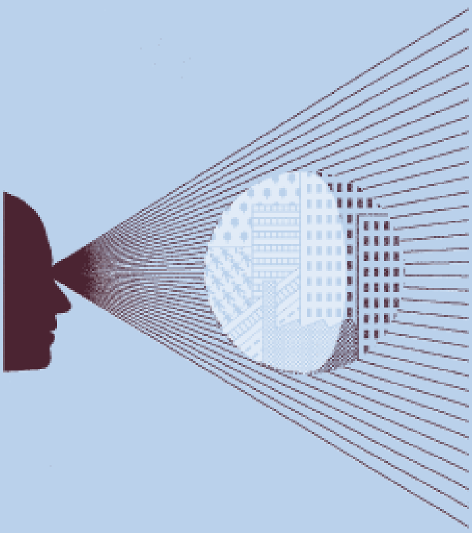
Oxera

What are the costs and benefits of annual and seasonal scaled zonal loss charging?

Prepared for
ELEXON

September 2006



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1 Introduction

1.1 Terms of reference

This study assesses the potential impact of the proposed introduction of a scaled zonal transmission losses scheme, applicable throughout Great Britain (hereafter referred to as P204).[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 P198.[2] The approach used for this current CBA is identical to that used in the previous P198 analysis. Specifically, the analysis of P204 in this report uses the same Central market scenario as that presented in the P198 analysis to allow the industry to compare results with those presented under the previous proposal for both annual scaled loss charging and seasonal scaled loss charging.

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 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.

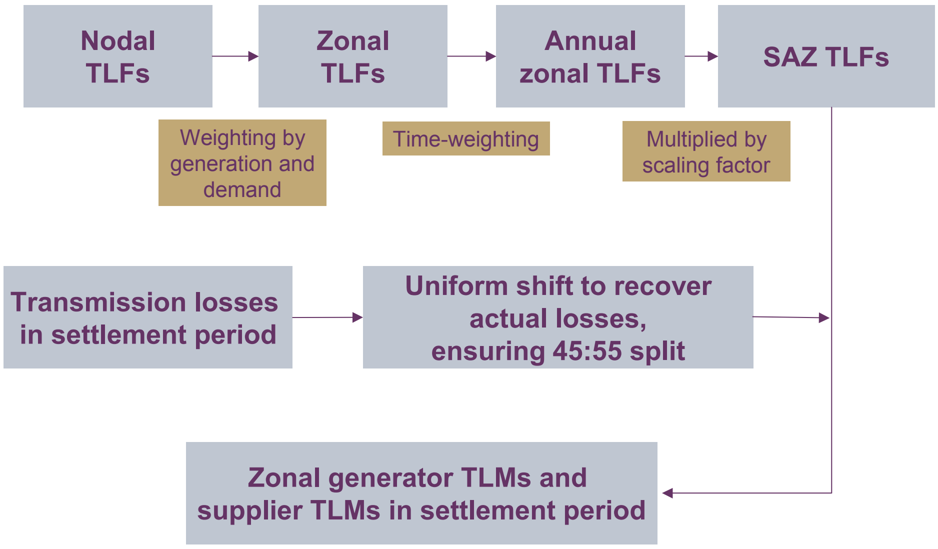
Under the proposed P204 methodology, TLMs will differ between grid supply point (GSP) groups. Nodal transmission loss factors (TLFs) for historic settlement periods are derived from load–flow modelling. They are converted into scaled annual zonal TLFs (SAZ TLFs) by weighting across nodes using absolute flows, and then weighting across different settlement

[1] BSC Modification Proposal P204, ‘Scaled Zonal Transmission Losses’, http://www.elexon.co.uk/documents/modifications/204/P204.doc
[2] Oxera (2006), 'What are the costs and benefits of zonal loss charging?', July.

periods adjusted by a scaling factor. Whereas P198 used a scaling factor of 0.5, P204 suggests the use of a different factor to scale TLFs to SAZ TLFs. The value of the scaling factor is to be derived year-on-year (based on algebra provided to Oxera by ELEXON) and is such that, on average, no Balancing Mechanism unit is credited with energy due to the allocation of variable transmission losses.

SAZ TLFs are fixed annually, and give rise to differentials between loss charges in different zones. SAZ TLFs are shifted up and down uniformly to derive TLMs for each settlement period that recovers actual losses in the ratio 45:55 between generation and supply. The procedure for calculating SAZ TLMs is illustrated in Figure 1.1.

Figure 1.1 Derivation of SAZ TLFs and TLMs under P204 methodology



Source: Oxera.

1.3 Relevant impacts

The application of scaled 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 scaled zonal loss charging applied throughout Great Britain.

– **Reduction in losses**—scaled 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 scaled 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 scaled zonal loss charging and those under a uniform loss charging regime;

– *location of new entry*—similarly, if scaled 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 customers face lower loss charges, any induced consumption will reduce the size of the net benefits gained from other behavioural changes.

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 scaled 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 scaled 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, scaled 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.

– 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 scaled zonal

[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.

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 scaled 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, 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 scaled zonal loss transmission charging. Conversely, the Southern regions that will perhaps benefit under scaled zonal loss charging have significant potential for new offshore wind development. However, it is plausible that applying scaled zonal loss charging across Great Britain may reduce the overall growth of renewables generation.[5]

– **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.

Many of the above impacts were addressed in detail in Oxera's July 2006 analysis of P198, and found to range from minimal to non-existent. Rather than rehearse the same discussions within this report, where the impacts are likely to be either the same or less than those identified in the previous report, these will be referenced, but not quantified further.

1.4 Distributional impacts

Because efficiency benefits arise from the impact of scaled zonal loss charging on marginal generators and consumers, whereas transfer effects also include the impact of scaled 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 larger than the net national resource benefit of scaled 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, as stated in previous work, 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 in this study centres on comparing the results of modelling potential market outcomes under both uniform loss charging (the 'base case' under the current loss charging regime) and scaled zonal loss charging (the 'change case' representing implementation of P204).

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[6] to

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

[5] In Oxera's July 2006 analysis, *all* renewable technologies were investigated, not just wind. That analysis concluded—as is restated in section 3.9—that the introduction of zonal loss charging had no impact on the development of renewable technologies relative to the status quo.

[6] 2005/06 was only modelled in order to obtain SAZ TLFs for the modelling of 2006/07.

2015/16. This enabled the potential level of TLMs to be estimated under the scaled zonal loss charging methodology. Modelling the effect of these TLMs on the wholesale market enabled analysis of the potential impact of scaled zonal loss charging on:

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

In addition to impacts on the current fleet of generation assets, the importance of scaled zonal loss charging was previously 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. This analysis showed that there were significant locational signals present within the current access charging regime, and that, while the introduction of scaled zonal loss charging strengthens these signals, they are not sufficient to induce any further changes in plant location.

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 scaled zonal loss charging, and the potential direction and size of the net national resource benefit.

2 Modelling approach

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

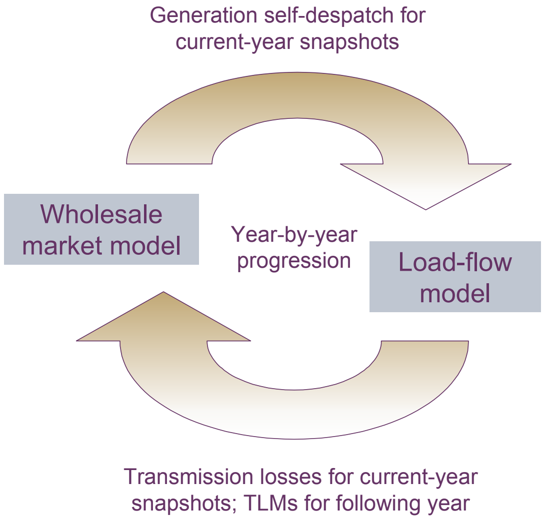
– **A full load–flow model of the GB transmission network**[7]—for given generator outputs, the model was run (by Professor Bialek) using two representations of the transmission network:

  – a DC network to estimate scaled zonal loss factors (as per P204);
  – 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 scaled zonal loss factors on the self-despatch decisions of generators and on other market outcomes (e.g., 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 SAZ TLMs for 2005/06, which were used to alter generation despatch decisions in 2006/07 under the scaled zonal loss charging regime.

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

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

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

These model runs allowed estimates to be made of the impact of scaled 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 scaled 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. SAZ 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 SAZ 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 SAZ 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. This allowed the total net benefit of scaled zonal loss charging to be calculated.

2.1 Use of snapshot periods

In evaluating the impacts of P204, 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 P204. 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[8] 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. Using algebra provided by ELEXON, the values of beta+ and beta– were calculated for each snapshot. The smaller of beta+ and beta– was then taken as the scaling factor beta for a given snapshot. Finally, the average annual scaling factor was determined from the three snapshots using the weights shown in Table 2.1. This average annual scaling factor was used to determine the SAZ TLFs to be used for the following modelling year.

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

2.2 Model validation

With the exception of the scaling factor, the methodology for calculating TLMs under P204 is identical to that for P198. As such, the calculation of TLFs based on 2005/06 data (for use in 2006/07 despatch) is identical to the previous modelling exercise. Therefore, the extensive model validation and verification exercise undertaken prior to the P198 analysis, and presented in the July 2006 Oxera report, still holds and is not reproduced here.

One additional validation step was performed to check the correctness of the calculated values of the scaling factor. The essence of P204 is to determine a value of the scaling factor beta such that the maximum resulting TLM for generators (or minimum TLM for suppliers) is equal to 1 when only variable transmission losses are considered. To check this, the TLMs for generators and suppliers were calculated for each snapshot using the scaling factor beta valid for that snapshot. Whenever beta+ was smaller then beta–, beta+ was taken to be the scaling factor beta for that snapshot, and the resulting TLMs for generators were checked to be such that the maximum value was equal to 1. Whenever beta– was smaller than beta+, beta– was taken to be the scaling factor for that snapshot, and the resulting TLMs for suppliers were checked to be such that the minimum value was equal to 1. As SAZ TLFs are calculated using a single annual average value of the scaling factor, the maximum values of actual TLMs for generators (and minimum values of TLMs for suppliers) were generally not exactly equal to 1.

2.3 Modelling scenario

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 on the generation sector—SO_2 and NO_X B limits,[9] and the limitations imposed by plant taking the Large Combustion Plant Directive (LCPD) opt-out derogation.

In order to undertake a meaningful cost–benefit analysis comparing scaled zonal loss charging with the current methodology, an underpinning Central scenario was developed, making assumptions on each of the drivers above.

2.3.1 Central scenario

The following describes briefly the major assumptions underpinning the Central scenario.

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.

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

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

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 was 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 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 (e.g., 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 assumes 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.

[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.
[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.

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 2.2.

Table 2.2 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 within the scenario.

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 2.3). 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 2.3 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 Summary of main scenario drivers

Table 2.4 sets out the main drivers of the Central scenario.

Table 2.4 Summary of main scenario drivers

Scenario	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
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

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 the Central 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 2.5.

Table 2.5 Zonal breakdown of new entry by year under the Central scenario (MW)

Year/zone	Eastern	East Midlands	Southern	South Eastern	South Wales	South Western	Total
2010						1,000	1,000
2011			850				850
2012				1,200			1,200
2013		800			1,000		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 Seasonal variant

The Seasonal scenario was a variant of the TLF methodology based around the Central market scenario; therefore the market outcomes were the same.

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

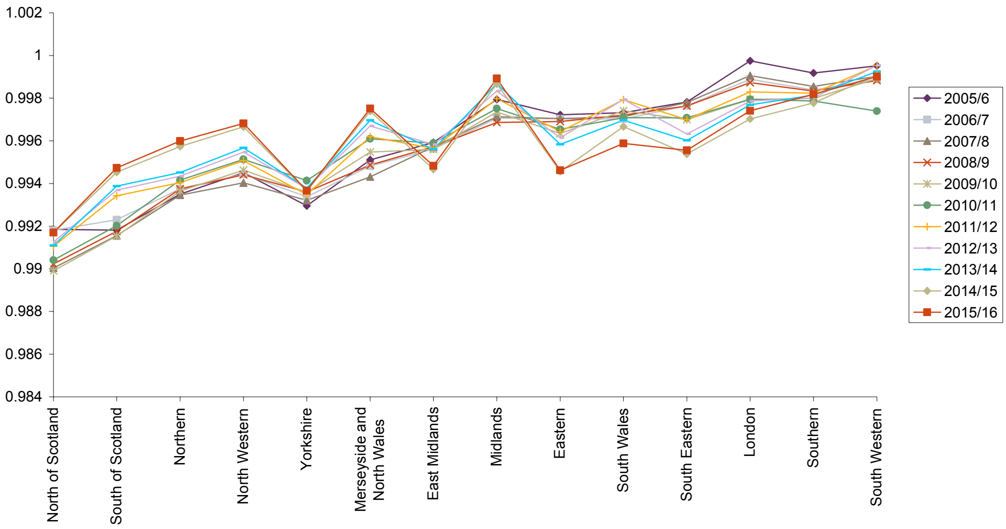
Source: ELEXON.

3.1 Estimated scaled annual zonal TLMs

Figures 3.1 and 3.2 show the variability of the scaled annual zonal TLMs over the modelling period for generators and suppliers, respectively. It is important to appreciate that the TLMs calculated recover only the variable losses as estimated by the load–flow program for a given snapshot. In practice, the TLMs will also have to recover fixed losses, which are difficult to predict. These will make the generator TLMs lower and the supplier TLMs higher. Also, the values of TLMs shown are the annual averages. In practice, they would be shifted uniformly from one trading period to the next in order to recover actual transmission losses.

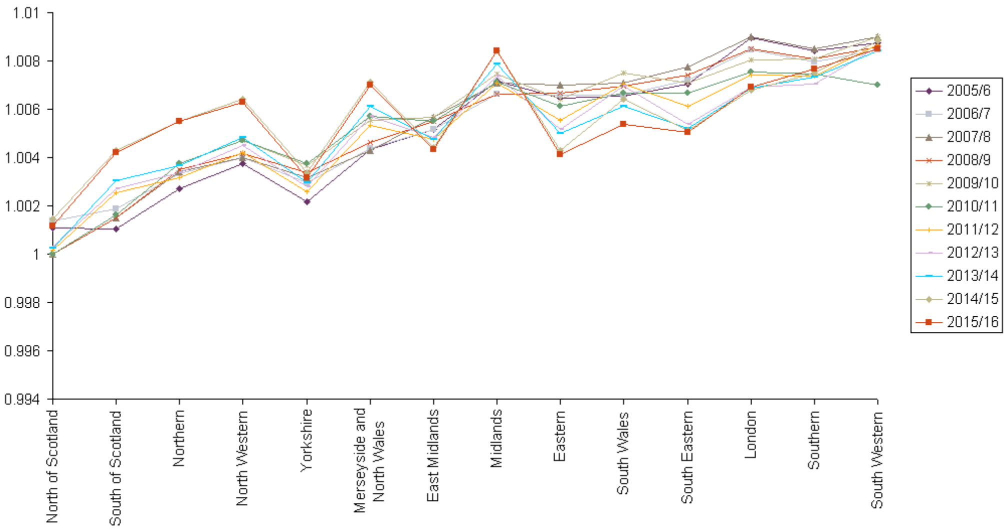
The geographical spread of scaled annual zonal TLMs under P204 is slightly less than 1%, and therefore is much less than under P198. All the generator TLMs are below 1, while all the supplier TLMs are above 1. This means that no generator or supplier is credited with energy as the result of the variable loss allocation. The year-on-year values of TLMs are relatively stable, with the exception of the last two years (20014/15 and 2015/16).

Figure 3.1 Scaled annual zonal TLMs for generators



Source: Oxera.

Figure 3.2 Scaled annual zonal TLMs for suppliers



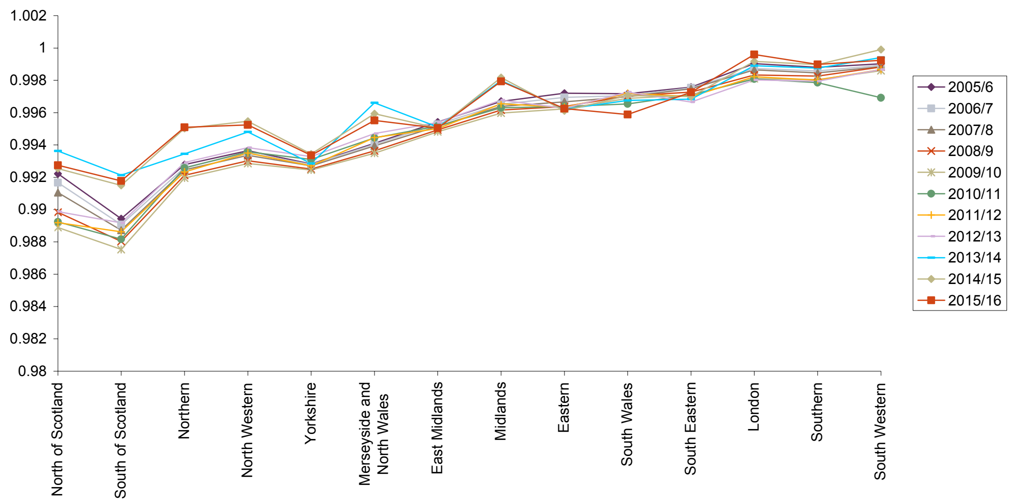
Source: Oxera.

3.2 Estimated scaled seasonal zonal TLMs

The diagrams below show the average values of delivery (generator) TLMs in each of four BSC seasons. The values shown are the seasonal averages while the actual TLM values change from one settlement period to the next as they have to recover the actual transmission losses incurred in a given period. The TLMs values have been calculated using a load flow program and therefore they recover variable losses only. In practice, TLMs will have to recover fixed losses as well so the actual values of generator TLMs are expected to be slightly lower, while the offtaking (supplier) TLMs are expected to be slightly higher.

Figure 3.3 shows variation in the seasonal zonal TLMs for BSC Winter. Until 2013/14, only the TLM values in Scotland and zone 11 change from year to year. From 2013/14 the TLM values start to change in other zones too and especially so in Scotland.

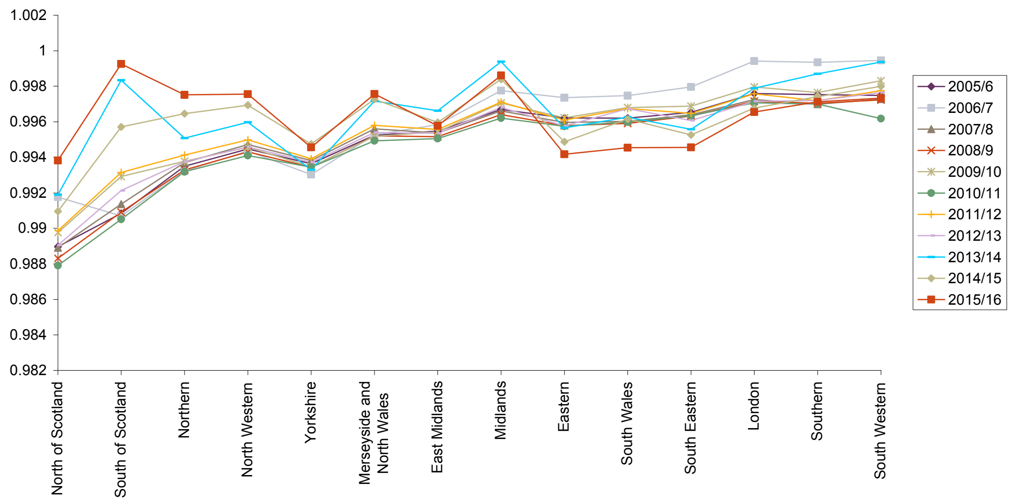
Figure 3.3 Scaled seasonal zonal TLMs for generators (BSC Winter)



Source: Oxera.

Figure 3.4 shows variation in the seasonal zonal TLMs for BSC Spring. Until 2013/14, the TLM values change slowly from year to year. From 2013/14 the TLM values start to change more in all the zones but especially in zone 13.

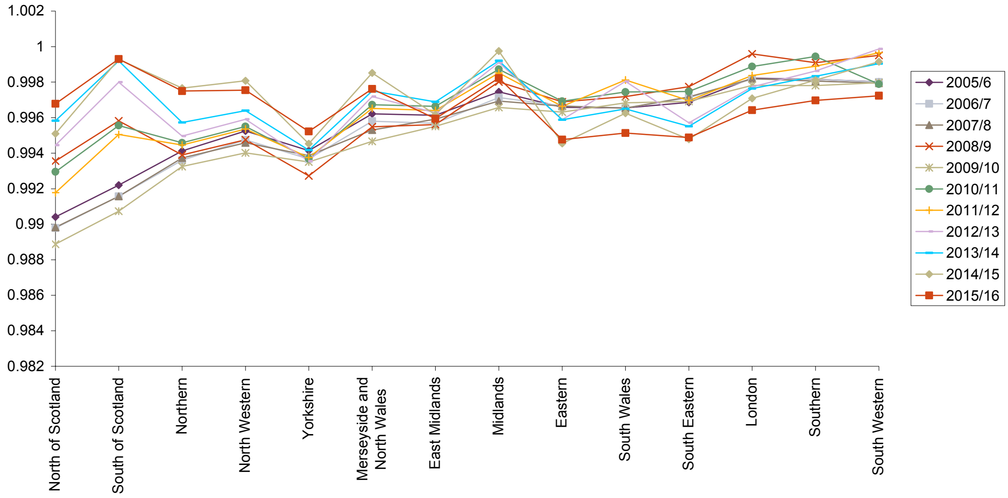
Figure 3.4 Scaled seasonal zonal TLMs for generators (BSC Spring)



Source: Oxera.

Figure 3.5 shows the TLMs in BSC Summer. Until 2008/9 the TLMs remain almost the same in all the zones. From 2008/9, the TLMs start to change slowly in all the zones apart from Scotland where the changes are much bigger. From 2014/15, there are big changes in all the zones.

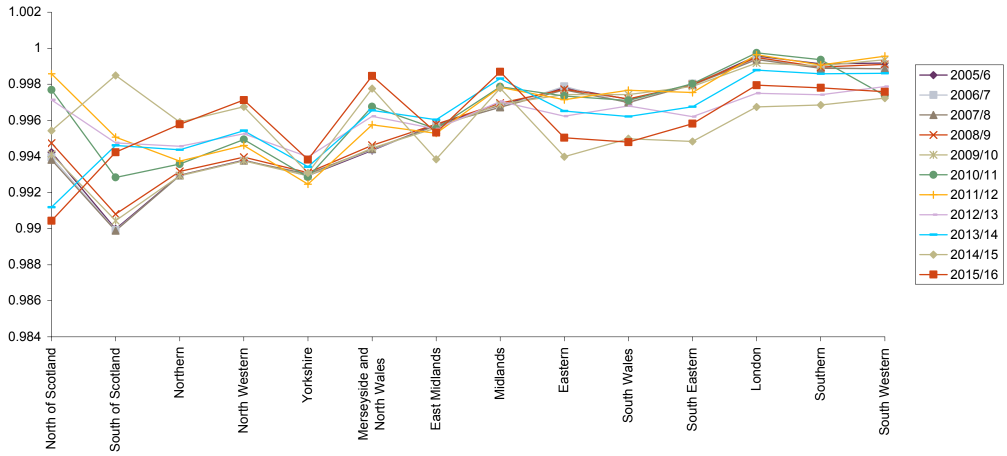
Figure 3.5 Scaled seasonal zonal TLMs for generators (BSC Summer)



Source: Oxera.

Figure 3.6 shows variation in the seasonal zonal TLMs for BSC Autumn. Until 2010/11, the TLM values change very little from year to year. From 2010/11 the TLM values become volatile, especially in Scotland.

Figure 3.6 Scaled seasonal zonal TLMs for generators (BSC Autumn)



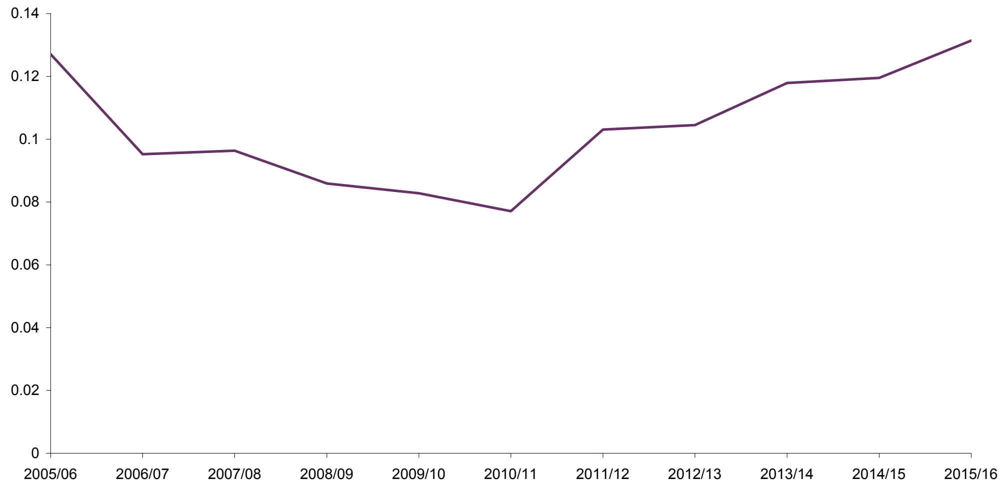
Source: Oxera.

3.3 Variability of the scaling factor beta

Figure 3.7 shows variability of the scaling factor beta over the modelling period under the Central scenario. Initially, the beta assumes a value of 0.127, and then falls before recovering towards the initial value towards the end of the modelling period. There was no consistency to whether it was beta+ or beta– that was smaller, and therefore no consistency as to which beta was used in the calculation, although more often than not beta+ was larger than beta–.

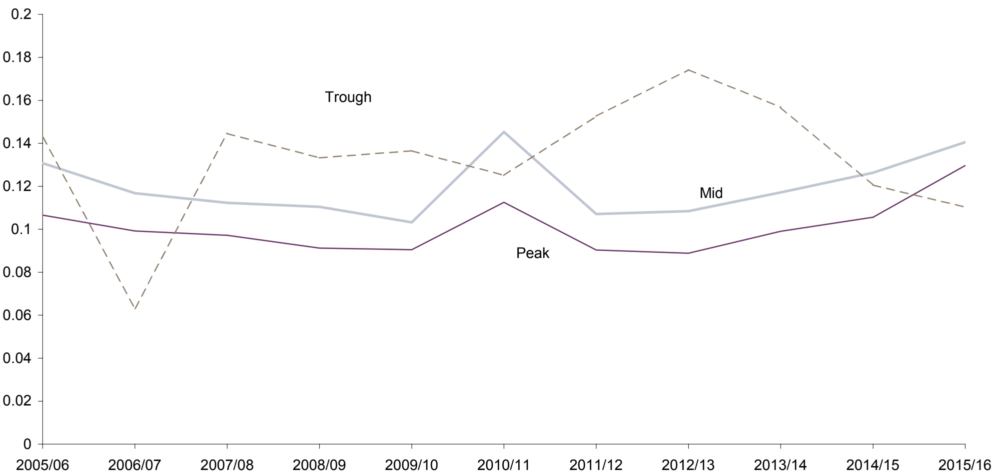
There was also no consistency to whether betas increase with the load (and therefore the level of variable losses) or decrease. Figure 3.8 and 3.9 show how beta+ and beta– behaved for the three modelled loading levels (peak, mid and trough) and over the modelling time horizon. Both betas tended to be smaller for peak than for midpoint load, which was to be expected, as the geographical spread of TLFs is wider at peak than at midpoint. Therefore, a lower value of the scaling factor is needed at peak in order to reduce the geographical spread. Betas for the trough period also tended to be higher than for midpoint, but occasionally the opposite case was found.

Figure 3.7 Variability of the scaling factor beta



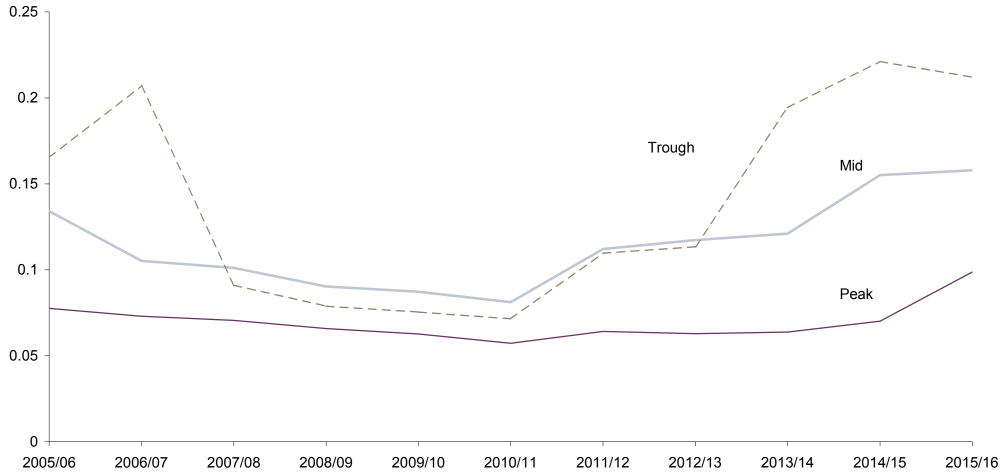
Source: Oxera.

Figure 3.8 Variability of beta+ for the three modelled loading levels



Source: Oxera.

Figure 3.9 Variability of beta– for the three modelled loading levels

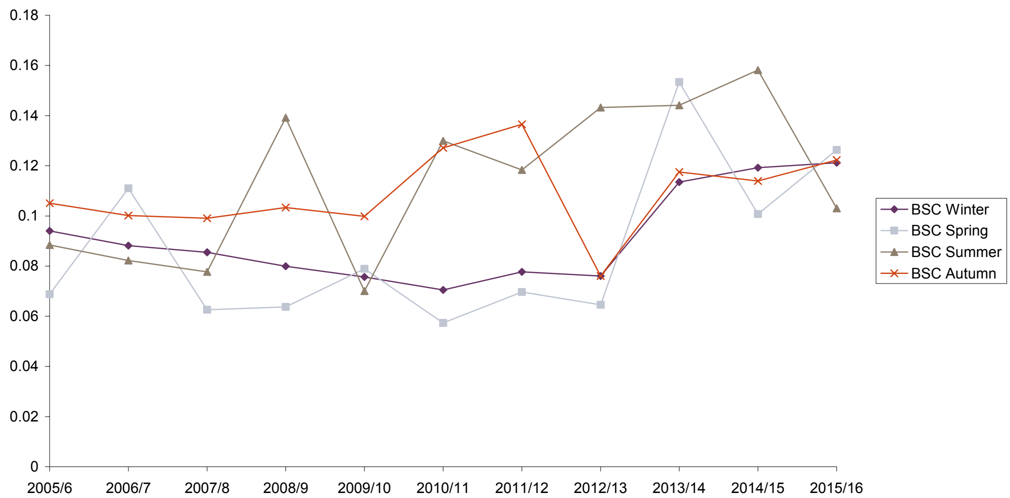


Source: Oxera.

Seasonal beta

Figure 3.10 shows average seasonal betas. In general, betas experienced a high level of volatility over the modelling horizon. Initially, betas in season 1 were slowly dropping, but then rose sharply from 2013/14. Betas for season 2 were initially quite stable, apart from 2006/07, and became quite volatile from 2013/14. Betas for season 3 were quite stable for the first three years, increased in 2008/9, returned to their initial level in 2009/10, and then rose again. Betas for season 4 were quite stable until 2009/10 and then increased sharply, dropping down only for 2012/13.

Figure 3.10 Seasonal betas



Source: Oxera

3.4 Patterns of generation during snapshot periods

Uniform and zonal condition results from the load–flow model were compared in order to calculate the loss difference occurring under the scaled zonal loss conditions. 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).

NB: at various stages during the following analysis comparisons are made between modelling in respect to P204 and work previously undertaken to assess P198. Where such comparisons occur they are explicitly between the results for annual TLMs under P204 and annual TLMs under P198 or ***between results for seasonal TLMs under P204 and seasonal TLMs under P198.***

As expected, the results show that where the introduction of scaled zonal loss charging induced large zonal redespatch effects, higher loss reductions were observed; where no inter-zonal redespatch occurred, loss savings were found to be negligible.

3.4.1 Central scenario

Table 3.2 below shows the effects of scaled annual zonal loss charging on despatch and losses under the Central scenario. It shows a limited degree of redespatch and loss savings; in the mid and trough snapshot periods with the majority of these occurring in the first two years. A more significant degree of zonal relocation of generation is observed in the peak period in all years of the modelling horizon, usually from Northern England zones into central and Southern England zones.

Changes in the profile of fuel mix are more limited, and occur in only one year, with CCGT gaining generation in two snapshots. This may be partly explained by the zonal shift away from Scotland, which has proportionally more coal plant.

Table 3.2 Change in despatch and losses in the Central scenario

	Peak		Mid		Trough	
Year	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)
2006/07	149MW from North Western into Eastern	–6.2	No change	–0.1	2,088MW from South Scotland into East Midlands, South Eastern	–57.6
2007/08	528MW from Midlands, North Western into Eastern	–22.4	1,055MW from Merseyside & North Wales into East Midlands, Midlands	–2.6	2,715MW from Northern, South Wales, South Scotland into Merseyside & North Wales, South Eastern, Yorkshire. 1,235MW from coal into CCGT	–84.7
2008/09	854MW from North Western, Yorkshire into Eastern	–55.8	No change	0	No change	0
2009/10	854MW from North Western, Yorkshire into Eastern	–40.9	No change	0	No change	0
2010/11	854MW from North Western, Yorkshire into Eastern	–53.5	No change	0	No change	0
2011/12	216MW from Yorkshire into Eastern	–11.5	No change	0	No change	0

Note: This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 3.2.
Source: Oxera.

Compared with the results under the P198 Central scenario, the greatest difference is in the later years, when the reduced locational despatch signals result in no despatch changes (when compared to the uniform result) during the mid and trough periods. The peak period redespatch has been largely unaffected.

3.4.2 Seasonal scenario

Tables 3.3 to 3.5 show the effects of scaled seasonal zonal loss charging on despatch and losses under the Seasonal scenario during peak, trough and midpoint periods. Broadly, the redespatch follows the expected trend of moving geographically from Northern zones towards mid and southern areas.

Generally, within the peak period, the signals during Winter offer similar savings when compared to the savings under P198's Seasonal scenario, although with lower reductions in later years. The results for the BSC summer show no change across the modelling horizon.

Table 3.3 Change in despatch and losses in the Seasonal scenario: peak period

	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	247MW from Yorkshire into Eastern	–12.2	801MW from North Western, Yorkshire into Eastern	–30.7	No change	0	36MW from Yorkshire into Eastern	–1.6
2007/08	247MW from Yorkshire into Eastern	–11.6	801MW from North Western, Yorkshire into Eastern	–29.8	No change	0	26MW from Merseyside & North Wales into East Midlands	–4.1
2008/09	186MW from Northern into East Midlands	–5.7	662MW from North Western, Yorkshire into Eastern	–23	No change	0	53MW from Merseyside & North Wales into East Midlands	–1.3
2009/10	323MW from Northern into East Midlands	–19.3	551MW from Yorkshire into Eastern	–30.7	No change	0	35MW from Yorkshire into South Wales. 35MW from CCGT into coal	–2.3
2010/11	448MW from Northern, Yorkshire into East Midlands, Southern. 67MW from CCGT into Oil	–24.7	800MW from North Western, Yorkshire into Eastern	–29.9	No change	0	1198MW from Northern, Yorkshire into East Midlands. 885MW from CCGT into coal	9.7
2011/12	2363MW from Eastern, Northern, Yorkshire into East Midlands, London, Southern, South Eastern. 67MW from CCGT into Oil	–17	209MW from Merseyside & North Wales into East Midlands	–4.1	No change	0	1837MW from Northern, North Western, Yorkshire into Eastern, East Midlands, Southern, South Wales. 885MW from CCGT into coal	–29.6

Note: This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 3.5.
Source: Oxera.

During trough periods, there are again less loss savings available when compared to the P198 analysis, with Winter peaks offering very limited savings during the period. Autumn is the exception, although here the results are still significantly lower than those under P198.

Table 3.4 Change in despatch and losses in the Seasonal scenario: trough period

	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	No change	0	455MW from South Scotland into South Eastern	–27.5	1601MW from South Scotland into East Midlands, Merseyside & North Wales, South Eastern, South Wales. 763MW from Coal into CCGT	–81.3	No change	0
2007/08	No change	0	1128MW from South Scotland into South Eastern	–110.8	No change	0.0	No change	0
2008/09	No change	0	No change	0	No change	0	2088MW from South Scotland into London, Southern. 701MW from Coal into CCGT	–149.1
2009/10	No change	0	No change	0	No change	0	2088MW from South Scotland into East Midlands, Southern	–147.8
2010/11	No change	0	No change	0	546MW from Eastern, North Western, Yorkshire into South Eastern	–4.5	2027MW from South Scotland into East Midlands, Southern	–134.9
2011/12	548MW from South Wales, South Western into London	27.5	No change	0	No change	0	2088MW from South Scotland into East Midlands, Southern	–108.1

Note: This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 3.6.
Source: Oxera.

Finally, midpoint results show reductions in losses during the Winter and Autumn similar to those under the P198 Seasonal scenario, while there are lower loss savings during Spring and, more significantly, Summer.

Table 3.5 Change in despatch and losses in the Seasonal scenario: midpoint period

	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	155MW from East Midlands into Eastern	–46.2	625MW from North Scotland into East Midlands. 625MW from CCGT into coal	–63.9	No change	0	213MW from Eastern into South Eastern	–3.3
2007/08	No change	–40.9	590MW from Yorkshire into Southern. 590MW from CCGT into coal	–32.4	No change	0	444MW from Eastern into South Eastern	–7
2008/09	912MW from Yorkshire into Eastern	–43.3	No change	0	1920MW from South Scotland into East Midlands, Southern	–48.9	587MW from Eastern, East Midlands into South Eastern	–11.5
2009/10	942MW from Yorkshire into Eastern	–45.2	1474MW from South Scotland into Southern	–135.2	No change	0	507MW from Eastern, East Midlands into South Eastern	–18.9
2010/11	109MW from East Midlands into Eastern, South Eastern	–40.6	No change	0	414MW from South Scotland into East Midlands	1.5	No change	0
2011/12	No change	0	512MW from South Scotland into Southern	–41.3	323MW from South Scotland into East Midlands	–3.8	237MW from South Scotland into North Scotland	–8.4

Note: This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 3.7.
Source: Oxera.

In summary, the introduction of scaled seasonal zonal loss charging does have an impact on despatch decisions, resulting in a general shift of generation from North to South. Beyond the first few years of the study, the impact of P204 is mainly during the peak periods.

Compared with the seasonal results from P198, scaled seasonal loss charging under P204 induces less North to South redespatch, and hence reduced loss savings.

3.5 Changes in annual zonal output

Table 3.6 shows how the application of estimated scaled 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. Uniform results were subtracted from scaled zonal results to obtain differences between the charging regimes.

3.5.1 Central scenario

The Central scenario shows a general pattern of generation moving away from Yorkshire, Northern, North Western and North Scotland plant towards Southern and South Eastern zones.

Table 3.6 Changes in annual output by zone in the Central scenario (GWh)

GSP group description	2006	2007	2008	2009	2010	2011
Eastern	545	600	650	741	–414	1,122
East Midlands	619	417	313	372	–247	–12
London	0	0	5	2	55	22
Merseyside & North Wales	–40	–42	–26	–82	490	–1
Midlands	–1	–102	0	0	0	0
Northern	–484	–605	–359	–370	0	0
North Western	–50	–130	–106	–91	–94	–195
Southern	1	20	–2	–3	54	4
South Eastern	46	186	166	121	340	205
South Wales	0	0	–13	3	16	–4
South Western	0	0	1	1	9	–7
Yorkshire	–723	–499	–506	–535	–273	–1,139
South Scotland	0	0	0	0	0	0
North Scotland	0	–1	–174	–196	16	–5
Reduction in losses	**86**	**154**	**51**	**37**	**48**	**11**

Note: This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 3.8.
Source: Oxera.

As was seen in the P198 analysis, there is a 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 scaled 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.

When compared against the results from the P198 analysis, the Southern zones do not appear to be increasing their output to the same extent as seen previously. This is mirrored in the lower reductions in output from the Northern and Scottish generators in the current results compared with those under P198. These two effects are a direct result of the weakened redespatch signals of P204 compared with P198.

3.5.2 Seasonal scenario

Table 3.7 shows the changes in output by zone for the seasonal variant. Again, the pattern is similar to that seen under the Central scenario, with movements generally being from the North and West towards the South and East. When compared to the annual scaled loss charging in the Central scenario, however, there are more substantial savings in losses following the introduction of seasonal scaled zonal charging.

Table 3.7 Changes in annual output by zone in the Seasonal scenario (GWh)

GSP group description	2006	2007	2008	2009	2010	2011
Eastern	530	603	1113	706	991	1043
East Midlands	593	449	296	294	–734	–18
London	0	0	–1	2	8	23
Merseyside & North Wales	–42	–28	–669	–128	34	–31
Midlands	–3	–101	0	0	0	0
Northern	–781	–816	–594	–490	0	0
North Western	–117	–129	–133	–118	–95	–215
Southern	3	24	111	–15	–9	0
South Eastern	46	185	301	111	241	182
South Wales	0	0	–18	3	8	–5
South Western	0	0	0	0	5	–15
Yorkshire	–460	–282	–513	–500	–567	–1,080
South Scotland	1	0	0	0	0	0
North Scotland	0	0	–171	–250	–4	–8
Reduction in losses	**231**	**97**	**279**	**385**	**122**	**124**

Note: This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 3.11.
Source: Oxera.

Comparing the results against those calculated under P198, there seems to be a systematic reduction in loss savings brought about by the weaker despatch signals provided by P204 when compared to P198. Again, as in the Central Scenario, the overall pattern shows lower reductions in output from the Northern generators and a similarly lower increase in Southern generation reflecting the shallower spread of despatch signals.

3.6 Changes in output by fuel type

3.6.1 Central scenario

Modelling in the Central scenario indicates a significant degree of fluctuation in the level of gas-fired generation across the modelling horizon. In earlier years the reduction in gas is generally passed through to an overall reduction in generation; in later years there is more interaction between coal and gas. There are small increases in the use of oil, pumped storage and OCGT in 2010/11, but few changes in other fuel types otherwise.

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

Fuel type	2006	2007	2008	2009	2010	2011
Oil	0	–1	0	0	72	0
Coal	–6	10	–12	–50	–401	–1
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	0	0	28	0
Hydro	0	0	0	0	0	0
External	0	0	0	0	0	0
OCGT	0	0	0	0	24	0
CCGT	–80	–163	–38	14	225	–10
CHP	0	0	0	0	0	0
Other	0	0	0	0	4	0
Reduction in losses	**86**	**154**	**51**	**37**	**48**	**11**

Note: This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 3.12.
Source: Oxera.

When comparing the above results with those from the P198 analysis, there are similar changes in the earlier years—i.e., there is still a bias in gas providing the main changes in output—although this does switch back to coal in 2009 and 2010.

3.6.2 Seasonal scenario

The Seasonal scenario shows far more fuel impact than the Central scenario, with the majority of this impact coming from gas-fired generation. Again, due to the closing differential between coal and gas prices in 2010, the switch here is for significant movements away from coal into gas, but still markedly less so than in P198's Seasonal scenario analysis.

Table 3.9 Changes in annual output by fuel type in the Seasonal scenario (GWh)

Fuel type	2006	2007	2008	2009	2010	2011
Oil	0	–1	–2	–3	–2	–4
Coal	–15	14	–44	–49	–823	–26
AGR	0	0	0	0	0	0
PWR	0	0	0	0	0	0
Magnox	0	0	0	0	0	0
Pumped storage	–1	0	0	0	–1	–1
Hydro	0	0	0	0	0	0
External	0	0	0	0	0	0
OCGT	0	0	0	0	–1	–1
CCGT	–215	–110	–232	–333	705	–91
CHP	0	0	0	0	0	0
Other	0	0	0	0	0	–1
Reduction in losses	**231**	**97**	**279**	**385**	**122**	**124**

Note: This table corresponds to equivalent P198 presented in Oxera July 2006, Table 3.15.
Source: Oxera.

The introduction of scaled seasonal zonal loss charging results in gas generation bearing the majority of the output reductions in the early years, switching to reductions in coal output towards the end of the decade, particularly in the Seasonal scenario.

When compared with the seasonal results under P198, seasonal scaled zonal loss charging induces broadly the same pattern of fuel switching, albeit with lower absolute changes (reflecting the reduced despatch signals and lower loss savings overall).

3.7 Impact on losses

Tables 3.10 and 3.11 below present the estimated change in losses obtained from the load–flow modelling for the Central scenario and the seasonal variant. 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 3.11 and 3.12 has been scaled by 100/60 to show the impact on total losses.

3.7.1 Near-term loss impacts

The following tables show the impact of scaled zonal loss charging on:

- estimated annual loss savings—from the snapshot load–flow modelling;
- total energy produced—the total annual demand on the generators prior to scaled 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 scaled annual and seasonal zonal loss charging.

3.7.2 Central scenario

Annual savings in losses are quite volatile, ranging from 11GWh to 154GWh during the modelling horizon. 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 3.10 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)	86	154	51	37	48	11
Total energy produced (GWh)	360,000	363,000	366,000	369,000	370,000	372,000
Loss saving as % of energy produced	0.02%	0.04%	0.01%	0.01%	0.01%	0.00%
Variable uniform losses (GWh)	3,800	4,081	3,913	4,043	3,844	3,677
Loss savings as % of variable losses	2.26%	3.78%	1.30%	0.91%	1.25%	0.29%
Estimated total losses (GWh)	6,333	6,802	6,522	6,738	6,406	6,129
Loss saving as % of total losses	1.36%	2.27%	0.78%	0.55%	0.75%	0.17%
Cost of electricity (£/MWh)	44.4	42.5	35.8	33.9	32.5	35.2
Value of total energy sold (£m)	16,000	15,400	13,100	12,500	12,000	13,100
Value of losses (£m)	3.4	6.0	1.6	1.0	1.4	0.3

Note: This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 3.17.
Source: Oxera.

Overall, the results show that the introduction of scaled annual zonal loss charging results in a slightly more efficient despatch than the uniform loss-charging regime, with average annual savings ranging from £0.3m to £6m per annum 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.

When compared to the analysis under P198, net benefits are, on average lower under P204, with two years being significantly lower. Highlighting 2009/10, the introduction of annual zonal loss charging under P198 resulted in significant movements in generation from Southern Scotland to more southerly zones, with subsequently large benefits in loss savings. In contrast, the introduction of annual scaled zonal loss charging did not result in as large a redespatch in generation, with subsequently only modest loss savings. The net impact is that implementing P204 rather than P198 offers significantly less (~66%) benefit.

Table 3.11 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)	231	97	279	385	122	126
Total energy produced (GWh)	360,000	363,000	366,000	369,000	370,000	372,000
Loss saving as % of energy produced	0.07%	0.03%	0.08%	0.11%	0.03%	0.04%
Variable uniform losses (GWh)	4,131	4,245	4,377	4,664	4,143	3,941
Loss savings as % of variable losses	5.59%	2.28%	6.37%	8.26%	2.94%	3.19%
Estimated total losses (GWh)	6,884	7,075	7,296	7,773	6,906	6,569
Loss saving as % of total losses	3.35%	1.37%	3.82%	4.96%	1.76%	1.92%
Cost of electricity (£/MWh)	44.4	42.5	35.8	33.9	32.5	35.2
Value of total energy sold (£m)	16,000	15,400	13,100	12,500	12,000	13,100
Value of losses (£m)	8.3	3.4	7.7	10.4	3.2	3.5

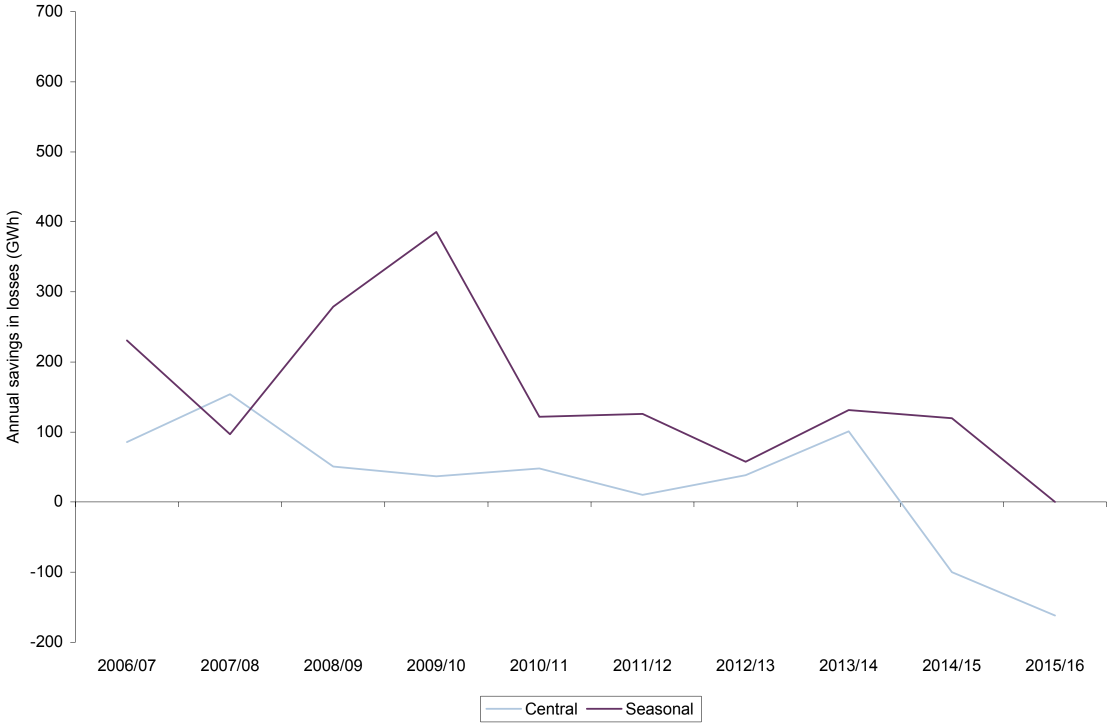
Note: This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 3.20.
Source: Oxera.

Seasonal rather than annual loss factors increase the loss savings compared with the Central scenario, owing to the more focused costing of losses across seasons. Again, the savings in losses are generally greater towards the start of the period than at the end.

When comparing the seasonal variant under P204 with the seasonal variant of P198, the former offers lower overall loss savings across the modelling horizon. Overall, the difference in net benefits between the two regimes (P198 seasonal and P204 seasonal) is more uniform, without any of the significant changes in any one year seen in the P204 Central scenario (discussed above). The overall redespatch benefit of implementing seasonal loss charging under P204 instead of P198 is therefore moderately less (a 50% reduction in net benefits).

Longer-term loss savings
While small loss savings are evident in the early years, towards the end of the modelling horizon results indicate a reversal of the effects of the regime, leading to increased losses in 2014/15 in the Central Scenario (see Figure 3.11). 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.

Figure 3.11 Annual loss savings (GWh)



Source: Oxera.

A similar pattern is observed in the Seasonal scenario (although loss savings remain positive until the end of the 10-year modelling horizon), again due to the location of new generation plant in the South.

The most striking difference between the annual and seasonal results for P204 is in 2009/10, when the introduction of seasonal scaled loss charging results in savings of 400GWh while annual scaled loss charging results in some 50GWh of loss savings. This is the result of the more focused signals achieved during the different seasons inducing changes in generation during the mid and trough periods under seasonal charging, whereas annual charging results in different despatches only during the peak period.

As discussed in the previous P198 analysis, the relocating of generation to the South is not a result of scaled zonal loss charging, as current incentives (such as TNUoS charges) are already leading to generation location decisions being biased towards the South.

Bringing together the values of loss savings from the data underpinning Tables 3.10 and 3.11 shows that in the Central scenario there are average cost savings of £1.0m per annum (average over ten years), with average annual savings of £2.7m between 2006 and 2011. The loss savings under the Seasonal scenario average £4.7m per annum over 10 years with average savings of £6.1m per annum over the first six.

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 the overall transfers in later years, and hence reduces the impact of scaled zonal loss charging. However, these reductions in losses occur *even under the current loss charging regime*.

3.8 Impact on electricity prices

Table 3.12 presents the year-on-year baseload electricity price, with changes overall being marginal. Results for the Central scenario show a general reduction in baseload price between 2006 and 2011, except in 2010/11 when modelling results indicate a slight increase in the uniform loss price. Analysing the whole modelled period, the price trend was one of decline over the first five years, followed by a levelling off and slight rise in the next five years. The seasonal baseload price showed a slight reduction compared to the central equivalent following the introduction of zonal losses.

Table 3.12 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	44.29	42.29	35.62	33.77	32.91	35.03
Seasonal	Uniform	44.44	42.47	35.80	33.91	32.52	35.15
Seasonal	Zonal	44.28	42.28	35.50	33.73	32.42	35.03

Note: This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 3.21.
Source: Oxera.

The introduction of either annual or seasonal scaled loss charging has a marginal and uncertain impact on wholesale electricity prices.

3.9 Other impacts

Previous Oxera work has examined the impact of zonal loss charging on a number of other areas of the GB electricity system. That analysis found that the introduction of zonal loss charging had little or no impact on:

– *the siting of new large-scale generation assets*—the current locational signals provided by transmission use of system charges already create incentives for new build in Southern generation zones;
– *incentives for new renewable build*—the support provided by the Renewables Obligation in general, coupled with local level planning difficulties for new projects (specifically wind), outweigh the locational signals of zonal loss charging;
– *development of the transmission system*—as the introduction of zonal loss charging has no impact on the siting of either new generation projects or new renewable projects, the future development of the transmission network is the same, with and without zonal loss charging;
– *operation of the interconnectors*—the patterns of despatch of the interconnectors (relative to other generation in the same zone) meant that they were not affected by changes in the loss charging regime;
– *perception of risks for new projects*—the introduction of zonal loss charging does not alter the perceived level of risk. 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.

As the signals on generation (both for the siting of new plant and the despatch of existing plant) are reduced under scaled zonal loss charging (P204) when compared with those under zonal loss charging (P198), the resultant impacts will continue to be minimal and are therefore not considered further.

4 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.[14] 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,[15] while the UK Treasury has used a figure of –0.187 to analyse the impact of tax changes.[16] 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.[17]

Based on the range of existing estimates, the high and low figures set out in Table 4.1 were used to assess the potential impact of scaled 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 4.1 Assumptions on electricity price elasticity

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

Source: Oxera.

Table 4.2 below provides estimates under the Central scenario 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 SAZ TLFs. This approach results in only very approximate estimates, since actual loss impacts will vary between nodes on the network and between time periods.

Overall, results from the Central scenario suggest a spread of benefits ranging from a saving of £69,000 to a loss of £2,000. There is a positive value of loss reduction in every zone except Midlands, which loses value, and South Wales and South Eastern, where there is almost no effect.

[14] For example, a demand elasticity of –0.3 means that, for a 1% increase in price, consumption would fall by 0.3%.
[15] Miller, J.I. (2001), 'Modelling Residential Demand for Electricity in the U.S: A Semiparametric Panel Data Approach', mimeo, Rice University, November.
[16] http://www.parliament.the-stationery-office.co.uk/pa/cm199798/cmhansrd/vo980210/text/80210w09.htm.
[17] http://www.nemmco.com.au/publications/soo/410–0023.pdf.

Table 4.2 Potential annual benefits from the demand-side response to scaled zonal loss charging: Central scenario

	Consumption (GWh)	Estimated change in consumption (MWh)				Estimated change in losses (MWh)		Estimated value of loss reduction (£)	
Scenario		Low		High		Low	High	Low	High
		Domestic	I&C	Domestic	I&C				
North Scotland	12,000	1,399	8,970	3,265	16,146	–750	–1,404	27,000	51,000
South Scotland	25,000	2,011	12,891	4,692	23,204	–1,012	–1,895	37,000	69,000
Northern	19,000	1,013	6,496	2,364	11,692	–337	–631	12,000	23,000
North Western	27,000	961	6,163	2,243	11,093	–262	–491	10,000	18,000
Yorkshire	29,000	1,852	11,871	4,321	21,368	–640	–1,199	23,000	44,000
Merseyside & North Wales	19,000	379	2,432	885	4,377	–88	–165	3,000	6,000
East Midlands	32,000	794	5,091	1,853	9,164	–126	–235	5,000	9,000
Midlands	36,000	–594	–3,807	–1,386	–6,853	32	59	–1,000	–2,000
Eastern	42,000	451	2,889	1,052	5,200	–21	–39	1,000	1,000
South Wales	14,000	–107	–686	–250	–1,235	6	11	0	0
South Eastern	26,000	1	5	2	9	0	0	0	0
London	35,000	–878	–5,626	–2,048	–10,128	–87	–164	3,000	6,000
Southern	39,000	–957	–6,134	–2,233	–11,041	–58	–108	2,000	4,000
South Western	15,000	–585	–3,749	–1,365	–6,749	–53	–99	2,000	4,000
Total	370,000	5,741	36,804	13,397	66,247	–3,397	–6,359	124,000	233,000

Note: The calculations in the above table use average SAZ TLFs and SAZ TLMs over the period 2006/07 to 2015/16, combined with averaged annual prices from the uniform and scaled zonal variants and average annual demand levels. This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 6.2.
Source: Oxera.

4.1.1 Seasonal variant

The demand response under the seasonal variant could result in annual savings of between £244,000 and £457,000 per annum, substantially lower than those available under the P198 variant.

Table 4.3 Potential benefits from the demand-side response to scaled zonal loss charging: Seasonal scenario

	Consumption (GWh)	Estimated change in consumption (MWh)				Estimated change in losses (MWh)		Estimated value of loss reduction (£)	
		Low		High		Low	High	Low	High
		Domestic	I&C	Domestic	I&C				
North Scotland	12,000	2,037	13,055	4,752	23,499	–809	–1,514	30,000	55,000
South Scotland	25,000	4,024	25,792	9,388	46,426	–1,938	–3,629	71,000	133,000
Northern	19,000	2,606	16,706	6,081	30,071	–856	–1,602	31,000	59,000
North Western	27,000	3,230	20,705	7,536	37,268	–794	–1,487	29,000	54,000
Yorkshire	29,000	4,268	27,359	9,959	49,246	–1,368	–2,561	50,000	94,000
Merseyside & North Wales	19,000	1,971	12,632	4,598	22,737	–380	–712	14,000	26,000
East Midlands	32,000	3,249	20,830	7,582	37,494	–451	–844	17,000	31,000
Midlands	36,000	2,389	15,314	5,574	27,565	–93	–174	3,000	6,000
Eastern	42,000	3,599	23,071	8,398	41,528	–176	–330	6,000	12,000
South Wales	14,000	1,115	7,150	2,603	12,870	–63	–117	2,000	4,000
South Eastern	26,000	2,000	12,818	4,666	23,073	–41	–77	2,000	3,000
London	35,000	1,765	11,316	4,119	20,368	137	257	–5,000	–9,000
Southern	39,000	1,969	12,622	4,594	22,720	108	202	–4,000	–7,000
South Western	15,000	668	4,282	1,559	7,708	55	102	–2,000	–4,000
Total	370,000	34,890	223,651	81,409	402,573	–6,669	–12,485	244,000	457,000

Note: The calculations in the above table use average SAZ TLFs and SAZ TLMs over the period 2006/07 to 2015/16, combined with averaged annual prices from the uniform and scaled zonal variants and average annual demand levels. This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 6.5.
Source: Oxera.

Demand-side response will, in both the short and long 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 £0.12m to £0.23m per annum in the Central scenario (compared with £0.43m to £0.81m per annum under P198), to £0.24m to £0.46m per annum in the Seasonal scenario (compared with £0.53m to £0.98m per annum under P198). The lower demand-side response under P204 is a result of the weakened signals on suppliers when compared with P198.

5 Implementation costs

The costs of implementing scaled 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 estimated implementation costs of P204 are marginally higher than those for P198 (as reported in the previous CBA, Oxera July 2006). The only difference between the costs summarised in Table 5.1 and those presented previously is an increase in Central costs of £24,000.[18]

5.1 Total implementation costs

Using the above information, Table 5.1 brings together the estimated implementation costs for market participants, the transmission company, and ELEXON.

Table 5.1 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	491	±35%
Total	**2,087**	**±60%**

Source: Oxera calculations.

5.1.1 Total ongoing costs

Similarly, should P204 be implemented, the expected annual operating costs for the Transmission Company and ELEXON are expected to be £10,000 higher than those presented in P198's CBA.[19] The costs to market participants are expected to be the same as those under P198. **Therefore, it is assumed that an annual figure of £100,000 is incurred by market participants, in addition to the £210,000 operational costs for the transmission company, and ELEXON, providing a total ongoing cost of ~£310,000 per annum.**

[18] Information provided to Oxera by ELEXON.

[19] Information provided to Oxera by ELEXON.

6 Overall cost–benefit

6.1 Summary of benefits

6.1.1 Redespatch

The results presented in section 3 suggest that the introduction of scaled 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). These generation shifts result in annual savings ranging from £0.3m to £6m per annum up to 2011/12 under the Central Scenario, with an average saving of £1.0m per annum up to 2015/16. Under the Seasonal scenario annual savings are generally higher, reflecting more targeted loss reductions, with savings of between £3.2m and £10.4m per annum up to 2011/12 and an average saving of £4.7m per annum up to 2015/16. Savings are generally higher in the earlier years, reflecting their higher cost of electricity, and the impact of new, predominantly Southern, generation from 2009/10 onwards.

6.1.2 Demand-side response

The analysis suggests that there would be limited demand-side response to scaled 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 £0.12m–£0.23m per annum for annual scaled loss charging and £0.24m–£0.46m per annum for seasonal scaled loss charging.

6.1.3 Other benefits

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

6.2 Comparison of benefits and costs

Table 6.1 combines the benefits discussed above with the ongoing operational and other offsetting costs to present a view of the net benefits to 2015/16.

Table 6.1 Scenarios of future benefits of scaled zonal transmission losses to 2015/16 (£m)

	Central	Seasonal
Assumed annual benefits		
Generation redespatch	1.0	4.7
Demand response	0.2	0.4
Assumed annual operating costs	0.3	0.3
Assumed implementation costs	2.1	2.1
NPV of future benefits to 2015/16	**3.8**	**32.4**

Note: This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 8.1.
Source: Oxera.

The overall net benefits have been constructed by calculating the benefits and costs for all years until 2015/16 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.[20]

Overall, the Central scenario suggests net benefits of £3.8m 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. Meanwhile, benefits under the Seasonal scenario are higher, with potential total net benefits of £32.4m.

The major difference between the seasonal and annual variants of P204 is the impact of the more targeted loss charging from Seasonal TLMs when compared to annual TLMs. In particular, in 2009/10 the seasonal variant achieves considerable loss savings by moving generation from the North towards the South, something that the flatter signals from the annual scenario fail to achieve. This is also apparent when comparing the overall results from P198 to those of P204. Under P198, the stronger locational signals were still sufficient to move a considerable amount of generation from North to South in the P198 Central scenario as well as the P198 Seasonal scenario.

[20] 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.

7 Distributional impacts

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

7.1 Generator and supplier transfers

Tables 7.1 and 7.2 show the change in loss payments under the Central scenario 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.

7.1.1 Generators

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

Table 7.1 Change in annual loss payments for hypothetical generators (£m)

Hypothetical generator	Location of assumed portfolio of 4 x 1GW plant	Total loss payments		
		Uniform	Zonal	Change
North	South of Scotland, North of Scotland, Yorkshire, Northern	6.24	9.72	3.47
South	Southern, South Western, South Wales, South Eastern	6.24	2.68	–3.56
Balanced	South of Scotland, Northern, Southern, South Eastern	6.24	6.03	–0.21

Note: A wholesale price of £45/MWh and plant load factors of 85% have been assumed. Zonal TLMs taken from 2006/07 modelling results This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 9.1.
Source: Oxera.

The figures show that a Northern generator with a 4 GW portfolio would see a £3.5m increase in its loss payments under a scaled zonal loss charging regime, while a Southern-based generator would benefit by nearly £3.6m.

7.1.2 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 20% of the overall national demand, spread evenly between four zones.

Table 7.2 Change in annual loss payments for hypothetical suppliers (£m)

		Total loss payments		
Hypothetical supplier	**Location of assumed customers**	**Uniform**	**Zonal**	**Change**
North	South of Scotland, North of Scotland, Yorkshire, Northern	19.64	7.81	–11.83
South	Southern, South Western, South Wales, South Eastern	19.64	26.04	6.40
Balanced	South of Scotland, Northern, Southern, South Eastern	19.64	17.36	–2.28

Note: A wholesale price of £45/MWh has been assumed. Zonal TLMs taken from 2006/07 modelling results. This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 9.2.
Source: Oxera.

A Southern supplier increases its loss payments by approximately £6.4m under scaled zonal charging compared with its Northern counterparts' decrease of approximately £12m.

7.2 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 party. Under each of the scenarios, the monetary value of transfers was calculated using the 2006/07 annual average baseload price for that scenario.

7.2.1 Central scenario

The resultant zonal changes for the Central scenario are shown in Table 7.3.

Table 7.3 Estimates of potential transfers between regions for 2006/07 in the Central scenario

	Demand (TWh)	Supplier TLMs	Transfers (£m)	Generation (TWh)	Generator TLMs	Transfers (£m)	Net transfers (£m)
North Scotland	11	1.001	2.19	9	0.992	–1.45	0.74
South Scotland	24	1.002	4.07	34	0.992	–4.67	–0.60
Northern	18	1.003	1.92	8	0.994	–0.61	1.31
North Western	26	1.004	1.93	17	0.994	–0.75	1.19
Yorkshire	28	1.003	3.40	76	0.993	–6.90	–3.50
Merseyside & North Wales	19	1.004	1.06	25	0.995	–0.68	0.38
East Midlands	31	1.005	0.65	46	0.996	0.40	1.05
Midlands	34	1.007	–1.49	15	0.997	1.08	–0.42
Eastern	40	1.007	–1.68	25	0.997	1.82	0.15
South Wales	14	1.007	–0.57	16	0.997	1.15	0.58
South Eastern	25	1.007	–1.70	47	0.998	4.62	2.92
London	34	1.008	–4.22	3	0.999	0.48	–3.74
Southern	38	1.008	–3.82	21	0.998	2.80	–1.03
South Western	14	1.008	–1.75	18	0.999	2.72	0.97

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 scaled 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. This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 9.3. Source: Oxera.

The calculations show that, on the supply side, Scottish suppliers might pay £6m less in losses, while suppliers in the zones in Northern England might reduce their loss charges by some £7m. Suppliers in the rest of England and Wales would see an equivalent increase in loss payments of around £14m. There are similar transfers between generating plant in the different regions. The calculations suggest that generators in Scotland might increase loss charges by around £6m; generators in the zones in Northern England might increase them by £8m; while generators in the rest of England and Wales might see equivalent reduction in the order of £14m.

7.2.2 Zonal transfers—Seasonal scenario

Overall, the results for the Seasonal scenario (Table 7.4) show similar distributional impacts when compared with the Central scenario. Scottish and Northern England suppliers might each receive total loss payment reductions of approximately £8m, while suppliers in the rest of England and Wales would see an equivalent increase of around £16m. On the generation side, the calculations suggest that generators in Scotland might increase loss payments by around £10m; those in the zones in Northern England might increase them by £8m; while generators in the rest of England and Wales might see equivalent reductions in the order of £17m.

Table 7.4 Estimates of overall potential transfers between regions for 2006/07 in the Seasonal scenario

	Demand (TWh)	Supplier TLMs	Transfers (£m)	Generation (TWh)	Generator TLMs	Transfers (£m)	Net transfers (£m)
North Scotland	11	1.002	2.01	6.74	0.981	–1.10	0.91
South Scotland	24	1.001	5.99	41.09	0.975	–9.10	–3.12
Northern	18	1.003	2.29	8.39	0.986	–0.75	1.54
North Western	26	1.004	2.12	17.38	0.991	–0.78	1.34
Yorkshire	28	1.003	3.45	72.18	0.986	–6.22	–2.77
Merseyside & North Wales	19	1.005	0.89	21.38	0.995	–0.33	0.56
East Midlands	31	1.006	0.37	47.50	0.998	1.17	1.55
Midlands	34	1.007	–1.66	14.90	1.005	1.25	–0.41
Eastern	40	1.007	–2.31	24.39	1.004	2.29	–0.02
South Wales	14	1.007	–0.69	16.46	1.004	1.44	0.76
South Eastern	25	1.008	–1.93	45.91	1.006	5.38	3.45
London	34	1.009	–4.53	2.71	1.013	0.46	–4.07
Southern	38	1.009	–4.70	14.28	1.011	2.40	–2.31
South Western	14	1.009	–1.81	17.61	1.013	2.97	1.16

Note: These figures are the aggregate results from the four individual seasonal results presented in Tables 7.5 to 7.8 below. This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 9.6.
Source: Oxera.

While the overall annual Seasonal results are similar to those under the Central scenario, the individual seasonal results (shown in Tables 7.5 to 7.8 below) exhibit significant variations when compared with each other, as would be expected.

Table 7.5 Estimates of potential transfers between regions for 2006/07 in the Winter Seasonal scenario

	Demand (TWh)	Supplier TLMs	Transfers (£m)	Generation (TWh)	Generator TLMs	Transfers (£m)	Net transfers (£m)
North Scotland	3	1.003	0.53	2	0.992	–0.25	0.28
South Scotland	7	1.000	1.96	13	0.989	–3.67	–1.70
Northern	5	1.004	0.62	2	0.993	–0.27	0.35
North Western	7	1.005	0.57	5	0.994	–0.36	0.21
Yorkshire	8	1.004	0.88	18	0.993	–1.99	–1.11
Merseyside & North Wales	5	1.005	0.27	7	0.994	–0.33	–0.06
East Midlands	9	1.006	–0.07	14	0.995	0.16	0.09
Midlands	10	1.008	–0.66	5	0.997	0.36	–0.30
Eastern	11	1.008	–0.98	8	0.997	0.72	–0.27
South Wales	4	1.008	–0.36	4	0.997	0.43	0.07
South Eastern	7	1.009	–0.81	12	0.998	1.49	0.68
London	9	1.010	–1.66	1	0.999	0.16	–1.50
Southern	10	1.010	–1.75	5	0.999	0.78	–0.98
South Western	4	1.010	–0.72	5	0.999	0.86	0.14

Note: The generation and demand figures in each zone are based on the results of the Winter Seasonal scenario for 2006/07. The transfers are calculated by comparing loss payments that would occur for generators and consumers in each region under scaled zonal loss charging and under uniform loss charging, with uniform factors calculated so that total annual loss payments across the country remain the same. The calculations assume an electricity price of £48/MWh. This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 9.7.
Source: Oxera.

In the Winter Seasonal scenario, Scottish suppliers' loss payments decrease by £2.5m, while the loss payments of Northern England suppliers fall by £2.1m. Southern suppliers see an increase in their loss payments of £6.8m. Southern generators see an overall reduction in their loss payments of £4.6m, while Northern and Scottish generators' loss payments increase by £2.6m and £3.9m respectively.

Table 7.6 Estimates of potential transfers between regions for 2006/07 in the Spring Seasonal scenario

	Demand (TWh)	Supplier TLMs	Transfers (£m)	Generation (TWh)	Generator TLMs	Transfers (£m)	Net transfers (£m)
North Scotland	3	1.001	0.61	2	0.992	–0.28	0.32
South Scotland	6	1.000	1.55	9	0.991	–1.77	–0.22
Northern	5	1.003	0.69	2	0.993	–0.16	0.52
North Western	6	1.004	0.66	4	0.994	–0.13	0.53
Yorkshire	7	1.003	1.11	19	0.993	–1.63	–0.52
Merseyside & North Wales	5	1.005	0.29	6	0.995	0.05	0.34
East Midlands	8	1.005	0.28	12	0.996	0.42	0.70
Midlands	8	1.007	–0.39	3	0.998	0.34	–0.04
Eastern	10	1.007	–0.28	6	0.997	0.64	0.36
South Wales	3	1.007	–0.11	4	0.997	0.42	0.30
South Eastern	6	1.007	–0.33	12	0.998	1.53	1.19
London	8	1.009	–0.99	1	0.999	0.17	–0.82
Southern	9	1.009	–1.06	4	0.999	0.67	–0.39
South Western	3	1.009	–0.41	5	0.999	0.89	0.47

Note: The generation and demand figures in each zone are based on the results of the Spring Seasonal scenario for 2006/07. The transfers are calculated by comparing loss payments that would occur for generators and consumers in each region under scaled zonal loss charging and under uniform loss charging, with uniform factors calculated so that total annual loss payments across the country remain the same. The calculations assume an electricity price of £43/MWh. This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 9.8.
Source: Oxera.

In the Spring Seasonal scenario, Scottish suppliers' loss payments decrease by £2.2m, while the loss payments of Northern England suppliers fall by a slightly higher £2.5m. Southern suppliers see an increase in their loss payments of £3m. Southern generators see an overall reduction in their loss payments of £5.9m, while Northern generators' loss payments increase by £1.9m and Scottish generators' loss payments increase by £2.1m.

Table 7.7 Estimates of potential transfers between regions for 2006/07 in the Summer Seasonal scenario

	Demand (TWh)	Supplier TLMs	Transfers (£m)	Generation (TWh)	Generator TLMs	Transfers (£m)	Net transfers (£m)
North Scotland	2	1.000	0.63	2	0.990	–0.53	0.10
South Scotland	5	1.002	0.94	8	0.992	–1.16	–0.22
Northern	4	1.004	0.39	2	0.994	–0.12	0.27
North Western	6	1.005	0.28	4	0.995	–0.05	0.23
Yorkshire	6	1.004	0.57	19	0.994	–1.03	–0.46
Merseyside & North Wales	4	1.006	0.03	4	0.996	0.11	0.14
East Midlands	7	1.006	0.07	9	0.996	0.23	0.30
Midlands	7	1.007	–0.36	3	0.997	0.23	–0.13
Eastern	9	1.007	–0.25	6	0.997	0.39	0.14
South Wales	3	1.007	–0.07	4	0.997	0.24	0.17
South Eastern	5	1.007	–0.25	11	0.997	0.91	0.65
London	7	1.008	–0.66	1	0.998	0.09	–0.58
Southern	8	1.008	–0.73	3	0.998	0.33	–0.40
South Western	3	1.008	–0.25	4	0.998	0.51	0.26

Note: The generation and demand figures in each zone are based on the results of the Summer Seasonal scenario for 2006/07. The transfers are calculated by comparing loss payments that would occur for generators and consumers in each region under scaled zonal loss charging and under uniform loss charging, with uniform factors calculated so that total annual loss payments across the country remain the same. The calculations assume an electricity price of £40/MWh. This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 9.9.
Source: Oxera.

In the Summer Seasonal scenario, Scottish suppliers' loss payments decrease by £1.6m, while the loss payments of Northern England suppliers fall by £1.2m. Southern suppliers see an increase in their loss payments of £2.5m. Southern generators see an overall reduction in their loss payments of £3m, while Northern and Scottish generators' loss payments increase by £1.2m and £1.7m respectively.

Table 7.8 Estimates of potential transfers between regions for 2006/07 in the Autumn Seasonal scenario

	Demand (TWh)	Supplier TLMs	Transfers (£m)	Generation (TWh)	Generator TLMs	Transfers (£m)	Net transfers (£m)
North Scotland	3	1.004	0.24	1	0.994	–0.04	0.21
South Scotland	6	1.000	1.53	11	0.990	–2.51	–0.98
Northern	4	1.003	0.59	2	0.993	–0.19	0.40
North Western	6	1.004	0.61	4	0.994	–0.24	0.37
Yorkshire	7	1.003	0.89	17	0.993	–1.56	–0.68
Merseyside & North Wales	4	1.005	0.31	5	0.994	–0.16	0.15
East Midlands	7	1.006	0.09	12	0.996	0.36	0.45
Midlands	8	1.007	–0.27	4	0.997	0.32	0.06
Eastern	9	1.008	–0.80	4	0.998	0.54	–0.26
South Wales	3	1.007	–0.14	4	0.997	0.35	0.21
South Eastern	6	1.008	–0.53	11	0.998	1.45	0.92
London	8	1.010	–1.23	0	0.999	0.05	–1.18
Southern	9	1.009	–1.16	4	0.999	0.62	–0.54
South Western	3	1.009	–0.42	4	0.999	0.71	0.29

Note: The generation and demand figures in each zone are based on the results of the Autumn scenario for 2006/07. The transfers are calculated by comparing loss payments that would occur for generators and consumers in each region under scaled zonal loss charging and under uniform loss charging, with uniform factors calculated so that total annual loss payments across the country remain the same. The calculations assume an electricity price of £45/MWh. This table corresponds to equivalent P198 analysis presented in Oxera July 2006, Table 9.10.
Source: Oxera.

In the Autumn Seasonal scenario, Scottish suppliers' loss payments decrease by £1.8m and total loss payments of the suppliers in Northern England fall by £2.1m. Southern suppliers see their loss payments increase by £4.1m. Southern generators see an overall reduction in their loss payments of £4.3m, while Northern and Scottish generators' loss payments increase by £2.0m and £2.5m respectively.

8 Conclusions

The introduction of scaled 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 up to £6m per annum, with an average annual saving of £1m under annual scaled zonal loss charging, and up to £10m per annum, with an average annual saving of £4.7m under seasonal scaled zonal loss charging;

– a demand response—net changes in demand as a result of price changes also introduce net benefits into the system of £0.12m–£0.23m per annum under annual scaled zonal loss charging, and £0.24m–£0.46m per annum under seasonal scaled zonal loss charging.

As discussed during previous zonal loss charging analysis:

– the introduction of scaled zonal transmission loss charging does not increase the incentives on new conventional generation, nor significantly alter the incentives for new renewable generation projects;

– 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 scaled 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 scaled zonal loss charging are largely up front, with an estimated £2.1m 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 £310,000 per annum.

Scaled zonal loss charging will result in 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.

High-level comparisons with P198 results

Table 8.1 below presents some of the high-level results from this analysis along side the same results from Oxera’s previous P198 analysis. It is evident from this table that, while P204 significantly reduces the distributional signals, it does so through lower loss reductions brought about by weakened redespatch signals compared to P198.

Table 8.1 High-level comparison of P204 and P198 results

	Annual		Seasonal	
	P204	P198	P204	P198
Loss savings				
Value of loss savings (2006/07–2011/12)				
Average (£m)	2.3	5.4	6.1	13.5
High (£m)	6.0	12.0	10.4	17.8
Low (£m)	0.3	1.6	3.2	7.1
Average value of annual loss savings 2006/07–2015/16 (£m)	1.0	2.9	4.7	8.9
Distributional impacts (2006/07 only)				
Suppliers				
Maximum (£m)	4.1	26.7	6.0	26.1
Minimum (£m)	–4.2	–23.9	–4.7	–20.7
Generators				
Maximum (£m)	4.6	26.2	5.4	23.2
Minimum (£m)	–6.9	–34.9	–9.1	–39.7

Note: P198 data from Oxera (2006)
Source: Oxera

Finally, for comparative purposes Table 8.2 shows the NPV of net benefits over the study horizon for annual and seasonal loss charging under P198 and P204.

Table 8.2 Comparison of the NPV of future benefits to 2015/16 under P204 and P198

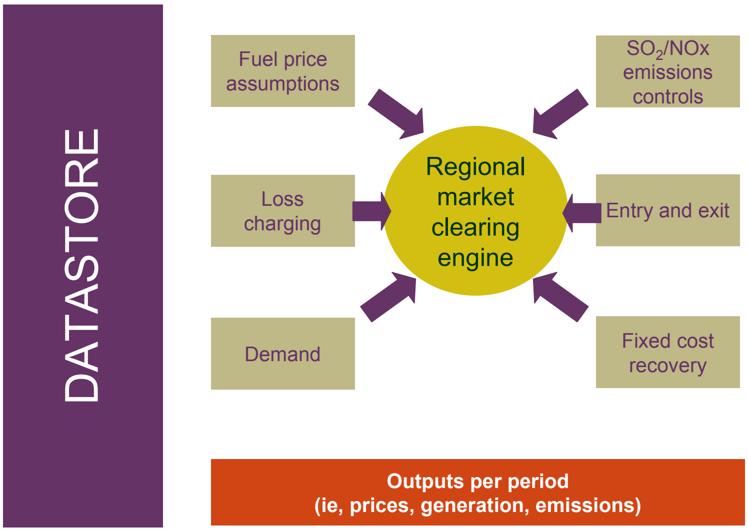
	Central	Seasonal
P204	3.8	32.4
P198	21.1	65.7

Note: P198 data from Oxera (2006)
Source: Oxera

Appendix 1 Oxera wholesale market model

The Oxera wholesale market model is a production cost model, with the facility for assessing the impact of scaled 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 scaled 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 scaled zonal loss charging. This allowed the impact of scaled zonal loss charging on a range of market outcomes to be examined.

Appendix 2 Snapshot TLMs

Central scenario

	2006	2006	2007	2007	2008	2008	2009	2009	2010	2010	2011	2011	2012	2012	2013	2013	2014	2014
	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup
1	0.997	1.007	0.997	1.007	0.997	1.007	0.996	1.006	0.997	1.006	0.996	1.006	0.996	1.005	0.996	1.005	0.995	1.004
2	0.996	1.005	0.996	1.006	0.996	1.005	0.996	1.006	0.996	1.005	0.996	1.005	0.996	1.005	0.996	1.005	0.995	1.004
3	0.999	1.008	0.999	1.009	0.999	1.008	0.998	1.008	0.998	1.008	0.998	1.007	0.998	1.007	0.998	1.007	0.997	1.007
4	0.995	1.004	0.994	1.004	0.995	1.005	0.995	1.006	0.996	1.006	0.996	1.005	0.997	1.006	0.997	1.006	0.997	1.007
5	0.997	1.007	0.997	1.007	0.997	1.007	0.997	1.007	0.998	1.007	0.998	1.007	0.998	1.007	0.999	1.008	0.999	1.008
6	0.994	1.003	0.993	1.003	0.994	1.004	0.994	1.004	0.994	1.004	0.994	1.003	0.994	1.003	0.995	1.004	0.996	1.005
7	0.994	1.004	0.994	1.004	0.994	1.004	0.995	1.005	0.995	1.005	0.995	1.004	0.995	1.005	0.996	1.005	0.997	1.006
8	0.998	1.008	0.999	1.009	0.998	1.008	0.998	1.008	0.998	1.007	0.998	1.007	0.998	1.007	0.998	1.007	0.998	1.008
9	0.998	1.007	0.998	1.008	0.998	1.007	0.997	1.007	0.997	1.007	0.997	1.006	0.996	1.005	0.996	1.005	0.995	1.005
10	0.997	1.007	0.997	1.007	0.997	1.007	0.997	1.008	0.997	1.007	0.998	1.007	0.998	1.007	0.997	1.006	0.997	1.006
11	0.999	1.008	0.999	1.009	0.999	1.009	0.999	1.009	0.997	1.007	1.000	1.009	1.000	1.009	0.999	1.008	0.999	1.009
12	0.993	1.003	0.993	1.003	0.994	1.003	0.994	1.004	0.994	1.004	0.993	1.003	0.994	1.003	0.994	1.003	0.994	1.003
13	0.992	1.002	0.992	1.002	0.992	1.002	0.992	1.002	0.992	1.002	0.993	1.003	0.994	1.003	0.994	1.003	0.995	1.004
14	0.992	1.001	0.990	1.000	0.990	1.000	0.990	1.000	0.990	1.000	0.991	1.000	0.991	1.000	0.991	1.000	0.992	1.001

Source: Oxera.

BSC Winter

S1	2006	2006	2007	2007	2008	2008	2009	2009	2010	2010	2011	2011	2012	2012	2013	2013	2014	2014
	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup
1	0.997	1.008	0.997	1.008	0.996	1.009	0.996	1.009	0.996	1.008	0.996	1.008	0.996	1.007	0.996	1.006	0.996	1.005
2	0.995	1.006	0.995	1.007	0.995	1.007	0.995	1.007	0.995	1.007	0.995	1.007	0.995	1.007	0.995	1.005	0.995	1.004
3	0.999	1.010	0.999	1.010	0.998	1.010	0.998	1.011	0.998	1.010	0.998	1.010	0.998	1.009	0.999	1.008	0.999	1.008
4	0.994	1.005	0.994	1.005	0.994	1.006	0.993	1.006	0.994	1.006	0.994	1.006	0.995	1.006	0.997	1.006	0.996	1.005
5	0.997	1.008	0.996	1.008	0.996	1.008	0.996	1.009	0.996	1.008	0.997	1.008	0.997	1.008	0.998	1.008	0.998	1.007
6	0.993	1.004	0.992	1.004	0.992	1.004	0.992	1.005	0.993	1.005	0.992	1.004	0.993	1.004	0.993	1.003	0.995	1.004
7	0.994	1.005	0.993	1.005	0.993	1.005	0.993	1.005	0.994	1.006	0.993	1.005	0.994	1.005	0.995	1.004	0.995	1.005
8	0.999	1.010	0.998	1.010	0.998	1.010	0.998	1.011	0.998	1.010	0.998	1.010	0.998	1.009	0.999	1.008	0.999	1.008
9	0.998	1.009	0.997	1.009	0.997	1.009	0.997	1.010	0.997	1.009	0.997	1.009	0.997	1.008	0.997	1.006	0.997	1.006
10	0.997	1.008	0.997	1.008	0.997	1.009	0.997	1.010	0.997	1.009	0.997	1.009	0.997	1.008	0.997	1.006	0.997	1.006
11	0.999	1.010	0.999	1.010	0.999	1.011	0.999	1.011	0.997	1.009	0.999	1.010	0.999	1.010	0.999	1.009	1.000	1.009
12	0.993	1.004	0.993	1.004	0.993	1.005	0.992	1.005	0.993	1.005	0.993	1.004	0.993	1.004	0.993	1.002	0.993	1.003
13	0.989	1.000	0.989	1.000	0.988	1.000	0.988	1.000	0.988	1.000	0.989	1.000	0.989	1.000	0.992	1.002	0.992	1.001
14	0.992	1.003	0.991	1.002	0.990	1.002	0.989	1.002	0.989	1.001	0.989	1.001	0.990	1.001	0.994	1.003	0.993	1.002

Source: Oxera.

BSC Spring

s2	2006	2006	2007	2007	2008	2008	2009	2009	2010	2010	2011	2011	2012	2012	2013	2013	2014	2014
	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup
1	0.997	1.007	0.996	1.007	0.996	1.007	0.996	1.006	0.996	1.008	0.996	1.006	0.996	1.007	0.996	1.004	0.995	1.004
2	0.996	1.005	0.995	1.006	0.995	1.007	0.995	1.006	0.995	1.007	0.996	1.006	0.995	1.006	0.997	1.005	0.996	1.005
3	0.999	1.009	0.997	1.008	0.997	1.009	0.998	1.008	0.997	1.009	0.998	1.008	0.997	1.008	0.998	1.006	0.997	1.006
4	0.995	1.005	0.996	1.007	0.995	1.007	0.995	1.005	0.995	1.007	0.996	1.006	0.995	1.006	0.997	1.006	0.997	1.006
5	0.998	1.007	0.997	1.008	0.996	1.008	0.997	1.007	0.996	1.008	0.997	1.007	0.997	1.008	0.999	1.008	0.998	1.008
6	0.993	1.003	0.994	1.005	0.993	1.005	0.994	1.004	0.993	1.005	0.994	1.004	0.994	1.005	0.995	1.004	0.996	1.006
7	0.994	1.004	0.995	1.006	0.994	1.006	0.995	1.005	0.994	1.006	0.995	1.005	0.995	1.006	0.996	1.004	0.997	1.006
8	0.999	1.009	0.997	1.008	0.997	1.009	0.998	1.008	0.997	1.009	0.997	1.007	0.997	1.008	0.999	1.007	0.997	1.007
9	0.998	1.007	0.996	1.007	0.996	1.008	0.997	1.007	0.996	1.008	0.996	1.007	0.996	1.007	0.996	1.004	0.995	1.004
10	0.997	1.007	0.996	1.007	0.996	1.008	0.997	1.007	0.996	1.008	0.997	1.007	0.997	1.008	0.996	1.005	0.996	1.005
11	0.999	1.009	0.997	1.008	0.997	1.009	0.998	1.009	0.996	1.008	0.998	1.008	0.998	1.009	0.999	1.008	0.998	1.007
12	0.993	1.003	0.994	1.005	0.993	1.005	0.993	1.004	0.993	1.006	0.994	1.004	0.994	1.005	0.993	1.002	0.995	1.004
13	0.991	1.000	0.991	1.002	0.991	1.003	0.993	1.003	0.991	1.003	0.993	1.003	0.992	1.003	0.998	1.007	0.996	1.005
14	0.992	1.001	0.989	1.000	0.988	1.000	0.990	1.000	0.988	1.000	0.990	1.000	0.989	1.000	0.992	1.000	0.991	1.000

Source: Oxera.

BSC Summer

S3	2006	2006	2007	2007	2008	2008	2009	2009	2010	2010	2011	2011	2012	2012	2013	2013	2014	2014
	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup
1	0.997	1.007	0.997	1.007	0.997	1.005	0.996	1.007	0.997	1.005	0.997	1.005	0.996	1.004	0.996	1.004	0.995	1.002
2	0.996	1.006	0.996	1.006	0.996	1.004	0.996	1.007	0.997	1.004	0.996	1.005	0.996	1.004	0.997	1.005	0.996	1.004
3	0.998	1.008	0.998	1.008	1.000	1.008	0.998	1.009	0.999	1.007	0.998	1.007	0.998	1.006	0.998	1.005	0.997	1.005
4	0.996	1.006	0.995	1.005	0.995	1.004	0.995	1.006	0.997	1.005	0.997	1.005	0.997	1.005	0.997	1.005	0.999	1.006
5	0.997	1.007	0.997	1.007	0.998	1.007	0.997	1.008	0.999	1.007	0.999	1.007	0.999	1.007	0.999	1.007	1.000	1.008
6	0.994	1.004	0.994	1.004	0.994	1.002	0.993	1.004	0.995	1.002	0.994	1.003	0.995	1.003	0.996	1.003	0.998	1.005
7	0.995	1.005	0.995	1.005	0.995	1.003	0.994	1.005	0.996	1.003	0.995	1.004	0.996	1.004	0.996	1.004	0.998	1.006
8	0.998	1.008	0.998	1.008	0.999	1.008	0.998	1.009	0.999	1.007	0.999	1.007	0.999	1.007	0.998	1.006	0.998	1.006
9	0.997	1.007	0.997	1.007	0.998	1.006	0.997	1.008	0.997	1.005	0.997	1.005	0.996	1.004	0.996	1.003	0.995	1.003
10	0.997	1.007	0.997	1.007	0.997	1.006	0.997	1.008	0.997	1.005	0.998	1.006	0.998	1.006	0.996	1.004	0.996	1.004
11	0.998	1.008	0.998	1.008	1.000	1.008	0.998	1.009	0.998	1.006	1.000	1.008	1.000	1.008	0.999	1.007	0.999	1.007
12	0.994	1.004	0.994	1.004	0.993	1.001	0.994	1.005	0.994	1.002	0.994	1.002	0.994	1.002	0.994	1.002	0.995	1.002
13	0.992	1.002	0.992	1.002	0.996	1.004	0.991	1.002	0.996	1.003	0.995	1.003	0.998	1.006	0.999	1.007	0.999	1.007
14	0.990	1.000	0.990	1.000	0.994	1.002	0.989	1.000	0.993	1.001	0.992	1.000	0.994	1.002	0.996	1.003	0.995	1.003

Source: Oxera.

BSC Autumn

S4	2006	2006	2007	2007	2008	2008	2009	2009	2010	2010	2011	2011	2012	2012	2013	2013	2014	2014
	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup	Gen	Sup
1	0.998	1.008	0.998	1.008	0.998	1.007	0.997	1.007	0.997	1.006	0.997	1.006	0.996	1.005	0.997	1.005	0.994	1.004
2	0.996	1.006	0.996	1.006	0.996	1.005	0.996	1.006	0.996	1.004	0.995	1.004	0.996	1.005	0.996	1.005	0.994	1.004
3	0.999	1.010	0.999	1.010	0.999	1.009	0.999	1.009	1.000	1.008	1.000	1.008	0.998	1.007	0.999	1.008	0.997	1.007
4	0.994	1.005	0.994	1.005	0.995	1.004	0.994	1.004	0.997	1.005	0.996	1.004	0.996	1.005	0.997	1.005	0.998	1.008
5	0.997	1.007	0.997	1.007	0.997	1.007	0.997	1.007	0.998	1.007	0.998	1.006	0.997	1.006	0.998	1.007	0.998	1.008
6	0.993	1.003	0.993	1.003	0.993	1.003	0.993	1.003	0.994	1.002	0.994	1.002	0.995	1.004	0.994	1.003	0.996	1.006
7	0.994	1.004	0.994	1.004	0.994	1.004	0.994	1.004	0.995	1.004	0.995	1.003	0.995	1.004	0.995	1.004	0.997	1.007
8	0.999	1.009	0.999	1.009	0.999	1.009	0.999	1.009	0.999	1.008	0.999	1.008	0.997	1.007	0.999	1.008	0.997	1.007
9	0.998	1.008	0.998	1.008	0.998	1.008	0.998	1.008	0.998	1.007	0.998	1.006	0.996	1.005	0.997	1.006	0.995	1.005
10	0.997	1.007	0.997	1.007	0.997	1.007	0.997	1.007	0.997	1.006	0.998	1.006	0.997	1.006	0.996	1.005	0.995	1.005
11	0.999	1.009	0.999	1.009	0.999	1.009	0.999	1.009	0.997	1.006	1.000	1.008	0.998	1.007	0.999	1.008	0.997	1.008
12	0.993	1.003	0.993	1.003	0.993	1.003	0.993	1.003	0.993	1.002	0.992	1.001	0.994	1.003	0.993	1.002	0.993	1.003
13	0.990	1.000	0.990	1.000	0.991	1.000	0.990	1.000	0.993	1.002	0.995	1.003	0.995	1.004	0.995	1.004	0.998	1.009
14	0.994	1.004	0.994	1.004	0.995	1.004	0.994	1.004	0.998	1.006	0.999	1.007	0.997	1.006	0.991	1.000	0.995	1.006

Source: Oxera.

Oxera
Park Central
40/41 Park End Street
Oxford OX1 1JD
United Kingdom

Tel: +44 (0) 1865 253 000
Fax: +44 (0) 1865 251 172

www.oxera.com