Review of electricity market design in Great Britain

PHASE 2 REPORT – PUBLIC SUMMARY

AUGUST 2023

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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 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 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 reoptimised 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.

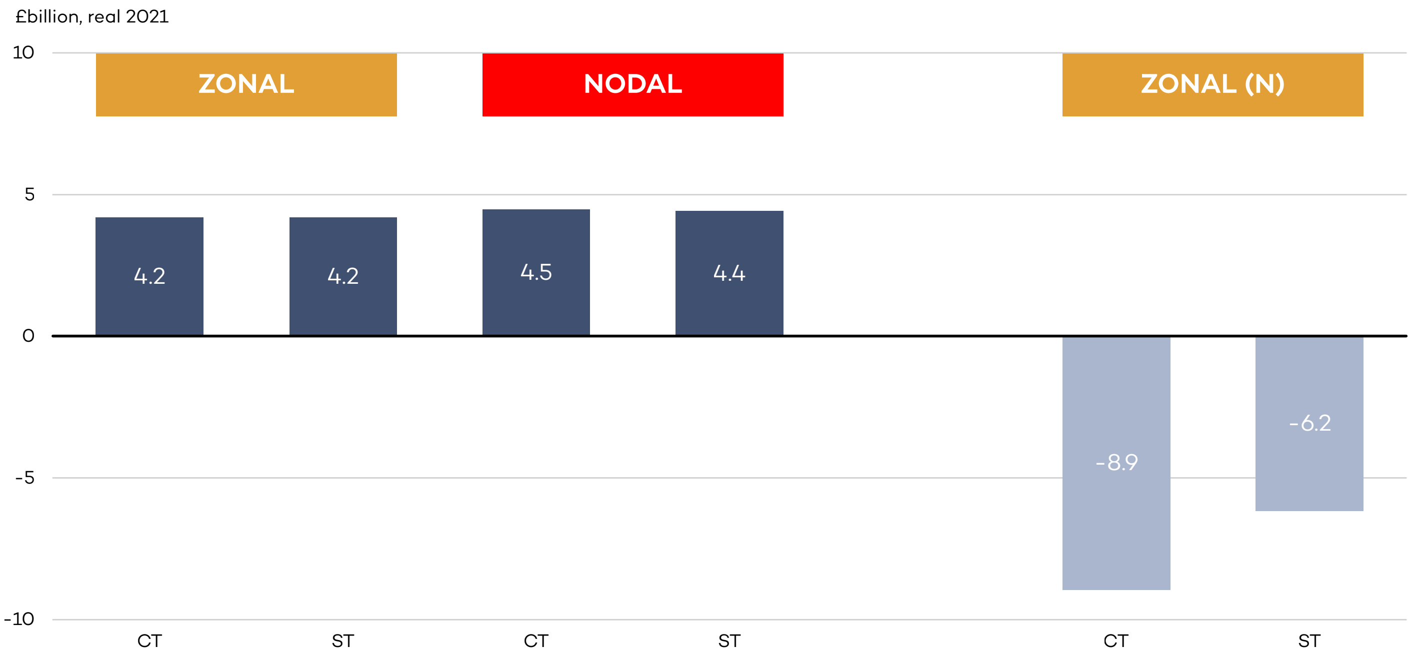

Exhibit 2 – Total economic welfare benefit, Zonal and Nodal cases versus National BAU by scenario (Net Present Value, £billion real 2021)

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 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 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.

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.
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.

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%

Exhibit 3 – Combinations of hurdle rate increases in the Zonal case that eliminate all economic welfare benefit relative to National BAU

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.

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.

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 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.

		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	●	●	●	●

Exhibit 4 – Locational signal strength by technology based on energy market gross margin less locational grid charts – National BAU and Zonal cases

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.

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.

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 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 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.

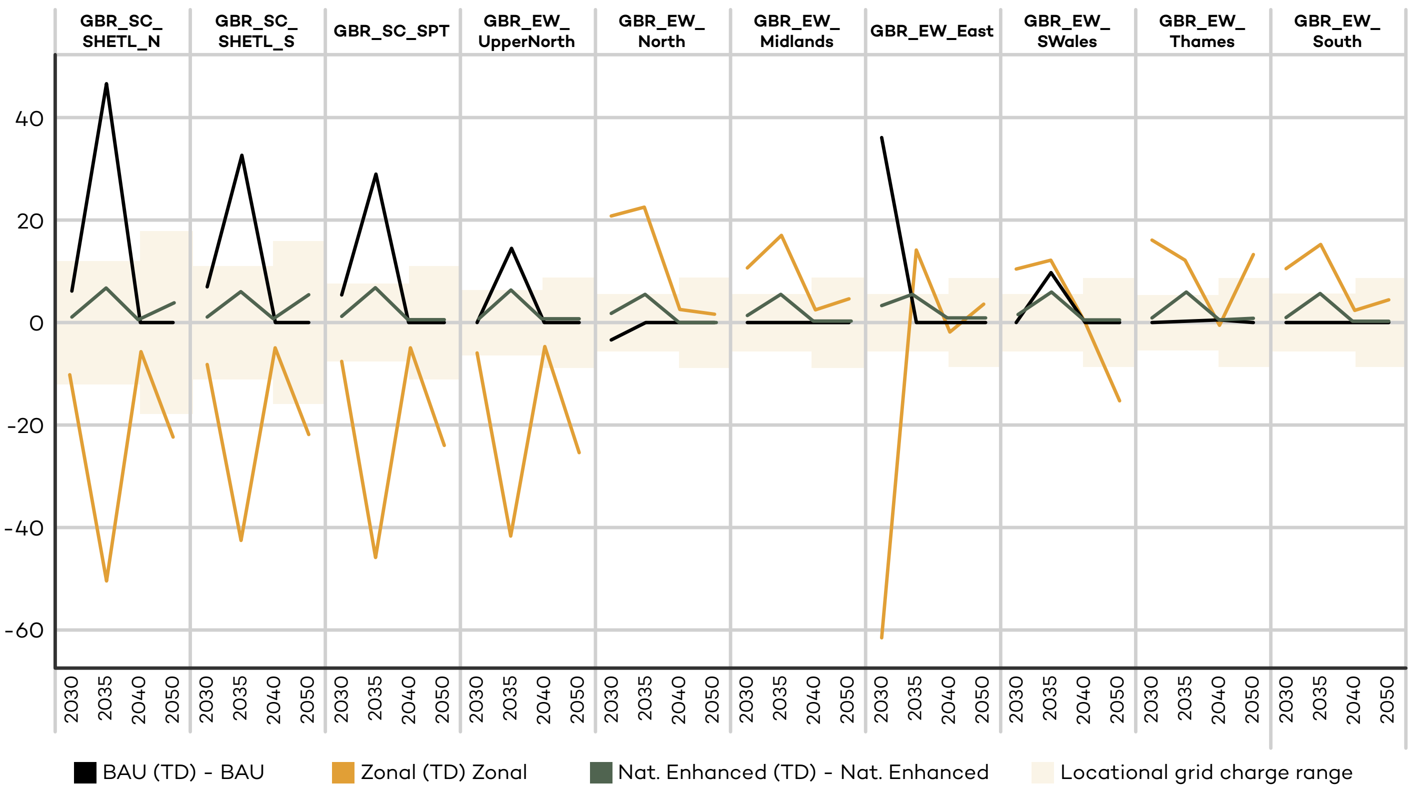

Exhibit 5 – Energy market plus redispatch gross margins for merchant onshore wind, impact of transmission delay (TD) on Zonal and National BAU cases compared, – Consumer Transformation (£/kW)

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 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.

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

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.

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.

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Making Future

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