Appendix 5.2: Locational pricing in the electricity market in Great Britain

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Introduction

1. This appendix describes the effects on competition of the absence of locational variation in the electricity wholesale spot price under current market arrangements despite locational variation in costs.

2. This appendix also describes current components of wholesale costs and the degree to which they vary by location. We outline the history of attempts to bring more locational elements into wholesale prices. We then briefly describe the rationale for geographical variation in spot prices due to losses and network congestion. Finally, we review existing work that attempts to quantify the benefits to competition of introducing more locational spot pricing.

Locational components in wholesale prices under current market rules

3. Table 1 provides a breakdown of the components of electricity wholesale costs and summarises whether they currently contain locational elements.[1]

[1] Summaries of current arrangements for cost elements are presented in Annex A to this appendix.

Table 1: Geography in GB electricity wholesale prices

Cost	*Locational elements in current arrangements*
Generation	Yes
Transmission congestion	No
Transmission losses	No
Transmission network investment	Yes
Transmission connection	Yes
Distribution network	Yes
Distribution losses	Yes

Source: CMA research.

4. **Generation costs** – approximately 40%[2] of total spending on electricity by end users – contain locational elements to the extent that fuels incur costs in being transported to power stations and that other costs are location-specific. For gas power stations, the locational element comes mainly through the pricing of the gas transport network.

5. **Transmission congestion costs** – arise from the fact that, when transmission lines represent a bottleneck, it is not possible to generate electricity from the cheapest sources.[3] The biggest source of these bottlenecks in the GB wholesale electricity market is network capacity between Scotland and England, with there being more opportunity for cheap generation in Scotland than the ability to transport electricity south. This bottleneck is worsening due to the increase in zero incremental cost wind generation in Scotland, which increases the price disparity between Scotland and England and Wales, thus increasing the opportunities for profitable flow of electricity southwards that will sometimes be frustrated by transmission constraints. However, such transmission constraints are expected to abate following the implementation of plans for transmission capacity expansion between England and Scotland. SSE goes so far as to argue that 'existing and planned network upgrades (*e.g.*, Beauly-Denny and the West Coast Bootstrap) will make, or have already made, much of the Working Paper's discussion of constraints in the GB market redundant'.[4]

[2] CMA calculation based on National Grid 2014/15 estimates of system costs.
[3] Imagine a shop that usually buys its milk from an efficient farm with low production costs and passes that through into low prices to consumers; however, when the road to the farm is congested it has to buy the milk from another farm that is more expensive. The cost of the congestion in this instance is the price difference between the expensive and the cheap milk. We do not have an estimate of the proportion of costs attributable to transmission congestion because it is not simple to separate these costs from other balancing costs that National Grid incurs.
[4] The links could be completed as early as 2017, which is the date approved by Ofgem under its network pricing regulation. Modelling by Redpoint (part of Ofgem's impact assessment of CMP213) showed a sustained drop in constraint management costs right up to 2030, but congestion then rises again as renewable generation increases.

6. Congestion costs are currently incurred by National Grid through the balancing mechanism (BM) and are averaged over all producers and consumers on a pro rata per MWh basis and included in Balancing Services Use of System (BSUoS) charges. There is no locational element to this cost. However, because transmission investment lags behind congestion under "connect and manage" arrangements,[5] there is scope for competition and efficiency to be enhanced if there were a locational element.

7. **Transmission losses** – about 2%[6] of total spending on electricity – arise because energy is lost in transport at high transmission voltages. For example, a given demand in London needs more generation from Scotland to satisfy it than from the Isle of Grain. Losses are currently largely recovered by adjustments to Balancing and Settlement Code (BSC) parties' metered volumes, which encourages generators to produce approximately 1% more than they are contracted for and suppliers to contract for approximately 1% more than their customers' demand. This adjustment accounts for losses in transmission and is not varied by location. A supplier is charged for the full amount consumed as reconciled through end-point meter readings. This therefore contains losses in the distribution network, which vary by location. There is a levy applied on all suppliers for 'Assistance for Areas with High Electricity Distribution Costs', which currently benefits the North of Scotland.[7] .

8. **Transmission network investment costs** – about 7% of total spending on electricity[8] – are levied in order to allow the grid owners[9] to recover investment costs. These charges have locational elements and are regulated by Ofgem. The locational elements of charging provide some locational signals for the siting of generation and demand. Charges vary on a zonal basis to reflect network investment costs (in simple terms, the length of transmission wires). Generators in regions further from demand centres (eg North Scotland or Cornwall) pay more, while consumers pay less. Charges can be negative – for example there is a subsidy to site generation close to London from other site generation investments.

9. **Transmission connection costs** – about 0.6%[10] of total spending on electricity – are designed to enable National Grid to recover the immediate

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[5] 'Connect and manage' refers to the policy by which renewable capacity can connect paying only direct connection costs and National Grid is then to 'manage' any knock-on congestion.
[6] *National Grid Electricity Ten Year Statement 2014*.
[7] See National Grid, *Assistance for Areas with High Electricity Distribution Costs*.
[8] *National Grid Electricity Ten Year Statement 2014.*
[9] These are National Grid Electricity Transmission, Scottish Power Transmission, Scottish Hydro Transmission and various offshore transmission owners.
[10] CMA calculation.

costs that it incurs in connecting generators to the grid. These charges are essentially locational and are regulated by Ofgem.

10. **Distribution network costs** – about 8%[11] of total spending on electricity – are analogous to transmission network costs[12] but occur at the distribution level.

11. **Distribution losses** – arise from the fact that a supplier is charged for the full amount consumed as reconciled through end-point meter readings. This therefore contains losses in the distribution network, which vary by location.

12. The revenues which licensees can earn from running the transmission and distribution networks are regulated by Ofgem. We have not considered in the context of our investigation whether network access charges are set at efficient or competitive levels.

A brief history of attempted reforms to locational pricing

13. In 1990, at the time of privatisation, it was decided that the market would be liberalised without regard to transmission losses but that this would be fixed soon afterwards. In 1994, the body in charge of governing the Pool started work on the issue. After three years' consideration and two appeals to the regulator, an industry-wide agreement was concluded whereby losses would be factored into wholesale prices gradually over five years. Legal action to obtain a judicial review was launched by some of those opposed to this decision. However, with the launch of the New Electricity Trading Arrangements process in 1998, the legal challenge was put aside.[13]

14. During the major redesign of the GB wholesale electricity market between 1998 and 2001, it was decided that decisions on the future treatment of losses would be left to the modification procedures of the BSC. This process began in 2002 with three BSC modification proposals: P75, P82 and P105.[14] P82 was approved by Ofgem. However, it was successfully challenged by way of judicial review on the basis that the decision was procedurally flawed. Between December 2005 and July 2006 four modification proposals were raised: P198 (by RWE), P200 (by Teesside Power Limited), P203 (by RWE) and P204 (by British Energy). Ofgem was minded to approve P203 and reject the other proposals.[15] It then delayed its final decision as, having considered

[11] CMA calculation.
[12] These are network investments costs and connection costs.
[13] Much of this early history is summarised in R Green (1997), Transmission pricing in England and Wales, *Utilities Policy* (6)3. Ofgem has published a history of zonal pricing from 1989 to 2006.
[14] All of these modifications had the intent of making the charging for transmission losses more cost-reflective.
[15] Ofgem, (2007), *Zonal transmission losses – the Authority's 'minded-to' decisions*, document reference 153/07.

the responses to its consultation, it wished further analysis to be carried out to inform its final decision.[16] The decision to delay the process was successfully challenged by way of judicial review by (among others) Teesside Power Limited and British Energy.[17] Ofgem published a letter on 17 July 2008 informing that it had decided not to appeal the court's order[18] and was therefore not in a position to reach a decision on the modification proposals.[19]

15. Four months later, on 28 November 2008, RWE raised a new modification proposal, P229, proposing a zonal basis for charging for transmission losses.[20] Ofgem decided to reject the modification. Its reasons were that it could not satisfy itself that approval was consistent with its statutory duties and principal objective. Specifically, Ofgem raised questions concerning the large distributional consequences of the proposal, the 'relatively modest scale and uncertainty of expected efficiency benefits'[21], and the fact that locational pricing might be required at a European level as early as 2015.

16. Currently the European electricity market is divided into bidding zones, which should be defined in a manner to ensure efficient congestion management and overall market efficiency. GB constitutes one bidding zone for this purpose. The European Commission has developed a draft network code (that is expected to be adopted by summer 2015), the Capacity Allocation and Congestion Management (CACM) regulation, which sets out rules facilitating allocation and congestion management between bidding zones. Under the CACM, the Agency for the Cooperation of Energy Regulators (ACER) is required to assess the efficiency of current bidding zone configuration every three years.[22] If the technical or market report published as a result of this assessment[23] reveals inefficiencies in the configuration of zones in a national electricity market, ACER may request the Transmission System Operators (TSOs) for that market (ie for GB National Grid, SSE and Sottish Power Transmission) to launch a review of an existing bidding zone configuration.[24]

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[16] Ofgem (2007), open letter *Zonal transmission losses proposals.*
[17] Teesside Power et al v Gas and Electricity Markets Authority, CO/11010/2007: Defendant's detailed grounds of resistance.
[18] Ofgem (2008), open letter *Balancing and Settlement Code (BSC) modification proposals on zonal transmission losses*.
[19] At the time, the BSC modification process did not contemplate the possibility for Ofgem to 'send back' a modification proposal to the code panel with a request to carry out further analysis in order to assist Ofgem's decision making. This has now been introduced in the BSC as a result of Ofgem's code governance review (see Appendix 11.2: Codes and regulatory governance).
[20] Modification P229 – Introduction of a seasonal Zonal Transmission Losses scheme.
[21] Ofgem (2011), *Balancing and Settlement Code (BSC) P229: Introduction of a seasonal Zonal Transmission Losses Scheme (P229).* It is not clear why the expected benefits under P299 were considered 'modest' when essentially similar benefits under P203 had previously been thought to merit action by Ofgem.
[22] Article 33(1) of the CACM.
[23] Pursuant to Article 34(1) of the CACM.
[24] Article 34.7 CACM.

The CACM provides minimum criteria[25] for TSOs to review bidding zone configurations (relating to network security, overall market efficiency and the stability and robustness of bidding zones). Independently of the ACER's triennial obligatory assessment, a review of bidding zones may also be launched at any time (and following the same criteria and process) by subjects named in the CACM,[26] including, for GB, ACER, Ofgem following a recommendation from ACER, the three TSOs together or any of them with Ofgem's agreement. The CACM includes a preferred European model for congestion charging, where needed, by zonal splitting. Impact on competition of wholesale spot prices varying by location.

17. It is generally accepted that in a well-functioning market, prices should reflect the cost of alternative uses to which resources could be put. This means that the closer prices are to incremental costs of supply, the better those prices will be at allocating resources between competing uses.

Possible harm from the absence of locational adjustments for transmission losses

18. We can expect the absence of locational adjustments for transmission losses to create a system of cross subsidisation that distorts competition between generators and is likely to have both short- and long-run effects on generation and demand:

- in the short run, costs will be higher than would otherwise be the case, because cross subsidisation will lead to some plants generating when it would be less costly for them not to generate, and other plants, which it would be more efficient to use, not generating.[27] Similarly, cross subsidies will result in consumption failing to reflect fully the costs of providing the electricity; and

- in the long run, the lack of locational pricing may lead to inefficient investment in generation, including inefficient decisions over the extension or closure of plant. There could also be inefficiency in the location of demand, particularly high-consumption industrial demand.

[25] Articles 32 and 33 of the CACM.
[26] Article 32(1) of the CACM.
[27] This arises because a generator whose location entails lower losses than a competitor will produce less frequently - and overall system losses and costs will be higher - without locational charging than with it.

Possible harm from the absence of locational adjustments for congestion

19. The absence of locational adjustments for congestion is expected to lead to a short-run effect on competition:

(a) There will be an effect through demand response. Wholesale prices in export-constrained regions will be higher in the absence of congestion charging than they otherwise would be, leading to an under-consumption of electricity relative to other goods and a distortion of competition in favour of other goods; for example, households in Scotland would on average buy more electricity if prices varied locationally in a manner that reflected congestion. In the same way, wholesale prices in importing regions will be lower than they otherwise would be, thus encouraging over-consumption relative to costs. This effect depends on the responsiveness of consumption to prices. This is relatively low in the short run in electricity markets – elasticities are of the order of –0.1 (meaning that a 10% fall in the price of electricity induces a 1% increase in consumption).[28] However, two factors tend to make these price distortions an important concern despite low levels of price responsiveness: (i) low price responsiveness over large volumes can add up to large absolute effects; and (ii) price responsiveness is expected to rise with the introduction of smart meters.[29]

(b) The introduction of congestion charging would have longer-run investment impacts. Generators in importing regions, where prices are high, would receive higher energy payments than generators in export-constrained regions (where prices would be lower in constrained periods). This should make investment in generation in importing regions relatively more profitable under congestion charging than in its absence. In the same way, large consumers would face lower energy costs in export-constrained regions and would therefore be incentivised to locate or expand in those regions.[30] As noted in paragraph 8, locational choices are also influenced by the network charging methodology. Congestion

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[28] Elasticities in the very short run are even lower – there is essentially no responsiveness to real-time price in large parts of the electricity market in GB. See, for example, A Serletis, G Timilsina and O Vasetsky (2011) International evidence on aggregate short-run and long-run interfuel substitution?, Energy Economics 33, pp209–216.
[29] We consider the potential impact of smart meters on consumption in Appendix 8.6: Gas and electricity settlement and metering. As a very rough indicator of the magnitude of the price-responsiveness effect, we subtract from the £73 million estimate of net benefit attributable to incorporating losses and congestion from Green (Nodal pricing of electricity: how much does it cost to get it wrong?, *Journal of Regulatory Economics,* Vol: 31, Pages: 125-149, 2007) the £15 million benefit attributable to losses only in Green (1994) to get a value of £58 million. We emphasise that this is an extremely rough way of estimating the magnitude of the effect.
[30] There are a large number of ways in which location decisions for generation and large demand can be influenced by policy. An approach based on connection costs and transmission investment recovery rules are one such way.

charging would have an impact on location beyond this: it is a signal based on energy production or use, rather than capacity use.[31] The absence of congestion pricing could therefore lead to some degree of inefficiency in the locational choices of investments. However, we recognise that the locational decisions of investments can be significantly influenced by the wider network charging methodology.

20. We do not think there will be a large effect from better technical efficiency of electricity production, equivalent to the effect described for losses in Section 5. The reason for this is that National Grid currently uses a competitive mechanism to buy balancing services through BM bids and has an incentive to minimise congestion costs. This system has been open to criticism of inefficiency in the past due to the exercise of time-bound locational market power. However, the introduction of the Transmission Constraint Licence Condition, which will be in force until 15 July 2017, into the generation standard licence conditions, has made the abuse of market power arising from the location of the generator a breach of licence. This has made it very risky for generators to manipulate BM bids for profit, further reducing the chance of technical inefficiency. In addition, regulations such as the EU's Regulations on Energy Market Integrity and Transparency[32] have been designed to identify abuse of market power and capacity withholding.[33] Penalties under these regulations provide a further disincentive for parties to engage in unilateral market power strategies. Overall, we believe that the current system of congestion charging is likely to create near-efficient technical efficiency and that a move to more congestion charging would not impact that significantly.

Estimates of the costs of the absence of locational adjustments

Transmission losses

21. The benefits of locational pricing of transmission losses, which could be expected in a well-functioning market for the reasons set out in paragraph 18 above, have been widely and recently analysed. We examine the benefits that studies associate to locational pricing of transmission losses in order to gain an estimate of the harm arising from their current absence.

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[31] So, for example, an energy user who could take advantage of the existence of low-price intermittent wind output in Scotland would be rewarded under locational pricing but not necessarily under a capacity-based network charging regime.
[32] Regulation (EU) No 1227/2011 of the European Parliament and of the Council on wholesale energy market integrity and transparency (REMIT), adopted on 8 December 2011 and entered into force on 28 December 2011.
[33] Similarly, such behaviour could amount to an abuse of dominant position prohibited under competition law.

22. The impact of charging cost-reflectively for transmission losses in GB has been thoroughly investigated as recently as 2011 in the context of the RWE-sponsored modification proposal P229.[34] The cost benefit analyses undertaken in relation to P229 were conducted by LE/Ventyx (for Elexon) and Redpoint (for Ofgem), while a third group of experts, Brattle, reviewed the LE/Ventyx work for Ofgem. These report a ten-year net present value (NPV) benefit from the introduction of locational pricing of losses of between £160 million (Redpoint) and £275 million (LE/Ventyx).[35] These values are based on forward-looking modelling of the sort commonly conducted in energy sector impact analyses and the studies appear to us to be credible and to have been conducted with due rigour and expertise.

23. The methodology was similar in both the LE/Ventryx and Redpoint analyses, and involved full electricity market simulations that compared system costs with and without zonal losses. Future scenarios on the location of new investment were imposed and did not vary by scenario, implying that no benefit was attributed to the (long run) possible investment impacts of charging for losses. In this sense, the estimates of the (short run) benefits are an underestimate. The benefits accrue from the energy saved from more frequently generating electricity closer to its point of consumption.

24. In all these cost-benefit analyses, the transitional costs of implementation of zonal charging are assumed to be negligible. The reason for this is that the systems are already in place for losses to be included in prices. The introduction of locational pricing of losses would involve changing, in National Grid's settlement systems, a parameter that is currently zero to a value that varies by generator depending on the location of its plants. The implementation cost is not in actual fact zero, in that a process needs to be put in place to calculate and agree the actual variable loss adjustment factors to be used.[36]

25. Within the context of the proposed modification P229 in 2011, Ofgem concluded that overall P299 would contribute to the BSC objective of 'promoting effective competition in the generation and supply of electricity, and […] promoting such competition in the sale and purchase of electricity'. Ofgem also found that the complexity and implementation cost of introducing

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[34] Ofgem (2011), *Impact Assessment on RWE proposal P229 – seasonal zonal transmission losses scheme*.
[35] A substantial proportion of the savings relate to environmental benefits from sulphur dioxide and nitrogen oxide reductions, arising from the fact that less coal and gas would need to be consumed in order to satisfy demand under a locational loss-charging scheme.
[36] In principle and in the IT systems that currently handle settlement, the adjustment factor could be specific to each plant. It could also be averaged over zones. We have not considered which of these would be best.

charges for losses is likely to be low. Ofgem concluded that 'on balance P229 […] better facilitates the Applicable BSC Objectives'.

26. We have reviewed the quantitative assessments and we agree with Ofgem's conclusion relating to the impact of locational pricing of losses on the BSC objectives. We do not believe that there have been material changes to the electricity system since 2011 that would significantly alter this conclusion.[37]

27. However, despite its above-mentioned conclusion that 'on balance P229 […] better facilitates the Applicable BSC Objectives', Ofgem ruled against the proposal on the following grounds:

(a) It would have a large distributional impact.

(b) The impact on wholesale prices and therefore on consumers was very uncertain.

(c) Locational pricing in general might be looked at in the context of market splitting under the EU's CACM mechanism.

28. Ofgem's explanation for rejecting the modification proposal P229 was that the immediate benefits of the reform were low and uncertain, the context for decision-making might change in the medium term, and therefore, Ofgem could not satisfy itself that the proposals would operate in the interest of existing and future consumers.[38]

29. We consider below the detailed components in the argument and provisionally find that Ofgem's quantitative modelling does not support Ofgem's decision to rule against P229.

30. Ofgem stated that 'Analysis by our economic consultants, Redpoint, suggests that wholesale prices might rise, although the analysis is highly sensitive to assumptions.'[39] Redpoint actually said that its most accurate simulation of price changes showed that 'The average TLM-adjusted[40] P229

[37] RWE has submitted an updated cost-benefit analysis that forecasts net benefits until 2030 of around £300million in NPV terms. We have not had time to assess this analysis in detail and will do so as part of our remedies process.
[38] Ofgem, (2011), 'Balancing and Settlement code (BSC) P229 Introduction of a seasonal Zonal Transmission Losses scheme'.
[39] Ibid.
[40] Redpoint usefully summarises the current methodology for incorporating losses as follows:
Transmission losses are allocated in the BSC by applying Transmission Loss Multipliers (TLMs) to scale up or down metered volumes for demand and generation. TLMs are calculated for each settlement period for demand and generation according to the following formula:
TLM = TLF + 1+ TLMO+/-
where TLMO+ = - (0.45 x total losses volume) / (total generation output volume); and
TLMO - = (0.55 x total losses volume) / (total demand volume).

price change is negligible, at around 0.04 £/MWh.' In the early years, Redpoint considered that prices would fall. One would expect a more accurate incorporation of transport costs in the retail price for electricity to lead to a fall in the total cost of energy generation through the effect of more efficient generation choices. Eventually, such falls in total cost should be reflected in lower average prices, although this can be slow in electricity systems, and therefore a fall in the average retail price of electricity.

31. Ofgem requested Brattle, another consultancy, to review the modelling work done for P229 by LE/Ventryx for Elexon. Brattle, in its report to Ofgem, explicitly emphasised the same methodological point on prices:

> LE/Ventyx found that zonal losses led to price increases in all years and scenarios. However, our analysis suggests that had TLMs been included instead then prices might have instead decreased or, at any rate, stayed broadly constant.[41] This finding is of considerable importance when it comes to assessing the impact of P229 on consumers and also means that LE/Ventyx are likely to have over-estimated the distributional effects of zonal losses (since these also depend on wholesale price changes).[42]

32. Together, the Redpoint and Brattle analyses imply that little evidential weight should be put on the prospect of a significant price rise.[43]

33. Having noted the possible scale of price increases and redistribution from customers to generators, Ofgem went on to argue that 'However, if either of the P229 proposals were only implemented for a short time, it is not clear that the resultant redistribution of wealth from consumers to generators is in customers' interests, even if there is an overall NPV benefit because the long-term market efficiencies would not have taken place'.[44]

The Transmission Losses Adjustment (TLMO+/-) uniformly adjusts metered volumes such that 45% of total losses in the period are allocated to 'delivering Units' (eg generators) and 55% are allocated to 'offtaking Units' (eg customer demand). The Transmission Loss Factor (TLF) is Unit specific, thereby enabling losses to be allocated on a locational basis in principle. TLFs are currently set to zero for all Units and have no practical effect.

[41] LE/Ventrix, for modelling convenience, compared results of modelling TLM = 0 with TLM = TLF, where TLF was determined zonally. A more accurate approximation would have been TLM = 1+ TLMO (the current method) with TLM = 0.55*TLF, (055 because 45% of losses are borne by generators). On average, the second comparison is zero, whereas on average, the first is equal to average TLFs. This made a minor difference to NPVs but a material difference to an estimate of price changes.

[42] Brattle (2010), *A review of LE/Ventyx's cost-benefit analysis of Modification P229*.

[43] SSE, in its response to the working paper, suggested that 'locational pricing of losses and constraints could lead to increased wholesale costs should there be a high incidence of marginal generation located in high cost areas of the network'.

[44]Ofgem (2011), 'Balancing and Settlement code (BSC) P229 Introduction of a seasonal Zonal Transmission Losses scheme'.

34. The first point to note with this component of the argument is that it relies on there being a significant redistribution from consumers to generators – in other words a price rise. We have seen that this is contested by the consultants Ofgem employed to investigate the question. The argument further claims that if the benefits only last a few years, then they will be small. This is of course true but not surprising or unique to this particular modification proposal. Moreover, the scale of the benefits assessed did not include long-term effects arising from changes to investment location.

35. However, the argument does not provide any reason to believe that the modification would be incompatible with the market splitting changes that Ofgem is evaluating or that the benefits of the modification proposal would not continue to accrue. If the CACM process were to lead to a market splitting between Scotland and England and Wales, the two markets would be treated like any two European markets. Prices would be determined within a market and the markets would be "coupled" through day-ahead auctions and the trading of transmission capacity rights. The question of losses would continue to be material: how should generation output metered at the interconnection point be assessed in its contribution to demand? Even if market splitting might require a change to the identity of the supplying unit (no longer a specific plant, but instead an interconnection point), it would still require an adjustment for transmission losses.

36. The argument that the early years of a reform do not themselves amount to a compelling case for reform would seem to be the opposite of good regulatory practice: they ensure that only the shortest-term benefits materialise.

37. We believe that Ofgem was right to conclude that there would be net benefits to competition of introducing more locational charging of losses.

38. RWE, in its response to our locational pricing working paper, agreed that locational pricing of losses had net benefits to competition. Ofgem, Centrica, EDF Energy and Horizon all agreed, to various degrees, that there would be some benefits arising from pricing losses more accurately but expressed concerns about the size of the benefits and costs (including distributional effects) of introducing locational pricing. These arguments relate to the proportionality of the introduction of locational pricing in GB, which we would consider as part of a decision on remedies. SSE provided four additional arguments against locational adjustments for losses, which we consider in turn.

It would add to existing customer confusion brought about by locational variation in distribution network costs

39. As a result of the implementation of locational pricing of losses, costs of transmission would vary by regions within GB which would lead to different tariffs being available for the same contract in different regions. Some parties have argued that these price differentials might lead to customers' confusion.

40. This seems implausible to us. Customers searching for a tariff may possibly be confused by the profusion of tariffs on offer to them. However, it is hard to see significant confusion arising from different tariffs available elsewhere. PCWs do not display tariffs that the searcher cannot sign-up to, and suppliers' tariffs already vary regionally. It is true that regional variation vitiates the possibility of national advertising campaigns announcing a national price. But transmission loss-adjustment would not add to this problem, since regional variation through differential distribution network charging would remain.

It would be very complex to calculate location-specific loss adjustment factors

41. This is disputed by RWE, which considers that complexity would be low, arguing that 'the transitional costs of implementing locational signals for transmission losses in the electricity market in Great Britain would be low, in part because much of the work associated with introducing a zonal transmission losses scheme has already been completed.'

It would significantly impact the economic return of existing generation assets

42. It is true that any correction that leads to more competitive prices will have some impact on revenues for some participants and will therefore have an impact on asset values (some upwards, some downwards). Ofgem remarked in its consideration of P229 that the introduction of loss-adjustments had been talked about repeatedly in the industry, so that the risk of this happening over, at least, the long term should already have been factored into investment decisions and therefore overall returns. RWE agreed with this point, arguing that 'whilst distributional effects would occur, given that this has been the direction of travel for many, many years and is the most economically efficient outcome, it is reasonable to assume that such a change should have been considered in any investment decision since privatisation.'

43. We have also considered whether the sort of asset impairment described by SSE would have costs in terms of security of supply. However, we provisionally consider that, if a plant's fixed, but not sunk, costs are very high it would no longer choose to operate only at peak times. However, if that is the case, then cost-minimisation would require that it does not run and instead

be replaced by another plant, possibly more suited to peak operation. Financial impairment, which is what SSE is referring to, includes sunk cost recovery, while day-to-day commercial decisions do not. While we can see an impact on the former, we can see no risk from locational pricing of losses to the latter.

44. It would possibly increase the cost of providing ancillary services to the system operator in Scotland. This is possible, in that ancillary services mostly have to be supplied by a moderately flexible thermal plant. If some fixed costs of a thermal plant are not recovered in the energy markets because of locational pricing, then the costs of supplying ancillary services would rise. It is possible that Peterhead, an SSE CCGT in Scotland, might find itself in that situation for some periods. Peterhead supplies National Grid with voltage support, a service that is sometimes jointly produced with energy. It is possible that the cost of that service would rise if Peterhead were to earn revenues in the energy market less often. However, charging for losses even in this case would not depart from the economic case for cost-reflective pricing.

Congestion

45. There are no comprehensive or recent assessments of the costs and benefits of market splitting in the GB electricity system. The last comprehensive assessment of the costs and benefits of implementing a zonal pricing scheme is by Green, published in 2007 but using data from 1997.[45] This study applied only to England and Wales and considered splitting this area into 12 zones. The combined annual benefit of congestion and losses pricing was estimated to be £73m.

46. The most recent study was a very partial quantification of splitting Scotland from England and Wales by Staffell and Green in 2014.[46] They found that on average domestic consumers in Scotland would benefit by an estimated £64 off their annual energy bills.[47] Generators in Scotland would have lower revenues.[48] Consumers in energy-importing areas (such as south-east England) would face higher prices (an estimated average increase in annual

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[45] Nodal pricing of electricity: how much does it cost to get it wrong?, *Journal of Regulatory Economics,* Vol: 31, pp125–149, 2007.
[46] I Staffell and R Green (2014) *Electricity markets in Great Britain: better together?*.
[47] I Staffell and R Green (2014) *Electricity markets in Great Britain: better together?.*
[48] This assumes that the market under locational pricing of congestion would be no less competitive. Locational rents are currently controlled to a degree through the Transmission Constraint Licence Condition (TCLC). It would be necessary to make sure that analogous measures were in place to avoid the exploitation of locational rents under split markets.

energy bills of up to £14),[49] while generators there would enjoy higher revenues. While this study looked at distributional effects it did not try to estimate a net benefit figure.

47. Conceptually, the net benefit calculation this study identified would be composed of:

(a) gains from static efficiency (mainly demand response);

(b) gains from dynamic efficiency (mainly location of new generation and new demand);

(c) costs from increases in transactions costs; EDF Energy argued that 'the introduction of zonal pricing increases the complexity and potential cost of hedging and risk management which could act as a barrier to entry for small players'; SSE raised a similar objection, adding that such a reduction in liquidity could lead to a reduction in competition for end-customers;

(d) costs from reductions in liquidity due fragmentation of the market with possible impacts on entry and therefore dynamic efficiency; Ofgem, EDF Energy, and Scottish Power have pointed to the existence of these costs; and

(e) one-off transitional costs; SSE and Scottish Power have noted that this might be high.

EDF Energy also pointed to the possibility of costs from more effective exercise of market power in the light of small (and therefore more concentrated) areas.

48. An assessment of the likely costs and benefits over time needs to take a view of the expected levels of transmission investment, since this will be a significant determinant of the level of congestion costs. SSE and EDF Energy noted that expected transmission investment was likely to render transmission constraints much less important in the coming years. National Grid has to some degree confirmed this view.

[49] I Staffell and R Green (2014) *Electricity markets in Great Britain: better together?*. This estimate does not take account of benefits that would be passed back to consumers from the elimination of congestion costs in BSUoS charge. The explanatory note further states that, in order to have regard to Ofgem's statutory duties, aims or objectives of the regulator, the remedy contemplated by the CMA must be consistent with the regulator duties.

49. We did not receive any responses to our working paper in favour of increased cost-reflectivity of congestion constraints.

Zonal vs nodal congestion pricing

50. We had suggested in our wholesale electricity market rules working paper[50] that self-dispatch might be incompatible with congestion charging and that one benefit of a return to a centralised pool might be the implementation of nodal pricing.

51. RWE and SSE both commented that self-dispatch was compatible with locational charging. Specifically, with market splitting, it would be possible to calculate different imbalances prices for different zones. Whilst the very granular nodal pricing systems that are seen in some markets in the USA (for example ERCOT in Texas) may not be possible without a mandatory wholesale pool and centralised dispatch, the preferred EU model for congestion charging under the CACM (as described in paragraph 16) does not require a mandatory pool with centralised dispatch. This argument is considered further in Appendix 5.1: Wholesale electricity market rules.

52. The CACM process will periodically determine the costs and benefits of different levels of splitting. We can assume that this review process will consider the full cost-benefit of splitting, including such issues as reduced liquidity, increased complexity, and, if relevant, any changes required in the operation of the balancing markets.

[50] Wholesale electricity market rules working paper.

Annex A: A summary of current charging arrangements

Component of electricity costs	**Description**	**How charged for in current arrangements?**
Generation costs	Short- and long-run costs incurred by generators in producing electricity. Variable costs include fuel costs (for thermal generators), carbon allowance costs, variable operational costs. Fixed costs include recovery of generation plant investment (capital) costs, fixed operating costs.	Wholesale electricity price (spot price or forward contracts) plus additional earnings in BM for flexible plant. CfDs for new low-carbon generation from 2014. Capacity payments for existing and new capacity from 2018/19.
Transmission constraint costs (ie congestion costs)	Short-run cost of transporting electricity from one point to another over high-voltage long-distance transmission wires, when there is limited capacity available relative to amount of generation that wishes to dispatch. Equal to the difference in marginal generation cost of meeting demand in export-constrained (lower-cost) zone versus marginal generation cost of meeting demand in import-constrained (higher-cost) zone.	National Grid takes system balancing actions in the BM to resolve transmission constraints. Costs of these actions are socialised across all market participants via BSUoS charges. They are levied on an output basis (£/kWh), split 50% on generation and 50% on demand (load).
Transmission loss costs	Short-run cost associated with the electricity that is lost as heat when being transmitted. Equal to the additional cost of generation that needs to be brought onto the network to make up for the electricity lost.	National Grid takes energy balancing actions in the BM to ensure the balancing of supply and demand, taking account of losses on the wires due to heat. Generators are settled on approximately 1% less power than they are metered to have produced while suppliers are settled against the actual reconciled energy volumes consumed, which include both transmission and distribution losses.