Review of the report for Ofgem by FTI and the Energy Systems Catapult on "Assessment of locational wholesale electricity market design options in GB"

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1 Introduction

We have been commissioned by Ofgem to provide an independent review of the report delivered to Ofgem on work led by FTI with the Energy Systems Catapult on the subject of locational marginal pricing (LMP), either zonal or nodal, and a quantified assessment of what costs and benefits it might bring were it to be introduced in Great Britain.

Locational marginal pricing in the GB electricity wholesale market, in either zonal or nodal form, with prices discovered via a centralised dispatch – in existing markets using LMP, carried out at the day ahead stage – has often been cited as a way of reducing what is seen as excessive costs to consumers of re-dispatch actions taken by the Electricity System Operator (ESO) to change power flows resulting from, in Britain's current wholesale market, market participants' self-dispatch. Re-dispatch actions might be needed simply to ensure that total production matches total demand plus power losses on the transmission network along with suitable margins of reserve power production, or in order to ensure that network limits are not breached and the system would remain stable were some kind of fault outage to occur. The focus of attention in debates about LMP has been the cost of actions driven by respect of network limits, i.e. the cost of network constraints. In the last few years, LMP has also been cited as a way of encouraging the offering of flexibility from storage and demand.

In the view of proponents of LMP there is a need both for centralised dispatch to make efficient use of available resources, including available network capacity, and to provide signals to developers of new resources seeking to use the network – generation, storage and interconnectors to other countries – to locate in places that make use of existing (or anticipated) network capacity rather than take the risk that the centralised dispatch would either not schedule them or would split the market by location giving them a lower price for the energy that they produce than that seen at other locations. Conversely, in places where energy sources are scarce and the network's ability to import power is limited, the potential for a market that is split by location to offer a higher price than elsewhere can, it is argued, attract additional resources. Similarly, demand can be attracted to places where the local price is low. However, it is argued by others that a change to LMP creates significant upheaval and introduces new risks for market participants that will result in higher costs.

Would a change to wholesale electricity market arrangements in Britain be worth it? It is, of course, necessary to make an attempt to estimate what economic benefits, if any, would result from a change. This is what FTI, in collaboration with the Energy Systems Catapult, has been engaged by Ofgem to do.

In the first part of our review, in section 2 of this report, we step through FTI's report commenting on what is presented, sometimes to agree with what is said, sometimes to ask for more detail and sometimes to present an alternative view or challenge.

In the second part, in section 3, we present our overall views on the work FTI has conducted and the results they presented. We offer some final remarks in section 4.

Note that the version of FTI's report we have reviewed up to and including chapter 8 is one that was provided to us by Ofgem on August 31st 2023. On September 21st we came to understand that that was not the final version of FTI's report. Thus, some of what we have commented on and noted in sections 2.1 to 2.7 below may have been changed in the final version. We also note that we have lacked time to review the appendices to FTI's report in any detail. Some of the extra information that we feel could have been usefully provided may have been included there. However, we also understand that the main changes between the first and second versions of FTI's report that we have seen were made in chapters 9 to 12 for which we reviewed the second version.

2 Specific comments on content of FTI's report

In this section we make detailed comments prompted by specific segments of text included in FTI's report. However, it should be noted that the version of the report we reviewed was that passed on to us by Ofgem on August 31st. The final version of FTI's report might have the text we quote in differently numbered paragraphs, or the text might have been changed or deleted.

2.1 Chapter 2 of FTI's report

In our view this chapter presents a generally good explanation of the key differences in market arrangements.

Paragraph 2.61: differences in cash flows are mentioned. We would have welcomed discussion of the implications of those differences arising from the results of FTI's modelling, e.g. generators receiving less than they bargained for when entering a CfD auction.

2.73: "As well as short-term effects, locational pricing may have impacts on the electricity market in the long run. These could arise as the differences in financial flows set out above may induce differences in where on the electricity system market participants choose to locate **and, potentially also, closure decisions**." [Emphasis added]. That bolded part is not, apparently, expanded upon. Early economic retirement of, in particular, dispatchable plant is seemingly becoming an increasing feature of US nodal markets that comes with an associated security of supply risk[1]. In GB, this would likely need to be mitigated against via an increasingly important and costly capacity market mechanism. This would be true in both a national and a locational market, but would it potentially be heightened or accelerated (at least in certain regions) in a locational market? This point feeds more widely into points around increased risk under LMP of external factors undermining the business case for continued operation of existing generation or investment in new plant and the extent to which the business case of producers is accounted for in the modelling.

2.77: "investment in new generation capacity can increase rather than reduce consumer costs" if the transmission network's capacity is insufficient for it.

2.78: "This runs the risk of encouraging generators to site in areas of the network that are not beneficial to the energy system as a whole, because the transmission system limits the extent to which they can produce." However, the transmission network's capacity need not remain fixed.

2.80: "Storage providers could expect to earn higher revenues where expected price volatility is high and so, to the extent that they are able to move their plant, might be expected to locate in such areas. By locating in areas with high price volatility, storage providers should reduce such volatility over time, with potential system benefits as a result." We agree that this is generally true though it seems to us that the duration of each low price period relative to the high price periods is important to revenues: you might fill your battery during a low price period but be unable to earn money for that energy for many hours or even days until the next high price period.

2.86: "While there are no locational signals that, per se, drive transmission investment…" We are not entirely sure what FTI mean by this and tend to think that the statement is incorrect. For example, the transmission licensees in GB currently receive very strong signals via constraint costs.

2.88: We note that there is also a security of supply driver for transmission capacity. In theory, it might be subject to a financial appraisal, but it seems to us that it is difficult to get a value of lost

[1] See concerns raised by US ISO/RTO's here. https://www.pjm.com/-/media/documents/other-fed-state/20230808-comments-of-joint-isos-rtos-docket-epa-hq-oar-2023-0072.ashx

load (VoLL) or such like that everyone is happy with. In a national market is there also the possibility that new transmission can drive down average wholesale costs (by facilitating access to cheaper generation) as well as reduce constraint costs? Would that impact on net welfare gain or simply represent a theoretical transfer from producer to consumer?

We would have been interested in seeing an example with significant volumes of zero marginal cost generation.

2.91: TNUoS. "… that tariffs are higher for generators in areas of the network that tend to be distant from main centres of load (and therefore more likely to be behind transmission constraints) and lower (or even negative) for generators that are sited close to load (and therefore are determined to use less of the network)." Actually, TNUoS as currently calculated takes no account of existing network limits. In effect the methodology assumes perfect expansion of the network for a particular power flow. It is more reflective of total MW over how many km than of network limits. (Arguably, one of the weaknesses of TNUoS is that it fails to reflect temporal variation within a year).

2.92: "Moreover, the evolving nature of the GB energy system means that the optimal transmission charge is likely to change significantly over time." Similarly, revenues under LMP (or from the BM) will change significantly over time.

2.97: "in practice current expectations about the impacts of charging on the location of demand and generation are embedded in the Future Energy Scenarios ("FES") that lie at the core of our modelling." Herein lies what seems to us to be one of the main weakness of FTI's approach: that so much is implicit in the FES-derived scenarios that, in our view, ought to have been treated explicitly, in particular the impact of future TNUoS charges.

2.2 Chapter 3

3.8: "To the extent that the transmission network capacity was, in reality, insufficient to convey the aggregate scheduled generation to the intended consumers, the ESO would intervene by increasing and decreasing the output of some generators in specific locations of the network to ensure overall system balance was achieved in real time". And, over the longer run, reinforce the network.

3.22: Actually, since BETTA, my understanding is that access hasn't been based on "first come, first served" but on "first to apply, first served". (I interpret "first come" as meaning "first to connect" or, at least, with an earlier connection date in the connection application. That was in place in NETA and is, I think, more or less what Ofgem and the ESO are now advocating.)

Also, it seems to us that that "first come, first served" only changes who gets first access to network capacity. The bigger issue is whether anyone is made to wait for network capacity to be built. That, it seems to us, is the biggest issue with Connect and Manage: it is not "Invest and Connect". Under Invest and Connect, no-one would have been allowed to connect until the network capacity was – according to the network licensees' analysis (which could be wrong) – sufficient to allow the connection without excessive constraint costs.

Fig. 3-1: We think the presentation of the chart – which we understand was originally published by the ESO – needs to be much more careful and clear about what it is really saying and what the market point really is. For example, the heatmap does not really give a good feel for how often these types of figures are reached. Also, how much of the BOA plus trade action is due to network constraints and how much for simple energy balancing or management of Rate of Change of Frequency (RoCoF) risks? (We note that the chart only runs to 2019. RoCoF constraints were a significant driver for ESO actions then and are likely to have been reduced since through the

"Accelerated loss of mains change programme"). And how much of the energy balancing need would a centralised, day ahead market resolve?

An important caveat in the wider discussion of constraint costs that is often missed is that the recent sharp rise has largely been driven by the global rise in the cost of gas with turn on costs for gas accounting for perhaps two-thirds or more of thermal constraint costs. The costs of running these gas plants would still be borne even in an LMP market. While the modelling will inherently reflect that reality the narrative when discussing constraints costs often does not. Another pertinent point is that the real transfer capacity across key boundaries can often be significantly lower than the stated maximum transfer capacity, particularly true of capacity to transfer out of Scottish territory in recent months and years due to outages for ongoing line upgrades (see e.g. the ESO weekly transparency forum update). The recent picture may therefore have been inflated on 2 fronts.

3.19: Growth of renewables. "GB market design, this means that, everything else held equal, we would expect there to be more interventions by the ESO near to real time". It seems to us that this depends on how accurate Final Physical Notifications (FPNs) in the Balancing Mechanism are. At 60 to 90 minutes ahead of real time, generators' forecasts of their own renewable production ought to be quite good most of the time. Thus, if the decentralised market works as the New Electricity Trading Arrangements (NETA) advocates believed it would, there should not be any particular change in the volume of SO actions due simply to the nature of generation. However, whatever the accuracy of Figure 3-1, the volume of actions has increased. What is really the cause?

3.27: "under-delivery of transmission network capacity relative to expectation (and relative to the roll-out of generation in export-constrained areas of the network) would be expected to increase constraint costs, other things equal". Yes, we agree.

3.33: "Even with the very significant volumes of additional transmission build-out under the HND plan, the ESO expects annual constraint costs to reach £3bn, albeit at a later date in the mid-2030s. Constraint costs are not expected to return to the levels observed at the beginning of this decade (let alone to the levels observed only five or 10 years ago)." This might be expected if you try to put ~50 GW of wind in Scotland as FES 2021 does, even with the ambition of the Holistic Network Design (HND) in which investment is assumed to slow after 2030 while wind connection continues apace. The HND ScotWind update or subsequent iterations of the NOA may change the picture again. As noted, the basic story is that constraint costs rise if transmission investment fails to keep pace with renewable deployment. On the other hand, some kind of intervention would seem to be necessary in order to avoid building multiple gigawatts of wind in locations where the ability to usefully utilise incremental increases in generation output might be expected to be extremely low for any extended period of time.

We find the international commentary to be very shallow.

2.3 Chapter 4

4.29: various advantages of centralised scheduling are cited. However, it seems to us that how generators behave in a real decentralised/self-scheduling market is quite hard to model. (An idealised one would be quite easy to model).

4.31: "Given these uncertainties and conflicting views, we have not sought to model these effects in deriving our overall assessment of the costs and benefits of greater locational pricing in the wholesale market". It is a pity that, after outlining all the potential advantages, no attempt is made to model them. To the extent there is evidence from the United States on this it suggests that it mainly derives from more efficient use of fuel in coal and gas plants – not necessarily a big driver in the future GB system.

Are the signals to transmission development really *improved* or just *changed*?

4.34: "In this sense, under the current market design, generators do not receive a price signal from the wholesale market to site in areas that would most benefit the system, and siting decisions are largely taken on the basis of (i) private costs to the generator; and (ii) forecasted climate conditions in the area (in the case of renewable generators). Importantly, in our modelling of the current market design, the capacity and location of all generators is fixed to that set out in the relevant FES 21 scenario, provided by the ESO for this assessment in a confidential dataset." Although TNUoS is mentioned in footnote 98, who knows what factors the ESO took into account when developing FES 2021 and whether what they came up with is reasonable. For example, is it likely that there would be 50 GW+ of wind in Scotland in the 2030s?

We can understand why the ESO does not want to give away what they are assuming for precise locations of generation, information that might easily be mapped to actual connection applications and interpreted as the ESO commenting on the viability or otherwise of those projects. (We are sure the ESO has a view but they will not want to publish it). However, we think it would be not unreasonable for zonal total capacities of each main generation type to be published for the different scenarios. After all, these are only scenarios, not forecasts.

4.36: "With wholesale prices varying based on the demand for electricity, generators are particularly incentivised to site either closer to demand sources, or in areas with excess transmission capacity. In this sense, locational price signals can help incentivise generation to site in more optimal locations from a system perspective, by 'internalising' the cost of transmission constraints to some extent. This effect is compounded for storage assets, given their participation as both a buyer and a seller of power in different periods on the wholesale market." In theory, yes, provided the market participants can model the system and likely revenues. FTI had great difficulty in modelling the GB system and LMPs; will every market participant manage to do it, especially if they are prevented from having access to data the ESO gave to FTI under a non-disclosure agreement (NDA)?

4.37: "in our modelling of the zonal and nodal markets we allow a limited proportion of new-build generation assets, and all grid-connected storage assets, to re-site in response to wholesale price signals, relative to the location set out in FES." Relocation is allowed but total capacities are fixed. This therefore does not take any account of whether revenues in the initial or changed locations would be sufficient to cover the costs of those resources. Although CfD-backed generators (for as long as the CfD lasts) would be protected against changes in wholesale prices[2], under existing CfD arrangements they would not be protected against dispatch (or volume) risk arising from potentially selling fewer units of energy than was assumed in making a final investment decision. Changes to revenues in any particular location may, for new resources, result in failure to open there (or, if nowhere gives a positive net present value (NPV), anywhere) or, for existing resources, closure.

Moreover, we do not need LMP signals to know if a new wind farm might be subject to very high curtailment in a region. Having FES 2021 as the fixed comparator case when we cannot be assured that it has inherently sensible locating of generation relative to the transmission background (or transmission upgrades to match that) risks embedding improbable benefits in the results. Does FTI's "dispatch only" case – the sensitivity they run which puts the new generation siting from the nodal

[2] Note that some CfDs have rules under which there is no pay-out when the reference price is at or below zero for certain periods.

model back into the national model – represent a better baseline result for consideration than the others presented?

Recent work by AFRY[3] which sought to do similar analysis to FTI did seek to optimise location of generation in their national market comparator case and found lower benefits from a move to LMP by including this step. Does this represent an additional step that the ESO could or should have undertaken for the FES but it might be supposed have not, i.e. to properly align the geographical spread of generation with the available network?

4.38: "The effect of this re-siting is captured by a change in the wholesale and balancing costs of meeting demand in specific regions." However, this seems not to have been captured by any assessment of the overall financial viability of individual generators or storage facilities.

(If lots of generators are zero marginal cost (ZMC) and sitting behind the same network constraint, how does the model distinguish between them?)

4.44: "by encouraging new generation capacity, storage and large consumers to site in a way that takes account of persistent bottlenecks on the transmission network, locational pricing can encourage a more efficient use of the existing transmission network, thereby reducing the need for incremental transmission investments". OK, but the most obvious counterfactual in today's market has not been tested: the impact of strengthened TNUoS signals. FTI are relying on scenarios from the ESO, and who knows what they have assumed or tested. FTI are trying very hard to be transparent – good! – but it seems to us that they have not been helped by the ESO being very opaque.

4.45: "within each modelled scenario, the network topology is consistent for each of the market designs that we model." This is pragmatic given the difficulty of designing the network but it fails to show how much money might be saved from a network designed against long-term market behaviours in an LMP world.

In the modelling they have done and in letting some of the resources relocate, FTI are effectively modelling each participant's perfect ability to forecast LMPs. Is this realistic?

4.72: FTI estimate "the change in producer surplus, that is the change in revenues minus the change in associated costs of generation". A key thing that does not appear to be included is the potential impact of changes on investment and financial viability of system resources, even with any given cost of capital assumption. That is, a change in producer surplus is estimated, but not whether that producer surplus is, in absolute terms, positive or negative. The result for the country could be a failure to meet emissions reduction targets or ensure security of supply. By fixing the generation and storage capacity, the modelling is unable to explore those potential effects. If generation (or storage) is financially unviable, the owners might simply raise their prices or, for plant types eligible to enter CfD auctions, raise their CfD auction submissions and so have an impact on apparent consumer benefits[4].

4.75: "We do not consider the impact of other generation contracts such as ancillary service contracts or Capacity Market contracts. This is because we consider that they can be overlaid onto any wholesale electricity market design without any material issues, and that the cost impact would

[3] At the time of writing AFRY's full report has not been published but a presentation of their work can be found here: https://www.youtube.com/watch?v=h1VG9N41cGw&t=4s&ab_channel=AFRY

[4] We note that a significant amount of generation capacity is currently not supported by Government-backed CfDs. This is likely to be true also in future years and includes generators with CfDs that have reached the end of the 15 year term.

be relatively small". We are dubious about this assertion, especially in respect of how Capacity Market (CM) costs might grow if unabated fossil plant closes and new low carbon schedulable plant fails to open. However, it is immaterial for the modelling presented because the generation and storage capacities have been fixed.

2.4 Chapter 5

5.7: points of modelling detail: "we run a long-term expansion model (the "long-term model") which determines the optimal evolution of generation capacity to meet demand at least cost. This optimises the investment decisions of new generation and storage assets subject to key input assumptions, including local climate profiles and transmission build, and a simplified chronological load modelling approach".

- We think FTI needed to be more precise here. Our understanding is that they are determining the location of fixed total capacities of generation and storage of different types, which is not the same thing as optimising the generation and storage mix to meet demand at least cost, including long-run costs. (For example, a full optimisation might choose to build one type of generation instead of another).
- In what way is the load modelling approach simplified? From what it is written elsewhere, we assume that is "chronological" in the sense of using time series, i.e. time specific sequences of values. This is important especially in respect of potential constraints on generation such as ramp rates and minimum on and off times, and for the charging and discharging of storage and time-shifting of demand. We would have welcomed information on how storage and flexible demand are constrained[5].
- Are capital costs for variable renewables assumed to be the same in every location so that the cost of energy from them varies only with local weather conditions and the associated impact on availability of power?

We think figure 5-1 could have been drawn so as to make clear which things are taken as fixed, and which are optimised/allowed to vary.

5.10: "The long-term model is a cost-based model and does not implicitly consider the financial viability of generating units, rather it focuses on meeting demand at least cost to the system". It seems to us that this is an extremely important note.

FTI, in common with many (most?) independent electricity market modellers, make the assumption that every producer offers energy at their short run marginal cost (SRMC), usually citing the further assumption of a fully competitive market. We would have welcomed evidence of whether this assumption holds up in real markets. As we discuss in section 3.3, we wonder whether low merit generation might offer energy at prices nearer to long-run costs than short-run.

5.20: "while we are cognisant of potential reforms to the TNUoS regime, we have assumed that the current regime continues". We note that FTI have, apparently, not attempted any assessment of what incentives to market participants' behaviour might arise from TNUoS charge but have simply used the ESO's assumptions about impacts of TNUoS on the generation and storage mixes in the two FES scenarios they have used. We also note that, at the time the study was started and given the status afforded across the sector to the FES, it was not unreasonable to use the most recent FES as

[5] The extra information we recommend may have been provided in the appendices to the report. We apologise that we did not have time to review them.

some sort of starting point. However, in our view, the fixing of generation and storage capacities creates problems with interpretation of the results.

2.5 Chapter 6

6.3: "we focus on presenting a full picture of outcomes under the LtW (NOA7) scenario in the main body of our report". We are unsure as to why this scenario is the main focus (with results for other scenarios given in the appendices). It uses an older and less complete picture of transmission reinforcements than LtW (HND).

Fig 6-2: there is a lot of interconnection to Norway, some of it connected in Scotland. We note that new interconnection between Britain and Norway is currently being blocked by the Norwegian government.

Fig 6-4: one particular limitation of the zones chosen is that they make no distinction between west coast and east coast. The zonal market, with the zones as drawn, will not show any transmission impact from relocating between west and east.

6.25: "Combined offshore and onshore wind capacity in Scotland is still expected to reach c.52GW by 2040 in the zonal model, constituting a less than 10% decrease under zonal market arrangements compared to that forecasted by FES 21 for the current market design". We note that some generation capacity moves from the south of Scotland to the north, presumably to benefit from higher capacity factors, but that total wind generation capacity in Scotland remains very high even after the use of modelling to choose location (in order to give a minimum total cost of energy). Some offshore wind also relocates to the Celtic Sea.

6.26: "As detailed further in Box 6-1, Scottish zones see much higher price volatility between hours, with wholesale prices regularly dropping close to zero in windy periods. Price volatility between hours is relatively more limited in England and Wales." It would have been good to see price duration curves for each zone for one or two key years, and to see some comparison with price duration for the national market.

Box 6-1:

- Are any constraints put on battery charging and discharging in the model, e.g. state of charge must be the same at the end of a given period as at the beginning? (The period might be 24 hours or a week. We note that the operational modelling appears to work in weekly blocks). Might that lead to, for example, wind being curtailed in order to allow batteries to discharge? It might also be that the optimisation is able to sequence battery capacity in a given zone, i.e. charge one after another, and discharge one after another. We suppose that a centralised dispatch could do that in a way in which a decentralised market probably would not. However, while that might be an optimal utilisation of given storage capacity, nothing is said about the financial viability of that capacity.
- The total duration of £0/MWh isn't actually very clear from Fig 6-6. The price seems well above zero for more of the time than we would have expected.
- "Under the LtW (NOA7) scenario, most of the flexibility on the system is not provided by grid connected batteries, but rather by thermal generation in the early years and by the demand side and interconnectors in the later years". Was a sensitivity case performed: with and without demand side management?
- "our modelling shows that it is more commercially attractive to site batteries in Scotland." However, this is under the constraint of a fixed total battery capacity for the whole of GB.

For the optimisation to find it cheaper to locate batteries in Scotland is not the same thing as saying the batteries would actually be commercially viable in Scotland.

6.31: "As a result, wind farms in North Scotland benefit from higher volume of generation and are not penalised by lower capture prices". What are the capture prices?

We note limits on onshore capacity in England and Wales. Was there any shifting of offshore to onshore or vice versa? We also note that nodal results run counter to the zonal push from southern to northern Scotland, apparently due to within-zone constraints.

Fig 6-10 in Box 6-2: we note that total production is higher in the FES in 2025 than in FTI's modelling, and lower in 2040. Is that due to, for example, differences in demand, or in interconnector transfers?

6.42: "The nodal model, by design, does not require additional intervention by the ESO to balance the system". This seems to us to be unlikely to be true in reality. Are FTI saying that system operators in existing LMP-based markets in PJM, ERCOT, etc. take no within day actions to balance the system?[6]

Fig 6-11: There are differences in total production. Is this down to interconnectors, network losses (which are not taken into account in a decentralised market, even though it is long more often than it's short?) or a mixture?

Box 6-2: the results on interconnectors between national and locational market will be very sensitive to the price put on interconnector actions in the BM and to the fossil fuel Offer price uplift. Why should the ESO in future not be able to access generation in France or Ireland at, potentially, a cheaper price than a CCGT in England? Do SO to SO trades currently reflect costs of actions sufficiently accurately and are interconnectors used as efficiently as they could be?

6.51: "We have discussed our approach with ESO regarding the modelling of the BM and validated our findings that interconnectors become the main asset to be constrained-on as gas generation is phased-out". If EVs and other demand are genuinely smart and, as shown in the nodal scenarios, can be scheduled by location, why could flexible demand not be a BM option?

Box 6-4: "interconnector offers are only accepted once there are no more gas generators available. This assumption is based on historic data, which shows that gas generators are more likely to be used for balancing rather than interconnectors." We are not sure that historic patterns are a good guide to the future as the generation capacity mix is changing everywhere. Today, constraining off nuclear output in France in order to back off imports from France would naturally be expected to be expensive. In cases where France is not importing at a maximum and more power is needed in GB, it

[6] It might be asked whether a comparison of a zonal or nodal market with a 'national' market would require modelling of within-day actions. Because FTI's modelling has, in effect, assumed perfect foresight at a day ahead stage in each (with an idealised day-ahead dispatch without network constraints used as a proxy for today's decentralised market arrangements), it could be argued that a comparison does not. We would note that Bid and Offer prices used in the assessment of BM costs in the 'national' market come from hour ahead in an actual market that is subject to uncertainty and has decentralised dispatch that might be seen as sub-optimal for reasons in addition to the neglect of network limits (or perhaps arising from exploitation of them). The effect of this on the market arrangement comparison might be small, though. However, the initial statement – "The nodal model, by design, does not require additional intervention by the ESO to balance the system" – is, it seems to us, still incorrect. We also feel that work should be done to understand how owners of resources in a system with high penetration of variable renewables and interconnector capacity would manage risk at the day ahead stage and in intraday markets.

can currently be expected that British CCGTs would be cheaper than French coal or whatever would be needed in France. However, as the availability of generation in interconnected countries changes, different relationships may be expected to emerge, as implied through the zonal and nodal results where the market price in France is only slightly higher than that in GB for the case shown in Box 6-2.

In respect of charging of electric vehicles (EVs), it is worth noting that there are already trials in place under the status quo to allow for locationally differentiated time of use tariffs to achieve some of the same outcomes as LMP.

6.59: "Pre-gate closure takes place if there is more renewable generation across GB than demand and export capacity combined". Is there much in the national, decentralised market (with lots of renewables on CfDs) to drive this? Or is it being assumed that the ESO will take pre-gate action? Is this the negative pricing rule in the CfD kicking in? It is our understanding that generators from the 2nd and 3rd CfD auction rounds (AR2 and AR3) will not self-schedule if there are 6 consecutive hours of negative prices as they will not get paid; for generators with CfDs from AR4 onwards, we understand that this applies for any negative hours.

6.64: "Over the 15 year modelling period, moving to nodal markets reduces wind curtailment by c.327 TWh or 40%, while zonal markets lead to a c.209TWh or 26% reduction, indicating that under more locationally granular pricing, the GB market is able to utilise the same quantity of wind generation with a lower number of wind turbines (and therefore lower investment)." For context, it would have been useful to know the final energy production from wind in the three market models.

These differences look big and yet, from the earlier results on siting, only quite modest amounts of generation capacity appear to have relocated. We are therefore a bit confused as to how the curtailment differences can be so large. Perhaps a large part of it is driven by large differences in the final few years, i.e. 2035-2040. It does potentially suggest that the wind capacity that gets moved out of the North and into the Celtic Sea is effectively facing near 100% curtailment in the national scenario. If true, it implies that the starting assumptions for the main presented body of results (based on FES spatial distribution of generation coupled with the two transmission scenarios) are not very reasonable. The very large reduction in curtailment when HND network reinforcements are included supports the suggestion that starting assumption for transmission capacity is too small, or that generator placement is unrealistic. The much smaller curtailment figures for the System Transformation scenario may also be noted.

Curtailment (TWh)	National	Zonal
LtW (NOA 7)	327	209
LtW (HND)	165	81
Sys Tr	160	52

Fig 6-16: We find it a bit difficult to reconcile the very similar total emissions shown here in 2040 with the very large differences in wind curtailment shown in Fig 6-15.

6.67; "However, nodal and zonal markets reduce emissions in all other modelled years relative to the status quo national market. Generation from fossil fuel plants is replaced by renewable generation and interconnector imports, as described in paragraph 6.44." This suggests that global emissions could be increasing via the European mainland[7].

[7] See, for example, https://pureportal.strath.ac.uk/en/publications/the-impact-of-interconnectors-on-the-gb-electricity-sector-and-eu

6.68: "The reduction in emissions would allow the UK to reach its net zero targets earlier or to create extra headroom for other industries, where emission reduction is more challenging." According to the modelling, the accumulated differences in emissions between 2025 and 2040 between the markets are significant. However, the FES 2021 scenarios were developed before the UK Government adopted a 2035 target for a zero carbon system and one would assume that, if the decentralised, national market was failing to reduce emissions by enough, some intervention would happen if we still have that same basic market structure.

Interconnector Flows: it is worth noting how some of FTI's key results are highly dependent on the assumed market cost in other countries in Europe. Whether import and export patterns materially change under different sensitivities would be worth exploring. The results as presented are hard to parse (% changes rather than TWh). The results in respect of interconnectors apparently drive around a third of the total nodal benefit. A deeper understanding of them and their dependencies is required and would have benefitted from richer discussion.

(Incidentally, we are unsure as to whether FTI were given good advice by whoever they were liaising with at the ESO in respect of 7 zones sufficing, especially in respect of the south of England and the Highlands).

Fig 6-26: We find it interesting how total curtailment is similar for the three markets in 2025 and 2030. Total curtailment is quite large for all of them in 2035 and 2040, but with quite big differences between National and Nodal. How much of that is down to the ESO, in respect of network reinforcements, not yet having "formed a coordinated view beyond 2030"[8] and not really addressing the generation background beyond that date?

2.6 Chapter 7

7.30: "Scottish prices increase to £31.8 per MWh in 2035 and begin to converge to prices in the other zones, as many of the new large-scale transmission projects come online and the re-siting of generation to more southern zones starts to take effect". From what we can remember of the discussion on relocation in an earlier chapter, there is not much movement of generation capacity across the main boundaries: wind between northern and southern Scotland and solar between midlands and south of England. We would have welcomed discussion of how the magnitudes of changes lead to the convergences shown for 2030 and 2040. We speculate that the main difference is around 7 GW of offshore wind capacity getting moved South (to the southernmost zone and, presumably, the Celtic Sea) from North Scotland and North England zones.

(With the benefit of hindsight, definition of the zones would have followed running of the nodal model.)

7.42: "Under nodal markets, as the market takes into account all transmission constraints which are reflected in the nodal wholesale price, there are no congestion [constraint] costs incurred by the ESO". As previously noted, this is idealised – the model is assuming that every actor (and the day ahead market clearance) has perfect foresight.

[8] The "Network Options Assessment 2021/22 Refresh" document dated July 2022, focused on network developments up to 2030. In that document, the ESO also said, "Looking beyond 2030, the NOA 2021/22 Refresh has signalled a requirement for a further 17 onshore reinforcement options at a cost exceeding £6 billion. These reinforcements alongside new proposals will be evaluated to provide a coordinated view beyond 2030 in our HND follow up process." https://www.nationalgrideso.com/document/262981/download We do not know if the ESO has completed that evaluation or if the "new proposals" were shared with FTI for inclusion in their modelling.

Fig 7-10: There are lots of constraints that bite in the south, especially in 2035 and 2040 suggesting either that the zones have not been drawn very well or the ESO's reinforcement plans have not yet progressed far enough to address those parts of the network in those years.

Fig 7-11: Given that the LtW (NOA7) scenario has the highest constraint costs but an out of date network development plan, some stakeholders might regard it as a bit strange that FTI have focused on that scenario (albeit they have included the others in appendices).

CfD payments: the assumed strike prices are based on BEIS estimates of levelised cost of energy (LCOE). We would have welcomed greater clarity on what these assumptions actually are. They seem to show offshore wind with a higher strike price than other renewables. This is not what Government expected for the most recent CfD auctions where onshore wind was allowed to bid at £52/MWh (2012) while offshore wind got priced out with a cap of £44/MWh.

Fig 7-15: A few billion pounds per year is a lot of money but, compared to total cost of electricity (from the modelling) of around £80/MWh from 2030 onwards, the savings of (from 2030 onwards) between £3 and £5/MWh do not look so big.

FTI go to some length to try to justify their estimates of constraint costs. Large elements of that are what is assumed for thermal plant Offer Uplift and the cost of interconnector actions. Some key things to improve the likelihood of different actors recovering their long-run costs appear not to have been considered:

1. Uplift on CfD strike prices to reflect anticipated dispatch risk
2. Uplift on prices offered into the centralised market by low merit plant, something likely to be of increasing importance as utilisation drops as a result of growth of use of renewables. The lack of uplift in the centralised market seems to us to be an inconsistency with the treatment of constraint costs. (In our view, it is not just about pay-as-bid versus pay-as-clear. Our understanding is that uplifts can also be seen in pay-as-clear markets).

7.72: the same point. "Wholesale costs increase under locational pricing, as some of the generators, which are paid through the BM in the status quo would receive payments through the wholesale market". However, it seems to us that there is an inconsistency here. Generators receiving Offer acceptances in the BM are generally low merit and are modelled in the BM as offering power at inflated prices relative to their SRMC. As we discuss in section 3.3, one explanation for inflated prices is that it is justified as a way of covering long-run costs. FTI tell us that they have based BM prices on historical experience. However, historical experience of prices is not used in the modelling of the zonal and nodal centralised markets. Of course, a centralised market in England and Wales has not existed since the introduction of the New Electricity Trading Arrangements (NETA) in 2000 so there is no recent GB-specific experience available, but trends might be observed from other markets. In particular, do low merit generators in other markets tend to offer energy at prices above the SRMC?

7.76: "Difference in prices between connected nodes and zones leads to the creation of congestion rents within GB. For the purposes of our assessment, we have assumed that this benefit is accrued to consumers". For the purpose of informing readers, a summary of other uses to which congestion rent is put in different markets around the world would have been useful. (We discuss congestion rent in section 3.4.4).

7.93: wholesale market prices and CfD top-ups per MWh change in the different markets. However – something not mentioned in FTI's report – so, too, do the number of MWh for which they get paid.

7.99: "we assume that all of the uplift that is assumed for the BM offers is the result of the pay-as-bid clearing and is captured by producers as a surplus. In practice, some of this uplift reflects actual costs borne by generators, such as start costs. *This assumption leads to an overestimation of the negative effect on producers and an underestimation of total GB socioeconomic benefits, as a result of locational pricing, making this assumption conservative*." [Emphasis added]. We admit that we struggled to fully understand the emphasised text but have been told by one of the authors of the FTI report that "in the national price system, … we assume [the high prices in the BM] are all profits to producers. This means that, in our comparison between national and locational pricing, we find a bigger reduction in producer profits and a smaller increase in socioeconomic benefits, than would be the case if we were to assume that the high prices partially reflected genuine costs".

Fig 7-25: given the claimed consumer benefits and changes to things like curtailment, we are surprised that the changes to producer surplus are so small in 2040, and for zonal in 2035.

2.7 Chapter 8

8.11: "Market participant costs have been adjusted based on the relative installed capacities of the jurisdiction (in the year the CBA was conducted) and in GB in 2021". We are not sure that that works. It seems to us that each participant will incur costs, more or less regardless of the capacity they have.

Fig 8-1, implementation costs: it would have been useful for FTI to have been clear about which of these are forecasted costs, and which are actual costs. As we know, for IT projects, the latter have a habit of being much higher than the former.

8.14: "ERCOT's 2008 CBA, which was conducted mid-implementation, highlighted significant unexpected cost overruns, primarily due to issues around integrating different systems in different regions. These issues were not experienced in other jurisdictions, and may be unlikely to occur in GB due to the national role of the ESO". We disagree with the last assertion. We wonder if FTI have compared the projected costs of any previous IT projects implemented by the ESO in GB with outturn costs.

8.23: "we have assumed that implementation costs would be £500m". So, after citing £40-60 million for SO costs, FTI finally come to something close to ERCOT's costs, which seems not unreasonable to us.

8.27: "Overall we note that the quantum of implementation costs is materially lower than all of the other costs and benefits identified in this study". This is a fair comment.

8.34: "With regards to the wholesale market, our modelling suggests that wholesale price volatility at a given location would on average increase slightly under locational pricing. For instance, in 2030, the average volatility of nodal prices (averaged equally across all nodes) is 0.92 while the average volatility of the national price is 0.91. This average masks significant variability across the country. For instance, in 2030 (LtW scenario), our modelling suggests that, under nodal pricing, the top 20 nodes by size of load would have lower variance of prices than would be the case under national pricing."

- "Slightly". This appears to run counter to what was argued earlier in FTI's report about volatility being increased significantly and being a good thing for investors in storage capacity.

- The main stakeholder concern appears to be around investment in generation. To take the nodes with highest demand does not address concerns about volatility at nodes at which generation already exists or at which new generation might credibly be developed.

On risk:

- Yes, CfDs can help. Yes, TNUoS risk should be reduced. Yes, BM volatility ought to be reduced (although it would not be eliminated). However, FTRs are a very uncertain proposition. From our understanding, there are significant problems with FTRs as used in other countries and, most particularly, there are currently no FTR products designed for variable renewables.
- We agree that network risk increases, though at present there is also a dependency on policies such as "Connect and Manage" versus "Invest and Connect". With the latter, projects developing new connections to the network are exposed to the risk that their connection date will be very far into the future.
- It seems us that it will generally be difficult to forecast what LMPs will be in future.
- 8.54: "Our assessment of the relationship between risks faced by market participants and the cost of capital suggests that locational pricing could alter the cost of capital, for instance by changing the correlation between returns on investment in the electricity market and general market returns, or by changing price risk for market participants not covered by regulatory support mechanisms. However, our assessment of risks provides qualitative evidence that the overall risk could move in either direction. This provides an indicative suggestion that the magnitude in either direction could be limited, because of the range of potentially countervailing factors that we have identified." Locational pricing introduces a price risk for investors not benefitting from a mechanism such as CfD or remuneration based on a regulated asset base (RAB). We also note that even holders of CfDs are exposed to volume risks.

Box 8-1: "Most or all of the price risks identified by Frontier appear likely to be diversifiable, for instance by investing in a range of generation assets across the country." It seems to us to be important here to discuss the type of generation through which risk would supposedly be diversifiable. The key is that expected revenues from the different investments are inversely correlated or, at worst, very weakly correlated. That suggests, for example, that investment in more wind generation, even if at the other end of the country, might not deliver a very effective diversification. Outputs from wind farms separated by increasing distances have decreasing correlation but, within Britain, they still see quite significant correlations. Other types of generation, such as natural gas with CCS or hydrogen-powered CCGTs, might provide better diversification but there is limited capacity required and they may be subject to similar network risk along the east coast of Britain as offshore wind farms. Enduring market mechanisms to encourage investment in such plant are currently absent.

"Frontier does not take into account the impact of those features of energy markets that could mitigate and manage exposure to risks, including CfDs and FTRs." Any discussion of FTRs must address the lack of long-term products in markets where FTRs are used and the lack of any product suitable for wind generators[9]. It ought also to discuss the meaning of use of congestion rent in

[9] Our understanding is that basis risk is introduced for any Power Purchase Agreement (PPA)/contract that is settled at a trading hub rather than a local node. FTR products tend to be fixed volume for 24 hour or designed for peak periods. An FTR holder only gets an (approximately) perfect hedge when their plant's output equals

conjunction with FTRs and, in particular, whether they represent increased risk to consumers (certainly compared to a case in which congestion is returned to consumers, something that FTI assumes in its cost-benefit analysis[10]).

8.62: "The case studies of countries that have adopted locational wholesale pricing, discussed in Appendix 4, do not suggest strong effects of locational pricing on either the pace or cost of renewables investment. Jurisdictions both with and without locational pricing have seen rapid increases in the capacity of renewable generators in recent years. Instead, factors other than market design, particularly the geographical characteristics of a region and the nature of policy incentives, appear to be more important drivers of investment in generation capacity." This appears disingenuous. Yes, geographical characteristics and policy support have been important drivers such that investment has happened in spite of LMP. However, so too has investment in transmission network capacity. In places where that network investment has stopped, our impression is that generation investment has also stopped.

8.64: "Moreover, there are several tools that could help investors mitigate the effects from more granular locational pricing." We would have welcomed further discussion of this.

8.71: "considerable proportion of trades in the national market design do not reflect the physical realities of the network. This means that some liquidity in these markets is illusory – that trades are being made on an unconstrained commodity that may or may not be realised. As such, the effect of many of these trades would either be unwound or counter-traded in the BM." This seems to us to be fair comment.

8.72: "Moreover, one further deficiency of national market designs is the lack of liquid forward markets for generating resources in import-constrained areas who may seek to contract their outputs at the BM price." We are sorry that we find it difficult to understand the point being made here.

(Much of the discussion in chapter 8 feels to us like advocacy of LMP rather than honest, objective discussion of the issues).

8.75: "Unlike the GB national self-scheduling market design, the wide spread of exchange-traded products negates the need to find a counterparty and allows all market participants easier access." Our understanding of the current GB market is that there *is* a lot of exchange trading, albeit that the amount might have been changing in recent years[11].

8.76: "As such, throughout our research on international case studies, and from our discussions with US energy experts, we have not observed any critical issues concerning liquidity around these

the FTR volume. This works well for baseload but not variable plant, hence the developing concept of "wind FTRs". See, for example a presentation published by the International Association for Energy Economics, https://www.youtube.com/watch?v=AQQNDqo1iqw&ab_channel=IAEE

[10] Our understanding is that the main reason the offering of FTRs was rejected in Australia is because of the risk to the market operator issuing them and, as a consequence, to consumers.

[11] We admit to difficulty in finding sources of evidence beyond charts published by Ofgem in its data portal, https://www.ofgem.gov.uk/energy-data-and-research/data-portal/wholesale-market-indicators . These point to the monthly volume of 'over the counter' trades falling from a high of 142 TWh in November 2016 to 40 TWh in June 2023, and the churn ratio declining from 5.8 to 3.1 in the same period. ('Churn' is defined by Ofgem as the number of times one unit of electricity is traded. The average monthly electricity demand in the UK across 2022 was around 27 TWh).

markets." However, there *have* been significant problems with FTR markets as they have been set up to date[12].

2.8 Chapter 9

One of main worries about FTI's work and the associated report is that what is not taken into account is the impact of locational pricing on generators and the extent to which, in order to remain financially viable, they would need to increase prices of their offers of energy or, for new generation able to bid for Government-back CfDs, their bids in a CfD auction. These higher prices would need to be paid by consumers.

Estimation of changes to producer surplus do not address whether absolute values of producer surplus would be positive or negative. We regret absence of assessment and reporting of capture prices.

FTI "explore a range of transitional and mitigation measures that policymakers could use to support the transition to locational pricing, and how these measures may affect the overall impact on consumers". We do not know if this was really within the scope of their work. If it was, in our view Ofgem should really also have commissioned work looking into whether the claimed benefits of locational pricing could be achieved by other means.

Intra-GB congestion rent represents a significant chunk of the estimated socioeconomic benefits. We would have welcomed discussion of how that might be affected under different structures of FTR markets, e.g. in terms of the split between producers and consumers.

Table 9-1: "although less transmission is likely to be required in locational markets". This is the assumption generally made in the economics textbooks. However, we would caution that it should be tested for the specific case of GB where massive changes to the generation background are being sought. It might conceivably turn out that *more* transmission is needed than shown in NOA7.

"Fixed capacity mix: overall generation capacity and technology mix is fixed to FES21. Change in the mix of technologies between national and locational market designs could further increase efficiency and reduce costs of achieving Net Zero". The fixed capacities of each generation technology are a major limitation of the study. However, contrary to what is asserted by FTI, it seems us that relaxation of that constraint might lead to higher or lower total costs – it is not clear to us that, even given the ESO's assumptions on exogenous factors, the generation mixes in any of the FES21 scenarios would be the cheapest ways of meeting demand with a certain level of reliability in any of market scenarios. Furthermore, importantly, if the potential for generators to fail to cover their costs is not addressed, targets for decarbonisation of the electricity system may be missed or standards for electricity supply reliability might not be met.

"Operational benefits: our modelling does not account for operational benefits from centralised scheduling vs self-scheduling as well as other dispatch benefits. For example, we do not consider the impact of the ability to co-optimise energy and reserves more efficiently in a nodal market." We agree that this is potentially an important factor and could bring benefits, especially in respect of efficient utilisation of storage and interconnectors. However, including in markets that use LMP today, our understanding is that there remain significant mathematical challenges in developing

[12] See some of the cases discussed in Gill, MacIver and Bell, *Exploring Market Change in the GB Electricity System: the Potential Impact of Locational Marginal Pricing*, https://pureportal.strath.ac.uk/en/publications/exploring-market-change-in-the-gb-electricity-system-the-potentia-2

multi-period dispatch algorithms that deal effectively with non-convexities such as integer variables. It seems to us that there are also questions around:

- compatibility around any attempt to more efficiently (from a GB perspective) dispatch interconnectors with market rules prevailing at the other end of each interconnector;
- treatment of uncertainty between whenever a centralised dispatch algorithm is run and real time around actual demand and availability of power from variable renewables;
- how what is likely to be the continued option for market participants to self-schedule might play out.

The potential for locational pricing to beneficially influence decisions on siting of new resources might be regarded as too uncertain to be relied on in an argument for transitioning to locational pricing. The operational benefits of centralised, locational dispatch might conceivably be significant enough for locational pricing still to be pursued. However, centralised dispatch would have an impact on investment in resources that would still need to be carefully assessed.

We note that the impact of planned network outages for maintenance and construction work makes network capacity less than has been assumed. The impact of construction outages, in particular, can reduce inter-area transfer capacity by up to 50% across certain boundaries for a very large part of the year in which the work is taking place[13]. Such reduction of capacity would increase the volume and total cost of BM actions, and would cause more curtailment and higher congestion rent in a locational pricing world.

“Further policy support for existing generation: additional grandfathering of existing generation (e.g. compensating for reduction in constrained-off payments) will lead to a reduction in consumer benefits (typically though a reduction in congestion rent in lieu of higher producer surplus) and no change in producer benefits”. This is a very important point that seems to us to merit further work.

“No change in cost of capital: we assumed no change in cost of capital due to lack of evidence, but an increase would reduce the estimated benefits, and a decrease would increase the estimated benefits.” On balance, we consider that an increase is more likely than a decrease.

“No other reforms assumed: assessment based on the current market structure and policy landscape. Further changes (e.g. network charging, Capacity Market reforms) could change the overall benefits”. This is true and is an important acknowledgement. The extent to which better siting and incremental improvements to the BM and other elements of the market design could change outcomes in the counterfactual national scenario is worthy of exploration.

“Modelling year: delaying the start of the modelling year may lead to multiple effects in both directions”. A large proportion of the modelled benefits appear to accrue during the assumed period of high gas prices between 2025 and 2030. It might be interesting to extrapolate from current runs the 15-year benefits if taken from a more realistic start date of 2028 or 2030. There might be a significant reduction in apparent benefits.

We note that the estimated total socioeconomic benefits for the LtW (HND) scenario are significantly lower than those for the LtW (NOA7) scenario. The HND network investments are the result of a more up to date appraisal by the ESO and might therefore be regarded as more realistic

[13] See, for example, reports by the ESO in their “transparency forum” of boundary transfer capabilities in Scotland.

(albeit more expensive and difficult to deliver with the potential for delay). However, we also note that FTI has not included costs of transmission enhancements in the analysis.

The Steady Progression (SP) scenario, in which decarbonisation targets are missed, has not been assessed. We note that one potential consequence of a move to locational pricing is that investment in low carbon generation is slowed (or existing generation closes early). Thus, a transition to locational pricing might be a cause of something like an SP scenario.

Much is made of the estimated percentage benefit to consumers of a move to nodal pricing and how, according to FTI's assessment, it exceeds a threshold used to justify NETA in the late 1990s. However:

- might total socioeconomic benefit be a better metric than just consumer benefit?
- given the constraint on total generation capacities used in the modelling, might total costs of electricity have been underestimated?
- given, among other things, the way in which costs of support for low carbon generation are recovered via consumer bills, percentages might be better expressed relative to total retail costs faced by consumers.
- congestion rent might not accrue to consumers depending on whether and how FTRs are implemented. (We note, in particular, the significance of congestion rent in Figs 9-7 and 9-8).

It would be interesting to see Figs 9-7 and 9-8 expressed on a per MWh basis. Is that what is shown in Fig 9-9? We would have welcomed clarity that what is shown is the net consumer benefit per MWh, not just the wholesale price. Again, the impact on the results of the constraints in the modelling imposed on total generation capacity should be noted.

9.46: "low marginal cost renewable generation is rolled-out and prices are less frequently set by fossil fuel generators." Is there still a missing money problem when prices are set by zero marginal cost generation? This problem might be argued to apply only to generation without a CfD, but that could be a significant amount. From what we recall, FTI's analysis assumes that 50% of future onshore wind and solar capacity is deployed without a CfD. Without a capture price analysis, it is not possible to know how much of this would be financially viable. Also, it might be argued that a significant amount of zero marginal cost (ZMC) generation can only operate – and set wholesale market prices – because of CfDs, the costs of which are underpinned by GB consumers. In situations in which ZMC generation is setting the price at a location in GB and energy from it is being exported to another country, it might be argued that GB consumers are subsidising energy users in other countries.

9.55: "[emissions are] driven primarily by utilising renewable resources and flexibility assets more efficiently in locational pricing markets, thereby reducing the proportion of electricity generated via fossil fuels". . We recall again that the generation backgrounds used in the FTI work come from the 2021 edition of the FES. In FES21, large volumes of bioenergy with carbon capture and storage (BECCS) are assumed and total emissions become very negative in later years. It seems to us that the BECCS assumptions built into FES21, mean that the emissions numbers and the apparent benefits coming from carbon pricing should be taken with a pinch of salt[14].

[14] The work by AFRY for the CCC published on March 2023 has only 20 TWh of energy production from BECCS in 2035 and 2040, equating to, at best, -16 MtCO2e. That is added on to other emissions, ending up with net electricity sector emissions of around 15 MtCO2e in 2030 and 5 MtCO2e in both2035 and 2040). Also, the

9.69: “any attempts to dampen the locational effect on wholesale prices, or reallocate consumer surplus to market participants would unavoidably reduce consumer benefits.” However, the estimate of consumer benefits may already be subject to error and attention should be paid to what is needed to ensure that the generation capacity mix is sufficient for reliable supply with minimal emissions.

In general, we suspect that many readers would, like us, need to think carefully to fully grasp what drives the reported changes in total socioeconomic welfare as opposed to things that give a net neutral transfer between producer and consumer. We think the report might have done a better job of fleshing that out. .

Box 9-3: “To date there have been minimal issues with existing renewable investments (as they were typically under contract with the retailer who purchased FTRs and/or received them in the allocation process).” We find it difficult to understand the point being made here.

2.9 Chapter 10

10.10 “in a nodal market, the resolution of transmission constraints is inherent to the market design itself and that there is, therefore, no requirement for the ESO to incur constraint costs by intervening in the market to resolve congestion”. This seems to us to only be true to the extent that the centralised dispatch has perfect foresight.

10.22: “if the estimated incremental cost of the transmission reinforcements was greater than £3bn then the investment would, under a strict socioeconomic assessment approach in a nodal market, be net detrimental to society.” The modelling is done with a fixed total generation capacity. There has been no estimate of total producer welfare, only of changes. As has been discussed by others, there is also controversy about what the net benefits of a switch to a nodal market would be, particularly given uncertainty around cost of capital impacts[15], and uncertainty about whether, and under what conditions, such a major market change should happen[16]. Hence, the assertion that transmission reinforcements with an incremental cost of more than £3 billion would be detrimental should be approached with caution[17].

10.24: the modelling has, to a certain extent, idealised the location of generation given the transmission capacity upgrades. If the generation, in a sense, follows the upgrades, the total welfare will appear less than if it had not.

- If the transmission upgrades had not been done, generation would have gone somewhere else, if it had been able to.

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extent to which FTI’s results represent carbon displacement to central and eastern Europe would be worth exploring (and would be explorable via their model). What are the net global emission impacts?

[15] See, for example https://afry.com/sites/default/files/2023-09/afry_brochure_energy_market_report_phase_two_summary_report.pdf and https://auroraer.com/wp-content/uploads/2023/09/Locational-Marginal-Pricing-GB-Aurora-Public-Report.pdf. A report published by UKERC in April 2023, among other things, highlighted the degree of sensitivity of the cost of the energy transition to cost of capital changes. See https://ukerc.ac.uk/publications/transition-risk-investment-signals/

[16] One point highlighted in our report with Simon Gill published in February 2023 is that, based on experience from LMP-based markets in the US and stakeholder insight interviews, there needs to be an appropriate level of network capacity for locational signals to provide useful incentives rather than just be penal. See https://pureportal.strath.ac.uk/en/publications/exploring-market-change-in-the-gb-electricity-system-the-potentia-2

[17] With present day market arrangements, the ESO’s assessment of the HND network reinforcements plans suggests a significant benefit arising from those reinforcements.

- If it had not been able to move, a need for transmission would be revealed.
- Wouldn’t a fairer assessment of the merits of transmission investment under self-scheduling and LMP have compared the same generation background, both amount and location?
- FTI estimated the potential carbon benefits of moving between market designs. Could similar benefits not be attributed to the facilitation of renewables via transmission investment? (We note that total values for emissions are not given, just relative changes between scenarios).

It seems to us that there is a chicken and egg situation between transmission and generation.

- Experience from Texas suggests that if transmission is not built, the generation will not come.
- If transmission is built and generation fits with transmission, the after-the-fact apparent value of the transmission through social welfare will appear small.

In our view, one difficulty with many idealised treatments of locational pricing is that they treat transmission as fixed. As FTI acknowledge, changes to transmission can bring improved social welfare but also represent risks to generators. So, too, do changes to the generation background as a result of investments by other parties, or to dispatches as a result of changes in fuel prices. However, the ‘lumpiness’ of transmission and the challenges of getting major developments through planning and regulatory approvals processes arguably make the potential impact of transmission development one of the hardest things for market participants to predict.

Footnote 214: “The latter was introduced in the US as part of FERC Order 1000 and could be used in the assessment of transmission needed to connect generation assets to meet environmental targets. It would seem to us that the level of non-economic benefits would be invariant to the market design (for example, the same volume of renewable generation capacity is connected in each market design scenario) and therefore the same level of ‘non-economic’ benefits would accrue for the transmission enhancement that we assess.”

- Firstly, facilitation of renewable generation is not just a ‘non-economic’ benefit.
- Secondly, FTI’s modelling has the same, assumed total generation capacity in each market model and constrained the modelling to reflect it. In reality, it is very likely that a different market model would incentivise generation investment in very different ways.

10.27: uplifts to Offer prices “reflect the idiosyncratic nature of the pay-as-bid BM, the locational value of electricity, and potentially also a degree of market power. Hence, while some of the uplift may reflect underlying costs (the start-up costs) it also potentially includes other non-economic cost factors.” Any or all of these factors might be true. However, the potential that the Offer prices are closer to the long-run costs that low merit generation needs to recover in order to stay operational (and help to meet demand) should also be kept in mind.

10.28: Bid prices. This is another key difference between how FTI has modelled self-scheduling and the BM compared with how they have modelled locational pricing.

- Except in respect of generators with CfDs and the impact of negative pricing rules, for the self-scheduling world, generators in export-limited areas are not exposed to dispatch risk as they are compensated for not operating[18].
- In the locational pricing world as modelled by FTI, generators are not compensated for not being dispatched. The consequence is the possibility that the revenues are insufficient to support operation at all, with the potential results that government targets for, for example, offshore wind are missed, that emissions are higher than otherwise and, if sufficient schedulable plant fails to remain open or turn up, that reliability of supply will be worse.
- "this element of the reduction in cost can only be a reduction in transfers from consumers to generators. While no doubt welcome from a consumer perspective, from a socioeconomic perspective this has zero economic value". We have difficulty with the assertion of zero economic value. It may actually have an economic cost.

10.30:

- "the NOA methodology appears to conflate both economic cost savings (that arise from the reduced need to incur costs of constrained-on generators) and the transfers that incur in the BM as a result of participants including uplifts in bids and offers from the underlying cost, and also because of the transfers to compensate constrained off plant – particularly those that hold CfDs." It would be reasonable, in general, for sums paid by the ESO in the BM to compensate BM units for reasonably incurred costs. If a generator incurs costs in starting up or increasing output, those costs should be paid if they are needed for the system in order to meet demand and keep the system stable. If a generator incurs costs in decreasing output, again those costs should be paid if they're needed for the system.
- "the BM bids and offers do not completely reflect underlying economic costs." We assume that this refers to the prices quoted by BM participants for dispatch or re-dispatch actions in the BM and the costs to those participants of their actions. What is stated might be true. However, if it is, it seems to us to most likely be because of market power or game playing.
- "we note that the risk of overvaluing the benefits of transmission enhancements appears to be true under the current national pricing regime". If there is game-playing that has not been addressed by regulatory action then, yes. However, actually, it seems to us that FTI is under-estimating costs in their modelling of a locational pricing world. (See further discussion of the evaluation of benefits in reducing BM costs in section 3.4.2).

It seems to us that the concept of scarcity pricing is important in discussions about cost versus value. According to Papavasiliou in *Scarcity pricing and the missing European market for real-time reserve capacity*[19]: "Scarcity pricing refers to the notion of increasing energy prices above the marginal cost of the marginal unit under conditions where the system is short on generation capacity. Scarcity pricing generates profits for generating resources that serve towards covering the capital costs of these units. Scarcity pricing is therefore essential for attracting investment in a market."

It is absolutely critical to test whether

- FTI's assumptions on re-locatability of resource investments are reasonable;

[18] The negative pricing rule in new and future CfD arrangements might mean that, when there is a national rather than a local surplus, a good portion of CfD generators (not to mention those assumed to be merchant) are at volume risk under the national market.

[19] https://www.sciencedirect.com/science/article/pii/S104061902030155X#sec0015

- the prices used in both BM costs assessments and locational pricing assessments are reasonable;
- generation, storage and interconnector investments in a locational pricing world are financially viable.

The above need to be tested urgently in light of the possibility that FTI's assertions that locational pricing would lead to less need for transmission will cause further delays to development of enhanced transmission capacity that most key stakeholders agree is needed sooner rather than later.

2.10 Chapter 11

11.21: "this sensitivity [on retaining a 'national' market but assuming generation is better sited relative to assumed transmission capacity in NOA7] demonstrates that consumers specifically, and GB more widely, would still accrue significant benefits in a move to greater locational granularity of wholesale prices, even if the siting decisions of generators were determined optimally by a central planning function". However, as noted elsewhere, we have concerns about the costs used.

"Load shielding". This an interesting exploration of the idea that national pricing (for demand) leads to flexible demand flexing at the wrong times.

"whether consumers would be able to opt out of a load shielding policy should they prefer to pay the local price at their connected node". This seems to us to be comparable to consumers opting in or out of time of use pricing today but potentially much more lop-sided as people in low cost zones are likely to opt-in and those in high cost zones opt-out. Who covers the costs if only people who financially benefit opt-in?

We note in respect of siting that electrolysers' locations have been determined without consideration of access to hydrogen networks or storage. FTI say the majority are located in Scotland, potentially based on what was said in FES 2021[20].

Our interpretation of Fig 11-10 and Table 11-2 is that shielding has only a modest impact. In other words, it does not seem very important for the prices at which the centralised market clears or for curtailment of wind.

We are curious as to why is the SysTr (NOA7) scenario being discussed when almost everything else in the main report is centred on LtW (NOA7). We speculate that this is because the LtW scenario has more vehicle to grid (V2G) capacity which is considered to be exposed to nodal signals. We assume this is enough to mean that load shielding has even more modest impact for the LtW scenario and the benefits of exposing additional domestic demand to nodal prices are even more limited in that scenario.

We note that comparison of Fig 11-11 with 11-12 suggests a decrease in socioeconomic benefits of only £1.7 billion across the entire 2025-40 period.

11.58 "our modelling cannot capture the broader negative impact that a load shielding policy could have on the development and uptake of price-responsive demand technologies across the GB system … A load shielding policy would reduce the ability of price-responsive demand technologies

[20] For some of our own GB system modelling, we used FES 2022-23 to site electrolysers (though without access to full siting information from the ESO meaning that we had to infer some things) and less than half of the capacity was in Scotland. (Capacity outside of Scotland does not help with curtailment of generation within Scotland due to network limits).

to provide flexibility to the system. To the extent that this reduces the incentive for demand-side operators and technology providers to innovate, … a load shielding policy could limit the deployment of an important form of low carbon flexibility for the future system." We agree with this. However, the extent to which the amount of flexibility assumed in the base case from sources other than EVs would actually happen even in a nodal pricing world is also untested.

2.11 Chapter 12

12.11: "We observe that while the wholesale price impact may vary considerably, net consumer benefits are positive in each region". If we take the overall net consumer benefits in each region as given, there would still likely be arguments about 'postcode lottery' on who benefits most. FTI have produced sensitivity analysis on what change in the weighted average cost of capital (WACC) would be required to wipe out the calculated benefits of LMP. This analysis has been done on a national level, but it would be interesting to assess whether particular regions would be vulnerable to being worse off under LMP than in a national market for changes in WACC that are more modest than those presented. The political challenges inherent in navigating this distributional impact would seem one of the least discussed, and potentially hardest parts for policy makers to justify if a move to locational pricing was pursued. This should not be underestimated when assessing the deliverability of LMP.

3 General comments and conclusions

The task taken on by FTI is extremely challenging. It requires modelling of sufficient detail of the GB transmission network and connected generation, storage, interconnectors and demand for a whole year of operation in order to take account of variations in demand and the availability of generation, in particular weather-dependent renewables such as wind and solar. This should be done for a number of future scenarios and a number of years, and should compare costs and benefits between current market arrangements and proposed, revised arrangements.

The following factors are fundamental to the comparison.

1. What the network's capacity is assumed to be and what the location of generation, storage and interconnectors are assumed to be in the absence of locational pricing.
2. How market participants are assumed to respond to the incentives given by the different market arrangements.
3. Assumed prices:
   - for different actions offered to the ESO for re-dispatch actions in the Balancing Mechanism (BM).
   - for energy offered into a centralised day-ahead dispatch algorithm.
4. How the overall economic impacts of a revised market are quantified in comparison with the existing market.

The above factors are discussed in the following subsections.

3.1 How much network capacity is assumed, and technicalities of the modelling

In respect of much of the modelling detail, it seems to us that FTI have done as well as might reasonably be expected. They have used network data provided to them by the ESO – what better source might there be? – and taken the ESO's advice on how to construct zones for the zonal version of LMP. They have also taken the ESO's advice on prices in the BM. However, they have used ENTSO-E data for generator technical parameters, demand and for the availability of wind and solar power. ENTSO-E is a body with significant authority; it is reasonable to turn to it for information. The generator parameters ought to be credible, but they might be different from those seen in the BM. In our experience of ENTSO-E's demand time series data may encompass less flexibility than could be reasonably expected in the future GB system – the derivation of effects of EV charging and electrified heat is not clear[21].

FTI's 'base case' for network, generation, storage and interconnector capacity on the system is drawn from the ESO's 2021 FES. There is, for example, a very large amount of new offshore wind generation connected in Scotland but no network reinforcements other than those in the HND which, we understand, forms a "coordinated view" only out to 2030[22]. We question whether the combination of generation and network capacity is credible. The 'Connect and Manage' regime has allowed generation to connect before completion of transmission network reinforcements judged by the ESO and the transmission owners to be necessary to accommodate that connection[23]. However,

[21] It appears from a discussion of flexible demand in one of the appendices that FTI have not simply used the 'raw' ENTSO-E demand profiles but have made some modifications. On initial reading, those modifications would seem to be reasonable but we have not had time to review in detail.

[22] See the "Network Options Assessment 2021/22 Refresh" document dated July 2022, https://www.nationalgrideso.com/document/262981/download

[23] For information on 'Connect and Manage' see, for example, https://www.gov.uk/guidance/electricity-network-delivery-and-access#connect-and-manage

in its 'Open letter on future reform to the electricity connections process' published on May 16th 2023, Ofgem said, "The connections regime could potentially become more closely integrated with system planning, and may involve changes to arrangements such as Connect and Manage." [24]. One change to 'Connect and Manage' could be a return to 'Invest and Connect'. This would require generation connections and network capacity to be broadly consistent, and for new generation to be given connection dates that are dependent on transmission reinforcements being completed[25]. The result for FTI's analysis for a given generation background is that BM costs are likely to have been over-estimated as there is less transmission capacity in the model than would likely be the case for that generation background in reality. According to FTI's modelling, when generation and transmission are well matched, the benefits of LMP appear to be more modest.

It seems to us that, with the benefit of hindsight, different zonal delineations might have been used, in particular to see network limits on flows between east and west in the southern half of Britain. (In our experience, quite what advice is received from the ESO depends on exactly who you talk to).

The network's capacity relative to where generation, demand, storage and interconnectors are located depends not just on the physical infrastructure but also on ambient conditions (affecting thermal ratings, i.e. limits determined by how hot conductors can be allowed to get) and outages, both planned and unplanned. The system is operated to be secure against unplanned outages of single system elements. Security-constrained optimal power flow (SC-OPF) has been in existence for many years that is capable of determining a dispatch or a re-dispatch that respects both pre-fault and post-fault limits for generation, storage, interconnectors, flexible demand and the network although, typically, only network thermal limits are considered in an approximation of network flows. In our opinion, for the purposes of FTI's study, that would be sufficient, although we note that, according to the report, the software they used was not capable of modelling security constraints. They used a pre-determined adjustment to pre-fault power flows as an attempt to account for that. With the time and information available to us, we have not been able to assess the accuracy of that and whether it generally results in an over-estimate or under-estimate of network capacity.

We would also note that the network's capacity is quite commonly depleted due to planned outages to allow for maintenance or construction work to be carried out safely. The latter category of outages can each be lengthy taking, for an overhead line reconductoring, for example, many months. This seems not to have been modelled in any way by FTI although, to be fair, we are not confident that the ESO models it in its network investment planning, either[26]. The result is that network capacity in many weeks of the year will have been over-estimated. That will have affected results in modelling both of the current market and of a zonal or nodal market. FTI's results from the LtW (HND) scenario when compared with the LtW (NOA7) scenario which has the same total generation capacity and demand but more network capacity suggest that more network capacity would reduce BM costs but also reduce congestion rent and price divergence between locations in an LMP based market. Without the benefit of new modelling, we cannot say what the impact of

[24] https://www.ofgem.gov.uk/sites/default/files/2023-05/Open%20Letter%20Connections%20%28Final%2016.5.23%29.pdf.

[25] This would result in later connection dates than would have been the case for generation entitled to take advantage of 'Connect and Manage'.

[26] The network must be sized to facilitate maintenance of the network while still meeting network users' needs. However, the modelling of planned outages far into the future is extremely challenging.

neglect of planned outages would be on the study's general conclusions but one might expect that it may be the source of underestimation of both constraint costs and congestion rent.

3.2 Assumptions on market participants' responses to signals

In the modelling of zonal and nodal markets, the location of generation has been allowed to change, subject to the total capacities of each type being the same and limits on how much extra capacity might be developed in any zone. Within those constraints, market participants are assumed to have such perfect foresight that the result of their siting decisions and centralised dispatch is that total costs to consumers, given assumed prices, availabilities and so on, are minimised.

Locations of solar PV and both onshore and offshore wind are allowed to change in FTI's modelling up to certain limits. It is worth considering how much of these types of generation are in the FES21 generation background that is the starting point for FTI's modelling and how much is in each zone, and how much is in each zone at the end of the modelling. We expect that this will be of particular interest to generation developers and stakeholders such as The Crown Estate that will be considering the resource potential and costs of development in the different zones. Developers will already have portfolio of projects at specific locations at different stages of development and will be considering further, new development options. They will make judgments on the likely viability of each were LMP to be introduced.

We have found it quite difficult to get a clear picture of the results in respect of location of solar PV and wind capacity and regret the absence of clear tabulation of FES21 capacities of each generation type in each zone in each year, the constraints imposed on maximum capacities, and the results of the modelling. In respect of wind, the following seems to us to be what has resulted from FTI's modelling of a nodal market for the LtW scenario with a network with NOA7 reinforcements. For the capacities in zones 3-7 in the FES21 LtW scenario and the relocation of generation into different zones, the best information we can find is from 'eyeballing' what is in Figures 6-4 and 6-8 of FTI's report. For zones 1 and 2 more accurate installed capacity assumptions can be derived from publicly available FES data. Many of the numbers reported below should be taken as nearest round estimates.

- Onshore wind has shifted from the SPT-owned network region (zone 2), mostly north to the SHETL-owned region (zone 1)
    - Only half as much additional capacity has been developed in the model in the SHETL area as the modelled constraints allow: up by 3.5 GW in 2030 compared with a starting point of 9.5 GW in FES21, up by 4.75 GW in 2035 compared with 10.7 GW, and up by 5.5 GW in 2040 compared with 10.9 GW.
- For offshore wind, there has been a general shift from north to south in 2030 and 2035 but a more complex picture in 2040.
    - In 2030, compared with FES21 numbers there is 2 GW less capacity in the SHETL area (zone 1; FES21 had 8.6 GW) with more in zone 4 (Yorkshire, Lancashire and North Wales, 1 GW; FES21 had roughly 9 GW) and zone 7 (south coast, 1 GW; FES21 had 0 GW).
    - In 2035, there is 6 GW less in the SHETL area (FES21 had 16.6 GW), 1 GW less in the SPT area (zone 2; FES21 had 12.9 GW), 1.5 GW less in zone 3 (Cumbria and Northumberland; FES21 had roughly 7 GW) with more mostly in the south coast zone (zone 7, 7.5 GW; FES21 had 0 GW) with some in zone 6 (south, 1 GW; FES21 had roughly 18 GW)

- In 2040, compared with FES21 numbers, there is 4.5 GW less in the SHETL area (FES21 had 18.1 GW) but 4 GW more in the SPT area (FES21 had 13.5 GW) with 4 GW less in zone 3 (Cumbria and Northumberland; FES21 had roughly 8 GW) and 4 GW less in zone 4 (Yorkshire, Lancashire and North Wales; FES21 had around 21 GW). There is 1 GW less in zone 6 (south; FES21 had roughly 18 GW) but 7.5 GW more in zone 7 (south coast; FES21 had 0 GW)

In respect of the onshore wind results, given that the main network constraints concern north to south power flows across a succession of transmission bottlenecks, it seems, on the face of it, counterintuitive that generation capacity should shift further north. However, with various network bottlenecks lying to the south and the only other option for relocation of onshore wind capacity being Wales, it may be that, while network constraints limit the production of energy, some onshore wind capacity shifts further north to exploit higher wind speeds and higher capacity factors.

For the offshore wind results, there is a general shift from north to south, a pattern that will interact with the model's optimisation of the location of onshore wind and whether, in effect, the model prioritises onshore wind's use of finite network capacity. It also looks like a complex picture for 2040, potentially, at least in part, as a consequence of some post-2035 network reinforcements having been included in the model but, as stated in NOA7, not being coordinated across the country post-2030[27].

It would not be reasonable to expect market participants to have perfect foresight. In principle, in order to inform their own locational decisions, they should carry out the sort of modelling that FTI has done and has found so challenging even with access to data the ESO treats as confidential and, presumably, would not share with every market participant. It would, in our view, be extremely difficult to model imperfect foresight and see what impact that would have. It might, in some way and relative to an ideal outcome, lead to too little relocation or relocation to the wrong places. However, it seems to us that a general conclusion is that the ability of LMP to provide signals over and above those that already exist within the national market framework informing changes of location should not be over-stated.

We note that FTI have taken the total generation capacity as fixed. That is, they have assumed that signals from LMP do not lead to market participants investing in less (or more) capacity in total. Given the complexities of modelling of different influences on investment and the difficulty of subsequently discerning which outcome was due to which influence, we can understand why the decision was made to keep the modelling simple and make that assumption. However, we believe it has very important implications for interpretation of FTI's results. We return to this in section 3.4.

3.3 Price assumptions

One important theme in FTI's report is the estimated magnitude of BM costs under current market arrangements. FTI, understandably, give emphasis in their report to how they took advice from the ESO on what basic assumptions to make on Bid and Offer prices, and how similar their results are to those from the ESO for a similar future scenario. They also note that the Bid and Offer prices that the ESO assumes – and which have been used by FTI in their modelling and include an 'uplift' in the Offer prices relative to what FTI say would be the short-run marginal cost – are based on empirical

[27] The 2023 Electricity Ten Year Statement – published after the time at which we understand the building of FTI's model was completed – includes significant reinforcements for 2036-38 https://www.nationalgrideso.com/document/286591/download . It may also be noted that transmission reinforcements plans are still under development by the ESO, in particular for the 2030s with, so we understand, an update the Holistic Network Plan (HND) due around the time of writing of this review.

evidence. However, FTI express surprise at how big total annual BM constraint costs are. They also question the ESO's approach, e.g. in chapter 10:

> "the NOA methodology appears to conflate both economic cost savings (that arise from the reduced need to incur costs of constrained-on generators) and the transfers that incur in the BM as a result of participants including uplifts in bids and offers from the underlying cost, and also because of the transfers to compensate constrained off plant – particularly those that hold CfDs."

It seems to us that it would be reasonable, in general, for sums paid by the ESO in the BM to compensate BM units for reasonably incurred costs. If a generator incurs costs in starting up or increasing output, those costs should be paid if the action is needed for the system in order to meet demand and keep the system stable. If a generator incurs costs in decreasing output, again those costs should be paid if the actions is needed for the system. However, as we discuss in section 3.4.2, the overall impact on social welfare needs to be thought about.

FTI also state:

> "the BM bids and offers do not completely reflect underlying economic costs."

We assume that this refers to the prices quoted by BM participants for dispatch or re-dispatch actions in the BM and the costs to those participants of their actions. What is stated might be true. However, if it is, it seems to us to most likely be because of market power or game playing.

In this context, in our view it would be useful to recall the idea of scarcity pricing. According to Papavasiliou in *Scarcity pricing and the missing European market for real-time reserve capacity*[28]:

> "Scarcity pricing refers to the notion of increasing energy prices above the marginal cost of the marginal unit under conditions where the system is short on generation capacity. Scarcity pricing generates profits for generating resources that serve towards covering the capital costs of these units. Scarcity pricing is therefore essential for attracting investment in a market."

While we might take issue with the reference to profits – we would prefer to refer to revenues – the significant point is about the recovery of long-run costs. This is important in an electricity market for low merit generation that runs relatively infrequently and sells relatively few units of energy. While some authors assert that scarcity pricing may be expected, reasonably, to go as high as the value buyers put on the commodity or service – in the case of electricity, the value of lost load – the key point is that offers by low merit sources may be expected generally to tend towards long-run costs.

FTI asserts that the nature of the BM as a pay-as-bid market encourages each participant to inflate the price at which it offers a service. That might or might not be true. Low merit sources get run less often and produce relatively little energy, presumably because they offer energy at higher prices than higher merit plant due to their underling costs being higher. Even in a pay-as-clear market, by being low merit, they benefit less from inframarginal rent than higher merit sources. FTI acknowledge that there may be costs in addition to the simple cost of providing an additional megawatt-hours – they cite start-up costs – that might be factored into an Offer price. We would suggest that generation not dispatched at its maximum available output by the decentralised market and therefore able to offer additional energy may be expected to quote prices at which energy is

[28] See https://www.sciencedirect.com/science/article/pii/S104061902030155X#sec0015

offered that tend towards long-run costs in a manner entirely consistent with scarcity pricing[29]. Indeed, generation that is dispatched relatively infrequently in a centralised market might be expected to do the same.

FTI also state:

> “we note that the risk of overvaluing the benefits of transmission enhancements appears to be true under the current national pricing regime”.

If there is game-playing by participants in the BM – leading to BM costs being higher than they should be and the value of additional transmission in reducing those costs being higher than it should be – and that game-playing has not been addressed by regulatory action then, yes. However, actually, it seems to us that FTI is likely to be *under-estimating* costs in their modelling of a locational pricing world due to:

1. the assumption that all generation, including low merit plant, offers energy at its short-run marginal cost;
2. failure to account for revenues lost by generators in export constrained locations.

As already discussed, the idea of scarcity pricing suggests that generation that is relatively infrequently required or from which relatively little energy is bought can be expected to offer energy at prices above a short-run marginal cost based on the marginal cost of fuel and tending towards the long-run cost. FTI has simply stated an assumption that all generation in a centralised, pay-as-clear market would offer energy at a short-run marginal cost plus start-up cost . In contrast with modelling of the BM, they have seemingly not sought empirical evidence of prices and have not offered any in their report.

3.4 Economic assessment

3.4.1 Consumer benefit or total socioeconomic welfare?

Two means of representing the economic impact of any change to market arrangements are suggested by FTI: the change to “consumer benefit”; and the change to “socioeconomic welfare”.

We take “consumer benefit” to be synonymous with consumer surplus, i.e. the difference between what consumers are, in theory, prepared to pay for a product or service and what they actually pay. A reduction in what they pay would represent an increase in consumer surplus or consumer benefit.

We take “socioeconomic welfare” to be synonymous with social welfare, i.e. the sum of consumer surplus and producer surplus where the latter is the difference between what producers get paid and what their costs are.

[29] The Capacity Market (CM) in Britain represents a complicating factor. That serves to contribute towards meeting the long-run costs of generation that is relatively infrequently called on by the regular energy market but which is judged to be needed for security of supply reasons, i.e. to meet demand on occasions when it is particularly high, coincident with occasions when total availability of generation is relatively low. While normally thought of on a national scale, similar considerations of being needed to meet demand apply on a local scale, e.g. when it is impossible to import enough power into an area to meet demand in that area. The existence of the CM ought to prompt questions about the extent to which low merit generation might reasonably quote Offer prices that are close to or even exceed long-run costs. We also note that the BM might be changed to pay-as-clear. However, if it is, attention should be paid to the potential for excessive inframarginal rent. We would suggest that market splitting driven by locational transmission limits should be considered for similar reasons to those typically presented in support of LMP.

It seems to us that estimation of the absolute value of consumer surplus in respect of electricity is extremely difficult as consumer responses to changes in the price of electricity are relatively inelastic, there being few, if any, substitutes for the service provided by electricity[30], and because the value that consumers place on electricity, in monetary terms, is difficult to determine. Instead, policy levers are often used as a proxy for that value, expressed in Britain through the Capacity Market and through standards for network design and system operation[31].

Another aspect of policy is the desire for reduction in the greenhouse gas emissions associated with the production and use of energy. Although, as noted by FTI, a price might be set for carbon emissions, such a price is currently set for only certain sectors of the economy or driven by emissions caps across only certain sectors[32]. Policy to drive emissions reduction across the economy as a whole therefore depends on a wider collection of means. In respect of electricity, although the Government has set an objective of zero carbon electricity production by 2035 ("subject to security supply"), those means are yet to be fully articulated[33].

For extremely important features of the electricity system – carbon emissions and security (or reliability) of supply – we are left with Government policy to drive what Government interprets as desirable outcomes for society as a whole. It does not depend solely on consumer surplus. Crucially, in order to achieve these outcomes, in our liberalised electricity market, we depend on private parties investing in and operating appropriate facilities. That, in turn, depends on them being able to at least recover their costs or else they will either not invest in new facilities or will shut down existing ones. In other words, they must receive an adequate producer surplus over and above their short run costs of production in order to cover their long run costs which include investment costs. Thus, any assessment of what a particular set of market arrangements achieves must include producer surplus as well as consumer surplus, i.e. it must address the impact on *total social welfare* while meeting Government objectives for security of supply and carbon emissions. It must also look

[30] In principle, half-hourly metering and time-of-use tariffs across most of the consumer base might start to reveal some elasticity. However, it should also be noted that shifting of demand in time is a different thing from use of less energy, i.e. "demand destruction" as the gas sector calls it. A lot of the former might be more easily envisaged than a lot of the latter aside from adoption of more energy efficient appliances or practices where a service is still gained from the use of energy rather than foregone.

[31] The Capacity Market in Great Britain has the basic aim of ensuring that there is enough generation, flexible demand, interconnector and storage capacity for peak demand to be met with a 'Loss of Load Expectation' (LOLE) of no more than 3 hours per year. This is an example of a 'generation adequacy' standard. Against a background of lots of uncertainties such as forced outages of generation and how weather impacts on demand the availability of power from renewables, the standard sets a maximum acceptable average for the time in which not all demand is met as a result of a basic shortage of power. The level of 3 hours was set by the UK Government. The transmission network's minimum capability to transfer power and make use of available generation to meet peak demand is set in the Security and Quality of Standard (SQSS), compliance with which is a licence condition for the electricity transmission owners and the ESO. The SQSS also dictates that the system should be operated so that, broadly speaking, the network's physical limits are respected, the system is stable and demand can be met even after the fault-related outage of any one item of equipment. Together, the design standard and operating rules in the SQSS lead to a certain level of reliability with which demand for electricity from the transmission network can be met, given that enough power is available somewhere and just needs to be moved to where it's needed. Reliability of supply to demand connected to a distribution network in Britain is a function of a minimum network design standard set out in Engineering Recommendation P2 (ER P2) and the Distribution Network Owners' responses to a reliability incentive set by Ofgem. Any revisions to the SQSS and ER P2 are the result of consultations and approval by Ofgem.

[32] The impact of a cap is, obviously, heavily dependent on the level at which the cap is set.

[33] For further discussion see, for example, https://www.theccc.org.uk/publication/delivering-a-reliable-decarbonised-power-system/

specifically at producer surplus and address whether it is sufficient for existing assets to continue to be operated and for new assets to be developed.

Given the difficulty of quantifying total consumer surplus, it seems reasonable to estimate the change in consumer surplus – or "net consumer benefit" – resulting from a change in market arrangements. This is what FTI has attempted to do. Through its use of future scenarios in which Government decarbonisation targets for electricity production are met and, we suppose, "generation adequacy" is acceptable – i.e. there is, at the national level of generation versus demand, sufficient security of supply – FTI has also taken headline Government policy as having been delivered. In principle, they can then look at the differences made to the costs of meeting those objectives that result from changes to market structure. However, as we discuss in the next subsections, we see some difficulties in the way FTI have done that, and a potential problem with the way the ESO puts a value on transmission reinforcement today.

3.4.2 What happens to social welfare as a result of BM actions?

FTI raise some questions about the way that the economic benefits of reduction in the cost of constraint actions taken in today's market in the Balancing Mechanism (BM) are quantified.

The SO incurs costs for constraint actions in three ways:

1. Through what it pays for Offers to
    a. increase generation output or storage discharging
    b. reduce demand or storage charging
2. Through what it pays for Bids to
    a. reduce generation output or storage discharging
    b. increase demand or storage charging
3. Through what it pays for SO-SO actions to alter interconnector flows

Let us assume that, in the current decentralised, 'national' market, generation and demand are balanced for GB as a whole in the particular time period in which the ESO needs to take action to change power flows across the network, i.e. to manage "network constraints". Certain producer surplus and consumer surplus arise from the 'national' market condition. How will the ESO's actions change the producer and consumer surpluses?

1. Offer acceptances. In general, extra costs will be incurred relative to the initial, unconstrained dispatch. If the sums paid in Offer acceptances only cover those costs, there will be no change to the producer surplus – additional revenue flowing to producers through BM Offer acceptances will only cover additional costs of generation. However, the costs are met by consumers so the consumer surplus decreases and there is a negative impact on social welfare.
2. Bid acceptances.
    a. Positive Bids: these are where the owner of the BM unit, typically a thermal power station, will pay the ESO for the right to reduce its output.
    b. Negative Bids: these are where the owner of the BM unit, typically a wind farm, wants to be paid for a reduction in output.

A thermal power station will offer to pay the ESO for a reduction in output as it is deemed to still be meeting its energy market obligations but can do so by using less fuel. A payment by the generator would, on the face of it, reduce producer surplus and, because money to the ESO in the BM eventually goes to the consumer, increase consumer surplus. However, if the generator's savings in fuel costs are equal to the amount they pay to the ESO, there is no net impact on producer surplus.

The increase in consumer surplus through the payment to the ESO, in effect, represents a budget used by the ESO to help meet the cost of production to replace what has been re-dispatched downwards.

Generators in receipt of Renewables Obligation Certificates (ROCs) would lose money by having their output curtailed as they would receive fewer ROCs. Generators holding Government-awarded low carbon Contracts for Difference (CfDs) would also lose money by having their output curtailed if the reference price for the CfD – which we might, for the sake of argument, assume to be equal to the system marginal price in the unconstrained national market – is lower than the strike price. These two categories of generator would therefore be expected to request payment from the ESO for such a reduction in output[34]. For generators with approximately zero marginal costs of physically producing energy, if it is assumed that Bid prices are set only to cover lost income from ROCs or CfDs, there is no net change in producer surplus. From the consumer perspective, what they pay out through the BM for these accepted Bids is balanced by what they save on reduced cost of ROCs or CfDs. Overall, then, there is no net impact on social welfare.

From the perspective of generators with CfDs, there is another circumstance that should be considered: where the reference price, i.e. in general terms, the wholesale market price, is higher than the strike price. In this case, if the generator produces energy, it would have to make a payment *to* the CfD counter party, i.e. for Government awarded CfDs, the Low Carbon Contracts Company (LCCC). It would therefore save money by not producing and may therefore be expected to quote a positive Bid[35]. If that Bid is accepted by the ESO, money will flow from the generator to the ESO. If this sum is equal to what the generator saves, there is no net impact on producer surplus. In respect of the BM, the receipt of money adds to the consumer surplus. However, what the LCCC receives is reduced, reducing consumer surplus by the same amount. Thus, there would be no net impact on social welfare.

It therefore seems to us that, with the above assumptions of Offer and Bid prices reflecting only costs, the net social welfare impact of BM actions due to network constraints would be represented only by:

- any money received by the ESO through acceptance of positive Bids from non-CfD and non-ROC generation;
- what the ESO pays in Offer acceptances.

That is, our feeling is that money paid out by the ESO to CfD or ROC generation for acceptance of negative Bids should not be included in the assessment of the total social welfare impact of BM actions. Relative to current practice by the ESO, this would reduce the apparent benefit of network reinforcements[36].

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[34] There is always some uncertainty about how much power a wind farm will be able to produce at any given time in the future, even as little as an hour ahead. It is our understanding that wind farms, including merchant developments, tend to assume that they can 'spill' energy above their BM Final Physical Notification (FPN) and be paid for it at the System Sell Price. Action through the BM to fix their output at certain level lower than their FPN would mean losing that opportunity. The Bid price might therefore factor in that lost income. However, we also understand that some wind farms err on the upside when declaring an FPN in anticipation of having a Bid accepted to reduce output.

[35] Actually, the generator may already have reduced its output in the decentralised, self-dispatch market before gate closure for the BM.

[36] Note that our assessment is based on the assumption that Bid and Offer prices only cover the costs incurred (or, for positive Bids, benefits received) by the associated BM units.

Questions should still be asked about whether what is paid out (or received) by the ESO for actions to manage constraints does only cover costs. This question might be asked specifically for the case of actions taken by the ESO in Britain to change power flows on interconnectors. We note the observation in FTI's report that the ESO has told them that interconnector actions through "SO-SO trades" are typically more expensive than anything else. In principle, the physical effect of any action should only be re-dispatch of generation (or storage or demand) in the country at the remote end; these actions should, in theory, only cover costs in the same way as re-dispatch actions within GB should.

3.4.3 What happens to producer revenues in an LMP world?

In a locational pricing world with centralised dispatch, a generator in an export-constrained region faces two risks:

1. Price risk where, if they are dispatched, they receive a price from the centralised market for each unit of production that is less than what they had been assuming when developing the project.
2. Dispatch, or volume, risk where, due to limits on the network, they are not dispatched and, hence, produce fewer units of energy than they had been assuming would be.

A generator in receipt of a Government-awarded CfD would be compensated for any price lower than the strike price set in the contract, so they would, with a nationally set strike price, not be exposed to any price risk[37]. However, they would still be exposed to dispatch risk. It may also be noted that, with the introduction of the negative pricing rule in CfDs there is already, within the national market for some existing wind farms and future CfD holders, an inherent volume risk where, at times of a national level surplus of generation, they can expect to self-curtail on the basis that they would not to receive the CfD support payment for volumes of energy produced at times when the reference price is negative. In a locational market, generators would be exposed to the dispatch risk associated with their local zone or node; for generators in export constrained areas, this may represent an increased risk relative to the situation in a national market.

FTI's modelling of zonal and nodal markets and analysis of the results shows a reduction in producer surplus as a result of changes to capture prices in different locations – in effect, due to the market splitting geographically and inframarginal rent being reduced – and consumer surplus increasing as a result of lower total cost of energy when considering the combined impact of wholesale energy costs and congestion rent which is assumed to accrue to consumers. They also quantify the increase in cost of CfD support as a result of lower wholesale energy prices received by CfD holders. This is funded by consumers outside the wholesale energy market and so reduces any net gain in social welfare apparent solely from the wholesale market modelling (or increases any net loss).

Relative to the present day market, although producers in receipt of traditional CfDs might be in a neutral position in respect of price per MWh, those in export constrained locations would still sell fewer units of energy[38].

Compared with in a decentralised, national market, a merchant generator[39] would be exposed to both risks. In theory, the generator might hedge against price risk through purchase of Financial

[37] As is discussed in Gill, MacIver and Bell, *Exploring Market Change in the GB Electricity System: the Potential Impact of Locational Marginal Pricing*, there are many possible variants of CfD arrangement that would expose generators to different risks and incentivise different behaviours. See https://strathprints.strath.ac.uk/83869/
[38] A "deemed CfD" could mitigate this risk.
[39] That is, a generator not in receipt of ROCs or a CfD backed by Government.

Transmission Rights (FTRs) but, as far as we understand, would be unable to use FTRs to hedge against dispatch risk. (See the discussion in section 3.4.4).

The potential impact of reduction in producer surplus is such that some existing generators and some new developments might be rendered financially unviable for the owners and either close or fail to open. The result of that, if other generation is not developed instead, would be failure to meet decarbonisation objectives or achieve sufficient security of supply, or both. The potential for that to happen is not shown in FTI's modelling as the optimisation is not constrained to ensure that, in minimising total cost of energy, each individual generator's revenues cover its costs. The same is true for storage. Instead, the optimisation used a given, fixed, total capacity for each type of generation and for storage capacity. Moreover, there is no analysis of the results to assess the revenues gained by generators of different types and storage in different locations and whether they cover the long-run costs.

We note that FTI said the following in paragraph 2.73 of the version of the report that we reviewed:

> "As well as short-term effects, locational pricing may have impacts on the electricity market in the long run. These could arise as the differences in financial flows set out above may induce differences in where on the electricity system market participants choose to locate **and, potentially also, closure decisions**." [Emphasis added].

That bolded part is not, apparently, expanded upon. As far as we are aware, early economic retirement of, in particular, dispatchable plant but also, for example, renewables that have exhausted their subsidy is becoming an increasing feature of US nodal markets and brings with it an associated security of supply risk[40].

3.4.4 What happens to congestion rent?

A significant element of the consumer benefit of locational pricing estimated by FTI is represented by congestion rent gathered by the market operator and returned to consumers. In the LtW (NOA7) scenario this is estimated to be as big as £27.1 billion over the period 2025-40 compared with total consumer benefits of £50.8 billion and socioeconomic benefits over the same period of £24 billion.

As discussed in section 3.4.3, there are two main elements to producer risk: price risk and dispatch risk. FTI's report shows CfD payments – a transfer from consumers to producers – being used to compensate CfD holders for the reduction in producer surplus associated with lower capture prices in the locational market compared with the decentralised, national market.

For producers not in receipt of CfDs that protect them from price risk, FTI argue that FTRs can hedge it. In markets where these are currently used, our understanding is that FTRs can either be auctioned off by the market operator or allocated for free to market participants. Either way, the payments that flow from holding an FTR are funded from congestion rent.

Because FTRs are a hedging instrument, where they are auctioned off (and assuming competitive auctions) they should, in theory, be largely neutral in social welfare terms. Either market conditions outturn as forecast in which case the price paid at auction should be approximately equal to the FTR revenue received in which case both producer and consumer surplus would be left unchanged by the addition of an FTR; or market conditions outturn differently to forecast in which case the

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[40] See concerns raised by US independent system operators and regional transmission operators here. https://www.pjm.com/-/media/documents/other-fed-state/20230808-comments-of-joint-isos-rtos-docket-epa-hq-oar-2023-0072.ashx

producer or the consumer may end up better off than the case without the FTR. However, even here the impact is only a transfer between producer and consumer.

4 Final remarks

An assessment of the potential costs and benefits of a change of the wholesale electricity market in Great Britain to one based on centralised dispatch and locational marginal pricing is an extremely challenging exercise. No model, whether of a physical system or a market, is ever perfect; there is a lack of information and the modeller is required to make many judgments. In developing its modelling of LMP and a comparison with a decentralised, ‘national’ market, FTI has sought advice from stakeholders, in particular the ESO, and has tried, in their report, to be open about the judgments and assumptions it has made. However, because there are so many judgments, interpretation of how the results have emerged and what they mean must also be subject to judgment.

In our review, we have identified various ways in which we think different judgments could have been made in the modelling and in the presentation of results. Because of the complexities of market and electricity system operation, it is impossible for us to say, without further detailed modelling, what the impacts of those different judgments would have been. We nevertheless try to draw together the possible directions of change to the apparent social welfare impact of a transition to a locational electricity wholesale market.

In respect of BM costs and negative impact on social welfare in the present day market of very high BM costs for network constraints, we think they have:

- perhaps been under-estimated in some ways, in particular due to an over-estimate of available transmission capacity due to neglect of planned outages and an approximation of secure system operation;
- over-estimated in others, e.g. due to relatively little transmission reinforcement being modelled after 2030[41] the inclusion of all Bid acceptance costs and an approximation of the impact of secure system operation on the available transmission capacity.

We think the magnitude of increase in social welfare in moving to a locational pricing world has perhaps been:

- overestimated due to
    - use of the geographical placement of generation provided by the ESO in FES 2021 as an exogenous and fixed input in the comparator case without assurance that this represents a sensible or plausible outcome relative to the transmission network background. For example, a relative lack of transmission reinforcement after 2030 would appear to be inconsistent with the given generation background.
    - approximation of secure system operation.
    - .
- underestimated due to
    - over-estimate of available transmission capacity due to neglect of planned outages and approximation of secure system operation.
    - neglect of the cost of transmission and the theoretical possibility that, with stronger locational signals, less would need to be built.

We also note:

[41] In the “Network Options Assessment 2021/22 Refresh” document dated July 2022, the ESO notes the need for “a coordinated view beyond 2030” still to be done. https://www.nationalgrideso.com/document/262981/download

- that FTI's assessment of the net benefits of introduction of zonal or nodal pricing starts from 2025 whereas, even with an immediate commitment for such a market arrangement to be adopted, it is very unlikely that the new market would be in place by then. The extent to which results for the period 2025-30 drive the overall conclusions on total socio-economic benefits is not completely clear.
- the assumption in modelling of the locational market that each generator offers energy at the short-run marginal cost plus start-up cost and the neglect of the potential impact of scarcity pricing.
- the assumption that revenues from congestion rent would be passed directly on to consumers whereas, if financial transmission rights (FTRs) are offered to energy producers, congestion rent would most likely be used to fund them and might be seen as adding to producer surplus or, more specifically, lessening the reduction in producer surplus resulting from a change from a national to a locational market rather than contributing to consumer surplus. The overall impact on producer and consumer surplus would depend heavily on how FTRs were allocated: whether they were auctioned off or allocated for free (both approaches are used in US markets). Either way would formalise a particular expectation of transfer between consumers and producers, and act as a mechanism to limit unexpected changes in that transfer. Ultimately, they would not simply 'add' to consumer surplus. We also note, however, that US markets where FTRs are offered have seen challenges relating to their articulation and management.
- the apparent assumption that the capital costs of building generation would be the same in every location.
- our understanding is that FTI have modelled only specific years and used interpolation to estimate costs in other years whereas transmission reinforcements included in, for example, NOA7, would happen in specific years leading to a step change in apparent costs[42].
- that changes to TNUoS charges in both the national market and a locational market could have a material impact on social welfare.
- the lack of an assessment of BM costs in the market comparison. There is what we regard as an incorrect statement in FTI's report that "The nodal model, by design, does not require additional intervention by the ESO to balance the system". Neither market participants nor the ESO or market operator will have perfect foresight on, in particular, demand and the availability of renewables either when a centralised dispatch is being carried out or, in a decentralised market, when self-dispatch is being done. There will therefore still be a need for intraday action, including a BM, in all markets. Perfect foresight has been assumed in FTI's modelling of all the markets whereas, in reality, there would be uncertainty. In our view, there is the potential for BM costs in a market with centralised day-ahead dispatch to be lower than in a decentralised market. However, that and market participants' likely management of uncertainty would need to be evaluated.
- the absence of consideration of whether or not individual projects would be viable in a locational market which could in turn impact on social welfare outcomes if projects do succeed in being developed albeit with greater cost recovery. If enough projects of the right type are not developed, security of supply and/or decarbonisation targets would be put at risk.

[42] This effect would be true in any of the market models although, it seems to us, quite how big the impact would be will depend on the market model.

We were particularly struck by the size of the interconnector impacts where, according to the modelling – in particular, we suppose of the new Norwegian interconnector landing in Scotland, a development that is currently being blocked by the Norwegian government – interconnectors in the decentralised, national market would often flow in such a direction as to make within-GB network constraints worse.

The overall result of the above set of possible over-estimates and under-estimates is, in our judgment, that FTI's modelling results are, on balance, more likely to be an over-estimate of the socioeconomic benefits of changing to a locational market than an under-estimate. However, we cannot be confident in that opinion and are in no position to judge the magnitude of over-estimate.

It is still possible that a repeated analysis similar to FTI's with different assumptions more in line with what we feel would have been right would suggest a net benefit to change. However, there are also the ongoing questions about how realistic it is for generation to be developed in different locations, how much extra capital, operation and maintenance costs, if any, generators would be exposed to in different locations, and what impact LMP, in particular dispatch risk, would have on the cost of capital for new low carbon generation. We leave it to stakeholders more qualified than ourselves to debate those issues.

What FTI were engaged to do was an assessment solely of a change to LMP. They were not asked to assess the potential impacts of other policies or market arrangements that might sit alongside the main wholesale market for electrical energy. These other arrangements include Government-backed CfDs (which could take on many different forms), the capacity market, the way the Balancing Mechanism is set up (including such aspects as the time of gate closure) and the way that costs of balancing services and the electricity network are recovered. In our view, it is essential that policy makers assess packages of measures since any one of them, on its own, is unlikely to meet the overarching goal of secure supply of zero carbon electricity by 2035 at least cost. A suitably designed package has the potential to offset the disadvantages of any one reform while retaining its main advantages. We would strongly encourage judgments on whether to adopt zonal or nodal pricing and centralised dispatch to be made on the basis of them – or retention of a 'national' market with or without centralised dispatch – forming part of a package.