Energy market investigation

Locational pricing in the electricity market in Great Britain

23 February 2015

This is one of a series of consultative working papers which will be published during the course of the investigation. This paper should be read alongside the updated issues statement and the other working papers which accompany it. These papers do not form the inquiry group's provisional findings. The group is carrying forward its information-gathering and analysis work and will proceed to prepare its provisional findings, which are currently scheduled for publication in May 2015, taking into consideration responses to the consultation on the updated issues statement and the working papers. Parties wishing to comment on this paper should send their comments to energymarket@cma.gsi.gov.uk by 18 March 2015.

Contents

Page

Summary

1. This paper 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. There is a wide consensus that in principle a well-functioning market would have spot prices that include an element reflecting short-run locational costs. The impact on competition – on the technical efficiency of production; on the competition between fuels and other goods in consumption; and on the competition between locations for siting generation and supply – would be positive. An estimate of the net economic benefits of short-run locational pricing within England and Wales suggests they may be of the order of £70 million per year.[1]

2. The lack of locational wholesale price variation constitutes a well-recognised problem with the current market arrangements. Repeated attempts have been made to remedy the problem since privatisation. Ofgem has consulted on whether to reform aspects of the system under the recent Project TransmiT, which reported in 2012. The project chose not to focus on the question of transmission losses or congestion pricing.[2]

3. The existence of physical limitations on the electricity transmission network requires National Grid to manage the supply (and demand) of electricity being generated at different locations on the network. This is done through a set of market rules that allow parties (mainly generators) to submit a price at which they are willing to increase or decrease generation away from their planned output. Due to physical network restrictions, these rules may have been open to manipulation, in response to which Ofgem introduced the Transmission Constraint Licence Condition (TCLC) which effectively makes exploitation of locational market power a breach of licence.[3] Throughout this paper, we assume that the TCLC is fully effective, so that the current system of compensation for congestion neither generates unnecessarily high transfers nor leads to incentives for technically inefficient production patterns. Relaxing this assumption would add to the benefits of explicit congestion pricing.

4. This paper will describe 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 briefly describe the

---

[1] This estimate is based on an England and Wales electricity market divided into 12 regions (R Green (2007) Nodal pricing of electricity: how much does it cost to get it wrong?, *Journal of Regulatory Economics*, 31(2), pp125–149, hereafter "Green (2007)"). Adding Scotland to the calculation would increase this net benefit figure; as a very rough estimate, one might think of it adding the same amount as the average benefit per region modelled, or approximately £6 million. The Green (2007) estimate is based on figures that are now old and further work in this area would require new estimates to be produced.
[2] Project TransmiT.
[3] Ofgem (2012) *Transmission Constraint Licence Condition guidance*.

rationale for geographical variation in spot prices due to losses and network congestion. We summarise existing work that attempts to quantify the benefits on competition of introducing locational spot pricing. Finally we assess the distributional effects of locational pricing.

5. We welcome views from parties, especially of the likely welfare and distributional impacts of increasing locational elements of wholesale pricing as well as the likely transitional costs of increasing the degree of locational pricing.

Locational components in wholesale prices under current market rules

6. Table 1 provides a breakdown of the components of wholesale costs and summarises whether they currently contain locational elements.[4]

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

Source: Competition and Markets Authority (CMA) research.

7. **Generation costs** – about 40%[5] 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.

8. **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.[6] 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 ability to transport electricity south. This bottleneck is worsening due to the increase in zero incremental cost wind

[4] Summaries of current arrangements for cost elements are presented in Appendix A.
[5] CMA calculation.
[6] 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.

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. But it is expected to abate following the implementation of plans for transmission capacity expansion between England and Scotland. 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, there is scope for competition and efficiency to be enhanced if there were a locational element.

9. **Transmission losses** – about 2%[7] of total spending on electricity – arise because energy is lost in transport at transmission voltages. 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 contract and suppliers to contract approximately 1% more than their customers' demand. Fine tuning of production to meet losses is made through the BM and the losses are charged back to parties as part of the BSUoS charges. There is no locational element to the metered volume adjustments, though competition and efficiency would be enhanced if there were.

10. **Transmission network investment costs** – about 7% of total spending on electricity – are levied in order to allow the grid owners[8] a return on investment. 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.

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

---

[7] CMA calculation.
[8] These are National Grid Electricity Transmission, Scottish Power Transmission, Scottish Hydro Transmission and various offshore transmission owners.
[9] CMA calculation.

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

12. **Distribution network costs** – about 8%[10] of total spending on electricity – are analogous to all the transmission network costs but occur at the distribution level. As with transmission, neither losses nor congestion are currently locationally charged, whereas investment and connection costs are. Congestion and losses at the distribution level are a small component of wholesale costs.

13. 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 this paper whether network access charges are set at efficient or competitive levels.

A brief history of attempted reforms to locational pricing

14. 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.[11]

15. 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. 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, P200, P203 and P204. Ofgem was minded to approve P203 but delayed its final decision. The decision to delay the process was successfully challenged by way of judicial review[12] and the Authority was not entitled to make a final decision.

---

[10] CMA calculation.
[11] 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.
[12] Teesside Power et al v Gas and Electricity Markets Authority, CO/11010/2007: Defendant's detailed grounds of resistance.

16. In 2008, a new modification proposal from RWE npower appeared, P229, proposing a zonal basis for charging for losses.[13] Ofgem's governing body, the Gas and Electricity Markets Authority, 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'[14] (the proposal addressed losses only and not congestion), and the fact that locational pricing might be required at a European level as early as 2015.[15]

17. All of these attempted changes have related to the inclusion of transmission losses in the wholesale price and not to congestion costs. The incorporation of losses would be a relatively modest incremental change from the point of view of market arrangements – it would involve compensating suppliers for net electricity delivered rather than gross electricity supplied. The incorporation of congestion pricing could require a larger change in the market arrangements, although even here some reform options could remain reasonably close to current arrangements.

Impact on competition of wholesale spot prices varying by location

18. 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.

19. The absence of charging for transmission losses is the simplest case of detriment to consider. We can expect it to lead to:

   (a) a distortion of competition between generating sources, since a generator whose location entails lower losses does not benefit from this efficiency. We would expect this to be the largest and most straightforward detriment;

   (b) a distortion of consumption choices between electricity and other goods or services. In the absence of charging for losses, prices in places close to

[13] Modification P229 – Introduction of a seasonal Zonal Transmission Losses scheme.
[14] 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 P198 had previously been thought to merit action by Ofgem.
[15] The European Commission has developed a Capacity Allocation and Congestion Management (CACM) regulation. CACM provides Ofgem with the formal ability to launch a review to consider whether Great Britain has the appropriate configuration of zones in the electricity market. CACM provides minimum criteria for reviewing bidding zone configurations. It may be that the code will impose some restrictions on possible ways of implementing locational pricing; it may also be that the introduction of the code will present an opportunity for Ofgem to reconsider locational pricing overall.

generation are relatively too high and consumption therefore too low, while prices far away from generation are relatively too low and consumption therefore too high. This is a diffuse effect but applied over a very large component of consumption; and

(c) a distortion of competition for location of both generation facilities and high-consumption industrial facilities, since a producer (or conceivably a very large consumer, such as an aluminium smelter) does not benefit from making efficient locational decisions; this is a long-run effect.

20. The absence of congestion charging is expected to lead to a short-run effect on competition:

(a) 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 energy if prices varied locationally. 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).[16] 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.[17]

(b) We assume that the current system of managing congestion is close to being technically efficient, in the sense that there is no way to meet current demand at a lower cost. This assumption is justified on the basis that National Grid uses a competitive mechanism to buy balancing services through BM bids and has an incentive to minimise congestion costs. The introduction of the TCLC 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 Regulations on Energy

---

[16] 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. 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.
[17] We consider the potential impact of smart meters on consumption in the gas and electricity settlement and metering working paper. 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 (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.

Market Integrity and Transparency have been designed to identify abuse of market power and capacity withholding.[18] Penalties under these regulations provide a further disincentive for parties to engage in unilateral market power strategies.

21. 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.[19] As noted in paragraph 10, locational choices are also influenced by the network charging methodology. Congestion charging would have an impact on location beyond this: it is a signal based on energy production or use, rather than capacity use.[20]

Potential economic benefits of more locational pricing

22. We have not found arguments in principle questioning the benefits to competition and net economic welfare from increased accuracy in locational pricing. Several studies have estimated the degree of detriment from the current practice of averaging and spreading congestion costs and transmission losses.

23. Table 2 summarises these studies. The studies that considered only the impacts of losses (the first four listed) suggested a range of benefits, modest in the short run, but growing to be as high as £40 million per annum in the long run. The 2006 and two 2010 studies were impact assessments of the respective proposed modifications. They considered both long-run and short-run effects. The immediate impact appeared to be a net benefit of around £6 million per year. These studies did not require any assumptions to be made about consumer responses to prices – benefits arose from improved technical efficiency of production. Of the estimates we have seen, only Green (2007) considered the benefits of incorporating both losses and congestion charging. However, this study related to England and Wales only. Moreover, it was

[18] Similarly, such behaviour could amount to an abuse of dominant position prohibited under competition law.
[19] 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.
[20] 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.

performed on a 1997 model of the industry. It considered only the short-run net benefits from locational pricing; the long-run benefits would be expected to be higher. The latest estimate reported was by Staffell and Green from 2014.[21] They estimated an impact on prices in Scotland versus England and Wales under market splitting but did not report net economic benefits from such a split.

24. Modelling exercises of this sort should not be thought to provide accurate forecasts of benefits. At best, they give us an idea of the order of magnitude of the effects. The nature of the GB wholesale and retail electricity markets means that models should provide reasonably good estimates of the anticipated short-run effect on prices and the short-run effect of these on demand. However, the impact on competition for location is much more speculative, since many factors will influence a small number of discrete investment choices.

Table 2: Studies into the net benefits of locational pricing in GB electricity market

Study	*Date*	*Losses*	*Congestion*	*Detriment*
Green[22]	1994	✓		£2m pa in the short run, £15m pa in the long run due to investment location
Oxera/ELEXON Oxera (2006) (Central Scenario) – Modelling for BSC Mod P198[23]	2006	✓		£1.6–£9m pa in the short run, £5.2–£40m pa in the long run
LE/Ventyx (2010) Modelling for BSC Mod P229 IA[24]	2010	✓		Ten-year Net Present Value (NPV) of £46m (approx £6m pa at 5% discount)
Redpoint (2010) Modelling for BSC Mod P229 IA[25]	2010	✓		Ten-year NPV of £48m (approx £6m pa at 5% discount)
Green	2007	✓	✓	£73m pa (1997 figures)
Staffell and Green	2014		✓	£64 pa off fuel bills in Scotland and ~£14 rise in England and Wales (E&W)

Source: CMA research.

25. Within the context of Project TransmiT, the government asked three academic teams to consider the question of how best to reflect locational cost variation in wholesale prices. All three teams recommended some form of inclusion of transmission losses and congestion costs in wholesale prices.[26] Another academic team, the University of Exeter's Energy Policy Group (the Exeter

[21] I Staffell and R Green (2014) *Electricity markets in Great Britain: better together?*. Presentation at the Scottish Government Policy Forum, Edinburgh, 7 March.
[22] Green, R.J. (1994) Do Electricity Transmission Networks need Optimal Spot Prices? Mimeo, University of Cambridge (Hereafter "Green (1994)").
[23] Modification P198 – Introduction of a Zonal Transmission Losses scheme.
[24] Modification P229 – Introduction of a seasonal Zonal Transmission Losses scheme.
[25] Modification P229 – Introduction of a seasonal Zonal Transmission Losses scheme.
[26] The summary of recommendations is available at Exeter EPG's Critique of the three original expert reports to Project TransmiT. One of the three academic teams, while acknowledging the attractions of full reflection of losses and congestion costs, also argued that the investment benefits could be achieved by a reform of charges for network investment cost recovery.

EPG) was then asked to produce a summary of these three pieces of work and to assess on its own account whether transmission charging arrangements should be used to promote low carbon generation, how these arrangements could be restructured and what might be the short- and long-run implications in terms of costs and security of supply. The Exeter EPG concluded that the academic teams had not given sufficient attention to the possible impacts of locational pricing on investment in renewable generation. While the EPG supported in principle the delivery of locational signals, via either transmission charges or energy prices, due consideration needed to be given to the particular constraints faced by intermittent renewable generators. The best locations for wind generation, for example, are often in areas which are not well served by the electricity grid and could be subject to high locational prices. If there were no changes in the subsidy regime, locational pricing could therefore discourage renewable investment.[27] The introduction of Contracts for Difference (CfDs) as a subsidy mechanism for investments from 2018, however, should alleviate this concern: investors will receive the CfD price regardless of the price for which the generator in which they have invested sells its output.

26. If wind investment in Scotland is determined to be the best way to meet the UK's environmental objectives, it would still be possible to achieve this investment in the face of lower Scottish prices, for example by offering higher CfD strike prices for Scottish offshore wind. In that way, the subsidy would be targeted at its explicit object, and what is in effect an environmental subsidy would not be wasted going to fossil fuel generators in Scotland. The option of supporting renewables through hidden subsidies is unlikely to be best for competition or for efficiency.

27. An argument against a move to locational pricing could be the extent of transitional costs. We have not at this stage conducted a careful investigation of the costs of transition to either a zonal or a nodal model. We would welcome comments from parties on transitional costs.

28. Several electricity markets in the USA have transitioned from single-price systems to zonal or nodal[28] price markets in the last ten years. An international comparison of costs and benefits suggests that transition costs have been less than one year of benefits.[29] However, these figures should be

---

[27] In addition, the EPG pointed out that the delivery of the UK's renewable targets would be made more expensive if high locational prices closed down otherwise economically viable onshore wind options that then needed to be replaced by more expensive offshore capacity.

[28] 'Zonal markets' refers to a market design in which quite large geographical areas are treated as separate locations (for example England and Wales, and Scotland). Nodal market designs have a much larger number of separate prices – thousands in the case of Texas.

[29] See Climate Policy Initiative (2011) *International experience of nodal pricing implementation*.

interpreted with care, since the move to locational pricing was usually not the only – or even the major – element of reform. We would expect that a move to full nodal pricing would be more disruptive than a zonal split.

29. Many electricity markets include pricing of transmission losses and congestion. The main Australian market, the Nordic market and markets in most of the north-eastern USA, Texas and California are all examples of markets that have adopted either zonal or nodal approaches. Other markets – for example the Spanish market – have adopted a national price. It is possible that locational pricing makes sense for systems that suffer persistent transmission constraints.

Distributional effects of more locational pricing

30. Locational pricing would have distributional consequences for both generators and consumers. Consumers in areas where generation is plentiful but transmission constrained (for example Scotland) would enjoy lower prices – academic research suggests that on average domestic consumers would benefit from an estimated £64 off annual energy bills.[30] Generators in those areas would have lower revenues.[31] Consumers in energy-importing areas (such as south-east England) would face higher prices (an estimated average increase in annual energy bills of up to £14),[32] while generators there would enjoy higher revenues.

31. The north of Great Britain tends to have plentiful generation relative to demand while the south tends to have a shortage. This is compounded by the location of renewable generation. This means, in broad terms, that consumers in the north would be net beneficiaries from increased locational pricing, while consumers in the south would be less well off.

32. The geographical distribution of fuel poverty means that reducing bills in the north would tend to help to alleviate fuel poverty, while the smaller increase in prices in the south would have a more modest impact on the fuel-poor.[33]

33. Conversely, generators in the north would earn lower operating profits and generators in the south greater operating profits. The most recent study, by

[30] I Staffell and R Green (2014) *Electricity markets in Great Britain: better together?*.
[31] This assumes that the market under locational pricing would be no less competitive. Locational rents are currently controlled to a degree through the TCLC. It would be necessary to make sure that analogous measures were in place to avoid the exploitation of locational rents under split markets.
[32] I Staffell and R Green (2014) *Electricity markets in Great Britain: better together?*. This estimate does not take account of benefits which would be passed back to consumers from the elimination of congestion costs in BSUoS charges.
[33] Table 3.9 in J Hills (2012) *Getting the measure of fuel poverty: final report of the Fuel Poverty Review* shows the distribution of fuel poverty by English region. The regions with the highest proportion of households that are 'Low Income High [Energy] Cost' are the Midlands, the North East and the North West.

Staffell and Green in 2014, looked at a two-region electricity market, with separate prices in Scotland and in England and Wales. It found, for example, that a large combined-cycle gas turbine power station in Scotland would see its annual profits (before investment) fall from £77 million to £43 million in a locationally priced market.

34. In general, a move to locational pricing would benefit some existing generators – those with assets further south – and would create a loss for generators with assets further north.

Non-distributional effects of locational pricing on competition

35. Whatever the exact magnitude and distribution of costs and benefits for individual consumers, suppliers and generators, the net economic effect of more location cost reflectivity should be positive (subject to possible knock-on, implementation or transition issues). The reasons for this are threefold.

36. The first reason is that the absence of pricing for transmission losses may make the system technically inefficient in that a generator in the north that was more expensive (once losses had been factored in) could come to be favoured at certain times over a more efficient generator in the south.

37. The second reason concerns the allocation of resources more generally. Under the current market rules, a proportion of the energy consumed in England and Wales is purchased at a low, smeared price that is below the cost of production.[34] If the cost-reflective, higher price were to be charged, then two things would happen: first, consumers in England and Wales would pay more for electricity – a transfer to producers with no net overall benefit; and second, they would also consume less electricity – energy consumption is effectively subsidised in the south, leading overall to a level of energy use that reduces economic welfare.[35] An opposite effect would occur in Scotland: under the current market rules, electricity is being purchased at a high, smeared price that exceeds its cost of production. If the cost-reflective lower price were to be charged, two things would occur: first, consumers in Scotland

[34] We assume in this argument that there is no market power in the GB wholesale electricity market. If there were market power in either the importing or exporting zone, then the results might be complicated. A first-level effect of introducing more locational pricing would be to reduce the incentive to exercise market power in any one zone for a generator with production assets in both zones. Under a single-priced wholesale electricity market, price manipulation earns returns on all output, whereas in a split market, price manipulation (for example through withholding) earns excess returns only on the output in that market. In this way, locational pricing can be a protection against some forms of exercise of market power.
[35] The idea that a reduction in energy use due to an increase in prices might lead to a net economic benefit comes from consideration of what alternative uses the inputs required could have been put to: when used in electricity production in this situation, some inputs are being used when the willingness to pay for them is lower than their cost. In an alternative use of these inputs, this situation could be reversed and a contribution made to net economic welfare.

would pay less for electricity, which would be simply a transfer from producers; and second, consumers would buy more electricity (at a price which continued to exceed the cost of production). This would be a benefit to both producers and consumers and would represent a real net effect of moving to locational prices. In a static economic analysis, the changes in payments from better locational pricing are either transfers between producers and consumers that net off, or else represent real and positive changes in behaviour.

38. The third reason comes from longer-run incentives. The argument of paragraphs 35 and following is a static economic welfare argument. There are longer-run investment effects from locational pricing that will add to net benefits. In the presence of locational pricing we would expect, for example, that energy-intensive industry would be incentivised to locate in areas of cheaper electricity (for example in Scotland) and away from expensive locations. At the margin, some projects would be worthwhile at low prices and not at high prices, thus changing levels of investment. Similarly with investment in generation plant: it would be encouraged in the south and discouraged in the north.[36]

---

[36] The effect on renewables investment highlighted by the Exeter EPG and noted in paragraph 25 is not properly speaking an impact of locational pricing, but rather of the design of the support system for decarbonisation in the UK.

Appendix 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. Costs of these actions are socialised across all market participants via BSUoS charges, as for constraint costs above.[37]

[37] See ELEXON website: Losses.