Appendix 6.2: Responses to remedies

Introduction

1. Parties made submissions and proposals in relation to the remedy proposed in the provisional decision on remedies. This appendix considers these submissions in detail and offers counter-arguments where appropriate. We consider these comments under four broad headings:

   (a) Our modelling of remedy design choices.

   (b) Our process of evidence gathering.

   (c) Our proposals on implementation date and method.

   (d) Our due regard to all of Ofgem's statutory obligations.

Parties' comments concerning the modelling of the impact of remedies

2. In this sub-section, we report parties' comments concerning our modelling of the benefits of the remedy proposed in the Provisional Decision on Remedies. We also respond to specific arguments raised by the parties.

Generation/demand split

3. SSE[1] considered that the additional benefit attributed to the 100:0 split of costs was based on a flawed analysis – if the multipliers for the 45:55 split of costs were cost reflective then moving to 100% case should not alter dispatch decisions.

4. We are in partial agreement with this comment. It is true that if what had been properly modelled had been the split of fixed losses between generators and demand, then it would have had no impact on dispatch decisions. However, what was modelled, and what we intended to model, was full and semi-marginal variable loss factors. We made an error of interpretation in relating these to the generator/demand split of fixed losses, which we do not intend to change.

5. Intergen[2] disagreed with the CMA's proposed remedy and considered that if transmission losses were to be applied 100% to generators this would add further costs to marginal generation plant and result in a significant impact on short-run marginal costs. Furthermore, it considered that applying

[1] SSE response to provisional decision on remedies, paragraph 8.4.1 (a), p65.
[2] Intergen response to provisional decision on remedies, p3.

transmission losses to generation only would represent a significant and unfair advantage to interconnectors, which were currently exempt from transmission losses.

6. This comment is a result of the error described in paragraph 5.80 footnote 148. The CMA was modelling and intended to model full versus marginal losses. We do not intend to change the allocation of fixed losses.

7. EDF Energy[3] sought further clarity as to whether the CMA's provisional decision to charge 100% of losses to generation meant 100% of losses in aggregate while preserving locational differences for generation and demand or whether it meant that no demand would be allocated any part of transmission losses. Additionally it noted that a move to 100% would put GB generators at a cost disadvantage to continental generation and exacerbate existing cross-border distortions.

8. This question similarly results from the error described in paragraph 5.80 footnote 148. The CMA was modelling and intending to model full versus marginal losses. We do not intend to change the allocation of fixed losses. We do not intend to change the contribution of demand sources to variable loss charges.

9. SSE[4] similarly said that the introduction of locational pricing for losses and the allocation of 100% of the costs of those losses to GB generators will further distort competition between interconnected generators and GB generators and place GB generators to an even greater competitive disadvantage.

10. For the reasons noted above, we believe that that this comment results from the error set out in paragraph 5.80 footnote 148.

11. Dong Energy[5] commented that the CMA had not appropriately considered the impact on trade and competitiveness of UK generators in Europe: levying losses fully on GB generators would lead to them becoming less competitive with continental European generators and potentially increase imports from continental generators, which were much further away from the centres of UK demand, and could lead to higher losses. It commented that generation and demand both contributed to locational losses and it was not fair that generators would be paying costs for which they did not contribute to.

12. We do not believe that this criticism holds, for three reasons: first, we have now chosen to apply semi-marginal loss factors, not full-marginal factors;

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[3] EDF Energy response to provisional decision on remedies, paragraph 3.13, p19.
[4] SSE response to provisional decision on remedies, paragraph 8.7.1, p69.
[5] Dong Energy response to provisional decision on remedies, p3.

second, we have stated that we believe that it would be beneficial for Ofgem and for the industry to examine the implementation of EU regulation on interconnector loss charging mechanisms; third, we have argued that even in the absence of any change to the interconnector regime, the benefits of loss charging on the rest of the market continue to be significant.

13. Renewable UK[6] said the CMA's remedy would put GB generators at a competitive disadvantage in relation to European suppliers, and this effect could not be considered immaterial without further, more in-depth analysis. Similar views were expressed by Scottish Power[7] who considered that if, as proposed, 100% of losses were to be borne by generators, the cross-border trade distortion would be further exacerbated. Accordingly, it believed that the CMA should include in its remedies a recommendation that Ofgem (i) conducts an assessment of cross-border network charging distortions (which include, and extend beyond, transmission losses), and (ii) takes steps to mitigate any distortions identified.

14. We do not believe that these criticisms are valid for the same reasons as those given in the assessment of the criticism of DONG above.

15. Drax[8] considered that applying losses 100% to generators would exacerbate the existing distortion between GB generators and European imports and that measures were required to level the playing field to avoid a detrimental impact on GB security of supply.

16. We do not believe that this comment is relevant; see replies to EDF Energy, Intergen, and Dong Energy above.

17. A number of other parties[9] considered that to charge 100% of losses to generation would exacerbate the existing distortion between GB generators and imports from continental Europe.

18. We do not intend to pursue a full-marginal remedy. Nevertheless, we agree that better charging of losses for imports would also be beneficial and we would encourage Ofgem and the industry to implement European regulation in such a way that transmission losses due to imports are charged in a more incremental-cost reflective manner.

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[6] Renewable UK response to provisional decision on remedies, p3.
[7] Scottish Power response to provisional decision on remedies, paragraph 3.2, p6.
[8] Drax response to provisional decision on remedies, p2.
[9] Drax response to provisional decision on remedies, p2. Intergen response to provisional decision on remedies, p3. SSE response to provisional decision on remedies, paragraph 8.7.2, p69.

19. RWE[10] considered the provisional decision to allocate all losses to generators appropriate due to the fact that generators would generally be better able to respond to the locational signals arising from the allocation of losses.

20. We agree with RWE that generators are currently more able to respond to losses than suppliers. However, we believe that consumers do have opportunity to respond to price signals, and these opportunities are only increasing. In the short run, these opportunities are quantity adjustments; in the long run, there may be locational adjustments. For these reasons, we now support the regime of charging suppliers for their contribution to losses as envisaged by P229.

21. E.ON[11] expressed concerns that as demand response became more prevalent in the market and competed with generation directly to provide a number of energy balancing services, the change to the allocation would mean that there were different market signals between demand and generation, which could lead to inefficiencies.

22. The Renewable Energy Association[12] said that the move to push transmission losses completely on to the transmission connected generators would likely have a negative impact on embedded generators, who were predominantly renewable. As national transmission losses currently average about 2% a year, the current ratio of 45:55 split between generator and supplier charges meant that suppliers must affectively buy excess generation to equate for half the national losses. Suppliers were able to avoid this cost by sourcing power from embedded generators who did not use the transmission network, as there power was used locally and therefore not susceptible to transmission loss costs. The supplier passed this onto the generator as an embedded benefit. With 100% of transmission losses being covered by generators, suppliers would no longer have the incentive to provide transmission loss avoidance as a benefit to embedded generators.

23. We agree with E.ON for the reasons given in paragraph 20. For these reasons, we now support the regime of charging suppliers for their contribution to losses as envisaged by P229.

24. Centrica[13] did not consider that the proposal to allocate all losses to generators could be cost-reflective for the following reasons:

[10] RWE response to provisional decision on remedies, paragraph 39.3, p12.
[11] E.ON response to provisional decision on remedies, paragraph 44, p8.
[12] The Renewable Energy Association response to provisional decision on remedies, p4.
[13] Centrica response to provisional decision on remedies, paragraph 458, p89.

(a) A material proportion of total transmission losses are essentially fixed (unrelated to the level of generation output). They typically relate to the role of transformers and are thus driven by serving transmission offtakes/demand. These fixed losses are clearly unrelated to the location of generating plants.

(b) The level of variable (load-related) transmission losses is affected both by generation dispatch and the level of demand which is controllable via on-site generation or other demand-side response.

(c) A proposal that allocates all losses to generation on a locational basis will therefore fail to send the right price signals at either end of the system.

25. We agree with these concerns and we believe that they are the result of the error described in paragraph 5.80 footnote 148.

26. Centrica[14] considered that, for the proposed remedy to be proportionate and effective, the detailed design needed to ensure that transmission loss factors were cost reflective.

27. We believe that a system that is more cost-reflective than the current one can be effective without the system being fully and entirely cost reflective. We believe that it is a strength of our remedy that it implements P229, which, while not fully cost-reflective, has a low cost of implementation and a high chance of being successful.

Uncertainty over incremental costs and signals to investors

28. Drax[15] said that introducing locational pricing for transmission losses would increase generator uncertainty over their incremental costs and that the existing dispatch distortion (eg absence of locational pricing) would be replaced by a new distortion (eg uncertainty over incremental costs). Further it added that the introduction of locational charging for losses risked undermining investors' confidence at a time the UK was embarking on a major investment programme to upgrade and decarbonise the electricity system.

29. Scottish Renewables[16] considered that without any further details as to how the existing rules would change many developers were unable to assess the potential impacts that such a change would have on existing and future projects. This was a particular concern given the significant impact that a

[14] Centrica response to provisional decision on remedies, paragraph 451, p88.
[15] Drax response to provisional decision on remedies, p2.
[16] Scottish Renewables response to provisional decision on remedies, p1.

number of recent and unexpected policy decisions have had on investor confidence across the renewables sector.

30. We disagree with these comments. Exposing generators to locational losses does not introduce a new distortion. It corrects an existing distortion. The P229 mechanism sets locational loss factors a year in advance for each season and zone. Therefore, there is no risk that would hinder efficient dispatch, since loss factors are known at the time of dispatch. There has always been provision for the introduction of locational losses in British charging arrangements, and many attempts in the past to implement locational losses, so our remedy should not come as any surprise to investors.

Dynamic versus seasonal transmission loss factor and cost reflectivity

31. Intergen[17] supported the implementation of a seasonal transmission loss factor published in advance so that generators could incorporate this into their costs.

32. EDF Energy[18] highlighted again the trade-off between accuracy of the transmission loss factors and the ability of market participants to respond noting that under a solution like the one envisaged by the CMA, in line with P229, derived efficiency would be lower than the modelled theoretical efficiency improvements.

33. We agree with EDF Energy’s positive statement but not its views of the model. EDF Energy’s underlying point is that seasonal average loss factors may differ from the ‘true’ loss factor from hour to hour due to factors such as variation in wind output. We agree and have factored this into our welfare calculations. We apply seasonal average loss factors to despatch decisions (to simulate the P229 charging proposal), but calculate welfare savings using the hourly estimate of the ‘true’ loss factor, which is a function of prevailing hourly demand and wind output within our model. We disagree that the risk of mismatch between *(a)* charges based on average seasonal loss factors set ex ante and *(b)* out-turn ‘true’ loss factors necessarily implies that actual efficiency will be lower than the modelled efficiency improvements. We see no reason to expect any bias, and in practice the actual efficiency could be higher or lower depending on how accurately the charges reflect the out-turn loss factors.

[17] Intergen response to provisional decision on remedies, p2.
[18] EDF Energy response to provisional decision on remedies, paragraphs 3.7–3.9, p18.

34. RWE[19] said that the approach of modelling seasonal loss factors was in line with the proposals under BSC modification proposal P229. This was an appropriate starting point for treating losses on a more cost-reflective basis. RWE recognised that such an approach could not perfectly reflect losses in each Settlement Period, but provided a better approximation than a flat allocation as was currently the case and this was evidenced by NERA's report as well as earlier analysis relating to zonal losses.

35. SSE[20] considered that the combination of calculating loss factors in advance, adopting seasonal and regional averages, and using negative loss factors in some regions, meant that the proposed remedy would be far from cost reflective, and in effect result in arbitrary market distortions.

36. We agree with SSE's implication in this line of criticism that cost reflectivity is the right goal to aim for. There is no obvious reason why negative loss factors in some regions should undermine the 'cost reflectiveness' of the policy, provided they are reflective of underlying conditions on the transmission system. Regional and zonal averaging is a compromise between complexity and accuracy, and this compromise is made across many aspects of network access pricing (eg TNUoS).

Further charging reform and compatibility with policy

37. Drax[21] believed that more consideration needs to be given to the timing of transmission losses reform, given that similar work is being undertaken elsewhere and that modification to transmission losses charging should not be undertaken without understanding the wider future charging landscape.

38. Renewable Energy System Limited[22] said that the CMA had not considered the interaction between its proposed remedy and DECC's System Integration Cost work stream (not publically launched), which it expected would cover the issue of transmission loss pricing, European network rules and distributional impacts. It therefore considered that the 'Order' status of the CMA recommendations was inappropriate.

39. We disagree with this comment. We do not believe that the implementation of Capacity Allocation and Congestion Management regulation (CACM) is a reason for the delay of locationally-sensitive charging of losses, as it may have been when the GEMA board decided not to pursue P229. We are not

[19] RWE response to provisional decision on remedies, paragraph 39.5, p13
[20] SSE response to provisional decision on remedies, paragraph 8.5.2, p67.
[21] Drax response to provisional decision on remedies, p3.
[22] Renewable Systems Limited response to provisional decision on remedies, pp5 & 6.

aware of any other EU, Ofgem or DECC processes which will be hampered in their work by this reform.

40. One of the reasons that Ofgem offered for rejecting P229 was linked to one of the EU network codes, ie the Capacity Allocation and Congestion Management regulation (which at the time of Ofgem's decision was in an early stage of development) as well as changes to the incentives for the construction of new generating capacity (ie the capacity market). However, this EU network code entered into force in August 2015 and does not contain provisions that in our view would prevent, or undermine, the mechanism set out in our proposed remedy.

41. SSE[23] stated that the CMA's analysis had failed to consider renewable generation, as pricing signals produced by locational pricing for losses would work in the opposite direction to the government's policy on carbon reduction.

42. We disagree with this comment. Under CfDs, which are the main instrument for government's encouragement of renewables, revenue flows are not materially affected by locationally-sensitive losses charging.

Losses caused by the system operator

43. Drax[24] believed that more consideration needed to be given to the impact of National Grid's actions on the system and that losses resulting from these actions should not be factored into the losses calculation applied to generators.

44. We disagree with this comment. National Grid sometimes has to take actions to balance the system. We do not believe that there are reasons for treating losses arising from these actions in any way differently from any other action that leads to a balanced system.

Impact on consumers' bills

45. EDF Energy[25] said that the results from the modelling did not meet the evidential standard to demonstrate benefits to consumers, with bills rising and falling at different times under different scenarios. SSE[26] expressed a similar view and said that the CMA had provided no material evidence that the proposed remedy would be effective in generating positive outcomes for customers, noting that in all scenarios for the period 2027 to 2035 the remedy

[23] SSE response to working paper, para 12.
[24] Drax response to provisional decision on remedies, p3.
[25] EDF Energy response to provisional decision on remedies, paragraph 3.20, p20.
[26] SSE response to provisional decision on remedies, paragraphs 8.5.5 & 8.5.6, p67.

would result in increases in customers' bills and any benefits to customers were marginal up to 2026.

46. We do not agree with these comments. We have not used the model primarily as a price forecasting tool, but to assess the order of magnitude of the value of reduced waste of energy. Our wider investigation has provided us with confidence that the wholesale markets function well. Therefore, we can expect reductions in the long-run incremental cost of meeting electricity demand to be passed on to consumers.

47. Drax[27] said that the results from the cost-benefit analysis indicated that net benefit of the remedy per household and per annum was very uncertain, likely to be marginal at best and extremely sensitive to the modelling assumptions.

48. We do not agree with this statement as a critique of the reform. As explained in paragraph 46 above, the model establishes the order of magnitude of cost savings with a degree of confidence. We do not rely on the model for our confidence that these savings will be passed on to consumers. We rely instead on the full body of our analysis of competitive conditions in the upstream market.

49. The Renewable Energy Association[28] submitted that the detailed modelling performed by the CMA demonstrated that the implementation of the proposed remedy would bring a net benefit for consumers over ten years. However, the analysis failed to take into account the significant changes the UK grid was expecting to see over the next decade, which could see the grid transformed from the assumptions used in the CMA's model.

Distributional impacts

50. SSE argued that it would significantly impact the economic return of existing generation assets.[29]

51. 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

[27] Drax response to provisional decision on remedies, p2.
[28] The Renewable Energy Association response to provisional decision on remedies, pp3 & 4.
[29] SSE response to locational pricing in the electricity market in Great Britain working paper.

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.'

52. We have also considered whether the sort of asset impairment described by SSE would have costs in terms of security of supply. However, we 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.

53. 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.

54. Dong Energy[30] said that the design of the scheme had a significant influence on the distributional impacts of locational losses and, as the distributional impacts were significant, the impacts of the scheme on stakeholders should be quantified before any decision is made.

55. We do not agree with this comment. It is true that the reform will have some distributional impacts, as will any policy that moves a market from a worse to a better-functioning state. We accept that in some cases, distributional impacts, by reducing the willingness of investors to invest in a UK market at a given level of return, could lead to a deterioration in the proper functioning of a market. There is sometimes a legitimate concern to be raised about the impact on the cost of capital of regulatory interventions. However, we do not believe that this criticism is valid in this particular case. The introduction of locationally-sensitive loss charging has been on the agenda since

[30] Dong Energy response to provisional decision on remedies, pp1 & 2.

privatisation. No investor in the sector can plausibly claim that the introduction of the reform is a risk that could not have been considered at the time of investment. Therefore, we believe that the risk premium that investors already demand for investment in the sector includes any compensation for this reform.

56. EDF Energy [31] said that while there was some assessment of the distributional impacts based on NERA's work, the redistribution of value between different locations would be significant, particularly for generators, compared with the benefits achieved and only limited analysis had been performed on this.

57. We do not agree with this comment. We do not see a reason why the size of the distributional impacts relative to net benefits is *per se* an argument against a reform. As noted above, the relevant distributional consideration is whether a distributional impact significantly raises the cost of capital to firms in the future. This is a separate matter from the size of benefits. In this particular case, we do not believe that the distributional effects between generators will have a significant impact on the risk premium required by investors for the reason given in paragraph 51.

58. RWE[32] noted that distributional effects among generators arose as a result of the current arrangements not taking into account costs that were incurred though transmission losses. It considered that the magnitude of such distributional effects among generators was an indication of the existing AEC (and of the cross-subsidisation that currently existed) and as such demonstrated the degree to which the existing arrangements were inappropriate. Therefore, whilst it recognised that there may be a distributional impact on some generators, this was the inevitable consequence of addressing the historic cross-subsidisation that had taken place and of delivering an appropriate remedy to the AEC.

59. Haven Power[33] said the proposal for the introduction of locational transmission loss factors was in its view a mistake. Transmission losses made up a very small amount of customers' overall electricity costs; this change would introduce further costs on suppliers (for example for pricing system changes and quotation production costs) which were disproportionate to any benefit for customers.

[31] EDF Energy response to provisional decision on remedies, paragraphs 3.18 & 3.19, p20.
[32] RWE response to provisional decision on remedies, paragraph 39.2, p12.
[33] Haven Power response to provisional decision on remedies, p2.

60. While it is true that the price adjustment to transmission losses will be very small, the cumulative annual saving to the GB economy is of an order of magnitude that we do not consider to be small.

61. Drax[34] commented that losses made up a very small amount of a customer's overall electricity bill but the change proposed by the CMA would impose a huge cost on the industry (for example for pricing system changes and quotation production costs), which were disproportionate to any benefit for customers.

62. We do not accept this as a critique of the remedy. The impact on consumer bills may be small, but the order of magnitude of the total net benefit is large. We have taken the impact of the distributional consequences on the proper functioning of the market, as outlined in paragraph 57 above.

Treatment of offshore transmission losses

63. Centrica[35] said that the CMA was not clear as regards the proposed treatment of offshore transmission losses. It considered that under a cost-reflective locational losses arrangement, offshore generators should bear the full transmission losses which were attributable to them.

64. We do not propose to change the treatment of offshore transmission losses except in so far as they are affected by P229. We agree with the principle that Centrica is advancing and we have argued that we believe that the implementation of P229 is a proportionate and effective, although not optimal solution to the AEC found. We encourage the industry to implement even better locational pricing in the future.

Impact on intermittent generation

65. Dong Energy argued that the CMA had failed to give due account of the impact of the remedy on an electricity system with large volumes of inflexible and embedded generation- and demand-side responses. Levying losses fully on intermittent generation could have little to no effect on their dispatch whilst removing losses from embedded generation and DSR could reduce their incentives to dispatch efficiently and effectively.[36]

66. The Renewable Energy Association[37] said that generators had highlighted that the introduction of locational transmission loss pricing was unlikely, in

[34] Drax response to provisional decision on remedies, p1.
[35] Centrica response to provisional decision on remedies, paragraph 457, p89.
[36] Dong Energy response to provisional decision on remedies, pp3 & 4.
[37] The Renewable Energy Association response to provisional decision on remedies, p3.

itself, to have a significant influence on the decision of generators to locate in certain regions. It did however create a further cost for those renewable generators who were dependent on specific recourses in remote areas. As such, locational transmission loss pricing created a competitive disadvantage which was out of the renewable generators control, while favouring less location reliant generators, including fossil fuels. According to the Renewable Energy Association such a remedy therefore run counter to the UKs decarbonisation targets and could cost consumers more in the long run if the remedy resulted in a more expensive, and time restrictive, deployment of renewable technologies in order to meet legally binding climate change targets.

67. We are not implementing a remedy that will remove losses from demand sources, so DSR will not avoid the incentives. We agree that zero marginal cost generation, embedded or not, will not be greatly affected, and we conclude from this that the benefits of the reform will fall as the amount of zero marginal cost generation rises. However, this is going to take a long time. This is an effect that has been modelled in our estimates of impact as well as in the previous estimates, and the order of magnitude of the net benefits of the remedy continue to be substantial.

Impact on capacity market contracts

68. Centrica[38] said that given that the 2018/19 and 2019/20 Capacity Market auctions had already taken place there would be no scope for generators to respond to the locational loss proposals within the duration of those Capacity Market contracts and considered that there was a good case for transitional loss arrangements or a complete four-year deferral of their implementation once the detailed allocation mechanism had been designed by National Grid.

69. Scottish Renewables[39] submitted that the analysis presented did not appear to show any consideration of the impact that a change to TLM charges would have on projects with existing CfD contracts. It added that there appeared to be little consideration of the administration cost that a shift to location TLM charges would drive.

70. We do not agree with this proposal. A change in prices will have distributional effects (some will gain, others will lose), especially in an industry characterised by long-lived assets. However, we consider that the introduction of locationally-sensitive losses charging is a reasonable risk that investors should have factored into the cost of capital, especially given that this reform

[38] Centrica response to provisional decision on remedies, paragraph 460, p89.
[39] Scottish Renewables response to provisional decision on remedies, p2.

has been on the industry agenda for so long. The impact on the capacity mechanism specifically is simply the mechanism by which this change will change revenues from certain assets. It is not in itself a cause. The cause is the change in revenue flows to different assets.

Increase in customer confusion

71. As a result of the implementation of locational pricing of losses, costs of transmission would vary by region within GB which would lead to different tariffs being available for the same contract in different regions. SSE argued that these price differentials might lead to customers' confusion.[40]

72. 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 as regional variation through differential distribution network charging would remain.

Complexity of calculation

73. SSE commented that the process of calculating losses attributable to a particular generator for each settlement period was overly complex to be practical.

74. This is disputed by RWE, which considered 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.'

75. We note that P229 has been discussed in great implementation detail, including the process of appointing a firm to compute locational loss factors. There is no indication that this will be technically beyond the capabilities of a number of suppliers to offer.

76. Dong Energy expressed concerns over whether the benefits of locational pricing could justify the added transaction costs and complexity. It added that the introduction of locational pricing for transmission losses would have a disproportionate impact on smaller suppliers who might find it more difficult to

[40] SSE response to locational pricing in the electricity market in Great Britain working paper.

precisely factor in the additional costs. It considered that this could result in additional risk premiums that would drive additional costs for customers.

77. We disagree with this comment. Our remedy will involve the calculation of transmission loss factors annually, in advance. These will be made available to parties at least three months before being used. We therefore consider that all parties, including smaller suppliers, will have sufficient time to factor in the additional or reduced costs.

The process followed by the CMA

78. SSE[41] commented that the CMA did not adhere to the transparent and iterative process it had undertaken to follow by failing to publish a working paper with the details of NERA's model and its results.

79. We disagree with this comment and we respond to it in detail in Appendix 5.2, paragraphs 53-57.

Order versus a code modification

80. Dong Energy[42] considered it more appropriate that the CMA issue an order for Ofgem to look at locational losses, so that a full cost-benefit analysis could be performed and that the detail of a scheme and its implementation could be worked out before a decision is made.

81. EDF Energy[43] did not believe that the CMA had demonstrated that implementation by way of an order would be more effective than existing industry processes and said that BSC modifications would need to be raised in any case. It considered that the remedy would be most efficiently taken forward through the existing BSC process, as this would allow for industry-wide assessment of the detail, including costs, benefits and robust achievable implementation targets for this complex technical and commercial change. Centrica[44] made similar comments and said that implementation via the normal BSC modification route would reduce the likelihood of unintended consequences from the remedy's implementation.

82. Further, Centrica[45] voiced a concern that the CMA's proposal to place an order on National Grid was inconsistent with the better regulation principles which appeared to have motivated some of the CMA's other proposed

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[41] SSE response to PDR, paragraph 8.3.7, page 65.
[42] Dong Energy response to provisional decision on remedies, p5.
[43] EDF Energy response to provisional decision on remedies, paragraph 3.24, p21.
[44] Centrica response to provisional decision on remedies, paragraph 452, p88.
[45] Centrica response to provisional decision on remedies, paragraphs 452–454, p88.

remedies. It added that should the CMA proceed with its favoured implementation route, it was essential that key detailed design issues were addressed in the Locational Pricing Order itself – rather than leaving them to subsequent determination by National Grid. In its view, it would be appropriate for the CMA to consult on the content of the Locational Pricing Order before issuing its final report.

83. RWE[46] noted that the various attempts to introduce locational transmission losses had been beset by delays and protracted debate. It considered that it was in the interest of effective implementation to require National Grid, by means of an order, to develop the proposal in a timely manner. It added that once a locational losses scheme had been implemented in industry codes, there would be opportunities for modification proposals aimed at improving the method by which the allocation of transmission losses was calculated.

84. SSE[47] disagreed with the CMA's justifications for imposing an order and considered that Ofgem should follow a due process to introduce a change of this sort, to comprise appropriate consultation with industry, including an appropriate opportunity for peer review and challenge and a proper consideration of the best available evidence.

85. We disagree with these criticisms of the implementation proposed for the remedy. Our argument and detailed implementation choice are presented in Section 6 (see paragraphs 6.139 to 6.142). We have however modified our approach to the implementation of the remedy, so as to give the possibility for Ofgem and the industry to amend the rules underpinning the locational pricing for losses in the years to come so as to improve (if appropriate, for instance in order to move to a full marginal solution) or adapt to future developments the technical details set out in P229 (see paragraph 6.149).

Process followed by the CMA and assessment of remedy against BSC objectives

86. Dong Energy[48] submitted that it was not fair that the CMA's proposals were justified using work that has not had time to be properly and fairly scrutinised by all industry participants. Considering the significant impact of the CMA's proposals, it would have expected and appreciated a longer consultation period. Further, regarding the implementation date of the proposals, it added that it does not consider the CMA had proposed a sufficient lead-time for generators and other stakeholders to respond effectively. We described our

[46] RWE response to provisional decision on remedies, paragraph 39.6, p13.
[47] SSE response to provisional decision on remedies, paragraph 8.6.3, p68.
[48] Dong Energy response to provisional decision on remedies, p2.

process in Section 5, and the various iterations with parties, including a workshop with various parties including Dong Energy. We believe that, taking into consideration the constraints set out by our statutory timeframe, we have given appropriate opportunities to all interested parties to comment on our analysis. We also note that our remedy is identical on all technical aspects to P229, which was scrutinised in detail by the industry through its own industry-led process.

87. SSE[49] said that the CMA had not explicitly assessed the proposed remedy against relevant objectives of the BSC and it considered that the proposal conflicted with objectives b) and c) of the BSC (due to departures from cost reflectivity and revenue transfers between market participants which are disproportionate to perceived benefits). We have assessed the proposed remedy against the objectives set out in the 2002 Act, having had regard to Ofgem's statutory functions pursuant to Section 168 of the 2002 Act. We have also noted that Ofgem, in its decision regarding P229, concluded that 'on balance P229 […] better facilitates the Applicable BSC Objectives'. We have not identified any change of circumstance which would affect this assessment (nor have parties put to us any evidence of such a change of circumstance).

Ofgem's previous rejection of P229

88. SSE[50] commented that the CMA had failed to gather a sufficiently strong basis in evidence to set aside the conclusion that Ofgem had reached previously on P229.

89. In our provisional findings report,[51] we noted that proposals to modify the relevant industry codes in order to introduce locational charges for transmission losses had been raised in the past. The last time a modification proposal was submitted to Ofgem (BSC modification proposal P229, September 2011), Ofgem[52] concluded that the proposed modification would not be consistent with its principal objective and statutory duties. In its decision, Ofgem recognised however that P229 would have led to more efficient dispatch decisions due to cost signals allowing variable losses to be taken into account.

90. Ofgem found that, on balance, the improvements in cost reflectivity in the P229 proposals would help create a better level playing field for generators. It

[49] SSE response to provisional decision on remedies, Annex 3, para 1.3, p1.
[50] SSE response to PDR, paras 8.6.1 et seq, page 68.
[51] Energy market investigation provisional findings report, paragraphs 5.42 & 5.43.
[52] Ofgem modification proposal decision (September 2011), *Balancing and Settlement Code (BSC) P229: Introduction of a seasonal Zonal Transmission Losses scheme (P229)*.

also noted that not all generators needed to be able and willing to respond to achieve the benefits of the proposal.

91. However, Ofgem concluded that it could not satisfy itself that the implementation of P229 was in the best interest of existing and future customers. Specifically, Ofgem was concerned by:[53]

(a) the large distributional impact both between individual generators and between suppliers/customers, although Ofgem acknowledged that these distributional impacts might be justified by the longer-term benefit from a more efficient, cost-reflective market;

(b) the uncertainty around long-term benefits of this intervention, due to the changing regulatory environment; it noted in particular:

(i) a debate at EU level for greater integration of electricity markets focused on market-splitting approaches that create multiple price areas within a national system which could have superseded P229 before the full benefits had been realised, possibly as soon as 2015; and

(ii) in the UK, changes to the incentives for the construction of new generating capacity in Great Britain that the government was considering at the time, which may have resulted in some change to the existing GB market arrangements in the medium term that would have undone the benefits of the P229 proposals before any long-term market efficiencies had been realised; and

(c) the modest benefits arising from P229 in the short term (ie two years from implementation).

92. As noted in Section 5, paragraphs 5.46 to 5.56, we believe that circumstances have changed since Ofgem's decision relating of P229, and for the reasons set out in Section 6, paragraphs 6.188 to 6.197, we consider that the remedy is consistent with Ofgem's principal objective of promoting the best interests of existing and future customers. We noted in particular that we have found it difficult to reconcile Ofgem's decision with the evidence and analysis it commissioned and summarised in its impact assessment.

[53] Ofgem modification proposal decision (September 2011), *Balancing and Settlement Code (BSC) P229: Introduction of a seasonal Zonal Transmission Losses scheme (P229)*., pp6–7.

93. Specifically on distributional impacts, Ofgem's consultants did not suggest that significant redistribution from customers to generators was likely.[54]

94. Ofgem concluded that 'on balance P229 […] better facilitates the Applicable BSC Objectives', but nevertheless 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.

95. Ofgem's explanation for rejecting 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.[55]

96. 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.

97. Ofgem stated that 'Analysis by our economic consultants, Redpoint, suggests that wholesale prices might rise, although the analysis is highly sensitive to assumptions.'[56] Redpoint actually said that its most accurate simulation of price changes showed that 'The average TLM-adjusted[57] P229 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

[54] See *Impact Assessment on RWE proposal P229 - seasonal zonal transmission losses scheme*, 4.28
[55] Ofgem, (2011), *Balancing and Settlement code (BSC) P229 Introduction of a seasonal Zonal Transmission Losses scheme*.
[56] Ibid.
[57] 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).
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.
The modelling that we commissioned from NERA considered two alternative policies for losses charging. In the first, TLM = 0.45 MLF + 1 + TLMO+/- (referred to as the 45/55 scenario) and in the second, TLM = MLF + 1 + TLMO+/- (where MLF is the marginal loss factor: the incremental losses expected from a small change in injections or withdrawals at each node.). This is explained in further detail in paragraph 5.80 footnote 148.

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. We would not expect the sort of modelling conducted by Redpoint to provide accurate estimates of the total long-run impact of this kind of policy change on prices.

98. 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.[58] 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).[59]

99. Together, the Redpoint and Brattle analyses imply that little evidential weight should be put on the prospect of a significant price rise.[60]

100. Having noted the possible scale of price increases and redistribution from customers to generators, Ofgem went on to note 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'.[61]

101. The first point to note with this component of the comment 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 comment

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[58] 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 = 0.5*TLF+TLMO, (0.5 because P229 proposes semi-marginal variable loss factors). On average, the second comparison is zero, whereas on average, the first is equal to half average TLFs. This made a minor difference to NPVs but a material difference to an estimate of price changes.
[59] Brattle (2010), *A review of LE/Ventyx's cost-benefit analysis of Modification P229*.
[60] 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'.
[61] Ofgem (2011), *Balancing and Settlement code (BSC) P229 Introduction of a seasonal Zonal Transmission Losses scheme*.

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.

102. However, the comment 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.

103. National Grid has submitted to us an outline of a mechanism that would solve both the constraint charging problem, the losses charging issue and would also be consistent with the European Target Model.[62] In this sense, the National Grid outline is a good example of a solution that might arise out of CACM, rendering our own remedy otiose. The National Grid proposal involves market splitting the existing GB bidding zone at a finer grain than, for example, England/Scotland. We comment on this model in Section 6. We believe that it is attractive and may be a sensible option for the future. However, it is a big and complex modification which we do not believe would lead to a timely solution to the problem we have identified.

104. The remark 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.

105. We believe that Ofgem was right to conclude that there would be net benefits to competition of introducing more locational charging of losses. We instructed NERA to perform updated simulations of the impact of locationally-sensitive loss charging. The mode and results are described in detail in Appendix 6.2. These confirm the orders of magnitude of the previous studies.

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[62] National Grid response to notice regarding assessment methodology for losses proposed remedy – consultation on methodology and scenarios.