November 2002

JOINT ASSESSMENT REPORT

MODIFICATION PROPOSALS P75 - Introduction of Zonal Transmission Losses

MODIFICATION PROPOSAL P82 - Introduction of Zonal Transmission Losses on an Average Basis

Prepared by the Transmission Loss Factor Modification Group on behalf of the Balancing and Settlement Code Panel

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a Authorities

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Each BSC Panel Member	Various
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0.2 Second Draft for Modification Group Review (Incorporating Comments on First Draft)

0.3 Third Draft for Modification Group Review (Incorporating Comments on Second Draft)

0.4 Final Draft for Final Review (Incorporating Comments on Third Draft)

d Intellectual Property Rights and Copyright

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1 SUMMARY AND RECOMMENDATIONS

1.1 Modification Proposal P75

This report is a joint Assessment Report for Modification Proposal P75 'Introduction of Zonal Transmission Losses' and Modification Proposal P82 ' Introduction of Zonal Transmission Losses on an Average Basis'. Given that the two proposals were considered in parallel by the same Modification Group and address the same perceived defect this format was felt to be most appropriate.

1.1.1 Recommendations

On the basis of the analysis, consultation and assessment undertaken in respect of this Modification Proposal during the Assessment Procedure, and the resultant findings of this report, the Modification Group recommends that the BSC Panel should:

a) NOTE the P75 Assessment Report and the recommendations of the Transmission Loss Factor Modification Group;

b) ENDORSE the recommendation of the Transmission Loss Factor Modification Group and proceed to the Report Phase in accordance with Section F2.7 of the Code;

c) AGREE that the draft Modification Report contain a provisional recommendation that the Alternative Modification should be made with an Implementation Date of 1 April 2004 if a determination is made by the Authority prior to 31 December 2002;

d) AGREE that the Proposed Modification P75 should not be made;

e) In the event that the Authority determines that the Proposed Modification P75 should be made AGREE an Implementation Date of 1 April 2004 if a determination is made by the Authority prior to 31 December 2002;

f) AGREE that the draft Modification Report be issued for consultation and submitted to the Panel Meeting on 12 December 2002.

g) NOTE that P75 (Proposed and Alternative) and P82 (Proposed and Alternative) are mutually exclusive; and

h) NOTE the development and implementation costs for the Proposed Modification of £782,700 from BSC Central Service Agent[1]. This cost excludes ELEXON effort (approx. 500 man days) and procurement of the Transmission Loss Factor Agent.

1.1.2 Background

Modification Proposal P75 (P75) was submitted on 5 April 2002 by Powergen. P75 proposes that transmission losses should be allocated to 'generation' and 'demand' on a zonally differentiated basis with generation being grouped by TNUoS zone and demand by GSP Group. Whilst the BSC recognises that transmission losses could be allocated on a locational basis, the parameters to support this, the Transmission Loss Factors (TLFs), are currently set to zero. At present, allocation is on a uniform basis, with a defined split between 'generation' and 'demand'.

[1] Because the Alternative Modification was developed later on in the Assessment Procedure, no BSC Agent costs were obtained. However, it is believed to be a similar to the implementation cost for P82 - £109,100.

Under P75, a Transmission Loss Factor Agent (TLFA) would be appointed to calculate half-hourly TLFs on an ex-post basis using a ‘fully marginal’ methodology.

The Proposer of P75 believes that the introduction of such zonal differentiation would more accurately allocate the cost of losses to those market participants responsible for them, thus removing the inherent cross-subsidy that dampens cost signals in the current method of allocation. In the short-term, the Proposer asserts that the removal of such cross-subsidies would provide locational signals to help reduce overall transmission losses. In the long-term, the Proposer asserts that more efficient locational signals would encourage ‘more optimal’ siting of generation and demand.

ELEXON produced an Initial Written Assessment (IWA) recommending that P75 should be submitted to a one-month Definition Procedure in order to identify the detail absent in the proposal and identify the issues that would need to be considered during an Assessment Procedure. The Panel endorsed ELEXON’s recommendation on 18 April 2002, requesting that a Definition Report be presented at the 16 May 2002 Panel meeting. The Panel indicated that the Definition Procedure ought to be used to establish terms of reference for an Assessment Procedure and identify the issues that would need to be assessed.

A Modification Group, the Transmission Loss Factor Modification Group (TLFMG), was established to provide the appropriate expertise to take P75 forward. The TLFMG met twice during the Definition Procedure, on 29 April 2002 and 7 May 2002, to consider the responses received to a consultation exercise undertaken and to establish the requirements of any future Assessment Procedure. On the basis of those requirements, primarily the need to tender for and obtain a modelling service to help assess the impact of P75 and run a review meeting to raise industry awareness of P75, the TLFMG produced a Definition Report recommending a six-month Assessment Procedure. At its 16 May 2002 meeting, the Panel agreed to submit P75 to a six-month Assessment Procedure, with an Assessment Report scheduled to be presented at the 14 November Panel meeting. Modification Proposal P82 ‘Introduction of Zonal Transmission Losses on an Average Basis’ was considered at the same Panel meeting and submitted to six-month Assessment Procedure, to be considered in parallel with P75 by the TLFMG. In addition, the Panel requested an Interim Report for 18 July 2002.

During the Assessment Procedure the TLFMG considered a number of options that could constitute an alternative to the proposal submitted. An Alternative Modification was developed in which TLFs calculated on an ex-ante basis and phased in linearly over four years.

1.1.3 Rationale for Recommendations

On the basis of the analysis carried out and discussions held, there was a majority view that the Proposed Modification P75 did not better facilitate achievement of the Applicable BSC Objectives. The majority judged that, on balance, the gains in the accuracy of the allocation of the costs of transmission losses (i.e. Applicable BSC Objectives (b) and (c)) would be outweighed by the un-hedgeable risk (Applicable BSC Objective (c)) and costs associated (Applicable BSC Objective (d)) with an ex-post scheme.

However, there was a strong majority view that an Alternative Modification would better facilitate achievement of the Applicable BSC Objectives, as compared to the Proposed Modification and, by a small majority, would better facilitate achievement of the Applicable BSC Objectives, as compared to the current baseline BSC. The TLFMG, by a narrow majority, believed that an ex-ante/monthly version of P75 would avoid the cost and risk associated with an ex-post/half-hourly approach. In addition, it was felt that phased implementation would smooth the impact of zonal differentiation.

The TLFMG recommend that Proposed Modification P75 should not be made and that the Alternative Modification should be made with an Implementation Date of 1 April 2004.

1.2 Modification Proposal P82

1.2.1 Recommendations

On the basis of the analysis, consultation and assessment undertaken in respect of this Modification Proposal during the Assessment Procedure, and the resultant findings of this report, the Modification Group recommends that the BSC Panel should:

a) NOTE the P82 Assessment Report and the recommendations of the Transmission Loss Factor Modification Group;

b) ENDORSE the recommendation of the Transmission Loss Factor Modification Group and proceed to the Report Phase in accordance with Section F2.7 of the Code;

c) AGREE that the draft Modification Report contain a provisional recommendation that the Alternative Modification P82 should be made with an Implementation Date of 1 April 2004 if a determination is made by the Authority prior to the 31 December 2002;

d) AGREE that the Proposed Modification P82 should not be made;

e) In the event that the Authority determines that the Proposed Modification P82 should be made AGREE an Implementation Date of 1 April 2004 if a determination is made by the Authority prior to the 31 December 2002;

f) AGREE that the draft Modification Report be issued for consultation and submitted to the Panel Meeting on 12 December 2002;

g) NOTE that P75 (Proposed and Alternative) and P82 (Proposed and Alternative) are mutually exclusive; and

h) NOTE the development and implementation costs for the Alternative Modification of £109,100 from the BSC Central Service Agent. This cost excludes ELEXON effort (approx. 500 man days) and procurement of the Transmission Loss Factor Agent.

1.2.2 Background

Modification Proposal P82 (P82) was submitted on 3 May 2002 by First Hydro Company. P82 proposes the application of zonal differentiation of transmission losses on an average, as opposed to marginal, basis to generation and demand. The Proposer recommends grouping both generation and demand into zones based on GSP Groups. At present, allocation is on a fixed and uniform basis with a defined split between production and consumption. As mentioned previously, whilst the BSC recognises that transmission losses could be allocated on a locational basis, the parameters to support this, the Transmission Loss Factors (TLFs), are currently set to zero.

Under P82, a new BSC Agent would be appointed to calculate annual TLFs, on an ex-ante basis, using a methodology to be specified in the BSC. In addition, TLFs would be ‘scaled’ by a factor of 0.5 such that only variable losses (i.e. those caused by heating) would be allocated on a zonal basis approximately.

The Proposer believes that the introduction of such zonal differentiation of transmission losses would introduce long-term signals for the siting of generation and demand by allocating losses in such a manner that does not unduly penalise individual BM Units. In addition, losses would be allocated only according to the degree to which individual BM Units give rise to losses.

ELEXON produced an IWA recommending that P82 should be submitted to a six-month Assessment Procedure, and considered in parallel to P75 by the TLFMG given that the proposals seek to remedy the same perceived defect. The Panel, at its 16 May 2002 meeting, agreed to the recommendation and that an Assessment Report should be presented on 14 November 2002, with an Interim Report on 18 July 2002. Unlike for P75, ELEXON did not recommend a Definition Procedure because, whilst a number of the elements of P75 remained to be described, P82 provides a more comprehensive description of what is proposed.

1.2.3 Rationale for Recommendations

There was a majority view, on the basis of the analysis carried out and discussions held, that the Proposed Modification P82 would better facilitate achievement of the Applicable BSC Objectives. On balance, the majority deemed that zonal differentiation would result in a more accurate allocation of the cost of losses, thus facilitating better achievement of Applicable BSC Objectives (b) and (c). However, a strong majority opinion emerged that an Alternative Modification would better facilitate achievement of the Applicable BSC Objectives, relative to the Proposed Modification (and, therefore, relative to the current baseline BSC also). The Alternative Modification is identical to the Proposed Modification, except that it would be phased-in linearly over 4 years (the 'Beta' approach). The majority of the TLFMG judged that phased implementation would smooth the impact of zonal differentiation. Therefore, the TLFMG recommends that the Proposed Modification P82 should not eb made and that the Alternative Modification should be made with an Implementation Date of 1 April 2004.

1.3 Procedure Followed

The TLFMG carried out a joint Assessment Procedure for P75 and P82, in recognition of their similar solutions to the same perceived defect. A project plan was drawn up, and the TLFMG met 15 times to meet each objective of that plan.

The TLFMG decided to set up two subgroups in order to progress the business in an efficient manner during the six month Assessment Procedure:

- a 'Modelling Subgroup' to produce a requirement specification for the modelling service identified as necessary support the Assessment Procedure; and
- a 'Data Subgroup' to identify the input data that would need to be made available to the provider of such a modelling service.

The TLFMG produced an Interim Report containing an initial assessment of P75 and P82, a High Level Impact Assessment from the NETA Central Service (CSA)[2] and the requirement specification and a proposed tender process for the modelling service. The initial assessment came to the conclusion that modelling the interaction of P75 and P82 with BETTA would not be practical given the time available under the Assessment Procedure. Generating meaningful results would require a Scottish data set and the modelling of the Scottish transmission network. In addition, the TLFMG noted the observation made by the Authority representative at its meetings, that the *vires* of the BSC was limited to England and Wales. As a result, the TLFMG proposed giving no further consideration to any interactions with the Scottish network, beyond the interconnectors. The Panel approved the budgetary provisions to

[2] See Annex 2

undertake the modelling and agreed that the TLFMG need not undertake any further assessment of the interaction of P75 and P82 with BETTA.

Having secured Panel authorisation, ELEXON, on behalf of the TLFMG issued an Invitation to Tender (ITT) for the modelling service on 22 July 2002. A Tender Evaluation Board (TEB), composed of members from the full TLFMG and ELEXON, was established. Five tenders were received by the 2 August 2002 deadline and assessed by the TEB. Four of the tendering organisations were short-listed and invited to present their tenders to the TEB on 8 August 2002. On the basis of the tender submitted and the accompanying presentation, the TEB recommended that ELEXON's Chief Executive award the contract to Power Technologies International (PTI). The TEB was of the opinion that PTI combined the most economically advantageous tender with greatest capacity to deliver. ELEXON's Chief Executive ratified the recommendation and the contract was awarded to PTI on 15 August 2002. PTI delivered a final report, containing the modelling results, on 14 October 2002.

Fourth, the TLFMG produced and issued a consultation document containing an interim set of modelling results and the results of the Assessment Procedure up to that point on 2 October 2002. Twenty-nine responses were received by the 21 October 2002 deadline[3]. In addition, Detailed Level Impact Assessments (DLIAS) were sought and received from Parties, the NETA CSA and the Transmission Company by the same deadline[4].

Finally, on the basis of the consultation responses, impact assessments and modelling results, the TLFMG met twice more to formulate its recommendations and finalise its assessment.

[3] See Annex 4

[4] See Annexes 2,3 & 4

2 INTRODUCTION

This Report has been prepared by ELEXON Ltd., on behalf of the Balancing and Settlement Code Panel ('the Panel'), in accordance with the terms of the Balancing and Settlement Code ('BSC'). The BSC is the legal document containing the rules of the balancing mechanism and imbalance settlement process and related governance provisions. ELEXON is the company that performs the role and functions of the BSCCo, as defined in the BSC.

An electronic copy of this document can be found on the BSC website, at www.elexon.co.uk

2.1 Glossary of Terms

Listed below is a glossary of some specialist terms used within this document:

- **AC LOAD FLOW:** A modelling approach for an interconnected network utilising data that reflects alternating current (a.c.) electrical flows on that network.
- **BUSBAR:** A point of connection for generation, or demand, or power flows, on a network.
- **DC LOAD FLOW:** A modelling approach for an interconnected network utilising data that reflects alternating current (a.c.) electrical flows on that network, but with a set of simplifying assumptions that render the equations for the a.c. flows similar in form to those for a direct current (d.c.) flow.
- **NODE:** A point in a network model where two or more circuits meet. Equivalent to a busbar on a real system.
- **PHASE ANGLE:** A measure of the lag of voltage relative to an alternating current, at a point on the network.
- **POWER FACTOR:** The ratio of active power to reactive power, at a point on the network.
- **REACTIVE POWER:** A component of alternating current and voltage at a point on the network that does not contribute to the transmission of energy.
- **SLACK BUS:** A node in a network model that acts as a sink for surplus (or deficits of) power that arise as a result of inaccuracies with the model or data, or as a result of increments or decrements of flows at other nodes for modelling purposes. The slack bus also acts as a reference node for voltage and current phase angle.
- **TLF:** The Transmission Loss Factor is a factor used in the calculation of the multiplier TLM used to allocate transmission losses on a locational basis to BM Unit 'i' in Settlement Period 'j'.
- **TLM:** The Transmission Loss Multiplier is the factor applied to volumes of energy associated with BM Unit 'i' in Settlement Period 'j' at its point of connection to the Transmission System in order to adjust for Transmission Losses.
- **TLMO+:** The Delivering Transmission Losses Adjustment is a component used in the calculation of TLM for all BM Units in Delivering Trading Units, in Settlement Period 'j' and allows for overall correction of transmission loss allocations to match total metered losses.
- **TLMO-:** The Offtaking Transmission Loss Adjustment is a component used in the calculation of TLM for all BM Units in Offtaking Trading Units in Settlement Period 'j' and allows for overall correction of transmission loss allocations to match total metered losses.

3 MODIFICATION GROUP DETAILS

This Joint Assessment Report has been prepared by the Transmission Loss Factor Modification Group (TLFMG). The Membership of the Modification Group was as follows:

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In addition, the following attendees regularly attended and contributed to TLFMG meetings:

Attendee	Organisation	Email
Barbara Vest	RWE TDL	bavest@lineone.net
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4 DESCRIPTION OF PROPOSALS

4.1 Description of Proposals

The two Modification Proposals, as submitted, provided the TLFMG with the latitude to decide upon and finalise some of the detail absent in the proposed methodologies for generating zonal TLFs. Therefore, each proposal was refined to specify the type of load-flow model and network data to be used. In addition, P75 explicitly stated that certain elements of the proposed solution were suggestions only.

4.1.1 Modification Proposal P75

Modification Proposal P75 proposes that transmission losses should be allocated to 'generation' and 'demand' on a zonally differentiated basis with generation being grouped by TNUoS zone and demand by GSP Group. Whilst the BSC recognises that transmission losses could be allocated on a locational basis, the parameters to support this, the Transmission Loss Factors (TLFs), are currently set to zero. At present, allocation is on a uniform basis, with a defined split between 'generation' and 'demand'.

Under P75, a Transmission Loss Factor Agent (TLFA) would be appointed to calculate half-hourly TLFs on an ex-post basis using a 'fully marginal' methodology.

The Proposer of P75 believes that the introduction of such zonal differentiation of transmission Losses would more accurately target the cost of losses on those market participants responsible for them, thus removing the inherent cross-subsidy that dampens cost signals in the current method of allocation. In the short-term, the Proposer asserts that the removal of such cross-subsidies would provide locational signals to help reduce overall transmission losses. In the long-term, the Proposer asserts that more efficient locational signals would encourage 'more optimal' siting of generation and demand.

The Proposer explicitly stated that certain elements of the proposed solution were suggestions only, such elements included Settlement Period specific TLFs. On the basis of the Transmission Company DLIA, which indicated that the provision of half-hourly network data would be significantly more costly than that of daily data, the modelling results, which suggested that within-day variation in TLFs would be minimal, and the NETA Central System Agent DLIA, which entailed additional costs to accommodate half-hourly variations in TLF. The TLFMG decided that TLFs would be Settlement Day specific.

The Proposer had argued in favour of refining P75 into an ex-ante approach with TLFs applicable for a month. The rest of the TLFMG, however, believed this too significant a departure from the original proposal to constitute a refinement. Instead, this formulation emerged as a potential alternative to the original proposal (see section 10).

4.1.1.1 Summary of Key Characteristics

Incorporating the refinements made by the TLFMG to the proposed solution, the key characteristics of P75 can be summarised as follows:

Feature	**Modification Proposal P75**
TLF Methodology (TLFM)	'Marginal' & defined in BSC
TLF Calculation	Daily Ex-post
Validity of TLFs	One Settlement Day
Zonal Groupings	<u>Generation</u> –TNUoS zones <u>Demand</u> – GSP Groups
Type of Flow to be Modelled	DC
Network Configuration Data	Historic Intact Data
Process for Conversion of Metered Volumes into Nodal Metered	Specified mapping

Volumes	
Process for Conversion of Nodal TLFs into Zonal TLFs	'Volume-weighted' Averaging
Process for Conversion Half-hourly TLFs into Dail TLFs	Time-weighted Averaging

4.1.2 Modification Proposal P82

Modification Proposal P82 (P82) was submitted on 3 May 2002 by First Hydro Company. P82 proposes the application of zonal differentiation of transmission losses on an average, as opposed to marginal, basis to generation and demand. The Proposer recommends grouping both generation and demand into zones based on GSP Groups. At present, allocation is on a fixed and uniform basis with a defined split between production and consumption. As mentioned previously, whilst the BSC recognises that transmission losses could be allocated on a locational basis, the parameters to support this, the Transmission Loss Factors (TLFs), are currently set to zero.

Under P82, a new BSC Agent would be appointed to calculate annual TLFs, on an ex-ante basis, using a methodology to be specified in the BSC. In addition, TLFs would be 'scaled' by a factor of 0.5 such that only variable losses (i.e. those caused by heating) would be allocated on a zonal basis approximately.

The Proposer believes that the introduction of such zonal differentiation of transmission losses would introduce long-term signals for the siting of generation and demand by allocating losses in such a manner that does not unduly penalise individual BM Units. In addition, losses would be allocated only according to the degree to which individual BM Units give rise to losses.

4.1.2.1 Summary of Key Characteristics

Incorporating the refinements made by the TLFMG to the proposed solution, the key characteristics of P82 can be summarised as follows:

Feature	**Modification Proposal P82**
TLF Methodology (TLFM)	'Scaled Marginal' (i.e. scaling factor of 0.5) & defined in BSC
TLF Calculation	Annual Ex-ante
Validity of TLFs	One BSC Year (April to March)
Zonal Groupings	<u>Generation</u> – GSP Groups <u>Demand</u> – GSP Groups
Type of Flow to be Modelled	DC
Network Configuration Data	Historic Intact Data
Process for Conversion of Metered Volumes into Nodal Metered Volumes	Specified mapping
Process for Conversion of Nodal TLFs into Zonal TLFs	'Volume-weighted' Averaging
Process for Conversion Half-hourly TLFs into Annual TLFs	Time-weighted Averaging

5 INITIAL ASSESSMENT AGAINST APPLICABLE BSC OBJECTIVES

The initial assessment carried out by the TLFMG consisted of four aspects. First, the Applicable BSC Objectives were interpreted in relation to the two proposals. Second, a methodology for carrying out an impact assessment of the two proposals was agreed and carried out. Third, an assessment of the general principles embodied in the two proposals and their implications was carried out. Finally, the TLFMG focused on some more specific issues, to ensure that all elements included in the Terms of Reference for the Assessment Procedure set by the BSC Panel (see Annex 5), where possible, were covered.

5.1.1 Interpretation of the Applicable BSC Objectives

The TLFMG considered which of the Applicable BSC Objectives were relevant in the context of the two proposals. The conclusion was that Objectives C3.3 (b), (c) and (d) were relevant:

(b) The efficient discharge by the Transmission Company of the obligations imposed under the Transmission Licence.

(c) Promoting effective competition in the generation and supply of electricity and (so far as is consistent therewith) promoting such competition in the sale and purchase of electricity.

(d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements.

The TLFMG then considered what specific features might relate to the above objectives. This consideration took account of legal advice provided to the Panel in respect of the Applicable BSC Objectives (in a memo dated 7 March 2002) and resulted in the following conclusions:

<u>Objective (b):</u>

- Efficient operation of the Transmission System has three components:
    1. efficient despatch (i.e. least-cost use of generation to meet total demand, including losses), whether arranged by market participants or the System Operator;
    2. efficient conduct of operations and investment in the transmission system; and
    3. efficient location of demand and generation (so as to induce efficient investment in the transmission system).
- The primary measure of change in efficiency should be the likely impact on costs, both short term (despatch) and long term (investment). In this context, the impact on costs would be limited to avoidable costs and would exclude the sunk costs of existing producers, consumers and traders. Costs might include environmental costs.
- The other potential impact on efficiency is that arising from changes in demand and, hence, in benefits to consumers (i.e. ‘consumer surplus’). In this case, efficiency increases if consumers consume more electricity than before, at a price no lower than the additional (marginal) cost of producing it, or if consumers cut demand that they valued less than the marginal cost of production.

<u>Objective (c):</u>

- In the first instance, the TLFMG noted that competition is a tool that that should only be used when it produces efficient outcomes. It follows that in practice no proposal whose outcome is less efficient than the status quo can be viewed as promoting competition.
- The TLFMG also considered the concepts of 'discrimination', 'cross-subsidy' and 'predatory pricing'. In practice, it was considered that the interpretation of such concepts was that new arrangements should promote efficient new entry, or prevent inefficient exit from the market. Conversely, promoting inefficient competitors would be subsidisation, not competition.
- As per the advice to the Panel, implementation costs to participants would be considered against this Objective, in so far as potential barriers to entry may arise. However, since the number of competitors is not necessarily a measure of the degree of competition, the above points relating to efficiency would also need to be borne in mind, when considering the cost of the proposals to participants.
- The TLFMG noted the points made in the advice to the Panel, specifically that the scope of costs to be considered would be those costs relating to the generation, supply, sale and purchase of electricity. Other costs, such as those relating to distribution, could be noted, if necessary.

Objective (d);

- Noting the advice to the Panel in respect of this Objective, the TLFMG considered that the key issue in this context was the impact on ELEXON's costs for the implementation and administration of the BSC central systems.

5.1.2 Assessment Methodology: Cost-Benefit Analysis

The approach that the TLFMG agreed was to undertake some form of cost-benefit analysis. This approach entailed establishing a 'net present value' of the proposed arrangements by applying some financial value to all costs and benefits. Various components of this analysis could then allow consideration of the above Applicable BSC Objectives, as follows:

- cost of implementing and administering central systems (i.e. the procurement of a new BSC Agent) or an alternative implementation approach (Objective (d));
- cost of implementing and administering participant systems and the renegotiation of contracts (Objective (c));
- costs and benefits of changing the location of demand and generation. Short term costs or benefits would be associated with changes in patterns of output, interconnector flows and demand (Objective (b)). Long term costs or benefits would arise from changes in the location of generation capacity, interconnector capacity and demand, including changes in investment in generation and transmission (Objectives (b) and (c));
- costs and benefits arising from changing risk patterns due to the new arrangements (Objectives (b) and (c)); and
- costs and benefits arising from changes in overall emissions due to changes in the type of generation and the transportation of primary fuel (Objectives (b) and (c))

In order to provide an initial view of the potential short-term benefit to generation resulting from zonal differentiation, the TLFMG noted the work undertaken by NGC[5]. This work suggested a benefit of some

[5] The work was carried out in response to the Authority consultation document entitled 'Transmission Access and Losses under NETA: a Consultation Document' (May 2001) and subsequently reported in the Authority document entitled 'Transmission Access

£3m per annum, due to the reduction of overall system losses, as a result of zonal differentiation. The TLFMG noted the following key assumptions that underpinned this work:

- the generation, demand and network data used in the study were the 2001/2 forecasts for the year 2003/04;
- the strict short-run economic ranking order of generation (based on historic fuel and transport prices) was modelled first without, and then with, adjustment for locational TLFs; and
- the TLFs used were the marginal zonal TLFs for peak demand that were published in National Grid's 2001/2 Seven Year Statement.

The short-term impact of applying the TLFs to generation was estimated in terms of the total reduction in variable transmission losses, with electricity priced at £20/MWh. It should be noted that this work was undertaken prior to the introduction of NETA and that transmission losses for the given year were approximately 1.8%. At present, losses are estimated to be between 1.4% and 1.5%.

The TLFMG recognised the need to base its recommendations on an informed view of the likely effects of the proposed modifications. To this end, the TLFMG assembled information on the TLMs arising under each of the Modifications and sought consultation responses containing reliable data on the costs and benefits of their effects. Given the scope of costs and benefits listed above, the TLFMG sought answers from respondents to the following questions:

- What would it cost the respondent to implement new systems and to renegotiate contracts?
  - How would these costs differ according to whether the participant had to accommodate (1) P75-style half-hourly zonal TLMs or (2) P82-style annual zonal TLMs?
  - Do these costs depend on the size of the respondent, or would the cost be the same for all market participants undertaking similar activities (regardless of size)?
- NGC's estimate of the short-term benefits of changes in the pattern of generation predates NETA; how should it be updated?
  - To allow for changes in the pattern of generation since 2000?
  - To allow for changes in the (forecast) price of electricity?
  - To take account of (1) P75-style half-hourly TLFs or (2) P82-style annual TLFs?
- How much would the location of generation and demand change in response to the introduction of P75 or P82?
  - Given the likely TLMs emerging under either proposal, are the resulting differences in costs allocated to generation significant relative to other factors that dictate location of new generation and demand?
  - What impact would P75 or P82 have on decisions to open new generation plant or new facilities consuming electricity? When will this impact take effect?
  - What impact would P75 or P82 have on decisions to close existing generation plant or facilities consuming electricity? When will this impact take effect?
  - Would P75 or P82 affect the location of future demand growth and, if so, by how much?

and Losses under NETA: Revised Proposals' (February 2002). Both documents are available on the Ofgem website (www.ofgem.gov.uk).

  - How would P75 or P82 affect your own decisions on the location, closure or expansion of generation or demand?
- What new risks (if any) would the introduction of P75 and P82 impose on market participants?
  - What measures will market participants take to cope with these new risks?
  - How should the TLFMG assess the costs of these measures?
- What benefits (if any) would the introduction of P75 and P82 have in ensuring the efficient development of the transmission system by the Transmission Company?
  - What will the impact be on the overall level of use of system charges paid by system users over the long term?
  - How should the TLFMG assess these benefits?
- How would P75 and P82 change the overall shares of fuel used in generation?
  - What impact would these changes have on emissions?
  - What impact would P75 and P85 have on the transportation of primary fuels?
  - How should the TLFMG assess the costs/benefits of these changes?

5.1.2.1 Cost-Benefit Analysis

A quantitative analysis of costs and benefits associated with P75 was presented to the TLFMG at its meeting on 23 October 2002 by an attendee from NERA[6]. NERA explained that the analysis had been produced in response to an action placed by the Modification Group, and the work had been funded by a number of interested parties to advise their consultation responses.

A commentary on the NERA cost benefit analysis was received by the TLFMG on 30 October, and presented at its meeting on 5 November 2002[7]. The Proposer explained that the report had been produced by Campbell Carr on behalf of Powergen.

TLFMG consideration of the issues raised by these two papers is given in section 9.

5.1.3 Assessment of General Principles

The TLFMG, with the Applicable BSC Objectives and the agreed impact assessment methodology in mind, carried out a high level assessment of three of the general principles embodied in the two proposals.

5.1.3.1 Generation of TLFs: 'Fully Marginal' versus 'Scaled Marginal' Methodologies

The Proposer of P82, explained that a scaled marginal approach had been suggested so that heating losses (the variable component of transmission losses) would not be over-recovered on a zonal basis. However, the Proposer of P75 suggested that the fully marginal approach was designed to provide more robust cost signals through a sharper allocation of losses between North and South. He also noted that, in any event, there is no ultimate over-recovery of transmission losses given that the TLMO balancing factors under Section T2.3.1 of the BSC always ensure that TLMs recover the correct volume of transmission losses in each Settlement Period. However, it was noted that TLMOs adjust all TLMs such that the overall allocation of losses between generation and demand is maintained at the ratio of

[6] See Annex 5
[7] Seen Annex 5

45:55. This constitutes a different allocation of losses to individual BM Units from that resulting from the scaling of marginal TLFs.

The results of the modelling work confirmed that a scaling factor of 0.5 applied to marginal TLFs would approximately reflect the volume of heating losses (i.e. those that vary with power flow).

The TLFMG then considered the above in the light of the specific interpretation of the Applicable BSC Objectives. For Objective (b), some members considered that the least cost use of generation (and flexible demand) to meet demand (i.e. 'despatch' efficiency) should be considered on a marginal basis (i.e. what the cost of the next MW should be) and the P75 approach allocated losses in a manner consistent with that basis. Others were of the view that overall costs should be considered and that P75 would overemphasise the zonal allocation, effectively including fixed losses in the zonal differentiation (or alternatively that a marginal approach would allocate twice the average heating loss on a zonal basis because of the square law nature[8] of heating losses) and hence would result in a sub optimal 'despatch'.

In so far as efficient location was concerned, there were similar concerns that an overly strong signal might result in inefficient siting and hence inefficient transmission investment, although it was considered that the difference between the two approaches was minimal, given that other cost drivers may dominate siting decisions. The Group accepted that, in so far as the approach to NGC operations was concerned, the choice of marginal or scaled approach made no difference. The group also considered that any change in demand was likely to be minimal. In respect of Objective (c), there was a view that, again, P75 could lead to exaggerated differentiation, constituting cross-subsidy of fixed losses. It was also recognised that the issue of discrimination was not relevant to Suppliers, as all Suppliers would face the same cost at a location, in any event. It was also acknowledged that the adoption of either Proposal would lead to an increase in BSCCo costs. It was further noted that P75 was likely to be more costly than P82, given the close to real-time nature of the P75 approach.

5.1.3.2 Ability of Market Participants to Respond to 'Locational Signals'

In so far as Objective (b) was concerned, it was noted that both flexible demand and generation would, in principle, be able to change prices to reflect the zonal allocation of losses, thus enhancing the efficiency of despatch.

It was, however, the view of some TLFMG members that in considering the question of consumer surplus, domestic demand was unlikely to respond to the change in costs at different locations and that the response of industrial and commercial demand would be slight and not influenced by the choice between P75 and P82. A counter view was that being located in an unfavourable transmission loss zone might prompt a CHP plant, for example, to invest in increasing its efficiency. Similar opportunities to increase efficiency might exist for the demand-side. For example, in the case of an ex-post zonal differentiation scheme, those suppliers best able to manage the resulting commercial risk would be able to establish a competitive advantage. It was also noted that a distinction could be made between existing and future generation, or demand.

In so far as siting, leading to efficient investment was concerned, a view was put forward as to why the demand-side ought to be excluded from any zonal differentiation of transmission losses. It was first suggested that the purchase of electricity was not a core activity for demand and that the cost of electricity was not a key determinant in the siting decisions of demand. As a consequence, the demand-side (i.e. domestic, commercial and industrial electricity consumers) would not respond to the locational siting signals resulting from zonal differentiation. Secondly, it was suggested that, should

[8] Losses increase in proportion to the square of the current.

zonal differentiation be introduced, the current signal to load manage, primarily driven by Triad avoidance, could be reduced because sharpened locational signals might result in NGC attenuating the existing locational signals contained in their charging regime to compensate.

In respect of Objective (c) was concerned, it was suggested that other cost drivers might be of a higher order of magnitude and impact and would overwhelm any influence of differential loss allocation. However, it was also suggested that market entry, or exit might differentially affect different types of plant and demand, depending on the other drivers associated with the particular plant or demand type. Finally, it was noted that introducing zonal differentiation for the allocation of transmission losses, particularly alongside the uniform 'Use of System' charges incurred by suppliers in the same TNUoS zone, would not enhance competition in supply. Therefore, Applicable BSC Objective (c) would not be better facilitated by either P75 or P82 as they stand (i.e. applying to demand, as well as generation).

There was some support for the above views about demand and that such arguments could apply equally to CHP and renewable generators. These types of generators make siting decisions based on a specific set of factors, such as proximity to an energy source (e.g. wind-farms) or an industrial process (e.g. CHP), that inhibit their flexibility to respond to other locational signals.

However, the point was made that the same logic could equally be applied to any form of generation. For example, coal-fired plant needed to locate either close to its fuel supply (i.e. close to coalfields) or in areas providing easy access to such a supply (e.g. a port).

It was, however, noted that siting decisions in response to locational signals was as much to do with closure decisions as with the siting of new plant. Furthermore, it was suggested that failure to better target the cost of losses at those Parties who contribute to those losses could result in the closure of more economically efficient plant in the South in preference to less economically efficient plant in the North, for example.

The TLFMG was divided as to whether demand, CHP, or renewable generation were special cases regarding their ability to respond to locational signals.

Finally, it was pointed out that different treatment of transmission losses for generation and demand would create a distortion in the market. Furthermore, it was suggested that excluding demand from zonal differentiation would result in no signal for demand to locate close to generation. Some TLFMG members considered that this was not a meaningful aspiration, in any event. Furthermore, it was noted that, under either proposal, TLFs would continue to be non-zero even within a zone in which demand and generation were balanced. From an implementation perspective, it was also pointed out that, if the treatment of demand and generation were to differ, this would necessitate some way in BSC drafting to distinguish between different BM Units so as to identify which treatment they should qualify for. This may be difficult, particularly given the existence of Trading Units, Interconnectors, embedded Generators and so on.

Ultimately, it was concluded that the exclusion of demand would create distortions as well as issues for legal drafting and would, therefore be detrimental for both Objective (b), from a siting perspective and Objective (c), in terms of distortions. Furthermore, it was suggested that the exclusion of demand was a sufficiently significant departure from either of the two proposals as to constitute a further modification. In the light of the foregoing, the TLFMG concluded that appropriate consultation questions might shed further light on the responsiveness of various groups of market participants.

5.1.3.3 Phased Implementation of Zonal Differentiation

The TLFMG initially considered three options for phasing in the implementation of either of the two approaches. This consideration was given without prejudice to the overall assessment of the Modification Proposals themselves. These options may be summarised as follows;

- <u>Application of a uniform scaling factor (Beta) to the TLFs:</u> this approach entails the application of a factor (beta) to the TLFs, which would reduce the degree of zonal differentiation. This factor would periodically be increased, ultimately reaching an enduring value, such that the full impact of the particular approach was enabled.
- <u>Application of 'F' factors to individual BM Unit losses:</u> this approach entails a pre-determined amount of a BM Unit's metered volume being exposed to uniform transmission losses and the remainder being exposed to a zonally differentiated TLF. A more detailed description of how this approach would be implemented is given in Annex 3.
- <u>Application of factors on the basis of new-build or incumbent status:</u> this approach entails the use of some attenuating factor on individual TLFs to reduce the extent of any additional cost arising from the TLF for existing generation and demand.

A substantial proportion of the TLFMG were of the view that some form of phasing would better achieve Applicable BSC Objective C3 (c);

'*Promoting effective competition in the generation and supply of electricity and (so far as is consistent therewith) promoting such competition in the sale and purchase of electricity*.'

The rationale behind this view was that investments and sunk costs could be stranded as a result of a rule change such as that envisaged by the two Modification Proposals. Since these sunk costs are typically long term and irreversible, this scenario could undermine efficiency by harming long term cost recovery and disincentivising future investment. The counter-view was that notice of the introduction of zonal losses had, in effect, already taken place in that the Authority (and its predecessor) have been identifying the desire for some form of zonal Transmission Loss allocation scheme since 1990 and, hence, no phasing was now required. Some members of the TLFMG counter that such messages were not sufficiently certain to provide a basis for investment decisions, thus phasing remained necessary.

In so far as the uniform scaling approach was concerned, a majority of the TLFMG believed that the above Objective was better achieved, albeit in a crude fashion. This approach merely attenuates the impact over the phasing period, thus mitigating (but not removing) the impact on existing investment, whilst reducing the effect for new investment. A majority of the TLFMG considered that the 'F'-factor approach better achieved the above Objective to a greater extent than the uniform scaling approach, in that the effect of the proposals would be brought to bear on new investment to a much greater degree, whilst better insulating existing investment. Although, there was a counter view that this approach would be discriminatory, since it would effectively provide 'grandfathering' rights or options to existing users. However, there was a concern that the significant complexity of the 'F'-factor approach (involving some Panel decision making and BSCCo infrastructure) meant that the uniform scaling approach better achieved Applicable BSC Objective C3 (d);

' *Promoting efficiency in the implementation and administration of the balancing and settlement arrangements*.'

The TLFMG also considered that the 'new vs. incumbent' approach involved some further difficulties and that the 'F'-factor approach largely delivered the intent of this arrangement.

There were mixed opinions amongst the TLFMG as to whether phasing was required, although there was a majority view that the simplicity of the uniform scaling approach would be preferable to the 'F'-factor approach. In so far as any phasing timescales were concerned, the TLFMG noted a number of precedents that had been set for comparable circumstances; the TRANSCo LDZ charging arrangements are being phased in over a 25 year period, the NGC ICRP approach for TNUOS charging had been phased in over a 4 year period and it was noted that half the investment timescale for typical electricity schemes fell within a range of 10 to 15 years.

5.1.4 Specific Issues

The final element of the assessment carried out by the TLFMG was the consideration of issues arising from specific elements of the two proposals. The issues assessed were designed to cover, where possible, all elements of the TLFMG's Terms of Reference. The following subsections summarise the conclusions, if any, that the TLFMG reached on each of the issues.

5.1.4.1 Impact on the Market as a Whole

This particular aspect of the Terms of Reference included consideration of market length and impact on different market participant categories (both by location and by type). The TLFMG noted that consideration of market length was, essentially, a consideration of the perception of the differing risk associated with an ex-ante and an ex-post approach to zonal differentiation.

The TLFMG noted the modelling results associated with changes in generation (or demand), as given in Annex 3. The TLFMG considered that, with ex-post TLFs (P75), these changes did give rise to material perturbations in TLMs, being more pronounced local to any such change. Given that such changes might occur in an unplanned fashion, the TLFMG suggested that such impacts constituted a risk to participants which they could not manage. These changes would not be reflected immediately, under the P82 regime, but would feed through into the following year's TLFs, albeit scaled down (by 0.5) and weighted according to the time within the year that the changed pattern prevailed for. However, it was noted that current TLMs vary from period to period (see graph in Annex 3a) and that the issue is the predictability of such variations. Therefore, it is necessary to consider the relative prevalence of planned and unplanned events.

The TLFMG concluded that this issue was significant in respect of Objective (b) in that any undue unpredictability could lead to compounding errors in contracts or in Bid or Offer volumes in the Balance Mechanism, undermining optimal despatch. Over longer time periods, unpredictability would be smoothed although may remain an issue for long term siting and efficiency in market entry or market exit (objectives (b) and (c)).

5.1.4.2 Accuracy of 'Locational Signal' versus Increased Cost/Complexity/Volatility

In the first instance, it was suggested that any signal should be a reflection of the cost that should be allocated to the particular participant. It was also noted that the P75 proposal stated that its intention was to target costs better than at present, whilst P82 sought to allocate costs in a manner that was better than under current arrangements. Neither proposal had made claims to achieving precise cost allocation. The TLFMG's consideration of the accuracy of the locational signals under either proposed regime are given in section 1.4.4.

5.1.4.3 Additional Risk Introduced and Potential for Mitigating Measures

The TLFMG considered that the risks fall into two main categories; short-term risks associated with the uncertainty of TLFs or TLMs and long-term risks associated with changes in market participant behaviour. The potential mitigating measures were considered to be largely those of phased implementation and/or the smoothing of TLFs or TLMOs.

5.1.4.4 Proposed Zonal Groupings for Generation and Demand TLFs

The TLFMG noted that the use of TNUOS charging zones as zonal groupings for generation, as specified under P75, entailed reliance in the BSC on parameters that are external to the BSC and under a different governance regime. In so far as the effect of zones in general was concerned the TLFMG noted the outcome of the modelling, as given in Annex 7, which suggested that for some BM Units, their nodal TLMs would be closer to the zonal TLM of a neighbouring zone than to the zonal TLMs that they would actually be exposed to. However, it was recognised that the modelling results were a snapshot and that the spread of nodal TLM values relative to the zonal average may well change over time. There were mixed views as to whether this zonal differentiation was a closer approximation to the nodal variation than the current regime (which constitutes a single national zone, in effect). Some members were of the opinion that because both the TNUOS zone approach and the GSP Group approach gave rise to a clear north to south trend, they represented a clsoer approximation.

One suggestion was that the fairly wide spread of nodal TLMs within zones might have resulted from localised AC modelling effects. Some TLFMG members concluded that zonal TLFs were sufficiently accurate to lead to more efficient siting (i.e. better achievement of Objective (b) and to facilitate more efficient market entry and exit (Objective (c)).

In so far as using different zones for demand and generation, the TLFMG considered that ideally the same groups should be used for both generation and demand. Otherwise a distortion would be created in that there would be an incentive for excess demand and generation to be located in the same zone (and possibly for spurious amounts of such generation and demand) to exploit the differential in loss allocation (which already exists but would be exacerbated if different zones were to be adopted for zonal loss allocation) and thus undermine efficient despatch, efficient siting (Objective(b)) and efficient market entry and exit (Objective(c)). Nevertheless some TLFMG members were sceptical as to the extent of such theoretical gaming opportunities. They felt it was more important to estbalish zonal groupings that produced TLFs that were as representative of actual losses as possible, and that in this respect TNUoS Zones were preferable to GSP Groups for generation. However, a counter view existed amongst TLFMG members – TNUoS Zones would not necessarily provide a better fit because they were not created with losses in mind and the modelling results suggested there was little chose between them and GSP Groups.

The TLFMG undertook an analysis of the two proposals and concluded that the current overall split of 45:55 between generation and demand would be retained under each proposal.

5.1.4.5 Choice of Network For TLF Production

The TLFMG accepted that there were differences in outcome, depending on whether an intact, or indicative, network was used. It was also noted that the use of a representative network yielded no tangible difference as compared to an intact network (see Annex 7). It was further pointed out that changes to network configuration were not half-hour by half-hour instances, but were periodic. There was also a suggestion that, as a point of principle, the effect of a line outage should not be included in zonal allocation of losses, as this was an effect that should be taken account of in the incentives for NGC. The TLFMG concluded that, since P75 sought to reflect the actual half-hour by half-hour situation and reflect this in TLFs, then the indicative network appeared to be preferable, whilst for P82, the smearing of the effect of line outages implied by the use of an intact network seemed to be consistent with the average approach of that proposal.

In considering how the choice of network might influence the better achievement of BSC Objectives, the TLFMG noted that the view on whether, or not, the effect of line outages should be included was relevant to Objective (c) in that the issue was one of whether the associated cost should be allocated to certain participants, or not (and, hence, whether there was a distortion or not). From the perspective of Objective (b), it was suggested that efficient despatch might be enhanced with the use of an intact network, since this would be a more transparent approach. It was also suggested that the use of indicative networks would be more expensive than use of an intact network, since the former would require a more extensive update activity from NGC and that this extra effort might constitute spurious accuracy, given that other assumptions inherent to either proposal would outweigh the precision of the use of an indicative networks

5.1.4.6 Applicable Period For TLFs

In the first instance, the TLFMG confirmed that it considered that the degree to which source data was averaged should be commensurate with the period of applicability. For example, half-hourly source data should be used to produce half-hourly varying TLFs. On the other hand, if annual TLFs were preferred, TLFs should be averaged across the year. The TLFMG also considered that there were no compelling reasons to move to seasonal or daily varying TLFs. On the basis of the results of modelling (in Annex 5), the variations suggest that the choice should be between half-hour and annual varying TLFs. It was noted that, for half-hour varying TLFs, the potential variation constituted a risk (in being unforeseeable), although the TLFs might better reflect the variation in circumstances. Hence, from the perspective of Objective (b), the finer granularity of P75 would yield better optimisation of despatch, whilst for Objective(c), P82 might be better in terms of providing more predictable market entry or market exit signals. The TLFMG considered that P75 could be made more predictable (and cheaper to implement) by using daily TLFs, rather than half-hourly TLFs, and P82 could be made more responsive by moving to seasonal TLFs, rather than annual TLFs. However, it was suggested that predictability could best be improved by adopting an ex-ante, rather than ex-post approach. On balance, and in the light of the greater cost of providing half-hourly network data and of enhancing BSC Agent Systems, the TLFMG concluded that P75 should be refined such that TLFs would apply for a Settlement Day rather than a Settlement Period.

5.1.4.7 Interaction with Other Proposed Modifications to the BSC

The TLFMG did not identified any other Modification Proposals with which there would be a potential interaction.

5.1.4.8 Factors Affecting the Siting Decisions of Generation and Demand

The TLFMG recognised that such factors could contribute to the assessment of the two proposals and sought participant views on this issue through consultation.

5.1.4.9 Interaction with Related Relevant Governance Structures

The TLFMG noted that, if zonal differentiation were introduced, NGC may need to review its ‘Use of System’ charging methodology in order to ensure that the overall locational signals to transmission users continue to be appropriate. There may also be a need to reconsider the NGC incentive arrangements.

5.1.4.10 Interaction with Relevant Major Industry Initiatives (including BETTA)

The TLFMG came to the conclusion that modelling the interaction of the two proposals with BETTA would not be practical given the time available under the Assessment Procedure. Generating meaningful results would require a Scottish data set and the modelling of the Scottish transmission network. In addition, the TLFMG noted the observation made by the Authority representative at its meetings, that the vires of the BSC was limited to England and Wales. As a result, the TLFMG propose giving no further consideration to any interactions with the Scottish network, beyond the interconnectors.

It was also recognised that the transmission access initiative might need to take due account of the losses regime in place at the time.

5.1.4.11 Experience of Other Markets with Relevant Transmission Loss Schemes

The TLFMG sought information on how other markets deal with transmission losses. However, nothing substantive and relevant for inclusion in an Assessment Report has yet been considered.

6 MODELLING

ELEXON, on behalf of the TLFMG, procured a modelling service to support the Assessment Procedure. After a tender process, Power Technologies International (PTI) was awarded the contract to carry out the service on 15 August 2002. PTI delivered the final results to ELEXON on 14 October 2002.

6.1 Modelling Objectives

The aim of the modelling, amongst other things, was to model the magnitude and variability of TLFs under each of the Modification Proposals. Modelling was considered essential to gain an insight into the potential impact of the proposals on market participants and the market as a whole. The objectives of the modelling are described in the following subsections.

6.1.1 Objective A - Calculation of TLFs & TLMs

To generate Transmission Loss Factors (TLFs); factors representing the change in transmission losses arising from marginal changes in demand or generation at nodes on the transmission network, and Transmission Loss Multipliers (TLMs); variables that adjust actual metered data to reflect TLFs. TLFs and TLMs were generated for each of the proposals (P75 and P82) and under each of the scenarios specified .

The TLFMG required this objective to be met in order to assess the impact of the proposals on TLFs and TLMs.

6.1.2 Objective B – Estimation of Predictability & Stability of TLFs/TLMs

To establish the sensitivity of TLFs and TLMs to changes in demand and generation by both time and location. In addition, the variability of both TLFs and TLMs was required to be estimated for several time frames. The changes to be modelled were specified under the scenarios to be provided to the service provider.

6.1.3 Objective C - Credible & Accurate Model

To ensure that the TLFs and TLMs generated by the model were as accurate as possible, the model needed to accurately represent the physical characteristics of the England and Wales transmission network. In addition, the input data reflected the conditions prevailing on that network at the time in question.

To ensure that the TLFs and TLMs generated were credible, all assumptions used in the modelling were to be credible, accurate and clearly described.

6.1.4 Objective D – Transparent Model

To ensure maximum transparency of the modelling undertaken, the operation of the model and all input data was objectively derived from public sources (or provided by ELEXON) and all assumptions were to be clearly stated. In addition, the model use any data defined by the TLFMG and be capable of review by the TLFMG. Output data needed to be in a readily usable format. Finally, the model should be flexible and capable of quick turn around.

6.2 Assumptions

As is usually the case with such an exercise, a number of assumptions were required in order to execute the modelling. The following subsections summarise the key assumptions that were agreed for this modelling exercise.

6.2.1 Input data

The following key assumptions relating to input data were made:

- A number of assumptions were required in order to provide a complete mapping of BM Unit and GSP metered values onto network nodes.
- MWh values for each half-hour were assumed to give rise to fixed MW power injections.
- Where BM Unit data suggested negative losses (for example where some generation data may have been missing), generation was increased pro-rata to reflect demand and calculated losses.

6.2.2 Processing

Using the above input assumptions, an AC load flow study formed the basis of the TLF production process. In so far as assumptions in processing were concerned, those appropriate for an AC load flow study were adopted (see section 4 in PTI report in Annex 7)

6.2.3 Output data

The key output assumption was that each individual node on the modelled network was assumed to be a BM Unit, for the purposes of calculating TLMs.

6.3 Summary of Results

The final report from PTI is attached as Annex 7 of this report. The following subsections summarise the results for each of the Modification Proposals.

6.3.1 Sensitivity Analysis for Modification Proposal P75

The following observations were made by PTI on the basis of the modelling results:

- TLMs would vary across England & Wales;
- Zonal TLMs would vary across the England & Wales and over time;
- Magnitude and variability of zonal TLMs would, depend, among other factors, on location;
- Choice of network configuration data could have an effect on TLMs (i.e. there is a tangible difference between use of an ‘indicative’ and an ‘intact’ network);
- Constraints could have an impact on TLMs;
- Nodal TLMs for some nodes would be closer to neighbouring zonal TLMs;
- Once a suitable load flow data set has been established, it would take less than 10 seconds to obtain TLFs for all considered generations/demand points for a Settlement Period;
- Flows on the French inter-connector could have an impact on TLMs

- Zonal TLMs would only be locally sensitive to plant breakdown/removal or plant relocation; and
- Zonal TLMs would only be locally sensitive to increase in intermittent generation.

6.3.2 Zonal TLMs for Modification Proposal P75

In addition to the observations listed in the previous section, tables of the zonal TLMS for both generation and demand at the winter peak and summer trough were produced.

Table 1: Zonal TLMs for Demand for Peak and Trough Settlement Periods (P75)

GSPG Zone	02-Jan-02	01-Aug-01
	SP36	SP8
GSPG 0	1.02548	1.01557
GSPG 1	0.95076	0.98276
GSPG 2	0.96663	1.00608
GSPG 3	0.96394	0.99801
GSPG 4	0.97342	1.01860
GSPG 5	0.99868	1.01108
GSPG 6	1.00719	1.01783
GSPG 7	1.02860	1.00733
GSPG 8	1.02813	1.00744
GSPG 9	1.04604	1.01149
GSPG 10	1.05103	1.01646
GSPG 11	1.05314	1.02107
GSPG 12	1.06172	1.01970

Table 2: Zonal TLMs for Generation for Peak and Trough Settlement Periods (P75)

TNUoS Zone	02-Jan-02	01-Aug-01
	SP36	SP8
TNUoS 1	0.94433	0.96907
TNUoS 2	0.96427	0.98968
TNUoS 3	0.95527	0.99334
TNUoS 4	0.97430	1.01058
TNUoS 5	0.95585	1.03984
TNUoS 6	0.99934	1.01341
TNUoS 7	1.01437	0.99319
TNUoS 8	1.02545	0.99830
TNUoS 9	1.03982	0.99862

TNUoS 10	1.04084	1.00621
TNUoS 11	1.04374	0.99952
TNUoS 12	1.03793	1.01507
TNUoS 13	1.06809	1.02157
TNUoS 14	1.06025	1.01663
TNUoS 15	1.08130	1.02711

6.3.3 Sensitivity Analysis for Modification Proposal P82

The following observations were made by PTI on the basis of the modelling results:

- Magnitude and variability of zonal scaled half-hourly TLFs would depend, amongst other factors, on location;
- TLMs would vary across England & Wales;
- Modest temporal variation in zonal TLMs (which would be identical in all zones);
- Minimal temporal variation in zonal TLMs (zonal TLM values would depend on location);
- Almost non-existent daily variations in zonal TLMs on a typical autumn day;
- Minimal sensitivity of zonal TLMs to constraints (the effects of such events would be averaged in the following year);
- Nodal TLFs for some nodes would be closer to neighbouring zonal TLFs;
- Nodal TLMs for some nodes would be closer to neighbouring zonal TLMs;
- Minimal sensitivity of TLMs to flows on the French inter-connector (the effects of such events would be averaged in the following year);
- Scaling by TLFs by 0.5 would not precisely recover heating losses but appears a reasonable assumption;
- Minimal sensitivity of TLMs to plant breakdown/removal or plant relocation (the effects of such events would be averaged in the following year); and
- Minimal sensitivity of TLMs to an increase in intermittent generation (the effects of such events would be averaged in the following year).

6.3.4 Zonal TLMs for Modification Proposal P82

In addition to the observations listed in the previous section, tables of the zonal TLMS for both generation and demand at the winter peak and summer trough were produced.

Table 3: Zonal TLMs for Demand for Peak and Trough Settlement Periods (P82)

GSPG Zone	02-Jan-02 SP36	01-Aug-01 SP8
GSPG 0	0.99289	0.99196
GSPG 1	0.99676	0.99583
GSPG 2	0.99944	0.99851
GSPG 3	0.99943	0.99850
GSPG 4	1.00428	1.00335
GSPG 5	1.00932	1.00839
GSPG 6	1.01544	1.01451
GSPG 7	1.01135	1.01042
GSPG 8	1.01980	1.01887
GSPG 9	1.01269	1.01176
GSPG 10	1.02108	1.02015
GSPG 11	1.02261	1.02168
GSPG 12	1.02457	1.02364

Table 4: Zonal TLMs for Generation for Peak and Trough Settlement Periods (P82)

GSPG Zone	02-Jan-02 SP36	01-Aug-01 SP8
GSPG 0	0.97658	0.97688
GSPG 1	0.98045	0.98074
GSPG 2	0.98314	0.98343
GSPG 3	0.98312	0.98342
GSPG 4	0.98798	0.98827
GSPG 5	0.99301	0.99331
GSPG 6	0.99914	0.99943
GSPG 7	0.99505	0.99534
GSPG 8	1.00349	1.00379
GSPG 9	0.99638	0.99667
GSPG 10	1.00478	1.00507
GSPG 11	1.00631	1.00660
GSPG 12	1.00827	1.00856

6.4 Issues Arising From Modelling

Aside from the specified results, a number of observations were made by the modellers which the TLFMG have considered. Three specific issues have emerged; input data quality, the choice of slack bus and the degree of certainty associated with the underlying assumptions (particularly with regard to the choice between an AC and a DC load flow approach).

In so far as data quality was concerned, some of the input datasets gave rise to negative losses, implying some missing generation. To compensate, it was agreed that generation would be increased pro-rata to reflect calculated losses for those periods. The TLFMG did not consider this matter to be significant enough to diminish their confidence in the results of the model. In considering the potential for such an issue to arise in an operational environment, the TLFMG were of the view that this was only a risk for P75, since data clean-up could be undertaken for P82. Even for P75, it was noted that the CDCA employs default processes to ensure complete data. It was considered that some default rules for the relevant Agent, under P75 might be required.

In any model of an electrical system, because some approximations are inevitable, one node (i.e. point where two or more lines meet), known as a busbar on the real system, would be set up in the model to act as a sink for any surplus (or deficit) power. These surpluses (or deficits) arise from the above mentioned approximations and enable the model to converge on a solution. This busbar is known as the slack bus. The presumption that the choice of slack bus would not affect the differentials in TLF (although absolute values would change) was not supported by the modelling. Whilst the TLFMG are undertaking further work to assess this, they did not consider that this should diminish their confidence in the model. Relevant slides in Annex 8 illustrate the sensitivity to choice of slack bus.

Finally, it was considered that the use of an AC approach, ostensibly, making realistic assumptions as to voltage and reactive power circumstances on the network, constituted a more realistic scenario for producing TLFs. However, the issue with this approach is that these assumptions require judgements to be made based on normal system operating practice. In so far as establishing a comprehensive and unambiguous description as to how TLF production should be undertaken under the Code, it may be argued that less realistic assumptions should be made if those assumptions are absolute and do not require any such judgement. Arguably, the use of a so-called ‘DC’ load flow constitutes such an approach. In a ‘DC’ load flow, certain assumptions are made (as described in Annex 6 part (b)) which do not require judgements and represent an AC load flow study, but with equations that are similar to those associated with DC flows (hence the somewhat misleading description of ‘DC’ load flow). However, the TLFMG were not able to conclude which of the two approaches might be the more realistic, although the results of sensitivity to one element of the difference between the two sets of assumptions (those that reflect an AC study and those that reflect the ‘DC’ approach), that of power factor (a number that indicates the amount of reactive power at a node), suggested modest discrepancies between the two. However, some TLFMG members suggested that reactive power considerations, locally, might be important and use of an AC model could be sensitive to errors in such data and assumptions. Conversely, the assumptions of a ‘DC’ approach would not include such considerations at all. The TLFMG took the view that, since P75 sought to reflect a close to real circumstance for the production of TLFs, then an AC approach would be preferable, whilst for P82, the majority of the group held the view that given that P82 provided for an averaged approach, a DC study would be preferable. A DC approach was also felt to be more appropriate for the refined P75, were TLFs would be applicable for a Settlement Day.

7 SUMMARY OF CONSULTATION RESPONSES

The TLFMG produced and issued a consultation document containing an interim set of modelling results and the results of the Assessment Procedure up to that point on 2 October 2002. Twenty-nine responses were received by the 21 October 2002 deadline. The responses received have been reproduced in full in Annex 4.

7.1 High-Level Summary of Responses to P75

The following sections provide a high-level summary of the consultation responses received for P75. A more detailed analysis of responses is provided later. Twenty-nine responses, representing 59 Parties, were received by the 21 October 2002 deadline.

7.1.1 Achievement of Applicable BSC Objectives

Consultees were asked whether they believed either P75 or an alternative to P75 would better achieve Applicable BSC Objectives. Consultees were split in their opinions.

Yes	Yes (Unspecified Alternative)	Neither	No Comment
4	12	14	1

Responses suggested that there was little support for P75 as proposed. However, a substantial body of opinion appeared to believe that some sort of alternative version of the proposal would better achieve applicable BSC Objectives. Responses suggest that the characteristics sought in such an alternative were an ex-ante TLFM, scaling, and TLFs applicable over a longer time-frame (e.g. monthly, seasonal or annual). Another substantial body of opinion believed that neither P75 nor an Alternative to P75 would better achieve Applicable BSC Objectives.

7.1.2 Ex-Ante versus Ex-post

Ex-Ante	Ex-Post	Undecided/No Opinion
20	1	3

Were zonal transmission losses introduced, the majority of respondents indicated that they favoured an ex-ante over an ex-post approach. The main argument provided was that an ex-ante approach introduced less risk and uncertainty.

7.1.3 Applicable Time Frame for TLFs

Settlement Period	BSC Year	Other	No Opinion
5	12	5	2

Were zonal transmission losses introduced, the majority of respondents indicated that they favoured TLFs valid for a BSC year as opposed to a Settlement Period. In addition, two respondents indicated their preference for seasonal TLFs and three respondents indicated their preference for monthly TLFs.

7.1.4 Inclusion of Demand versus Exclusion of Demand

Inclusion of Demand	Exclusion of Demand
18	9

Were zonal losses introduced, a two-to-one majority of respondents indicated that they believed that the demand-side should be included in the new scheme. Those supporting inclusion believed that it would be equitable, given that demand contributes to losses on the system, and essential to sending out the right locational signals. Those supporting exclusion argued that the demand-side could not respond to the locational signals emitted by zonal TLFs.

7.1.5 Implementation Date

Were zonal transmission losses introduced, opinion fell broadly into two camps on lead-time required. A majority expressed the opinion that implementation should coincide with the start of the financial year and contracting rounds and that a minimum of one year's notice would be required. This body of opinion, therefore, favoured an April 2004 implementation. A minority expressed the opinion that zonal transmission losses should be introduced as soon as possible.

7.1.6 Phasing

Support	Reject	Undecided/No Opinion
16	6	2

Were zonal transmission losses introduced, a majority of respondents indicated that they felt that phased implementation would be necessary to smooth the transition to the new regime. More support was expressed for 'Beta' as opposed to 'F-Factor' phasing, with respondents quoting a time frame of between of between 4 and 25 years (the most common responses being around 10 or 15 years).

7.1.7 Zonal Groupings

GSPG/GSPG	TNUoS/GSPG	Other/No Preference
15	5	5

Were zonal losses introduced, a majority of respondents indicated that they favoured grouping both generation and demand by GSP Group, rather than generation by TNUoS Zone and demand by GSP Group. One respondent, however, expressed a preference for grouping both generation and demand by TNUoS zone.

7.2 High-Level Summary of Responses to P82

The following sections provide a high-level summary of the consultation responses received for P82. A more detailed analysis of responses is provided later. Twenty-nine responses, representing 57 Parties, were received by the 21 October 2002 deadline.

7.2.1 Achievement of Applicable BSC Objectives

Consultees were asked whether they believed either P82 or an unspecified alternative to P82 would better achieve Applicable BSC Objectives. Consultees were split in their opinions.

Yes	Yes (Unspecified Alternative)	Neither	No Comment
9	9	13	2

Consultation responses suggested that a substantial body of opinion believes either P82 or an alternative to P82 would better achieve Applicable BSC Objectives. Those supporting an alternative appear to favour some form of phasing. However, another substantial body of opinion believes that neither would better achieve the objectives.

7.2.2 Ex-Ante versus Ex-post

Ex-Ante	Ex-Post	Undecided / No Opinion
19	2	2

Were zonal transmission losses introduced, the majority of respondents indicated that they favoured an ex-ante over an ex-post approach. The main argument provided was that an ex-ante approach introduced less risk and uncertainty.

7.2.3 Applicable Time Frame for TLFs

Settlement Period	BSC Year	Other	No Opinion
3	14	4	1

Were zonal transmission losses introduced, the majority of respondents indicated that they favoured TLFs valid for a BSC year as opposed to a Settlement Period. In addition, two respondents indicated their preference for seasonal TLFs and three respondents indicated their preference for monthly TLFs.

7.2.4 Inclusion of Demand versus Exclusion of Demand

Inclusion of Demand	Exclusion of Demand
18	7

Were zonal losses introduced, a two-to-one majority of respondents indicated that they believed that the demand-side should be included in the new scheme. Those supporting inclusion believed that it would be equitable, given that demand contributes to losses on the system, and essential to sending out the right locational signals. Those supporting exclusion argued that the demand-side could not respond to the locational signals emitted by zonal TLFs.

7.2.5 Implementation Date

Were zonal transmision losses introduced, opinion fell broadly into two camps on lead-time required. A majority expressed the opinion that implementation should coincide with the start of the financial year and contracting rounds and that a minimum of one year's notice would be required. This body of opinion, therefore, favoured an April 2004 implementation. A minority expressed the opinion that zonal transmission losses should be introduced as soon as possible.

7.2.6 Phasing

Support	Reject	Undecided / No Opinion
16	6	0

Were zonal transmission losses introduced, a majority of respondents indicated that they felt that phased implementation would be necessary to smooth the transition to the new regime. More support was expressed for ‘Beta’ as opposed to ‘F-Factor’ phasing, with respondents quoting a time frame of between of between 4 and 25 years (the most common responses being around 10 or 15 years). In addition, a significant minority of respondents believed that implementation should coincide with the introduction of BETTA.

7.2.7 Zonal Groupings

GSPG / GSPG	TNUoS / GSPG	Other / No Preference
13	4	6

Were zonal losses introduced, a majority of respondents indicated that they favoured grouping both generation and demand by GSP Group, rather than generation by TNUoS Zone and demand by GSP Group. One respondent, however, expressed a preference for grouping both generation and demand by TNUoS zone.

8 FURTHER ANALYSIS AGAINST APPLICABLE BSC OBJECTIVES

In light of the consultation responses received, the TLFMG revisited its initial assessment of the two proposals against the Applicable BSC Objectives. The TLFMG noted the general tenor of the consultation responses and the range of views relating to the two proposals and the potential variants to them. However, it was noted that in some responses, preferences for an Alternative did not identify specific elements of an alternative proposal. Therefore, it was difficult to determine the true level of support for alternatives for the two proposals. Furthermore, consultation responses highlighted a number of arguments that had either not been considered by the TLFMG or were variants on arguments that the TLFMG had previously considered. The following section summarises these arguments and provides the further analysis of the proposals by the TLFMG in the light of these arguments and the consultation responses, in general.

8.1.1 Cost-Benefit Analysis

A number of respondents noted that no quantitative cost-benefit had been produced prior to the consultation that demonstrated increased efficiency arising from any of the proposals. Furthermore, some responses suggested that the short to medium term gains were more likely to be around £1m per annum, rather than the £3m per annum quoted in the consultation.

The TLFMG have subsequently considered both a cost-benefit analysis and a commentary on that analysis.

The cost-benefit analysis itself considered a number of hypotheses about the additional relocation of generation that P75 is likely to cause, using two sources of information about the costs that market participants would incur to incorporate the new scheme into their IT systems. Combining these hypotheses in a way believed to be reasonable, it was found that P75 has a negative net benefit, even before allowing for its effect on risk. It was also suggested at the TLFMG that for P82 the results of the cost-benefit analysis could be deduced by scaling both costs and benefits as determined for P75, on the basis that costs were likely to be lower, although any response to P82 was also likely to be reduced.

The commentary on the cost-benefit analysis submitted by Campbell Carr questions the appropriateness of the approach when used in the context of a BSC Modification in this context for the following reasons:

- Aspects of the analysis are outside the scope of the BSC's Objectives;
- The analysis is static and therefore does not take account of the effects of innovation and parties' responses to competition;
- Forecasts about inputs, such as fuel prices and differential load growth will be subject to variation;
- Ranges of data and their interactions are not taken into account; and
- Some forecasts of costs, for example Parties' systems costs, are based on limited information, there are alternatives but there is insufficient time to provide reliable and valid data.

8.1.2 Fully Marginal versus Scaled Approach

One respondent contended that the use of 'unscaled' TLFs was not reflective of costs and that negative 'costs' (which may arise from either P75 or P82, in principle) were counter-intuitive. It was further suggested that, because the resultant TLFs were to some extent inaccurate, further scaling should be contemplated to smear those inaccuracies. A view expressed at the TLFMG supported this argument and that negative values were reflective of a marginal signal, rather than a cost. However, there were counter views that a negative cost was reasonable in that some demand or generation could back off losses that would otherwise result.

One respondent expressed the view that the arguments expressed by the TLFMG on this matter did not relate to the Applicable BSC Objectives. Another respondent noted that the combined use of a scaling factor and the TLMOs would result in non-uniform adjustments to reflect 'fixed losses' and hence, might not be more cost-reflective than a fully marginal approach.

The TLFMG noted that a substantial number of respondents raised concerns over the fully marginal approach used to calculate the zonal TLFs under P75. The arguments given related mainly to the lack of justification for recovering fixed losses locationally, as they are an inherent feature of the transmission system and are not location dependent. The respondents suggested that a non-scaled approach would lead to a new cross subsidy, as those at the extremes of the network would be allocated a higher proportion of the fixed losses than those in more neutral zones. It was argued that this new cross subsidy could cause distorted locational signals, as the variation in TLFs across the network would be amplified. One respondent observed that these exaggerated TLFs could lead to distortions in the notional loss-adjusted merit order, therefore jeopardising achievement of Applicable BSC Objectives (b) and (c). However, Several respondents did comment on the non-ideal economic solution provided by the 0.5 scaling factor applied to the TLFs under P82.

8.1.3 Ability To Respond

In so far as the exclusion of demand was concerned, it was suggested in one response that the exclusion of any class of participant would be discriminatory. A number of those respondents arguing for the exclusion of demand suggested that benefits arising from a TLF may not be passed through to customers, at least initially due to the fixed nature of many retail contracts. Furthermore, a similar problem may exist as regards extra costs which may not be capable of being passed through, particularly given the degree of churn of customers. One suggestion at the TLFMG was that if all costs associated with the delivery of energy from station gates to customer premises were to be borne by generators, then this would naturally include transmission losses (potentially with zonal differentiation). However, it was recognised that this suggestion was a significantly wider proposition than those being considered under P75 and P82. It was further suggested that the exclusion of demand might also imply the exclusion of embedded generation, thus insulating such generation (along with demand) from Transmission Losses and thereby incentivising investment in such generation. In conclusion, the TLFMG continued to believe that no class of Party should be excluded.

8.1.4 Phased Implementation

One respondent suggested that phasing could be considered in the context of limiting impact year-on year, as was considered as part of the introduction of the ICRP charging arrangements for TNUOS. There was also one response that suggested that the phasing period should reflect contract timescales (noting that some contracts covered a four-year period). A further observation made in consultation responses was that a precedent existed for such costs being incurred without phasing which was that of certain TRANSCO charges (namely those associated with the unbundling of the TRANSCO metering business charges and the reallocation of over-recovered gas entry capacity charges). The TLFMG noted that, in so far as the NGC ICRP based TNUOS charges were concerned, the charges were introduced at a time when stable costs were required prior to an expected period of significant capital investment. Conversely, the current issue is that of maintaining some stability for existing investment.

The TLFMG accepted the need to consider phasing (or lack of it) alongside any lead time that might be needed as identified via the DLIA. A view from one respondent was that the effective date for zonal TLFs should be synchronised with the suggested implementation for Transmission Access and for the revised NGC incentive scheme; April, 2003. However, it was noted that this date was still being consulted upon. A full consideration of the potential implementation date is given below.

Whilst TLFMG views remained mixed as to the merits of phasing, on the basis of the above arguments, it was recognised that potential alternatives should be considered that incorporated phasing over four years (with an assumption that there would be a one year lead time for implementation). It should be noted, however, that there was only a small majority in favour of four years phasing for any unscaled approach, as opposed to a 9-year phasing timescale. Four years was considered an appropriate timescale to protect existing contracts made prior to the introduction of zonal losses whilst nine years was considered an appropriate length of time to protect investments made prior to the introduction of zonal losses..

8.1.5 Impact On the Market as a Whole

Some responses argued that the unhedgeable risk implied by an ex-post arrangement would lead to a premium on prices and would thus cause Applicable BSC Objectives to be achieved to a lesser extent than currently. Another respondent suggested that this could undermine incentives associated with capital investment. Conversely, another respondent suggested that the use of risk management tools could be used to deal with the ex-post TLFs and that this was consistent with the BSC arrangements generally.

Given the tenor of responses, along with the arguments raised, a majority view of the TLFMG was that an ex-post approach may not better achieve Applicable BSC Objectives and that a potential alternative to P75 retaining the key element of unscaled marginal TLFs, but taking an ex-ante approach, should be considered.

8.1.6 Accuracy of Locational Signal versus Increased Cost/Complexity/Volatility

One respondent argued that the complexity of the proposed arrangements would be such as to constitute a barrier to entry to small non-integrated generators. Some TLFMG members agreed that this was an issue and that either of the proposals would introduce incremental risk to participants. Others disagreed, considering that complexity, of itself, was not an issue.

8.1.7 Proposed Zonal Groupings for Generation and Demand

Some respondents suggested that any gaming arising from discrepancies between the treatment of demand and generation could be dealt with via licence arrangements, or via explicit changes to the BSC and, therefore, this difficulty should not preclude the use of different treatment for generation and demand (including the exclusion of demand altogether). A counter view was that such discrepancies might lead to artificial bundling (or unbundling) of generation and demand at a location. One response considered that the use of generation TNUOS zones for generator TLFs had been shown to be a closer fit to nodal TLFs by the modelling work and would be consistent with Use of System charging, whilst GSP Group zones had less relevance to Transmission flows and could diverge further over time. A counter view was that GSP Groups were within the vires of the BSC and, in any event, were less likely to change over time than generation TNUOS zones.

The TLFMG acknowledged the various arguments associated with the choice of zones and concluded that a potential alternative for P82 might be considered, with GSP Groups for demand and generation TNUOS zones for generation.

8.1.8 Choice of Network for TLF Production

One respondent suggested that, for an ex-ante solution, the chosen network should, nevertheless, be one that reflected the anticipated conditions, rather than the commensurate historic conditions. The TLFMG did not regard this proposal as compelling and were of the view that their original conclusions should stand.

8.1.9 Applicable Period for TLFs

One respondent considered that, for an ex-ante solution, the use of daily or monthly periods of applicability would give rise to more dynamic and accurate TLFs.

The TLFMG considered that there was some merit in considering as elements of potential alternatives to P75, the use of monthly TLFs (particularly as part of an ex-ante variant).

8.1.10 Interactions with Wider Issues

A number of respondents expressed some concerns associated with the interaction with the BETTA proposals. In particular, the need for a GB wide BSC to be consulted on, prior to any implementation of BETTA, could lead to zonal differentiation of losses being removed. Hence there is a risk of the implementation being nugatory. It was pointed out that the response that had alluded to this issue had suggested that this was a concern to be highlighted by the Panel and to be drawn to the Authority's attention. The TLFMG noted this.

One respondent suggested that there should be some certainty as to what changes would arise for TNUOS charging before proceeding with any of the proposals. It was, however, noted at the TLFMG that the TNUOS charging regime contained no explicit losses element and that the impact of a losses regime under the BSC should not be overstated.

One respondent suggested that the proposals were inconsistent with the shallow entry basis of NGCs TNUOS charging arrangements. However, as described above, another response argued that the use of generation TNUOS zones for TLFs was actually consistent with the TNUOS charging arrangements.

8.1.11 Approach for TLF Production

A number of respondents expressed concern that the slack bus issue may be significant, even though for the particular conditions modelled the TLFMG had determined that they retained confidence in the modelling results. The TLFMG noted that the issues associated with choice of slack bus were only relevant for AC load flows and was, therefore, no longer an issue for the DC approach.

One argument put forward in a response was that, given that a balance of demand and generation in a zone is desirable, the marginal approach to establishing TLFs (whether scaled or not) creates perverse incentives for both generation and demand to move to the Midlands and allocates larger TLFs for remote zones, even if those zones are largely balanced. By way of a solution to this, alternative approaches to establishing TLFs should be countenanced (with an extension to the Assessment timescale), or the current proposals should be rejected. One particular approach; the 'tracing' technique, was cited as having been adopted by the European Union for work on load flow modelling analysis. At the TLFMG it was further suggested that the preferred approach may be inappropriate for a long thin Transmission System. However, other TLFMG members suggested that the tracing technique remained unproven. It was also noted that the incentive to move to the Midlands, to some extent, arises from the volatility at the periphery of the System being amplified, as well as from the magnitude of the TLFs. The volatility element would be dampened by adopting an ex-ante, rather than an ex-post approach for TLF production.

8.1.12 Implementation

On the basis of the responses to consultation (by Parties) and to the DLIA (by the BSC Agent, ELEXON and NGC), costs and timescales have been suggested and are included in a Project Brief (see section 16). The TLFMG noted a number of key points:

- There were additional costs associated with an ex-post arrangement;
- Additional notice is required for the publication of TLFs for an ex-ante approach;
- Although not provided as a quantified impact, F-factor phasing would lead to additional cost;
- Some Parties had suggested that implementation should be synchronised with contracting rounds; and
- An initial planning appraisal suggested that the earliest implementation could be mid-November, 2003, on the basis of the assumptions given in section 16.

Some members of the TLFMG considered that taking the median of Party views on notice required was inappropriate and that a shorter period would be reasonable. It was further suggested that, although Parties had not made any distinction between P75 and P82, this view might be more appropriate for an ex-ante scheme, since it would not require changes to forecasting software. It was also noted that synchronisation with contract rounds concerned the need to avoid inefficiency (and therefore reduced achievement of Applicable BSC Objectives) associated with new contracts having to accommodate uncertainties, rather than the re-opening of existing contracts. The TLFMG, therefore concluded that two possibilities could be considered; April, 2004 or, subject to some reduced timescales for planned activities, October 2003.

The TLFMG considered the potential for shorter timescales for the TLFA procurement exercise and for the TLFA development. However, some TLFMG members expressed concern that such aspirations were unrealistic, particularly given that, for an ex-ante solution, TLFs would need to have been produced by mid-June. It was considered that, if initial TLFs would only apply until April, 2004, this implied fewer load flow studies, although it was also noted that the 50 studies undertaken for the modelling exercise had taken three months to procure and run (approximately 300 studies would required for this initial period, compared to 600 for the whole year). It was also suggested that there would be reduced benefit for an initial half year of TLFs and that waiting until April, 2004 would not constitute a material shortfall in perceived benefit. The majority of the TLFMG considered that an implementation date of October 2003 would be desirable, but it would present a riskier approach (due to the time to produce the values, publish them to market participants and approve them for use). Therefore, the TLFMG agreed that 1 April 2004 should be the recommended implementation date.

9 CONCLUSIONS & ALTERNATIVE MODIFICATIONS

9.1 Potential Alternatives to Modification Proposal P75

On the basis of the foregoing discussions, the following potential alternatives were considered in connection with P75:

Feature	**P75 Variant 1**	**P75 Variant 2**
TLF Methodology (TLFM)	'Marginal' & defined in BSC	'Marginal' & defined in BSC
TLF Calculation	Monthly Ex-ante	Monthly Ex-ante
Validity of TLFs	One Month	One Month
Zonal Groupings	Generation –TNUoS zones Demand – GSP Groups	Generation – TNUoS zones Demand – GSP Groups
Type of Flow to be Modelled	DC	DC
Network Configuration Data	Historic Intact Data	Historic Intact Data
Process for Conversion of Metered Volumes into Nodal Metered Volumes	Specified Mapping	Specified Mapping
Process for Conversion of Nodal TLFs into Zonal TLFs	'Volume-weighted' averaging	'Volume-weighted' Averaging
Process for Conversion of Half-hourly TLFs into Monthly TLFs	Time-weighted Averaging	Time-weighted Averaging
Phasing	None	Linear 'Beta' Phasing over 4 Years

9.2 Potential Alternatives to Modification Proposal P82

On the basis of the foregoing, the following potential alternatives were considered in connection with P82:

Feature	**P82 Variant 1**	**P82 Variant 2**
TLF Methodology (TLFM)	'Scaled Marginal' (i.e. scaling factor of 0.5) & defined in BSC	'Scaled Marginal' (i.e. scaling factor of 0.5) & defined in BSC
TLF Calculation	Annual Ex-ante	Annual Ex-ante
Validity of TLFs	One BSC Year (April to March)	One BSC Year (April to March)
Zonal Groupings	Generation – TNUoS zones Demand – GSP Groups	Generation – GSP Groups Demand – GSP Groups
Type of Flow to be Modelled	DC	DC
Network Configuration Data	Historic Intact	Historic Intact
Methodology for Converting Metered Volumes into Nodal Metered Volumes	Specified mapping	Specified mapping

'Averaging' Process for Converting Nodal TLFs into Zonal TLFs	'Volume-weighted' Averaging	'Volume-weighted' averaging
'Averaging' Process for Converting Half-hourly TLFs into Annual TLFs	Time-weighted Averaging	Time-weighted Averaging
Phasing	None	Linear 'Beta' Phasing over 4 Years

9.3 Alternative Modifications and Conclusions

9.3.1 Modification Proposal P75

The TLFMG agreed that 'variant 2' should constitute an Alternative Modification.

On the basis of the analysis carried out and discussions held, there was a majority view that the Proposed Modification P75 did not better facilitate achievement of the Applicable BSC Objectives. The majority judged that, on balance, the gains in the accuracy of the allocation of the costs of transmission losses (i.e. Applicable BSC Objectives (b) and (c)) would be outweighed by the un-hedgeable risk (Applicable BSC Objective (c)) and costs associated (Applicable BSC Objective (d)) with an ex-post scheme.

However, there was a strong majority view that an Alternative Modification would better facilitate achievement of the Applicable BSC Objectives, as compared to the Proposed Modification and, by a small majority, would better facilitate achievement of the Applicable BSC Objectives, as compared to the current baseline BSC. The TLFMG, by a narrow majority, believed that an ex-ante/monthly version of P75 would avoid the cost and risk associated with an ex-post/half-hourly approach. In addition, it was felt that phased implementation would smooth the impact of zonal differentiation.

9.3.2 Modification Proposal P82

The TLFMG agreed that 'variant 2' should constitute an Alternative Modification.

There was a majority view, on the basis of the analysis carried out and discussions held, that the Proposed Modification P82 would better facilitate achievement of the Applicable BSC Objectives. On balance, the majority deemed that zonal differentiation would result in a more accurate allocation of the cost of losses, thus facilitating better achievement of Applicable BSC Objectives (b) and (c). However, a strong majority opinion emerged that an Alternative Modification would better facilitate achievement of the Applicable BSC Objectives, relative to the Proposed Modification (and, therefore, relative to the current baseline BSC also). The Alternative Modification is identical to the Proposed Modification, except that it would be phased-in linearly over 4 years (the 'Beta' approach). The majority of the TLFMG judged that phased implementation would smooth the impact of zonal differentiation.

9.3.3 Other Conclusions

The TLFMG further noted a relative preference for Alternative Proposal P82 (and, indeed, that of Modification Proposal P82) over that of Alternative Proposal P75. The scaling was deemed to result in a more accurate allocation of the cost of transmission losses, fixed losses would not, erroneously, be allocated on a differential basis. The TLFMG further noted that, whilst two proposals would each be presented to the Panel, they were mutually exclusive and only one such proposal could be implemented.

10 IMPACT ON BSC AND BSCCO DOCUMENTATION

10.1 BSC

Implementation of either of the two Modifications would have significant impacts on the BSC, particularly Section T.

10.1.1 Section E: BSC Agents

Section E will have to be amended to recognise the existence of a new BSC Agent (i.e. the TLFA)

10.1.2 Section T: Settlement and Trading Charges

Both proposals would require insertion of an additional annex providing a high level description of the Transmission Factor Methodology and the Load Flow Model used to generate zonal TLFs. The Annex would include the following:

- Definitions of 'node', 'nodal TLF', 'load flow model', and 'Load Flow Model';
- An audit process for the 'Load Flow Model' (i.e. for the model actually used by the TLFA);
- Description of zones to be used;
- Description of mapping rules relating nodes to BMUs and BMUs to zones;
- Description of network data to be provided to TLFA by the Transmission Company (including obligation to do so);
- Description of data sample to be provided by CDCA to TLFA, including obligation to do so (P82 only);
- Volume-weighting methodology to convert nodal TLFs into zonal TLFs;
- Time-weighting methodology to convert half-hourly TLFs into daily/annual TLFs; and
- Phasing timetable (i.e. rate of change for Beta factor) (P82 Alternative only)

10.1.3 Section V: Reporting

An additional table to Annex V-1 ('Tables of Reports') Section V detailing the reporting requirements of the TLFA will need to be inserted.

10.2 Code Subsidiary Documents

The following existing Code Subsidiary Documents would requirement amendment to reflect the processes proposed by either of the two Modification Proposals:

- BSCP15 'BM Unit Registration' (update required to include obligation on the CRA to notify TLFA of registration of new BM Units and de-registration of existing BM Units);
- BSCP42 'Business Community' (update to section 1.6 to list TLFA in correct category)
- BSCP01 'Overview of Trading Arrangements' (update to reflect introduction of new BSC Agent and accompanying processes)

- NETA Data File Catalogue (update to include new flows from and to TLFA and changes to existing flows – i.e. new recipient of CDCA flows and revision to SAAI014 flow);
- BMRA/CRA/CDCA/SAA Service Descriptions (update to reflect new obligations on these Agents); and
- Reporting Catalogue (update to include new flows from and to TLFA and changes to existing flows – i.e. new recipient of CDCA flows and revision to SAAI014 flow)

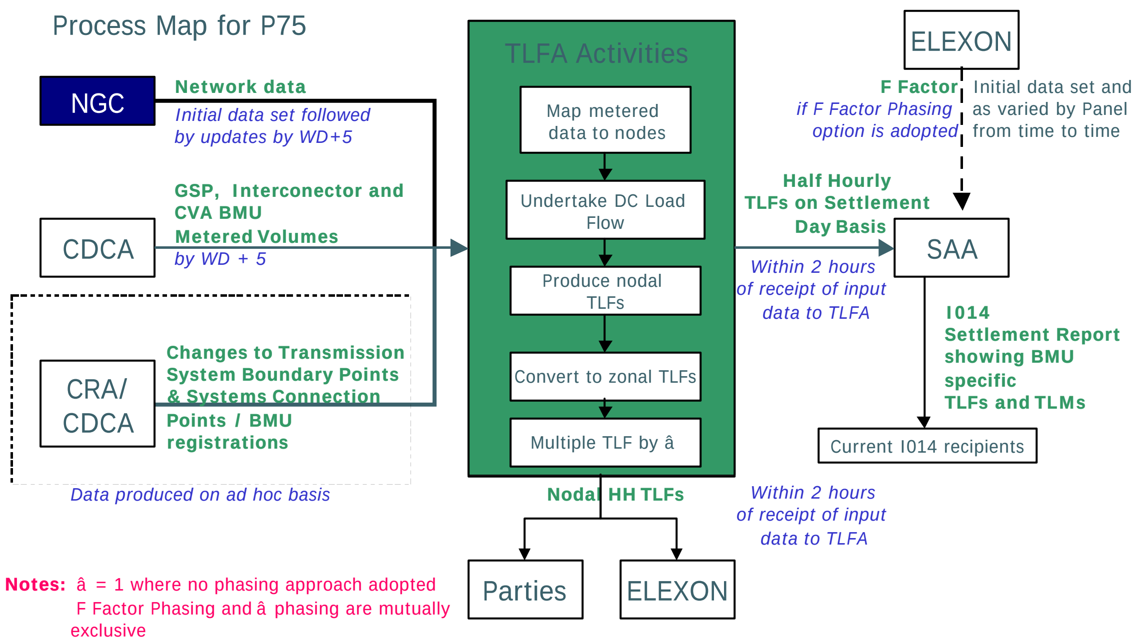
In addition to the above changes, the following new documents would need to be created:

- New BSCP for TLFA (i.e. detailing role carried out by TLFA and its interactions with Parties, ELEXON and existing BSC Agents);
- TLFA Service Description;
- TLFA User Requirement Specification;
- ‘Network Mapping Statement’ (i.e. document prepared by BSCCo specifying mapping rules); and
- ‘Load Flow Model Specification’ (established by Panel in consultation with the Transmission Company and the Authority)

11 IMPACT ON BSC SYSTEMS

11.1 Modification Proposal P75 Process Description

The diagram and text below provide a high level description of the processes required to implement P75:



The input to the TLFA system would be; GSP metered volumes, Interconnector metered volumes and non-embedded CVA BM Unit metered volumes other than those associated with Interconnectors, from the CDCA at the same time as that data is provided to the SAA for all Settlement Runs. Furthermore, on the same timescale, network data reflecting the intact network for each Settlement Day would be provided from NGC (this data would include impedance and susceptance data for lines, shunt reactances and SVCs). Also, there would be certain data provided on an ad-hoc basis; updates from the CRA/CDCA of any new Transmission System nodes and updates on changes to CVA and SVA BM Unit registrations.

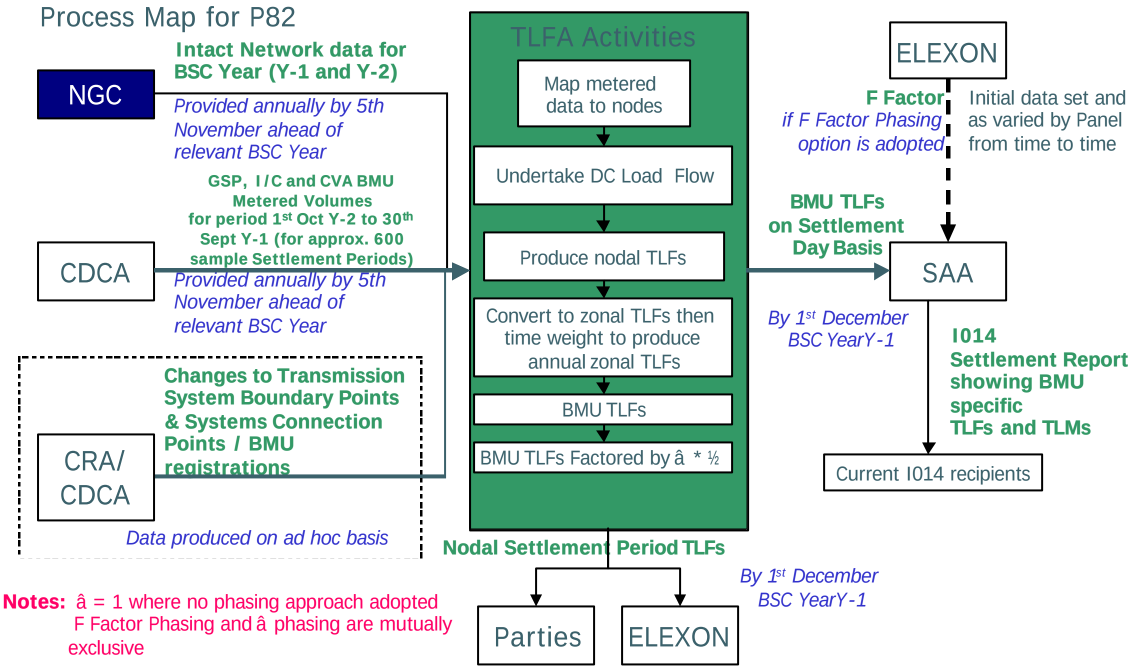
The TLFA actions would then be as follows. The metered data would need to be mapped onto nodes and a DC load flow would be run for each Settlement Day to produce nodal TLFs. These nodal TLFs would then be converted, using demand and generation weighting, to zonal TLFs (based on GSP Groups, with an extra zone for the Scottish Interconnector). By reference to the zone to node and node to BM Unit mappings, BM Unit TLFs would be established. The assumptions to set up the DC runs would be those specified in a BSC Subsidiary Document detailing the TLF Methodology (TLFM). This would be an on-line process and would require back-up and disaster recovery arrangements to be in place. Furthermore, if there were difficulties in producing certain TLF values, the most recent value for a similar Settlement Day would be used. The TLFA would maintain a BM Unit to node mapping, a GSPG to node mapping and a node to zone mapping for the network.

The TLFA would need to provide a report to the SAA, within 2 hours of receipt of input data, of BM Unit TLFs for each Settlement Day in question. The TLFA will also provide all Trading Parties and ELEXON with a batch report of nodal half-hourly TLFs, on request. There would also need to be appropriate performance reporting from the TLFA to ELEXON. Existing SAA reporting supports of BMU specific TLFs.

In order to establish the TLFA arrangements and produce initial TLFs, the following data sets would need to be populated; BM Unit to node mappings, GSPG to node mappings, and node to zone mappings. If a phased implementation were required, the uniform scaling approach would require that the TLFs produced by the TLFA should be scaled by the appropriate factor (by the TLFA) prior to being reported to the SAA.

11.2 Modification Proposal P82 Process Description

The diagram and text below provide a high level description of the processes required to implement P82:



The input to the TLFA system would be; The latest data available for a sample of approximately 600 Settlement Periods of GSP metered volumes, Interconnector metered volumes and non-embedded CVA BM Unit metered volumes other than those associated with Interconnectors, over the period from 1 November of BSC Year Y-2, to 31 October of BSC Year Y-1, by the 5 November of BSC Year Y-1, from the CDCA and data from NGC relating to an intact network for the relevant period, on the same timescale (the data would be as described above). There would also be ad-hoc data; CRA updates on Transmission System nodes and CRA updates on BM Unit registrations (CVA and SVA).

The TLFA actions would then be as follows. The metered data would need to be mapped onto nodes and a DC load flow would be run for each Settlement Period to produce nodal TLFs. Subsequently, the resulting half-hourly nodal TLFs would first be converted into half-hourly zonal TLFs using demand and generation weighting and then converted into annual zonal TLFs using time weighted averaging. Finally, by reference to the zone to node and node to BM Unit mappings, BM Unit TLFs would be established, these would then be factored by 0.5. The assumptions to set up the DC runs would be specified in a BSC Subsidiary Document detailing the TLFM. This would be a batch process and would require modest disaster recovery arrangements to be in place. The TLFA would maintain a BM Unit to node mapping, a GSPG to node mapping and a node to zone mapping for the network.

The TLFA would need to provide a report to the SAA of BM Unit TLFs, by 1 December of BSC Year Y-1 and, on similar timescales, a report to Trading Parties and to ELEXON of the nodal, Settlement Period TLFs. There would also be performance reporting provided to ELEXON. Existing SAA reporting supports of BMU specific TLFs.

In order to establish the TLFA arrangements and produce initial TLFs, the following data sets would need to be populated; BM Unit to node mappings, GSPG to node mappings, node to zone mappings and the identified sample Settlement Periods (with appropriate weightings). In order to actually create the initial TLFs, a bulk report of the sample Settlement Period CVA BM Unit metered volumes and GSP Group takes for the period of 1/11/01 to 31/10/02 (assuming implementation on or after 1 April, 2003) from the CDCA, along with intact network data for that period from NGC would be required. If a phased implementation were required, the uniform scaling approach would require that the scaling applied to the TLFs produced by the TLFA should be modified, as appropriate.

11.3 Registration

CRA would need to notify the TLFA changes to Transmission System Nodes and BM Unit registrations (i.e. registration of new units and de-registration of existing units) under both proposals.

11.4 Collection and Aggregation of Metered Data

CDCA would need to provide the TLFA with CVA BM Unit metered volumes and GSP Group Takes as input data, albeit to different timescales for P75 and P82 (see sections 7.1 and 7.2 above).

11.5 Settlement

SAA would need use zonal TLFs in the Settlement Calculations specified in Section T2 of the BSC, rather than zero as is currently the case.

11.6 Reporting

The TLFA would be required to report nodal half-hourly TLFs (i.e. the raw output of the Load Flow Model) to Parties and ELEXON, upon request. Given the large volume of data concerned, the TLFMG was of the opinion that some form of aggregated report would be appropriate. For instance, a month's worth of nodal half-hourly TLFs could be reported at a time.

The existing Settlement Report (SAA-I014), containing zonal TLFs, would continue to be distributed to Parties, the System Operator and ELEXON.

11.7 NETA Central Service Agent Costs

11.7.1 Modification Proposal P75

The NETA Central Service Agent provided the following indicative costs and timescales for implementing P75 as patch:

- Design & Build: £782,700 (ex VAT)
- Maintenance: £9,132 per month (ex VAT)
- Development Time: 22 weeks (elapsed time)

11.7.2 Modification Proposal Proposal P82

The NETA Central Service Agent provided the following indicative costs and timescales for implementing P82 as a patch:

- Design & Build: £109,100 (ex VAT)
- Maintenance: £1,272 per month (ex VAT)
- Operation: £168 per month (ex VAT)
- Development Time: 8 weeks (elapsed time)

12 IMPACT ON ELEXON

12.1 Documentation Changes

In addition to the Code Subsidiary Document changes cited in Section 6.2, ELEXON would required to make the following changes to existing documentation:

- Interface Definition Document (update to include new flows from and to TLFA and changes to existing flows – i.e. new recipient of CDCA flows and revision to SAAI014 flow);
- Business Process Model (update to show TLFA and its role within NETA processes); and
- BMRA/CDCA/CRA/SAA User Requirement Specifications (update to reflect changes in the Service Descriptions of these Agents)

12.2 Process Changes

The setting up of new Local Working Instructions (LWIs) and changes to existing LWIs are estimated to require 8 weeks of elapsed time and the expenditure of 8 man weeks of effort. Associated ongoing BSC Party and BSC Agent support is estimated to require 13 man weeks of work per year.

12.3 System Changes

TOMAS, ELEXON's market monitoring system, will require modification to replicate the changes to the BSC Central System software (principally the changes to SAA and the Settlement Report). Such changes are estimated to require 3 calendar months and the expenditure of 12 man weeks of effort. In addition, ongoing monitoring and issue resolution obligations will require 4 man weeks of work per year.

12.4 Time & Cost Implications

ELEXON estimate that implementation of the documentation, process and system changes required would take approximately man days. In addition, the changes would entail an operational maintenance effort of approximately 170 man days a year.

12.5 Procurement of TLFA

ELEXON estimates that the introduction of a new BSC Agent (i.e. the TLFA) would require a formal and competitive procurement project. Typically, completion of such a project would take approximately 5 months. Depending on ELEXON's workload at the time, and hence the need or otherwise to out-source elements of the work, a budget of between £75k to £100k would be required for the project were either of the proposals approved.

13 IMPACT ON PARTIES

On the basis of the DLIAs and consultation responses received from Parties (see Annex 4), the following systems were identified as being impacted by respondents:

- Demand forecasting;
- Billing;
- Settlement;
- Risk Management;
- Power Pricing; and
- Trading

Responses indicated that a lead-time of between 3 and 12 months would be required to implement the necessary changes. Two respondents cited costs for the additional developments required, one quoted a cost of £250,000 to £500,000 and the other a cost of £1,500,000 to £5,500,000 for P75 and £500,000 to £1,500,000.

14 SUMMARY OF TRANSMISSION COMPANY ANALYSIS

The Transmission Company provided a DLIA in relation to P75 and P82, focusing on the cost and time required to provide the TLFA with the necessary network data[9]. It noted that all cost and timescale figures are estimates subject to confirmation. In addition, the implementation timescales cited would apply only after detailed specification is confirmed and a definite instruction to proceed is given.

14.1 Provision of half hourly representative network data

The initial proposal requires daily network models updated (retrospectively) with half-hourly network configuration information. The provision of a daily network model to the TLFA, with half-hourly updates, would require the following system developments and operational procedures:

- A system change to provide an automatic facility to strip out LV and Scottish network data;
- a system to export the data in a usable format; and
- a system to provide retrospective information to the modelling agent of network reconfigurations and times and details of outages.

The provision of half-hourly network data would involve the following indicative costs:

- Development costs of £500,000 - £600,000; and
- Operational costs £50,000 - £100,000 per year.

The Transmission Company estimates that the changes would require between 6 and 9 months notice to implement depending on other commitments.

14.2 Provision of daily intact network data

The provision of an intact network model to the TLFA on a daily basis would require the following system developments and operational procedures:

- Strip out LV and Scottish network data;
- a system to export the data in a usable format; and
- a system to provide retrospective information to the modelling agent of any new transmission equipment commissioned.

The provision of daily network data would involve the following indicative costs:

- Development costs of £75,000 - £110,000; and
- Operational costs £50,000 - £100,000 per year.

The Transmission Company estimates that the changes would require between 4 and 8 months notice to implement depending on other commitments.

14.3 Provision of one intact network for the year

The provision of an intact network model to the TLFA on a yearly basis would require the following system developments and operational procedures:

[9] See Annex 4

- Strip out LV and Scottish network data; and
- a system to export the data in a usable format.

The provision of network data on an annual basis would involve the following indicative costs:

- Development costs of £10,000 - £20,000; and
- Operational costs £10,000 - £20,000 per year.

The Transmission Company estimates that the changes would require between 2 and 3 months notice to implement depending on other commitments.

15 PROJECT BRIEF

On the basis of the DLIAs received from Parties, the NETA Central Service Agent, the Transmission Company and from impacted department within the company, ELEXON has drawn up project briefs for each of the two Modification Proposals.

15.1 Modification Proposal P75

The implementation costs for P75 are as follows:

- BSC Central Service Agent development costs of £782,700; and
- ELEXON effort of approximately 500 man days.

A project brief has drawn up on the basis of the following assumptions:

<u>1 Authority Decision</u>

Assumption that the Authority delivers a positive determination the day after the December Panel meeting.

<u>2 Implementation Activities</u>

Implementation activities are based on impact assessments done in isolation without considering time specific resource constraints, other projects (e.g. P78 and CVA Release Programme) or Christmas.

<u>2a Party Lead Time</u>

Party impact assessments received report significant system development requirements. Systems identified as being impacted include demand forecasting, risk management, settlement, billing, power pricing and trading. Lead times cited ranged from 3 to 12 months, with a mid-point of 6 months. In addition, Parties would be required to develop and build a new interface with the TLFA (to receive new nodal TLF report).

<u>2b NGC System Development</u>

NGC have stated that their system developments to provide network data to the TLFA will require 4 - 8 months.

<u>2c NETA CSA Developments (i.e. Logica)</u>

Four of the BSC Systems require upgrading to support this change (CRA, SAA, BMRA & CDCA), each of which will need thorough testing to ensure that integrity is maintained. The NETA CSA DLIA indicates a 22 week development/implementation time, sequential activities include:

- Specification and documentation updates
- Detailed system design
- System development
- Unit/module testing
- System testing

2d ELEXON Produce TLFA BRS

ELEXON will require 15 working days to write and review a Business Requirement Specification for the TLFA.

2e TLFA Procurement

ELEXON believes a 5-month procurement procedure (based on EU procurement guidelines for the utility sector) is required. It should be recognise that this activity is the lengthiest and gives rise to the critical path, it is therefore an obvious target for challenge. The procurement process is the subject differing legal opinion.

2f TLFA Development

ELEXON estimates that the TLFA will require a minimum of 3 months to design and build the required systems (including any changes that need to be made to the Load Flow Model to be used) and interfaces with Parties, NGC, ELEXON and BSC Central Systems. This estimate is based on the fact that PTI, the modelling agent engaged during the Assessment Procedure, took 8 weeks to model sixty Settlement Periods of data using an 'off-the-shelf' load flow model.

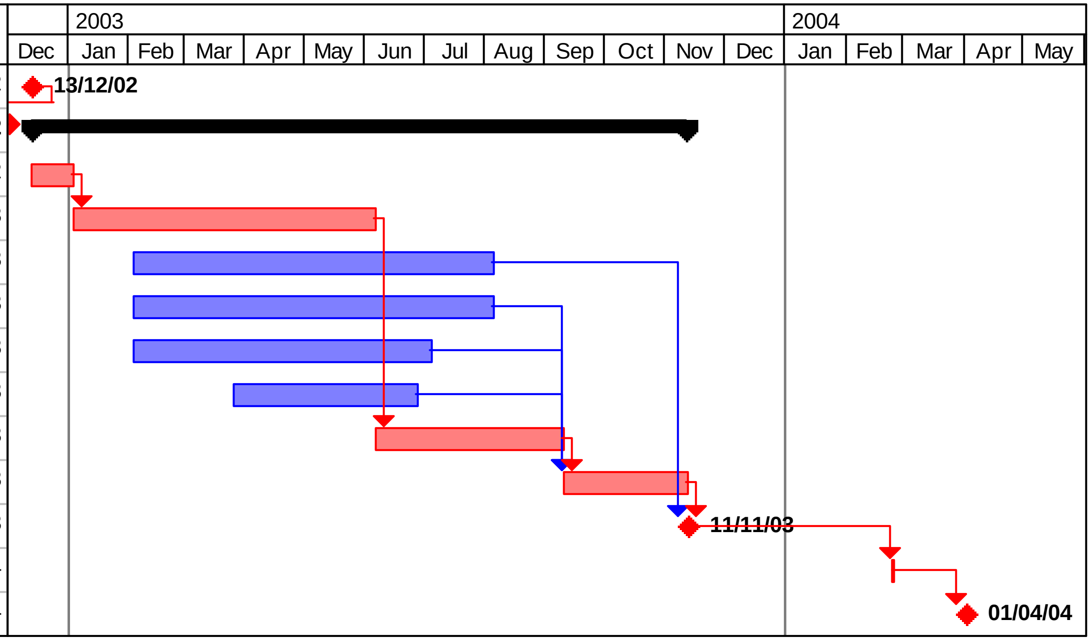
2g ELEXON documentation and Software Changes

New operational procedures will need to be developed to support the new flows and agent interfaces, this requires amendments to 15 documents, including code subsidiary documents, and a suit of 3 new documents to support the TLFA functions (including a detailed Transmission Loss Factor Methodology embedded in a new BSCP). The ELEXON managed market monitoring and reporting application TOMAS will require upgrading to recognise and process the new TLF data items. Collectively, these changes are estimated to take 3 months.

2h Industry Testing and Trialling

To ensure that the IT systems of all market participants continue to interface and communicate effectively a period of industry testing is scheduled, this will involve the new TLFA, NGC, at least one of each industry 'type' and the NETA CSA. This will provide assurance that the end to end process and supporting systems operate as expected. In addition a period of trialling will be facilitated providing an opportunity for all BSC Parties/Agents to exercise their upgraded systems with those at the NETA CSA. ELEXON estimate that testing and trialling will take 9 weeks.

Task Name	Duration	Start
Authority Decision	0 days	13/12/2002
P75 Implementation Activities	**237.5 days**	**13/12/2002**
ELEXON Produce TLFA BRS	15 days	13/12/2002
TLFA Procurement (standard)	110 days	03/01/2003
Party Lead Time (Median specified by Parties in DLIA)	131 days	03/02/2003
NGC System Development	131 days	03/02/2003
Logica System Development (CVA Release)	110 days	03/02/2003
ELEXON Document & S/W changes	67.5 days	26/03/2003
TLFA System Development (Unverified Estimate)	67.5 days	06/06/2003
Industry Testing and Trialling	45 days	09/09/2003
Earliest System Implementation Date	0 days	11/11/2003
Corresponding CVA Release	1 day	24/02/2004
1st Contract Round after CVA Release	0 days	01/04/2004



The above implementation plan suggests that the earliest possible implementation date would be 11 November 2003. However, given that both the majority of the TLFMG and consultation respondents believe that implementation should coincide with the start of a financial year and the date of a contracting round, the 1 April 2004 is recommended.

15.2 Modification Proposal P82

The implementation costs for P82 are as follows:

- BSC Central Service Agent development costs of£109,100; and
- ELEXON effort of approximately 500 man days.

A project brief has drawn up on the basis of the following assumptions:

1 Authority Decision

Assumption that the Authority delivers a positive determination the day after the December Panel meeting.

2 Implementation Activities

Implementation activities are based on impact assessments done in isolation without considering time specific resource constraints, other projects (e.g. P78 and CVA Release Programme) or Christmas.

2a Party Lead Time

Party impact assessments received report significant system development requirements. Systems identified as being impacted include demand forecasting, risk management, settlement, billing, power pricing and trading. Lead times cited ranged from 3 to 12 months, with a mid-point of 6 months. In addition, Parties would be required to develop and build a new interface with the TLFA (to receive new nodal TLF report).

2b NGC System Development

NGC have stated that their system developments to provide network data to the TLFA will require 2 - 3 months.

2c NETA CSA Developments (i.e. Logica)

Four of the BSC Systems require upgrading to support this change (CRA, SAA, BMRA & CDCA), each of which will need thorough testing to ensure that integrity is maintained. The NETA CASA DLIA indicates an 8 week development/implementation time, sequential activities include:

- Specification and documentation updates
- Detailed system design
- System development
- Unit/module testing

- System testing

2d ELEXON Produce TLFA BRS

ELEXON will require 15 working days to write and review a Business Requirement Specification for the TLFA.

2e TLFA Procurement

ELEXON believes a 5-month procurement procedure (based on EU procurement guidelines for the utility sector) is required. It should be recognise that this activity is the lengthiest and gives rise to the critical path, it is therefore an obvious target for challenge. The procurement process is the subject differing legal opinion.

2f TLFA Development

ELEXON estimates that the TLFA will require a minimum of 3 months to design and build the required systems (including any changes that need to be made to the Load Flow Model to be used) and interfaces with Parties, NGC, ELEXON and BSC Central Systems. This estimate is based on the fact that PTI, the modelling agent engaged during the Assessment Procedure, took 8 weeks to model sixty Settlement Periods of data using an 'off-the-shelf' load flow model.

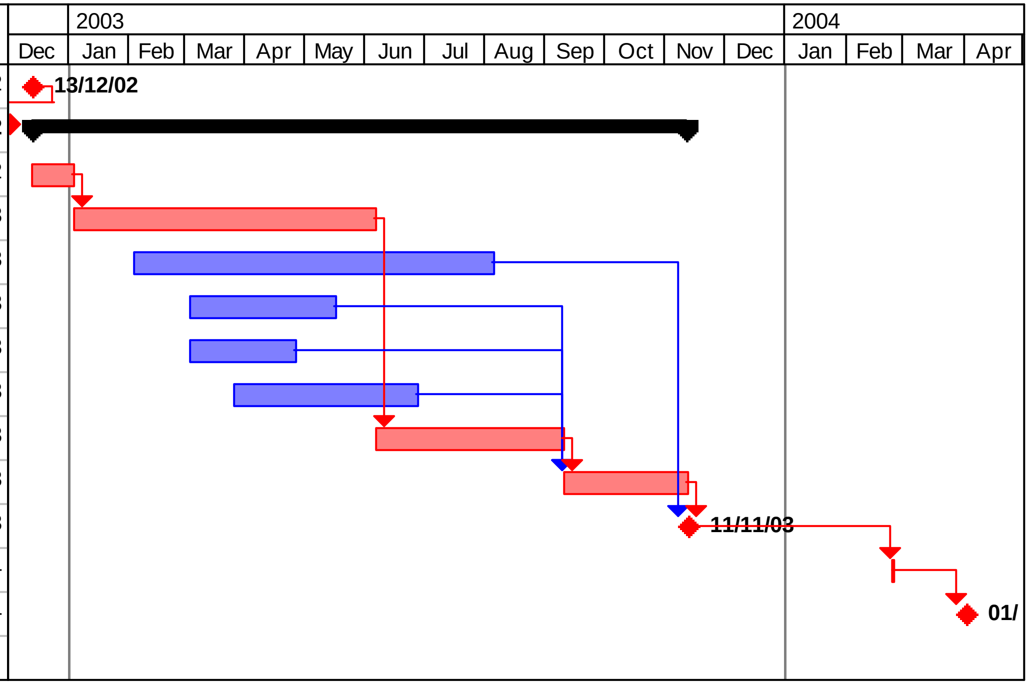
2g ELEXON documentation and Software Changes

New operational procedures will need to be developed to support the new flows and agent interfaces, this requires amendments to 15 documents, including code subsidiary documents, and a suit of 3 new documents to support the TLFA functions (including a detailed Transmission Loss Factor Methodology embedded in a new BSCP). The ELEXON managed market monitoring and reporting application TOMAS will require upgrading to recognise and process the new TLF data items. Collectively, these changes are estimated to take 3 months.

2h Industry Testing and Trialling

To ensure that the IT systems of all market participants continue to interface and communicate effectively a period of industry testing is scheduled, this will involve the new TLFA, NGC, at least one of each industry 'type' and the NETA CSA. This will provide assurance that the end to end process and supporting systems operate as expected. In addition a period of trialling will be facilitated providing an opportunity for all BSC Parties/Agents to exercise their upgraded systems with those at the NETA CSA. ELEXON estimate that testing and trialling will take 9 weeks.

Task Name	Duration	Start
Authority Decision	0 days	13/12/2002
P82 Implementation Activities	**237.5 days**	**13/12/2002**
ELEXON Produce TLFA BRS	15 days	13/12/2002
TLFA Procurement (standard)	110 days	03/01/2003
Party Lead Time (Median specified by Parties in DLIA)	131 days	03/02/2003
NGC System Development	55 days	03/03/2003
Logica System Development (CVA Release)	40 days	03/03/2003
ELEXON Document & S/W changes	67.5 days	26/03/2003
TLFA System Development (Unverified Estimate)	67.5 days	06/06/2003
Industry Testing and Trialling	45 days	09/09/2003
Earliest System Implementation Date	0 days	11/11/2003
Corresponding CVA Release	1 day	24/02/2004
1st Contract Round after CVA Release	0 days	01/04/2004



The above implementation plan suggests that the earliest possible implementation date would be 11 November 2003. However, given that both the majority of the TLFMG and consultation respondents believe that implementation should coincide with the start of a financial year and the date of a contracting round, the 1 April 2004 is recommended.

ANNEX 1 – PROPOSED TEXT TO MODIFY THE BSC

See attachments 1 & 2

ANNEX 2 – BSC AGENT IMPACT ASSESSMENTS

See attachments 3, 4 & 5

ANNEX 3 – TRANSMISSION COMPANY IMPACT ASSESSMENT

See attachment 6

ANNEX 4 – PARTY CONSULTATION RESPONSES & IMPACT ASSESSMENTS

See attachments 6,7 & 9

ANNEX 5 – COST-BENEFIT ANALYSIS

See attachments 10, 11 & 12

ANNEX 6 – PROPOSED PHASING SCHEMES

See attachments 13, 14 & 15

ANNEX 7 – MODELLING RESULTS

See attachment 16

ANNEX 8 – TERMS OF REFERENCE

See attachment 17