What are the costs and benefits of zonal loss charging?

Prepared for ELEXON

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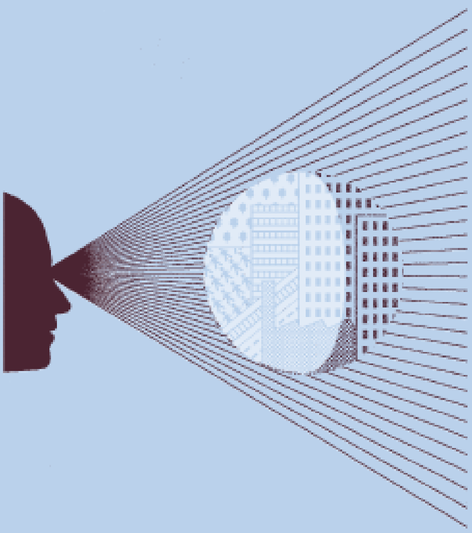

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1 Introduction

1.1 Terms of reference

This study assesses the potential impact of the proposed introduction of a zonal transmission losses scheme, applicable throughout Great Britain (hereafter referred to as P198).[1] The terms of reference for the study required examination of:

– the implementation costs to parties;
– the initial distributional impact;
– the impact on transmission losses;
– the impact on generation;
– the impact on demand; and
– the impact on the transmission system;

but explicitly excluded examination of the impact on the environment and consumers.

In conjunction with Oxera, academic experts in this field, Professor Janusz Bialek, Edinburgh University, and Professor Stanislaw Ziemianek, Warsaw University of Technology, carried out the load–flow modelling for the project using software developed for this type of exercise.

Oxera previously undertook a cost–benefit analysis (CBA) of proposals for zonal loss charging in relation to Modification P82.[2] The approach used for this current CBA is similar to that used in the previous P82 analysis, although the underlying modelling here is based on current market conditions, capturing all pertinent changes since 2003.

1.2 Background information

Power losses are incurred when electricity flows through the transmission system, and are measured as the difference between generation and demand.

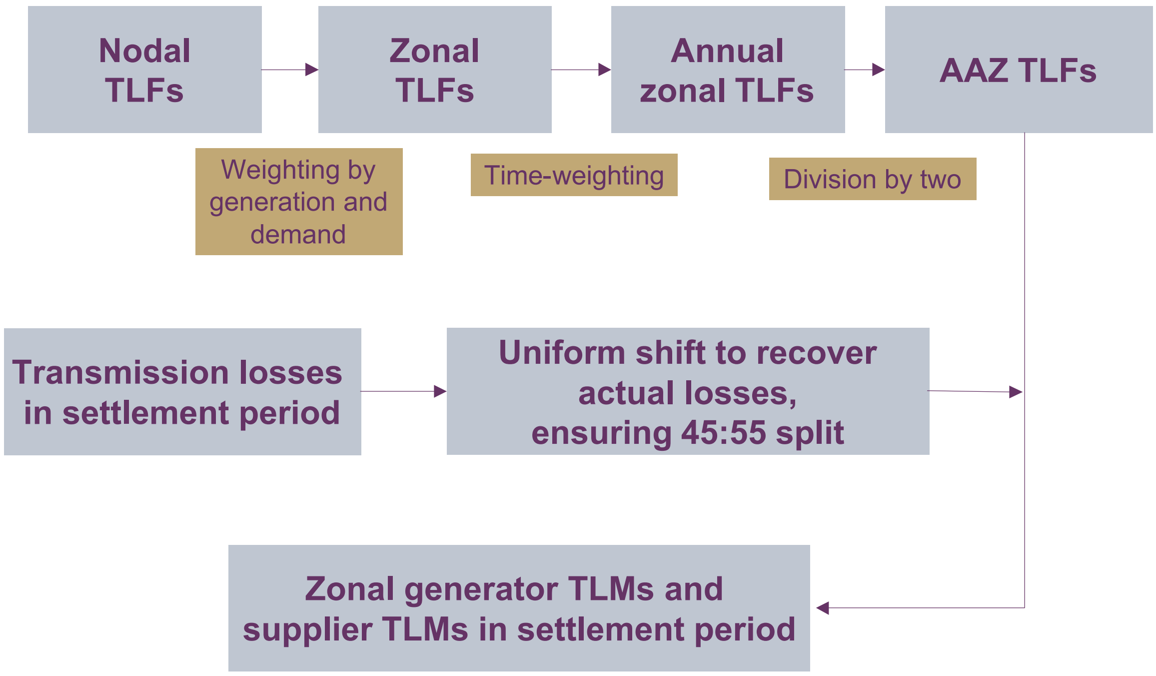
At present, losses in Great Britain are allocated to Balancing and Settlement Code (BSC) parties by scaling the output of generators and the demand attributed to suppliers using transmission loss multipliers (TLMs). A generator TLM of 0.9, for example, means that, for 100 MW of generation, the company would be attributed 90 MW. Likewise, a supplier TLM of 1.1 means that, for 100 MW of actual demand, the supplier would be attributed 110 MW. Total scaling of all generation and demand should exactly recover the level of transmission losses. Losses are split in the ratio 45:55 between generators and suppliers, and are recovered on a uniform basis across the country.

Under the proposed P198 methodology, TLMs will differ between grid supply point (GSP) groups. Nodal transmission loss factors (TLFs) for historic settlement periods are derived from load–flow modelling, and are converted into adjusted annual zonal TLFs (AAZ TLFs) by weighting across nodes using absolute flows, weighting across different settlement periods and dividing by two. AAZ TLFs are fixed annually, and give rise to differentials between loss charges in different zones. AAZ TLFs are shifted up and down uniformly to derive TLMs for

[1] BSC Modification Proposal P198, ‘Introduction of a Zonal Transmission Losses Scheme’, http://www.elexon.co.uk/documents/modifications/198/P198.pdf
[2] Oxera (2003), 'Impact of zonal transmission losses applied throughout Great Britain', June.

each settlement period that recovers actual losses in the ratio 45:55 between generation and supply. The procedure for calculating zonal TLMs is illustrated in Figure 1.1.

Figure 1.1 Derivation of AAZ TLFs and TLMs under P198 methodology



Source: Oxera.

1.3 Relevant impacts

The application of zonal loss charging throughout Great Britain could affect market outcomes such as the pattern of generation and the financial position of generators. In carrying out the analysis for this study, care has been taken to distinguish between impacts that represent additional national resource benefits or costs, and those that represent economic transfers between market participants.

The following costs and benefits have been identified as potential impacts of zonal loss charging applied throughout Great Britain.

– **Reduction in losses**—zonal loss charging is expected to reduce transmission losses compared with the existing uniform charging methodology, by encouraging market participants to take loss effects into account when making their decisions. Given that the cost of losses is shared between generators and suppliers, responses to zonal loss charging could occur on both sides of the market: on the generation side, it might affect generators' despatch decisions, as well as longer-term decisions regarding plant closure/mothballing and entry/return of mothballed plant; on the demand side, any response would be through consumers' consumption and locational decisions.

– **Offsetting costs**—the reduction in losses represents a gross rather than a net benefit, and will be partly offset by changes in other costs. This can be illustrated by reference to the following examples:

  – *generation redespatch*—suppose that zonal loss charging changes despatch in a certain half-hour so that, instead of a Northern generator operating, a Southern generator is despatched. Since the Northern generator would have operated without zonal loss charging, the marginal generation cost (exclusive of the loss impact) of the Southern generator must be higher. This impact is captured in the wholesale market modelling by comparing the total costs of generation under zonal loss charging and those under a uniform loss charging regime;

– *location of new entry*—similarly, if zonal loss charging switches the location of new entry, the fact that the plant would otherwise have located elsewhere suggests that other elements of its costs are higher in the new location;
– *demand-side response*—in regions where zonal loss charging increases consumer costs, any consumption which is deterred, and which leads to loss-reduction benefits, has some value to the consumer which will be forgone. (Conversely, in regions where customers face lower loss charges, any induced consumption will have some additional positive value.)

The existence of these offsetting costs was discussed in Oxera (2003) and estimated at the time. In this report ***the net benefits from the generation sector from loss reductions have been estimated directly*** by comparing the total cost of generation under uniform loss charging with that under zonal loss charging, thereby accounting for the reduction in overall generation required due to avoided losses, and the offsetting increases in output from more expensive plant.

– **Reduction in required generation capacity**—lower losses may reduce generation capacity requirements. However, such benefits may only be realisable where the generation capacity margin is tight and loss reductions allow new investment to be avoided, since otherwise capacity costs are largely sunk. Oxera considers that the effect of zonal loss charging on generation capacity is captured through the electricity price used to value any loss reduction. In other words, in years when the market is signalling a requirement for new capacity through high prices, the monetary value of loss reductions will be higher.

– **Increase in perceptions of risk**—it has been argued that, by precipitating large transfers between generating companies, zonal loss charging might add to perceptions of risk and increase the cost of capital for new investments. With regard to this argument, the following are worth noting:

  – *perceptions of risk are forward-looking*. Given that changes to the loss charging regime, at least in England and Wales, have been mooted since the time of privatisation (and hence past investments have been made in an environment of uncertainty), it is not clear that reaching a decision on locational loss charging will necessarily increase the forward-looking risks faced by investors;

  – *changes to the loss charging regime are a diversifiable risk*. An investor holding a balanced portfolio of generator shares would be unaffected by changes to loss charging arrangements since costs are simply transferred between different generation companies. As noted in a recent study on the cost of capital,[3] any regulatory action that has an effect that can be diversified away does not affect the cost of capital.

  Consequently, this issue is not addressed further.[4]

– **Impact on renewables**—most of the UK's favourable onshore renewable resources are in Scotland and the North of England. These regions are most likely to be adversely affected by zonal loss transmission charging. Conversely, the Southern regions that will

[3] Wright, S., Mason, R. and Miles, D. (2003), 'A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the U.K.', Smithers & Co, February.

[4] In carrying out the modelling, the estimate of new-entry costs assumed that zonal loss charging would have no impact on the cost of capital for new-build projects.

perhaps benefit under zonal loss charging have significant potential for new offshore wind development. However, it is plausible that applying zonal loss charging across Great Britain may reduce the overall growth of renewables generation.

– **Implementation and operation costs**—these may arise for both the system operator and market participants. Relevant costs include modifying IT systems and the potential legal costs of renegotiating contracts.

1.4 Distributional impacts

Because efficiency benefits arise from the impact of zonal loss charging on marginal generators and consumers, whereas transfer effects also include the impact of zonal loss charging on infra-marginal generating plant and consumers, it is to be expected that the size of transfers between generating plant and consumers in different regions will be of a higher order of magnitude than the net national resource benefit of zonal loss charging.

This study has produced a quantitative estimate (under specific assumptions) of the potential size of transfers compared with the net national resource benefits. However, the weight that should be placed on transfer effects relative to efficiency benefits is ultimately a matter of judgement.

1.5 Overview of approach

The approach taken for this study has centred on comparing the results of modelling potential market scenarios under both uniform loss charging (the 'base case' under the current loss charging regime) and zonal loss charging (the 'change case' representing implementation of P198).

Full load–flow modelling of the Great Britain transmission networks has been conducted alongside modelling of the wholesale electricity market for the period from 2005/06[5] to 2015/16. This enabled the potential level of TLMs to be estimated under conditions of zonal loss charging. Modelling the effect of these TLMs on the wholesale market enabled analysis of the potential impact of zonal loss charging on:

– transmission losses;
– the transmission system;
– distributional consequences for generators and consumers in different regions;
– demand;
– generation.

A central case and three alternative scenarios were modelled to provide an indication of the individual impact of the key factors on the results.

Alongside the modelling analysis, the importance of zonal loss charging was compared with other factors that might affect the location of plant entering and exiting the market, such as fuel transportation costs and NGC transmission network use of system (TNUoS) charges.

Figures for the demand elasticity of different types of consumer were used to calculate the potential size of any demand response.

The final stage of the analysis considered the implementation and operation costs of zonal loss charging, and the potential direction and size of the net national resource benefit.

[5] 2005/06 was only modelled in order to obtain AAZ TLFs for the modelling of 2006/07.

2 Modelling approach

To quantify the impact of zonal loss charging on physical network variables and wholesale market outcomes, the following two models were run.

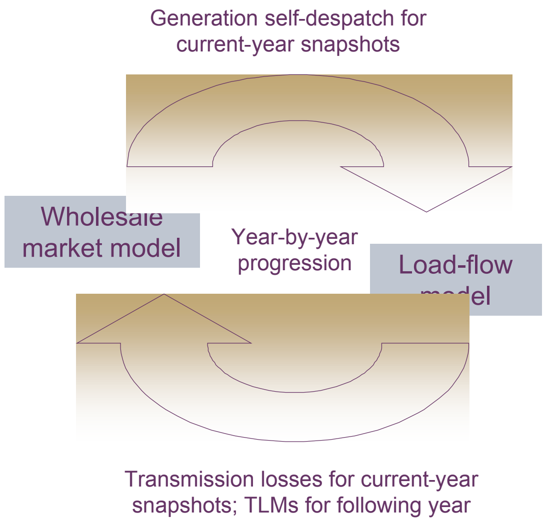
– **A full load–flow model of the GB transmission network**[6]—for given generator outputs, the model was run (by Professor Bialek) using two representations of the transmission network:

  – a DC network to estimate zonal loss factors (as per P198); and
  – an AC network to calculate estimates of the level of variable transmission losses.

– **Oxera's wholesale market model**, which was used to analyse the impact of zonal loss factors on the self-despatch decisions of generators and on other market outcomes (eg, transfers between generators, and emissions levels).

Figure 2.1 illustrates the interaction between the two models.

Figure 2.1 Interaction between the wholesale and load–flow models



Source: Oxera.

The modelling process involved the following steps.

– The wholesale market model was run for snapshot estimates of peak, midpoint and trough demand conditions in 2005/06, with transmission losses recovered on a uniform basis. Using the generator outputs estimated by the wholesale market model, the load–flow model was employed to estimate AAZ TLMs for 2005/06, which were used to alter generation despatch decisions in 2006/07 under the zonal loss charging regime.

– The wholesale market model was then run twice for 2006/07, using:

  – the AAZ TLMs calculated from the load–flow modelling exercise;
  – an estimated uniform TLM.

[6] The transmission network includes all relevant 132kV connections and transmission lines.

These model runs allowed estimates to be made of the impact of zonal loss charging on the pattern of generation for the three snapshot periods in that year.

– The generator outputs for 2006/07 under both uniform and zonal loss charging were fed back into the load–flow modelling to give an estimate of the potential change in transmission losses for three snapshot periods for 2006/07 data, with losses calculated using generation conditions and nodal TLFs. AAZ TLMs for 2007/08 were then calculated.

– This year-by-year process continued, with the wholesale market model despatched one year at a time, and the results fed into the load–flow model to give estimated TLFs for the following year.

This completed the joint wholesale market/load–flow modelling. The estimated AAZ TLMs were then used to model wholesale market behaviour across all demand conditions (rather than just the three snapshot periods). The price at which generators are willing to despatch was modelled as short-run avoidable costs adjusted by the generator AAZ TLM. Intuitively, this reflects the fact that the more output is scaled back, the higher the market price will need to be to allow a generating unit to cover its overall avoidable costs. The total level of demand to be met was reduced by the estimated level of losses, allowing the total net benefit of zonal loss charging to be calculated.

2.1 Use of snapshot periods

In evaluating the impacts of P198, it is necessary to reduce the computational burden, given both the length of the modelling horizon and the number of scenarios to be investigated. Therefore, the approach outlined above uses load flows during three snapshot periods in each year (peak, midpoint and trough demand conditions) to estimate the zonal TLFs and TLMs according to the methodology set out in P198. The snapshots were chosen to best represent 'typical' network loading conditions as well as those at either extreme (peak and trough loading conditions). They were calculated by taking load–duration curve[7] data from NGC's 'Seven Year Statement', and identifying the proportion of time when demand was closest to each of the three types of snapshot demand period being modelled. The time durations covered by the snapshot periods are set out in Table 2.1.

Table 2.1 Time-weighting coefficients derived from the load–duration curve

Snapshot period	% of time covered
Peak	10.4
Midpoint	73.8
Trough	15.8

Source: Oxera.

Individual nodal TLFs were obtained as an output of the load–flow modelling of the snapshot periods. They were then averaged to obtain zonal TLFs using weights equal to the sum of the absolute value of generation and demand at a given node. The AAZ TLFs were then calculated by halving the zonal TLFs and using the time-weighting factors in Table 2.1 to aggregate the results for the three snapshot periods.

[7] A load–duration curve shows the percentage of time at which demand is at different levels.

2.2 Model validation

Before simulations for the ten years could be carried out, the TLFs calculated by the load–flow model run at the University of Edinburgh, and the wholesale market model run by Oxera, were validated against the TLFs calculated by Siemens PTI and provided by ELEXON. The validation was performed in two steps: load–flow model validation, and economic model validation.

2.2.1 Load–flow validation

For this exercise, the data was entered into the DC load–flow program run by the University of Edinburgh in order to calculate TLFs. The validation was performed using 625 samples of actual data (ie, network data and metered volumes) from 2005/06 provided by ELEXON. Table 2.2 compares the two sets of TLFs. Differences are negligible and show that the DC load–flow program employed produced consistent results.

Table 2.2 Comparison between PTI and Oxera AAZ TLFs using the same input data

Zone	PTI	Oxera (DC load–flow)	Difference
1	–0.00742	–0.00747	4.7E-05
2	–0.01038	–0.01043	5.2E-05
3	0.00039	0.000729	–3.4E-04
4	–0.01399	–0.01404	5.2E-05
5	–0.00133	–0.00135	1.7E-05
6	–0.02355	–0.02368	1.3E-04
7	–0.01625	–0.01631	6.0E-05
8	0.00414	0.004146	–6.0E-06
9	–0.0043	–0.00432	1.8E-05
10	0.0053	0.005309	–9.0E-06
11	0.00963	0.009653	–2.3E-05
12	–0.02127	–0.0214	1.3E-04
13	–0.02561	–0.0257	8.9E-05
14	–0.02818	–0.02824	5.9E-05

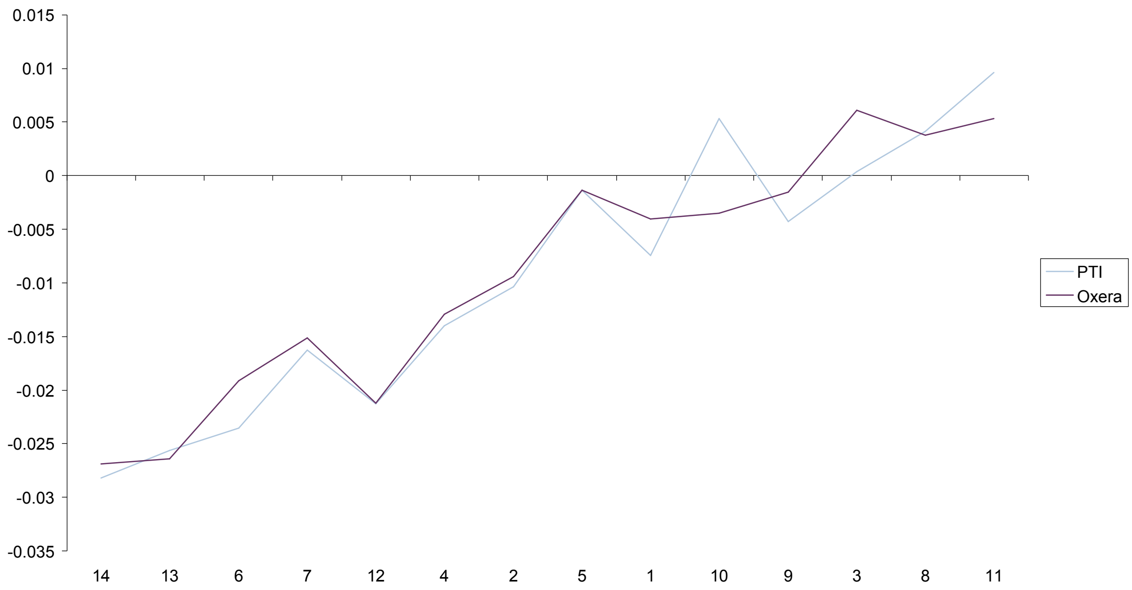
Source: Oxera.

2.2.2 Economic model validation

The Oxera wholesale market model was validated using the technique of hindcasting—ie, producing results for the same year, 2005/06, using Oxera's model, which will then be used to produce forecasts of despatches for the next ten years. This step was also used to validate the assumption that taking three load snapshots per year produces reasonably good estimates of TLFs.

Oxera's wholesale market model was run for the year 2005/06 in order to produce outputs of all the power plants for the three snapshots: peak, trough and midpoint. Demand data (loading of GSP transformers) was taken from the 2005 Seven Year Statement and scaled proportionally to correspond to the three loading snapshots. These despatch and demand values were then fed into University of Edinburgh's DC load–flow program, which also used the same network data as in the first part of the validation exercise. Figure 2.2 below shows the resulting TLFs.

Figure 2.2 Comparison between PTI and Oxera AAZ TLFs based on Oxera market simulation



Note: Zones reordered North to South.
Source: Oxera.

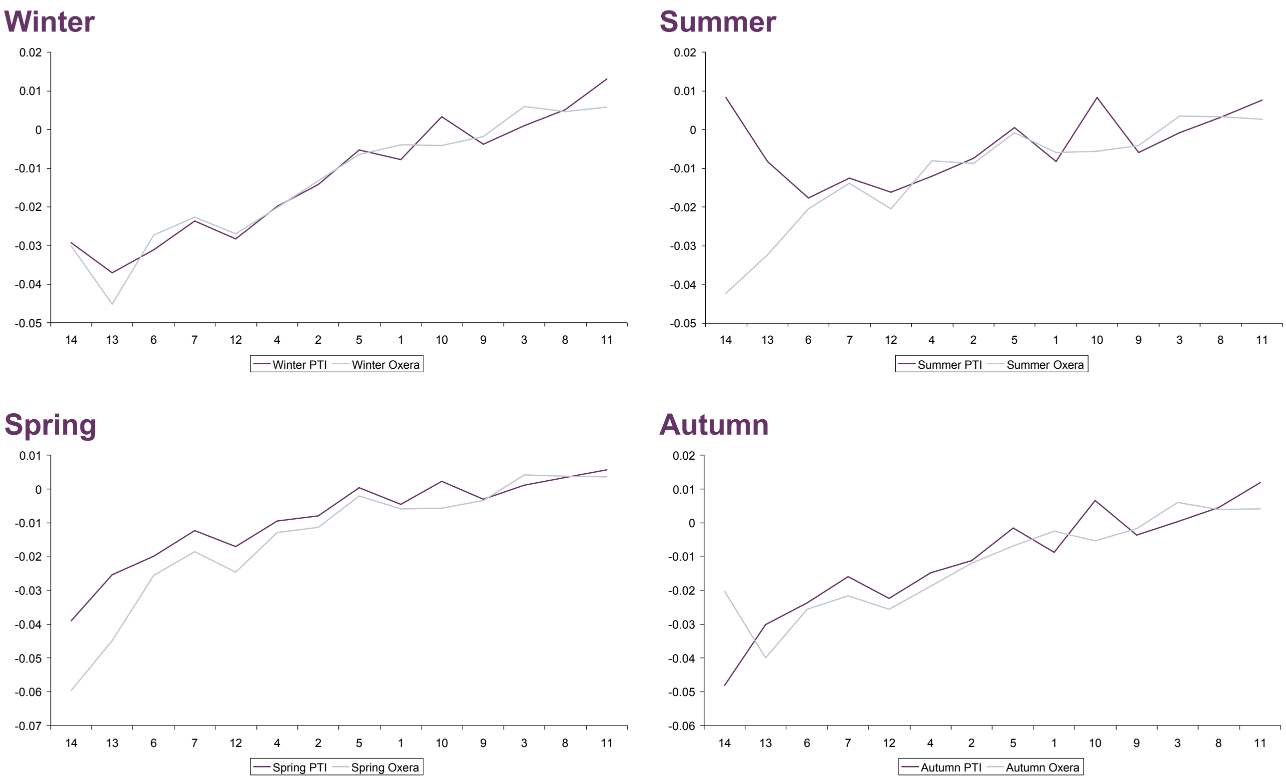
For almost all the zones the differences in TLFs were below 0.005. Only for zone 10 was the difference slightly higher, equal to 0.009, which is also acceptable. The differences are to be expected, as Oxera's wholesale market model predicts outputs of power plants assuming that they follow optimal despatch principles. In practice, power plant outputs are also affected by other, difficult to model, factors, such as corporate strategies, opportunities for gaming arising through the Balancing Mechanism, etc.

By way of example, the major difference in AAZ TLFs is in zone 10 (South Wales), where the Oxera TLF was calculated as negative, while the Siemens PTI TLF was positive. Investigation of the results from both models pointed to the pattern of output from the Aberthaw plant as being the driver of these differences. The snapshot modelling of the system sees Aberthaw producing during each of the three snapshot periods (effectively mimicking baseload load factor). However, in the data provided by ELEXON, Aberthaw ran at an estimated load factor of approximately 40% (or half that assumed by the snapshot modelling). This result alters the import/export balance across the entire year between the two sets of results, with the outcome being a reversal of the AAZ TLFs.

Seasonal results

A similar exercise was carried out for seasonal modelling, with the results for both PTI modelling and Oxera's approach shown in Figure 2.3 below. In general, there was reasonably good agreement, with the major difference being apparent in the results for the Scottish zones (13 and 14) during the summer. This is a function of the assumed loadings during a time when net electricity flows in these zones are sensitive to actual loading at the time.

Figure 2.3 Comparison between PTI and Oxera adjusted seasonal zonal TLFs based on Oxera market simulation



Source: Oxera.

The overall conclusions are that:

– the University of Edinburgh DC load–flow program produces almost exactly the same AAZ TLFs as the PTI program;
– Oxera's wholesale market model produced credible results and could be used for predicting AAZ TLFs in future years;[8]
– using three load snapshots per year produces reasonably good estimates of AAZ TLFs;
– the overall seasonal result comparison shows reasonable similarities, with BSC Summer indicating larger differences than the other seasons.

2.3 Modelling scenarios

In any energy market modelling exercise, assumptions need to be made about the future development of key underlying inputs into the model. In the case of electricity market modelling, the significant drivers of outturn electricity prices are:

– input fuel costs;
– plant capacities and efficiencies;
– CO_2 emission costs;
– overall electricity demand and changes in the level of embedded generation;
– limits placed on the generation sector—ie, SO_2 and NO_X B limits,[9] and the limitations imposed by plant taking the Large Combustion Plants Directive (LCPD) opt-out derogation.

[8] The accuracy of any model predictions of TLFs will depend on how well the underlying assumptions reflect actual outcomes.

In terms of testing the behaviour of the system under a range of significant input changes, three market scenarios (Central, Gas and Demand) were constructed around variations in input fuel costs (specifically the relative costs of coal and gas) and demand growth. These were:

– Central: mid-range assumptions;
– Gas: lower gas prices;
– Demand: higher demand for electricity.

The inputs used for each scenario and the reasons for them are outlined below.

2.3.1 Central scenario

The following is a brief description of the major assumptions underpinning the Central scenario. With the exception of different assumptions on the level of demand growth and the gas price (discussed in the relevant sections), these assumptions hold across all of the market scenarios.

Fuel price

Each scenario was based on the underlying fossil-fuel prices used by the DTI in its Updated Energy Projections work[10] feeding into the EU Emissions Trading Scheme (EU ETS) Phase II National Allocation Plan (NAP). For the Central scenario, the DTI's central fuel price was used because it reflected current relativities for annual fuel prices, with gas prices being at a premium compared with coal prices. It is plausible that this situation could continue for at least the foreseeable future, making this a suitable choice.

Demand

The demand forecast used in the Central scenario was based on National Grid's 'Base' demand forecast in its 2005 Seven Year Statement. This was selected as it showed relatively modest growth compared with the end-user forecasts, and allowed for a significant degree of demand growth variation between the Central and Demand scenarios.

Renewable growth

The growth in renewable generation was modelled independently using Oxera's Renewables Obligation model. This is to allow growth in different regions of different technologies to be allocated for the purposes of the load–flow modelling. Of principal interest was the growth in onshore wind generation in Scotland and the development of offshore wind, principally in England and Wales, most of which was assumed to become transmission-connected. Also of importance was to ensure that the modelling did not double-count the growth in embedded generation when using National Grid's figures (which are net of embedded generation).

EU Emissions Trading Scheme

Of principal significance here is the assumed path of the EU ETS allowance price across the modelling horizon.[11] The allowance price is fixed during each phase of the EU ETS.

– Phase I, €20/t CO_2: EU ETS allowance prices have varied significantly over recent months, reflecting both changes in some of the underlying fundamentals (increased coal-burn across Europe over the course of 2005) and some of the immaturities in the

[9] The company-specific limits placed on annual power station emissions of SO_2 and NOx.

[10] DTI (2006), 'UK Energy and CO_2 Emissions Projections: Updated Projections to 2020', February.

[11] The EU ETS allowance price will be a determining factor in the decision to switch from coal- to gas-fired generation. The incentive to switch to gas will increase as the EU ETS price rises.

market (many participants have been reluctant to sell until they had a clearer view of their requirements relative to their allocations).

– Phase II, €20/t CO_2: there is still significant uncertainty over Member States' likely emissions caps for Phase II NAPs. At the very least, guidance from the Commission indicates that the caps in Phase I set an upper bound for those in Phase II.[12] This implies that there is likely to be a tightening of overall allowances. However, against this is the potential impact of responses to the EU ETS, with companies changing their usage patterns, by either switching fuel or investing in more energy-efficient technologies. On balance, it would therefore seem prudent to keep allowance prices the same as for Phase I.

– Phase III, €30/t CO_2: it is particularly difficult to predict EU ETS allowance prices during Phase III, principally because some of the fundamental design issues have yet to be resolved (eg, the level of allowances to be auctioned versus those to be grandfathered). However, on an underlying assumption that the EU continues to tackle climate change, one possible baseline becomes the social cost of carbon; in 2005 terms, this is £75/tonne of carbon, or approximately €30/t CO_2.[13]

Environmental limitations
The Central scenario—and indeed the Gas and Demand scenarios—assume that the current coal-fired power stations that have opted for emission limit values (ELVs) under the LCPD will fit flue-gas desulphurisation (FGD) by the start of 2008. Plant that have opted for the National Emission Reduction Plan are able to operate freely under their emissions cap, while plant that have opted out of the Directive will be limited to 20,000 hours of generation between 2008 and 2015.

In addition to the restrictions discussed above, the coal-fired stations in England and Wales are assumed to operate under the annual company B limits for SO_2 and NO_X as set out by the Environment Agency for the periods 2006–08 and post-2008.

Plant closures
The only exogenous closure decisions within the scenarios are those of the existing nuclear fleet. It is assumed that there will be no life extensions of existing nuclear plant (beyond those already announced), resulting in the nuclear closure profile presented in Table 2.3.

[12] European Commission (2005), 'Communication from the Commission: Further Guidance on Allocation Plans for the 2008 to 2012 Trading Period of the EU Emission Trading Scheme', December.
[13] Clarkson, R. and Deyes, K. (2002), 'Estimating the Social Cost of Carbon', prepared for Defra and HM Treasury, Government Economic Service Working Paper 140, January.

Table 2.3 Planned nuclear closures

Plant	Capacity (MW)	Year of closure
Dungeness A	445	2006
Sizewell A	470	2006
Oldbury	475	2008
Wylfa	1,081	2010
Hunterston B	1,190	2011
Hinkley Point B	1,297	2011
Hartlepool	1,210	2014
Heysham 1	1,165	2014

Source: Oxera assumptions.

All other plant closure decisions were based on market outcomes under the different scenarios.

New entry
New entry was deemed to be new combined-cycle gas turbine (CCGT) stations across the modelling horizon. The projects included in the modelling were those that were already significantly advanced but not yet under construction; already had Section 36 consent or were with the DTI for Section 36 consideration; or had been announced in the general press (see Table 2.4). Their on-stream dates are a function of market developments in each of the scenarios. As discussed in more detail later, most of these projects are in advantageous Southern transmission zones.

Table 2.4 Projects used to represent possible new entry

Project	Capacity (MW)	Zone
Langage	1,000	11
Marchwood	850	8
Isle of Grain	1,200	9
Staythorpe stage 1	800	2
Pembroke I	1,000	10
Sutton Bridge CCGT	1,200	1
West Burton CCGT	1,200	2
Uskmouth	800	10
Staythorpe stage 2	800	2
Partington	380	4
Drakelow CCGT	1,200	2
Pembroke II	1,000	10
Milford Haven CCGT	2,000	10
Generic CCGT	1,000	7
Generic CCGT	2,000	2

Source: National Grid, DTI, company press releases.

2.3.2 Alternative business scenarios

In addition to the Central scenario, two other business scenarios were modelled in order to gain greater understanding of the impact of major changes in the underlying market on any conclusions drawn from analysing zonal loss charging.

Gas scenario

The main driving force behind this scenario was to reverse the relative competitiveness of coal- and gas-fired generation and hence the patterns of generation from these plant. To this end, the DTI's central scenario (favouring gas) was chosen, as the rapid decline in gas prices quickly saw gas become the cheaper fuel. In addition to changing the patterns of generation, the results gave an overall lower out-turn wholesale electricity price, allowing an assessment of the extent to which the net benefits are influenced by electricity prices.

Demand scenario

To investigate the impact of bringing forward significant levels of new generation capacity, a second scenario with higher demand growth was used. To achieve this, National Grid's 'High' demand scenario was used. This scenario sees demand for transmission-connected generation grow at a significantly faster rate than in the Central scenario (as shown in Table 2.5). Since the fuel prices are the same as in the Central scenario, the long-term new-entry price is the same as in the Central scenario.

2.3.3 Summary of main scenario drivers

Table 2.5 sets out the main drivers of the Central scenario, as discussed above, and shows the alternative values used in the Demand and Gas scenarios.

Table 2.5 Summary of main scenario drivers and alternative scenario values

Scenario	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
Central										
Coal price (£/tonne ARA)	33	32	30	29	27	27	27	27	26	26
Gas price (p/therm NBP)	46	43	40	37	34	34	34	34	35	35
Peak demand (GW)	62.4	62.9	63.5	64.0	64.1	64.4	64.7	65.0	65.3	65.6
EU ETS allowance price (€/tCO_2)	20	20	20	20	20	20	20	30	30	30
Gas										
Coal price (£/tonne ARA)	33	32	30	29	27	27	27	27	26	26
Gas price (p/therm NBP)	36.4	31.8	27.2	22.6	18.0	18.3	18.6	18.9	19.2	19.5
Demand										
Peak demand (GW)	63.8	65.2	66.7	68.1	69.4	70.6	71.8	73	74.2	75.4

Note: ARA, Amsterdam–Rotterdam–Antwerp; NBP, National Balancing Point.
Source: Oxera.

Oxera notes that the assumptions of prices for gas, coal and EU ETS allowance presented above represent underlying assumptions of the fundamental drivers in these markets. These will not necessarily be the same as the prices currently presented in the forward commodity markets.

2.4 Overall scenario outcomes

The overall market developments under each scenario are described below, setting the scene for the discussion on TLFs and losses in later sections. The out-turn prices are presented in section 3.6.

2.4.1 Central scenario

In the Central scenario, the continued favourability of coal prices means that the coal fleet is well utilised throughout the modelling horizon. For this reason, little in the way of closure of the existing coal stations is seen, with the opt-out plant remaining on the system throughout the period.

Prices dip during the early years on the back of falling fuel costs, but then rise to support new capacity from 2010 onwards following continued demand growth and some early nuclear retirements, with new capacity developing as shown in Table 2.6 below.

Table 2.6 Zonal breakdown of new entry by year under the Central scenario (MW)

Year/zone	1	2	8	9	10	11	Total
2010						1000	1,000
2011			850				850
2012				1,200			1,200
2013		800			1000		1,800
2014	1,200	1,200					2,400
2015					800		800
Total	**1,200**	**2,000**	**850**	**1,200**	**1,800**	**1,000**	**8,050**

Source: Oxera.

2.4.2 Demand scenario

Prices in the Demand scenario fall initially, as in the Central scenario, although the reduction is muted by the higher growth in demand. Prices generally remain higher across the period until they stabilise at new-entry costs from 2010/11 onwards.

Again, the relativities of fuel prices ensure that coal-fired generation is in high demand. There is also increased demand growth; however, the constraints on the coal stations as a result of environmental limitations (LCPD and B limits) mean that there is little scope for them to increase output. Hence, in this scenario, gas-fired output increases to meet the higher demand (rising to 25% above the Central scenario in 2010 and 30% in 2015).

This increased demand growth necessitates the bringing forward of the proposed new projects in the early years and substantially more new investment throughout the modelling horizon. The resulting build programme is as outlined in Table 2.7.

Table 2.7 Zonal breakdown of new entry by year under the Demand scenario (MW)

Year/zone	1	2	4	7	8	9	10	11	Total
2009								1,000	1,000
2010					850	1,200			2,050
2011	1,200	2,000					1,800		5,000
2012		2,000	380						2,380
2013							1,000		1,000
2014				1,000			2,000		3,000
2015		2,000							2,000
Total	**1,200**	**6,000**	**380**	**1,000**	**850**	**1,200**	**4,800**	**1,000**	**16,430**

Source: Oxera.

2.4.3 Gas scenario

As shown in Table 2.8, prices fall significantly more quickly in the Gas scenario than in the Central scenario, driven by the rapid decline in underlying gas prices.

The reduction in gas prices also results in a bringing forward of new investment, as the lower gas price in relation to coal improves the value of a new CCGT compared with the Central scenario.

The lower gas prices and subsequent increase in new build in this scenario raises gas-fired output compared with the Central scenario (gas-burn is 25% higher by 2010 and 40% higher by 2015). This increase comes at the expense of coal-fired production, with output being reduced by 50% compared with the Central scenario by 2010 and 60% by 2015.

Table 2.8 Zonal breakdown of new entry by year under the Gas scenario (MW)

Year/zone	1	2	4	8	9	10	11	Total
2009							1,000	1,000
2010				850	1,200			2,050
2011		800						800
2012						1,000		1,000
2013	1,200	1,200						2,400
2014		800	380			800		1,980
2015		1,200						1,200
Total	**1,200**	**4,000**	**380**	**850**	**1,200**	**1,800**	**1,000**	**10,430**

Source: Oxera.

2.4.4 Seasonal scenario

The Seasonal scenario was a variant of the TLF methodology based around the Central scenario. Therefore, the market outcomes were as in the Central scenario.

3 Modelling results

The findings of the joint load–flow/market modelling exercise are summarised in this section. In the following analysis, the mapping of regions and zones is as set out in Table 3.1.

Table 3.1 TLF zone and GSP groups

Geographic location (North–South)	TLF zone	GSP group	GSP group description
1	14	P	North Scotland
2	13	N	South Scotland
3	6	F	Northern
4	7	G	North Western
5	12	M	Yorkshire
6	4	D	Merseyside & North Wales
7	2	B	East Midlands
8	5	E	Midlands
9	1	A	Eastern
10	10	K	South Wales
11	9	J	South Eastern
12	3	C	London
13	8	H	Southern
14	11	L	South Western

Source: ELEXON.

3.1 Estimated adjusted annual zonal TLFs

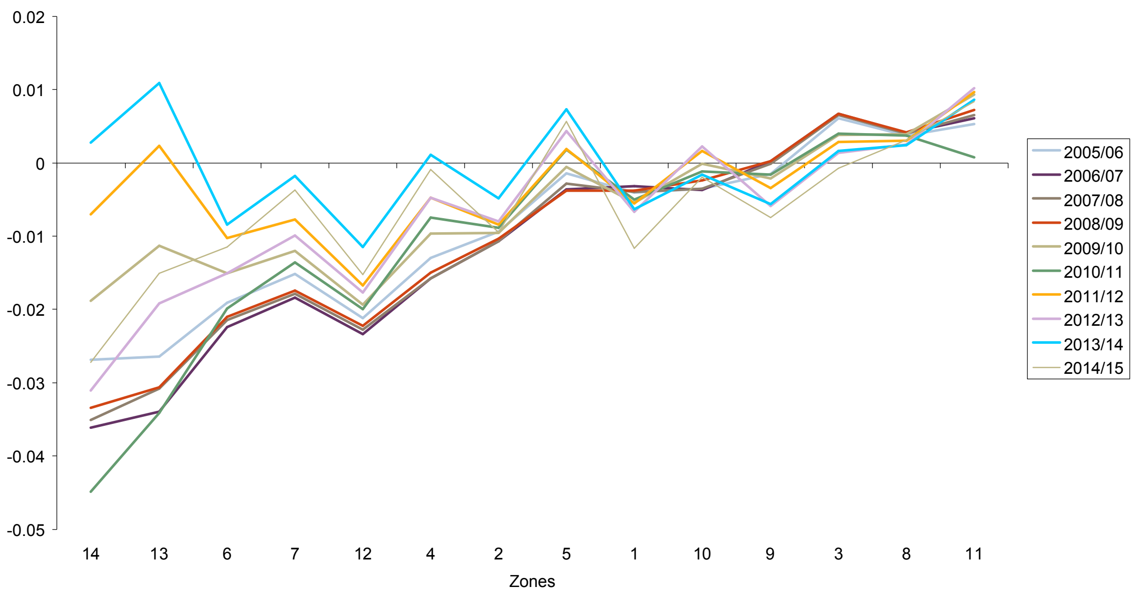
The evolution of AAZ TLFs across the modelling horizon for each of the scenarios modelled is presented below. The TLMs faced by generators and suppliers will be equal to zonal TLFs shifted uniformly by such an amount that the exact level of losses is recovered and in the correct proportion (45:55). Thus, the values of the shift will change, and can, in theory, be different in every settlement period. Hence, in this report, the values of zonal TLFs will be shown, which stay constant for a given year, rather than actual TLMs faced by generators and suppliers, as these change for every settlement period.

3.1.1 Central scenario

Figure 3.1 shows the evolution of AAZ TLFs under the Central scenario. The high volatility exhibited in the AAZ TLFs across the period, especially in Scotland (zones 13, 14), suggests that the influence of P198 could be quite strong in Scotland, which produces only about 10% of GB generation but has an extensive and remote transmission network. Hence, even small changes in Scottish generation patterns have a significant influence on the values of AAZ TLFs, as is demonstrated most clearly in 2013/14 when the Scottish AAZ TLFs become positive. This is attributable to the closure of the Hunterston nuclear power station within the Southern Scotland zone. The loss of this 1.2 GW of baseload capacity results in Scotland changing from a net exporter during the three snapshot periods modelled to a net importer, with the subsequent positive AAZ TLF. This result is particularly sensitive to the output of Longannet, with the station acting close to the marginal generator during the mid-demand period snapshots, and thereby resulting in some large output changes for small changes in market conditions.

A considerable variability, although less severe than that in Scotland, can be observed in other zones, with the exception of zones 1, 2, 3, 8, 9 (Eastern, East Midlands, London, Southern, and South Eastern), where the AAZ TLFs remain reasonably constant.

Figure 3.1 Adjusted annual zonal TLFs for the Central scenario

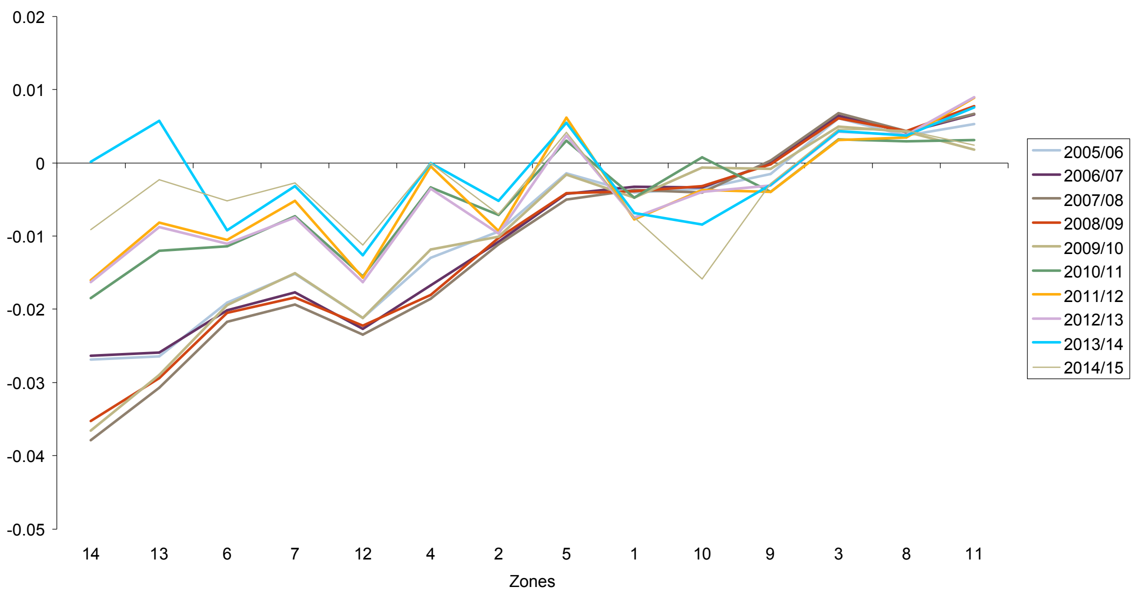


Source: Oxera.

3.1.2 Demand scenario

Figure 3.2 shows the results for the Demand scenario. Here, the changes are similar. For 2007–09, AAZ TLFs become more negative in zones 13, 14, placing sharper signals on Scottish generators. AAZ TLFs rise in Scotland, reaching positive values in 2014/15.

Figure 3.2 Adjusted annual zonal TLFs for the Demand scenario

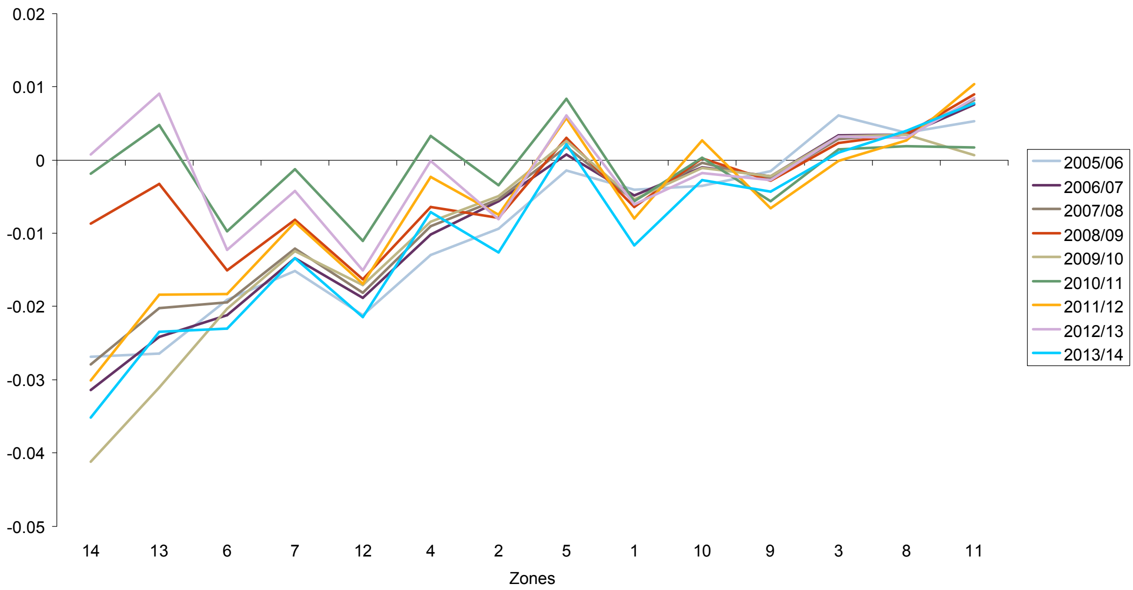


Source: Oxera.

3.1.3 Gas scenario

Figure 3.3 shows the results for the Gas scenario. In Scotland, AAZ TLFs remain relatively constant in years 2006/07, 2007/08, 2011/12 and 2013/14. In 2009/10 they become more negative. In years 2008/09, 2010/11 and 2012/13, they exhibit an upward trend, becoming positive in 2010/11 and 2012/13. Other zones remain relatively constant, with the exception of zones 4, 5, 6, 7 (Merseyside & North Wales, Midlands, Northern and North Western).

Figure 3.3 Adjusted annual zonal TLFs for the Gas scenario



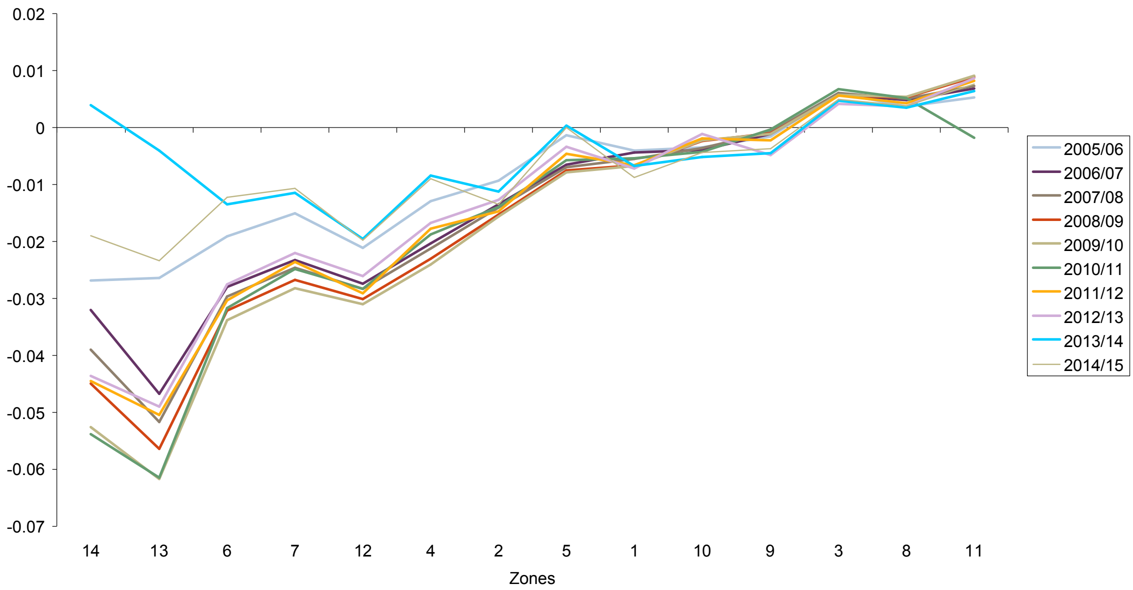
Source: Oxera.

3.1.4 Seasonal sensitivity

Figures 3.4–3.7 show changes in seasonal TLFs—2005/06 AAZ TLFs are annual averages, while the remaining ones are seasonal. In BSC Winter network flows are heavier and seasonal AAZ TLFs are therefore below annual averages. For other seasons the comparison is less clear. In general, seasonal AAZ TLFs exhibit a similar volatility, as they seem to be less volatile than annual AAZ TLFs, especially for Scotland. The seasonal months are defined as follows:

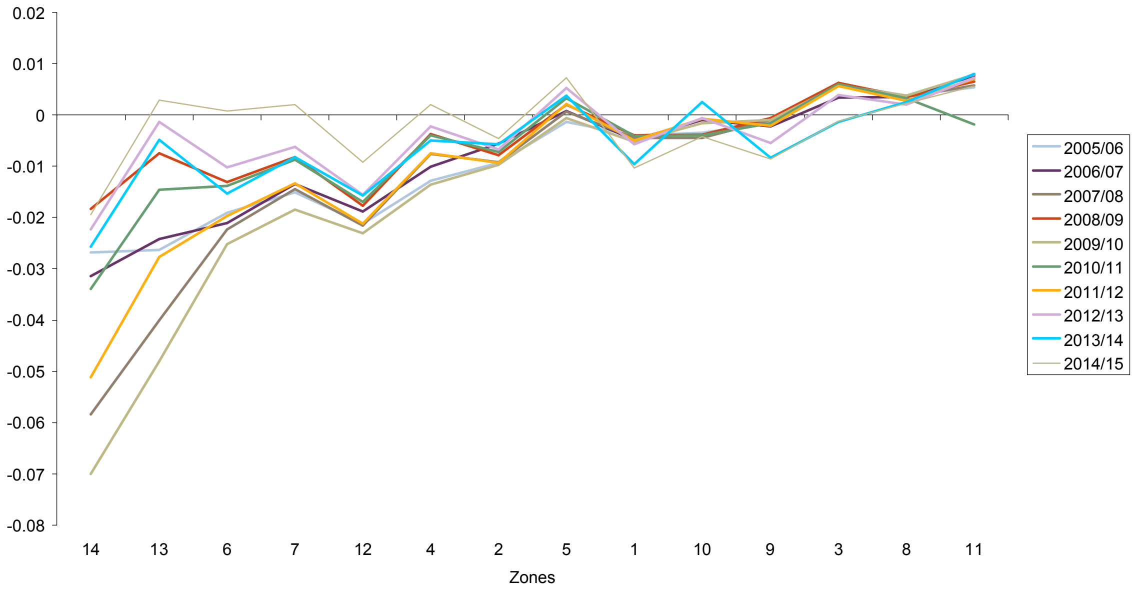
BSC Winter	Dec–Feb;
BSC Spring	Mar–May
BSC Summer	Jun–Aug
BSC Autumn	Sep–Nov

Figure 3.4 Adjusted seasonal zonal TLFs for BSC Winter



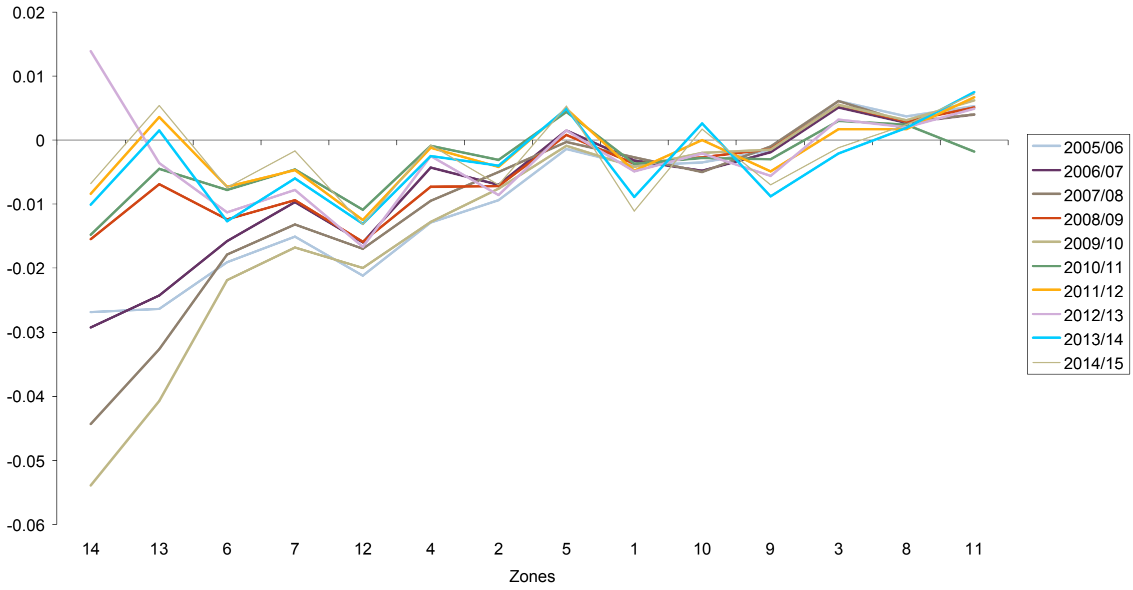
Source: Oxera.

Figure 3.5 Adjusted seasonal zonal TLFs for BSC Spring



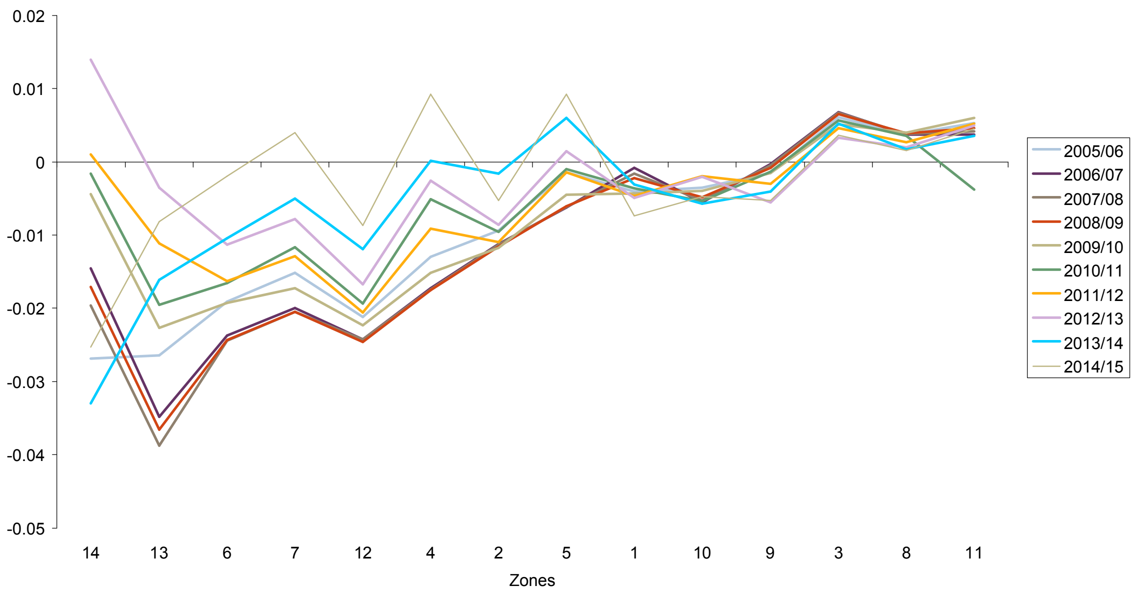
Source: Oxera.

Figure 3.6 Adjusted seasonal zonal TLFs for BSC Summer



Source: Oxera.

Figure 3.7 Adjusted seasonal zonal TLFs for BSC Autumn



Source: Oxera.

Overall, across all scenarios, the signals for generators in the Scottish zones are higher than those on generators in the England and Wales, although the Northern, North Western and Yorkshire zones also face significant signals. The results in the Scottish zones are, however, much more sensitive to loading changes than those in England and Wales, exhibiting higher volatility, especially after 2010/11, as a result of the closure of Hunterston power station tightening the supply/demand balance in Scotland. The resultant AAZ TLFs are therefore sensitive to the output of Longannet, which operates close to the marginal plant for significant periods of time in some scenarios.

3.2 Patterns of generation during snapshot periods

The impact of zonal loss charging on the pattern of generation has been analysed both for the snapshot demand periods used for the load–flow modelling and for the full wholesale market modelling subsequently undertaken.

Uniform and zonal condition results from the load–flow model were compared to calculate the loss difference in each scenario. Outputs from the despatch model at each generator were aggregated by zone and, independently, by fuel type to obtain information on where generation had shifted from plant to plant (ie, the redespatch).

Tables 3.2–3.4 below show the effects on despatch and losses under the Central, Gas, Demand and Seasonal scenarios. All show a reduction in overall losses under a zonal loss charging system in the short term, as would be expected with the more efficient signals and sufficient generation capacity. A significant degree of zonal relocation of generation is observed in all scenarios, usually from Scottish and Northern English zones into central and Southern English zones. To a much lesser extent, the results show changes in the profile of fuel mix. This is usually, but not exclusively, a change from coal to gas, a large proportion of which may be explained by the zonal shift away from Scotland, which contains proportionally more coal plants.

Broadly, the results support the intuitive conclusion that the larger the redespatch, the higher the loss reductions.

3.2.1 Central scenario

The modelling shows a general trend of a shift in generation from North to South under a zonal loss charging regime, resulting in a net reduction in overall losses in earlier years. This pattern broadly continues in later years. In the peak period, Eastern Zone plants appear to be the primary beneficiaries; in the trough, South Eastern plants gain the most. Plants in the Yorkshire and South Scotland zones are frequently redespatched under a zonal loss charging structure.

Table 3.2 Change in despatch and losses under the Central scenario

	Peak		Mid		Trough	
Year	**Redespatch**	**Loss change (MW)**	**Redespatch**	**Loss change (MW)**	**Redespatch**	**Loss change (MW)**
2006/07	148 MW from North Western into Eastern	–5.3	No change	0	2,488 MW from Yorkshire and South Scotland into East Midlands and South Eastern	–61.4
2007/08	148 MW from North Western into Eastern	–10.5	401 MW from Merseyside & North Wales into East Midlands	–9.1	2,768 MW from Yorkshire, South Scotland, North Scotland into East Midlands, South Eastern, South Wales	–119.9
2008/09	854 MW from Yorkshire and North Western into Eastern	–55.8	No change	0	1,503 MW from Yorkshire and North Scotland into Southern and South Wales. 153 MW from gas generation into coal	–40.5
2009/10	854 MW from Yorkshire and North Western into Eastern	–40.9	1538 MW from South Scotland into East Midlands and Midlands	–50.9	1,737 MW from Yorkshire and Northern into South Eastern and South Wales	–38.8
2010/11	854 MW from Yorkshire and North Western into Eastern	–53.5	213 MW coal generation from East Midlands into gas generation in Eastern	–0.3	687 MW from Yorkshire into South Eastern	–16
2011/12	216 MW from Yorkshire into Eastern	–11.5	1,477 MW from South Scotland into Eastern, East Midlands and Midlands (557 MW coal generation into gas)	–18.5	1,444 MW from Northern and Yorkshire into South Eastern	–24.9

Source: Oxera.

3.2.2 Demand scenario

Loss savings overall are higher in the Demand scenario, particularly during the mid snapshot. Some large shifts in generation location occur in the trough, still following the general North to South trend. Overall, zonal movement is lower than in the Central scenario.

Table 3.3 Change in despatch and losses under the Demand scenario

	Peak		Mid		Trough	
Year	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)
2006/07	854 MW from North Western, Yorkshire into Eastern	–33.7	No change	0	2,088 MW from South Scotland into East Midlands, Southern, South Eastern	–56.7
2007/08	51 MW from Merseyside & North Wales into East Midlands	–1.5	364 MW from South Scotland into South Eastern, South Wales (180 MW from coal into gas)	–25.6	2,240 MW from South Scotland, Yorkshire into South Eastern, East Midlands, South Wales (207 MW from coal into gas)	–135.6
2008/09	250 MW from Yorkshire into Eastern	–12.7	960 MW from South Scotland into Eastern, South Eastern, South Wales (905 MW from coal into gas)	–81.9	1,350 MW from Yorkshire, North Scotland into Southern (69 MW from coal into gas)	–49.1
2009/10	250 MW from Yorkshire into Eastern	–12.7	123 MW from Merseyside & North Wales into East Midlands	–1.7	350 MW from Yorkshire into South Eastern	–6.9
2010/11	250 MW from Yorkshire into Eastern	–11.1	971 MW from South Scotland, Yorkshire into Midlands, Eastern	–39.1	1,334 MW from South Eastern into Yorkshire, Northern	–11.8
2011/12	854 MW from North Western, Yorkshire into Eastern, South Eastern	–32.6	453 MW from East Midlands into Eastern	2	No change	0

Source: Oxera.

3.2.3 Gas scenario

The Gas scenario shows a similar pattern of North to South generation movement, but in greater volumes in the peak and mid periods. Conversely, redespatch in the trough period is significantly lower than in the Central scenario. Loss savings are consistently high in the mid period throughout the short to medium term, but much less in the earlier years in the trough.

Table 3.4 Change in despatch and losses under the Gas scenario

	Peak		Mid		Trough	
Year	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)
2006/07	208 MW from North Western, Yorkshire into Eastern	–16.8	1,632 MW from Yorkshire, East Midlands, South Scotland into Southern (519 MW from gas into coal)	–51.3	140 MW from North Western into South Eastern	–5.7
2007/08	470 MW from North Western, Yorkshire into Eastern	–31.2	1,632 MW from East Midlands, Yorkshire, South Scotland into Southern	–87.2	78 MW gas in Northern into coal in Midlands	–1.5
2008/09	854 MW from North Western, Yorkshire into Eastern	–55.8	3,041 MW from Northern, Yorkshire, South Scotland into East Midlands and Southern	–63.9	183 MW from Northern into East Midlands	1.3
2009/10	922 MW gas from East Midlands, Northern into coal in Midlands	–19.9	2,340 MW from East Midlands, Northern, Yorkshire into South Scotland, Southern	–50.2	234 MW from Yorkshire into Eastern	–2.3
2010/11	2,280 MW from South Scotland into East Midlands, Southern	–118.3	2,497 MW from Northern, Yorkshire, South Scotland into East Midlands, Southern	–34.7	190 MW from Merseyside and North Wales into East Midlands	–0.9
2011/12	130 MW from Northern into Southern	–7.7	1,598 MW from Northern, Yorkshire into East Midlands, Southern, South Scotland	–49.7	15 MW from Northern into North Western	0

Source: Oxera.

3.2.4 Seasonal sensitivity

Tables 3.5–3.7 below show seasonal variation in redespatch and losses when seasonal loss factors are used. Season 3 (June–August), the season of lowest demand, typically displays the highest amount of redespatch. This is in line with results from the Demand scenario. Under low demand conditions, fewer plants are running at full load, power exchange bids are closer, and zonal loss charging has a comparatively greater effect.

Table 3.5 Peak demand period under seasonal scenarios

	BSC Winter		BSC Spring		BSC Summer		BSC Autumn	
	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)
2006/07	247 MW from Yorkshire into Eastern	–12.2	801 MW from North Western, Yorkshire into Eastern	100.4	No change	0	36 MW from Yorkshire into Eastern	–1.6
2007/08	247 MW from Yorkshire into Eastern	–12	801 MW from North Western, Yorkshire into Eastern	–30.8	893 MW from South Scotland into Merseyside & North Wales, South Wales. 709 MW from coal into CCGT	–45.7	63 MW from Merseyside & North Wales into East Midlands	–1.4
2008/09	186 MW from Northern into East Midlands	–5.7	662 MW from North Western, Yorkshire into Eastern	–23	334 MW from South Scotland into Eastern, South Wales. 709 MW from coal into CCGT	7.8	53 MW from Merseyside & North Wales into East Midlands	–1.3
2009/10	323 MW from Northern into East Midlands	–19.3	551 MW from Yorkshire into Eastern	–30.7	No change	0	923 MW from South Scotland into Eastern, South Wales	–70
2010/11	201 MW from Northern into East Midlands	–6	800 MW from North Western, Yorkshire into Eastern	–29.9	732 MW from South Scotland into Midlands	–44.7	800 MW from Northern into East Midlands, North Western	–26.7
2011/12	1,437 MW from Northern into East Midlands, North Western, Yorkshire	–36.7	No change	0	No change	0	335 MW from Northern into East Midlands	–18.7

Source: Oxera.

Table 3.6 Trough demand period under seasonal scenarios

	BSC Winter		BSC Spring		BSC Summer		BSC Autumn	
	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)
2006/07	786 MW from South Scotland into Eastern, South Wales	–85.7	2,088 MW from South Scotland into Southern, South Eastern	–78	3118 MW from Northern, South Scotland, North Scotland into East Midlands, Merseyside & North Wales, South Eastern, South Wales. 142 MW from CCGT into coal	–113.3	1,750 MW from South Scotland into Southern	–143.9
2007/08	800 MW from South Scotland into Eastern, South Wales	–91.6	2,109 MW from South Scotland, North Scotland into Merseyside & North Wales, South Eastern, South Wales. 650 MW from coal into CCGT	–150.4	938 MW from Northern, Yorkshire into South Eastern	–14.9	1,709 MW from Yorkshire, South Scotland into Southern	–138
2008/09	775 MW from South Scotland into Eastern	–88.7	2084 MW from Northern, Yorkshire, North Scotland into Southern. 650 MW from coal into CCGT	–58.9	898 MW from Northern, Yorkshire into South Eastern	–10.8	2,088 MW from South Scotland into London, Southern	–149.1
2009/10	760 MW from South Scotland into Eastern	–92.9	No change	0	1540 MW from Northern, Yorkshire into South Eastern	–39.1	3,375 MW from Northern, Yorkshire, South Scotland into East Midlands, Southern	–212.8
2010/11	809 MW from South Scotland into London, South Western. 809 MW from coal into CCGT	–66	1,737 MW from Northern, Yorkshire into South Eastern, South Wales	–35.1	546 MW from Eastern, North Western, Yorkshire into South Eastern	–4.5	4,071 MW from East Midlands, Northern, Yorkshire, South Scotland into Southern, South Eastern, South Western. 2,296 MW from coal into CCGT	–218.6
2011/12	1140 MW from South Scotland into Eastern, London. 809 MW from coal into CCGT	–102	No change	0	853 MW from Yorkshire into South Eastern	–6.9	3,825 MW from Northern, Yorkshire, South Scotland into Eastern, East Midlands, Southern, South Eastern. 2,296 MW from coal into CCGT	–151.7

Source: Oxera.

Table 3.7 Midpoint demand period under seasonal scenarios

	BSC Winter		BSC Spring		BSC Summer		BSC Autumn	
	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)
2006/07	155 MW from East Midlands into Eastern	–46.2	1,044 MW from North Scotland into East Midlands, Midlands. 1,044 MW from CCGT into coal	–105	1,625 MW from Yorkshire, South Scotland into Southern. 585 MW from CCGT into coal	–71.5	213 MW from Eastern into South Eastern	–3.3
2007/08	124 MW from East Midlands into Eastern	–36.6	701 MW from Yorkshire into Southern. 675 MW from CCGT into coal	–30.1	1792 MW from East Midlands, Yorkshire into Merseyside & North Wales, Southern. 160 MW from coal into CCGT	–61.3	444 MW from Eastern into South Eastern	–5.6
2008/09	912 MW from Yorkshire into Eastern	–43.3	2088 MW from South Scotland into East Midlands, Southern. 675 MW from CCGT into coal	–111.5	2549 MW from Northern, South Scotland into East Midlands, Southern. 160 MW from coal into CCGT	–72.3	587 MW from Eastern, East Midlands into South Eastern	–11.5
2009/10	942 MW from Yorkshire into Eastern	–45.2	1474 MW from East Midlands, Yorkshire into Southern	–69.2	1632 MW from East Midlands, Yorkshire into Southern	–63.2	1065 MW from East Midlands, South Scotland into Eastern, South Eastern, South Wales. 844 MW from coal into CCGT	–68.6
2010/11	109 MW from East Midlands into Eastern, South Eastern	–40.6	2296 MW from Northern, South Scotland into Southern, South Eastern. 630 MW from coal into CCGT	–163	2012 MW from Northern, Yorkshire, South Scotland into East Midlands, Southern	–44.7	No change	0
2011/12	68 MW from North Scotland into South Wales	–5.7	512 MW from South Scotland into Southern. 630 MW from coal into CCGT	–41.3	1955 MW from Yorkshire, South Scotland into East Midlands, Southern	–36.8	237 MW from South Scotland into North Scotland	–8.4

Source: Oxera.

In summary, the introduction of zonal loss charging does have an impact on despatch decisions, resulting in a general shift of generation from North to South across all scenarios. The magnitude of loss savings reacts as expected, increasing as the size of the shift increases.

3.3 Changes in annual zonal output

Tables 3.8–3.11 show how the application of estimated zonal TLMs affected the geographical pattern of generation compared with outcomes under uniform loss charging, with Oxera's model run across the whole year rather than for snapshot periods. These figures were calculated aggregating the annual output figures from the full-year results within the despatch model to zonal and fuel levels. Zonal results were subtracted from uniform results to obtain differences between the charging regimes.

3.3.1 Central scenario

The Central scenario shows a general pattern of generation moving away from Yorkshire and Scotland plants towards Southern and South Eastern zones. This pattern is evident to a greater or lesser extent in all of the scenarios.

Table 3.8 Changes in annual output by zone in the Central scenario (GWh)

GSP Group description	2006	2007	2008	2009	2010	2011
Eastern	557	777	884	695	1,147	1,334
East Midlands	960	181	310	488	–2160	–60
London	0	6	5	12	55	60
Merseyside & North Wales	–20	–22	–642	–351	488	105
Midlands	–103	–104	0	0	0	0
Northern	–533	–603	–362	–393	0	0
North Western	–50	–131	–107	–124	–94	–69
Southern	91	165	1,442	909	599	412
South Eastern	150	419	639	123	799	233
South Wales	5	7	90	47	35	36
South Western	0	0	0	26	9	–7
Yorkshire	–1,140	–918	–1,286	–1,408	–946	–1,233
South Scotland	–1	–1	0	0	0	–274
North Scotland	–5	–11	–1,081	–443	–4	–700
Reduction in losses	**90**	**235**	**107**	**420**	**73**	**163**

Source: Oxera.

Of particular note within this scenario is the significant change in the zonal impact for the East Midlands region in 2010 (with large movements out of the region compared with earlier years). This is a result of the year-on-year fuel changes and the relationship between gas and coal generation in the merit orders. In 2010 the relative gas and coal prices are such that the movement from uniform to zonal TLMs changes the merit-order positions of a coal-fired station in East Midlands and a number of gas-fired plant in other regions during the summer months. The net effect is that the gas stations run ahead of the coal station during the summer, a situation that does not arise with the combinations of fuel prices and demand conditions in other years.

3.3.2 Demand scenario

The Demand scenario shows less overall shift away from Yorkshire and Scotland in comparison with the Central scenario. The pattern of zonal generation shift is broadly the same, although estimates of generation in the East Midlands are less volatile than in the Central scenario.

Table 3.9 Changes in annual output by zone in the Demand scenario (GWh)

GSP Group description	2006	2007	2008	2009	2010	2011
Eastern	730	618	360	513	1,631	1,444
East Midlands	616	523	686	752	133	–1,103
London	2	8	10	8	29	11
Merseyside & North Wales	–190	62	–336	–196	55	1
Midlands	5	–3	0	0	0	0
Northern	–609	–836	–671	–742	–350	0
North Western	–159	–101	–145	–132	–155	–77
Southern	–70	–46	444	481	379	302
South Eastern	240	29	184	371	678	531
South Wales	3	2	17	–63	45	94
South Western	0	0	–3	1	–6	–6
Yorkshire	–665	–596	–811	–803	–1,171	–1,145
South Scotland	–7	–2	–1	0	–1,101	0
North Scotland	–5	–12	–343	–221	–450	–69
Reduction in losses	**109**	**355**	**609**	**32**	**281**	**16**

Source: Oxera.

3.3.3 Gas scenario

Estimates in the Gas scenario indicate stronger movement away from the Northern zones, particularly Northern and South Scotland.

Table 3.10 Changes in annual output by zone in the Gas scenario (GWh)

GSP Group description	2006	2007	2008	2009	2010	2011
Eastern	347	447	353	35	62	77
East Midlands	1,577	945	4,508	1,011	6,307	2,251
London	1	–1	–2	–1	1	0
Merseyside & North Wales	–48	–121	–206	–7	–14	–5
Midlands	45	53	–45	583	164	101
Northern	–1,255	–1,960	–1,429	–2,502	–1,883	–3,979
North Western	–113	–105	–19	0	26	94
Southern	132	6	0	336	2,837	3,030
South Eastern	0	83	46	68	108	23
South Wales	15	7	55	–16	–15	–19
South Western	–2	–1	0	0	–1	0
Yorkshire	–1,041	70	–827	–2466	–1,072	–3,828
South Scotland	–4	–2	–2,896	2,614	–6,853	1,926
North Scotland	–3	–16	–1	–1	0	0
Reduction in losses	**349**	**595**	**463**	**346**	**334**	**328**

Source: Oxera.

3.3.4 Seasonal scenario

The Seasonal scenario follows the same overall pattern of zonal shift as the Central scenario, although some variation in magnitude of shift occurs. Output changes are substantially lower in Yorkshire in the seasonal breakdown.

Table 3.11 Changes in annual output by zone in the Seasonal scenario (GWh)

GSP Group description	2006	2007	2008	2009	2010	2011
Eastern	572	546	930	938	2,952	1,142
East Midlands	1,033	502	286	294	–582	–150
London	0	4	4	6	20	44
Merseyside & North Wales	–69	–21	–530	–555	352	89
Midlands	–126	–25	0	0	0	0
Northern	–1,149	–1,147	–604	–429	0	0
North Western	–140	–116	–122	–129	–72	–163
Southern	182	327	1,220	1,187	842	287
South Eastern	150	139	203	148	779	235
South Wales	3	4	–26	88	44	26
South Western	0	0	–1	25	4	–15
Yorkshire	–939	–588	–1,079	–1,034	–860	–1,426
South Scotland	0	5	0	0	–2,943	–1
North Scotland	–21	–14	–792	–1,099	–1,097	–342
Reduction in losses	**504**	**383**	**512**	**559**	**559**	**272**

Source: Oxera.

As identified in section 3.3 above, zonal loss charging results in switching of generation away from the North towards the South in the snapshot periods. The results in this section show that this pattern holds across the year overall. The Gas scenario sees the greatest shifts in generation patterns, with larger transfers between gas and coal resulting in changes in generation locational patterns following the introduction of zonal losses. The Demand scenario sees slightly less overall fuel switching, as more of the generation fleet is needed to match demand, especially in the early years.

3.3.5 Impact on 132kV connected generation

One of the issues in the terms of reference to be addressed was whether the introduction of P198 would affect geographically proximate generation connected to different voltage levels, and whether the fact that 132kV connected generation incurs more losses sharpens the despatch signals or indeed discourages investment in, and connection to, the 132kV system.

There is no difference in the signals faced by a 132kV generator compared with one connected to a higher voltage, either geographically proximate or within the same TLF zone. This is a direct result of the zonal averaging used in the P198 methodology, whereby ***all*** generators within any zone use the same AAZ TLF throughout the year to calculate their TLMs. As discussed previously, given that some of the generators within a zone are connected to the 132kV network, that zone's AAZ TLF will be worse. However, again, this affects all generators, not just those connected to 132kV.

In terms of ongoing decisions to connect to higher voltages, any new plant choosing to do so will have a minor impact on the zone's AAZ TLFs for future years. However, again, the impact on the individual generator will be greatly muted via the marginal change in the overall AZZ TLFs for the entire zone rather than just for its new connection.

3.4 Changes in output by fuel type

3.4.1 Central scenario

Modelling in the Central scenario indicates a significant degree of interchange between coal- and gas-fired generation, with gas generation being favoured to a large extent from 2007 onwards (see Table 3.12). There is a minor shift towards oil, pumped storage and OCGT in 2010/11, but few changes in other fuel types otherwise.

Table 3.12 Changes in annual output by fuel type in the Central scenario (GWh)

Fuel type	2006	2007	2008	2009	2010	2011
Oil	6	–1	–1	–3	72	–6
Coal	274	–276	54	–256	–2,295	–313
AGR	0	0	0	0	0	0
PWR	0	0	0	0	0	0
Magnox	0	0	0	0	0	0
Pumped storage	–6	0	0	0	28	1
Hydro	0	0	0	0	0	0
External	0	0	0	0	0	0
OCGT	0	0	0	0	24	–5
CCGT	–364	43	–160	–160	2,096	160
CHP	0	0	0	0	0	0
Other	0	0	0	0	4	–1
Reduction in losses	**90**	**235**	**107**	**420**	**73**	**163**

Source: Oxera.

3.4.2 Demand scenario

Estimates of fuel change in the Demand scenario are lower than in the Central scenario, particularly in the earlier years (see Table 3.13). This is likely to be due to increased load factor in the early years of the gas plant (coal stations are limited in their ability to respond to demand increases due to environmental limitations), with the introduction of zonal loss charging resulting in redespatches between these plant.

Table 3.13 Changes in annual output by fuel type in the Demand scenario (GWh)

Fuel type	2006	2007	2008	2009	2010	2011
Oil	0	–1	–10	0	–6	0
Coal	92	9	7	–74	–1,187	–1,101
AGR	0	0	0	0	0	0
PWR	0	0	0	0	0	0
Magnox	0	0	0	0	0	0
Pumped storage	–1	–5	1	0	–2	0
Hydro	0	0	0	0	0	0
External	0	0	0	0	0	0
OCGT	0	0	–6	0	–2	0
CCGT	–199	–358	–601	43	916	1,080
CHP	0	0	0	0	0	0
Other	0	0	0	0	–1	0
Reduction in losses	**109**	**355**	**609**	**32**	**281**	**16**

Source: Oxera.

3.4.3 Gas scenario

Results in the Gas scenario suggest that there is movement away from gas between the uniform and zonal regimes in the early years (see Table 3.14). This is due to the transition of the gas price from being generally higher than coal to being relatively cheaper than coal. As the gas price falls, less efficient CCGT start operating at higher load factors, interacting more with some of the lower-efficiency coal stations. The interlacing of these plants mean that, under zonal loss charging, coal plants in the South become more competitive than Northern gas plants, resulting in the subsequent movement away from gas to coal. In the later years, the relative values of gas and coal mean that the introduction of zonal losses results in switching of despatch within plant types (ie, coal and gas), rather than between them.

Table 3.14 Changes in annual output by fuel in the Gas scenario (GWh)

	2006	2007	2008	2009	2010	2011
Oil	0	0	–1	–1	0	0
Coal	469	455	–465	236	–294	–289
AGR	0	0	0	0	0	0
PWR	0	0	0	0	0	0
Magnox	0	0	0	0	0	0
Pumped storage	0	0	–1	0	0	0
Hydro	0	0	0	0	0	0
External	0	0	0	0	0	0
OCGT	–2	–4	–3	–1	0	0
CCGT	–816	–1046	6	–580	–39	–39
CHP	0	0	0	0	0	0
Other	0	0	0	0	0	0
Reduction in losses	**349**	**595**	**463**	**346**	**334**	**328**

Source: Oxera.

3.4.4 Seasonal scenario

As shown in Table 3.15, the results for the Seasonal scenario broadly mirror the pattern observed in the Central scenario, with large movements away from coal generation and into gas after 2006/07.

Table 3.15 Changes in annual output by fuel in the seasonal scenario (GWh)

Fuel type	2006	2007	2008	2009	2010	2011
Oil	5	–2	–4	–4	–9	–9
Coal	272	–70	–55	–250	–3424	–91
AGR	0	0	0	0	0	0
PWR	0	0	0	0	0	0
Magnox	0	0	0	0	0	0
Pumped storage	–7	0	0	0	–3	0
Hydro	0	0	0	0	0	0
External	0	0	0	0	0	0
OCGT	0	0	0	0	–3	–6
CCGT	–773	–310	–453	–304	2880	–166
CHP	0	0	0	0	0	0
Other	0	0	0	0	0	–1
Reduction in losses	**504**	**383**	**512**	**559**	**559**	**272**

Source: Oxera.

The introduction of zonal loss charging results in fuel switching in all scenarios, particularly in the near term. The increased interlacing of gas and coal plants in the merit stack during the lowering of gas prices in the Gas scenario results in higher shifts between these two generation types when compared with the other scenarios. This is in addition to higher overall transfers between zones (as identified above).

3.5 Impact on losses

Tables 3.17 to 3.20 below present the estimated change in losses obtained from the load–flow modelling. Annual loss savings are calculated by time-weighting the loss savings in each snapshot period to gross them up to annual figures. Two factors should be noted here:

– the snapshot losses are highly dependent on the exact configuration of the network and its loading. Therefore the estimated loss savings can show significant variations year-on-year and between scenarios; and
– the savings in losses only relate to their variable component. Inspection of National Grid’s Seven Year Statement shows that, indicatively, the variable proportion of losses ranges from 55% to 60%, with the remainder of the losses being fixed. To estimate the overall impact on total losses, the percentage of variable losses in Tables 3.18 to 3.21 has been multiplied by 60% to show the impact on total losses.

There are two significant differences between the results in the Oxera (2003) paper, and those presented below: an overall upward movement in energy costs and a change in the approach used to estimate loss savings.

3.5.1 Change in underlying prices

The first difference is a fundamental increase in underlying energy costs. The value of any loss savings is directly proportional to the cost of electricity displaced. Global energy prices have risen significantly since 2003, and as a result the electricity costs used in this analysis are approximately twice the levels used in the 2003 analysis.

3.5.2 Change in loss estimation approach

In the previous Oxera modelling work, two methods were identified for estimating the value of loss savings. Table 3.16 describes the methods and their advantages and disadvantages.

Table 3.16 Methods of estimating the loss impact of changes in despatch

	Method	Advantage	Disadvantage
1	Multiplication of nodal TLFs[1] from the load–flow modelling to the estimated changes in the output of individual plant produced by running the wholesale market model across the whole year	Relatively realistic assessment of how plant outputs may change across the year as a whole following the application of AAZ TLFs	Nodal TLFs are highly volatile—they depend on the specific loading conditions of the network, and are affected by changes in despatch.[2] For some plant, the net change in annual output may aggregate positive and negative changes with separate loss impacts
2	Extrapolation of results from snapshot demand periods using time-weighting factors	For the snapshot periods, the estimates for the change in losses are relatively robust as they are generated by full load–flow modelling	Three snapshot periods are unlikely to be representative of the year as a whole; time-weighting factors place very high weight on single snapshot period (midpoint)

Note: [1] Nodal TLFs give the marginal change in losses for a change in flows at a node, but are specific to a particular loading condition of the network. TLFs assess the marginal change in losses due to a small change in output. For large changes in output, the marginal reduction in losses due to further alterations in output is likely to fall.
Source: Oxera.

In addition to the disadvantages of method 1, there is the added complexity that the TLFs are only valid for marginal changes in output, and therefore not valid across a whole range of generation changes. Given that the modelling approach uses snapshot periods as a proxy for actual generation and demand patterns throughout the year, and that the actual losses are calculated on the basis of these system loadings, it is now considered that method 2 provides a better estimate of the loss savings.

As a result of these changes—in both underlying prices and loss estimation approach—the values presented in this report will be higher than those presented in 2003.

3.5.3 Near-term loss impacts

The following tables show the impact of zonal loss charging out to 2011/12. Information is presented on:

– estimated annual loss savings—from the snapshot load–flow modelling;
– total energy produced—the total annual demand on the generators prior to zonal loss charging;
– the percentage of total energy produced that the loss savings represent;
– the estimated *variable* transmission losses from the load–flow modelling under uniform loss charging;
– the estimated loss savings as a percentage of the variable transmission losses;
– the estimated *total* transmission losses from the load–flow modelling under uniform loss charging;
– the estimated loss savings as a percentage of the total transmission losses;

– the market price of electricity under uniform loss charging;
– the total value of energy produced under uniform loss charging; and
– the net benefit of reduced losses under zonal loss charging.

3.5.4 Central scenario

Central scenario estimates of annual loss savings fluctuate year-on-year from 73 GWh to 420 GWh. In contrast, variable uniform losses remain roughly consistent throughout. Volatility in the level of losses from year to year is the result of using only three snapshots per year.

Table 3.17 Estimated annual loss savings in the Central scenario

Central scenario	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Annual savings in losses (GWh)	90	235	107	420	73	165
Total energy produced (GWh)	360,000	363,000	366,000	369,000	370,000	372,000
Percentage of energy produced	0.03%	0.06%	0.03%	0.11%	0.02%	0.04%
Variable uniform losses (GWh)	3,800	4,081	3,913	4,043	3,844	3,677
Percentage of variable losses	2.37%	5.75%	2.73%	10.38%	1.89%	4.48%
Estimated total losses (GWh)	6,333	6,802	6,522	6,738	6,406	6,129
Percentage of total losses	1.42%	3.45%	1.64%	6.23%	1.13%	2.69%
Price of electricity (£/MWh)	44.4	42.5	35.8	33.9	32.5	35.2
Value of energy produced (£m)	16,000	15,400	13,100	12,500	12,000	13,100
Value of savings in losses (£m)	3.4	9.0	1.6	12.0	1.9	4.5

Source: Oxera.

3.5.5 Demand scenario

Loss savings under the Demand scenario are similarly volatile. Although the levels of losses do not follow the same annual pattern as the Central scenario, variable uniform losses are of approximately the same magnitude as the numbers in the Central scenario.

Table 3.18 Estimated annual loss savings in the Demand scenario

Demand scenario	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Annual savings in losses (GWh)	109	355	609	32	279	17
Total energy produced (GWh)	368,000	376,000	385,000	393,000	401,000	407,000
Percentage of energy produced	0.03%	0.09%	0.16%	0.01%	0.07%	0.00%
Variable uniform losses (GWh)	3,937	4,348	4,553	3,866	3,769	4,189
Percentage of variable losses	2.76%	8.16%	13.37%	0.82%	7.41%	0.40%
Estimated total losses (GWh)	6,561	7,247	7,588	6,443	6,282	6,982
Percentage of total losses	1.66%	4.90%	8.02%	0.49%	4.45%	0.24%
Price of electricity (£/MWh)	46.5	45.5	38.0	35.7	33.8	35.5
Value of energy produced (£m)	17,100	17,100	14,600	14,000	13,600	14,500
Value of savings in losses £m	4.0	12.7	18.3	0.5	6.7	0.3

Source: Oxera.

3.5.6 Gas scenario

Estimated annual loss savings in the Gas scenario are more stable. The levels are consistently higher than in the Central scenario, a result of the higher substitution from gas to coal in the earlier years as the two fuels undergo transition in their relativities, and subsequently the percentage of overall losses is higher under these assumptions.

Table 3.19 Estimated annual loss savings in the Gas scenario

Gas scenario	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Annual savings in losses (GWh)	355	595	463	346	334	328
Total energy produced (GWh)	360,000	363,000	366,000	369,000	370,000	372,000
Percentage of energy produced	0.10%	0.16%	0.13%	0.09%	0.09%	0.09%
Variable uniform losses (GWh)	3,825	4,133	4,179	3,897	3,710	4,099
Percentage of variable losses	9.27%	14.39%	11.07%	8.88%	9.00%	7.99%
Estimated total losses (GWh)	6,376	6,888	6,966	6,496	6,183	6,831
Percentage of total losses	0.06	0.09	0.07	0.05	0.05	0.05
Price of electricity (£/MWh)	37.2	33.9	29.6	28.2	26.6	26.6
Value of energy produced (£m)	13,400	12,300	10,800	10,400	9,800	9,900
Value of savings in losses £m	11.5	18.1	11.5	8.1	6.8	6.5

Source: Oxera.

3.5.7 Seasonal scenario

The introduction of seasonal rather than annual loss factors increases the loss savings when compared with the Central scenario. This is driven by a more focused reallocation of losses during different times of the year, especially with respect to the transfers between Scotland and England and Wales.

Table 3.20 Estimated annual loss savings in the Seasonal scenario

Seasonal scenario	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Annual savings in losses (GWh)	491	373	497	545	538	252
Total energy produced (GWh)	360,000	363,000	366,000	369,000	370,000	372,000
Percentage of energy produced	0.14%	0.11%	0.14%	0.15%	0.15%	0.07%
Variable uniform losses (GWh)	4,131	4,272	4,315	4,664	4,143	3,941
Percentage of variable losses	11.89%	8.73%	11.52%	11.68%	12.99%	6.38%
Estimated total losses (GWh)	6,884	7,119	7,191	7,773	6,906	6,569
Percentage of total losses	0.07	0.05	0.07	0.07	0.08	0.04
Price of electricity (£/MWh)	44.4	42.5	35.8	33.9	32.5	35.2
Value of energy produced (£m)	16,000	15,400	13,100	12,500	12,000	13,100
Value of savings in losses £m	17.8	13.1	13.5	13.8	15.7	7.1

Source: Oxera.

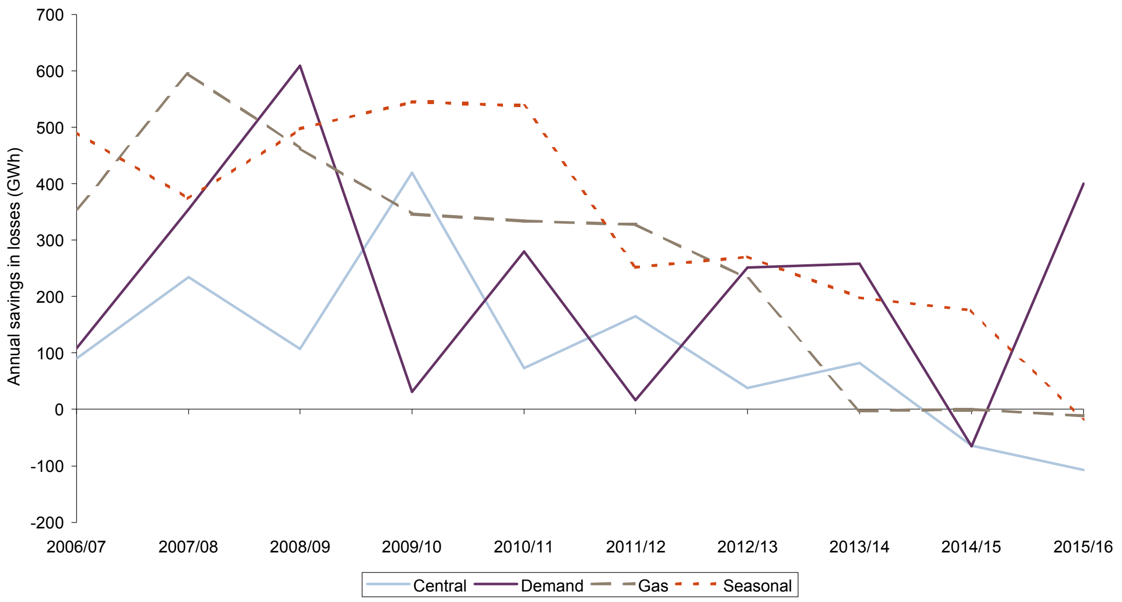
Overall, the results show that, in the near term, the introduction of zonal loss charging results in a more efficient despatch across all scenarios, with average annual savings ranging from £5m to £14m between 2006 and 2011. There are significant variations in the estimates of year-on-year loss savings, although this is a function of the snapshot estimation used in the analysis.

Within the market sensitivities, there is little difference in the loss savings between the Central and Demand scenarios out to 2011. However, the Gas scenario appears to offer higher loss saving. This is because, under this scenario, the output of coal-fired stations is more sensitive to changes in transmission loss factors. (The other two scenarios see coal-fired power stations running at very high load factors.)

Seasonal rather than annual loss factors increase the loss savings compared with the Central scenario, owing to the more focused reallocation of losses during different times of the year.

While loss savings are evident in the early years, there is an overall reduction in the savings brought about by zonal loss charging towards the end of the modelling horizon (see Figure 3.8). This is a direct result of the introduction of new capacity (predominantly) in the Southern zones throughout the modelling horizon, reducing the need for large North to South transfers. However, as discussed in section 5.1.3, this is not a result of zonal loss charging, as current incentives (such as TNUoS charges) are already leading to generation location decisions being biased towards the South.

Figure 3.8 Annual loss savings (GWh)



Source: Oxera.

Bringing together the values of loss savings from the data underpinning Tables 3.17 to 3.20 shows that there are average cost savings of between £3m and £9m per annum (averaged over ten years), with average savings of between £5m and £14m between 2006 and 2011. These loss savings are generally higher at the start of the period, as the development of new build in the South from 2009/10 or 2010/11 reduces overall transfers in later years. However, these reductions on losses occur *even under the current loss charging regime***.**

3.6 Impact on electricity prices

Table 3.21 presents the year-on-year baseload electricity price, with changes overall being marginal. Results for the Central scenario show no clear bias either up or down following the introduction of average zonal losses. Results for the alternative scenarios indicate that the price under zonal charging is consistently lower than under uniform charging. Throughout the Seasonal scenario prices closely mirror those in the Central scenario. In all modelling scenarios, prices broadly fall over the first five years, before levelling off or rising in subsequent years, a result of the underlying fuel and EU ETS costs.

Table 3.21 Time-weighted wholesale (baseload) price (£/MWh)

Scenario	Losses	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Central	Uniform	44.44	42.47	35.80	33.91	32.52	35.15
Central	Zonal	44.45	42.31	35.58	33.82	32.87	35.15
Gas	Uniform	37.22	33.94	29.63	28.25	26.60	26.63
Gas	Zonal	37.06	33.81	29.49	28.18	26.57	26.53
Demand	Uniform	46.48	45.50	37.98	35.68	33.81	35.52
Demand	Zonal	46.08	45.32	37.75	35.51	33.72	35.34
Seasonal	Uniform	44.44	42.47	35.80	33.91	32.52	35.15
Seasonal	Zonal	44.43	42.41	35.52	33.77	32.44	35.06

Source: Oxera.

The introduction of AAZ TLFs has a marginal and uncertain impact on wholesale electricity prices.

4 Impact on the transmission system

Zonal charging for losses may change despatch and therefore also network flows. From the security point of view, the most important question is whether the shifts in loading patterns increase or decrease the loading on the most important network interfaces—ie, those that operate at, or close to, their maximum load. National Grid recognises 17 boundaries, but arguably the most important interface is the loading on the Scotland–England Interconnector.[14]

Table 4.1 shows the differences in zonal exports between the zonal and uniform charging at peak load for the Central scenario. The positive figures indicate that the export from a zone has increased due to the introduction of zonal loss charging; if negative, it has decreased. A column of zeros indicates that the despatch for the uniform and zonal charging losses is the same. The differences have been calculated within the loss accuracy; thus, small differences indicate that zonal exports are similar and the difference is due to changed losses only. The total of zones 13 and 14 is equal to the change in the loading on the Scotland–England Interconnector due to the introduction of P198.

Table 4.1 Differences in peak zonal exports between annual zonal and uniform charging for losses (MW): Central scenario

	2006/7	2007/8	2008/9	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
1	0	–1	–6	634	–6	–1	–5	0	0	0
2	0	0	–4	–3	–5	–1	–4	0	0	0
3	149	148	849	212	850	215	728	0	0	0
4	0	0	–3	–2	–2	0	–3	0	0	0
5	–1	–1	–5	–4	–5	–1	–4	0	0	0
6	0	–1	–3	–3	–3	–1	–2	0	0	0
7	–149	–150	–152	–152	–153	0	–152	0	0	0
8	–1	–1	–6	–4	–6	–1	–5	0	0	0
9	–1	0	–4	–3	–3	–1	119	0	0	0
10	0	–1	–2	–1	–2	0	–2	0	0	0
11	0	0	–2	–1	–2	–1	–2	0	0	0
12	0	–1	–710	–709	–710	–217	–709	0	0	0
13	–1	–1	–4	–3	–3	0	–3	0	0	0
14	–1	0	–1	–2	–2	–1	–1	0	0	0
Losses	**5**	**9**	**53**	**41**	**52**	**10**	**45**	**0**	**0**	**0**

Source: Oxera.

[14] Since the introduction of the British Electricity Trading and Transmission Arrangements (BETTA) in April 2005, the Scotland–England interconnector is now a part of the integrated GB transmission network and no special arrangements for access are required. However, for ease of exposition, the discussion continues to identify the link between the relevant zones through this historic terminology.

Table 4.2 shows the same comparison for the Demand scenario. The situation is similar to that in the Central scenario, as the introduction of P198 seems to have little effect on the loading of the Scotland–England Interconnector.

Table 4.2 Differences in peak zonal exports between annual zonal and uniform charging for losses (MW): Demand scenario

	2006/7	2007/8	2008/9	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
1	635	0	248	249	248	634	0	0	0	–29
2	–3	51	–1	–1	–1	–2	0	0	0	–3
3	213	0	–1	–1	–1	177	0	0	0	–4
4	–2	–51	–1	–1	–1	–2	0	0	0	–2
5	–3	–1	–1	–1	–1	–3	0	0	0	–4
6	–2	0	–1	0	–1	–2	0	0	0	–2
7	–152	0	–1	–1	0	–151	–100	0	0	–2
8	–4	0	–1	–2	–1	–4	0	0	0	741
9	–2	0	–1	–1	–1	33	99	0	0	–3
10	–1	0	–1	–1	–1	–1	0	0	0	–2
11	–1	0	–1	–1	0	–1	0	0	0	–2
12	–709	0	–251	–250	–250	–708	0	0	0	–723
13	–2	0	–1	–1	0	–2	–1	0	0	–3
14	–1	0	0	0	–1	–1	–1	0	0	–1
Losses	**34**	**1**	**14**	**12**	**11**	**33**	**3**	**0**	**0**	**39**

Source: Oxera.

Table 4.3 shows the comparison for the Gas scenario. Here the situation is different, as the introduction of P198 has caused a reduction in the Scottish exports by 2,288 MW in 2010/11 due to Longannet not being scheduled at peak. This does not happen in other years, which may suggest that production at Longannet is quite sensitive to assumptions.

Table 4.3 Differences in peak zonal exports between annual zonal and uniform charging for losses (MW): Gas scenario

	2006/7	2007/8	2008/9	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
1	–2	–3	–6	–140	–13	–1	0	0	0	0
2	–1	–2	–4	–386	743	–1	0	168	0	0
3	312	467	849	–2	–12	–1	0	0	0	0
4	–1	–1	–3	–1	–6	0	0	0	0	0
5	–2	–3	–5	920	–12	–1	0	0	0	0
6	–1	–2	–3	–401	–7	0	0	0	0	0
7	–150	–151	–152	–1	–9	–1	0	–1	0	0
8	–2	–4	–6	–2	1515	130	0	0	0	0
9	–1	–2	–4	–1	–8	–1	0	0	0	0
10	0	–1	–2	–1	–5	0	0	0	0	0
11	–1	–1	–2	–1	–5	–1	0	0	0	0
12	–166	–323	–710	–1	–8	–131	0	–169	0	0
13	–2	–3	–4	–1	–2288	0	0	0	0	0
14	–1	–1	–1	0	–3	0	0	0	0	0
Losses	**18**	**30**	**53**	**18**	**118**	**8**	**0**	**2**	**0**	**0**

Source: Oxera.

Table 4.4 shows the differences in zonal exports between the seasonal zonal and uniform charging at peak load. Here, again, there is little difference for the Scottish exports.

Table 4.4 Differences in peak zonal exports between seasonal zonal and uniform charging for losses (MW)

	2006/7	2007/8	2008/9	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
1	245	245	184	–60	200	381	142	81	–3	–2
2	–2	–1	–1	380	0	378	–1	0	–3	–1
3	–1	–1	–1	–2	0	–3	0	0	574	–2
4	–1	–1	0	–1	0	–2	0	0	–2	–1
5	–1	–2	–1	–2	–1	–3	–1	–1	–3	–2
6	0	–1	–186	–324	–202	–1439	–143	0	–2	–1
7	–1	–1	0	–2	–1	206	0	–1	–3	–1
8	–1	–2	–1	–2	–1	–4	0	–1	–3	–2
9	0	0	0	–1	–1	–2	–1	0	94	398
10	–1	–1	0	–1	0	–2	0	0	–2	–1
11	–1	–1	–1	–1	0	–2	0	0	–1	0
12	–248	–248	0	–2	–1	460	0	0	–676	–400
13	–1	–1	0	–1	0	–3	0	–83	–2	–1
14	0	0	0	–1	0	–2	0	0	–1	0
Losses	**13**	**15**	**7**	**20**	**7**	**37**	**4**	**5**	**33**	**16**

Source: Oxera.

In conclusion, the simulations suggest that the introduction of P198 may lighten the load on the Scotland–England Interconnector due to a possibility of the output of Longannet being replaced by English generation. However, this occurred in only one year and in only one of the scenarios analysed. Therefore, it is unlikely that the introduction of P198 would change or delay any transmission network reinforcement. From the system security point of view, transmission system requirements are determined on the basis of 'the worst-case scenario'—ie, with Longannet operating.

Overall, the introduction of AAZ TLFs has a negligible impact on the transmission system across the modelling horizon.

4.1 Impact on interconnectors

The section above looked at the Scotland–England interconnector in the context of an integrated AC network. However, there are a number of existing and proposed DC interconnectors linking Great Britain with other electricity markets. During the course of the market and AAZ TLF analysis, the impact of introducing zonal loss charging on external interconnectors was examined, with very marginal impacts being observed.

– Moyle interconnector—the need for exports across this interconnector is likely to remain significant (ie, close to full-load exports) for the foreseeable future. It will therefore not be affected by the introduction of zonal loss charging.

– French interconnector—this is in zone 9 (South Eastern). Within this zone, the estimated AAZ TLFs are such that there are relatively small differences between its TLMs under zonal and uniform charging. As such, the introduction of zonal loss charging has little impact on its operations. This is discussed in more detail below.

– Proposed Netherlands interconnector—this is also sited within zone 9, which means that it, too, is unaffected by the introduction of zonal loss charging.

4.1.1 French interconnector

To support the assertion of no impact on the operations of the French interconnector, the analysis below highlights the changes that have occurred within the South East as a result of the introduction of zonal loss charges within one year—2007/08.

Analysis of the monthly patterns of generation changes in zone 9 (the South East) suggests that only Kingsnorth and Medway have changed output as a result of the introduction of zonal loss charging (see Table 4.5).

Table 4.5 Changes in patterns of monthly generation within the South East (GWh)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Kingsnorth	171	–118	130	–92	–89	104	–50	245	–124	–70	261	–165
Medway	1	0	4	7	14	1	2	0	0	71	51	66

Source: Oxera.

Kingsnorth's generation pattern oscillates throughout the period; some months produce less under zonal loss charging and others produce more, with no clear pattern across the year. The net result of all of these changes is a small increase in overall output (approximately 2%). This behaviour is the result of the station's owner re-optimising its coal fleet's operations under its overall sulphur constraints in response to changes in price across the year. It is not a systematic change in the region's output in response to the introduction of zonal losses.

Medway's operations are characterised by slight increases in production in the winter months. During these periods, the plant is operating above the French interconnector on a marginal cost basis (which is already at full capacity), and therefore the interconnector flows are not affected.

5 Impact on generation entry, exit and mothballing

Regional variations in the cost of losses are compared below against other factors that might affect location. The implications for long-run entry, exit and mothballing decisions by generators are then discussed.

5.1 Factors affecting location

The range of factors that might affect the location of generating plant include:

– zonal loss charges;
– fuel transportation costs;
– NGC's TNUoS charges;
– the availability and cost of land; and
– planning consent for new plant build.

The following sections focus on how the first three factors vary between regions.

5.1.1 Zonal loss charges

Analysis using the approach described in section 2 above results in estimated TLMs and annual loss charges of a hypothetical 1 GW power station in each of the loss charging zones as shown in Table 5.1.

Table 5.1 Estimated TLMs and zonal loss payments (£m)

	Central scenario		Gas scenario		Demand scenario	
	TLM	Loss charge[1]	TLM	Loss charge[2]	TLM	Loss charge[1]
Eastern	1.002	–0.70	1.000	0.08	1.003	–1.00
East Midlands	0.996	1.08	0.998	0.50	0.997	0.91
London	1.012	–3.67	1.009	–2.55	1.013	–3.97
Merseyside & North Wales	0.993	2.10	0.996	1.32	0.992	2.49
Midlands	1.004	–1.25	1.006	–1.88	1.004	–1.19
Northern	0.987	3.82	0.986	4.18	0.987	3.84
North Western	0.991	2.76	0.993	2.17	0.990	2.93
Southern	1.010	–3.10	1.009	–2.54	1.011	–3.41
South Eastern	1.006	–1.69	1.003	–0.81	1.007	–2.04
South Wales	1.004	–1.15	1.004	–1.14	1.004	–1.29
South Western	1.013	–3.98	1.011	–3.31	1.013	–3.85
Yorkshire	0.985	4.48	0.987	3.97	0.985	4.43
South of Scotland	0.981	5.57	0.984	4.78	0.979	6.26
North of Scotland	0.978	6.55	0.978	6.62	0.975	7.54

Notes: The estimated TLMs shown are an average of 2006/07–2010/11. [1] Using a new-entry cost of £35/MWh. [2] Using a new-entry cost of £25/MWh.
Source: Oxera calculations.

From the results presented in the above table, Table 5.2 below highlights the spread in TLMs and loss payments between the most beneficial transmission zone (South Western) and the zone with the most punitive loss charges, both including and excluding Scotland.

Table 5.2 Estimated TLMs and zonal loss payments (£m)

	Central scenario		Gas scenario		Demand scenario	
	TLM	Loss charge[1]	TLM	Loss charge[2]	TLM	Loss charge[1]
All						
Max.	0.978	5.73	0.978	4.31	0.975	6.60
Min.	1.013	–3.49	1.011	–2.15	1.013	–3.48
Difference	0.035	9.21	0.033	6.46	0.039	10.07
Excl. Scotland						
Max.	0.985	3.92	0.986	2.72	0.985	3.88
Min.	1.013	–3.49	1.011	–2.15	1.013	–3.48
Difference	0.028	7.40	0.025	4.87	0.028	7.35

Notes: The estimated TLMs shown are an average of 2006/07–2010/11. [1] Using a new-entry cost of £35/MWh. [2] Using a new-entry cost of £25/MWh.
Source: Oxera calculations.

Table 5.2 shows that, while the TLM differentials are similar across the three scenarios (both including and excluding Scotland), the financial impacts of the losses are highly dependent on the value of electricity in each scenario, with the lower price of gas assumed in the Gas scenario resulting in long-run entry costs 25% lower than those in the Central and Demand scenarios. This accounts for the majority of the cost differential reducing from £9.2–£10.1m to £6.5m for the whole of the UK, and from £7.4m to £4.9m when Scotland is excluded. For comparative purposes, total generation sales for the new plant are £260m (Central and Demand scenarios) and £195m (Gas scenario).

5.1.2 Fuel transportation charges

Table 5.3 shows the National Transmission System (NTS) exit charges for a hypothetical 1 GW plant, calculated by averaging per GSP the NTS exit charges reported for gas-fired power stations. Other elements of gas transportation charges do not vary on a regional basis for NTS-connected plants buying their gas at the National Balancing Point (NBP). NTS exit charges are inversely correlated to zonal loss charges, tending to be higher in Southern and Western regions, largely because of the gas network structure and the location of beach entry terminals. The table shows that the maximum differential between zones is around £3.4m per annum.

Table 5.3 Regional variations in cost of losses and gas transportation costs

GSP group	Average fuel charge (pence/peak-day kWh/day)	Estimated annual payment for a 1 GW plant (£m)
Eastern	0.00698	1.11
East Midlands	0.00245	0.39
London	0.0005	0.08
Merseyside & North Wales	0.01	1.59
Midlands	n/a	n/a
Northern	0.0001	0.02
North Western	0.0023	0.37
Southern	0.0157	2.50
South Eastern	0.009	1.43
South Wales	0.0212	3.38
South Western	0.0145	2.31
Yorkshire	0.0005	0.08
South of Scotland	0.0001	0.02
North of Scotland	0.0001	0.02

Note: Based on assumed efficiency of 55%.
Source: NGC, Oxera calculations.

5.1.3 TNUoS charges

Geographically, TNUoS charges follow the same pattern as zonal loss charges, with figures showing that Southern plants benefit more than Northern plants (see Table 5.4). For a hypothetical 1 GW plant across the zones, the maximum annual payment is £20.5m in Northern Scotland, and a minimum of a negative charge (ie, a payment to the generator from NGC) of £9.1m in the South West, a spread of £29.6m per annum. When England and Wales is considered excluding Scotland, the spread of TNUoS charges remains the same (Northern charges are the same as Scottish charges).

Table 5.4 Schedule of TNUoS generation charges (£/kW), 2006/07

Generation zone	Zone area	Generation tariff (£/kW)
1	Peterhead	18.393741
2	North Scotland	20.519472
3	Skye	13.297995
4	Western Highlands	18.621394
5	Central Highlands	15.412503
6	Cruachan	13.521386
7	Argyll	13.521386
8	Stirlingshire	13.065240
9	South Scotland	12.140893
10	North East England	8.885489
11	Humber, Lancashire & SW Scotland	5.613850
12	Anglesey	6.283570
13	Dinorwig	8.938682
14	South Yorks & North Wales	3.835629
15	Midlands & South East	1.219345
16	Central London	–5.495111
17	North London	0.362093
18	Oxon & South Coast	–0.513619
19	South Wales & Gloucester	–2.736627
20	Wessex	–5.065004
21	Peninsula	–9.145693

Source: NGC.

The scale of the regional variation in TNUoS charges suggests that transmission charging methodology would be a greater factor in locational decisions than the impact of the transmission zonal loss charging regime or fuel transportation costs, when considered across the whole of Great Britain. Even when considering only England and Wales, the impact of zonal loss charging is approximately half that of the TNUoS charging. These signals imply that post-generation transmission costs are higher than the pre-generation fuel transportation costs.

5.1.4 Comparison of factors

Tables 5.5 and 5.6 examine how TNUoS charges, NTS exit charges and zonal loss payments (priced at both £35/MWh and £25/MWh) might vary for three hypothetical baseload CCGT generators in different areas of the country. Three of the regions selected reflect actual proposed locations of new build under consideration,[15] while the remaining two (Northern, and Southern Scotland) were selected to provide a wider range of overall costs. These areas chosen were:

- South Wales, proposed location of the Pembroke and Milford Haven CCGTs;
- South Eastern, proposed location of the Isle of Grain CCGT;
- Yorkshire, location of the proposed Scunthorpe plant;
- Northern England; and
- South of Scotland.

Table 5.5 New-entry cost elements that vary on a regional basis with £35/MWh energy costs (£m)

Hypothetical CCGT plant	GSP group	Generation tariff zone	Assumed NTS exit charge	TNUoS charge	Regional comparison *(before zonal loss charging)*	Zonal loss charging payments	Regional comparison *(after zonal loss charging)*
South Wales	10	19	3.38	–2.74	0.64	–0.94	–0.29
South Eastern	9	15	1.43	1.22	2.65	0.00	2.65
Yorkshire	12	14	0.08	3.84	3.92	3.73	7.64
Northern	6	10	0.02	8.89	8.91	3.39	12.29
Southern Scotland	13	9	0.02	12.14	12.16	5.47	17.63
Difference							
excl. Scotland			–3.4	11.6	8.3	4.3	12.6
incl. Scotland			–3.36	14.9	**11.5**	6.4	**17.9**

Source: Oxera.

Table 5.6 New entry cost elements that vary on a regional basis with £25/MWh energy costs (£m)

Hypothetical CCGT plant	GSP group	Generation tariff zone	Assumed NTS exit charge	TNUoS charge	Regional comparison *(before zonal loss charging)*	Zonal loss charging payments	Regional comparison *(after zonal loss charging)*
South Wales	10	19	3.38	–2.74	0.64	–0.67	–0.03
South Eastern	9	15	1.43	1.22	2.65	0.00	2.65
Yorkshire	12	14	0.08	3.84	3.92	2.66	6.58
Northern	6	10	0.02	8.89	8.91	2.42	11.33
Southern Scotland	13	9	0.02	12.14	12.16	3.91	16.07
Difference							
excl. Scotland			–3.4	11.6	8.3	3.1	11.4
incl. Scotland			–3.36	14.9	**11.5**	4.6	**16.1**

Source: Oxera.

[15] http://www.nationalgrid.com/uk/library/documents/sys05/dddownloaddisplay.asp?sp=sys_Table3_2

Tables 5.5 and 5.6 indicate that the introduction of zonal loss charging does further incentivise the location of new generation toward the South, reinforcing the signals provided by TNUoS charging. When viewed across Great Britain as a whole, the signals are muted compared with the TNUoS charge; however, for relocation decisions within England and Wales, the signal is slightly sharper.

It is also clear from the comparison of the two tables how significant expected out-turn energy costs are when evaluating the impact of losses. The higher electricity price in the Demand and Central scenarios magnifies the differences when compared with the lower price in the Gas scenario.

Finally, while the introduction of zonal loss charging does provide further locational signals to new generation assets, the impact of this on new-build decisions is uncertain, especially in relation to other non-cost-related issues, principally planning permission and land availability.

5.2 Impact on medium-term projects

While the introduction of zonal transmission losses provides a further locational signal for the sighting of new power stations, in the medium term (ie, until the end of the study period), it is unlikely to have a significant impact on any new developments. This is because, of the projects either currently with Section 36 consent, with the DTI for Section 36 approval, or announced in the general media, a significant proportion are favourable transmission loss charging areas, mainly the South, South East and South Wales. This is seen Table 5.7, taken from National Grid’s 2006 Seven Year Statement.

Table 5.7 Locations of proposed new CCGT plant

Project	Proposed capacity (MW)	National Grid study zone
Langage stage 1	850	South West England
Pembroke 1 stage 1	800	S Wales & Central England
Drakelow D	1,230	Midlands
Pembroke 1 stage 2	1,200	S Wales & Central England
Marchwood	900	Central S Coast
Immingham CHP stage 2	601	Yorkshire
Scunthorpe	294	Yorkshire
Uskmouth 2 Stage 1	425	S Wales & Central England
Grain Re-powering Stage 1	590	Thames Estuary
Uskmouth 2 Stage 2	425	S Wales & Central England
Langage stage 2	400	South West England
Pembroke 2 stage 1	400	S Wales & Central England
Pembroke 2 stage 2	1,600	S Wales & Central England
Grain Re-powering Stage 2	590	Thames Estuary

Source: National Grid.

5.3 Impact on longer-term projects

In the longer term, it is highly uncertain how much impact zonal loss charging will have. Both the need for new generation and the type of generation used to fulfil any growth in demand beyond this point are subject to considerable uncertainty. For example, should there be any new initiatives to stem demand growth—for example, greater incentives for energy efficiency or larger take-up of small-scale CHP—the need for new generation post-2015 would be reduced significantly. Similarly, a strong case for nuclear new build could result in the commencement of a new-build programme soon after the current review, resulting in less need for additional conventional capacity. Such a programme could focus, at least in the first instance, on locating at existing nuclear power station sites (where space is not an issue), as local planning issues are likely to be less of a burden, and is therefore unlikely to be affected by changes in the loss charging regime.

In a similar vein, the continued value of coal as a fuel source when compared with gas could see the introduction of new coal-fired generation (offsetting the need for new gas plant). Again, some of the most likely locations for new coal-fired stations are sites of existing plant that have taken the LCPD opt-out derogation, ending their useful life within 20,000 hours of the start of 2008. A number of market participants are actively looking at upgrades to existing coal-fired stations or new coal-fired projects—eg, Scottish & Southern Energy's supercritical proposal at Ferrybridge, RWE's supercritical proposal at Tilbury, and E.ON's IGCC project at Drakelow. At these sites, the existence of significant infrastructure—fuel transportation and handling equipment, transmission connections, cooling infrastructure—means that there would be significant benefits in using these sites. Moreover, planning applications may be more straightforward for such sites.

5.3.1 Potential longer-term benefits

As part of the overall evaluation, it is necessary to estimate the impact of potential longer-term location benefits of zonal loss charging. As discussed, the impact of zonal loss charging on the long-run location of generation is subject to a large degree of uncertainty. Consequently, this section presents speculative scenarios that are intended to provide rough indications of the potential size of any long-run benefit under specific assumptions.

Given the discussion in section 5.2 above on the limited impact of P198 on locational decisions in the medium term, scenarios for post-2015/16 are investigated for each of the three sensitivities. The scenarios assume that it is the location of *baseload* capacity that is altered over time. This might reflect a situation where locational signals change decisions about the siting of new CCGT build, and look specifically at the relocation of 1 GW, 2 GW, 3 GW and 4 GW of generation capacity into the Southern zone from Yorkshire, Eastern and South Scotland (although this last one is only investigated for 1 GW, as Oxera is not aware of any significant plans for new CCGTs in Scotland).

Rough approximations for loss reductions from these changes in location were calculated by multiplying the annual output of the relocated plant (calculated using an assumed load factor of 85%) by the difference between the AAZ TLFs[16] for the original zone and those for the new zone. This may not provide accurate estimates, as AAZ TLFs vary significantly according to network loading conditions; however, they do provide indicative values for loss savings. The change in losses was converted into an annual monetary benefit using an assumed electricity price of £35/MWh for the Central and Demand scenarios and £25/MWh for the Gas scenario. Table 5.8 below presents the results.

[16] The value number used was the annual zonal TLF, before being halved to obtain AAZ TLFs, as the calculation concerns the physical change in losses for a change in generation in a zone, whereas the division by two is an adjustment used to derive loss charges.

Table 5.8 Scenarios of annual longer-term benefits

GW relocated	GSP From	GSP To	Central[1] Estimated loss reduction (GWh)	Central[1] Estimated annual benefit (£m)	Demand[1] Estimated loss reduction (GWh)	Demand[1] Estimated annual benefit (£m)	Gas[2] Estimated loss reduction (GWh)	Gas[2] Estimated annual benefit (£m)
1	12	8	286	10.0	267	9.3	283	7.1
1	1	8	149	5.2	157	5.5	172	4.3
1	13	8	208	7.3	130	4.6	91	2.3
2	12	8	571	20.0	534	18.7	565	14.1
2	1	8	298	10.4	314	11.0	345	8.6
3	12	8	857	30.0	801	28.0	848	21.2
3	1	8	448	15.7	470	16.5	517	12.9
4	12	8	1,142	40.0	1,068	37.4	1,130	28.3
4	1	8	597	20.9	627	22.0	690	17.2

Notes: [1] Using a new-entry cost of £35/MWh. [2] Using a new-entry cost of £25/MWh.
Source: Oxera calculations.

The figures in Table 5.8 show a wide range for the potential long-run benefits of zonal loss charging, from £2.3m per annum from the relocation of 1 GW of baseload generation from zone 13 to zone 8 in the Gas scenario, to a figure of £40m obtained from the relocation of 4 GW from zone 12 to zone 8 in the Central scenario. The Gas scenario net benefits are lower overall than the other two scenarios, with the majority of the difference being attributable to the different long-run new-entry cost differences.

However, there are several other factors that should be taken into account in deriving a realistic estimate of the benefits.

– The discussion in section 5.1 highlighted that zonal loss charging is only one of the factors that might affect the location of generation plant, and that others, such as TNUoS charging (and planning permission in the case of new build), may exert a greater influence.
– The scenarios are based on the relocation of baseload plant, which would change flow patterns, with potential beneficial effects on losses during all time periods. However, if zonal loss charging changes the location of mid-merit or peaking plant, loss reductions would only occur during periods of higher demand.
– The methodology of using estimated zonal TLFs to calculate potential loss reductions will systematically tend to overestimate the effect on losses. This is because, as generation is switched between zones, the marginal loss benefit of switching further generation will tend to fall. Hence, multiplying by TLFs calculated using the initial pattern of generation will overstate the final impact.

For these reasons, Oxera considers that a range of £1m–£20m per annum would be a more prudent estimate for the level of longer-term potential benefits post-2015/16.

In summary, the introduction of zonal loss charging strengthens the locational signals that already exist (via TNUoS charges) for building new power stations closer to the demand centres. However, the strength of this signal relative to other changes is uncertain. In the medium term, it is unclear that the introduction of zonal loss charging will result in any changes to the location of new-build projects, as a significant proportion of these are already planned in advantageous transmission zones.

In the longer term (beyond 2015/16), the range of potential benefits is large and very uncertain, with estimates of between of £1m and £20m per annum.

5.4 Impact on new renewable generation

Large-scale generation projects are not the only generation assets to be affected by the introduction of zonal loss charging, which also has the potential to change the locational decisions for renewable generators.

In Oxera (2003), it was concluded that:

> Including the embedded benefit gained from the avoidance of supplier transmission losses in the rate-of-return calculation suggests that the marginal impact of zonal loss charging on the IRR of a distributed generation project would range between –1.7% and 0.6%[17] for onshore wind projects (assuming that the distributed generator obtains 100% of the supplier's embedded benefits, and that the costs are similar to those incurred for larger-scale plant connecting to the high-voltage grid).

The report went on to note:

> Zonal loss charging would therefore provide price signals encouraging development of distributed generation in Southerly zones relative to zones in the North. However, as for transmission, these price signals would be of lower magnitude than other locational signals, such as embedded benefits from avoided TNUoS or connection charges.

Finally, it concluded that:

> The analysis has shown that applying zonal loss charging across Great Britain would have a ***marginal impact on the profitability of renewables projects connected to transmission networks and large distributed generators***. It would adversely affect projects located in Scotland and, to a lesser extent, in the North of England, while providing some benefits to those located in Wales, South Western, South East and Eastern demand zones. In the latter areas, zonal loss charging would provide increased financial benefits to smaller-scale distributed plant. Given the marginal financial effect on renewables, it seems ***unlikely*** that zonal loss charging will materially affect the probability of meeting the government's renewables target.

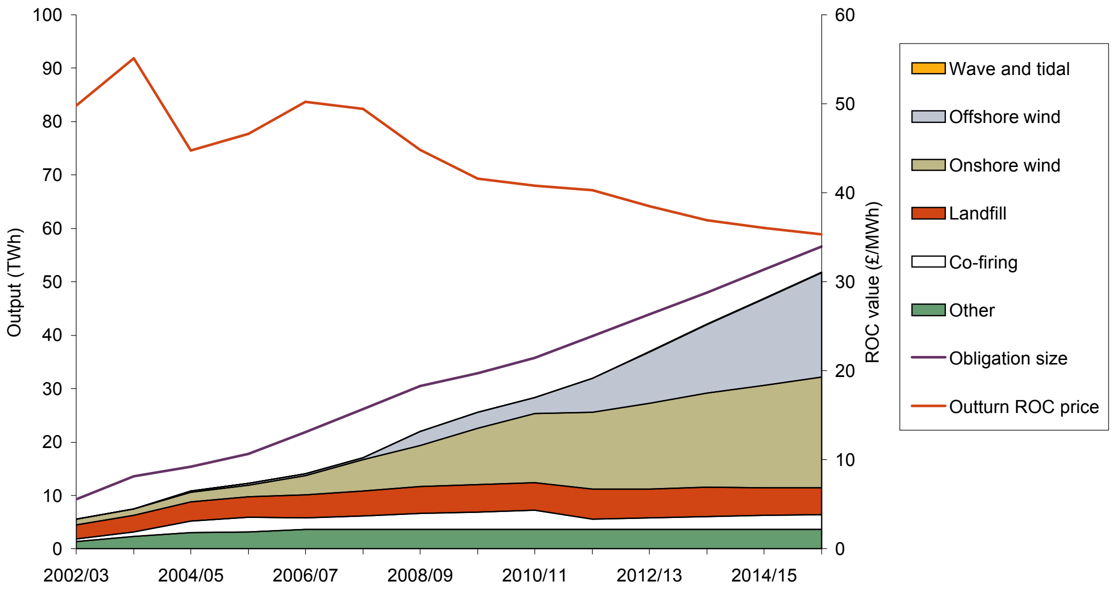
To determine whether the implications of the above statements were valid, and that the changes in zonal loss charges would not have any impact on renewable generation investments, Oxera used its Renewables Obligation model. This model makes assumptions on future electricity prices and renewable generation costs in order to estimate the Renewables Obligation Certificate (ROC) prices required to support different renewable generation projects. An iterative process is used to find a consistent set of renewable generation levels and ROC prices, taking into account the operation of the buyout mechanism and limits on the maximum resource size and rates of build for the different technologies.

The model has been populated with cost estimates covering a range of technologies (onshore and offshore wind, landfill gas, wave and tidal technology, photovoltaic, small-scale hydro) as well as their total resource availability. In the case of onshore and offshore wind, the total resources are defined within different regions of England, Wales and Scotland, and are further broken down into wind speed sites within these regions, each with their own unique build costs.

[17] In this instance, a 1.7% reduction in IRR should be interpreted as IRR * 0.017 rather than IRR – 1.7%; for example, a project with a 10% IRR would see its IRR decrease to 9.83%, not to 8.3%.

The results of the model run are shown in Figure 5.1.

Figure 5.1 Development of renewable generation and ROC prices under the Central scenario



Source: Oxera.

Analysis of the underlying results shows that, over the next few years (at least up to 2010/11), the growth of onshore wind generation is expected to be constrained more by delays in the planning process obtaining access to the transmission system than by the level of support provided by the Renewables Obligation.

When the underlying results of all scenarios are analysed, it is shown that the build decisions of individual renewable sites—either embedded or transmission-connected—are not affected by the introduction of zonal loss charging. Therefore, while there may be some distributional impacts, there are no net welfare losses or benefits to the system as a whole.

In summary, due to the design of the Renewables Obligation (specifically its bluntness as a policy tool) and non-economic difficulties in obtaining significant volumes of onshore wind new build in the early years, the introduction of zonal loss charging will have little, if any, impact on renewable new build across the period to 2015/16.

5.5 Perception of risk

It has been argued that, by precipitating large transfers between generating companies, zonal loss charging might increase perceptions of risk and raise the cost of capital for new investments. With regard to this argument, it is worthwhile noting the following.

– Perceptions of risk are forward-looking. Given that changes to the loss charging regime, at least in England and Wales, have been mooted since the time of privatisation (and hence past investments have been made in an environment of uncertainty), it is not clear that reaching a decision on locational loss charging will necessarily increase the forward-looking risks faced by investors.

– Changes to the loss charging regime represent a diversifiable risk. An investor holding a balanced portfolio of generator shares would be unaffected by changes to loss charging arrangements, since costs are simply transferred between different generation companies. As noted in a previous study on the cost of capital,[18] any regulatory action that has an effect that can be diversified away does not have an impact on the cost of capital.

– If the concern relates to the wider risk of changes to the market arrangements (which in some cases might not be diversifiable), it is not clear that zonal loss charging is as significant as some of the other developments that have occurred in recent years (such as the introduction of BETTA).

As a result of the above points, Oxera concludes that **there is no increase in the perceived level of risk due to the introduction of zonal loss charging**. This does not imply that there is no risk faced by electricity companies, only that the introduction of zonal losses should not alter views of either regulatory or sector-specific risk factors. Consequently, the issue is not addressed further.[19]

[18] Wright, Mason and Miles (2003), op. cit.

[19] In carrying out the modelling, Oxera's estimate of new-entry costs assumed that zonal loss charging would have no impact on the cost of capital for new-build projects.

6 Potential demand-side response

The potential impact of retail price changes on consumption has been estimated by applying existing estimates of the elasticity of demand, which give the percentage change in consumption for a 1% change in price.[20] While electricity demand is generally perceived to be relatively inelastic (ie, changes in price have a relatively small effect on consumption), a range of figures has been put forward for the precise level of demand elasticity. For example, for the domestic sector, Miller (2001) produced an estimate of –0.37,[21] while the UK Treasury has used a figure of –0.187 to analyse the impact of tax changes.[22] Previous modelling work by Oxera has produced an estimate of long-run price elasticity for the domestic sector of –0.33. Elasticity estimates for industrial and commercial (I&C) customers tend to be slightly higher. For example, a study for the Australian market estimated domestic elasticity as –0.25, and produced figures of –0.35 and –0.38 respectively for the I&C sectors.[23]

Based on the range of existing estimates, the high and low figures set out in Table 6.1 were used to assess the potential impact of zonal loss charging on consumption. The high figures are more likely to apply in the long run, when consumers have the greatest scope to respond to price changes.

Table 6.1 Assumptions on electricity price elasticity

	Low scenario	High scenario
Domestic	–0.15	–0.35
I&C	–0.25	–0.45

Source: Oxera.

Tables 6.2–6.5 below provide estimates under the scenarios of the potential annual change in consumption by domestic and I&C customers in different GSP groups, calculated from the application of the elasticity assumptions to data on consumption broken down by GSP group. As there was no precise breakdown between domestic and I&C consumption in each region, the figures have been calculated using an assumed volume split of 33:67 for all zones. The tables also provide estimates of the potential impact on transmission losses, based on the use of AAZ TLFs. This approach results in only very approximate estimates, since actual loss impacts will vary between nodes on the network and between time periods.

[20] For example, a demand elasticity of –0.3 means that, for a 1% increase in price, consumption would fall by 0.3%.

[21] Miller, J.I. (2001), 'Modelling Residential Demand for Electricity in the U.S: A Semiparametric Panel Data Approach', mimeo, Rice University, November.

[22] http://www.parliament.the-stationery-office.co.uk/pa/cm199798/cmhansrd/vo980210/text/80210w09.htm.

[23] http://www.nemmco.com.au/publications/soo/410-0023.pdf.

Overall, modelling indicates values of loss reductions of up to £1.2m under the high electricity price elasticity scenario. Maximum estimated loss reduction values occur in Northern England and Southern Scotland, reaching nearly £300,000. In the Eastern, Midlands and South Wales zones, the value of loss reductions becomes negative, due to a proportionally higher consumption increase than price decrease, leading to more electricity purchases. South Wales shows the strongest signs of this behaviour, with a £21,000 reduction in benefits.

Table 6.2 Potential annual benefits from the demand-side response to zonal loss charging: Central scenario

	Consumption (GWh)	Estimated change in consumption (MWh)				Estimated change in losses (MWh)		Estimated value of loss reduction (£)	
		Low scenario		High scenario		Low scenario	High scenario	Low scenario	High scenario
		Domestic	I&C	Domestic	I&C				
North Scotland	10,000	3,573	22,905	8,337	41,229	–1,915	–3,585	70,000	131,000
South Scotland	23,000	4,678	29,984	10,914	53,971	–2,354	–4,408	86,000	161,000
Northern	47,000	8,261	52,954	19,275	95,317	–2,747	–5,143	101,000	188,000
North Western	27,000	2,229	14,285	5,200	25,714	–607	–1,137	22,000	42,000
Yorkshire	29,000	6,523	41,815	15,221	75,267	–2,256	–4,223	83,000	155,000
Merseyside & North Wales	64,000	1,323	8,483	3,088	15,269	–308	–577	11,000	21,000
East Midlands	19,000	778	4,989	1,816	8,980	–123	–230	5,000	8,000
Midlands	9,000	–1,420	–9,100	–3,312	–16,380	76	142	–3,000	–5,000
Eastern	22,000	–480	–3,078	–1,121	–5,541	22	42	–1,000	–2,000
South Wales	51,000	–5,663	–36,301	–13,214	–65,342	310	580	–11,000	–21,000
South Eastern	11,000	–856	–5,486	–1,997	–9,875	–3	–6	0	0
London	10,000	–1,999	–12,814	–4,664	–23,065	–199	–373	7,000	14,000
Southern	24,000	–4,719	–30,248	–11,010	–54,446	–284	–532	10,000	19,000
South Western	23,000	–6,487	–41,583	–15,136	–74,850	–585	–1,094	21,000	40,000
Total	**369,000**	**5,741**	**36,804**	**13,397**	**66,247**	**–10,975**	**–20,544**	**401,000**	**751,000**

Note: The calculations in the above and subsequent tables use average AAZ TLFs and AAZ TLMs over the period 2006/07 to 2015/16, combined with averaged annual prices from the uniform and zonal variants and average annual demand levels.
Source: Oxera.

Changes under the Demand scenario assumptions are mixed. The total value of loss reduction has increased to £1.2m, largely on the back of higher prices.

Table 6.3 Potential annual benefits from the demand-side response to zonal loss charging: Demand scenario

	Consumption (GWh)	Estimated change in consumption (MWh)				Estimated change in losses (MWh)		Estimated value of loss reduction (£)	
		Low scenario		High scenario		Low scenario	High scenario	Low scenario	High scenario
		Domestic	I&C	Domestic	I&C				
North Scotland	11,000	4,220	27,050	9,846	48,691	–2,169	–4,061	83,000	154,000
South Scotland	25,000	6,377	40,880	14,880	73,583	–3,152	–5,901	120,000	224,000
Northern	51,000	11,586	74,272	27,035	133,689	–3,921	–7,340	149,000	279,000
North Western	29,000	4,484	28,745	10,463	51,742	–1,316	–2,463	50,000	94,000
Yorkshire	31,000	9,044	57,973	21,102	104,351	–3,241	–6,067	123,000	231,000
Merseyside & North Wales	69,000	7,079	45,381	16,519	81,686	–1,922	–3,598	73,000	137,000
East Midlands	21,000	2,422	15,528	5,652	27,950	–410	–768	16,000	29,000
Midlands	10,000	–734	–4,707	–1,713	–8,472	55	103	–2,000	–4,000
Eastern	24,000	1,240	7,950	2,894	14,310	–57	–106	2,000	4,000
South Wales	55,000	930	5,961	2,170	10,731	–49	–91	2,000	3,000
South Eastern	12,000	–238	–1,525	–555	–2,745	–2	–4	0	0
London	11,000	–1,605	–10,287	–3,745	–18,517	–164	–307	6,000	12,000
Southern	26,000	–3,496	–22,413	–8,158	–40,344	–223	–418	8,000	16,000
South Western	25,000	–4,679	–29,995	–10,918	–53,991	–447	–838	17,000	32,000
Total	**400,000**	**36,631**	**234,813**	**85,472**	**422,663**	**–17,018**	**–31,858**	**647,000**	**1,211,000**

Source: Oxera.

In comparison with the Central scenario, the Gas scenario assumptions slightly dampen the value estimates of loss reductions, principally driven by lower overall prices. Overall the loss reduction is down slightly on the Central scenario. The value of potential demand-side savings ranges from £0.3 to £0.6m.

Table 6.4 Potential annual benefits from the demand-side response to zonal loss charging: Gas scenario

	Consumption (GW)	Estimated change in consumption (MWh)				Estimated change in losses (MWh)		Estimated value of loss reduction (£)	
		Low scenario		High scenario		Low scenario	High scenario	Low scenario	High scenario
		Domestic	I&C	Domestic	I&C				
North Scotland	10,000	3,075	19,711	7,175	35,480	–1,684	–3,153	50,000	94,000
South Scotland	23,000	3,009	19,291	7,022	34,724	–1,333	–2,496	40,000	75,000
Northern	47,000	11,553	74,059	26,957	133,305	–3,650	–6,833	109,000	205,000
North Western	27,000	2,352	15,077	5,488	27,138	–665	–1,245	20,000	37,000
Yorkshire	29,000	7,178	46,015	16,749	82,827	–2,437	–4,562	73,000	137,000
Merseyside & North Wales	64,000	901	5,773	2,101	10,392	–249	–466	7,000	14,000
East Midlands	19,000	1,408	9,028	3,286	16,250	–226	–423	7,000	13,000
Midlands	9,000	–1,346	–8,625	–3,140	–15,525	96	180	–3,000	–5,000
Eastern	22,000	1,511	9,688	3,527	17,439	–64	–120	2,000	4,000
South Wales	51,000	–2,623	–16,814	–6,120	–30,265	78	146	–2,000	–4,000
South Eastern	11,000	2	16	6	29	0	0	0	0
London	10,000	–1,103	–7,072	–2,574	–12,730	–118	–221	4,000	7,000
Southern	24,000	–3,199	–20,509	–7,465	–36,916	–199	–373	6,000	11,000
South Western	23,000	–4,692	–30,076	–10,948	–54,136	–483	–905	14,000	27,000
Total	**369,000**	**18,028**	**115,561**	**42,064**	**208,010**	**–10,935**	**–20,470**	**327,000**	**615,000**

Source: Oxera.

The Seasonal scenario shows wider spread in results when compared with the Central scenario, with GB-wide savings of between £0.5m in the short term and £1m in the longer term. This is the result of a more focused demand response brought about by the introduction of seasonal loss factors.

Table 6.5 Potential annual benefits from the demand-side response to zonal loss charging: Seasonal scenario

	Consumption (GWh)	Estimated change in consumption (MWh)				Estimated change in losses (MWh)		Estimated value of loss reduction (£)	
		Low scenario		High scenario		Low scenario	High scenario	Low scenario	High scenario
		Domestic	I&C	Domestic	I&C				
North Scotland	10,000	3,944	25,283	9,203	45,510	–1,566	–2,932	57,000	107,000
South Scotland	24,000	8,484	54,386	19,796	97,894	–4,087	–7,651	150,000	280,000
Northern	47,000	11,076	70,999	25,844	127,798	–3,636	–6,807	133,000	249,000
North Western	27,000	3,799	24,355	8,865	43,839	–934	–1,749	34,000	64,000
Yorkshire	29,000	7,700	49,360	17,967	88,848	–2,468	–4,620	90,000	169,000
Merseyside & North Wales	64,000	4,177	26,778	9,747	48,201	–806	–1,509	30,000	55,000
East Midlands	19,000	1,226	7,856	2,860	14,141	–170	–318	6,000	12,000
Midlands	9,000	–983	–6,300	–2,293	–11,341	38	72	–1,000	–3,000
Eastern	22,000	–182	–1,168	–425	–2,102	9	17	0	–1,000
South Wales	51,000	–2,888	–18,510	–6,738	–33,319	162	304	–6,000	–11,000
South Eastern	11,000	–593	–3,802	–1,384	–6,843	12	23	0	–1,000
London	10,000	–1,926	–12,349	–4,495	–22,228	–150	–280	5,000	10,000
Southern	24,000	–4,106	–26,319	–9,580	–47,374	–225	–421	8,000	15,000
South Western	23,000	–5,007	–32,094	–11,682	–57,769	–410	–768	15,000	28,000
Total	**370,000**	**24,722**	**158,476**	**57,685**	**285,256**	**–14,231**	**–26,640**	**521,000**	**973,000**

Source: Oxera.

Overall, there is a reasonably wide range of potential demand-side responses, from £0.3m to £1.2 per annum.

Demand-side response will, in the short run, result in modest savings in overall levels of losses through mixed changes in consumer response. While increases in prices for demand customers in Southern regions result in reductions in consumption, Northern consumers increase consumption on the back of reductions in price. The resulting benefits range from £0.3m to £0.6m per annum. In the long term, should price changes endure, consumers will take slightly greater reductions in demand (as alternative energy sources are found), or more fundamentally increase consumption patterns on the back of long-term price reductions. Overall, changes in the longer term could account for loss savings of between £0.6 and £1.2m per annum.

7 Implementation costs

The costs of implementing zonal loss charging in Great Britain comprise initial set-up costs and ongoing operating costs for BSC parties and/or their agents, the transmission company, and ELEXON. The data gathered from the industry by ELEXON as part of its impact assessment of the proposed modification is reviewed below.

7.1 Transmission company costs

The transmission company estimates that it would incur:

– £40,000 in initial set-up and operation costs for the first BSC year of the scheme; and
– £40,000 in ongoing annual operational costs.

7.2 ELEXON costs

ELEXON's costs are broken down into implementation and ongoing operational costs.

– Implementation costs cover Logica central system agent (CSA) costs, transmission loss factor agent (TLFA) and load–flow model review (LFMR) costs, BSC audit costs, other 'demand-led' implementation costs, and ELEXON resource costs (see Table 7.1, which also shows estimated tolerances).

Table 7.1 Estimated central implementation costs (£)

	Cost	Tolerance
Total demand-led implementation costs, of which	335,170	±50%
Logica CSA	35,876	–
TLFA/LFMR	250,000	±50%
BSC audit	15,000	±50%
Other implementation costs	34,295	±70%
ELEXON resources	132,000	±5%
Total	**467,170**	**±35%**

Source: ELEXON.

– Ongoing operational costs cover the annual BSC year costs for Logica CSA operation and maintenance, TLFA/LFMR operational costs, BSC auditor costs and other ELEXON operational costs (see Table 7.2).

Table 7.2 Estimated central operational costs (£)

	Cost	Tolerance
Logica CSA	2,645	–
TLFA/LFMR	100,000	±50%
BSC auditor	40,000	±50%
ELEXON operational costs	15,400	±5%
Total	**158,045**	**±45%**

Source: ELEXON.

7.3 BSC participant costs

The impact assessment drew responses from eight participants: six major electricity market participants (E.ON UK, Scottish & Southern, EDF Energy, ScottishPower, npower and British Energy), United Utilities, and Energy Services Metering. The last two respondents (United Utilities, and Energy Services Metering) indicated that there would be no impact on their businesses from the introduction of zonal loss charging. Among the six large electricity companies there was a diverse range of views, as shown in Table 7.3.

Table 7.3 BSC party cost estimates (£)

Company	Cost estimate (£'000)
E.ON UK	0
Scottish & Southern	Confidential costs provided
EDF Energy	150–200
ScottishPower	~200
npower	Confidential costs provided
British Energy	>100

Source: ELEXON

Table 7.3 demonstrates the wide range of implementation costs that could be incurred by each company, should P198 be implemented. One possible reason for the wide range of estimates is the extent to which the existing infrastructure (eg, IT systems, trading systems, forecasting systems, market interfaces, generation/portfolio management and trading systems) has been developed with zonal transmission losses in mind. The industry, overall, would have undertaken significant levels of investment between P82's original acceptance in January 2003 by the Authority and its subsequent revocation in January 2004. However, it is not entirely certain that these modifications:

– were ever fully implemented; or

– are still in place (eg, companies' systems may have gone through more upgrades without the relevant changes in place).

Bearing the above points in mind, the range of implementation costs reported in Table 7.3 does not seem unreasonable, and can therefore be used to support an industry-wide estimate of total costs. Taking the responses above as a basis, an estimated 'average' implementation cost of £112,000 can be derived for a large electricity company.

7.4 Generation sector

Five of the six electricity companies in Table 7.3 account for 50% of the transmission-connected generation capacity in Great Britain (npower's response appears to be from its downstream businesses), while the inclusion of four others (RWE, Drax, Centrica and BNFL Magnox) raise this figure to 75%. Therefore, a combined implementation cost of £896,000 would seem a reasonable estimate for this proportion of the generation sector.

Of the remaining capacity, there are approximately 20 companies with one or two conventional generation assets connected to the GB transmission system, and a further 25 with renewable stations. The implementation requirements for these participants would not run to the same levels as the large integrated companies, although they are not negligible. As there is no direct evidence of these participants' costs, an estimate will have to be made. As with the large companies above, there will be potential development work to internal systems—for example, IT systems, trading systems, forecasting systems, market interfaces, generation management and trading systems—as well as testing and integration. Oxera estimates that these efforts would entail, on average, 60 working days of effort. When costed at £220/day (the same rate as ELEXON's internal costings), the total for the remaining generation sector (estimated 40 companies) is £528,000.

7.5 Domestic retailers

The domestic retail sector is dominated by six companies: British Gas (Centrica), EDF Energy, Powergen (E.ON), npower (RWE), ScottishPower and Scottish & Southern. Between them, they control over 98% of domestic sales. As each of these already has a corresponding generation business, it is assumed that their combined implementation costs are captured within the estimates above.

7.6 Industrial and commercial retailers

As with the domestic sector, the I&C sector is dominated by the six large players above, as well as British Energy. Again, these companies' implementation costs are assumed to have been captured within their generation assets. However, there are up to ten other participants in the I&C market not already accounted for. Again, in the absence of industry estimates, it is difficult to establish what their implementation costs are likely to be. However, using a similar approach to that for the smaller generation businesses, Oxera estimates that 60 working days' effort would be required to bring I&C suppliers' systems up to date. Using the same £220/day as before, the total implementation costs for these companies is therefore £132,000.

7.7 Total implementation costs

Using the above information, Table 7.4 brings together the estimated implementation costs for market participants, and the central agents.

Table 7.4 Estimated implementation costs (£'000)

	Cost	Tolerance
Vertically integrated generators	896	±50%
Other generators	528	±100%
I&C retailers (not captured within generators)	132	±100%
Total market participants	**1,556**	**±70%**
Transmission company costs	40	–
Central costs	467	±35%
Total	**2,063**	**±60%**

Source: Oxera calculations.

7.7.1 Total ongoing costs Domestic

Should P198 be implemented, it is unclear that market participants would face significant additional costs going forward. There will be some additional operating costs associated with data compliance and interfacing with the central agencies, but these are likely to be relatively small. **Therefore, it is assumed that an annual figure of £100,000 is incurred by market participants, providing a total ongoing cost of ~£300,000 per annum.**

8 Overall cost–benefit

8.1 Summary of benefits

8.1.1 Redespatch

The results presented in section 3 suggest that the introduction of zonal loss charging will result in changes in redespatch, moving generation from the zones with the highest transmission loss penalties (predominantly in the North) towards more favourable transmission zones (mainly in the South). The results of these generation shifts result in average annual savings ranging from £3m to £9m across the modelled ten-year horizon, with potential savings of up to £5m–£14m to 2011/12, with this higher value a reflection of the higher cost of electricity in the early years, and the impact of new, predominantly Southern generation from 2009/10 onwards.[24]

8.1.2 Demand-side response

The analysis suggests that there would be limited demand-side response to zonal loss charging, principally because the expected impact on final retail bills is small and electricity demand is generally perceived as inelastic. The value of loss-reduction benefits from changes in the pattern of consumption has been estimated in the range of £0.3m–£1.2m per annum.

8.1.3 Long-term relocation benefits

In the longer term, the introduction of zonal transmission losses could give rise to net benefits of a similar order of magnitude to those resulting from redespatch—£1m–£20m per annum. However, as the analysis in section 5 suggests that there are already significant locational signals, which are likely to site new plant in advantageous transmission zones during the study period, the long-term impacts will not be realised until beyond 2015.

8.1.4 Other benefits

Of all the other areas investigated within the scope of this report, none provided any additional benefits from the introduction of zonal loss charging.

[24] By way of comparison the 2011/12 savings represent approximately 0.038–0.107% of the estimated value of total electricity produced.

8.2 Comparison of benefits and costs

Tables 8.1 and 8.2 combine the benefits discussed above with the ongoing operational and other offsetting costs to present a view of the net benefits to 2015/16, and, for illustrative purposes only, to 2020/21.

Table 8.1 Scenarios of future benefits of AZTL to 2015/16 (£m)

	Central	Demand	Gas	Seasonal
Assumed annual benefits				
Generation redespatch	2.9	6.4	6.0	8.9
Demand response	0.6	0.9	0.5	0.7
Assumed annual operating costs	0.3	0.3	0.3	0.3
Assumed implementation costs	2.0	2.0	2.0	2.0
NPV of future benefits to 2015/16	**20.8**	**49.0**	**43.0**	**65.6**

Source: Oxera.

Table 8.2 Scenarios of future benefits of AZTL to 2020/21 (£m)

	Central	Demand	Gas	Seasonal
Assumed annual benefits				
Generation redespatch	2.9	6.4	6.0	8.9
Demand response	0.6	0.9	0.5	0.7
Relocation of generation (from 2015/16)	10.6	9.8	7.3	10.6
Assumed annual operating costs	0.3	0.3	0.3	0.3
Assumed implementation costs	2.0	2.0	2.0	2.0
NPV of future benefits to 2020/21	**64.8**	**103.0**	**86.1**	**129.3**

Source: Oxera.

The overall net benefits have been constructed by calculating the benefits and costs for all years until 2015/26 (or 2020/21) and then discounting them back to 2006/07, the year in which implementation costs would be incurred. A discount rate of 3.5% has been used.[25]

Overall, the Central scenario suggests net benefits of ~£21m across the ten-year study horizon. As noted above, a significant proportion of these are during the first five years before new entry (which is already expected to be built in the South) reduces the general pattern of North to South transfers.

The two other market scenarios offer higher savings overall, partly due to higher overall prices in the Demand scenario and higher overall loss savings in the Gas scenario.

The introduction of seasonal loss factors also improved the overall net benefits of zonal loss charging.

[25] This has been taken from HM Treasury (2003), 'Treasury Green Book: Appraisal and Evaluation in Central Government, Treasury Guidance', January. It was deemed appropriate to use this rate since this analysis evaluates a regulatory rule change. This is consistent with the analysis undertaken in 2003.

9 Distributional impacts

The introduction of zonal loss charging will result in transfers between generators and suppliers in different transmission charging zones and the overall transfers between different zones. The magnitude of these changes for 2006/07 is estimated below, based on the modelling results for that year.

9.1 Generator and supplier transfers

Tables 9.1 and 9.2 show the change in loss payments for hypothetical generators and retailers with a portfolio of assets and/or retail customers either concentrated in the North or in the South, or spread around the country.

9.1.1 Generators

The hypothetical generator has a portfolio of four 1 GW power stations in different zones.

Table 9.1 Change in annual loss payments for hypothetical generators (£m)

		Total loss payments		
Hypothetical generator	Location of assumed portfolio of 4 x 1 GW plant	Uniform	Zonal	Change
North	13, 14, 12, 6	9.62	22.44	12.81
South	8, 11, 10, 9	9.62	–10.26	–19.88
Balanced	13, 6, 8, 9	9.62	5.58	–4.04

Note: A wholesale price of £45/MWh and plant load factors of 85% have been assumed. Zonal TLMs taken from 2006/07 modelling results.
Source: Oxera.

The figures show that a Northern generator with a 4 GW portfolio would see an increase in its loss payments of approximately £13m under a zonal loss charging regime, while a Southern-based generator would benefit by about £20m.

9.1.2 Suppliers

To investigate the potential transfers between suppliers, a similar exercise to that carried out above for generators was undertaken using hypothetical suppliers. The hypothetical supplier is assumed to have approximately 7% of the overall national demand in each of the four zones in which it operates.

Table 9.2 Change in annual loss payments for hypothetical suppliers (£m)

		Total loss payments		
Hypothetical generator	Location of assumed portfolio of 4 x 1 GW plant	Uniform	Zonal	Change
North	13, 14, 12, 6	30.97	–35.25	–66.22
South	8, 11, 10, 9	30.97	49.44	18.47
Balanced	13, 6, 8, 9	30.97	8.42	–22.55

Note: A wholesale price of £45/MWh has been assumed. Zonal TLMs taken from 2006/07 modelling results.
Source: Oxera.

The pattern of transfers is reversed compared with the impact on generation owners, as would be anticipated, with the hypothetical Northern supplier's loss charges reduced by £66m and the Southern supplier increasing its loss payments by £18m. The balanced participant would see an overall reduction in loss payments of £23m.

9.1.3 Zonal transfers

While the above analysis shows potential changes to identical hypothetical players, another view can be gained by looking at the overall changes at a regional level, without ascribing the impacts to any particular player. The results are shown in Table 9.3.

Table 9.3 Estimates of potential transfers between regions for 2006/07

	Demand (TWh)	Supplier TLMs	Transfers (£m)	Generation (TWh)	Generator TLMs	Transfers (£m)	Net transfers (£m)
North Scotland	10	0.979	10.57	9	0.972	–9.26	1.31
South Scotland	23	0.981	21.79	37	0.974	–34.07	–12.28
Northern	46	0.992	20.61	8	0.986	–3.46	17.14
North Western	26	0.997	6.98	17	0.990	–4.09	2.89
Yorkshire	28	0.992	13.55	76	0.985	–34.85	–21.31
Merseyside & North Wales	62	0.999	9.23	25	0.993	–2.99	6.24
East Midlands	19	1.004	–1.41	45	0.998	4.79	3.38
Midlands	9	1.011	–3.44	15	1.005	6.17	2.73
Eastern	22	1.012	–8.96	25	1.005	11.17	2.21
South Wales	50	1.011	–19.19	16	1.005	6.69	–12.50
South Eastern	11	1.015	–6.12	44	1.009	26.20	20.08
London	10	1.022	–8.13	3	1.015	2.59	–5.54
Southern	23	1.019	–16.80	21	1.012	16.13	–0.67
South Western	23	1.021	–18.67	18	1.014	14.97	–3.69
Total	**360**		**0**	**360**		**0**	**0**

Note: The generation and demand figures in each zone are based on the results of the Central scenario for 2006/07. The transfers are calculated by comparing loss payments that would occur for generators and consumers in each region under zonal loss charging and under uniform loss charging, with uniform factors calculated so that total loss payments across the country remain the same. The calculations assume an electricity price of £45/MWh. The totals may not sum due to rounding.
Source: Oxera.

The calculations show that the potential transfers between consumers and generators in each region are substantial for the base scenario in this year, and may be significantly larger than estimated efficiency gains from zonal loss charging. On the demand side, the figures suggest that Scottish electricity consumers might receive total benefits of approximately £32m, while consumers in the Northern English zones might receive total benefits in the region of £41m. Consumers in the rest of England and Wales would see an equivalent disbenefit of around £73m. The transfers between generating plant in different regions are also large. The calculations suggest that generators in Scotland might lose around £43m; generators in the Northern English zones might lose £42m; while generators in the rest of England and Wales might see equivalent gains in the order of £85m.

10 Conclusions

The introduction of zonal loss charging results in a number of benefits being realised by the system overall, specifically through:

– short-term redespatch changes (reducing the transfers of electricity across the transmission network and subsequently reducing losses), leading to benefits of between £3m and £9m per annum;

– a demand response—net changes in demand as a result of price changes also introduce net benefits into the system (£0.3–£1.2m per annum).

The relative strengths of the above benefits depend on the underlying market development, with changes in both the level of redespatch and the out-turn price of electricity at which losses are valued having significant impacts—the two alternative market scenarios analysed produced higher net benefits than the Central Scenario.

The introduction of adjusted ***seasonal*** zonal TLFs also increases the benefits under the base case when compared with using a single adjusted ***annual*** zonal TLF.

While the introduction of zonal loss charging does strengthen the signals for locating new plant closer to demand, the relative importance of this is ambiguous. Furthermore, analysis of the proposed new build suggests that the current signals are already providing sufficient incentives to build closer to demand as a significant proportion of current plans involve building in the South. For other new generation types—in particular, renewables—the introduction of zonal loss charging has no significant impact on the project's profitability and hence its likelihood of going ahead.

The presence of 132kV lines in Scotland influences the loss factors for the two Scottish zones, but Balancing Mechanism units connected to 132kV are neither further disadvantaged nor do they face sharper signals than an equivalent unit connected to a higher voltage within the same zone.

The introduction of zonal loss charging has negligible impact on the transmission network operation and development when compared with the same scenarios under uniform loss charging.

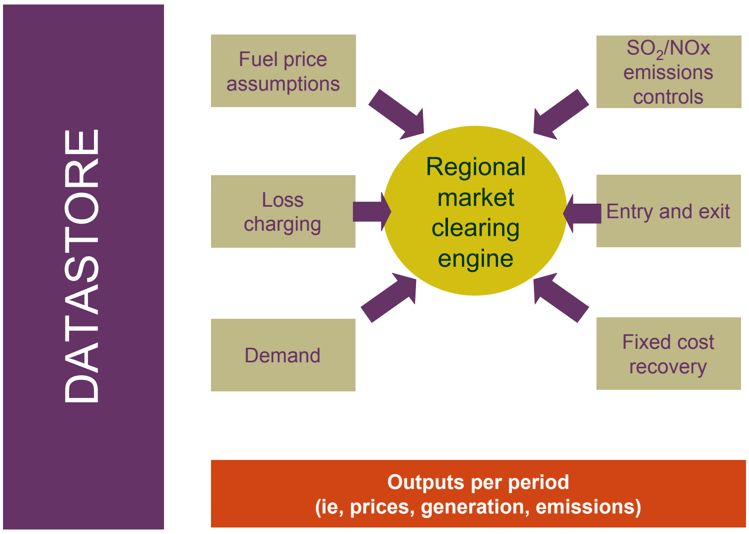
The implementation costs of zonal loss charging are largely up front, with an estimated £2m required for both central systems developments and market participants to make relevant changes to their systems. There is also an expected ongoing cost of some £300,000 per annum.

Zonal loss charging will result in significant transfers between market participants, with increased loss payments being made by generators in the North and suppliers in the South, and decreased loss payments being made by Southern generators and Northern suppliers.

Appendix 1 Oxera wholesale market model

The Oxera wholesale market model is a production cost model, with the facility for assessing the impact of zonal TLMs on generation despatch. Figure A1.1 illustrates the interactions in the model.

Figure A1.1 Oxera's electricity wholesale model



Source: Oxera.

For each time period, the model ranks the available generation on the basis of short-run marginal costs, reflecting:

– input fuel costs;
– plant efficiencies;
– loss charges;
– variable operating and maintenance costs;
– the variable costs of operating emissions-abatement equipment.

The ranked generators are then despatched against total demand. This calculation is performed simultaneously for all periods being modelled, thereby allowing the model to restrict SO_2 and NOx emissions (either individually or at a company level) for annual runs. The model allows transmission constraints across zones of the network to be taken into account—in particular, across the Scotland–England interconnector.

The model assumes that plant exit the market when their lifetime expires or when they are no longer economic to run. Oxera assumes that the published lifetimes of nuclear stations are adhered to, and that the lifetime of other plant can be extended, at least to 2015. New CCGT entry is assumed to occur when the average market price exceeds the long-run marginal cost of new-entry plant.

The model generates values for the following variables for each period:

– wholesale electricity prices;
– electricity generation;
– load factors of each plant;
– emissions.

For this project, Oxera ran its wholesale market model in two modes:

– snapshot demand mode—for selected demand conditions, the model was run to simulate despatch decisions under uniform and zonal loss charging, in order to provide inputs into the load–flow modelling exercise;

– full load–duration curve mode—once the load–flow modelling had produced estimates of TLMs for all years, the wholesale market model was run again using monthly load–duration curves for both uniform and zonal loss charging. This allowed the impact of zonal loss charging on a range of market outcomes to be examined.

Appendix 2 Validation of load–flow and despatching programs

Central scenario

	2006	2006	2007	2007	2008	2008	2009	2009	2010	2010	2011	2011	2012	2012	2013	2013	2014	2014
	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply
1	1.003	1.010	1.004	1.011	1.003	1.010	0.998	1.005	1.002	1.009	0.996	1.003	0.998	1.005	0.992	1.000	0.992	1.000
2	0.996	1.003	0.997	1.004	0.997	1.004	0.994	1.001	0.998	1.005	0.993	1.000	0.997	1.003	0.994	1.001	0.994	1.002
3	1.013	1.020	1.014	1.021	1.014	1.021	1.008	1.015	1.011	1.018	1.004	1.011	1.006	1.013	1.001	1.008	1.003	1.011
4	0.993	0.999	0.992	0.999	0.992	0.999	0.994	1.001	1.000	1.006	0.997	1.003	1.000	1.006	1.000	1.007	1.003	1.010
5	1.004	1.011	1.005	1.012	1.003	1.010	1.003	1.010	1.009	1.015	1.003	1.010	1.009	1.015	1.006	1.013	1.009	1.017
6	0.987	0.994	0.986	0.993	0.986	0.993	0.989	0.996	0.987	0.994	0.991	0.998	0.989	0.996	0.990	0.998	0.992	1.000
7	0.990	0.997	0.990	0.997	0.990	0.997	0.992	0.999	0.994	1.000	0.994	1.000	0.995	1.001	0.997	1.004	1.000	1.008
8	1.011	1.017	1.012	1.019	1.011	1.018	1.008	1.015	1.011	1.017	1.005	1.011	1.007	1.014	1.001	1.009	1.007	1.014
9	1.006	1.013	1.008	1.014	1.007	1.014	1.002	1.009	1.006	1.012	0.998	1.005	0.999	1.005	0.993	1.000	0.996	1.004
10	1.003	1.010	1.004	1.011	1.005	1.012	1.004	1.011	1.006	1.013	1.003	1.010	1.007	1.013	0.997	1.005	1.002	1.009
11	1.013	1.020	1.014	1.021	1.014	1.021	1.013	1.020	1.008	1.014	1.011	1.018	1.015	1.021	1.007	1.015	1.012	1.020
12	0.985	0.992	0.985	0.992	0.985	0.992	0.984	0.991	0.987	0.994	0.985	0.991	0.987	0.994	0.987	0.995	0.989	0.996
13	0.980	0.987	0.977	0.984	0.977	0.983	0.993	1.000	0.973	0.980	1.004	1.011	0.985	0.992	1.010	1.017	0.989	0.996
14	0.979	0.986	0.973	0.979	0.974	0.981	0.985	0.992	0.962	0.969	0.995	1.001	0.973	0.980	1.002	1.009	0.977	0.984

Source: Oxera.

Demand scenario

	2006	2006	2007	2007	2008	2008	2009	2009	2010	2010	2011	2011	2012	2012	2013	2013	2014	2014
	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply
1	1.004	1.011	1.005	1.011	1.004	1.010	1.002	1.009	0.998	1.004	0.994	1.001	0.995	1.002	0.993	1.000	0.993	1.001
2	0.996	1.003	0.997	1.004	0.997	1.004	0.997	1.003	0.996	1.002	0.993	1.000	0.993	1.000	0.994	1.002	0.994	1.001
3	1.013	1.020	1.015	1.022	1.014	1.020	1.012	1.018	1.006	1.012	1.005	1.012	1.007	1.014	1.004	1.011	1.006	1.013
4	0.990	0.997	0.990	0.996	0.989	0.996	0.995	1.002	0.999	1.006	1.002	1.009	0.999	1.006	1.000	1.007	1.000	1.007
5	1.003	1.010	1.003	1.010	1.003	1.010	1.005	1.012	1.006	1.012	1.008	1.015	1.006	1.013	1.005	1.012	1.006	1.014
6	0.987	0.994	0.987	0.993	0.987	0.994	0.987	0.994	0.991	0.998	0.991	0.999	0.991	0.998	0.990	0.998	0.993	1.001
7	0.989	0.996	0.989	0.996	0.989	0.996	0.992	0.998	0.995	1.002	0.997	1.004	0.995	1.002	0.997	1.004	0.996	1.004
8	1.011	1.018	1.013	1.019	1.012	1.019	1.011	1.018	1.006	1.012	1.005	1.013	1.006	1.013	1.003	1.011	1.007	1.015
9	1.007	1.014	1.009	1.015	1.007	1.014	1.006	1.013	0.999	1.005	0.998	1.005	0.999	1.006	0.997	1.004	0.999	1.006
10	1.004	1.011	1.004	1.011	1.004	1.011	1.006	1.013	1.003	1.010	0.998	1.006	0.998	1.006	0.991	0.998	0.994	1.001
11	1.014	1.020	1.015	1.022	1.015	1.022	1.009	1.015	1.006	1.012	1.011	1.018	1.011	1.018	1.007	1.014	1.009	1.017
12	0.984	0.991	0.985	0.992	0.985	0.992	0.986	0.992	0.987	0.993	0.986	0.994	0.986	0.993	0.987	0.994	0.988	0.996
13	0.981	0.988	0.978	0.984	0.978	0.985	0.978	0.984	0.991	0.997	0.994	1.001	0.994	1.001	1.005	1.013	0.994	1.001
14	0.981	0.988	0.970	0.977	0.972	0.979	0.970	0.977	0.984	0.991	0.986	0.993	0.986	0.993	1.000	1.007	0.986	0.993

Source: Oxera.

Gas scenario

	2006	2006	2007	2007	2008	2008	2009	2009	2010	2010	2011	2011	2012	2012	2013	2013	2014	2014
	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply
1	1.001	1.007	0.999	1.006	0.995	1.003	1.001	1.007	0.994	1.000	0.996	1.003	0.994	1.001	0.995	1.003	0.990	0.997
2	1.000	1.007	0.999	1.006	0.994	1.001	1.001	1.008	0.996	1.003	0.997	1.004	0.992	0.999	0.994	1.002	0.988	0.996
3	1.009	1.016	1.008	1.014	1.004	1.012	1.009	1.016	1.001	1.008	1.004	1.011	1.003	1.010	1.008	1.016	1.002	1.010
4	0.995	1.002	0.996	1.002	0.995	1.003	0.998	1.004	1.003	1.009	1.002	1.009	1.000	1.007	1.000	1.008	1.001	1.009
5	1.006	1.013	1.006	1.013	1.005	1.012	1.009	1.015	1.008	1.014	1.010	1.017	1.006	1.013	1.009	1.017	1.006	1.014
6	0.984	0.991	0.985	0.992	0.987	0.994	0.986	0.992	0.990	0.996	0.986	0.993	0.988	0.995	0.984	0.992	0.993	1.001
7	0.992	0.999	0.993	0.999	0.994	1.001	0.994	1.000	0.998	1.005	0.996	1.003	0.996	1.003	0.994	1.001	1.000	1.008
8	1.009	1.016	1.008	1.015	1.005	1.013	1.010	1.016	1.001	1.008	1.007	1.014	1.003	1.010	1.011	1.019	1.004	1.012
9	1.003	1.010	1.002	1.009	0.999	1.007	1.004	1.010	0.994	1.000	0.998	1.005	0.997	1.005	1.003	1.010	0.996	1.004
10	1.005	1.011	1.004	1.011	1.002	1.010	1.005	1.012	1.000	1.006	1.007	1.014	0.998	1.006	1.004	1.012	0.995	1.003
11	1.013	1.020	1.013	1.020	1.011	1.018	1.007	1.013	1.001	1.008	1.015	1.022	1.008	1.016	1.015	1.023	1.007	1.015
12	0.987	0.993	0.987	0.993	0.985	0.993	0.989	0.996	0.988	0.995	0.987	0.994	0.985	0.992	0.986	0.993	0.986	0.994
13	0.981	0.988	0.984	0.991	0.998	1.006	0.975	0.982	1.004	1.011	0.986	0.993	1.009	1.016	0.984	0.991	1.013	1.021
14	0.974	0.981	0.977	0.984	0.993	1.001	0.965	0.971	0.998	1.004	0.974	0.981	1.001	1.008	0.972	0.980	1.005	1.013

Source: Oxera.

BSC Winter

S1	2006	2006	2007	2007	2008	2008	2009	2009	2010	2010	2011	2011	2012	2012	2013	2013	2014	2014
	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply
1	1.007	1.014	1.007	1.014	1.007	1.014	1.009	1.015	1.009	1.015	1.006	1.013	1.004	1.011	0.997	1.003	0.997	1.004
2	0.998	1.005	0.999	1.005	0.999	1.006	1.000	1.007	1.000	1.007	0.998	1.004	0.999	1.006	0.992	0.999	0.992	0.999
3	1.017	1.024	1.019	1.025	1.020	1.027	1.021	1.028	1.021	1.028	1.018	1.025	1.016	1.022	1.008	1.015	1.011	1.017
4	0.991	0.998	0.991	0.998	0.991	0.998	0.991	0.998	0.996	1.002	0.995	1.001	0.995	1.001	0.995	1.002	0.997	1.003
5	1.005	1.012	1.006	1.012	1.007	1.013	1.007	1.014	1.009	1.015	1.008	1.015	1.008	1.015	1.004	1.010	1.006	1.012
6	0.984	0.990	0.983	0.990	0.982	0.989	0.981	0.988	0.983	0.989	0.982	0.989	0.984	0.991	0.990	0.997	0.994	1.000
7	0.988	0.995	0.988	0.995	0.987	0.994	0.987	0.994	0.990	0.996	0.989	0.996	0.990	0.996	0.992	0.999	0.995	1.002
8	1.016	1.023	1.018	1.024	1.019	1.026	1.021	1.028	1.019	1.026	1.017	1.023	1.015	1.022	1.007	1.014	1.010	1.016
9	1.010	1.017	1.012	1.019	1.013	1.020	1.014	1.021	1.014	1.021	1.010	1.017	1.007	1.013	0.999	1.006	1.002	1.009
10	1.008	1.014	1.009	1.016	1.012	1.019	1.013	1.020	1.010	1.017	1.011	1.017	1.010	1.017	0.998	1.005	1.002	1.008
11	1.018	1.025	1.020	1.027	1.023	1.030	1.024	1.031	1.013	1.019	1.021	1.027	1.020	1.027	1.010	1.017	1.014	1.020
12	0.984	0.991	0.984	0.991	0.984	0.991	0.984	0.991	0.986	0.993	0.983	0.990	0.985	0.992	0.984	0.991	0.986	0.993
13	0.965	0.971	0.961	0.968	0.958	0.965	0.954	0.960	0.953	0.959	0.962	0.969	0.963	0.969	0.999	1.006	0.983	0.989
14	0.980	0.986	0.974	0.980	0.969	0.976	0.963	0.970	0.961	0.967	0.968	0.975	0.968	0.975	1.007	1.014	0.987	0.994

Source: Oxera.

BSC Spring

s2	2006	2006	2007	2007	2008	2008	2009	2009	2010	2010	2011	2011	2012	2012	2013	2013	2014	2014
	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply
1	1.001	1.007	1.004	1.011	0.998	1.005	1.005	1.012	1.000	1.006	1.002	1.009	0.996	1.003	0.994	1.001	0.991	0.997
2	1.000	1.007	0.999	1.006	0.995	1.002	1.001	1.008	0.997	1.003	0.998	1.004	0.995	1.002	0.998	1.005	0.996	1.003
3	1.009	1.016	1.014	1.021	1.009	1.016	1.016	1.023	1.010	1.016	1.012	1.019	1.006	1.013	1.002	1.009	1.000	1.006
4	0.995	1.002	1.001	1.008	0.999	1.006	0.997	1.004	1.000	1.006	0.999	1.006	1.000	1.007	0.999	1.006	1.003	1.009
5	1.006	1.013	1.009	1.016	1.004	1.011	1.010	1.017	1.007	1.014	1.009	1.016	1.007	1.014	1.008	1.014	1.008	1.015
6	0.984	0.991	0.986	0.993	0.989	0.996	0.985	0.992	0.990	0.997	0.987	0.994	0.992	0.999	0.988	0.995	1.002	1.008
7	0.992	0.999	0.994	1.001	0.994	1.001	0.992	0.999	0.995	1.002	0.993	1.000	0.996	1.003	0.996	1.002	1.003	1.009
8	1.009	1.016	1.012	1.019	1.006	1.013	1.014	1.021	1.007	1.014	1.010	1.016	1.004	1.011	1.006	1.013	1.003	1.010
9	1.003	1.010	1.007	1.015	1.002	1.009	1.010	1.017	1.002	1.009	1.005	1.011	0.997	1.003	0.995	1.002	0.992	0.999
10	1.005	1.011	1.004	1.011	0.999	1.006	1.009	1.016	1.000	1.006	1.006	1.013	1.002	1.008	1.006	1.013	0.997	1.003
11	1.013	1.020	1.014	1.021	1.009	1.016	1.019	1.026	1.002	1.009	1.014	1.021	1.009	1.016	1.012	1.019	1.007	1.013
12	0.987	0.993	0.987	0.994	0.985	0.992	0.988	0.995	0.987	0.994	0.986	0.992	0.986	0.993	0.988	0.995	0.992	0.998
13	0.981	0.988	0.968	0.975	0.995	1.002	0.963	0.970	0.989	0.996	0.979	0.986	1.001	1.007	0.999	1.006	1.004	1.010
14	0.974	0.981	0.950	0.957	0.984	0.991	0.941	0.948	0.970	0.977	0.956	0.962	0.980	0.986	0.978	0.985	0.981	0.988

Source: Oxera.

BSC Summer

S3	2006	2006	2007	2007	2008	2008	2009	2009	2010	2010	2011	2011	2012	2012	2013	2013	2014	2014
	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply
1	1.001	1.008	1.004	1.010	0.999	1.005	1.005	1.011	0.997	1.003	0.996	1.002	0.998	1.003	0.993	0.999	0.990	0.997
2	0.997	1.004	1.001	1.008	0.995	1.002	1.001	1.007	0.998	1.004	0.996	1.002	0.994	1.000	0.998	1.004	0.995	1.001
3	1.009	1.016	1.013	1.019	1.008	1.014	1.014	1.021	1.004	1.010	1.002	1.008	1.006	1.011	1.000	1.006	1.000	1.007
4	1.000	1.007	0.997	1.003	0.995	1.002	0.996	1.002	1.000	1.006	0.999	1.005	1.000	1.006	1.000	1.006	1.001	1.007
5	1.006	1.012	1.006	1.012	1.003	1.010	1.008	1.014	1.005	1.011	1.005	1.011	1.004	1.010	1.007	1.013	1.007	1.013
6	0.989	0.995	0.989	0.995	0.990	0.997	0.987	0.993	0.993	0.999	0.993	0.999	0.991	0.997	0.990	0.996	0.994	1.000
7	0.995	1.001	0.993	0.999	0.993	0.999	0.992	0.998	0.996	1.002	0.996	1.002	0.995	1.000	0.996	1.002	1.000	1.006
8	1.007	1.014	1.009	1.015	1.005	1.012	1.012	1.018	1.003	1.009	1.002	1.008	1.004	1.010	1.004	1.010	1.004	1.010
9	1.003	1.009	1.005	1.012	1.001	1.007	1.007	1.014	0.998	1.004	0.996	1.002	0.997	1.003	0.994	1.000	0.994	1.001
10	1.000	1.006	1.002	1.008	1.000	1.006	1.007	1.013	0.998	1.004	1.001	1.006	1.000	1.006	1.005	1.011	1.003	1.010
11	1.008	1.015	1.010	1.017	1.008	1.014	1.015	1.021	0.999	1.005	1.007	1.013	1.007	1.013	1.010	1.016	1.009	1.015
12	0.988	0.995	0.989	0.996	0.987	0.993	0.989	0.995	0.990	0.996	0.988	0.994	0.986	0.991	0.989	0.995	0.988	0.995
13	0.980	0.987	0.974	0.980	0.996	1.002	0.968	0.974	0.997	1.002	1.004	1.010	0.999	1.005	1.004	1.010	1.007	1.013
14	0.975	0.982	0.962	0.968	0.987	0.993	0.955	0.961	0.986	0.992	0.992	0.998	1.016	1.022	0.992	0.998	0.995	1.001

Source: Oxera.

BSC Autumn

S4	2006	2006	2007	2007	2008	2008	2009	2009	2010	2010	2011	2011	2012	2012	2013	2013	2014	2014
	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply	Generation	Supply
1	1.008	1.014	1.008	1.014	1.007	1.013	1.003	1.008	1.002	1.007	1.000	1.006	0.998	1.003	0.999	1.005	0.993	1.000
2	0.998	1.004	0.999	1.004	0.998	1.004	0.995	1.001	0.996	1.001	0.994	1.000	0.994	1.000	1.001	1.007	0.995	1.002
3	1.016	1.022	1.017	1.022	1.016	1.022	1.012	1.018	1.011	1.016	1.009	1.015	1.006	1.011	1.008	1.014	1.004	1.011
4	0.992	0.998	0.992	0.998	0.992	0.998	0.992	0.998	1.000	1.006	0.996	1.001	1.000	1.006	1.002	1.009	1.010	1.017
5	1.003	1.009	1.004	1.009	1.004	1.009	1.002	1.008	1.004	1.010	1.003	1.009	1.004	1.010	1.008	1.015	1.010	1.017
6	0.986	0.991	0.985	0.991	0.985	0.991	0.988	0.993	0.989	0.994	0.988	0.994	0.991	0.997	0.992	0.998	0.998	1.005
7	0.989	0.995	0.989	0.995	0.989	0.995	0.990	0.995	0.994	0.999	0.992	0.998	0.995	1.000	0.997	1.004	1.004	1.011
8	1.013	1.019	1.014	1.019	1.013	1.019	1.011	1.017	1.009	1.014	1.007	1.013	1.004	1.010	1.004	1.010	1.002	1.009
9	1.009	1.015	1.009	1.015	1.009	1.015	1.005	1.011	1.004	1.009	1.002	1.008	0.997	1.003	0.998	1.005	0.995	1.002
10	1.004	1.009	1.005	1.010	1.005	1.010	1.003	1.009	1.000	1.005	1.003	1.009	1.000	1.006	0.997	1.003	0.996	1.003
11	1.013	1.019	1.014	1.020	1.014	1.020	1.013	1.019	1.001	1.007	1.010	1.016	1.007	1.013	1.006	1.012	1.005	1.012
12	0.985	0.991	0.986	0.991	0.985	0.991	0.985	0.990	0.986	0.991	0.984	0.990	0.986	0.991	0.990	0.997	0.992	0.999
13	0.974	0.980	0.971	0.977	0.973	0.979	0.984	0.990	0.986	0.991	0.994	0.999	0.999	1.005	0.986	0.992	0.992	0.999
14	0.995	1.000	0.990	0.996	0.992	0.998	1.002	1.008	1.004	1.009	1.006	1.012	1.016	1.022	0.969	0.976	0.975	0.982

Source: Oxera.

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