ASSESSMENT REPORT for Modification Proposal P198
'Introduction of a Zonal Transmission Losses Scheme'

Prepared by: P198 Modification Group

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Proposed Modification P198 seeks to allocate the 'variable' (heating) element of transmission losses to Parties on a 'zonal' locational basis, according to the extent to which each Party is estimated to give rise to them. The solution for Proposed Modification P198 is based closely on previous Modification Proposal P82. It involves the calculation of one Adjusted Annual Zonal Transmission Loss Factor (TLF) value per TLF Zone for each BSC Year, with no phased implementation. TLF Zones would be based on Grid Supply Point Groups, and the TLFs would be calculated on an annual ex-ante (forecast) basis for each forthcoming BSC Year (1 April – 31 March). All BM Units within a Zone would receive the Adjusted Annual Zonal TLF value for that Zone in every Settlement Period of the applicable BSC Year.

Alternative Modification P198 is the same as the Proposed Modification, except that it comprises:

- An annual ex-ante calculation of four Adjusted Seasonal Zonal TLF values for each TLF Zone, one for each BSC Season; and
- A linear phased implementation of these Adjusted Seasonal Zonal TLF values over the first four BSC Years of the scheme, such that TLFs are applied at 20% of their full value in BSC Year 1, 40% in BSC Year 2, 60% in BSC Year 3, 80% in BSC Year 4, and 100% in BSC Year 5 and all subsequent years.

MODIFICATION GROUP'S RECOMMENDATIONS

The P198 Modification Group invites the BSC Panel to:

- **AGREE that Proposed Modification P198 should not be made;**
- **AGREE that Alternative Modification P198 should not be made;**
- **AGREE a provisional Implementation Date for both the Proposed and Alternative Modifications of 1 April 2008 if an Authority decision is received on or before 22 March 2007, or 1 October 2008 if the Authority decision is received after 22 March 2007 but on or before 20 September 2007;**
- **AGREE the draft legal text for Proposed Modification P198;**
- **AGREE the draft legal text for Alternative Modification P198;**
- **AGREE that Modification Proposal P198 be submitted to the Report Phase; and**
- **AGREE that the P198 draft Modification Report be issued for consultation and submitted to the Panel for consideration at its meeting on 14 September 2006.**

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SUMMARY OF IMPACTED PARTIES AND DOCUMENTS

As far as the Modification Group has been able to assess, the following parties/documents would be impacted by P198.

Please note that this table represents a summary of the full impact assessment results in Appendix 3.

Parties		**Sections of the BSC**		**Code Subsidiary Documents**	
Distribution System Operators	☐	A	☐	BSC Procedures	☒
Generators	☒	B	☐	Codes of Practice	☐
Interconnectors	☒	C	☐	BSC Service Descriptions	☒
Licence Exemptable Generators	☒	D	☐	Party Service Lines	☐
Non-Physical Traders	☐	E	☒	Data Catalogues	☐
Suppliers	☒	F	☐	Communication Requirements Documents	☒
Transmission Company	☒	G	☐	Reporting Catalogue	☒
Party Agents		H	☒	Load Flow Model Specification*	☒
Data Aggregators	☐	I	☐	**Core Industry Documents**	
Data Collectors	☐	J	☐	Ancillary Services Agreement	☐
Meter Administrators	☐	K	☐	British Grid Systems Agreement	☐
Meter Operator Agents	☐	L	☐	Data Transfer Services Agreement	☐
ECVNA	☐	M	☐	Distribution Codes	☐
MVRNA	☐	N	☐	Distribution Connection Agreements	☐
BSC Agents		O	☐	Distribution Use of System Agreements	☐
SAA	☒	P	☐	Grid Code	☐
FAA	☐	Q	☐	Master Registration Agreement	☐
BMRA	☒	R	☐	Supplemental Agreements	☐
ECVAA	☐	S	☐	Use of Interconnector Agreement	☐
CDCA	☒	T	☒	**BSCCo**	
TAA	☐	U	☐	Internal Working Procedures	☒
CRA	☒	V	☒	**BSC Panel/Panel Committees**	
SVAA	☐	W	☐	Working Practices	☒
Teleswitch Agent	☐	X	☒	**Other**	
BSC Auditor	☒			Market Index Data Provider	☐
Profile Administrator	☐			Market Index Definition Statement	☐
Certification Agent	☐			System Operator-Transmission Owner Code	☐
Transmission Loss Factor Agent*	☒			Transmission Licence	☐
Other Agents				Network Mapping Statement*	☒
Supplier Meter Registration Agent	☐			Load Flow Model Reviewer*	☒
Data Transfer Service Provider	☐				

*New document/role introduced by P198

1 EXECUTIVE SUMMARY

The key conclusions of the P198 Modification Group ('the Group') are outlined below. The Group:

- **AGREED** that the solution for Proposed Modification P198 should be based on that previously developed for Proposed Modification P82, unless a specific reason was identified for diverging from that solution;
- **AGREED** some minor refinements to these solution requirements in respect of communication and escrow arrangements for the Transmission Loss Factor Agent (TLFA), publication of certain data relating to the calculation of zonal Transmission Loss Factors (TLFs), and the start and end dates for the Reference Year used in the annual TLF calculation;
- **COMMISSIONED** a load-flow modelling analysis by an independent consultant of the likely magnitude and variability of TLFs during the first year of implementation, using 2005/2006 data;
- **AGREED** that 0.5 was the appropriate scaling factor to allocate the level of variable losses calculated by the TLFA, and that this scaling factor should be 'hard-wired' in the Code;
- **AGREED** that the TLF values for each BSC Year should be published on the BSC Website no less than three months prior to the start of the applicable BSC Year;
- **UNDERTOOK** an initial industry consultation on a variety of potential options for an Alternative Modification;
- **DEVELOPED** an Alternative Modification which involves the calculation of seasonal rather than annual zonal TLF values, and a linear phased implementation of these seasonal TLFs over the first four BSC Years of the scheme;
- **NOTED** that the central implementation costs for the Proposed Modification were estimated to be approximately £467,000 (with an associated tolerance of +/-35%), with annual operational costs in the region of £158,000 (with an associated tolerance of +/-45%);
- **NOTED** that the central implementation costs for the Alternative Modification were estimated to be approximately £10,000 higher than those for the Proposed Modification, with marginally lower annual operational costs;
- **COMMISSIONED** an independent consultant to provide a cost-benefit analysis of P198, including a projection of the likely future impact of TLFs on the market over ten years;
- **AGREED** by majority that the Proposed Modification would not better facilitate the achievement of the Applicable BSC Objectives when compared to the current Code baseline;
- **AGREED** by majority that the Alternative Modification would better facilitate the achievement of the Applicable BSC Objectives when compared to the Proposed Modification, but would not better facilitate the achievement of the Applicable BSC Objectives when compared to the current Code baseline;
- **NOTED** that both the Proposed and Alternative Modifications would require twelve months' development time, driven by the timescales required to procure the TLFA and develop TLFA systems; and
- **AGREED** that the Implementation Date for both the Proposed and Alternative Modifications should be tied to Parties' contract rounds – giving the following proposed dates:
    - 1 April 2008, if an Authority decision is received on or before 22 March 2007; or
    - 1 October 2008, if an Authority decision is received after 22 March 2007 but on or before 20 September 2007.

Section 2 explains the existing allocation of transmission losses, outlines the intention of P198, and provides a summary of other previous and current Modification Proposals in this area. A description of the Proposed Modification and Alternative Modification solutions is provided in Section 3. Further information regarding the Group's discussions of the areas set out in the P198 Terms of Reference is contained in Section 4, whilst a copy of the Group's full Terms of Reference is provided in Appendix 2 along with details of the Group's membership and the process followed.

A summary of the Group's views regarding the merits of the Proposed Modification and Alternative Modification can be found in Section 6, whilst the draft legal text for the Proposed and Alternative Modifications is provided in Appendix 1. Details of the responses to the impact assessments for the Proposed Modification and Alternative Modification are contained in Appendix 3. Summaries of the responses received to the first and second Assessment Procedure consultations can be found in Sections 4.6 and 5 respectively, along with the Group's discussion of these responses. Full copies of the individual consultation responses received are provided in Appendices 4 and 7. The full results of the TLF load-flow modelling exercise and cost-benefit analysis are provided in Appendices 5 and 6 respectively.

Please note that definitions of the technical terms highlighted in **bold** within this document can be found in Section 7.

2 BACKGROUND

2.1 Types of Transmission Losses

The total metered energy which can be drawn from the Transmission System to meet demand will always be less than that delivered onto the Transmission System by generation, since some energy is used up in the process of transporting electricity. The energy 'lost' from the Transmission System is commonly referred to as '**transmission losses**'. Transmission losses can be considered to comprise two main elements: 'fixed' losses and 'variable' losses.

Fixed losses are those which do not vary significantly with the 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 the transformers and lines. Variable losses increase with the current (and associated power flow) and the length of line in which it flows.

References to 'fixed' and 'variable' losses throughout this document have the meaning given above, whilst the term **'total' transmission losses** is used to represent the sum of fixed and variable losses (i.e. the total energy lost from the Transmission System at any given point in time, calculated as the difference between total generation and demand).

2.2 Existing Allocation Mechanism for Transmission Losses

The rules and calculations for allocating transmission losses to Parties are set out in Section T2 of the Balancing and Settlement Code ('the Code'). These involve the adjustment of individual BM Unit Metered Volumes in Settlement to allocate transmission losses, whilst ensuring that total adjusted generation matches total adjusted demand in any given Settlement Period. Transmission losses are thereby allocated to Parties as part of their Trading Charges.

Under the existing 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. Although a parameter for a 'differential' allocation of some or all transmission losses is included in the Code, this is currently set to zero so has no practical effect. In the Section T calculation, this parameter is represented by the **Transmission Loss Factor** (TLF=0). This value can only be amended through a modification to the Code.

The formula below represents a simplified version of the Section T calculation for each BM Unit's share of total transmission losses in any given Settlement Period:

$$TLM=1+TLF+TLMO^{+/-}$$

A **Transmission Loss Multiplier** (TLM) is generated for each individual BM Unit, and represents the factor used to scale each BM Unit's Metered Volume in Settlement. The **Transmission Losses Adjustment** (TLMO) uniformly adjusts all generation delivery or all demand offtake to ensure an exact allocation of the actual level of total losses in a given Settlement Period. The calculation of TLMO also includes the application of an '**alpha (α) factor**' of 0.45 such that 45% of these total losses are allocated across all delivering Trading Units in aggregate (through the $TLMO^+$) whilst 55% are allocated across all offtaking Trading Units in aggregate (through the $TLMO^-$).[1]

The formulae below represent simplified versions of the $TLMO^+$ and $TLMO^-$ calculations:

TLMO⁺ = -(0.45(total transmission losses in Settlement Period) + generators' share of transmission losses already allocated through TLF in Settlement Period) / total volume of generation in Settlement Period*

TLMO⁻ = (-0.55(total transmission losses in Settlement Period) – Suppliers' share of transmission losses already allocated through TLF in Settlement Period) / total volume of demand in Settlement Period*

The value of $TLMO^+$ is the same in each Settlement Period for every BM Unit in all delivering Trading Units. The value of $TLMO^-$ is the same for every BM Unit in all offtaking Trading Units.

Since under the existing Code baseline the value of TLF is set to zero, the TLMO is currently the only determining factor in the calculation of each BM Unit's TLM. Two uniform TLM values are therefore currently applied: one to all BM Units in delivering Trading Units, and one to all BM Units in offtaking Trading Units. Each Party's overall allocation of transmission losses is dependent on the Metered Volumes of the BM Units to which this TLM is applied. Metered Volumes for BM Units in 'delivering' (exporting) Trading Units are currently scaled down (multiplied by $1+TLF+TLMO^+$), whilst Metered Volumes for BM Units in 'offtaking' (importing) Trading Units are scaled up (multiplied by $1+TLF+TLMO^-$).

[1] In practice, this split is designed to be equivalent to a 50:50 allocation, but with allowance for the fact that metering for most generation connections is on the high voltage side of the supergrid transformer, whereas that for demand is on the low voltage side. The 45:55 allocation of transmission losses is intended to allow for supergrid transformer losses for demand connections which are in addition to the metered flow.

2.3 Modification Proposal P198

The Proposer of P198 argues that the existing locational split between northern generation and southern demand is neither economic, efficient, nor good for the environment, since it results in the transportation of electricity over large distances – increasing the amount of energy lost through variable (heating) losses. The Proposer argues that the Code's current uniform allocation of variable losses does not provide the appropriate economic signals to site new generation closer to existing demand (and vice versa), since it fails to target the costs of such losses on those Parties who cause electricity to be transported the furthest distance. The Proposer considers that this results in a cross-subsidy, whereby southern generators and northern Suppliers have to pay part of the costs of transporting electricity to the south.

P198 proposes to allocate variable losses to Parties on a 'zonal' basis through the TLF, according to the extent to which each Party gives rise to them. In the short-term, the Proposer believes that the locational economic signals generated by P198 would remove existing cross-subsidies and lead to more efficient despatch (i.e. more efficient use of existing generation closer to demand). In the longer-term, the Proposer believes that these signals would encourage more efficient siting of new plant and load in areas where generation or demand is respectively limited. The Proposer believes that these changes in market behaviour would lead to a reduction in the level of total transmission losses.

The solution put forward by the Proposer for Proposed Modification P198 is based closely on previous Modification Proposal P82. The key elements of P82 which are replicated within the P198 Modification Proposal are as follows:

- Zonal TLFs would be calculated on an ex-ante (forecast) basis;
- Zonal TLFs would be calculated annually for each BSC Year using data from a previous 'reference year';
- Zonal TLFs would be applied to both generation and demand;
- TLF Zones for both generation and demand would be based on Grid Supply Point (GSP) Groups;
- Zonal TLFs would be scaled to allocate only variable losses (with fixed losses continuing to be allocated through the TLMO);
- Zonal TLFs would be published at least one month prior to use in Settlement; and
- There would be no phased or 'hedged' implementation.

Further information regarding P82 can be found in Section 2.4. For a copy of the original Modification Proposal as submitted by the Proposer, please refer to the P198 Initial Written Assessment (IWA). Section 3 outlines the solutions for the Proposed Modification and Alternative Modification as developed by the Group.

2.4 Related Modification Proposals

This section provides an overview of other previous and current Modification Proposals in the area of transmission losses. Table 1 on the following page summarises the key features of these proposals.

Table 1 – Summary of Transmission Losses Modification Proposals

Aspect of Solution	P75 Proposed	P75 Alternative	P82 Proposed	P82 Alternative	P105	P109	P198 Proposed	P198 Alternative	P200 Proposed	P200 Alternative	P203 Proposed	P204 Proposed
Scope of Zonal TLF Calculation	Fully Marginal (Fixed & Variable Losses)	Fully Marginal (Fixed & Variable Losses)	Scaled Marginal (Variable Losses Only)	Scaled Marginal (Variable Losses Only)	Fully Marginal (Fixed & Variable Losses)	-	Scaled Marginal (Variable Losses Only)	Scaled Marginal (Variable Losses Only)	Scaled Marginal (Variable Losses Only)	Scaled Marginal (Variable Losses Only)	Scaled Marginal (Variable Losses Only)	Scaled Marginal (Variable Losses Only)
Scaling Factor	-	-	0.5	0.5	-	-	0.5	0.5	0.5	0.5	0.5	TBC – to ensure no energy credits
Applicable Period for TLFs	Settlement Day	Calendar Month	BSC Year	BSC Year	Calendar Month	-	BSC Year	BSC Season	BSC Year	BSC Season	BSC Season	TBC
Nature of TLF Calculation	Ex-Post	Ex-Ante	Ex-Ante	Ex-Ante	Ex-Ante	-	Ex-Ante	Ex-Ante	Ex-Ante	Ex-Ante	Ex-Ante	Ex-Ante
Frequency of TLF Calculation	Daily	Annual	Annual	Annual	Annual	-	Annual	Annual	Annual	Annual	Annual	Annual
Applicable Zones for Production BM Units	TNUoS Zone	TNUoS Zone	GSP Group	GSP Group	TNUoS Zone	-	GSP Group	GSP Group	GSP Group	GSP Group	GSP Group	GSP Group
Applicable Zones for Consumption BM Units	GSP Group	GSP Group	GSP Group	GSP Group	GSP Group	-	GSP Group	GSP Group	GSP Group	GSP Group	GSP Group	GSP Group
Mitigation of Impacts?	No	Yes	No	Yes	No	Yes	No	Yes	Yes	Yes	No	No
Type of Mitigation	-	Linear Phasing	-	Linear Phasing	-	Hedging	-	Linear Phasing	Hedging	Hedging	-	-
Period of Mitigation	-	4 Years	-	4 Years	-	15 Years	-	4 Years	15 Years	15 Years	-	-

2.4.1 Overview of Other Past and Present Transmission Losses Modification Proposals

a) Previous Transmission Losses Modification Proposals

Three previous Modification Proposals have sought to introduce a Code mechanism to calculate non-uniform, locational, TLF values:

- P75 'Introduction of Zonal Transmission Losses' (raised by Powergen in April 2002);
- P82 'Introduction of Zonal Transmission Losses on an Average Basis' (raised by First Hydro in May 2002); and
- P105 'Introduction of Zonal Transmission Losses on a Marginal Basis Without Phased Implementation' (raised by Powergen in October 2002).

Alternative Modifications were also developed for P75 and P82, with the result that five mutually-exclusive TLF methodologies were put forward to the Authority for decision.

In addition, Modification Proposal P109 'A Hedging Scheme for Changes to TLF in Section T of the Code' was raised by British Energy in November 2002. P109 proposed that a 'hedging scheme' should be introduced in Section T, to mitigate the impact of TLFs over a 15-year period. Unlike the other proposals, P109 did not itself seek to stipulate a methodology for calculating TLFs. Instead it proposed to include the hedging mechanism in the Code such that it could be used were a non-uniform TLF calculation to be introduced by P75, P82, P105 or another Modification Proposal.

P75, P82, P105 and P109 were considered by the Transmission Loss Factor Modification Group (TLFMG) during 2002/03. P75, P105 and P109 were rejected by the Authority (References 1-3), whilst Proposed Modification P82 was approved in January 2003 for implementation in April 2004 (Reference 4). However, the approval of P82 was quashed by the High Court in January 2004 following a judicial review, and P82 was remitted to the Authority for redecision where it was subsequently rejected (Reference 5). As a result, the value of TLF remains set to a uniform value of zero within the Code. Further information regarding P82 can be found in Section 2.4.2 below.

b) Current Transmission Losses Modification Proposals

In addition to P198, there are also currently three other Pending Modification Proposals being progressed in the area of zonal transmission losses, as follows:

- Modification Proposal P200 'Introduction of a Zonal Transmission Losses Scheme with Transitional Scheme' (raised by Teesside Power Limited on 21 April 2006);
- Modification Proposal P203 'Introduction of a Seasonal Zonal Transmission Losses Scheme' (raised by RWE Npower on 26 June 2006); and
- Modification Proposal P204 'Scaled Zonal Transmission Losses' (raised by British Energy Power & Energy Trading Ltd on 3 July 2006).

An Alternative Modification has also been developed for P200. All of the proposals seek to introduce a locational allocation of variable losses through the calculation of 'zonal' TLF values, although their precise calculations and applications of these values differ. Please note that all of these Modification Proposals (including any Alternatives) are mutually exclusive, such that only one could be approved by the Authority for implementation.

Further information regarding P200, P203 and P204 can be found in Sections 2.4.3-2.4.5 below.

2.4.2 P82 Development and Modification Proposal P125

Although P82 was never fully implemented, all of the development work had already been completed prior to the conclusion of the judicial review. Much of the original P82 functionality (legal text, system development, Code Subsidiary Document changes and BSCCo working procedures) therefore remains re-usable and under the ownership of BSCCo. However, a key exception is the Load Flow Model developed by the TLFA, the new BSC Agent which would have been created by P82 to operationally calculate zonal TLFs. Although an organisation was initially procured by BSCCo to fulfil the TLFA role, the subsequent P82 judicial review ruling meant that it was no longer required. The TLFA contract was consequently terminated, and the Intellectual Property Rights (IPR) to the P82 Load Flow Model remain with the organisation concerned.

The scope and assessment of P75, P82, P105 and P109 was limited to transmission losses occurring on the England and Wales Transmission System. Following the Authority's approval of P82, a defect was identified in the P82 legal text relating to the application of a locational TLF value to the Scottish Interconnector. Modification Proposal P125 'Apportionment of the Scottish Interconnector flows to the Northern and North Western GSP Groups for the purposes of calculating losses' was raised by Scottish and Southern Energy in March 2003 to correct this defect, and was approved by the Authority in August 2003.

After the P82 judicial review ruling, the P125 changes served no practical purpose and were 'backed out' of the Code by Modification Proposal P165 'Housekeeping Modification – Removal of Approved Modification P125' in April 2004. Since then the introduction of the British Electricity Trading and Transmission Arrangements (BETTA) in April 2005 has subsequently extended the scope of the Code to incorporate Scotland, such that it now covers the GB-wide Transmission System. It should be noted that the defect identified by P125 could therefore no longer arise under a GB transmission losses scheme, since the Scottish Interconnector no longer exists under BETTA.

Further detail regarding P82 can be found in the joint P75/P82 Assessment Report (Reference 6) and the P82 Modification Report (Reference 7). For more information regarding P75, P105, P109 and P125, please refer to the respective Modification Reports (References 8-11).

2.4.3 Modification Proposal P200

P200 was raised part-way through the Assessment Procedure for P198. Proposed Modification P200 seeks to introduce zonal TLFs calculated under the same methodology as P198, but with the addition of a 'hedging' scheme to mitigate the impact of TLFs on existing generators over 15 years. The hedging scheme proposed by P200 shares some similarities with previous 'hedging' proposal P109, although there are significant differences between the two proposals.

The potential for a 'hedging' or 'grandfathering' scheme was discussed by the P198 Modification Group as a potential option for an Alternative Modification to P198. However, it was not progressed since a majority of the Group believed that such a scheme was less likely to better facilitate the achievement of the Applicable BSC Objectives compared with a 'linear' phasing scheme for TLFs (see Section 4.6 for further details). P200 was subsequently raised as a separate Modification Proposal. The P200 Group also developed an Alternative Modification for P200, which comprises an annual calculation of Adjusted Seasonal Zonal TLFs with the addition of a hedging scheme.

The majority recommendation of the P200 Group is that neither Proposed Modification P200 nor Alternative Modification P200 should be made. Further information can be found in the P200 Assessment Report (Reference 12), which will be presented to the BSC Panel ('the Panel') on 10 August 2006 in parallel with the P198 Assessment Report.

Due to the related nature of the proposals, the P200 Modification Group was formed from members and attendees of the P198 Group. Although the resulting membership of the P200 Group was slightly different than that for the P198 Group, some aspects of the P198 and P200 progression were conducted in parallel for efficiency. In accordance with the Modification Procedures set out in Section F of the Code, the two proposals were assessed separately by the respective Groups as to whether they would better facilitate the achievement of the Applicable BSC Objectives compared with the existing Code baseline – and not compared with each other. The Groups noted that the Authority would have the wider remit to consider whether one of the proposals would better facilitate the achievement of the Applicable BSC Objectives overall. The P200 Group did, however, consider that it would be useful to indicate a preference between the two proposals, such that this could be taken into account by the Panel and the Authority. Details of this preference can be found in Section 6.

For further information regarding P200 – including a comparison of the key features of its proposed hedging scheme with previous Modification Proposal P109 – please refer to the P200 Assessment Report. Since P200 mirrors the P198 requirements with the addition of a hedging scheme, it is therefore advisable to read the P198 Assessment Report prior to that for P200.

2.4.4 Modification Proposal P203

P203 was raised part-way through the P198 and P200 Assessment Procedures. Proposed Modification P203 seeks to introduce an annual calculation of seasonal TLF values which is based on Alternative Modification P198, except that (unlike P198 Alternative) there would be no phased implementation of these values. The solution proposed by P203 had therefore been considered by the P198 Group as a potential option for an Alternative Modification. Further detail regarding the Group's discussion in this area can be found in Section 4.8.

The P203 Modification Group was formed from members of the P198 and P200 Modification Groups. The majority recommendation of this Group is that Proposed Modification P203 should not be made. No Alternative Modification was developed for P203. Further information can be found in the P203 Assessment Report (Reference 13), which will be presented to the Panel on 10 August 2006 in parallel with the Assessment Reports for P198 and P200. Note that P203 was assessed separately by the Group on its own merits compared with the existing Code baseline – and not compared with P198 or P200. A majority of members of the P203 Group did, however, consider that it would be helpful to indicate a preference between the two proposals, such that this could be taken into account by the Panel and the Authority. Details of this preference can be found in Section 6.

Since the solution for P203 (with the exception of the removal of the phasing element) is based on that for Alternative Modification P198, it is advisable to read the P198 Assessment Report prior to that for P203.

2.4.5 Modification Proposal P204

P204 was also raised part-way through the P198 and P200 Assessment Procedures. Like P198, Proposed Modification P204 seeks to introduce a zonal scheme for the allocation of variable losses, whereby TLF values would be calculated on an ex-ante basis for each TLF Zone. However, the principle behind P204 is different to P198, since it seeks to ensure that no BM Units are credited with energy (i.e. receive payments) through the TLM.

P204 had been considered as a potential option for an Alternative Modification to P198. However, the Group agreed by majority not to further assess such an option under P198 – believing either that it was outside the scope of P198, or that it required a substantive assessment in its own right and would be better assessed via a separate Modification Proposal. Further detail can be found in Section 4.6. P204 was subsequently raised as a separate Modification Proposal.

P204 is currently within the Assessment Procedure, with an Assessment Report scheduled to be presented to the Panel on 12 October 2006 (two months behind P198, P200 and P203). The P204 Modification Group (which was formed from members of the P198 and P200 Modification Groups) has not yet developed a view regarding the merits of P204. Further information can be found in the P204 IWA (Reference 14).

3 SUMMARY OF P198 SOLUTION

3.1 Proposed Modification

The Proposed Modification would allocate the variable element of transmission losses to Parties on a 'zonal' locational basis through the TLF, according to the extent to which each Party is estimated to give rise to variable losses. The remaining transmission losses in each Settlement Period would continue to be allocated to Parties on a non-locational basis through the TLMO, and the overall 45:55 allocation of total transmission losses to generation and demand would be retained.

The solution for Proposed Modification P198 is based closely on Proposed Modification P82, and involves the following 'scaled marginal' methodology for calculating locational TLFs:

1) An electrical model of the Transmission System (a '**Load Flow Model'**) would be built, containing '**Nodes**' to represent points where energy flows on or off the Transmission System or where two or more circuits on the network meet. Each Node on the Transmission System would be identified by the Transmission Company, and would be allocated to a specific **Zone** on the transmission network on the basis of a '**Network Mapping Statement**' maintained by BSCCo. The TLF Zones would be set by the Panel, based on the geographic areas covered by GSP Groups. Since there are currently 14 GSP Groups, there would therefore be 14 TLF Zones.

2) TLFs would be calculated on an **ex-ante** basis (i.e. forecasted) for each BSC Year, using Metered Volumes and **Network Data** for **Sample Settlement Periods** from a preceding 12-month period (the '**Reference Year**'). The required Metered Volumes and Network Data would be provided by the Central Data Collection Agent (CDCA) and the Transmission Company respectively.

3) Prior to the start of each BSC Year (1 April – 31 March), the Load Flow Model would be run by a **Transmission Loss Factor Agent** ('the TLFA') to calculate how an incremental (or 'marginal') increase (or 'injection') in power at each individual Node would affect the total losses from the Transmission System. The output of the Load Flow Model would be a TLF value for each Node in each of the Sample Settlement Periods. Positive TLF values would be produced for Nodes where an incremental increase in generation (or reduction in demand) had the effect of decreasing total transmission losses. Negative TLF values would be produced for Nodes where an incremental increase in generation (or reduction in demand) had the effect of increasing total transmission losses. For example, if an injection of an extra unit of energy at a Node increased total losses by 0.02%, the TLF for that Node in that Settlement Period would be -0.02.

4) The TLFA would average these raw **Nodal TLFs** across all the Nodes in each TLF Zone by 'volume-weighted' averaging, to give 14 **Zonal TLF** values for each Sample Settlement Period (one per TLF Zone). The TLFA would then convert these to **Annual Zonal TLFs** by 'time-weighted' averaging.

5) The TLFA would adjust the Annual Zonal TLFs by an appropriate scaling factor such that the volume of energy allocated via the TLFs was comparable to the volume of variable losses calculated by the Load Flow Model.[2] These 14 **Adjusted Annual Zonal TLFs** (one per TLF Zone) would be made publicly available by BSCCo no less than three months prior to their use in the TLM Settlement calculation for the applicable BSC Year.

[2] Such scaling is necessary due to the square load relationship of heating losses to power (i.e. they increase in proportion to the square of the current). Without the scaling, the zonal TLFs would recover more than the actual level of variable losses calculated by the Load Flow Model. Further information can be found in Section 4.4.

6) Each BM Unit would be allocated to a specific TLF Zone by BSCCo on the basis of the Network Mapping Statement, with any question or dispute over their zonal allocation to be resolved by the Panel. Using the Network Mapping Statement, the TLFA would determine the TLF value to be applied to each BM Unit in the TLM Settlement calculation for the applicable BSC Year. This **BM Unit-Specific TLF** would be the Adjusted Annual Zonal TLF value for the Zone in which the BM Unit was located. All BM Units within a Zone would therefore receive the same single TLF value (the Adjusted Annual Zonal TLF for that Zone), for every Settlement Period within the applicable BSC Year. A positive TLF value would increase the value of TLM used to scale a BM Unit's Metered Volume (a benefit to generators and disadvantage to Suppliers), whilst a negative TLF value would decrease the value of TLM (a benefit to Suppliers and disadvantage to generators).

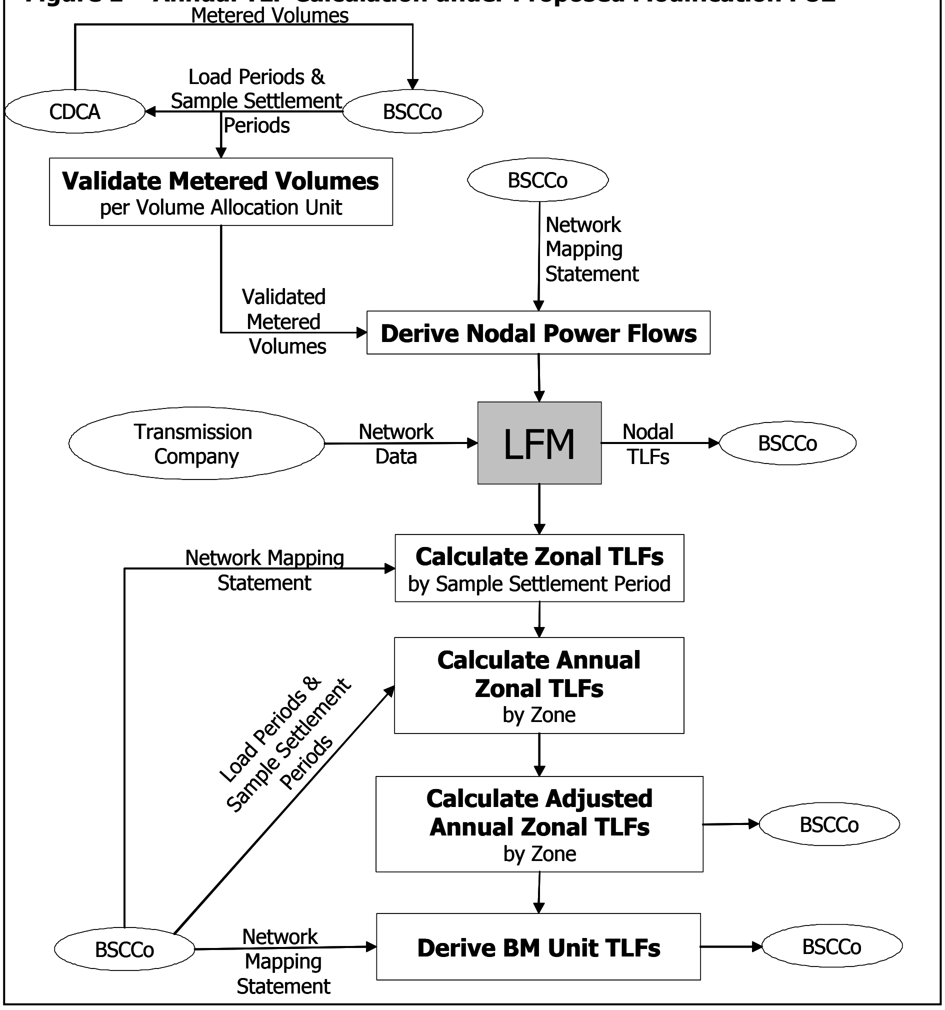
7) The BM Unit-Specific TLFs calculated by the TLFA would be registered in BSC Systems by the Central Registration Agent (CRA), and would be used by the Balancing Mechanism Reporting Agent (BMRA) and the Settlement Administration Agent within the Balancing Mechanism Reporting Service (BMRS) and Settlement calculations respectively.

8) The remaining 'fixed' element of transmission losses would continue to be allocated to Parties on a non-locational basis through the TLMO, and the overall 45:55 allocation of total transmission losses to generation and demand would be retained.

Under Proposed Modification P198, there would be no phased implementation or 'hedging' of exposure to the new zonal TLFs, which would therefore take full effect from the first Settlement Period on the Implementation Date.

The diagram below outlines the high-level annual process which would have been followed by the TLFA to calculate BM Unit-Specific TLFs for each BSC Year under P82 (on which P198 is based).

Figure 1 – Annual TLF Calculation under Proposed Modification P82



3.2 Alternative Modification

Under the Alternative Modification developed by the Group, the TLFA would calculate Nodal TLFs and Zonal TLFs in the same way as for the Proposed Modification, but would time-weight by BSC Season rather than by BSC Year to calculate a set of four **Seasonal Zonal TLFs** for each TLF Zone – one for each BSC Season.

The BSC Seasons are already defined in Section K of the Code, and are:

BSC Spring: 1 March – 31 May inclusive;

BSC Summer: 1 June – 31 August inclusive;

BSC Autumn: 1 September – 30 November inclusive; and

BSC Winter: 1 December – 28 February inclusive (or 29 February in a leap year).

These Seasonal Zonal TLFs would be multiplied under the same 0.5 scaling factor as under the Proposed Modification to ensure that the level of variable losses allocated through these TLFs was comparable to that calculated by the Load Flow Model. However, under the Alternative Modification, the Seasonal Zonal TLFs would also be multiplied by an additional **'beta' (β) scaling factor** to create the final set of four **Adjusted Seasonal Zonal TLFs**.

The value of the β scaling factor would be as follows:

Applicable BSC Year 1:	0.2
Applicable BSC Year 2:	0.4
Applicable BSC Year 3:	0.6
Applicable BSC Year 4:	0.8
Applicable BSC Year 5 onwards:	1.0.

Adjusted Seasonal Zonal TLF values would therefore be phased in linearly over the first four BSC Years of the scheme, such that they were applied at 20% of their full value in BSC Year 1, 40% in BSC Year 2, 60% in BSC Year 3, 80% in BSC Year 4, and 100% in BSC Year 5 and all subsequent years. This scaling would be undertaken by the TLFA as part of its annual ex-ante calculation of TLFs, and would apply equally to all BM Units.

All BM Units within a Zone would receive the Adjusted Seasonal Zonal TLF value for that Zone in the applicable season. TLFs would be recalculated for each BSC Year, based on data from a previous Reference Year.

Since the BSC Spring season (1 March – 31 May) spans the beginning of a new BSC Year on 1 April, the new set of TLFs for each year would therefore come into effect part-way through this season. This would result in a changeover from the BSC Spring seasonal TLF value applied to a BM Unit on the last Settlement Period on 31 March to a new value for that season which was effective from the first Settlement Period on 1 April.

Further detail regarding the Group's development of the solution for the Alternative Modification can be found in Section 4.8.

4 GROUP'S CONSIDERATION OF AREAS RAISED BY THE TERMS OF REFERENCE

This section outlines the conclusions of the Group regarding the areas set out in the P198 Terms of Reference. For a summary of the process followed by the Group in progressing P198 (including a copy of the full Terms of Reference), please refer to Appendix 2.

4.1 Modification Group Membership

At its meeting on 12 January 2006, the Panel agreed that the P198 Modification Group should be formed from the original membership of the TLFMG as far as possible, since this group undertook the assessment of previous transmission losses proposals P75, P82, P105 and P109. However, it recognised that the TLFMG had not met since early 2003, and that many of its members might therefore no longer be available. The Panel therefore agreed that the P198 Modification Group should be supplemented as necessary with any members of the current Standing Modification Groups[3] who had expertise in the area of transmission losses. Details of the P198 Group's membership can be found in Appendix 2. All meetings of the Group were held in open session and, in addition to the core membership of the Group, many market participants were involved in the discussions as attendees. In addition, the Panel requested that representation be sought from certain specific bodies as set out below.

4.1.1 Scottish Transmission Owner Representation

Section F2.4.5A of the Code allows (but does not require) the Panel to invite a representative of the System Operator-Transmission Owner Code (STC) Committee to join the Modification Group for any BSC Modification Proposal which may have an impact on the STC. Although P198 was not anticipated to have any impact on the STC itself, the Panel noted that the proposal sought to influence the behaviour and location of generation and demand. The Panel therefore considered that P198 had the potential to affect future patterns of investment in the Transmission System by the two Scottish Transmission Owners as well as the Transmission Company for England and Wales. The Panel agreed with BSCCo's recommendation that members of the STC Committee representing the Scottish Transmission Owners should therefore be invited to participate in the P198 Modification Group.

An invitation for Scottish Transmission Owners to participate in the Group was extended by the Transmission Company (in its role as the STC Code owner) on behalf of the Panel at the STC Committee meeting on 17 January 2006. Following a request by the Transmission Company at the Panel meeting on 9 February 2006, BSCCo also wrote to each of the four Scottish Transmission Owner members of the STC Committee individually, to encourage their participation. Responses declining the Panel's invitation were received from two of these members – stating that, since P198 would have no impact on the STC itself, they did not believe any Scottish Transmission Owner participation in the P198 assessment to be necessary. No Scottish Transmission Owner representative therefore attended the P198 meetings. The Transmission Company's analysis and impact assessment during the Assessment Procedure confirmed that there would be no impact on the STC (see Appendix 3). The Modification Group agreed that no specific information was required from the Scottish Transmission Owners to support its assessment of P198, since its analysis would be based on post-BETTA BSC data.

[3] Governance Standing Modification Group, Pricing Standing Modification Group, Settlement Standing Modification Group and Volume Allocation Standing Modification Group.

4.1.2 User Organisation Representation

The Panel agreed that an invitation for membership of the P198 Modification Group should also be extended to organisations representing large energy users, to ensure that the impact of P198 on such users was adequately considered. The following organisations were therefore invited to nominate members for the Group, and were also subsequently invited to respond to the P198 second Assessment Procedure consultation and/or attend the industry education seminar hosted by BSCCo (see below):

- Major Energy Users Council;
- Utility Buyers Forum;
- Chemical Industries Association;
- Corus Group; and
- Energy Intensive Users Group.

However, none of these organisations accepted the invitation to attend the Group meetings or seminar, or provided consultation responses in respect of P198.

4.1.3 Industry Education Seminar

The Panel requested that an industry 'seminar' be held to support the consultation process for those participants who had been unable to attend the Modification Group meetings. BSCCo investigated the possibility of using an existing CVA Forum for this purpose; however, since none was scheduled during the consultation period, a separate one-off 'education seminar' was arranged for 5 July 2006 to jointly present the contents of the P198 and P200 consultation documents to interested participants. The seminar also included a high-level explanation of P203 and P204, which were raised shortly before the event.[4]

4.2 Areas Considered as Relevant Background to Assessment

4.2.1 Previous Modification Proposals P75, P82, P105 and P109

The Group noted that the BSC Modification Procedures required P198 to be assessed on its own merits against the Applicable BSC Objectives, compared with the current version of the Code. In addition, the Group noted that a substantial period of time had passed since the assessment of Modification Proposals P75, P82, P105 and P109 – and that there had been significant changes in the market (including the introduction of BETTA), which required the arguments regarding zonal transmission losses to be considered afresh. The Group therefore agreed that the arguments previously expressed in relation to these proposals should not fetter its assessment of P198.

However, the Group agreed that these factors did not prevent it from being mindful of the previous proposals, or from considering whether aspects of their assessment remained applicable to P198. In particular, the Group noted the relevance of the previous work to its development of the Proposed Modification (given the Proposer's intention to base this on Proposed Modification P82), and to its consideration of any possible options for an Alternative Modification.

References to P75, P82, P105 and P109 have therefore been made throughout this Section 4 where the Group considered that aspects of those proposals were relevant to its discussions regarding P198.

[4] Copies of the seminar presentation slides can be found on the BSC Website at: http://www.elexon.co.uk/AboutElexon/Events/EventDetail.aspx?eid=297.

4.2.2 Previous DTI Conclusions on Transmission Losses

In accordance with its Terms of Reference, the Group confirmed that the Department of Trade and Industry (DTI) had not placed any moratorium on the raising of a new zonal transmission losses Modification Proposal following the DTI's statement in June 2003 that it was 'not minded to' include P82 in the GB Code at BETTA Go-Live.[5]

The Group agreed that there was therefore no procedural barrier to considering P198.

4.2.3 Developments in the European Union

In accordance with its Terms of Reference, the Group undertook a high-level investigation as to whether there was any EU policy in favour of a particular charging method for transmission losses. The Group found no evidence of any policy document in favour of either a uniform or locational allocation of losses, and noted that EU countries have adopted various methods of charging for transmission losses (some through the market, some through 'use of system' charging).[6] Although the Group established that a locational charging scheme had been suggested for cross-border trades within the EU, it noted that this was still at an early stage of consideration.[7] The Group also agreed that such a scheme was not directly relevant to P198, since losses across Interconnectors did not constitute 'transmission' losses under the Code.

The Group therefore did not identify any evidence that a GB locational transmission losses scheme would be inconsistent with wider EU policy. The Group agreed not to examine this area further, since potential EU developments fell outside the scope of its assessment of P198 against the Applicable BSC Objectives. However, the Group noted that any wider policy considerations could be taken into account by the Authority when making its decision on P198, as part of the Authority's wider statutory duties.

One member considered that it was important not to put in place any potential barriers to cross-border trade, as this could infringe EU guidelines. Having noted the results of the TLF modelling and cost-benefit analysis exercises (see Sections 4.4 and 4.7), this member was satisfied that P198 was unlikely to increase the costs of cross-border trade.

4.2.4 Transmission Network Use of System Charging

The Group noted the view of the Transmission Company that P198 would have no direct impact on its Transmission Network Use of System (TNUoS) charging scheme (see Appendix 3). The Group noted that there could be an indirect interaction between TNUoS and a zonal transmission losses scheme, to the extent that both sets of charges aim to provide 'locational' economic signals to Transmission System connectees. The Group therefore agreed that TNUoS was a relevant consideration for the P198 cost-benefit analysis, since this sought to examine the long-term impact of P198 relative to other factors in the market (see Section 4.7). However, the Group noted that any detailed consideration of the impact of P198 on TNUoS fell outside the scope of its assessment.

The Group therefore agreed that any potential interaction with TNUoS outside the Code should not form part of its recommendations against the Applicable BSC Objectives, but could be considered by the Authority under its wider remit.

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[5] The DTI's statement was made following the Authority's approval of P82, but prior to the conclusion of the judicial review. The final page of the DTI's document 'Transmission Losses in a GB Electricity Market: A DTI Consultation Paper' (published 27 June 2003) states that its conclusion that it is not minded to include P82 in the GB Code "does not preclude proposals for changes to the charging for Transmission Losses to be put forward in the future by the industry… It is obviously possible, through the modifications process, for the industry to reconsider this issue in the context of the GB market and in light of experience, if appropriate". The full document can be found on the DTI website at the following link: http://www.dti.gov.uk/energy/domestic_markets/electricity_trading/lossresponse.pdf.

[6] See, for example, the European Transmission System Operator Tariffs Task Force study 'Comparison on transmission pricing in Europe: Synthesis 2004' (April 2005) at http://www.etso-net.org/upload/documents/08-04-05%20Synthesis%202004%20FINAL%20%20.pdf.

[7] See 'Guidelines on Transmission Tarification: Explanatory Note' (European Regulators' Group for Electricity and Gas, 18 July 2005): http://europa.eu.int/comm/energy/electricity/florence/doc/florence_12/ergeg_tariff_guidelines.pdf

4.3 Detail of Proposed Modification Solution and Legal Text

4.3.1 Scope of Solution

The Group noted the intention of the Proposer to base Proposed Modification P198 on Proposed Modification P82. The Group therefore agreed that the previous P82 development work and legal text should be reused for the Proposed Modification, unless a specific reason was identified for diverging from the P82 requirements. The Group agreed that this approach would promote efficiency, since it would reduce the amount of implementation effort required. Except where indicated within this Section 4.3, the solution requirements and legal text for Proposed Modification P198 are therefore identical to those for Proposed Modification P82. A copy of the draft legal text for Proposed Modification P198 is provided in Appendix 1. The Group has reviewed the draft legal text and confirmed that the text delivers its agreed solution.

Further information regarding the detailed solution requirements for the two proposals can be found in the Requirements Specification for Proposed Modification P198 and the Business Requirements Specification (BRS) for P82 (Reference 15). A copy of the P82 legal text can also be found in Appendix A of the P82 BRS (note that this version of the text also includes the P125 changes relating to the Scottish Interconnector).

4.3.2 Nature of TLFA Role

The Group noted the intention of the Modification Proposal that the calculation of zonal TLFs should be carried out by a 'TLF agent or service provider'. The Group noted that the P82 legal text had established the TLFA as a new BSC Agent, and therefore required its compliance with the full BSC Agent obligations set out in Section E of the Code. In accordance with its Terms of Reference, the Group considered the most appropriate nature and scope of the TLFA role under P198.

The Group noted BSCCo's advice that establishing the TLFA as a full BSC Agent under P198 would offer greatest transparency and reassurance to Parties, since Section E prescribes the contents, management and procurement of BSC Agent Contracts. For example:

- The Panel must approve the Tender Framework Statement and Service Description used to procure a new BSC Agent;
- BSC Agent Service Descriptions are Code Subsidiary Documents, and are therefore governed by the change process set out in Section F of the Code and Balancing and Settlement Code Procedure (BSCP) 40 'Change Management';
- The Panel must approve any new BSC Agent Contract, and must be consulted on the underlying BSC Agent Contract Principles;
- BSC Parties are prevented from acting as BSC Agents; and
- The determinations and calculations made by BSC Agents for the purposes of Settlement form part of the BSC Audit as required by Section H5.5 of the Code.

The Group noted that the provisions of Section T1.5 of the Code regarding the Market Index Data Provider (MIDP) represented an example of data being submitted into Settlement by a non-BSC Agent. However, the Group noted that a specific set of factors had determined the scope of the MIDP role – including the recognition that the entities able to provide Market Index Data were likely to be Parties, and therefore would be prevented by Section E from acting as BSC Agents.

The Group queried whether the organisation which had been awarded the P82 TLFA contract in 2003 would be used as the P198 TLFA. BSCCo advised that, since the original TLFA contract had been terminated in 2004 following the P82 judicial review, a procurement exercise would be required for P198. BSCCo clarified that Section E of the Code requires a full competitive procurement process to be followed for new BSC Agents, and that (depending on the outcome of this process) it was therefore possible that a different organisation might fulfil the role of TLFA under P198. The Group queried whether a full procurement exercise would be required were the TLFA to be a non-BSC Agent. BSCCo advised that this would still be the case, since the estimated value of the TLFA contract was above the threshold at which EU guidelines advise that a full procurement should be undertaken. The Group noted that establishing the TLFA as a non-BSC Agent was therefore unlikely to deliver any savings in procurement effort, and agreed to establish the P198 TLFA as a BSC Agent as the most robust solution. The Group noted that this approach would exclude BSCCo from performing the role of the TLFA, since the Code precludes BSCCo from acting as a BSC Agent.

4.3.3 TLFA Communications

The Group noted that although the P82 legal text had referred to communications directly between the TLFA and other BSC Agents/the Transmission Company, in practice BSCCo was to act as an interface between the TLFA and these participants in order to minimise the changes required to BSC Systems. The Group therefore agreed that the same approach should also be adopted under P198 for efficiency. This refinement was incorporated in the P198 legal text.

4.3.4 Access Arrangements for Load Flow Model

a) Escrow Agent

The Group noted that the P82 legal text had required the TLFA to establish a copy of the Load Flow Model in escrow, and to be responsible for the payment of all fees due to the relevant **escrow agent**. BSCCo advised that escrow arrangements were a standard requirement for BSC Agents, to ensure the integrity of the BSC Systems in emergency situations.

The Group noted that the P82 text had required the Panel to set specific terms of reference for the TLFA escrow agent. The Group noted that this requirement was inconsistent with the arrangements for other BSC Agents, which are subject to a standard escrow agreement developed by BSCCo. The Group agreed that retaining a requirement for the Panel to set the Terms of Reference would increase the administrative effort required to support P198 with no visible additional benefit to industry. The Group therefore agreed that the Code should refer to the escrow agent's Terms of Reference being set by BSCCo. This refinement was incorporated in the P198 legal text.

b) Load Flow Model Reviewer

The Group noted that, under P82, the Panel had been required to appoint an independent Load Flow Model Reviewer for the following purposes:

- To inspect and test the Load Flow Model and report to the Panel as to the compliance of the Load Flow Model with the Load Flow Model Specification:
  - Before the Load Flow Model was first used (i.e. prior to the Implementation Date);
  - Upon any subsequent modification to the Load Flow Model;
  - On any other occasion on which the Panel decided to obtain such a report, and
- To verify and report to the Trading Disputes Committee (TDC) as to whether Nodal TLFs were determined in accordance with the Load Flow Model, on any occasion when it was necessary to do so for the purpose of a Trading Dispute.

The Group noted the Proposer's intention to base the solution for Proposed Modification P198 on P82, and agreed that the above requirements should therefore be retained under P198. Some members of the Group queried whether there had been a requirement for the Load Flow Model Reviewer to test the compliance of the Load Flow Model prior to its use in every BSC Year of the scheme. BSCCo clarified that this would not have been required under the P82 legal text – unless a modification had been made to the Load Flow Model during the previous year, or the Panel had specifically requested such a report. This was discussed further by the Group as part of its consideration of the approval process for TLF values (see Section 4.3.5 below).

One member queried what would happen if the Load Flow Model was found to be non-compliant prior to the first use of TLF values on the Implementation Date. The Group noted that this was an extremely unlikely situation, but that if it arose an extension to the Implementation Date could be sought by the Panel under the existing provisions of Section F2.11 of the Code. The same member queried the circumstances in which a Trading Dispute might be raised against TLF values. This was discussed further by the Group as part of its consideration of the criteria for retrospective recalculation of TLFs (see Section 4.3.12).

c) BSC Auditor

The Group noted that, since Section H5.1.3 of the Code states that the BSC Audit shall include 'the determinations and calculations made by BSC Agents for the purposes of Settlement', the scope of the BSC Audit would therefore need to be extended under P198 to include the new TLFA systems and processes. Some members queried whether there was a degree of overlap between the role of the BSC Auditor and that of the Load Flow Model Reviewer. BSCCo clarified that there would be key differences between the two roles as follows:

- The BSC Auditor would only report on the compliance of TLFA systems and processes retrospectively following the end of each Audit Period (i.e. at the end of each BSC Year once the TLFs had been calculated and used in Settlement). In contrast, the Load Flow Model Reviewer would report on the compliance of the Load Flow Model prospectively prior to its first use and following any subsequent modification to the model. In addition, the Load Flow Model Reviewer could review the compliance of the model during a BSC Year as a results of an ad-hoc request from the Panel or as part of a Trading Dispute.
- The BSC Auditor would only report only on how compliance could be strengthened prospectively (i.e. in the next BSC Year). In contrast, on the basis of the Load Flow Model Reviewer's report, the Panel could ensure retrospective compliance by determining that TLFs should be recalculated part-way through a BSC Year as the result of a Trading Dispute.

The Group also noted that power-flow modelling was an extremely technical and specialised field, and that a Load Flow Model Reviewer with independent expertise in this area was required to 'audit' the calculations within the Load Flow Model. The Group noted that the BSC Auditor would focus on the wider TLFA systems and processes surrounding the Load Flow Model, including the conversion of Nodal TLFs to the final BM Unit-Specific TLFs.

d) Other Parties

The Group noted that the P82 legal text had explicitly stated that the TLFA would not be required to make available or disclose the Load Flow Model to any party other than the Load Flow Model Reviewer or BSC Auditor. Some members queried this exclusion and argued that Parties should have the right to access the model. BSCCo noted that the Load Flow Model would be a piece of proprietary software whose IPR would be owned by the organisation appointed as the TLFA, and which would be operated from that organisation's offices once a year. It therefore queried whether it would be appropriate or possible to grant a right to Parties to access the model itself, although it suggested that the model specification and its full input and output data could be made available to Parties. Some members suggested that the TLFA should be required to grant a licence to BSCCo to operate a version of the model from BSCCo's offices, on behalf of any Party which might wish to input its own data into the model to analyse future scenarios. However, other members were concerned at the expense this could incur to BSCCo – both in terms of the TLFA contractual negotiations/payments and in providing such an on-site service to Parties. Uncertainty was also expressed as to whether BSCCo would have the technical knowledge of power-flow modelling to be able to tailor the operation of the model to meet individual Parties' modelling requirements.

Some members suggested that the TLFA's Load Flow Model should be required to be web-based, such that it could be accessed by all Parties – or to be run using Excel in a similar way to the Transmission Company's TNUoS load-flow model. However, the Group noted that this would require the development of a substantially different model to that previously developed for P82 – and that investigations would need to be undertaken to establish whether there were potential service providers able to meet such a specification. Again, concerns were expressed by members regarding the possible costs of this requirement, as well as the potential implications of its development on the Assessment Procedure timetable. The Group noted that Parties do not have a right under the Code to access other BSC Systems, although the outputs of those systems are made available to Parties through data flows. Some members argued that there was nothing to prevent Parties from purchasing their own load-flow modelling software to 'validate' their TLF values using the TLFA's input and output data, or to run their own scenarios. These members considered that this would be similar to the way in which many Parties use their own software to monitor other Settlement calculations, but do not have a right to access the BSC's Settlement system.

A majority of members therefore agreed that Parties should not be given a right under the Code to access the Load Flow Model. However, some members suggested that the Code should give BSCCo right of access to the model in order to provide 'maximum assurance' to Parties. BSCCo advised that the P82 legal text had not provided for such a right, and queried the circumstances in which it would be expected to utilise it – since the escrow arrangements for the Load Flow Model would ensure the model's integrity, whilst the Load Flow Model Reviewer would ensure its technical robustness. The Group agreed by majority not to progress this potential requirement further. However, it agreed that as much of the Load Flow Model input and output data as possible should be made available to Parties on request. This was discussed further by the Group as part of its consideration of the data publication requirements for P198 (see Section 4.3.9 below).

4.3.5 Process for TLF 'Endorsement'

The Group noted that the Modification Proposal referred to the Panel 'endorsing' TLF values prior to their use in each BSC Year. The Proposer clarified that this had been included in the proposal simply to mirror the wording of the P82 Modification Proposal. BSCCo advised that such a requirement had not been included in the P82 legal text, suggesting that the TLFMG had decided not to progress it as part of the final solution requirements. It advised that, if the Panel was to be asked to 'approve' or 'endorse' TLF values, there would need to be tightly-defined criteria on which the Panel would base its decision.

Some members argued that the Panel should base its endorsement on an annual report by the Load Flow Model Reviewer, arguing that the Panel would have no way of knowing whether TLFs had been correctly calculated without such a report. However, a majority of members believed that the provision of an annual report by the Load Flow Model Reviewer was not required – since the model would have been checked prior to its first use and on any subsequent change to the model. These members noted that a requirement for an annual report was likely to lead to increased operational costs, since this had not been a requirement under P82.

Other members suggested that a process should be developed for Parties to 'appeal' their TLF values to the Panel, possibly including the requirement for an annual industry consultation on the values calculated by the TLFA. However, a majority of members disagreed with this suggestion, arguing that an appeals process had not been part of the P82 solution or the Proposer's intention for P198. These members queried what the grounds for an appeal could be if the TLFs had been correctly calculated by the Load Flow Model in accordance with the legal text – noting that any incorrect calculation of TLFs would constitute a Settlement error, and could be progressed under the existing Trading Disputes process. These members argued that, if Parties disagreed with the principle of the TLF calculation, this should be raised in their responses to the Assessment Procedure consultation as an argument against P198 – rather than form a rationale for including an appeals process within the modification.

Some members argued that, since the TLFs applied in any given year would have been calculated using Metered Volumes from the previous year, Parties should be able to appeal their values on the grounds that their behaviour in this 'Reference Year' had been 'atypical' and would not be a good representation for the year ahead. However, a majority of members argued that allocating losses through Trading Charges a year in arrears was simply a consequence of the ex-ante nature of the scheme proposed by the Modification Proposal. Some members noted that appealing one BM Unit's TLF value would effectively mean appealing the TLF value for all BM Units in that Zone. Other members noted that including a window for an industry consultation and/or appeals on TLF values would mean that TLFs would have to be calculated further in advance of the start of the BSC Year, and was therefore likely to make the data used in the calculation more historic as well as increasing the implementation timescales for P198.

One member of the Group stated that Parties should be able to appeal the allocation of their BM Units to a particular Zone – for example, where they were close to the border between two Zones. BSCCo clarified that the P82 legal text had included the ability for Parties to appeal their zonal allocation to the Panel prior to the start of the applicable BSC Year, but that this was different to appealing the actual TLF values for the Zones. The Group noted this ability in the P82 text, which was considered further as part of its discussions regarding the Network Mapping Statement (see Section 4.3.11 below).

Some members suggested that the Panel's endorsement should be limited to the process followed to calculate the TLF values, rather than the values themselves. These members suggested that BSCCo could provide an annual high-level report to the Panel, outlining the variation of TLFs for the applicable BSC Year from those used in the previous BSC Year. Under this approach, if the Panel was concerned that any variation was unsatisfactorily explained, it could request that the Load Flow Model Reviewer undertook an 'ad-hoc' review of the calculation of Nodal TLFs. However, other members argued that this was still simply a case of establishing whether the TLFs had been correctly calculated or not, and that this was already adequately covered by the P82 Load Flow Model Reviewer provisions and the existing Disputes process. These members also noted that the P82 text already contained the ability for the Panel to request an 'ad-hoc' report from the Load Flow Model Reviewer if it believed that this was required. One member suggested that the Panel should only be required to 'endorse' the TLFs prior to their first use on the Implementation Date, and not thereafter. However, it was noted that this was already covered by the requirement for the Load Flow Model Reviewer to report on the compliance of the model prior to the Implementation Date.

A majority of members therefore agreed that the legal text should not place an obligation on the Panel to annually 'endorse' TLF values. The Proposer was in agreement with this approach.

4.3.6 Party Notice Period for Publication of TLFs

The Group noted that the Modification Proposal required TLF values to be published on the BSC Website 'at least one month' prior to their use in Settlement for the applicable BSC Year. The Proposer clarified that the intention of this requirement was to ensure that Parties had adequate time to take account of the values within their contracts for that year. The Group noted that the P82 legal text had not specified a date for the publication of TLFs, but had required the TLFA to send the TLFs to BSCCo in early December in the preceding BSC Year. In practice, TLF values would therefore have been published in mid to late December (providing 3–3.5 months' notice prior to the start of the BSC Year on 1 April).

The Group agreed that the P198 legal text should specify the date of publication, and agreed to seek views from Parties regarding the most appropriate date as part of the Proposed Modification impact assessment. The majority of impact assessment respondents indicated that three months would be acceptable as a minimum notice period – although some of these respondents stated that they would prefer six months. One respondent believed that a minimum of six months' notice should be given, whilst another respondent indicated that they would only require a minimal lead time (see Section 4.5 for further details).

A minority of members argued in favour of providing six months' notice of TLF values to Parties. BSCCo noted that this would push back the timescales for undertaking the TLF calculation, such that the end date of the Reference Year would have to be three months earlier than under P82 – meaning that the data used in the calculation would be more historic. It was also noted that providing a six-month notice period in the first year of the scheme, rather than three, would effectively require an additional three months to be added to the implementation lead time.

A majority of members believed that three months' notice would provide adequate time for Parties to take account of TLFs in their annual contract rounds for the forthcoming BSC Year, and noted that this would be consistent with P82. By majority, the Group therefore agreed that the P198 legal text should specify that TLF values should be published no less than three months prior to the start of the applicable BSC Year.

4.3.7 Duration of Reference Year

The Group noted the intention of the Modification Proposal that TLF values be calculated on an annual 'ex-ante' basis using data from a previous 'reference' year. The Group note that it was not possible for the Reference Year to be the previous BSC Year to that in which TLFs would apply, since there would need to be a period of time between the end of the Reference Year and the beginning of the applicable BSC Year for the TLFA to calculate the TLF values.

The Group agreed that the exact start and end dates of the Reference Year were relatively unimportant – providing that the same date range was used in each year of the TLF calculation, and that the Reference Year covered a consecutive 12-month period ending in the BSC Year prior to that in which the TLFs would apply. The Group noted that the P82 Reference Year ran from 1 October – 31 September, due to the timescales required to derive and publish TLFs before the start of the BSC Year on 1 April. The Group noted that the date range of the Reference Year was therefore dependent on the date by which TLFs needed to be made available to Parties. Since the Group had agreed a three-month publication lead time, it initially agreed that the same Reference Year could be used for P198 as under P82.

However, BSCCo advised that ending the Reference Year in September had only allowed a month for the CDCA and the Transmission Company to assemble the required input data, and a month for the TLFA to calculate TLFs using that data. BSCCo advised that these timescales had proven to be very tight during the P82 implementation, and therefore suggested that the start and end dates of the Reference Year be moved forward by one month under P198 – such that the Reference Year ended on 31 August. A member queried whether this would affect Parties' notice of the TLF values. BSCCo clarified that TLF values would still be published three months in advance of their use in Settlement, and that the suggestion to move the Reference Year forward by one month was simply to allow more time for the values to be calculated. The Group noted that this would effectively mean that the data used in the annual TLF calculation was a month more historic, but believed any disadvantages of this to be outweighed by the benefit of allowing more time for the TLFA to verify the inputs and outputs of the TLF calculation. In the calculation of TLFs for the BSC Year beginning 1 April 2008, the TLFA would therefore use a Reference Year of 1 September 2006 – 31 August 2007. This refinement was incorporated in the P198 legal text.

4.3.8 Input Data Requirements for Load Flow Model

The Group noted that the following input data had been required for the Load Flow Model under P82:

- A list of all Nodes on the Transmission System – to be provided and kept up-to-date by the Transmission Company;
- The TLF Zones – to be set by the Panel prior to the Implementation Date and periodically reviewed thereafter;
- Network Data relating to the Transmission System in the Reference Year – to be provided annually by the Transmission Company;
- A set of mutually-exclusive **Load Periods**, representing typically different levels of load on the Transmission System during the Reference Year – to be set annually by the Panel;
- A set of representative Sample Settlement Periods within each Load Period – to be set annually by the Panel (for P82, 623 Sample Settlement Periods were used);
- Metered Volumes for each Volume Allocation Unit in every Sample Settlement Period of the Reference Year – to be provided annually by the CDCA (using data from the latest Settlement Run available at the end of the Reference Year); and
- A Network Mapping Statement, which mapped Volume Allocation Units to Nodes and Nodes to TLF Zones – to be provided annually by BSCCo, and kept up-to-date throughout the year to reflect changes in BM Unit registrations.

The Group agreed that the same input data would be required for the Load Flow Model under P198. Further detail in respect of the Group's discussions regarding the definition of the TLF Zones and the Network Mapping Statement can be found in Section 4.3.11.

4.3.9 TLF Data Publication Requirements

a) Data Published on BSC Website

The Group noted that BSCCo was already required to publish the TLF value for every BM Unit in accordance with Section V4.2.3 of the Code, although such values are all currently set to zero.[8] The Group noted that there was therefore no need to include any additional obligation within the P198 legal text for BSCCo to publish BM Unit-Specific TLFs.

The Group noted that the P82 legal text had not contained an explicit requirement for BSCCo to publish the Adjusted Annual Zonal TLF value for each TLF Zone, although in practice these had been published on the BSC Website as part of the P82 implementation. The Group agreed that the P198 legal text should include a specific requirement regarding the publication of these values, for maximum transparency. The Group agreed that this would aid Parties in validating their BM Unit-Specific TLFs, and would help potential new entrants ascertain the TLF value that could apply to them in different locations. This refinement was incorporated in the P198 legal text.

A member of the Group queried whether the Load Periods and Sample Settlement Periods used in the Load Flow Model would have been published under P82. BSCCo clarified that there had been no explicit requirement to publish this information, but that in practice it would have formed part of a publicly-available Panel paper. The Group agreed that, for maximum transparency, the list of Load Periods and Sample Settlement Periods should be published in a dedicated 'TLF' area of the BSC Website along with the actual TLF values. This refinement was incorporated in the P198 legal text. The Group agreed that the inclusion of this requirement would aid Parties in validating their TLF values, and noted that it would require minimal cost since the data would already be held by BSCCo.

b) Data Made Available on Request

Some members queried whether the full input and output data from the Load Flow Model had been made available under P82. BSCCo clarified that the P82 legal text had included a requirement for the TLFA to provide the full Nodal TLFs to any Party on request, but had not provided for any other 'raw' data to be made available. The Group queried whether there was any reason why the full input and output data could not be provided – noting that publication of this data would aid Parties in validating their TLF values, and in analysing potential future scenarios. BSCCo clarified that none of the data concerned was confidential. The Group therefore agreed that, in addition to Nodal TLFs, the following input and output data should be made available to any Party on request:

- The Network Data provided by the Transmission Company and used in the TLFA's annual calculation of TLFs;
- The Metered Volumes provided by the CDCA and used in the TLFA's annual calculation of TLFs; and
- The nodal power flows, and underlying circuit and transformer power flows generated by the Load Flow Model and used in the TLFA's annual calculation of TLFs.

These refinements were incorporated in the P198 legal text. The Group noted that the inclusion of these requirements would incur minimal cost, since the data would be readily available from BSCCo and the TLFA.

BSCCo advised that the precise format in which power flow data could be made available would depend on the specific Load Flow Model software which was developed by the organisation awarded the TLFA contract. The Group noted that the format of the data would therefore not be prescribed in the legal text, but would be detailed in a Code Subsidiary Document such as the TLFA Service Description.

[8] See http://www.elexon.co.uk/documents/Market_Data/Market_Data_-_Static_Data_-_CRS_Registration_Data/bm_units.csv

4.3.10 Impact of P198 on ETLMOs

The Group noted that, in accordance with Sections V2.5.2 and V2.6.3 of the Code, Estimated Transmission Losses Adjustments (ETLMOs) are used in derived data calculations on the BMRS – since the actual metered data that determines the value of $TLMO^{+/-}$ is not available until after the BMRS data must be published. BSCCo advised that the Code requires the Panel to determine and periodically review these ETLMO values, and that in practice this determination is delegated to the Imbalance Settlement Group (ISG).

The Group noted that ETLMO values for each BSC Year are currently based on actual TLMOs from the previous year. However, it noted that, if P198 was approved, this approach would no longer be appropriate – since TLF values (one component of TLMOs) would no longer be zero. BSCCo advised that, as part of the P82 implementation, the ISG had therefore agreed a revised methodology for calculating ETLMOs.[9] The Group noted that this methodology could be reused for P198, and would be subsumed within the ISG's existing review process under Section V2.6.3 of the Code. ETLMO values would continue to be published on the BSC Website as currently.[10] The Group therefore agreed that there was no need to include any provisions regarding ETLMOs within the P198 legal text.

One member queried whether the aggregated 'delivery' and 'offtake' Metered Volumes used in the ETLMO and TLMO calculations could be made available to Parties. BSCCo clarified that this information can already be derived via existing Settlement flows.

4.3.11 Network Mapping Statement and Determination of TLF Zones

a) Contents

The Group noted that the P82 legal text had required BSCCo to prepare a Network Mapping Statement containing:

1) For each Volume Allocation Unit (other than a GSP Group or BM Unit embedded in a Distribution System), the Node which represents or best represents that Volume Allocation Unit or (as the case may be) the Boundary Point(s) at which that Volume Allocation Unit is connected to the Transmission System (since one Node may represent several such points);
2) For each Node, the Zone in which the Node lies or should best be considered to lie; and
3) For each BM Unit, the Zone in which the BM Unit lies – established on the basis of 1) and 2) above, except that:
    i) Interconnector BM Units lie in the Zone in which the Node for the relevant Interconnector lies; and
    ii) Supplier BM Units and other BM Units embedded in a Distribution System lie in the Zone which represents the geographical area of the corresponding GSP Group.

BSCCo advised that, during implementation of P82, the legal text had created some ambiguity as to whether a zonal mapping was required for all Nodes. BSCCo clarified that only Nodes corresponding to Volume Allocation Units needed to be mapped to Zones for the purposes of the Load Flow Model, and that it was not actually possible to map GSP Groups to individual Nodes. The Group therefore agreed that this provision should be clarified for P198, such that the Network Mapping Statement only mapped those Nodes representing Volume Allocation Units to Zones. This refinement was incorporated in the P198 legal text.

[9] See ISG paper 35/391 at the following link: http://www.elexon.co.uk/bscpanelandcommittees/panelcommittees/isg/meetings.aspx?year=2003&meeting_type_id=3.
[10] See http://www.elexon.co.uk/marketdata/staticdata/Parameters/default.aspx.

The Group noted that the P82 legal text had required the Panel to determine the constitution of the Zones used in the TLF calculation, based on the following criteria:

- Each Zone would represent the geographic area in which a GSP Group lies, determined by the Panel (applying such criteria as it shall decide in its discretion) such that the Zones were mutually exclusive and comprised the whole of (and nothing but) the authorised area under the Transmission Licence;
- The Panel could from time to time review (and upon reasonable notice to Parties change) its determination of any Zones, where there was any change in GSP Groups, or upon the application of a Party, or upon its own initiative;
- Any change in the determination of any Zone(s) would only be effective in relation to BSC Years for which (at the time the change was made) TLFs had not already been determined; and
- The Panel could (but would not be required to) consult any Party on the determination of any part of the boundary of a Zone where it considered that there was material doubt as to such determination.

The Group noted that the reference to 'the authorised area under the Transmission Licence' was no longer appropriate under BETTA, since the Transmission Company's authorised transmission area related only to England and Wales. The Group agreed to seek the views of the Transmission Company as to the most appropriate reference to additionally incorporate the transmission areas of the two Scottish Transmission Owners, such that it reflected the area covered by the whole of the GB Transmission System. As part of its analysis and impact assessment of P198, the Transmission Company advised that the most appropriate reference would be to 'the area specified in Schedule 1 of the Transmission Licence' (see Appendix 3). The Group noted that Schedule 1 of the Transmission Licence currently specifies this area as being 'Great Britain', but that there was the potential for this definition to change in the future to incorporate any further transmission areas for offshore generation. The Group noted that referring to the Transmission Licence in the legal text rather than directly to 'Great Britain' would therefore avoid the need for any future 'housekeeping' changes to the Code to take account of offshore generation. This minor refinement was incorporated in the P198 legal text.

The Group noted that the issue identified by P125 – which introduced a specific Zone for the Scottish Interconnector, to take account of the fact that its physical location was split over two GSP Group areas – no longer arose under BETTA. The Group agreed that there were no issues with allocating the French and Moyle Interconnectors to specific TLF Zones.

b) Maintenance

The Group noted that the P82 legal text had required BSCCo to issue the Network Mapping Statement for an industry consultation prior to its use by the TLFA in the annual TLF calculation. The Group noted that the legal text had provided for Parties to question or dispute the allocation of their BM Units to TLF Zones, and for any such 'appeal' to be heard and determined by the Panel in consultation with the Lead Party(ies) of the affected BM Unit(s) and the Transmission Company. The Group agreed that these provisions remained appropriate for P198.

The Group noted that ad-hoc updates to the Network Mapping Statement would be required throughout a BSC Year, in order that new BM Units which registered during a year could be mapped to a Zone and assigned a TLF value for the remainder of that year. BSCCo clarified that, under the P82 legal text, the TLF applied to the new BM Unit would be the Adjusted Annual Zonal TLF already derived by the TLFA for the Zone to which the BM Unit was mapped. TLFs would therefore not be retrospectively recalculated for existing BM Units as a result of a change in one BM Unit's registration.

The Group noted that, due to this need to keep the Network Mapping Statement up to date at all times, the P82 legal text had included a specific change process for the statement rather than establishing it as a Code Subsidiary Document which could only be amended via a Modification Proposal or Change Proposal. However, BSCCo advised that this change process had proven to be complex and inefficient to administer during implementation, since the P82 legal text implied that a full industry consultation needed to be undertaken every time the Network Mapping Statement was updated. Since changes to BM Unit registrations occurred at least once per month, in practice BSCCo would have been required to undertake a consultation and present the results to the ISG during every month of every year of the scheme. BSCCo questioned whether this level of consultation was required for 'ad-hoc' updates, since the Zone assigned to a new BM Unit part-way through a year would not affect other BM Units until the annual calculation of TLFs for the following BSC Year. BSCCo therefore suggested a revised process for P198, whereby:

- There would be an annual industry consultation on the Network Mapping Statement prior to the determination of TLFs for a BSC Year, when all Parties would have the opportunity to question or dispute the mapping of any BM Unit to a Zone; and
- Any subsequent updates to the Network Mapping Statement throughout that BSC Year would be published on the BSC Website rather than issued for industry consultation, and the Lead Party of any new BM Unit registering part-way through the year would have the opportunity to question or dispute the mapping of its BM Unit to a Zone.

The Group agreed that this represented a more efficient approach. This refinement was therefore incorporated in the P198 legal text.

4.3.12 Criteria for Retrospective Recalculation of TLFs

The Group requested clarification of the circumstances in which TLF values could have been retrospectively recalculated under the P82 legal text. BSCCo clarified that the following rules would have applied:

- A Party would not be able to raise a Trading Query or Trading Dispute against the compliance of the Load Flow Model design with the Load Flow Model Specification, once the Load Flow Model Reviewer had confirmed such compliance to the Panel.
- A Party would only be able to raise a Trading Query or Trading Dispute against the operation of the Load Flow Model, where:
  - It believed that the input data used in the Load Flow Model (Network Data and Metered Volumes) contained one or more 'manifest errors';
  - It believed that the input data had not been correctly applied by the TLFA in accordance with the Network Mapping Statement;
  - It believed that Nodal TLFs had been incorrectly calculated by the Load Flow Model;
  - It believed that Adjusted Annual Zonal TLFs had been incorrectly calculated by the TLFA;
  - It believed that one or more BM Unit-Specific TLFs had been incorrectly determined by the TLFA; and/or
  - It believed that one or more BM Unit-Specific TLFs had been incorrectly registered and applied in Settlement by CRA/SAA.
- Where a Trading Query or Trading Dispute was raised, the Load Flow Model Reviewer would be instructed to report to the TDC as to whether Nodal TLFs had been properly determined in accordance with the Load Flow Model.
- The Load Flow Model Reviewer's report to the TDC regarding Nodal TLFs would be final and binding on all Parties (save in the case of fraud or manifest error).

- Nodal TLFs would be deemed to have been properly determined if the data inputs provided by the Transmission Company (Network Data) and CDCA (Metered Volumes) contained no manifest errors and had been correctly applied within the Load Flow Model by the TLFA in accordance with the Network Mapping Statement.
- A Trading Dispute would only be upheld by the TDC where:
  - The Load Flow Model Reviewer determined that Nodal TLFs had not been determined in accordance with the Load Flow Model;
  - The TDC determined that there had been an error in the TLFA's conversion of Nodal TLF values to BM Unit-Specific TLF values;
  - The TDC determined that the BM Unit-Specific TLF values produced by the TLFA had not been correctly registered by the CRA; and/or
  - The TDC determined that the BM Unit-Specific TLF values registered by the CRA had not been correctly applied in Settlement by the SAA.
- TLF values could only be retrospectively recalculated as the result of an upheld Trading Dispute and following Panel approval.
- Trading Queries and Trading Disputes relating to TLFs would be subject to the usual process set out in Section W of the Code and in BSCP11 'Trading Queries and Trading Disputes', including the cut-off dates for raising Trading Queries.

BSCCo advised that the above process should not be confused with the ability for Parties to appeal the zonal allocation of their BM Units to the Panel, since such appeals would not take the form of Trading Queries (see Section 4.3.11 above).

A member of the Group queried what would be meant by a 'manifest error' in the Network Data and Metered Volumes. BSCCo advised that this was limited to self-evident and obvious errors (for example, Metered Volumes being allocated to the wrong Volume Allocation Unit within the data file sent to the TLFA). BSCCo clarified that it would not cover any changes to BM Unit Metered Volumes which arose after the data had been provided by the CDCA (for example, as a result of later Settlement runs) – since such adjustments would represent a consequence of the normal Settlement process and not a Settlement error. The member disagreed with this approach, and argued that TLF values should be retrospectively recalculated in such circumstances. However, a majority of members argued that this would undermine the purpose of an annual ex-ante scheme, which was intended to fix TLF values for a year such that they could be incorporated in Parties' contracts.

Some members queried whether use of the term 'manifest error' in the legal text was confusing, since it could be confused with the Manifest Error process set out in Section Q of the Code (which relates to errors in Bid-Offer Acceptances). BSCCo advised that it believed the term was legally robust, and that its usage was similar to the ability of the Panel to raise Modification Proposals to correct 'manifest errors' in the Code under Section F2.1.1.

The Group therefore agreed by majority that no refinements to the P82 solution were required in this area under P198.

4.3.13 Value and Governance of Scaling Factor

The Group noted that the Modification Proposal specified the use of a scaling factor within the TLF calculation, to ensure that the level of variable losses allocated through TLFs was comparable to the actual level of variable losses calculated by the Load Flow Model. Following its consideration of the TLF modelling results, the Group agreed that the value of the scaling factor should be set to 0.5 (consistent with that used for P82). Further information regarding the rationale behind this scaling factor can be found in Section 4.4.

The Group noted that the Modification Proposal referred to the value of the scaling factor being 'fixed under the governance of the BSC'. In accordance with its Terms of Reference, the Group considered whether the scaling factor value should be 'hard-wired' into the Code (such that it could only be amended via a Modification Proposal), or should be a parameter which could be periodically reviewed by the Panel. A majority of members agreed that the value should be hard-coded in the legal text. These members argued that, since the scaling factor was an important determinant in the calculation of TLFs, this approach would give maximum transparency and certainty regarding TLF values. One member initially disagreed, and argued that a more accurate approach would be to set a different scaling factor for every half-hour Settlement Period rather than one average value. However, the results of the TLF modelling exercise demonstrated that there would be only a negligible half-hourly variation in scaling factor values, and that there had been no change in the value since the original assessment of P82. The Group therefore agreed that a fixed average value was appropriate. Further detail can be found in Section 4.4.

The Group noted that the P82 legal text had referred to the Annual Zonal TLFs being divided by two, rather than multiplied by 0.5. Although both approaches were technically correct, the Group agreed with BSCCo's suggestion that multiplying by 0.5 might be less confusing since it more clearly showed the value of the scaling factor. This minor refinement was incorporated in the P198 legal text.

One member noted that the scheme proposed by P198 involved a 'scaled marginal' methodology in that it only proposed to allocate variable losses on a zonal basis. This member suggested that a more appropriate approach might be a 'fully marginal' methodology, whereby both fixed and variable losses were allocated zonally through the TLF – potentially similar to the scheme proposed by previous Modification Proposal P75. However, the Proposer argued that this could result in a 'reverse cross-subsidy', since fixed losses would not vary according to power flow. Other members of the Group noted that a 'fully marginal' scheme was outside the scope of P198, since the defect identified by the Modification Proposal related purely to the allocation of variable losses. The potential for a 'fully marginal' approach was therefore not discussed further by the Group.

The same member suggested that the scaling factor should have a different intention to that set out in the Modification Proposal. This member argued that, rather than simply ensuring that the level of variable losses allocated through TLFs was comparable to the variable losses calculated by the Load Flow Model, the scaling factor should scale all TLFs such that no BM Units were credited with energy as a result of the scheme. This was considered by the Group as a potential option for an Alternative Modification, and further detail regarding the Group's discussions in this area can be found in Section 4.6.

4.4 Overview of TLF Modelling Exercise

4.4.1 Modification Group's Initial Discussions

a) Rationale for Undertaking Modelling

The Group noted that the TLFMG had procured an external load-flow modelling consultant during the Assessment Procedure for P75 and P82, to aid it in choosing the methodology and type of Load Flow Model to be used in the calculation of TLFs. The purpose of this modelling exercise had been to ascertain the likely magnitude and variability of the TLF values which would be generated by the proposals in the first year of the scheme. A copy of the P75/P82 modelling analysis can be found in Annex 16 of the P75/P82 Assessment Report.

The Group noted that the P75/P82 modelling had been undertaken in 2002 – based on the then current England and Wales Transmission System, and on historic data from the 2001/2002 BSC Year. Due to the introduction of BETTA in 2005 and the period of time which had elapsed since the original modelling, the Group agreed with the view of BSCCo and the Panel that the exercise be repeated for P198 in order to include Scottish data and obtain more up-to-date results.

b) Scope of Modelling

The purpose of the P198 modelling exercise was to establish the magnitude and variability of the TLF values which would have been generated for the 2006/2007 BSC Year had P198 been in place. The detailed focus on one year enabled the Group to test the sensitivity of TLF values to various different scenarios. This in turn supported it in choosing the detailed solution requirements for the Proposed Modification, considering the appropriateness of the solution proposed by P198, and developing any potential options for an Alternative Modification.

Following consideration of the modelling results, the Group also commissioned a forward-looking cost-benefit analysis of P198 to analyse the projected impacts of the Proposed Modification and any preferred Alternative option on the market over ten years. Further details of this cost-benefit analysis can be found in Section 4.7.

c) Choice of Service Provider

Siemens PTI (PTI) was selected by BSCCo to provide the modelling service. PTI had previously provided the modelling work for P75 and P82, and had performed the role of the TLFA during the P82 development. As the TLFA systems developed for P82 were still available, reusing these systems for the P198 modelling was considered to represent the most efficient solution. Utilising the TLFA systems also provided additional assurance, since the calculation approach and system functionality had been tested and verified during the P82 development process. Finally, using these systems enabled the modelling to be run using the P82 definition of Load Periods – allowing the use of 623 Sample Settlement Periods compared to the 55 used in the original P75/P82 modelling.

d) Input Data

Repeating the TLF modelling on a GB-wide basis required the extension of the Load Flow Model to incorporate Scotland, and the provision of more recent GB input data (Metered Volumes, Nodes and Network Data) by BSCCo and the Transmission Company. As no Scottish BSC data was available before BETTA Go-Live in April 2005, and the modelling was commenced in February 2006, Network Data and Metered Volumes for 1 April 2005 – 31 January 2006 were used in the model. This data was weighted such that February 2006 was represented by January 2006, and March 2006 by April 2005. Following the conclusion of the modelling, BSCCo subsequently compared the weighted data for these months with the actual Settlement data for February and March 2006 as shown in Figure 2 on the following page.

Figure 2 – Comparison of Weighted and Actual Data for February-March 2006

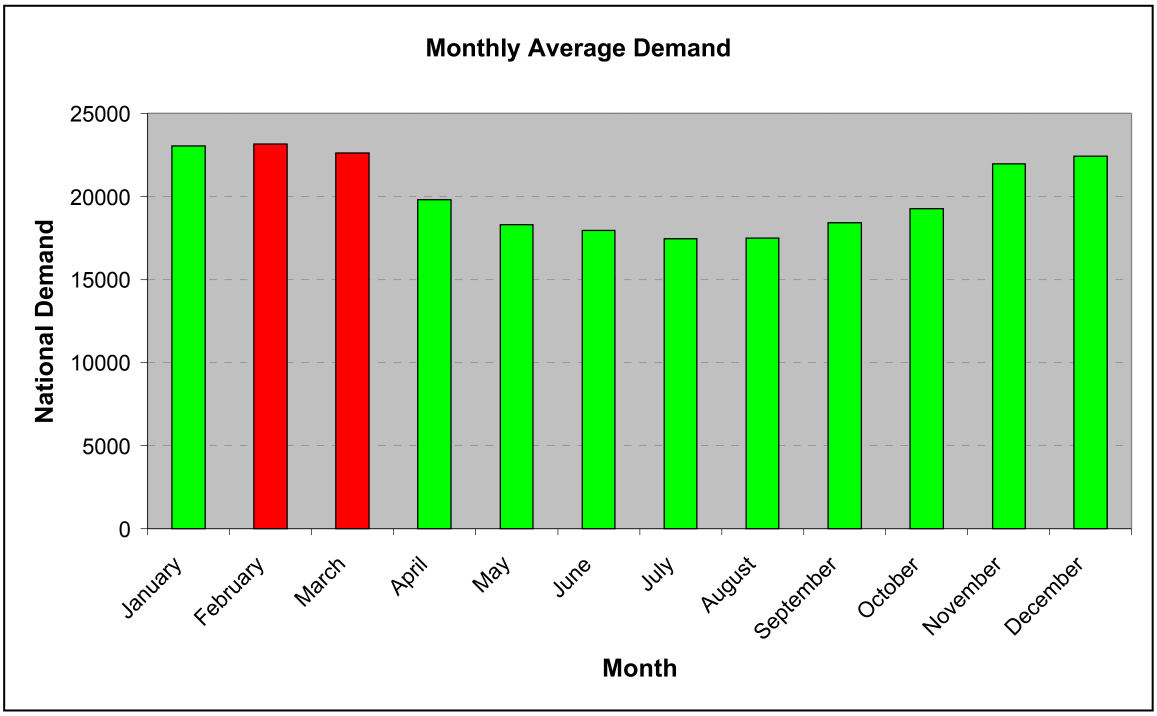


Figure 2 illustrates that February 2006 was probably fairly well represented by the data from January 2006. However, the average demand in March 2006 was closer to the demand for Winter 2006 than that for April 2005. This suggests that the actual influence of March 2006 data on TLFs would be closer to that of the winter months than the April 2005 data used for that month in the modelling. Note that the modelling performed for P198 was only intended to provide an indication of the likely pattern of TLFs, and not to calculate the values which would actually be used in live implementation – since these would be recalculated using a full year of actual data from the most recent Reference Year.

e) Output Data

The output of the modelling exercise was a report by PTI to the Group, setting out the conclusions of the analysis. The full report is attached as Appendix 5. The remainder of this section provides a high-level summary of the analysis.

The raw input and output data of the modelling exercise were also made available to members of the Group on request, to support their own analysis. In addition, PTI attended two meetings of the Group to present the results of the initial analysis and its further investigations.

f) Choice of Load Flow Model

The Group noted that power flows could be analysed using two different types of Load Flow Model:

1) An alternating current (AC) model, which utilises data that reflects AC electrical flows on the network (i.e. it calculates both the active and reactive power flows in each line, and the magnitude and phase angle of the voltage at each Node);[11] or

2) A direct current (DC) model, which applies a set of simplifying assumptions to the AC flows in order to render them similar to a DC flow (i.e. it calculates only active power flows and the voltage phase angle).

[11] Reactive power is a component of alternating current and voltage which does not contribute to the transmission of energy. A phase angle is a measure of the lag of voltage.

The Group noted that the Modification Proposal was silent on whether an AC or DC Load Flow Model should be used to calculate TLFs. It noted that the original P75/P82 modelling undertaken by the TLFMG had used an AC model, but that (on the basis of the modelling results) a DC model had been chosen by the Group as the final Load Flow Model to be used operationally by the TLFA.

The Group considered that an AC model was potentially more accurate, but noted the advice of the Transmission Company that it would not be possible to use actual reactive power flows since these represented confidential information. The Group noted that this would necessitate the use of assumptions based on National Grid's Seven Year Statement, and agreed with the previous conclusion of the TLFMG that these assumptions would diminish the robustness of an AC model. The Group noted that PTI had also suggested that a DC model would be more appropriate, since it would require less assumptions. The Group therefore agreed that a DC model should be used for the P198 modelling and solution – since this approach would be consistent with the 'live' TLFA model for P82, and the linear load-flows of a DC model would be extremely robust.

As a detailed comparison of AC and DC models was carried out as part of the P75/P82 modelling, no additional work in this area was therefore undertaken for P198.

g) Choice of Network

The Group noted that the electricity Transmission System could be represented in three different ways within a load-flow model:

1) As an '**intact network**' – the complete overall capability of the transmission network, assuming that all lines are in operation and that there are no equipment outages (i.e. no transformers or lines out of service);

2) As an '**indicative network**' – an approximation of the transmission network in existence at a specific point in time (i.e. a snapshot of the network during a specific Settlement Period), which is based on the intact network but includes all known equipment outages; or

3) As a '**representative network**' – an approximation of the typical configuration of the transmission network over a longer period (e.g. a year), which is based on the intact network but allows for the average outages over the period (known as 'scaled impedence').

The Group noted that the Modification Proposal stipulated the use of an intact network for the Proposed Modification, and that this was consistent with P82. However, it agreed that the modelling exercise should test the sensitivity of TLFs to this choice of network. Further information can be found in Section i) below.

h) Choice of Slack Bus

A 'slack bus' or 'slack node' is a Node in the Load Flow Model that acts as a sink for any surplus or deficit in power that arises as a result of approximations within the model, and which also acts as a reference Node for voltage and phase angle.

The Group noted that, in an AC model, both the absolute values of TLFs and the differentials between the TLFs for each Zone would be sensitive to the choice of slack node. However, in a DC model, the slack node would only affect the absolute TLF values. Further information regarding the Group's discussions in this area can be found in Section 4.4.2 below.

Since the scope of the modelling was limited to the use of a DC model, the Group agreed that the slack node for P198 should be based on National Grid's standard slack at Cowley. This was consistent with the choice of slack node in the 'live' P82 TLFA model.

i) Choice of Modelling Tasks

Twelve modelling tasks were undertaken, as set out below. For further details regarding the requirements developed by the Group for these tasks, please refer to the P198 Modelling Requirements Specification.

Task 1 – Establish Baseline Adjusted Annual TLFs and TLMs

The purpose of this task was to calculate the TLFs and TLMs which would have applied had the Proposed Modification been in place during the 2006/2007 BSC Year. These then formed the basis for consideration of various sensitivities. The calculations set out in the P82 Load Flow Model Specification were used by PTI to calculate the TLFs. TLMs were then calculated by BSCCo using these TLFs.

Task 2 – Establish Temporal Variability of TLFs and TLMs by Zone

The purpose of this task was to establish the sensitivity of TLFs to time-weighted averaging, by comparing the Adjusted Annual Zonal TLFs to zonal TLFs calculated for a BSC Season, calendar month, Settlement Day and Settlement Period.

Task 3 – Compare Nodal Values to Zonal Values

The purpose of this task was to establish the sensitivity of TLFs to the use of zonal averaging. For this task, Adjusted Annual Nodal TLFs were calculated for each Node in a Zone, and were compared to the Adjusted Annual Zonal TLF for that Zone.

Task 4 – Establish Degree to which 0.5 Scaling Factor Correctly Allocates Heating Losses

Losses are not constant with power. Since the Load Flow Model would only establish the relationship between variable losses and power (the TLF) at the margin (i.e. for a marginal injection of power at each Node), applying TLFs to whole Metered Volumes would therefore over allocate variable losses. A scaling factor is therefore required to ensure that the losses allocated through TLFs would be comparable to the level of variable losses calculated by the Load Flow Model.

The purpose of Task 4 was to establish the appropriate value of the scaling factor, by calculating the correct scaling factor for each Sample Settlement Period and establishing the extent to which these deviated from the 'fixed' 0.5 scaling factor suggested by the Modification Proposal. The correct scaling factor for each Settlement Period was established by applying Nodal TLFs to nodal power flows, and identifying the scaling factor for the Nodal TLFs which would exactly recover the level of variable losses calculated by the Load Flow Model.

The Group noted that the purpose of the scaling factor was not explicitly to distinguish between fixed and variable losses, since the Load Flow Model would only calculate variable (heating) losses. However, it noted that, without scaling, the model would overallocate losses at a zonal level – with the result that some additional 'fixed' losses were allocated through TLFs. The Group noted that the intention of the Modification Proposal was only to allocate variable losses on a zonal basis, and that scaling was therefore required to ensure that the level of losses allocated through TLFs was comparable to the level of variable losses calculated by the model. Fixed loses would therefore continue to be allocated through the TLMO on a uniform basis as currently.

Task 5 – Consider Impact of Using an Intact Network on TLFs

The purpose of this task was to establish the sensitivity of the TLF calculation to the use of an intact network, by comparing the TLFs calculated under this approach with those calculated using representative networks for each of the four BSC Seasons. The seasonal representative network data was provided by the Transmission Company.

Task 6 – Examine Sensitivity of TLFs to Constraints

The purpose of this task was to establish the sensitivity of TLFs to constraints on the Transmission System, by recalculating Adjusted Annual Zonal TLFs using Network Data for a constrained network. The constraint data was provided by the Transmission Company.

Task 7 – Examine Sensitivity of TLFs to Interconnector Flows

The purpose of this task was to examine the sensitivity of TLFs to flows on the French and Moyle Interconnectors, using a number of different indicative operation regimes for these Interconnectors.

Task 8 – Examine Sensitivity of TLFs to Participants Responding to Signals

The purpose of this task was to examine the impact on TLFs of participants responding to the locational signals introduced by the scheme. For this task, the output of three northern power stations of varying size and location were artificially relocated to the South Eastern Zone.

Task 9 – Examine Extent to Which Demand/Generation Relocation Reduces Heating Losses

This task represented an extension of Task 8, using the same three cases but focusing on the impact of their relocation on the level of variable losses.

Task 10 – Examine Sensitivity of TLFs to Breakdown/Withdrawal of Plant

The purpose of this task was to examine the impact of a plant breakdown or withdrawal on TLF values, using both a northern and southern generating plant. The output of the chosen plant was set to zero, and the Metered Volumes of all other generators were increased proportionally to account for the 'missing' generation.

Task 11 – Examine Sensitivity of TLFs to an Increase in Intermittent Generation

The purpose of this task was to examine the impact of increased intermittent generation on TLF values by artificially creating a new wind farm and introducing it at various locations. The output of other generators was decreased proportionally to account for this 'new' generation.

Task 12 – Examine Sensitivity of TLFs to Inclusion of 132kV Transmission Network in Scotland

The purpose of this task was therefore to examine the impact of including losses from the Scottish 132kV Transmission System in the TLF calculation under P198.[12]

For this task, the resistance of the 132kV transmission lines was set to zero, whilst leaving the reactance of the lines intact. This removed the contribution of the 132kV lines to the TLF calculation, whilst preserving their influence on overall power flows.

[12] The transmission network in England and Wales is defined at that operating at voltages of 275kV and 400kV, while in Scotland it also contains the 132kV level. Losses from the 132kV lines tend to be proportionally higher than in the higher-voltage lines.

4.4.2 Results of Modelling Tasks and Group's Discussion of Results

This section summarises the high-level results of the analysis. For the detailed results of each task, please refer to the full PTI Modelling Report in Appendix 5.

Task 1 – Establish Baseline Adjusted Annual TLFs and TLMs

The results of this task demonstrated that the Proposed Modification would result in geographically variable TLFs, and therefore geographically variable TLMs. The TLF values for each Zone are shown in Figure 3 below, with the Zones ordered geographically from north to south. A key to the Zones is provided in Table 2.

Figure 3 – PTI Adjusted Annual Zonal TLFs for 2006/2007

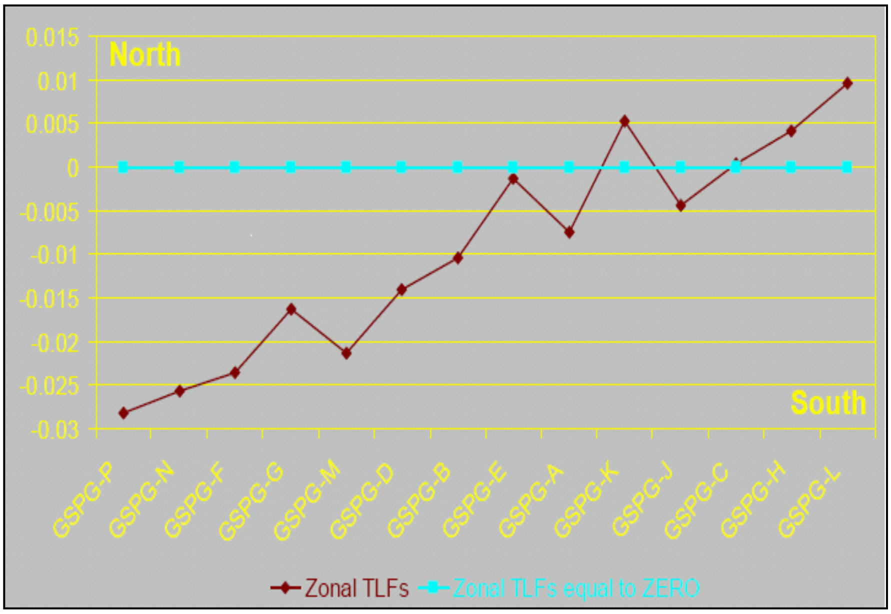


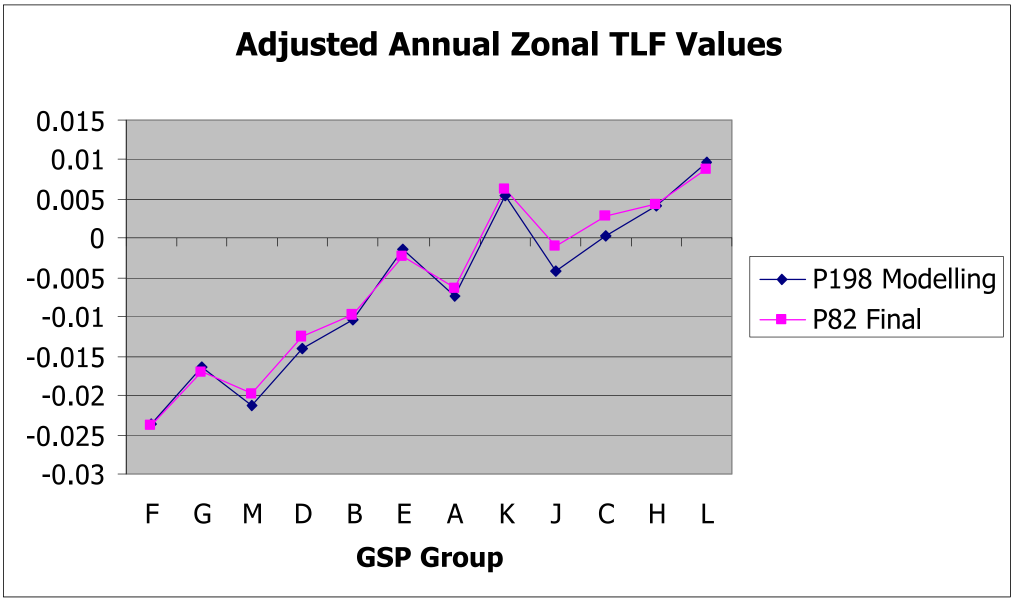
Table 2 – Key to TLF Zones

TLF Zone	GSP Group	GSP Group Name
1	A	Eastern
2	B	East Midlands
3	C	LE Distribution
4	D	Merseyside & North Wales
5	E	Midlands
6	F	Northern
7	G	North Western
8	H	Southern
9	J	South Eastern
10	K	South Wales
11	L	South Western
12	M	Yorkshire Electricity
13	N	South of Scotland
14	P	North of Scotland

The Group agreed that the locational pattern of the differentials between the Adjusted Annual Zonal TLFs was as expected, with the most negative TLF values in the north (a disbenefit to northern generation and a benefit to northern demand) and the most positive values in the south (a benefit to southern generation and a disbenefit to southern demand).

The Group also noted analysis by BSCCo (Figure 4) which showed that the TLFs generated by the P198 modelling for England and Wales were consistent with those produced in 2003 as part of the P82 implementation.

Figure 4 – BSCCo Comparison of P198 and P82 TLF Values for England and Wales



The Group noted that, in a DC model, only the absolute TLF values (and not the differentials between the values) would be sensitive to the choice of slack node. Whilst the line shown in Figure 3 might therefore move up or down according to the choice of slack node, the gradient of the line would remain unchanged. The Group noted that the absolute TLF value for each Zone was unimportant under P198 – since the TLMO would uniformly adjust these values whilst preserving the differentials, such that losses were allocated 45:55 to generation and demand through the TLM. The Group noted that BM Units would therefore never be exposed directly to the 'raw' TLF values under P198, but only to TLMs – and that it was the differentials between the TLF values for different Zones, rather than their absolute values, which would provide any despatch or locational signals to Parties.

Using the TLF values calculated by PTI and Metered Volumes from 2005/2006, BSCCo calculated the TLMs for delivering and offtaking Trading Units which would have been likely to apply in 2006/2007 under the Proposed Modification.[13] Since TLMs vary by Settlement Period, TLMs were calculated for both a 'peak' and a 'trough' Settlement Period as shown in Figures 5 and 6 on the following page. The dotted lines represent the TLMs which were applied to delivery and offtaking Trading Units under the current Code baseline during 2005/2006.

[13] Please note that these TLMs are only indicative, since 'live' TLMs are calculated retrospectively using actual Metered Volumes from the year concerned.

Figure 5 – BSCCo TLMs for 2006/2007 'Peak' Settlement Period

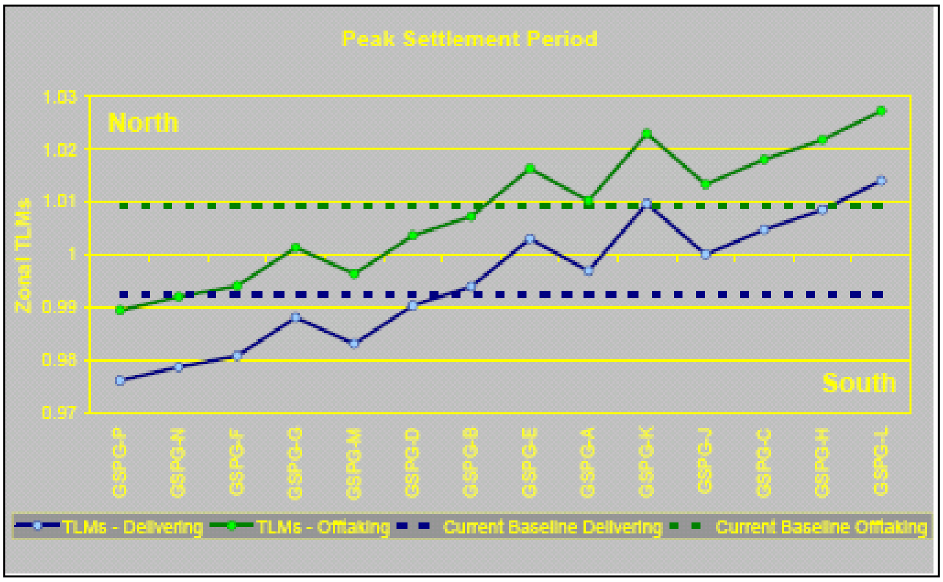
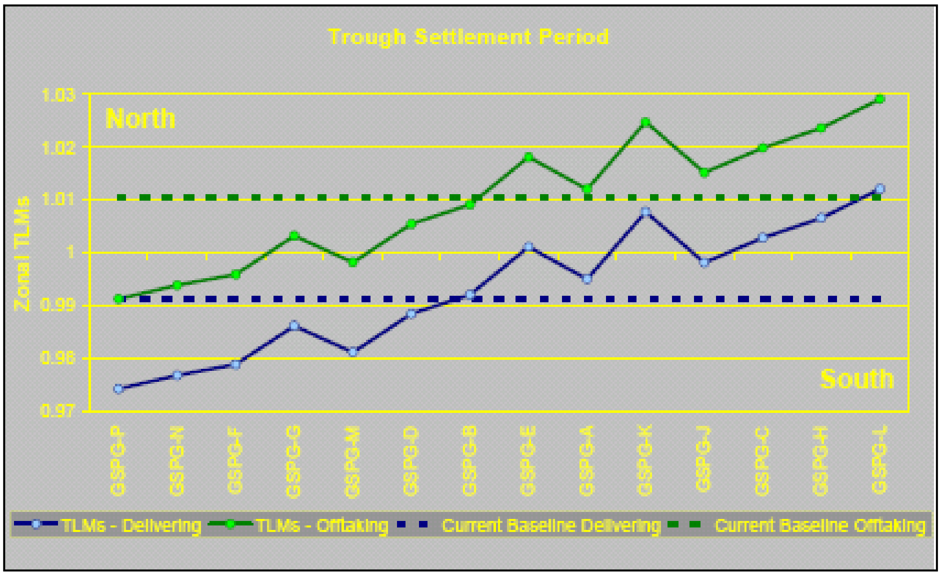


Figure 6 – BSCCo TLMs for 2006/2007 'Trough' Settlement Period



The Group noted that, under the existing Code baseline, transmission losses are allocated by 'debiting' energy from all BM Units through the TLM – with the amount of energy debited (i.e. the share of losses allocated) to each BM Unit being dependent on the size of its Metered Volume. Generation for all BM Units in delivering Trading Units is currently scaled down, whilst demand for all BM Units is scaled up – with the result that all Parties with a non-zero Metered Volume pay a share of the cost of the lost energy. The Group noted that this principle would change under the locational TLF values introduced by P198, although there would continue to be a 45:55 allocation of total losses to generation and demand overall.

Under P198, BM Units in the most advantageous TLF Zones (e.g. generators in the most southern Zones and Suppliers in the most northern Zones) would actually be credited with energy through their resulting TLMs, since their Metered Volumes would be scaled up (made more positive). This would be a benefit to both generators and Suppliers – since it would respectively increase their volume of generation or decrease their volume of demand to the point that they received payments as a result of zonal TLFs. The Metered Volumes of BM Units in the other Zones would be scaled down (made more negative) through energy debits, decreasing their volume of generation or increasing their demand. Whether the share of losses allocated to these BM Units was lesser or greater than their existing uniform allocation would depend on the TLF value for their particular Zone.

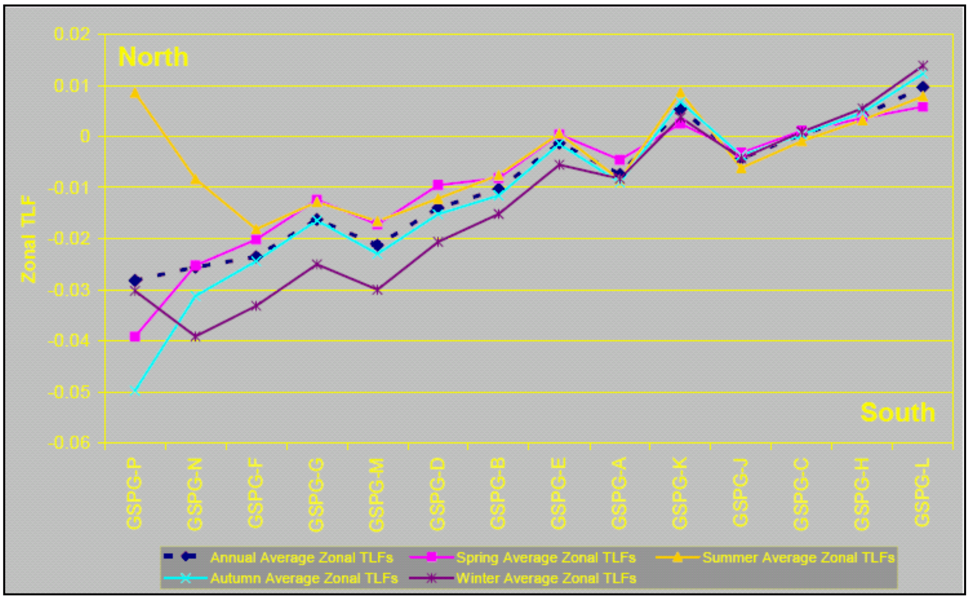
The Group noted that this effect of P198 reflected the Proposer's intention to provide signals to Parties as to the impact of their output on the level of variable losses, since the most advantageous TLFs would be received by BM Units whose output was determined to actually reduce overall losses on the system. Further detail of the Group's discussions as to whether this was appropriate can be found in Sections 4.6 and 4.7.

Task 2 – Establish Temporal Variability of TLFs and TLMs by Zone

The results of this task highlighted that there could be a significant temporal variation from an annual average in the northern Zones, and that this variation was most pronounced in Scotland. This northern temporal variation had not been highlighted as a significant area in the P75/P82 modelling, since the previous modelling had not included Scotland and had been based on substantially less Sample Settlement Periods.

The greatest variation was between annual and seasonal TLFs, as shown in Figure 7 below. This finding led the Group to develop a potential option for an Alternative Modification whereby separate TLFs would be calculated for each BSC Season rather than one annual value for a whole BSC Year (see Section 4.6). This potential Alternative was subsequently included in the scope of the cost-benefit analysis (see Section 4.7).

Figure 7 – PTI Adjusted Seasonal Zonal TLFs for 2006/2007



The results suggested that, in some Settlement Periods, increased northern generation could actually decrease the level of transmission losses. This can be seen in Figure 7 where the TLF for northern Scotland (GSP Group P/Zone 14) was substantially more positive in the BSC Summer season. PTI clarified that, in some Sample Settlement Periods, GSP Group P had switched from net export to net import.

Some members of the Group believed this result to be counterintuitive, and argued that it appeared to contradict the principle of P198 that northern generators and southern Suppliers contributed the most to the level of losses. These members were concerned that using annual TLFs might provide the wrong signal to Scottish generators – encouraging them to generate in summer even though that generation would increase losses. Other members believed that consideration of a north-south divide was oversimplistic. These members argued that the results reflected the seasonal pattern of northern generation, and demonstrated the sensitivity of TLFs to changes in behaviour at the geographical extremities of the country. These members suggested that changes in the south were likely to be more localised than in Scotland, since increased southern generation was more likely to be offset by local demand. These members therefore did not necessarily believe that the results undermined the principle of P198. Some argued that the issue would be resolved if seasonal rather than annual TLFs were adopted.

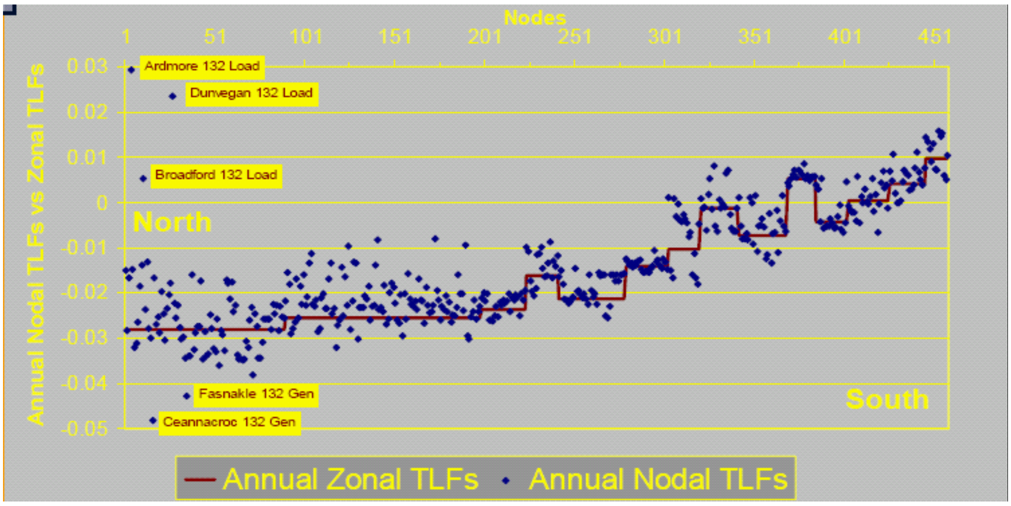
The results showed that monthly and daily TLFs were closer to the seasonal TLFs than to the annual average. A minority of members remained concerned that there was still a significant variation between peak and offpeak TLFs at the Settlement Period level. However, the other members of the Group believed this variation to be less significant – and argued that having different TLFs for peak and offpeak would create uncertainty for Parties, since it would mean that TLFs could vary on a half-hourly basis. By majority, the Group therefore agreed not to conduct further analysis of any other form of temporal variation.

Task 3 – Compare Nodal Values to Zonal Values

The results demonstrated that the Nodal TLFs for some Nodes could be significantly different from their zonal TLFs. Again, this variation was most pronounced in Scotland.

The Group identified five Nodes in GSP Group P/Zone 14 (northern Scotland) whose variation from the zonal average was particularly marked, and requested that PTI undertake further analysis to identify these Nodes and the drivers behind their variation. Figure 8 below shows the comparison of Nodal TLFs with the zonal averages, and highlights the five 'outlying' Nodes (of which two were generation, and three demand).

Figure 8 – PTI Comparison of Adjusted Annual Nodal TLFs and Adjusted Annual Zonal TLFs



PTI advised that the main factor underlying the variation at these Nodes was their remote geographical location. All five Nodes were located at the end of 'long thin' transmission lines – with the result that any behaviour at these Nodes (including demand) could contribute to increasing losses, due to the distance which needed to be travelled by the electricity. It was noted that these Nodes were connected to 132kV transmission lines, whose losses tend be proportionally higher than 275kV and 400kV lines.

Some members argued that the results demonstrated that 132kV-connected participants would be disproportionately impacted by the introduction of P198. One member suggested that a different Zone should be created for the 'outlying' Nodes, although it was noted that this would require an Alternative Modification since the Modification Proposal specified Zones based on GSP Groups. The Group also noted that it would be difficult to have TLF Zones for demand which were not based on GSP Groups (see Section 4.6 for further details of the Group's discussion of a potential Alternative option in this area). Another member argued that the results showed that average TLFs were inappropriate, and that they should be applied at the nodal level.

Other members did not agree that the impact on 132kV transmission connections would be disproportionate, noting the results of Task 12 (see below). These members did not believe that a change to Zones was required, and argued that the 'outlying' Nodes were simply an extreme example of the variation inherent in the averaging process. It was noted that the annual average would actually be beneficial for the 'outlying' Nodes, since it would result in a less negative TLF for the generating Nodes and a less positive TLF for the demand Nodes.

Further detail regarding these arguments can be found in the Group's discussions of potential options for an Alternative Modification in Section 4.6.

Task 4 – Establish Degree to which a 0.5 Scaling Factor Correctly Allocates Heating Losses

Table 3 below shows the range in the individual Sample Settlement Period scaling factors, the average of these factors, and the standard deviation of the half-hourly scaling factors from that average.

Table 3 – Settlement Period scaling factors compared with 0.5 value

	Sample Settlement Period Scaling Factors
Maximum	0.5001012
Minimum	0.4999952
Average	0.5000371
Standard Deviation	0.000024

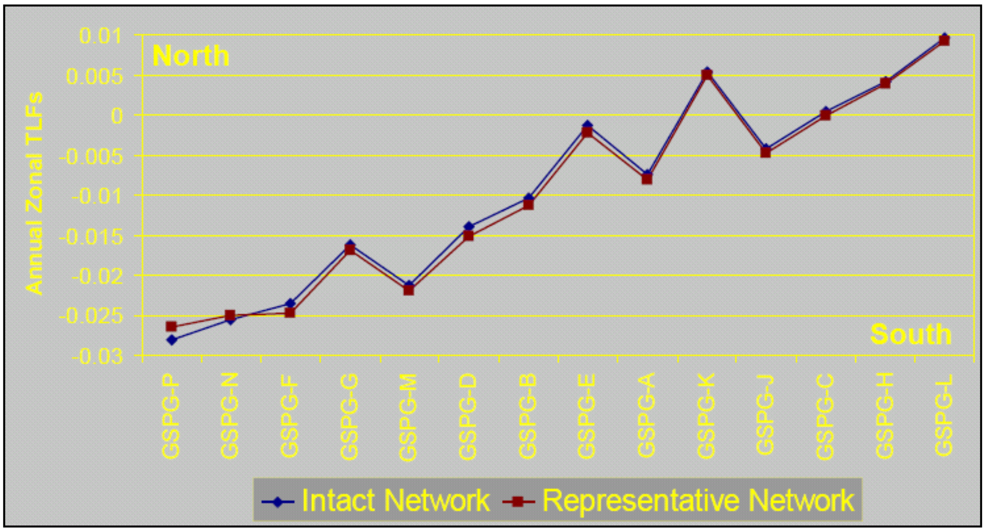
On the basis of these results, the Group unanimously agreed that 0.5 continued to be the appropriate scaling factor to ensure that the level of variable losses allocated through TLFs was comparable to that calculated by a DC Load Flow Model. The Group noted that a fixed 0.5 scaling factor would not give an exact allocation – since it would be applied to TLFs which had been averaged by time and Zone, rather than to individual half-hourly Nodal TLFs. However, the Group agreed that the modelling results gave confidence that a fixed 0.5 value was an accurate approximation.

In carrying out Task 4, some areas for further consideration was raised by PTI regarding the allocation of the losses calculated by the model. Further information regarding these areas can be found in Section 4.4.3.

Task 5 – Consider Impact of Using an Intact Network on TLFs

The results of this task demonstrated that, although the choice of network could affect TLF values, this effect would not be significant as shown in Figure 9 below.

Figure 9 – PTI Comparison of TLFs Based on Intact and Representative Networks



On the basis of these results, the Group therefore unanimously agreed not to consider any potential Alternative in this area.

Task 6 – Examine Sensitivity of TLFs to Constraints

The results of this task demonstrated that transmission constraints could affect TLF values. However, the Group agreed that no refinements to the methodology were required in this area, since any constraints would already be captured in the metered data used in the TLF calculation.

Task 7 – Examine Sensitivity of TLFs to Interconnector Flows

The results of this task demonstrated that Interconnector flows could influence individual Settlement Period zonal TLFs, but that this effect would be averaged over a year. The Group agreed that no refinements to the methodology were required in this area, since the effect of Interconnector flows would already be captured in the metered data used in the TLF calculation.

Task 8 – Examine Sensitivity of TLFs to Participants Responding to Signals

The results of this task demonstrated that, in some cases, participants responding to locational signals could influence Adjusted Annual Zonal TLFs significantly. The extent of this impact would be dependent on the location and size of the participant concerned. The Group noted that TLF values would therefore be sensitive to the relocation of large plant – which could impact TLFs for all Zones, and not just locally.

The Group agreed that these results were in line with its intuitive expectations. Further modelling in this area was carried out as part of the cost-benefit analysis, which examined the impact of the P198 locational signals over a ten-year period. More detail can be found in Section 4.7.

Task 9 – Impact Extent to Which Demand/Generation Relocation Reduces Heating Losses

The results of this task demonstrated that, in some cases, participants responding to locational signals could change the overall level of variable losses significantly. As for Task 8, the extent of this impact would be dependent on the location and size of the participant concerned. The Group noted that the analysis suggested that moving a large power station from a northern to a southern Zone could reduce losses by approximately 8%.

The Group agreed that these results were intuitively in line with those for Task 8 above. Further modelling in this area was carried out as part of the cost-benefit analysis, and more detail can be found in Section 4.7.

Task 10 – Examine Sensitivity of TLFs to Breakdown/Withdrawal of Plant

The results of this task demonstrated that the effect of plant breakdown or withdrawal on TLFs would be greatest in the north, when a local plant was affected.

The Group agreed that this result was in line with its intuitive expectations, since TLFs were more variable in the north. Further modelling in this area was carried out as part of the cost-benefit analysis, and more detail can be found in Section 4.7.

Task 11 – Examine Sensitivity of TLFs to an Increase in Intermittent Generation

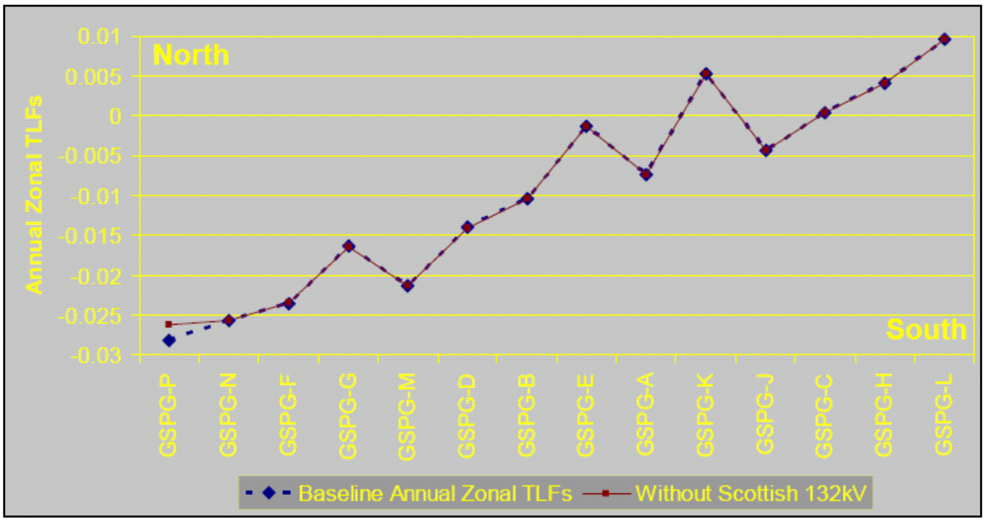
The results of this task demonstrated that increased intermittent generation could affect TLFs, and that in most cases the effect would be on the TLFs for the local Zones.

The Group agreed that this result was in line with its intuitive expectations. Further modelling in this area was carried out as part of the cost-benefit analysis, and more detail can be found in Section 4.7.

Task 12 – Examine Sensitivity of TLFs to Inclusion of 132kV Transmission Network in Scotland

As shown in Figure 10 below, the results of this task demonstrated that the effect of including the 132kV element of the Transmission System would be relatively small and of local character (primarily limited to northern Scotland).

Figure 10 – PTI Comparison of TLFs With and Without 132kV Transmission Network



The Group noted these results. Further detail regarding the Group's discussions of the appropriateness of including the 132kV element of the Transmission System in a zonal transmission losses scheme can be found in Section 4.6.

4.4.3 Other Areas Arising From Modelling Results

The PTI analysis also identified three areas for further consideration by the Group as follows:

- The inclusion of some minor non-Transmission System elements in the Network Data;
- An issue relating to the definition of the Metered Data Sample used in the Load Flow Model; and
- The consequence of applying the P82 zonal averaging methodology to nodal flows.

Further detail regarding each of these areas is provided below.

a) Network Data

During the modelling calculations, PTI noted that a relatively small number of elements in Scotland not belonging to the GB Transmission System had been included within the Network Data provided by the Transmission Company without their resistance set to zero – with the result that these elements contributed to the TLFs calculated by the model. However, following further investigations by PTI and BSCCo, it was established that the heating losses in these elements accounted for less than 0.17% of the total GB heating losses, and that their influence on the TLF calculation was therefore negligible.

The Group agreed that the erroneous inclusion of these elements in the Network Data did therefore not affect its confidence in the modelling results.

b) Metered Data Sample Definition

Table 4A below shows the level of variable losses calculated by the Load Flow Model using nodal power flows, compared with the level of total transmission losses (comprising both fixed and variable losses) calculated using the metered data sample used in the model. As can be seen from the table, there is a significant difference between the two totals, which is not satisfactorily explained by the inclusion of fixed losses in the metered data.

Table 4A – Original Comparison of Calculated Variable Losses with Total Metered Volume Losses

Values Across 623 Sample Settlement Periods	
Total transmission losses calculated from P198 metered data sample	272,107 MWh
Total variable losses calculated using Load Flow Model	125,549 MWh
Estimated fixed losses included in metered data sample	70,000 MWh to 90,000 MWh
Remaining unaccounted quantity of variable losses	**Approx. 70,000 MWh**

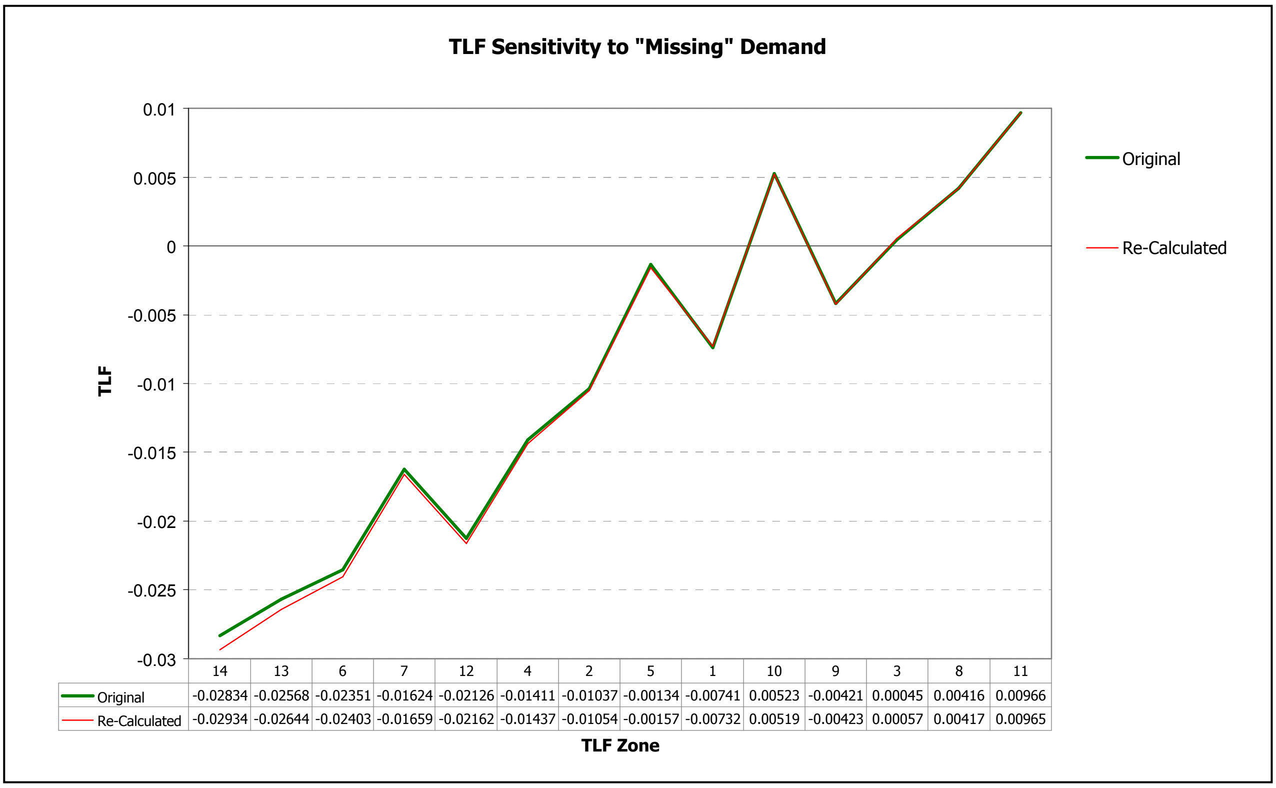
Further investigation by PTI and BSCCo revealed that the total losses implied by the metered data sample used in the P198 modelling was significantly higher than the actual total losses in Settlement for 2005/2006 (i.e. the actual difference between total BM Unit generation and total BM Unit demand). In contrast, the level of variable losses actually calculated by the Load Flow Model using this input data was as expected (i.e. when added to the estimated level of fixed losses it gave a volume of energy approximate to the actual level of losses in 2005/2006). The same issue was found to arise in the P82 metered data sample, which suggested that the issue was related to the definition of the sample metered data used in the Load Flow Model rather than a problem with the model itself.

BSCCo believes that the potential source of the higher-than-expected level of losses in the metered data sample may be the approach taken to aggregate metered data for a small number of 'shared' GSPs in the model input data, which may mean that some demand is not being reflected in the sample data. Quantifying the impact of this issue on TLFs is not simplistic, since the TLF calculation is based on nodal power flows rather than the raw metered data included in the sample. Nodal power flows are derived from Metered Volumes in such a way that any losses are initially eliminated (effectively generation is scaled down and demand scaled up until they are equal). Flows on the transmission network are then generated from the nodal power flows, and the losses used to calculate TLFs are based on these network flows. Hence, the level of losses in the sample does not directly influence the calculated TLFs, and any impact is likely to be reduced by the averaging process used in the calculation. However, there may be some influence on nodal power flows across the sample, and the impact on Nodal TLFs for particular Nodes may be more significant.

Whilst the Group unanimously agreed that this issue did not diminish its confidence in the modelling results, it agreed that further investigation should be undertaken to identify potential ways of addressing it in the 'live' implementation of P198. Initial work by BSCCo concluded that there may be around 24 affected GSPs; however, it was unable to identify the affected 'minority' flows at these shared GSPs and therefore to quantify the precise materiality of the issue. Further detail of BSCCo's investigations in this area can be found in Appendix 8. The Group agreed that the issue did not materially undermine the results of the Assessment Procedure. However, it continued to believe that it was desirable to address the issue prior to implementation. In particular, some members noted that the affected GSPs were located predominantly in the south, and were concerned that this could affect TLFs for these Zones.

In order to offer additional reassurance to the Group that the materiality of the issue was likely to be minor, BSCCo subsequently commissioned PTI to repeat the calculation of Adjusted Annual Zonal TLFs – this time smearing the amount of demand which had been missing from the original metered data across the 24 shared GSPs. The Group noted that this would not give an exact representation of the materiality of the issue (since the exact proportion of the demand attributable to each of these GSPs had not been identified), but that it would give a reasonable approximation. Figure 11 below shows the results of this further analysis.

Figure 11 – PTI Analysis of Sensitivity of TLFs to 'Missing' Demand



	14	13	6	7	12	4	2	5	1	10	9	3	8	11
Original	-0.02834	-0.02568	-0.02351	-0.01624	-0.02126	-0.01411	-0.01037	-0.00134	-0.00741	0.00523	-0.00421	0.00045	0.00416	0.00966
Re-Calculated	-0.02934	-0.02644	-0.02403	-0.01659	-0.02162	-0.01437	-0.01054	-0.00157	-0.00732	0.00519	-0.00423	0.00057	0.00417	0.00965

The Group noted that TLFs in Scotland and Northern England appeared to be the most sensitive to the allocation of this additional demand. Some members believed this to be consistent with the findings of other aspects of the PTI analysis (which had shown TLFs in these Zones to be the most sensitive to changes in output), although one member believed this to be counter-intuitive.

Table 4B below shows the comparison between the revised level of variable losses calculated by the Load Flow Model on the basis of the revised metered data.

Table 4B – Revised Comparison of Calculated Variable Losses with Total Metered Volume Losses

Values Across 623 Sample Settlement Periods	
Total transmission losses calculated from revised P198 metered data sample	190,313 MWh
Total revised variable losses calculated using Load Flow Model	127,000 MWh
Initially estimated fixed losses	70,000 MWh to 90,000 MWh
Remaining unaccounted quantity of variable losses	**None**

The Group noted that the level of variable losses calculated by the model using the revised metered data was not materially higher than that calculated on the basis of the previous metered data. The Group noted that this supported the conclusion that the metered data sample has only an indirect affect on the level of losses calculated by the model.

The Group agreed that the extra PTI analysis provided additional comfort regarding the materiality of the issue, but agreed that it should be resolved prior to the live implementation of P198. The Group noted that, since the issue related to the metered data sample used in the TLF calculation, it would also arise under P200, P203, P204 and any other transmission losses Modification Proposal which used the same methodology. The Group noted BSCCo's advice that it is considering a potential solution to the issue whereby Licensed Distribution System Operators would be required to resubmit aggregation rules for shared GSPs as a one-off activity during implementation – such that the aggregated Metered Volume for each GSP reflected the net flow from the Transmission System. Further detail regarding this potential solution can be found in Appendix 8. The Group noted that no additional changes were required to the legal text in order to reflect this solution.

One member of the Group considered that the issue should be resolved regardless of whether a zonal transmission losses scheme was approved by the Authority – since, although the current GSP aggregation rules do not represent a material issue for Settlement, this member believed there to be a broader issue regarding the transparency of minority flows within these rules for shared GSPs. BSCCo advised that, should a zonal transmission losses scheme not be approved, it would seek the views of the ISG as to whether it wished to progress this broader issue.

c) Zonal Averaging Methodology

The calculations used to convert Nodal TLFs to Zonal TLFs in the P198 modelling were based on the 'live' P82 calculations (i.e. those which had been set out in the P82 legal text). This methodology uses 'volume-weighted' averaging such that the absolute nodal power flows for all Nodes within a Zone are averaged together to obtain one TLF for that Zone. However, PTI advised that a consequence of averaging absolute values was that the resulting TLFs would give an underallocation of variable losses by approximately two-thirds as shown in Table 5 below. Note that this is not related to the discrepancy in losses outlined in Section b) above, since the comparison is between the level of variable losses calculated by the model using nodal power flows and the allocation of variable losses through the TLFs which were calculated on the basis of those nodal flows. Note also that it does not undermine the modelling conclusions regarding the appropriateness of a 0.5 scaling factor – since the scaling factor exactly recovers the amount of variable losses calculated by the model when applied through Nodal TLFs to nodal power flows. This suggested that the issue was a mathematical consequence of the averaging methodology adopted by the Group.

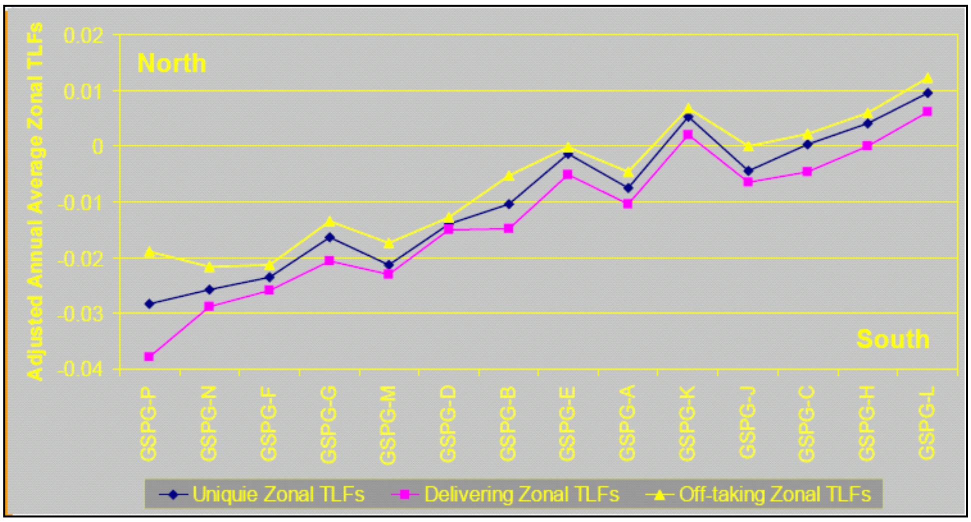
Table 5 – Allocation of Calculated Variable Losses under P82 Methodology

Values Across 623 Sample Settlement Periods	
Total variable losses calculated using Load Flow Model	125,549 MWh
Total variable losses allocated through Adjusted Annual Zonal TLFs under P82 methodology	41,268 MWh

Further investigation by PTI and BSCCo revealed that this consequence of the zonal averaging had not been identified during the P75/P82 modelling exercise, since the P75/P82 analysis had utilised a different zonal averaging approach which preserved the sign conventions of the different nodal power flows within a Zone (positive for delivery and negative for offtake). However, this original approach had subsequently been discarded by the TLFMG, since it effectively created one Zonal TLF per Zone which was a 'net' figure. This had created the risk that in rare cases – where delivery and offtake within a Zone were closely balanced – the calculation might sum to zero, or create TLFs which were extremely disproportionate where there was a small divider. The TLFMG had therefore abandoned this approach in favour of averaging absolute flows.

A third approach to the zonal averaging was suggested by PTI. This approach would avoid the problems of averaging flows with opposite signs by effectively creating two TLF values per Zone: one to be applied to all delivering Nodes, and one to all offtaking Nodes. These values would be calculated by separately averaging the power flows of all delivering Nodes and all offtaking Nodes within a Zone. Figure 12 on the following page shows the TLF values which would be calculated under this approach.

Figure 12 – Alternative Zonal Averaging Methodology



The Group noted that this approach would require an Alternative Modification, since the Modification Proposal specified the use of a single TLF per Zone.

A minority of members initially argued in favour of further consideration being given to this issue as a potential option for an Alternative Modification. However, a majority of the Group believed that the alternative methodology would create uncertainty for Parties as to which TLF would apply to their BM Units, as BM Units can switch from being part of 'delivering' or 'offtaking' Trading Units depending on the Metered Volumes of all BM Units in their Trading Unit in any given Settlement Period. These members believed that it would be difficult for Parties to take account of this variability in their contracts. Moreover, these members did not believe that the alternative methodology would necessarily be any more accurate, for the following reasons:

- *The 'delivery' or 'offtake' status of a BM Unit would not necessarily correspond to whether an individual Node was delivering or offtaking* – these members noted that it was not possible to apply TLFs at the nodal level (since Supplier BM Units cannot be mapped directly to Nodes), and argued that using BM Unit status (which depends on Trading Unit behaviour) as a proxy for nodal flows could create its own inaccuracies.

- *The differentials between Zones would be relatively unchanged* – these members noted that the geographical pattern of TLFs shown in Figure 12 was similar regardless of which approach was adopted, and argued that there would therefore be little difference in the signals provided to Parties under the two approaches.

- *Any difference in the absolute values of zonal TLFs would be accounted for through the TLMO* – these members argued that the absolute difference between the TLFs shown in Figure 12 was unimportant, since the absolute values would already be uniformly adjusted by the TLMO such to preserve the 45:55 split of total losses.

A majority of members therefore did not believe that there was a defect to be addressed in the P82 methodology, but that the level of allocation was simply a result of the average nature of the scheme. These members argued that the original methodology remained appropriate for P198.

By majority, the Group therefore agreed not to progress the potential alternative methodology further. The Proposer – whilst not supportive of this decision – clarified that they believed PTI's further investigations had demonstrated that the issue was not as significant as they had initially believed, and that there was therefore no defect in the Proposed Modification solution.

4.5 Proposed Modification Implementation Approach and Costs

4.5.1 Modification Group's Initial Discussions

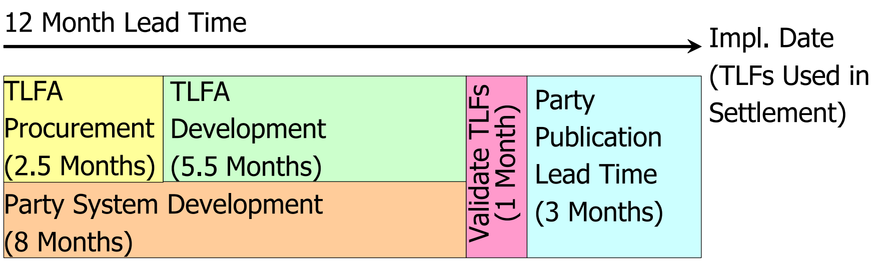
The Group noted that the Modification Proposal suggested an Implementation Date for P198 of 1 April 2007. The Proposer clarified that they believed it to be essential for the Implementation Date to coincide with Parties' contractual rounds, such that the TLF values for each year could be factored into Parties' contracts for that year. The Group noted that this was in line with the approach previously followed by the TLFMG for Modification Proposals P75, P82 and P105, and unanimously agreed with the principle that the Implementation Date should be tied to contract rounds.

In accordance with its Terms of Reference, the Group undertook an impact assessment to establish the lead time which would be required to implement the Proposed Modification – as well as the costs which would be incurred by the industry as a result of its implementation and operation. Summaries of the costs and lead times provided in response to this impact assessment are given in Sections 4.5.2 and 4.5.3 below, whilst details of the Group's discussion of the impact assessment results can be found in Section 4.5.4. For the full impact assessment results, please refer to Appendix 3.

4.5.2 Implementation Lead Time

Figure 13 below sets out the critical path for the implementation of the Proposed Modification, based on the lead times given in the impact assessment responses. Although there would be other implementation activities undertaken in parallel with those shown below (such as changes to BSC Agent documentation and Code Subsidiary Documents), these have not been included since they do not determine the required timescales.

Figure 13 – Proposed Modification Implementation Timeline



An explanation of these lead times is provided below:

- **Procurement of the TLFA by BSCCo** – due to the ability to reuse elements of the P82 TLFA procurement documentation, this lead time represents half of the lead time which was required to procure the TLFA under P82.
- **TLFA development** – the estimated lead time for this activity was based on the development timescale which was required by the P82 TLFA.
- **Party development lead time** – the estimated lead time for this activity was based on the maximum lead time provided by the Party impact assessment (other timescales provided by Parties were three months and six months, whilst other Parties required only minimal lead time). The maximum lead time was used since Parties' system development would take place in parallel with the TLFA procurement and development, for which the estimated combined lead time was eight months. A reduced Party lead time would therefore not reduce the overall implementation lead time for the Proposed Modification.
- **Validation of TLFs** – the estimated lead time for this activity was based on the timescales which were required during the P82 development for the Load Flow Model Reviewer to report to the Panel on whether the model developed by the TLFA was fit for purpose.

- **Party publication lead time** – this was based on the three-month publication notice period for TLF values agreed by the Group (see Section 4.3.6).

A total implementation lead time of twelve months would therefore be required for the Proposed Modification.

4.5.3 Implementation and Operational Costs

a) Transmission Company

The Transmission Company estimated that it would incur the following costs as a result of Proposed Modification P198:

- £40,000 in initial implementation costs (including development costs and operational costs for the first BSC Year of the scheme); and
- £40,000 in ongoing operational costs per subsequent BSC Year.

The Transmission Company estimated that both its initial implementation effort and annual operational activities would require six weeks' lead time.

b) BSC Parties

The costs quoted by those Parties which responded to the Proposed Modification impact assessment ranged from nil to six-figure sums, with the average being in the region of £200,000. The costs provided by these Parties reflected the extent of the changes which would be required to their systems to take account of zonal TLF values.

c) BSCCo/BSC Agents

The tables on the following page show the estimated central implementation and operational costs of the Proposed Modification.

PROPOSED MODIFICATION IMPLEMENTATION COSTS[14]

		Cost	Tolerance
Logica CSA Cost	Change Specific Cost Release Cost	£18,762 £17,114	Nil Nil
	Total Logica CSA Cost	£35,876	Nil
TLFA/Load Flow Model Reviewer Cost	Development, Testing and Deployment	£250,000	+/- 50%
BSC Audit Cost	Planning and Development	£15,000	+/- 50%
Implementation Cost	External Programme Audit Design Clarifications Additional Resource Costs Additional Testing/Audit Support Costs	£0 £14,294 £0 £20,000	Nil +/- 100% Nil +/- 50%
Total Demand Led Implementation Cost		£335,170	+/- 50%
ELEXON Implementation Resource Cost		600 man days £132,000	+/- 5%
Total Implementation Cost		**£467,170**	**+/- 35%**

PROPOSED MODIFICATION ONGOING SUPPORT AND MAINTENANCE COSTS

	Cost	Tolerance
Logica CSA Operation Cost Per BSC Year Logica CSA Maintenance Cost Per BSC Year	£2,645 £0	Nil Nil
TLFA/Load Flow Model Reviewer Operational Cost Per BSC Year	£100,000	+/- 50%
BSC Auditor Cost Per BSC Year	£40,000	+/- 50%
ELEXON Operational Cost Per BSC Year	70 man days £15,400	+/- 5%
Total Operational Cost Per BSC Year	**£158,045**	**+/- 45%**

A detailed explanation of these costs is provided on the following page.

[14] An explanation of the cost terms used in this section can be found on the BSC Website at the following link: http://www.elexon.co.uk/documents/Change_and_Implementation/Modifications_Process_-_Related_Documents/Clarification_of_Costs_in_Modification_Procedure_Reports.pdf

i) Logica Central Services Agent

The Logica Central Services Agent (CSA) and ELEXON cost estimates were based on the results of the Proposed Modification impact assessment undertaken by the Group. Since the system functionality for annual zonal TLFs was previously developed for P82, the costs for Proposed Modification P198 shown here are limited to testing this functionality and updating documentation.

ii) TLFA/Load Flow Model Reviewer

The TLFA and Load Flow Model Reviewer would be new roles created by P198. A competitive tender process would be required for these roles, and the costs given therefore reflect the possibility that different organisations may be appointed than were used for the P82 development. In the absence of available impact assessments for these organisations, these costs were estimated by BSCCo based on the following:

- The range of development and operational costs quoted within the bids which were submitted for the P82 TLFA role in 2003;
- The actual expenditure which was incurred by the P82 Load Flow Model Reviewer as part of the P82 development work during 2003; and
- An estimate of the likely Load Flow Model Reviewer operational costs, based on the day rate of the P82 Load Flow Model Reviewer and an assumption of five man days' effort per BSC Year (equivalent to the provision of services in support of one Trading Dispute per year).

The 50% tolerance associated with the TLFA/Load Flow Model Reviewer costs reflects the uncertainty of the applicability of these costs to Proposed Modification P198, and the possibility for significant cost-savings if the outcome of the TLFA competitive tender was that the P82 organisations were re-used.

iii) BSC Auditor

Since the BSC Audit is required to include the systems and processes of all BSC Agents, the BSC Audit Scope would need to be extended to cover the new TLFA role created by P198. The exact impact and costs resulting from this extension would depend on the specific TLFA audit requirements set by the Panel as part of its annual agreement of the BSC Audit Scope.

Since the P82 judicial review ruling occurred before the P82 TLFA had been incorporated into the BSC Audit Scope, no costs for the Audit impact of a zonal transmission losses scheme were available to the Group. The costs of extending the BSC Audit to include the MIDPs in 2002/2003 were therefore used by BSCCo to estimate the likely order of magnitude of the additional Audit costs for Proposed Modification P198. The 50% tolerance associated with these costs reflects the uncertainty of the applicability of the MIDP Audit costs to the TLFA role.

iv) Implementation Costs

The twelve-month implementation lead time for the Proposed Modification, coupled with a 1 April Implementation Date, means that it would not be possible to align the TLFA systems development with BSCCo's standard release strategy. The Proposed Modification would therefore be implemented largely as a 'stand-alone' project, with the associated release overheads that this would incur. Note that the costs shown here do not include those which would be required to resolve the metered data sample issue identified in Section 4.4.3 as a one-off activity prior to implementation.

v) Operational Costs

Under the Proposed Modification, zonal TLFs would be calculated on an ex-ante basis for each BSC Year. The total operational cost for each year therefore includes the activities required to calculate TLFs for the following year, in addition to other operational activities such as allocating TLF values to any new BM Units which registered part-way through a year.

4.5.4 Modification Group's Conclusions

The Group noted the costs and twelve-month lead time for the Proposed Modification arising from the impact assessment results.

One member expressed surprise at the costs and lead times quoted by Parties, and considered that these should be minimal as the development work had already been undertaken for P82. However, other members noted that Parties who had entered the GB market after the P82 judicial review ruling in early 2004 (including Scottish participants at BETTA Go-Live) might not have built the functionality for zonal TLFs into their systems, whilst other Parties might have replaced or amended their systems in the intervening period.

The Group noted that the implementation lead time for P82 had been fourteen and a half months. Some members stated that they would have expected the lead time for Proposed Modification P198 to be less than twelve months, since they believed that the P82 development work could be re-used. BSCCo clarified that the timescales were driven by the need to undertake a full competitive procurement exercise for the TLFA role. Further detail in this area can be found in Section 4.3.2.

The Group noted that one respondent to the impact assessment had stated that they believed the implementation lead time for P198 should take account of the possibility that the Authority's decision might be appealed to the Competition Commission, such that implementation work would only commence after the end of the Competition Commission's twelve-week appeals process. One member suggested that this would avoid nugatory implementation work being undertaken by the industry, as had happened in the case of P82. Other members of the Group disagreed, and argued that the possibility of an appeal was not a sufficient rationale to add three months to the implementation timetable. These members noted that BSCCo and the Panel had an obligation under Section F1.2 to ensure that the Code facilitated the achievement of the Applicable BSC Objectives, and to implement Approved Modifications in a timely manner. BSCCo advised that, since the P82 judicial review, a Conditional Implementation Date process had been introduced into the Code by Modification Proposal P180, to allow further 'fall-back' Implementation Dates to be put forward to the Authority in the event of a judicial review or an appeal.[15] It was also noted that the TLFA contract would not be signed until two and a half months after the P198 decision, by which point BSCCo would be aware of the existence of any legal challenge and could factor this into the structure of the contract if required.

The Group noted that, given the twelve-month lead time, the Implementation Date of 1 April 2007 which had originally been suggested by the Proposer would not be achievable. The Group therefore initially considered an Implementation Date of 1 October 2007 with a fall-back of 1 April 2008. The Group agreed that, whilst an October implementation might not be tied to Parties' full annual contract rounds, it would allow TLFs to be factored into autumn contracts and would prevent delaying implementation until the following April. However – following its agreement to subsequently extend the Assessment Procedure such that the TLF modelling and cost-benefit analysis could be completed – the Group noted that a 1 October 2007 implementation would also no longer be achievable, since it would require a decision by the end of September 2006 (the month that the final P198 Modification Report is scheduled to be submitted to the Authority).

[15] Modification Proposal P180 'Revision to BSC Modification Implementation Dates, where an Authority decision is referred to appeal or judicial review'.

The Group therefore unanimously agreed the following provisional Implementation Dates for the Proposed Modification:

- 1 April 2008, if an Authority decision is received on or before 22 March 2007; or
- 1 October 2008, if an Authority decision is received after 22 March 2007 but on or before 20 September 2007.

The new zonal TLFs would come into effect from the first Settlement Period on the Implementation Date. For a 1 April implementation, this would also be the first Settlement Period on the first day of the BSC Year. For a 1 October implementation, the first set of TLF values applied from this date would still be annual values calculated using a full Reference Year of data – however, they would only apply for six months during this first year. TLFs for all subsequent years would be calculated and applied on an annual basis for each full BSC Year. The Group agreed that the P198 legal text needed to be sufficiently flexible to cover the possibility of either an April or October implementation in the first year of the scheme. Clarifications were therefore included within the legal drafting to cover the eventuality that P198 was implemented part-way through a BSC Year.

The Group agreed to include a specific question regarding its proposed implementation approach within the second Assessment Procedure consultation.

4.6 Consideration of Options for an Alternative Modification and First Assessment Consultation Responses

The Group noted that there were a large number of potential options for an Alternative Modification which could arise from consideration of the key principles raised by P198, although not all of these options were necessarily supported by the Group. Some of the options were potentially similar to the areas previously considered under Modification Proposals P75, P82, P105 and P109, whilst some arose from the Group's consideration of the extension of a P82-style scheme to include Scotland.

The Group agreed that there could be inefficiencies in terms of costs and timescales if a detailed assessment was to be undertaken for all of these options. However, members of the Group were uncomfortable with the idea of discarding any of the options without first seeking the views of the industry on their potential merits. The Group therefore agreed to undertake an initial, high-level, industry consultation on a variety of potential options for an Alternative Modification. The aim of this consultation was to aid the Group in narrowing the range of options to be considered, such that only those which the industry believed might better facilitate the achievement of the Applicable BSC Objectives were assessed further. Some members of the Group were also uncertain as to whether all of the potential Alternative options would address the issue or defect identified by the Modification Proposal.[16] Legal advice was provided by BSCCo in this area, and was included within the consultation.

[16] Section F2.6.2 of the Code states that "The purpose of the Assessment Procedure is to evaluate whether the Proposed Modification identified in a Modification Proposal better facilitates the achievement of the Applicable BSC Objective(s) and whether an alternative modification would, as compared with the Proposed Modification, better facilitate achievement of the Applicable BSC Objective(s) in relation to the issue or defect identified in the Modification Proposal".

Consultation respondents were invited to indicate whether they believed there to be one or more potential options for an Alternative Modification (whether identified by the Group or otherwise) which might better facilitate the achievement of the Applicable BSC Objectives when compared with the Proposed Modification. Respondents were requested to refer to specific Applicable BSC Objectives in support of their views, and to provide rationale as to how the potential option(s) would meet the defect identified by the Modification Proposal. Views were not sought as to whether either the Proposed Modification or any of the potential Alternative options would better facilitate the achievement of the Applicable BSC Objectives compared to the current Code baseline, since this would form the subject of a subsequent industry consultation. Respondents were not specifically requested to rank the potential Alternatives in order of preference, or to identify any possible combinations of options which might form part of any final Alternative Modification. For further information regarding the scope of the consultation, please refer to the First Assessment Procedure Consultation Document for P198.

The following sections provide further detail regarding each of the options which formed part of the first Assessment Procedure consultation, the views of consultation respondents regarding these options, and the Group's final decision whether or not to progress each option further. A summary table showing the numbers of respondents in support of each option is provided on the following page. Full copies of the individual responses received can be found in Appendix 4.

Table 6 – Responses to First Assessment Procedure Consultation

14 responses (representing 64 BSC Parties and 4 non-Parties) were received to the P198 first Assessment Procedure consultation.

A summary of the consultation responses is provided in the table below.

Potential Alternative Option	**1**	**2**	**3**			**4**	**5**			**6**	**7**	
	Ex-Post	**More Frequent Ex-Ante**	**Different Zones**			**Phasing/ Grandfathering**	**Exclude Certain BMUs**			**Exclude 132kV Trans. Losses**	**Change to 45:55 Split**	
			Less	More	Not Spec-ified		132kV	Suppliers	Renew-ables		More to Demand	100% NGET
Respondents Supporting Further Assessment	**3**	**6**	**2**	**2**	**1**	**8**	**2**	**1**	**1**	**4**	**4**	**1**
No. of Parties Represented	13	24	5	12	2	30	10	1	0	17	22	7
No. of Non-Parties Represented	0	3	3	0	0	3	0	0	1	3	0	0

4.6.1 Potential Alternative Option 1 – Ex-Post TLF Calculation

a) Modification Group's Initial Discussions

The Group noted that a potential option for an Alternative Modification could be an ex-post scheme (i.e. a retrospective calculation of TLF values, based on actual data). The Group noted that potential approaches for an ex-post scheme could be to retrospectively derive TLFs for each half-hour Settlement Period (as originally suggested by the P75 Modification Proposal) or for each Settlement Day (as subsequently developed by the TLFMG as part of the solution for Proposed Modification P75).

b) BSCCo Legal Advice

No legal advice was requested by the Group in respect of this option.

c) Results of First Assessment Procedure Consultation

A minority of respondents supported further assessment of this option.

The different arguments expressed by respondents in favour of this option were that:

- An ex-post scheme would give a more accurate calculation and allocation of variable losses; and/or
- An ex-post scheme could encourage more efficient forecasts and the location of plant for different purposes.

The different arguments expressed by respondents against an ex-post scheme were that:

- The costs and complexity of such a scheme were likely to be high (one respondent stated that they therefore supported an ex-post calculation by Settlement Day, rather than by Settlement Period);
- The retrospective nature of an ex-post calculation would increase Parties' risk exposure, since TLF values would not be known in advance;
- It would not be possible to hedge the risk created by an ex-post scheme;
- This increased risk could increase costs to Suppliers, and therefore to consumers; and/or
- The time spent developing an ex-post scheme could delay the implementation of the benefits associated with P198.

One respondent referred to specific Applicable BSC Objectives – citing Objectives (b) and (c) in support of their views against an ex-post scheme.

Two respondents referred to the issue or defect identified by P198. One of these respondents, whilst not believing that an ex-post scheme would better facilitate the achievement of the Applicable BSC Objectives, did believe that such a scheme would address the defects identified by P198 (lack of cost-reflectivity and inefficiencies in the use of energy). The other respondent argued that use of actual data would meet the defect by providing the most efficient solution in allocation of costs and delivery of investment signals.

d) Modification Group's Further Discussions

Some members of the Group considered that an ex-post scheme could give the most accurate allocation of transmission losses, and might therefore be the most cost-reflective solution – better addressing the defect identified by P198. Some members believed that an ex-post nodal calculation and application of TLF values in each Settlement Period would be the most accurate possible solution, since use of an ex-ante or average calculation would introduce a level of approximation. However, the Group believed that any potential increase in accuracy was likely to be outweighed by the 'unhedgable risk' created by a retrospective calculation, and by the likely costs of the BSC Systems changes which would be required to support it. The Group noted that both of these consequences of an ex-post scheme had been significant factors in the TLFMG's recommendation, and the Authority's decision, to reject Modification Proposal P75.[17]

Following consideration of the responses to the first Assessment Procedure consultation, the Group initially agreed to defer any further assessment of this potential Alternative option pending the findings of the TLF modelling results regarding the temporal sensitivity of TLFs. On the basis of the modelling results, the Group subsequently agreed by majority that the most significant temporal variation was between seasonal and annual TLFs – and that there would therefore be little additional benefit in a calculating TLFs by Settlement Period or by Settlement Day (see Section 4.4 for further details of the modelling results). On the basis of these results and the arguments outlined above, the Group therefore unanimously agreed not to assess a potential ex-post Alternative option further.

4.6.2 Potential Alternative Option 2 – Higher-Granularity Ex-Ante TLF Calculation

a) Modification Group's Initial Discussions

The Group noted that another potential option for an Alternative Modification could be a higher-granularity ex-ante calculation of TLFs (i.e. retaining the advance forecast nature of the TLF calculation based on historic data). Two possible approaches were suggested by members as follows:

- *An ex-ante calculation of Adjusted Monthly Zonal TLFs* – twelve TLF values would be calculated for each TLF Zone in each BSC Year of the scheme (one for every calendar month in that BSC Year, based on data from each calendar month in a previous Reference Year); or
- *An ex-ante calculation of Adjusted Seasonal Zonal TLFs* – four TLF values would be calculated for each TLF Zone in each BSC Year of the scheme (one for every BSC Season in that year, based on data from each season in a previous Reference Year).

Both of these approaches formed part of the first Assessment Procedure consultation.

b) BSCCo Legal Advice

No legal advice was requested by the Group in respect of this option.

[17] The implementation costs for existing BSC Agents (excluding the TLFA) under P75 were estimated to be in the region of £800,000, with ongoing operational costs of around £100,000 per annum. For further detail, please refer to the P75/P82 Assessment Report.

c) Results of First Assessment Procedure Consultation

A large minority of respondents supported further assessment of a higher-granularity ex-ante TLF calculation.

The argument expressed by respondents in favour of this option was that:

- A higher-granularity calculation might better reflect variation in behaviour throughout a year (three respondents expressed a preference for monthly values, whilst one supported consideration of intra-day variation).

The different arguments expressed by respondents against this option were that:

- A higher-granularity calculation might not have any greater impact on long-term decisions;
- Such a scheme might lead to increased cost and complexity; and/or
- The time spent developing this option could delay the implementation of the benefits associated with P198, with negative impacts on competition and efficiency.

One respondent referred to specific Applicable BSC Objectives – citing Objectives (b) and (c) in support of their views that a higher-granularity calculation should be progressed.

One respondent referred to the issue or defect identified by P198, believing that a monthly calculation would better address the defects identified by P198 (lack of cost-reflectivity and inefficiencies in the use of energy).

d) Modification Group's Further Discussions

Following consideration of the responses to the first Assessment Procedure consultation, the Group initially agreed to defer any further assessment of this potential Alternative option pending the findings of the TLF modelling results regarding the temporal sensitivity of TLFs. The modelling results subsequently demonstrated that there could be a significant variation between annual and seasonal TLFs, but that this variation would be less pronounced at the monthly level (see Section 4.4 for further details).

On the basis of these modelling results, the Group agreed by majority to include the option of seasonal TLFs within the cost-benefit analysis (see Section 4.7) and not to consider any other higher-granularity calculation further. Following its consideration of the results of the cost-benefit analysis and second Assessment Procedure Consultation (see Sections 4.7 and 5), the Group agreed by majority to include a seasonal TLF calculation within the final Alternative Modification for P198. Further information on the views of the Group regarding the merits of this Alternative can be found in Section 6.

4.6.3 Potential Alternative Option 3 – Different Constitution of TLF Zones

a) Modification Group's Initial Discussions

The Group noted that one potential option for an Alternative Modification could be a different constitution of TLF Zones. The Group noted that, under P75 and P105, different sets of Zones were used for generation (based on TNUoS zones) and demand (based on GSP Groups).

Some members noted that, under this option, there could be a minimum of two zones – one for generation, and one for demand.

b) BSCCo Legal Advice

No legal advice was requested by the Group in respect of this option.

c) Results of First Assessment Procedure Consultation

A large minority of respondents supported some form of amendment to the TLF Zones. However, there was no majority of these respondents in favour of any one approach – with some respondents supporting more Zones and others supporting less.

Some respondents supported the use of fewer Zones, although none put forward a suggestion as to the revised basis for these Zones. One respondent believed that fewer Zones would better meet the defect identified by P198, although they did not necessarily agree that a defect existed for generation. Another respondent believed that fewer Zones would minimise the intra-Zone variation in TLFs.

In contrast, one respondent argued in favour of having one Zone per Node – effectively applying TLFs at the nodal level.

The different arguments expressed by those respondents who were against any revision to the TLF Zones were that:

- Zones for demand could only be based on GSP Groups, due to the nature of the BSC Settlement system; and/or
- Zones for generation and demand needed to be the same to avoid any distortions in signals, or a difference in the treatment of those generators who were embedded in a GSP Group compared to other generators at the same locality who were directly connected to the Transmission System.

Two respondents referred to specific Applicable BSC Objectives. One respondent cited Objectives (b), (c) and (d) in support of their view that fewer Zones would be desirable, but would not be possible due to the need to base demand Zones on GSP Groups. This respondent also believed that fewer Zones, though impractical, would better address the defects identified by P198 (lack of cost-reflectivity and inefficient use of energy). The other respondent believed that fewer Zones would better facilitate the achievement of Applicable BSC Objectives (c) and (d).

d) Modification Group's Further Discussions

The Group noted the previous conclusion of the TLFMG in respect of P75 that the use of different Zones for generation and demand could result in perverse economic signals, since the TLFs for generation and demand at the same locality would not be equal and opposite. The Group agreed with the view of the TLFMG that the use of different Zones could also be open to 'gaming', as it might be possible to arbitrage between supply and generation at a particular location. The Group therefore agreed with the view of those respondents to the first Assessment Procedure consultation who argued that the basis of the TLF Zones should be identical for generation and demand.

The Group also agreed with the view of some consultation respondents that, due to the design of the BSC Settlement systems, the only possible basis of TLF Zones for demand would be GSP Groups. The Group agreed that it was therefore difficult to see how there could be any different basis for the Zones than the use of GSP Groups for both generation and demand. On the basis of these conclusions, the Group unanimously agreed not to further assess any potential Alternative option in this area.

4.6.4 Potential Alternative Option 4 – Phased or Mitigated Implementation of TLFs

a) Modification Group's Initial Discussions

The Group noted that another potential option for an Alternative Modification could be a phased implementation and/or mitigated implementation of zonal TLFs. Two possible approaches were suggested by members as follows:

- *A 'linear' phased implementation of TLFs, potentially similar to the Alternative Modifications for P75 and P82* – under this approach the proportion of the TLF values applied to BM Units would be gradually increased over a specified period, through an additional scaling factor which would apply equally to all BM Units; and/or
- *A 'grandfathering' or 'hedging' scheme, potentially similar to that previously proposed by P109* – under this approach full zonal TLF values would be applied to new entrants, but TLFs for existing entrants would be 'mitigated' such that they only applied to any variation in output from a certain 'protected' volume of energy.

Both of these approaches formed part of the first Assessment Procedure consultation.

b) BSCCo Legal Advice

Some members of the Group were uncertain as to whether a 'grandfathering' or 'hedging' scheme would address the defect identified by the Modification Proposal. However, as the Group had not at that stage developed an overview of how such a 'grandfathering' scheme might work, BSCCo indicated that it would be difficult to provide legal advice in this area in the absence of more detail. The Group agreed by majority to defer any further development of this option pending the views of respondents to the first Assessment Procedure consultation.

c) Results of First Assessment Procedure Consultation

A large majority of respondents supported further consideration of a phased and/or mitigated implementation of TLFs.

The different arguments expressed by respondents in support of this option were that:

- Phasing would ameliorate the windfall gains and losses which would be created by the Proposed Modification, thereby better promoting competition;
- Phasing would allow a more managed approach to implementation, reducing the regulatory risk to investment and future cost of capital associated with a step-change to the current rules;
- A grandfathering scheme would prevent sterilisation of the assets of existing generators, who would be unable to respond to the locational signals created by P198 and would therefore be disproportionately penalised by the scheme;
- The locational signals created by P198 would ignore other factors in the location of existing generation, which would prevent generators from being able to respond to those signals;
- Phasing would reduce risk for demand, which would be unable to respond to locational signals; and/or
- Phasing or grandfathering would retain the short-term efficiencies of P198 whilst protecting against windfall gains and losses – thus better promoting economic efficiency.

Two respondents referred to the issue or defect identified by P198. One of these respondents stated that phasing and/or grandfathering would better meet the defect than the Proposed Modification. The other respondent also believed that either of these approaches would better address the defects identified by P198 (lack of cost-reflectivity and inefficiencies in the use of energy).

Two respondents referred to specific Applicable BSC Objectives in support of their views. One respondent argued that phasing or grandfathering would better facilitate Objectives (c) and (d) when compared with the Proposed Modification. The other respondent stated that this potential Alternative option would better facilitate Objective (c).

The argument expressed by respondents against the progression of a phasing or grandfathering option was that it would delay implementation of the benefits associated with P198, and therefore could not be viewed as better facilitating the achievement of the Applicable BSC Objectives.

d) Modification Group's Further Discussions

A majority of members agreed with the views expressed by a majority of consultation respondents that the inclusion of some kind of phasing or grandfathering would avoid penalising existing participants, who had made their investment decision on the basis of the current 'uniform' allocation of transmission losses. These members argued that existing participants would be unable to respond to the locational signals generated by P198, and would therefore be subject to windfall gains or losses depending on their geographical location. These members believed that P198 would thereby subject existing participants to regulatory risk, which would be reflected in an increase in the cost of capital. Some members considered that a grandfathering approach would best recognise that existing participants could only respond to the short-term marginal despatch signals created by P198 (i.e. by generating or consuming more or less), and not to the long-term signals regarding location. These members did not agree with the view of some consultation respondents that phasing or grandfathering would delay the benefits of P198 – arguing that they would give a more efficient implementation of any benefits associated with zonal loss charging.

A minority of members (including the Proposer) disagreed, and argued that phasing or grandfathering would delay the benefits of P198 by maintaining an element of the existing cross-subsidy between generation (south to north) and demand (north to south). These members argued that it was not possible to view such a delay as better facilitating the achievement of the Applicable BSC Objectives, or as fully addressing the defect identified by P198 – and noted that the Authority had previously expressed this view in its decision letters regarding P75, P82 and P109. The Proposer argued that existing participants accepted a degree of regulatory risk in becoming signatories to the Code, since the Code rules could be amended at any time via a Modification Proposal. The Proposer believed that it would not be appropriate for a Code modification to contain a scheme to 'hedge' its own effects, or to protect Parties' commercial positions – and noted that Parties could develop their own commercial hedging mechanisms outside the Code if they believed these were required. The Proposer also considered that any effect of Code changes on the cost of capital was unproven, and were likely to be negligible compared with other investment factors such as the cost of land.

The Group considered whether to assess both phasing or grandfathering further, and unanimously agreed to only assess the approach which it believed was most likely to better facilitate the Applicable BSC Objectives. By a narrow majority, the Group agreed to only progress a 'linear phasing' approach to the application of TLFs, along the lines of that previously considered as an Alternative Modification to P82. The arguments expressed by these members were that:

- The simplicity of a linear phasing approach would be more efficient, compared with the complexity and increased costs which were likely to be involved in a grandfathering scheme;[18] and
- Linear phasing would apply equally to all types of Parties, whilst the Authority had previously raised concerns in its P109 decision letter that a grandfathering scheme would give different treatment to different types of BM Units.

[18] The implementation costs for existing BSC Agents (excluding the TLFA) under P109 were estimated to be in the region of £1.3 million, with ongoing operational costs of around £200,000 per annum. For further detail, please refer to the P109 Modification Report.

A substantial minority of members disagreed, and argued that a linear phasing scheme would simply scale down TLF values, and therefore the signals generated by those TLFs – since it would reduce the differentials between the values for different Zones. These members believed that a grandfathering scheme would preserve the P198 signals at the margin, by preserving the differentials between Zones and applying full TLFs to any variation from a 'protected' historic level of output. These members therefore believed that such a scheme would therefore be the most economically efficient approach. Modification Proposal P200 was subsequently raised by Teesside Power Ltd, which seeks to introduce zonal TLF values with a 'hedging' scheme to mitigate the application of those TLFs to existing generators. Further information can be found in the P200 Assessment Report.

Following its consideration of the results of the cost-benefit analysis and second Assessment Procedure consultation (see Sections 4.7 and 5), the Group agreed by majority to include a linear phasing approach within the final Alternative Modification for P198. Further information on the views of the Group regarding the merits of this Alternative can be found in Section 6.

4.6.5 Potential Alternative Option 5 – Exclusion of Certain BM Units from Application of TLFs

a) Modification Group's Initial Discussions

Various members of the Modification Group suggested that an option for a potential Alternative Modification could be to exclude one, some or all of the following types of BM Units from the application of zonal TLFs:

a) BM Units connected to the 132kV transmission network;

b) Supplier BM Units;

c) BM Units relating to wind generating plant; and/or

d) BM Units relating to renewable generating plant.

All of these options formed part of the first Assessment Procedure consultation.

The Group noted that one possible approach for this option could be to calculate zonal TLFs for the 'excluded' BM Units through the Load Flow Model, but to set the TLF values used in Settlement for these BM Units to zero so that they were not applied. Under this approach, the share of variable losses which was not allocated to 'excluded' BM Units on a zonal basis would be smeared across all BM Units (including the 'excluded' BM Units) on a non-locational basis through the TLMO, along with their non-locational share of 'fixed' losses – retaining the existing overall 45:55 allocation of total transmission losses to generation and demand.

b) BSCCo Legal Advice

Some members of the Group were uncertain as to whether this potential Alternative option would address the defect identified by the Modification Proposal, and the Group therefore agreed to seek legal advice from BSCCo in this area.

A summary of BSCCo's legal interpretation of the issue or defect identified by P198 is that the variable element of transmission losses is currently allocated on a uniform basis and, as such, the cost which Parties pay for variable losses bears no relation to the extent to which each Party has given rise to these losses. If certain types of BM Units were to be excluded from the P198 locational calculation for variable losses, then it would be necessary to establish that they do not cause variable losses in order to address the defect identified by P198.

A summary of this legal advice was provided to the industry as part of the first Assessment Procedure consultation.

c) Results of First Assessment Procedure Consultation

A minority of respondents supported the exclusion of certain types of BM Units from the application of TLFs, believing that this would better promote competition. However, these respondents were divided over which types of BM Units should be excluded.

Some respondents believed that Supplier BM Units should be excluded from the application of TLFs, arguing that demand would not be able to respond to the locational signals created by P198. One respondent argued that all 'good quality' Combined Heat and Power (CHP) plant should be excluded, on the basis of the benefits that they delivered in terms of wider energy and environmental objectives. Another respondent supported the exclusion of renewables from the scheme. This respondent argued that such BM Units were by necessity located in the north of Scotland, and that P198 could therefore discourage renewable investment where resource was optimal. Two respondents supported the exclusion of those BM Units which were connected to the 132kV elements of the Transmission System, arguing that these BM Units would be disproportionately impacted by the scheme since losses from 132kV lines would be higher. One of these respondents argued that 132kV transmission-connected BM Units should be allocated 'distribution' Line Loss Factors and not Transmission Loss Factors, consistent with the treatment of 132kV distribution lines in England and Wales.

The different arguments expressed by respondents against excluding any BM Units from the scheme were that:

- There could be no grounds for an arbitrary or selective application of the scheme, which should either be determined to be sufficiently robust to apply to all Parties or should be rejected in its entirety;
- Exclusion of certain BM Units was not 'in the spirit' of the original proposal, and any form of carve-out for particular users would promote an arbitrary cross-subsidy on the basis of type of generation or network voltage;
- Certain parties should not be excluded, since all were responsible for transmission losses;
- Some wind generators in the south-west would benefit from a zonal transmission losses scheme, and excluding all renewables would deny such generators this benefit;
- If the government wished to support wind or other renewable generation, this support should be given transparently outside the BSC;
- BM Units connected to the 132kV element of the Transmission System could not be excluded from the allocation of transmission losses, since these lines were legally defined by their function (i.e. transmission) rather than their voltage; and/or
- Demand could not be excluded from the application of TLFs, as this would create discrimination between local generators depending on whether they were embedded or not.

One respondent stated that they agreed with BSCCo's legal advice, and believed that 132kV transmission-connected BM Units could not be excluded – arguing that these lines formed an integral part of the Transmission System and should therefore be allocated their share of 'transmission' losses. One respondent noted that 132kV elements of the Transmission System were not exclusive to Scotland, and that there were some (very limited) examples of 132kV transmission assets in England and Wales.

One respondent acknowledged the rationale for proposing the exclusion of certain BM Units, and believed that it could address the defects identified by P198. However, this respondent was uncertain as to whether this approach would constitute too much 'positive discrimination'.

No respondents referred to specific Applicable BSC Objectives in respect of this potential Alternative option.

d) Modification Group's Further Discussions

A majority of members agreed with BSCCo's legal advice that the exclusion of certain types of BM Units from a zonal TLF calculation would not meet the intention of P198 to allocate variable transmission losses according to the extent to which BM Units cause these losses, since all BM Units contribute to the level of such losses. The Proposer argued that excluding certain BM Units from the application of TLFs would mean that the variable losses caused by those BM Units were still smeared uniformly across all Parties through the TLMO, perpetuating an element of the cross-subsidy that P198 sought to remove.

A minority of members disagreed, and argued that the Proposed Modification itself would not meet the defect identified by the Proposer since not all BM Units would be able to respond to the signals which it created. These members disagreed with BSCCo's legal advice, and argued that the exclusion of certain BM Units would therefore better meet the defect identified by the Modification Proposal than the Proposed Modification by allocating the cost of losses more reflectively.

Some members argued in favour of excluding those BM Units which were connected to the 132kV element of the Transmission System in Scotland, arguing that these BM Units would be disproportionately penalised by the scheme since losses from 132kV lines would be higher than those of 275kV and 400kV lines. These members believed that BM Units connected to 132kV transmission lines should not be allocated TLFs, but should receive Line Loss Factors in the same way as those 132kV lines which are classed as being part of a distribution system.

However, a majority of members disagreed with this suggestion. These members noted that P198 sought to allocate transmission losses to BM Units according to the extent to which they were caused. Since 'transmission' losses are defined as being losses from the Transmission System – which includes certain 132kV lines in addition to the higher-voltage network – these members believed that excluding 132kV transmission-connected BM Units would not address the defect identified by P198.

By majority, the Group therefore agreed not to progress this potential Alternative option further.

4.6.6 Potential Alternative Option 6 – Exclusion of 132kV Transmission Losses from TLF Calculation

a) Modification Group's Initial Discussions

Some members of the Group suggested that a potential option for an Alternative Modification could be to exclude those variable losses relating to the 132kV elements of the Transmission System from the Load Flow Model altogether, such that these losses did not form part of the TLF calculation and continued to be allocated through the TLMO on a uniform basis.

b) BSCCo Legal Advice

Some members of the Group were uncertain as to whether this potential Alternative option would address the defect identified by the Modification Proposal, and the Group therefore agreed to seek legal advice from BSCCo in this area. BSCCo's legal advice was that, if certain elements of the Transmission System were to be excluded from the P198 locational calculation for variable losses, it would be necessary to establish that these elements of the Transmission System do not cause variable transmission losses in order to address the defect identified by P198.

A summary of this legal advice was provided to the industry as part of the first Assessment Procedure consultation.

c) Results of First Assessment Procedure Consultation

A minority of respondents supported the exclusion of transmission losses from 132kV transmission lines in the calculation of TLFs.

In addition to the arguments put forward for Potential Alternative Option 5, some of these respondents argued that the inclusion of losses from the 132kV element of the Transmission System in the TLF calculation would create disproportionality between the TLFs for Scotland and those for England and Wales. One respondent referred to Applicable BSC Objective (c) in support of this view.

The arguments put forward against further progression of this option were the same as those put forward in respect of Potential Alternative Option 5.

d) Modification Group's Further Discussions

The arguments expressed by members in respect of this potential Alternative option were very similar to those put forward regarding Potential Alternative Option 5.

A minority of members argued in favour of excluding losses from 132kV transmission lines, arguing that their inclusion would create a disproportionality between TLF values in Scotland and those in England and Wales. These members believed that losses from 132kV transmission lines should not be used in the TLF calculation, and that all 132kV connections should receive Line Loss Factors. A majority of members disagreed, arguing that – in order to address the defect identified by P198 – this would require a change to the definition of the Transmission System to exclude all 132kV lines and class them as distribution. These members noted that such a change was outside the scope of P198, and also outside the vires of the Code. One member noted that there were also a limited number of 132kV transmission assets in England and Wales, and therefore did not agree that including 132kV transmission losses in the TLF calculation would discriminate against Scotland.

By majority, the Group therefore agreed not to progress this potential Alternative option further.

4.6.7 Potential Alternative Option 7 – Different Allocation of Transmission Losses for Generation and Demand

a) Modification Group's Initial Discussions

Some members of the Group suggested that a potential option for an Alternative Modification would be to amend the existing 45:55 overall allocation of total transmission losses, such that a different proportion would be allocated to generation and demand. Some members noted that, at its most extreme, this option could take the form of a 100% allocation to either generation or demand.

b) BSCCo Legal Advice

Some members of the Group were uncertain as to whether this potential Alternative option would address the issue or defect identified by the Modification Proposal, and the Group therefore agreed to seek legal advice from BSCCo in this area. BSCCo's legal interpretation is that the issue or defect identified by P198 relates purely to the uniform allocation of variable losses. BSCCo's legal advice was therefore that a change to the existing 45:55 allocation of *total* transmission losses (which includes fixed losses in addition to variable losses) would be seeking to address a broader defect than that identified by P198.

A summary of this legal advice was provided to the industry as part of the first Assessment Procedure consultation.

c) Results of First Assessment Procedure Consultation

A substantial minority of respondents supported amending the existing 45:55 split, such that a greater proportion or 100% of all transmission losses was allocated to demand – with less or none allocated to generation. These respondents argued that this would recognise that the cost of all transmission losses would ultimately be passed to consumers, and would therefore meet the defect identified by P198 by being the most 'cost-reflective' solution. One respondent also argued that all transmission losses were ultimately caused by demand. One respondent argued that allocating all losses to demand would better facilitate the achievement of Applicable BSC Objectives (b) and (c), whilst one believed that it would better facilitate Objective (d). Some of these respondents also believed that a 100% allocation to demand would be consistent with the approach taken in other EU states. One respondent suggested a different variation of this potential Alternative option, whereby all transmission losses would be allocated to the Transmission Company, rather than to individual generators and Suppliers.

However, a majority of respondents did not support further consideration of this potential Alternative option. Two of these respondents stated that they agreed with BSCCo's legal advice that a change to the 45:55 allocation of total transmission losses was outside the scope of P198 and would require a separate Modification Proposal. One respondent stated that they believed a 100% allocation to the Transmission Company was also outside the scope of P198. One respondent argued that generation and demand should be treated equally, and stated that they did not believe there to be any potential improvement to the existing 45:55 allocation.

d) Modification Group's Further Discussions

A minority of members disagreed with BSCCo's legal advice and argued that a greater or 100% allocation of transmission losses to demand would better address the defect identified by P198. These members argued that all losses were ultimately caused by demand, and that this approach would therefore give the most cost-reflective allocation.

A majority of members disagreed with this view, since they agreed with BSCCo's view that the defect identified by P198 related only to the allocation of variable losses. These members therefore believed that a change in the allocation of total transmission losses would be seeking to address a broader defect than P198, and would therefore be outside the scope of the Modification Proposal.

Some members stated that they were sympathetic to the suggestion that all transmission losses should be allocated to the Transmission Company, since they believed that the BSC was not necessarily the best mechanism for allocating losses. One member stated that they believed there to be a rationale for including transmission losses within the Transmission Company's TNUoS charging methodology. However, these members agreed that this approach would be seeking to address a different defect to P198, and would therefore be outside the scope of P198.

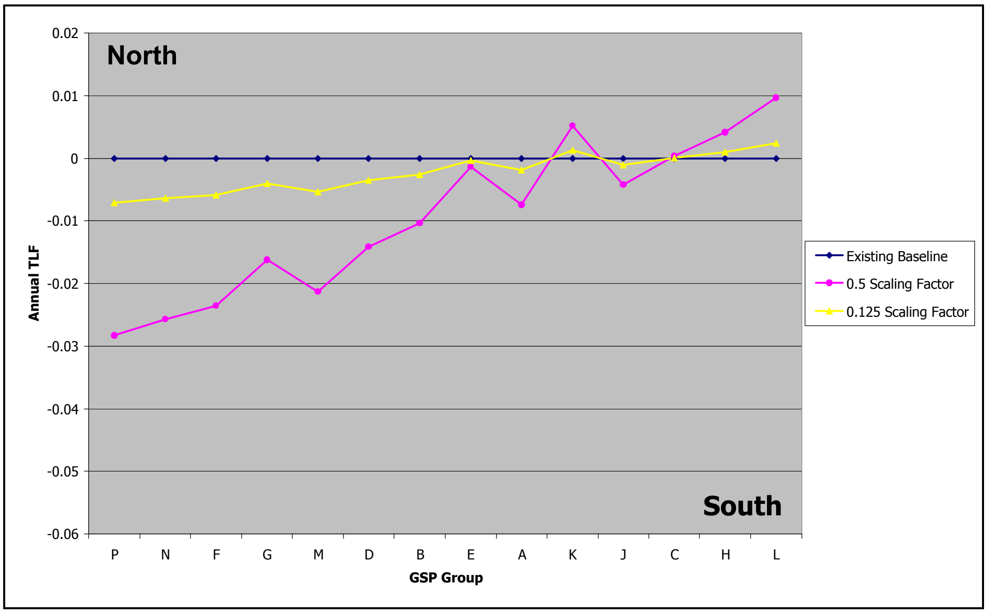
4.6.8 Potential Alternative Option 8 – Alternative Scaling Approach for TLFs

Two respondents to the first Assessment Procedure consultation suggested a further potential option for an Alternative Modification, whereby the TLF values generated by the Load Flow Model would be scaled with the aim of allocating 'no negative TLFs'. These respondents described the intention of this option as being to allocate a zero or positive fraction of variable losses to every Node, such that no negative fraction of variable losses was attributable to any given Node. Since this potential option initially appeared to relate to the appropriateness of the 0.5 TLF scaling factor suggested by the Proposer, the Group agreed to defer further consideration of this suggestion pending the outcome of the TLF modelling exercise.

On the basis of the modelling results, the Group unanimously agreed that 0.5 continued to be the appropriate scaling factor to ensure that the level of variable losses allocated through TLFs was comparable to that calculated by the Load Flow Model. Further detail regarding the modelling results can be found in Section 4.4. However, one member of the Group – whilst not disagreeing with this conclusion – clarified that their 'alternative scaling' approach had been based on a different principle, whereby it would attempt to ensure that no BM Units were credited with energy (i.e. received a negative share of losses) through the TLM. This member believed that it would be inappropriate for Parties to receive payments as a result of transmission losses, and that the TLFs should therefore be scaled such that, on average over time, no individual flow was credited with energy as a result of transmission variable heating loss adjustments. Under this approach, all BM Units would therefore receive an energy debit (i.e. pay a share of the cost of losses) – although whether an individual BM Unit's debit was less or greater than its current uniform share of losses would depend on the TLF for its Zone.

The member noted that there could be several approaches to delivering this intention, but believed that the simplest would be to calculate a different average scaling factor to be fixed in the Code. The member advised that their initial analysis suggested that the value of such an alternative scaling factor could be in the region of 0.125 – resulting in the TLFs shown in Figure 14 below.

Figure 14 – 'Alternative Scaling' Approach to TLFs



Some members of the Group stated that they were sympathetic with the intention of this approach, but that they believed it to be addressing a different defect to that identified by P198. Some of these members were also unconvinced that a fixed alternative scaling factor would be the most accurate way of achieving the intention of this approach – since this would be an approximation which was unlikely to prevent BM Units being credited with energy in all half-hour Settlement Periods.

One member suggested that a more accurate approach might be to derive a different scaling factor for each half hour. This member believed that it would therefore be preferable for 'alternative scaling' to be raised as a Standing Issue or a separate Modification Proposal, to allow the industry to consider the most appropriate solution. Other members supported this suggestion, believing that the 'alternative scaling' approach would require a substantive assessment in its own right. These members noted that such an approach would alter the differentials between the TLFs for different Zones, and believed that further work would be required to investigate its impact on the allocation of losses (including its effect on the signals created by the scheme).

Other members of the Group also believed that progression of an 'alternative scaling' approach was outside the scope of P198, and would require a separate Modification Proposal. By majority, the Group therefore agreed not to assess this potential Alternative option further. P204 was subsequently raised as a separate Modification Proposal in this area.

4.7 Overview of Cost-Benefit Analysis

4.7.1 Modification Group's Initial Discussions

a) Rationale for Undertaking Cost-Benefit Analysis

The Group noted that no unified cost-benefit analysis had been undertaken by the TLFMG during 2002. Instead, two 'competing' sets of analysis had been obtained by individual TLFMG members for P75 as follows:

- National Economic Research Associates (NERA) – 'Cost Benefit of Transmission Losses Proposal P75' and 'Cost Benefit Analysis of P75: Response to Campbell Carr'; and
- Campbell Carr – 'A Commentary on NERA's Cost Benefit Analysis of Transmission Losses Proposal, prepared for Powergen'.[19]

In addition, the TLFMG relied on analysis produced by the Transmission Company in 2001 regarding the possible economic signals of a zonal transmission losses scheme. This analysis was produced prior to the raising of P75, P82 and P105, as part of an Ofgem consultation on transmission access and charging arrangements under NETA – and its results can be found in the Ofgem conclusions document (Reference 16).

The NERA analysis had concluded that P75 would have no net benefit, whilst Campbell Carr questioned the procedural validity of using a cost-benefit analysis for BSC Modification Proposals and also disputed the assumptions used by NERA. The Group noted that NERA had also provided analysis in support of the P109 'hedging' scheme, but that no specific cost-benefit analysis had been carried out for P82 during the Assessment Procedure. The Group noted that some Panel Members and consultation respondents had considered that the TLFMG had failed to demonstrate whether a zonal transmission losses scheme would be more cost-reflective than the existing Code baseline. The Group noted that these participants had been concerned that P75, P82 and P105 would simply result in short-term windfall gains and losses to Parties, with no proven net benefit for the industry.

The Group noted that the following specific analysis of P82 had subsequently been undertaken following its approval by the Authority in 2003, as part of the DTI's consideration whether to include P82 in the GB BSC under BETTA:

- Oxford Economic Research Associates (OXERA) – 'A Report to the DTI: The Impact of Average Zonal Transmission Losses Applied Throughout Great Britain' (Reference 17); and
- ILEX Energy Consulting – 'A Report to the Scottish Executive: Assessing the Introduction of Zonal Charging for Transmission Losses in Great Britain' (Reference 18).

The OXERA analysis had concluded that any positive net benefit of P82 to the GB market was ambiguous. The ILEX report had concluded that P82 would have a subtle impact on Scottish generation, but did not comment specifically on its cost-benefits.

The Group therefore noted that there were a variety of historic cost-benefit analyses available regarding a zonal transmission losses scheme, but that the scope and findings of these analyses were different or conflicting.

[19] Copies of the NERA and Campbell Carr analysis can be found in the joint P75/P82 Assessment Report.

The Group noted that, in setting the Terms of Reference for the P198 Assessment Procedure, the Panel had agreed with BSCCo's recommendation that the Group should:

- Develop and agree the requirements for undertaking a cost-benefit analysis of P198;
- Instruct BSCCo to procure an independent external consultant to undertake the cost-benefit analysis in accordance with the requirements developed by the Group; and
- Agree that the cost-benefit analysis results were produced in accordance with the Group's requirements (even if not all members of the Group agreed with the specific findings).

The Group noted that the Panel believed that the production of such an analysis would be an essential aid to industry participants in formulating views as to the costs and benefits of P198.

One member of the Group argued that a cost-benefit analysis was not a valid element of the Modification Procedures, since they believed it did not relate directly to the Applicable BSC Objectives. However, the other members of the Group disagreed with this view, and believed that a cost-benefit analysis of P198 would be a key aid to the Group in assessing the merits of the Modification Proposal. These members believed that a standard part of a Modification Group's assessment of whether a Modification Proposal would better facilitate the achievement of the Applicable BSC Objectives is an analysis of the costs and benefits of the proposal. These members noted that undertaking a cost-benefit analysis of P198 fell outside the expertise of BSCCo and the members of the Group – since the perceived benefits of a zonal transmission losses scheme would depend on the ability of the scheme to influence short and long-term market behaviour through economic signals. These members therefore supported the Panel's request that an independent analysis be sought from an external consultant with expertise in undertaking economic forward-modelling of the energy market. These members also believed that it was essential to undertake fresh quantitative analysis, rather than a qualitative critique of previous work in this area, in order to re-evaluate the underlying assumptions and capture developments in the market since 2002/2003.

b) Scope of Cost-Benefit Analysis

The Group agreed that the overall objective of the cost-benefit analysis should be to assess the future costs and benefits of P198 to the market. The Group agreed that the scope of the analysis should take into account both short-term impacts (such as implementation costs, effects on despatch, and the immediate impact on charges paid by generators and Suppliers) and long-term effects (such as any impact on the future development and location of generation and demand). The Group agreed that it was unlikely to be possible to undertake detailed quantitative modelling beyond around 2012 – since this date represented the end of the period covered by the Transmission Company's Seven Year Statement, and no detailed network information would therefore be available beyond this point. However, the Group expressed a preference for examining the impacts of P198 up to 2015/16, in order to take full account of planned plant closure and new build during the next ten years. The Group agreed that the external consultant should therefore model the first five years of the study period in detail, but that the results of the remaining five years could be extrapolated if necessary.

The Group noted that the cost-benefit analysis would represent a tool to aid the Group in its assessment of P198 against the Applicable BSC Objectives, but not the assessment itself. The Group noted that members would therefore be able to disagree with the specific findings of the analysis, whilst agreeing that the analysis covered the areas specified by the Group. The Group agreed that the cost-benefit analysis should focus purely on the net economic benefit of P198, and that the consultant should not be required to take a view of the merits of P198 against the Applicable BSC Objectives – since this was a judgement which would be subsequently made by the Group. However, the Group recognised that members would need to tie the perceived costs and benefits of P198 to the Applicable BSC Objectives when making its final recommendation to the Panel. The Group therefore agreed that any explicit quantification of the following areas should be excluded from the scope of the cost-benefit analysis, since these potential impacts fell outside the scope of the BSC:

- Any impact of P198 on the environment; and
- Any impact of P198 on consumers.

The Group noted that the Authority would be able to consider any impacts in these areas as part of its wider statutory duties, when making its decision on P198.

The Group agreed that TNUoS was a relevant background consideration for the cost-benefit analysis, since this sought to examine the long-term impact of P198 relative to other factors in the market. However, members noted that any detailed assessment of the impact of P198 on existing TNUoS signals fell outside the remit of the Group.

c) Choice of Methodology

The Group agreed that, in order to analyse the long-term impact of zonal TLFs, the external consultant should be required to calculate 'evolved' TLF values for each Zone over the next ten BSC Years. The Group noted that this was likely to require a load-flow modelling capability. The Group agreed that the initial TLF values generated by the cost-benefit analysis consultant for 2006/2007 should be validated against those calculated by PTI using 623 Sample Settlement Periods, to ensure consistency between the workings of the load-flow models. However, the Group noted that it might not be possible for the cost-benefit analysis consultant to model 623 Sample Settlement Periods for each of the ten years of the study period in the timescales available for the analysis – and that use of a smaller number of sample periods might be required to reduce the amount of computations required.

In addition, the Group agreed that the consultant should provide a quantitative prediction of the changes in market behaviour which would result from P198. The Group noted that this was likely to require the use of an economic despatch model.

The Group agreed that the precise methodology to deliver these requirements should be chosen by the consultant based on its expertise.

d) Choice of Scenarios, Assumptions and Sensitivities

The Group agreed that the consultant should create the following scenarios:

i) A 'base-case' scenario to quantify the changes in the market over ten years without the introduction of P198 (i.e. based on the current uniform allocation of transmission losses); and

ii) A 'change-case' scenario to quantify the changes in the market over ten years following the introduction of P198.

The Group agreed that this would allow a comparison of market evolution with and without P198.

The Group agreed that the base-case and change-case scenarios should be based on the same 'business as usual' environment (i.e. the change-case would represent the base-case scenario with the introduction of P198). The Group noted that assumptions would need to be made regarding how market conditions might credibly change over the ten-year period – including consideration of factors such as market prices and demand growth. Some members of the Group argued that the assumptions to be used in the analysis should be specified by the Group, although there was no agreement as to what these assumptions should be. A majority of members disagreed, and argued that the consultant should choose the assumptions based on its economic and market expertise. However, these members did consider that it was essential for the consultant to detail the assumptions used, and to test the sensitivity of those assumptions which it believed to be the most susceptible to change – such that a range of possible net benefits were calculated.

By majority, the Group therefore agreed to specify the areas in which it believed assumptions would be required, but to leave the choice of assumptions to the consultant. It also agreed to specify any background considerations or documents (such as the Seven Year Statement or government policy) which it believed should be taken into account by the consultant in formulating its assumptions. Further information on the Group's requirements can be found in the P198 Cost-Benefit Analysis Requirements Specification.

Following its consideration of the PTI modelling results and the responses to the first Assessment Procedure consultation (see Sections 4.4 and 4.6), the Group agreed to include an additional sensitivity examining the difference in impact between the use of Adjusted Annual Zonal TLFs and Adjusted Seasonal Zonal TLFs. By majority, the Group agreed not to include any other potential Alternative option within the scope of the cost-benefit analysis, since it believed that the impact of a linear phasing option could be qualitatively derived by the Group using the consultant's analysis results.

e) Input Data

The Group agreed that the following input data should be provided to the cost-benefit analysis consultant:

- The non-confidential implementation and operational costs of P198 to BSC Parties, BSC Agents, BSCCo and the Transmission Company – as provided in response to the Proposed Modification impact assessment (see Section 4.5);
- The TLFs calculated by PTI for 2006/2007 using historic 2005/2006 data; and
- Any other outputs of the PTI modelling exercise which might be required by the consultant to validate the results of its own load-flow model.

In addition, the Group also specified a variety of public documents to be taken into account in the analysis. Further detail can be found in the P198 Cost-Benefit Analysis Requirements Specification.

The Group agreed that, to ensure maximum transparency of the analysis, all input data should be objectively derived from public sources or provided by BSCCo.

f) Choice of Cost-Benefit Analysis Tasks

The following outlines at a high level the specific analysis tasks which the Group agreed should be included within the cost-benefit analysis:

- Quantification of the implementation costs of P198 to Parties as a whole;
- Quantification of the initial distributional impacts of P198 on Parties;
- Quantification of the impact of P198 on the volume and cost of transmission losses;
- Quantification of the impact of P198 on existing and future generation (including by location, size and fuel-type);
- Quantification of the impact of P198 on existing and future demand; and
- Quantification of the impact of P198 on the operation and development of the Transmission System (including the impact on, and of, constraints).

Further detail regarding the requirements underlying each of these tasks can be found in the P198 Cost-Benefit Analysis Requirements Specification.

The Group agreed that the cost-benefit analysis should give specific consideration to the impact of P198 on connectees to the 132kV element of the Transmission System. A minority of members argued that the analysis carried out by PTI, which examined the influence of losses from 132kV transmission lines on TLF values, should be repeated by the cost-benefit analysis provider for each of the ten years of the study period. However, a majority of members disagreed – noting that this would require a substantial amount of additional load-flow modelling. These members argued that the cost-benefit analysis should be limited to examination of whether the signals resulting from TLF values would have any differential impact on those participants who were connected to the 132kV element of the Transmission System, compared with other participants in the same Zones who were connected to the higher-voltage network. The requirements for the analysis were therefore based on this majority view.

Some members of the Group initially argued that the cost-benefit analysis should seek to quantify whether the P198 allocation of transmission losses would be more 'cost-reflective' than the existing Code baseline. The Proposer believed that this would, in effect, quantify the materiality of the existing 'cross-subsidy' which P198 sought to remove. However, other members of the Group considered that these terms were subjective. Some members did not necessarily believe that the cross-subsidy identified by P198 existed, and argued that – rather than being more 'cost-reflective' – P198 would result in 'windfall' gains and losses to Parties with no obvious benefit. Other members argued that the purpose of the cost-benefit analysis was to objectively quantify the net economic effect of the proposed scheme, and that the appropriateness of this effect was a judgement which could be subsequently made by the Group on the basis of the analysis results. On balance, the Group therefore agreed not to include a requirement to quantify the 'cost-reflectivity' of P198.

One member noted that the economic modelling which would be carried out by the consultant would be based on an assumption of economic despatch. This member questioned how realistic this assumption was, given that there were other factors in Parties' behaviour such as their contractual positions. However, the Group noted that the consultant would not have knowledge of Parties' portfolios or contracts. Some members therefore argued that the cost-benefit analysis should include consideration of the limitations of economic despatch modelling. However, a majority of members believed that adding this to the requirements would add little value, since this was a subjective judgement which could be made by members of the Group. By majority, the Group therefore agreed not to include this requirement.

A minority of members argued that the cost-benefit analysis should seek to quantify the impact of P198 on perceptions of regulatory risk and on the cost of capital to Parties. However, following its initial tender exercise, BSCCo advised that all of the potential service providers who had provided proposals for the analysis either believed that quantitative analysis in this area was not possible or that the issue was not material. A majority of members argued that individual Parties would be best placed to comment on this potential effect of P198, and noted that views could be sought as part of the consultation process. By majority, the Group therefore agreed not to include a specific requirement for quantitative analysis in this area, but to include risk and cost of capital as a background area to be considered qualitatively in the analysis. The Group also agreed that the second Assessment Procedure consultation should include a specific question in this area.

g) Choice of Service Provider

A commercial tender process was followed by BSCCo in order to identify potential service providers and to evaluate possible approaches. After initial research of the marketplace, eleven organisations expressed an interest in bidding to become the cost-benefit analysis provider. However, due to a number of issues (including conflicts of interest, lack of specific electricity market expertise, and lack of resources), only five of these eleven organisations submitted an initial proposal for the service. These five organisations were invited to discuss their proposals with BSCCo, and the approaches and clarifications from this exercise were fed back into the Modification Group as an aid to developing its final requirements.

Following the Group's production of the final Cost-Benefit Analysis Requirements Specification, the five organisations were invited to submit a final proposal on the basis of this specification. Proposals were received from three of these organisations. All proposals were evaluated against a variety of technical, commercial and organisational criteria by BSCCo. On the basis of this evaluation, OXERA was awarded the contract for the service.

OXERA's proposed methodology was based on an iterative process of load-flow modelling and economic-despatch modelling. Under this approach, a load-flow model was used to calculate TLFs for the 2006/07 year using historic 2005/06 data. These values were then fed into an economic despatch model to measure their effect on the generation merit order. The resulting changes in despatch were then used in the load-flow model to calculate the affect on losses and the TLF values for the subsequent year. This process was repeated for the ten years of the study period. In order to reduce the amount of computations required for the analysis, OXERA's calculation of evolved TLFs was based on load-flow modelling of a small number of 'snapshot' periods.

h) Output of Analysis

The output of the cost-benefit analysis was a report by OXERA to the Group, setting out the conclusions of the analysis. The full report is attached as Appendix 6. Section 4.7.2 below provides a high-level summary of the analysis, whilst details of the Group's discussion of the results can be found in Sections 4.7.3 and 4.7.4.

In addition, OXERA attended a meeting of the Group to present the results of the analysis.

4.7.2 Results of Cost-Benefit Analysis

The key conclusions of the cost-benefit analysis are set out at a high level below. For further detail regarding these conclusions, please refer to the full analysis report in Appendix 6.

a) Net Benefit to Market

The cost-benefit analysis identified a total net benefit from the introduction of P198 of £21 million – £66 million over the ten years of the study period.

These figures are net of the P198 implementation costs (a one-off cost to the market, estimated to be in the region of £2 million), operational costs (estimated at £300,000 per year), and of the assumed offsetting resource costs to Parties (for example, the use of higher-priced fuel during redespatch).

The figures comprise a range of net benefits, calculated using the following in addition to the central 'business as usual' change-case scenario:

- A sensitivity based on higher-demand growth;
- A sensitivity based on lower gas prices, where the price relativities of gas and coal were reversed; and
- A sensitivity based on the central scenario, but with the use of Adjusted Seasonal Zonal TLFs rather than Adjusted Annual Zonal TLFs.

A breakdown of the figures is provided in Table 7 on the following page.

Table 7 – OXERA Scenarios of Future Benefits of P198 to 2015/2016 (£m)

OXERA Assumed Future Benefits	Central Scenario	Demand Scenario	Gas Scenario	Seasonal TLFs Scenario
Generation Redespatch (per annum)	2.9	6.4	6.0	8.9
Demand Response (per annum)	0.6	0.9	0.5	0.8
Assumed Operating Costs (per annum)	0.3	0.3	0.3	0.3
Assumed Implementation Costs	2.0	2.0	2.0	2.0
Net Present Value of Future Benefits to 2015/2016, Net of Offsetting Cost Increases	**21.1**	**49.0**	**42.9**	**65.7**

The net benefit of using seasonal TLFs was therefore estimated by OXERA to be treble that of using annual TLFs under the central scenario.

Please note that the demand response and total benefit figures given in Table 7 above have been amended slightly from those provided in the P198 Second Assessment Procedure Consultation Document, following OXERA's subsequent identification of an error in the demand response figures. Corresponding amendments have also been made to Sections 6 and 8 of the cost-benefit analysis report in Appendix 6. Although the correction of this error altered the estimated annual changes in consumption per TLF Zone, the resulting differences in the net benefit figures were minor and in the order of £0.1-£0.2m. The Group agreed that the correction of this error should be brought to the attention of the Panel and the industry; however, it agreed that the amended figures did not alter its overall views regarding P198. An additional consultation was subsequently issued to industry, which identified the correction of this error and sought confirmation from respondents that the amended data did not alter their views regarding P198. The responses received to this consultation can be found in Appendix 9 (note that, at the date of production of this report, these responses were not yet available but will be provided to the Panel at its meeting on 10 August 2006).

b) Distributional Impacts

OXERA also estimated the distributional effects for Parties which would occur during the first year of the scheme, as a result of the changeover from the current uniform allocation of losses to the new locationally-based allocation. These effects are set out below. OXERA concluded that whether these distributional impacts affected the net benefits identified in Table 7 was a judgement to be made by the industry.

i) Impacts by TLF Zone

Figures 15 and 16 on the following page show the total annualised distributional impacts for generators and Suppliers in each individual TLF Zone for 2006/07, as estimated by OXERA for each scenario. These graphs were produced by BSCCo using the figures provided in Section 9 of the OXERA cost-benefit analysis report. The transfer figures in the graphs show the difference in Parties' Trading Charges which OXERA estimated would occur under each scenario, compared with the existing uniform TLM calculation under the current Code baseline. Negative transfers within the graphs represent an increase in payments compared with the current baseline, whilst positive transfers represent a decrease in payments. Note that the figures represent the total transfers across all generators or Suppliers within a Zone, and not the individual impact on any specific Parties. Please note also that the figures do not take account of any portfolio effects which might offset these impacts for any individual Parties.

The figures underlying these graphs can be found in Section 9 of the OXERA cost-benefit analysis report in Appendix 5. Although the transfer figures by Zone contained in Figures 15-16 and in Section 9 of the OXERA report will not exactly sum to zero (since these are rounded figures), the precise transfer figures underlying these rounded totals would sum to zero. The £/MWh values of the electricity price used by OXERA to calculate these transfers can also be found in Section 9 of the cost-benefit analysis report.

Figure 15 – OXERA Annualised Distributional Impacts on Generators (2006/07)

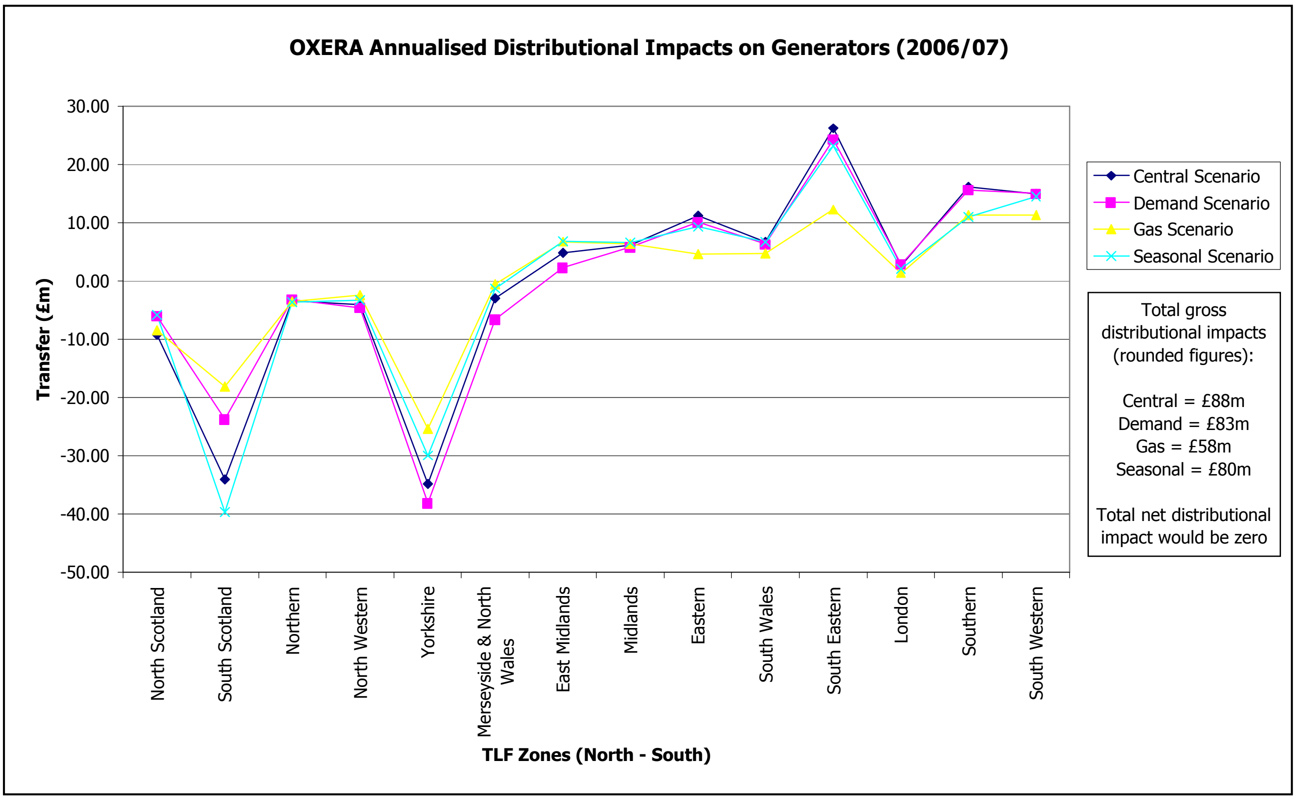
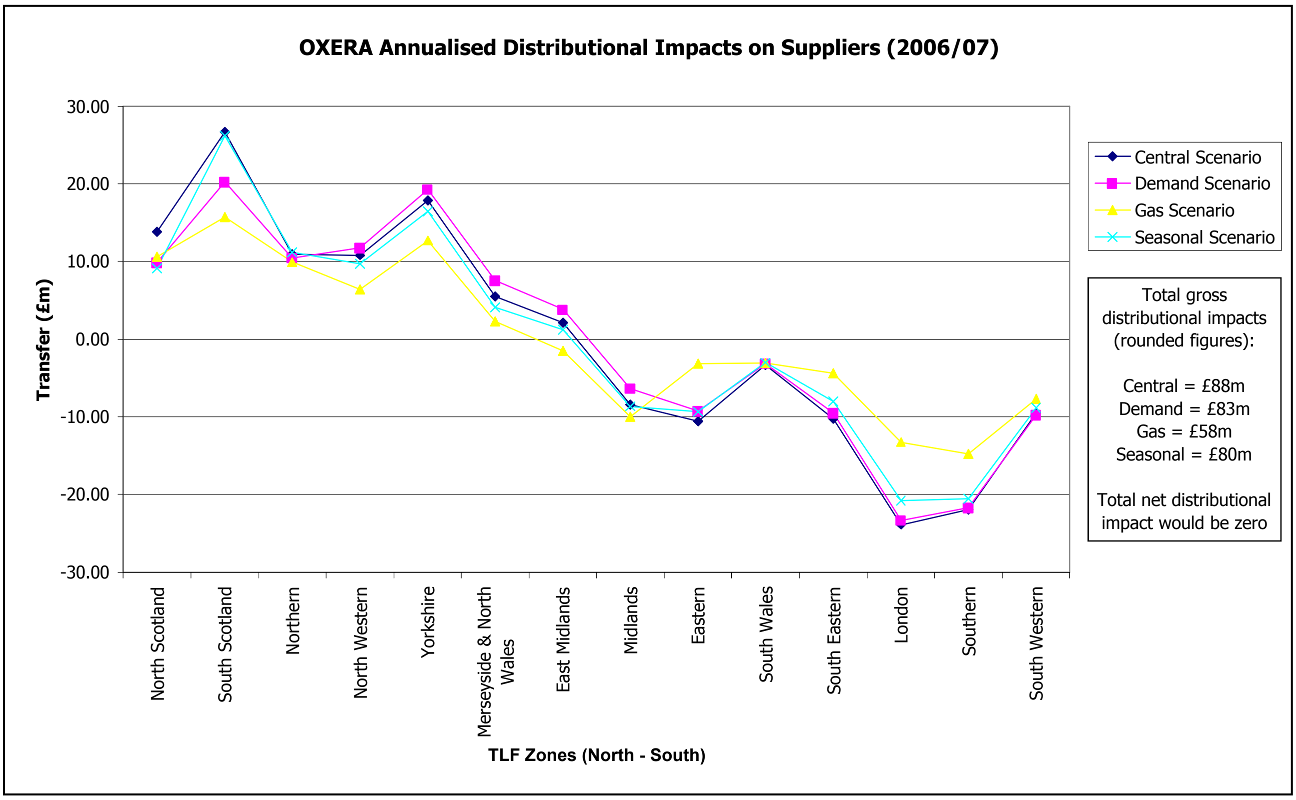


Figure 16 – OXERA Annualised Distributional Impacts on Suppliers (2006/07)



In Figures 15 and 16, the distributional impacts of seasonal TLFs have been annualised (i.e. the figures represent the summation of the distributional effects in each season) in order that they can be compared with the other scenarios based on annual TLFs. Figures 17 and 18 below show the estimated distributional effects of seasonal TLFs on generators and Suppliers for each BSC Season in 2006/07. These graphs were produced by BSCCo using the figures provided in Section 9 of the OXERA cost-benefit analysis report. The £/MWh values of the electricity price used by OXERA to calculate these transfers for each season can also be found in Section 9 of the cost-benefit analysis report.

Figure 17 – OXERA Seasonal Distributional Impacts on Generators (2006/07)

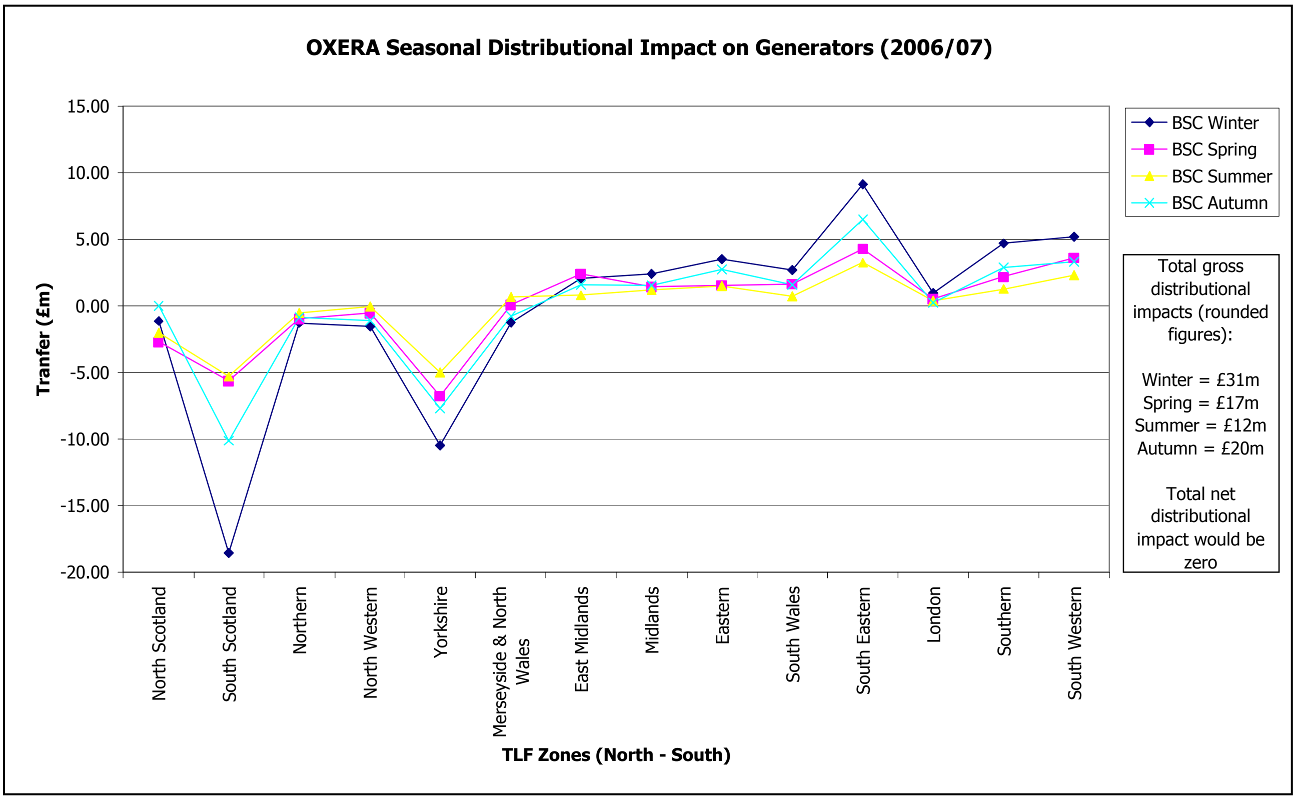
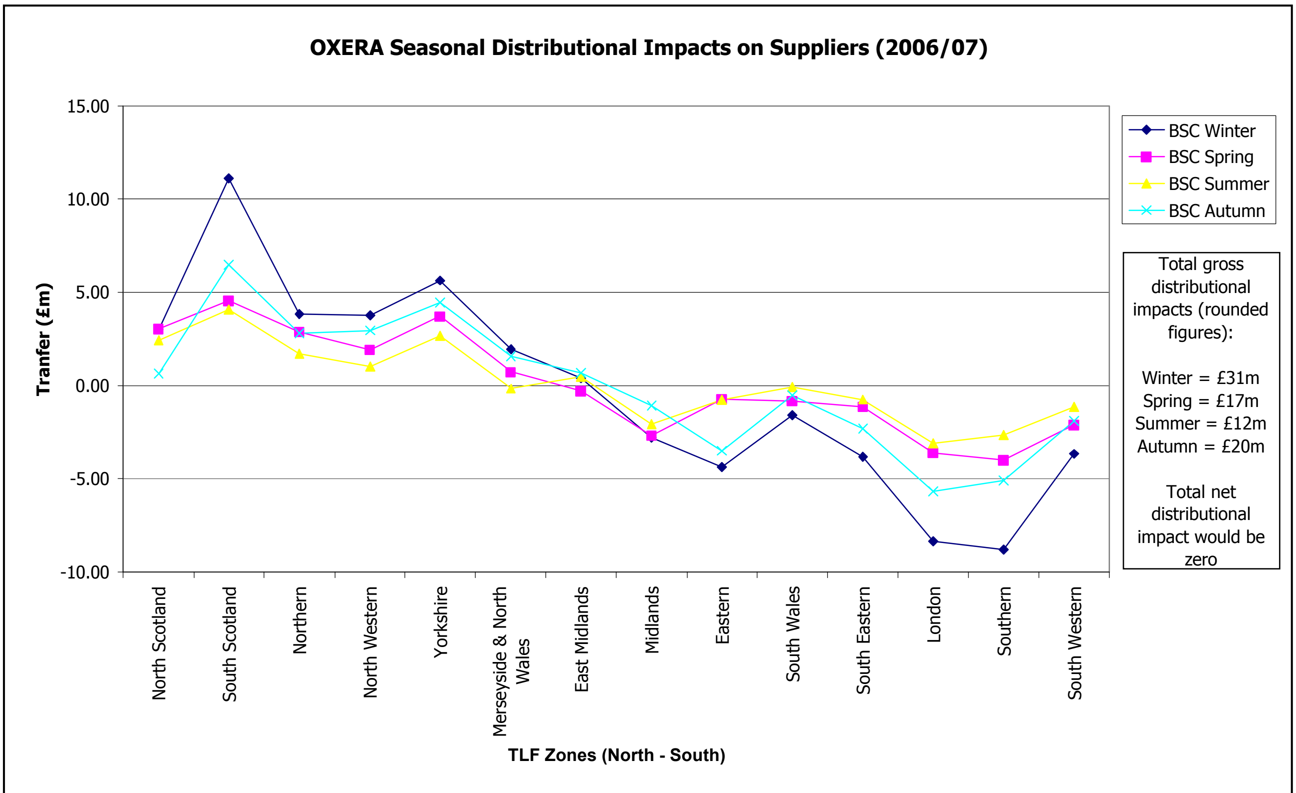


Figure 18 – OXERA Seasonal Distributional Impacts on Suppliers (2006/07)



ii) Impact by Geographic Region (North/South)

Tables 8-11 below show the total distributional impacts estimated by OXERA for each scenario by geographic region (Scotland, northern England, and the south). These geographic areas represent OXERA's aggregations of the following TLF Zones:

- Scotland: North Scotland and Southern Scotland (GSP Groups P and N);
- Northern England: Northern, North Western and Yorkshire (GSP Groups F, G and M); and
- South: Merseyside & North Wales, East Midlands, Midlands, Eastern, South Wales, South Eastern, London, Southern and South Western (GSP Groups A, B, C, D, E, H, J, K, and L).

Please note that the distributional impacts for these regions shown in Tables 8-11 represent the net total distributional effect on generators and Suppliers in each region, and that not all Zones within the southern region experienced transfers in the same direction (i.e. generators/Suppliers in some southern Zones were estimated to experience an increase in charges, whilst others were estimated to experience a decrease). The totals in these tables are therefore different to the summations of all positive or all negative transfers in each scenario which are shown in Figures 15-18. For a breakdown by individual Zone, please refer to Figures 15-18 above or to the detailed zonal tables in Section 9 of the OXERA cost-benefit analysis report in Appendix 5. Please note also that, due to the geographic aggregations and the fact that they are based on rounded totals for each TLF Zone, the totals shown in the tables will not sum to zero.

The Group noted that, although some parts of Section 9 of the OXERA report referred to distributional impacts on consumers, these were actually the impacts on Suppliers – since consideration of whether such costs would be passed on to consumers had been specifically excluded from the scope of the cost-benefit analysis.

Table 8 – OXERA Annualised Northern Distributional Impacts of P198 (2006/2007)

	Central Scenario	Demand Scenario	Gas Scenario	Seasonal Scenario
Generators (Net Total)	Increase payments by: £43m in Scotland £42m in Northern England	Increase payments by: £30m in Scotland £46m in Northern England	Increase payments by: £27m in Scotland £31m in Northern England	Increase payments by: £45m in Scotland £36m in Northern England
Suppliers (Net Total)	Decrease payments by: £41m in Scotland £40m in Northern England	Decrease payments by: £30m in Scotland £42m in Northern England	Decrease payments by: £26m in Scotland £29m in Northern England	Decrease payments by: £35m in Scotland £37m in Northern England

Table 9 – OXERA Annualised Southern Distributional Impacts of P198 (2006/2007)

	Central Scenario	Demand Scenario	Gas Scenario	Seasonal Scenario
Generators (Net Total)	Decrease payments by: £85m	Decrease payments by: £76m	Decrease payments by: £58m	Decrease payments by: £80m
Suppliers (Net Total)	Increase payments by: £80m	Increase payments by: £72m	Increase payments by: £55m	Increase payments by: £72m

The total distributional effect of P198 was therefore less under the demand, gas and seasonal scenarios compared with the central scenario.

The figures shown for the seasonal scenario in Tables 8 and 9 above represent a summation of the distributional effects for the four individual BSC Seasons (i.e. annualised figures). Tables 10 and 11 below show the impacts per season. A breakdown of these results by Zone can be found in the cost-benefit analysis report in Appendix 6.

Table 10 – OXERA Northern Distributional Impacts of P198 by BSC Season (2006/2007)

	BSC Winter	BSC Spring	BSC Summer	BSC Autumn
Generators (Net Total)	Increase payments by: £20m in Scotland £13m in Northern England	Increase payments by: £8m in Scotland £8m in Northern England	Increase payments by: £7m in Scotland £6m in Northern England	Increase payments by: £10m in Scotland £10m in Northern England
Suppliers (Net Total)	Decrease payments by: £14m in Scotland £13m in Northern England	Decrease payments by: £8m in Scotland £9m in Northern England	Decrease payments by: £7m in Scotland £5m in Northern England	Decrease payments by: £7m in Scotland £10m in Northern England

Table 11 – OXERA Southern Distributional Impacts of P198 by BSC Season (2006/2007)

	BSC Winter	BSC Spring	BSC Summer	BSC Autumn
Generators (Net Total)	Decrease payments by: £29m	Decrease payments by: £18m	Decrease payments by: £12m	Decrease payments by: £20m
Suppliers (Net Total)	Increase payments by: £31m	Increase payments by: £15m	Increase payments by: £10m	Increase payments by: £18m

Please note that only the distributional impacts under the central scenario were provided to the industry in the P198 Second Assessment Procedure Consultation Document. Following the consultation, a data error was subsequently identified in these figures for Suppliers, which has been corrected within Tables 8 and 9 within this Assessment Report and in Section 9 of the updated version of the cost-benefit analysis report provided in Appendix 6. Specifically, the OXERA analysis now estimates the net decrease in charges for Scottish Suppliers under the central scenario at £41m (increased from £32m), the net decrease in charges for Suppliers in northern England at £40m (reduced from £41m), and the net increase in charges for southern Suppliers at £80m (increased from £73m). Although the correction of this error did not alter the overall geographic pattern or magnitude of the distributional effects, it did alter the figures provided for Suppliers in specific Zones – with the distributional effects for Suppliers in some Zones being higher under the revised figures, and those for other Zones being lower. Although the average magnitude of this change was around £4m per Zone, the difference in impact for some individual Zones was in the region of over £10m. In addition, the distributional effects identified for Suppliers in the East Midlands Zone under the central scenario switched from a net loss of £1.4m to a net gain of £2.1m as a result of correcting the error. The correction of the error did not affect the distributional impacts for generators.

Although the Group agreed that the correction of data errors in the cost-benefit analysis should be brought to the attention of the Panel and the industry, it agreed that the amended figures did not alter its overall views regarding P198. An additional consultation was subsequently issued to industry, which identified the correction of the errors and sought confirmation from respondents that the amended data did not alter their views regarding P198. The responses received to this consultation can be found in Appendix 9 (note that, at the date of production of this report, these responses were not yet available but will be provided to the Panel at its meeting on 10 August 2006).

Following the P198 Assessment Procedure consultation, OXERA also subsequently provided the Group with details of the distributional effects under the demand, gas and seasonal scenarios at the request of BSCCo (as detailed in Tables 10 and 11). Whilst the overall annualised results under the seasonal scenario were similar to those under the central scenario, the individual seasonal results exhibited significant variations between season. The Group agreed that this was in line with its intuitive expectations, since the PTI analysis had demonstrated the seasonal variability of TLF values.

c) Despatch Signals

OXERA concluded that P198 would lead to more economically-efficient despatch under the central change-case and all sensitivities, with changes in the generation merit order generally being from the north to the south. The range of resulting benefits assumed by OXERA is shown in Table 7 above, with the highest savings occurring under the seasonal TLFs sensitivity (primarily in the BSC Winter season).

Some degree of fuel switching occurred in all cases, but was highest under the lower-gas-price sensitivity due to the increased interlacing of gas and coal plant in the merit stack.

d) Impact on Transmission Losses

OXERA concluded that the more efficient despatch generated by P198 would lead to a reduction in the volume of transmission losses under the central change-case scenario and in all of the sensitivities. Again, the highest level of reduction occurred under the seasonal TLFs sensitivity. The cost-savings resulting from the reduction differed according to the sensitivity. For example, the value of the slightly-higher reduction in losses under the demand sensitivity was substantially higher due to higher prices. Similarly, the higher reduction in losses under the gas sensitivity was to some degree offset by lower prices.

Whilst savings in transmission losses were evident in the early years of the study period, OXERA noted an overall reduction in these savings towards the end of the modelling horizon. This is shown in Figure 19 below.

Figure 19 – OXERA Assumed Annual Loss Savings (GWh)

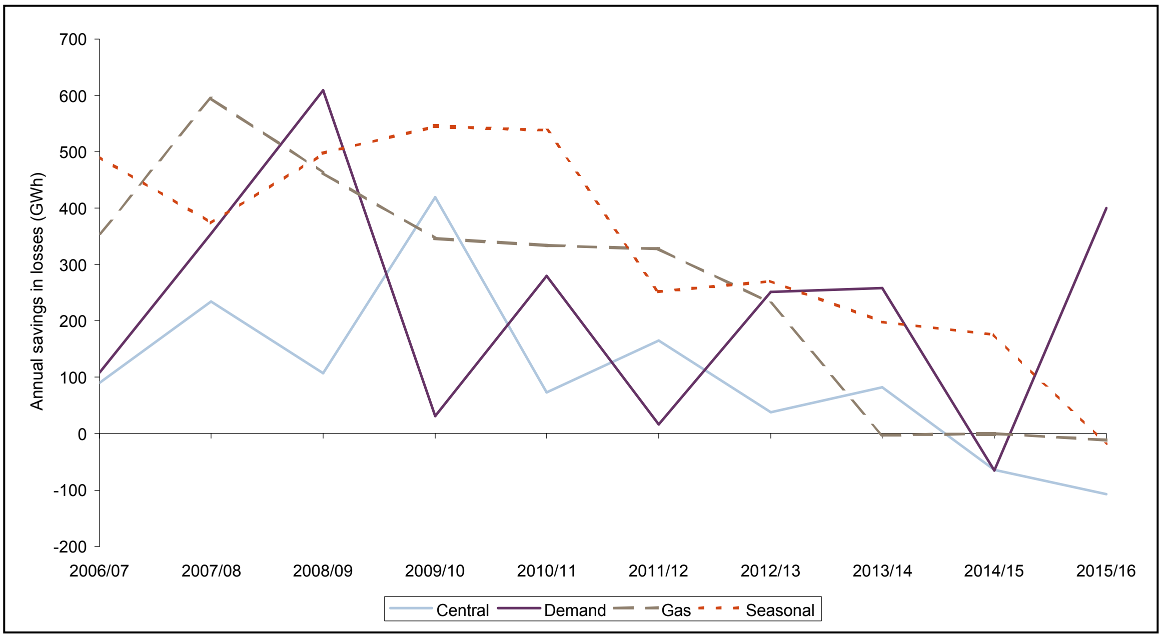


Figure 19 shows the energy (in GWh) which would be saved under P198 compared with the current baseline (i.e. the reduction in losses which would be directly attributable to P198). OXERA concluded that, whilst P198 would give an evident reduction in losses in the early years of the scheme (highest under the use of seasonal TLFs), from around 2012 the amount of savings directly attributable to P198 would reduce. This would be due to the introduction of planned new build in the south from this time, which resulted in a more geographically-balanced system and therefore reduced losses. Since the plans to introduce new southern capacity are already in existence under the current Code baseline, OXERA concluded that the potential for any incremental savings from P198 would therefore be reduced in these years.

In 2014/15, the incremental savings in losses under P198 reduced to zero or became negative in some scenarios. This implied that in these years there could be an equal or increased level of losses under P198 compared with the existing baseline. OXERA clarified that this perceived increase in losses could be partly explained by the fact that, as the system became more in balance after 2012, the level of losses became more sensitive to marginal changes in despatch. Other factors in this result could be the chosen modelling approach (based on the use of three snapshot periods per year/season) or the ex-ante nature of the P198 TLF calculation (which is based on the previous year's despatch patterns).

e) Locational Signals

OXERA concluded that the geographical pattern of TLFs under P198 would reinforce the existing locational signals already provided by the Transmission Company's TNUoS charging. However, OXERA concluded that the strength of the P198 signals would be approximately one-third of those provided by TNUoS, and that the effect of P198 in this area was therefore ambiguous.

Moreover, OXERA noted that over 90% of potential new Combined Coal and Gas Turbine (CCGT) projects identified in the Transmission Company's 2006 Seven Year Statement were in southern Zones – suggesting that TNUoS is already providing signals for new generation to locate in the south. OXERA considered that any long-term impacts of P198 were therefore unlikely to be realised until beyond 2015.

Finally, OXERA considered that the impact of the P198 signals on new-build decisions was uncertain in relation to other non-cost-related issues, such as planning permission and land availability.

f) Impact on Different Classes of Generator

OXERA concluded that P198 would have an ambiguous signal on the siting of future large-scale conventional plant, and would be unlikely to have a significant impact before 2015 due to existing plans for southern build.

OXERA concluded that P198 would have a minimal impact on future renewable, nuclear and embedded generation. OXERA considered that any negative effects of TLFs on renewables would be offset by the protection offered by the government's Renewables Obligation scheme, whilst availability of land and planning consent were likely to be the most significant factors in the location of new nuclear plant.

OXERA concluded that, whilst the presence of 132kV transmission lines in Scotland would influence the TLF values for the Scottish Zones, it would not lead to any difference in signals for generators in these Zones according to whether they were connected to 132kV, 275kV or 400kV transmission lines – since all generators within a Zone would receive the same TLF, and therefore the same signals.

g) Impact on Demand

OXERA concluded that there would be limited demand-side response to P198, primarily due to the perceived inelasticity of demand.

h) Impact on Interconnectors

OXERA did not identify any significant impacts of P198 on Interconnectors. It concluded that the Moyle Interconnector was likely to be exporting to full capacity for the foreseeable future, and would not be affected by the introduction of zonal TLFs – whilst the French Interconnector was cited in a Zone with a relatively neutral TLF (i.e. where the difference between the TLMs under the uniform and zonal allocation scenarios was relatively small).

i) Impact on Transmission System

OXERA did not identify any significant impacts on the development or operation of the Transmission System as a result of P198. Its analysis demonstrated that, in the study period, no stations would have relocated as a result of P198, and that all new plant build within the period was already planned for the south. As a result, OXERA concluded that P198 would therefore have little impact on the pattern of location or timing of connection to the Transmission System.

j) Impact on Risk/Cost of Capital

OXERA did not believe that the introduction of P198 would increase perceptions of risk or the cost of capital for new investments. In support of this conclusion, OXERA argued that:

i) Since the possibility of a zonal transmission losses scheme had been mooted since privatisation, any regulatory uncertainty for Parties in this area would have affected all investment decisions made from privatisation onwards. OXERA therefore concluded that it was unlikely that the introduction of P198 would increase the forward-looking risks faced by investors.

ii) An investor holding a balanced portfolio of generator shares would be unaffected by P198, since costs would be transferred between different generation companies. OXERA concluded that any risk which is diversifiable would not affect the cost of capital.

iii) P198 was unlikely to give rise to any greater risk than other recent market changes such as BETTA. OXERA noted that a degree of risk was inherent in any change to the market arrangements, but concluded that P198 would not increase perceptions of this risk.

OXERA did not imply that there is no risk faced by electricity companies; rather that the introduction of P198 would not alter views of either regulatory or sector-specific risk factors.

On the basis of these views, OXERA did not address this area further.

4.7.3 Modification Group's Discussion of Results

Some members of the Group noted that range of net benefit shown by the P198 cost-benefit analysis was higher than the £6.7 million – £55.5 million established by OXERA's previous analysis for the DTI in 2003. OXERA clarified that there were two main factors underpinning this difference, as follows:

- Electricity prices had doubled since 2003, giving a higher value to any reduction in transmission losses; and
- OXERA had taken a different approach to calculating the reduction of losses under P198, which it believed to be more accurate than that previously used for the 2003 analysis.

The Group also noted that the analysis for the DTI had covered a period of seventeen years (2002/2003 – 2019/2020) rather than the ten years examined for P198, and that the two sets of figures were therefore not directly comparable. It also noted that, due to the passage of time since 2003, the P198 analysis was based on a different market environment and transmission network. OXERA clarified that, notwithstanding its previous work for the DTI, a full repeat of the analysis had been undertaken for P198 based on current market conditions.

Some members queried the rationale behind the choice of a different methodology for calculating the level of transmission losses under P198. OXERA clarified that its previous analysis had used changes in unit output to calculate the reduction in losses, and that this may have understated the reduction. For the P198 analysis, OXERA had used the load-flow model itself to calculate the level of losses – and believed this approach to be more accurate.

Some members noted that the OXERA load-flow modelling had been based on the use of three 'snapshots' (peak, midpoint and trough) throughout a year, compared to the 623 Sample Settlement Periods used by PTI in the TLF modelling exercise. BSCCo clarified that a requirement to use 623 periods for each of the ten years of the cost-benefit analysis would have required a substantial processing ability, and would have significantly prolonged the timescales required for the analysis. OXERA clarified that the approach taken had been consistent with that previously followed in its analysis for the DTI – with the exception that, for the new seasonal TLFs task, twelve snapshots had been used (three for each of the four BSC Seasons). One member queried which periods had been used for the snapshots. OXERA clarified that the snapshots did not correspond to any individual Sample Settlement Periods, but were artificial approximations designed to be representative of typical network loading connections at points of high, medium and low demand. These had been calculated using load-duration curve data from the Seven Year Statement. OXERA also clarified that, whilst the load-flow modelling to establish evolved TLFs had been based on snapshots, its economic despatch modelling had been run on the basis of whole years.

Some members queried why the evolved TLF values for Scotland became positive in 2013/2014. OXERA clarified that it had investigated this result in detail, and believed it to be caused by the planned closure of the Hunterston plant in 2010/2011 – which had made the Scottish TLFs much more sensitive to the marginal output of Longannet.

4.7.4 Modification Group's Conclusions

The Modification Group unanimously agreed that the cost-benefit analysis had delivered the requirements of the Group.

Whilst a majority of members accepted the overall conclusions of the analysis, some members did not support certain specific findings of the report as follows:

- One member did not agree that there would be no difference in signals for connectees to the 132kV element of the Transmission System – and believed that the inclusion of 132kV transmission losses within the P198 scheme would disproportionately impact both such connections and other participants within the Scottish Zones. This member believed this to be demonstrated by the previous results of the PTI analysis.
- Another member did not agree with the conclusion of the analysis that there would be no significant impact on renewables, believing that such participants would be unable to respond to any signals created by P198 and would therefore be disproportionately impacted by the introduction of zonal TLFs. The Group agreed to include a specific question within the second Assessment Procedure consultation as to whether P198 would have a disproportionate impact on any class or classes of Party. Details of the responses received can be found in Section 5.
- Some members did not agree with OXERA's conclusions regarding perceptions of risk and cost of capital. These members believed that economic counter-arguments could be put forward to demonstrate that the impact of P198 in these areas could be significant. The Group agreed to include a specific question in this area as part of the second Assessment Procedure consultation. Details of the responses received can be found in Section 5.
- One member believed that the net benefit identified by the analysis was unlikely to be realised in practice, since there were likely to be other factors in Parties' behaviour aside from economic despatch.

- The Proposer did not agree that P198 would provide no long-term signals. The Proposer believed that the findings of the analysis demonstrated that Parties were already taking the potential introduction of a zonal transmission losses scheme into account when making planning decisions, since the introduction of such a scheme had been foreshadowed since privatisation.

Further detail in respect of the Group's views of the cost-benefit analysis can be found in Section 6, which sets out the views of members regarding the merits of the Proposed Modification against the Applicable BSC Objectives.

4.8 Detail of Final Alternative Modification Solution and Legal Text

On the basis of the cost-benefit analysis results, the Group considered whether to develop an Alternative Modification comprising seasonal TLFs and/or a linear phased application of those TLFs. Not all members who supported seasonal TLFs supported linear phasing, and vice versa. The Group noted that, under the BSC Modification Procedures, only one final Alternative Modification could be put forward to the Authority for decision – and that it was therefore not possible to develop seasonal TLFs and linear phasing as separate Alternatives. The Group noted that including both options within one Alternative would involve the risk that such an Alternative might be rejected by the Authority, were the Authority to disagree with one of these elements. The Group noted that this risk might be increased by the fact that some members in support of one of the options did not necessarily support the other. However, since there was a majority of members in favour of each element (although not all of these members were necessarily in favour of both), the Group agreed by majority that both seasonal TLFs and linear phasing should form part of the Alternative Modification to P198. Modification Proposal P203 was subsequently raised by RWE Npower, which seeks to introduce an annual calculation of seasonal TLFs without a phased implementation. Proposed Modification P203 is therefore the same as Alternative Modification P198, except that (unlike P198 Alternative) there would be no phased implementation of the seasonal TLFs.

The Group agreed that only minor changes to the Proposed Modification solution and legal text were required to support the Alternative Modification. The sections below set out the Group's discussions regarding these changes. For a full description of the Alternative Modification solution, please refer to the Requirements Specification for Alternative Modification P198. A copy of the draft legal text for Alternative Modification P198 can be found in Appendix 1. The Group has reviewed this text and confirmed that it delivers its agreed solution.

4.8.1 Solution for Seasonal TLF Calculation

The Group unanimously agreed that the calculation of Adjusted Seasonal Zonal TLFs should continue to be an annual ex-ante calculation based on data from a previous Reference Year, since this would allow the values for all four seasons to be made available to Parties in advance of the applicable BSC Year. The Group noted that the start and end dates of the BSC Seasons were already defined in Section K of the Code.

The Group noted that the intention of an annual calculation was that TLFs would last for a BSC Year (1 April – 31 March), such that the advance publication of TLFs could be factored into Parties' annual contract rounds. However, the Group noted that none of the start dates of the individual BSC Seasons corresponded to the start date of a BSC Year, since the BSC Spring Season lasted from 1 March – 31 May.

The Group therefore considered three possible solution approaches for a seasonal TLF calculation as set out on the following pages.

a) Approach 1: Leave applicable period as the BSC Year (1 April – 31 March)

Under this approach, there would effectively be five TLF values per BM Unit in each BSC Year, with the following start and end dates:

- Spring TLF 1 (1 April – 31 May);
- Summer TLF (1 June – 31 August);
- Autumn TLF (1 September – 30 November);
- Winter TLF (1 December – 28/29 February); and
- Spring TLF 2 (1 March – 31 March).

Spring TLF 1 and Spring TLF 2 would represent the same single value (i.e. the same number) calculated by the TLFA for the BSC Spring season. However, when entering the seasonal TLFs into the central BSC Systems, this value would need to be split in two due to the need to have start and end dates within a particular BSC Year.

Due to the annual nature of the TLF calculation, the Spring TLF value applicable to a BM Unit would therefore change on 1 April each year (part-way through the BSC Spring season).

b) Approach 2: Use different applicable period tied to BSC Seasons

Under this approach, the applicable period for TLFs would be twelve months from either 1 March, 1 June, 1 September or 1 December (i.e. implementation and the annual calculation would be tied to one of the BSC Seasons).

This approach would require a different duration for the Reference Year in the TLF calculation.

c) Approach 3: Use quarters rather than BSC Seasons

Under this approach, the applicable period for TLFs would still be a BSC Year (1 April – 31 March). However, the BSC Year would be divided into quarters ('TLF Seasons'), such that none of these quarters overlapped the start of the BSC Year. These would therefore be different to BSC Seasons, and the exact date ranges would need to be decided by the Group.

There would therefore be four values per BM Unit in each BSC Year – one for each of the 'TLF Seasons'.

d) Modification Group's Discussions

The Group noted the following results of the Alternative Modification impact assessment, which demonstrated that there was minimal difference between the additional central implementation costs of the three Alternative Modification approaches as compared with the Proposed Modification (see Table 12 below).

Table 12 – Additional BSC Agent Cost of Different Seasonal TLF Approaches Compared with Proposed Modification

Type of Cost	Manual Approach 1	Manual Approach 2	Manual Approach 3	Scripted Approaches 1-3
Implementation	£0	£0	£0	£7,102
Operational (per annum)	£1,380	£255	£3,405	£-1,095

The Group noted that the advantage of Approach 1 would be that the annual calculation could still be tied to Parties' contract rounds, whilst the potential disadvantage of this approach would be added complexity for Parties created by a change in their Spring TLF value part-way through a season. The Group noted that the advantage of Approach 2 would be that it avoided changing TLF values part-way through a BSC Season, but that the disadvantage of this approach would be that the annual calculation and publication of TLF values would not align with Parties' annual contract rounds. Finally, the Group noted that the advantage of Approach 3 would be that it would avoid changing the timing of the annual calculation of TLF values. However, it noted that the use of quarters rather than BSC Seasons might not be an accurate reflection of patterns in Parties' behaviour throughout a year.

The Group unanimously agreed that the use of quarters under Approach 3 would not be appropriate. Members argued that the BSC Seasons were already established in the Code, and were intended to be reflective of national seasonal patterns of behaviour. Some members also noted that the PTI modelling had concluded that variations in TLF values within a BSC Season were less pronounced than between BSC Seasons, and considered that this demonstrated that BSC Seasons were the most appropriate reflection of patterns in behaviour. The Group therefore agreed that basing a seasonal TLF calculation on different quarterly periods would be arbitrary, and was not appropriate.

Whilst the Group noted that Approach 2 offered simplicity, it unanimously agreed that the annual TLF calculation needed to be tied to the financial year in order that Parties could factor the TLFs into their contracts. The Group therefore unanimously agreed that Approach 1 should be adopted as the final solution for the seasonal TLF calculation under the Alternative Modification. The Group noted that a clause had therefore been included within the legal text for the Alternative, clarifying that – within a BSC Year – the BSC Spring season would comprise the periods 1 April – 31 May and 1 March – 31 March in that BSC Year.

A member queried whether the calculation of seasonal values would require different input data to be provided to the TLFA. BSCCo clarified that the same Reference Year could be used to calculate seasonal TLFs as for the calculation of annual values. Since the specific Load Periods and Sample Settlement Periods to be used would be set by the Panel, consideration would be given during implementation as to which periods would be most reflective of BSC Seasons. Network Data and Metered Volumes would then be provided in respect of these Sample Settlement Periods. The Group noted that the same input data had been used by PTI to calculate TLFs at different levels of temporal granularity.

e) Choice of Manual or Automated Loading of TLF Values

The Group noted that, under the Proposed Modification solution, the single annual TLF value for each BM Unit would be manually entered into BSC Systems by the CRA. The Group agreed with BSCCo's advice that the use of four seasonal values per BM Units would create a greater potential for human error were a manual approach to be retained for the Alternative. The Group therefore unanimously agreed with BSCCo's suggestion that a more automated approach should be followed, whereby a script would be used to load the TLF values. The Group noted that this would incur an initial implementation cost, but would reduce the yearly operational costs thereafter as shown in Table 12.

4.8.2 Solution for Linear Phasing

The Group unanimously agreed that the solution and legal text for the linear phasing element of Alternative Modification P198 should be based on that previously used for Alternative Modification P82. The Group noted, that under this approach, an additional 'beta' scaling factor would be applied by the TLFA such that the value of TLFs was gradually scaled up from 20% of their full value in BSC Year 1 to 100% in BSC Year 5 and onwards.

4.9 Alternative Modification Implementation Approach and Costs

4.9.1 Modification Group's Initial Discussions

The Group unanimously agreed that the same implementation approach should be followed for the Alternative Modification as for the Proposed Modification, whereby the Implementation Date was tied to Parties' contractual rounds.

The Group undertook an impact assessment to determine if the Alternative Modification would incur any additional costs or lead time compared with the Proposed Modification.

4.9.2 Implementation and Operational Costs

The tables on the following page show the estimated central implementation and operational costs of the Proposed Modification. Please note that, as for the Proposed Modification, these costs do not include those which would be required to resolve the metered data sample issue identified in Section 4.4.3 as a one-off activity prior to implementation. The sections below outline the additional costs associated with the Alternative Modification when compared with the Proposed Modification.

a) Transmission Company

The Transmission Company analysis confirmed that the Alternative Modification would have no additional impact on the Transmission Company compared with the Proposed Modification.

b) BSCCo

The BSCCo impact assessment confirmed that the Alternative Modification would increase the amount of required ELEXON implementation effort by thirteen man days (equating to £2,860) compared with the Proposed Modification, in order to amend BSC Systems documentation to reflect the use of multiple TLF values per BM Unit.

There would be no increase in ELEXON operational costs.

c) BSC Parties

The majority of Parties which responded to the Alternative Modification impact assessment stated that any additional work and costs incurred by the Alternative Modification would be subsumed within the figures already provided in respect of the Proposed Modification. One Party stated that it would require an extra month's development time in addition to the 3-6 months it had previously quoted for the Proposed Modification.

d) BSC Agents

The Logica impact assessment confirmed that the costs of amending BSC Systems to take account of seasonal TLF values under the Alternative Modification would be approximately £7,000 higher than the implementation costs for the Proposed Modification. This would be offset by a reduction in operational costs by approximately £1,000 per BSC Year of the scheme, reflecting the Group's choice of a scripted loading approach to seasonal TLF values (see Section 4.8).

Although the use of seasonal TLFs and linear phasing under the Alternative Modification would impact the TLFA and Load Flow Model Reviewer, these additional impacts would be covered by the tolerance associated with the costs provided for the Proposed Modification.

ALTERNATIVE MODIFICATION IMPLEMENTATION COSTS[20]

		Cost	Tolerance
Logica CSA Cost	Change Specific Cost Release Cost	£25,864 £17,114	Nil Nil
	Total Logica CSA Cost	£42,978	Nil
TLFA/Load Flow Model Reviewer Cost	Development, Testing and Deployment	£250,000	+/- 50%
BSC Audit Cost	Planning and Development	£15,000	+/- 50%
Implementation Cost	External Programme Audit Design Clarifications Additional Resource Costs Additional Testing/Audit Support Costs	£0 £14,294 £0 £20,000	Nil +/- 100% Nil +/- 50%
Total Demand Led Implementation Cost		£342,272	+/- 50%
ELEXON Implementation Resource Cost		613 man days £134,860	+/- 5%
Total Implementation Cost		**£477,132**	**+/- 35%**

ALTERNATIVE MODIFICATION ONGOING SUPPORT AND MAINTENANCE COSTS

	Cost	Tolerance
Logica CSA Operation Cost Per BSC Year Logica CSA Maintenance Cost Per BSC Year	£1,550 £0	Nil Nil
TLFA/Load Flow Model Reviewer Operational Cost Per BSC Year	£100,000	+/- 50%
BSC Auditor Cost Per BSC Year	£40,000	+/- 50%
ELEXON Operational Cost Per BSC Year	70 man days £15,400	+/- 5%
Total Operational Cost Per BSC Year	**£156,950**	**+/- 45%**

[20] An explanation of the cost terms used in this section can be found on the BSC Website at the following link: http://www.elexon.co.uk/documents/Change_and_Implementation/Modifications_Process_-_Related_Documents/Clarification_of_Costs_in_Modification_Procedure_Reports.pdf

4.9.3 Implementation Lead Time

Although the Alternative Modification would increase the amount of Logica and ELEXON implementation effort, this additional work could be paralleled with the TLFA procurement and development. The same twelve-month lead time could therefore be achieved for the Alternative Modification as set out for the Proposed Modification in Section 4.5.

4.9.4 Modification Group's Conclusions

The Group noted that the Alternative Modification would result in a minor increase in cost, but would not require any additional implementation lead time when compared with the Proposed Modification.

The Group therefore unanimously agreed that the following provisional Implementation Dates should apply to the Alternative Modification in addition to the Proposed Modification:

- 1 April 2008, if an Authority decision is received on or before 22 March 2007; or
- 1 October 2008, if an Authority decision is received after 22 March 2007, but on or before 20 September 2007.

As for the Proposed Modification, the new zonal TLF values would therefore take effect from the first Settlement Period on the Implementation Date. For a 1 April implementation, this would also be the first Settlement Period on the first day of the BSC Year (part-way through the BSC Spring season). For a 1 October implementation (part-way through BSC Autumn), TLF values would only apply for six months during the first BSC Year of the scheme – from part-way through the BSC Autumn season to part-way through BSC Spring, when the next year's Spring TLF value would take effect. TLFs for all subsequent years would be applied on a seasonal basis for each full BSC Year. The Group agreed that the P198 legal text needed to be sufficiently flexible to cover the possibility of either an April or October implementation in the first year of the scheme. Clarifications were therefore included within the legal drafting to cover the eventuality that P198 was implemented part-way through a BSC Year.

As for the Proposed Modification, the Group agreed to include a specific question regarding this proposed implementation approach within the second Assessment Procedure consultation. Details of the consultation responses received in this area can be found in Section 5.

5 GROUP'S CONSIDERATION OF SECOND ASSESSMENT CONSULTATION RESPONSES

21 responses (representing 75 BSC Parties and 4 non-Parties) were received to the P198 second Assessment Procedure consultation.

Table 13 on the following page provides a summary of the numbers of these respondents in support of each view, whilst Sections 5.1-5.9 detail the arguments expressed and the Group's resulting discussions of these arguments. One respondent (a Party Agent) gave a neutral response to all of the consultation questions, since P198 would have no impact on any Party Agents.

Table 13 also includes one late response which was received following the consultation deadline and the Group's final meeting. This response was received too late to be considered in detail by the Group, and is therefore not included in the summary of arguments in the following pages. However, the arguments expressed by the respondent were very similar to those expressed by other respondents to the consultation. The late response is therefore not believed to contain any arguments which had not already been considered by the Group during the Assessment Procedure.[21]

Full copies of the individual responses received can be found in Appendix 7.

Table 13 – Responses to Second Assessment Procedure Consultation

Numbers in bold represent the majority view. Bracketed numbers show the number of BSC Parties represented by the respondent(s), whilst numbers preceded by a + show the number of non-Parties represented.

	Question	Yes	No	Neutral	No Comment
Q1	Do you believe that Proposed Modification P198 would better facilitate the achievement of the Applicable BSC Objectives compared with the current Code baseline?	4 (29)	**13 (45+1)**	2 (1+1)	2 (0+2)
Q2	Do you believe that Alternative Modification P198 would better facilitate the achievement of the Applicable BSC Objectives compared with the Proposed Modification?	**9 (42+1)**	8 (32)	2 (1+1)	2 (0+2)
Q3	Do you believe that Alternative Modification P198 would better facilitate the achievement of the Applicable BSC Objectives compared with the current Code baseline?	4 (29)	**13 (45+1)**	2 (1+1)	2 (0+2)
Q4	Do you believe that P198 would have a disproportionate impact on any class or classes of Parties?	**14 (49+1)**	4 (26)	1 (0+1)	2 (0+2)
Q5	Do you believe that P198 would have an impact on perceptions of risk and/or the cost of capital?	**9 (24+1)**	5 (36)	4 (14+1)	3 (1+2)
Q6	Do you support the implementation approach described in the consultation document?	**12 (61)**	4 (12)	3 (2+2)	2 (0+2)
Q7	Do you believe there are any alternative solutions that the Modification Group has not identified and that should be considered?	4 (11)	**12 (61+1)**	2 (2+1)	3 (1+2)
Q8	Does P198 raise any issues that you believe have not been identified so far and that should be progressed as part of the Assessment Procedure?	7 (15+3)	**12 (59)**	1 (0+1)	1 (1)

[21] The late response was received on 26th July 2006, approximately one week following the Group's final meeting on 18th July. Although the response had originally been submitted prior to the consultation deadline on 14th July, it had been inadvertently sent to an incorrect email address and was therefore not received in time for consideration by the Group. The individual response concerned has been provided with the other consultation responses in Appendix 7, and is marked as a late response for reference.

The Group noted that many of the responses referred to areas which fell outside the scope of its assessment of P198 under the Applicable BSC Objectives. The Group noted that these areas could be considered by the Authority as part of its wider statutory duties, and that the Authority had recently published a letter stating that its current assumption was that a Regulatory Impact Assessment would be undertaken for P198.[22]

5.1 Respondents' Views of Proposed Modification Compared with Existing Code Baseline

5.1.1 Views of Respondents

a) Majority View

A majority of respondents believed that overall the Proposed Modification **would not** better facilitate the achievement of the Applicable BSC Objectives compared with the existing Code baseline.

The majority of those respondents who opposed the Proposed Modification did not identify any impact on the achievement of Applicable BSC Objective (a). One of these respondents refuted any suggestion that the existing arrangements discriminated against any Party. However, one respondent believed that the Proposed Modification would have a negative effect on Applicable BSC Objective (a), as this respondent believed that it would discriminate against some Parties whilst favouring others through the transfer of capital value and windfalls.

The different arguments expressed by these respondents against the other BSC Objectives were as follows:[23]

Applicable BSC Objective (b)

- The despatch benefits identified by the cost-benefit analysis were unlikely to be realised in practice since they were based on an assumption of economic despatch which would not reflect other commercial drivers in Parties' output;
- The Proposed Modification would not provide a long-term signal to Parties, since the cost-benefit analysis demonstrated that other existing signals are already incentivising new southern generation; and/or
- The Proposed Modification would give an inconsistent, contradictory and uncertain short-term despatch signal (some respondents believed this to be a result of the approximations inherent in the ex-ante and average nature of the P198 TLF calculation).

Applicable BSC Objective (c)

- The TLF calculation under the Proposed Modification would result in allocations of losses to BM Units which were larger than the actual loss attributable to any individual BM Unit in isolation – creating windfall winners and losers;
- The distributional effects of the Proposed Modification identified by the cost-benefit analysis would represent windfall gains and losses for existing investments, which would not be able to respond to locational signals (some respondents did not agree that the existing arrangements represented a cross-subsidy, and therefore did not agree that a defect existed in the Code – whilst one believed that the effect of any existing cross-subsidy was far outweighed by the influence of other locational factors);
- These distributional effects – when combined with the implementation costs to Parties – would be inequitable and anti-competitive, and would outweigh any benefits associated with redespatch;

[22] http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/15174_P198_Code_Mod_Impact_Assessment_260506.pdf
[23] Note that not all respondents referred to specific Applicable BSC Objectives or referred to the same Objective, so arguments in these sections have been grouped according to the Objective cited by the majority of respondents in relation to each view.

- The concept of 'cost-reflectivity' is undefined, and it has not been proven that P198 would enhance the process of competitive rivalry between Parties;
- The Proposed Modification would present a barrier to entry into the market;
- The Proposed Modification would not outweigh other locational factors in the siting of generation and demand;
- The nature of the TLF calculation would mean that the signals provided to any one Party were also dependent on the actions of other Parties, which would be outside its control and would change from year to year – creating uncertainty for participants; and/or
- The Proposed Modification would send incorrect or inconsistent signals to participants as a result of intra-year and between-year variation in behaviour, and due to the approximations contained in the TLF calculation.

Applicable BSC Objective (d)

- The Proposed Modification would add cost and complexity to the BSC arrangements, thereby reducing efficiency (some respondents believed this impact on Objective (d) to be more significant than others, whilst some respondents who opposed the Proposed Modification did not identify an impact on Applicable BSC Objective (d)).

Some respondents argued that the Proposed Modification would have a disproportionate impact on certain classes of Party, whilst some argued that it would negatively impact perceptions of risk and/or the cost of capital. These arguments have been detailed in Sections 5.4 and 5.5 below.

One respondent did not believe that any despatch benefits were a relevant factor to be considered under Applicable BSC Objectives, since they believed Objective (b) to relate to efficient operation of the Transmission System and not the overall efficiency of the system itself.

b) Minority View

A minority of respondents believed that the Proposed Modification **would** better facilitate the achievement of the Applicable BSC Objectives compared with the existing Code baseline.

The different arguments expressed by respondents in favour of the Proposed Modification were as follows:

Applicable BSC Objective (a)

- The Proposed Modification would remove the market distortions and discrimination which are inherent in the cross-subsidy created by the existing uniform allocation of losses.

Applicable BSC Objective (b)

- The cost-benefit analysis demonstrated that the Proposed Modification would lead to more efficient and economic short-term plant despatch, and thereby a reduction in the level of losses; and/or
- The Proposed Modification would lead to more efficient and economic long-term plant investment decisions, by reinforcing other existing signals.

Applicable BSC Objective (c)

- The current uniform allocation is contrary to market principles and hinders the ability of competitive generation and retail businesses to reflect the cost of losses in their tariffs; and/or
- The Proposed Modification would provide a more cost-reflective allocation of variable losses – thereby promoting competition by removing an existing cross-subsidy and allocating the costs of losses to Parties according to the extent to which Parties contributed to such losses.

None of these respondents believed that P198 would affect the achievement of Applicable BSC Objective (d).

Two respondents were **neutral** regarding the merits of the Proposed Modification. One of these respondents believed that any benefits under Applicable BSC Objective (b) through redespatch could be limited and would be balanced against the distributional effects under Objective (c) and increased costs under Objective (d).

5.1.2 Modification Group's Discussion of Responses

The Group agreed that the majority of the arguments expressed by respondents in this area had already previously been considered by the Group during the Assessment Procedure. However, some new arguments or points of clarification were identified and discussed by the Group as follows:

a) One respondent believed that the incentive for Suppliers to balance their supply to demand would reduce the ability of generators to change their despatch. The Group noted this view.

b) One respondent believed that the Proposed Modification would reduce the ability of generators to change their despatch decisions, as Suppliers would request more generation in order to ensure that they did not close with a short position. The Group noted this view.

c) One respondent stated that the Proposed Modification would have no short-term effect, and that any efficiency benefits would only be realised in the long term. The Group agreed that this view appeared to be based on a misunderstanding of the cost-benefit analysis results, which had identified only short-term despatch benefits from P198. BSCCo subsequently contacted the respondent to clarify the findings of the cost-benefit analysis.

d) Some respondents believed that the Proposed Modification would create signals which overlapped with, or contradicted, the signals already provided by the Transmission Company's TNUoS charging methodology. The Group noted the view of the Transmission Company that P198 would not have a direct impact on TNUoS charging, and the conclusion of the cost-benefit analysis that the P198 signals would reinforce the existing TNUoS signals. However, the Group agreed that direct consideration of any interaction with TNUoS fell outside the scope of its assessment of P198 under the Applicable BSC Objectives, and would need to be considered by the Authority under its wider remit.

e) One respondent noted the conclusion of the cost-benefit analysis that the long-term locational impacts of P198 were uncertain, and considered that this represented a 'major gap' in the assessment of P198. The Group did not believe that any further assessment was required in this area. It noted that the cost-benefit analysis conclusion was based on the fact that no generating plant relocated within the study period – and agreed that, whilst it demonstrated that the locational effects of P198 might be ambiguous and unlikely to be realised until beyond 2015, substantial analysis had been undertaken to support this conclusion. The Group agreed that it would not be possible to quantitatively model the effect of P198 beyond 2015, due to the uncertainty of market conditions beyond this point.

f) One respondent referred to a negative impact on end consumers in support of their views against the Proposed Modification. The Group noted that consideration of any impact on consumers fell outside the scope of its assessment under the Applicable BSC Objectives, and would need to be considered by the Authority under its wider remit.

g) Some respondents referred to a negative impact on the government's environmental objectives. Further detail can be found in Section 5.4 below.

h) One respondent believed the cost-benefit analysis to be 'flawed', since the TLFs which it generated for 2005/06 using snapshot periods were not identical to those calculated by PTI using 623 Sample Settlement Periods for the same year. This respondent believed that implementation of P198 should be delayed until these differences had been explained. The Group noted that the differences between the OXERA and PTI TLF values were a consequence of the different sample periods used in the respective calculations, and that a detailed comparison and explanation of these values had been provided within Section 2.2 of the cost-benefit analysis report. The Group also noted that OXERA had undertaken a detailed validation of the results generated by its load-flow model using the full 623 Sample Settlement Periods prior to utilising its snapshot approach. By majority, the Group agreed that no further explanation of these results was required, and that the area was therefore a matter of judgement for participants as to whether the conclusions of the cost-benefit analysis were likely to be realised in practice.

i) The same respondent noted that the PTI modelling and the initial starting point for the OXERA modelling had been actual 2005/06 data. The respondent considered that, since this represented a period of high gas prices, use of this data could result in a distorted outcome. The respondent believed that no detailed consideration of this appeared to have been taken into account. The Group noted that the nature of the P198 TLF calculation was that TLF values would be based on the previous year's behaviour, which would include the influence of factors such as fuel price. However, the Group noted that the cost-benefit analysis had examined the sensitivity of TLFs to such factors by including a scenario which reversed the current relativities of coal and gas prices over the next ten years. The Group therefore agreed that no further analysis was required in this area.

5.2 Respondents' Views of Alternative Modification Compared with Proposed Modification

5.2.1 Views of Respondents

a) Majority View

A majority of respondents believed that the Alternative Modification **would** better facilitate the achievement of the Applicable BSC Objectives when compared with the Proposed Modification.

The different arguments expressed by respondents in support of this view were as follows:

Applicable BSC Objective (b)

- The TLF modelling demonstrated that the use of seasonal TLFs would provide a more accurate allocation of losses by reflecting intra-year variation in behaviour;
- The cost-benefit analysis demonstrated that seasonal TLFs would provide stronger economic signals, leading to more efficient despatch and a greater reduction in losses compared with the Proposed Modification; and/or
- A seasonal granularity would involve less approximations than annual values.

Applicable BSC Objective (c)

- A phased implementation over four years would mitigate the initial anti-competitive and destabilising distributional effects of P198 in the short term, whilst longer-term contracts were renegotiated.

Applicable BSC Objective (d)

- Any difference in implementation and operational costs under the Alternative Modification would be negligible compared with the Proposed Modification; and/or
- Any additional complexity from higher-granularity TLF values would not be significant.

Some respondents referred to perceived impacts on perceptions of risk and/or the cost of capital in support of their views. These arguments have been detailed in Section 5.5 below. No respondents believed that the Alternative Modification would have a different impact on Applicable BSC Objective (a) compared with the Proposed Modification.

b) Minority View

A large minority of respondents believed that the Alternative Modification **would not** better facilitate the achievement of the Applicable BSC Objectives when compared with the Proposed Modification.

Some respondents believed that, although the use of seasonal TLFs would provide a more accurate allocation of losses (thereby better facilitating Applicable BSC Objective (b)), the phasing element of the Alternative would delay the realisation of these benefits and therefore could not be viewed as better facilitating the achievement of the Applicable BSC Objectives compared with the Proposed Modification. Other respondents supported phasing but not the use of seasonal TLF values. One of these respondents believed that the higher despatch benefits identified by the cost-benefit analysis for seasonal TLF values might not be realised in practice – whilst others believed that the Alternative would add further cost, complexity and/or uncertainty to the BSC arrangements, giving a negative impact on Applicable BSC Objective (d).

Two respondents were **neutral** as to whether the Alternative Modification would be better than the Proposed Modification. One of these respondents believed that delaying any benefits of the scheme through phasing was likely to offset any increased accuracy under the use of seasonal TLF values.

5.2.2 Modification Group's Discussion of Responses

The Group agreed that the majority of the arguments expressed by respondents in this area had already previously been considered by the Group during the Assessment Procedure. However, some points of clarification were identified and discussed by the Group as follows:

a) One respondent believed that seasonal TLF values would create moving charges which could prove difficult to forecast, but stated that they would support the use of seasonal values if it was felt likely that this would alter the generation merit order enough to encourage greater efficiency in the operation of the market. The Group agreed that this response appeared to be based on a misunderstanding of the contents of the consultation document, since the four seasonal TLF values for a given year would still be calculated ex-ante and published three months in advance of the applicable BSC Year. In addition, the cost-benefit analysis had identified significantly higher despatch benefits under the Alternative compared with the Proposed Modification. BSCCo subsequently contacted the respondent to clarify the Alternative Modification solution and the findings of the cost-benefit analysis.

b) One respondent argued that phasing would not delay the benefits associated with P198, since they believed that any benefits would only be realised in the longer term (15 years+). The Group agreed that this appeared to be based on a misunderstanding of the cost-benefit analysis results, which had identified only short-term despatch benefits from P198. BSCCo subsequently contacted the respondent to clarify the findings of the OXERA analysis.

5.3 Respondents' Views of Alternative Modification Compared with Existing Code Baseline

5.3.1 Views of Respondents

a) Majority View

A majority of respondents believed that the Alternative Modification **would not** better facilitate the achievement of the Applicable BSC Objectives when compared with the existing Code baseline. Although many of these respondents believed that the Alternative would be better than the Proposed Modification (see Section 5.2 above), they did not believe that its additional benefits would be sufficient to fully outweigh the negative impacts of the scheme. The arguments put forward by these respondents against the Alternative were therefore very similar to those previously expressed against the Proposed Modification (see Section 5.1).

b) Minority View

A minority of respondents believed that the Alternative Modification **would** better facilitate the achievement of the Applicable BSC Objectives when compared with the existing Code baseline. Although many of these respondents did not believe that the Alternative would be better than the Proposed Modification (see Section 5.2), they believed that it would still be better than the existing Code baseline by partly or ultimately addressing the defect identified by the Modification Proposal.

Two respondents were neutral as to whether the Alternative Modification would be better than the existing baseline, consistent with their neutral views regarding the Proposed Modification.

5.3.2 Modification Group's Discussion of Responses

The Group agreed that no new arguments or points of clarification had been raised by respondents in this area.

5.4 Respondents' Views of Proportionality of Impact on Parties

5.4.1 Views of Respondents

The views of respondents in this area generally influenced their views as to whether P198 would better facilitate the achievement of the Applicable BSC Objectives – since most respondents who believed that P198 would have a disproportionate impact on certain Parties argued that this would have a negative impact on the achievement of Applicable BSC Objective (c). The arguments of respondents in this area applied to both the Proposed and Alternative Modifications.

a) Majority View

A majority of respondents believed that P198 **would** have a disproportionate impact on certain classes of Party. The following different types of Party were identified by respondents as being disproportionately impacted (note that not all of these respondents cited impacts on all of these Parties):

- **Existing Parties**: Some respondents believed that P198 would create windfall gains and losses which penalised existing investments made on the basis of other factors prior to zonal loss charging, since existing Parties would not be able to respond to any locational signals created by the scheme.
- **New entrants**: Some respondents argued that P198 would present a barrier to entry for new participants in the market (some respondents considered that this would be especially true for smaller players). This argument was generally linked to respondents' views regarding perceptions of risk and the cost of capital (see Section 5.5).

- **Small Parties**: Some respondents believed that P198 would have a negative effect on smaller Parties, for whom implementation costs would be proportionally greater – and who were perceived to be less likely to be able to respond to signals to vary their despatch.
- **Non-portfolio players**: Some respondents considered that P198 would have an especially negative effect on non-portfolio players at the geographic extremities of the country, who (unlike vertically-integrated Parties) would not have a portfolio with which to mitigate any impact on one side of their business (this argument was generally related to views regarding regulatory risk and the cost of capital – see Section 5.5 below).
- **Renewables**: Some respondents argued that P198 would have a disproportionate impact on renewable generation, which they believed would be predominantly located in the 'worst' TLF Zones. These respondents considered that renewables would be unable to respond to any locational and/or despatch signals created by the scheme due to their need to site close to energy sources and the intermittent nature of their generation. These respondents therefore disagreed with the conclusion of the cost-benefit analysis that any impact on renewables would be offset by the higher financial incentives provided by the government's Renewables Obligation scheme. Some respondents argued that, since renewable generation would be unable to respond to signals, their cost base would be increased by the value of the re-distribution amounts created by P198. One respondent also believed that P198 would penalise Suppliers who purchased directly from renewable generators. Finally, one respondent believed that P198 would have a negative impact on microgeneration which was subject to Non Half Hourly (NHH) metering (further detail regarding this argument can be found in Section 5.4.2 below).
- **Suppliers**: Some respondents believed that P198 would have a disproportionate impact on Suppliers, since the cost-benefit analysis demonstrated that demand would be largely unable to respond to the signals created by the scheme.
- **CHP plant**: One respondent argued that P198 would have a negative impact on CHP plant, since they believed that such plant would be unable to respond to the signals of the scheme since their electricity generation is a secondary process tied to heat production.
- **Nuclear generation**: One respondent argued that implementation of P198 would lead to increased costs for Parties such as nuclear generators, since they believed that such generators run at baseload and would therefore be unable to change their operational regime readily.
- **132kV transmission-connected BM Units**: One respondent believed that P198 would have a negative impact on BM Units connected to the 132kV elements of the transmission system, since losses from these lines would be higher.

b) Minority View

A minority of respondents believed that P198 **would not** have a disproportionate impact on any class or classes or Party. The different arguments expressed by respondents in support of this view were as follows:

- Although there would be a redistributive impact between Parties, a locational losses scheme has been discussed for many years and would simply reinforce existing locational signals in the market;
- A windfall is by definition an unexpected occurrence, and there is plentiful evidence that the industry has known about the potential implementation of a non-uniform transmission losses scheme for many years;
- Although there would be redistributive impacts, all classes of Party would be treated equally; and/or
- P198 would remove an existing disproportionality or cross-subsidy in the allocation of losses, and so would have a more proportionate impact on every class of Party than the existing Code baseline.

One respondent was **neutral** on this issue.

5.4.2 Modification Group's Discussion of Responses

The Group agreed that the majority of the arguments expressed by respondents in this area had already previously been considered by the Group during the Assessment Procedure. However, some new arguments or points of clarification were identified and discussed by the Group as follows:

a) One respondent believed that P198 would have a disproportionate impact on microgeneration, arguing that since such generation is subject to NHH metering it would be unable to respond to any despatch signals. However, no members of the Group believed that P198 would have a specific disproportionate impact on microgeneration. Some members believed that any domestic microgeneration would reduce bills to consumers, regardless of the signals created by P198. The Group also noted that direct consideration of this area lay outside the scope of its assessment under the Applicable BSC Objectives (see below). BSCCo has subsequently contacted the respondent to seek clarification of their views. The respondent clarified that they believed that NHH generation would not be able to respond to despatch signals to the same extent as HH generation.

b) Some respondents believed that P198 would have a negative impact on the government's environmental policy. The Group noted that this consideration fell outside the scope of the Applicable BSC Objectives, and that any impact on the environment would need to be considered by the Authority under its wider remit.

c) Some respondents referred to costs being passed through from Suppliers to consumers. The Group agreed that any consideration of consumers fell outside the scope of its assessment, but could be considered by the Authority.

d) Some respondents believed that P198 would have a disproportionate impact on small Parties, and might present a barrier to entry into the market for such Parties. The Group noted this argument, which had not been explicitly considered within the consultation document. One member of the Group indicated that they agreed with this view.

5.5 Respondents' Views of Impact on Risk/Cost of Capital

5.5.1 Views of Respondents

a) Majority View

A majority of respondents disagreed with the conclusions of the cost-benefit analysis in this area, and believed that P198 **would** have a negative impact on perceptions of regulatory risk and thereby on the cost of capital. These respondents believed that this would have a negative impact on the achievement of Applicable BSC Objective (c), and some believed that it represented a barrier to entry. These views generally applied to both the Proposed and Alternative Modifications, with respondents believing that phasing over four years would not be sufficient to fully mitigate these impacts.

The different arguments expressed by these respondents were that:

- The variability and volatility associated with year-on-year or season-on-season changes to loss calculations would introduce further regulatory risk, which would be translated into financial risk (and increased cost) by the providers of capital;
- P198 would significantly increase the regulatory risk associated with new generation build – imposing a premium on the cost of capital for both new and existing generation;
- Any change which significantly affects the cost-base of Suppliers introduces volatility and thereby affects the cost of capital;
- Any form of regulatory risk would affect future investment decisions; and/or

- The nature of the BSC and the constant prospect of ongoing modifications must have an impact on the perception of regulatory risk.

One respondent believed that the effect on the cost of capital was inarguable, although they considered that this effect might be small.

b) Minority View

A minority of respondents believed that P198 **would not** have a negative impact on perceptions of regulatory risk or the cost of capital. The different arguments expressed by respondents in support of this view were as follows:

- The possibility of a zonal transmission losses scheme has been discussed since privatisation, and therefore should have already been factored into market expectations;
- Although there is an element of regulatory risk inherent in the BSC's Modification Process, there is no reason why P198 should represent a higher level of risk than any other Modification Proposal; and/or
- Parties accept a degree of regulatory risk in becoming signatories to a Code which contains a process for its own modification.

Some of these respondents agreed that regulatory risk could affect the cost of capital. However, these respondents did not agree that P198 itself would increase regulatory risk, and therefore did not believe that it would have any incremental impact on cost of capital. One respondent stated that they agreed with the conclusion of the cost-benefit analysis that any risk associated with P198 would be forward-looking and diversifiable, and would therefore not impact the cost of capital.

Another minority of respondents were **neutral** as to whether P198 would have an impact in this area. One of these respondents believed that any significant Modification Proposal would add to regulatory uncertainty in the short term, but did not believe that P198 in particular would have any impact on general levels of regulatory risk or any meaningful impact on the cost of capital.

5.5.2 Modification Group's Discussion of Responses

The Group agreed that the majority of the arguments expressed by respondents in this area had already previously been considered by the Group during the Assessment Procedure. However, some new arguments or points of clarification were identified and discussed by the Group as follows:

a) One respondent argued that considerations regarding regulatory risk and the cost of capital fell outside the scope of the Applicable BSC Objectives. A majority of members did not agree with this argument, and believed that any area which had the potential to affect the costs of entry to, or participation in, the market was a direct consideration under Applicable BSC Objective (c).

b) One respondent commissioned a paper from NERA Economic Consulting, which put forward economic arguments to dispute what it perceived as OXERA's assertion that regulatory risk did not affect the cost of capital. The Group noted that the OXERA cost-benefit analysis had acknowledged that regulatory risk exists in the market, but had concluded that P198 would not itself increase regulatory risk (see Section 4.7 of this Assessment Report and Section 5.5 of the cost-benefit analysis report). The Group agreed that it was a matter of judgement for participants as to whether they agreed with these findings. The Group therefore agreed that the NERA paper should be treated as a respondent's view regarding the findings of the cost-benefit analysis, and should be taken into account in the same way as the other consultation responses. A copy of the NERA paper is contained in the consultation responses in Appendix 7.

5.6 Respondents' Views on Implementation Approach

5.6.1 Views of Respondents

a) Majority View

A majority of respondents **agreed** with the implementation approach proposed by the Group. The different arguments expressed by respondents in support of the proposed approach were as follows:

- The proposed implementation approach had been carefully considered by the Modification Group, and represented an area of consensus within the Group;
- April 2008 represents the earliest achievable Implementation Date, due to the need to allow sufficient lead time for all system and process changes and the desirability of aligning implementation with contract rounds.

One respondent, although supportive of the proposed approach, stated that they remained concerned about what they perceived as the high costs and relatively slow implementation time frame for the proposal. One respondent stated that, if the Implementation Date should slip, any revised date should be the next suitable 1 April or 1 October date to coincide with contract rounds.

b) Minority View

A minority of respondents **disagreed** with the implementation approach proposed by the Group.

Most of these respondents stated that, since they did not support P198, they could not support the proposed implementation approach. Two respondents argued that, if P198 was approved, implementation should be as long as possible. One of these respondents believed that the proposed lead times for the implementation of P198 and publication of TLF values were too short to counter the perceived destabilising impact of the proposal. One respondent did not provide rationale for their disagreement with the proposed approach.

However, although there was therefore some disagreement regarding the proposed lead time (and as to whether the modification should be implemented at all), no respondents suggested different Implementation Dates to those proposed by the Group.

Another minority of respondents were **neutral** in this area. One respondent did not express overall agreement or disagreement with the implementation approach, but stated that they would support a phased implementation with sufficient lead times to allow affected Parties to take appropriate measures.

5.6.2 Modification Group's Discussion of Responses

The Group agreed that the majority of the arguments expressed by respondents in this area had already previously been considered by the Group during the Assessment Procedure. However, some new arguments or points of clarification were identified and discussed by the Group as follows:

a) One respondent, although supportive of the proposed implementation approach, believed that it might be prudent to factor the possibility of a legal challenge into the implementation timetable. The Group noted that it had taken this argument into account when considering the most appropriate implementation approach, but had agreed that adding extra implementation time to cover the possibility of a legal challenge was not necessary or appropriate. Further detail regarding the Group's discussions in this area can be found in Section 4.5.4.

b) One respondent stated that it would be useful to the market if the TLFA were to re-calculate TLFs using 2005/06 data during implementation, in order to validate these against the TLFs calculated by the PTI modelling in the P198 Assessment Procedure. However, a majority of members believed that it would not be appropriate to add such a requirement to the P198 legal text. These members noted that the 'live' TLFs for a 2008 implementation would be recalculated based on data from the 2006/07 Reference Year, and that a requirement to also calculate TLFs using 2005/06 data prior to implementation might increase the required TLFA effort and lead time. These members believed that such a requirement would not add value to the legal text, since this already requires the Load Flow Model Reviewer to ensure that the Load Flow Model is compliant with its specification prior to implementation. However, the Group noted that there was nothing to prevent BSCCo from contractually pursing such a requirement with the TLFA as part of the pre-implementation testing of its systems.

5.7 Alternative Solutions Identified by Respondents

A majority of respondents either **did not** believe there to be any alternative solutions which the Modification Group had not identified and which should be considered further, or were **neutral** in this area. Some of these respondents referred to the amount of work already conducted by the Group in this area, and the other related Modification Proposals which had also been raised.

A minority of respondents **did** identify alternative solutions which they believed required further consideration. The solutions suggested by these respondents, and the Group's discussion of these suggestions, are summarised below.

a) One respondent believed that the Group should give consideration to a 'more sensitive' solution that allowed the market to adjust to the impact of the modification in a more appropriate way. The respondent suggested that a solution which allowed for a rolling average of TLFs over multiple years would reduce the possibility of further destabilising step-changes. Some members were sympathetic to the argument that such an approach could reduce uncertainty, but noted that its impact would need to be fully assessed. The Group noted that it would not be possible to model what the resulting TLFs would be under this approach, since only one year of post-BETTA BSC metered data was currently available (the 2005/2006 data already used in the PTI analysis). The Group therefore agreed not to progress this option under P198, although some members noted that it could form a potential Modification Proposal in the future once more years of GB-wide data were available.

b) One respondent suggested that an alternative solution would be a phased implementation of annual TLF values (i.e. phasing as per the Group's Alternative but without seasonal TLFs). The Group agreed that this option had already been fully discussed during its consideration of whether to include both phasing and seasonal TLFs in the Alternative Modification (see Section 4.8). The Group was also uncertain as to whether the respondent believed this option to be superior to the Alternative Modification developed by the Group, since the respondent had indicated support for seasonal TLFs in another part of their consultation response.

c) One respondent stated that, in abstract terms, a zonal transmission losses scheme could have merit, provided that it produced accurate dynamic losses, did not apply to existing plant, reflected the costs of operation within year, and contained evaluation of the 'right' level of locationality. The Group agreed that this appeared to be a suggestion for a different Modification Proposal, rather than support for a specific Alternative to P198.

d) One respondent believed that introduction of a zonal losses scheme within the BSC would not be the best way to encourage economic location of generation or demand. This respondent believed that transmission losses would be best managed through transmission charging and the Connection and Use of System Code. The Group noted that this view represented part of the respondent's rationale for not supporting P198, but agreed that consideration of alternative mechanisms outside the BSC fell outside the scope of its assessment.

e) One respondent noted that the Modification Group had considered and rejected a number of potential alternative solutions. The respondent believed that some of these solutions might be preferable to the Proposed and Alternative Modifications developed by the Group. However, the respondent noted that some of these solutions could require considerable additional analysis, and that they could be raised as new Modification Proposals.

f) One respondent stated that no reference had been made in the consultation document as to the impact that the actions of the System Operator could have on the level of transmission losses, and believed that this might require further analysis. The Group noted that the Transmission Company had financial incentives to reduce losses under the System Operator Incentive Scheme set by Ofgem. However, the Group noted the view of OXERA that this incentive would still exist under P198, since the target level of losses in the Incentive Scheme is reset each year based on the previous year's losses. The Group noted that the cost-benefit analysis had been based on the assumption of economic despatch, and therefore did not take account of any despatch decisions which might be made by the Transmission Company specifically to reduce losses. However, the Group noted that the assumption of economic despatch was applied by OXERA to its modelling of the evolution of losses under the current baseline as well as under P198, such that any savings in losses identified under the P198 scenario were directly attributable to the modification. The Group agreed that no further analysis was therefore required in this area.

   Some members noted that the Incentive Scheme related to investment in loss-reducing equipment as well as balancing mechanism decisions, but that this would be captured in the OXERA analysis since this concluded that P198 would not alter existing patterns of investment in the Transmission System over the ten years of the study period. Finally, the Group noted that direct consideration of any interaction between P198 and the System Operator Incentive Scheme fell outside the scope of its assessment under the Applicable BSC Objectives, and would need to be considered by the Authority.

5.8 Further Issues Raised by Respondents

A majority of respondents either **did not** believe there to be any further issues regarding P198 which had not been considered by the Modification Group, or were **neutral** in this area.

A minority of respondents **did** identify issues which they believed required further consideration. The issues raised by these respondents, and the Group's discussion of these issues, are summarised below.

a) One respondent believed that there had been no assessment of the materiality of P198 on different types of Supplier (for example, according to whether they also owned generation assets and the size and type of customer portfolio). This respondent believed that Suppliers without generation assets would be unable to offset the impact of P198 on their operations. The Group noted that the cost-benefit analysis had examined the distributional effects on three hypothetical Suppliers of the same size, but whose customer base was respectively concentrated in the north, south or balanced across the whole country (see Section 9.1 of the cost-benefit analysis report). The Group noted that, for the purpose of this exercise, these hypothetical Suppliers had been assumed not to own any generation assets. The Group noted that OXERA would not have had knowledge of individual Suppliers' actual portfolios, and also agreed that it would not have been appropriate for the cost-benefit analysis or the Group to consider individual Parties' commercial positions.

b) One respondent stated that they were disappointed that a System-Operator or Transmission-Owner approach to management of transmission losses had not been considered in parallel with P198, although the respondent noted that such an approach would not necessarily fall within the vires of the BSC or meet the defect identified by P198. Although some members were sympathetic to this suggestion, the Group agreed that consideration of such an approach fell outside the scope of P198 and of the BSC. The Group noted that it had previously discussed the possibility of allocating all transmission losses to the Transmission Company, but that this had also been deemed to be outside the scope of P198 (see Section 4.6.7). The Group therefore agreed that no further discussion in this area was required.

c) One respondent stated that the cost to the industry as a whole of progressing a modification which had (as P82) already been rejected by the DTI should be considered. The Group noted that the DTI had not placed any moratorium on the raising of any future transmission losses Modification Proposal, and that the Code allows Parties to raise Modification Proposals in areas where they believe an issue or defect exists. The Group agreed that P198 therefore needed to be considered on its own merits as to whether it would better facilitate the achievement of the Applicable BSC Objectives compared with the current Code baseline.

d) One respondent believed that there were environmental issues which should be identified and progressed, as well as a potential impact on consumers. The Group agreed that any impacts in this area fell outside the scope of the Applicable BSC Objectives, and would need to be considered by the Authority as part of its wider statutory duties.

e) One respondent noted that the government's Energy Review and the Transmission Company's Winter Outlook Update had been published during the P198 consultation period. This respondent therefore believed that there might be additional issues arising from these documents that needed to be taken into account when considering the merits of P198. The Group noted this view, but agreed that any consideration of these documents fell outside the scope of its assessment under the BSC.

f) Some respondents believed that the introduction of P198 could have a negative impact on the government's Renewables Obligation scheme. Some of these respondents believed that the benefits of this scheme were being systematically eroded by other changes in the market. One respondent was especially concerned that the value of Renewables Obligation Certificates (ROCs) could be diminished by P198 if Metered Volumes were to be scaled down for losses. The Group noted that the Metered Volumes of Parties are already scaled down to account for losses under the current arrangements, and queried whether there was an interaction with ROCs since these are allocated per MWh of renewable energy. The Group noted that any direct impact in this area was outside the scope of the Applicable BSC Objectives as ROCs are issued by Ofgem, but agreed that it would be useful to clarify whether this view of the respondent was based on a factual error. BSCCo subsequently clarified with the respondent and Ofgem that ROCs are issued according to onsite metered output at renewable plant, and not in relation to the Metered Volume data held in Settlement under the BSC. The allocation of ROCs would therefore not be affected by any scaling in Metered Volumes under P198.[24]

[24] See, for example, the Ofgem document 'Renewables Obligation: Guidance for generators over 50MW' (http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/14593_ROlargegenerators.pdf?wtfrom=/ofgem/work/index.jsp&section=/areasofwork/renewobligation).

5.9 Further Comments of Respondents

Many of the further comments made by respondents reiterated arguments already expressed elsewhere within their responses (in particular, their support or opposition to the Modification Proposal). In addition to these reiterated views, the following further points were made:

a) One respondent agreed with the conclusion of the cost-benefit analysis that the pattern of new generation reflects the influence of existing locational signals in the market. However, the respondent believed that this also demonstrated that Parties are already responding to the possibility of the introduction of a zonal transmission losses scheme, and therefore did not agree that P198 would not provide a locational signal. The Group noted this view, and agreed that it did not represent a new argument as it had been previously expressed during its earlier discussions.

b) One respondent believed that each time a new measure was introduced into the market, consumer confidence was undermined – and that, regardless of the merits of the proposal, regularly shifting costs creates the impression that signals are not fixed and are constantly subject to change. Since many of these signals are long-term, the respondent considered that such constant changes can be counterproductive as consumers cease to respond to both the new signals and already-existing signals in the market. Although the Group noted that any impact on consumers fell outside the scope of its assessment under the Applicable BSC Objectives, one member believed that the arguments made by the respondent could also apply to generators' response to signals and was related to perceptions of regulatory risk. This view was noted by the Group.

c) The same respondent queried whether existing locational signals in the market were effective, if there was a continuing mismatch between the location of generation and demand. The respondent believed that if existing signals were working then the defect identified by P198 would be less pronounced, whereas if they were not then the cost-benefit analysis had demonstrated that any additional P198 locational signals would have a negligible effect. The Group noted the conclusion of the cost-benefit analysis that existing signals were incentivising new southern generation to be built, and that the additional effect of P198 on location of new investment would therefore be ambiguous. However, the Group noted that the cost-benefit analysis had identified significant benefits from P198's short-term despatch signals. The Group noted that there had been differing views as to whether these benefits would be realised in practice, or would be offset by the distributional impacts of P198.

d) The same respondent stated that it was contradictory for environmental considerations to be excluded from the cost-benefit analysis but to be cited as a reason for implementation. The Group agreed that this view appeared to be based on a reading of the original Modification Proposal, which had contained the Proposer's views regarding potential environmental benefits from P198. The Group noted that it had explicitly excluded environmental considerations from its assessment of P198 against the Applicable BSC Objectives, and noted that this area would therefore need to be considered by the Authority as part of its wider statutory duties.

e) Another respondent considered that, once the current raft of transmission losses proposals had been taken to the Report Phase, the area of transmission losses should not be considered further. The Group noted that the raising of any future proposals was outside its control, but considered that it would not be inappropriate for further modifications to be raised if Parties believed that alternative solutions would genuinely better facilitate the achievement of the Applicable BSC Objectives compared to the existing baseline and the current proposals.

f) The same respondent stated that new northern generation is already being constrained by grid access, and that part of the benefit identified for P198 was therefore already being effected. The Group noted that the benefits identified by the cost-benefit analysis for P198 had been those which were directly attributable to the modification, compared with any changes in despatch or location which might already occur under the current baseline. The Group therefore agreed that there was therefore no element of 'double-counting' of benefits in this area. The Group also noted the conclusion of the cost-benefit analysis that the locational signals of P198 would have an ambiguous impact compared with other existing locational factors in the market, and that the arguments of the respondents therefore appeared to be in line with this view.

g) Some respondents stated that the Authority should consider the impact on the environment and consumers in its impact assessment. One of these respondents believed that the Authority should also consider what the respondent perceived to be a move by southern generators to improve cashflows and increase the cost and value of the Renewables Obligation. The Group noted that the Authority's decision would be based on consideration of whether P198 would be consistent with its wider statutory duties, in addition to whether it would better facilitate the achievement of the Applicable BSC Objectives.

h) One respondent expressed concern regarding what they perceived as the very short length of the P198 consultation period, which had run in parallel with P200. The respondent believed that this may have resulted in the industry not being able to comment fairly on the changes. The Group noted that a two-week consultation period had been provided, which was consistent with the normal duration for Assessment Procedure consultations – and that this had been the maximum time available within the constraints of the P198 Assessment Procedure timetable. The Group noted that efforts had been made by BSCCo to support the consultation process by hosting an educational seminar, and members stated that they were encouraged by the fact that responses had been received from smaller participants who did not usually respond to Modification Proposal consultations. The Group also noted that participants would have a further opportunity to comment on P198 during the Report Phase.

i) One respondent provided a number of further comments, which it believed should be considered by the Panel as follows:

    i) The respondent believed that P198 could provide incorrect locational signals. The Group noted this view, and agreed that it did not represent a new argument as it had already been expressed during its previous discussions;

    ii) In support of the above view, the respondent argued that the Transmission Company's Seven Year Statement demonstrated a net deficit in generation in the north-east of England but that P198 would disincentivise the location of new generation in this area. The Group noted this view, but also noted that there was not agreement amongst members that this was the case;

    iii) The respondent did not believe that the existing uniform allocation of losses represented a cross-subsidy. The Group noted this view, and agreed that it did not represent a new argument as it had already been expressed during its previous discussions;

    iv) The respondent disagreed with the view of the Proposer that P198 would provide long-term locational signals – citing the conclusions of the cost-benefit analysis in this area. The Group noted this view, and agreed that it did not represent a new argument as it had already been expressed during its earlier discussions;

    v) The respondent disagreed with the majority view of the Group that the Load Flow Model should not be made available to Parties. The Group noted this view, but also noted that this area had been considered extensively by the Group during the Assessment Procedure (see Section 4.3.4). By majority, the Group therefore agreed not to reconsider its previous conclusions in this area;

vi) The respondent considered that, under P198, certain Parties would suffer a loss which was far greater than the net saving in the costs of variable losses. This view was also expressed by two other respondents to the consultation, one of whom stated that it would be inappropriate for Parties to receive a negative allocation of losses (i.e. to receive payments through the TLM). The Group noted this view, but also noted that there was disagreement amongst members over whether the distributional effects of P198 were appropriate or disproportionate – as well as to whether these effects would increase regulatory risk. The Group noted that the concerns of some Parties in this area had led to the raising of Modification Proposals P200 and P204.

j) One respondent referred to the costs to the industry which it believed were likely to result from the Transmission Company's recent Income Adjusting Event request, and queried whether it would therefore be appropriate to introduce a change to the allocation of transmission losses. The Group agreed that such considerations fell outside the Applicable BSC Objectives, but could be considered by the Authority under its wider remit.

k) One respondent believed that the actions of the System Operator would have an impact on the level of transmission losses through system requirements. This was similar to an argument expressed by another respondent in a different area of the consultation, and the Group's consideration of this view can be found in Section 5.8 above.

6 GROUP'S ASSESSMENT OF P198 AGAINST APPLICABLE BSC OBJECTIVES

This section outlines the views of the Modification Group regarding the merits of P198 against the Applicable BSC Objectives.

6.1 Proposed Modification

Table 14 – Modification Group's View of Proposed Modification

Proposed Modification better facilitates?	Applicable BSC Objectives				
	(a)	(b)	(c)	(d)	Overall
Yes	Minority	**Majority**	Minority	None	Minority
No	None	Minority	**Majority**	Minority	**Majority**
Neutral	**Majority**	Minority	Minority	**Majority**	Minority

Applicable BSC Objective (a) – The efficient discharge by the Transmission Company of the obligations imposed upon it by the Transmission Licence

The **MAJORITY** view of the Group was that the Proposed Modification would have a **NEUTRAL** effect on the achievement of Applicable BSC Objective (a). This was consistent with the view provided within the Transmission Company Analysis, where the Transmission Company concluded that P198 would have no impact on its ability to discharge its licence obligations (see Appendix 3).

The view of a **MINORITY** of members was that the Proposed Modification **WOULD** better facilitate the achievement of Applicable BSC Objective (a), by removing the market distortions and discrimination generated by the existing uniform allocation of variable losses. This reflected the view provided by the Authority in the P75 and original P82 decision letters that *"addressing the cross-subsidy in the present transmission losses charging arrangements through more cost-reflective charging will also help to remove the discrimination that exists in the present arrangements".*

Applicable BSC Objective (b) – The efficient, economic and co-ordinated operation of the GB transmission system

The **MAJORITY** view of the Group was that the Proposed Modification **WOULD** better facilitate the achievement of Applicable BSC Objective (b). These members believed that the external cost-benefit analysis had highlighted a significant reduction in the level of variable losses should the Proposed Modification be approved, as a result of more efficient short-term plant despatch. One member argued that this would have a positive effect on Applicable BSC Objective (b), even at the lower end of the savings identified by the cost-benefit analysis. Although some of these members believed that the cost-benefit analysis demonstrated that the long-term signals provided by P198 might be ambiguous, they believed that the identified savings from redespatch would still deliver a net efficiency benefit.

One member of the Group also argued that, in addition to introducing more efficient short-term despatch, P198 would introduce long-term signals influencing business decisions regarding investment in both generation and demand. This member believed that the results of the cost-benefit analysis demonstrated that Parties are already taking account of the possible introduction of a zonal transmission losses scheme in their planning decisions, since the introduction of such a scheme has been discussed for several years.

The view of a **MINORITY** of members was that the Proposed Modification would have a **NEUTRAL** impact on the achievement of Applicable BSC Objective (b). This view was generally based on the findings of the cost-benefit analysis that P198 would not result in the relocation of any existing generating plant. These members argued that this demonstrated that the Proposed Modification would not provide a long-term signal to the market relative to other existing signals, and that any efficiency benefit would therefore be negligible. One member believed that the Proposed Modification would not have a significant impact on plant despatch. Noting that this was not necessarily supported by the cost-benefit analysis, this member considered that the analysis had been based on an economic despatch model which might not be representative of realistic market conditions. Another member argued that a reduction in the level of variable losses was not a relevant consideration against Applicable BSC Objective (b) – which they believed related to the efficient operation of the Transmission System, rather than the efficiency of the system itself.

The view of another **MINORITY** of members was that the Proposed Modification **WOULD NOT** better facilitate the achievement of Applicable BSC Objective (b). These members did not believe that the Proposed Modification would lead to more efficient despatch.

Applicable BSC Objective (c) – Promoting 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

The **MAJORITY** view of the Group was that the Proposed Modification **WOULD NOT** better facilitate the achievement of Applicable BSC Objective (c). These members noted the distributional effects of P198 highlighted in the cost-benefit analysis, and believed that these represented windfall gains and losses which would penalise existing investment decisions with a negative impact on competition. Some members disagreed with the findings of the cost-benefit analysis regarding renewables, which they argued would be disproportionately impacted by the Proposed Modification. One member also argued that the Proposed Modification would have a negative impact on CHP plant. Another member considered that it would be impractical for demand to respond to the P198 signals, and did not agree that the existing arrangements represented a cross-subsidy. Additionally, some members believed that the Proposed Modification would increase volatility and would raise the cost of capital for new entrants to the market, thereby representing a barrier to entry.

A **MINORITY** of members believed that the Proposed Modification **WOULD** better facilitate the achievement of Applicable BSC Objective (c). Some of these members did not believe that the distributional impacts of P198 were a valid consideration against its approval, since they believed that these represented the removal of the cross-subsidy between Suppliers (north to south) and generators (south to north) which was inherent in the existing uniform allocation of variable losses. Some members also believed that the zonal nature of the scheme would ensure that individual BM Units were not unduly penalised, whilst basing the scheme on an ex-ante calculation would allow Parties to estimate the impact of TLFs on their charges and reflect these in their advance contracts. The same member argued that Parties already took account of regulatory risk in becoming a Code signatory, and therefore did not believe that the Proposed Modification would have any impact in this area. Another member argued that the Proposed Modification would give better signals for participants in the Balancing Mechanism, thereby promoting competition.

One member of the Group argued that P198 would also introduce long-term signals influencing business decisions regarding investment in both generation and demand. This member believed that the results of the cost-benefit analysis demonstrated that Parties are already taking account of the possible introduction of a zonal transmission losses scheme in their planning decisions, since the introduction of such a scheme has been discussed for several years.

Another **MINORITY** of members believed that the Proposed Modification would have a **NEUTRAL** impact on the achievement of Applicable BSC Objective (c). These members believed that the arguments detailed above were finely balanced, such that there was no overall positive or negative impact on competition. One of these members stated that they did not believe that the Proposed Modification would have any impact on investment.

Applicable BSC Objective (d) – Promoting efficiency in the implementation and administration of the balancing and settlement arrangements

The **MAJORITY** view of the Group was that the Proposed Modification would have a **NEUTRAL** effect on the achievement of Applicable BSC Objective (d). These members believed that the implementation costs of the proposal were not significant. Some members considered that increased cost and complexity in the balancing and settlement arrangements was not in itself a negative effect, if the process which was being introduced promoted efficiencies.

A **MINORITY** of members believed that the Proposed Modification **WOULD NOT** better facilitate the achievement of Applicable BSC Objective (d). These members argued that the Proposed Modification would add cost and complexity to the BSC arrangements, reducing overall efficiency. One member noted that the method used to recover variable losses through TLFs was significantly under-recovering these due to the averaging effect, and considered that this could therefore not be more efficient than the current Code baseline.

Summary

On balance, a **MAJORITY** of members believed that any benefits under Applicable BSC Objective (b) would be limited and would be outweighed by a negative impact on Applicable BSC Objective (c). These members therefore believed that the Proposed Modification **WOULD NOT** better facilitate the achievement of the Applicable BSC Objectives overall, and should not be made.

Another member stated that, although they believed that the balance between the potential benefits and disbenefits of the Proposed Modification would lead to a neutral effect overall, they believed that the Proposed Modification should not be made since the case for change was unproven.

A **MINORITY** of members believed that the Proposed Modification **WOULD** better facilitate the achievement of both Applicable BSC Objectives (b) and (c), and should therefore be made. Some of these members also believed that the Proposed Modification would better facilitate the achievement of Applicable BSC Objective (a).

Another **MINORITY** of members believed that any potential benefit under Applicable BSC Objective (b) and any negative impact under Objective (c) would be finely balanced. These members therefore stated that they remained **NEUTRAL** as to whether the Proposed Modification would better facilitate the achievement of the Applicable BSC Objectives overall.

6.2 Alternative Modification

Table 15 – Modification Group's View of Alternative Modification

Better facilitates Applicable BSC Objectives?	Compared with Proposed Modification	Compared with existing Code baseline
Yes	**Majority**	Minority
No	Minority	**Majority**
Neutral	Minority	Minority

5.2.1 Alternative Modification compared with Proposed Modification

Applicable BSC Objective (a) – The efficient discharge by the Transmission Company of the obligations imposed upon it by the Transmission Licence

The **UNANIMOUS** view of the Group was that the Alternative Modification would have a **NEUTRAL** effect on the achievement of Applicable BSC Objective (a) compared with the Proposed Modification.

Applicable BSC Objective (b) – The efficient, economic and co-ordinated operation of the GB transmission system

The **MAJORITY** view of the Group was that the Alternative Modification **WOULD** better facilitate the achievement of Applicable BSC Objective (b) when compared with the Proposed Modification. These members believed that the external TLF modelling and cost-benefit analysis exercises had demonstrated that seasonal TLF values would represent a better reflection of the actual behaviour of BM Units within Zones, provide a more accurate short-term signal to generators, lead to more efficient plant despatch, and thereby offer the greatest reduction in variable losses. However, these members did not believe there to be any difference in the long-term locational signals generated by the Proposed and Alternative Modifications.

The view of a **MINORITY** of members was that the Alternative Modification **WOULD NOT** better facilitate the achievement of Applicable BSC Objective (b) when compared with the Proposed Modification. These members believed that introducing a linear phasing element into the solution would delay the realisation of the benefits associated with seasonal TLFs.

Applicable BSC Objective (c) – Promoting 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

The **MAJORITY** view of the Group was that that Alternative Modification **WOULD** better facilitate the achievement of Applicable BSC Objective (c) when compared with the Proposed Modification. Some of these members argued that the results of the TLF modelling exercise had demonstrated that seasonal TLF values would be a more accurate allocation of variable losses than a single annual average. Other members argued that a phased implementation would mitigate the windfall gains and losses created by a sudden step-change to a zonal transmission losses scheme, and would provide time for Parties to gradually take account of the new zonal TLFs in their contracts. One member stated that the contracts of some Parties were of three years' duration, and considered that a phased implementation over four years would ensure that such Parties were not disproportionately penalised on the basis of contracts entered into under the current arrangements.

The view of a **MINORITY** of members was that the Alternative Modification **WOULD NOT** better facilitate the achievement of Applicable BSC Objective (c) when compared with the Proposed Modification. Although some (but not all) of these members believed that the use of seasonal TLFs would better facilitate this Objective, all of these members believed that introducing a linear phasing element into the solution would delay the realisation of the benefits associated with a zonal transmission losses scheme.

Applicable BSC Objective (d) – Promoting efficiency in the implementation and administration of the balancing and settlement arrangements

The **MAJORITY** view of the Group was that the Alternative Modification would have a **NEUTRAL** effect on the achievement of Applicable BSC Objective (d) when compared to the Proposed Modification, since these members noted that the implementation costs of both the Proposed and Alternative Modifications were very similar.

The view of a **MINORITY** of the Group was that the Alternative Modification **WOULD NOT** better facilitate the achievement of Applicable BSC Objective (d) when compared to the Proposed Modification. These members believed that introducing a seasonal change in TLF values would add further complexity to the BSC arrangements, and would decrease predictability and stability.

Summary

On balance, a **MAJORITY** of members believed that the Alternative Modification **WOULD** better facilitate the achievement of Applicable BSC Objectives (b) and (c) compared with the Proposed Modification. Most of these members believed that these Applicable BSC Objectives would be better facilitated by both the seasonal TLFs and phasing elements of the Alternative Modification, and that the Alternative would have a neutral impact on the achievement of Applicable BSC Objective (d) compared with the Proposed Modification. These members did not believe that it was inconsistent to support both elements of the Alternative, arguing that the seasonal element would give a more accurate allocation of losses whilst phasing would smooth the effect of a step-change in the rules (especially for Parties with long-term contracts).

One member believed that the introduction of a seasonal change in TLF values would have a negative impact on the achievement of Applicable BSC Objective (d) when compared with the Proposed Modification. However, this member believed this to be outweighed by the benefits of phasing under Objectives (b) and (c), such that they believed that the Alternative Modification would better facilitate the achievement of the Applicable BSC Objectives overall when compared with the Proposed Modification.

A **MINORITY** of members believed that the Alternative Modification **WOULD NOT** better facilitate the achievement of the Applicable BSC Objectives compared with the Proposed Modification. One of these members believed that any additional benefit to Applicable BSC Objectives (b) and (c) resulting from seasonal TLFs would be outweighed by the delay in these benefits resulting from linear phasing. Another member did not believe that either of the seasonal TLFs or phasing elements of the Alternative Modification would better facilitate the achievement of the Applicable BSC Objectives compared with the Proposed Modification, and believed that both of these elements would have a negative impact on the achievement of Applicable BSC Objective (d).

Another **MINORITY** of members stated that they remained **NEUTRAL** as to whether the Alternative Modification would better facilitate the achievement of the Applicable BSC Objectives when compared with the Proposed Modification. One of these members believed that any potential increase in accuracy through the use of seasonal TLFs would be balanced out by its increased complexity and volatility, and stated that they found it difficult to see how phasing would better facilitate the achievement of the Applicable BSC Objectives.

5.2.2 Alternative Modification compared with Existing Code Baseline

On balance, the **MAJORITY** view of the Group was that the Alternative Modification **WOULD NOT** better facilitate the achievement of the Applicable BSC Objectives when compared with the existing Code baseline, and that the Alternative Modification should therefore not be made. Whilst some believed that the Alternative Modification would be better than the Proposed Modification, all of these members believed that the arguments expressed against the Proposed Modification in Section 6.1 above would still be present under the use of seasonal TLFs, and would not be fully mitigated by the inclusion of a linear phasing approach.

The view of a **MINORITY** of members was that the Alternative Modification **WOULD** better facilitate the achievement of the Applicable BSC Objectives when compared with the existing Code baseline. Although some of these members believed that the Alternative Modification would be inferior to the Proposed Modification due to its inclusion of seasonal TLFs and/or linear phasing, all of these members believed that the Alternative would still partly address the cross-subsidy present in the existing arrangements.

Another **MINORITY** of members believed that any potential benefit under Applicable BSC Objective (b) and any negative impact under Objective (c) would be finely balanced. These members therefore stated that they remained **NEUTRAL** as to whether the Alternative Modification would better facilitate the achievement of the Applicable BSC Objectives overall.

6.3 Final Recommendation to the Panel

On the basis of the above assessment, the Modification Group therefore agreed a **MAJORITY** recommendation to the Panel that:

- The Proposed Modification **SHOULD NOT** be made; and that
- The Alternative Modification **SHOULD NOT** be made.

Details of the Group's recommended Implementation Date and legal text can be found in Section 4.

6.4 Interaction with P200

In accordance with the BSC Modification Procedures, P198 and P200 were assessed separately by their respective Modification Groups as to whether they would better facilitate the achievement of the Applicable BSC Objectives compared with the existing Code baseline – and not compared with each other. The Group noted that the majority recommendation of the P200 Group was that neither the P200 Proposed nor Alternative Modifications should be made. However, the P198 Group noted that the P200 Group (which comprised a slightly different membership) had considered that it would be useful to indicate a preference between P198 and P200, so that this could be taken into account by the Panel and the Authority. However, the P198 Group noted that the P200 Group had been divided over whether one of the proposals would be better than the other, such that there was no majority preference between them.

6.5 Interaction with P203

As for P200, P203 was assessed separately to the other related Modification Proposals on its own merits. The majority recommendation of the P203 Modification Group is that P203 should not be made. However, a majority of members of the P203 Group considered that it would be useful to indicate a preference between P198 and P203, so that this could be taken into account by the Panel and the Authority.

A majority of members of the P203 Group expressed a preference for Proposed Modification P203 over Proposed Modification P198, due to the use of seasonal rather than annual TLF values. No members of the P203 Group expressed a preference for Proposed Modification P198 over Proposed Modification P203. A minority of members abstained – either because they did not have a strong preference either way, or since they did not believe that it was appropriate to express a preference between stand-alone Modification Proposals.

A narrow majority of members of the P203 Group expressed a preference for Alternative Modification P198 over Proposed Modification P203, due to its inclusion of phasing. A large minority of members of the P203 Group did not support phasing, and therefore expressed a preference for Proposed Modification P203 over P198 Alternative. One member abstained.

6.6 Interaction with P204

P204 is currently part-way through the Assessment Procedure. The P204 Modification Group has not yet developed a provisional view of whether P204 would better facilitate the achievement of the Applicable BSC Objectives compared with the current Code baseline.

7 TERMS USED IN THIS DOCUMENT

Other acronyms and defined terms take the meanings defined in Section X of the Code.

Term	Definition
Adjusted Annual Zonal TLFs	Annual Zonal TLFs, adjusted through a scaling factor to ensure that the volume of energy allocated via TLFs is comparable to the volume of variable losses calculated by the Load Flow Model.
Adjusted Seasonal Zonal TLFs	Seasonal Zonal TLFs, adjusted through scaling factors to ensure that the volume of energy allocated via TLFs is comparable to the volume of variable losses calculated by the Load Flow Model, and to achieve a phased implementation of these values over four years via the β factor.
'Alpha' (α) factor	The scaling factor applied to total transmission losses such that, in aggregate, 45% are allocated to delivering Trading Units and 55% are allocated to offtaking Trading Units.
Annual Zonal TLFs	Zonal TLFs for each Sample Settlement Period, converted to annual figures by 'time-weighted' averaging.
'Beta' (β) factor	A scaling factor used to achieve a phased implementation of zonal TLFs, by scaling down the TLF values in the first four BSC Years of the scheme such that they gradually increase to their full value in the fifth BSC Year.
BM Unit-Specific TLFs	The TLF value for each BM Unit to be used in the calculation of $TLMO^{+/-}$ and TLM, comprising the TLF for the Zone in which the BM Unit is located.
Escrow agent	An agent with whom a copy of the Load Flow Model would be deposited by the TLFA, in order to ensure the integrity of the Model.
Estimated Transmission Losses Adjustment (ETLMO)	Used in data calculations on the Balancing Mechanism Reporting Service to estimate the value of the Transmission Losses Adjustment.
Ex-ante	Based on forecast data.
Ex-Post	Based on actual data.
Fixed losses	The element of transmission losses which occurs in overhead lines and transformers, and which depends on voltage levels and climatic conditions.

Term	Definition
Indicative network	An approximation of the transmission network in existence at a specific point in time (i.e. a snapshot of the network during a specific Settlement Period), which is based on a intact network but includes all known equipment outages.
Intact network	The complete overall capability of the transmission network, assuming that all lines are in operation and that there are no equipment outages (i.e. no transformers or lines out of service).
Load Flow Model	A mathematical model of an electrical network which represents power flows between pairs of adjacent Nodes on the network, and from which Nodal TLFs can be determined for each Node for given power flows.
Load Flow Model Reviewer	An independent expert appointed by the Panel for the purpose of verifying that the Load Flow Model complies with the Load Flow Model Specification.
Load Flow Model Specification	The specification for the Load Flow Model of the Transmission System, providing assumptions and approximations to be made in the model.
Load Periods	Periods representing typically different levels of load on the Transmission System, to be determined by the Panel such that every Settlement Period in the Reference Year falls into one and only one Load Period.
Network Data	Data relating to the Transmission System, provided by the Transmission Company for use in the Load Flow Model.
Network Mapping Statement	A statement which maps Volume Allocation Units to Nodes, Nodes to Zones and BM Units to Zones for the purposes of the Load Flow Model.
Nodal TLFs	In relation to a Node on a network and a given power flow at the Node, a Nodal TLF is the rate of change of electrical losses on the network with respect to change of power flow at that Node (with network balance being maintained by a Slack Node).
Node	A point on an electrical network at which a power flow on to or off the network can occur, or where two or more circuits (forming part of the network) meet. For the purposes of P198, a Node represents such a point on the Transmission System as identified by the Transmission Company.
Reference Year	A historic twelve-month period, from which data for Sample Settlement Periods is used to generate Transmission Loss Factors.
Representative network	An approximation of the typical configuration of the transmission network over a longer period (e.g. a year), which is based on an intact network but includes the average outages over the period.
Sample Settlement Period	Representative Settlement Periods within each Load Period, to be determined by the Panel.
Seasonal Zonal TLFs	Zonal TLFs for each Sample Settlement Period, converted to figures for each BSC System by 'time-weighted' averaging.
Slack Node (sometimes called 'slack bus')	A Node that acts (for the purposes of the Load Flow Model) as a sink for power flow surpluses or deficits arising from approximations in the model, and which acts (in relation to adjacent Nodes) as the reference Node for calculating the phase angle of the power flow between the Nodes.
Total transmission losses	The sum of fixed losses and variable losses in any given period.
Transmission losses	The energy lost during the flow of power across the Transmission System (calculated as the difference between total generation and demand).
Transmission Losses Adjustment (TLMO)	The parameter for allocating the proportion of transmission losses which is not allocated through the Transmission Loss Factor, and which is applied on a uniform basis.

Term	Definition
Transmission Loss Factor (TLF)	The parameter for allocating some or all transmission losses on a non-uniform basis, and which is currently set to zero.
Transmission Loss Factor Agent (TLFA)	A new BSC Agent, responsible for calculating Transmission Loss Factor values.
Transmission Loss Multiplier (TLM)	The factor used to scale BM Unit Metered Volumes in Settlement in order to allocate total transmission losses to Parties.
Variable Losses	The element of transmission losses which occurs through the heating of transmission lines, cables and transformers, and which increases with the current (and associated power flow) and length of line in which it flows.
Zonal TLFs	Nodal TLFs, averaged across all the Nodes in each Zone by 'volume-weighted' averaging for each Sample Settlement Period.
Zone	The geographic area in which a GSP Group lies, determined by the Panel (applying such criteria as it shall decide in its discretion) but so that the Zones are mutually exclusive and comprise the whole of (and nothing but) the area specified in Schedule 1 of the Transmission Licence.

8 DOCUMENT CONTROL

8.1 Authorities

Version	Date	Author	Recipient	Reason for Issue
0.1	25/07/06	Kathryn Coffin	P198 Modification Group, Sarah Jones, Justin Andrews, Tom Bowcutt, John Lucas, Richard O'Malley, Chris Rowell	For review
0.2	03/08/06	Kathryn Coffin	Sarah Jones	Updated draft incorporating review comments
1.0	04/08/06	P198 Modification Group	BSC Panel	For Panel decision
2.0	18/08/06	P198 Modification Group		Reissued with correction of minor typos

8.2 References

Ref.	Document Title	Owner	Issue Date	Version
1	Ofgem decision in relation to Modification Proposal P75 'Introduction of Zonal Transmission Losses' ELEXON - Modification Proposal 075	Ofgem	17/01/03	N/A
2	Ofgem decision in relation to Modification Proposal P105 'Introduction of Zonal Transmission Losses on a Marginal Basis Without Phased Implementation' ELEXON - Modification Proposal 105	Ofgem	17/01/03	N/A
3	Ofgem decision in relation to Modification Proposal P109 'A Hedging Scheme for Changes to TLF in Section T of the Code' ELEXON - Modification Proposal 109	Ofgem	03/06/03	N/A
4	Ofgem decision in relation to Modification Proposal P82 'Introduction of Zonal Transmission Losses on an Average Basis' ELEXON - Modification Proposal 082	Ofgem	17/01/03	N/A

Ref.	Document Title	Owner	Issue Date	Version
5	Ofgem notice in relation to Modification Proposal P82 'Introduction of Zonal Transmission Losses on an Average Basis' ELEXON - Modification Proposal 082	Ofgem	30/01/04	N/A
6	Joint Assessment Report for Modification Proposals P75 'Introduction of Zonal Transmission Losses' and P82 'Introduction of Zonal Transmission Losses on an Average Basis' ELEXON - Modification Proposal 082	BSCCo	08/11/02	1.0
7	Modification Report for Modification Proposal P82 'Introduction of Zonal Transmission Losses on an Average Basis' ELEXON - Modification Proposal 082	BSCCo	16/12/02	1.0
8	Modification Report for Modification Proposal P75 'Introduction of Zonal Transmission Losses' ELEXON - Modification Proposal 075	BSCCo	16/12/02	1.0
9	Modification Report for Modification Proposal P105 'Introduction of Zonal Transmission Losses on a Marginal Basis Without Phased Implementation' ELEXON - Modification Proposal 105	BSCCo	16/12/02	1.0
10	Modification Report for Modification Proposal P109 'A Hedging Scheme for Changes to TLF in Section T of the Code' ELEXON - Modification Proposal 109	BSCCo	18/03/03	1.0
11	Modification Report for Modification Proposal P125 'Apportionment of the Scottish Interconnector flows to the Northern and North Western GSP Groups for the purposes of calculating losses' ELEXON - Modification Proposal 125	BSCCo	16/07/03	1.0
12	Assessment Report for Modification Proposal P200 'Introduction of a Zonal Transmission Losses Scheme with Transitional Scheme' ELEXON - Modification Proposal 200	BSCCo	04/08/06	1.0
13	Assessment Report for Modification Proposal P203 'Introduction of a Seasonal Zonal Transmission Losses Scheme' ELEXON - Modification Proposal 203	BSCCo	04/08/06	1.0
14	Initial Written Assessment for Modification Proposal P204 'Scaled Zonal Transmission Losses' ELEXON - Modification Proposal 204	BSCCo	07/07/06	1.0
15	Business Requirements Solution for Modification Proposal P82 'Introduction of Zonal Transmission Losses on an Average Basis' ELEXON - November 03 Release	BSCCo	15/05/03	1.0
16	'Transmission Access and Losses under NETA: Revised Proposals' http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/1396_19transaccess.pdf	Ofgem	February 2002	N/A
17	'A Report to the DTI: The Impact of Average Zonal Transmission Losses Applied Throughout Great Britain' www.oxera.com/main.aspx?id=233	OXERA Consulting Ltd	June 2003	N/A
18	'A Report to the Scottish Executive: Assessing the Introduction of Zonal Charging for Transmission Losses in Great Britain' www.ilexenergy.com/?t=6_3Archive2003#ZonalCharging	ILEX Energy Consulting	March 2003	2.0

8.3 Intellectual Property Rights, Copyright and Disclaimer

APPENDIX 1: DRAFT LEGAL TEXT

Draft legal text for the Proposed Modification is attached as a separate document, Appendix 1A.

Draft legal text for the Alternative Modification is attached as a separate document, Appendix 1B.

APPENDIX 2: PROCESS FOLLOWED

a) P198 Timetable and Process Followed

The table below shows the timetable and process followed in progressing P198 through the Modification Procedures.

In order that the external TLF modelling and cost-benefit analysis could be completed, a longer Assessment Procedure timetable was required for P198 than the normal maximum of three months. The total duration of the Assessment Procedure was seven months, and this timetable was agreed by the Panel in accordance with Section F2.2.9 of the Code.

Copies of all documents referred to in the table can be found on the BSC Website at ELEXON – Modification Proposal 198 – with the exception of Panel presentation slides which can be found at ELEXON - BSC Panel Meetings 2006, and the details of the P198/P200 industry education seminar which can be found at ELEXON - Diary and Event Archive.

Date	Event
16/12/05	Modification Proposal P198 raised by RWE Npower
12/01/06	IWA presented to the Panel – 4-month Assessment Procedure initiated, and initial expenditure agreed for TLF modelling and cost-benefit analysis
18/01/06	First Modification Group meeting held
26/01/06	Second Modification Group meeting held
08/02/06	Modelling Requirements Specification finalised
09/02/06	Verbal update presented to the Panel
13/02/06	Proposed Modification Requirements Specification issued for BSC Agent impact assessment
13/02/06	Proposed Modification request for Party/Party Agent impact assessments issued
13/02/06	Proposed Modification request for Transmission Company analysis issued
13/02/06	Proposed Modification request for BSCCo impact assessment issued
13/02/06	First Assessment Procedure Consultation issued
20/02/06	External TLF modelling exercise commenced by Siemens PTI
27/02/06	Proposed Modification impact assessment responses returned
27/02/06	First Assessment Procedure Consultation responses returned
02/03/06	Third Modification Group meeting held
09/03/06	Interim Report presented to the Panel – 2-month Assessment Procedure extension granted
13/03/06	Fourth Modification Group meeting held

Date	Event
21/03/06	Cost-Benefit Analysis Requirements Specification finalised
08/04/06	Verbal update presented to the Panel – further expenditure agreed for TLF modelling and cost-benefit analysis
13/04/06	Siemens PTI TLF modelling exercise concluded
18/04/06	Proposed Modification external cost-benefit analysis commenced by OXERA
21/04/06	Modification Proposal P200 raised by Teesside Power
24/04/06	Fifth Modification Group meeting held
25/04/06	Further external TLF modelling work commenced by Siemens PTI
10/05/06	Sixth Modification Group meeting held
11/05/06	Verbal update presented to the Panel – final TLF modelling expenditure noted
11/05/06	Alternative Modification external cost-benefit analysis commenced by OXERA
31/05/06	Alternative Modification Requirements Specification issued for BSC Agent impact assessment
31/05/06	Alternative Modification request for Transmission Company analysis issued
31/05/06	Alternative Modification request for Party/Party Agent impact assessment issued
30/05/06	Alternative Modification request for BSCCo impact assessment issued
08/06/06	Verbal update presented to the Panel – further 1-month Assessment Procedure extension granted
12/06/06	Alternative Modification impact assessment responses returned
14/06/06	OXERA cost-benefit analysis concluded
15/06/06	Seventh Modification Group meeting held
26/06/06	Modification Proposal P203 raised by RWE Npower
30/06/06	Second Assessment Procedure Consultation issued
03/07/06	Modification Proposal P204 raised by British Energy Power & Energy Trading Ltd
05/07/06	Industry education session held to support P198/P200 consultations
13/07/06	Verbal update presented to the Panel
14/07/06	Second Assessment Procedure Consultation responses returned
18/07/06	Eighth Modification Group meeting held
01/08/06	Cost-Benefit Analysis Data Correction Consultation issued
08/08/06	Cost-Benefit Analysis Data Correction Consultation responses returned
10/08/06	Assessment Report presented to the Panel

b) P198 Progression Costs

Please note that the ELEXON resource estimate shown in the table has increased from that provided in the IWA to reflect the 2-month extension to the Assessment Procedure agreed by the Panel at its meeting on 9 March 2006, the further 1-month extension granted by the Panel at its meeting on 8 June 2006, and the actual ELEXON effort expended by the point the final extension was granted.

The legal/expert cost has also been updated to take account of the Panel's final approved expenditure for the TLF modelling exercise and cost-benefit analysis. This expenditure was approved by the Panel in accordance with Section F2.6.8 of the Code, which requires a Modification Group to seek the agreement of the Panel before undertaking any activities which may incur significant costs.

ESTIMATED COSTS OF PROGRESSING MODIFICATION PROPOSAL[25]

Meeting Costs	£7,000 (half shared with P200)
Legal/Expert Cost	£116,500
Impact Assessment Cost	£5,000
ELEXON Resource	230 man days, equating to £57,000

[25] Clarification of the meanings of the cost terms in this appendix can be found on the BSC Website at the following link: http://www.elexon.co.uk/documents/Change_and_Implementation/Modifications_Process_-_Related_Documents/Clarification_of_Costs_in_Modification_Procedure_Reports.pdf.

c) P198 Modification Group Membership and Attendance

The table below shows which members of the Modification Group and other industry attendees were present at the Modification Group meetings during the Assessment Procedure.

i) Members

* = member of TLFMG for P82

** = attendee at TLFMG meetings for P82

Member	Organisation	18/1	26/1	2/3	13/3	24/4	10/5	15/6	18/7
Sarah Jones	ELEXON (Chair)	Y	Y	Y	Y	Y	Y	Y	Y
Kathryn Coffin	ELEXON (Lead Analyst)	N	Y	Y	Y	Y	Y	Y	Y
Bill Reed*	RWE Npower (Proposer's Representative)	Y	Y	Y	Y	Y	Y	Y	Y
Guy Phillips	National Grid	Y	Y	Y	Y	Y	Y	N	N
Andrew Truswell	National Grid	N	N	N	N	N	N	Y	Y
Steve Drummond	EDF Trading	Part	Y	Y	Y	Y	N	Y	Y
David Lewis	EDF Energy	N	N	Y	Y	Y	Y	Y	Y
Man Kwong Liu	SAIC	Y	Y	Y	Y	Y	Y	Y	Y
Martin Mate*	British Energy	Y	Y	Y	Y	Y	Y	N	Y
Garth Graham**	Scottish and Southern	Y	Y	N	N	Y	Y	Y	Y
Mark Manley	Centrica	N	Y	Y	Y	N	N	N	N
Keith Miller**	KM Energy	Y	Y	Y	Y	Y	Y	Y	Y
Richard Ford**	BWEA	Y	Y	Y	Y	Y	Y	N	N
Libby Glazebrook	International Power	Y	Y	Y	N	Y	Y	Y	N
Bob Brown	Cornwall Energy Associates	Y	Y	Y	Y	Y	Y	Y	Y
Peter Bolitho*	E.ON	N	Y	Y	N	N	N	N	Y
Kirsten Elliott-Smith	Conoco Phillips	Y	Y	N	N	N	Y	Y	N

ii) Attendees

Attendee	Organisation	18/1	26/1	2/3	13/3	24/4	10/5	15/6	18/7
Richard O'Malley	ELEXON (Lawyer)	Y	Y	Y	Y	Y	N	Part	Y
Tom Bowcutt	ELEXON (Technical Support)	Y	N	Y	N	Y	Y	N	Part
John Lucas	ELEXON (Technical Support)	Y	Y	N	Y	Y	N	N	N
Justin Andrews	ELEXON (Technical Support)	N	N	N	N	N	N	Part	Y
Richard Hall	Ofgem	Y	Y	N	N	Y	N	N	N
Amrik Bal	Ofgem	Y	N	N	N	N	N	N	N
Grant MacEachran	Ofgem	N	Y	N	Part	Y	Y	Y	Y
David Edward	Ofgem	N	N	Y	Y	N	N	N	N
Lesley Nugent	Ofgem	N	N	Y	N	N	N	N	N
Steve Mackay	Ofgem	N	N	N	N	N	N	N	N
Dipen Gadhia	Ofgem	N	N	N	N	N	Y	N	N
Cheryl Mundie	Ofgem	N	N	N	N	N	N	N	Y
Barbara Vest	BSC Panel	Part	Y	N	N	N	Part	N	N
Graham Thomas	BSC Panel	Part	N	N	N	N	N	N	N
Richard Jones	Npower	N	Y	N	N	N	N	N	N
Steve Moore	EDF Energy	Y	Y	N	N	N	N	N	N
Helen Snowdin	Garrad Hassan	N	N	Y	N	Y	N	N	N
Rhys Stanwix	Scottish and Southern	N	N	Y	N	N	N	N	N
Graham Shuttleworth**	NERA	N	N	N	Y	Y	Y	Y	Y
Dave Wilkerson	Centrica	N	N	N	N	Part	N	N	Y
Ben Sheehy	E.ON	N	N	N	N	Y	Y	Y	Y
Srdjan Curcic	Siemens PTI	N	N	N	N	Y	Y	N	N
Mick Barlow	Siemens PTI	N	N	N	N	Y	Y	N	N
Murray Hartley	OXERA	N	N	N	N	N	N	Y	N
Louise Allport	British Energy	N	N	N	N	N	N	Y	N

d) Copy of Original Modification Group Terms of Reference

Modification Proposal P198 will be considered by a new Modification Group, the 'P198 Modification Group' (formed from members of the original P82 Transmission Loss Factor Modification Group, supplemented by the expertise of current Standing Modification Group members, a representative of the System Operator-Transmission Owner Code Committee, and representatives of customer organisations), in accordance with the following Terms of Reference.

The Modification Group will carry out an Assessment Procedure in respect of Modification Proposal P198 pursuant to section F2.6 of the Balancing and Settlement Code.

The Modification Group will produce an Assessment Report for consideration at the BSC Panel Meeting on 11 May 2006, with an Interim Report to be presented at the Panel Meeting on 9 March 2006.

The Modification Group shall consider:

- The following background information:
  - The TLFMG's previous assessment of P75, P82 and P105;
  - The Authority's decisions on P75, P82 and P105;
  - The DTI's previous assessment of the merits of zonal transmission losses in a GB market, including confirmation that no moratorium was placed on the raising of a new GB losses Modification Proposal; and
  - Current developments in the Europe Union regarding transmission losses charging.
- The appropriateness of the following key aspects of the solution proposed by P198, in order to aid the Group's assessment against the Applicable BSC Objectives and to identify any potential Alternative Modifications:
  - TLFs to be calculated on an ex-ante basis;
  - TLFs to be calculated annually for each BSC Year using data from a previous 'reference year';
  - Zonal TLFs to be applied to both generation and demand;
  - TLF zones for both generation and demand to be based on GSP Groups;
  - TLFs to be scaled to only recover variable losses;
  - TLFs to be published at least one month prior to use;
  - TLFs to be calculated by a TLF agent/service provider; and
  - No phased implementation or 'grandfathering' scheme.
- Confirmation of whether a change to the overall 45:55 allocation of transmission losses would fall within the scope of an Alternative Modification or would require a separate Modification Proposal;
- The value of the scaling factor to be used to recover only variable losses;
- The governance arrangements for the scaling factor (e.g. 'hard-wired' in Code or Panel parameter);
- The period to be covered by the reference year;
- The exact process and timetable for approving and publishing TLFs;
- The nature of the TLF agent/service provider role;

- The variability and magnitude of TLFs under P198 – to be established through a modelling exercise provided by an external consultant, in accordance with a set of requirements produced by the Group (this should include identification of whether the P82 modelling requirements are still appropriate, and any additional requirements or input data needed to reflect the inclusion of Scotland under BETTA);
- A cost-benefit analysis of P198 – to be undertaken by an external consultant, in accordance with a set of requirements produced by the Group which should include as a minimum:
  - An assessment of the impact of P198 on different classes of Party;
  - An assessment of the impact of P198 on renewables and CHP plant;
  - An assessment of the impact of P198 on future generation (both large-scale and small-scale);
  - An assessment of the potential impact of P198 on the costs of carbon emissions to Parties (linked to Applicable BSC Objective (c)); and
  - Any risks which might be associated with a zonal losses scheme.
- Any interaction between P198 and National Grid's Transmission Network Use of System charging;
- Any new issues arising from extending the P82 solution to Scotland (e.g. the differences between the England and Wales Transmission System and the 132kv Transmission System in Scotland); and
- Any interaction between transmission losses and constraints on the Transmission System.

APPENDIX 3: RESULTS OF IMPACT ASSESSMENT

a) Impact on BSC Systems and Processes

System / Process	Impact of Proposed Modification	Impact of Alternative
BM Unit Registration	The CRA would be required to amend its BM Unit registration process so that a single Adjusted Annual Zonal TLF value for each BM Unit is obtained from the TLFA (via BSCCo) for each BSC Year, and is registered in BSC Systems. These values would be reported to the BMRA, SAA and BSCCo using existing data flows.	The CRA would be required to amend its BM Unit registration process so that four Adjusted Seasonal Zonal TLF values for each BM Unit are obtained from the TLFA (via BSCCo) for each BSC Year, and are registered in BSC Systems.
Central Data Collection	The CDCA would be required to provide the TLFA (via BSCCo) with Metered Volume data for the Sample Settlement Periods used in the Load Flow Model.	As Proposed Modification.
BMRS	The BMRA would be required to receive a single Adjusted Annual Zonal TLF value for each BM Unit from the CRA, and to use these values in BMRA reporting during the applicable BSC Year.	The BMRA would be required to receive four Adjusted Seasonal Zonal TLF values for each BM Unit from the CRA, and to use these values in BMRA reporting during the applicable BSC Year.

System / Process	Impact of Proposed Modification	Impact of Alternative
Settlement Administration	The SAA would be required to receive a single Adjusted Annual Zonal TLF value for each BM Unit from the CRA, and to apply these values in Settlement calculations during the applicable BSC Year.	The SAA would be required to receive four Adjusted Seasonal Zonal TLF values for each BM Unit from the CRA, and to apply these values in Settlement calculations during the applicable BSC Year.
Derivation of Zonal TLFs	A new BSC process, with supporting systems, would be introduced for the TLFA to derive TLFs through the application of a Load Flow Model in accordance with a Network Mapping Statement, Load Flow Model Specification, and new calculations in Section T of the Code. The output of this new TLFA process would be a set of 14 Adjusted Annual Zonal TLF values (one per Zone). All BM Units within a Zone would receive the single Adjusted Annual Zonal TLF value for that Zone.	As for Proposed Modification, except that the output of the annual TLFA process would be a set of four Adjusted Seasonal Zonal TLF values (one per BSC Season in the year) for each of the 14 TLF Zones – giving 56 Adjusted Seasonal Zonal TLF values in total for each BSC Year. The calculation of these values would include the use of a β scaling factor, such that the TLFs were set to less than their full value in the first four BSC Years of the scheme.

All of the above processes would contain the flexibility to handle the following activities:

- Ad-hoc prospective registration of TLFs for new BM Units; and
- Ad-hoc retrospective recalculation of TLF values following an upheld Trading Dispute.

BSC Agent documentation (e.g. Interface Definition and Design, Design Specifications, System Specifications, Manual System Specifications and Operating System Manuals) would need to be amended/developed to reflect the changes outlined above.

Copies of the full BSC Agent impact assessments of the Proposed Modification and Alternative Modification are provided as part of a separate document, Appendix 3A

b) Impact on BSC Agent Contractual Arrangements

BSC Agent Contract	Impact of Proposed Modification	Impact of Alternative
Transmission Loss Factor Agent	A full BSC Agent procurement exercise would need to be undertaken, and appropriate contractual arrangements created, for the TLFA in accordance with Section E of the Code.	As for Proposed Modification.
BSC Auditor	The scope of the BSC Audit would need to be extended to include the new BSC Agent, the TLFA.	As for Proposed Modification.

c) Impact on BSC Parties and Party Agents

Parties may wish to verify the allocation of their BM Units to Zones. Parties that have developed their own systems to monitor the Settlement calculations would also need to amend these to take account of the existence of non-zero TLF values.

P198 has no impact on any Party Agents.

Full copies of the non-confidential Party and Party Agent impact assessment responses for the Proposed Modification and Alternative Modification are provided as part of a separate document, Appendix 3Ay.

Please note that some respondents provided confidential cost information to support their assessments, which has been removed from the response tables and has not been provided to the Group or the Panel. This confidential information was also excluded from the implementation cost estimates provided to OXERA, to ensure that the results of the external cost-benefit analysis were transparent and based only on publicly-available data. However, all confidential information received will be provided to the Authority, and will therefore be taken into account as part of the Authority's decision-making process.

d) Impact on Transmission Company

Both the Proposed Modification and Alternative Modification would have the following impact on the Transmission Company:

- The Transmission Company would be required to support BSCCo and the Panel in establishing and maintaining the Network Mapping Statement – including the maintenance of an up-to-date list of all Nodes on the Transmission System, and assistance in resolving any question or dispute over the allocation of individual BM Units to Zones; and
- The Transmission Company would be required to support the TLFA and the Panel in maintaining the Load Flow Model, including the provision of relevant Network Data and any necessary information to aid the Panel in its determination of Load Periods.

The Transmission Company did not believe that P198 would have an impact on its ability to discharge its obligations under the Transmission Licence, and remained neutral as to whether the Proposed Modification or Alternative Modification would better facilitate the achievement of the Applicable BSC Objectives. The Transmission Company believed that any impact of P198 on the security of supply was ambiguous, given the factors other than losses which influence despatch and investment decisions. The Transmission Company did not identify any changes which might be required to other industry codes, or any direct interaction between P198 and TNUoS charging.

Full copies of the Transmission Company's analysis of the Proposed and Alternative Modifications are provided as part of a separate document, Appendix 3A.

e) Impact on BSC Panel

Both the Proposed Modification and Alternative Modification would have the following impact on the Panel:

- The Panel would be responsible for approving the Load Flow Model, the Load Flow Model Specification, the TLFA Service Description, the Load Flow Model Reviewer Terms of Reference and the Network Mapping Statement;
- The Panel would be responsible for establishing the definitive list of TLF Zones for use in the Network Mapping Statement and Load Flow Model, including the resolution of any question or dispute over the mapping of individual BM Units to Zones;
- The Panel would be responsible for establishing, for use in the Load Flow Model, a number of different Load Periods to represent varying levels of load on the Transmission System;

- The Panel would be responsible for establishing, for use in the Load Flow Model, the number of Sample Settlement Periods to be used in each Load Period;
- The Panel would be responsible for establishing a revised BSC Audit Scope incorporating the TLFA; and
- The Panel (aided by an independent Load Flow Model Reviewer) would be responsible for ensuring that the Load Flow Model complies with the Load Flow Model Specification – including retrospectively, where the calculation or use of TLFs is the subject of a Trading Dispute.

f) Impact on BSCCo

<table>
<tr><th>Area of Business</th><th>Impact of Proposed Modification</th><th>Impact of Alternative</th></tr>
<tr><td>BSC Website</td><td>BSCCo would be required to publish the following TLF data and documents on the BSC Website:
The Adjusted Annual Zonal TLF value for each TLF Zone in the applicable BSC Year;
The version of the Network Mapping Statement used in the annual TLF calculation, and any subsequent amendments to that statement to take account of changes in BM Unit registrations; and
The Load Periods and Sample Settlement Periods used in the TLF calculation for the applicable BSC Year.
Any existing website references to TLF=0 would also need to be amended.</td><td>As for Proposed Modification, except that the TLF values published would be the four Adjusted Seasonal Zonal TLF values for each TLF Zone in the applicable BSC Year and would represent scaled down values in the first four BSC Years of the scheme.</td></tr>
<tr><td>Communications</td><td>BSCCo would produce an information sheet for Parties explaining the new P198 process, for publication on the BSC Website.</td><td>As for Proposed Modification.</td></tr>
<tr><td>Working Procedures</td><td>BSCCo would need to put in place appropriate working practices to support its Code obligations regarding the derivation and use of TLFs. These would include processes for requesting Node information and Network Data from the Transmission Company, requesting Metered Volume data from the CDCA, and allocating new BM Units to Zones.</td><td>As for Proposed Modification.</td></tr>
</table>

Area of Business	Impact of Proposed Modification	Impact of Alternative
BSC Panel/Panel Committee Support	BSCCo would be required to assist the Panel in its determination of TLF Zones, Load Periods and Sample Settlement Periods. BSCCo would be required to support the Panel in its determination of any question or dispute over the mapping of individual BM Units to TLF Zones (potentially including the development of appeal guidelines). BSCCo would be required to develop a revised methodology for ETLMO values to reflect zonal TLFs, and to support the ISG in its approval of that methodology. Any potential incorrect calculation or use of TLF values in Settlement would form the subject of a Trading Dispute, under the normal process administered by BSCCo on behalf of the TDC. BSCCo and TDC working practices regarding such Disputes would require additional steps for the TDC to decide whether to obtain a report from the Load Flow Model Reviewer on the compliance of the Load Flow Model with its specification, and for the Panel to determine whether TLFs should be recalculated.	As for Proposed Modification.
Change and Configuration Management	BSCCo would be required to maintain the Network Mapping Statement on behalf of the Panel, under a specific change process to be detailed in the Code.	As for Proposed Modification.
Procurement and Contract Management	BSCCo would be required to procure the TLFA and Load Flow Model Reviewer, and to manage the resulting contracts. BSCCo would also be required to manage the escrow arrangements for the Load Flow Model.	As for Proposed Modification.
Performance Assurance	BSCCo would be required to provide any necessary additional support to the BSC Auditor and the Panel in extending the scope of the BSC Audit to incorporate the TLFA.	As for Proposed Modification.

g) Impact on Code

Code Section	Impact of Proposed Modification	Impact of Alternative
Section E 'BSC Agents'	The TLFA would need to be added to the list of existing BSC Agents in Section E.	As for Proposed Modification.
Section H 'General'	The Load Flow Model Specification would need to be added to the list of Code Subsidiary Documents in Section H.	As for Proposed Modification.
Section T 'Settlement and Trading Charges'	Section T would require amendments to detail the rights and obligations of all relevant parties regarding the derivation of Adjusted Annual Zonal TLFs and their use in Settlement.	As for Proposed Modification, except that the TLF values derived would be Adjusted Seasonal Zonal TLFs and would represent scaled down values in the first four BSC Years of the scheme.
Section V 'Reporting'	Section V would require amendment to detail the provision by BSCCo of the following TLF data to Parties on request: • The Network Data and Metered Volumes used in the TLF calculation for the applicable BSC Year; • The circuit and transformer power flows generated by the Load Flow Model; • The raw nodal power flows calculated by the Load Flow Model and used in the TLF calculation for the applicable BSC Year; and • The raw Nodal TLFs calculated by the Load Flow Model and used in the TLF calculation for the applicable BSC Year.	As for Proposed Modification.
Section X 'Definitions and Reporting'	Section X would require amendment to detail any new Code-defined terms or acronyms required for P198.	As for Proposed Modification, but including definitions to reflect the seasonal and phased nature of the TLF calculation.

h) Impact on Code Subsidiary Documents

Document	Impact of Proposed Modification	Impact of Alternative
BSCP01 'Overview of the Trading Arrangements'	Amendments would be required to reflect the derivation of non-zero TLFs and their use in Settlement calculations.	As for Proposed Modification.
BSCP15 'BM Unit Registration'	Amendments would be required to include the process for allocating a single Adjusted Annual Zonal TLF value to each BM Unit in each applicable BSC Year.	Amendments would be required to include the process for allocating four Adjusted Seasonal Zonal TLF values to each BM Unit in the applicable BSC Year.
BSCP38 'Authorisations'	Amendments would be required to include an authorisation process for Parties to request input and output data files relating to the Load Flow Model (Network Data, Metered Volumes, power flows and Nodal TLFs).	As for Proposed Modification.
BSCP41 'Report Requests and Authorisations'	As above.	As above.
Reporting Catalogue	Amendments would be required to reflect the new/amended reporting requirements introduced by P198.	As for Proposed Modification.
Communications Requirement Document	Amendments would be required to reflect the rules for communicating with the TLFA via BSCCo.	As for Proposed Modification.
BSC Agent Service Descriptions	The BMRS, BSC Auditor, CDCA, CRA and SAA Service Descriptions would need to be amended to reflect the new obligations on these Agents in respect of zonal TLFs. A new Service Description would need to be developed for the TLFA.	As for Proposed Modification.
Load Flow Model Specification	The specification for the TLFA Load Flow Model would be established as a new Code Subsidiary Document.	As for Proposed Modification.

i) Impact on Core Industry Documents/System Operator-Transmission Owner Code

No impact.

j) Impact on Other Configurable Items

Document	Impact of Proposed Modification	Impact of Alternative
User Requirements Specifications	The BMRS, BSC Website, CDCA, and CRA URSs would need to be amended to reflect the new obligations on these Agents in respect of zonal TLFs. A new URS would need to be developed for the TLFA.	As for Proposed Modification.

k) Impact on BSCCo Memorandum and Articles of Association

No impact.

l) Impact on Governance and Regulatory Framework

The Group agreed that the following potential impacts of the Proposed and Alternative Modifications fell outside the vires of the Code, and could therefore not form part of its assessment against the Applicable BSC Objectives:

- Impact on the environment (through changes in carbon emissions, plant-mix, or the location of generation and demand);
- Impact on consumers (through the passing on of costs or cost-savings by Parties, or changes in the location of demand); and
- Impact on the existing locational signals provided by the Transmission Company's TNUoS charging.

The Group noted that these areas could be taken into account by the Authority as part of its wider statutory duties when making its decision whether to approve P198. The Group noted that the Authority would also be able to consider to what extent the locational transmission losses scheme proposed by P198 would be consistent with wider developments in the European Union.

APPENDIX 4: RESULTS OF FIRST ASSESSMENT PROCEDURE CONSULTATION

Copies of the full responses received to the P198 first Assessment Procedure consultation are attached as a separate document, Appendix 4A. A summary of the arguments made by respondents can be found in Section 4.6, along with the Group's consideration of these arguments.

APPENDIX 5: RESULTS OF TLF MODELLING EXERCISE

A copy of the full PTI load-flow modelling report is attached as a separate document, Appendix 5A.

APPENDIX 6: RESULTS OF COST-BENEFIT ANALYSIS

A copy of the full OXERA cost-benefit analysis report is attached as a separate document, Appendix 6A.

APPENDIX 7: RESULTS OF SECOND ASSESSMENT PROCEDURE CONSULTATION

Copies of the full responses received to the P198 second Assessment Procedure consultation are attached as a separate document, Appendix 7A. A summary of the arguments made by respondents can be found in Section 5, along with the Group's consideration of these arguments

APPENDIX 8: INVESTIGATION OF LOAD-FLOW MODELLING METERED DATA SAMPLE

This appendix sets out the results of ELEXON's investigation of the metered data sample defined under P82 and utilised in the P198 load-flow modelling work.

Current Approach

When performing the load-flow modelling, a view of the net flow onto, or off, the Transmission System at each Node on the network is required. Therefore, the TLFA is provided with a metered data sample including:

- Directly Connected BM Unit Metered Volumes (types T_ and M_);
- Aggregated Interconnector Metered Volumes; and
- Aggregated Grid Supply Point (GSP) Metered Volumes.

Issue

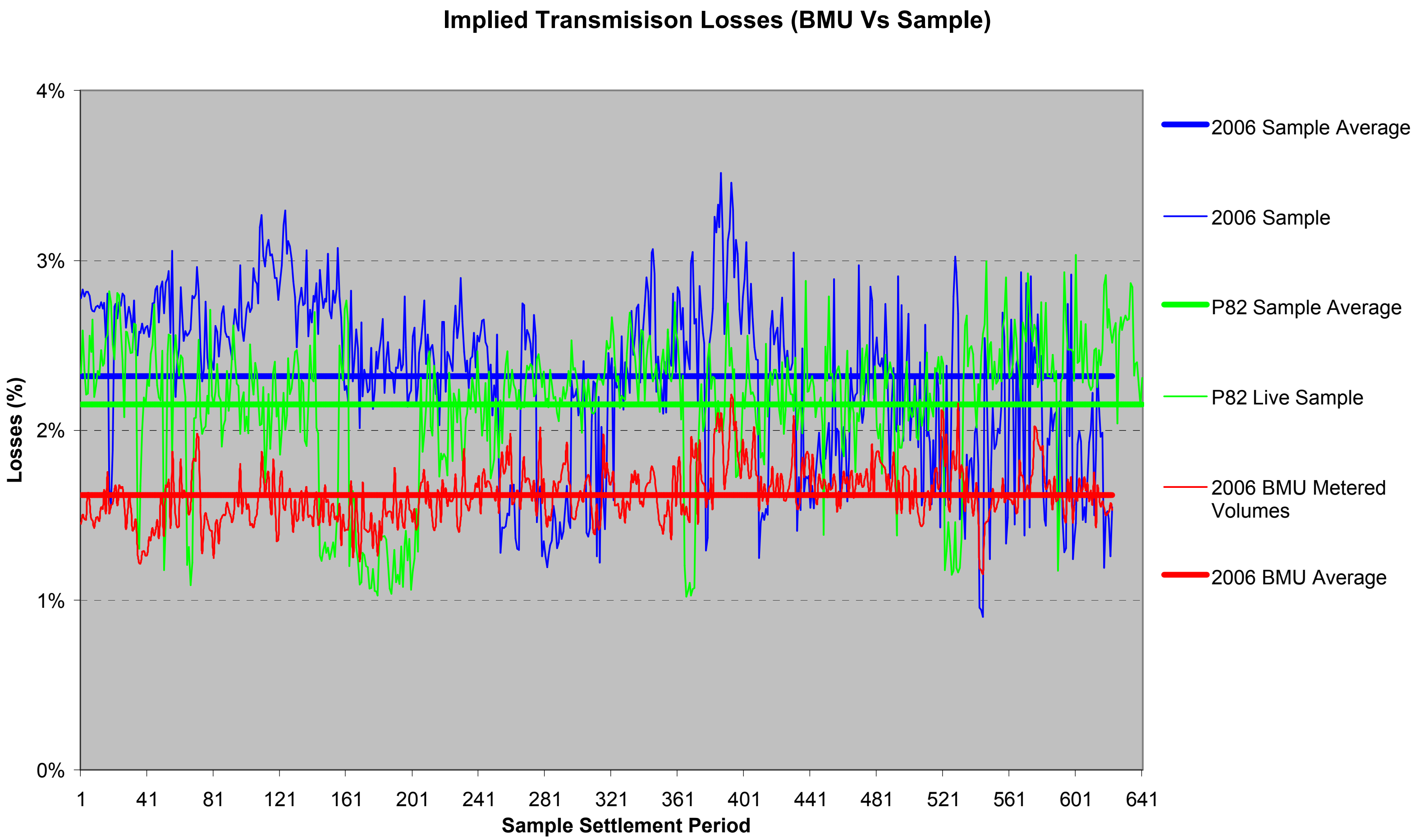
The level of losses implied by the metered data in the P82 and P198 sample is higher than would be expected (on average 2.3% per Settlement Period, as compared to an expected level of around 1.6%). In addition, the P198 sample illustrates a higher level of implied losses than is present in the BM Unit data for the same period (i.e. derived utilising Interconnector and Supplier BMUs, rather than Aggregated GSP and Interconnector Metered Data). The implied level of losses present in the BM Unit data was found to be 1.62% on average. The average Settlement Period difference between the level of losses implied by the P198 sample and the BM Unit data was found to be 131 MWh (a difference of 80,000 MWh across the sample). The issue is illustrated in the following examples:

Example 1: 14 September 2005 SP27

In this example Settlement Period, the level of losses implied by the input data is 274 MWh more than in the BM Unit data.

	Input Data	BMU_Period_Data	Diff
Total	640	366	274
T_	19532	19532	0
M_	66	66	0
Interconnector	160	160	0
GSPs / (Supplier BMUs - EmGen)	-19118	-19391	274

Example 2: Full Sample



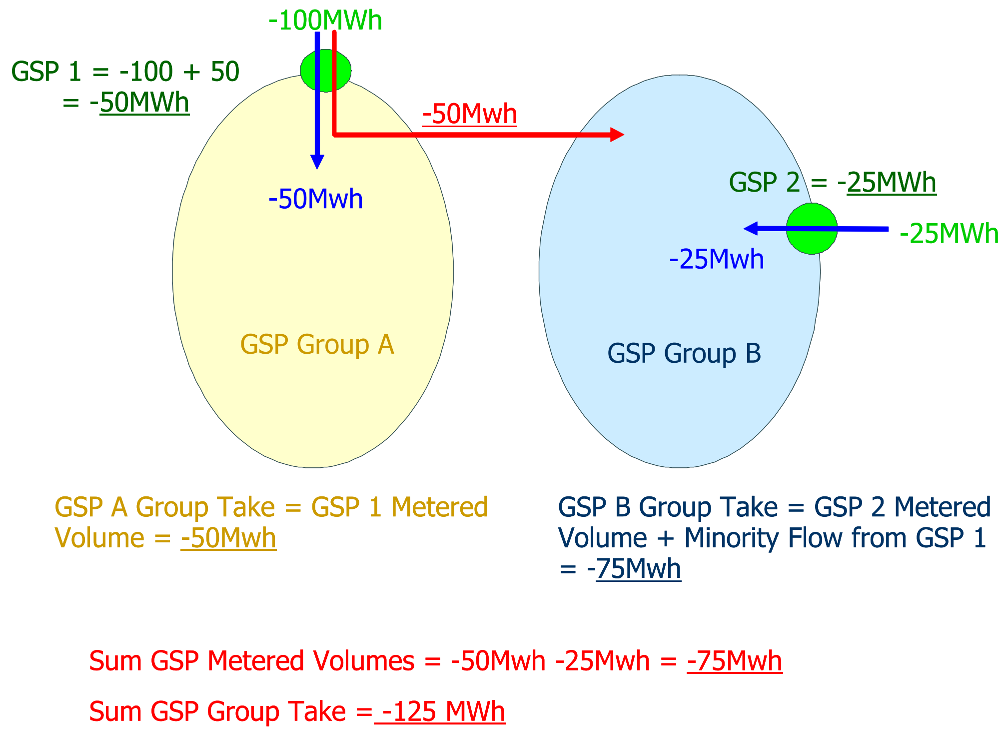
In this example, the P82 and P198 sample losses are generally higher than those derived from BM Unit data for an equivalent time period.

Potential Source of the Issue

Investigations have identified a potential source of the discrepancy as the aggregation approach for "shared" GSPs.

Although each feeder connecting a GSP to the Transmission system is metered, the value that is calculated and reported for Settlement purposes is the total flow of energy from the Transmission System to the GSP. The Registrant of a GSP Metering System (the Licenced Distribution System Operator or LDSO) has to submit a set of Aggregation Rules that allow the CDCA to calculate the total flow.

However, there is an exception to the above where the output feeders from a GSP feed more than one GSP Group. This type of GSP is known as a shared GSP. At these shared GSPs the majority and minority LDSOs' takes are calculated separately. The total energy flowing into the GSP from the Transmission System is metered and the energy flowing to the minority LDSO is metered. The majority LDSO's take is then calculated by subtracting the minority LDSO's take from the total GSP flow using Aggregation Rules submitted to the CDCA by the majority LDSO. It is this majority LDSO flow that is reported as the GSP Metered Volume in Settlement. The minority flow is not present in the aggregated Metered volume for any individual GSP, but is added into the GSP Group Take for the relevant GSP Group to ensure that Settlement calculations are correct.

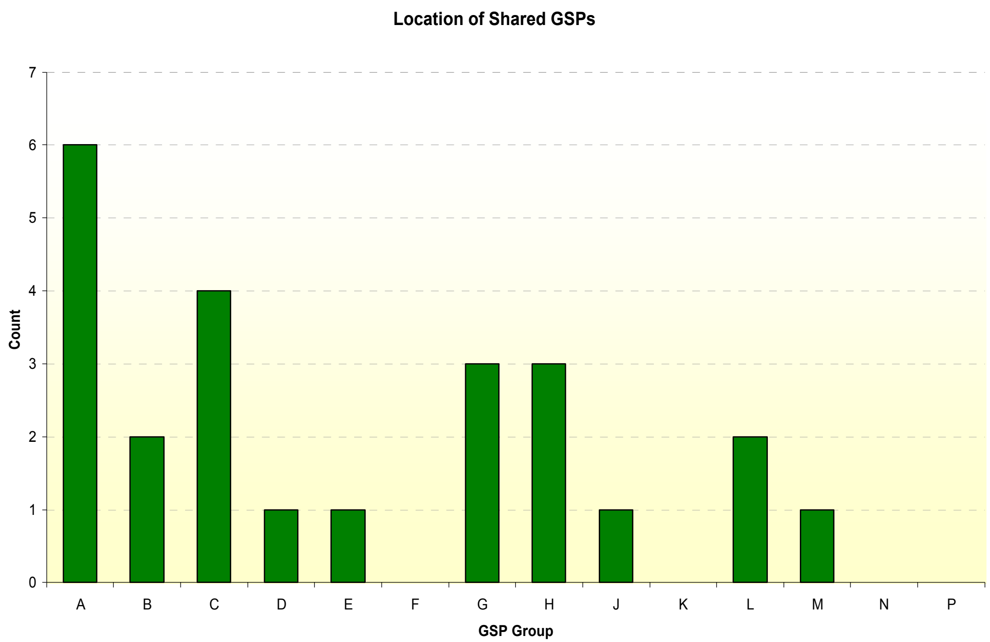


Due to the approach for deriving the aggregated metered volumes for GSPs, the sum of GSP aggregated metered volumes is not equal to the total demand flowing through all GSPs (since the minority volumes at shared GSPs will not be included). As a consequence, the level of demand in the load-flow sample will be lower than the actual demand, and subsequently the implied level of transmission losses will appear higher. A simplified example is provided in the diagram.

Affected GSPs

Manual investigation of registered metering dispensations was conducted in an attempt to identify the number and location of affected GSPs. The concept of a shared GSP is not formally recognised; hence the identification process was necessarily somewhat subjective. In addition, it was not practical to identify the volume of energy affected at individual GSPs. Although the minority flow will always be fully accounted for in the aggregation rules for the associated GSP Group, there is no consistent approach used to account for it. Hence, without iterative discussion with the Registrant and CDCA, it was not feasible to identify the associated metering systems and thereby isolate the individual volumes affected within the P198 Assessment Procedure timetable.

24 GSPs were identified as potentially affected (~7% of total GSPs and ~5% of total nodes). The average impact per shared GSP in a Settlement Period was 5MWh (10% of average GSP Demand). The chart illustrates the number of affected GSPs in each GSP Group.



Impact on TLFs

Quantifying the impact of the issue on TLFs is not simplistic; however consideration of the potential influence suggests the impact is unlikely to be substantial.

TLF calculations are based on nodal power flows, rather than the raw metered data included in the sample. Nodal power flows are derived from Metered Volumes by eliminating all losses (effectively generation is scaled down and demand scaled up until they are equal). Flows on the transmission network are then generated from the nodal power flows, and losses used to calculate TLFs based on these network flows. Hence, the level of losses in the sample does not directly influence the calculated TLFs.

The issue may have an influence on the overall level of nodal power flows across the sample as a consequence of the process used to eliminate losses when calculating nodal power flows. The scaling required is of the order of 1-2%; hence this effect is unlikely to have a significant impact on resulting TLFs. The impact on individual nodal TLFs may be more substantial; however given the extent of averaging in the overall process it is not likely that there would be a significant impact on resulting Zonal Average TLFs.

Accounting for Affected GSPs

A potential solution to account for affected GSPs in the metered data sample would be to undertake:

- A one-off manual investigation of metering dispensation records to identify those GSPs affected by the issue;
- A one-off investigation of the aggregation rules for the identified GSPs and the associated GSP Groups, in order to identify the metering systems associated with the minority flows;
- A one-off preparation of revised aggregation rules for affected GSPs such that the aggregate GSP Metered Volume represents the total flow from the Transmission System (i.e. includes the minority flow); and
- A one-off amendment of aggregation rules for the parent GSP Groups of the affected GSPs, such that the minority flow is subtracted from the GSP Group Take (i.e. netting off the minority flow included in the aggregate Metered Volume of affected GSPs).

APPENDIX 9: RESULTS OF DATA CORRECTION CONSULTATION

Copies of the full responses received to the cost-benefit analysis data correction consultation are attached as a separate document, Appendix 7A (note that, at the time of the production of this report, these responses were not yet available but will be provided to the Panel at its meeting on 10 August 2006).