A REVIEW OF OXERA'S COST-BENEFIT ANALYSIS OF THE INTRODUCTION OF 'ZONAL LOSSES'

MARCH 2008

The Brattle Group

The Brattle Group, Ltd.
198 High Holborn
London WC1V 7BD
United Kingdom

Tel: +44-20-7406-1700
Fax: +44-20-7406-1701
Email: office@brattle.co.uk

Contents

1 Executive Summary

The Brattle Group has been asked by Ofgem to review the cost-benefit analysis commissioned by the Balancing and Settlement Code (BSC) Modifications Group and carried out by Oxera. The work examined a number of proposed Balancing and Settlement Code (BSC) Modifications associated with the introduction of zonal losses (P198 and its alternative, P200 and its alternative, P203 and P204). The Oxera analysis was set out in the two Oxera reports[1,2] and submitted to the Authority as part of the Final Modification Reports (FMRs) on the proposals. Specifically, we were asked to consider:

- Were the terms of reference for the Oxera analysis appropriate?
- Did the Oxera analysis fulfil its terms of reference?
- Was Oxera's modelling methodology appropriate for the given terms of reference?
- Are the input assumptions underpinning Oxera's market scenarios credible?
- Are the conclusions of the Oxera analysis reasonable?

We also considered criticisms of Oxera's analysis raised by third-parties. Note that we were not asked to consider the merits of the proposed Modifications either in isolation or in relation to the Applicable BSC Objectives nor were we asked to comment on the additional analysis carried out by Ofgem as part of its "Minded To" and Impact Assessment consultations.

Though we have not had direct contact with Oxera, we were able to put written questions to them via Ofgem and Elexon. To reduce the burden on both Ofgem and Oxera, we did not put questions to Oxera on issues that did not seem to have a material affect on the outcome of the study.

Oxera's methodology

Oxera has separately considered the impact of zonal losses in the short and longer term. For the short term, Oxera has calculated what the difference in total generation costs would be with and without zonal losses, and has investigated the impact of annual loss factors, seasonal loss factors and scaled seasonal loss factors. It has done this by using load flow modelling to determine how zonal losses might develop over the period from 2006/07 to 2015/16. Oxera has separately investigated the potential impact on demand by considering the effect that changing prices due to zonal losses would have on the level of demand in different regions. For the longer term, Oxera has considered the extent to which zonal losses might affect where new plants are built. In particular, Oxera used its Renewables Obligations model to estimate the effect of zonal loss factors on the growth and profitability of renewable generation.

[1] Oxera, 'What are the costs and benefits of zonal loss charging?' July 2006 – this report was commissioned as part of the assessment process for P198 and is hereafter referred to as the July 2006 report.

[2] Oxera 'What are the costs and benefits of annual and seasonal scaled zonal loss charging?' which was commissioned as part of the assessment process for P204 and is hereafter referred to as the September 2006 report.

Oxera has also estimated the total implementation and operating costs for BSC Parties and the central systems of adopting zonal loss factors. Finally, Oxera has explored the likely distributional effects that zonal loss factors would have had in 2006/07.

Oxera's main findings

Oxera found that the introduction of zonal losses results in a number of benefits being realised by the system overall, specifically through short-term redespatch benefits and a demand response. In other words, Oxera generally found that all the types of zonal losses proposed under the various modifications would, to varying extents, reduce the total generation costs associated with meeting a given level of demand. However, it is worth noting that this was not always true in the last two to three years that Oxera modelled (2013/14 to 2015/16) where Oxera found dis-benefits in some of the cases it studied.. Nonetheless, because Oxera's estimates of the implementation and operating costs associated with zonal loss factors were relatively low, Oxera found that all the cases it studied led to a positive present value for the net benefits of introducing zonal losses.

Oxera also concluded that, at least in the short to medium term, zonal losses were unlikely to result in large efficiency gains with respect to generator siting decisions and reduced costs of the transmission network. Zonal losses simply strengthen the existing locational signals in the existing (zonal) Transmission Network Use of System (TNUoS) charges. If the existing signals are already effective in directing efficient plant location, then the introduction of zonal losses will have no additional efficiency effects with respect to plant location. For similar reasons Oxera found that the impact of zonal losses on new entry in the long term was very uncertain, although likely to lead to a small net annual benefit if zonal losses caused plant to move to the south that would not otherwise have done so. Oxera also concluded that zonal losses would have little, if any, the impact on the growth of renewables before 2015/16 since other factors (the design of the Renewables Obligation and non-economic difficulties) would be a more important limit on renewables building rates. As regards the profitability of renewables projects, Oxera concluded that overall the introduction of zonal losses would only have a marginal impact although there would be some distributional effects.

As regards distributional effects in 2006/07 (the only year in which they were calculated), Oxera concluded that zonal loss charging would result in significant transfers between market participants. Generators in the north and suppliers in the south would face increased loss payments whilst, conversely, generators in the south and suppliers in the north would pay less for losses.

Oxera's terms of reference

We consider that the terms of reference issued by the BSC Modification Group were reasonable although it would have been appropriate to have requested additional distributional analysis (in terms of the effects on the costs and/or profits of specific companies or types of companies), better specified the time period to be analysed and ask for the analysis to be extended for a longer period. We also consider that it might have been appropriate to ask Oxera to analyse whether it was likely that locational signals would be over-stated through the combined effects of TNUoS charges and zonal losses, although we accept that this somewhat of a moot point given that TNUoS charges do not fall under the governance of the BSC. In any event, Ofgem subsequently investigated this issue in its Impact Assessment and its ‘Minded to’ consultation.

Oxera has largely fulfilled the terms of reference that it was set. There are a number of minor areas where Oxera’s analysis appears only partially to fulfil the terms of reference (for example, there is little analysis of the impact of zonal losses broken down by generator size) but none of these omissions is significant in terms of the overall conclusions.

Modelling methodology

We have also concluded that Oxera’s modelling methodology is a generally appropriate approach. However, Oxera’s estimation of the net benefits of the Modifications hinge largely on calculations based on only 3 (annual TLFs) or 12 (seasonal TLFs) snapshot periods. It would clearly have been preferable to include more periods although we appreciate the magnitude of the task involved in carrying out numerous load flow analyses. We cannot preclude the possibility that the benefits found by Oxera might have been materially different, either lower or higher, if more periods had been modelled but our simple modelling suggests that it is unlikely that more snapshots would have led to a different overall conclusion.

We also note that Oxera’s TLF analysis was based on implementation of zonal loss charging in 2006/07, whereas it would have been more consistent with the modification proposals to model its implementation in 2008/09, with the current uniform loss charging arrangements applying in 2006/07 and 2007/08. In that way the TLFs derived for 2008/09 would have been based on patterns of generation reflecting uniform loss charging, with all subsequent years based on zonal loss charging. In addition, the cable between Britain and the Netherlands (the BritNed cable) has not been modelled: the BritNed cable could affect TLFs, and so, at least in the year it which it is commissioned, reduce the benefits of zonal losses since it would effectively be a “market shock” (an issue we discuss below). We accept, however, that proper accounting of the impact of the Britned cable would have required the detailed modelling of interactions between the Dutch and GB markets, which did not form part of Oxera’s terms of reference. Finally, it would have been preferable to have integrated the investigation of the impact of zonal losses on generation and demand, rather than considering them separately.

Oxera’s inputs

Over a year has passed since Oxera produced its reports and so it is not surprising that the assumptions Oxera used in July and September 2006 are now somewhat out of date. It is also the case that Oxera’s input fuel prices seem to differ from the DTI’s fuel prices on which it claims to rely. While this has no material affect on the reasonableness or otherwise of Oxera’s results, the fuel prices lack transparency as to how they were derived, and this does not fully comply with the terms of reference.

The gas prices used, while below the forward prices existing at the time Oxera prepared its studies, are now in line with market expectations as of December 2007. However, the lack of seasonality in the gas prices Oxera have used could introduce errors into the modelling because it means that the snapshots may not reflect market conditions. Where Oxera models annual loss factors the errors are only likely to affect the peak snapshots, which are representative of winter conditions, since the other two snapshots are representative of periods from periods throughout the year. However, where Oxera models seasonal loss factors, the lack of seasonal gas prices could affect all the snapshots. On the other hand, our simple model indicates that the benefits may if anything be increased by adding seasonality. The coal prices Oxera has used, while reasonably consistent with the contemporaneous forward prices at the time Oxera prepared its report, are now significantly lower than current coal forward prices. Oxera's carbon prices are in line with both current and 2006 market expectations. On the basis of some simple modelling, we do not believe however that updating Oxera's fuel price assumptions would lead to any fundamental change in the conclusions that can be drawn from its analysis.

Critique of Oxera's main findings

The introduction of zonal losses produces a benefit because a system of zonal losses more accurately reflects the losses a plant causes. With zonal losses, more efficient dispatch is possible, since the rational outcome is for dispatch to be based on costs *including* the cost of losses. Consequently, the better TLFs approximate the actual losses caused by a plant, the more efficient the system will be and the greater will be the benefits relative to a system of uniform losses.

We believe that Oxera's general conclusions on the benefits of zonal losses are robust. However, we have concluded that there are more reasons why Oxera may have over-estimated the likely net benefits than there are reasons why it may have under-estimated them. Our concerns regarding potential over-estimation relate primarily to Oxera's methodology and whether it has appropriately assessed the risks inherent in all the modifications. By contrast, the potential for Oxera to have under-estimated the effect of zonal losses relates largely to its input assumptions, where actual future outcomes are inevitably uncertain. Overall, therefore, we consider it more likely than not that Oxera may have over-estimated the net benefits to some extent.

One of the main shortcomings in the Oxera analysis is that it has not sufficiently considered what would happen if the transmission loss multiplier (TLM)[3] for a given zone is a poor proxy for the losses for which that zone is responsible ('actual losses'). Such an outcome is possible under all the Modifications for two reasons. First, they all involve using TLFs for a given year that have been calculated on the basis of conditions in the previous year. Thus, any change in market conditions e.g. significant new entry, plant retirements or changes in relative fuel costs, whether foreseen or unforeseen, could lead to differences between the TLM for a given zone and actual losses.

Second, the zonal Transmission Loss Factors (TLFs)[4] that feed into the TLMs will have been averaged over a wide range of market conditions (either a year or a season) and this can also lead to differences between a zone's TLM and the losses generators in that zone actually create in particular periods. A large difference between the TLM of a zone and the losses attributable to that zone in any given period is the main risk that the Modifications create, since this could, for any given year, reduce the benefits significantly or even produce a net dis-benefit. A net dis-

[3] The TLM is a measure of losses. For example, a TLM of 98% means that a generator is credited with 98% of its output at the point of receipt.

[4] The TLF is used to calculate the TLM. For example, ignoring the effect of the TLMO scaling factor used to ensure that allocated losses match actual losses, a TLF of 2% means that a generator has a TLM of 1 – 2% = 98%.

benefit could arise if uniform losses are a better approximation of the losses generators cause than the zonal TLMs. In this case, uniform losses could lead to more efficient despatch than using zonal TLMs based on TLFs from the previous year. However, such effects should be transitory, unless the market continues to change significantly from year to year, because TLMs in subsequent years will reflect the effects of previous changes in market conditions.

We accept that Oxera's analysis has captured some of these effects in that it used averaged TLFs based on conditions from the previous year, as specified in all the modification proposals. However, we do not consider that the scenarios Oxera have investigated sufficiently investigate the potential inefficiencies caused by using TLFs from the previous year. For example, in the Gas scenario gas prices are consistently lower from one year to the next. But the gas-price related scenario that is most likely to reduce the benefits of the proposals is if gas prices cycle between being low in one year and high in the next, since this would cause TLFs in one year to be a poor proxy for TLFs in the next year. As we outline above, this would reduce the benefit of zonal losses, relative to a situation with a stable gas price, and where consequently TLFs in one year are a good proxy for TLFs in the next. A similar effect would occur for other 'shocks' or changes such as the addition of the BritNed cable or a significant change in the transmission network. We have carried out some simple modelling that suggests that such outcomes would reduce, but not remove, the net benefits Oxera estimates because, as discussed above, such effects should be transitory.

Additionally, we consider that Oxera may have under-estimated, possibly by around 20%, the likely level of implementation costs. We accept that Oxera was required under its terms of reference to rely upon implementation costs provided by Elexon but we have some concerns over the use that Oxera made of these data in extrapolating these results to estimate total costs over all BSC parties. This is partly because Oxera appears to have missed out some generators in estimating the costs for market participants who did not provide their own estimates to Elexon. We also consider it would be prudent to adopt a higher daily rate when estimating these costs, since the rate used by Oxera is Elexon's internal rate which may be unrealistic if external contractors have to be used. However, whilst higher implementation costs would reduce the net present value of the benefits from zonal losses, they would have to be increased to a highly implausible level in order for the introduction of zonal losses to lead to a negative net present value.

We have also sought to investigate whether, for some reason, Oxera's input assumptions led to unrealistically high net benefits. We have explored the effect of changing the input assumptions with regard to fuel prices and carbon costs and concluded that this would not be the case. For example, including current coal prices (which are much higher than Oxera assumed) increases the benefits of introducing zonal losses, since it shifts more production to gas-fired plant which generally have lower losses than coal-fired plant.

In a number of the scenarios it has considered, Oxera finds dis-benefits in the last two to three years modelled. In the absence of any changes to market conditions i.e. changes in relative fuel prices or in the geographical distribution of generation plants, there should be a trend of the net benefits from introducing zonal losses increasing over time, as the TLFs gradually converge towards the actual loss factors, until a 'steady state' of benefits is reached (though the increase in benefits from one year to the next will decrease over time). If locational signals from network charges cause developers to build new plants in the south of the GB rather than in the north then, over time, actual losses, and consequently the benefit of introducing zonal losses, will reduce. However, we see no reason to believe that in the longer term redespatch benefits should disappear, since, in general, the zonal loss factors should always be a better approximation to actual losses than a system of uniform losses, and hence zonal losses should result in net benefits (except in occasional years where there are large changes in market conditions). We suspect that the projected dis-benefits found by Oxera result from the use of a static transmission network from 2012/13 onwards – new lines are not added in the model as they would be in reality – understandably, since such additions would be very difficult to predict. This means that the likelihood of "artificial" constraints emerging on the network, which would in practice not to be seen because of network upgrades, will increase the further out that Oxera looks. Such artificial constraints probably bias the estimated benefits downward and thus account for the dis-benefits that Oxera finds.

In calculating the present value of the net benefits, Oxera uses a discount rate which is, in our opinion, too low, and also ignores the annual pattern of benefits in its calculations and simply uses the average annual benefits. We have re-calculated the net present value of the benefits using higher discount rates and actual annual benefits. Moving from using average annual benefits for generation redespatch to using yearly data changes the NPV by between -£6.5 million and +£3.7m, depending on the scenario. Increasing the discount rate used in the calculations decreases the NPVs by between £1.3 million (Central scenario) and £4.5 million (Seasonal case under the Central scenario). However, regardless of the discount rate used and the methodology, for any reasonable discount rate the zonal losses proposals should yield net benefits in present value terms.

We have concluded that Oxera's analysis, while originally designed to consider only two of the six loss proposals[5] explicitly, P198 original and P204, is also relevant to P200, P200 alternative and P203. It is more difficult to extrapolate Oxera's results to P198 alternative, since this proposal involves the gradual phasing in of zonal losses. We estimate that assuming a linear relationship between the phasing of the TLFs and the benefits will underestimate benefits.

Updating Oxera's new entry cost analysis to account for recent changes in gas and electricity transportation charges serves to reinforce the conclusion that zonal losses are unlikely to have any significant impact on generators' siting decisions. As regards the potential impact of zonal loss factors on renewables, we agree with Oxera that issues such as difficulties in obtaining planning permission and the operation of the Renewables Obligation scheme are likely to be the dominant determinants of renewables growth. However, we cannot rule out the possibility that zonal loss factors might deter some projects in the north of GB that were only marginally profitable with uniform loss charging. Nonetheless, Oxera's finding that the introduction of zonal losses would only have a marginal impact on the overall profitability of renewables seems reasonable.

Finally, whilst Oxera's analysis of the distributional effects of zonal losses appears reasonable for 2006/07 it may not be particularly representative of what would happen over the longer term. This is simply because the spread in zonal loss factors that Oxera finds in the first

[5] Whilst there have been only four recent BSC Modification Proposals that relate to the introduction of zonal losses, an alternative proposal was added to the original proposal for two of these Modifications (P198 and P200).

year of its scenarios is often not typical of those it projects for other years. We also consider that it might have been useful for Oxera to have provided data on the number of companies, possibly by type e.g. utility, generator, supplier etc., that are likely to be winners and losers under zonal losses.

2 Introduction

Four BSC modification proposals to introduce locational allocation of variable transmission losses have been submitted to the Authority (P198 and its alternative, P200 and its alternative, P203 and P204). As part of the assessment procedure for these proposals, Oxera was commissioned by Elexon to undertake a cost benefit analysis. The Oxera analysis was set out in the two Oxera reports[6,7] and submitted to the Authority as part of the Final Modification Reports (FMRs) on the proposals. The Authority took the Oxera analysis into account in reaching its minded-to decisions of May 2007 to approve P203 and reject the other proposals. The reasons for those minded to decisions were set out in Ofgem's consultation document of June 2007 (the 'minded-to consultation'), which followed on from Ofgem's impact assessment (the 'impact assessment') of February 2007. For all the modification proposals, the BSC Panel recommended that the earliest implementation date should be 1 April 2008 and then only if an Authority decision was received on or before 22 March 2007.[8]

The Oxera analysis was criticised by a number of respondents to both Elexon's consultations and Ofgem's consultations, in the latter case parties also criticised Ofgem's use of Oxera's analysis in its assessment of the efficiency benefits and associated impact on emissions. In particular, Oxera submitted a response to the minded-to consultation stating its view that Ofgem had "placed more weight than appropriate" on Oxera's analysis in reaching those minded-to decisions.[9]

In the light of all the information available to it, including all the responses to the minded-to consultation, the Authority announced on 14 September 2007 that it would be appropriate for Ofgem to undertake a further review of Oxera's analysis, and the reliance placed upon it, before the Authority makes its final decisions with respect to the proposals.

The Brattle Group was selected by Ofgem to undertake this review of Oxera's analysis and this report contains our findings. In reviewing Oxera's reports, we have also taken into account the comments made by respondents to the various consultations, the assessment and modification reports for the various proposals (to the extent that they deal with Oxera's cost benefit analysis) and Oxera's replies to a number of questions that we raised. All the material on which we have relied is available, or will be available, on either Elexon's or Ofgem's websites, and we have included our questions to Oxera in connection with this study and its responses in Appendix VI and Appendix VII.

---

[6] Oxera, 'What are the costs and benefits of zonal loss charging?' July 2006 – this report was commissioned as part of the assessment process for P198 and is hereafter referred to as the July 2006 report.

[7] Oxera 'What are the costs and benefits of annual and seasonal scaled zonal loss charging?' which was commissioned as part of the assessment process for P204 and is hereafter referred to as the September 2006 report.

[8] For example, the BSC Panel recommended an implementation date of 1 October 2008 if the Authority reached a decision after 22 March 2007 but before 20 September 2007.

[9] Oxera, Response to consultation on Zonal transmission losses – the Authority's 'minded-to' decisions, July 31st 2007.

2.1 Treatment of losses – current and proposed

Transmission losses can be divided into two types:

- *Fixed losses* are those which do not vary significantly with power flow. In transformers, the losses arise from magnetising the iron core. In overhead lines, they include losses dependent on the voltage levels, length of line and climatic conditions.
- *Variable losses* arise through the heat caused by current flowing through transformers and lines. Variable losses increase with the current (and associated power flow) and the length of line in which it flows.

Transmission losses are allocated to BSC Parties (‘Parties’) as part of their Trading Charges, by adjusting individual BM Unit Metered Volumes in Settlement through a Transmission Loss Multiplier (TLM). Under the current Code provisions, both fixed and variable transmission losses in each Settlement Period are allocated to Parties on a ‘uniform’ (non-locational) basis in proportion to each Party’s metered energy. The current allocation of transmission losses therefore does not take account of the extent to which individual Parties give rise to such losses. In simplified form, the TLMs can be represented by the following equation:

$$TLM = 1 + TLF + TLMO$$

The transmission loss factors (TLF) are currently set to zero but are included in the BSC so as to provide the possibility of including unit specific loss factors. The Transmission Losses Adjustments (TLMO) are calculated separately for generators ($TLMO^+$) and suppliers (TLMO).The $TLMO^+$ is the same for all generators and the $TLMO^-$ is the same for all suppliers. They are set so as to ensure that generators are allocated 45% of actual losses and suppliers are allocated the remaining 55%.

The four modifications, and their alternatives, all propose allocating the costs of variable transmission losses on a zonal basis so that all the generators (or suppliers) within a zone are allocated the same TLM but the TLMs vary between zones.[10] The grid supply point (GSP) groups that are used to levy demand Transmission Network Use of System Charges would define the losses zones. All the proposals would require the zonal loss factors to be set ex-ante, based on data from the previous year but they differ in whether or not there would be single loss factor in each zone for a year (P198, P200) or seasonal loss factors (P198 alternative, P200 alternative, P203 and P204). P204 also differs from all the other proposed modifications in that the loss factors would be scaled to ensure that no generator is credited with producing more electricity than it has actually generated, as can be the case if negative zonal loss factors are allowed.

In addition to incorporating seasonal loss factors, P198 alternative also differs from P198 in that the zonal loss factors would only be phased in linearly over four years from the implementation date instead of being applied in full force immediately. The two P200 proposals also differ from all the other proposals in that existing generators would be hedged from the

---

[10] The exception to this is modification proposal P200/200A, where the TLM varies within a zone for generators in the hedging scheme.

effects of zonal loss factors – at least to the extent that their future output levels matched their historic output levels.

Table 1 gives a short summary of the recent BSC Modification proposals relevant to zonal losses.

Table 1: Summary of BSC modification proposals for zonal losses

Mod. No.	***Time period for TLFs***	***Other features***
P198	Annual	Ex ante scaled marginal TLFs for variable losses applied by GSP Group, scaling factor of 0.5
P198 Alternative	Seasonal	As P198 apart from seasonal TLFs, which are phased in over 4 years
P200	Annual	As P198 except that existing generators are partially hedged against zonal losses for 15 years
P200 Alternative	Seasonal	As P200 i.e. P198 with hedging, apart from seasonal TLFs
P203	Seasonal	As P198 apart from seasonal TLFs i.e. the same as P198 Alternative without phasing
P204	Seasonal	As P198 apart from seasonal TLFs and seasonal scaling to ensure no negative allocation of losses

2.2 Structure of the report

The rest of this report is structured as follows. Section 3 discusses the terms of reference set for the two Oxera studies by the BSC Modification Groups for P198 and P204. It considers whether the terms of reference were appropriate and the extent to which Oxera fulfilled them. The next section, Section 4 describes the methodology that Oxera adopted for its cost-benefit analysis including the scenarios it studied. It considers the extent to which the studies, which were originally designed to analyse P198 original and P204, are also relevant to the assessment of the other zonal losses proposals. We also discuss to what extent Oxera's methodology was appropriate. Section 5 deals with Oxera's input assumptions: were they appropriate at the time the studies were undertaken and are they still appropriate? This naturally leads on to a discussion of the results that Oxera presented in reports, which is covered in Section 6. We check these results with some simple modelling in Section 7. We discuss the concerns regarding Oxera's analysis that have been raised by interested parties (Section 8). Finally, in Section 9, we consider to what extent Oxera's conclusions are robust.

3 Elexon's terms of reference

3.1 Summary of terms of reference

3.1.1 Process by which Oxera was retained

Before describing the terms of reference given to Oxera, we briefly summarise the process by which Oxera was retained to perform the work.

Modification proposal P198 was submitted on 16th December 2005. The Initial written assessment of P198 was published on 6th January 2006 and agreed the expenditure required for an external consultant to help estimate the costs and benefits of the proposal. Subsequently, the BSC Panel considered P198 at its meeting on 12 January 2006 and submitted the proposal to an Assessment Procedure to be conducted by the P198 Modification Group. The Modification Group agreed that modelling of the likely cost-benefit impact on allocation of Transmission Losses under P198 should be performed to support its development and assessment of P198, and published a modelling requirements specification in February 2006.

In March 2006 the terms of reference for the cost-benefit analysis were finalised by the Modification Group for P198 and published by Elexon as "Cost-Benefit Analysis Requirements Specification for Modification Proposal P198". This document was the basis for a competitive tender process for the performance of the cost-benefit analysis. Oxera was awarded the work at the conclusion of this process.

The initial terms of reference focused on the original P198 Modification, which involved annual zonal loss factors. In the course of developing options for P198 Alternative the Modification Group subsequently asked Oxera to extend its analysis to include a case using seasonal TLFs. All of this analysis was covered in Oxera's July 2006 report. Both the P198 Modification Group and the BSC Panel concluded that Oxera's analysis met its terms of reference.

Subsequently, the Modification Groups for P200/200A and P203 decided that they could rely on Oxera's analysis for P198/P198 A, and that further analysis was not required. However, when it came to consideration of P204, Oxera was commissioned to carry out further analysis (see Section 3.1.3), which was described in its September 2006 report.

3.1.2 Terms of reference for Oxera's July 2006 analysis

The terms of reference required the consultant to perform a transparent, credible and robust analysis to quantify the net benefit of implementing P198 over a ten year period. This analysis was to be based on the calculation of annual zonal TLFs for each year so as to enable the market response to these TLFs to be quantified and the effect of this response on the volume and costs of losses to be assessed. As discussed above, the scope of work was later extended to include analysis of the impact of seasonal zonal loss factors.

The consultant was required to consider the impact on generation (by location, fuel type, and size) and on demand (by location, type – domestic/non-domestic, and level) but consideration of the impact of P198 on the environment and consumers was explicitly excluded. However, the consultant was required to quantify the effect of zonal TLFs on the transmission system in terms of their impact on transmission constraints and the limits that transmission constraints might place on the ability of generation and demand to respond to locational signals.

In analysing the impact of zonal losses on generation, the consultant was required to quantify its impact on:

- The operation and despatch of existing plants (e.g. through increased/decreased production, and decisions to mothball or close plants);
- The growth of future generation (e.g. fuel mix, siting and investment decisions for new plant, and decisions to run previously mothballed plant) and the level of plant margin available to the System Operator;
- Imports and exports via interconnectors;
- Generators connected to 132 kV compared to the impact on geographically proximate generators connected to 275kV and 400kV;
- Wholesale electricity prices; and
- The cost of carbon emissions to generators.

The consultant was required to quantify the costs and benefits over the first five years in detail but was allowed to use extrapolation for later years providing the approach taken in doing so was clearly described. The consultant was not obliged to use its own load flow model to estimate the annual zonal TLFs but if it chose to do so it had to demonstrate that the zonal TLFs for 2005/06 produced by the model were consistent with those provided by Elexon. The consultant was also required to demonstrate that the methodology it adopted for calculating annual zonal TLFs was consistent with the approach that would be adopted if P198 was implemented.

The terms of reference required the consultant to develop a “base case”, under which P198 was not implemented, and a “change case”, under which P198 is implemented. Apart from the treatment of transmission losses, the two cases were otherwise to be based on the same assumptions regarding market conditions over the ten-year study period (i.e. same fuel prices, fuel transportation costs, generation despatch, profile and growth, carbon prices, demand profile and growth, interconnector trade, and the transmission network) taking into account government policy on energy and the environment. The consultant was also asked to consider the following when deciding what assumptions to use:

a) Ofgem’s System Operator Incentive Scheme;

b) National Grid’s Seven Year Statement;

c) National Grid’s Transmission Network Use of System charging methodology;

d) Perceptions of risk and the cost of capital in new investment decisions.

The consultant was required to perform sensitivity testing of the key assumptions to which it believed the analysis results were least robust and to provide the rationale for the sensitivities and full details on them.

The terms of reference also required the consultant to quantify the implementation costs of P198 to BSC Parties as a whole and to provide details of the methodology and assumptions involved. (Elexon would provide estimated implementation and operational cost estimates for various market participants - BSC Parties that had provided non-confidential data during the P198 impact assessment, BSC agents, National Grid and Elexon itself).

The consultant was also required to provide an assessment of the initial distributional impact of P198 based on what might have been expected to have happened if P198 had been implemented for the 2006/07 BSC Year, including the magnitude and locational pattern of the distributional impact.

3.1.3 Terms of reference for Oxera's September 2006 report

Modification proposal P204 was submitted on 3rd July 2006, and an initial assessment of the proposed modification was published on 7th July 2006. In the initial assessment, it was noted that the differentials between the TLF/TLM values for different zones would be less than for P198 and P200, due to the proposed scaling approach. Accordingly, it was recommended that the Modification Group should commission further external cost-benefit analysis from Oxera for P204, to examine the effect of the reduced differentials on the signals provided by a zonal transmission losses scheme. To reduce the scope of work and cost, it was suggested that the P204 cost-benefit analysis should only use the input assumptions for the Central scenario modelled by Oxera under P198.

The Modification Group for P204 subsequently commissioned a further external cost-benefit analysis from Oxera to examine the effect of P204 on the signals provided by zonal transmission losses. In particular, focus was placed on the impact on the despatch signals, distributional effects and the overall level of losses. The Group agreed the following scope for the analysis:

1. Adopt the same approach as for the cost-benefit analysis performed for P198 using the central scenario market assumptions;

2. Repeat the Central scenario using the annual TLF values but with the P204 scaling factor re-calculated for each of the ten years based on the TLF values calculated for that year; and

3. Repeat the seasonal case under the Central scenario using seasonal TLF values and four seasonal scaling factors per year which are recalculated in each of the ten years.

The Modification Group asked Oxera for analysis for both annual and seasonal scaled TLFs so that the analysis could inform its ongoing development of the solution to P204 and potential alternatives.

3.2 Were the terms of reference for Oxera's analysis appropriate?

The terms of reference given to Oxera were issued by the Modification Group and, as such, were presumably intended to provide analysis that would assist the BSC Panel and other Parties in reaching a decision as to whether or not to recommend the implementation of any of the zonal losses modifications. In other words, we have assessed whether the terms of reference were likely to provide economic data applicable to an assessment of whether the Modifications would better facilitate the achievement of the Applicable BSC Objectives, which are:

a) The efficient discharge by the Transmission Company of the obligations imposed under the Transmission License;

b) The efficient, economic and co-coordinated operation of the GB transmission system;

c) The promotion of effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity;

d) The promotion of efficiency in the implementation and administration of the balancing and settlement arrangements.

The terms of reference specifically excluded an analysis of the effect on consumers. In other words the Modification Group's did not interpret the Applicable BSC Objectives to include the interests of consumers. Whether or not this correct seem to be a legal issue on which we are not qualified to opine or comment.

Despite the fact that Applicable BSC Objective (c) relates to the promotion of competition, there was no explicit requirement to consider the effect of zonal losses on competition in generation in the terms of reference. This seems to us reasonable because the analysis required under the terms of reference e.g. the distributional analysis, naturally provides insights into the effect of zonal losses on various aspects of competition. Furthermore, we considered whether there would have been merit in requiring an analysis of the effects of zonal losses on the shape of the merit order. For example, if the introduction of zonal losses flattened the merit order this would increase the number of generators offering power at a similar price and, hence, foster competition. However, we concluded that the effect of zonal losses on the merit order was very uncertain and highly dependent on fuel prices. Even relatively minor changes in coal and gas prices could have a larger effect on the merit order than the introduction of zonal losses. Hence, any effect of zonal losses on competition in generation is likely to be unstable and difficult to quantify with any certainty. Accordingly, it seems reasonable that such an analysis was left out of the terms of reference.

Consequently, in general terms, we consider that the terms of reference were appropriate. However, there are several specific areas where we consider that the terms of reference could have been better defined.

The first area concerns the fact that an analysis of distributional impacts was only requested for 2006/07. As we noted in Section 2, the earliest implementation date for any of the proposed modifications was 1st April 2008. Therefore, not only does it seem curious to concentrate on a year in which the Modifications could not be in force but we consider that it would have been desirable to have extended the distributional analysis to all the years that were modelled. Such an analysis would have been an additional helpful input to consideration of the possible competition impacts of the Modifications, as required to assess the Modifications against the third BSC Applicable Objective.

The second area relates to the ten year period to be analysed. This is not well defined in the terms of reference and Oxera appears to have assumed that it covers the period from 2006/07 to 2015/16. (On the other hand, for its net present value analysis, Oxera effectively assumes that zonal loss factors will be introduced from 2007/08 onwards.) We do not know whether this assumption was agreed with Elexon and/or the Modification Group but it is clearly inconsistent with the timetable described in the Modification Group's modification report; by September 2006 when the Final Modification Report for P198 was published, the recommended implementation date was 1 April 2008 at the earliest. Given the iterative nature of the modelling methodology, the loss factors for the first year in which zonal losses are implemented may be quite different to those that would apply in subsequent years. This is because the TLFs for that year are based on load flow analysis derived from the situation with uniform losses, unlike the TLFs for all subsequent years. Consequently, there is likely to be a larger difference between the TLMs and actual losses in the first year of a scheme than there will be in future years. In other words, there will be a substantial change between the conditions incorporated in the load flow modelling used to generate the first year loss factors and those that will actually occur in the first year of zonal losses since the introduction of zonal losses should alter generators' behaviour. Ignoring the effect of other possible changes in market conditions, we would expect the redespatch benefits associated with zonal losses to be lower in the first year they are implemented than in subsequent years because the TLMs in the first year are less likely accurately to reflect the geographical spread of actual losses than in subsequent years. (This is simply one example of the impact of a 'shock' in market conditions, which we discuss in more detail in later sections. In this case, the "shock" is the change in market rules rather than in fuel prices or plants on the system.)

As requested by its terms of reference, Oxera has separately considered the impact of zonal losses on generation and demand. To the extent that demand does react to zonal loss signals, this might be expected to have an additional impact on generation. Changes in the pattern of demand should affect both the TLFs and the actual losses measured by Oxera. Consequently, it might have been more appropriate to consider the two effects jointly rather than separately. We acknowledge, however, that the speed with which demand would respond to zonal loss signals is difficult to estimate since it depends on how rapidly consumers are exposed to the signals i.e. how frequently their tariffs are updated and also potentially the length of time required for consumers to improve their energy efficiency. This makes it problematic to incorporate demand side response into the load flow modelling. However, it would have been useful if the terms of reference had asked Oxera to carry out, say, a single year's sensitivity to see what influence demand side effects were likely to have on redespatch benefits.

The final area where we consider that it would have been possible to improve the terms of reference relates to the relatively short period for which the analysis was required – 5 years in detail and 10 years in total. Whilst we appreciate the difficulties of extending load flow modelling far out into the future due to the large number of assumptions that have to be made (on the development of the transmission network as well as the evolution of the plant mix), a longer time horizon would have been more consistent with the timescales considered when making plant investment decisions. A longer period of analysis might have enabled Oxera to answer the question of whether or not the introduction of zonal losses only results in benefits related to generation due to plant redespatching. Note that, whilst we cannot be certain, our view, based on our assessment of the likely impact of zonal losses on siting decisions (see Section 6.1.3), is that redespatch effects are likely to be the dominant benefit from introducing zonal losses with longer term benefits being much less important.

We also think that it might have been appropriate for the terms of reference to require that the interaction between TNUoS charges and zonal losses be considered. Specifically, we wonder whether the question as to whether the combination of zonal TNUoS charges and zonal loss factors might give rise to over-stated locational signals should have been asked. We acknowledge that TNUoS charges do not normally fall within the remit of the BSC, being subject to governance under the Transmission Licence, but the scope of the BSC Applicable Objectives are relatively broad so that, in this instance, TNUoS charges might have been a relevant consideration. For example, it could be argued that the operation of the transmission system would be less economic or efficient if the zonal signals to which market participants were exposed were over-stated. In any event, this issue was subsequently considered by Ofgem[11] as part of the additional analysis it undertook in reaching its "minded to" decision.

3.3 Did the Oxera analysis fulfil its terms of reference?

In Table 2 below we consider each of the requirements set out in Oxera's terms of reference and describe whether, and to what extent, it has been fulfilled by Oxera. Unless otherwise stated, the comments apply to both the July and September 2006 reports.

Overall, it is reasonable to conclude that Oxera fulfilled its terms of reference for both the July and September reports and this is certainly true in respect of the key quantifications. However, there are number of requirements that Oxera has only partially fulfilled. For example, there is a lack of clarity in the reports surrounding some significant assumptions and methodological details – as we describe in more detail later the fuel prices Oxera used do not seem to match the cited source, and it is not readily apparent that all the results are presented in real terms. Also, Oxera has not provided any analysis on the impact of the cost of carbon.

We return, in later sections of the report, to consider in more detail certain aspects of Oxera's analysis, in particular the credibility and robustness of its findings.

Table 2: Were the Terms of Reference Fulfilled?

Requirements in Terms of Reference	Fulfilled by Oxera?	Commentary
Quantify the costs and benefits in detail for the first five years.	In general	For impact on generation, Oxera provided results for six years. (Longer term effects are not dealt with in detail by year but are unlikely to vary by year.) Impact on demand only provided for average TLFs (averaged over ten year period).
Perform a transparent, credible and robust analysis	Generally	Oxera's analysis is credible, particularly for the earlier years, and probably robust, but it is not particularly transparent. However, the lack of transparency in some areas does not compromise the validity of Oxera's conclusions.

[11] This analysis was undertaken jointly with NGET.

Requirements in Terms of Reference	**Fulfilled by Oxera?**	**Commentary**
Calculate adjusted annual zonal transmission loss factors for the study period.	Yes	The average zonal TLMs and the zonal TLFs for each snapshot were provided for each year and each scenario. However, Oxera did not provide the TLMs they used for the uniform losses case. Oxera did not take account of fixed losses in either its analysis of uniform losses or zonal losses, but since it is concerned solely with differences between uniform and zonal losses this will have had little, if any, impact on the results.
Demonstrate that load-flow model produces base TLFs that are consistent with those provided by Elexon	Yes	The agreement between Siemens Power Technologies International (PTI) and Oxera TLFs is generally reasonable. Zone 10 is an exception in this respect where PTI finds a TLF of 0.005 and Oxera a TLF of -0.004 – a difference of 0.009. Oxera's explanation for this difference (that in the snapshot modelling a plant in Zone 10 ran at twice the load factor as was the case in reality) highlights the limitations associated with using only 3 snapshot periods.
Demonstrate that its TLFs are consistent with the live implementation of P198.	Yes	The methodology that Oxera adopted in estimating zonal TLFs for future years is consistent with that envisaged under P198 and P204.
Develop a "base case" and a "change case".	Yes	Oxera has produced results for both uniform and zonal losses.
Use input data that is objectively derived or provided by Elexon.	In principle, yes	Oxera claims to have used fuel prices taken from a DTI report, however there appear to be some discrepancies between the values reported by Oxera and those included in the DTI report to which it refers (see Section 5). Whilst this reduces the transparency of the analysis, our simple modelling suggests that these discrepancies do not undermine the conclusions that Oxera reaches.
Clearly describe all assumptions and the rationale for these assumptions.	Partially	Not all the assumptions made by Oxera have been described in detail e.g. plant closures, treatment of plant opted out from LCPD etc. We have sought clarification from Oxera on a number of input assumptions which seemed material to its conclusions.

Requirements in Terms of Reference	**Fulfilled by Oxera?**	**Commentary**
Consider existing government energy policy including the latest Ofgem/DTI JESS report.	Yes	Oxera analysed the effect of zonal losses on the rate of renewables growth using its Renewables Obligations model. Oxera concluded that there would be no significant effect on reaching renewables targets.
Consider existing government environmental policy.	Presumably	Although not explicitly stated, we assume that Oxera's assumptions on renewables growth are in line with government policy.
Consider Ofgem's System Operator Incentive Scheme.	Unclear	Not mentioned by Oxera.
Consider National Grid's Seven Year Statement.	Yes	Used to determine new plant build (except for renewables), demand and network development (until 2011/12).
Consider National Grid's Transmission Network Use of System charging. Methodology.	Yes	Taken into account in estimating whether zonal losses would have an impact on generator siting decisions.
Consider perceptions of risk and the cost of capital in new investment decisions.	Yes	Oxera concludes that there should be no impact and so does not consider the issue further.
Perform sensitivity testing of the key assumptions to which results are least robust.	Partially	Oxera performs sensitivity testing of fuel prices and demand, and also performed sensitivity testing on the elasticity of demand. However, the range of values tested is quite small and the sensitivities do not address the key uncertainties. As we show later in the report, Oxera's choice of sensitivities may lead to the net benefits being over-estimated but does not discredit its overall conclusions.
Provide full details and rationalisation of the sensitivities used.	Yes	Provided rationale for fuel prices, new entry, demand and demand elasticity.
Quantify the impact on transmission losses and the cost of these losses.	Yes	Provides annual savings in losses and the value of these savings for the first six years of study period. Also provides an average for the full study period.

Requirements in Terms of Reference	Fulfilled by Oxera?	Commentary
Quantify the impact on generation despatch by location, fuel-type and size of plant.	Mostly	Impact by location and fuel-type is provided but not by size of plant.
Quantify the impact on the growth of generation plant.	Broadly	Discusses the impact in general terms but does not directly attempt to quantify it.
Quantify the impact on imports and exports via interconnectors.	Partially	The report states that the impact on the Moyle, French and BritNed cables was investigated. However, in response to one of our questions, it has emerged that BritNed was not included in the analysis. We discuss this point further in Section 4.5.4.
Quantify the impact on generators connected to 132 kV compared to geographically proximate generators connected to 275kV and 400kV.	Yes	Concluded that there would be no difference in impact because TLFs are averaged across zones.
Quantify the impact on wholesale electricity prices.	Yes	Prices for each scenario under each loss charging methodology are shown for first six-years of study period.
Quantify the impact on the cost of carbon to generators.	No	Oxera did not quantify the impact on the cost of carbon to generators, though the cost of carbon was included in Oxera's calculations.
Quantify impact on required generation capacity	Not directly	Since Oxera concluded that the introduction of zonal losses would have no material impact on the transmission system, it presumably follows that there would be no impact on security of supply requirements.
Quantify the impact on demand and demand growth including the impact on the location, type and the level of demand.	Yes	Oxera considers domestic and commercial/industrial users separately, estimates the change in consumption, losses and value of losses for each zone, and discusses the demand response in the short run and longer term.
Quantify the impact on the operation and development of the transmission system including on transmission constraints.	Partially	Information in changes in peak zonal exports is provided but this does not address the effects on any within-zone constraints. Also, constraints often occur away from peaks and this is not considered.

Requirements in Terms of Reference	Fulfilled by Oxera?	Commentary
Quantify the implementation costs of P198 and provide methodology and assumptions.	Yes	As Section 5.6 describes, we believe that Oxera may have under-estimated the likely implementation costs. However, any reasonable changes to Oxera's estimates could not be sufficient to outweigh the redespatch benefits found by Oxera.
Quantify the extent to which the base TLFs lead to movement of money between Parties including the magnitude and locational pattern.	Yes	Oxera showed how the loss payments would change for a hypothetical generator and supplier in the North, South and elsewhere in 2006/07. Oxera also showed how the loss payments would change for suppliers/generators in each zone. Oxera did not analyse the effects on individual Parties, but it is unclear whether this was part of the terms of reference. Also, as discussed above in Section 3.2, we question whether the fact that the terms of reference only required an analysis of 2006/07 was appropriate.
The impact of the transmission constraints on the costs and benefits of P198.	Partially	Not explicitly discussed.

3.4 Conclusions on the terms of reference

We conclude that Oxera has largely fulfilled the terms of reference that it was set. There are a number of minor areas where Oxera's analysis appears only partially to fulfil the terms of reference (for example, there is little analysis of the impact of zonal losses broken down by generator size) but none of these omissions is significant in terms of the overall conclusions.

4 Oxera's Methodology

4.1 Overview of Oxera's Short-term Methodology

As far as short-term effects are concerned, Oxera followed the modelling methodology suggested in the terms of reference, which mimicked what would happen if any of the Modification proposals was implemented.

4.1.1 Oxera's main assumptions

Regarding the Large Combustion Plant Directive (LCPD), Oxera assumed that existing 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, and that 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. Oxera also assumed that coal-fired stations in England and Wales operate under the annual company B limits for SO2 and NOX as set out by the Environment Agency for the periods 2006–08 and post-2008.

With respect to plant closure decisions, the only closure decisions imposed on the scenarios are those of the existing nuclear fleet – Oxera assumed that there will be no life extensions of existing nuclear plant (beyond those already announced). Oxera based all other plant closure decisions on market outcomes under the different scenarios (discussed below).

Oxera assumed that new plant would take the form of combined-cycle gas turbine (CCGT) stations and new renewable generation. 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 trade press. The on-stream dates of the plants were a function of market developments in each of the scenarios. Oxera found that many of these new plants were in Southern transmission zones with relatively low transmission losses.

The basic demand forecast used in Oxera's scenarios i.e. in the Central and Gas scenarios, was based on National Grid's 'Base' demand forecast in its 2005 Seven Year Statement,. The growth in renewable generation was modelled independently using Oxera's Renewables Obligation model. Oxera included the full-cost of carbon in its despatch model. Table 3 on page 26 (Section 4.3) details the fuel prices Oxera used.

In its analysis, Oxera also made assumptions regarding the short run marginal costs of each plant, based on its efficiency, input fuel and its variable operating and maintenance costs (including the variable costs of operating emissions abatement equipment). Furthermore, Oxera's economic dispatch model allows it to take into account maintenance requirements and the effects of transmission constraints across zones of the network.

4.1.2 Modelling steps

The first step was to determine the zonal TLFs for each year modelled in detail. For each year, this involved:

1) running Oxera's economic despatch model for peak, midpoint and trough by year i.e. 3 snapshots per year, or season i.e. 12 snapshots per year, for the previous year (incorporating, where appropriate, the estimated zonal variable TLMs for that year into generators' offers); and

2) using the outputs from this analysis as an input to a load flow model and using the outputs of that model to determine the TLFs for each zone. These TLFs were then used to calculate the TLMs for the following year. The modelling assumed an "intact" electricity network (i.e. that there were no transmission outages).

The peak snapshot is representative of the load during the top 10.4% hours, the trough snapshot is representative of the load during the lowest 15.8% of hours and midpoint represents the remaining hours.[12] In order to determine the transmission losses under the base (uniform losses) case, this iterative process was also carried out assuming a merit order based on incorporating uniform variable losses into generators' offers.

Oxera then ran its economic despatch model across each year for both the base and change cases to assess the impact of the TLFs in that year. This process was adopted for all four scenarios analysed.

The snapshot modelling was used to analyse the impact of the Modifications on: the volume and cost of losses, patterns of generation and the transmission system. The economic despatch modelling was used to analyse the impact of the Modifications on annual output by zone and fuel type and on electricity prices. As discussed above, the net benefits from redespatching are given by the change in costs (mainly fuel) for generating an amount of electricity net of losses, with and without zonal losses. In making these calculations, the loss savings are scaled down to remove loss savings associated with reactive losses, which are estimated to account for 10-15% of losses.

The calculation of the impact of the Modifications on demand is carried out separately from the analysis of the impact on generation. Oxera estimates the price elasticity of demand for domestic and commercial/industrial and consumers and then assumes that the prices faced by consumers will directly reflect the cost of the losses they are allocated. In this way, Oxera determines the likely change in consumption levels by zone. From these changes in consumption, Oxera estimates the change in losses and the value associated with that change in losses, valued on the basis of wholesale electricity prices. In carrying out this analysis, Oxera uses the average of the loss factors for the period 2006/07 to 2015/16 and the average annual electricity prices over the same period.

The annual benefits of zonal losses are calculated as the net value of reduced losses from redespatch following implementation of zonal losses plus the benefits from demand responding to the zonal loss charging. Oxera estimates the implementation and ongoing costs of zonal losses based on data provided by Elexon (for the costs of the transmission owner, BSC Agents, Elexon and some BSC Parties) plus its own estimate of the costs for BSC Parties who had not provided data to Elexon (or whose data was confidential). In making its estimates for these Parties`, Oxera

[12] The same percentages apply to the snapshots for each season under the Seasonal scenario. Thus, for example, the Spring peak snapshot is representative of the top 10.4% of Spring periods.

assumed that the implementation costs for each Party would amount to 60 days of effort at a cost of £220/day (Elexon's internal cost rate). For on-going operating costs for BSC Parties, Oxera assumed an annual cost of £100,000. The present value of the net benefits was calculated using a discount rate of 3.5%, the 2003 HM Treasury value for Central Government Evaluations.

4.1.3 Comparing costs and benefits of loss reductions

There has been a lot of confusion regarding how Oxera calculated generation redespatch benefits. Indeed, Oxera appears to have made contradictory statements in its reports and its responses to questions asked by participants. For example, in an answer to one query on how costs and benefits were calculated, Oxera explained that it estimated the net benefit of zonal losses as the savings from zonal losses less any increase in generating costs, and that it estimated the savings in losses as the volume of losses saved multiplied by the weighted average price of electricity.[13] On the other hand, in its July 2006 report, Oxera indicated that it had measured the net benefits directly.[14]

To clarify the situation for this report, we asked Oxera precisely how it carried out its calculations and presented it with a spreadsheet showing simplified possible methodologies. Most of the benefits that Oxera attributes to the introduction of zonal losses come from its calculation of net redespatch benefits (as opposed to other effects like demand response) so it is important to understand precisely how Oxera modelled these benefits.

4.1.3.1 Oxera's calculations

Oxera has confirmed to us (see Appendix VII) that it has calculated net redespatch benefits as the difference between the total generation costs with zonal losses and the total generation costs with uniform losses. In other words, Oxera accounts for both savings in losses and the change in the cost of generation which results from the use of zonal losses.

Oxera has noted that introducing zonal losses may result in the despatch of plants that have higher marginal costs (excluding the impact of losses) than would have been the case under uniform losses. For example, when the impact of losses is ignored, a plant that has marginal costs of £35/MWh might be replaced with a plant with a marginal cost of £36/MWh although clearly the second plant must have lower costs *when losses are included in the calculation of marginal costs*. By measuring the change in total generation costs, Oxera captures this effect as well as the effect of a reduced overall level of generation due to a fall in the volume of losses that has to be covered.

4.1.3.2 Meaning of net benefits calculated

The zonal losses proposals will affect:

---

[13] Further question on Oxera cost benefit analysis for Transmission Losses Modification Proposals, Elexon – available at www.elexon.co.uk.

[14] "the net benefits from the generation sector from loss reductions have been estimated directly", page 3, July 2006 report.

1. Consumers –the price of electricity and the volume of losses for which consumers must pay will change. This change is known as the change in consumer surplus – in other words a change in the benefits consumers get from using electricity;
2. Generators – generators will be affected for the same reasons as consumers. The change they face is simply the change in their profits;
3. The total costs of generating electricity to meet a given level of demand – both the plant used to generate the electricity and the gross volume of electricity that has to be generated i.e. the volume generated at the station gate before losses are taken into account, will change.

Mathematically, the sum of 1 (change in consumer surplus) and 2 (change in generators' profits) above equals 3 (the change in the cost of generating electricity). As we have just explained, Oxera has confirmed that it is the third measure of the effects of losses that it has calculated. In other words, Oxera asks: what is the cost of the inputs (essentially fuel) required to deliver a given amount of electricity (net of losses) with and without a zonal losses proposal? This is also the approach we take in our own simple model, discussed in Section 7.

In an example in Appendix I, we illustrate that (in aggregate) changes in generators' profits can differ from the calculated changes in costs. However, whether generators' profits are higher or lower than the changes in costs will depend on the actual TLM's applied in each year, and the effect that the TLMs have on prices. Hence it is not clear if Oxera's published net-benefits has under or over-estimated the actual effect of the proposals on generators.

Oxera's approach estimates the net effect on consumers and generators (i.e. the overall societal effect) of introducing zonal losses by looking at changes in costs. This is a common approach to performing cost-benefit analyses when one is interested in the effect on all parties in society.

4.1.4 Distributional effects

Oxera used the methodology just described to investigate the likely distributional effects of introducing zonal loss factors in 2006/07 in two ways. First, it considered what would happen to the total loss payments made by hypothetical generators and suppliers under three sets of assumptions: (1) the generator has plants (or the supplier has customers) only in the north; (2) the generator has plants (or the supplier has customers) only in the south and (3) the generator has a geographically balanced set of power plants (or the supplier has customers in both the north and south). Oxera calculated the loss payments by multiplying its estimate of the volume of losses attributable to the hypothetical generator/supplier by the annual average baseload price for 2006/07.

Second, Oxera looked at the transfers between regions without ascribing the effects to any particular players. Thus, for example, it looked at the changes in loss payments made by generators and suppliers in a particular zone and the net changes (generation plus demand) in that zone. In comparing the cases with and without zonal losses, Oxera used uniform factors that yielded the same total loss payments as those it found with zonal loss factors.

4.2 Overview of Oxera's Long-term Methodology

Oxera's approach to considering the longer term effects of the introduction of zonal losses was to consider whether there would be any impact on where new power plants might be sited. It did this by analysing to what extent the locational signals that already exist from transmission charges for both gas and electricity are likely to be amplified by the zonal loss signals. In addition, Oxera produced some "speculative scenarios" on what impact changes in siting decisions might have over the longer term. Oxera only carried out this analysis for the annual loss factor scenarios (without scaling) that it was initially commissioned to carry out.

Oxera also considered the potential impact of zonal losses on the growth and overall profitability of renewable generation. To do this, Oxera used its Renewables Obligation model, which involves an iterative process to determine consistent levels of renewable build and buy out prices taking account of the buyout mechanism and limits on maximum resource size and rates of build for different technologies.

4.3 Cases studied by Oxera

Oxera's terms of reference required them to perform one model run with uniform losses and another with zonal losses, so that the difference between these cases represented the effect of zonal losses relative to the status quo. The inputs for both model runs – with and without zonal losses – were kept the same.

In its July 2006 report, where Oxera dealt with the original P198 Modification, Oxera modelled a Central scenario and two sensitivities – a Gas scenario (in which gas prices were lower than the Central scenario) and a Demand scenario, (in which demand growth was higher than in the Central scenario). Table 3 details the differences between the inputs under all three scenarios. Oxera performed calculations for these scenarios using annual loss factors and three snapshot periods.

Subsequently, Oxera's scope was extended to investigate the effects of P198 Alternative. This work involved re-calculating the results of the Central scenario using seasonal TLMs and 12 snapshot periods. Oxera included the results of this work in its July 2006 report.

In its September 2006 report, Oxera dealt with P204. Oxera only carried out analysis based on the input assumptions from the Central scenario from its previous report. Oxera was asked to analyse the impact of both annual and seasonal scaled loss factors because the Modification Group was still considering which approach might be more appropriate. In the end, however, the only Modification proposal that was agreed was based on seasonal scaled loss factors.

Table 3: Oxera's fuel price, carbon price and demand assumptions

	2006/7	2007/8	2008/9	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/6
Central case										
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	64.1	64.4	64.7	65	65.3	65.6
EU ETS price, €/tCO2	20	20	20	20	20	20	20	30	30	30
Gas scenario										
Coal price, £/tonne, ARA	33	32	30	29	27	27	27	27	26	26
Gas price, p/therm NBP	36.4	31.8	27.2	22.6	18	18.3	18.6	18.9	19.2	19.5
Demand scenario										
Peak demand, GW	63.8	65.2	66.7	68.1	69.4	70.6	71.8	73	74.2	75.4

4.4 Applicability of Oxera's work to the relevant modifications

The Seasonal case in Oxera's July 2006 report was used by the P198 BSC Modification Group in its assessment of the P198 Alternative proposal and also used by the P200 and P203 BSC Modification Groups in their assessments of the P200 Alternative and P203 proposals. In addition, all three annual scenarios were used to assess the original P200 proposal. It seems clear that Oxera's Seasonal case analysis provides an appropriate basis of analysing P203, since this modification is simply a seasonal version of the original P198 proposal.

However, the case of P200 and P200 Alternative, where most existing generators are only exposed to annual or seasonal zonal losses at the margin, is less clear. The Modification Group was divided on the issue of whether Oxera's analysis for P198 was also applicable for evaluating P200.[15] The Modification Group concluded that the effect of P200 would be similar to P198, since P200 should produce the same TLFs as P198. We agree that P200 should give generators the same marginal cost incentives as P198 and that, therefore, offers, despatch and the cost of generation and losses should be the same as under P198. One potential difference between P200 and P198 is that individual generators' profits are different under P200, and this could create differences in retirement decisions and hence benefits between P198 and P200. However, since retirement decisions depend on a wide range of factors, we expect this to be a second order effect, within the error margin of the model's results.

We also note that Oxera's Seasonal case analysis is only an accurate long-term assessment of P198 Alternative, where the seasonal TLFs are phased in over four years. This is because the benefits of zonal losses are likely to be non-linear, so that applying e.g. X% of the calculated TLFs would yield more or less than X% of the benefits of the original P198 proposal.

We have used our simple model – discussed in more detail in Section 7 – to estimate the benefits of phasing in the loss factors relative to the case where full loss factors are introduced immediately. Our results – illustrated in Table 4 – indicate that e.g. using 20% of the TLFs will produce about 60% of the benefits of the full TLFs. While our model uses annual TLFs – not seasonal TLFs as in P198 Alternative – we would expect the ratio of the benefits to the 'strength'

[15] See for example, Elexon, Assessment Report for Modification Proposal P200, §4.10 p.29.

of the TLFs to be similar whether seasonal or annual TLFs are used. Hence, we conclude that assuming a linear relationship between the phasing of the TLFs and the benefits will underestimate the benefits of P198 Alternative during the years when phasing applies (although, of course, P203 – P198 Alternative without phasing – will still have higher overall benefits than P198 Alternative). Note that the analysis in Table 4 is based on Oxera's loss factors for 2006/07 under the Central scenario.

Table 4: Estimate of benefits of phased loss factors

Scaling factor	Percentage of full benefits
0.2	63%
0.4	63%
0.6	88%
0.8	97%
1	100%

4.5 Was Oxera's methodology appropriate?

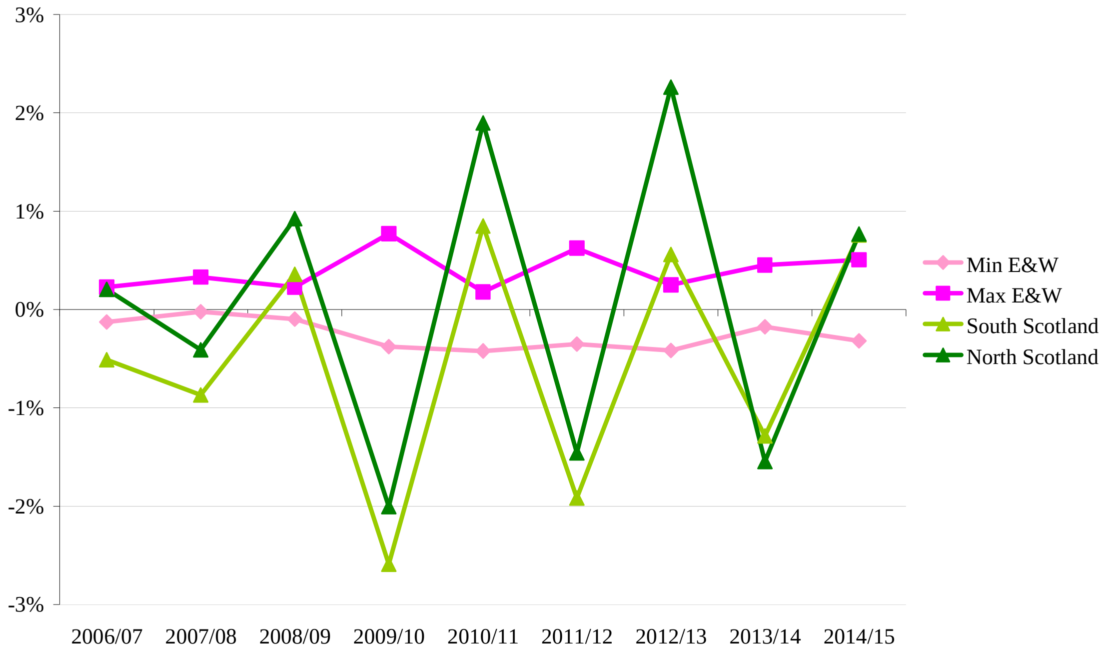
We consider that Oxera's general approach to the analysis was appropriate. In particular, the use of an iterative approach to determining how zonal TLFs might evolve mimicked what would occur if any of the Modifications were implemented and was consistent with the suggested approach in Oxera's terms of reference. However, we consider that there are a number of areas where the methodology could have been improved.

4.5.1 Use of at most 12 snapshots

We consider that it was inappropriate to use at most 12 snapshot periods for the load flow modelling. It is difficult to be sure that this will have (a) generated accurate annual zonal TLFs under all circumstances and (b) accurately captured the effect of those TLFs on losses.

In respect of the accuracy of the zonal TLFs, we acknowledge that, in general, Oxera's results for 2006/07 produce results that are in good agreement with those produced by PTI, who analysed 643 snapshot periods. It is also the case that the averages of the TLFs from the seasonal scenario are generally close to the annual TLFs, see Figure 1 below (although there is some limited evidence that the differences increase over time, as might be expected). Both these facts provide some reassurance that the TLFs may not be unduly influenced by the use of so few snapshots. However, the differences between the annual TLFs and the average of the seasonal TLFs are significantly larger for the Scottish zones, which generally seem to be the zones where the TLFs are most variable. It would be interesting, for example, to see what loss savings are generated when the TLFs from the Central scenario are used in all 12 of the snapshots for the Seasonal case.

Figure 1: Comparison of TLFs – Difference between Central scenario values and the average of the Seasonal case values under P198



It is also the case that, even if the TLFs are accurate, using only 3 snapshots may not adequately capture what happens when the TLFs are applied across a year. That this may be a concern can be seen from the fact that the precise weighting of the snapshots can have a significant impact on the results. In all the zonal loss cases studied (except the case with scaled annual TLFs, which was studied by Oxera but not actually included in any of the final Modification proposals), at least two thirds of the net benefits in each year came from either the mid-merit or trough snapshot. This means, for example, that if the weight of the trough snapshot is reduced by 5 percentage points and the weight of the mid snapshot correspondingly increased, then the savings found by Oxera during the first three years for the Central scenario (2006/07 to 2008/09) reduce by over 20%. It is, of course, true that if the weightings attached to the snapshots changed then the underlying demand and generation assumptions would also change so that different results might be found. Nonetheless, our example illustrates the point that a lot of weight has to be placed on a small number of outcomes so that relatively small shifts in assumptions could have a significant effect on the magnitude of the benefits found. (Note that we include the results for all zonal loss cases and modification proposals in Appendix III.)

4.5.2 Modelling post 2011/12

Second, we have concerns that the modelling from the period from 2011/12 onwards may be unreliable. This is because significant new capacity are assumed to come on-line but, as we understand it, no changes are made to the transmission system because this period is beyond the end of the period analysed in National Grid's 2005 Seven Year Statement on which Oxera relied. In both reports, under the Central scenario Oxera finds that introducing a zonal charging scheme leads to net dis-benefits in 2014/15 and 2015/16[16]. This could merely be a result of the way the Modifications specify that the TLFs should be calculated – if market conditions (relative fuel prices, the distribution of plant on the transmission system) change significantly from one year to the next, the zonal TLFs could generate incorrect pricing signals and hence yield higher variable losses than with uniform charging (an issue we discuss in more detail in section 7.4).

However, it seems likely to us that part of the reason for the calculated dis-benefits is an increasing mismatch between the transmission network modelled (which is fixed after 2011/12[17]) and the transmission network that would develop in reality (which would evolve to deal with constraints). It seems likely that the use of a fixed network will, over time, increase the likelihood of "artificial" constraints emerging, which in practice would never develop because network upgrades would be undertaken in time to prevent their emergence. The presence of such "artificial" constraints, which will affect the network under both zonal and uniform losses, may mean that the impact of changes in the distribution of generating plant from one year to the next may be amplified. Consequently, the modelled zonal TLFs may be a worse representation of the actual geographical distribution of losses than uniform losses and thus lead to dis-benefits.

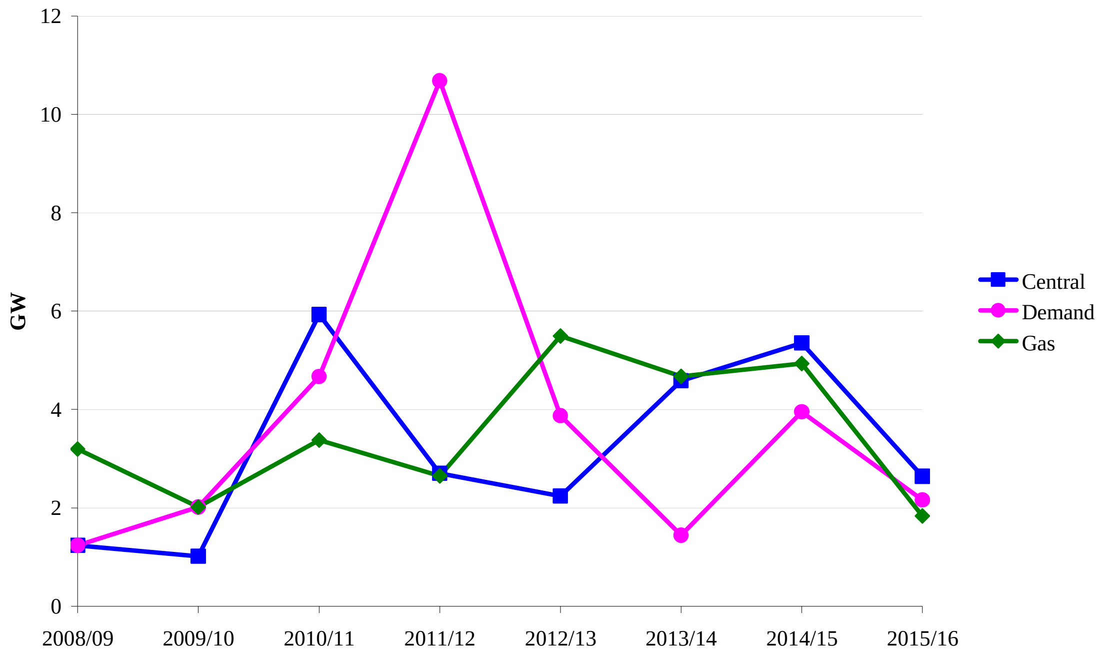
Figure 2 shows the absolute changes in capacity by year i.e. conventional and renewable new entry plus plant retirements.[18] It shows that both the Central and Gas scenarios have relatively high capacity changes from 2012 onwards, supporting our view that any dis-benefits found result from a combination of changing market conditions and a lack of modelled transmission network upgrades. This view is further supported by the fact that there is a reasonable level of negative correlation between capacity changes and net redespatch benefits under the Central and Demand annual TLF scenarios (around -0.5).

[16] See Figure 5 below.

[17] Oxera clarified that this was the approach it had taken to network modelling in a letter to Elexon dated December 21 2007, available on Elexon's website and included in Appendix VII.

[18] This data was provided by Oxera in response to one of our questions, see Appendix VII.

Figure 2: Absolute changes in capacity by year (retirements plus new build)



We note that Oxera ascribes the dis-benefit from zonal losses in 2014/15 and 2015/16 to a reduction in the need for large North to South transfers[19] but we do not believe this to be the correct explanation. Whilst a reduction in the need for North to South transfers will reduce the benefits to be derived from zonal losses it will not result in uniform charging generating lower losses overall unless the zonal TLFs are not a good reflection of the geographical spread of actual losses. As we have just discussed, we consider that a more plausible explanation for the dis-benefits is that they reflect the problems associated with using a network configuration that is fixed from 2011/12 onwards. In this respect, therefore, Oxera may have under-estimated the benefits of zonal losses although, as we have discussed, the potential for transitory dis-benefits inherently exists under all the modification proposals.

4.5.3 Distributional effects

Oxera's analysis of distributional effects is limited in two respects. First, Oxera only looks at 2006/07 but we accept that this was all that was specified in its terms of reference. The problem with looking at a single year is that it may not be representative of what would happen more generally – a point we discuss further in Section 6.1.3.

Second, Oxera only looked at distributional effects in general terms either by reference to a hypothetical generator/supplier or by looking at what happens at a zonal level. We accept that there would have been difficulties in presenting data for specific companies but it would have been informative to present data on at least the number of companies whose losses payments[20]

---

[19] See, for example, page 29 of Oxera's September 2006 report.

[20] Loss volumes multiplied by annual average baseload prices.

would be likely to increase or decrease due to the introduction of zonal losses. A further breakdown by type of company e.g. integrated utility, generator, renewables only generator, supplier etc. would also have been helpful in making an overall assessment of the modifications.

4.5.4 Interconnector modelling

Oxera's approach to modelling interconnectors was not described in its reports. In response to our question on the modelling of the interconnectors between GB and France and GB and the Netherlands, Oxera clarified that the French interconnector was modelled as a generator (i.e. a net importer of power).[21] We did not ask Oxera how it modelled the Moyle interconnector between GB and Ireland, but presumably it employed a similar technique by treating the Moyle interconnector as a load. Such an approach would be reasonable, since modelling the connected markets would impose an unreasonable computational burden on the load-flow model.

However, Oxera also clarified that it have not modelled the cable between Britain and the Netherlands (the BritNed cable), noting that the BritNed cable had not been formally approved at the time it undertook its modelling. This is true, but Oxera also included other plant, the construction of which was not certain but rather likely. It would have been logical to apply a similar approach to the interconnectors. We accept that proper accounting of the impact of the Britned cable would have required the detailed modelling of interactions between the Dutch and GB markets, which did not form part of Oxera's terms of reference. Unlike the case of the French interconnector, there is no data on historic flows on which to base a simplified analysis of the Britned cable.

Oxera note that the effect of the introduction of zonal losses on the interconnectors is small, since zonal losses would not change import and export flows. However, the introduction of a new interconnector – BritNed – could change actual losses, and make the TLMs being used to despatch plant inaccurate. This could reduce the benefits of zonal losses, perhaps considerably, for the year in which the BritNed cable is commissioned. Subsequent years would then use TLMs derived from despatch with the BritNed cable present so that any effects should be transitory. The investigation of using ex-ante TLFs is an issue we discuss in more detail in Section 7.4.

4.6 Conclusions on Oxera's methodology and the robustness of the results

Oxera's general conclusion is that the introduction of zonal losses would introduce net benefits from generation redespatch and demand side adjustments. Whilst we believe that the shortcomings we have identified with Oxera's methodology suggest that the precise magnitude of these net benefits found by Oxera may be questionable, we do not consider that the shortcomings are sufficient to invalidate the overall conclusion. For example, while we think that the use of 3 or 12 snapshots is too few, in respect of the accuracy of the zonal TLFs, we acknowledge that, in general, Oxera's results for 2006/07 produce results that are in good agreement with those produced by PTI, who analysed 643 snapshot periods. It is also the case that the averages of the TLFs from the seasonal case are generally close to the annual TLFs. Similarly, while Oxera's use of a static transmission network may have contributed to dis-benefits it found in the last two or three years of most of the zonal loss cases studied, this assumption will not have had an effect on

---

[21] See Oxera's clarification responses dated December 21st 2007, available from www.elexon.co.uk .

earlier years modelled. Oxera have not modelled BritNed, but BritNed's inclusion would have only reduced benefits for one year, and the reduction in benefits would likely not be large (we investigate the issue in more detail in section 7.4).

In addition, we consider that Oxera's approach to estimating longer term impacts – concentrating on the likely impact of zonal losses on siting decisions and renewables build – is appropriate. Finally, given its terms of reference, Oxera's approach to measuring distributional effects appears generally reasonable although, as we discussed in the preceding section, we consider that the terms of reference may have been too limited in this respect. However, it would have been helpful to provide some high-level data on the numbers of companies likely to benefit or lose out from the introduction of zonal loss factors.

5 Input assumptions

Ofgem have asked us to comment on the validity of Oxera's input assumptions given the information available at the time, and given the information available at the time this study was prepared (December 2007). Our terms of reference also asked us to consider if Oxera's inputs were 'credible'. Table 3 on page 26 (Section 4.3 above) details the fuel price assumptions Oxera used in its scenarios (note that the seasonal and scaled seasonal cases are based on the Central scenario). The Central scenario prices are also reproduced in figures in this section of the report.

In its report Oxera acknowledges that the fuel prices it uses may differ from prices in the forward commodity markets. However, the forward commodity prices available at the time and current forward prices represent a useful benchmark of the 'credibility' or 'validity' of Oxera's fuel price assumptions. If Oxera's fuel prices are very different from the forward prices at the time the study was prepared this would raise questions about why such a difference existed.

For convenience, in this section we refer only to the July 2006 report. However, since Oxera used the same inputs in the Central scenario for both its July 2006 and September 2006 reports, our analysis applies to both Oxera reports and hence all its analysis that is relevant to the zonal losses proposals.

5.1 Gas prices

Figure 3 compares the gas prices used in the July 2006 Oxera study with the price forecasts from the DTI on which Oxera claims to rely.[22] It also includes the forward prices available both at the time the July 2006 report was prepared and more recent forward prices. We have examined Oxera's fuel price assumptions over the period 2006/07 to 2009/10, since this is the range for which gas forward prices are available.

So as to compare forward prices (which are always quoted in 'money-of-the-day' or 'nominal' terms) we have converted the real Oxera and DTI prices into nominal terms, using an annual inflation rate of 2% (the Bank of England's target inflation rate). We assume that since Oxera first published its results in June 2006, the most up-to-date forward prices that would have been available to Oxera were from April/May 2006.

While Oxera does not say so explicitly, we assume that the prices quoted in its July 2006 report are in real 2006 money. Since the DTI report only gives prices for 2005, 2010, 2015 and 2020, and Oxera needed fuel prices for every year between 2006 and 2016, Oxera must have had to interpolate between the DTI's prices. Hence, we would expect Oxera's fuel prices for 2006 to 2009 to fall roughly between the 2005 and 2010 numbers used in the DTI report. However, as Figure 3 illustrates, this is not the case. Gas prices in Oxera's Central scenario are quite significantly above the DTI gas prices. For example, in 2010 DTI uses a price of about 30p/therm in nominal terms (DTI Central Scenario – favouring coal) whereas Oxera use 37 p/therm.

[22] Oxera July 2006 report §2.3.1 p.11. DTI (2006), 'UK Energy and CO2 Emissions Projections: Updated Projections to 2020' February 2006, hereafter referred to as the February 2006 DTI Report.

Another consultant (NERA) also investigated Oxera's price assumptions for gas and coal on behalf of a BSC Party (we discuss coal prices below).[23] NERA concluded that Oxera may have based its prices on a second DTI report which was published in July 2006, since NERA found that Oxera's prices match the July 2006 DTI numbers more closely than they do the February 2006 DTI report. However, NERA still did not find a satisfactory match between Oxera's numbers and the July 2006 DTI's numbers. Since Oxera published a first version of its July 2006 report in June 2006, and Oxera's fuel price assumptions were the same in its July 2006 report[24], it seems unlikely that Oxera relied only on the July 2006 DTI report – in this respect, we note the possibility that the data were updated prior to the report's publication.

However, we note that *validity of Oxera's results is not directly affected by the apparent mismatch between the fuel prices quoted by Oxera and the DTI.* For that, a more relevant question is whether Oxera's fuel prices matched market expectations at the time or currently. The mismatch between DTI's and Oxera's assumed fuel prices is more an issue of transparency than of accuracy of the final results.

Figure 3 also shows that all the gas prices used by Oxera were well below the forward prices available at the time. For example, in its Central scenario Oxera uses a gas price of 46 p/therm for 2006/07, whereas the forward curve was predicting prices of 66 p/therm. Consequently, it seems unlikely that the discrepancies between the gas prices in the DTI and Oxera reports can be attributed to Oxera updating the DTI figures without mentioning this in its reports. However, recent developments have shifted the National Balancing Point (NBP)[25] forward curve closer to Oxera's assumptions. The average December 2007 forward prices for the 2007/08 gas year gave a price of 46.8 p/therm, similar to the 44 p/therm used for 2007/08 in Oxera's Central scenario. However, forward prices from December 2007 increase from 2008, whereas Oxera's gas prices fall. Hence, we conclude that the gas prices used by Oxera in the July 2006 study reflect recent market expectations for NBP gas prices in the first few years, but diverge from recent market expectations by about 10p/therm of 25% for 2008 onward. We investigate the effect that changes in Oxera's input assumptions might have on its results in Section 7 and find that updating Oxera's gas price assumptions would be unlikely to result in any fundamental changes to the conclusions that can be drawn from its analysis.

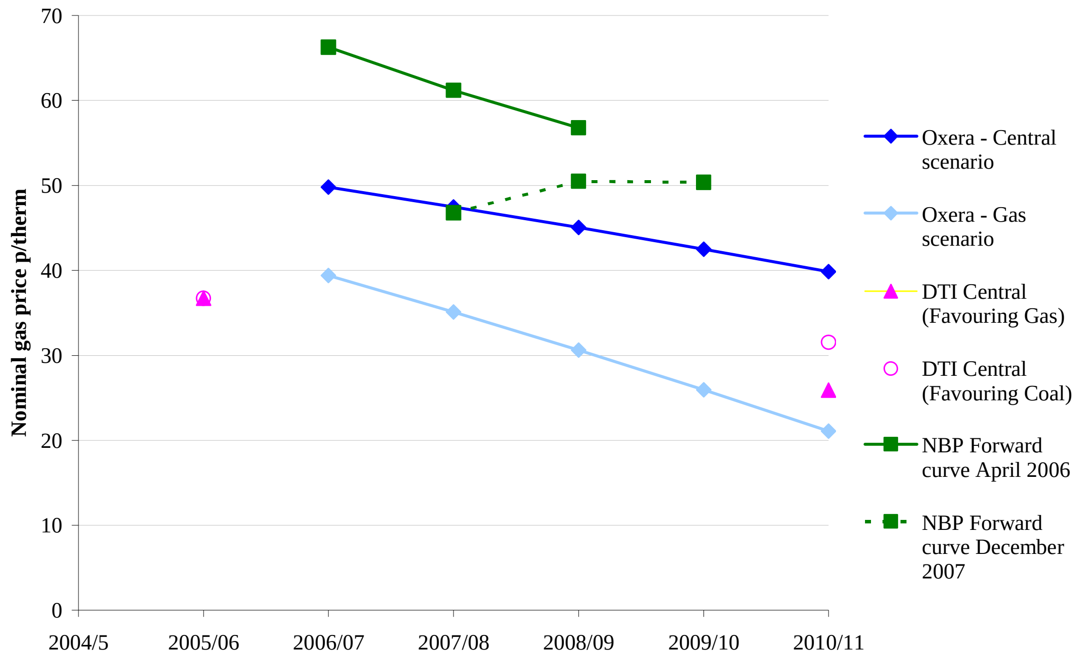
---

[23] NERA, Cost Benefit Analysis for Zonal Transmission Loss Factors: A Review For Teesside Power Ltd, 27th July 2007.

[24] The June report was subsequently found to contain data-errors, and so was re-issued in July 2006.

[25] A notional point in the UK National Transmission System (NTS) used as a delivery point for gas which is traded 'entry paid' i.e., already in the NTS, rather than at the beach. For accounting and balancing purposes all gas is said to flow through this point.

Figure 3: Comparison of Oxera's gas prices with the DTI's prices and forward prices



5.1.1 Peak and average gas prices

For a given year, it appears that Oxera used the same gas price throughout the year since there is no mention of monthly gas prices being incorporated in the analysis. However, in reality gas prices in the GB market are highly seasonal. For example, we calculate that, based on NBP gas prices between 2000 and 2004 inclusive, the average weekly gas-price in December and January was 130% of the annual average gas price.[26] This means that during the peak snapshots Oxera modelled to derive its annual TLFs, gas prices would likely be 30% higher than the average price used. (The same would also be true for all three winter snapshots in Oxeras's seasonal TLF analysis – although to a slightly lesser extent since the BSC Winter season also includes February.) The December 2007 forward curve also shows seasonality, with forward prices for January about 18% higher than the average price for the 2008/09 gas year (note that forward curves typically show less seasonal price differences than historical spot prices). Applying a 30% higher gas price to the modelling of winter periods would have affected the merit order and Oxera's results in winter, with gas less likely to run than Oxera's modelling predicts. However, in Section 7.2, we conclude that higher gas prices would not reduce the benefits predicted by Oxera.

The effects of seasonality in gas prices are likely to have some impact on all the seasonal snapshots modelled by Oxera, since they each relate to periods from within a three month window. However, they are unlikely to have had any material impact on the mid and trough snapshots modelled by Oxera when calculating annual TLFs. This is because these snapshots are

[26] We do not use prices from 2005 and 2006. During these years the GB gas market was relatively tight (prior to new gas supply coming on stream) – winter/average price differentials were larger than normal, but do not represent a good basis for predicting future winter/average price differences. For example, winter 2005/06 saw very high winter prices of over £1/therm, which we do not include in our calculations.

intended to be representative of periods that can occur throughout the year rather than in one particular month or season.

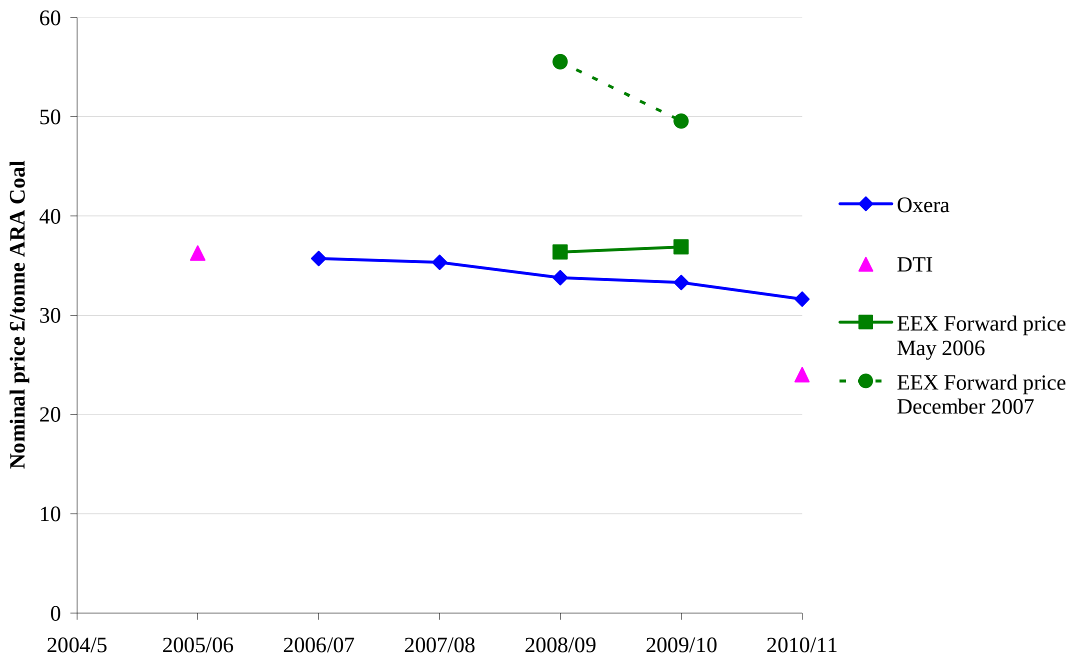
5.2 Coal prices

As Figure 4 shows, we have also compared the coal prices Oxera used with DTI's coal price forecasts and forward prices both from the time Oxera did its work and more recently (December 2007). As with the gas prices, we have converted all prices to nominal terms. We have also converted the DTI's prices from US dollars to pounds sterling using the exchange rates Oxera could have used in May 2006. We have converted forward coal prices – which are quoted in US dollars – to pounds sterling using the exchange rates published at the same time as the forward prices.

Figure 4 illustrates that the coal prices used by Oxera are both roughly between the DTI's 2005 and 2010 coal prices, and are similar to, though a bit lower than, the forward prices prevailing at the time Oxera carried out its analysis. However, recent developments in the coal market have led to a very significant increase in coal prices. Forward coal prices in December 2007 for 2008 were £55.5/tonne, and for 2009 prices were about £50/tonne. These forward prices are about 50% higher than the £34/tonne used by Oxera for 2008/09. We conclude that projected coal prices have changed significantly since Oxera carried out its study, and that this change could affect Oxera's results. We investigate this issue in Section 7 of this report and find that updating Oxera's coal price assumptions would be unlikely to result in any fundamental changes to the conclusions that can be drawn from its analysis.

We have commented, in Section 5.1.1 above, that we consider it would have been better if Oxera had included gas prices that changed by month in its analysis and that, as far as the annual TLFs calculated by Oxera are concerned, the effect of doing so would have been most significant for the peak snapshots. In this respect, it is worth noting that higher coal prices would reduce any effects that using seasonal gas prices might have had on Oxera's winter peak snapshot modelling because they would tend to restore the differential between coal and gas prices to that which Oxera assumed (as both gas and coal prices would now be higher). The effect on the other two snapshots modelled for annual loss factors is less certain but it is likely that high coal prices would act to increase the effect of using seasonal gas prices in the seasonal snapshots for, at least, the summer season where seasonal gas prices would be lower than the annual average gas price.

Figure 4: Comparison of Oxera coal prices with DTI prices and forward prices



5.3 Carbon prices

Oxera used a (real 2006) carbon price of €20/t CO_2 for Phase I of the EU's Emissions Trading Scheme (ETS), which lasted until the end of 2007. We note that actual carbon prices were well below this level during the latter part of 2006 and throughout 2007, at around €1-2/t CO_2. Hence, Oxera's results for 2006/07 and 2007/08 will have over-estimated the marginal costs of coal-fired plant relative to those of gas-fired plant. However, the sharp reduction in Phase I carbon prices was generally unforeseen by the market and forecasters, and so it is unsurprising that Oxera was also caught out. Oxera's over-estimation of Phase I carbon prices will also, to a degree, compensate for its under-estimate of coal prices, (discussed above). Coal emits more carbon per kWh of electricity generated than gas, and so higher carbon prices will make coal more expensive relative to gas once the cost of carbon is included. Finally, we note that since none of the BSC modification proposals will be implemented before 2008, Oxera's results for Phase I of the ETS are largely irrelevant, and so the mis-estimation of Phase I carbon prices will have no effect on the estimated costs and benefits from the relevant implementation dates of any of the proposals.

Oxera have used a (real) carbon price of €20/t CO_2 for Phase II of the ETS (which runs from 2008-2012), which is equivalent to about €23-24/t CO_2 in nominal terms. Oxera used a real price of €30/t CO_2 for Phase III prices. There is currently little guidance on what Phase III carbon prices might be. At present (January 2008), Point Carbon quotes a Phase II allowance price of €23/t CO_2 and the European Energy Exchange shows current forward prices for Phase II of €23-25/t CO_2. Hence, Oxera's assumptions with respect to the carbon prices seem reasonable and consistent with current market prices.

5.4 Choice of new entry zone

Oxera added a number of new generating projects to account for plant entry. Most of these projects were sufficiently advanced for their locations to be fixed. However, under the Demand scenario Oxera included two new 'generic' CCGT projects, one of 1,000 MW and the other of 2,000 MW and added these plants to zones 7 and 2 respectively.[27] There is no discussion of why zones 7 and 2 were chosen for the generic CCGTs in Oxera's July report. However, Oxera has since explained that these locations were selected after considering site availability, proximity to pipelines and TNUoS charges (letter to Elexon dated December 21st 2007). This seems a reasonable approach.

When choosing a location for the generic CCGTs, one guide could have been that the plants are most likely to go where most other plants have gone. The most popular zones for new plants with a known location are zones 10 and 2 with four new plants each. Zones 1, 4, 8, 9 and 11 each have one new plant, but no new plants (other than the generic CCGT) are built in zone 7.

However, one could also argue that putting the generic plants in the zones with the most new capacity could have created congestion which might not exist. This could slightly exaggerate the benefits of zonal losses, by creating congestion and high losses which the zonal loss modification then mitigates.

On balance, it seems it might have been more reasonable to put the new generic plant required under the Demand scenario in a zone chosen by at least one other plant developer (which would indicate that the zone is at least attractive to new plant), but not in the most popular zones (10 and 2). This would ensure that realistic locations are chosen while avoiding exaggerating the benefits of zonal losses. For example, generic CCGTs could be added to zones 1 and 11.

5.5 Other locational charges

In its analysis of new entry costs, Oxera relies on TNUoS and gas exit charges from 2006/07. The range of charges across the locations that Oxera studied has subsequently increased for electricity but decreased for gas, as shown in Table 5 and Table 6. below. As we discuss further in Section 6.1.2, the effect has been to increase the locational signals that already exist.

[27] Oxera July 2006 report, Table 2.4 p.13.

Table 5: Comparison of 2006/7 and 2007/8 TNUoS charges

TNUoS zone	2006/7 Zone Number	2006/7 TNUoS Charge (£/kW)	2007/8 Zone Number	2007/8 TNUoS Charge (£/kW)
South Scotland	9	12.140893	7	13.017061
North East England	10	8.885489	10	9.253848
South Yorks & North Wales	14	3.835629	13	3.996719
South East	15	1.219345	17	0.908414
South Wales & Gloucester	19	-2.736627	15	-2.457186
Range of charges		***14.87752***		***15.474247***

Table 6: Comparison of gas transportation charges over time

Size of plant (MW)	1,000
Efficiency	55%
Load factor	100%
Amount of gas used in a peak-day (MWh)	43,636

	Charge (p/peak-day kWh/day)				Annual payment (£mn)			
	2006/7	From Oct 07	Indicative from Oct 08	Indicative from Oct 09	2006/7	From Oct 07	Indicative from Oct 08	Indicative from Oct 09
Northern	0.0001	0.0001	0.0009	0.0062	0.02	0.02	0.14	0.99
South Eastern	0.0090	0.0113	0.0180	0.0175	1.43	1.80	2.87	2.79
South Wales	0.0212	0.0063	0.0019	0.0015	3.38	1.00	0.30	0.24
Yorkshire	0.0005	0.0001	0.0030	0.0026	0.08	0.02	0.48	0.41
South Scotland	0.0001	0.0001	0.0001	0.0001	0.02	0.02	0.02	0.02
Range of charges	***0.0211***	***0.0112***	***0.0179***	***0.0174***	***3.3607***	***1.7839***	***2.8510***	***2.7713***

5.6 Implementation costs

Elexon provided Oxera with estimates of the implementation costs for the central service providers and from the non-confidential responses of six major electricity companies (E.ON, EdF Energy, Scottish Power, British Energy, United Utilities and Energy Metering Services). Whilst the data provided to Elexon (which included two confidential responses) covered the implementation costs of approximately 50% of the generation market, Oxera had to estimate the implementation costs for the remaining BSC Parties. Oxera separately considered the costs likely to be associated with large generators, small generators, domestic retailers and industrial and commercial retailers. From the data provided to it, Oxera concluded that implementation costs of around £112,00 per large energy company might be a reasonable estimate. On the basis that around 8 companies account for 75% of the generation market, Oxera concluded that the implementation costs for large generators would be around £896,000. For smaller generators, Oxera assumed that, on average, each generator would undertake implementation activities lasting for 60 days at a cost of £220/day. Oxera added no additional estimate for domestic retailers on the grounds that this activity was undertaken by vertically integrated companies and so was included in either the costs provided to Elexon or its own estimate of generator costs. For suppliers to the industrial and commercial market, Oxera adopted the same assumptions as for generators.

The cost per day figure used in Oxera's estimates for smaller generators, which is the rate used in Elexon's internal costings, seems plausible if the effort was undertaken in house but likely to be too low if the work is outsourced. It might, therefore, be prudent to assume a higher cost – say 50% above Elexon's rate to account for the use of a mixture of in-house and external resources. Moreover, whilst Oxera refers to 45 generators for whom it needs to estimate costs (20 with conventional assets and 25 with renewable assets), the cost estimate that it includes is based on only 40 companies (40x60x220 = 528,000). Including an allowance for the remaining 5 companies (on its own, an additional £66,000) and increasing the costs to £330/day would add an extra £429,000, or 20%, to the implementation costs. We note that Oxera itself suggests that its total cost estimate could be 60% higher or lower than the one it presents. Even a 60% increase in implementation costs would have relatively little impact on the present value of the benefits assessed by Oxera over the period to 2015/16. For example, under the P198 Central scenario, it reduces the present value by around 5% (£1.2 million out of £23 million).

5.7 Conclusions on Oxera's input assumptions

The gas prices used, while below the forward prices existing at the time Oxera prepared its studies, were, at least in the short term, in line with market expectations as of December 2007. However, the lack of seasonality in the gas prices Oxera have used could introduce errors into the modelling because it means that the peak snapshots may not reflect market conditions (for the Seasonal case, this only applies to the Winter peak snapshot). The coal prices Oxera has used, while reasonably consistent with the contemporaneous forward prices at the time Oxera prepared its report, are now significantly lower than current coal forward prices. Oxera's carbon prices are in line with both current and 2006 market expectations. On the basis of some simple modelling, described in Section 7, we do not believe however that updating Oxera's fuel price assumptions would lead to any fundamental change in the conclusions that can be drawn from its analysis.

We also conclude that although Oxera may have under-estimated the likely level of overall implementation costs, these costs are sufficiently small compared to the estimated benefits that increasing them by any plausible amount is unlikely to cause any fundamental change in the conclusions that can be drawn from Oxera's analysis.

6 Results

6.1 Summary of results

6.1.1 Short-term effects under the Central scenario

Table 7 below summarises the main costs and benefits for the Modification proposals as calculated by Oxera. The net benefits of all the zonal losses proposals are NPV positive, but clearly the proposals which use seasonal TLFs have higher benefits than those using annual TLFs. This is perhaps unsurprising, since (ignoring the potential problems caused by their ex ante calculation) seasonal TLF's should better reflect the losses generators in that zone actually create in particular periods (the "actual" loss factors) than annual TLFs. This is because 'actual losses' will vary with the time of year and the pattern of generation and demand. The more closely TLFs resemble actual loss factors, the greater should be the benefits of a zonal losses proposal, assuming that generators respond to the loss signals and adjust their despatch patterns.

The benefits under P204 are lower than those under the other proposals that use seasonal loss factors because P204 involves 'scaling' the TLFs so that the generation TLMs are less than 1 (and the supplier TLMs are greater than 1). This means that the TLMs will not reflect actual losses as closely as the other seasonal TLMs.

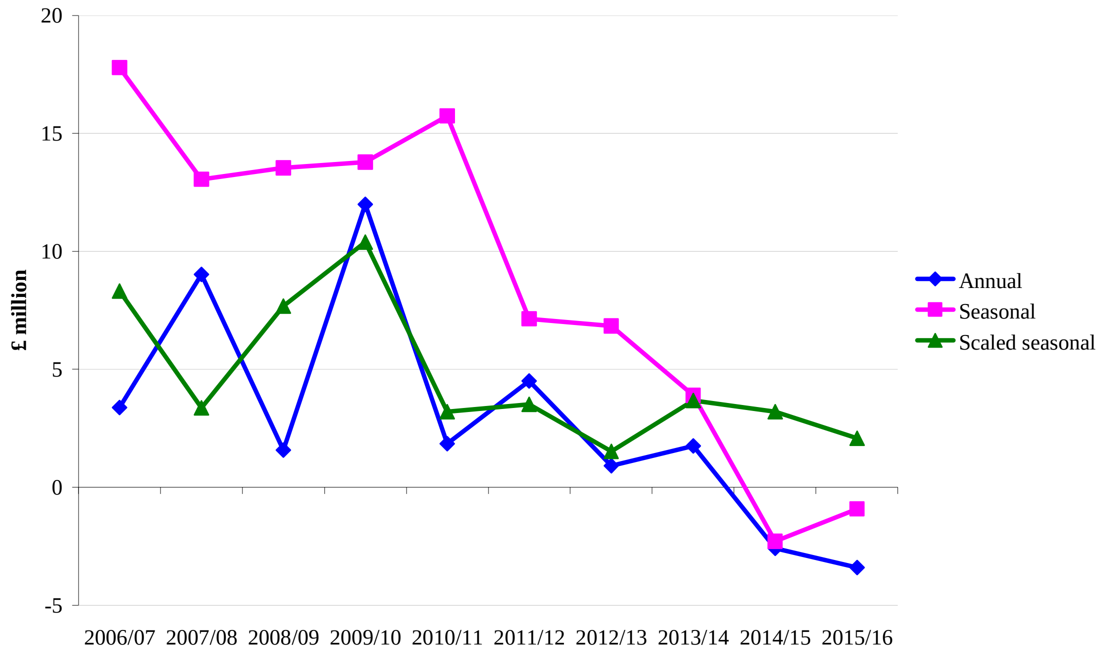
Table 7: Summary of benefits in Oxera's Central scenario to 2015/16 (£ million)

Applicable periods for TLFs	Annual	Seasonal	Scaled seasonal
Annual benefits/costs			
Generation re-despatch	2.9	8.9	4.7
Demand response	0.6	0.8	0.4
Operating costs	-0.3	0.3	0.3
Total annual net benefit	3.2	10	5.4
One-off implementation costs	2	2	2.1
NPV @3.5%	21.1	65.7	32.4

The year-on-year benefits from generation redespatch vary widely both within scenarios/zonal loss cases and between them. The variation between scenarios is perhaps only to be expected because they incorporate different assumptions on demand, generation and fuel prices and so the extent to which the conditions in any one year accurately reflect those that are assumed for the subsequent year might be expected to vary. This, in turn, means that the pattern of redespatch benefits can be expected to differ between scenarios.

However, Figure 5 below shows that even when the input assumptions remain the same i.e. the same scenario is considered – in this case the Central scenario – the pattern of net benefits varies significantly according to whether the TLMs are based on annual, seasonal or scaled seasonal TLFs. Whilst the overall pattern across all three cases is similar – higher benefits in the period until 2011/12 compared to the benefits thereafter – the pattern of peaks and dips varies between the cases.

Figure 5: Redespatch net benefits related to the Central scenario[28]



6.1.2 Comparison of results for annual loss factors across the three scenarios Oxera studied

In addition to its Central scenario, Oxera also analysed the effect of annual zonal loss factors under a high Demand scenario and a low Gas scenario. In both these scenarios, Oxera found that the net benefits of introducing zonal losses were approximately double (in present value terms), the net benefits under the Central scenario. Under both the Demand and Gas scenarios, the net benefit in terms of generation costs was significantly higher but for different reasons. The high Demand scenario led to higher generation costs and this amplified the effect of introducing zonal losses – in effect, the costs of losses was higher and so reductions in losses created greater net benefits. Under the low Gas scenario, there are greater loss savings in the early years because less efficient gas plant become competitive with coal plants and so there is greater fuel switching. Later on, the low gas prices reduce the differentials between the marginal costs of gas plants and so increase the opportunities for intra-fuel switching.

As regards demand side effects, these move in line with the electricity prices that Oxera projects under the two sensitivities. The Demand scenario has higher electricity prices and higher demand benefits (£0.3 million per year higher on average than under the Central scenario), whereas the Gas scenario has lower prices and lower demand benefits (£0.1 million per year on average).

---

[28] Although it was analysed under the Central scenario, the figure does not include the annual scaled losses case because, in the end, it did not correspond to any of the Modifications that were finally considered by the BSC Panel.

The directional effect on net benefits of both these sensitivities seem intuitively correct and confirmed by the results from the modelling we carried out, which is described in Section 7.

6.1.3 Distributional effects

Oxera concluded that zonal loss charging would result in significant transfers between market participants in 2006/07. Generators in the north and suppliers in the south would face increased loss payments whilst, conversely, generators in the south and suppliers in the north would pay less for losses.

These results are, unsurprisingly, consistent with the zonal loss factors that Oxera estimates for 2006/07. However, they may not be particularly representative of what might happen over the longer term. To illustrate why this is so, it is convenient to concentrate upon what happens to generators. Introducing zonal losses has two effects on generators. First, even if generators do not change the outputs of their plants, the loss payments (loss volumes multiplied by annual average baseload electricity price) to which they are exposed will change. Second, this change in loss payments may be modified if the output of particular plants changes as their position in the merit order shifts.

Based on the data provided by Oxera for the Central scenario with annual loss factors in Table3.8 and 9.3 of the July report, we conclude that the first effect is far more significant than the second effect. However, this finding depends on the fact that there is a significant geographical spread in the zonal loss factors in 2006/07. Oxera's analysis shows that, over time, the spread in zonal loss factors is likely to decline because most of the planned conventional plants are due to be built in the southern part of England. Consequently, distributional effects appear likely to decline over time even without considering the effects of generators' responding to the price signals from zonal losses.

If generators do respond to the price signals, which would be rational, then this is likely further to reduce the geographical spread in zonal loss factors (because plants with high losses will reduce their output) and hence erode distributional effects.

6.1.4 Longer term effects

Oxera concluded that zonal losses would strengthen the locational signals that already exist to build power stations close to demand. However, Oxera also concluded that it was uncertain how significant this effect would be since other non-cost related effects, such as planning permission and land availability, might be more important. Moreover, in the medium term i.e. until 2015/16, Oxera stated that there was unlikely to be any significant impact since most of the proposed power stations are favourably located with respect to transmission losses. Over the long term, Oxera estimated that the impact of any changes in siting decisions on net benefits was very uncertain but could lie in the range of £1-20 million per year.

As we noted in Section 5.5 above, the strength of the existing locational signals have increased since Oxera undertook its analysis. This suggests that the incremental effect that zonal losses might have on plant siting has reduced since Oxera's study, as demonstrated in Table 8 below. These changes only serve to strengthen Oxera's conclusions that zonal losses are unlikely to have any significant impact on generators' siting decisions.

Table 8: Regional new entry cost analysis using 2006/07 and 2007/08 charges (£m)[29]

Hypothetical CCGT plant	GSP group	Generation tariff zone	Regional comparison (before zonal loss charging) 2006/07	2007/08
South Wales	10	15	0.64	-1.45
South Eastern	9	17	2.65	2.71
Yorkshire	12	13	3.92	4.01
Northern	6	10	8.90	9.27
Southern Scotland	13	7	12.16	13.03
Difference				
excl. Scotland			8.3	10.7
incl. Scotland			11.5	14.5

Oxera also concluded that zonal losses would have little, if any, impact on the growth of renewables before 2015/16 since other factors (the design of the Renewables Obligation and non-economic difficulties) would be a more important limit on renewables building rates. Moreover, Oxera found that zonal losses only had a marginal impact on the overall profitability of renewable generation, although there were distributional effects with renewable generators in Scotland and the north of England being adversely affected and renewable generators in the south of England receiving some benefits.

Oxera has not provided details of the cost assumptions for different types of renewables that it has included in its analysis so it is not possible to verify its conclusions directly. However, its conclusions appear reasonable: difficulties in obtaining planning permission are generally cited as a major obstacle restricting the growth of renewables. On the other hand, we would expect that the introduction of zonal loss factors would have negative consequences for some renewable generation projects in the north of GB that were only marginally profitable with uniform loss factors. Consequently, Oxera's conclusions appear reasonable.

6.2 Net present value analysis

The cost-benefit analysis undertaken by Oxera involves trading off costs today against the future stream of benefits which a system of zonal losses could produce. Hence, the discount rate Oxera uses has a key role in determining the balance of benefits and costs. Oxera have discounted the costs and benefits using a discount rate of 3.5%, based on HM Treasury guidelines. Oxera argued that this was an appropriate discount rate because it was evaluating the costs and benefits of a regulatory rule change.[30]

---

[29] As in Oxera's reports, the "differences" shown at the bottom of the table correspond to the difference between the maximum and minimum values shown in a column or, when excluding Scotland, in a sub-set of a column.

[30] Oxera July 2006 report, footnote 25 p.67.

In general, the discount rate used to estimate the present value of a stream of payments should reflect the underlying risks of the project. Therefore, finance experts generally agree that the discount rate should vary according to the type of project being undertaken – just because a project is undertaken due to a rule change does not mean that the same discount rate will be applicable in all cases. In other words, the fact that HM Treasury considers that 3.5% is an appropriate discount rate evaluating central government projects does not necessarily mean that it is appropriate for evaluating the impact of zonal losses.

Two more relevant benchmarks for a discount rate are the cost of capital for electricity transmission and the cost of capital for electricity generation. In the most recent price control, Ofgem estimated National Grid Electricity Transmission's allowed rate of return at 4.4% real after-tax.[31] In Appendix IV we use Ofgem's estimate of the risk-free rate and market risk premium to estimate a real after-tax cost of capital for electricity generation of 5.35%. We think it is reasonable to use these estimates as the upper and lower limit of a plausible range of discount rates. Moreover, the discount rate of 3.5% used by Oxera is below the cost of capital for transmission, and likely underestimates the true risks facing the proposals.

The present values that Oxera published are calculated using the annual average benefits for all years, and that this distorts the results.[32] Hence, we have re-calculated the benefits using the actual benefits *for each year*. To enable us to do this, Oxera has sent us the estimated redespatch benefits for each year modelled i.e. out to 2015/16, since data for the years beyond 2011/12 was only provided in graphical form in Oxera's reports. We refer to the annual benefits data which Oxera sent us for the purposes of this report as the "January 2008" data.

While Oxera gave us the estimated redespatch benefits for each year modelled, it only gave us the present values for operating costs and demand response benefits. However, for the P198 Demand and Gas scenarios, the present values do not appear consistent with the annual average benefits presented in Oxera's reports. For example, for the P198 Demand scenario, the January 2008 data gives a present value of demand response of £2.9 million, which is equivalent to annual benefits of £0.35 million per year.[33] However, in its July 2006 report Oxera reported annual demand response benefits of £0.9 million per year for the P198 Demand scenario. We cannot explain these differences but have chosen not to question Oxera on this point since the January 2008 assumptions are less optimistic but still reinforce the general conclusion that zonal losses lead to net benefits.

Oxera's NPV analysis is based on discounting benefits and costs back to the beginning of 2006/07, on the assumption that the costs and revenues will be incurred at the end of each year. For its NPV analysis, Oxera has effectively assumed that zonal losses will be introduced at the beginning of 2007/08, with implementation costs being incurred in 2006/07. As we have previously pointed out, the TLMs that Oxera calculates are not consistent with this timetable

[31] Ofgem, Transmission Price Control Review: Final Proposals, Ref: 206/06, 4th December 2006.

[32] When calculating the present value (PV), benefits in early years will have a greater weighting than those in later years. Hence, if the early years had lower-than average benefits, calculating the benefits using the average annual benefit will over-estimate the PV.

[33] The present value of annual payments of £0.35 million for 10 years, discounted at 3.5%, is £2.9 million.

since its 2007/08 TLMs assume that zonal losses affected generators' behaviour in 2006/07. There is also an inconsistency in basing the benefits on an average that includes data from 2006/07 i.e. before the Modifications are assumed to come into force. The magnitude and direction of any effect will depend on the extent to which market conditions change from the year preceding the introduction of zonal losses to the first year of zonal losses. Consequently, it is difficult to estimate how material the impact of this inconsistency might be but it is worth recalling that the standard deviation of despatch benefits under most of the scenarios studied by Oxera is £4 million or less so impacts greater than this would seem unlikely.

In order to be able to compare our results with those presented by Oxera, we have based our analysis on Oxera's January 2008 data, even where these differ from the data Oxera published in its July and September 2006 reports. On this basis, in Table 9 we estimate the NPV of the costs and benefits of zonal losses using yearly generation redespatch data and a range of discount rates. We also show the results, based on an annual average analysis, that Oxera sent to us in January 2008 and the values that were published in Oxera's reports. Our analysis shows that moving from using annual average benefits for generation redespatch to using yearly data can change the NPV by between -£0.4 million (scaled Seasonal case) and +£3.7m (Demand scenario). This simply reflects differences between the scenarios in the timing of the bulk of the generation redespatch benefits.

Table 9: NPVs using alternative discount rates and approaches (£ million)

	Annual average data		**Yearly 2008 data**		
	Reports	**Jan 2008**	**Treasury DR**	**Transmission DR**	**Generation DR**
Discount rate	3.50%	3.50%	3.50%	4.40%	5.35%
Central	21.1	21.1	23.0	22.4	21.7
Demand	49.0	45.6	49.3	47.2	45.2
Gas	42.9	42.8	42.4	41.3	40.1
Seasonal	65.7	65.7	62.1	59.9	57.6
Scaled seasonal	32.4	32.4	30.4	29.0	27.7

As is only to be expected, increasing the discount rate used in the calculations decreases the NPVs by between £1.3 million (Central scenario) and £4.1 million (Demand scenario).

Regardless of the discount rate used and the methodology, and not withstanding differences between the 2008 and 2006 data provided by Oxera, for any reasonable discount rate the NPV of the benefits that Oxera forecasts will be positive. We estimate that for the introduction of zonal losses to lead to a zero NPV (and therefore no net benefits) one would need to use a discount rate of nearly 200%. This discount rate is clearly well in excess of any reasonable estimate of the cost of capital. Alternatively, the total benefits from redespatch and demand response would have to be less than £0.59 million in every year at a discount rate of 5.35% for the net present value to be zero. This again seems an unlikely outcome since it is less than 20% of the lowest annual average benefits found by Oxera.[34] In other words, fairly extreme assumptions have to be made in order to generate a negative NPV.

[34] This excludes the results from using scaled annual TLFs, which we ignore since such a proposal was never formally submitted for consideration.

7 Checking Oxera's results

In Section 5.2 we highlighted that since Oxera undertook its analysis the coal price has changed quite considerably. In addition, Oxera only looked at a single carbon price. In this section we investigate whether Oxera's results are robust against reasonable changes in the input assumptions. That is, we investigate whether Oxera's conclusion that the introduction of zonal losses leads to net benefits still holds under a wider range of input assumptions.

To investigate if changes in the coal price or carbon prices could have a large effect on Oxera's results, we have constructed a simple spreadsheet-based despatch model of the GB electricity market (hereafter referred to as 'the simple model'), we describe below. We use it to investigate the effect on the predicted benefits under a range of input assumptions, such as higher coal prices than assumed by Oxera. When investigating these sensitivities, we generally assume that the TLMs accurately reflect actual losses so that a merit order that takes account of the TLMs will lead to optimal despatch decisions. However, in Section 7.4 we investigate a case where the TLMs could diverge from actual losses. This could happen if there was a 'shock' to the GB generating market such as a sudden increase in gas prices. A large difference between TLMs and actual loss factors in any given year could cause the predicted benefits of zonal losses to reduce significantly.

7.1 Description and validation of the simple model

Our simple model contains a list of all transmission connected plant in GB, including wind and other renewables. It calculates the marginal cost of each plant (including fuel, carbon costs, other variable operating costs and losses) and orders the plants from the lowest marginal cost to the highest marginal cost in a 'despatch curve'. We create two despatch curves in the model: the first is for the situation with uniform losses; the second despatch curve is based on the zonal Transmission Loss Factors (TLMs) calculated by Oxera in its Central scenario.[35] As a result of the concerns expressed by respondents concerning the exclusion of fixed losses from Oxera's analysis (see Section 8.4 below), we decided to include fixed losses in most of our simple modelling. We use a uniform TLM of 0.992, in line with the data on fixed and variable losses provided in Oxera's July report.[36] (We note that Ofgem in its "minded to" consultation used a uniform variable generation loss factor of 0.995, this is consistent with the Oxera data which also yields a uniform variable generation loss factor of 0.995.[37])

[35] The TLMs are given in Appendix 2 of Oxera's July 2006 report.

[36] For example, in Table 3.19 (Central scenario) of Oxera's July 2006 report, Oxera states that total uniform losses were 6376 GWh out of a total of 360,00 GWh electricity produced. Assigning 45% of these losses to generators and calculating the percentage of total electricity produced for which these generation losses accounts yields a total uniform loss factor of 0.992.

[37] We estimate this value in the same way that we estimate the overall loss factor by dividing 45% of the reported volume of variable losses by the total electricity produced.

To adjust Oxera's generation TLMs so that they include both fixed and variable losses we subtract 0.003 from Oxera's figures.[38] (We also checked whether excluding fixed losses had any impact on the results of our simple modelling under the Central scenario and found none.)

For each hour of the year, we calculate the marginal plant by reading off demand against the despatch curve.[39] This enables us to calculate, both for the uniform loss despatch curve and the zonal loss despatch curve, which plants would be running in each hour. We can then calculate the change in generation for each zone when we switch to zonal losses from uniform losses. We also calculate the total cost of generating electricity, including losses, again with zonal losses and uniform losses. We can then calculate the reduction in generating costs which the introduction of zonal losses would produce. This is the same approach used by Oxera (see the discussion in Section 3.2 for more details on this point).

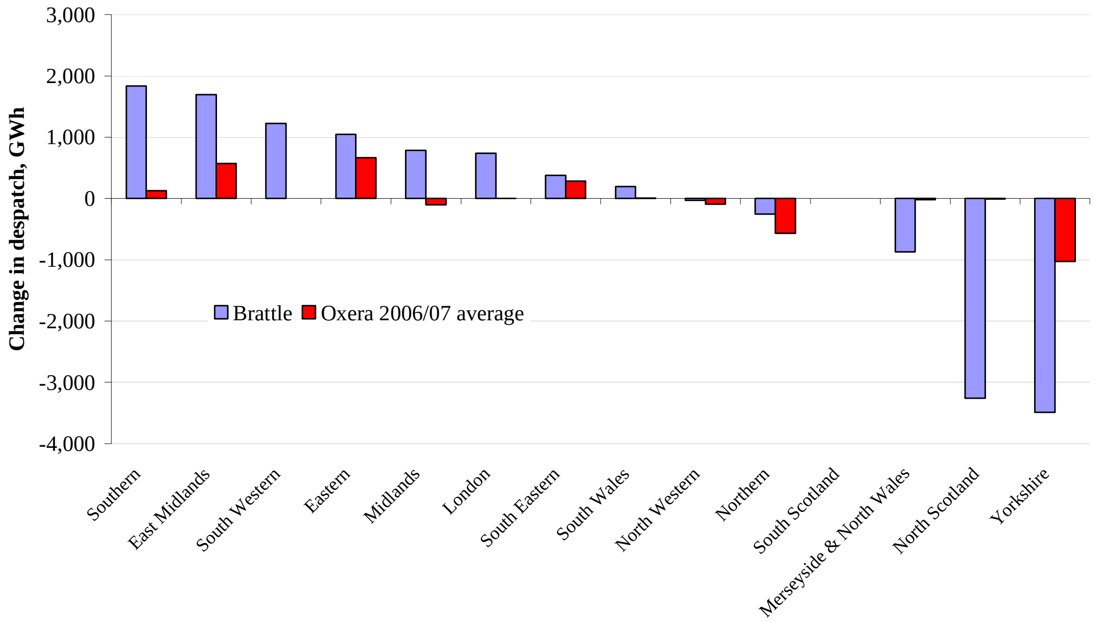
To simplify the model, we use only annual TLMs. Hence, our model is only directly comparable to the evaluation of the original P198 and P200 proposals effectively contained in Oxera's July 2006 report. However, if our simple model predicted a large reduction in benefits as a result of e.g. high coal prices, then this reduction would also apply on a roughly pro-rata basis to the BSC modification proposals which involved seasonal TLFs. Hence, our model is suitable for identifying the robustness of all of Oxera's conclusions, not just those which rely on annual loss factors.

Figure 6 shows the results of our model compared to Oxera's results for the Central scenario. In general, our simple model predicts much larger changes in generation between zones than Oxera. It is likely that the fact that our simple model ignores transmission constraints accounts for the difference between the two models. Also, our simple model will likely overestimate the changes in generation by zone, because it does not include maintenance periods. Maintenance of plant in zones with lower loss factors could cause plants in zones with higher loss factors (such as Yorkshire) to despatch more than our simple model predicts.

[38] Similar calculations to those described in footnote 36 show that the fixed losses account for a generation loss factor of around 0.003.

[39] To reduce the computation required, we actually use 36 'characteristic days' rather than 365 days, and then scale the results up to represent a whole year. Each month is modelled as a characteristic weekday, Saturday and Sunday, and each characteristic day has 24 hours.

Figure 6: Comparison of the change in generation by zone for 2006/07 from the introduction of P198, Central scenario assumptions, Brattle model and Oxera results



However, the main purpose of our simple model is not to replicate the Oxera economic despatch model, which is far more complex. Rather it is a simple tool to see if changes in the input assumptions can make a big difference to the predicted reduction in costs as a result of redespatch following the introduction of zonal losses.

7.2 Sensitivities performed with the simple model

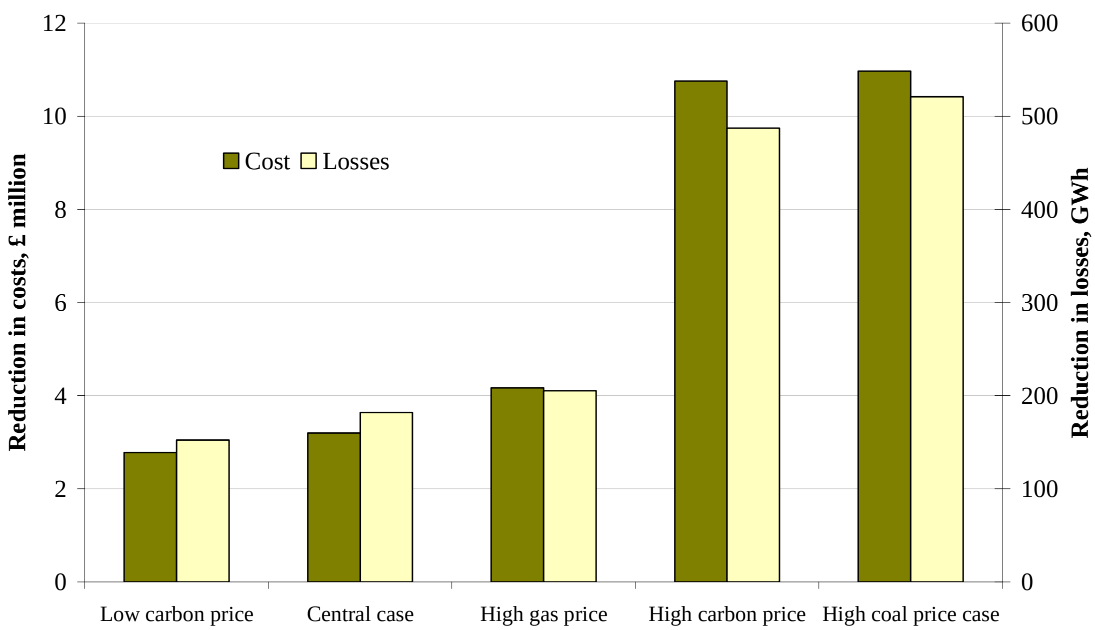
We have carried out a number of sensitivities, and estimated the changes in the savings which the introduction of zonal losses would realise. Table 10 shows the scenarios which we have modelled, and the corresponding savings from the introduction of zonal losses. Clearly, there are an almost infinite number of cases that we could have studied, but we have chosen to concentrate on sensitivities that seem relevant either because they reflect changes in market conditions since Oxera's reports or because they are likely to change the relative marginal costs of coal and gas plants in ways not investigated by Oxera. Figure 7 shows the same results graphically. Our estimated savings for the P198 Central scenario are £3.2 million, which is very close to Oxera's estimated savings for 2006/07 of £3.4 million. This gives some confidence that our simple model gives reasonable results.

However, not all our results seem to follow the same trend as Oxera's. We calculate 260 GWh of net output (i.e. after losses have been accounted for) switch from coal to gas. In Table 3.6.1 of its July report, Oxera shows most of the reduction in gross generation (before losses are accounted for) coming from CCGT plant. To explain these differences would require a more detailed examination of Oxera's results. However, since we are more interested in the *changes* in the projected savings as inputs change, rather than accurately reproducing Oxera's results, we did not pursue this issue further.

Table 10: Sensitivities on Oxera inputs and changes in estimated savings for 2006/07

Scenario	Consists of:	Cost reduction, £ mln
Low carbon price	Carbon @ €5/tCO_2.	2.8
Central case	As per Oxera	3.2
High gas price	Gas at 65 p/therm	4.2
High carbon price	Carbon @ €40/tCO_2.	10.8
High coal price case	Coal at £50/tonne	11.0

Figure 7: Sensitivities on Oxera inputs and changes in estimated savings for 2006/07



We only show results for 2007 because we can only base our TLMs on those calculated by Oxera (but allowing for fixed losses). Hence, if we change e.g. coal prices in 2007 relative to Oxera's assumptions, the TLMs for 2008 would be different to those presented in Oxera's report. Since we cannot calculate the changed TLMs, we would not be able to take this effect into account. Modelling only 2007 avoids this problem, because the TLMs are based on the previous year, the inputs for which we do not change.

As Figure 7 illustrates, only one scenario (the low carbon price) reduced the projected savings below those forecast in the Central scenario, and then only to a small extent. By contrast, the scenarios involving high coal and carbon prices approximately tripled the savings realised. Figure 7 also shows that the increased cost savings arise not only because the price of fuel has increased (so that a given reduction in losses is worth more) but also because there is an increase in the volume of loss savings i.e. in GWh terms. We discuss the reasons why the high-coal price scenario realises greater benefits for zonal losses than the Central scenario (and conversely why the low carbon price leads to reduced benefits) in more detail below.

7.3 The high-coal price scenario in more detail

Our model indicates that the displacement of coal-fired plant sited in locations with relatively high losses by gas-fired plant with relatively low losses is an important mechanism for realising cost savings from zonal losses. We illustrate why this is the case with a highly stylised example where for expositional purposes we assume that all coal plants are located in a zone with ‘high’ loss factors whereas all gas plants are in a zone were the zonal losses are equal to uniform losses (so that the introduction of zonal losses has no effect on the marginal costs of these plants). Suppose that, with uniform losses all coal plants had a marginal cost of £20/MWh, and all gas plant had a marginal cost of £30/MWh. Further, suppose that the introduction of zonal losses meant that all coal fired plant faced losses which added £2/MWh to their costs, but, as postulated above, there was no effect on the marginal costs of gas-fired plants from the introduction of zonal losses. In this example, introducing zonal losses would not bring about a reduction in losses. Coal-fired plant would still be cheaper than gas, and the losses would be exactly the same as before. Now suppose that with uniform losses coal-fired plant cost £29/MWh, and gas-fired plant cost £30/MWh. Now the introduction of zonal losses would increase the cost of coal-fired plant to £31/MWh – gas-fired plant would displace much of the coal-fired plant, and losses would fall dramatically. In other words, it is not high coal prices per se that lead to increased benefits but only coal prices that lead to marginal costs, excluding losses, that are close to the marginal costs of gas-fired plants.

As Figure 8 illustrates, the geographic distribution of power plants is such that the capacity of coal-fired plant in zones with below average TLMs (i.e. higher losses) is greater than the capacity of gas-fired plants in these zones. Accordingly, the marginal costs of coal plants are, on average, more affected by the introduction of zonal losses than those of gas plants. We calculate that (based on Oxera’s 2007/08 P198 Central TLMs) the introduction of zonal losses increases the average marginal cost of coal plant by 0.15%, but has no effect on the average marginal cost of gas-fired plant, since just as many gas-fired plants experience a decrease in costs as an increase.[40] Hence, the introduction of zonal losses will cause coal-fired plant to shift higher in the merit order, relative to gas-fired plants. (There is also, of course, some re-ordering of the relative positions of coal plants situated in regions with high and low loss factors which also affects the volume and cost of losses.)

[40] We have calculated the average marginal cost, weighted by capacity de-rated for outages.

Figure 8: Distribution of coal and gas plants between above and below average TLMs (based on 2007/08 TLMs)

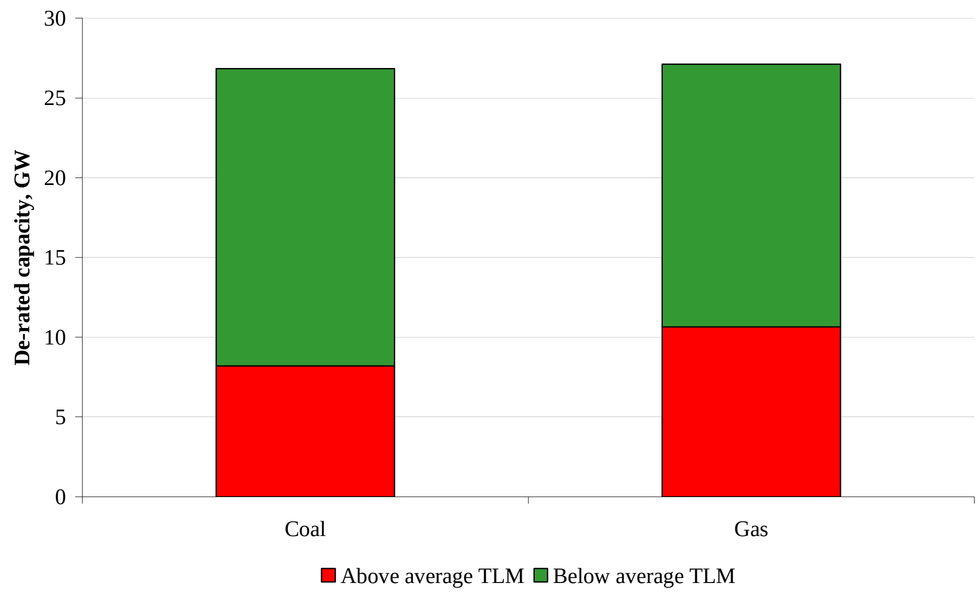


Figure 9 and Figure 10 illustrate the reason that high-coal prices increase the benefits of zonal losses, by showing the merit orders for the Central scenario and high coal price scenario respectively, based on the information used in our model. In the Central scenario with uniform losses, almost all coal-fired plants have lower marginal costs than those of gas-fired plants. As we note above, the introduction of zonal losses increases the cost of coal relative to gas. But in the Central scenario, most coal-fired plants remain cheaper than gas plants even when the cost increases due to zonal losses are taken into account. Accordingly, in our model gas-fired plant only displaces 260 GWh of coal-fired plant in 2007 in the Central scenario and there is a modest reduction in losses, because the introduction of zonal losses does not cause a significant change in the merit order.[41]

In the high coal-price scenario (illustrated in Figure 10), even with uniform losses many gas-fired plants are actually cheaper than coal-fired plant. Introducing zonal losses now makes coal-fired plant sufficiently expensive that 5,800 GWh of coal-fired plant is displaced by gas-fired plant. This increased displacement of coal-fired plant also results a larger reduction in losses than under the Central scenario. In sum, given Oxera’s Central gas prices increasing coal prices creates a merit order where the marginal costs of many coal and gas fired plants are sufficiently close together for zonal losses to make substantial changes to the merit order. (Note that the effect is similar to that seen under Oxera’s Gas scenario, where gas and coal become more competitive through a reduction in gas prices.)

We also note that using seasonal gas prices (i.e. gas prices that go up in winter) would reduce the benefits of zonal losses for the winter months, since many coal-fired plant would still be cheaper than gas-fired plant even with zonal losses (the merit order would look as in Figure 9 but

[41] Table 11 shows what other changes occur in the merit order.

with the marginal cost of the gas-fired plant shifted up). However, this result would at be partially offset if Oxera re-ran the analysis with today's higher coal prices.

Figure 9: 2007 Merit order with uniform losses Central scenario

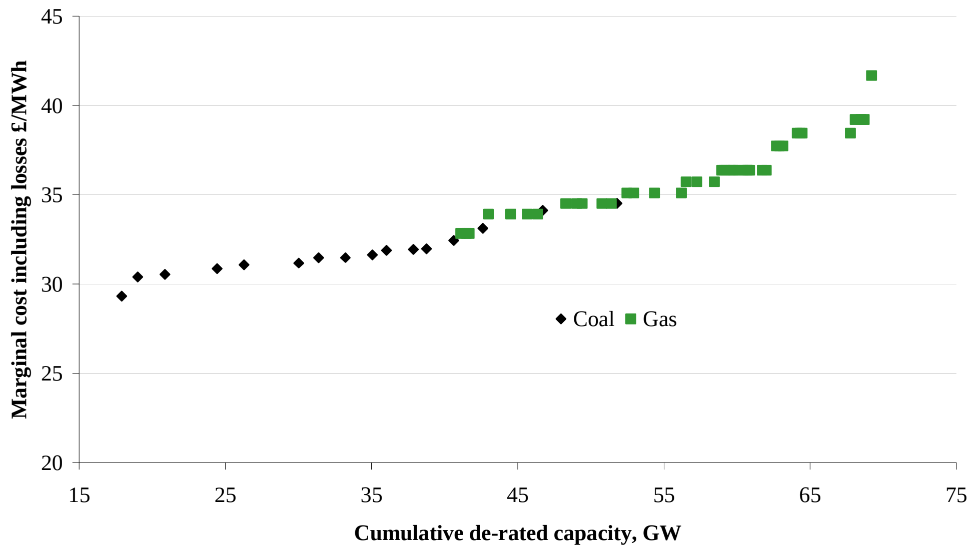
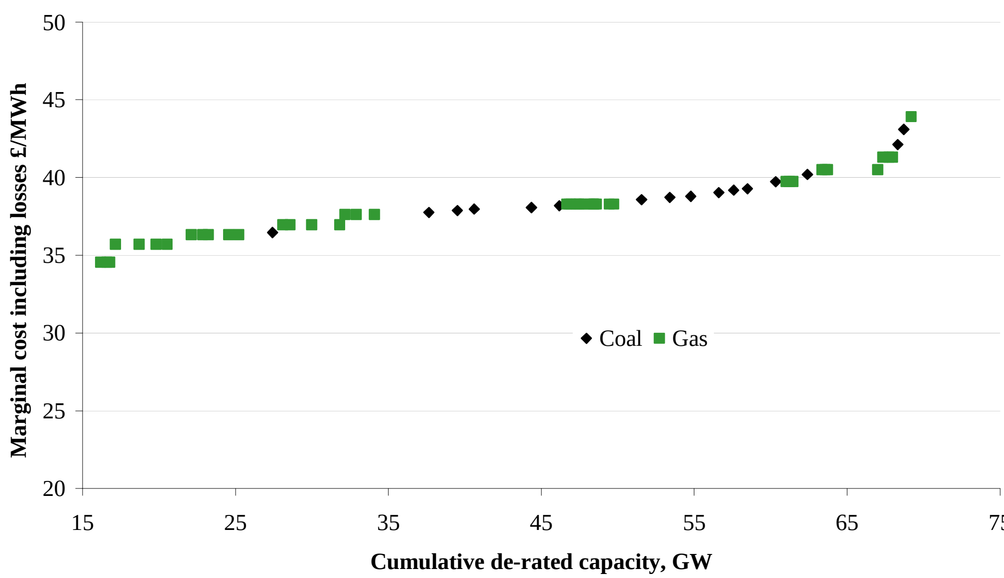


Figure 10: 2007 Merit order with uniform losses high coal price scenario



We have also tried increasing fuel transport charges for both gas and coal plant by 20%, but found that this made no significant difference to the results.

Note that the discussion above is to explain why a specific scenario (high coal prices) causes the benefits of zonal losses to increase, and the special role that switching from coal to gas plant has in this scenario. This does *not* imply that the majority of switching (when zonal losses are introduced) is *between* fuel types. Far from it – the majority of switching is *within* the same fuel type.

While our simple model does not allow us easily to analyse the amount of intra-fuel switching (when one gas-fired plant is displaced by another gas-fired plant for example) in GWh, we have analysed changes in the merit order when zonal losses are introduced to get an indication of the extent of intra-fuel switching. If a plant changes position in the merit order as a result of the introduction in zonal losses, this indicates that the plant will run more or less than before (depending on whether it has shifted down or up in the merit order respectively). Hence, a movement of a plant in the merit order indicates a change in its level of despatch. Table 11 indicates that 18% of plant did not change their position in the merit order, and 17% of changes in the merit order involve one coal plant being replaced with another. Nearly two-thirds (58%) of changes in the merit order are from one gas plant replacing another, implying that the majority of switching is between gas-fired plants. Only 7% of changes in the merit order involve a gas plant replacing a coal plant. There were no occasions on which a coal plant replaced a gas plant. (Note that fuel switching under Oxera's scenarios is discussed further in Section 8.3 below.)

Table 11: Analysis of changes in the merit order moving from uniform to zonal losses in the Central scenario, 2006/07

	Percentage of merit order changes
No change	18%
Coal to coal	17%
Gas to gas	58%
Coal to gas	7%

7.4 Differences between TLMs and actual losses

The proposed Modifications all depend on the use of TLMs based on the previous year's despatch. If the pattern of actual losses were to change significantly from one year to the next, so that the TLMs no longer reflected the geographical spread of actual losses, then there will be significant volatility in the TLMs and the introduction of zonal losses could conceivably increase costs in some years. To take a relatively extreme example for the purposes of exposition, suppose that, based on performance in 2008 a plant had a TLM for 2009 of 1.05 (so that it was credited with 5% more power than it actually produced). But in 2009 a change in the network (a plant retirement for example) causes the plant's actual loss factor to change to 0.95. In this case, the plant might generate more than under a uniform losses system, but the plant will actually be creating losses. Consequently, the introduction of zonal losses could actually increase the cost of losses relative to a system of uniform losses, and produce a net dis-benefit in 2009.

An example of this kind of shock seems to occur under P198 in Scotland in 2013/14 as the TLF for zone 14 turns positive for one year. Oxera attribute this effect to the closure of the

Hunterston nuclear power station.[42] Since this TLF is applied for 2014/15, by which time the market will have developed to take account of this closure, it may explain why Oxera finds a net dis-benefit in this year. We note, however, that it is possible that the effect of the shock may be exaggerated because, as we have discussed earlier, Oxera does not include any network development after 2012/13.

The effect of any shock (i.e. an event which causes despatch patterns and networks flows to change) will dissipate over time – the following year the TLFs will take account of the new situation although the effect of incorrect TLFs for that year will mean that the correction is not perfect. Nonetheless, the TLFs should once again be a reasonable proxy for the geographical spread of actual losses. However, if there are repeated shocks – for example a major plant retirement in one year followed by the addition of a new transmission line the next – the benefits of zonal losses could be reduced more significantly or for a longer time.[43]

To an extent, we can check for the significance of this effect by examining what impact plant additions have on Oxera's TLF estimates. If a plant addition caused a relatively large change in TLFs, this would indicate that the problem we outline above could be material, and that plant additions could cause TLMs to deviate significantly from the geographical spread of actual losses in a given year. In Table 12 we compare the average annual change in TLMs in a zone in the years before a new large scale conventional plant was added to the change in the TLM in the year the plant was added. We then calculate the ratio between these two numbers. Since Oxera assumes that renewables are added throughout the years it analysed across most of the zones[44], we have restricted our analysis to those zones (8 and 10) where only conventional plants are assumed to be added. In these zones, adding a large scale conventional plant results in the TLM increasing by at least three times the annual average of the changes in the years before a plant was added. Consequently, we conclude that plant additions can constitute shocks of the kind that lead to the spread of TLFs not being representative of the spread of actual losses. These types of shocks have, of course, already been included in Oxera's study.

Table 12: Effect of plant additions on TLMs

Year capacity added	Zone	Capacity added, MW	Average annual change in TLM before generation added	Change in TLM in the year that generation is added	Ratio, change in year when generation added to changes in previous years
2011	8	850	0.0020	0.0060	3.0
2013	10	1,000	0.0020	0.0100	5.0

Oxera has, however, not investigated the effect of e.g. a significant change in gas prices in one year to the next. Hence, we are concerned that one of the main risks inherent to the

[42] See page 19, Oxera July report. However, in data sent to us in January 2008, Hunterston is stated to close in 2011, see Appendix VI.

[43] While in theory a shock could cause TLFs to converge to the values representing actual losses more quickly, in practise this seems unlikely. Only further modelling would answer the questions definitively.

[44] Oxera provided us with data on its renewables assumptions, see Appendix V.

Modification proposals – that TLMs based on the previous year's despatch could be a poor proxy for actual losses – has not been explicitly investigated by the Oxera studies. For example, in the Gas scenario gas prices are consistently lower from one year to the next. But the type of scenario that is most likely to reduce the benefits of the proposal is, for example, one in which gas prices cycle between being low in one year but high in the next (or vice versa). Given the cyclical nature of prices in the liberalised GB gas market, such a scenario is not unrealistic. For example, average GB gas prices in 2005 were over 50% higher than 2004 prices. Similarly, the introduction of the BritNed cable could change TLMs significantly, reducing the benefits of zonal losses for the subsequent year. It would be interesting to see if the proposal to introduce zonal losses would still produce benefits in such a scenario.

To test the effects of a deviation between actual losses and the TLMs, we tried using TLMs from the Demand and Gas scenarios to represent actual losses in the Central scenario, for several different years. However, we could not find a case in the first few years where the estimated benefits were reduced, but this may have been because the scenarios Oxera examined were not sufficiently 'extreme'.

As mentioned above, in our simple model we generally assume that the TLMs represent 'actual' losses. In other words, if a zone has a TLM of 0.98, then we assume that physically only 98% of electricity generated in that zone will arrive at the consumer (2% of the electricity will be lost as heat). In reality, this will not always be the case – the TLM for a zone and the physical losses generators in a zone create will differ. To establish what it would take to reduce the benefits of introducing zonal losses to approximately zero in a given year, we adjusted the actual losses in our model to deviate from the TLMs. To return to the previous example, this could mean that a zone where only 98% of electricity arrives at the consumer may have a TLM of 0.99, so that generators do not bear the true cost of the losses they create. If the difference between TLMs and actual losses is large enough, a system of uniform losses can create more efficient despatch than zonal losses.

Specifically, we explored what happened when actual losses were represented as the predicted TLM plus or minus an adjustment factor. The same adjustment factor was used for all zones but it was deducted from the TLM when the TLM was below the average TLM and added to the TLM when the TLM was above the average TLM.[45] We found that if the TLMs differed from the actual losses by 0.007 or more, the benefits of introducing zonal losses were reduced to zero. Judging from the changes in TLMs illustrated in Table 12, a deviation between actual losses and TLMs of the order of 0.007 is large, but not wholly unrealistic. Consequently, it seems plausible that a significant shock could cause actual losses to deviate from TLMs sufficiently to result in a net dis-benefit.

We conclude that while Oxera has not explicitly investigated the main risk associated with the Modification proposals, it is unlikely that market shocks of the kind required to reduce redespatch benefits substantially will occur frequently enough to undermine the robustness of Oxera's conclusion that zonal losses lead to net benefits.

---

[45] For example, in 2006/07 East Midlands has a TLM of 0.990 (including fixed losses), which is below the average TLM. Hence we assume actual losses in the East Midlands zone is 0.990 + 0.007 = 0.997.

8 Concerns raised by interested parties

In their responses to the BSC and Ofgem consultations, interested parties have raised a number of concerns regarding Oxera's analysis and the reliance that Ofgem places upon it. These concerns, which we discuss below, focused on:

- Whether the model produced reliable results;
- The extent to which an assumption of economic despatch over-estimated the redespatch benefits;
- Whether the amount of switching between gas and coal seen in the Oxera analysis would actually happen; and
- The treatment of fixed losses.

In addition, concerns similar to those we have already discussed were raised by respondents. For instance, respondents commented on the inappropriateness of using only three snapshot periods for the load flow modelling and starting the ten year study before a realistic implementation date for zonal losses. Respondents also criticised the Oxera studies for their lack of transparency and clarity regarding input assumptions and modelling methodology (e.g. with regard to fuel prices) and for the lack of seasonality in fuel prices used in the Oxera study. As we have already discussed these issues we do not repeat our comments on them here except to emphasise that whilst there is some truth in the criticism we do not believe that they are sufficient to invalidate the overall conclusions that Oxera reached.

Respondents also raised a number of concerns of a more general nature that we do not address as they fall outside of our remit. For example, several respondents commented on the possibility that using TLFs set on a zonal ex ante basis could lead to situations where the zonal losses allocated to Parties did not accurately reflect the impact that they had on losses. However, this is a criticism of the Modifications that have been proposed rather than of Oxera's methodology. Moreover, we have already addressed the issue of whether the scenarios studied by Oxera adequately covered the likely impact of using ex ante TLFs in Section 7.4 above. Similarly, there were a number of comments on the analysis for embedded (distributed) generation contained in Ofgem's Impact Assessment but this issue was explicitly excluded from Oxera's terms of reference.

Below we discuss our views concerning the validity of the various criticism raised, concentrating mainly on the areas highlighted above, since these were raised by a number of respondents, but also considering some other issues that were raised by individual respondents.

8.1 Reliability of the results

Several respondents expressed concerns that the year-on-year volatility in TLFs seen in Oxera's July 2006 analysis suggest that the results presented are unreliable. For example, one respondent suggested that the outcome of a rational reaction to zonal losses would be a linear reduction in losses so the fact that Oxera's results were volatile suggested that its model was unreliable. Whilst it is true that some of the volatility may be associated with the use of at most 12 snapshots, the Modifications themselves are likely to generate volatility.

In a static world, where averaging effects have no impact, one would expect to see volatile results in the first few years of a zonal losses scheme. The TLMs for the first year in which the Modification is implemented are likely to provide locational signals that are too strong since they are based on an analysis of generation output patterns and load flows where market participants are not exposed to zonal losses. These over-strong locational signals will be likely to cause greater than optimal redespatch effects, which in turn will lead to TLMs for the second year that are too weak. Thus, the TLMs based on conditions in the second year will lead once again to over-strong locational signals, although these will be less out of step with actual losses than those calculated using uniform loss factors. This pattern of over and undershooting will continue, although we would expect – absent 'shocks' to the system – that the geographical spread in TLM's would approach the spread in actual losses over time.

8.2 Redespatch benefits over-estimated

Many respondents suggested that the use of economic despatching was likely to over-estimate the redespatch benefits. It was argued, for example, that:

- The use of economic despatch was tantamount to assuming that there was a centralised market (a "Pool"), which is not the case under BETTA;
- Portfolio generators only trade bilaterally at their portfolio level – any redespatching would be carried out within their portfolio;
- Fuel and power contracts would limit the flexibility of plants to respond to loss signals;
- CHP plants would be unable to adjust their output because of their need to provide steam.

We do not agree that the use of economic despatch is akin to modelling a Pool system – instead it represents the behaviour of rational players in a reasonably well functioning market. Even if a generator has contracted ahead of time, or is a portfolio generator, it still makes economic sense to reduce the output of plants that become "out of the money" and, if necessary, replace the lost generation with power purchases. It is, of course, impossible to be certain that generators will actually act rationally, but this is the only sensible assumption from a modelling perspective. Moreover, it is the approach traditionally taken in developing and evaluating policy options. In any event, the BSC Modification Group that commissioned the cost-benefit analysis accepted that the modelling would have to be undertaken assuming economic despatch.[46]

We do, however, accept that CHP plants may not be able to respond to cost signals by reducing their output. However, in response to a question that we put to Oxera when preparing this report, Oxera has explained that it has not assumed, in general, that CHP can flex in response to the zonal loss charges with the exception of the very large stations with a CHP element (e.g. Immingham) where it assumes that some flexing is possible. Consequently, respondents concerns regarding Oxera's CHP modelling seem unjustified. We note, moreover, that Oxera separately reports the change in the output of (presumably transmission connected) CHP plants in tables

[46] See page 73 of the Assessment Report for P198.

3.12 to 3.15 of its July report and tables 3.8 and 3.9 of its September report. In none of these tables does Oxera report a change in CHP output so that even if Oxera did not explicitly take the lack of flexibility into account, its failure to do so appears to have had no effect. As to the effect of fuel contracts on plant flexibility, this seems unlikely to be a significant issue. We understand that many gas supply contracts allow the purchaser to resell the gas, when it is economic to do so, so that plants with such contracts should be flexible. Equally, as regards coal, it would seem unusual not to have space to stockpile at least some additional coal volumes.

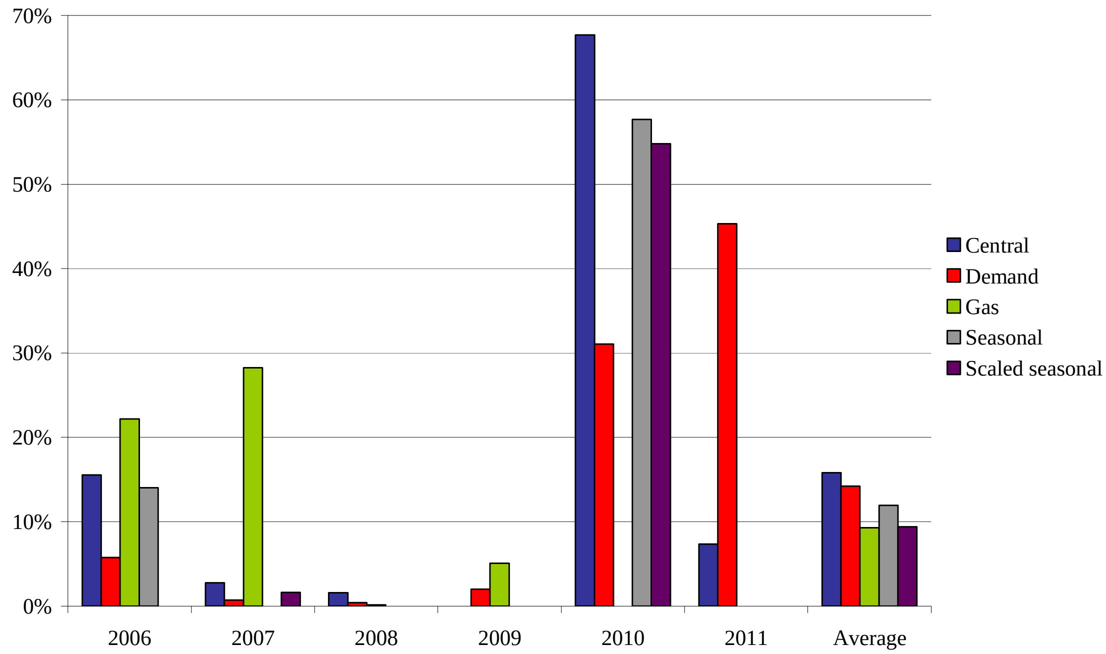
8.3 Switching between gas and coal

A number of respondents doubted that the fuel price differentials would be sufficient to cause the shift from coal to gas generation demonstrated by the Oxera analysis. However, the switching between coal to gas (i.e. from coal to gas or from gas to coal) is in most years a small amount of the total redespatch. (Most of the redespatch comes from switching within fuel types or reduced overall output due to a lower level of losses.) We illustrate this point with two types of data from the Oxera report.

First we show in Figure 11 the amount of switching between coal and gas (in GWh) under Oxera's detailed economic despatch modelling (from Section 3.4 of Oxera's July 2006 report) as a percentage of the total amount of switching between plants (from Section 3.3 of Oxera's July 2006 report).[47] We consider both switching from coal to gas and from gas to coal, although in all the scenarios except the Gas scenario over 85% of the inter-fuel switching is from coal to gas. As can be seen in Figure 11, the amount of coal/gas switching is only a large part of the total redespatch in a small number of cases and is zero or close to zero in a large number of years. On average the amount of coal/gas switching is less than 20% of the total redespatch (based on years 2006-11). Switching appears to be higher in years, such as 2010/11 under the Central/Seasonal scenarios, when there is a "shock" due to significant changes in the generating park (over 1.3 GW of plant retire and nearly 4.6 GW come on stream under the Central/Seasonal scenarios and it is the year with the highest turnover of plant under these scenarios).

[47] The values are calculated by identifying the fuel type where the greatest reduction in losses has occurred. If this loss is more than the reported overall reduction in losses, then this "excess" reduction is assumed to be due to fuel switching. For example, in 2006/07 in the Central scenario, CCGT output is reported to have dropped by 364 GWh and coal output to have increased by 274 GWh whereas overall losses have only dropped by 90GWh. Consequently, we deduce that there has been 274 GWh of switching from gas to coal. This accounts for just over 15% of the change in output from all plants that increased their output (1763 GWh), which can be deduced from the data on changes in plant output by GSP Group by adding up all the values where the output in a GSP Group has increased.

Figure 11: Amount of coal/gas switching as % of total redespatch



The second set of data we use from the Oxera reports is the redespatch (in MW) for each snapshot (Section 3.2 of Oxera' July 2006 report). We look at the snapshots as well as the annual economic analysis because the former provides specific details of the effects that are incorporated into the TLFs whilst the latter provides an overview of the broader results of using the resulting TLMs.

We calculate the amount of switching between coal and gas as a percentage of the total amount of redespatch (see Table 13) in a similar manner to that just described above. We only consider the three (or twelve) snapshot periods and the information presented in Table 13 shows the annualised results, calculated by applying the period weightings=.[48] Again no switching between coal and gas occurs in many instances. Across the scenarios, switching between coal and gas makes up l no more than 23% of the redespatch.

[48] In the case of the seasonal scenarios, we average the results across all four seasonal snapshots for a particular type of period i.e. we add up the values across all twelve snapshots and then divide by 4 to provide results that can be compared with those produced using annual TLFs and only 3 snapshots.

Table 13: Percentage of redespatch that involves switching between coal and gas (based on snapshot periods)

Scenario	2006	2007	2008	2009	2010	2011	Average
Central	0%	0%	7%	0%	44%	31%	14%
Demand	0%	26%	72%	0%	0%	0%	16%
Gas	31%	0%	0%	0%	0%	0%	5%
Seasonal	34%	24%	14%	13%	21%	30%	23%
Average	16%	13%	23%	3%	16%	15%	

Both sets of analysis confirm that fuel switching accounts for a relatively small percentage of the overall redespatch. It is not surprising that there are differences in the results that we find when we analyse Oxera's detailed economic modelling compared to those that we find from looking at its snapshot modelling. This is because the range of market conditions (generation availability, demand) incorporated in the detailed economic despatch modelling is far wider than those that can be captured in three or twelve snapshots. Different market conditions are likely to give rise to different outcomes in terms of redespatch.

8.4 Effects of fixed losses

There seems to be considerable confusion regarding the zonal loss factors presented by Oxera and whether or not fixed losses were taken into account in its analysis. Many respondents commented that they were surprised that the loss factors only reflected variable losses. They argued that not only did this make it difficult for them to analyse the impact of zonal losses on their specific positions, which will depend on the total losses they are allocated rather than just the variable losses, but it also under-estimated the impact on Parties of introducing zonal losses.

We agree that the earlier Oxera report (July 2006) did not make it clear that the TLMs it presented related only to variable losses for its analysis of both uniform and zonal losses. However, as we discussed in Section 7.1, it does not seem likely to us that the exclusion of fixed losses has had any material impact on Oxera's findings. Since the loss savings are measured as the difference between the base case (uniform charging) and the change case (zonal charging) the effects of fixed losses will be irrelevant except to the extent that they result in changes to the merit order under the zonal losses scheme. In our simple model (described in Section 7) we found that including fixed losses in the zonal losses case in the Central scenario did not make enough difference to plants' marginal costs to change the merit order. Therefore, the inclusion of fixed losses would make no difference in the estimated benefits of zonal losses in the Central scenario. Since there is no change in the pattern of generation when fixed losses are included in the Central scenario, it follows that the distributional effects of introducing zonal losses estimated by Oxera would not have changed if it had included fixed losses.

8.5 Other concerns

One respondent suggested that Oxera's analysis was unreliable because it was undertaken using a DC rather than an AC load flow model. This criticism does not seem justified since DC load flow modelling would be used to determine the TLFs if the Modifications were implemented.

Another respondent suggested that the net benefits would be negligible or even negative if the analysis had been extended for a longer period. This view is presumably based on the fact that Oxera shows dis-benefits from the introduction of zonal losses in the last two years that it modelled. However, as we have explained, in Section 4.5.2, we consider that this may be partly due to the fact that no changes to the network are assumed after 2011/12 and, in any event, is unlikely to be a persistent phenomenon.

One respondent suggested that Oxera had not correctly included the implementation costs provided by participants. We have checked that the data in the Final Modification Report (which summarises data provided to Elexon by market participants). The area that the respondent may be referring to is the BSC participant costs. Oxera estimates an average implementation cost of £112,000 for a large electricity company, though Oxera highlights the reasons why this estimate is subject to some uncertainty (see section 7.3 of its July 2006 report). In the final modification report for P198, the BSC Panel estimated that the average of the non-confidential estimates of implementation costs was £200,000. There were only four non-confidential cost estimates provided and these were not particularly precise (nil, £150,000-£200,000, around £200,000 and >£100,000). Consequently, both estimates of average costs are broadly consistent with the limited available data and, as we have previously commented, any plausible increase in implementation costs is unlikely to lead to a change in the overall conclusion that zonal losses will lead to a net benefit. However, we agree that there appear to be some minor problems with Oxera's estimated implementation costs, an issue we discuss in section 5.6.

A number of respondents voiced concerns that the Oxera analysis has not taken into account the offsetting effects of more costly plant being dispatched when zonal losses are in place. This is one of the issues on which we queried Oxera, who confirmed that its published benefits do include the offsetting effect of more costly plant being dispatched when zonal losses are in place. We discuss this issue in more detail in Section 4.1.3 above.

Another respondent criticised the Oxera analysis for failing to take into account all locational factors that affect investment decisions. However Oxera is clear in its analysis that other factors such as planning permission and land availability affect locational decisions and that its estimates of the size of long-run benefits of zonal losses are speculative. Oxera could also have performed sensitivities on the long-term benefits by considering the change in the size of the benefits had it chosen another zone for relocation. One respondent claims that Oxera's comparison of benefits and costs for period to 2020/21 is misleading because it uses a relocation savings estimate of £10.6 million which is based on Oxera's speculative estimate of £1 - 20 million. We agree that it would have been less misleading if Oxera has chosen to show a range of net benefits based on the range of long-term benefits.

One respondent suggested that the Oxera analysis should be revised to incorporate the effect of a number of power stations that are planned for the south. We are uncertain what this respondent is referring to as the Oxera reports state that the new power stations included in its study are "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…. most of …[which]… are in advantageous Southern transmission zones”.

9 Are Oxera's conclusions robust?

Oxera found that the introduction of zonal losses would lead to net benefits due to redespatching by generators and demand adjustments by suppliers. In reaching this conclusion, Oxera took account of implementation costs, which it estimated would only be of the order of £2 million for central systems and BSC Parties together, and on-going costs of around £0.3 million per year. It also concluded that, at least in the short to medium term, zonal losses were unlikely to have any impact on generator siting decisions (or on the growth of renewables) and that the impact of zonal losses on new entry in the long term was very uncertain, although likely to lead to a net annual benefit.

We believe that these general conclusions are robust although, as we have explained in the preceding sections, it is more likely than not that the extent of net benefits has been over-estimated to some extent by Oxera. Our concerns regarding potential over-estimation relate primarily to Oxera's methodology and whether it has appropriately assessed the risks inherent in all the modifications. By contrast, the potential for Oxera to have under-estimated the effect of zonal losses relates largely to its input assumptions, where actual future outcomes are inevitably uncertain. Overall, therefore, we consider it more likely than not that Oxera may have over-estimated the net benefits to some extent.

Nonetheless, we conclude that the introduction of zonal losses can be expected to produce some net redespatch benefits for the foreseeable future. We accept that the magnitude of these benefits will change over time, particularly if the distribution of generation plant around GB changes, and there may be occasional years when zonal losses actually result in a dis-benefit due to mismatches between the TLMs and actual losses. However, given the low level of implementation and operating costs associated with the Modifications, it is difficult to see how the net present value of introducing one of the Modification proposals could be anything other than positive.

In Section 6.1 we provided some commentary on the differences Oxera found in the benefits for the various Modification proposals. We noted that the overall pattern of benefits (seasonal TLFs give greater benefits than annual TLFs, scaled seasonal TLFs give less benefits than un-scaled seasonal TLFs) seemed reasonable for the reasons given in section 6.1. Furthermore, the increases in net benefits under the two sensitivities that Oxera studied (high demand and low gas prices) seem plausible and confirmed by our simple modelling. Higher demand will lead to more expensive plants being required to run so the impact of reducing losses will be increased. Higher costs lead to higher electricity prices and hence increased demand side benefits. Lower gas prices will mean that the marginal costs of gas and coal plants will be closer together so the introduction of zonal losses is likely to give rise to more opportunities for fuel switching to reduce losses. However, the lower electricity prices that result from the lower gas prices reduce the likely demand side benefits to some extent.

The extent to which the introduction of zonal losses would affect the behaviour of consumers or generators' new entry decisions seems likely to be much less significant. On the demand side, there may be some response but any effect from zonal losses could be swamped by changes in the level of electricity prices. As far as new entry decisions are concerned, not only are there strong locational signals already, from electricity transportation charges, but other factors such as the availability of suitable sites and planning permission may prove to be more decisive in determining where plants are built. We also agree with Oxera that zonal losses are likely only to have a marginal impact on the growth and overall profitability of renewables.. However, we cannot rule out the possibility that zonal loss factors might deter some projects in the north of GB that were only marginally profitable with uniform loss charging. Moreover, as Oxera acknowledges the introduction of zonal losses would alter the relative profitability of projects in Scotland and the north of England compared to those in the south of England.

Finally, whilst Oxera's analysis of the distributional effects of zonal losses appears reasonable for 2006/07 it may well not be representative of what would happen over the longer term. This simply reflects the fact the spread in zonal loss factors that Oxera finds in the first year of its scenarios is often not typical of those it projects for other years.

Appendix I : Measuring changes in costs and profits

As we discussed in Section 4.1.3.2, there are a number of different ways in which the effects of the despatch impact of zonal losses can be measured. Table 14 below gives a stylised example of the changes in generators' costs and profits from introducing zonal losses. The example illustrates that the change in costs is about £35 of cost savings, but that the increase in generators profits is higher at £62. The sum of changes in generator profits and consumer surplus equals the change in costs – hence in this example consumers experience a decrease in welfare of £27, due to the price increase caused by the introduction of zonal losses.

Table 14: Example of changes in costs and generator profits – all costs in £, output in MWh

Plant data

Plant number	MC (no losses)	Uniform LF	Zonal LF
1	15	0.95	0.95
2	22	0.95	0.9
3	25	0.95	1.05

Uniform losses case

Plant despatch

Plant	Gross output	Credited output	Net output	Physical Losses
1	100.0	95.0	95	5
2	61.1	58.1	55	6.1
3	0.0	0.0	0	0.0
Totals	161.1	153.1	150.0	11.1

Cost of generating	2,844
Volume of losses	11.1
Cost of losses	209.4
Marginal price	23.16
Price of losses	257.31
Genco revenue	3,544
Genco profit	700

Zonal losses case

Plant despatch

Plant	Gross output	Credited output	Net output	Losses
1	100	95	95	5
2	0	0	0	0
3	52.4	55	55	-2.6
Totals	152.4	150.0	150.0	2.4

Cost of generating	2,810
Volume of losses	2.4
Cost of losses	9.5
Marginal price	23.8
Price of losses	56.7
Genco revenue	3,571
Genco profit	762

Benefits

Cost benefit	34.9
Change in Genco profits	61.9

Appendix II Details of gas, coal and carbon price comparisons

Table 15: Prices from the DTI report converted to nominal terms

GJ/tonne ARA Coal	[1]	Brattle	25.12								
Inflation	[2]	Brattle	2%								
FX rate, US$/£	[3]	See note	1.77								
	Real 2004 prices					Nominal prices					
	Gas Central - favouring gas		Gas Central - favouring coal		Inflation factor	Gas Central - favouring gas		Gas Central - favouring coal			
	Gas p/therm	Coal $/GJ	Gas p/therm	Coal $/GJ		Gas p/therm	Coal $/GJ	Gas p/therm	Coal $/GJ	Coal $/tonne	Coal £/tonne
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
	DTI	DTI	DTI	DTI	See note	[A]x[E]	[B]x[E]	[C]x[E]	[D]x[E]	[I]x[1]	
2005	36	2.5	36	2.5	1.02	36.72	2.55	36.72	2.55	64.06	36.26
2010	23	1.5	28	1.5	1.13	25.90	1.69	31.53	1.69	42.43	24.02
2015	23	1.43	28	1.43	1.24	28.60	1.78	34.81	1.78	44.66	25.28
2020	23	1.35	28	1.35	1.37	31.57	1.85	38.44	1.85	46.55	26.35

Notes:
[2]: Average exchange rate for April 2006 as derived from European Central Bank data.
[E]: Prices for 2005 are inflated for 1 year from mid 2004 using the annual inflation rate in row [2]. One year of inflation is added for

Table 16: Prices from the July 2006 Oxera report converted to nominal terms

Inflation	[1]	Brattle	2%									
FX rate, US$/£	[2]	See note	1.77									
			2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
Real 2006 prices												
Gas price (Central), p/therm	[3]	Oxera	46	43	40	37	34	34	34	34	35	35
Gas price (Gas), p/therm	[4]	Oxera	36	32	27	23	18	18	19	19	19	20
Coal price, £/tonne ARA	[5]	Oxera	33	32	30	29	27	27	27	27	26	26
Carbon price, €/tonne	[6]	Oxera	20	20	20	20	20	20	20	30	30	30
Nominal prices												
Inflation factor	[7]	See note	1.01	1.03	1.05	1.07	1.09	1.12	1.14	1.16	1.18	1.21
Gas price (Central), p/therm	[8]	[3]x[7]	46	44	42	40	37	38	39	39	41	42
Gas price (Gas), p/therm	[9]	[4]x[7]	37	33	29	24	20	20	21	22	23	24
Coal price, £/tonne ARA	[10]	[5]x[7]	33	33	32	31	30	30	31	31	31	31
Coal price, $/tonne ARA	[11]	[2]x[10]	59	58	56	55	52	53	54	55	54	55
Carbon price, €/tonne	[12]	[6]x[7]	20	21	21	21	22	22	23	35	35	36

Notes:
OXERA prices from July 2006 OXERA Report, Table 2.5 p.14.
[2]: Average exchange rate for April 2006 as derived from European Central Bank data.
[7]: Prices for 2006/07 are inflated for 0.5 years from mid 2006 using the annual inflation rate in row [1]. One year of inflation is added for each subsequent year.

Table 17: Comparison of Oxera, DTI and forward gas prices, as plotted in Figure 3

			2004/5	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
Oxera - Central scenario	[1]	Appendix I			46	44	42	40	37
Oxera - Gas scenario	[2]	Appendix I			37	33	29	24	20
DTI Central (Favouring Gas)	[3]	Appendix I		36.72					25.90
DTI Central (Favouring Coal)	[4]	Appendix I		36.72					31.53
NBP Forward curve April 2006	[5]	See note			66.3	61.2	56.8		
NBP Forward curve December 2007	[6]	See note				46.8	50.5	50.4	

Notes

[5],[6]: Average forward prices from Platts. Forward curve constructed by The Brattle Group. 200X/0Y price is for the gas year Oct 0X to Sept. 0Y inclusive.

Table 18: Comparison of Oxera, DTI and forward coal prices, as plotted in Figure 4

	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
Oxera		33	33	32	31	30
DTI	36.26					24.02
EEX Forward price May 2006				36.37	36.88	
EEX Forward price December 2007				55.54	49.56	

Notes:

EEX forward prices are actually for Calender years. We have used the Cal-0X coal price for the year 200X/0X+1.

Appendix III : Percentage of loss savings from each snapshot

Table 19: Percentage of loss savings from each snapshot for all scenarios – Brattle calculations

Scenario	Year	Snapshot loss savings (MW)			Annual	Percentage of savings		
		Peak	Mid	Trough	loss savings TWh	Peak	Mid	Trough
Central	2006/07	-5.3	0	-61.4	-90	5%	0%	95%
	2007/08	-10.5	-9.1	-119.9	-234	4%	25%	71%
	2008/09	-55.8	0	-40.5	-107	48%	0%	52%
	2009/10	-40.9	-50.9	-38.8	-420	9%	78%	13%
	2010/11	-53.5	-0.3	-16	-73	67%	3%	30%
	2011/12	-11.5	-18.5	-24.9	-165	6%	73%	21%
Gas	2006/07	-16.8	-51.3	-5.7	-355	4%	93%	2%
	2007/08	-31.2	-87.2	-1.5	-594	5%	95%	0%
	2008/09	-55.8	-63.9	1.3	-462	11%	89%	0%
	2009/10	-19.9	-50.2	-2.3	-346	5%	94%	1%
	2010/11	-118.3	-34.7	-0.9	-333	32%	67%	0%
	2011/12	-7.7	-49.7	0	-328	2%	98%	0%
Demand	2006/07	-33.7	0	-56.7	-109	28%	0%	72%
	2007/08	-1.5	-25.6	-135.6	-355	0%	47%	53%
	2008/09	-12.7	-81.9	-4.1	-547	2%	97%	1%
	2009/10	-12.7	-1.7	-6.9	-32	36%	34%	30%
	2010/11	-11.1	-39.1	-11.8	-279	4%	91%	6%
	2011/12	-32.6	2	0	-17	177%	-77%	0%
Seasonal	2006/07	21.65	-56.5	-105.225	-491	-4%	74%	30%
	2007/08	-22.475	-33.4	-98.725	-373	5%	58%	37%
	2008/09	-5.55	-59.65	-76.875	-497	1%	78%	21%
	2009/10	-30	-61.55	-86.2	-545	5%	73%	22%
	2010/11	-26.825	-62.075	-81.05	-538	5%	75%	21%
	2011/12	-13.85	-23.05	-65.15	-252	5%	59%	36%
Central scaled	2006/07	-6.2	-0.1	-57.6	-86	7%	1%	93%
	2007/08	-22.4	-2.6	-84.7	-154	13%	11%	76%
	2008/09	-55.8	0	0	-51	100%	0%	0%
	2009/10	-40.9	0	0	-37	100%	0%	0%
	2010/11	-53.5	0	0	-49	100%	0%	0%
	2011/12	-11.5	0	0	-10	100%	0%	0%
Seasonal scaled	2006/07	-11.1	-28.4	-27.2	-231	4%	79%	16%
	2007/08	-11.4	-20.1	-27.7	-178	6%	73%	21%
	2008/09	-7.5	-25.9	-37.3	-226	3%	74%	23%
	2009/10	-13.1	-49.8	-37.0	-385	3%	84%	13%
	2010/11	-11.2	-9.8	-34.9	-122	8%	52%	40%
	2011/12	-5.8	-13.4	-27.0	-129	4%	67%	29%

Appendix IV : Generation cost of capital

Table 20: Ofgem and Brattle financial data

Ofgem WACC for Transmission			
Long Term Risk Free Rate	[1]	See Note	2.50%
Cost of Equity	[2]	See Note	7.00%
Assumptions			
Inflation	[3]	Assumed	2.00%
Term Premium	[4]	See Note	1.20%
Ofgem Nominal Rates			
Long Term Risk Free Rate	[5]	(1+[1])x(1+[3])-1	4.55%
Cost of Equity	[6]	(1+[2])x(1+[3])-1	9.14%
Short Term Risk Free Rate	[7]	[5]-[4]	3.35%
Comparison with TBG			
MRP used for TBG WACC Calculation	[8]	See Note	7.14%
Implied Beta for Transmission	[9]	([6]-[7])/[8]	0.81
Ofgem Lower Bound for Beta	[10]	See Note	0.50
Ofgem Upper Bound for Beta	[11]	See Note	1.00

Notes and Sources:
[1],[2]: Ofgem, *Transmission Price Control Final Proposals* , Dec 2006, p. 55.
[4]: Brealey, Caldwell and Lapuerta, *The Cost of Capital for the Nor-Ned Cable* , p. 9
[8]: Dimson, Marsh and Staunton, "The Worldwide Equity Premium: A Smaller Puzzle" in *Handbook of the Equity Risk Premium,* ed. R. Mehra (Elsevier, 2007), Table 3.
[10],[11]: Ofgem, *Transmission Price Control Final Proposals* , Dec 2006, p. 54.

Table 21: Brattle estimate of the cost of capital for electricity generation based on Ofgem parameters

			AES	Calpine
Short Term Risk Free Rate	[1]	Table 19	3.35%	3.35%
Beta	[2]	See Note	1.00	0.85
Market Risk Premium	[3]	Table 19	7.14%	7.14%
Cost of Equity	[4]	[1]+([2]x[3])	10.5%	9.4%
Cost of debt	[5]	See Note	8.39%	8.39%
Tax Rate	[6]	See Note	40%	40%
After-Tax Cost of Debt	[7]	[5]x(1-[6])	5.0%	5.0%
Leverage	[8]	See Note	47%	55%
Average Leverage	[9]	Average of [8]	51%	
Nominal After-Tax WACC	[10]	[8]x[7]+(1-[8])x[4])	7.93%	7.01%
WACC at average leverage	[11]	[10]-([9]-[8])x[5]x[6]	7.80%	7.14%
Inflation	[12]	Table 19	2.00%	2.00%
Real After-Tax WACC (at avg. leverage)	[13]	(1+[11])/(1+[12]) - 1	5.68%	5.04%
Average Real After-Tax WACC	[14]	Average of [13]	5.35%	

Notes and Sources:

[2]: Valueline. We take the betas calculated from the five year period 1996-2000 to avoid using years in which these two companies had unstable leverages.

[5]: In 2000 AES had an S&P rating of BB and Calpine had an S&P rating of BB+, thus it is appropriate to take the current yield on a BB rated bond as the cost of debt for a power generation company. We calculate a December 2007 average using daily data from Bloomberg.

[6]: KPMG's Corporate and Indirect Tax Rate Survey, 2007, p. 8.

[8]: Average of the leverage for each year 1996-2000 calculated using data from Annual Reports.

Appendix V : Example of Brattle cost-benefit analyses – P198 Central

	Costs		Benefits		Net	Discount factor	Discounted
	Implementation	Operating	Generation	Demand	benefit	(at 3.5%)	net benefit
	[A]	[B]	[C]	[D]	[E]	[F]	[G]
2006/07	-2.06				-2.1	0.97	-1.99
2007/08		-0.30	9.01	0.54	9.3	0.93	8.64
2008/09		-0.30	1.58	0.54	1.8	0.90	1.64
2009/10		-0.30	11.99	0.54	12.2	0.87	10.66
2010/11		-0.30	1.85	0.54	2.1	0.84	1.76
2011/12		-0.30	4.50	0.54	4.7	0.81	3.85
2012/13		-0.30	0.91	0.54	1.2	0.79	0.91
2013/14		-0.30	1.75	0.54	2.0	0.76	1.51
2014/15		-0.30	-2.59	0.54	-2.3	0.73	-1.72
2015/16		-0.30	-3.40	0.54	-3.2	0.71	-2.24
Total							23.02

Notes & Sources:
[A]: From Table 7.4 of Oxera's July 2006 report
[B]: From Table 8.1 of Oxera's July 2006 report, also consistent with Oxera Jan 2008 data
[C]: Oxera Jan 2008 data
[D]: annual value chosen to match present value reported in Oxera Jan 2008 data
[E] = [A]+[B]+[C]+[D]
[F] = 1/(1.035^(y-2005)
[G] = [E]x[F]

Appendix VI : Oxera's renewables and plant closure assumptions

Table 22 and Table 23 detail information provided to The Brattle Group by Oxera in response to a questions in connection with this work.

Table 22: Oxera's renewables assumptions

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
Offshore Wind	**0**	**0**	**727**	**154**	**0**	**0**	**1071**	**1071**	**1071**	**1052**
East Midlands Total	0	38	0	68	0	0	0	0	30	0
East England Total	0	85	53	0	270	0	0	0	0	102
London Total	0	0	0	0	0	0	0	0	0	0
North East Total	0	0	0	100	0	0	0	180	0	0
North West Total	0	75	0	34	0	0	90	0	30	0
South East Total	0	0	0	34	0	0	0	22	87	0
South West Total	0	100	0	158	0	0	0	239	30	0
West Midlands Total	0	0	0	34	0	0	0	0	30	80
Yorkshire and Humber Total	0	38	201	34	0	0	360	0	0	0
Scotland Total	593	270	507	519	336	638	114	0	299	0
Wales Total	0	201	0	34	360	0	0	0	132	456
Onshore total	**593**	**806**	**761**	**1013**	**966**	**638**	**564**	**441**	**638**	**638**
	593	**806**	**1487**	**1167**	**966**	**638**	**1636**	**1513**	**1709**	**1690**

Table 23: Oxera's plant closures by scenario

Station	Type	Zone	Capacity, MW	Plant closure dates Central scenario	Demand scenario	Gas scenario	Seasonal scenario
Littlebrook D	Oil	UK3	790	2013	2011	2008	2013
Fawley	Oil	UK8	518	2013	2011	2008	2013
Grain	Oil	UK9	650	2013	2011	2008	2013
Didcot A	Coal	UK8	2040	2016	2016		2016
Tilbury B	Coal	UK1	1020	2016		2012	2016
Aberthaw B	Coal	UK10	1506	2016	2016	2016	2016
Kingsnorth	Coal	UK9	1940		2016	2012	
High Marnham	Coal	UK2	756	2003	2003	2003	2003
Drakelow C	Coal	UK2	650	2003	2003	2003	2003
Ironbridge	Coal	UK5	970	2016	2016	2012	2016
Ferrybridge C	Coal	UK6	994.5	2016	2016	2013	2016
Eggborough	Coal	UK12	1002.5		2016	2016	
Cottam	Coal	UK2	1004		2016	2016	
Longannet with FGD	Coal	UK13	1200		2016	2016	
Longannet	Coal	UK13	1200		2016		
Cockenzie	Coal	UK13	1200	2015	2016	2013	2015
Peterhead	Oil	UK14	660	2013	2014	2016	2013
Torness	AGR	UK13	1250	2023	2023	2023	2023
Hunterston B	AGR	UK13	1190	2011	2011	2011	2011
Dungeness B	AGR	UK9	1100	2018	2018	2018	2018
Hartlepool	AGR	UK6	1210	2014	2014	2014	2014
Heysham 1	AGR	UK7	1165	2014	2014	2014	2014
Heysham 2	AGR	UK7	1322	2023	2023	2023	2023
Hinkley Point B	AGR	UK11	1297	2011	2011	2011	2011
Sizewell B	PWR	UK1	1220	2035	2035	2035	2035
Bradwell	Magnox	UK8	246	2002	2002	2002	2002
Dungeness A	Magnox	UK9	445	2006	2006	2006	2006
Oldbury	Magnox	UK5	475	2008	2008	2008	2008
Sizewell A	Magnox	UK1	470	2006	2006	2006	2006
Wylfa	Magnox	UK4	1081	2010	2010	2010	2010
Calder Hall	Magnox	UK6	168	2003	2003	2003	2003
Chapel Cross	Magnox	UK13	168	2004	2004	2004	2004
Roosecote	CCGT	UK7	220	2010	2010		2010
Killingholme A	CCGT	UK12	665	2010	2010		2010
Peterborough	CCGT	UK2	405	2010	2010		2010
Teesside	CCGT	UK6	1875	2010	2011		2010
Corby	CCGT	UK2	401		2015		
Rye House	CCGT	UK1	715	2010	2012		2011
Brigg	CCGT	UK12	260	2010	2012		2010
Deeside	CCGT	UK4	475	2012	2012		2012
Derwent	CCGT	UK2	232	2013	2015		2013
Sellafield	CCGT	UK7	155		2015		

Notes:
There were no differences in closures between the uniform and zonal loss charging scenarios.
Zones reflect Elexon alphabetical odereing of the zones e.g. 1=eastern etc

Appendix VII : Information provided by Oxera for this study

In this Appendix, we provide details of the questions that we asked Ofgem to put to Oxera in the course of our study and the responses that we received, except in relation to renewables build and plant closures which has been included in the previous Appendix. Note that most of this information is already available on Elexon’s website, in the area devoted to the P198 Modification.

Stuart Senior

ELEXON Limited

4th Floor

350 Euston Road

London

NW1 3AW

Direct Dial: 0141 331 6007

Email: Lesley.nugent@ofgem.gov.uk

Date: 12 December 2007

Dear Stuart

Balancing and Settlement Code ("BSC") modification proposals on zonal transmission losses - review of Oxera's analysis

Further to Alistair Buchanan's letter of 5 October 2007, David Gray wrote to you on 3 December 2007 advising that Ofgem has appointed the Brattle Group ("Brattle") to undertake the review of Oxera's analysis[49] on the BSC zonal transmission losses modification proposals[50]. My letter also advised that, subject to our discussions with Brattle, we anticipated contacting you in the near future with a request for information in relation to Oxera's analysis.

Brattle has now initiated its review and provided Ofgem with a list of questions in respect of Oxera's analysis. I have included the memo setting out Brattle's questions with this letter and request, as provided for under BSC Section C3.6, that Elexon provides the information requested by 21 December 2007.

Yours sincerely,

Lesley Nugent

Senior Manager, Transmission Networks

---

[49] Ofgem set out its intention to undertake this review in the following open letter: "The Authority's decisions on the zonal transmission losses proposals", 14 September 2007, ref 223/07 (www.ofgem.gov.uk)

[50] P198, P198 Alternative, P200, P200 Alternative, P203 and P204.

MEMORANDUM

TO: Oxera

FROM: The Brattle Group

SUBJECT: Questions of Zonal Loss Charging Studies

DATE: 6th December 2007

Below we provide questions we have on your July 2006 report entitled "What are the costs and benefits of zonal loss charging?" and your September 2006 report entitled "What are the costs and benefits of annual and seasonal scaled zonal loss charging?"

<u>Questions on July 2006 report</u>

1. On page 7 you write "[t]he total level of demand to be met was reduced by the estimated level of losses, allowing the total net benefit of zonal loss charging to be calculated". We assume that this reduction relates to the impact of zonal losses on demand that you estimate in Chapter 6. Can you confirm this and explain what you did?

2. On page 8 you say that "data … was taken from the 2005 Seven Year Statement and scaled proportionally to correspond to the three loading snapshots". Can you explain what you mean by "scaled proportionally"?

3. On page 9 you say that differences between your and PTI TLFs of 0.005 and 0.009 are acceptable. How did you decide whether a difference was acceptable or not? What criteria did you use?

4. On page 9, you show a comparison between the PTI TLFs and the TLFs from the load-flow model based on the despatch from your economic model and this is used as validation of the economic model. Did you perform any other type of validation of your economic model such as whether the model produces reliable simulations of prices or generation despatch across the year?

5. On page 9 you explain that difference between your TLF and the PTI TLF in zone 10 is due to different load factors being used for Aberthaw. When you undertook the more detailed economic modelling what load factor did you find for Aberthaw i.e. did you find it ran at baseload, as in your snapshots, or at mid-merit, as in the Elexon data? Did you confirm that adjusting Aberthaw's load factor resulted in a TLF for zone 10 that was similar to the PTI one? Did Aberthaw continue to operate at baseload in the snapshot periods throughout the period studied?

6. How did you incorporate the effects of plant maintenance into your snapshot modelling, particularly for the seasonal analysis?

7. On page 9 you say the differences in PTI and Oxera TLFs for the Scottish zones during the summer are "a function of the assumed loadings during a time when net electricity flows in these zones are sensitive to actual loading at the time". Can you explain this in more detail?

8. In the load flow modelling for future years, what assumptions did you incorporate regarding changes to the network?

9. On page 11 you describe how you modelled the growth in renewable generation. Could you provide us with a table showing the amount of wind (both offshore and onshore) added in each year and the zones in which these wind plants were added?

10. On page 12 you state that "plant that have opted out of the [LCPD] Directive will be limited to 20,000 hours of generation between 2008 and 2015". How did you apply this limit in your model? Did you assume the same limit on generation in each year or something different?

11. On page 13 you state that "[a]ll other plant closure decisions were based on market outcomes under the different scenarios". What criteria did you use for deciding whether non-nuclear plants should be closed? Which plants did you assume close under each scenario and when? Were the closures different between the uniform and zonal analyses?

12. On page 13 you show two new generic CCGT plants coming on line in zones 2 and 7 with capacities of 1,000MW and 2,000MW. Why did you choose these zones and plant sizes?

13. On page 30 you say that "[z]onal results were subtracted from uniform results to obtain differences between the charging regimes" but do you mean the other way round as Tables 3.8 to 3.11 suggest that uniform results were subtracted from zonal results? For example, the output in Scotland is shown decreasing in the tables, which would seem more likely to be an outcome of moving from uniform to zonal losses.

14. On page 38 you explain how you have used method 2 to estimate the value of loss savings. Did you test how different the savings would have been if you had used method 1?

15. On pages 45-46 you describe the minimal impact of zonal transmission losses on interconnectors linking the Great Britain with other markets. Could you explain how you modelled the development of flows across the French and Dutch interconnectors?

16. In Tables 5.5 and 5.6 you provide your analysis of the influence of TNUoS and NTS exit charges on locational decisions. It does not appear that you have taken any account of future changes in these charges, is this correct?

17. Tables 5.5 and 5.6 on page 51 show the difference excl. and incl. Scotland. Can you explain what you mean by "Difference"?

18. On page 59, the values quoted above Table 6.2 do not appear to correspond with those in the table, are these simply typos? For example, you state the "[t]he Midlands shows the strongest signs of this behaviour, with an £18,000 reduction in benefits" but the table shows £16,000.

19. On page 67 you show the results of NPV calculations of future benefits. Could you provide us with the data used in these calculations?

Questions on September 2006 report

Many of our above questions about your July 2006 report would also apply to your September 2006 report. We do not repeat the questions here but please provide separate answers for each report if your answers to any of the above questions would be different for each report. Please can you also provide us with the data used in your NPV calculations of future benefits as shown on page 36 of your September 2006 report.

(ii) Oxera's initial response to Ofgem's letter

David Jones
Change Assessment Manager, Change Delivery
Elexon Ltd
4th Floor, 350 Euston Road
London, NW1 3AW

December 21st 2007

Dear David

Preliminary response to information request on Zonal transmission losses

As you know, Oxera was commissioned by Elexon in 2006 to conduct a study on the impact of zonal transmission losses (ZTL) applied to the electricity system in Great Britain. The study involved load–flow modelling of the GB transmission networks, alongside modelling of the wholesale electricity market. Oxera undertook the study in conjunction with Professor Janusz Bialek from the University of Edinburgh and Professor Stanislaw Ziemianek from Warsaw University of Technology. The results of the analysis were presented in a July 2006 report entitled 'What are the costs and benefits of zonal loss charging?' and a September 2006 report entitled 'What are the costs and benefits of annual and seasonal scaled zonal loss charging?'

This letter sets out a preliminary response to an information request from Brattle on details of the reports, the methodologies and the underlying assumptions. The response should be considered preliminary given the short time available to respond and the unavailability of some of the relevant staff in the pre-Christmas period.

The questions set out below refer to the July 2006 report, though also generally to the September report. The main difference for the analysis in the September report is that 4*3= 12 snapshots were used per year due to using three snapshots for each season. This should improve the accuracy of the snapshot modelling.

Questions from Brattle are in bold. Responses are given below.

1.On page 7 you write "[t]he total level of demand to be met was reduced by the estimated level of losses, allowing the total net benefit of zonal loss charging to be calculated". We assume that this reduction relates to the impact of zonal losses on demand that you estimate in Chapter 6. Can you confirm this and explain what you did?

The key to understanding this is the description of load flow packages used on page 6. The so-called DC load flow program, which was used to estimate the TLFs as required by the Modifications, is lossless (i.e. network resistances are neglected). The actual level of variable losses due to a particular despatch pattern had to be evaluated using so-called AC load flow which contains resistances and in which total losses are calculated as the difference between generation and demand. As the input data to a load flow program are individual nodal demands and generations, the nodal demands had to be scaled proportionally down by the estimated level of variable losses and the AC program was run to calculate the actual variable losses. The procedure was repeated until the error (i.e. the difference between the assumed and the actual level of losses) was acceptably small. This is a standard trick in load flow studies in order to avoid the "chicken and egg" situation: you cannot run a load flow without specifying generation and demand in each node but you cannot do it as you do not know losses without running the load flow.

2.On page 8 you say that "data ... was taken from the 2005 Seven Year Statement and scaled proportionally to correspond to the three loading snapshots". Can you explain what you mean by "scaled proportionally"?

SYS data contains peak demand figures for GSP transformers so they had to be scaled down to correspond to the loading periods modelled.

3.On page 9 you say that differences between your and PTI TLFs of 0.005 and 0.009 are acceptable. How did you decide whether a difference was acceptable or not? What criteria did you use?

The assessment was based on our judgement taking into account the level of differences and the assessed explanations for them, as discussed in the following paragraph in the report.

4.On page 9, you show a comparison between the PTI TLFs and the TLFs from the load-flow model based on the despatch from your economic model and this is used as validation of the economic model. Did you perform any other type of validation of your economic model such as whether the model produces reliable simulations of prices or generation despatch across the year?

Yes, validation was done comparing the results of the simulation for 2005/6 to actual outputs for 2005/6 in addition to the TLF comparisons. Other validation exercises have been undertaken for the Oxera wholesale modelling during its use in other contexts.

5.On page 9 you explain that difference between your TLF and the PTI TLF in zone 10 is due to different load factors being used for Aberthaw. When you undertook the more detailed economic modelling what load factor did you find for Aberthaw i.e. did you find it ran at baseload, as in your snapshots, or at mid-merit, as in the Elexon data? Did you confirm that adjusting Aberthaw's load factor resulted in a TLF for zone 10 that was similar to the PTI one? Did Aberthaw continue to operate at baseload in the snapshot periods throughout the period studied?

The economic modelling over the year (including the emissions constraints) did show Aberthaw running as mid-merit, though its load factor under the assumed fuel prices increased from 2008 as opted-out stations had their output restricted.

6.How did you incorporate the effects of plant maintenance into your snapshot modelling, particularly for the seasonal analysis?

The Oxera wholesale model profiled plant outages for maintenance across months. However, the approach used for the snapshot analysis was similar to that used for the 2003 DTI analysis as summarised in the report as follows:

‘In carrying out the modelling, it was necessary to make some assumptions about the availability of plant for the three levels of snapshot demand that were modelled. OXERA assumed that a high proportion of plant would be available for generation during peak periods. For the off-peak and trough periods, two modelling options were considered: taking individual plant off-line; or scaling back the capacity of all plants of a given type to reflect overall availability. With regard to the first approach, OXERA concluded that the assumption as to which individual plant might be off-line during a particular demand period was too discretionary, and that the assumption might have a significant impact on flows. Therefore, OXERA adopted the second option, while recognising that, in practice, this pattern of plant availability is unlikely.’ (see Oxera’s 2003 DTI report: ‘The impact of average zonal transmission losses applied throughout Great Britain’, page 83).

7.On page 9 you say the differences in PTI and Oxera TLFs for the Scottish zones during the summer are "a function of the assumed loadings during a time when net electricity flows in

these zones are sensitive to actual loading at the time". Can you explain this in more detail?

The Modifications stipulated using the intact network model, i.e. assuming all transmission lines in service, and this was the assumption used in our modelling. In fact in summer some transmission lines are taken off-service for maintenance which may cause transmission constraints and forced off-merit generation – see NGET report on constraints at:

http://www.nationalgrid.com/NR/rdonlyres/F62370C0-1865-4FB3-8B06-AB6CE4DFFD77/16952/GBSQSSEconomicGuidance.ppt

The quoted NGET report says that export constraints in Scotland arise in summer due to summer transmission outages (for maintenance). We believe that this was the main reason for the summer differences between PTI and Oxera modelling results. PTI used the actual despatch data which included forced off-merit despatch to relieve actual transmission constraints while our modelling was based on the intact network model and hence did not show any summer constraints. Consequently we have used unmodified optimal despatch. Generally our simulations showed that TLFs in the Scottish zones, and especially in zone 14, were very sensitive to dispatch patterns. Hence any off-merit despatch affecting power flows in Scotland must have caused significant variations in TLFs. PTI results for summer show an unusual shift of TLFs in zone 14, presumably due to the constraints, which was not replicated in our simulations as we could not see any constraints due to using the intact network model.

8.In the load flow modelling for future years, what assumptions did you incorporate regarding changes to the network?

Changes to the network were made in accordance with those already announced in the SYS. The network configuration was the same in the uniform and zonal cases (ie, it was exogenous to the analysis).

9.On page 11 you describe how you modelled the growth in renewable generation. Could you provide us with a table showing the amount of wind (both offshore and onshore) added in each year and the zones in which these wind plants were added?

This will be provided separately.

10.On page 12 you state that "plant that have opted out of the [LCPD] Directive will be limited to 20,000 hours of generation between 2008 and 2015". How did you apply this limit in your model? Did you assume the same limit on generation in each year or something different?

The Oxera model in general optimised generation patterns for opted-out plant over the whole period 2008 to 2015, but this can only be applied when running multiple years at once. In the year-by-year analysis undertaken for the Elexon analysis annual limits were applied. This was consistent with DTI modelling at the time.

11.On page 13 you state that "[a]ll other plant closure decisions were based on market outcomes under the different scenarios". What criteria did you use for deciding whether non-nuclear plants should be closed? Which plants did you assume close under each scenario and when? Were the closures different between the uniform and zonal analyses?

Closures were based on the ability of the stations to cover operating costs over a period of time. No explicit mothballing decision was incorporated. There was some discretion used in circumstances where a station was only making small losses for one year or consistently making small losses (given some of the plant would have had balancing and reserve contracts that would have supported them for some of the shortfall).

Details of the individual station closures will be provided.

12.On page 13 you show two new generic CCGT plants coining on line in zones 2 and 7 with capacities of 1,000MW and 2,000MW. Why did you choose these zones and plant sizes?

The zones were chosen because it was considered that these areas would be most advantageous for new entry other things being equal. Issues such as the availability of sites, proximity to pipelines, TNUoS charges were considered. The capacity that enters in any give year is determined by the modelling results - if prices are high enough and stay high enough after entry then capacity is added.

13.On page 30 you say that "[z]onal results were subtracted from uniform results to obtain differences between the charging regimes" but do you mean the other way round as Tables 3.8 to 3,11 suggest that uniform results were subtracted from zonal results? For example, the output in Scotland is shown decreasing in the tables, which would seem more likely to be an outcome of moving from uniform to zonal losses.

This is correct.

14.On page 38 you explain how you have used method 2 to estimate the value of loss savings. Did you test how different the savings would have been if you had used method 1?

A more detailed comparison of the differences between Methods 1 and 2 is presented in the 2003 DTI report (pages 26 and 27). As discussed in the July 26 report it was concluded that Method 2 was preferable though both methods have advantages and disadvantages as discussed.

The concern with Method 1 is that marginal TLFs are valid only at the margin so multiplying them by generation at a node gives an overestimate. On the other hand using 3 snapshots per year for the second method amounts to linear averaging which may lead to a slight underestimation of the actual annual losses. Losses are approximately proportional to squared power flows so using an averaged power flow underestimates the losses. This error was smaller for modification P204 as when using the seasonal approach, 4*3 = 12 snapshots were used per year (3 snapshots for each season).

15.On pages 45-46 you describe the minimal impact of zonal transmission losses on interconnectors linking the Great Britain with other markets. Could you explain how you modelled the development of flows across the French and Dutch interconnectors?

The French interconnector was modelled effectively as a generator, though it had different availability profiles to capture the shape of imports and exports. The proposed Netherlands link was not modelled as constructed given its pending approval status in 2006.

16.In Tables 5.5 and 5.6 you provide your analysis of the influence of TNUoS and NTS exit charges on locational decisions. It does not appear that you have taken any account of future changes in these charges, is this correct?

This is correct – possible future changes in transmission charging levels or methodologies were not forecast.

17.Tables 5.5 and 5.6 on page 51show the difference excl. and incl. Scotland. Can you explain what you mean by "Difference"?

These tables were designed to give an idea of the ranges of these regional elements. Since Scotland was the outlier the table simply showed the ranges for these elements with and without Scotland included.

18.On page 59, the values quoted above Table 6.2 do not appear to correspond with those in

the table, are these simply typos? For example, you state the "[t]he Midlands shows the strongest signs of this behaviour, with an £18,000 reduction in benefits" but the table shows £16,000.

The text refers to all of the tables 6.2 to 6.5, not merely to Table 6.2. The maximum loss reduction referred to is seen in Table 6.5 while the £18,000 Midlands figure is seen in Table 6.4.

19.On page 67 you show the results of NPV calculations of future benefits. Could you provide us with the data used in these calculations?

This data will be provided separately. As with the 2003 DTI analysis (see pages 77 and 78 of the 2003 report) the estimated benefits were calculated in the following way:

- The annual results for the modelled period were used to give an estimate of the average value of generation redespatch per year resulting from the change. The NPV of this average annual benefit was then calculated over the two illustrative periods: to 2015/16 and to 2020/21.
- This was combined with the estimated average annual demand response benefits and operating costs.
- The one-off implementation costs were deducted.

An alternative approach would have been simply to discount each year's generation redespatch benefit individually for the estimated NPV to 2015/16 (which would have given slightly different figures – in some cases slightly higher and in some cases slightly lower), although this method could not have been used to estimate the NPV to 2020/21 since annual analysis was not conducted beyond 2015/16.

I hope that this addresses the queries raised. The additional data referred to will be sent separately.

Yours sincerely

Martin Brough

Director

(iii) Ofgem's supplemental question regarding CHP plants

ofgem

Stuart Senior

ELEXON Limited

4th Floor

350 Euston Road

London

NW1 3AW

Direct Dial: 0141 331 6007

Email: lesley.nugent@ofgem.gov.uk

Date: 9 January 2008

Dear Stuart

Balancing and Settlement Code ("BSC") modification proposals on zonal transmission losses - review of Oxera's analysis

I am writing to you further to my letter of 12 December 2007[51] which attached a list of questions compiled by the consultants that Ofgem has appointed (the Brattle Group ("Brattle")) to undertake the review of Oxera's analysis[52] on the BSC zonal transmission losses modification proposals[53].

We have received Oxera's 21 December 2007 letter to Elexon[54] setting out Oxera's preliminary response to those questions. Oxera's response identified some further information that is to be provided and I understand that this will be provided in the near future.

---

51 http://www.ofgem.gov.uk/Licensing/ElecCodes/BSCode/Ias/Documents1/071212_Questions_for_Oxera.pdf

52 Ofgem set out its intention to undertake this review in the following open letter: "The Authority's decisions on the zonal transmission losses proposals", 14 September 2007, ref 223/07 (www.ofgem.gov.uk)

53 P198, P198 Alternative, P200, P200 Alternative, P203 and P204.

54 http://www.elexon.co.uk/documents/modifications/198/Oxera_letter.pdf

In the course of carrying out the review, Brattle has identified the following additional question on Oxera's analysis:

"Did Oxera assume that the ability of CHP plants to respond to the cost signals associated with zonal loss charging was constrained by their commitments to produce heat and/or power for their industrial partners?"

I would be grateful if you could provide, as provided for under BSC Section C3.6, a response to this question together with the additional information referred to in Oxera's preliminary response, by 16 January 2008.

Yours sincerely,

Lesley Nugent

Senior Manager, Networks

(iv) Oxera's response to Ofgem's question regarding CHP plants

From: Martin Brough [mailto:Martin_Brough@oxera.com]
Sent: 17 January 2008 14:05
To: Lesley Nugent
Cc: Cheryl Mundie; David Jones; Min Zhu
Subject: RE: Response to information request

Lesley

In response to the question about CHP, we have not assumed in general that CHP could flex in response to the zonal loss charges with the exception of the very large stations with a CHP element (eg Immingham) where we assume that some flex is possible.

Regards

Martin

(v) Oxera's CBA analysis data

CBA data

Figures in £m
Data shows annual year-by-year value of redespatch, together with the NPV assuming implementation for 2007/8

Discount rate **3.50%**

P198 Central

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	NPV (as published) based on annual averages	Alternative NPV based on year-by-year discounting
Generation redespatch	3.4	9.0	1.6	12.0	1.9	4.5	0.9	1.8	-2.6	-3.4	21.3	23.2
Demand response											4.0	4.0
Operating costs											2.2	2.2
Implementation costs											2.0	2.0
NPV to 2015/16											**21.1**	**23.0**

P198 Seasonal

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	NPV (as published) based on annual averages	Alternative NPV based on year-by-year discounting
Generation redespatch	17.8	13.1	13.5	13.8	15.7	7.1	6.8	3.9	-2.3	-0.9	65.1	61.4
Demand response											4.8	4.8
Operating costs											2.2	2.2
Implementation costs											2.0	2.0
NPV to 2015/16											**65.7**	**62.1**

P198 Demand

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	NPV (as published) based on annual averages	Alternative NPV based on year-by-year discounting
Generation redespatch	4.0	12.7	18.3	0.5	6.7	0.3	6.1	7.0	-2.4	11.2	47.3	51.0
Demand response											2.9	2.9
Operating costs											2.6	2.6
Implementation costs											2.0	2.0
NPV to 2015/16											**45.6**	**49.3**

P198 Gas

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	NPV (as published) based on annual averages	Alternative NPV based on year-by-year discounting
Generation redespatch	11.5	18.1	11.5	8.1	6.8	6.5	4.6	-2.6	-2.3	-2.2	44.1	43.7
Demand response											2.9	2.9
Operating costs											2.2	2.2
Implementation costs											2.0	2.0
NPV to 2015/16											**42.8**	**42.4**

P204 Central

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	NPV (as published) based on annual averages	Alternative NPV based on year-by-year discounting
Generation redespatch	3.5	6.0	1.6	1.0	1.4	0.3	1.1	3.2	-3.3	-5.2	7.0	6.5
Demand response											1.1	1.1
Operating costs											2.3	2.3
Implementation costs											2.1	2.1
NPV to 2015/16											**3.8**	**3.3**

P204 Seasonal

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	NPV (as published) based on annual averages	Alternative NPV based on year-by-year discounting
Generation redespatch	8.3	3.4	7.7	10.4	3.2	3.5	1.5	3.7	3.2	2.1	34.5	32.5
Demand response											2.2	2.2
Operating costs											2.3	2.3
Implementation costs											2.1	2.1
NPV to 2015/16											**32.4**	**30.4**

(vi) Ofgem's further question on net generation benefits

Stuart Senior

ELEXON Limited

4th Floor

350 Euston Road

London

NW1 3AW

Direct Dial: 0141 331 6007

Email: lesley.nugent@ofgem.gov.uk

Date: 22 January 2008

value for all customers

Dear Stuart

Balancing and Settlement Code ("BSC") modification proposals on zonal transmission losses - review of Oxera's analysis

I am writing to you further to my letters of 12 December 2007[55] and 9 January 2008 which set out a number of questions compiled by the consultants that Ofgem has appointed (the Brattle Group ("Brattle")) to undertake the review of Oxera's analysis[56] on the BSC zonal transmission losses modification proposals[57].

We have now received Oxera's responses to those questions. Brattle have identified a further issue on which they would like information from Oxera.

We would be grateful for clarification on exactly how Oxera calculated the net benefits associated with zonal losses. Brattle have provided the attached spreadsheet setting out an example of despatch under uniform and zonal losses. They have calculated:

---

55 http://www.ofgem.gov.uk/Licensing/ElecCodes/BSCode/Ias/Documents1/071212_Questions_for_Oxera.pdf

56 Ofgem set out its intention to undertake this review in the following open letter: "The Authority's decisions on the zonal transmission losses proposals", 14 September 2007, ref 223/07 (www.ofgem.gov.uk)

57 P198, P198 Alternative, P200, P200 Alternative, P203 and P204.

1) the cost benefit – i.e. the overall reduction in generating costs required to meet demand (net of losses);
2) the change in generator profits;
3) benefits calculated according to the way Brattle understand Oxera's methodology.

It would appear from this example that Oxera's method gives benefits which do not match the change in generator profits or the change in costs. It is therefore not clear exactly what benefits Oxera are calculating.

We would be grateful if you could ask Oxera to explain in more detail how they calculated the benefits, and to illustrate their methodology on the attached spreadsheet example.

I would be grateful if you could provide a response, as provided for under BSC Section C3.6, by 29 January 2008.

Yours sincerely

Lesley Nugent

Senior Manager, Networks

All plants gross capacity 100 MW
Net demand (after losses) = 150 MW

Plant data

Plant number	MC (no losses)	Uniform LF	Zonal LF
1	15	0.95	0.95
2	22	0.95	0.9
3	25	0.95	1.05

Uniform losses case

Plant despatch

Plant	Gross output	Credited output	Net output	Physical Losses
1	100.0	95.0	95	5
2	61.1	58.1	55	6.1
3	0.0	0.0	0	0.0
Totals	161.1	153.1	150.0	11.1

Cost of generating	2,844
Volume of losses	11.1
Cost of losses	209.4
Marginal price	23.16
Price of losses	257.31
Genco revenue	3,544
Genco profit	700

Zonal losses case

Plant despatch

Plant	Gross output	Credited output	Net output	Losses
1	100	95	95	5
2	0	0	0	0
3	52.4	55	55	-2.6
Totals	152.4	150.0	150.0	2.4

Cost of generating	2,810
Volume of losses	2.4
Cost of losses	9.5
Marginal price	23.8
Price of losses	56.7
Genco revenue	3,571
Genco profit	762

Benefits

Cost benefit	34.9
Change in Genco profits	61.9

Oxera benefit calculation

Loss savings	202
Generation costs -	157
Net benefits	45

(vii) Oxera's response to Ofgem's letter on net generation benefits

January 29th 2008
Dear David

Response to further information request on Zonal transmission losses
This letter sets out Oxera's response to Ofgem's letter of January 22nd 2008, explaining in more detail the costbenefit
analysis carried out by Oxera in its two Zonal transmission losses reports.

The CBA includes consideration of four items: the annual generation redespatch benefits, the demand response benefits, the annual operating costs and the implementation costs.

The redespatch benefits reflect the reduction in the total generation cost in the zonal losses scenario compared to the uniform losses scenario for meeting the fixed level of net demand. This figure takes account of (a) the reduction in transmission losses associated with the changes to the generation dispatch and (b) the higher operational costs of generation associated with the new dispatch profile. The dispatch profiles are calculated against a fixed final demand requirement since the demand-side response is calculated as a second-order effect separately in the papers.

In terms of the spreadsheet sent with the Ofgem letter, the net dispatch benefit corresponds to the 'Cost benefit' of 34.9 in the example given (ie the difference in generation costs of meeting the net demand of 150MW taking into account both the lower losses and higher marginal costs incurred). These net figures are shown in the Oxera papers as 'Value of savings in losses' in tables 3.17 to 3.20 in the July 2006 paper and 'Value of losses' in tables 3.10 and 3.11 in the September 2006 paper. They show the value of the losses savings net of the higher marginal generation costs.

I hope that this addresses the query raised.

Yours sincerely
Martin Brough
Director