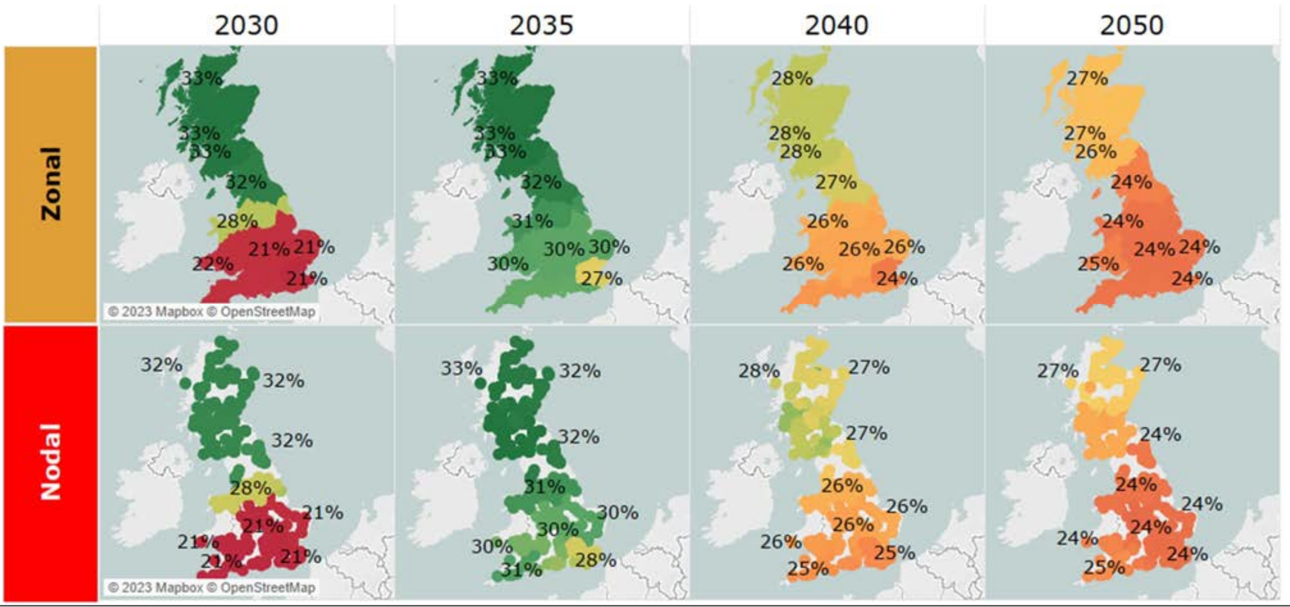


Exhibit 8.55 shows price duration curves for two sample nodes (Bradford West and Pentir, Wylfa) within the North zone alongside the price duration curve from the Zonal case. The variation in prices across the nodes is limited, reflecting the fact that most of the congestion rent that occurs is associated with the boundary restrictions between zones rather than within-zone constraints. This illustrates the effectiveness of the 11-zone market we have modelled in capturing the main transmission constraints. Exhibit 8.56 shows a similar pattern of node versus zone variation in the System Transformation scenario.

Exhibit 8.55 – Price duration curves for North, Nodal – Consumer Transformation (£/MWh, real 2021)

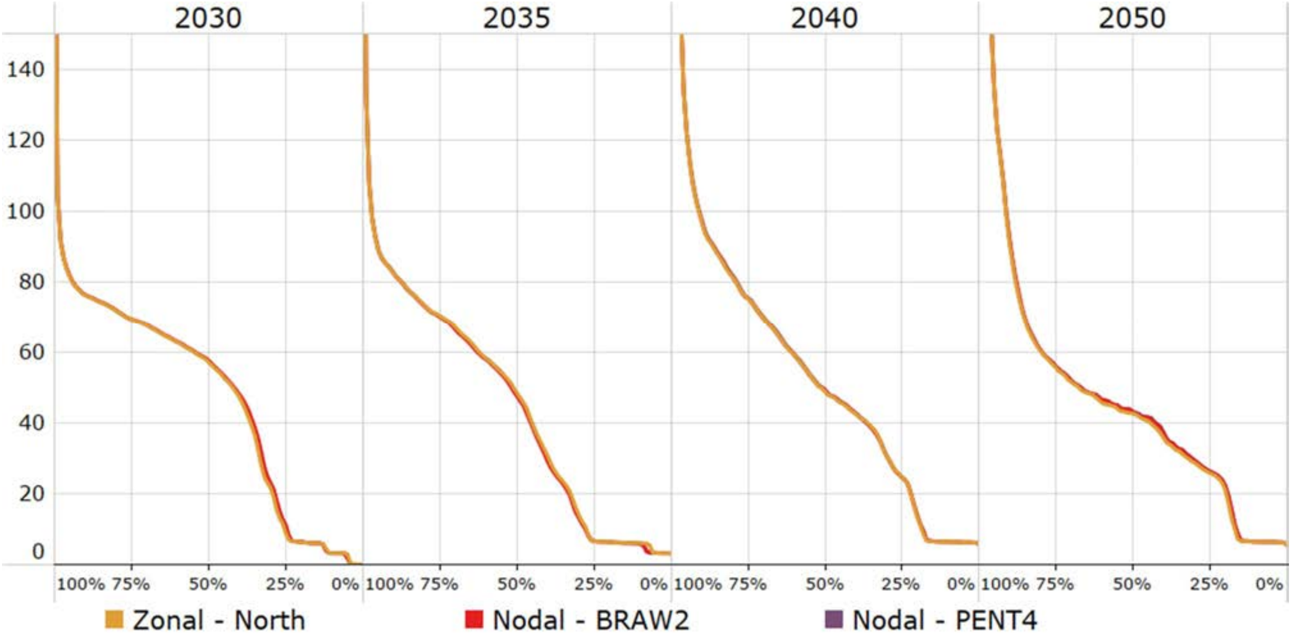


Exhibit 8.56 – Price duration curves for North, Nodal – System Transformation (£/MWh, real 2021)

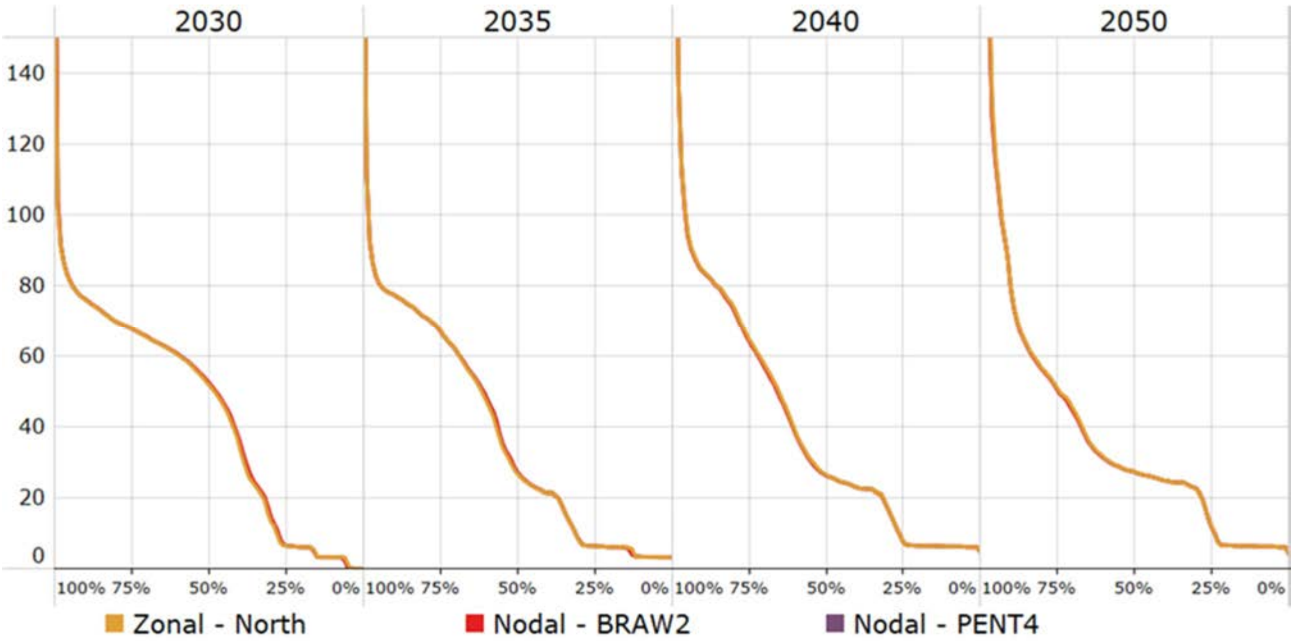


Exhibit 8.57 compares annual average energy market gross margins for merchant onshore wind for the same sample nodes in the North zone. There is some variation between the three over time, despite a similar starting point in 2030, including on whether a node is moving above and below what would be the Zonal price over time (in PENT4) or persistently below (BRAW4).

Exhibit 8.57 – Energy market gross margin for merchant onshore wind at different nodes in North, Nodal – Consumer Transformation (£/kW)

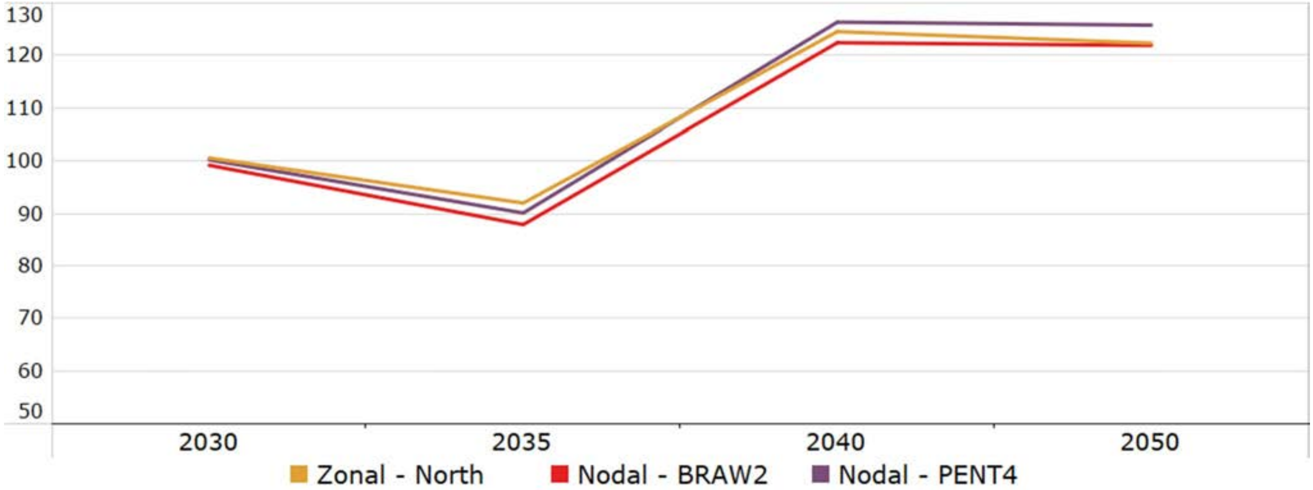


Exhibit 8.58 below shows a very similar pattern of nodal versus zonal variation in the System Transformation scenario.

Exhibit 8.58 – Energy market gross margin for merchant onshore wind at different nodes in North, Nodal – System Transformation (£/kW)

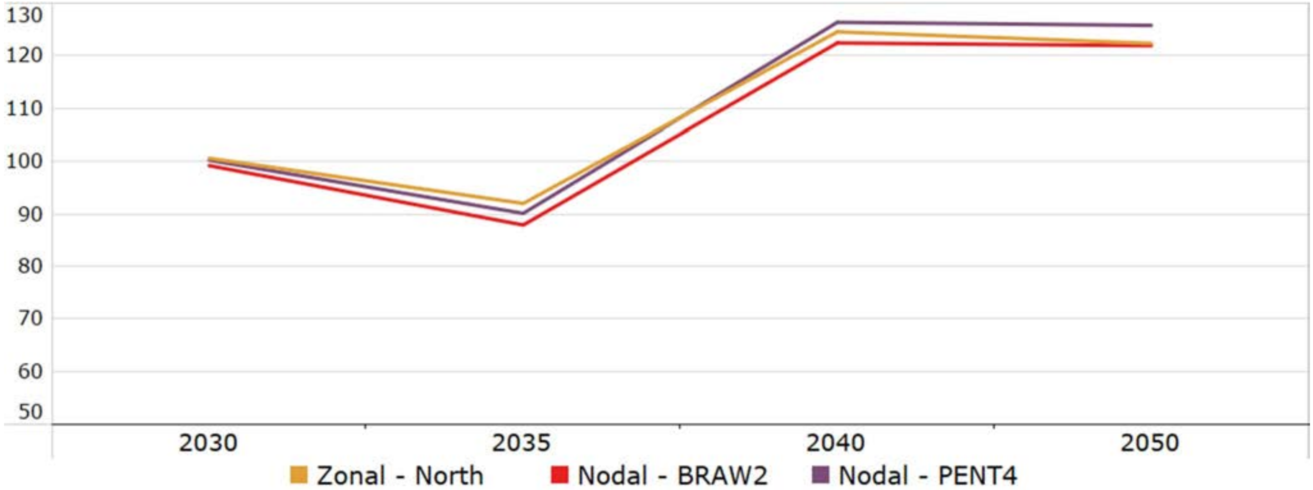


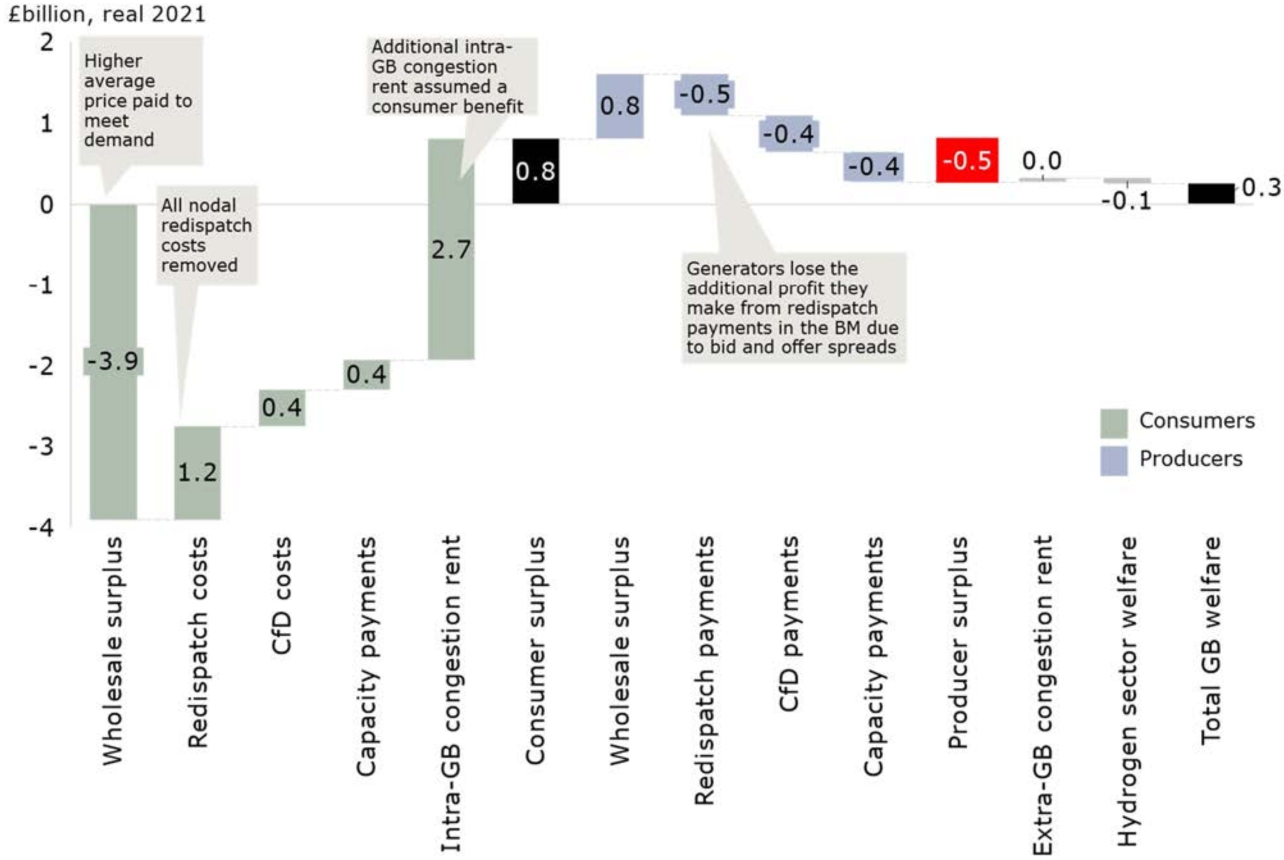
Exhibit 8.59 illustrates the change in economic welfare going from a zonal market with nodal redispatch to a nodal market. Consumers pay £3.9 billion more over the discount period 2028-2050 due to higher power prices, although assigning all the additional congestion rent (£2.7 billion) to them still enables a positive consumer surplus of £0.8 billion; this would be sensitive in practice to any reallocation of the much larger £2.7 billion figure to producers. The additional total overall welfare benefit of £0.3 billion is mainly improvement in operational efficiency to reach the final dispatch, given that the grid and capacity mix are identical.

There will be some sensitivity of the nodal welfare to the modelling assumptions:

- We have not fully optimised the locations of build within what were the zones in the zonal market. In part due to the difficulty of producing reliable long-term projections of nodal market outcomes, many generators are not expected to rely on forecasts of price spreads between a nodal price and the typical price in that part of the country (such as based on our modelled zones). The location of generation and load centres will also be impacted by land availability, planning permission, etc.
- The zonal boundary constraints have been imposed onto the nodal model to ensure consistency in grid expansion with the Zonal case[41]. We have looked at reinforcing the network where the saving achieved by a new power line would exceed the costs, though this can only be done as an approximation, given the discrete nature of power lines. Some lines entirely within one zone are relatively short, which makes reinforcing cheaper, while underground lines in populated places may be significantly more costly.
- Some other studies have shown significantly more congestion in a nodal system than a zonal system. While there would be some increase in congestion, we view a very large increase as unlikely - high congestion is probably a sign that either easy and/or low cost reinforcements are not being included, or that the zone boundaries are in the wrong place.

[41] We note that boundary capabilities cannot be derived directly from the nodal grid data, as they further represent voltage requirements, N-1 stability etc, as well as operational experience gained by NGESO.

Exhibit 8.59 – Total economic welfare benefit breakdown, Nodal versus Zonal with nodal redispatch, Consumer Transformation (Net Present Value 2028-50, £billion real 2021)



Overall, we have found some evidence of incremental improvements to interconnector dispatch and overall operational efficiency in the Nodal case compared with the Zonal, and a small increment in overall economic welfare. As for many of the other comparisons between cases, where precisely the allocation of the small overall benefits lands between consumers and producers would be highly sensitive to societal decisions which we have not attempted to model.

Annex A Summary of cases

Exhibit A.1 – Summary of cases with full scenario modelling

Case	Market granularity	Locational grid charges	CfD type	CfD reference price	Changes in new entrant hurdle rate assumptions (relative to National BAU)
National BAU	National	BAU TNUoS	BAU	National	-
Zonal	11 zones	-	Enhanced	Zonal	OCGT capacity: +50bps Other non-CfD capacity: +100bps
Nodal	511 nodes	-	Enhanced	Nodal	OCGT capacity: +50bps Other non-CfD capacity: +100bps
National Enhanced	National	Enhanced	Enhanced	National	-
Zonal (N)	11 zones	-	Enhanced	National	CfD capacity: +100bps OCGT capacity: +50bps Other non-CfD capacity: +100bps

Notes: BAU CfD-type arrangements comprise award of 15-year support contracts based on lowest price within a pot, and payment based on metered output in periods when reference price is above zero. Enhanced CfD-type arrangements comprises award of 15-year contracts based on least cost of top-up payments, and payment based on deemed generation output. In the Zonal (N) case the national reference price is a proxy national price based on a generation-weighted average of the zonal prices.

Exhibit A.2 – Summary of sensitivity cases

Sensitivity case	Base case for the sensitivity case	Description of changes in the sensitivity case relative to the base case
National BAU (TD)	National	Network reinforcements in 2030 and all later years assumed to be delayed by 5 years (no delay prior to 2028, intermediate delays for 2028 and 2029)
Zonal (TD)	Zonal	Network reinforcements in 2030 and all later years assumed to be delayed by 5 years (no delay prior to 2028, intermediate delays for 2028 and 2029)
National Enhanced (TD)	National Enhanced	Network reinforcements in 2030 and all later years assumed to be delayed by 5 years (no delay prior to 2028, intermediate delays for 2028 and 2029)
Zonal – no cost of capital increase	Zonal	Increases in new entrant hurdle rate of +100bps for non-CfD capacity (+50bps for OCGT capacity) are removed; the sensitivity assumes the same new entrant hurdle rates as the National BAU case for all technology types
Zonal (N) – nuclear CfD sensitivity	Zonal (N)	All new entrant nuclear capacity (not just Hinkley Point C) is assumed to be supported via a CfD indexed to a proxy national price, with a +100bps increase in hurdle rate assumed
Zonal (N) – no cost of capital increase	Zonal (N)	Increases in new entrant hurdle rate of +100bps for non-CfD capacity (+50bps for OCGT capacity) and +100bps for CfD-supported capacity are removed

TABLE OF EXHIBITS

Quality control

Roles	Name	Date
Authors	Stephen Woodhouse, Tom Williams	29/08/2023
Approvers	Matthew Brown, Matthew Hanson	29/08/2023

Document control

Version	Date	Comments
100	29/08/2023	
200	06/09/2023	Corrected Exhibit 8.12 Corrected Exhibit 8.16
300	15/09/2023	Added Exhibit in Key Messages Added Exhibit 2.1 Minor typographical and wording corrections
400	20/10/2023	Corrected Exhibit 8.38 Minor typographical and wording corrections
500	11/12/2023	Added names of funding clients on p.21 Added additional wording on modelled years on p.30 Updated Exhibit 8.11 to include 2025 Minor typographical correction on p.39

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