Stage 04: Draft Modification Report

What stage is this document in the process?

01 Initial Written Assessment

02 Definition Procedure

03 Assessment Procedure

04 Report Phase

P229: Introduction of a seasonal Zonal Transmission Losses scheme

P229 aims to allocate variable transmission losses on the GB transmission system to generators and demand customers on a zonal basis, such that allocated costs better reflect the impact on total losses. A Transmission Loss Factor (TLF) would be calculated for each BSC Season and TLF Zone to achieve this.

P229 Alternative argues all participants would have real losses associated with their operation, so TLFs should be scaled such that, in principle, the best outcome for a participant is not to be allocated any costs associated with variable losses.

The Panel recommends **rejection** of both Proposed and Alternative Modification

High Impact: Generators, Suppliers, Licence Exemptable Generators and Interconnector users

Medium Impact: The Transmission Company, ELEXON, Central Data Collection Agent (CDCA), Central Registration Agent (CRA), Settlement Administration Agent (SAA), and Balancing Mechanism Reporting Agent (BMRA)

166/04

P229

Draft Modification Report

5 March 2010

Version 0.6

Contents

About this document:

This document is the P229 Draft Modification Report. This report was updated following the Report phase industry consultation and will be considered by the Panel on 11 March 2010. The Panel will consider the consultation responses and recommendations and agree a final view on whether or not P229 should be approved by the Authority.

Any questions?

Contact:
Dean Riddell

dean.riddell @elexon.co.uk

0207 380 4366

1 Summary

Why Change?

The Code allocates volumes (and therefore costs) associated with both fixed and variable transmission losses to Parties on a uniform basis, with no regard for the location of generators or demand customers in the network.

P229 contends that this method of allocation of transmission losses does not take account of the extent to which participants give rise to losses, which is an inherent and unjustified cross-subsidy in the existing arrangements. It further contends that customers in the North and generators in the South effectively pay part of the cost of transmitting electricity from Northern generators to Southern demand customers.

The rationale for P229 Proposed is that it would remove the cross-subsidy and allow costs associated with variable transmission losses to be allocated on a more cost-reflective basis.

P229 Rationale

The Proposer believes P229 will remove a cross-subsidy and allow variable transmission losses to be allocated cost-reflectively.

Solution

P229 Proposed would introduce an annual advance calculation of Seasonal Zonal TLFs that would be applied in Settlement to better reflect Parties' contribution to the costs associated with variable transmission losses.

Alternative Solution

The P229 Alternative developed by the Group is the same as P229 Proposed, except that scaling factors would be calculated and applied to the TLFs. The aim is that the best result possible for a participant is to be allocated none of the costs of variable losses (instead of it being possible to be allocated negative losses and thereby effectively 'credited' energy, as under the Proposed).

Impacts & Costs

Implementation of P229 (Proposed or Alternative) by ELEXON would involve procurement of a new BSC Agent, the TLFA, to conduct the Load Flow Modelling required by P229.

Introduction of P229 would affect generators, Suppliers and interconnectors due to the distributional impact. The impact would vary across Parties, but most have identified impacts due to changing their systems and processes to reflect non-uniform allocation of losses.

Implementation

The recommended Implementation Date for P229 (Proposed and Alternative) is:

- 1 October 2011 if approval is received from the Authority on or before 30 September 2010;
- 1 April 2012 if approval is received from the Authority after 30 September 2010 but on or before 31 March 2011; or
- 1 October 2012 if approval is received from the Authority after 31 March 2011 but on or before 30 September 2011.

The Case for Change

It is contended the P229 Proposed Modification would remove the cross subsidy inherent in the current arrangements for transmission losses allocation. Under P229 Proposed the costs associated with variable transmission losses would be allocated to Parties on a cost reflective basis. This would lead to savings due to more efficient plant despatch due to the signals that would result from the calculation and application of TLFs.

A counterview is that introduction of P229 Proposed would cause windfall gains by some Parties and windfall losses by others, and that there is no cross subsidy at present but P229 Proposed would introduce one, which would be detrimental to competition. In addition it is argued that P229 Proposed is not more cost reflective and not all participants can respond to the signals of TLFs. It is also suggested P229 Proposed would introduce uncertainty and risk.

The argument for the P229 Alternative Modification is that it would retain some of the benefits of P229 Proposed while mitigating the distributional impacts on Parties and the uncertainty and risk. Some Modification Group members believe the Alternative solution is more cost reflective than the Proposed because it would remove the current cross subsidy while avoiding introducing a new cross subsidy, i.e. the distributional impacts, and it is consistent with the view that all participants on the Transmission System cause losses.

Other Group members reject this argument and believe the Alternative simply dilutes the benefits of the Proposed.

The Group's discussion of the responses to the P229 Assessment Procedure consultation can be found the Detailed Assessment of P229 (Attachment A). The views of respondents were in line with those of the Group. The majority of respondents believed that neither P229 Proposed nor P229 Alternative would better facilitate the Applicable BSC Objectives, but the majority believed the Alternative to be better than the Proposed.

Recommendations

The Panel's recommendation is that the P229 Proposed and Alternative Modifications should not be made because neither better facilitate the Applicable BSC Objectives compared with the existing baseline.

The Panel's **majority** view is that compared with the existing baseline P229 Proposed:

- Would be neutral with respect to Applicable BSC Objective (a);
- Would not better facilitate Applicable BSC Objective (b);
- Would not better facilitate Applicable BSC Objective (c); and
- Would not better facilitate Applicable BSC Objective (d).

The Panel's **unanimous** view is that compared with the existing baseline P229 Alternative:

- Would be neutral with respect to Applicable BSC Objective (a);
- Would not better facilitate Applicable BSC Objective (b);
- Would not better facilitate Applicable BSC Objective (c); and
- Would not better facilitate Applicable BSC Objective (d).

The Panel's majority view is that P229 Alternative would better facilitate the Applicable BSC Objectives compared with P229 Proposed.

2 Why Change?

What are Transmission Losses?

When electricity is transmitted over the Transmission System some energy is 'lost'. This lost energy is 'transmission losses'. Transmission losses are comprised of two main elements, 'fixed' losses and 'variable' losses.

Fixed losses arise in Transformers and overhead lines and do not vary significantly with power flow. Variable losses are due to the heat caused by the flow of current and vary with current flow and length of the line in which it flows. The allocation of variable losses under the BSC is the focus of P229.

Existing Transmission Losses Arrangements

Under the existing Code provisions both fixed and variable transmission losses are allocated to Parties uniformly, and independent of location, based on each Party's metered energy. The current allocation of transmission losses therefore does not take account of the extent to which individual Parties give rise to such losses.

A parameter for non-uniform allocation of transmission losses is included in the Code; the Transmission Loss Factor (TLF). But the value of the TLF parameter is currently set to zero, so it has no effect in practice. Details of the transmission losses arrangements in the Code, including the relevant calculations in Section T, can be found in Attachment A.

What is the Issue?

The current BSC arrangements allocate total transmission losses to Parties on a uniform basis, including variable losses. 45% of all losses are allocated to delivering (generating) Trading Units and 55% to offtaking (demand) Trading Units. No account is taken of the location of generators or demand customers within the network.

P229 contends that this means the cost of variable losses is allocated amongst Parties with no regard to the extent to which they give rise to them. This means demand customers located close to an abundance of generation and generators situated near a large amount of demand pay some of the costs of transmitting electricity from generators to demand customers that are isolated from one another.

In the context of the GB Transmission system, with a lot of generation currently based in the North and significant demand in the South, this means customers in the North and generators in the South pay part of the cost of transmitting electricity from Northern generators to Southern demand customers.

The Proposer believes this situation equates to an inherent and unjustified cross-subsidy in the existing arrangements. The rationale for the P229 Proposed Modification is that it would remove this cross-subsidy and enable the costs associated with variable transmission losses to be allocated on a more cost-reflective basis.

Where can I find more information?

The Detailed Assessment of P229 is Attachment A to this document. Further details of the types of transmission losses and the current Code arrangements for the allocation of transmission losses can be found in the Detailed Assessment. It also contains information on related changes, particularly P82, which was approved and partly implemented before being rejected following judicial review.

3 Solution

Summary

P229 proposes to change the arrangements for allocating transmission losses, and associated costs, across generators and demand customers on the GB transmission system. Under P229 TLF Zones would be created based on the 14 GSP Groups. Historical data would be used to annually calculate a TLF for each BSC season for each TLF Zone for the following year.

Two important points to note about P229 are the treatment of fixed losses and the absence of any mitigation:

- P229 would affect only the allocation of variable losses. **Fixed transmission losses** would continue to be allocated to Parties on a non-locational basis through the TLMO. The 45:55 split in the allocation of total transmission losses across generation and demand would be retained; and
- There would be **no mitigation** of the effects of P229. Unlike some previous losses proposals, there is no proposal for phased implementation or 'hedging' of exposure to the Zonal TLFs. The Zonal TLFs would take full effect from the first Settlement Period on the Implementation Date.

What is the P229 Proposed solution?

P229 is substantially the same as the solution proposed by P203. P229 uses Seasonal TLF values (not annual), does not include any transitional scheme/phased implementation and, unlike previous proposals, includes provisions for the treatment of offshore Transmission Systems. The P229 Proposed solution can be summarised as follows:

Load Flow Model

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

TLF calculation

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

Transmission Loss Factor Agent

Prior to the start of each BSC Year (1 April – 31 March), the Load Flow Model would be run by a Transmission Loss Factor Agent ('the TLFA'). The TLFA would calculate how an incremental increase in power injection at each Node would affect the total variable losses on the Transmission System. The output of the Load Flow Model would be a TLF value for each Node in each of the Sample Settlement Periods.

- Positive TLF values would be produced for Nodes where an incremental increase in generation (or reduction in demand) had the effect of decreasing variable losses.
- Negative TLF values would be produced for Nodes where an incremental increase in generation (or reduction in demand) had the effect of increasing variable losses.

For example, if an extra 1kWh injection at a Node increased variable losses by 0.02kWh, the TLF for the Node in that Settlement Period would be -0.02. The TLFA would average the Nodal TLFs across all Nodes in each TLF Zone by volume-weighted averaging, to give a Zonal TLF value for each TLF Zone for each Sample Settlement Period.

The TLFA would convert these Zonal TLF values to Seasonal Zonal TLFs by time-weighted averaging, calculating four Seasonal Zonal TLFs for each TLF Zone – one for each BSC Season, as defined in Section K of the Code:

- BSC Spring: 1 March – 31 May inclusive;
- BSC Summer: 1 June – 31 August inclusive;
- BSC Autumn: 1 September – 30 November inclusive; and
- BSC Winter: 1 December – 28 February inclusive (or 29 February in a leap year).

Adjusted Seasonal Zonal TLFs

The TLFA would adjust the Seasonal Zonal TLFs by a scaling factor of 0.5 such that the net volume of energy allocated via the TLFs is comparable to the volume of variable losses calculated by the Load Flow Model. These Adjusted Seasonal Zonal TLFs would be published by BSCCo no less than three months prior to their use in the TLM Settlement calculation for the applicable BSC Season.

Treatment of BM Units

Each BM Unit would be allocated to a TLF Zone by BSCCo using the Network Mapping Statement. Any question or dispute over allocation would be resolved by the Panel. The TLFA would determine the TLF value to be applied to each BM Unit in the TLM Settlement calculation for the applicable BSC Season (i.e. the Adjusted Seasonal Zonal TLF value for the relevant TLF Zone). All BM Units in a Zone would receive the same TLF value for every Settlement Period in a BSC Season.

A positive TLF would increase the TLM value used to scale a BM Unit's Metered Volume, which would be a benefit to generators and a disadvantage to Suppliers. A negative TLF would decrease the TLM value, which would be a benefit to Suppliers and a disadvantage to generators.

BM Unit-Specific TLFs

The Adjusted Seasonal Zonal TLF that applies to, and is registered against, a particular BM Unit is referred to in this document as a 'BM Unit-Specific TLF'. Note that all BM Units in the same Zone and for a particular Season would be assigned the same BM Unit-Specific TLF.

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

What about offshore connections?

Offshore nodes

As noted above, TLF Zones would be based on the geographical areas of GSP Groups. In June 2009 the BSC was amended to include provisions for offshore transmission networks (which fall outside the geographical area of any GSP Group) which will become effective at go-live in June 2010. For these offshore Nodes (including both DC and AC offshore networks and offshore networks connected to distribution systems), which are part of the Transmission System, the onshore GSP Group to which the network is connected would be the basis for allocating Nodes to TLF Zones, subject to Panel determination.

The criteria for Panel determination of the allocation of offshore Nodes is not defined as part of the solution. The aim is that offshore Nodes are allocated to the onshore GSP Group to which they are connected. If there is any doubt over which Zone an offshore generator should be assigned to (i.e. because they are connected to an offshore transmission system which connects to the onshore Transmission System in more than one GSP Group area) the Panel shall decide, applying such criteria as it sees fit and requesting such information as required.

Offshore networks connected via a Distribution System

The P229 solution provides for situations where a Distribution System is situated between an Offshore Network and the Transmission System (a so-called 'DNO Sandwich'). Because losses over Distribution Systems are not Transmission Losses they would be excluded from TLF calculation.

This would be achieved by modelling the onshore connection point of an offshore network (which is connected to a Distribution System) as connected to the GSP via which that Distribution System is connected to the Transmission System. If the Distribution System is connected to the Transmission System via multiple GSPs the onshore connection point could be modelled as connected to multiple GSPs as appropriate, with a proportion of its flow allocated to each GSP. Assignment of onshore connection points to GSPs, and the allocation of proportions of their flows to these GSPs, would be done by the TLFA using Distribution System data provided by the pertinent LDSO.

Any LDSO to whose Distribution System an offshore network connects would be required to provide to ELEXON Distribution System data that identifies which GSP(s) the energy from the offshore system's onshore connection node(s) should be considered to flow to. This information would include an estimate of the percentage of the flow that goes to each GSP, i.e. a single assumed value for each Reference Year.

High Voltage DC networks

At present the Transmission System does not include any High Voltage DC (HVDC) networks. Such technology may be introduced in the future, as generation (e.g. wind farms) are built further from shore, and that the techniques used to model losses on such networks would differ from those used for the AC Transmission System. However, because it will be some years before any such HVDC system enters operation, the Group concluded it would be appropriate to consider this issue when and if required, when more information will be available on how such networks would be operated. Therefore offshore HVDC networks are not included in the P229 solution. A separate Modification would be needed to incorporate HVDC networks, when the date and nature of their introduction and the details of their operation and technical characteristics are known.

Summary

The Group developed a P229 Alternative solution with the aim of preserving the benefit of allocating transmission losses more cost reflectively, as under P229 Proposed, while reducing the distributional impact on Parties in comparison with P229 Proposed. The Alternative is the same as P229 Proposed, except for the addition of the calculation of a scaling factor for each Season.

Under the Proposed Modification, Seasonal Zonal TLFs are adjusted by a scaling factor which is fixed at 0.5. This means the volume of energy allocated in the Sample Settlement Periods via the TLFs is comparable to the volume of variable losses calculated by the Load Flow Model.

The Alternative solution replaces the fixed scaling factor of 0.5 with an annually calculated scaling factor '**β**' for each Season. This factor is applied to Seasonal zonal TLF values before they are used in Settlement.

Scaling factor, β

The intent of applying the '**β**' scaling factor is to avoid BM Units being credited with energy due to the application of Zonal TLFs via their TLM. In practice the Alternative aims to achieve this on average, but will not achieve it in every circumstance (i.e. some relatively small credits will occur).

The Alternative does not alter the Code's treatment of BM Units in Trading Units whereby BM Units with opposite flow direction to the Trading Unit as a whole may receive a benefit compared with the main direction. This following equations show how the scaling factors $\boldsymbol{\beta^+_j}$ and $\boldsymbol{\beta^-_j}$ are calculated to achieve the intent of P229 Alternative in a given Settlement Period (j):

$$\beta^+_j = \min(1, \alpha * VL_j / [\, Max(TLF) * \Sigma^+(QM) – \Sigma^+(TLF*QM) \,]\,)$$

$$\beta^-_j = \min(1, (1-\alpha) * VL_j / [\, Min(TLF) * \Sigma^-(QM) - \Sigma^-(TLF*QM) \,]\,)$$

$$\beta_j = \min(\beta^+_j , \beta^-_j)$$

Where:

- α is the parameter (equal to 0.45) defined in Section T2.2.1(b) of the Code;
- VL_j is the level of Variable Losses in the Settlement Period;
- Max(TLF) and Min(TLF) are the maximum and minimum unscaled Zonal TLF values for any BM Unit in that period;
- Σ^+(QM) and Σ^-(QM) are the total metered volumes for BM Units in delivering and offtaking Trading Units respectively; and
- Σ^+(QM*TLF) and Σ^-(QM*TLF) are the sum of $QM_{ij}*TLF_{ij}$ over delivering and offtaking Trading Units respectively.

The equations cap the scaling factors at 1, so that they would not scale up any zonal TLFs (i.e. in the event of division by a small number or zero, as might occur if the spread of TLFs was very small).

How would the Alternative solution work?

Each year the TLFA calculates a single average scaling factor for each Season to cover delivering and offtaking BM Units. This calculation would be done ex-ante, similar to the annual process for calculation of zonal TLFs. So the TLFA can calculate and apply scaling factors, P229 Alternative requires that, in addition to the requirements of P229 Proposed, the following process is carried out:

1. TLFA estimates the total variable losses (in accordance with the methodology in the LFM Specification) in each Sample Settlement Period used for zonal TLF calculation (as part of the calculation of TLF values);
2. TLFA receives the total Metered Volumes for each Zone from ELEXON, split by delivering and offtaking Trading Units[1], to use in scaling factor calculation. Includes Zonal Delivering Metered Volume (QM^{+}_{Zj}) and Zonal Offtaking Metered Volume (QM^{-}_{Zj}) for each Zone and Sample Settlement Period. This information will be sent in a file to the TLFA (the data in the file will be sourced from the SAA-I014 Settlement Report which ELEXON receives from the SAA and loads into the TOMAS system);
3. TLFA determines a scaling factor for delivery and a scaling factor for offtake for each Sample Settlement Period based on the use of Seasonal zonal TLFs;
4. TLFA calculates four time-weighted average Seasonal scaling factors. These overall scaling factors are the average of the minimum of the two scaling factor values in each Sample Settlement Period, as described above (in point 3.); and
5. TLFA applies the scaling factors to Seasonal zonal TLFs before they are input into central systems. Note that because the scaling factors would be incorporated into TLF values before the values are provided to the CRA, there is no impact on central systems (e.g. CRA, SAA or BMRA).

[1] The volume data for each boundary node does not explicitly distinguish flows by BSC Trading Unit.

Why was it done?

Cost-benefit analysis was conducted by independent consultants to help the Group, the Panel and the industry to assess the merits of P229. The Group believed that an expert and independent analysis of the costs and benefits associated with P229 would help them conduct a thorough assessment of P229 and would assist them in considering P229's impact on facilitation of the Applicable BSC Objectives.

This section summarises what was done for the P229 CBA and gives an overview of the results; further information and description of the P229 CBA work can be found in Attachment A. The full P229 Proposed CBA Report and P229 Alternative CBA Annex are also available on the P229 webpage.

What is cost-benefit analysis?

Appraising a proposal by quantifying and comparing its costs and benefits, in order to identify the best course of action.

The aim is to judge the worth of a proposal relative to the status quo.

What was done?

The Group agreed the requirements for the P229 CBA. These requirements addressed areas for improvement identified in the critique, by the Brattle Group on behalf of Ofgem, of the CBA for previous losses Modification Proposals.

A notable change from previous CBA was that a full, hourly modelling approach was used to produce evolved TLFs, in contrast with the 'snapshot' approach used previously. In addition the P229 CBA also considered environmental impacts, following the direction that impacts on the environment should be considered under the BSC Modification process. P229 was the first BSC Modification to include assessment of environmental impact.

Methodology

The P229 CBA covered both the P229 Proposed Modification and the P229 Alternative solution. The CBA consisted of two main elements; Modelling evolved TLFs over a defined analysis period of ten years, and a CBA assessment which used the results of the modelling to quantify various impacts of introducing P229.

The CBA modelled:

- A **'base-case'** representing the development of the market over the ten-year analysis period without the introduction of P229 (i.e. based on the current uniform allocation of transmission losses with zero TLF values); and
- A **'change-case'** identical to the base-case except that it includes P229 Seasonal zonal TLFs.

The CBA consultants developed the assumptions and input information used in the modelling in accordance with the requirements specified by the Group. The impact of P229 Proposed was identified by comparing the results of the base- and change-cases; since the only difference between the two is the introduction of P229 Proposed, any difference in the results is ascribed to P229.

Scenarios

In addition to a central reference change-case, the CBA consultants modelled various scenarios designed to test the sensitivity of the CBA results to changes to key factors.

The reason for this is that it is unrealistic to expect that the market will develop exactly in line with the CBA consultant's best-estimate predictions. Examining the sensitivity of the CBA results to plausible variations in market conditions ('sensitivity scenarios') means the impact of deviations from the predicted development of the market can be better understood. This increases the robustness of the CBA and informs assessment of P229.

The sensitivity scenarios examined were:

1. **Reference Scenario**: Most likely or 'central' scenario; P229 Seasonal zonal TLFs applied to the best-estimate of market developments.
2. **High Gas Price Scenario**: Increased gas prices; all other fuel prices and assumptions unchanged relative to the Reference scenario.
3. **Low Gas Price Scenario**: Decreased gas prices; all other fuel prices and assumptions unchanged relative to the Reference scenario.
4. **Volatile Fuel Price Scenario**: All fuel prices varied from year to year with no consistent pattern; all other assumptions unchanged relative to the Reference scenario.
5. **Aggressive Offshore Wind**: More Offshore generation added; all other assumptions unchanged relative to the Reference scenario.
6. **Alternative Nuclear**: Nuclear generators added; introduction of some non-nuclear generators were consequently delayed, all other assumptions unchanged relative to the Reference scenario.

Further details about these scenarios and why they were selected by the Group can be found in Attachment A. The Reference scenario was examined for the P229 Alternative (see CBA annex).

The Group's views

The Group agreed that the CBA fulfilled the Group's specified requirements and endorsed the CBA as robust and fit for the purpose of assisting the Group in its assessment of P229.

Though they agreed the CBA was robust and fit for purpose, a majority of the Group were concerned with two main areas of the CBA. First, they believed the Weighted Average Cost of Capital (WACC) value used to discount the modelled costs and benefits was too low. Second, the offshore generation developments applied in the CBA modelling were believed to be significantly underestimated. These Group members were concerned that the offshore generation modelled did not account for the full amount indicated for connection in Rounds 1 and 2 of offshore development, or the significantly larger developments planned for Round 3, in either the P229 Proposed Reference Change Case or the Aggressive Wind sensitivity Change Case.

The Group addressed the WACC concern by determining its own WACC value and applying it to the cost-benefit results. The CBA consultants noted the Group's offshore generation concern, and maintained that in their expert opinion the assumptions of the model were robust and, in their view, a realistic representation of future developments in their assessment and at the time of undertaking the analysis. Despite this the Group's concern remained, and they agreed that the best course was to document their concerns and the consultants' response in order that both can be considered as part of assessment of P229.

In response to the Group's continuing concern the CBA consultants acknowledged that there have been developments since the analysis, with the biggest being in the future development of offshore wind generation (as noted by the Group). However, in their opinion little truly solid new information is available. Although it is anticipated that a lot of offshore wind generation will be created, there is still considerable uncertainty around where new generators will actually connect, precisely when they will connect, what the generation profiles will be, etc. They believe that this cannot be considered to invalidate the CBA.

The consultants did note that, generally, the accuracy/usefulness of any analysis of this sort (i.e. using assumptions/estimations and forecast modelling) tends to decrease as real world events enter the modelled period and actual circumstances align with the model or diverge from it. However, they did not believe that this effect was particularly pronounced with regard to the P229 CBA.

A Group member questioned the consultants' response, noting that they believed that the uncertainties identified could have been overcome early in the P229 Assessment Procedure (January 2009) and incorporated into the CBA. This member believed that the joint Crown Estate and National Grid report of December 2008 detailed where new generation will connect, that an equitable and transparent methodology could have been used to approximate when generation would connect and queried why generation profiles would be substantially different from those used for offshore generation included in the CBA.

The independent cost-benefit analysis was commissioned by the Group because they could not perform such analysis itself. Therefore the Group set out requirements for the CBA but left final decisions on methodology to the CBA consultant's independent expertise. The requirements specification agreed by the Group and used to procure the CBA consultant and set its terms of reference did not include a requirement to model a particular amount of offshore wind, but rather that the consultants should use their expertise and take into account all relevant information.

A minority of the Group was also concerned that future offshore HVDC infrastructure was not modelled as part of the CBA, since its development was indicated by the ENSG report and the P229 load flow modelling exercise (Task 10) indicated that offshore HVDC elements could have a significant impact on TLFs (notwithstanding that this was an approximation of offshore HVDC elements and not intended to be representative of actual developments).

Details of the Group's concerns and discussions, its alternative WACC value and resultant cost-benefits, and the CBA consultants' explanation of the offshore approach employed in the P229 CBA can all be found in Attachment A.

What did the CBA show?

The results of the CBA are covered in detail in Attachment A, and can be found in full in the P229 Proposed CBA Report and P229 Alternative CBA Annex on the P229 webpage. This section summarises the key results and overall findings of the P229 CBA at a high level.

The table below shows the overall cost-benefit for the central Reference scenario (P229 Proposed), the five sensitivity scenarios and the Reference scenario (P229 Alternative). These figures were produced by applying cost-benefit analysis methods to the results of the modelled 10-year analysis period (2011-2021) and are net of all estimated implementation and operational costs.

The CBA figures are net present values produced by discounting the modelling results using the central post-tax WACC of 4.2%. The analysis indicated very significant benefits associated with reductions in NOx and SOx emissions, and the benefits are presented with and without these emissions effects, so Parties can consider how much weight to give them.

The distributional impacts on different types of participants, depending on their location, are not shown in the table below, and are covered separately.

LE concluded that the net benefits of Proposed Modification P229 would be positive and significant over the analysed period. Benefits associated with demand response were relatively small compared with the benefits of generation response. The cost-benefit was positive for all scenarios without the inclusion of benefits associated with reduced SOx/NOx emissions. Including SOx/NOx effects generally had the effect of significantly increasing the benefits of a scenario, except for the high gas price sensitivity scenario where inclusion of SOx/NOx causes the cost-benefit to become negative. This appears to indicate the emissions reductions are a consequence of the effect of a losses scheme on emitting generators in their current locations of generation, rather than a general result.

Note that the total benefits shown in the table below are the net present value of benefits over the ten year modelled period.

Total benefits associated with each CBA scenario (figures rounded to nearest £0.5m)

	Proposed (reference)	**High gas**	**Low gas**	**Volatile fuel**	**Wind**	**Nuclear**	**Alternative**
Benefits, £m (no SOx/NOx)	46	98	4	46.5	52	39	12.5
Benefits, £m (inc. SOx/NOx)	275	-20	73	173	266	222	76
Demand benefits, £m	2	3	0.5	1.5	2	2	0
Total benefits £m	**277**	**-17**	**73.5**	**174.5**	**268**	**224**	**76**

Further details of the elements that comprise the generation response benefits, the CBA conclusions and the methods used in the P229 CBA can be found in the summary in Attachment A and in the P229 CBA Report.

The table below shows the distributional impact of P229 under the various scenarios in terms of transfers between participant types in Northern regions and those in Southern regions. The figures for supply and generators are the amounts that would be 'paid' collectively by some Parties and 'received' by other Parties. The **net** transfer would be zero (i.e. all money paid by one set of participants is received by the others).

However, the overall magnitude of transfer shown in this table is the **sum** of the magnitude of the amount paid *and* the magnitude of the amount received, for both supply and generators (magnitudes of transfers for supply and generators is shown in brackets beneath the total). Though it may appear to be 'double counting' the transfers, the reason for using this value is that the Group believes it best represents the true distributional impact on Parties. This is because any amount paid by a group of participants is a disadvantage to them, and any amount received by a group of participants is a benefit to them.

Therefore the Group believes the measure of the relative benefits or disadvantages that Parties would experience is the total of the quantified benefit for some and the quantified disadvantage for others. This applies whether the distributional impact is regarded as removal of an existing cross-subsidy (i.e. a positive effect) or the introduction of windfall gains and losses (i.e. a negative effect).

Note that the distributional impact values shown in the table below are annual (i.e. these values are calculated for the year 2001-12 but distributional impacts like this would occur each year).

Annual (2011-12) distributional impact of each CBA scenario (figures rounded to nearest £0.5m)

	Proposed (reference)	**High gas**	**Low gas**	**Volatile fuel**	**Wind**	**Nuclear**[2]	**Alternative**
Supply, £m (South to North)	37	48	15.5	43	39	37	16
Generators, £m (North to South)	31	41	14	36	33	31	13
Magnitude of transfer, £m	**135** (74+61)	**178** (96+82)	**58** (31+27)	**158** (86+72)	**143** (78+65)	**135** (74+61)	**58** (32+26)

Details of the zones included in the 'North' and 'South' regions, and graphical representations of the distributional impacts, can be found in Attachment A.

[2] Distributional impact under nuclear scenario identical to Reference scenario as there is no difference between these two scenarios in the first year (2011 - 12) of the analysis period.

6 Load Flow Modelling

Why was it done?

A Load Flow Modelling exercise was conducted for P229 in order to calculate Seasonal Zonal TLFs using the same methodology that would be applied in live operation of P229, based on actual network data and using historic metered volume data. The purpose of this was to establish baseline TLFs that could be used to test the CBA consultant's approach for modelling future TLFs, to assess the sensitivity of TLF calculation to a range of different factors and to identify any potential issues with the load flow modelling approach proposed by P229.

What was done?

The Load Flow Modeller first established baseline TLFs via defined load flow modelling procedures using network information provided by National Grid and Metered Volume data from ELEXON. Baseline TLFs are TLFs produced without any manipulation of the input data and simulate the production of TLFs operationally using actual data.

The modeller then calculated TLFs with various changes made to the modelling methodology, network information and/or Metered Volume data in order to examine how sensitive TLF production was to these changes. This was done by comparing them to the baseline TLF results. The sensitivities investigated were:

- Temporal variability of TLFs;
- Seasonal Average Nodal TLFs compared with Seasonal Average Zonal TLFs;
- Interconnector flows (French and Moyle);
- Participants responding to signals;
- Effect of demand/generation relocation on overall heating losses;
- Breakdown/withdrawal of plant;
- Intermittent generation;
- Inclusion of Offshore Transmission nodes; and
- Impact of significant offshore developments (large offshore delivery, new interconnectors and offshore HVDC circuits).

Further details of these tasks can be found in the P229 Load Flow Modelling report, which is available on the P229 webpage. ELEXON produced TLMs for selected modelling tasks.

What did the Load Flow Modelling show?

The results of the Load Flow Modelling were generally in line with intuitive expectations and the indications of previous modelling exercises. P229 would result in TLFs that vary on a geographic basis, which would cause TLMs to vary geographically also.

The new elements of investigation were the inclusion firstly of existing offshore nodes as part of the Transmission System, to simulate introduction of Offshore Transmission, and the inclusion of large scale offshore generation and offshore networks to approximate potential long term offshore developments.

The modelling results showed that approximating the inclusion of present levels of offshore generation as part of the Transmission System does not have a significant effect on TLFs. However, the modelling results indicated that the inclusion of large offshore generators, new interconnectors and HVDC links could have a large impact on TLFs.

Impacts

Implementation of P229 would impact a range of ELEXON departments including Change Implementation and various operational teams.

No significant impacts on existing BSC Agents have been identified, but implementation would involve some work by ELEXON service providers to effectively reinstate the partially implemented P82 functionality. Implementation of P229 would also include procurement of a new agent, the TLFA, and the appointment of a Load Flow Model Reviewer.

Respondents to the P229 industry Impact Assessment noted that their systems and processes reflect the current uniform allocation of losses; changing these to reflect Transmission Losses allocation under P229 would be the source of most of the impacts upon them.

The estimated costs to ELEXON and BSC Parties to implement P229 are shown below. Further details of ELEXON activities, Party impacts and other impacts such as changes to the Code and other documentation, and the impact on the BSC Panel, can be found in the Detailed Assessment (Attachment A).

Full details of the responses to the P229 IA can be found on the P229 webpage.

Estimated Costs

ELEXON Cost		ELEXON Service Provider cost	**Total Cost**
Man days	Cost		
350	£84,000	£31,000	**£115,000**

Note that these estimated costs include procurement of the TLFA but not any implementation or operational costs directly applicable to the TLFA itself.

Indicative industry costs
11 Parties responded to the P229 industry Impact Assessment, identifying a range of impacts. Identified costs were generally around **£200,000 per Party** (where costs were estimated). Several Parties identified minimal impacts, the cost of which would be absorbed into the cost of **business as usual** activities. Two respondents identified significant system impacts; one of these estimated costs of around **£300,000 - £600,000**.

Implementation Approach

The Group agreed that P229 should be implemented on either 1 April, to coincide with Parties' annual contractual rounds, or 1 October in order to align with mid-yearly contract rounds. This would allow Parties to take into account the effect of TLFs in their contracts.

Seasonal TLFs must be made available to Parties at least 3 months before being used in Settlement and the results of the P229 Impact Assessment indicate that most Parties require 6-9 months to implement P229. Therefore an implementation lead time of 12 months in total would allow most participants to complete their own implementation activities prior to receiving the first TLFs.

A twelve month P229 implementation timescale would include TLFA procurement and Load Flow Model Reviewer appointment; establishment and adoption of the Load Flow Model by the TLFA; development of TLFA systems, processes and documentation; calculation of Adjusted Seasonal Zonal TLFs; and the publication of Adjusted Seasonal Zonal TLFs to Parties 3 months before they are used in Settlement. Parties would effectively have nine months to amend their own systems, processes and documentation before TLFs are first published.

Implementation of P229 would be not be 'phased' in any way, i.e. there would be no gradual linear introduction of non-zero TLFs, or 'grandfathering' scheme limiting application to above a certain volume of energy, as proposed for some previous Losses Modification Proposals.

The final P229 Modification Report will be issued to the Authority in March 2010. The Group noted that a 1 October implementation of P229 would be more complicated than a 1 April implementation (though timescales would not be affected) due to the need to apply half the normal TLFs for the year, but the Group believed that this would not cause any material issues and that if it was determined that P229 is superior to the baseline it should be implemented as soon as is practicable.

Though they felt it was unlikely that a decision could be made by 1 October 2010, the Group wanted to allow the most flexibility possible in P229 implementation, so decided to include 1 October 2010 as a decision date. However, they also believed it would be prudent to include two other decision dates which they regard as feasible.

The Group therefore recommend the following Implementation Dates for P229 (Proposed and Alternative):

- 1 October 2011 if approval is received from the Authority on or before 30 September 2010;
- 1 April 2012 if approval is received from the Authority after 30 September 2010 but on or before 31 March 2011; or
- 1 October 2012 if approval is received from the Authority after 31 March 2011 but on or before 30 September 2011.

Group discussions

The detailed discussions of the Group can be found in Attachment A. The Group's discussions covered the analysis carried out to support assessment of P229, the impacts of P229 and responses to the P229 Assessment Procedure industry consultation, and the effect on the facilitation of the Applicable BSC Objectives. Details of the Group's initial views prior to consultation, the responses to the industry consultation and the Group's further discussions can be found in Attachment A.

This section summarises the final conclusions of the Group with regard to the impact of P229 on the Objectives.

Note that references to 'majority' or 'minority' in all the tables below apply to the view on whether the Applicable BSC Objective in question would benefit overall. The summaries capture all views provided by Group members, but not all Group members that ascribed to a particular view necessarily agreed with every argument put forward in support of that view.

Proposed vs baseline

The Group agreed by majority that P229 Proposed would not better facilitate the Applicable BSC Objectives overall compared with the current baseline.

Applicable BSC Objectives - Pros and Cons		
	Benefits	**Disadvantages**
(a)	Majority: None identified Minority: • Would remove discrimination in the current allocation of variable losses	Majority: None identified Minority: • Would introduce discrimination into the allocation of variable losses
(b)	Minority: • More efficient despatch due to cost signals allowing variable losses to be taken into account • More efficient market entry/exit due to cost signals allowing variable losses to be taken into account in decisions on where to locate new plant or whether to continue/cease operation of existing plant (though a relatively small factor in such decisions) • Production savings and reduction in variable losses due to reduced generation because of more efficient despatch (as first bullet), also resulting in environmental benefit by reducing emissions	Majority: • Benefits due to P229 Proposed are uncertain and would be offset by the additional complexity it would introduce to the arrangements • Inherent inaccuracies in the methodology for calculating TLFs (and hence TLMs) mean P229 Proposed would not be cost-reflective and would not give a more accurate and appropriate allocation of losses • Locational signals are already provided by TNUoS charges and cost signals from P229 Proposed would interfere with this existing mechanism • Would have a detrimental effect on investment, including investment in renewable generation projects, which would have a negative environmental impact • Potential impact on security of supply

(c)	Minority: • Removes cross-subsidy inherent in current uniform allocation of variable losses • Allocates variable losses on a more cost reflective basis than the baseline which would promote competition • Produces cost signals that would better reflect participants contribution to variable losses, which would enhance competition and reduce overall variable losses	Majority: • Causes distributional transfer between market participants based on type and location which are windfall gains and windfall losses, to the detriment of competition • Transfer is disproportionate to any benefit of P229 • Not cost reflective of contribution to variable losses because it allocates negative variable losses, whereas all participants on the system cause losses • Introduces a new cross-subsidy because some participants benefit from being credited with energy, while others would be penalised by being debited energy • Disproportionate impact on classes of participants who cannot respond to signals: demand, renewables, combined heat and power (CHP) plant and nuclear generators • Inherent inaccuracies mean it does not guarantee more accurate and appropriate allocation, so rather than removing the existing cross subsidy, it would create a new, less transparent cross subsidy • Socialisation of losses within zones would give inappropriate market entry/exit signals • Socialisation within zones unfairly increases the burden to existing generation when a new generator connects with high losses (as these are currently socialised amongst the entire GB) • Negative impact on all investment due to introducing uncertainty and unpredictability into the allocation of transmission losses over the lifetime of the investment, which needs to be factored into investment decisions • Negative impact on investment in renewables due to increased cost of investment in unfavourable zones • Discriminates between new and existing generators • Additional complexity creates a barrier to market entry

(d)	None identified Minority: • Neutral because no significant additional expenditure or complexity	Majority: • Implementation and operation would add cost and complexity to the administration of the Code • No Code defect so any additional cost or complexity is not warranted

Alternative vs baseline

The Group agreed by majority that P229 Alternative would not better facilitate the Applicable BSC Objectives overall compared with the current baseline.

Arguments applied to the Proposed were generally applicable to the Alternative, but the magnitude of impacts (both benefits and drawbacks) is reduced. Therefore only the **additional** arguments applied to the Alternative are shown in the table below, though these should be considered in conjunction with the arguments above relating to the Proposed against the baseline.

Applicable BSC Objectives - additional Pros and Cons under Alternative		
	Benefits	**Disadvantages**
(a)	No additional points identified	No additional points identified
(b)	Majority: No additional points identified One member: • Benefits are uncertain but risk is managed by scaling methodology	Majority: No additional points identified One member: • Additional inaccuracy of scaling i.e. arbitrary adjustment of losses to avoid crediting energy to BM Units, means not cost-reflective
(c)	Majority: No additional points identified Minority: • **Partially** removes the cross-subsidy inherent in the current uniform allocation of variable losses • Risk of windfall gains/losses sufficiently mitigated by use of scaling factor to cap benefit for individual generators at zero allocation of variable losses; therefore a net benefit for competition	Majority: No additional points identified One member: • Additional inaccuracy of scaling, i.e. arbitrary adjustment of losses to avoid crediting energy to BM Units, reduces the cost reflectivity of the allocation of losses
(d)	No additional points identified	No additional points identified

Alternative vs Proposed

The Group agreed by majority that P229 Alternative would better facilitate the Applicable BSC Objectives compared with P229 Proposed.

The Group agreed by majority that when comparing the Proposed and Alternative there would be a neutral impact on Objectives (a) and (d) and that the Alternative would better facilitate Objectives (b) and (c). Overall the Group by majority considered the Alternative better than the Proposed.

Applicable BSC Objectives - benefits of Proposed and Alternative		
	Arguments for Proposed	**Arguments for Alternative**
(a)	Majority: None identified	Majority: None identified One member: • Alternative would be neutral whilst Proposed would introduce discrimination into the allocation of variable losses
(b)	Minority: • More efficient operation of Transmission System due to better despatch • Benefits of reduced losses (i.e. savings due to reduced generation and environmental benefits) greater under P229 Proposed • Contains fewer sources of inaccuracy	Majority: • More cost reflective than the Proposed (i.e. reflects that all participants contribute to losses) which would lead to more efficient operation of Transmission System as decisions made on more cost-reflective basis • Negative impacts are reduced compared with the Proposed (particularly on model accuracy and investment)
(c)	Minority: • More cost reflective and sends the right signals to participants (compared with the Alternative which sends diluted signals) • More properly allocates variable transmission losses to participants • Contains fewer sources of inaccuracy	Majority: • More cost reflective; reflects that all participants contribute to losses (so none should be allocated negative losses) and does not introduce new cross subsidies • Reduces magnitude of windfall gains/losses relative to Proposed • Mitigates risks of windfall gains/losses, inappropriate allocation for some zones/times and uncertainty of benefits realisation under P229 Proposed • Negative impacts are reduced compared with the Proposed (particularly on model accuracy and investment)
(d)	Majority: None identified One member: • Proposed would be neutral whilst the Alternative would introduce the additional complexity of the scaling methodology for no benefit	Majority: None identified One member: • There is no defect in the Code, and while both Alternative and Proposed would not better facilitate (d) the effect of the Proposed would be to move further from the baseline

9 Initial Panel Discussions

The Panel considered the P229 Assessment Report on 11 February 2010. The majority view of the P229 Group was that, with reference to the impact on the Applicable BSC Objectives, neither P229 Proposed nor P229 Alternative was better than the existing Code baseline. The Group therefore recommended in the Assessment Report that neither P229 Proposed nor Alternative should be made. By majority the Group considered P229 Alternative to be superior to P229 Proposed, though neither was better than the baseline.

After considering the Group's views and discussions, the views of respondents to the P229 Assessment phase consultation and Impact Assessment, and the results of the analysis conducted to support assessment of P229, the Panel agreed with the Group's recommendations by a strong majority.

Panel's consideration of Assessment Report

The Panel discussed the results of the P229 Cost Benefit Analysis and the modelling done for the CBA. A Panel member commented that a limitation of the modelling was that it was necessary for it to consider the actions of market participants as occurring in the environment of a 'perfectly competitive' market. The member acknowledged this was an unavoidable characteristic of modelling in this manner, but noted that it means contracts between participants are not taken into account. Contracts between participants would limit their ability to change their operations and despatch in response to the signals from TLFs, meaning participants will not always behave in the manner predicted by a perfectly competitive and unconstrained model. The member believed that because of this the CBA overestimated the benefits of P229, as the benefits are primarily due to improved despatch by participants.

A Panel member was intrigued that the effect of all the CBA sensitivity analysis scenarios was to lower the overall benefits of implementing P229. They would expect that some alternative scenarios around the central case to increase the benefits and others to decrease them. The member also noted that demand had reduced more than would have been predicted at the outset of the CBA modelling, and no sensitivity scenario covered this fall in demand.

Another member agreed, but noted that the overall benefits with the effect of SOx/NOx emissions excluded follow a more 'conventional' pattern, with most being of a comparable magnitude to those of the central scenario while some are greater and some smaller. The member believed that this implied the counterintuitive pattern was driven by the SOx/NOx element.

A Panel member considered the Group's discussions around the WACC value used in the calculation of the net present value of the forecast benefits, firstly noting that a huge WACC value would need to be applied to cause the benefits forecast by the CBA to switch from positive to negative (i.e. become costs/liabilities). Though most of the Group felt that the WACC value calculated and applied by the CBA consultants was far too low, the Panel member believed that the consultant's value was reasonable, though probably a little low. The member believed some of the WACC values suggested by Group members were much too high.

The Panel considered the Group's challenge of the amount of offshore wind generation included in the CBA modelling. Most of the Group believed that the amount of offshore wind generation was significantly too low, though the Group did agree that the CBA was fit for purpose. A Panel member noted that the CBA included analysis of a scenario with more offshore wind generation to assess the sensitivity of the CBA results to this factor, which indicated the results were not disproportionately sensitive to the level of offshore wind generation. However, another member noted that the amount of offshore wind generation in the sensitivity scenario was still small compared with the amount now expected in Rounds 1, 2 and 3 of offshore development. The Panel was sympathetic to the views of Group members that more offshore wind generation should have been included in the P229 CBA, but also noted the lower level of information available at the time the CBA modelling was done and the continuing elements of uncertainty in this area. The Panel agreed with the Group that the P229 CBA was fit for the purpose of assisting the assessment of P229.

A Panel member commented that P229 would impact TNUoS charges by affecting energy volumes through the impact on despatch identified by the CBA. The Group had agreed such an effect was out of scope of P229 and it was not included in the CBA modelling or quantified in the P229 CBA. The Panel agreed that the consideration of any impact on TNUoS charging was outside the scope of the BSC, but noted that the Authority would need to consider this aspect, under of its wider regulatory remit, when deciding whether to approve P229.

A Panel member noted that the load flow modelling, which is part of P229 Proposed and Alternative solutions, involves incremental injections of power at system nodes in order to gauge the effect on variable losses on the system, and the use of a 'slack node' to absorb these injections. The member suggested that this approach may result in an allocation of variable losses that is not truly locational, though the member could not suggest an alternative approach that would deliver better results.

A Panel member commented that the trading site arrangements were intended to shelter participants from locational charges, and noted that trading sites had not been considered. The Panel noted that the Group had considered a similar effect in relation to embedded generators. The member also noted that P229 (Proposed or Alternative) would be more liable to have a negative impact on participants operating in a single zone than on larger companies with a diverse portfolio, who can choose how to operate different assets in various zones.

Panel's initial views against the Applicable BSC Objectives

A Panel member commented that they regarded the principle of locational allocation of variable losses as essentially a good thing. However, they believed that consideration of P229 should recognise that there are different ways that locational allocation could be achieved, and should also take into account the impact of applying a new scheme to the established arrangements. They noted that the impact of P229 (Proposed or Alternative) would not be as great as a more radical methodology for locational allocation of variable losses. For instance, the ex-ante, Seasonal zonal scheme proposed by P229 would not have as much effect as an approach using a nodal, daily and/or ex-post allocation methodology.

This member also believed that small Suppliers would not fully understand the P229 arrangements, and that this was a significant issue that should be taken into due consideration. The member felt that overall assessment of P229 had been dominated by the perspective of generators, with little recognition that operating on the Supply side of the market would be more complicated.

The member also questioned whether a real Code defect had been identified, and doubted that P229 would impact site location decisions. They believed that the example in Centrica's consultation response effectively illustrated that the benefits of P229 are relatively modest but unintended consequences of the change could result in significant and unjustified disadvantages to some participants.

The member believed that Applicable BSC Objective (c) in particular would be negatively impacted by implementation of P229. They believed that the differential impact of zonally allocated variable losses would have an effect on competition, because integrated participants would be able to manage the impact on them via their diverse portfolios spread across various locations.

The member also agreed with the point raised in the Panel's discussions that the effect of generator's contracts would impact how they would operate and that could not be included in the CBA modelling. They believed that this had led to the benefits being overestimated.

The member also noted the significant wealth transfer between participants predicted by the CBA, believed that there would be a significant negative impact on investment, and believed that new participants would need to model the effects of the P229 at significant expense. They believed that all these areas would have a detrimental effect on competition in the market.

In summary, this member felt that implementation of both P229 Proposed and Alternative would result in relatively small benefits which had to be set against significant probable detriments. They therefore believed that both the Proposed and Alternative are inferior to the existing Code baseline. They believed that the Alternative is better than the Proposed.

Another member also stated that they believed that neither P229 Proposed nor P229 Alternative was better than the existing baseline. They were concerned that the locational effect of introducing P229 was uncertain due to the interactions with TNUoS charging. The member also felt that there was additional regulatory uncertainty in the industry, due to DECC's position and the issues raised by Ofgem in its recent announcement on Project Discovery, which should be considered when deciding whether P229 should be implemented.

This member also noted they gave weight to the arguments that existing Parties would not be less able to respond to P229 than new entrants, and that the transfers between participants would amount to windfall gains and losses, which would be detrimental to competition. Overall, they believed that neither P229 Proposed nor P229 Alternative would better facilitate achievement of Applicable BSC Objective (a), both would have a detrimental impact on the facilitation of Objectives (b) and (c), and neither would better facilitate achievement of Objective (d).

The member also questioned whether it had been demonstrated that there was a Code defect to address. This member declined to give a preference between the Proposed and Alternative Modifications, stating that it would serve no useful purpose since they believed both to be inferior to the baseline.

Another Panel member believed that aside from any benefit indicated by the analysis of P229 it had not been demonstrated that P229 Proposed or Alternative would remove the cross-subsidy contended by the Proposer. This member also felt that P229 would add uncertainty to investment decisions which would have a negative impact on investment and would disproportionately impact smaller participants for the reasons already described, i.e. its additional complexity and because smaller players are less able to mitigate the impact of TLF signals. This member believed that both P229 Proposed and P229 Alternative are inferior to the existing baseline, but the Alternative is better than the Proposed.

Another Panel member interpreted the assessment and analysis of P229 as showing superficially that implementation of either P229 Proposed or Alternative would have associated benefits, without recognising the difficulty of realising those benefits in practice. They also believed that the analysis of P229 benefits did not recognise that fundamentally the Transmission System exists to connect network assets, i.e. allocation of network losses should not distort the use of the network, and the prospective despatch benefits identified by the CBA would result from such an impact.

This member noted that P229 Proposed and Alternative would still socialise variable losses, just on a smaller scale (zonally instead of nationally). They which they viewed this as a drawback against Applicable BSC Objective (b) because socialisation on a smaller scale would increase the impacts on individual participants. They also believed there would be a negative impact against Objective (c) due to a detrimental impact on investment, contribution to plant exiting the market, inflation of cost of capital and distribution of wealth transfer between participants, as well as the competition arguments already expressed.

The member believed that believed that both the Proposed and Alternative are inferior to the existing Code baseline, but the Alternative is better than the Proposed.

Another Panel member stated that their views on the benefits of P229 were guided by the CBA figures excluding the effect of SOx/NOx emission reductions, which they believed should be treated with caution due to the way they were calculated from the CBA modelling results and the approach to assigning to them a monetary value. The member noted that this caution was reflected in responses to the P229 Assessment phase consultation, particularly noting that this was true of the response of RWE Npower (the Proposer of P229).

The member also noted that they believed the benefits identified by the analysis of P229 would not necessarily be passed on to consumers as savings, though they acknowledged that consideration of the impact on end customers was not within the scope of the BSC Modification process. However, they did believe it was relevant to note that demand could not respond to TLFs as generators would be able to.

This member believed the principal considerations were against Applicable BSC Objective (c). They agreed with the points raised by other members, noting that discrimination would result from the difference in the impact on individual generators and Parties with a portfolio of assets and that the significant complexity would be a barrier to market entry. The member also believed P229 would cause a transfer of wealth between participants that was unjustified and disproportionate to any benefits, and that it would have a disproportionate impact on renewables and on other types of generator that are unable to respond to TLF signals. These considerations led the member to believe that both P229 Proposed and Alternative would have a detrimental impact on Objectives (b) and (c).

The member believed that both the Proposed and Alternative are inferior to the existing Code baseline, but the Alternative is better than the Proposed.

Another member agreed with the points raised by other members, particularly noting that the ability of the demand side of the market to respond to TLF signals is limited compared with that of the generation side. They believed that both the Proposed and Alternative are inferior to the existing Code baseline, but the Alternative is better than the Proposed.

This member declined to express a preference between the Proposed and Alternative Modifications on the basis it would serve no useful purpose since they believed both to be inferior to the baseline.

Another Panel member believed that the P229 analysis indicated that both P229 Proposed and P229 Alternative were unlikely to have a measurable impact on plant location and would result in increased prices, along with increased complexity and significant wealth transfer between participants. They therefore questioned the aim of P229 and its ability to deliver an overall benefit, and suggested that some kind of grandfathering scheme might be more appropriate.

The member agreed with the arguments already put forward, and believed that both the Proposed and Alternative are inferior to the existing Code baseline, but the Alternative is better than the Proposed.

Another Panel member believed that both the Proposed and Alternative would just replace one form of socialising variable losses with anther, by socialising on a zonal basis instead of nationally. This member also supported the argument that no participants should be allocated negative volumes of variable losses, and was concerned that the forecast benefits of P229 were relatively small and could easily be swept away by comparatively minor actions by participants or changes in market conditions.

This member also believed that P229 might have a significant impact on TNUoS charges that had not been explored and quantified; though they noted that any TNUoS impact was outside the scope of the BSC they believed the Authority would need to consider all possible impacts ion this area. The member felt that TNUoS should be the main mechanism to reduce losses and any negative impact on or interference with TNUoS charges should be considered.

For both Proposed and Alternative this member identified no impact on Applicable BSC Objective (a). They believed there would be detrimental impacts on competition, i.e. against Objective (c), because large participants are naturally insulated against the negative impact of P229, and because the impacts of participants' operations on others within the same zone is more acute, because the effect is socialised only across that zone instead of being spread across the entire system. Objective (d) would be negatively impacted due to the additional complexity of the P229 arrangements.

The member believed that the Alternative was better than the Proposed against Objective (b) because in principle it would not allocate negative volumes of variable losses. They believed that though the Alternative mitigates the negative impacts to some extent, both the Proposed and Alternative are inferior to the existing Code baseline, but the Alternative is better than the Proposed.

The National Grid representative noted the Panel's considerations and commented that though National Grid are incentivised to reduce system losses, and TNUoS charging already exists, National Grid cannot influence where generators choose to locate on the system. The representative believed that P229 TLFs could provide a signal that could potentially influence the location of new generation, and this would allow minimisation of variable losses to be included in siting decisions, in addition to all other relevant factors. They believed this would be beneficial for the efficiency of the operation of the system.

The representative accepted that P229 would add complexity to the Code arrangements, but noted that the arrangements are already very complex and questioned whether the increase would be significant. They acknowledged that National Grid seek to reduce system losses, but believed that this did not mean that this responsibility must necessarily rest National Grid only.

Another Panel member noted that they agreed with all the points raised against implementation of P229 Proposed and Alternative. This member believed that both the

Proposed and Alternative would have particularly negative impacts on facilitation of Applicable BSC Objectives (b) and (c). The detriment against (b) were somewhat mitigated under the Alternative, but there were very significant drawbacks against Objective (c) under both Proposed and Alternative.

The member therefore believed that both the Proposed and Alternative are inferior to the existing Code baseline, but that the Alternative is better than the Proposed.

Another Panel member gave consideration to the basis of P229, stating that they did not believe that there was any reason in principle why delivery costs in the form of variable losses should not be reflected in participants costs. They believed that the benefit predicted by the CBA was relatively small compared with industry costs overall, but was significantly greater than those associated with the average Modification. The member also believed that thought the predicted benefits may have been over- or underestimated by the CBA, they remain large compared with the associated costs.

This member considered the windfall gains and losses, and questioned whether these would be within the remit of the Panel. They also believed that such gains and losses would not affect competition per se, though they may affect the equitability of the market. The member also commented that it was not possible for P229 to affect the cost of capital for investments.

On the basis of these considerations the member believed that P229 Proposed would have a positive impact on facilitation of Applicable BSC Objectives (b) and (c). However, they believed that the Alternative would reduce the benefits associated with the Proposed and would have additional complexity and inaccuracy associated with it due to its variable scaling methodology. Overall, the member felt that the cost associated with variable losses and it should be reflected to participants as much as possible.

This member therefore believed that P229 Proposed is better than the existing Code baseline but P229 Alternative is not.

Proposed compared with baseline

The Panel agreed by majority an initial view that P229 Proposed would not better facilitate the Applicable BSC Objectives overall compared with the current baseline.

The majority of the Panel supported the views of the majority of the P229 Modification Group, but put most weight against the arguments the Panel had detailed against Objectives (b) and (c). These included that P229 Proposed would add complexity to the Code arrangements, that the predicted benefits may not be realised and that it would result in windfall gains and losses that would be disproportionate to the potential benefits.

Based on these views and the considerations detailed above the majority of the Panel believed that P229 Proposed would not better facilitate the Applicable BSC Objectives overall and that (compared with the existing baseline) P229 Proposed:

- Would be neutral with respect to Applicable BSC Objective (a);
- Would not better facilitate Applicable BSC Objective (b);
- Would not better facilitate Applicable BSC Objective (c); and
- Would not better facilitate Applicable BSC Objective (d).

A minority of the Panel, one member, believed that P229 Proposed would better facilitate the Applicable BSC Objectives overall. This member believed that P229 Proposed would have a positive impact against Objectives (b) and (c) due to the benefits predicted by the analysis of P229. The minority of the Panel therefore believed that (compared with the existing baseline) P229 Proposed:

- Would be neutral with respect to Applicable BSC Objective (a);
- Would better facilitate Applicable BSC Objective (b);
- Would better facilitate Applicable BSC Objective (c); and
- Would not better facilitate Applicable BSC Objective (d).

Alternative compared with baseline

The Panel unanimously agreed an initial view that P229 Alternative would not better facilitate the Applicable BSC Objectives overall compared with the current baseline.

The Panel supported the views of the majority of the P229 Modification Group, but put most weight against the arguments the Panel had detailed against Objectives (b) and (c). These included that P229 Proposed would add complexity to the Code arrangements, that the predicted benefits may not be realised and that it would result in windfall gains and losses that would be disproportionate to the potential benefits.

Based on these views and the considerations detailed above the Panel all believed that P229 Alternative would not better facilitate the Applicable BSC Objectives overall and that (compared with the existing baseline) P229 Alternative:

- Would be neutral with respect to Applicable BSC Objective (a);
- Would not better facilitate Applicable BSC Objective (b);
- Would not better facilitate Applicable BSC Objective (c); and
- Would not better facilitate Applicable BSC Objective (d).

Alternative compared with Proposed

The Panel agreed by majority an initial view that P229 Alternative would better facilitate the Applicable BSC Objectives overall compared with P229 Proposed.

The majority of the Panel supported the views of the majority of the P229 Modification Group, but put most weight against the mitigation of the negative impacts the Panel had detailed against Objectives (b) and (c). This included reduction of the windfall gains and losses that would result from implementation of P229.

Based on these views and the considerations detailed above the majority of the Panel believed that (compared with P229 Proposed) P229 Alternative:

- Would be neutral with respect to Applicable BSC Objective (a);
- Would better facilitate Applicable BSC Objective (b);
- Would better facilitate Applicable BSC Objective (c); and
- Would be neutral with respect to Applicable BSC Objective (d).

A minority of the Panel, one member, believed that P229 Proposed would better facilitate the Applicable BSC Objectives overall compared with P229 Alternative. This member believed that the Alternative would reduce the positive impact against Objectives (b) and (c) by reducing the benefits of P229 while also introducing additional complexity and inaccuracy due to its variable scaling methodology. A minority of the Panel therefore believed that (compared with P229 Alternative) P229 Proposed:

- Would be neutral with respect to Applicable BSC Objective (a);
- Would better facilitate Applicable BSC Objective (b);
- Would better facilitate Applicable BSC Objective (c); and
- Would be neutral with respect to Applicable BSC Objective (d).

A minority of the Panel, two members, did not give their views on the effect on the Applicable BSC Objectives of P229 Alternative compared with P229 Proposed. These members did not believe that expressing a preference between the two would serve any useful purpose, because they believed both to be inferior to the existing baseline.

Panel's initial recommendations

Having considered the P229 Assessment Report, the Panel initially recommended that:

- That Proposed Modification P229 should not be made;
- That Alternative Modification P229 should not be made;
- An initial Implementation Date for both Proposed Modification P229 and Alternative Modification P229 of:
    - 1 October 2011 if approval is received from the Authority on or before 30 September 2010; or
    - 1 April 2012 if approval is received from the Authority after 30 September 2010 but on or before 31 March 2011; or
    - 1 October 2012 if approval is received from the Authority after 31 March 2011 but on or before 30 September 2011.

10 Report Phase Consultation Responses

The following table summarises the responses received to the Report Phase Consultation. The majority of respondents agree with the recommendations made by the Panel.

	Question	Responses
1	Do you agree with the Panel's initial view that the Proposed Modification should be rejected?	7 Yes 2 No
2	Do you agree with the Panel's initial view that the Alternative Modification should be rejected?	7 Yes 2 No
3	Do you agree with the Panel's initial view that, while both are inferior to the baseline, P229 Alternative is superior to P229 Proposed?	6 Yes 2 No 1 Neutral
4	Do you agree with the Panel's suggested Implementation Dates for P229 Proposed and P229 Alternative?	7 Yes 1 No 1 Neutral
5	Do you agree that the legal text for P229 Proposed and P229 Alternative delivers the intent of the Proposed and Alternative?	7 Yes 1 No 1 Neutral
8	Do you have any further comments on P229?	4 Yes 4 No

New arguments?

No arguments were raised in the responses to the Report Phase Consultation that had not already been considered by the P229 Modification Group or the Panel. All but one of the respondents had previously responded to the Assessment Consultation, and none of these respondents had changed their previously stated views or comments.

The respondent who had not commented during the Assessment Consultation supported the recommendations of the Panel. They argued that P229 ignores the fact that decisions on plant location are based on factors other than economic assessment, e.g. geographical constraints of renewable generation. They believed that by ignoring the existence of such constraints P229 would discourage renewable generation, and therefore P229 is inconsistent with public policy.

11 Recommendations

Having considered the P229 draft Modification Report, we invite the Panel to:

- NOTE the P229 draft Modification Report and the consultation responses;
- CONFIRM the recommendation to the Authority contained in the P229 draft Modification Report that Proposed Modification P229 should not be made;
- CONFIRM the recommendation to the Authority contained in the P229 draft Modification Report that Alternative Modification P229 should not be made;
- APPROVE an Implementation Date for both Proposed Modification P229 and Alternative Modification P229 of:
  - 1 October 2011 if approval is received from the Authority on or before 30 September 2010; or
  - 1 April 2012 if approval is received from the Authority after 30 September 2010 but on or before 31 March 2011; or
  - 1 October 2012 if approval is received from the Authority after 31 March 2011 but on or before 30 September 2011;
- APPROVE the legal text for Proposed Modification P229;
- APPROVE the legal text for Alternative Modification P229; and
- APPROVE the P229 Modification Report or INSTRUCT the Modification Secretary to make such changes to the report as may be specified by the Panel.

12 Further Information

More information is available in:

Attachment A: Detailed Assessment

This includes details of impacts and costs, Modification Group membership and discussions, a summary of the P229 Cost-Benefit Analysis, the issues raised by the P229 Assessment Procedure consultation, the process followed for P229 and a glossary of terms.

Attachment B: Legal Text Proposed

Attachment C: Legal Text Alternative

Further information can be found on the P229 page of the ELEXON website (P229 webpage), including:

- Responses to the P229 Report phase consultation;
- The P229 Assessment Report;
- Responses to the P229 Assessment phase consultation and impact assessment;
- All P229 Modification documents including the Assessment Procedure Consultation; and
- The full P229 Load Flow Modelling report and P229 Cost-Benefit Analysis report.

All other P229 documentation and data should be considered in conjunction with this report, and all such material is part of the Assessment of P229.

Stage 03: Attachment A: Detailed Assessment for P229

P229: Introduction of a seasonal Zonal Transmission Losses scheme

What stage is this document in the process?

01 Initial Written Assessment

02 Definition Procedure

03 Assessment Procedure

04 Report Phase

Contents

About this document:

This is Attachment A to the P229 Assessment Report. This attachment provides additional detail on the Cost Benefit Analysis and Load Flow Modelling undertaken for P229 and on the Modification Group's discussions, the responses to the P229 Assessment Procedure consultation and the Group's final views.

165/05

P229
Detailed Assessment

5 February 2010

Version 2.0

1 Background

Existing Transmission Losses Arrangements

Under the existing Balancing and Settlement Code (BSC) provisions, fixed and variable transmission losses are allocated to Parties on a uniform (i.e. non-locational) basis in proportion to each Party's metered energy. The current allocation of transmission losses therefore does not take account of the extent to which individual Parties give rise to such losses due to their location.

The existing mechanism for allocating transmission losses to Parties is set out in a calculation in Section T of the BSC. A simplified version of this calculation is:

Transmission Loss Factor (TLF) + Transmission Losses Adjustment (TLMO) = Transmission Loss Multiplier (TLM)

The elements of this calculation are explained below:

1 + TLF *+ TLMO = TLM*

Transmission Loss Factor (TLF) is a parameter for a non-uniform allocation of transmission losses to each BM Unit originally built into this calculation. However, it is currently defined to be zero so has no effect in practice. A modification of the Code is necessary to amend the TLF value.

1 + TLF + ***TLMO*** *= TLM*

The **Transmission Losses Adjustment (TLMO)** is used to ensure that all losses are allocated to Parties through Metered Volumes, whatever the value of TLF. There are two values of TLMO; delivering (exporting) and offtaking (importing):

- The delivering TLMO **(TLMO+)** uniformly adjusts the volumes of all BM Units in delivering Trading Units (generators) so they receive 45% of total losses;
- The offtaking TLMO **(TLMO-)** uniformly adjusts the volumes of all BM Units in offtaking Trading Units (demand) so they receive 55% of total losses.

1 + TLF + TLMO = ***TLM***

A Transmission Loss Multiplier (TLM) is a factor used to scale each BM Unit's Metered Volumes in Settlement. A TLM is generated for each individual BM Unit. Since the value of TLF is presently zero the TLMO determines the calculation of each BM Unit's TLM. This means two uniform TLM values are currently applied - one to all BM Units in delivering Trading Units, and one to all BM Units in offtaking Trading Units. Each Party's overall allocation of transmission losses is dependent on the Metered Volumes of the BM Units to which the TLM is applied. Transmission losses are allocated to Parties as an adjustment to the volumes used in determining Trading Charges.

Any questions?

Contact:
Dean Riddell

dean.riddell@elexon.co.uk

020 7380 4366

Related Changes

Between December 2005 and July 2006 four Modification Proposals were raised which all concerned Zonal Transmission Losses schemes, and were:

- P198 - Introduction of a Zonal Transmission Losses scheme
- P200 - Introduction of a Zonal Transmission Losses scheme with Transitional Scheme
- P203 - Introduction of a seasonal Zonal Transmission Losses scheme
- P204 - Scaled Zonal Transmission Losses

On 17 July 2008, the Authority published an open letter stating it was no longer in a position to reach a decision on these four Modification Proposals. The Modification Proposals are therefore closed.

The solution proposed by P229 is essentially the same as that proposed by P203, with the addition of a proposed method for dealing with offshore Transmission Systems.

Partial Implementation of Modification P82

Before the Modification Proposals noted above, in May 2002 Modification Proposal P82 'Introduction of Zonal Transmission Losses on an Average Basis' was raised. P82 was approved for implementation, but this approval was quashed by the High Court in January 2004 following judicial review. P82 was remitted to the Authority for re-decision and subsequently rejected.

Though P82 was not implemented, the development work was completed prior to the judicial review's conclusion. Much of the original P82 functionality (legal text, system development, Code Subsidiary Document changes and BSCCo working procedures) is re-usable and owned by BSCCo. Exceptions are the Load Flow Model and the Transmission Loss Factor Agent (TLFA), the new BSC Agent which would have been created by P82 to calculate TLFs using the Load Flow Model. An organisation was procured to fill the TLFA role but because P82 was not implemented, the TLFA was not required and the TLFA contract was terminated. If P229 is approved a new TLFA procurement would be required.

2 Terms of Reference

P229 Terms of Reference		
The P229 Modification Group consists of members of the P203 Modification Group, and other Standing Modification Group members with relevant expertise. The Group's Terms of Reference for the P229 comprised the following items.		
Ref		**Section**
01	**Proposed Solution** Confirm and document the P229 solution. The P229 Proposal states that it's based on work already completed under P203.The Group should ensure it has considered whether aspects of the P203 solution remain applicable to P229 and highlight any new areas, such as the additional offshore provision, which should be included.	Assessment Report
02	**Offshore Transmission** Unlike previous Transmission Losses Modifications, P229 includes provision for offshore nodes. P229 Assessment should consider the following areas where offshore transmission may pose additional issues (this list is not intended to be exhaustive): • The appropriate baseline against which to assess P229 (given Offshore Transmission had not yet been introduced into the Code when P229 was raised); • Detailing how offshore nodes are incorporated into the P229 solution; • Any effect of using offshore nodes in load flow modelling; • Impact on the load flow modelling requirements if it is necessary to model DC offshore networks; • Treatment under P229 of offshore transmission systems connected to the onshore system through the geographical areas of more than one GSP Group (i.e. it is unclear which TLF Zone the offshore nodes should be assigned to; and • Consideration of any interaction between the legal text to implement P229 in the Codes and the legal text to enact offshore transmission.	7. Load Flow Modelling Analysis, Assessment report
03	**Environmental Impact** The BSC Modification Process is obliged to assess the environmental impact of proposals and suitably quantify such impact. This could be in terms of carbon emissions or carbon-equivalent values for other pollutants. The P229 Group should consider how to most effectively assess environmental impact for P229.	4. Cost Benefit Analysis Results

04	**Assessment and Analysis:** **a) Requirement to undertake new analysis under P229** The following analysis was undertaken to support the previous Transmission losses Modifications: • **Load Flow Modelling** • **Cost-Benefit Analysis** P203 used the results of analysis in these areas that was previously undertaken for P198. P229 is based on P203, but new load flow modelling and cost benefit analysis is required as part of P229 Assessment for the following reasons: • In the time since the original work was conducted unforeseen events/changes could have occurred which will affect the outcome of analyses; • The scope and requirements for cost-benefit analysis have been changed by the need to include assessment of the environmental impact of P229; and • The inclusion of offshore nodes in P229 alters the model and assumptions on which the previous analysis was based.	3. Cost Benefit Analysis Approach & 4. Load Flow Modelling Analysis
05	**Assessment and Analysis:** **b) Review and utilisation of previous analysis** Consideration should be given to any use that can be made of the work completed for the previous Transmission Losses Modifications, such as: • It is anticipated that the load flow modelling can be obtained from the same source, and that therefore no substantial procurement is required in this area; • The load flow modelling work required is expected to be basically the same as for P198, therefore the P198 modelling specification can be used as the basis for the P229 specification (suitably updated, i.e. including offshore nodes); • The previous sourcing and procurement of cost-benefit analysis could assist in these areas for P229; and Efficiency benefits could be achieved by using the P203 cost-benefit analysis request as a template for requesting cost-benefit analysis for P229 (suitably updated, i.e. including environmental impact).	3. Cost Benefit Analysis Approach & 4. Load Flow Modelling Analysis

3 Cost Benefit Analysis Approach

Why did the Group commission an independent cost-benefit analysis?

A standard part of a Modification Group's assessment of whether a Modification Proposal better facilitates the achievement of the Applicable BSC Objectives is an analysis of the costs and benefits of the proposal. For most Modification Proposals this analysis is undertaken by the relevant Modification Group, using data and analysis from ELEXON where needed.

However, analysis of a zonal transmission losses scheme falls outside ELEXON's expertise, as it requires forward economic modelling of the energy market. This is because the perceived benefits of such a scheme depend on its ability to influence short and long-term market behaviour through economic signals.

When P229 was presented to the Panel it was noted that an independent cost-benefit analysis had been commissioned for the previous transmission losses Modification Proposals (P198, P200, P203 and P204) in 2006, and that it was appropriate to similarly obtain external cost-benefit analysis of P229.

Both the Modification Group and the Panel agreed that a detailed cost-benefit analysis would be an essential aid for it and the wider industry in assessing the merits of P229. The Group also believed that, given the divided opinions and strength of feeling which a zonal losses scheme has historically generated in the industry (due to its potential financial impact on Parties), collectively commissioning an independent expert view could add an extra element of robustness to the Group's assessment.

The Panel and the Group also felt it necessary to undertake fresh quantitative analysis, rather than a qualitative critique of previous work in this area, due to:

- The amount of time which has passed since the earlier analysis (which may mean that previous assumptions are no longer appropriate);
- More recent Authority guidance that environmental considerations such as carbon emissions can and should be taken into account when assessing Modification Proposals against the Applicable BSC Objectives; and
- The need to include offshore nodes in the P229 solution (which may require new and/or different assumptions than previously undertaken).

The Group therefore agreed to:

- Develop and agree the requirements for undertaking a cost-benefit analysis of P229; and
- Instruct ELEXON to procure an independent external consultant to undertake the cost-benefit analysis in accordance with the Group's requirements.

The Group noted that the key outcome would be for it to agree that the analysis results had been produced in accordance with its requirements, even if individual members did not necessarily agree with all the specific findings of the analysis.

What were the Group's requirements for the CBA?

Below is a summary of the Group's requirements. You can download the Group's full specification for the cost-benefit analysis here.

Aims and scope

The Group agreed that the overall objective of the cost-benefit analysis should be to quantify the net future benefit of P229 to the GB electricity market, taking into account both short-term impacts and long-term effects.

The Group agreed that, in order to establish the net benefit, it would be necessary for the cost-benefit analysis consultant to estimate the total cost to Parties of implementing P229. It noted that this would require some extrapolation, using the individual cost information provided by impact assessment respondents.

Since the P229 Proposed Modification solution was so similar to previous Modification Proposal P203 (which had itself been based on P198), the P198/P203 cost-benefit analysis specification was as a starting point. The Group's discussions therefore focused on identifying where any changes to that specification were required, taking account of any lessons learned from the previous Oxera analysis. Following the Group's development of a P229 Alternative Modification based on P204, it also subsequently agreed the requirements for the cost-benefit analysis of this Alternative using Oxera's P204 analysis as a reference.

It was noted that the purpose of the cost-benefit analysis would be a tool to help in the assessment of P229 against the Applicable BSC Objectives, but would not be the assessment itself as members' could agree or disagree with the findings. The Group agreed that the cost-benefit analysis should therefore focus purely on the net economic benefit of P229, and that the consultant should not be required to take a view of its merits against the Applicable BSC Objectives – since this was a judgement which would be made subsequently by the Group.

However, the Group recognised that members would need to tie the perceived costs and benefits of P229 to the Applicable BSC Objectives when making the Group's final recommendation to the Panel. The Group therefore agreed that any explicit quantification of the impact on consumers (as distinct from Suppliers or demand in general) should be excluded from the analysis scope, as this fell outside the Applicable BSC Objectives and could be considered by the Authority as part of its wider statutory duties when making its decision on P229.

Choice of methodology

In order to analyse the long-term impact of zonal TLFs the CBA consultant was required to calculate 'evolved' TLFs for each Zone over the ten-year analysis period. These 'evolved' TLFs would then be used to predict the changes in market behaviour (and thereby the costs and benefits) which would result from P229.

The Group agreed that the TLF values should be validated against those which the Load Flow Modeller had calculated to ensure consistency.

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

should have the opportunity to review the consultant's proposed approach before work began.

Choice of assumptions, scenarios and sensitivities

The CBA consultant was requested to use the following:

1. A **'base-case'** representing the predicted changes in the market over the ten-year analysis period without the introduction of P229 (i.e. based on the current uniform allocation of transmission losses with zero TLF values); and

2. A **'change-case'** representing the base-case but with the introduction of P229 seasonal zonal TLFs.

The Group agreed that the consultant should choose which assumptions to apply, based on its economic and market expertise. However, the Group agreed that it was essential for the consultant to detail the assumptions used, and to test the sensitivity of those assumptions which it believed to be the most susceptible to change – such that a range of possible net benefits was calculated. The Group also agreed that it should have the opportunity to review the consultant's proposed assumptions before work began.

Input data

The following input data were provided to the CBA consultant:

- The non-confidential implementation and operational costs of P229 to BSC Parties, BSC Agents, ELEXON and the Transmission Company – as provided in response to the P229 impact assessment;

- The TLFs calculated by Siemens PTI for 2008/09 using historic data from 2007/08; and

- Any other outputs of the Siemens PTI modelling exercise which might be required by the consultant to validate the results of its own load-flow model.

In addition, the Group also specified a variety of public documents (such as National Grid's Seven Year Statement) which it believed should be taken into account in the analysis. You can find a list of these in the Group's full specification for the service.

Choice of tasks

At a high level the Group agreed the CBA should include the quantification of:

- The implementation costs of P229 to Parties as a whole;

- The initial distributional impacts of P229 on Parties (i.e. the extent to which P229 will give rise to movement of money between Parties through changes to their Trading Charges, and the magnitude and locational pattern of this movement);

- The impact of P229 on the volume and cost of transmission losses;

- The impact of P229 on existing and future generation (i.e. how generators would respond to the signals created by P229);

- The impact of P229 on existing and future demand response and growth (i.e. how demand would respond to the P229 signals);

- The impact of P229 on the operation and development of the Transmission System (including the impact on, and of, constraints); and
- The short-term and long-term environmental impacts of P229 (including the impact on carbon emissions and other air pollutants).

You can find further detail on the Group's requirements for each of these tasks in its full specification for the service.

Who provided the analysis and what was their approach?

Following a commercial tender process ELEXON awarded the contract for the P229 cost-benefit analysis to London Economics (LE) in association with Ventyx.

The output of the cost-benefit analysis was a report by LE/Ventyx to the Group, setting out the conclusions of the analysis. You can download this report here. LE/Ventyx personnel also attended meetings of the Group to present their approach/assumptions (before starting work) and the analysis results.

Chosen approach

LE/Ventyx's approach consisted of applying standard cost-benefit analysis discounting techniques to results from load-flow modelling using Ventyx's proprietary software and GB electricity market forecast assumptions over the ten-year period from 2011/12 to 2020/21.

The modelling produced estimated TLFs using the forecast data by simulating each market year explicitly. Each simulated market year produced a set of hourly 'actual' TLFs, which were used to calculate the zonal seasonal TLFs to be applied to the next market year. In each simulated market year, the zonal seasonal TLFs resulting from the prior year were applied to the Metered Volumes of generators and Suppliers using the Transmission System.

LE/Ventyx used full modelling of the Transmission System and despatch for every hour in each year of the analysis period. This removed the need for 'snapshot' periods and iterative modelling between despatch and load-flow, which had previously been used by Oxera and had caused concern for some Parties about the accuracy of results. It therefore more closely reflected how TLFs would be calculated and implemented in practice, with more factors being internalised in the model, and also avoided the sampling error or sampling bias possible when basing the analysis on just a small selection of sample periods.

To validate the results of its load-flow modelling, LE/Ventyx used the same 2007/08 time period and network data as Siemens PTI to calculate a set of TLFs for comparison. The resulting TLFs matched closely, giving confidence that the cost-benefit analysis simulation model was closely aligned with the 'real-life' TLF calculation which would be used under P229. Note, however, that the two sets of TLFs will not match exactly as the Siemens PTI TLFs were calculated from actual Metered Volumes while the LE/Ventyx TLFs were based on a market simulation. While this simulation is intended to be realistic, it is not intended to match historical data perfectly. You can find the full results of the comparison in Section 4.8 of LE/Ventyx's report, and further details of its modelling approach in Section 2 of its report.

Scenarios

LE/Ventyx modelled 6 scenarios to test the sensitivity of its conclusions to changes in the most important input forecasts. The Group used both the advice of LE/Ventyx and their own discussions to choose the scenarios. The Group also suggested assumptions for LE/Ventyx to use, but agreed to leave exact assumptions to their expertise as long as these assumptions were clearly detailed.

The scenarios were:

1. **Reference Scenario:** This was based on 'business as usual' (BAU) assumptions but with the addition of P229 seasonal zonal TLFs. This is considered to be the most likely or 'central' scenario (at the time of initiation of the analysis).
2. **High Gas Price Scenario:** All gas prices were set to be 30% higher than in the Reference Scenario, with all other fuels and assumptions unchanged.
3. **Low Gas Price Scenario:** All gas prices were set to be 30% lower than in the Reference Scenario, with all other fuels and assumptions unchanged.
4. **Volatile Fuel Price Scenario:** All fuel prices were set to be 'volatile' (i.e. higher in some years and lower in others with no consistent pattern). All other assumptions remained unchanged from the Reference Scenario.
5. **Aggressive Offshore Wind:** 1,200MW of additional Offshore wind generation was added to that used in the Reference Scenario. The accuracy to which this level of additional generation reflects 'real-life' potential Offshore development is not the key factor in this scenario. This is because its purpose is simply to test whether the conclusions for the Reference Scenario are sensitive to the level of Offshore wind.
6. **Alternative Nuclear:** Five additional nuclear generators were added as coming online between 2017 and 2021, compared with the one new nuclear generator in 2017 under the Reference Scenario. The new non-nuclear thermal generators which came online between 2017 and 2021 in the Reference Scenario were delayed by 2 years to keep total capacity expansion in line with the Reference Scenario. All other assumptions remained unchanged from the Reference Scenario.

   Note that, as no changes were made to the assumptions for the Alternative Nuclear scenario before 2017, the 2011-2016 results for this scenario are identical to the Reference Scenario and differences only appear between 2017-2021.

In all scenarios, LE/Ventyx used seasonal fuel price forecasts as requested by the Group. The Group agreed that it was important to reflect seasonal variations in fuel prices, particularly given that TLFs would be applied on a seasonal basis under P229.

Note that the primary source of network information for the cost-benefit analysis was National Grid's Seven Year Statement (SYS). LE/Ventyx used the 2008 SYS (covering the years 2008/09 – 2014/15), as this was the current version at the time its modelling was undertaken.

Sections 3 and 4 of LE/Ventyx's report give further details of the assumptions which it used for the Reference Scenario, while Section 6.1 of its report describes the relevant changes in assumptions for the other 5 'sensitivity' scenarios.

For each scenario, the results represent the difference between the 'base-case' and the 'change-case' (i.e. the difference between running each scenario with and without P229 seasonal zonal TLFs). This ensures that the net cost-benefit for each individual scenario is wholly attributable to P229.

Because each scenario employed a base-case without P229 and a change-case including P229, the differences between the results of each scenario are wholly attributable to the differences in scenario assumptions described above.

4 Cost Benefit Analysis Results

What were the results of the Proposed Modification cost-benefit analysis?

The following sections set out LE/Ventyx's key conclusions from its cost-benefit analysis of Proposed Modification P229. You can download its full analysis report here.

Following the Group's development of an Alternative Modification, ELEXON and the Group commissioned LE/Ventyx to carry out an additional cost-benefit analysis of this Alternative. The results of the Alternative Modification analysis are summarised separately below. LE/Ventyx documented the full findings of this analysis in a separate report which you can also download here.

All tables and graphs shown in this document have been produced by ELEXON using the figures in LE/Ventyx's report

Overall conclusions and net benefit to market

Table 1 shows the total net cost-benefit for each of the 6 Proposed Modification scenarios over the 10-year analysis period. These figures are net of the implementation/operation costs to ELEXON, BSC Agents, the Transmission Company and Parties. **LE/Ventyx concluded that the net benefits of Proposed Modification P229 are predicted to be positive and significant on a net present value (NPV) basis.**

LE/Ventyx estimated that the total implementation costs to all Parties, which it extrapolated from the individual Party impact assessment responses, would be £3.42m (this figure being the mid-point of its estimates). This figure does not represent the individual implementation cost per party, but rather the total estimated cost of all Parties. Combining the estimated implementation costs to all parties with the estimation of central implementation costs, gives a total one-off implementation cost of £3.85m and ongoing annual operation costs of £0.157m across all Parties.

Table 1 – LE/Ventyx scenarios of future benefits of Proposed Modification P229 to 2020/2021 (£m discounted figures)

NPV of all benefits 2011-2021 (£m with 4.42% discount rate)	P229 Proposed Modification - Scenarios Modelled					
	Reference (BAU + P229)	High Gas Price	Low Gas Price	Volatile Fuel Price	Aggr. Offshore Wind	Alternative Nuclear
Generation response benefits excluding NOx/SOx	46.12	97.77	4.30	46.48	52.13	38.76
Generation response benefits including NOx/SOx	275.16	-19.97	73.19	172.82	265.94	222.36
Demand response benefits	1.74	3.23	0.36	1.73	1.82	1.59
TOTAL all benefits	**276.90**	**-16.74**	**73.55**	**174.55**	**267.76**	**223.95**

LE/Ventyx noted that its results are similar to those obtained for previous zonal transmission losses Modification Proposals. As expected, the financial impact of seasonal zonal TLFs favours generation in the South and demand in the North. However, the distributional impacts on Parties' Trading Charges have not been netted off against the benefits shown in Table 1, due to differing industry views on whether these should be counted as a 'cost' or as the removal of an existing cross-subsidy. LE concluded that the appropriate 'weighting' to be given to these impacts was a matter for the industry. The distributional impacts are explained in more detail below.

LE/Ventyx's overall findings for Proposed Modification P229 were as follows:

- **Redespatch benefits:** The main benefit of the Proposed Modification comes from generators' short term response to the TLF signals, where changes in generation despatch give reductions in the level of transmission losses, and therefore in the overall level of generation required to meet demand. This delivers reductions in total generation production costs through fuel savings. The locational impacts on generation despatch are largely similar across scenarios, with generation increasing in the south and decreasing in the north.

- **Impact on generation types:** LE considered that there would be no disproportionate impact on any particular type of generation (e.g. on renewables).

- **Transmission System benefits:** The reduction in generation will benefit the Transmission System by reducing overall line flows, and has the potential to reduce system congestion.

- **Emissions benefits:** Besides reducing CO_2 emissions (which are included in the generation response benefits), there are also reductions in emissions for sulphur and nitrogen oxides (SOx and NOx). These form some of the most environmentally important emissions from the production of electric power and cause acid rain, smog and risk to human health. Unlike CO_2 emissions, which are priced through the EU Emissions Trading Scheme (ETS), there is more (and significant) uncertainty associated with the most appropriate price to apply to the volume reduction in SOx and NOx emissions. LE/Ventyx used marginal abatement cost estimates but considered that, despite the uncertainty, these were likely to be conservative. This is because the 'social value' of reducing these emissions could be considerably higher.

  LE/Ventyx did not quantify the impact on other pollutants such as soot, ash, particulates, heavy metals (e.g. mercury), or the smog impacts of SOx/NOx. This was because it is difficult to quantify the value (price) of these emissions with any precision, and good references for fuel-specific levels of these emissions were not available. However, LE/Ventyx considered that in general reductions in transmission losses under P229 would reduce emissions of all types, since the total amount of power required would be reduced.

- **Impact on market prices:** The overall net impact on wholesale prices is expected to be small. The system marginal cost (or competitive price) is expected to rise by about 0.59% for peak prices and by 0.71% for off-peak prices.

- **Overall sensitivity of benefits to scenarios:** With one exception, the results of the cost-benefit analysis are not particularly sensitive to the scenario assumption changes. When excluding consideration of SOx and NOx, there is a positive net benefit under each of the scenarios. However, including the value of SOx and NOx reductions generally yields much larger benefits. The exception is the High Gas Price Scenario, where these emissions actually increase – resulting in a negative overall benefit for that scenario despite it having the highest generation production cost savings. This is because the high price of gas under this scenario results in fuel switching away from gas in favour of coal and oil (which cause more emissions).

- **Plant location:** LE/Ventyx concluded that there is unlikely to be any measurable impact on plant entry, exit or mothballing. It considered that the P229 signals would be outweighed by other locational charges and location-specific concerns such as planning permission and land/fuel costs. This result was not sensitive to scenario assumptions. LE/Ventyx noted that Transmission Use of System (TNUoS) charges already provide a locational signal, and that these (despite being substantially larger than the financial impact of TLFs) appear to have had little impact on changing overall plant location decisions.

- **Demand benefits:** There is predicted to be a small but positive demand-side response to the P229 zonal TLF signals. This is expected to have benefits for the Transmission System, the level of transmission losses, capacity needs and emissions reductions. LE/Ventyx used a single elasticity estimate (the percentage by which customers are able, and therefore likely, to change their level of consumption in response to a given % change in price) of -0.25% across all scenarios, years and Zones. Although this gives some uncertainty around the demand impact estimates, LE/Ventyx considered that there is a large body of evidence to suggest that aggregate elasticities may be small but are significantly different from zero (in the region of -0.1% to -0.3%).[1] It also noted that any estimate of demand elasticity assumes that Suppliers pass on any changes in their costs to consumers (and that under P229 this would be according to the customer's location). Ultimately, LE/Ventyx concluded that the overall net benefits of P229 are not sensitive to the level of demand response.

- **Accuracy of signals:** LE/Ventyx noted previous concerns from earlier Modification Proposals that setting TLFs on an ex-ante (estimated) basis using the previous year's data could result in 'incorrect' signals for a particular Settlement Period. LE/Ventyx considered that reducing the time between the estimated TLFs and the actual TLFs that occur in the Settlement Period could give even greater benefits than those shown in Table 1. However it concluded that, while an ex-ante scheme might naturally reduce the potential benefits, there would still be a positive net benefit from ex-ante TLFs under Proposed Modification P229.

Further information on LE/Ventyx's key results is provided on the following pages. For a full version of the CBA report please see attachment D.

[1] LE noted that precise estimates of demand elasticity by customer type, location, time and other factors were outside the scope of the P229 cost-benefit analysis. However, it noted that, while previous studies of demand elasticity have shown that the degree of elasticity varies between industrial, residential and commercial customers, all three have been shown to respond to price signals. You can find more information in Sections 3.4 and 7.3 of LE's report.

Discount rate

LE/Ventyx used a weighted average cost of capital (WACC) discount rate of 4.42%, to address some concerns that the 3.5% rate used previously was too low, although this had been based on HM Treasury guidelines.

An after-tax WACC value was chosen by LE/Ventyx as a before-tax value would be applied to any profits which are taxable, and transmission losses (the reduction in which is the primary driver of the benefits of P229) are not subject to tax.

LE/Ventyx tested the sensitivity of its results to its chosen discount rate, by recalculating the figures for the Reference Scenario using:

- A lower after-tax WACC value of 3.5%; and
- A higher after-tax WACC value of 5.2%.

These gave overall net cost-benefit figures (including NOx/SOx) of £289.96m and £266.75m respectively, compared with £276.90m using the 4.42% after-tax WACC.

In general, the pattern of costs and benefits, (relatively small upfront costs and then largely steady benefits) indicates that the overall conclusions will not be sensitive to the discount rate used.

LE/Ventyx concluded that the cost-benefit analysis results were therefore largely insensitive to reasonable changes in the discount rate.

You can find more information on LE/Ventyx's choice of discount rate in Section 3.2 of its report.

Distributional impacts

Graphs 1 and 2 show the total annualised distributional impacts under Proposed Modification P229 in 2011/12, split between generators and Suppliers and broken down by TLF Zone. The results for all 6 Proposed Modification scenarios are shown, but the Reference and Alternative Nuclear scenarios are presented as a single line since their figures are identical (due to there being no difference in assumptions between these scenarios until 2017).

The transfer figures for each scenario represent the changes to Trading Charges applied to Parties, grouped by generation and supply, which would occur from the introduction of seasonal zonal TLFs compared with the existing uniform allocation of transmission losses in that scenario. The distributional impacts are created by the TLMs for different Zones. It is the differentials in TLMs/charges between Zones which provide the P229 signals to Parties.

Distributional impacts were studied only for the 2011/12 BSC Year, to quantify the impact on Trading Charges of moving from one set of rules to the other.

Note that the figures represent the total financial transfers across all generators or Suppliers in a Zone, and not the individual commercial impacts on any Party. The figures do not take account of any portfolio effects which might offset these impacts for a particular Party (e.g. a Party which operates, for instance, generation and supply in the same zone would receive offsetting charges).

You can find the figures for the graphs in Sections 5.7, 6.2.8, 6.3.7, 6.4.7, 6.5.7 and 6.6.8 of LE/Ventyx's report.

Graphs 3 and 4 show the distributional impacts for generators and Suppliers under each of the same 6 Proposed Modification scenarios in 2011/12. However, in these graphs, ELEXON has aggregated LE/Ventyx's transfer figures for each Zone into 3 general geographic areas (Scotland, Northern England and the South).

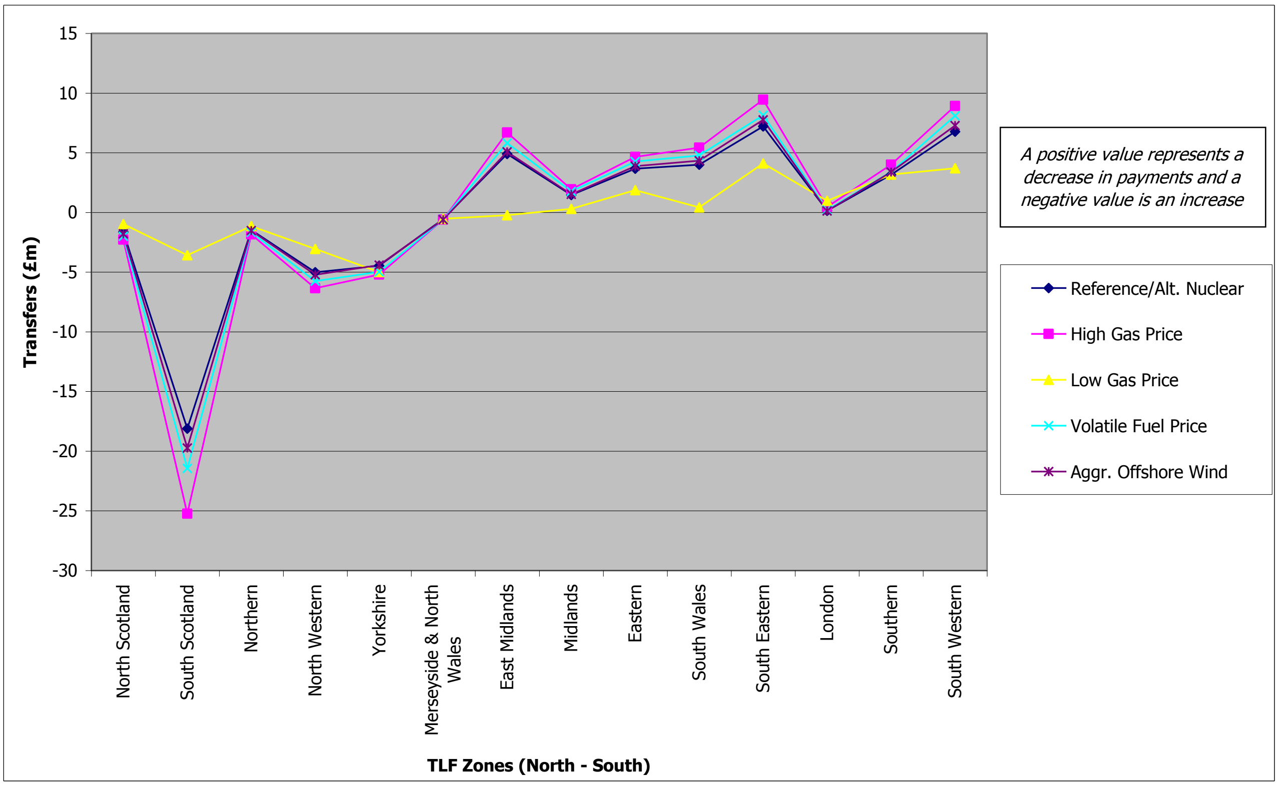
These areas comprise the following TLF Zones:

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

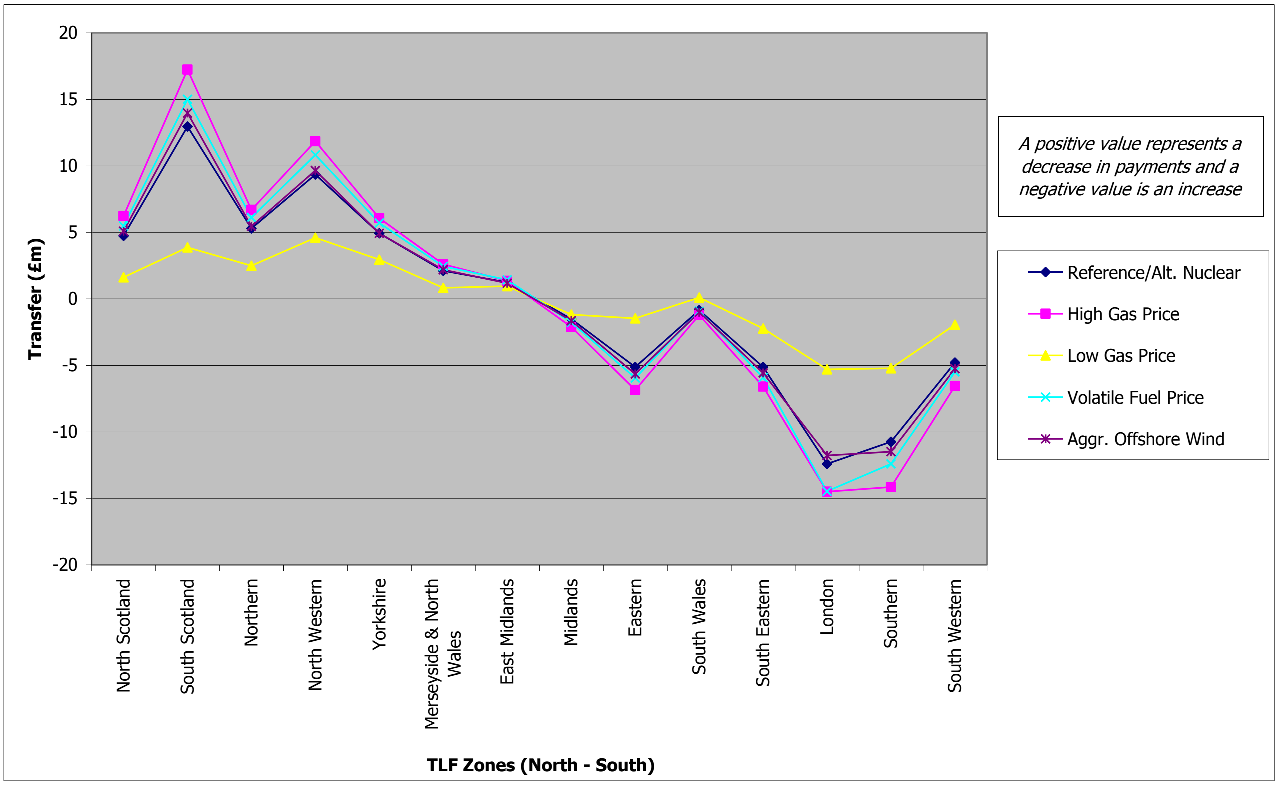
Again, the figures are the totals across all generators or Suppliers in each area and do not take account of portfolio effects. Note that they are also net totals, as some Zones in the South experienced an increase in charges while others experienced a decrease. These totals will therefore be different to the summation of all positive or all negative transfers in each scenario as detailed in Graphs 1 and 2.

Graphs 3 and 4 include details of the 'gross' distributional effects on generators and Suppliers (the sum of the absolute values of all the transfers). However, the net distributional effect across generators will be zero, as will that across Suppliers. This is because P229 redistributes money from some generators/ Suppliers to others according to the extent to which their geographic location affects the level of transmission losses.

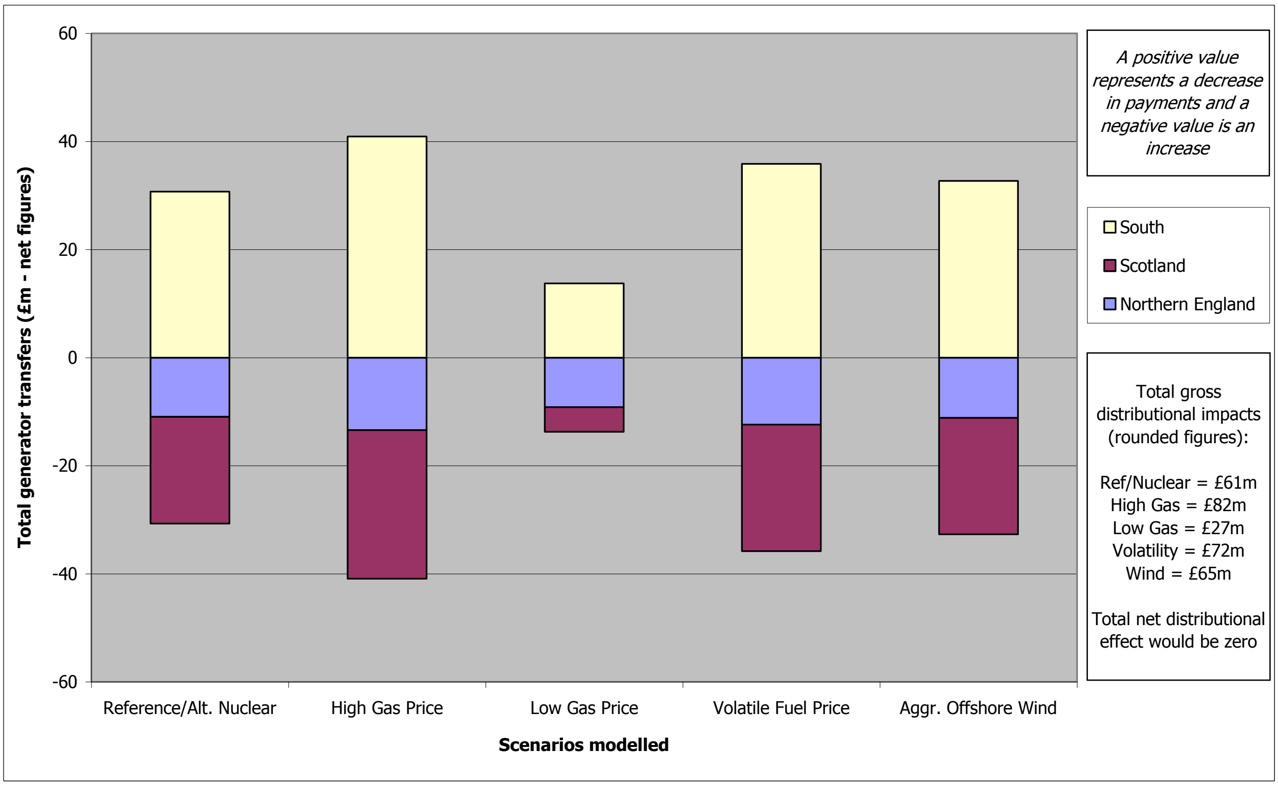
Graph 1 – Annualised distributional impacts on generators by TLF Zone (2011/12)



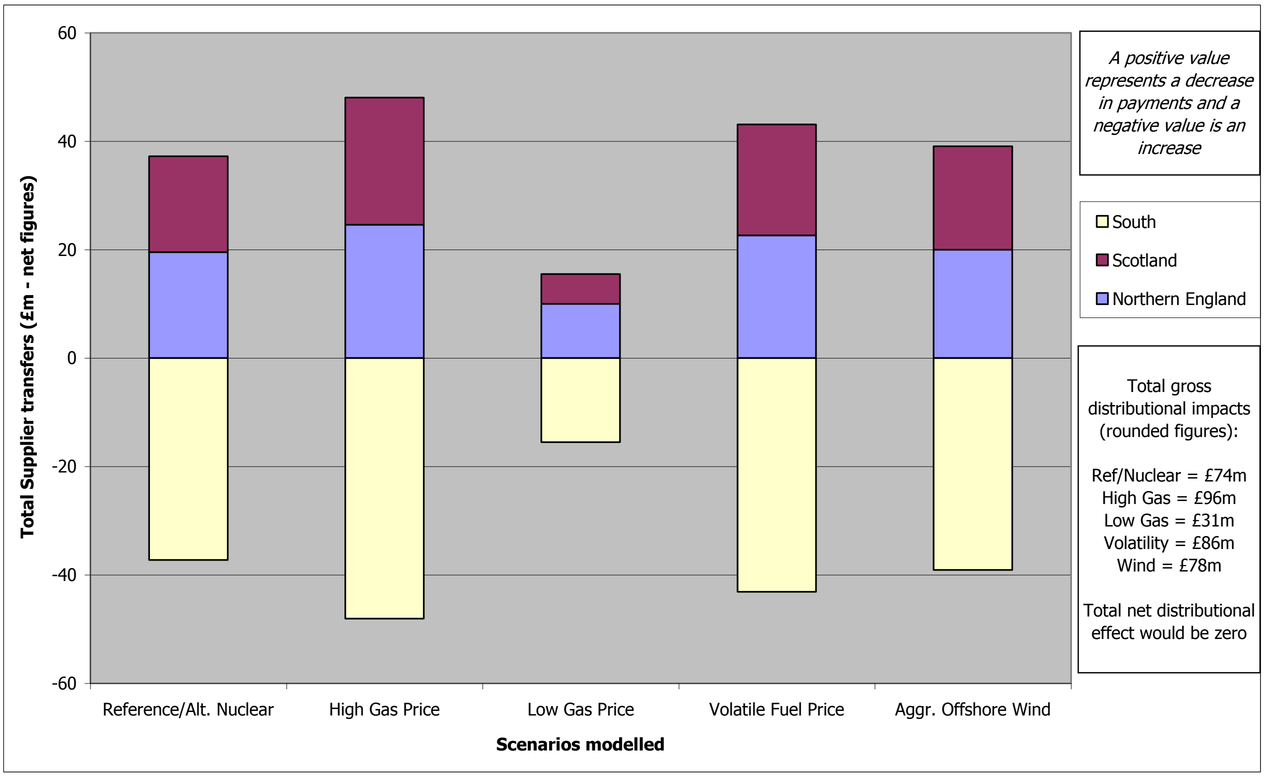
Graph 2 – Annualised distributional impacts on Suppliers by TLF Zone (2011/12)



Graph 3 – Annualised distributional impacts on generators by geographic region (2011/12)



Graph 4 – Annualised distributional impacts on Suppliers by geographic region (2011/12)

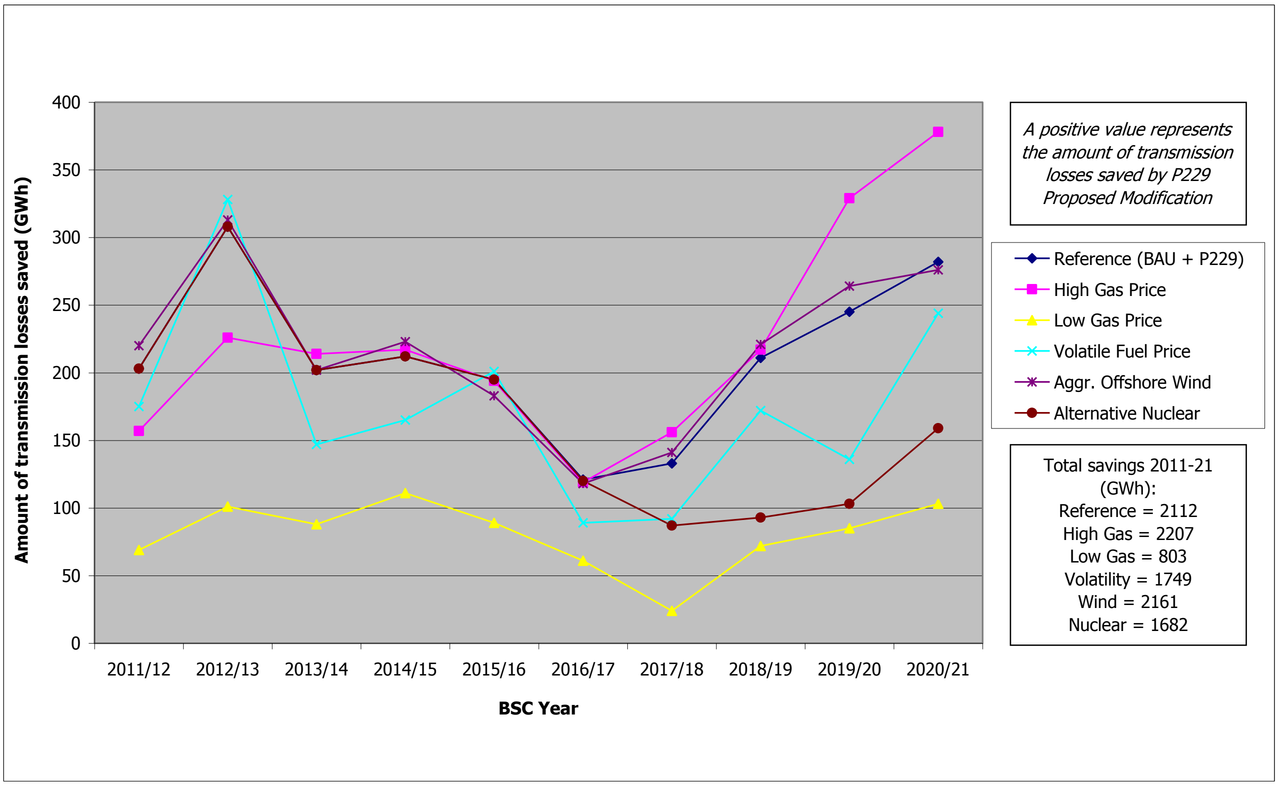


Impact on generation and transmission losses

Graph 5 shows the amount of transmission losses which would be saved under each of the scenarios for Proposed Modification P229.

This is the difference between the amount of transmission losses which occurred when applying seasonal zonal TLFs and that which would have been caused under the existing uniform allocation of losses (zero TLFs) in that scenario. You can find the figures behind this graph in Section 7.2.2 of LE/Ventyx's report. Although LE/Ventyx presented savings as negative figures, they are shown in the graph as positive values to make it easier to see where the level of savings rises and falls.

Graph 5 – Amount of transmission losses saved by Proposed Modification (GWh)



There are loss savings in each year of the analysis period under each scenario. These savings in GWh terms are significant, reaching over 250GWh in some years under all but the Low Gas Price scenario. For the Reference Scenario, the average annual reduction across the sample years amounts to 211.2GWh, which is almost 5.8% of existing grid losses.

The savings follow a similar trend across all scenarios, with initially high levels of savings falling in the middle years and rising again towards the end of the analysis period. The fall in years 2015-2017 is mainly due to the planned plant entry and exit in these years. Because the P229 TLFs for each BSC Year are calculated using the previous year's data, any significant deviation of entry and exit from the previous year would tend to reduce the savings from the introduction of seasonal zonal TLFs in any one year.

The High Gas Price Scenario has the highest level of loss savings. In this scenario, the increased gas price makes the financial value of any savings higher. It also makes the P229 TLFs 'keener', in the sense that there is greater incentive to shift despatch around the system. The Low Gas Price Scenario has the reverse effect. In line with this, the Volatile Fuel Price scenario results in volatility in loss savings between years.

The results for the Reference and Alternative Nuclear scenarios are identical until 2017, when the new nuclear base-load is introduced.

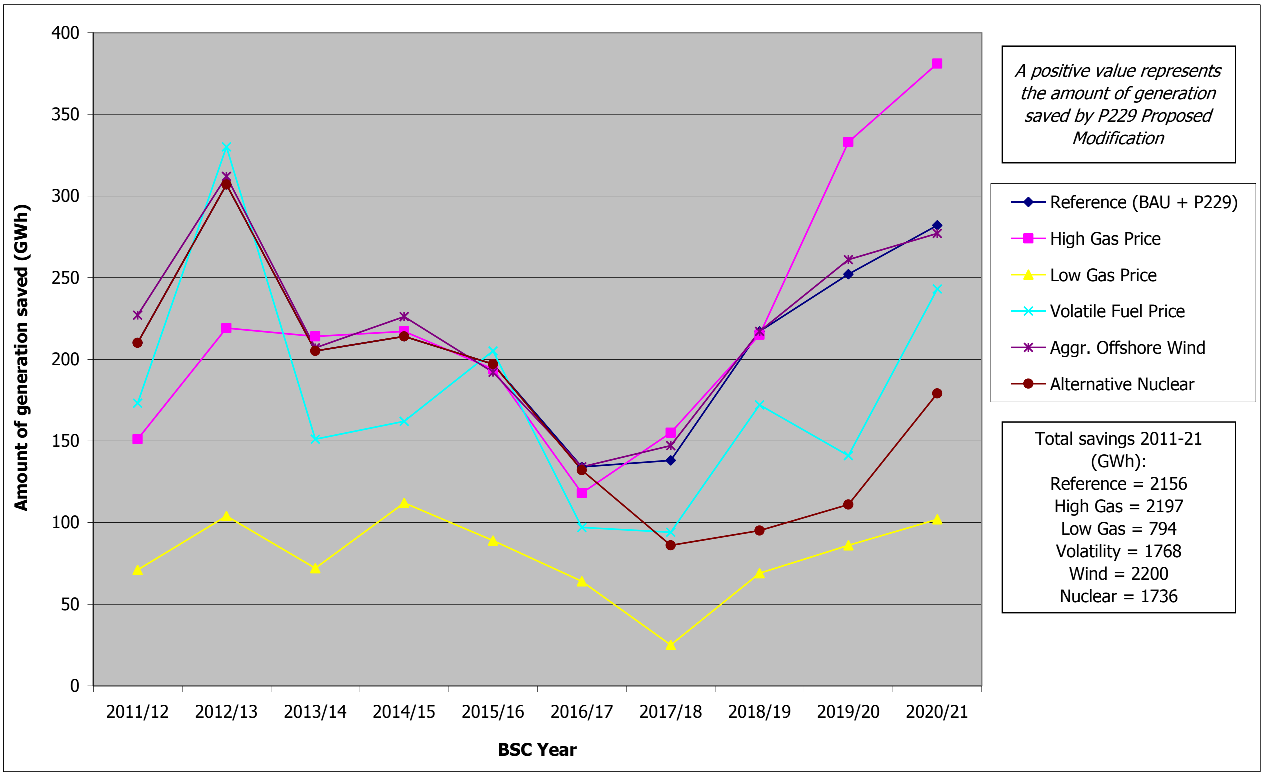
Graph 6 shows the amount (volume of energy in GWh) of generation which would be saved by Proposed Modification P229.

For each scenario, this is the difference between the volume of generation needed under a uniform loss allocation and seasonal zonal TLFs. You can find the figures behind this graph in Section 7.2.1 of LE/Ventyx's report. Again, LE/Ventyx presented savings as negative values but the graph shows them as positive for ease of understanding.

As would be expected, the trend is largely identical to that of the loss savings. This is because the reduction in transmission losses reduces the amount of generation needed to meet demand. Across all scenarios, the reductions in losses under the Proposed Modification account for at least 80% of the reductions in annual generation.

As for the loss reductions, the fall in savings in years 2015-2017 is due to significant plant entry and exit causing a greater mismatch between the year-ahead estimated TLFs and the actual TLFs that occur during real despatch.

Graph 6 – Amount of generation saved by Proposed Modification P229 (GWh)



Graph 7 shows the amount (in £m) of production costs which generators would save under Proposed Modification P229.

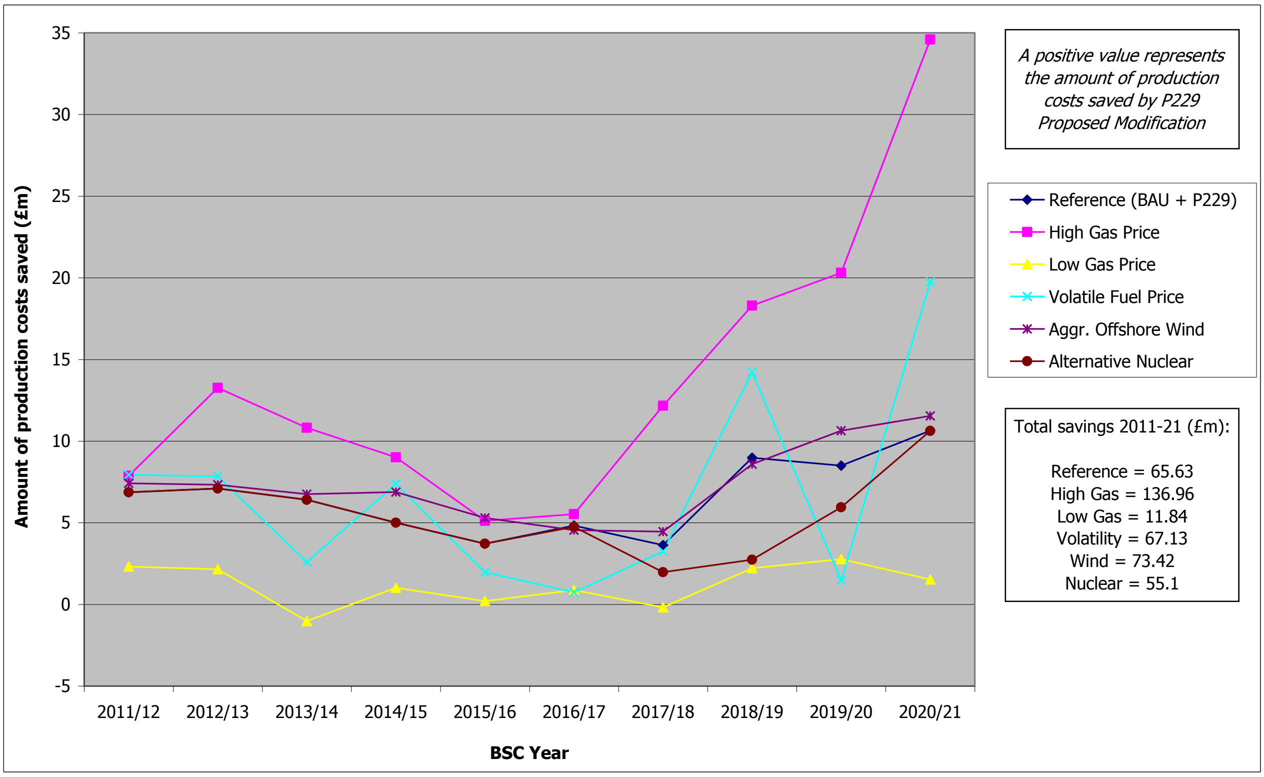
Again, the figures for each scenario are the difference between production costs under the current uniform charging and under seasonal zonal TLFs. You can find the figures behind this graph in Section 7.2.3 of LE/Ventyx's report.

The trend mirrors that of the savings in losses/generation, because the production costs are the net fuel savings (reduced fuel consumption) caused by the reduction in transmission losses and changes to despatch.

With just two exceptions (both in the Low Gas Price Scenario), there are positive net production cost savings in each year of the analysis. The average NPV across scenarios is £6.8m.

Note that the figures in Graph 7 also include the costs of changes in CO_2 emissions, because these emissions form part of generators' production costs under the EU ETS scheme. The CO_2 emission changes are explained in more detail below.

Graph 7 – Amount of production costs saved by Proposed Modification P229 (£m)



Impact on environmental emissions

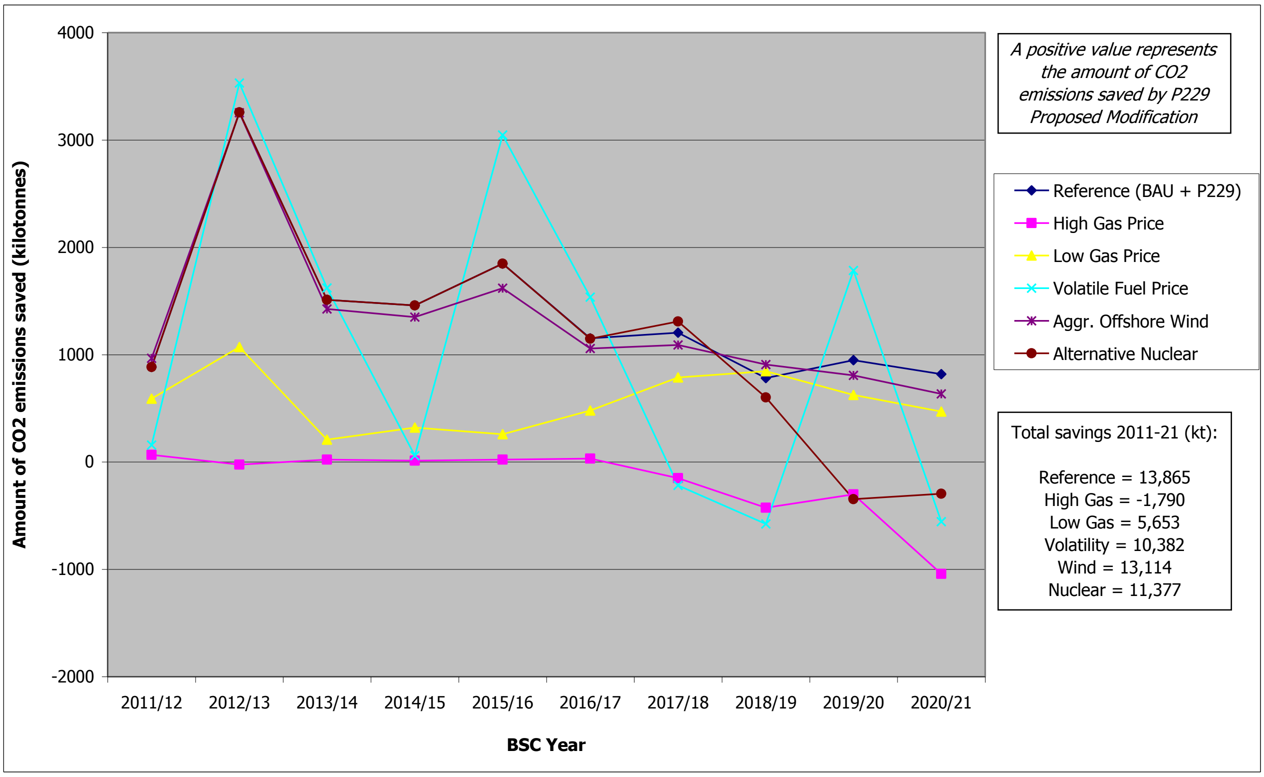
Graphs 8, 9 and 10 show the impact of Proposed Modification P229 on the amount of CO_2, NOx and SOx emissions respectively. Savings are shown as positive values.

For each Proposed Modification scenario, the figures in the graphs are the difference in kilotonnes between the amount of emissions which occurred under seasonal zonal TLFs compared with that which was caused under the uniform allocation of transmission losses (zero TLFs) in that scenario. You can find the figures behind the graphs in Sections 7.2.4-7.2.6 of LE/Ventyx's report.

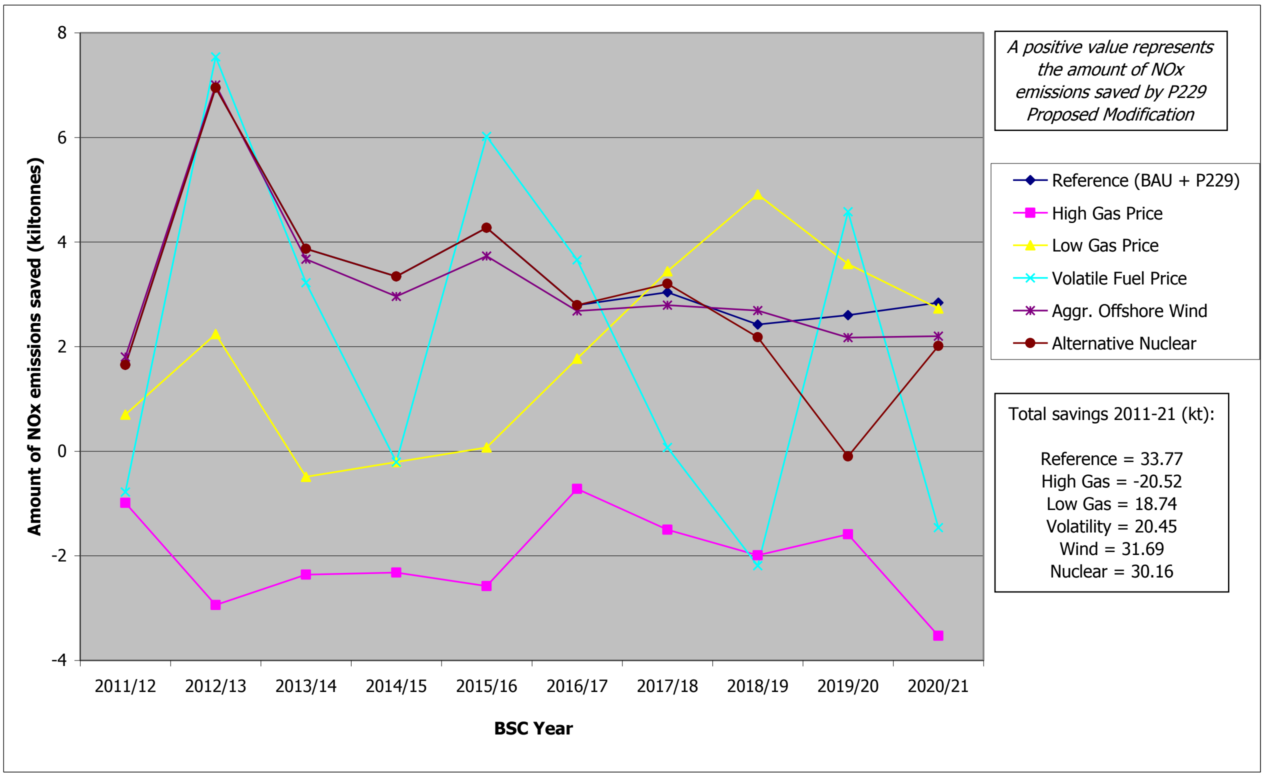
The financial benefit of CO_2 reductions is priced according to the EU ETS and is therefore included in the production cost savings shown in Graph 7. The treatment of CO_2 output is therefore similar to that of fuel input. Marginal abatement costs of £1,319 per tonne and £2,493 per tonne were used to price NOx and SOx emissions respectively in the overall benefit figures in Table 1.

Because the magnitude of SOx savings is much greater than those for NOx emissions, reductions in SOx emissions are one of the biggest financial benefits from Proposed Modification P229.

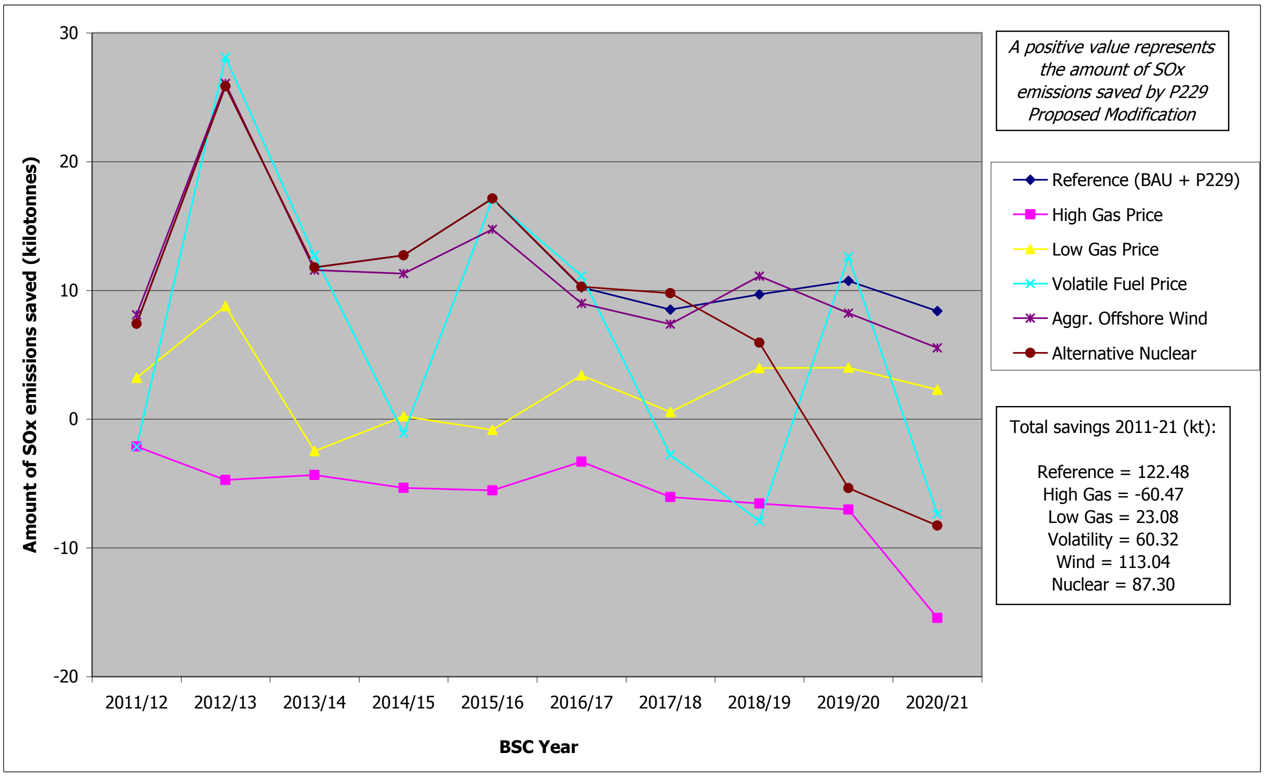
Graph 8 – Amount of CO_2 emissions saved by Proposed Modification P229 (kilotonnes)



Graph 9 – Amount of NOx emissions saved by Proposed Modification P229 (kilotonnes)



Graph 10 – Amount of SOx emissions saved by Proposed Modification P229 (kilotonnes)



Reductions in all 3 emissions types follow a similar trend over time. However, differences in the level of reductions are most pronounced in scenarios with changing fuel prices. If the fuel price rises, the analysis estimates that there will be a partial switch between low-emission and high-emission fuels, resulting in an increase in the volume and value of emissions. The reverse is true of a reduction in fuel price.

As expected, the emissions savings under the Volatile Fuel Price Scenario are themselves volatile. This is because the savings are a function of both loss reductions (lower total generation) and fuel switching, which in this scenario could go either way as relative fuel prices change.

Again, the results for the Reference and Alternative Nuclear scenarios are identical until 2017. However, by 2019 there is an increase in emissions under the Alternative Nuclear Scenario due to the introduction of a significant amount of base-load nuclear capacity. Although the overall level of emissions in the Alternative Nuclear Scenario is lower than the Reference Scenario, the opportunity for P229 zonal TLFs to reduce emissions is reduced due to the significant increase in (zero-emission) nuclear generation. The emissions savings which are directly attributable to P229 (which is what the graphs show) are therefore lower in this scenario.

Impact on market prices

Graphs 11 and 12 show the changes in Off-Peak and Peak wholesale prices under Proposed Modification P229. Increases are represented as positive values, and decreases as negative.

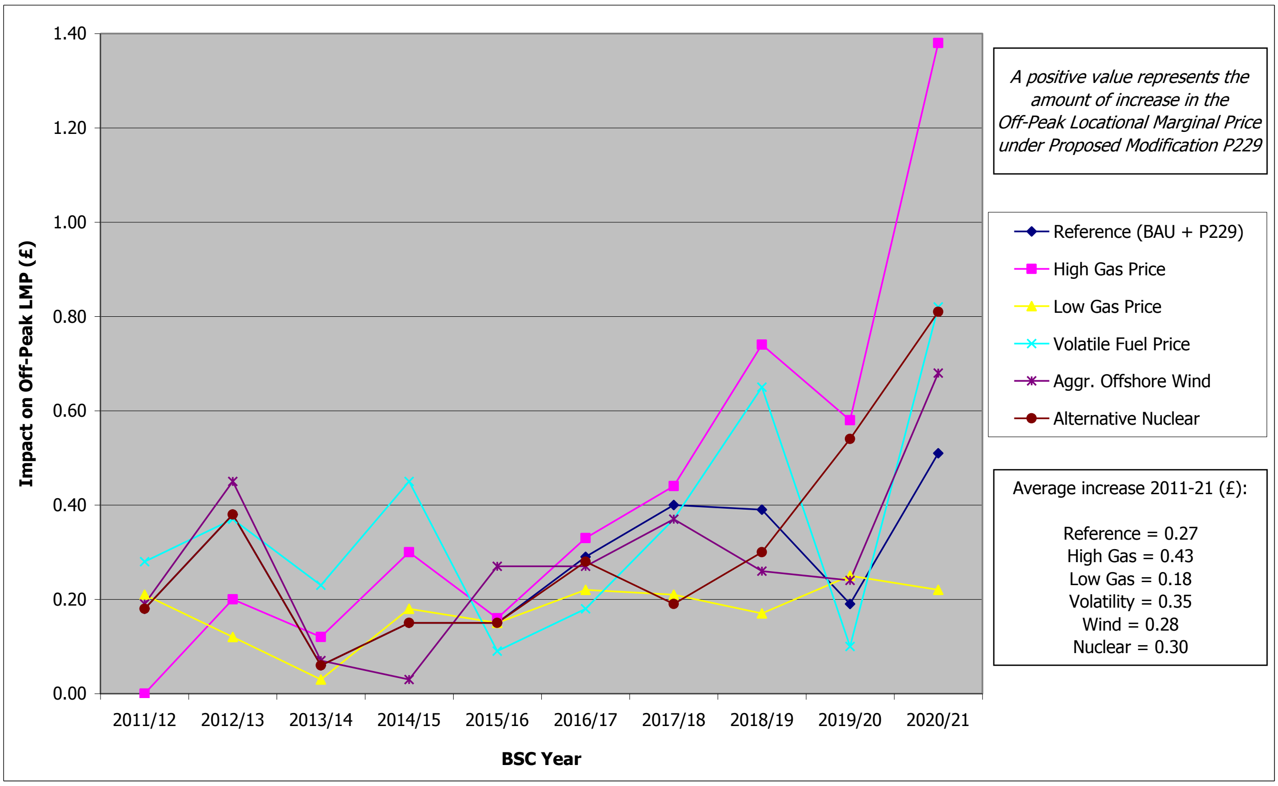
Since LE/Ventyx assumed competitive despatch and competitive pricing, the prices used in this analysis are the locational marginal costs from the despatch (LMPs), and are the load weighted-average of the hourly simultaneous optimisation of despatch and transmission.

For each Proposed Modification scenario, the figures in the graphs represent the difference in price under seasonal zonal TLFs compared with a uniform allocation of transmission losses (zero TLFs) in that scenario. You can find the figures behind the graphs in Sections 7.2.7 and 7.2.8 of LE/Ventyx's report.

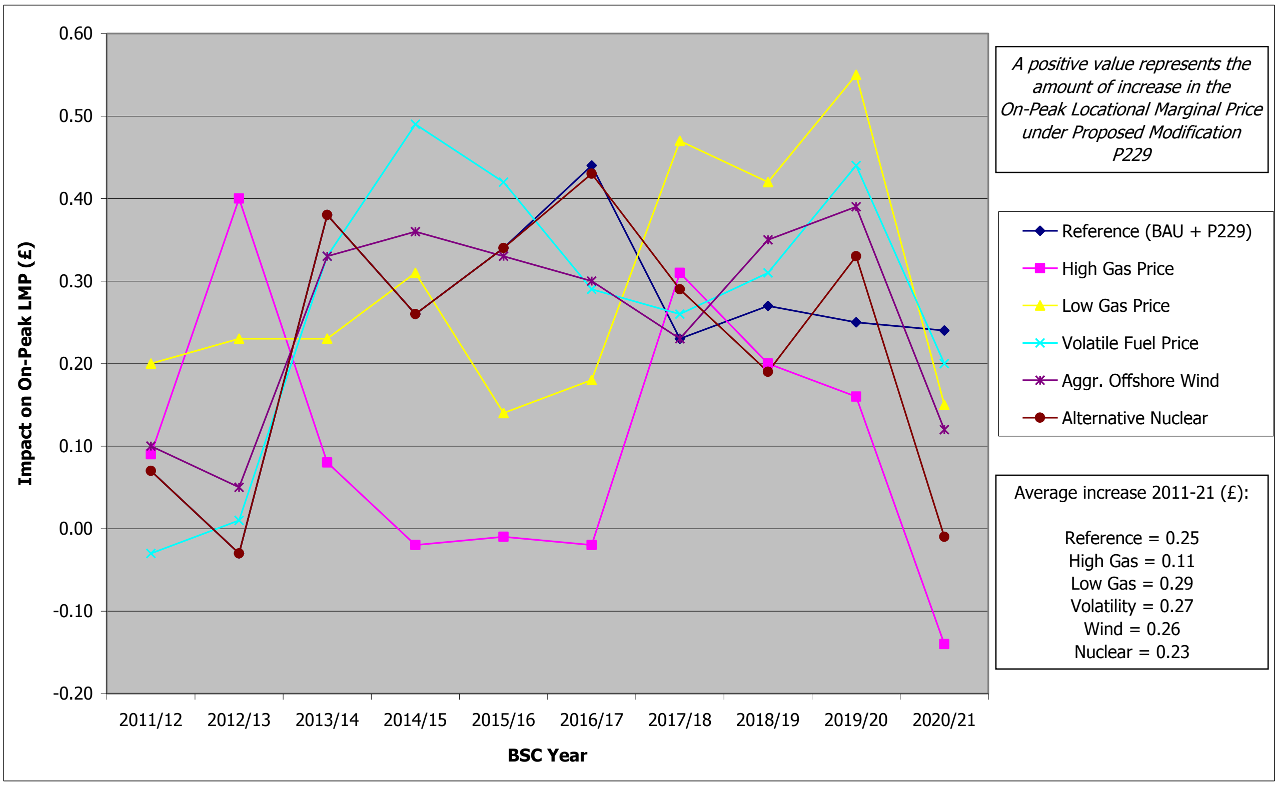
In general, the LMPs are higher under the Proposed Modification. This is intuitive as the pure despatch cost, ignoring transmission losses, should be optimal with respect to cost minimising without transmission losses. Therefore, optimising over both despatch and losses, while minimising cost on the whole, should raise the pure unit cost of despatch (LMPs).

However, the overall impact under all scenarios is small, and is lower for Peak prices than for Off-Peak. The greatest change in Off-Peak prices occurs under the High Gas Price Scenario, with the greatest Peak change in the Low Gas Scenario.

Graph 11 – Impact of Proposed Modification P229 on Off-Peak Locational Marginal Price (£)



Graph 12 – Impact of Proposed Modification P229 on On-Peak Locational Marginal Price (£)



Impact on the Transmission System

Impact on flows

LE/Ventyx examined the % change in annual flows over the GB Transmission System by voltage level (132kV, 275kV and 400kV) and by year.

It concluded that the reduction in transmission losses/generation under Proposed Modification P229 has the effect of reducing flows on the system at each voltage level, and in every year of each scenario. The amount of savings are small but significant, and increase with the voltage level under all scenarios such that they are greatest at 400kV. You can find the specific figures in Sections 5.8, 6.2.9, 6.3.8, 6.4.8, 6.5.8 and 6.6.9 of LE/Ventyx's report.

For many of the years in the analysis period, the High Gas Price Scenario gives reductions in 400kV line flows which are approximately twice as high as those in the low gas price scenario.

LE/Ventyx concluded that P229 would have no difference in impact on generators who are connected to the 132kV transmission network, compared with those connected at 275kV or 400kV, because all generators within a Zone receive the same TLF regardless of voltage.

Impact on congestion

Graph 13 shows the % change which Proposed Modification P229 causes in the annual number of hours with Transmission System congestion. Savings are represented as negative values.

In most of the scenarios, there are significant reductions in congestion. The increase in congestion in the later years of all but the Alternative Nuclear Scenario is due to plant entry and exit, and the fact that no transmission expansion was modelled beyond the point described in National Grid's 2008 SYS (which ended in 2014/15). LE/Ventyx expected that congestion would typically increase over time and that, in reality, over a ten-year period some of these issues would be addressed by the System Operator.

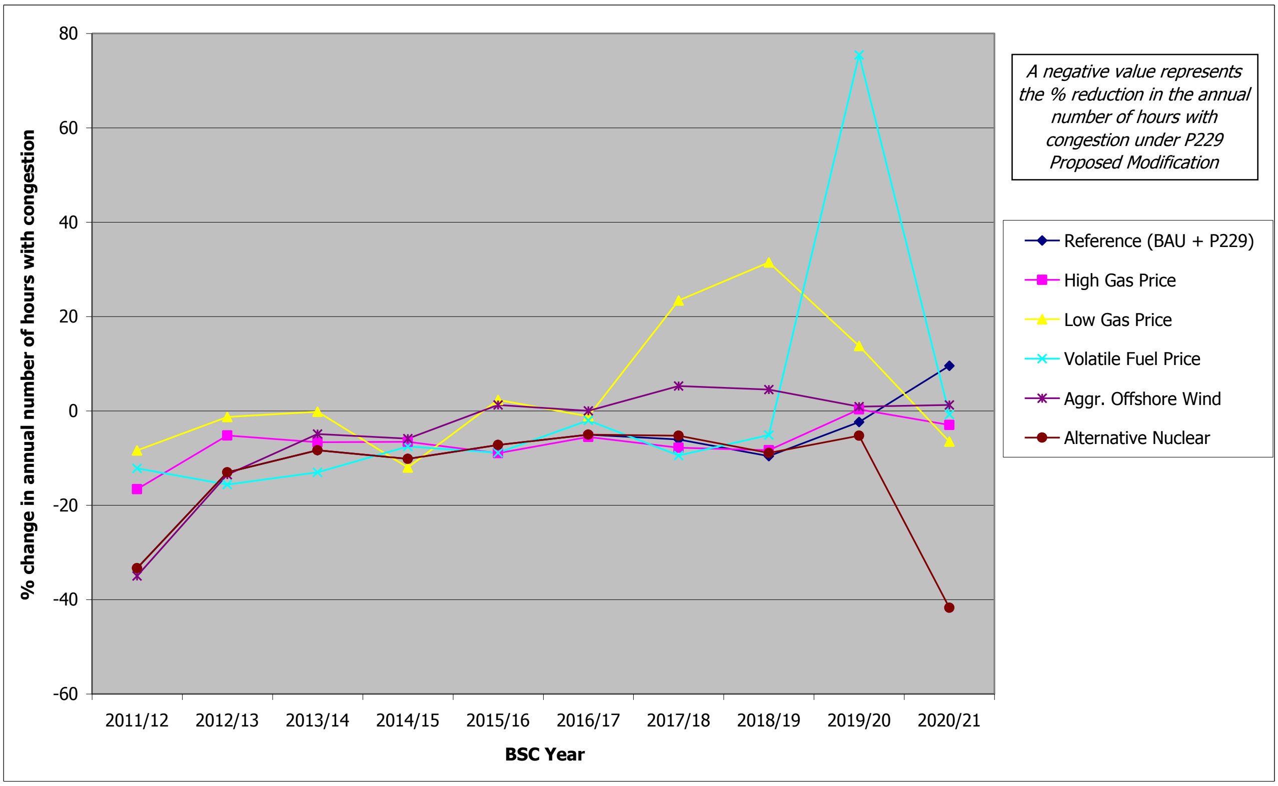
The exception to this trend is the Alternative Nuclear Scenario, where the introduction of new nuclear base-load from 2017 reduces the total number of congested hours.

Reductions in congestion fluctuate more, and are lower, under the Low Gas Price Scenario than the High Gas Price Scenario. This reflects the lesser impact of TLF signals under a low gas price (see the section on generation response above for a more detailed explanation). The greatest differences between individual years are in the Volatile Fuel Price Scenario. The high increase in 2019 under this scenario is a % increase on what is a low base, and may also reflect some additional uncertainty in later years.

You can find the figures for this graph in Sections 5.8, 6.2.9, 6.3.8, 6.4.8, 6.5.8 and 6.6.9 of LE/Ventyx's report.

LE/Ventyx considered that it is difficult to say precisely what the impact of P229 would be on Transmission System capacity requirements. Reductions in transmission losses would be akin to having additional generation and capacity at certain times. However, these losses are only a small % of total production and capacity. Capacity also only becomes an issue at peak system times or under rare events, and public data on these is unavailable. Overall, LE/Ventyx concluded that Proposed Modification P229 could have a small and positive, though probably somewhat insignificant, impact on total capacity requirements.

Graph 13 – % change in number of congested hours under Proposed Modification P229



Impact on renewable generation (transmission connected and embedded)

LE/Ventyx concluded that Proposed Modification P229 would not have any discernable impact on renewables, and especially not on future renewable capacity/energy.

LE/Ventyx considered that the site location and the available ambient conditions for power generation are often highly site-specific and idiosyncratic. Large-scale renewables are likely to be Offshore and Onshore wind, where wind conditions and grid and other infrastructure siting factors will be paramount. LE/Ventyx noted that, using information on planned projects from Round 1 and 2 schemes, large Offshore wind generation is going in the South (where generators' Trading Charges will reduce under P229) as well as the North (where generators' Trading Charges will increase).

LE/Ventyx considered that small-scale renewables are more likely to be embedded in a Distribution System, and so would not explicitly face the impacts of P229. One of benefits of embedded generation is that it decreases losses (potentially at the transmission and distribution level) by reducing the demand within a Zone. This benefit is highest in Zones with a lot of demand (e.g. in the South) or where transmission connections are further away (e.g. in the North). LE concluded that this suggests an ambiguous, if any, impact on embedded generation. You can find more information in Section 7.4 of LE/Ventyx's report.

What were the results of the Alternative Modification cost-benefit analysis?

The following sections set out LE/Ventyx's key conclusions from its cost-benefit analysis of Alternative Modification P229. You can download its full analysis report here.

All tables and graphs have been produced by ELEXON using the figures in LE/Ventyx's report.

To model the effects of the Alternative Modification, LE/Ventyx recalculated the seasonal zonal TLFs such that these were scaled down to prevent energy 'credits'. All other modelling techniques/calculations were unchanged.

LE/Ventyx then re-ran the Reference Scenario using these TLFs but with all other assumptions remaining the same. This allows the Alternative Modification results to be compared directly with those for the Proposed Modification Reference Scenario, as the 'base case' (of the current uniform loss charging under BAU assumptions) is identical.

Any difference in results between the Alternative Modification and the Proposed Modification Reference Scenario is therefore wholly attributable to the scaling of the TLFs.

Overall conclusions and net benefit to market

Table 2 shows the total net cost-benefit for the Alternative Modification over the 10-year analysis period, compared with the Proposed Modification Reference Scenario.

As in Table 1, these figures are net of the P229 implementation/operation costs but do not take account of the distributional impact on Parties' Trading Charges.

Alternative Modification P229 scales down the seasonal zonal TLFs to ensure that they do not result in any energy 'credits'. As expected, it therefore reduces the distributional impacts of the TLFs, but also reduces the benefits compared with the Proposed Modification. This is because it is the distributional impacts which give the financial signals for generation re-despatch and demand response.

The net present benefit (NPV) under the Alternative is over 70% lower than the Proposed Modification Reference Scenario. LE/Ventyx concluded that it was for the those considering the P229 CBA results to decide how to weigh this against the reduced distributional impacts, and to judge the appropriateness of Parties receiving energy 'credits' as a result of Seasonal zonal TLFs.

Table 2 – LE/Ventyx scenarios of future benefits of Alternative Modification P229 to 2020/2021 (£m discounted figures)

NPV of all benefits 2011-2021 (£m with 4.42% discount rate)	Proposed Modification	Alternative Modification	Difference	% Difference
Generation response benefits excluding NOx/SOx	46.12	12.44	-33.7	-73.0
Generation response benefits including NOx/SOx	275.16	75.90	-199.3	-72.4
Demand response benefits	1.74	0.09	-1.7	-94.8
TOTAL all benefits	**276.90**	**76.00**	**-200.9**	**-72.6**

The areas of benefit from the Alternative Modification are consistent with those for the Proposed Modification Reference Scenario, as are the trends over time. However, in each set of results the overall magnitude of the impact is smaller under the Alternative because of the scaling down of TLFs.

Further information on the Alternative Modification results, and how these compare with the Proposed Modification, is provided below

Distributional impacts

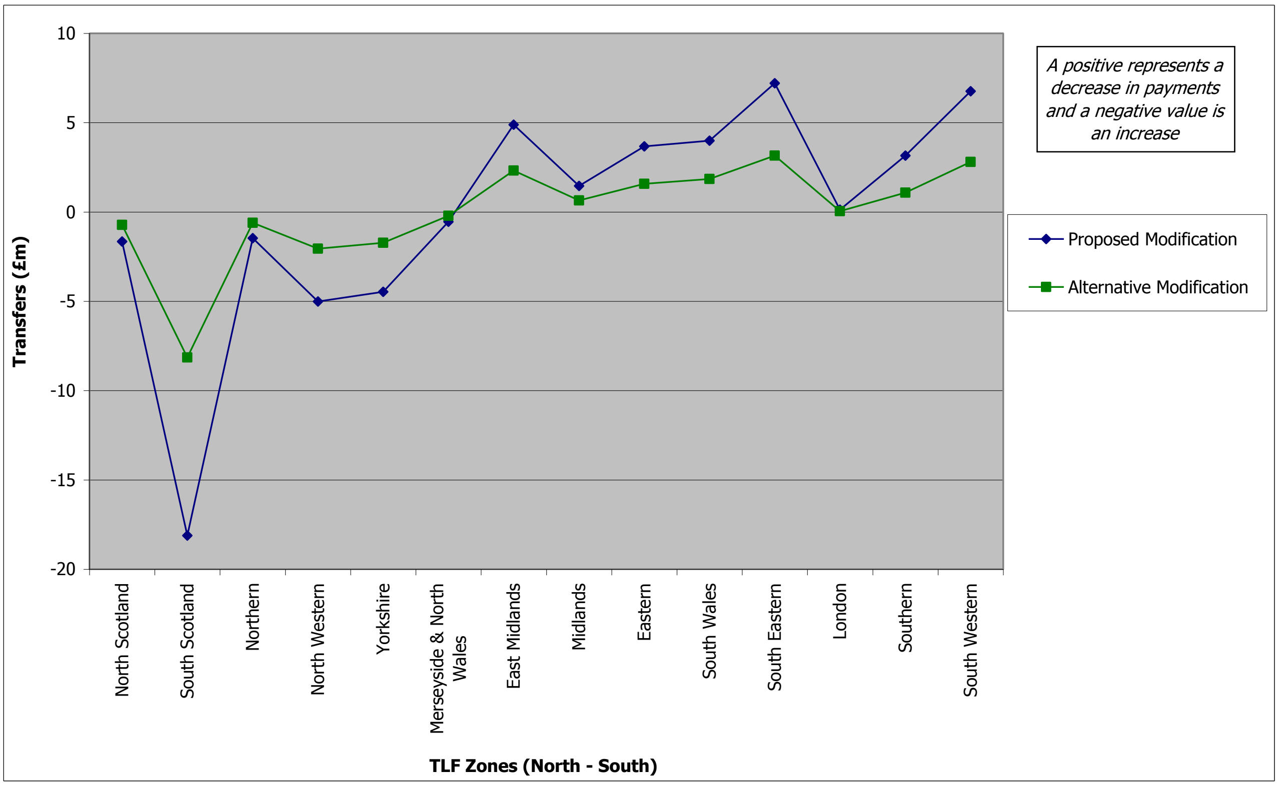
Graphs 13 and 14 show the total annualised distributional impacts for 2011/12 under the Alternative Modification (Reference Scenario), compared with the Proposed Modification (Reference Scenario).

Graphs 15 and 16 show the distributional impacts for generators and Suppliers aggregated by geographic area.

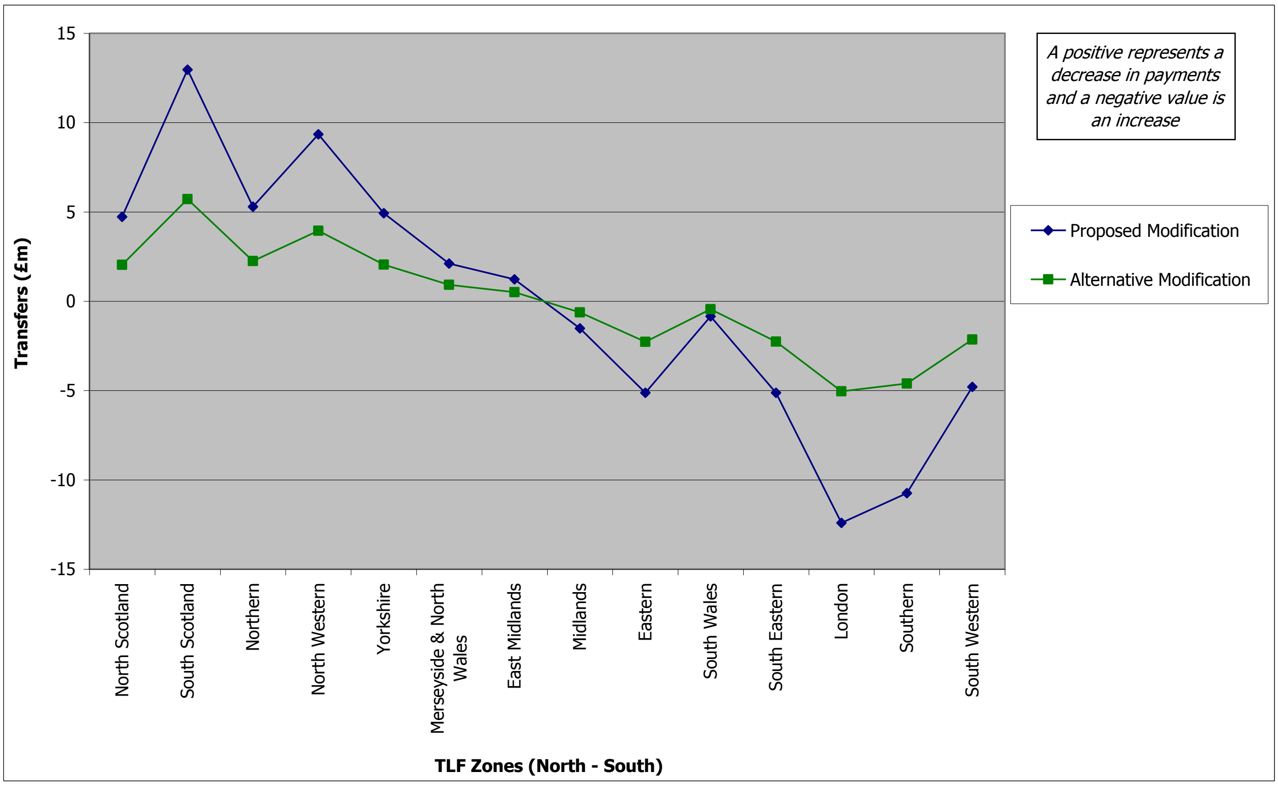
The basis for these figures is identical to Graphs 1-4. You can find the Alternative Modification figures in Section A1.3.8 of LE/Ventyx's report.

The locational pattern of the distributional impacts is consistent between the Proposed and Alternative Modifications. However, under the Alternative the magnitude of the impacts is reduced. On average by Zone, the impact is reduced by 59% for generators and 56% for Suppliers.

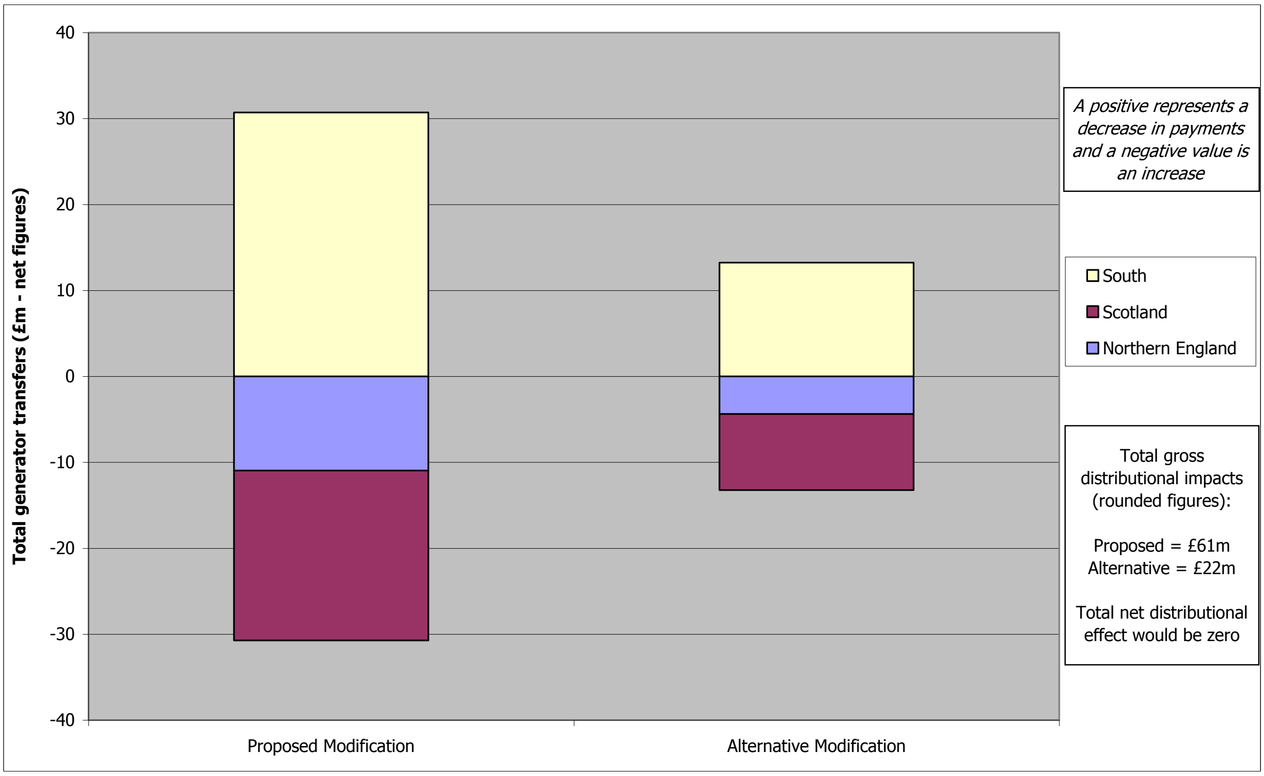
Graph 14 – Annualised distributional impacts on generators by TLF Zone (2011/12)



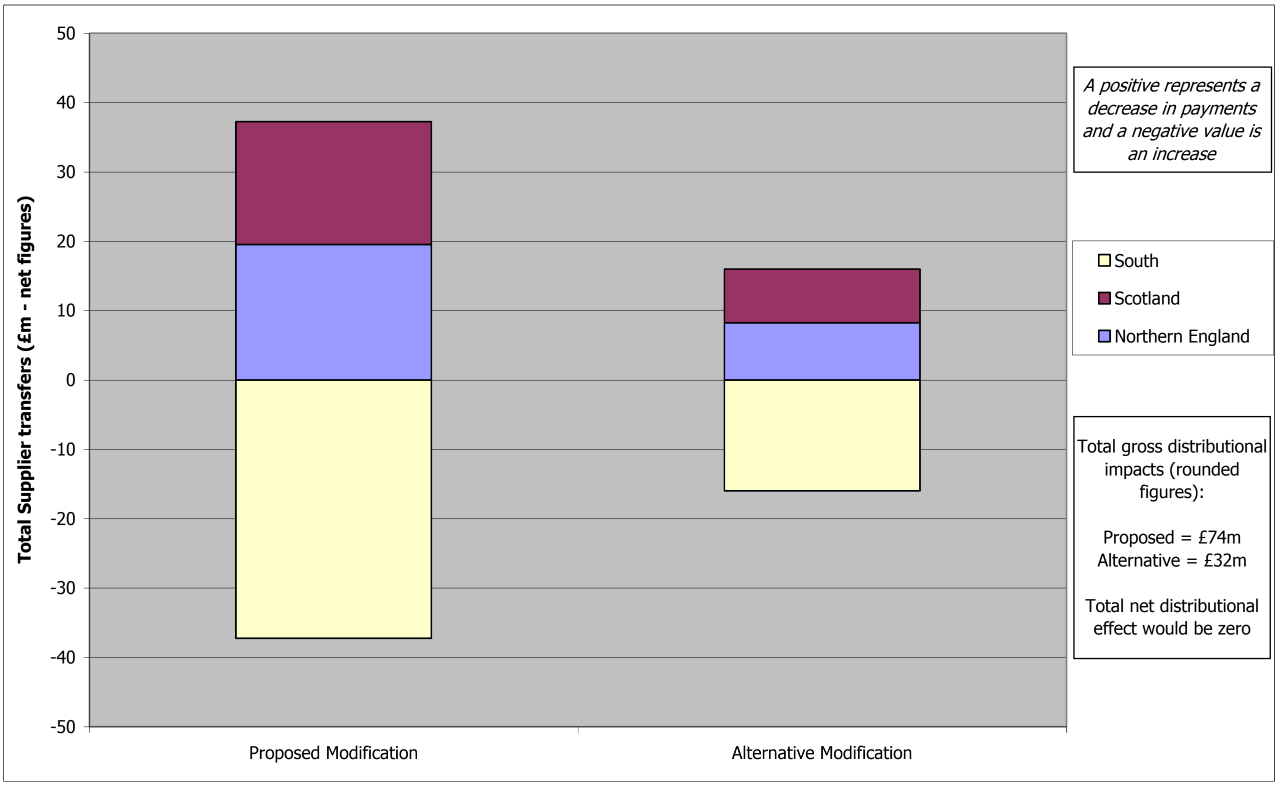
Graph 15 – Annualised distributional impacts on Suppliers by TLF Zone (2011/12)



Graph 16 – Annualised distributional impacts on generators by geographic region (2011/12)



Graph 17 – Annualised distributional impacts on Suppliers by geographic region (2011/12)



Impact on generation and transmission losses

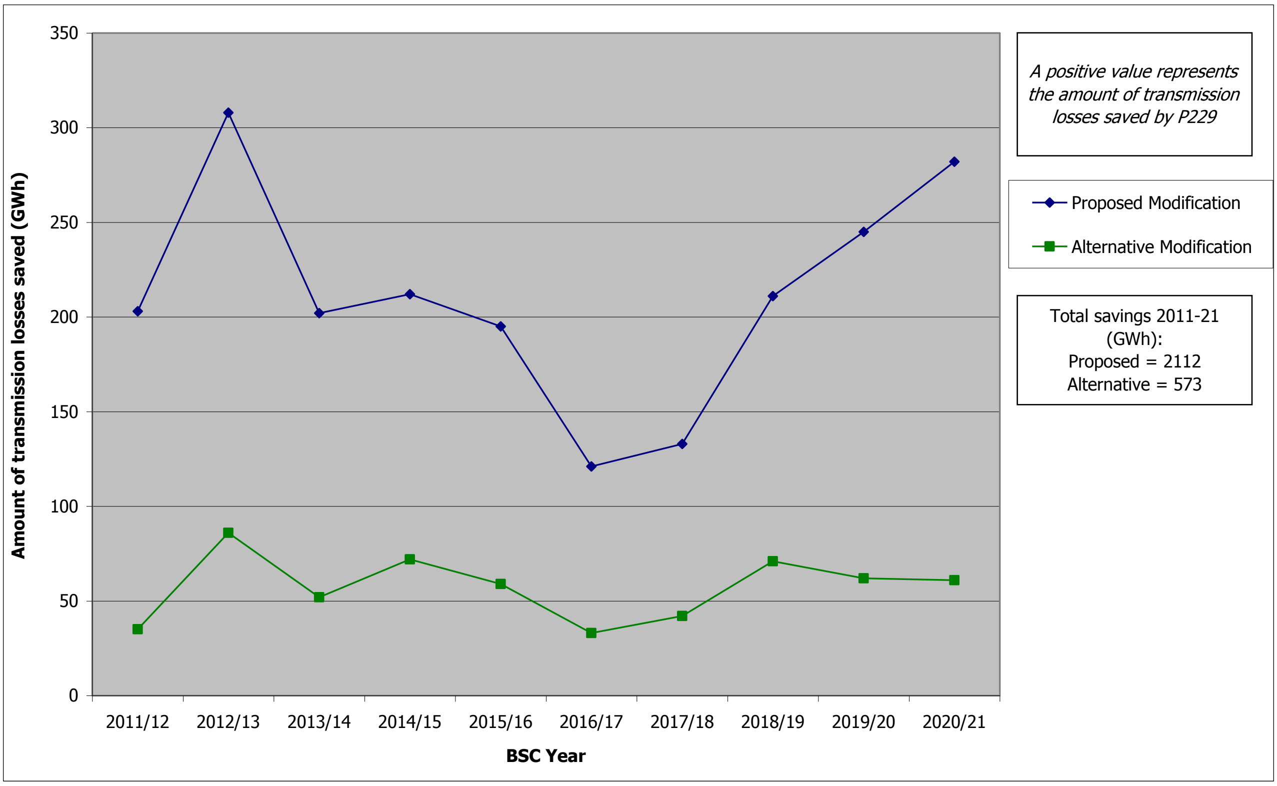
Graph 17 shows the amount of transmission losses which would be saved under the Alternative Modification (Reference Scenario) compared with the Proposed Modification (Reference Scenario).

Graph 18 shows the amount of generation which would be saved by the Alternative compared with the Proposed Modification, while Graph 19 shows the production cost savings.

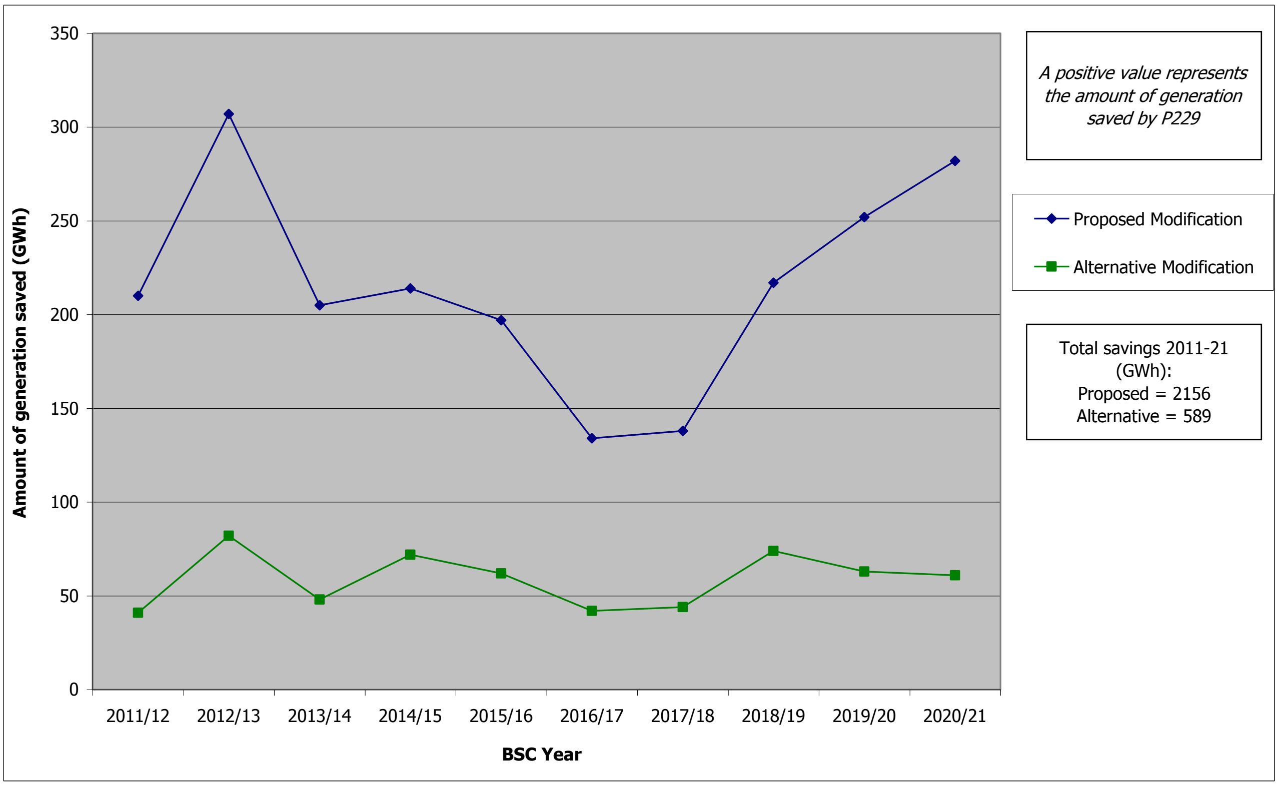
The basis for these figures is identical to Graphs 5, 6 and 7. You can find the Alternative Modification figures in Annex 2 of LE/Ventyx's report, Comparison of Results (Table A2.1).

As for the Proposed Modification, the Alternative gives significant savings in each year of the analysis period. These savings follow a similar trend, with production cost savings being driven by loss reductions. However, the scale of the savings is considerably less under the Alternative. Loss savings reach a peak of just over 80GWh, compared with just over 300GWh for the Proposed Modification.

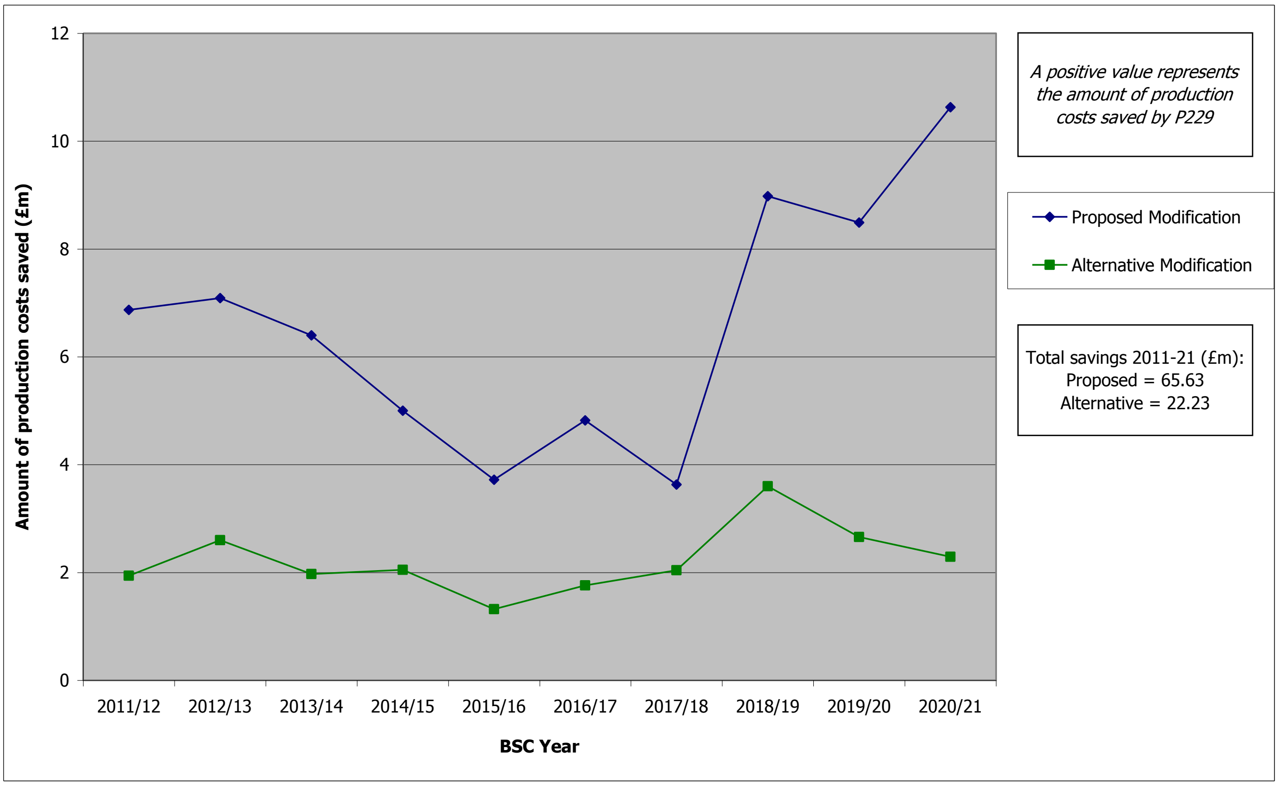
Graph 18 – Amount of transmission losses saved by Alternative Modification P229 (GWh)



Graph 19 – Amount of generation saved by Alternative Modification P229 (GWh)



Graph 20 – Amount of production costs saved by Alternative Modification P229 (£m)



Impact on environmental emissions

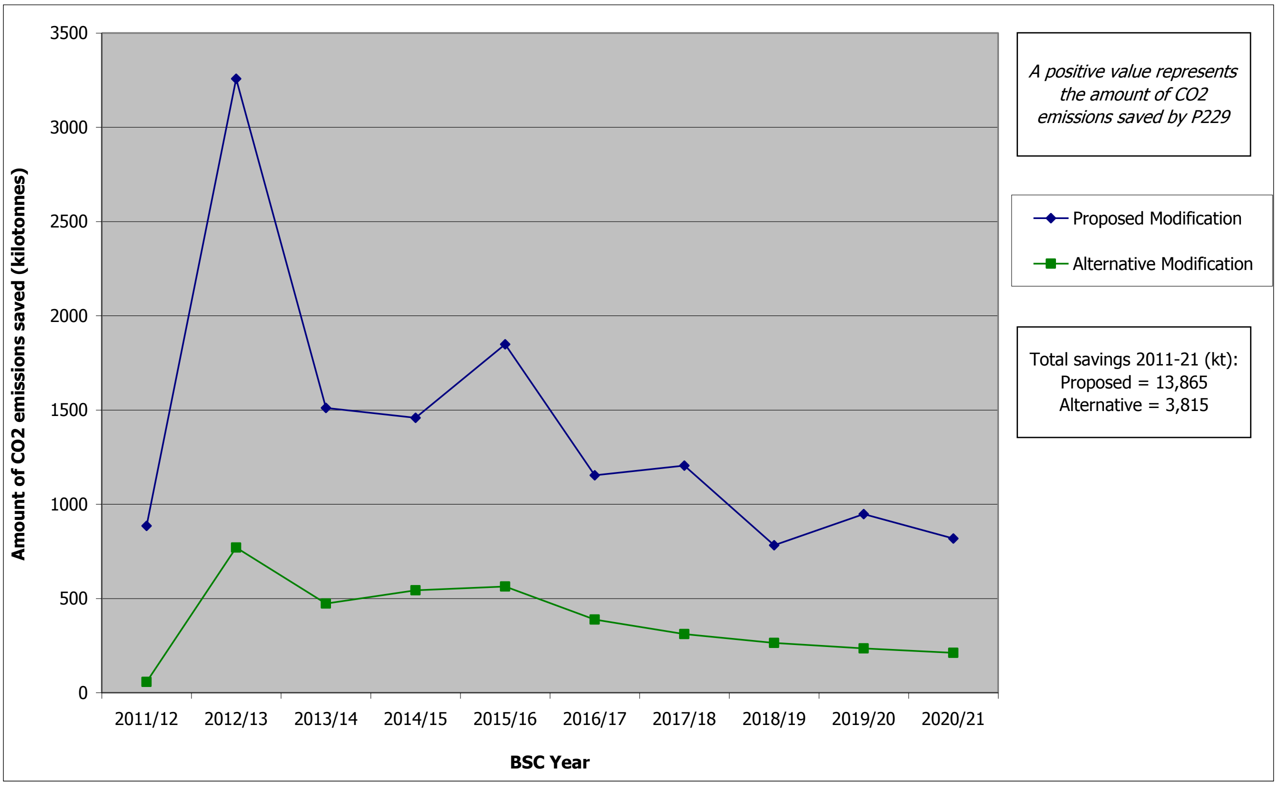
Graphs 20, 21 and 22 compare the impacts of the Alternative Modification (Reference Scenario) and Proposed Modification (Reference Scenario) on the amount of CO_2, NOx and SOx emissions.

The basis for these figures is identical to Graphs 8, 9 and 10. You can find the Alternative Modification figures in Annex 2 of LE/Ventyx's report, Comparison of Results (Table A2.1).

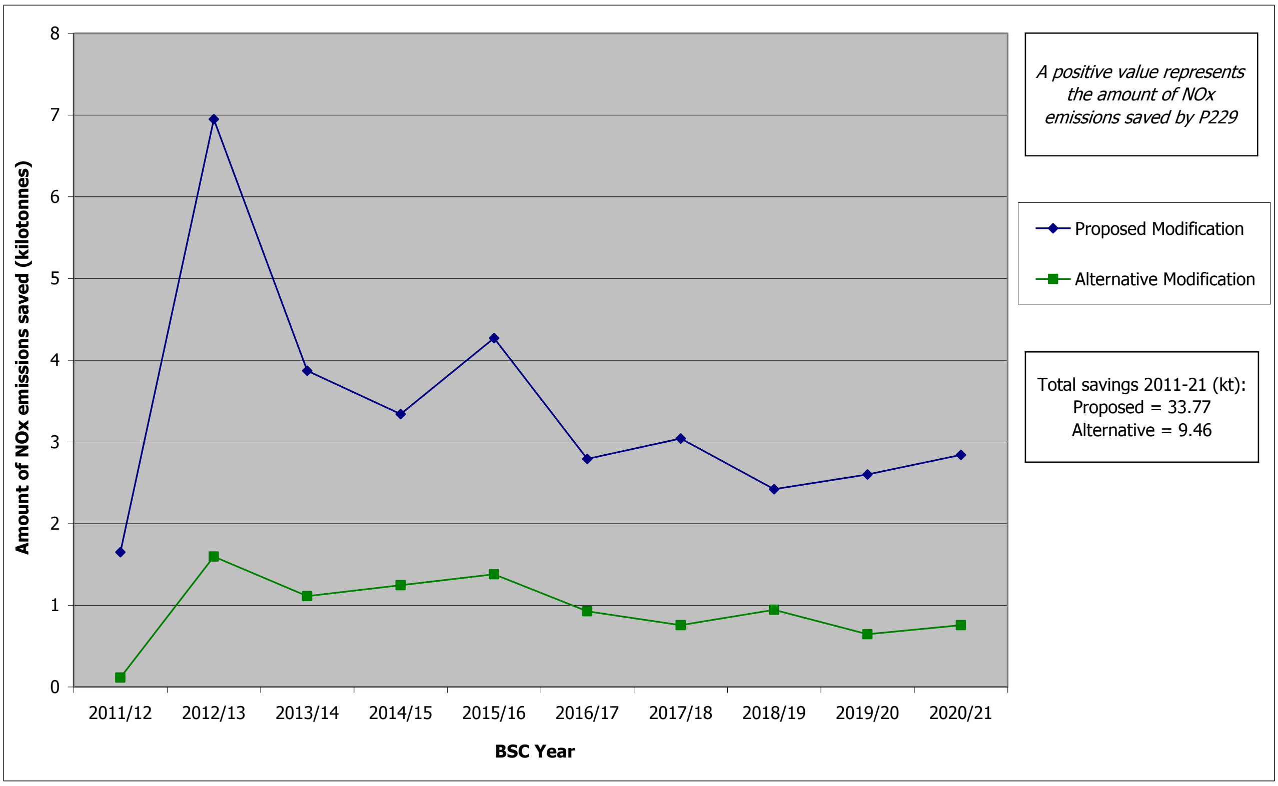
Savings follow a similar trend under the Alternative to the Proposed Modification, but are smaller overall.

Note that, as for the Proposed Modification, the price of the CO_2 emissions reduction was captured in the production cost savings for the Alternative Modification. NOx and SOx emissions were priced separately under the Alternative using the same marginal abatement cost figures as the Proposed Modification. Again, the biggest financial savings come from the reduction in SOx emissions.

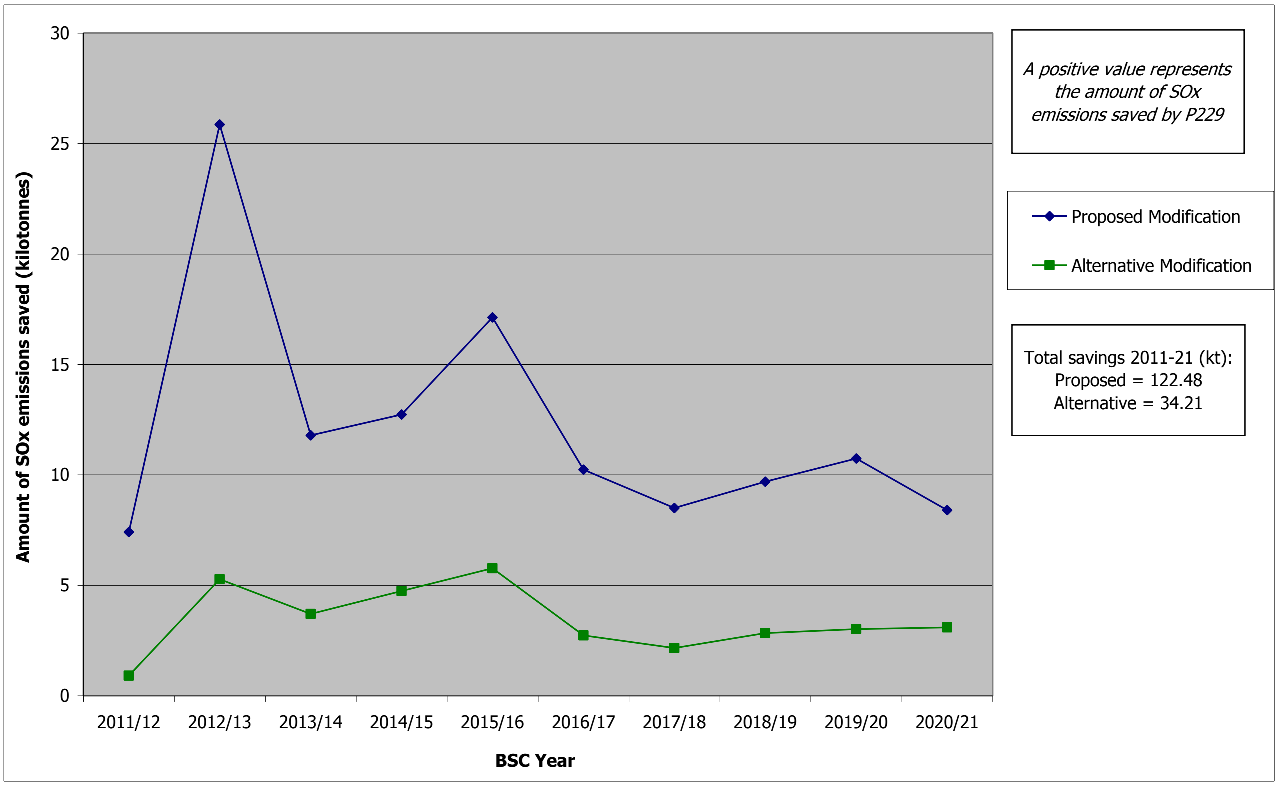
Graph 21 – Amount of CO_2 emissions saved by Alternative Modification P229 (kilotonnes)



Graph 22 – Amount of NOx emissions saved by Alternative Modification P229 (kilotonnes)



Graph 23 – Amount of SOx emissions saved by Alternative Modification P229 (kilotonnes)



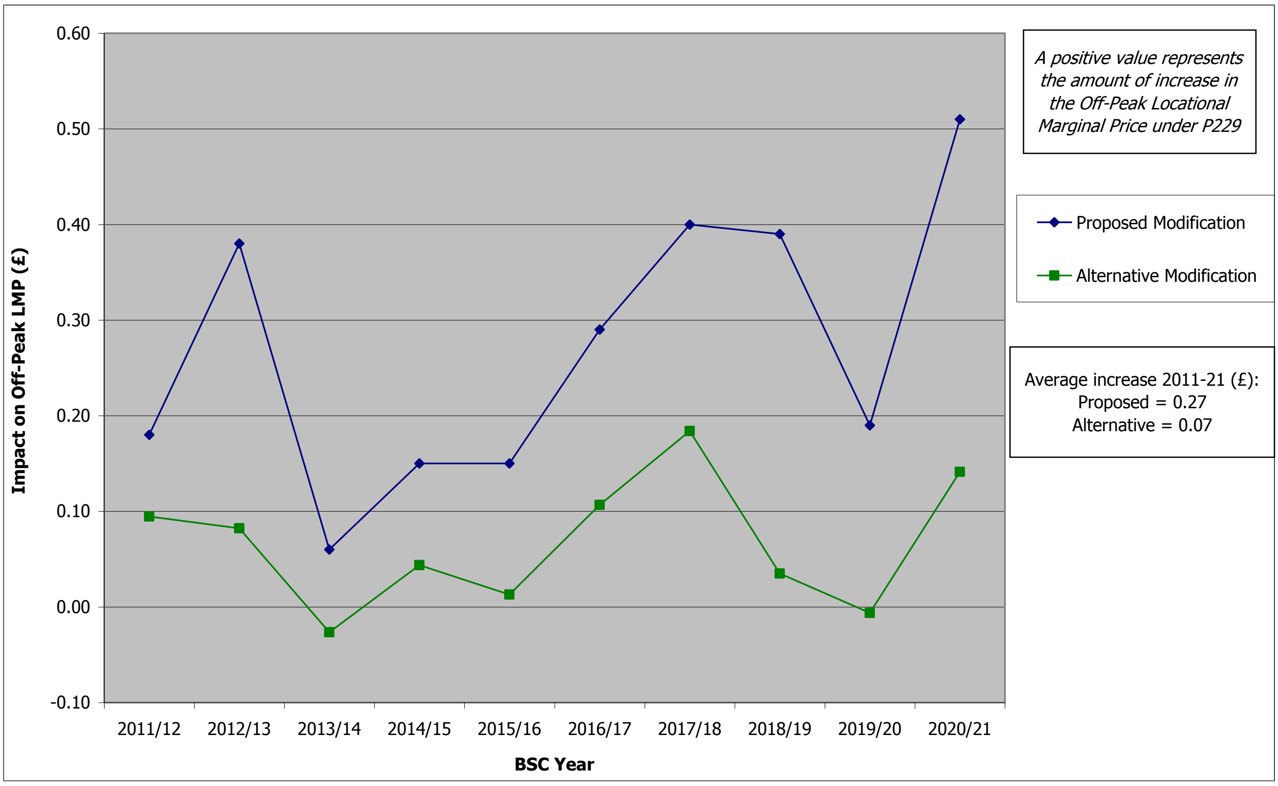
Impact on market prices

Graphs 23 and 24 compare the impacts of the Alternative Modification (Reference Scenario) and Proposed Modification (Reference Scenario) on Off-Peak and Peak wholesale prices (LMPs).

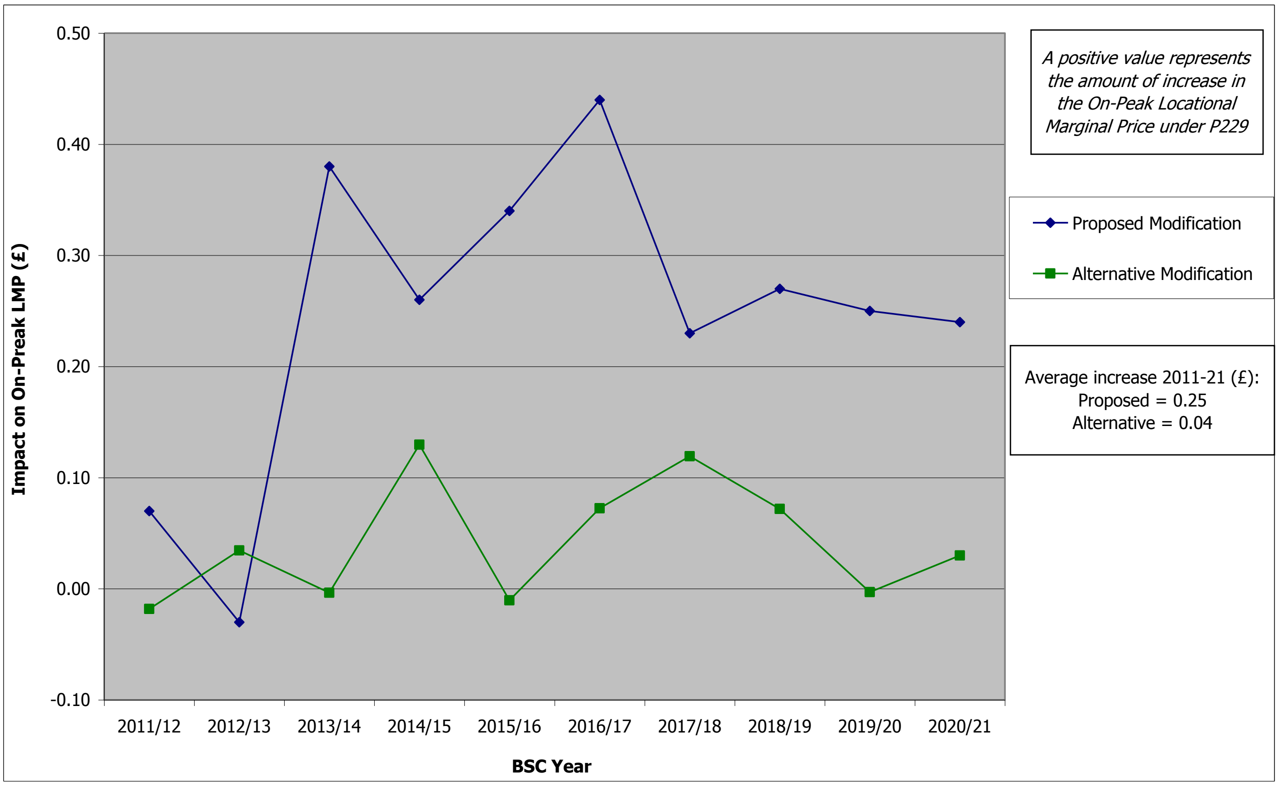
The basis for these figures is identical to Graphs 11 and 12. You can find the Alternative Modification figures in Annex 2 of LE/Ventyx's report, Comparison of Results (Table A2.1).

Again, the overall trends are consistent with those for the Proposed Modification but with a smaller magnitude.

Graph 24 – Impact of Alternative Modification P229 on Off-Peak Locational Marginal Price (£)



Graph 25 – Impact of Alternative Modification P229 on On-Peak Locational Marginal Price (£)



Impact on the Transmission System

LE/Ventyx concluded that, like the Proposed Modification, Alternative Modification P229 would reduce flows on the system by small but significant amounts.

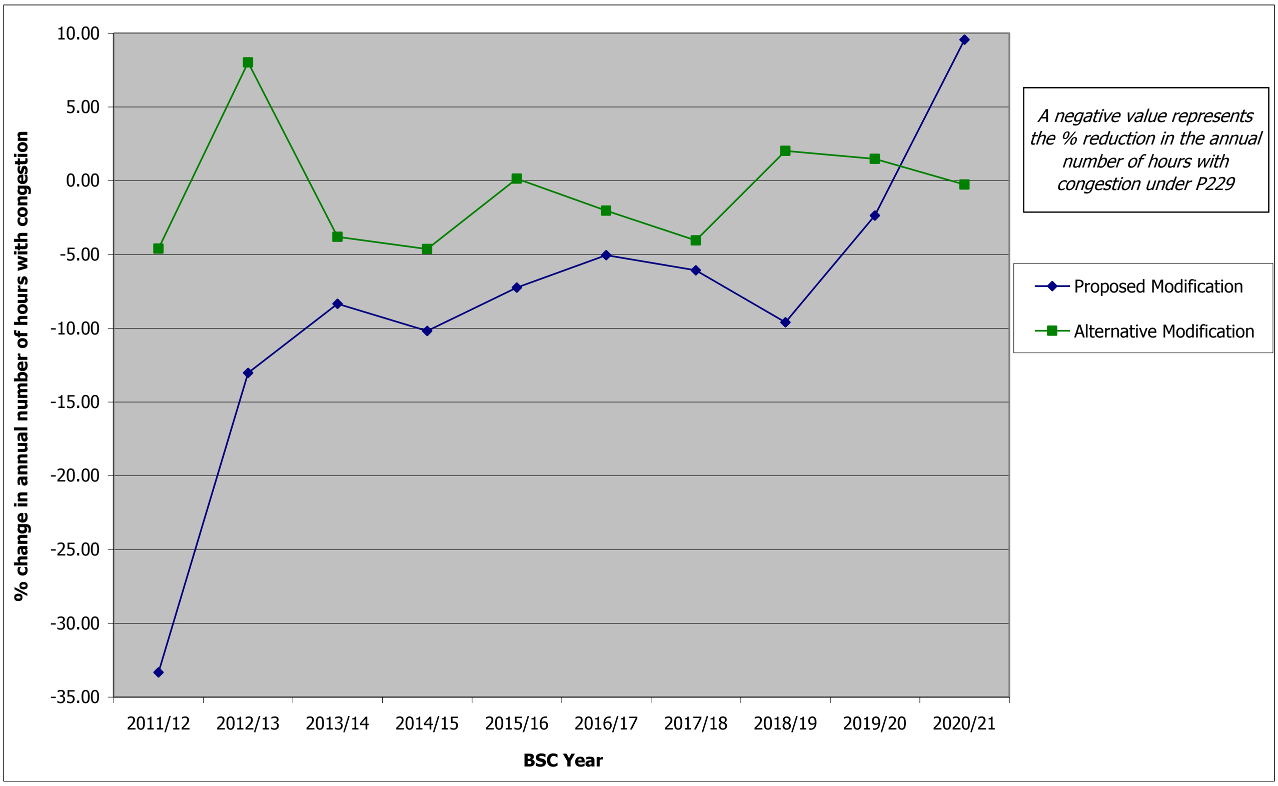
Savings are again greatest on the 400kV voltage lines, and the pattern of reduction is consistent with the Proposed Modification. However, the size of the savings is smaller under the Alternative. You can find the specific figures in Section A1.3.9 of LE/Ventyx's report.

Graph 25 compares the % change in the number of congested hours under the Proposed Modification (Reference Scenario) and Alternative Modification (Reference Scenario).

The basis for these figures is identical to Graph 13. You can find the Alternative Modification figures in Section A1.3.10 of LE/Ventyx's report.

The Alternative reduces congestion in approximately half of the analysis years, although by a smaller amount of hours than the Proposed Modification.

Graph 26 - % change in number of congested hours under Alternative Modification P229



5 Group's Discussions on CBA Approach

This section sets out the Groups discussions regarding the requirements, assumptions and sensitivities that the CBA consultant was task with undertaking. For information on the Groups discussions of the results please see section 6.

Requirements

Brattle Critique

When considering the requirements for the cost-benefit analysis, the Group took into account the comments and conclusions in the Brattle Group critique (commissioned by Ofgem) of previous losses Modifications CBA. The critique broadly endorsed the results and of the methods used but identified some specific areas for improvement, which the Group set out to address in the CBA for P229.

Modelling the market under the proposed Seasonal zonal losses allocation scheme is an important aspect of the CBA project. Previous CBA had used three representative 'snapshots' per BSC Season (i.e. 12 per year). The Brattle critique concluded that though the methodology was generally sound it would have been improved by using a greater number of snapshots. The P229 Group agreed that the CBA modelling for P229 should use more periods to model the effects, but were not able to specify an appropriate amount. The Group agreed that this issue should be highlighted in the CBA requirements specification for prospective CBA service providers, with a request that they propose an appropriate modelling methodology.

Another issue noted in the critique was that it would have been more appropriate to use an analysis period that reflected the proposed implementation date of the Modification Proposal, rather than using a period that started at the time the analysis was initiated. The Group therefore agreed that the CBA service provider should be asked to be mindful of the potential Implementation Date of P229 in conducting its analysis.

The Group also discussed the overall length of the analysis period. The previous CBA modelled a period of 10 years (5 of those in detail) and the critique suggested that a longer period would have been more consistent with the timescales involved in plant investment decisions. The Group considered that they could not determine an appropriate period, but agreed that the CBA must model at least a ten year period, and the CBA service provider should be asked to advise on whether a longer period should be examined in detail.

Transmission Charges

The Group noted the current ongoing work in relation to transmission access and constraints and discussed the extent to which use of transmission system charges should be included in the analysis. The representatives from National Grid and Ofgem both noted that the Modification must be assessed against the current baseline.

Some member's views remained that the current uncertainties/scenarios for transmission and balancing charges were relevant, e.g. transmission access costs, constraints, enforced despatch/administered compensation, locational balancing costs. A member commented that if these areas were considered outside the Group's scope, he believed Ofgem's impact assessment would need to cover these issues because they impact locational costs (probably affecting siting and despatch decisions more than losses).

Modelling approach

The P229 CBA modelling methodology, including input assumptions, was presented to the Group prior to the P229 CBA project beginning. The CBA included a full modelling exercise covering 10 years, at an hourly granularity, and used zonal demand data, provided by ELEXON, to calculate zonal load shapes.

Seasonal TLFs

The Group noted that an hourly approach to modelling TLFs had been proposed, and sought clarification that the CBA modelling would calculate and use Seasonal TLFs (i.e. consistent with P229) and not hourly TLFs; i.e. what TLF values would be used in the hourly despatch modelling: the actual TLF values for that hour, or average TLF values for the previous year (as proposed by P229). The consultants confirmed that the model has the capability to run either way, but would use average TLF values for the previous year, consistency with P229 proposal.

The CBA consultants described the approach for incorporating offshore wind generation into the CBA, noting that information is limited and that any additional information in this area would be welcome. The CBA approach would be to apply a calculated hourly load factor (i.e. over a year) to the installed offshore capacity, to approximate the actual expected delivery.

Seasonal Nodal Averaging

The Group asked the CBA consultants to clarify the method of averaging the nodal hourly TLF values to get Seasonal zonal values. The P229 proposal calculates a volume-weighted average across nodes to get hourly zonal values, and then does a weighted average of these for a number of 'snapshot' periods to get Seasonal zonal values.

The CBA modeling calculates zonal TLFs by first aggregating the hourly nodal TLFs by calculating volume-weighted average zonal TLFs. These hourly zonal TLFs are then aggregated to Seasonal zonal TLFs by calculating load-weighted average TLFs over entire Seasons. The Group were satisfied that this process models P229 TLFs adequately for the purpose of the P229 CBA.

Treatment of TNUoS and BSUoS

The Group requested also clarification on the assumed costs to be used in despatch modelling. A member noted that they understood transport costs (including Coal and Gas) were included, but were unsure of how electricity transport costs (transmission access (Connection/ TNUoS) and balancing services (BSUoS)) were included. It was believed that transmission costs were not to be included.

The CBA consultant clarified that neither TNUoS nor BSUoS were incorporated in the CBA modeling for the following reasons:

For Generation:

- TNUoS is not dependent on the variable MWh use of the system due to changes in generation. This means changes in a generator's costs and benefits due to TNUoS charges, regardless of location, would be net zero – i.e. TNUoS charges would be the same under the base and change cases.

- Changes in TLFs would not have any predictable impact on balancing needs, and therefore BSUoS charges. Generators should be in balance, so TLF magnitude should not affect balancing charges. Therefore change in BSUoS charges between base and change cases is net zero.

For Demand:

- If there is some elasticity to demand then the there could be an impact on the amount of demand between the base and change cases due TNUoS charge effects, which would affect costs and benefits based on the new set of TLFs. TNUoS impact was not modeled but a demand elasticity factor was incorporated into the CBA modeling which allowed the response of demand to be incorporated.

- In a similar manner as for generators, TLF effects would not make any predictable change in balancing needs for demand. Therefore change in BSUoS charges between base and change cases is net zero.

Embedded Generation

Embedded generation (i.e. generation connected within Distribution Systems) is not part of the Transmission System, and is not 'visible' in a disaggregated manner (i.e. only its net impact on GSP metered volumes reaches the Transmission System). This is in contrast with generation that is directly connected to the Transmission System, whose impact can be separately identified.

The Group considered the effect that embedded generation could have on demand and the extent to which it was included in the CBA modelling. With renewable generation anticipated to increase, it is likely that embedded generation would increase (which could also mean historic information may not be a good indicator of future levels of embedded generation). If demand stayed constant such an increase in embedded generation would lead to a net reduction in Distribution Systems' offtake from the Transmission System via GSPs (and if demand decreased would augment the overall net demand decrease). If GSP demand also increased, growth in embedded generation would act to slow the rate of demand growth. Likewise, introduction of Smart/Advanced meters could have an impact, such as potentially acting to decrease demand and increase customer elasticity.

A Group member commented that the Government and NG forecast increasing embedded generation, eventually leading to a point where areas that are currently offtaking may produce power, and noted that this possibility was not explored as part of the CBA.

The CBA consultant noted that as embedded generation is netted off demand, the generation will not be visible (as described above). However, it will reduce demand at the GSP. Therefore the levels of GSP demand going forward should reflect a forecast level of embedded generation consistent with the base case assumptions of the CBA. It was noted that changes in embedded generation were not included explicitly in the CBA but were considered as part of the CBA methodology.

Cost of Capital

The Group discussed the use and application of cost of capital in the CBA. The approach would use available Weighted Average Cost of Capital (WACC) information from Ofgem with appropriate adjustment for the type of user being considered.

A Group member commented that a regulatory cost of capital of this kind may not be appropriate for application to individual companies, as a regulatory timescale would be different to the timescales relevant to companies, e.g. the timescales for operational life of their systems. The consultants agreed in principle with this comment, but noted that Ofgem's WACC includes different timescales. Another member agreed that it was acceptable to use this WACC as the difference in timescales would not be an issue for the CBA, but rather would be important for individual companies making decisions, e.g. regarding siting plant.

The consultants explained that cost of capital would be applied in the model in post-processing, i.e. after estimation of costs and benefits. The determination of the WACC value applied in the P229 CBA, and the higher and lower WACC sensitivities is discussed at some length in the CBA report for P229 Proposed (see CBA report, Section 3.2 'The discount rate for CBA').

The Group also requested an additional scenario using a higher level WACC. LE/Ventyx undertook this scenario. However, the Group felt that this increased level was still too low. See the section on sensitivities and Section 6 below for further details.

What is Weighted Average Cost of Capital?

A company's assets are financed by either debt or equity. WACC is the average cost of the sources of financing, each of which is weighted by its respective use in the given situation. By taking a weighted average, we can see how much interest the company has to pay for every pound/dollar it finances.

Sensitivity Scenarios

The P229 CBA examined the sensitivity of costs and benefits to conditions under several different market scenarios. The Group noted that previous losses Modification Proposals had only modelled the following two scenarios:

- **Gas scenario** (**lower gas prices):** examining the effect of reversing the relative competitiveness of coal- and gas-fired generation, and hence the patterns of generation from these plant. A scenario favouring gas was used, in which gas became the cheaper fuel; and

- **Demand scenario (higher demand for electricity):** investigating the impact of significant levels of new generation capacity. A scenario with higher demand growth, and therefore significantly greater demand for transmission-connected generation, was used.

The Group noted that an area for improvement identified in the Brattle Group's review was that the previous analysis did not sufficiently consider what would happen if the Transmission Loss Multiplier (TLM) for a given Zone was different to the actual losses. The review stated this could occur for the following two reasons:

1. Zonal TLFs for a given year are calculated on the basis of conditions in the corresponding Season of the previous year, so any change in market conditions (e.g. significant new entry or changes in relative fuel costs) could lead to differences between the TLM for a given zone and actual losses.

2. Zonal TLFs are averaged over a wide range of market conditions over a Season, which can lead to differences between a Zone's TLM and its actual losses.

A significant difference between a Zone's TLM and its actual losses in a given period could materially reduce benefits or even cause a net dis-benefit. Therefore, the review considered that further scenarios that examined the impacts on TLFs should have been undertaken.

Agreed Scenarios for sensitivity testing

The Group was mindful of the need to choose scenarios for sensitivity testing that were relevant, i.e. which had a rationale for how TLFs would be impacted, were plausible and/or addressed a specific criticism.

The Group discussed the extent to which use of transmission system charges should be included in the analysis, noting the ongoing work relating to transmission access and management of constraints. National Grid and Ofgem representatives both commented that P229 must be assessed against the current baseline. However, some members still believed that the current uncertainties around, and possible changes in, transmission and balancing charges were relevant to P229 and should be taken into account in the CBA.

These members believed that relevant changes could be anticipated in areas such as transmission access costs, management of constraints, enforced despatch/administered compensation and locational balancing costs, and therefore advocated a Transmission System Charging scenario of some sort. After considering this the Group agreed that it was not appropriate, within the remit of the BSC Modification process to assess proposals against the current baseline, to incorporate into the analysis specific changes that are proposed (or anticipated) but not yet approved, such as potential changes to Transmission System charges. The Group therefore agreed not to pursue investigation of CBA sensitivity to changes in Transmission System charging

The Group agreed that a 'demand' scenario was not required as they did not believe a variation in demand would have a significant impact on TLFs.

Having considered the criticisms of previous work, recommendations from the CBA consultants and ELEXON and the Group's discussions on this subject, the Group agreed the following scenarios:

1) A **'long term fuel price volatility'** scenario to address criticism of the previous CBA;

2) A **'high gas price'** scenario as this was likely to impact TLFs and was recommended by the CBA consultants;

3) A **'low gas price'** scenario to enable assessment of a range of developments in fuel prices; and

4) An **'aggressive development of offshore generation'** scenario as the Group believed this could have a material impact on TLFs.

Additionally, after preliminary presentation and discussion of the CBA results, the Group agreed that a further scenario should be included to examine the sensitivity of the CBA results to the level of nuclear generation. The following scenario was therefore agreed:

5) An **'Alternative Nuclear'** scenario. The Group requested an increased level of nuclear generation in the south of England as they believed a material change in nuclear capacity, and the location and timing of new nuclear build, could affect TLFs and the CBA; and

The Group also had concerns that the WACC values applied in the base case were too low and were not reflective of most Parties WACC values. The Group therefore requested a higher value be used. Section 6 contains further details on this.

6 Group's Discussions on CBA Results

This section highlights the Groups discussions on the CBA results. Whilst the Group have endorsed the CBA results there were 2 key areas of comment: WACC values and the inclusion of Offshore Round 3. These concerns are summarised below along with the Groups more general comments on the CBA results.

Group concerns on the WACC applied to the CBA

As part of the base case the CBA assessed the sensitivity of the results to the value of Weighted Average Cost of Capital. This was done by applying higher and lower WACC values to the CBA results. The higher and lower WACC values were determined by the CBA consultants after considering all the information available to them, including information and views form the Group.

As noted in section 5 above the Group felt the WACC values used in the base case were too low and requested that a further scenario be carried out with a higher WACC value.

The Group considered the WACC values used in the CBA (both in the base case and higher WACC scenario). Some Group members felt that the WACC values applied to the CBA were acceptable since they were based on a transparent and theoretically supportable methodology which is set out in the CBA Report. However, a majority of the Group felt that the WACC values used were too low to be reflective of WACC values that would apply to non-regulated businesses.

A majority of the Group was concerned because they believed that a reasonable WACC value for most market participants would be higher than the Ofgem TPCR WACC of 6.25% (adjusted to 6.14% in the CBA) pre-tax applied to a regulated business. This reflects the non-regulated and much more risky type of business (e.g. generation) participants generally engage in (i.e. compared with network operations which are subject to the Ofgem TPCR).

The Group agreed that it would not be appropriate to request that the CBA contain results adjusted by WACC values that the CBA consultants were not able to support with their defined methodology and independent expertise. Equally the Group was not able to ignore their concern that the WACC values applied were not appropriate for the types of businesses covered by the CBA and which would be impacted by P229.

The Group therefore agreed that they would consider the information available to them via their associated companies and from publicly available sources and determine a new WACC to use to recalculate the CBA for inclusion in the P229 Assessment. The aim of this was to enable Parties to easily compare the CBA results with various levels of WACC applied.

Parties can come to their own conclusion about the adjusted value which they feel is most representative of the impact of the CBA on the **whole market**, taking into account both the independent expertise and transparent methodology of the CBA consultants and the strong concerns and wide industry knowledge of the Group. It must be noted that it is not intended that participants should look for the result that is calculated on the basis of a WACC value closest to that which is applicable to the participant as an individual company; the WACC value applied to the CBA result is intended to adjust it in a manner that is appropriate when taking into account all participants in the market.

Group's applied WACC

The Group considered that the information available to them indicated that sizeable market participants have a pre-tax WACC applied in the approximate range of 8-13%. The Group also believed that a pre-tax WACC of about 16-17% is typically applied to smaller participants (e.g. independent generators and privately financed, non-vertically integrated companies). However, taking into account the effect of the return required by investors the WACC applicable to smaller participants could actually rise to around 20%.

Taking into account this information, the Group considered that adjustment of the raw CBA using a WACC of 10% (pre-tax) would be appropriate. Note that this value was determined through qualitative consideration of market factors, not a rigorous mathematic methodology. The Group did consider publicly available WACC information for nine companies[2] that operate in the GB electricity market, and noted that the average pre-tax WACC for these companies (at 30 June 2009) was 10.1%.

Post-tax WACC values were applied in the P229 CBA, calculated by applying a tax rate of 28% (calculated by the CBA consultants as described in the CBA report). In order to be consistent the Group's agreed value of 10% (pre-tax) was adjusted to a post-tax WACC using the same tax figure. This results in the Group's WACC value, post-tax, being 7.2%.

The rationale for this value is that a 7.2% post-tax WACC is around the centre of the approximate range of values applied to sizeable companies, but should be large enough to take some account of the higher WACC typically applied to smaller market participants. The value of 7.2% is significantly higher than the central WACC value of 4.42% (post-tax) and the upper WACC of 5.2% (post-tax) applied in the P229 CBA.

The tables below show the CBA results for P229 discounted using the Group's WACC, and a comparison with the values used in the CBA report. Tables are included for the reference change case (i.e. P229 Proposed central scenario), the five sensitivity scenarios and the P229 Alternative. Note that the upper and lower WACC values were applied to only the reference change case, and therefore only the tables relating to the reference change case (i.e. the first two tables below) include figures adjusted by these values. In all cases results are presented both with and without the impact of SOx/NOx effects included in the cost-benefit figures.

[2] i) SSE; ii) Drax; iii) RWE; iv) Centrica; v) International Power; vi) Iberdrola; vii) EdF; viii) E.On; and xi) GdF Suez.

P229 Proposed reference case CBA: NOx/SOx excluded (all figures £m)					
		CBA report: Annual Discounted CBA			**P229 Group**
Year	**Annual CBA**	**Lower 3.5%**	**Central 4.42%**	**Higher 5.2%**	**7.2%**
2011	2.87	2.77	2.74	2.72	2.68
2012	6.94	6.47	6.35	6.26	6.04
2013	6.25	5.62	5.47	5.35	5.07
2014	4.84	4.21	4.06	3.94	3.66
2015	3.56	2.99	2.86	2.75	2.51
2016	4.66	3.78	3.58	3.42	3.07
2017	3.47	2.72	2.55	2.42	2.13
2018	8.82	6.67	6.19	5.83	5.06
2019	8.34	6.08	5.6	5.23	4.46
2020	10.47	7.38	6.73	6.24	5.22
Totals	**60.22**	**48.68**	**46.12**	**44.15**	**39.91**
Discounted Demand Side Benefits		1.82	1.74	1.68	1.54
Total (including Discounted Demand-Side Benefits)		**50.5**	**47.86**	**45.83**	**41.45**

P229 Proposed reference case CBA: NOx/SOx included (all figures £m)					
		CBA report: Annual Discounted CBA			**P229 Group**
Year	**Annual CBA**	**Lower 3.5%**	**Central 4.42%**	**Higher 5.2%**	**7.2%**
2011	17.98	17.36	17.2	17.07	16.77
2012	63.81	59.5	58.41	57.54	55.53
2013	34.55	31.11	30.26	29.58	28.05
2014	33.49	29.12	28.07	27.23	25.36
2015	42.1	35.34	33.75	32.5	29.74
2016	28.75	23.3	22.05	21.07	18.94
2017	25.95	20.31	19.05	18.06	15.95
2018	31.72	23.97	22.27	20.96	18.19
2019	33.83	24.69	22.73	21.23	18.09
2020	33.27	23.44	21.38	19.83	16.60
Totals	**345.45**	**288.14**	**275.16**	**265.07**	**243.22**
Discounted Demand Side Benefits		1.82	1.74	1.68	1.54
Total (including Discounted Demand-Side Benefits)		**289.96**	**276.9**	**266.75**	**244.76**

P229 Sensitivity Scenarios discounted CBA: NOx/SOx excluded (all figures £m)										
	High Gas discounted CBA		**Low Gas discounted CBA**		**Fuel Volatility discounted CBA**		**Wind discounted CBA**		**Nuclear discounted CBA**	
Year	Central 4.42%	Group 7.2%	Central 4.42%	Group 7.2%	Central 4.42%	Group 7.2%	Central 4.42%	Group 7.2%	Central 4.42%	Group 7.2%
2011	3.69	3.60	-1.63	-1.59	3.76	3.67	3.25	3.17	2.74	2.68
2012	11.99	11.40	1.83	1.74	7.03	6.68	6.56	6.23	6.35	6.04
2013	9.34	8.65	-1.04	-0.97	2.14	1.98	5.77	5.35	5.47	5.07
2014	7.41	6.69	0.71	0.64	6.04	5.46	5.63	5.09	4.06	3.66
2015	3.98	3.51	0.04	0.04	1.45	1.28	4.12	3.63	2.86	2.51
2016	4.12	3.54	0.55	0.47	0.45	0.38	3.37	2.89	3.52	3.02
2017	8.81	7.38	-0.25	-0.21	2.27	1.90	3.15	2.64	1.33	1.12
2018	12.74	10.41	1.44	1.18	9.87	8.06	5.92	4.83	1.81	1.48
2019	13.54	10.78	1.76	1.40	0.89	0.71	7.03	5.60	3.89	3.10
2020	22.13	17.18	0.88	0.68	12.59	9.78	7.32	5.68	6.73	5.22
Sub Total	**97.77**	**83.15**	**4.30**	**3.39**	**46.48**	**39.89**	**52.13**	**45.12**	**38.76**	**33.91**
Demand Side	3.23	2.84	0.36	0.32	1.73	1.53	1.82	1.61	1.59	1.42
Total	**101.00**	**85.99**	**4.65**	**3.71**	**48.21**	**41.42**	**53.95**	**46.73**	**40.35**	**35.33**

P229 Scenarios discounted CBA: NOx/SOx included (all figures £m)										
	High Gas discounted CBA		**Low Gas discounted CBA**		**Fuel Volatility discounted CBA**		**Wind discounted CBA**		**Nuclear discounted CBA**	
Year	Central 4.42%	Group 7.2%	Central 4.42%	Group 7.2%	Central 4.42%	Group 7.2%	Central 4.42%	Group 7.2%	Central 4.42%	Group 7.2%
2011	-1.81	-1.76	4.58	4.47	-1.21	-1.18	19.04	18.56	17.20	16.77
2012	-1.74	-1.65	19.18	18.23	63.57	60.43	59.03	56.11	58.41	55.53
2013	-2.09	-1.94	-5.46	-5.07	26.53	24.59	29.81	27.62	30.26	28.05
2014	-4.87	-4.41	0.49	0.44	4.14	3.75	26.95	24.35	28.07	25.36
2015	-8.79	-7.75	-0.83	-0.73	36.32	32.00	30.86	27.19	33.75	29.74
2016	-1.44	-1.24	8.59	7.37	21.98	18.88	20.11	17.28	22.06	18.95
2017	-1.49	-1.25	7.94	6.64	-0.81	-0.68	17.81	14.91	19.69	16.49
2018	1.11	0.91	16.36	13.36	-3.71	-3.03	24.17	19.74	13.14	10.73
2019	2.55	2.03	13.54	10.78	24.18	19.25	20.54	16.36	-2.20	-1.75

2020	-1.39	-1.08	8.82	6.85	1.83	1.42	17.63	13.69	1.97	1.53
Sub Total	**-19.97**	**-18.15**	**73.19**	**62.35**	**172.82**	**155.43**	**265.94**	**235.81**	**222.36**	**201.39**
Demand Side	3.23	2.84	0.36	0.32	1.73	1.53	1.82	1.61	1.59	1.42
Total	**-16.73**	**-15.31**	**73.55**	**62.66**	**174.55**	**156.97**	**267.76**	**237.42**	**223.95**	**202.82**

P229 Alternative reference case CBA (all figures £m)						
	NOx/SOx excluded			**NOx/SOx included**		
Year	Annual CBA (£m)	Discounted CBA (£m) Central 4.42%	Discounted CBA (£m) Group 7.2%	Annual CBA (£m)	discounted CBA (£m) Central 4.42%	discounted CBA (£m) Group 7.2%
2011	-2.07	-1.98	-1.93	-0.45	-0.43	-0.42
2012	2.44	2.24	2.12	14.52	13.29	12.64
2013	1.82	1.59	1.48	10.41	9.12	8.45
2014	1.89	1.58	1.43	12.56	10.53	9.51
2015	1.16	0.93	0.82	13.97	11.20	9.87
2016	1.60	1.23	1.05	8.56	6.57	5.64
2017	1.88	1.38	1.16	7.53	5.53	4.63
2018	3.44	2.42	1.97	10.84	7.61	6.22
2019	2.50	1.68	1.34	9.40	6.31	5.03
2020	2.14	1.37	1.07	9.62	6.18	4.80
Sub Total	**-2.07**	**12.44**	**10.51**	**-0.45**	**75.90**	**66.36**
Discounted Demand Side Benefits		0.09	0.08	N/A	0.09	0.08
Total (including Discounted Demand-Side Benefits)		**12.54**	**10.59**	N/A	**76.00**	**66.44**

Concerns on Offshore Developments included in the CBA

The Group considered the offshore generation developments that were included in the P229 CBA, both under the Reference Case and the Aggressive Wind scenario. The Group agreed that the P229 CBA was, overall, fit for its intended purpose of assisting the Group to assess P229. However, the majority of the Group were concerned about the developments in offshore generation that had been included in the CBA modelling.

The specific concern was that developments planned for Round 3 of Offshore Connection were not included in full in either the P229 Proposed Reference Change Case or the Aggressive Wind sensitivity Change Case. Group members queried this as they believed it put the CBA modelling assumptions in conflict with stated government targets.

One member noted that the National Grid Crown Estate 'Round 3 Offshore Wind Farm Connection Study' had been available and flagged to the CBA consultants since initiation of the CBA project, and believed this report would have provided all the information needed to model Offshore Round 3 developments, and that this should have been done.

This member believed that there could be a twofold impact on the CBA in later years of the study due to neglecting the Round 3 developments. Firstly, the exclusion of the locational losses and environmental impact of Round 3 developments and secondly the inclusion of generation that would have retired if the output form Round 3 was included, with its impacts on transmission losses the environmental.

Some Group members, while acknowledging the concerns, believed that the offshore developments used in the CBA were reasonable, though possibly somewhat less than might have been expected.

The CBA consultants undertook to address the Group's concerns by explaining the treatment of offshore development in the P229 CBA with reference to the aims, methods and capabilities the P229 CBA modelling, and the reasons that they believe that due consideration has been given to future developments in offshore wind generation in the P229 CBA.

The Group agreed the parameters and aims of the modelled scenarios in discussion with the CBA consultants, and it should be noted that the Aggressive Wind scenario was never intended to explore full introduction of Round 3 as such, but rather to assess the sensitivity of the CBA results to relatively incremental changes in levels of offshore wind generation.

The conclusion of the CBA is that the results do not appear sensitive to additional offshore wind generation of the order of that added to the modelling under the Aggressive Wind scenario. The CBA consultants believe that it is reasonable to conclude that this would hold for levels of wind additions that are fairly similar to the Aggressive Wind scenario, say up to around an additional 2GW, but they cannot be certain that this insensitivity would hold for an addition of, say, 20GW of offshore wind generation.

The CBA consultants believe that any judgement of the validity of the analysis with respect to offshore wind developments must be based on the information available at the time that the sensitivity scenario was developed and modelling initiated. The Government strategies and Green Paper were not issued until after presentation of CBA results, i.e. long after modelling had been completed.

The CBA consultant's views on offshore wind under the reference change case, and the amount of additional generation added for the aggressive offshore wind scenario, were based on their professional opinions in terms of both connections and MW capacity for each scenario. The information on onshore and offshore wind generation, for both the base/reference case and the aggressive offshore wind scenario were developed from the CBA modeller's (Ventyx) professional forecast which is used as standard in their analyses.

The scenarios (including the base case) were developed around March/April 2009. At this time, fuel prices were hitting recent historical lows, project finance was at a standstill, demand was falling rapidly, etc. The modelled wind capacity was based on prudent judgments by the CBA consultants on the feasibility and economics of large addition of offshore wind capacity in the GB market over the P229 CBA study period. Their judgments took into account demand for power, costs, recent experiences of implementing offshore projects and variables like planning permission, turbine prices, etc.

The locations of modelled wind generation were based on connections and existing likely lines, and public documentation from National Grid. The location of wind generators not yet planned or sited is extremely uncertain. Also, while government support has led to new offshore capacity being built, budgets are under increasing pressure and it remains to be seen whether such support will be sustained.

It was also felt that the location of both retired and added plant would be extremely uncertain. Thus adding large amounts of wind capacity would have involved compounded uncertainty, due to the location of the wind generation, the location plant retirements and other factors. This uncertainty would cause results to become increasingly arbitrary due to judgments made regarding, for instance:

- Which thermal plant to retire;
- Assumptions about the load factors of new wind generators; and
- Locating wind generation (i.e. with no basis for a locational judgment; it can't be located at the sites of existing wind generation because it is so much bigger, unlike the approach the CBA modellers were able to use in the Aggressive Wind scenario).

Furthermore, the CBA consultants believe it is important to consider the inherent uncertainty in making such decisions in this type analysis. They believe that it would be erroneous to consider that recent decisions and plans have removed the uncertainty over the amount of wind generation that will be built by 2020. The inherent uncertainty remains since what actually happens depends on variables and occurrences in the meantime, e.g. a range of associated costs could rise or fall, such as the cost of fuel etc. In support of this the CBA consultants note a recent Ofgem presentation on transmission access reform[3] noted that:

- Meeting renewable targets for 2020 will be challenging;
- Longer term targets create major uncertainties and challenges; and
- The coming years are a period of unprecedented uncertainty and speed of change.

Approximate Seasonal Zonal TLMs

The Group believed that calculating and publishing TLMs based on the P229 CBA data would assist Parties to assess P229 and encourage them to respond to the P229 industry consultation. The Group felt this would be particularly useful for smaller Parties that are less able to dedicate resources to modelling exercises of their own to investigate the possible impact of P229. The Group therefore asked ELEXON to use the Seasonal zonal TLFs and the zonal delivering and offtaking energy volumes produced by the CBA modelling exercise to calculate TLMs for the 10 year CBA analysis period. Note that using Seasonal zonal TLFs and zonal volumes in this way does not produce true TLFs, but rather approximate Seasonal zonal TLMs. The Group believed that such TLMs would be of use to Parties as it would provide a simple means of obtaining an indication of the impact that P229 would have on them if implemented. Parties can look up the TLM applicable to them (either delivering or offtaking) in any zone and for any Season in the analysis period (2011-2021) and gauge the impact of P229 by applying the relevant TLMs. The approximate Seasonal zonal TLMs can be found on the P229 webpage.

General Group Comments

The Group noted that National Grid information and forecasts were a major source of input data for the P229 CBA and as such generators already approved for construction were included in the study. However, at the time the CBA study was initiated this NG data had not been updated since the economic downturn, so the CBA consultants adjusted it for use in the CBA modelling.

The Group considered the validation of the CBA modelling against the results of the P229 Load Flow Modelling exercise. The Group noted that there was around a 15% difference between the actual Average Zonal Loss Factors and those produced by the CBA modelling, but that this represents good agreement between the two considering that

[3] http://www.nationalgrid.com/NR/rdonlyres/AA5503F8-849E-47E4-9B54-AD8A85D89408/24313/Ofgempresentation.pdf

this is a comparison between calculations using actual market data and a methodology that includes modelling random outage patterns and planned maintenance. This degree of correlation gives confidence in the modelling for future years without metered volumes.

Co2/SOx/NOx and Renewables

The Group noted a key result of the P229 CBA is that, in comparison with the modelled Base Case, the central Change Case for P229 Proposed gives production cost savings for all years modelled, i.e. 2011-2020. Production costs encompass losses, generation activities and CO_2 emissions. The CBA also shows significant reductions in NOx and SOx emissions each year relative to the Base Case, though these are not included as production costs because NOx/SOx costs did not feed into the into the optimal despatch modelling. NOx/SOx reductions of the order of 10s of kT per year were estimated (with greater reduction in SOx than NOx), though this is in the context that UK emissions of NOx/SOx are around 380-390kT per year.

Ventyx explained that variance in results was primarily due to the retirement of coal plant that is opted-out of the LCPD and the impact this would have on generation mix and redespatch activities. The effects shown by the modelled results were where intuitively expected given the anticipated plant retirements. For instance the biggest reduction in CO_2 emissions is around 2012 which is due to the impact of opted out coal plant retirements. Note that plant retire under the Base Case and Change Cases, it is the impact that the retirements have on the operation due to P229 (e.g. redespatch) which affects the level of benefits.

The Group noted that within the CBA modelling plant are dispatched based on their position within merit order stacks, which take into account annual availabilities. Output constraints imposed by the LCPD and IED are captured within the model. This allows calculation of the gross margins for different plant on the system. Where gross margins are insufficient to cover annual fixed operating costs of a plant it is assumed that it is retired.

Under the fuel volatility scenario change case CO_2, SOx and NOx emissions are increased relative to the Base Case in some years. This is due to generation switching to 'dirtier' fuels due to the volatility introduced into fuel prices.

Because optimisation of generation with respect to CO2 emissions was an aspect of the modelling, but not optimisation with respect to SOx/NOx, greater reduction is seen in CO_2 than other emissions. The estimated impacts of P229 on renewables and offshore wind showed no regional pattern; nor impacts on embedded generation, which were not significant.

Hydro generators were included in the model and their operation was optimised as part of the modelling. A Group member noted that hydro generators operate in respond to market prices, not load; the CBA consultants accepted that this was a limitation of the modelling method. Their qualitative assessment was that the response of hydro plant would not significantly change the results and would be expected to increase the benefits under P229 compared with the baseline.

The Group noted that congestion around the years 2014-16 was primarily due to new build generation, but that congestion does not have a significant impact on the P229 CBA. A modelling assumption was adjustments would be made in response to congestion, and therefore congestion was not given much weight, relative to other factors, in order to avoid its effect skewing the impact of P229. However, congestion was not predicted to increase under P229.

Gas Transportation

A Group member believed that redespatch under P229 would cause additional gas pumping costs, which would be uniformly smeared across all Parties. The member queried whether such costs could be taken into account, noting the Base case gas price forecasts in Section 4.1.1 give only tariffs. The CBA consultants explained these costs could be modelled but not without adding significant cost and complexity to the CBA modelling; this would have been unwarranted as the consultants believe that adding gas pumping costs would have had a minimal impact on the outcome of the CBA.

The Group member accepted the difficulty of modelling gas transportation costs, but was surprised the consultants believed such costs would have a minimal impact on the results. The member believed that, though they may be small in comparison to overall energy costs, gas transportation costs are of a similar magnitude to the cost of losses and would therefore have an impact on the CBA; they would not expect it would affect despatch decisions, but that as an associated cost it would contribute to the overall cost-benefit.

Wholesale Prices

A Group member noted that the P229 CBA indicated a small increase in wholesale prices, and queried whether this could be represented as a monetary value (i.e. total cost to the market) so it could be related to the overall cost-benefit.

The CBA consultants explained that though it would have been straightforward to multiply the estimated price difference per MWh by the total volume of energy demand in a year, the result could have been considered misleading for a number of reasons. First, the degree to which a wholesale price increase (or decrease) feeds through to the final consumer is uncertain, and depends in part on the level of competition. Second, it is difficult to say how meaningful an overall cost change due to wholesale price increase would be, given that the overall wholesale price increase is at the margin.

However, overall the cost-benefit is the net impact of various factors including for instance changes in losses and changes in wholesale prices, and if this is a benefit overall then it can all potentially be passed on as a benefit, notwithstanding that it may be comprised in part of a wholesale price increase. So the actual impact on the price of electricity is based on the wholesale price rise and the effect of efficiency savings, and the degree to which each are passed on; if all savings are passed on the benefit is the net benefit shown by the CBA results.

The Group member accepted this but noted that he would see benefit in applying the price increase not to the whole demand volume, but rather to the volume traded in the market (e.g. the MIDS volume). The member believed that the wholesale price represents a material cost to the industry.

P229 Load Flow Modelling analysis

The Group considered the impact of the P229 solution on the load flow modelling to be undertaken, particularly in light of the fact that, in contrast to previous transmission losses Modifications, P229 provides for offshore transmission. P229 is essentially the same as Modification Proposal P203, with the addition of provision for nodes located offshore.

The Group discussed the requirements specification for the load flow modelling analysis conducted for previous losses Modifications, and discussed how the forthcoming introduction of an offshore transmission regime would affect the modelling requirements. Under the new offshore transmission arrangements offshore lines of 132kV or above will become part of the transmission system.

As part of the load flow modelling National Grid provides an 'intact network' model. The Group agreed that the effect of including offshore nodes should be taken into account in the modelling. However, National Grid clarified that their transmission network model does not include any offshore circuits. National Grid were therefore unable to provide an intact model including current offshore circuits as though they are Offshore Transmission.

The Group noted that the Load Flow Modeller was able to construct a model including current offshore circuits as part of the Transmission System by amending the network supplied by National Grid. This would be done using their industry knowledge and where necessary appropriate approximations and reasonable assumptions, with the amendments being subject to agreement by the Modification Group.

The modelling includes a number of sensitivities as well as a 'baseline' scenario. The scenarios are designed to determine the sensitivity of TLFs (and TLMs) calculated under the P229 methodology to various factors. The Group noted that though the Offshore Transmission regime was not in place at the time of commissioning the load flow modelling, it would be in place when P229 would be implemented if approved; the Group therefore considered whether the baseline modelling scenario should include all existing offshore nodes that meet the criteria for offshore transmission as part of the Transmission System.

A Group member suggested that the modelling baseline scenario should include current offshore circuits as Offshore Transmission, rather than using the network model 'as is' (i.e. NG's model with no offshore circuits). The member argued that it would be a more accurate representation of the baseline situation when P229 is implemented, if approved. The Group noted that if this approach was used the 'actual' baseline scenario, i.e. intact network with no offshore circuits included, would still be assessed as a sensitivity.

The 'DNO sandwich' issue

The Group noted the possibility of a situation arising where a Distribution System is situated between the Transmission System and an Offshore Network, a so-called 'DNO Sandwich'. In this case losses incurred between the Offshore Network and Transmission System would not be included in Transmission Loss charging. The Group was concerned that this might be difficult to take into account in the Load Flow Modelling (for the purposes of analysis for P229 and in active calculation of TLFs) and also that the losses in the intervening Distribution System could have an effect on the losses attributable to Transmission that would not be taken into account under a locational TLF regime.

The Group noted that at present offshore generators connected to the Transmission System via a Distribution System receive derogations to allow them to do so. Upon introduction of Offshore Transmission all networks of 132kV capacity or greater would become Offshore Transmission. The Group considered that there are not presently many offshore generators connected to Distribution Systems that would become Offshore Transmission, but that in future, and following introduction of Offshore Transmission, more offshore networks could be connected via Distribution Systems.

Since losses on the Transmission System are significantly less than Distribution System losses, the Group agreed that consideration needed to be given to how to conduct load flow modelling in DNO sandwich situations in order that TLFs are not influenced by Distribution System losses. The Group agreed to seek advice from the Load Flow Modeller with respect to the incorporation of Distribution-connected offshore networks into the modelling methodology, and whether this would have an impact on the calculation of Transmission Losses.

The Group considered that the methodology for incorporating the variable losses of offshore lines should be tested to ensure it is sufficiently robust and therefore agreed that the Load Flow Modelling exercise should include examination of the sensitivity of TLFs to the inclusion of Offshore Networks. The Group believed this could be done by modelling, in addition to the current baseline, the existing network but with existing derogated offshore generators treated as Offshore Transmission (i.e. where such generators would meet the applicable criteria for classification of Offshore Transmission when Offshore Transmission is introduced).

Methodology

The Load Flow Modeller developed an approach for modelling Offshore Transmission losses. This methodology is described in detail in the section below. It was applied in the load flow modelling exercise and would be used operationally if P229 is approved (either Proposed or Alternative).

In essence the methodology is to approximate direct connection from the transformer of offshore nodes to the node which connects the relevant Distribution System to the GSP. The Modeller suggested several existing offshore generators for inclusion in the P229 modelling as offshore networks. These generators were all greater than 20MW capacity, and the modeller supplied equivalent values for nodes, lines, transformers and onshore connections for the modelling.

Only offshore networks connected at 132kV and over will be classified as Offshore Transmission, and all but one of the suggested existing offshore generators were connected below 132kV. The Group agreed that the modelling analysis should not include any offshore networks which would not be part of the Transmission System after the introduction of Offshore Transmission. This meant that all but one of the networks originally proposed by the modeller was unsuitable. However, it was preferable that the analysis should include more than one Offshore Transmission network, so the Group decided to extend the analysis to include offshore networks expected to be on-line by April 2011 (i.e. the earliest mooted P229 Implementation Date).

The Group noted that this approach differs from the original intent of investigating the effect on TLFs of including existing offshore networks as offshore transmission.

However, the Group considered that including offshore generators that would be active relatively soon would increase the value of this investigation, and were confident that this approach would not significantly impinge upon the investigation of longer term, larger scale offshore development which was conducted as a separate part of the modelling exercise. The Group suggested that the modeller should consider recently issued Ofgem documentation[4] which included the latest plans for the new offshore regime, and also noted that further information on connections dates can be found in the NG TEC Register[5].

As well as the method proposed by the Modeller for modelling Offshore Transmission networks connected via a Distribution System, and which was ultimately agreed by the Group, the Group considered a different option of modelling by treating the offshore network as a GSP and approximating a short-circuit connection directly to the Load Flow Model system slack node (Cowley). Under both methods the offshore network's delivery (or offtake) would be added to (or deducted from) the Distribution Network's offtake from/delivery to the appropriate GSP or GSPs (e.g. delivery from an offshore network would be added to the delivery from a GSP, and the Distribution Network's offtake from that GSP would increase by the same volume).

The option of treating offshore networks as GSPs was considered after a Group member enquired whether this would be the most appropriate approach. The modeller did not identify any benefit to this method over the original proposal, and considered it to be an unusual modelling arrangement that would require further consideration before it could be confirmed as a viable approach. No drawbacks were identified with respect to the Modeller's originally proposed methodology (as set out above) so the Group agreed it should be adopted for the P229 Modelling and as part of the enduring P229 solution.

Under Offshore Transmission, generators must have Settlement Metering at the offshore generation node (or apply for a dispensation), and there would also be operational GSP metering (i.e. not Settlement metering) at the onshore connection. Barrow is the only the Group and Modeller were aware of), and it does not have Settlement metering offshore. In this case any differences between the power generated offshore and the power delivered onshore (i.e. due to losses in the offshore/onshore connecting line) should be taken into account. This might be done by applying a suitable transmission line loss factor to adjust the relevant Metered Volume.

The Group discussed whether metering placement could impact the modelling for P229 (analysis or enduring solution) but believed any metering not situated at the correct transmission boundary metering point would be adjusted in accordance with accepted principles (either in the meter, in aggregation rules or via CVA Line Loss Factors). The Group agreed that any additional adjustment for line losses between an onshore Distribution System and onshore GSP was a distribution issue which should be considered in due course, but that it was not relevant for the P229 Load Flow Modelling analysis or enduring solution.

All identified offshore networks were relatively isolated, and it was therefore clear which GSP were closest (i.e. the GSP each offshore network would be modelled as connected to). However, the Modeller noted this would not necessarily always be the case, and

[4] Offshore Electricity Transmission: Updated Proposals for the Competitive Tender Process (Consultation, March 2009): http://www.ofgem.gov.uk/Networks/offtrans/pdc/cdr/cons2009/Documents1/Offshore%20Electricity%20Transmission%20Updated%20Proposals%20for%20the%20Competitive%20Tender%20Process.pdf

[5] NG TEC Register: http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/tectrading/

the investigation of planned offshore networks could produce more ambiguous situations. The modeller had previously noted a possible approach of 'splitting' a network's delivery or offtake between two or more different GSPs that are of a similar proximity to it.

The methodology effectively removes DNO networks from the modelling by linking each Offshore Transmission System Connection Point to the nearest GSP on the onshore Transmission System. The technically 'ideal' way to achieve this would be to model the flows on the DNO network to establish which GSP(s) energy is actually flowing to, but the Modeller believed that approximating direct connection to the closest GSP was an acceptable and more practical proxy.

The Group considered whether the sensitivity of TLFs to the choice of 'closest' onshore GSP should be tested. This might be done by linking an Offshore Transmission System Connection Point to different GSPs within a Distribution System to see what impact it has to the resultant TLFs. However, the Load Flow Modeller did not believe this choice would have a significant impact on TLFs. The Group therefore agreed it was not necessary to investigate this further.

The Group noted that choosing the Node in the onshore Transmission System which each Offshore Transmission System Connection Point is linked to (i.e. the 'closest GSP') in the Load Flow Modelling would be an issue for the enduring P229 solution. The Group also agreed that the choice of such GSP should be made by the TLFA as part of the process of constructing the Network Mapping Statement. The Group noted that there are existing ISG processes for allocating BMUs which may be relevant and useful for this.

The Group also considered that the agreed methodology satisfied the following requirements:

- Losses on lines extending to offshore platforms, and the consequent difference this causes between metered volumes offshore and at the onshore connection, are appropriately taken into account;
- Any effect of offshore networks being AC or DC is taken into account; and
- Method for offshore networks is appropriate and can be applied consistently in the P229 modelling analysis and in the enduring operation of P229 if approved.

Task 10

The Group considered the results of the investigation of the impact on TLFs of large scale future offshore developments (Load Flow Modelling Task 10). It was apparent from the Seasonal plots of TLFs that the TLFs under Task 10 varied from the Base TLFs (from Task 1). This variance this was most significant with respect to the Scottish Zones (GSP Groups P and N).

The Modeller explained TLFs were not calculated with each element of Task 10 in isolation but only with all elements combined (i.e. increased offshore generation, new interconnectors and High Voltage DC connections between Scotland and England). However it was still possible to deduce the reasons for the variations and the greater divergence in the Scottish zones. As well as the Scottish zones (GSP Groups P and N), which showed significant change, the Yorkshire zone (GSP Group M) was of interest since it was relatively unchanged despite significant additional delivery from new offshore wind generators.

The Modeller believed that the new HVDC connectors had the most impact on TLFs. The addition of the HVDC connections was equivalent to adding significant loads in the North (of the magnitude of medium sized towns) and significant delivery in the South. Compared with this, the effect of the new interconnectors and offshore generation also modelled was not as significant. In addition, though the generation capacity added into the system by the new offshore wind generators was sizeable, the modelled delivery was scaled to the delivery pattern of a typical intermittent generator (the same pattern used throughout the Load Flow Modelling exercise) which results in delivery of 26% of the generators' absolute capacity, on average, compared with the typical profile of 40% delivery for offshore wind farms.

Calculation of Zonal TLFs

The Load Flow Modeller observed that TLFs produced under the P229 methodology had a tendency to under recover losses. This is believed to be a consequence of using Zonal rather than Nodal TLF values. Though the calculation of TLMs corrects under-recovery (via TLMO application), it does so by uniformly scaling so that the correct volume of losses is recovered overall, whereas the observed under-recovery by TLFs is not uniform across nodes/zones. So while the TLMO ensures that all losses are allocated overall, the effect of non-uniform under recovery by TLFs is to introduce differences between zones (i.e. due to the non-uniformity) that persist after TLMO correction, despite recovery of all losses being ensured.

The Proposer believed that the important point was whether the signals from TLFs under P229 are cost-reflective despite the observed tendency to under-recover losses. There was no practicable solution available to remove or mitigate the under-recovery and the Group did not believe that this observed tendency would affect the question of whether P229 was better than the current baseline.

The Group also considered whether to make a slight amendment to the averaging used in TLF calculation. The method of volume-weighted averaging has historically been part of losses proposals, i.e. using the absolute value of nodal flow. The Load Flow Modeller put forward an option of using the square of nodal flow in weighting, because this method had a slightly better theoretical basis than use of the absolute value. However, in practice both options produce practically the same results.

The Group agreed by majority to retain the use of the absolute value because it would be consistent with the established methodology considered under previous losses proposals (P198, P203 etc) and it produces results that for practical purposes are the same as those produced using the square of the nodal flow.

Methodology for modelling Offshore Transmission Nodes

Present case: Figure 1 shows the present situation for offshore generation. Presently any offshore generators, such as the offshore wind farm in figure 1, are connected to a Distribution System run by Licensed Distribution System Operator (LDSO); they are not part of the Transmission System and are not 'visible' to the Transmission System Operator. Power is imported to the Distribution System from Grid Supply Points (GSPs); in figure 1 power is imported from GSPs 'A', 'B' and 'C'. Transformers are used to step down the power from the Transmission System to the voltage level of the distribution system – these transformers are part of the Transmission System.

Figure 1: Present case

Offshore Transmission: Upon introduction of Offshore Transmission, offshore networks (like the wind farm in this example) would become part of the Transmission System, i.e. from the offshore connection point node (excluding any internal network, e.g. from individual turbines to the connection point node) to the onshore connection point (whether to a Distribution System or to the Transmission System). As in this example, offshore networks may be physically connected via the Distribution Network. Figure 2 shows the situation under Offshore Transmission; power from the offshore wind farm is delivered to the Distribution System via an offshore node, offshore cable, step-up transformer and onshore connection, all of which would be part of the Transmission System.

If the wind farm is part of GSP Group A, then from the SO's perspective there would no longer be a simple import of 60MW from GSP A to the Distribution System. Instead there would be an import of 70MW from GSP A to the Distribution System and an export of 10MW from the wind farm to GSP A.

Figure 2: Model under Offshore Transmission

Modelling Under P229: Under P229, calculation of TLFs would involve approximating direct connection of offshore nodes to the appropriate GSP when modelling the Transmission System. The P229 Load Flow Modeller proposes that this would be done by assuming connection of the wind farm's step-up transformer directly to the nearest Distribution System's connection to the GSP. This arrangement is shown in figure 3.

Figure 3: Model for P229

Group discussions

P229 Proposed

In support of P229 Proposed it was argued that a Seasonal zonal scheme for allocating Transmission Losses is more cost reflective than the current uniform allocation of losses, and removes the current cross subsidy contained in the current allocation method.

A Group member argued against P229 proposed by commenting that the introduction of a Seasonal zonal scheme would result in windfall gains for some Parties and windfall losses for others, which would have a negative effect on competition.

The aim of P229 Proposed was queried, i.e. whether it is removal of the cross-subsidy or creation of a signal to reduce line losses. The Proposer clarified that the aim is definitely the removal of the cross subsidy, thereby making allocation of losses more cost reflective.

A member commented that the rationale was that increased cost reflectivity would promote competition, and agreed that if a Transmission System was being designed from scratch, it might be sensible to consider a seasonal zonal scheme (or similar method) for allocation of losses; however, since P229 would amend an established system the potential benefits must be compared with the magnitude of the transfer between participants.

A member commented that the effects shown in the CBA may be decreased in reality since the CBA is based on central despatch, while in reality Parties will generate to meet their contracts. Another member noted that cost signals for P229 will add to the existing signals, so will be a factor in Parties' activities.

A Group member commented that P229 could increase regulatory risk and uncertainty; another member supported this and suggested that the increase in risk would result in an increase in Parties' cost of capital. A member suggested that though introduction of P229 was part of regulatory risk the introduction of a zonal losses scheme of some kind had been considered for a long time and was a well publicised possibility. Some of the Group believed that Parties already take account of regulatory risk in becoming a signatory to the Code.

A member suggested there would also be increased uncertainty around TLMs if P229 was introduced, as TLFs would be calculated annually. Another member suggested that the CBA does not include investment risk, and suggested that Suppliers might build in a risk premium in response to the added uncertainty. Another member noted that some kind of zonal losses allocation scheme has been a possibility since privatisation, and as such is a longstanding risk that has been known to Parties.

The Proposer noted that the analysis had demonstrated that P229 would reduce losses. A member suggested that the redespatch effects predicted by the CBA would come from marginal generators, which would be the same generators that NG would utilise for balancing actions; therefore the effect of cost signals due to P229 could be impacted by interaction with directions from NG determining generators' operation.

A member suggested that the zonal averaging inherent in P229 was a drawback, since for instance the methodology could result in similar generators on either side of a zonal boundary being assigned different TLFs which though correct in terms of the P229 methodology is not reflective of their actual contribution to losses. The Proposer accepted this possibility but argued that the magnitude of the effect of this type of inaccuracy was less than that of the inaccuracy inherent in the current uniform allocation of variable losses.

The member suggested that introduction of P229 would just mean that inaccuracies due to national averaging were replaced by inaccuracies due to Zonal averaging; the Proposer accepted this but noted that the rationale for P229 was that Seasonal zonal losses allocation (i.e. with zonal averaging) would result in a more appropriate and cost-reflective allocation of variable losses than the current uniform method (i.e. effectively averaging on a national basis).

A member suggested that P229 Proposed would give long term signals for long-term investment in generation and demand; this effect was difficult to quantify but the member believed that though it may be relatively small the locationally allocated variable loss cost signals would still be a factor in investment signals, among many other factors.

The Group considered whether P229 could have a detrimental impact on maintaining security of supply; for example, the Group considered a hypothetical situation of a significant amount of wind generation being built in Scotland, tending to operate in preference to conventional plant due to policies and incentives promoting renewable energy. This could lead to conventional plant becoming uneconomic to operate and exiting the market earlier than they might have done without P229. This could lead to a situation where there is insufficient conventional generation installed locally to ensure security of supply when conditions are adverse for operation of renewables. The Group noted that the chance of this situation occurring was difficult to quantify but not consider it to be a significant risk, and believed that in any case the system operator would be likely to act before such a situation could develop. However, since there is a suggestion P229 could affect investment and plant entry/exit decisions, the Group felt that the discussion of this possibility was relevant.

The Group considered that possibility that types of market participant could be disproportionately impacted by introduction of P229. Group members speculated that the following types of participant could be disproportionately impacted:

- Demand customers, because it is difficult for demand to effectively respond to either short- or long-term signals;
- Generators whose ability to respond to signals promoting despatch minimising losses is relatively limited owing to their mode of operation, e.g. renewables, combined heat and power (CHP) plant); and
- Existing generators because their location is fixed, unlike new plant whose investors can take into account loss signals before making decisions on market entry.

Some Group members noted that they believed that the current arrangements for loss allocation were are an appropriate and accepted means of socialising the impact of transmission losses, not a cross-subsidy. A member commented that the current method means the risk of any change in the distribution of losses, which could have a significant adverse impact on individual participants, was dealt with by sharing it amongst all Parties.

P229 Alternative

The Proposer questioned the validity of the Alternative, since the CBA showed that the net benefit of the Alternative was less than that of the Proposed, arguing that this demonstrated that the Alternative was inferior to the Proposed and therefore not a valid Alternative. Other Group members argued that the result of the CBA was only a factor to be taken into account in determining benefits against the Applicable BSC Objectives.

A member commented that the rationale of the Alternative was that it would preserve marginal signals to reduce losses, but change the distributional effect of the losses allocation scheme (i.e. decrease the distributional impact). The Proposer stated that the Alternative simply dilutes the effect of P229 Proposed.

A Group member suggested that P229 Proposed goes too far in its removal of the cross-subsidy, with the result that a new, different cross subsidy is created; the member suggested that this was illustrated by the fact P229 would result in some participants benefiting by being credited with energy while others would be disadvantaged by being debited energy (relative to the baseline) due to the effect of TLFs on TLMs, leading effectively to a net transfer of money between Parties.

Another member noted that a methodology that has a positive effect on some and a negative effect on others does not automatically mean a cross subsidy is occurring; if losses are allocated more correctly and this leads effectively to a transfer of money between Parties, this redistribution would be appropriate and not indicative of a cross-subsidy. The member further argued participants not receiving positive or negative signals as a result of actions they take which have an effect on the system would contribute to inefficient system operation. The member believed that the Alternative had not been demonstrated to be cost reflective.

Some Group members believed it was appropriate that no Parties should be credited with energy (i.e. allocated negative variable losses) because all BM Units cause transmission losses. These members felt this was apparent because if considered in isolation all BM Units must cause losses. The Alternative aims to deliver an allocation of variable losses such that no participants are allocated negative losses; these Group members therefore believed that the P229 Alternative methodology was in fact more cost reflective than P229 Proposed.

However, other Group members disagreed with this argument, taking the counterview that considering the system as a whole, rather than isolated parties, it is possible for BM Units to reduce losses rather than causing them, relatively speaking. For example, if a generator located close to a demand customer meets the demand for energy instead of a generator located further away from the customer, it **does** reduce losses. These members therefore believed that P229 Proposed is cost reflective (and is more cost reflective than the Alternative).

These considerations led the Group to be split on whether the Alternative would partially or totally remove cross-subsidy from the variable losses allocation arrangements:

- The Proposer believed that the magnitude of the cross-subsidy was a calculable value that could be found via use of the load flow modelling, with a fixed scaling factor of 0.5, employed by P229 Proposed, and further believed that full removal of this cross-subsidy did not amount to a new cross subsidy but would deliver a representative allocation of losses; conversely therefore since the Alternative would not remove the whole of this cross subsidy it only partially removes cross-subsidy from the allocation arrangements; and
- Some Group members disagreed and believed that by using a scaling factor (i.e. fixed 0.5) that would result in gains by some participants (i.e. allocation of negative losses) P229 Proposed would introduce a new cross subsidy; because P229 Alternative would apply the load flow model such that no participants would be allocated negative losses (so far as practicable), the Alternative solution would actually deliver an allocation of variable losses free from cross-subsidy.

The Group agreed that in general, most of the advantages of the Proposed (e.g. cost signals leading to reduced losses) and its drawbacks (e.g. redistribution of costs among Parties) would also apply to the Alternative, but each be less significant. In summary, the Alternative would mitigate the distributional impacts on Parties but would also reduce the benefits that could be delivered compared with the Proposed Modification.

Provisional views against the Applicable BSC Objectives

These are the provisional Group views only and are presented for information; the Group's final views can be found in Section 10, below.

Group voting on provisional views

The Modification Group developed and analysed a potential P229 Alternative Modification. It is a potential Alternative because the Group has not made a final decision on whether the Alternative solution better facilitates the Applicable BSC Objectives compared with P229 Proposed. For an Alternative Modification to be presented to the BSC Panel and the Authority a majority of the Group must believe that it better facilitates the Applicable BSC Objectives compared with the Proposed Modification. The Group is presenting the potential Alternative for consultation so they can obtain industry views which will help them make a fully informed final decision.

The Modification Group has set out its provisional views to help Parties assess P229 and respond to the consultation. The Group intends that its views will capture the arguments for and against P229, which respondents may use as the basis for expressing their own views against the Applicable BSC Objectives, along with any additional arguments they may identify. The Modification Group will vote to determine its final views before making a final recommendation to the Panel.

The Group voted to determine its provisional views after discussing the benefits and drawbacks of P229, both Proposed and Alternative. When comparing P229 Proposed and P229 Alternative to the current baseline, the majority of the Group believed that:

- The Proposed **would not** better facilitate the Applicable BSC Objectives; and
- The Alternative **would** better facilitate the Applicable BSC Objectives.

The Group also took a provisional vote on whether they believed the proposed Alternative Modification better facilitates the Applicable BSC Objectives when compared to the Proposed Modification. The majority of the Group believed that:

- The Alternative **would not** better facilitate the Applicable BSC Objectives **compared with the Proposed**.

This appears to produce an anomalous result. The provisional vote indicates that while the majority of the Group believe the potential P229 Alternative **is** better than the baseline, and P229 Proposed **is not**, as the voting stands the potential Alternative **would not** be presented to the Panel because the majority of the Group believe that the Proposed solution is better than the Alternative. This means the provisional recommendation of the Group is to reject P229 Proposed, with no P229 Alternative presented.

The cause of this apparent anomaly is that all Group members who believed the Proposed is better than the baseline also believed that the Alternative is better than the baseline, but that the Proposed is better than the Alternative, whereas none of the Group members who believed that the Alternative is better than the Proposed believed that the Proposed is better than the baseline.

In spite of these peculiarities in the voting results, all arguments and views expressed by the Group have been fully captured and presented in this industry consultation.

1. Proposed vs baseline:

The Group provisionally agreed by a narrow majority that P229 Proposed would not better facilitate the Applicable BSC Objectives overall compared with the current baseline.

Objective (a)

The Group **UNANIMOUSLY** agreed there were no arguments relating to Objective (a) and as such the Proposed Modification was neutral with respect to this Objective.

Objective (b)

The **MAJORITY** of the Group believed the Proposed Modification would better facilitate Objective (b) for the following reasons:

- It would result in more efficient despatch because participants would receive cost signals that would allow variable losses to be taken into account in despatch decisions
- It would result in more efficient market entry/exit because participants would receive cost signals that would allow variable losses to be taken into account in decisions on where to locate new plant or whether to continue/cease operation of existing plant – though this would be a relatively small factor in such decisions
- It would result in production savings and a reductions in variable losses, due to reduced generation because of more efficient despatch, which would also result in an environmental benefit due to reduced emissions

One Group member believed the Proposed Modification would not better facilitate Objective (b) for the following reasons:

- To obtain the benefits of more efficient despatch it is important that the allocation of losses is cost reflective so that Parties factor the correct costs into their despatch decisions, but the Group member believed that inherent inaccuracies[6] in the methodology for calculating TLFs (and hence TLMs) mean the P229 solution would not deliver costs that reflect the impact of a BM Unit (due to operation and location) on total losses in each and every Settlement Period; therefore the member did not believe that P229 Proposed would result in a more accurate and appropriate allocation that would reflect costs on all Parties in a fair and equitable manner
- The Group member believed that:
    - The most significant contribution to environmental benefits (over the P229 CBA analysis period) will be investment in renewable generation over the next ten years, and therefore the most significant environmental impact of P229 is whether it would affect Parties' investment in renewable generation over the next ten years;
    - A large proportion of new renewable generation will be onshore or offshore wind generation, and that the economics of such projects are extremely marginal (demonstrated by their subsidy via the ROC mechanism);

[6] The Group member believed these inaccuracies include:

- Use of an ex-ante model to determine TLFs, which uses Sample Settlement Periods from the previous year;
- Averaging TLFs across nodes within a GSP Group; the load flow modelling results comparing nodal and zonal TLFs showed a zonal TLF could be quite different from TLFs that allocated on a nodal basis in the North;
- That a Seasonal TLF averages across all Settlement Periods in that Season; and
- That a DC model is used to model an AC system in order to calculate TLFs.

- Given that consideration of any changes to the ROC mechanism is outside the scope of P229, P229 Proposed would alter the economics of renewables investment such that it would encourage renewable projects in the South and discourage those in the North relative to the current situation);
- The location of wind generation projects is primarily determined by access to the resource which is usually areas far from demand, and therefore the member believed that, all else being equal, P229 Proposed would have a negative effect on investment in the majority of such projects, and would therefore have a negative environmental impact.

One Group member was neutral with respect to the impact of the Proposed Modification on Objective (b) because though the CBA shows benefits the member is awaiting clarification on some outstanding points, and the member believes there is a potential for an increase in balancing services activities that would offset efficiency benefits.

Objective (c)

The **MAJORITY** of the Group believed the Proposed Modification would not better facilitate Objective (c) for one or more of the following reasons:

- It would cause a distributional transfer between market participants based on their type and location which would amount to windfall gains for some and windfall losses for others, which would have a detrimental impact on competition
- This transfer is disproportionate to any benefit P229 Proposed would cause
- It is not cost reflective of participants' contribution to variable losses because it would result in some being allocated negative variable losses (i.e. being credited with energy) whereas all participants on the system cause losses so the best result possible for any particular participant should be allocation of zero variable losses
- It would introduce a new cross-subsidy because some participants would benefit from being credited with energy as a result of their allocation of variable losses, while others would be penalised by being debited energy
- It would have a disproportionate impact on some classes of participants who are unable to respond to signals, including the following:
    - Demand – less able to respond to short- or long-term signals;
    - Renewables – generate according to outside conditions, e.g. wind generators, so cannot respond to signals;
    - Combined heat and power (CHP) plant – must run to produce required heat, so cannot respond to signals; and
    - Nuclear generators – run at constant capacity to avoid changing production, so cannot respond to signals.
- Locational transmission losses allocation is intended to provide Parties with a cost reflective allocation of losses, providing an incentive to Parties to behave in a manner consistent with the costs they cause to the system; to realise this intent, it is important losses are calculated accurately before being allocated to those causing them; but inherent inaccuracies[6] with the P229 Proposed methodology mean it does not guarantee a more accurate and appropriate allocation that would reflect costs on all Parties in a fair and equitable manner, and therefore rather than removing the

existing cross subsidy, P229 Proposed would create a new, less transparent cross subsidy, which would be detrimental to competition

- The socialisation of losses allocation within zones would lead to inappropriate signals for market entry/exit, as particular participants may receive signals that do not reflect their actual contribution to variable losses
- Negative impact on investment in renewables as it would increase the cost of investment in renewable generators that would be located in unfavourable zones
- Introduce discrimination between new generators, which can respond to locational signals, and existing generators, which cannot change their location in response to variable losses allocation

A **MINORITY** of the Group believed the Proposed Modification would better facilitate Objective (c) for the following reasons:

- It would remove the cross-subsidy inherent in the current uniform allocation of variable losses
- It would allocate variable losses on a more cost reflective basis than the baseline which would promote competition
- It would produce cost signals that would better reflect participants contribution to variable losses, which would enhance competition and tend to reduce overall variable losses by promoting more efficient despatch, with consequential environmental benefits

Objective (d)

The **MAJORITY** of the Group believed the Proposed Modification would not better facilitate Objective (d) because it would add additional complexity to the BSC arrangements, but noted that:

1. Changes generally add complexity and/or cost
2. This must be measured against the benefits a particular change would bring
3. In the case of P229 Proposed the added complexity would not be significant
4. Considerations under Objective (d) would be minor compared to those under (b) and (c)

A **MINORITY** of the Group believed the Proposed Modification would be neutral with respect to Objective (d) because it would not result in significant additional expenditure or complexity in the BSC arrangements.

2. Alternative vs baseline:

The Group provisionally agreed by majority that P229 Alternative would better facilitate the Applicable BSC Objectives overall compared with the current baseline.

Arguments applied to the Proposed were generally applicable to the Alternative, but the magnitude of impacts (both benefits and drawbacks) is reduced. **The following arguments apply only to the Alternative, but should be considered in conjunction with the arguments above relating to the Proposed against the baseline.**

Objective (b)

One Group member believed the Alternative Modification would not better facilitate Objective (b) for the following reason:

- To obtain the benefits of more efficient despatch it is important that the allocation of losses is cost reflective so that Parties factor the correct costs into their despatch decisions, but the Group member believed that inherent inaccuracies (which include all the inaccuracies of the Proposed[6] **and also the arbitrary adjustment of losses to avoid crediting energy to BM Units that reduce losses**) in the methodology for calculating TLFs (and hence TLMs) mean the P229 solution would not deliver costs that reflect the impact of a BM Unit (due to operation and location) on total losses in each and every Settlement Period; therefore the member did not believe that P229 Alternative would result in a more accurate and appropriate allocation that would reflect costs on all Parties in a fair and equitable manner

Objective (c)

The **MAJORITY** of the Group believed the Alternative Modification would better facilitate Objective (c) for the following reasons:

- P229 Alternative would **partially** remove the cross-subsidy inherent in the current uniform allocation of variable losses

- P229 Alternative has a risk of causing windfall gains and losses among participants, but this is sufficiently **mitigated by the use of a scaling factor** which aims to cap the benefit for individual generators at zero allocation of variable losses, that there would be a net benefit for competition

A **MINORITY** of the Group believed the Alternative Modification would not better facilitate Objective (c) for the following reasons:

- Locational transmission losses allocation is intended to provide Parties with a cost reflective allocation of losses, providing an incentive to Parties to behave in a manner consistent with the costs they cause to the system; to realise this intent, it is important losses are calculated accurately before being allocated to those causing them; but inherent inaccuracies with the P229 Alternative methodology (which include all the inaccuracies of the Proposed[6] **and also the arbitrary adjustment of losses to avoid crediting energy to BM Units that reduce losses**) mean it does not guarantee a more accurate and appropriate allocation that would reflect costs on all Parties in a fair and equitable manner, and therefore rather than removing the existing cross subsidy, P229 Alternative would create a new, less transparent cross subsidy which would be difficult to understand, which would be detrimental to competition

3. Alternative vs Proposed:

The Group provisionally agreed by narrow majority that P229 Alternative would not better facilitate the Applicable BSC Objectives compared with P229 Proposed.

Objective (a)

The Group did not identify any arguments relating to Objective (a).

Objective (b)

The **MAJORITY** of the Group believed the Proposed Modification would better facilitate Objective (b) compared with the Alternative, for the following reasons:

- P229 Proposed would result in more efficient operation of the Transmission System due to better despatch
- The benefits due to reduced losses, i.e. savings due to reduced generation and environmental benefits, are greater under P229 Proposed
- The P229 Proposed methodology for calculating variable transmission losses contains fewer sources of inaccuracy than that of P229 Alternative

One Group member believed the Alternative Modification would better facilitate Objective (b) compared with the Proposed because the Alternative is more cost reflective than the Proposed (i.e. it reflects all participants contribute to losses) and would therefore lead to more efficient operation of the Transmission System since decisions would be made on a more cost-reflective basis

A **MINORITY** of the Group believed there would be no difference in facilitation of Objective (b) under the Proposed and Alternative Modifications, and did not identify any arguments relating to Objective (b).

Objective (c)

The **MAJORITY** of the Group believed the Proposed Modification would better facilitate Objective (c) compared with the Alternative, for the following reasons:

- P229 Proposed is more cost reflective and sends the right signals to participants (compared with the Alternative which sends diluted signals)
- P229 Proposed more properly allocates variable transmission losses to participants
- The P229 Proposed methodology for calculating variable transmission losses contains fewer sources of inaccuracy than that of P229 Alternative

A **MINORITY** of the Group believed the Alternative Modification would better facilitate Objective (c) compared with the Proposed, for the following reasons:

- P229 Alternative is more cost reflective, reflecting that all participants contribute to losses (so none should be allocated negative losses) and does not introduce any new cross subsidies into the arrangements
- P229 Alternative would reduce the magnitude of windfall gains and losses relative to those that would result from P229 Proposed
- P229 Alternative mitigates the risks of windfall gains/losses and uncertainty of benefits realisation under P229 Proposed

Objective (d)

The Group **UNANIMOUSLY** agreed there would be no difference in facilitation of Objective (d) under the Proposed and Alternative Modifications, and did not identify any arguments relating to Objective (d).

Summary of consultation responses

The full set of responses to the P229 Assessment Procedure can be found on the P229 webpage.

Summary table of responses to the P229 Assessment Procedure consultation

Question	Response
1. Would the Proposed Modification P229 help to achieve the Applicable BSC Objectives?	Yes: 4 No: 12
2. Would the Alternative Modification P229 help to achieve the Applicable BSC Objectives compared to the current baseline?	Yes: 4 No: 12
3. Would the Alternative Modification P229 help to achieve of the Applicable BSC Objectives when compared to the Proposed Modification?	Yes: 12 No: 4
4. Are there alternative solutions that the Modification Group has not identified which they should consider?	Yes: 1 No: 15
5. Do you support the implementation approach described in the consultation document?	Yes: 11 No: 4 Neutral/other: 1
6. Do you have any views on the analysis undertaken on behalf of the Group or the Group's assessment of P229? For instance with respect to environmental impact, security of supply, offshore wind development (e.g. offshore Round 3) and investment in generation or the Transmission Systems. Have these views had any impact on your consideration of P229?	Yes: 9 No: 6 Neutral/other: 1
7. Do you have any views on the Group's assessment of the impact of P229 on the environment and the analysis of environmental impact in the P229 CBA? For instance any other environmental impacts the Group should consider or the analysis of emissions contained in the P229 CBA (i.e. the approach to CO2, NOx/SOx). Have these views had any impact on your consideration of P229?	Yes: 11 No: 4 Neutral/other: 1
8. Do you have any further comments on P229?	Yes: 7 No: 8 Neutral/other: 1
9. Is there anything further you believe the P229 Group should consider regarding the potential interaction of HVDC with the Load Flow Model in the future?	Yes: 3 No: 11 Neutral/other: 2

Other potential Alternative solutions

Only one consultation respondent suggested that there was a further alternative solution that the Group should consider. The respondent was surprised that the differences between peak and off peak periods and/or working day and non-working days were not considered in the same way as Seasons though it was unlikely that this would have changed their overall view.

The Group believed that the respondent was suggesting that a Zonal scheme based on shorter time periods than BSC Seasons should be considered as a solution. A Group member supported this, commenting that they had raised a similar point earlier that the Group had not pursued. The Group accepted that a solution based on the user of shorter time periods would be expected to be more accurate than a Seasonal scheme, but believed that a solution using a Seasonal basis gave a balance between the level of accuracy achieved and providing participants with some certainty regarding losses charging for the following year.

Implementation approach

11 of the 16 consultation respondents supported the Group's proposed implementation approach for P229. Four respondents disagreed with the proposed approach, with three providing reasons.

Two disagreeing respondents believed that while a 12 month lead time was appropriate for P229 implementation (both Proposed and Alternative) implementation should be at the beginning of the contract year (i.e. 1 April), and that implementation on 1 October, which was put forward as a compromise to allow some flexibility in P229 implementation (i.e. so that if 1 April implementation is not achievable due to the data approval is received it is not automatically necessary for implementation to be delayed an entire year) while retaining some link to Suppliers' contract rounds.

The respondents felt that a non-1 April implementation of P229 would distort the market place as customers would find their expected costs being altered, and that the earliest possible implementation date should be 1 April 2012.

One respondent felt it should be recognised that companies have already hedged some capacity beyond the proposed implementation dates in 2011 and 2012; they believed that a change to losses charging could render some hedges uneconomical and that it would be unacceptable for a change to charging to impact on commercial decisions that have already been made.

One respondent believed that other changes concerning transmission access should be taken into account when the Authority considers P229, and that it would also be worthwhile to take into account the introduction of other changes to transmission arrangements with the implementation of the next transmission price control, which they believed would be likely to be in April 2013. The respondent therefore believed that the earliest date for P229 implementation should be 1 April 2013.

The Group considered the drivers behind constructing decision and implementation dates for P229. The Group agreed that a minimum 12 month lead time from P229 approval was necessary, and believed that an October implementation date would be acceptable; the driver for setting the decision cut-off dates was the time needed by the Authority to reach a decision.

The Group considered the viability of presenting the Authority with an open-ended decision/implementation date combination such that P229 would be implemented on the closest 1 April or 1 October that is at least 12 months from Authority approval. In this case the Group still felt that a cut-off date would be required based on the date when the analysis of P229 could no longer be usefully applied. However, the Group agreed that market participants and potential new entrants needed some certainty about when changes would be implemented, and that this was especially true of P229 as it would have a material affect on Parties. The Group therefore believed it was appropriate to present the Authority with finite decision cut-off dates, and for this reason did not pursue any further the issue of potentially forming a recommendation on the length of time the P229 analysis should be regarded as valid.

The Group did however note the delays incurred since the issue of P229 for consultation, including the implementation approach, and that P229 would now be submitted to the Authority for decision after the March Panel meeting. This would mean that to achieve implementation on 1 October 2011 a decision would be required from the Authority by 30 September 2010, giving the Authority just over six months to make a decision on P229. The Group felt that a reasonable period to reach a decision would be a year, but both the Group and Authority representative wanted to retain the flexibility in potential P229 implementation afforded by including the 1 October 2011, though a decision by this date is unlikely. The Group therefore agreed to present the following three decision/implementation date combinations[7], which apply to both the Proposed and Alternative, to the Authority:

- 1 October 2011 if approval is received from the Authority on or before 30 September 2010;
- 1 April 2012 if approval is received from the Authority after 30 September 2010 but on or before 31 March 2011; or
- 1 October 2012 if approval is received from the Authority after 31 March 2011 but on or before 30 September 2011.

External analysis and assessment of environmental impacts

The Group considered the consultation responses concerning the analysis of P229 and the Group's assessment thus far, particularly with regard to environmental impacts. Nine respondents commented on the analysis and 11 had views on the assessment of the environmental impact, but the issues that they raised had largely already been considered and documented by the Group.

The Group noted that several respondents supported the concerns of some Group members that the WACC value used in the P229 CBA was significantly too low, and that the level of wind generation in the CBA's aggressive wind sensitivity scenario was significantly too low to be representative of the level of generation now anticipated to be introduced under Round 3 of offshore wind generation development.

The Group noted that a respondent disagreed with the view in the P229 CBA that additional gas transportation costs resulting from the impact on the operations of gas fired stations in the South would have had a minimal impact on the outcome of the CBA. The respondent felt that this amounted to transferring a cost in the electricity industry to a different cost in the gas industry, and questioned whether this was appropriate. The Group considered that this impact would be a geographically apportioned charge associated with electricity transport being transferred to gas transport, in which the cost of gas loss is socialised on a non-geographic basis. However the Group was unable to quantify this impact.

The Group noted that a respondent had commented that the estimate of Parties' implementation costs used in the CBA was too low, as £1.5M divided by the 219 Parties gives an average implementation cost of under £7,000, which the respondent considered unrealistically low. The Group considered that the CBA consultant had based their estimate of industry implementation costs on the P229 impact assessments provided by Parties, and that the averaging gave a simplistic view which did not take into account that several individual companies comprise multiple Parties. It was also noted that while some companies had identified significant impacts and costs associated with implementation of

[7] Note the Group amended the dates to the conventional form of 'on or before' a date to avoid confusion, but the dates are the same as those discussed and consulted upon, e.g. 'on or before 30 September 2010' is equivalent to 'before 1 October'.

P229 others were able to incorporate P229 as part of their normal activities, with no material additional effort or cost required.

One respondent was concerned that P229 would have a disproportionate impact on some Parties because of the treatment of Scottish 132kV lines. This was because 132kV lines are included as part of the transmission network in Scotland, but are classed as distribution in England and Wales, coupled with the fact that losses on 132kV lines (circa 8%) are higher than those on higher voltage lines (about 2%). The respondent therefore believed that inclusion of Scottish 132kV lines in the P229 provisions would result in an inconsistent approach to the losses of 132kV lines. A Group member supported this view, but overall the Group believed that since 132kV lines are treated as transmission in Scotland such lines should be part of the P229 transmission losses provisions.

Generally, respondents felt that the monetary value assigned to the impact of P229 on emissions should be treated with some caution due to the judgement and assumptions necessarily used in their calculation. The Group agreed to the extent that they believed that the calculated value should be considered in conjunction with the actual volume of emissions.

Potential future interaction with HVDC lines

Three consultation respondents commented on issues around the potential interaction of High Voltage DC lines with the load flow model.

One respondent, while accepting the decision not to include provisions for future HVDC networks in P229, believed the P229 Load Flow Modelling exercise had indicated that HVDC networks could have a material impact and therefore, noting that the ENSG report suggests an offshore HVDC network could potentially be implemented by 2015, felt that a CBA scenario including HVDC infrastructure should be carried out.

Another respondent agreed that the exclusion of potential future HVDC circuits within the transmission system from P229 was pragmatic. However, the respondent believed that the proposals for the treatment of HVDC networks considered by the Group, before they agreed HVDC provisions should not be included in P229, would be inconsistent with the aim of allocating losses more cost reflectively.

Another respondent made no comment on the approach to HVDC lines under P229 but gave a detailed response to the recommendations considered by the Group before agreeing HVDC provisions should not be included in P229. The respondent had concerns with the recommendations, noting in relation to several that a similar approach should be applied to the flows on the France-England interconnector DC circuits to avoid discriminating between flows on DC circuits.

Impacts on smaller participants and consumers

The Group noted that the P229 consultation had received a number of respondents from smaller participants, including several smaller Suppliers and a large industrial consumer, and believed that it would be useful to highlight the views of these participants. Several responses, including a letter received from Consumer Focus, also commented upon the possible impact of P229 on end consumers; while the Group was mindful that the impact on end consumers does not fall under the Applicable BSC Objectives and is therefore not considered under the BSC Modification process, they believed it would be useful to note identified impacts and issues on consumers to facilitate the Authority's consideration of P229 under its wider regulatory remit.

Several respondents representing smaller companies noted that they were unable to consider all of the analysis presented to support the assessment of P229 due to its volume and complexity, and were also concerned that for smaller participant the impact of the additional complexity in the BSC arrangements of P229 would outweigh any benefits. Respondents believed this additional complexity would make it harder for small players and new entrants to compete. A respondent felt that understanding, forecasting and managing variation in TLFs would be difficult and impose further transactional costs on the market, costs which would be likely to be disproportionately larger for smaller players.

Credibility of P229 analysis

The Group believed that given the issues with the P229 analysis raised by Group members previously, and which are reflected in the concerns of some consultation respondents, they should consider the validity of the analysis conducted to support their assessment of P229 and confirm their views for the purposes of this report.

A minority of the Group were totally satisfied with the analysis. One Group member noted that the Group had accepted the analysis prior to the issue of the P229 Assessment Procedure consultation and they did not believe anything had occurred since then that would affect the Group's assessment of P229, and another member commented that if the Group requested any further analysis to assuage any concerns they felt it would not give any further insight than there is great uncertainty about how the market will develop over the modelled period which could materially impact the benefits of P229 implementation.

The majority of the Group expressed some dissatisfaction with the P229 CBA, but accepted that it was based on the CBA consultant's view as an independent expert. Group members were specifically concerned because they believed the amount of offshore wind generation that will be introduced in Round 3 of offshore development had been significantly understated in the CBA and also because they believed that the WACC value used in the CBA was too low (though the latter concern was mitigated by the inclusion on behalf of the Group of figures adjusted using higher WACC values in the P229 documentation).

One Group member went further, stating that they believed the P229 analysis was no longer credible, though they were still able to form a view on P229 with respect to the Applicable BSC Objectives. The member felt the P229 CBA was no longer credible because of developments that had occurred since the CBA modeller had developed the inputs and assumptions for the modelling undertaken to support the CBA. The member stated that they had noted reservations about the analysis at the time that P229 was issued for industry consultation, but had agreed the P229 CBA was fit for consultation; since then developments in the market and the concerns raised in the P229 consultation responses had led them to now believe that the P229 CBA was no longer credible.

On the basis of these considerations the Group therefore agreed by majority that the P229 analysis was adequate for the assessment of P229, and all members believed that they were able to give views against the Applicable BSC Objectives.

In response to the Group's concern about offshore generation the CBA consultants acknowledged that there have been developments since the analysis, with the biggest being in the future development of offshore wind generation (as noted by the Group). However, in their opinion little truly solid new information is available. Although it is anticipated that a lot of offshore wind generation will be created, there is still considerable uncertainty around where new generators will actually connect, precisely when they will connect, what the generation profiles will be, etc. They believe that this cannot be considered to invalidate the CBA.

The consultants did note that, generally, the accuracy/usefulness of any analysis of this sort (i.e. using assumptions/estimations and forecast modelling) tends to decrease as real world events enter the modelled period and actual circumstances align with the model or diverge from it. However, they did not believe that this effect was particularly pronounced with regard to the P229 CBA.

A Group member questioned the consultants' response, noting that they believed that the uncertainties identified could have been overcome early in the P229 Assessment Procedure (January 2009) and incorporated into the CBA. This member believed that the joint Crown Estate and National Grid report of December 2008 detailed where new generation will connect, that an equitable and transparent methodology could have been used to approximate when generation would connect and queried why generation profiles would be substantially different from those used for offshore generation included in the CBA.

The independent cost-benefit analysis was commissioned by the Group because they could not perform such analysis itself. Therefore the Group set out requirements for the CBA but left final decisions on methodology to the CBA consultant's independent expertise. The requirements specification agreed by the Group and used to procure the CBA consultant and set its terms of reference did not include a requirement to model a particular amount of offshore wind, but rather that the consultants should use their expertise and take into account all relevant information.

A minority of the Group was also concerned that offshore HVDC infrastructure was not modelled as part of the CBA, since its development was indicated by the ENSG report and the P229 load flow modelling exercise (Task 10) indicated that offshore HVDC elements could have a significant impact on TLFs (notwithstanding that this was an approximation of offshore HVDC elements and not intended to be representative of actual developments).

Respondents views on impact on the Applicable BSC Objectives

Consultation respondents offered many arguments and considerations in support of their views on P229 against the Applicable BSC Objectives. Many of these supported factors already discussed by the Group. The Group noted particularly the following points which they believed either raised issues not already covered in their consideration of P229 or illustrated or confirmed issues they had discussed previously.

Impact on low-carbon generation

A respondent noted that in addition to their belief that a locational losses regime should not be used because locational incentives are already provided by TNUoS charges, they also believed a locational losses scheme is unlikely to have the desired effect. The respondent stated that siting for a large proportion of UK low-carbon plant is dictated by:

- Offshore wind zones - for offshore wind generators;
- The Nuclear National Policy Statement (NPS) - for nuclear plant; and
- Wind speed characteristics - for onshore wind.

Further, they stated that for new coal plant both fuel delivery and Carbon Capture and Storage (CCS) infrastructure access are key siting criteria, while cooling is a factor for both Combined Cycle Gas Turbine (CCGT) and coal plant. For these reasons the respondent believed that locational incentives from P229 would be likely to have a negligible impact on siting decisions for generation plant, but believed that by increasing the costs for generators associated with some locations P229 would reduce the economic viability of siting plant in these locations, and thereby might cause some investments in low-carbon plant to be abandoned. The respondent believed that because the CCGT siting is the least constrained an increase in locational incentives by P229 could tend to encourage development of higher CO_2 emitting plant instead of low-carbon plant.

The respondent noted that the Renewables Obligation Certificate (ROC) is a single, clear incentive mechanism to encourage development of new renewable generation. The 2009 iteration of the Renewables Order (following Government review of renewable financial incentives) makes additional provision for increased support for Offshore Wind. This additional support is intended to give the proper level of subsidy to encourage new offshore wind investment. The Government's review did not envisage additional schemes such as locational losses, and the respondent therefore believed that additional complexity introduced by P229 would be likely to add additional uncertainty to investment decisions.

Overall the respondent therefore believed P229 could discourage investment in low-carbon generation, which would be contrary to the UK's energy policy.

Distributional impact

A respondent commented that if trading arrangements were being designed from scratch they would agree that zonal losses should be applied, but that introducing P229 at this stage would result in excessive transfer from Northern generators to Southern generators (estimated £31m in 2011) despite the fact that both create losses. They felt that the presentation of the distributional impact underplayed the scale of these transfers, since assuming similar distributional impacts in each year gives a North to South transfer of over £300m compare with overall expected benefits of £48m.

The respondent felt that the distributional impact of P229 must be considered alongside the potential benefit, and provided an illustrative example of the scale of the P229 distributional impact. The respondent estimated, by comparing the P229 TLM data for 2008 with actual TLMs, that under P229 their generator at Saltend would pay around £5.5m more each year for losses under P229. The costs to this one generator alone would thus exceed the total forecast benefits. Given this and similar analysis of other generators they were also concerned that the distributional impacts are considerably understated. The respondent believed that the scale of the distributional impact represented a windfall loss for Northern generators (and a gain for generators in the South).

Benefits for embedded exemptable generation

A respondent noted that embedded generation that is licence exempt is allocated the offtake TLM. The respondent believed that under a P229 locational losses scheme this would result in incentives to site licence exempt embedded generation where it is unattractive to have licensed generation (i.e. in the North) and reduced incentive to locate in the South. They were also concerned that P229 would introduce a perverse incentive to run embedded plant counter to optimal despatch, which would negate some of the re-despatch benefits forecast by the CBA.

The Group considered this and agreed that it was not a valid concern because the effect would be the same since only a single TLM is assigned to each TLF Zone. However, the Group did believe that it was possible that embedded plant could operate differently or 'flip' their status between delivering and offtaking. The Group noted that embedded generation was not modelled separately as part of the P229 CBA.

Predicted P229 benefits

A respondent believed that an overall re-despatch benefit is theoretically possible only if participants are given signals that correctly reflect their individual impact on the shared cost of losses and they are reasonably able to respond to such signals. They noted P229 would "allocate an energy volume to every BM Unit which would be uncertain, unavoidable, and beyond the control of its owner, being dependent on the behaviour of other BM Units and the properties of the Transmission System, in each half-hour, each season, and in the longer term".

This respondent noted that the P229 CBA shows theoretical net benefits arising from an assumed simple response of marginal generators to the proposed volume adjusters, but the estimated energy cost savings average £7m/year from an £8.4bn/year total i.e. 0.08% of total energy costs, equivalent to a 0.02 £/MWh reduction in average energy prices. The benefits vary between scenarios, but in all cases the impact on net energy costs is relatively very small, and the respondent believed that other factors could cancel or outweigh the forecast benefit, for example:

- TLFs increase uncertainty in generators' out-turn energy costs; because this is unmanageable, it would be passed through to purchasers in a risk premium on the market price of energy set by marginal generators;
- TLFs increase uncertainty in Suppliers' out-turn energy costs, both in the short term in individual half-hours and the long term where the factors would not be known; this would be passed through to customers in a risk premium;
- Generators and Suppliers would need resources to manage the uncertainty and additional complexity associated with a locational transmission losses;
- The effective future capacity of generation investments would become less certain;
- A significant step change in the value of some assets would arise from P229; regulatory imposition of such a change would increase the perception of regulatory risk with potential consequences for future investment;
- Approximations in the TLF methodology (e.g. averaging over zone and season) mean individual locations could be allocated losses costs which give the wrong signal, and in some cases completely the opposite signal to that which would theoretically give benefits (though the CBA allowed for this in estimating generation despatch costs the respondent did not think the impact on market prices was fully considered);
- Generators' physical operating constraints (e.g. start-up, shutdown, load changing, part-loading and interaction between units), and potentially commercial constraints, mean actual despatch may not match theoretical despatch;
- There is no indication P229 would significantly affect locational siting decisions to the national benefit since losses are a relatively minor factor in such decisions compared with transmission access costs (which are related to losses), planning, fuel source, social and other factors. The estimated reduction in the net cost of losses under P229 is due to short term despatch effects and is relatively small and uncertain compared to the overall value of losses, and relative to the potentially inaccurate redistribution of losses between BM Units in different zones; and
- It is possible that those that benefit from P229 might retain the benefits rather than pass them on, e.g. existing marginal generators might have no incentive to pass on benefits, nor might suppliers with customers on long term contracts.

Proposed vs baseline

The Group agreed by majority that P229 Proposed would not better facilitate the Applicable BSC Objectives overall compared with the current baseline.

Objective (a)

The **MAJORITY** of the Group believed there were no arguments relating to Objective (a) and as such the Proposed Modification was neutral with respect to this Objective.

A **MINORITY** of the Group believed the Proposed Modification would better facilitate Objective (a) for the following reasons:

- It would remove discrimination inherent in the current allocation of variable losses

A **MINORITY** of the Group believed the Proposed Modification would not better facilitate Objective (a) for the following reasons:

- It would introduce discrimination into the allocation of variable losses

Objective (b)

A **MAJORITY** of the Group believed the Proposed Modification would not better facilitate Objective (b) for the following reasons:

- Benefits due to P229 Proposed are uncertain and would be offset by the additional complexity it would introduce to the arrangements;
- Inherent inaccuracies[8] in the methodology for calculating TLFs (and hence TLMs) mean P229 Proposed would not be cost-reflective and would not give a more accurate and appropriate allocation of losses;
- Locational signals are already provided by TNUoS charges and cost signals from P229 Proposed would interfere with this existing mechanism;
- P229 Proposed would have a detrimental effect on investment, including investment in renewable generation projects, which would have a negative environmental impact[9]; and
- A negative impact on investment could potentially negatively impact security of supply.

A **MINORITY** of the Group believed the Proposed Modification would better facilitate Objective (b) for the following reasons:

- It would result in more efficient despatch because participants would receive cost signals that would allow variable losses to be taken into account in despatch decisions;
- It would result in more efficient market entry/exit because participants would receive cost signals that would allow variable losses to be taken into account in decisions on

[8] Group members believed these inaccuracies include:

- Use of an ex-ante model to determine TLFs, which uses Sample Settlement Periods from the previous year;
- Averaging TLFs across nodes within a GSP Group; the load flow modelling results comparing nodal and zonal TLFs showed a zonal TLF could be quite different from TLFs that allocated on a nodal basis in the North;
- That a Seasonal TLF averages across all Settlement Periods in that Season; and
- That a DC model is used to model an AC system in order to calculate TLFs.

[9] See discussions and provisional views for further details.

where to locate new plant or whether to continue/cease operation of existing plant – though this would be a relatively small factor in such decisions; and

- It would result in production savings and a reduction in variable losses, due to reduced generation because of more efficient despatch, which would also result in an environmental benefit due to reduced emissions.

A **MINORITY** of the Group believed that P229 Proposed would have a neutral effect on Objective (b) because though the CBA indicates in theory there would be a benefit, members were not convinced that this benefit would be realised in practice and there are potential negative impacts (as outlined against the majority view, above).

Objective (c)

The **MAJORITY** of the Group believed the Proposed Modification would not better facilitate Objective (c) for one or more of the following reasons:

- It would cause a distributional transfer between market participants based on their type and location which would amount to windfall gains for some and windfall losses for others, which would have a detrimental impact on competition;
- This transfer is disproportionate to any benefit P229 Proposed would cause;
- It is not cost reflective of participants' contribution to variable losses because it would result in some being allocated negative variable losses (i.e. being credited with energy) whereas all participants on the system cause losses so the best result possible for any particular participant should be allocation of zero variable losses;
- It would introduce a new cross-subsidy because some participants would benefit from being credited with energy as a result of their allocation of variable losses, while others would be penalised by being debited energy;
- It would have a disproportionate impact on some classes of participants who are unable to respond to signals, including the following:
    - Demand – less able to respond to short- or long-term signals;
    - Renewables – generate according to outside conditions, e.g. wind generators, so cannot respond to signals;
    - Combined heat and power (CHP) plant – must run to produce required heat, so cannot respond to signals; and
    - Nuclear generators – run at constant capacity to avoid changing production, so cannot respond to signals;
- Inherent inaccuracies[6] in the P229 Proposed methodology mean it does not guarantee a more accurate and appropriate allocation that would reflect costs on all Parties in a fair and equitable manner, and therefore rather than removing the existing cross subsidy, P229 Proposed would create a new, less transparent cross subsidy, which would be detrimental to competition;
- The socialisation of losses allocation within zones would lead to inappropriate signals for market entry/exit, as particular participants may receive signals that do not reflect their actual contribution to variable losses;

- The socialisation of losses within zones unfairly increases the burden to existing generation when a new generator connects with high losses (as these are currently socialised amongst the entire GB);
- Negative impact on all investment due to introducing uncertainty and unpredictability into the allocation of transmission losses over the lifetime of the investment, which needs to be factored into investment decisions;
- Negative impact on investment in renewables as it would increase the cost of investment in renewable generators that would be located in unfavourable zones;
- Introduce discrimination between new generators, which can respond to locational signals, and existing generators, which cannot change their location in response to variable losses allocation; and
- Additional complexity creates a barrier to market entry.

A **MINORITY** of the Group believed the Proposed Modification would better facilitate Objective (c) for the following reasons:

- It would remove the cross-subsidy inherent in the current uniform allocation of variable losses;
- It would allocate variable losses on a more cost reflective basis than the baseline which would promote competition; and
- It would produce cost signals that would better reflect participants contribution to variable losses, which would enhance competition and tend to reduce overall variable losses by promoting more efficient despatch, with consequential environmental benefits.

Objective (d)

The **MAJORITY** of the Group believed the Proposed Modification would not better facilitate Objective (d) because it would add additional complexity to the BSC arrangements for one or more of the following reasons:

- Implementation and operation of P229 would add cost and complexity to the administration of the Code; and
- There is no defect in the Code so any additional cost or complexity is not warranted.

Group members noted that considerations under Objective (d) are relatively minor compared to those under (b) and (c).

A **MINORITY** of the Group believed the Proposed Modification would be neutral with respect to Objective (d) because it would not result in significant additional expenditure or complexity in the BSC arrangements.

Alternative vs baseline

The Group agreed by a narrow majority that P229 Alternative would not better facilitate the Applicable BSC Objectives overall compared with the current baseline.

Arguments applied to the Proposed were generally applicable to the Alternative, but the magnitude of impacts (both benefits and drawbacks) is reduced. **The following arguments apply only to the Alternative, but should be considered in conjunction with the arguments above relating to the Proposed against the baseline.**

Objective (a)

The **MAJORITY** of the Group believed there were no arguments relating to Objective (a) and as such the Alternative Modification was neutral with respect to this Objective.

A **MINORITY** of the Group believed the Alternative Modification would better facilitate Objective (a) for the following reason:

- It would remove discrimination inherent in the current allocation of variable losses.

ONE Group member believed the Alternative Modification would not better facilitate Objective (a) for the following reason:

- It would introduce discrimination into the allocation of variable losses.

Objective (b)

The **MAJORITY** of the Group believed the Alternative Modification would better facilitate Objective (b) for the following reasons:

- The arguments set out above in relation to the Proposed Modification; and
- Additionally one member believed that while the benefits of P229 are uncertain the associated risk is managed by the scaling methodology.

A **MINORITY** of the Group believed the Alternative Modification would not better facilitate Objective (b) for the following reasons:

- The arguments set out above in relation to the Proposed Modification; and
- Additionally one member believed that the inaccuracy introduced by the scaling methodology, i.e. the arbitrary adjustment of losses to avoid crediting energy to BM Units that reduce losses, means the Alternative is not cost-reflective.

A **MINORITY** of the Group believed that P229 Alternative would have a neutral effect on Objective (b) because though the CBA indicates in theory there would be a benefit, a member was not convinced that this benefit would be realised in practice.

Objective (c)

The **MAJORITY** of the Group believed the Alternative Modification would not better facilitate Objective (c) for the following reasons:

- The arguments set out above in relation to the Proposed Modification; and
- Additionally one member believed that the inaccuracy introduced by the scaling methodology, i.e. the arbitrary adjustment of losses to avoid crediting energy to BM Units that reduce losses, adds to the new, less transparent cross subsidy the Alternative would introduce and reduces the cost reflectivity of losses allocation, which would be detrimental to competition.

A **MINORITY** of the Group believed the Alternative Modification would better facilitate Objective (c) for the following reasons:

- P229 Alternative would **partially** remove the cross-subsidy inherent in the current uniform allocation of variable losses; and
- P229 Alternative has a risk of causing windfall gains and losses among participants, but this is sufficiently **mitigated by the use of a scaling factor** which aims to cap

the benefit for individual generators at zero allocation of variable losses, that there would be a net benefit for competition.

Objective (d)

The **MAJORITY** of the Group believed the Alternative Modification would not better facilitate Objective (d) because it would add additional complexity to the BSC arrangements for one or more of the reasons set out above in relation to the Proposed Modification.

Group members noted that considerations under Objective (d) are relatively minor compared to those under (b) and (c).

A **MINORITY** of the Group believed the Alternative Modification would be neutral with respect to Objective (d) because it would not result in significant additional expenditure or complexity in the BSC arrangements.

Alternative vs Proposed

The Group agreed by majority that P229 Alternative would better facilitate the Applicable BSC Objectives compared with P229 Proposed.

The Group agreed by majority that when comparing the Proposed and Alternative there would be a neutral impact on Objectives (a) and (d) and that the Alternative would better facilitate Objectives (b) and (c). Overall the Group by majority considered the Alternative better than the Proposed.

Objective (a)

The **MAJORITY** of the Group believed there would be no difference in facilitation of Objective (a) under the Proposed and Alternative Modifications.

ONE Group member believed the Alternative Modification would better facilitate Objective (a) compared with the Proposed for the following reason:

- The Alternative would be neutral with respect to Objective (a) whilst the Proposed would not better facilitate Objective (a) because it would introduce discrimination into the allocation of variable losses.

Objective (b)

The **MAJORITY** of the Group believed the Alternative Modification would better facilitate Objective (b) compared with the Proposed for the following reasons:

- The Alternative is more cost reflective than the Proposed (i.e. it reflects all participants contribute to losses) and would lead to more efficient operation of the Transmission System as decisions would be made on a more cost-reflective basis; and

- Negative impacts are reduced compared with the Proposed, particularly the effect of model accuracy and the impact on investment.

A **MINORITY** of the Group believed the Proposed Modification would better facilitate Objective (b) compared with the Alternative, for the following reasons:

- P229 Proposed would result in more efficient operation of the Transmission System due to better despatch;

- The benefits due to reduced losses, i.e. savings due to reduced generation and environmental benefits, are greater under P229 Proposed; and

- The P229 Proposed methodology for calculating variable transmission losses contains fewer sources of inaccuracy than that of P229 Alternative.

A **MINORITY** of the Group believed there would be no difference in facilitation of Objective (b) under the Proposed and Alternative Modifications.

Objective (c)

The **MAJORITY** of the Group believed the Alternative Modification would better facilitate Objective (c) compared with the Proposed, for the following reasons:

- P229 Alternative is more cost reflective, reflecting that all participants contribute to losses (so none should be allocated negative losses) and does not introduce any new cross subsidies into the arrangements;
- P229 Alternative would reduce the magnitude of windfall gains and losses relative to those that would result from P229 Proposed;
- P229 Alternative mitigates the risks of windfall gains/losses, inappropriate allocation for some zones/times and uncertainty of benefits realisation under P229 Proposed; and
- Negative impacts are reduced compared with the Proposed, particularly the effect of model accuracy and the impact on investment.

A **MINORITY** of the Group believed the Proposed Modification would better facilitate Objective (c) compared with the Alternative, for the following reasons:

- P229 Proposed is more cost reflective and sends the right signals to participants (compared with the Alternative which sends diluted signals);
- P229 Proposed more properly allocates variable transmission losses to participants; and
- The P229 Proposed methodology for calculating variable transmission losses contains fewer sources of inaccuracy than that of P229 Alternative.

Objective (d)

The **MAJORITY** of the Group believed there would be no difference in facilitation of Objective (d) under the Proposed and Alternative Modifications.

ONE Group member believed the Proposed Modification would better facilitate Objective (d) compared with the Alternative for the following reason:

- The Proposed would be neutral with respect to Objective (d) whilst the Alternative would not better facilitate Objective (d) because it would introduce the additional complexity of the scaling methodology for no benefit.

ONE Group member believed the Alternative Modification would better facilitate Objective (d) compared with the Proposed for the following reason:

- There is no defect in the Code, and while both the Alternative and Proposed would not better facilitate Objective (d) the effect of the Proposed would be to move further from the baseline.

11 Impacts

a) Impact on BSC Systems and Processes

BSC System / Process	Potential Impact of Proposed Modification
BM Unit Registration	The CRA would be required to amend its BM Unit registration process so that Adjusted Seasonal Zonal TLF values for each BM Unit are obtained from the TLFA (via BSCCo) for each BSC Year, and are registered in BSC Systems. These values would be reported using existing data flows.
Central Data Collection	The CDCA would be required to provide the TLFA (via BSCCo) with Metered Volume data for the Sample Settlement Periods used in the Load Flow Model.
BMRS	The BMRA would be required to receive Adjusted Seasonal Zonal TLF values for each BM Unit from the CRA, and to use these values in BMRA reporting during the applicable BSC Year.
Settlement Administration	The SAA would be required to receive Adjusted Seasonal Zonal TLF values for each BM Unit from the CRA, and to apply these values in Settlement calculations during the applicable BSC Year.
Derivation of Zonal TLFs	A new BSC process, with supporting systems, would be introduced for the TLFA to derive TLFs through the application of a Load Flow Model in accordance with a Network Mapping Statement, Load Flow Model Specification, and new calculations in Section T of the Code. The output of this new process would be a set of four Adjusted Seasonal Zonal TLF values (one per BSC Season in the year) for each of the 14 TLF Zones. All BM Units within a Zone would receive the Adjusted Seasonal Zonal TLF value for that Zone in the relevant BSC Season.

b) Impact on BSC Agent Contractual Arrangements

BSC Agent Contract	Potential Impact of Proposed Modification
Transmission Loss Factor Agent	**New agent.** A full BSC Agent procurement exercise would be required, and appropriate contractual arrangements created, for the TLFA, in accordance with Section E of the Code.
BSC Auditor (PwC)	Extended the scope of the BSC Audit to include the TLFA.
LogicaCMG	BMRA, CRA, CDCA, SAA may be impacted.

c) Impact on BSC Parties and Party Agents

Parties

11 Parties responded to the P229 industry Impact Assessment. Respondents identified a range of impacts. Implementation lead times identified by Parties were generally in the range 6-9 months, with costs around £200,000 (where costs were identified). Several Parties, with minimal impacts, identified lead times of only a matter of weeks. Two respondents identified implementation timescales of 12 months due to significant system impacts; one of these Parties estimated costs of £300,000 - £600,000.

A number of respondents noted that their systems and processes reflect the current uniform allocation of losses and changing these to reflect Transmission Losses allocation under P229 would be the source of most of the impacts. One respondent noted that they estimated the impact of P229 implementation on them would be limited given the development work already completed due to previous rejected losses Modification Proposals (i.e. P82). Impacts of P229 Implementation identified by respondents included the following:

- Review, update and testing of IT systems required, e.g. forecasting, risk management, Settlement reporting/validation and commercial arrangements/trading.
- Checking BMUs had been assigned to the correct GSP group.
- Modification of data models to reflect the new arrangements.

Full details of the responses to the P229 IA can be found on the P229 webpage on the ELEXON website.

LDSOs

LDSOs would need to provide any additional information that ELEXON and/or the Panel may require to prepare the Network Mapping Statement.

Any LDSO to whose network an Offshore Transmission System connects would need to provide Distribution System Data identifying which GSP(s) on the onshore Transmission System the energy from that offshore system flows to.

Party Agents

No impact on any Party Agents.

d) Impact on Transmission Company

- Support BSCCo and the Panel in establishing and maintaining the Network Mapping Statement, including maintenance of an up-to-date list of all Nodes on the Transmission System, and assistance in resolving any questions or disputes over the allocation of individual BM Units to Zones; and
- Support the TLFA and the Panel in maintaining the Load Flow Model, including the provision of relevant Network Data and any necessary information to aid the Panel in determining Load Periods.

e) Impact on BSCCo

Area of Business	Potential Impact of Proposed Modification
Change Implementation	A special release would be required to deliver the TLFA service, requiring (at a minimum) the following: • Procurement of new BSC Agent (TLFA) and new service provider (Model Reviewer), managed as a procurement project within the P229 Release. • Testing of TLFA system for production of Annual TLFs. • Implementation and review of TLFA documentation, CDCA URS and related docs and the IDD Part 2, and other CSD changes. • Changes due to requirement for CRA to store and use seasonal TLFs.
Change Coordination	Implement approved changes to the Code and Code Subsidiary Documents.
Corporate Assurance & Finance teams	Support procurement and implementation.
Governance & Regulatory Affairs	Implementation and management of operational impact on the Panel.
Legal	Support development and assessment of P229.
Commercial Management and Procurement	Procurement would be required as part of implementation of P229.
Central Services Data and Planning	Support majority of the operational processes during lead up to implementation and on an ongoing basis after go-live.
Customer Operations	Training for the ELEXON helpdesk and OSM service regarding new processes.

f) Impact on BSC Panel

- Approval of the Load Flow Model, the Load Flow Model Specification, the TLFA Service Description, the Load Flow Model Reviewer Terms of Reference and the Network Mapping Statement;
- Establishing the definitive list of TLF Zones for use in the Network Mapping Statement and Load Flow Model, including resolution of any question or dispute over the mapping of individual BM Units to Zones;
- Establishing a number of different Load Periods to represent varying levels of load on the Transmission System for use in the Load Flow Model;
- Establishing the number of Sample Settlement Periods to be used in each Load Period for use in the Load Flow Model;
- Establishing a revised BSC Audit Scope incorporating the TLFA; and
- With the aid of an independent Load Flow Model Reviewer, ensuring that the Load Flow Model complies with the Load Flow Model Specification (including retrospectively, where the calculation or use of TLFs is the subject of a Trading Dispute).

g) Impact on Code

Code Section	Potential Impact of Proposed Modification
Section E 'BSC Agents'	Add TLFA to the list of BSC Agents in Section E.
Section H 'General'	Add the Load Flow Model Specification to the list of Code Subsidiary Documents in Section H.
Section T 'Settlement and Trading Charges'	Amend to detail the rights and obligations of all relevant parties regarding the derivation of Adjusted Seasonal Zonal TLFs and their use in Settlement.
Section V 'Reporting'	Amend to detail the provision by BSCCo of the following TLF data to Parties on request: • The Network Data and Metered Volumes used in the TLF calculation for the applicable BSC Year; • The raw nodal power flows calculated by the Load Flow Model and used in the TLF calculation for the applicable BSC Year; and • The raw Nodal TLFs calculated by the Load Flow Model and used in the TLF calculation for the applicable BSC Year.
Section X 'Definitions and Reporting'	Amend to detail any new Code-defined terms or acronyms for P229.

h) Impact on Code Subsidiary Documents

Document	Potential Impact of Proposed Modification
BSCP01 'Overview of the Trading Arrangements'	Amend to reflect the derivation of non-zero TLFs and their use in Settlement calculations.
BSCP15 'BM Unit Registration'	Amend to include the process for allocating four Adjusted Seasonal Zonal TLF values to each BM Unit in the applicable BSC Year.
BSCP38 'Authorisations'	Amend to include an authorisation process for Parties to request input and output data files relating to the Load Flow Model (Network Data, Metered Volumes, power flows and Nodal TLFs).
BSCP41 'Report Requests and Authorisations'	As above.
Reporting Catalogue	Amend to reflect new/amended reporting requirements.
Communications Requirement Document	Amend to reflect rules for communicating with the TLFA via BSCCo.
BSC Agent Service Descriptions	Amend BMRS, BSC Auditor, CDCA, CRA and SAA Service Descriptions to reflect new obligations on these Agents in respect of zonal TLFs. New Service Description – for the TLFA.
Load Flow Model Specification	New Code Subsidiary Document – establish the specification for the TLFA Load Flow Model.

i) Impact on Core Industry Documents/System Operator-Transmission Owner Code

No impact.

j) Impact on Other Configurable Items

Document	Potential Impact of Proposed Modification
User Requirements Specifications	The BMRS, BSC Website, CDCA, and CRA URSs would need to be amended to reflect the new obligations on these Agents in respect of zonal TLFs. New URS required – for the TLFA.

k) Impact on BSCCo Memorandum and Articles of Association

No impact.

l) Impact on Governance and Regulatory Framework

The following impacts fall outside the scope of the Code and can not therefore form part of assessment of P229 against the Applicable BSC Objectives. However these areas could be taken into account by the Authority in the context of its wider statutory duties:

- Impact on consumers (through the passing on of costs or cost-savings by Parties, or changes in the location of demand);
- Impact on the existing locational signals provided by the Transmission Company's TNUoS charging.

12 Modification Group membership

P229 Modification Group

Member	Organisation	18/12	27/3	27/4	19/5	18/6	25/6	6/7	7/10	13/10	28/10	18/01
Adam Lattimore	ELEXON (Chairman)	√	√	√	√	√	√	√	√	√	√	√
Dean Riddell	ELEXON (Lead Analyst)	√	√	√	X	√	√	√	√	√	√	√
Bill Reed	RWE Npower (Proposer)	√	√	√	√	√	√	√	√	√	X	√
Rob Smith	National Grid	√	√	√	X	X	X	X	X	X	X	√
Neil Rowley	National Grid	-	-	√	√	√	√	√	√	√	☎	√
Chris Stewart	Centrica	√	√	√	√	√	√	X	√	√	☎	√
Garth Graham	Scottish and Southern	√	X	X	√	√	√	√	X	√	☎	√
Man Kwong Liu	SAIC	√	√	√	√	√	√	√	√	√	X	√
Esther Sutton	E.ON	√	√	√	√	√	√	√	X	√	☎	√
Stuart Cotten	Drax Power	√	√	√	√	√	√	√	√	√	☎	√
Emma Williams	First Hydro	√	√ (part)	√	√	√	√	√	√	X	☎	√
Martin Mate	EDF	X	√	√	√	√	√	√	√	√	X	√
Lisa Waters	Waters Wye	√	X	X	√	√	√	X	√	X	X	√
Bob Brown	Cornwall Energy Associates	X	√	√	√	√	√	√	√	√	√	X
Attendee	**Organisation**											
Diane Mailer	ELEXON (Lawyer)	√	X	√	√	√ (part)	√	√	√	√	X	√
John Lucas	ELEXON (DA)	X	√	X	√ (part)	√ (part)	X	X	√	X	√	√
Sarah Jones	ELEXON (DA)	X	X	X	√	√	√	√	X	X	X	X
Kathryn Coffin	ELEXON (DA)	-	-	-	-	-	-	-	-	-	√	X
Justin Andrews	ELEXON Operational	√ (part)	X	X	X	X	X	X	X	X	X	X
Steve Wilkin	ELEXON Operational	-	√	√	√	√	√	√	X	X	X	X

Lesley Nugent	Ofgem	X	X	X	X	X	X	X	X	X	☎	X
Dena Barasi	Ofgem	-	√	√	√	√ (part)	√	√	√	√	X	√
Peter Bolitho	E.ON	√	X	X	X	X	X	X	X	X	X	X
Phil Lawless	GDF Suez (Teesside Power)	√	√	X	X	X	X	X	X	X	X	X
Ricky Hill	Centrica	-	√	√	√	√	√	√	X	X	X	X
Ged Armstrong	GDF Suez (Teesside Power)	-	√	√	X	√	√	√	X	X	X	X
Hannah McKinney	EDF			√	√	X	√	√	X	X	X	X
Andrew Horsler	Consumer Focus	-	√	X	X	X	√	X	√	√	X	X
Sebastian Eyre	EDF	-	-	-	-	-	√	X	X	√ (part)	X	√ (part)
Andy Colley	Scottish and Southern	-	-	-	-	-	-	-	√	X	X	X
Justin Cusack	GDF Suez (Teesside Power)	-	-	-	-	-	-	-	√	X	X	X
Paul Jones	E.ON	-	-	-	-	-	-	-	√	X	X	X
Charles Ruffell	RWE Npower	-	-	-	-	-	-	-	-	-	☎	X
Phil Broom	GDF Suez	-	-	-	-	-	-	-	-	-	-	☎ (part)

13 Glossary

Glossary Table

Acronym/Term	**Definition**
α (alpha) factor	The scaling factor applied to total transmission losses such that 45% are allocated to delivering Trading Units and 55% are allocated to offtaking Trading Units.
Ex-ante	Calculated beforehand.
Fixed losses	The element of transmission losses which is independent of the distance travelled by electricity.
Load Flow Model	An electrical model of the Transmission System, used to generate Transmission Loss Factor values.
Node	Used in a Load Flow Model to represent points where energy flows on or off the Transmission System.
Total transmission losses	The sum of fixed losses and variable losses in any given period.
Transmission losses	The energy lost from the Transmission System in transporting electricity (calculated as the difference between total generation and total demand).
Transmission Loss Adjustment (TLMO)	The parameter for recovering the costs of the proportion of transmission losses which are not recovered through the Transmission Loss Factor, and which is applied on a uniform basis.
Transmission Loss Factor (TLF)	The parameter for allocating some or all transmission losses on a non-uniform basis, and which is currently set to zero.
Transmission Loss Factor Agent (TLFA)	The entity responsible for calculating Transmission Loss Factor values.
Transmission Loss Multiplier (TLM)	The factor used to scale BM Unit Metered Volumes in Settlement in order to recover the costs of total transmission losses from Parties.
Variable losses	The element of transmission losses which occurs through heat, and which increases with the distance travelled by electricity.

P229 – PROPOSED DRAFT LEGAL TEXT

SECTION E: BSC AGENTS (version 4.0)

Paragraph 1.2.5 shall be amended by adding the following:

TLF Determination	Transmission Loss Factor Agent	TLFA

SECTION H: GENERAL (version 15)

Paragraph 1.2.4 shall be amended by adding the following:

(f) Communications Requirements Documents; ~~and~~

(g) the Reporting Catalogue; and

(h) the LFM Specification.

SECTION T: SETTLEMENT AND TRADING CHARGES (version 18)

The following paragraph 1.3.9 shall be added to Section T:

1.3.9 Data required from the TLFA are Transmission Loss Factors for all BM Units.

The following paragraph 1.12 shall be added to Section T:

1.12 **Annex T–2**

1.12.1 Annex T–2 shall apply for the purposes of the determination of Transmission Loss Factors.

Paragraph 2.2.1 shall be amended to read:

2.2.1 For the purposes of the Code, the Transmission Loss Factor ~~for each BM Unit,~~ and factor α~~,~~ shall be as follows:

(a) for each BM Unit TLF_{ij} shall be determined in accordance with Annex T-2;~~= 0 for all BM Units,~~ and

(b) $\alpha = 0.45$.

The following Annex T-2 shall be added:

ANNEX T-2

TRANSMISSION LOSS FACTORS

1. Introduction

1.1 This Annex T-2 sets out the basis for determining Transmission Loss Factors.

1.2 Transmission Loss Factors will be determined by the TLFA:

(a) by reference to Nodal TLFs determined by the application of the Load Flow Model in accordance with paragraph 8.2; and

(b) in accordance with the further provisions of paragraph 8.

1.3 For the purposes of this Annex T-2:

(a) a "**node**" is a point on an electrical network at which:

(i) a power flow on to or off the network can occur; or

(ii) two or more circuits (forming part of the network) meet;

(b) a "**load flow model**" is a mathematical model of an electrical network which represents power flows between pairs of adjacent nodes on the network, and from which nodal TLFs can be determined for each node for given power flows;

(c) a "**nodal TLF**", in relation to a node on a network and a given power flow at the node, is the rate of change of electrical losses on the network with respect to a change of power flow at that node, with network balance being maintained by the slack node;

(d) the "**Load Flow Model**" is the load flow model established and adopted by the TLFA in accordance with paragraph 3;

(e) the "**slack node**" is a node that acts:

(i) for the purposes of a load flow model, as a sink for power flow surpluses or as a source for power flow deficits arising from inaccuracies in the load flow model; and

(ii) in relation to each pair of adjacent nodes in a load flow model, as the reference node for calculating the phase angle of the power flow between the nodes;

(f) in relation to a BSC Year, BSC Spring shall be considered to be the periods 1st April to 31st May and 1st March to 31st March in that BSC Year; and

(g) in relation to the BSC Year (the "**first effective BSC Year**") in which the Relevant Implementation Date falls:

(i) unless the Relevant Implementation Date is 1st April:

(1) a reference to a BSC Year shall, where the context requires, be construed as a reference to the period from the Relevant Implementation Date to the end of the first effective BSC Year; and

(2) each of the dates specified in paragraphs 4.4(a)(ii), 4.4(b)(ii), 4.4(c), 7.3, 8.2(a), 8.2(b), 8.2(c), 8.2(d), 8.5(a), 8.5(b), 8.6(b) and 8.6(c) shall be extended by the period from the start of the first effective BSC Year to the Relevant Implementation Date; and

(ii) for the avoidance of doubt, this Annex T-2 shall take effect so as to require to be done anything necessary to be done before the Relevant Implementation Date in order to give effect to this Annex T-2 with effect on and from the Relevant Implementation Date.

2. LFM Specification

2.1 The Panel shall, in consultation with the Transmission Company and other Parties and the Authority, establish (to form part of the BSC Service Description for the TLFA) a specification ("**LFM Specification**") for a load flow model for the Transmission System, to operate based on the data inputs specified in paragraph 8.2(f), and consistent with the requirements in paragraph 2.2.

2.2 The LFM Specification shall provide for the following assumptions and approximations to be made in the load flow model:

(a) only electrical losses associated with power flows between adjacent nodes (forming part of the network) ("**Load Flow Model power flows**") will be used in determining nodal TLFs; and

(b) in respect of the power flow between adjacent nodes it is assumed:

(i) there is no Reactive Power component;

(ii) the ratio of the change of power flow over a circuit to the injection of power at a given node is not dependent on the overall electrical load on the network;

(iii) the sine of the voltage phase angle is equal to the phase angle (as measured in radians); and

(iv) the power flow in a circuit is equal to the difference in the voltage phase angles across the circuit multiplied by the circuit susceptance.

3. Load Flow Model

3.1 The TLFA shall establish, and (subject to paragraph 3.2) adopt and from time to time modify, a load flow model which implements and complies with the LFM Specification.

3.2 The TLFA shall not adopt such load flow model or a modification thereof unless the model reviewer has reported to the Panel (in such terms, and as to such materiality, as the Panel may decide) that such model or modification complies with the LFM Specification and the Panel accepts such model or modification; and the TLFA shall not modify the Load Flow Model except as the Panel may instruct or agree.

3.3 The Panel shall appoint, and may from time to time reappoint or replace, an independent expert (the "**model reviewer**") for the following purposes:

(a) to inspect and test the Load Flow Model and report to the Panel as to the compliance of the Load Flow Model with the LFM Specification or any particular aspect of the LFM Specification:

(i) before the Load Flow Model is first used for the purposes of this Annex T-2;

(ii) upon any modification of the Load Flow Model (whether upon a change to the LFM Specification or otherwise); and

(iii) on any other occasion on which the Panel decides to obtain such a report; and

(b) to verify and report to the Trading Disputes Committee as to whether Nodal TLFs were determined in accordance with the Load Flow Model, on any occasion on which it is necessary to do so for the purposes of any Trading Dispute.

3.4 Any report produced by the model reviewer on Nodal TLFs for the Trading Disputes Committee shall be final and binding on all Parties (save in the case of fraud or manifest error) and if a Party refers a Trading Dispute to arbitration under Section W3.6, then save in the case of fraud or manifest error, the arbitrator(s) appointed in accordance with Section H7 shall not have the power to open up, review or in any way revise the model reviewer's report on whether Nodal TLFs were, or were not, determined in accordance with the Load Flow Model.

3.5 BSCCo shall enter into a contract of engagement (for the term for which the model reviewer is appointed) with the model reviewer, which shall, inter alia:

(a) provide terms of reference set or approved by the Panel for the model reviewer; and

(b) require the model reviewer to enter into a confidentiality undertaking in favour of the TLFA in such terms as the Panel shall reasonably require or approve.

3.6 To ensure the integrity of the Load Flow Model:

(a) the TLFA shall deposit a copy of the Load Flow Model in escrow with an escrow agent in such form and on such terms and conditions as BSCCo may require; and

(b) the TLFA shall be responsible for the payment of all fees due to the escrow agent.

3.7 The TLFA shall be required to make the Load Flow Model (and any details thereof) available to the model reviewer and the BSC Auditor (and as may be required by the arbitral tribunal in connection with any arbitration); but shall not be required to make available or disclose the Load Flow Model or details thereof to the Panel, any Panel Committee or Parties other than to BSCCo as required for the provision of the reports set out in Table 9 in Annex V-1.

3.8 Subject to paragraph 3.4, once the Load Flow Model (or any modification thereof) has been adopted by the TLFA, Nodal TLFs which are properly determined by the Load Flow Model shall be definitive; and accordingly:

(a) (without prejudice to any question as to whether such Nodal TLFs were in fact properly determined) no Party may challenge or question on any grounds the validity of any Nodal TLF which was so determined; and

(b) any modification of the Load Flow Model shall have effect only prospectively, that is for the purposes of determining Transmission Loss Factors in respect of BSC Years for which (at the time the modification was made) Transmission Loss Factors have not already been determined in accordance with paragraph 8.

3.9 For the purposes of paragraph 3.8(a), Nodal TLFs are properly determined if they are determined by and only by the application of the Load Flow Model on the basis of data input in compliance with the further provisions of this Annex T-2.

4. Zones, Nodes and Mapping

4.1 For the purposes of this Annex T-2:

(a) a "**Zone**" is the geographic area:

(i) in which the following lie:

(1) a GSP Group (there being no more than one GSP Group in any one Zone);

(2) any part of an Offshore Transmission System which connects directly to that GSP Group; and/or

(3) any part of an Offshore Transmission System which connects to the onshore Transmission System at a point within the geographic area of that GSP Group; and

(ii) which is determined by the Panel (applying such criteria as it shall decide in its discretion) but so that the Zones are mutually exclusive and are contained within the area specified in Schedule 1 of the Transmission Licence;

(b) the Panel may from time to time review and upon reasonable notice to Parties change its determination of any Zones, where there is any change in the GSP Group, any change to a part of the Transmission System contained within the Zone, upon the application of a Party or otherwise on its own initiative; provided that a change in the determination of any Zone(s) shall be effective only in relation to BSC Years for which (at the time the change was made) Transmission Loss Factors have not already been determined in accordance with paragraph 8;

(c) the Panel may, but shall not be required to, consult any Party on the determination of any part of the boundary of a Zone where it considers there is material doubt as to such boundary; and

(d) the Panel shall publish a description of the Zones from time to time (but may do so by referring to any other document which describes or identifies the geographic areas determined by the Panel to be the Zones).

4.2 For the purposes of this Annex T-2:

(a) a "**Node**" is a node on the Transmission System;

(b) the Transmission Company shall:

(i) identify each Node and prepare, keep up-to-date, and maintain, a list of all Nodes, each identified or capable of being identified geographically; and

(ii) provide to BSCCo, as soon as practicable, each updated list of Nodes; and

(c) BSCCo shall publish the same on the BSC Website.

4.3 For the purposes of this Annex T-2:

(a) a "**network mapping statement**" is a statement of the following:

(i) for each Volume Allocation Unit (other than a GSP Group, or BM Unit embedded in a Distribution System), the Node which represents or best represents that Volume Allocation Unit or (as the case may be) the Boundary Point(s) at which that Volume Allocation Unit is connected to the Transmission System (it being recognised that one Node may represent several such points); and

(ii) for each Node which represents or best represents a Volume Allocation Unit in accordance with paragraph 4.3(a)(i), the Zone in which the Node lies or should best be considered to lie; and

(iii) for each BM Unit, the Zone in which the BM Unit lies, in accordance with what has been established under paragraphs (i) and (ii), except that:

(1) Interconnector BM Units lie in the Zone in which (in accordance with paragraph (ii)) the Node for the relevant Interconnector lies; and

(2) Supplier BM Units and other BM Units embedded in a Distribution System lie in the Zone which incorporates the geographical area of the corresponding GSP Group; and

(b) in relation to each BSC Year:

(i) the "**reference network mapping statement**" is the version of the network mapping statement approved by the Panel under paragraph 4.4(b);

(ii) for the purposes of determining Nodal power flows under paragraph 8.2(e) the reference network mapping statement shall be used and any update thereof under paragraph 4.4(d) shall have no effect;

(iii) the "**prevailing network mapping statement**" is the reference network mapping statement as from time to time updated by BSCCo under paragraph 4.4(d); and

(iv) the prevailing network mapping statement shall be used to determine the Zone in which each BM Unit is located for the purposes of determining from time to time the Transmission Loss Factor applicable to such BM Unit under paragraph 8.6(a).

4.4 For each BSC Year:

(a) BSCCo shall:

(i) prepare (on the basis of data relating to the Reference Year, and taking account of the prevailing network mapping statement for the preceding BSC Year) a draft reference network mapping statement;

(ii) provide a copy of the draft reference network mapping statement to the Panel and each Party, wherever practicable not later than 31st August in the preceding BSC Year; and

(iii) submit to the Panel any representations or comments on the draft statement which were received from Parties within ten Business Days after the statement was provided under paragraph (ii);

(b) the Panel shall approve the draft reference network mapping statement with such amendments (if any) as the Panel may decide, taking into account (inter alia):

(i) any representations and comments submitted to it under paragraph (a)(iii); and

(ii) any determination made by the Panel under paragraph 4.5 in relation to a question or dispute which was raised with the Panel within the 10 Business Days referred to in paragraph 4.4(a)(iii) in the preceding BSC Year;

(c) BSCCo shall, no later than 19th October in the preceding BSC Year, provide the approved reference network mapping statement to the TLFA and the Transmission Company and publish the same on the BSC Website; and

(d) following the approval of the reference network mapping statement under paragraph (b) BSCCo shall:

(i) from time to time update the reference network mapping statement (or prevailing network mapping statement as the case may be) so as to reflect any changes to, or in respect of, the list of Nodes, the definition of any Zone, BM Units, Transmission System Boundary Points or Systems Connection Points and any determination by the Panel under paragraph 4.5 (such updated reference network mapping statement being the prevailing network mapping statement); and

(ii) publish each such update of the prevailing network mapping statement on the BSC Website.

4.5 Any question or dispute as to the matters in sub-paragraphs (i) and (ii) of paragraph 4.3(a) shall be determined by the Panel in its discretion, after consultation with the Transmission Company and the Lead Party(ies) of the BM Unit(s) affected by such question or dispute, having regard (so far as appears to the Panel to be relevant) to the parts of the Transmission System in which power flows are typically most influenced by changes in power flows at the relevant Node or (as the case may be) the relevant BM Unit.

4.6 The Transmission Company, each Distribution System Operator, the CRA and the CDCA shall cooperate with and provide information as may be required to BSCCo and the Panel in connection with the preparation of each network mapping statement and the determination of any question or dispute under paragraph 4.5.

5. Transmission Network Data

5.1 For the purposes of this Annex T-2:

(a) "**Transmission Network Data**" means the following data relating to the Transmission System:

(i) the identity of each pair of adjacent Nodes; and

(ii) for each such pair of Nodes, values of the resistance and the reactance between the Nodes; and

(b) Transmission Network Data shall be established on the assumption of an 'intact network', that is disregarding any planned or other outage of any part of the Transmission System.

5.2 The Transmission Company shall determine Transmission Network Data in good faith and based on its operational knowledge of the Transmission System, and in accordance with any relevant assumption made in the LFM Specification, but in the absence of a manifest error no

Party may challenge or question the validity or correctness of the Transmission Network Data determined by the Transmission Company.

5.3 The Transmission Company and the TLFA shall cooperate so as to ensure that the form and medium in which Transmission Network Data is provided by the Transmission Company is compatible with the Load Flow Model and the BSC Agent System on which the Load Flow Model operates.

6. Distribution Network Data

6.1 For the purposes of this Annex T-2:

(a) "**Distribution Network Data**" means the following data showing power flows from an Offshore Transmission Connection Point to other Grid Supply Points on a Distribution System:

(i) the identity of each Node that represents an Offshore Transmission Connection Point (an "**Offshore Transmission Connection Point Node**");

(ii) the identity of each Node on a Distribution System (representing a Grid Supply Point) to which power flows from an Offshore Transmission Connection Point Node (a "**corresponding Node**"); and

(iii) the percentage of net energy received by each corresponding Node, of the total energy flowing from the Offshore Transmission Connection Point Node, as an estimated average value for each Reference Year; and

(b) Distribution Network Data shall be established on the assumption of an 'intact network', that is disregarding any planned or other outage of any part of a Distribution System.

6.2 Each Distribution System Operator shall determine Distribution Network Data in good faith for each Distribution System that it operates, based on the operation of that Distribution System and in accordance with any relevant assumption made in the LFM Specification.

6.3 Each Distribution System Operator and the TLFA shall cooperate so as to ensure that the form and medium in which Distribution Network Data is provided by the Distribution System Operator is compatible with the Load Flow Model and the BSC Agent System on which the Load Flow Model operates.

6.4 Any question or dispute as to the determination of Distribution Network Data pursuant to paragraph 6.2 shall be determined by the Panel in its discretion, after consultation with the relevant Distribution System Operator, the Transmission Company and the Lead Party(ies) of the BM Unit(s) affected by such question or dispute, having regard (so far as appears to the Panel to be relevant) to the parts of the Total System in which power flows are typically most influenced by changes in power flows at the relevant Node(s) or (as the case may be) the relevant BM Unit.

6.5 Each Distribution System Operator, the Transmission Company, the CRA and the CDCA shall cooperate with and provide information as may be required to BSCCo and the Panel in connection with the determination of any question or dispute under paragraph 6.4.

7. Sample Settlement Periods

7.1 For each BSC Year, Transmission Loss Factors shall be determined by reference to Nodal TLFs for sample Settlement Periods in the 12 month period (a "**Reference Year**") ending 31st August in the preceding BSC Year.

7.2 For the purposes of so determining Transmission Loss Factors, the Panel, after consultation with the Transmission Company and other Parties:

(a) shall divide the Reference Year into a number of different periods (each a "**Load Period**"), representing (in the opinion of the Panel) typically different levels of load on the Transmission System, defined by time of day, day of week, season and such other factors as the Panel considers relevant, such that every Settlement Period in the Reference Year falls into one and only one Load Period;

(b) shall specify, for each Load Period, a representative (in the opinion of the Panel) number of sample Settlement Periods (each a "**Sample Settlement Period**") within that Load Period; and

(c) will revise the specification of Load Periods or Sample Settlement Periods (if required) for each BSC Year.

7.3 BSCCo shall, not later than 31st August in the preceding BSC Year, notify the specification of each Load Period and the Sample Settlement Periods to the TLFA, the Transmission Company and the CDCA, and publish such specification on the BSC Website.

8. Determination of TLFs

8.1 For each BSC Year, Transmission Loss Factors for each BM Unit shall be determined in accordance with this paragraph 8.

8.2 For each Sample Settlement Period:

(a) the Transmission Company shall, not later than 5th October in the preceding BSC Year, send to BSCCo the Transmission Network Data;

(b) each Distribution System Operator shall, not later than 5th October in the preceding BSC Year, send to BSCCo the Distribution Network Data;

(c) the CDCA shall, not later than 5th October in the preceding BSC Year, send to BSCCo Metered Volumes for each Volume Allocation Unit (other than GSP Groups and BM Units embedded in a Distribution System);

(d) BSCCo shall, not later than 19th October in the preceding BSC Year, send to the TLFA the information received by BSCCo pursuant to paragraphs 8.2(a), 8.2(b) and 8.2(c);

(e) the TLFA shall translate the Metered Volume data provided by BSCCo to power flows (on the assumption they are constant in a Settlement Period) for each Node by applying the reference network mapping statement ("**Nodal power flows**"); and

(f) the TLFA shall input into the Load Flow Model the Transmission Network Data under paragraph (a), the Distribution Network Data under paragraph (b) and Nodal power flows under paragraph (e), and apply the Model to derive a nodal TLF for each Node ("**Nodal TLF**").

8.3 For each Sample Settlement Period, the TLFA shall determine the Zonal TLF (TLF_{Zj}) for each Zone according to the following formula:

$$TLF_{Zj} = \Sigma_N (TLF_{Nj} * QM_{Nj}) / \Sigma_N QM_{Nj}$$

where for that Settlement Period, and for each Node in that Zone (determined by the TLFA on the basis of the reference network mapping statement):

TLF_{Nj} is the value of Nodal TLF; and

QM_{Nj} is the absolute value of the Nodal power flow;

and where Σ_N is summation by Node in a Zone.

8.4 For each BSC Season (the "**relevant BSC Season**") in each BSC Year, the TLFA shall determine the Seasonal Zonal TLF (TLF_{Zs}) for each Zone according to the following formula:

$$TLF_{Zs} = \Sigma_p ((\Sigma_s TLF_{Zj} / S_{ps}) * J_{ps}) / \Sigma_p J_{ps}$$

where (in relation to the Reference Year):

S_{ps} is the number of Sample Settlement Periods within a Load Period which fall within the relevant BSC Season;

J_{ps} is the total number of Settlement Periods falling within a Load Period which fall within the relevant BSC Season;

Σ_s is summation by Sample Settlement Periods within a Load Period which fall within the relevant BSC Season; and

Σ_p is summation by Load Period within the relevant BSC Season.

8.5 For each BSC Year:

(a) the TLFA shall, not later than 30th November in the preceding BSC Year:

(i) determine the Adjusted Seasonal Zonal TLF ($ATLF_{Zs}$) for each Zone and each BSC Season according to the following formula:

$$ATLF_{Zs} = TLF_{Zs} * 0.5$$

(ii) send the Adjusted Seasonal Zonal TLFs to BSCCo; and

(b) BSCCo shall, not later than 31st December in the preceding BSC Year, publish the Adjusted Seasonal Zonal TLF ($ATLF_{Zs}$) for each Zone and each BSC Season on the BSC Website.

8.6 For each BSC Season in each BSC Year:

(a) the Transmission Loss Factor (TLF_{ij}) for each BM Unit shall be the Adjusted Seasonal Zonal TLF ($ATLF_{Zs}$) for the Zone in which that BM Unit is located (allocated on the basis of the prevailing network mapping statement) and for that BSC Season;

(b) the TLFA shall, not later than 30th November in the preceding BSC Year, determine and send the Transmission Loss Factors for each BM Unit to BSCCo;

(c) BSCCo shall, not later than 31st December in the preceding BSC Year, send such Transmission Loss Factors to the CRA; and

(d) upon any revision of the network mapping statement under paragraph 4.4(d), in relation to any BM Unit affected by such revision, BSCCo shall determine the new or revised Transmission Loss Factors (in accordance with the prevailing network mapping statement) and send such Transmission Loss Factors to the CRA.

8.7 The CRA shall maintain in CRS, as BM Unit registration data, the Transmission Loss Factors for each BM Unit.

SECTION V: REPORTING (version 25)

Amend the number of the heading to the following paragraph as follows:

3.~~1~~2 Reports

Amend paragraph 3.2.5 as follows:

3.2.5 Reports are to be provided:

(a) to Parties by the means specified in Section ~~0~~O; and

(b) to persons other than Parties by such means as the Panel may from time to time determine.

Insert new paragraph 4.6 as follows:

4.6 Transmission Loss Factor Data

4.6.1 BSCCo shall arrange for the report(s) and data set out in Table 9 in Annex V-1 to be made available as set out in that table.

4.6.2 Paragraph 3.2 shall apply for the purposes of paragraph 4.6.1 as if references in paragraph 3.2:

(a) to BSC Agents included BSCCo; and

(b) to Tables in Annex V-1 included Table 9.

The following text shall be deleted at Table 9 of Annex V-1:

~~THIS TABLE IS INTENTIONALLY LEFT BLANK~~

Insert as Table 9 at Annex V-1 the following:

TABLE 9 – TRANSMISSION LOSS FACTOR DATA

Name of Report(s) / Category of Data	**Frequency**	**Recipient**	**General Description**

Distribution Network Data	Annually	Any Party (on request)	Reports containing the Distribution Network Data for each Distribution System determined by the relevant Distribution System Operator in accordance with, and in the format specified in, paragraph 6 of Annex T-2.
Transmission Network Data	Annually	Any Party (on request)	A report containing the Transmission Network Data determined by the Transmission Company in accordance with, and in the format specified in, paragraph 5 of Annex T-2.
Metered Volumes	Annually	Any Party (on request)	A report containing the Metered Volume data provided to BSCCo in accordance with paragraph 8.2 of Annex T-2.
Nodal TLFs	Annually	Any Party (on request)	For each Node, a report providing Nodal TLFs as determined by the TLFA in accordance with paragraph 8.2 of Annex T-2.
Nodal power flows	Annually	Any Party (on request)	A report providing Nodal power flows as determined by the TLFA in accordance with paragraph 8.2 of Annex T-2.
Load Flow Model power flows	Annually	Any Party (on request)	A report containing the power flows which the LFM Specification provides for and upon which the Load Flow Model is established as described in paragraph 2.2 of Annex T-2.

SECTION X-1: GENERAL GLOSSARY (version 45)

The following new definitions shall be inserted in alphabetical order in Annex X-1:

"Distribution Network Data":	has the meaning given to that term in paragraph 6.1 of Annex T-2;
"Load Flow Model":	has the meaning given to that term in paragraph 1.3 of Annex T-2;
"Load Flow Model Specification" or **"LFM Specification"**:	has the meaning given to that term in paragraph 2.1 of Annex T-2;
"Load Period":	has the meaning given to that term in paragraph 7.2 of Annex T-2;

"Node":	has the meaning given to that term in paragraph 4.2 of Annex T-2;
"Reference Year":	has the meaning given to that term in paragraph 7.1 of Annex T-2;
"Sample Settlement Period":	has the meaning given to that term in paragraph 7.2 of Annex T-2;
"Transmission Network Data":	has the meaning given to that term in paragraph 5.1 of Annex T-2;
"Transmission Loss Factor Agent" or "TLFA":	means the BSC Agent for TLF Determination in accordance with Section E1.2.5;
"Zone":	has the meaning given to that term in paragraph 4.1 of Annex T-2;

The following definition in Annex X-1 shall be amended as follows:

"Trading Data":	means any data of a kind listed in Annex V-1, Tables 2-7and 9;

ANNEX X–2: TECHNICAL GLOSSARY (version 29)

The following new Subscripts shall be inserted in alphabetical order in Table X-1:

N		Node
Z		Zone

The following definition in Table X – 2 shall be amended as follows:

Transmission Loss Factor	TLF_{ij}		The factor specified in Section T2.2.1(a)., ~~being equal to zero.~~ *The Transmission Loss Factor is that factor used to allocate transmission losses on a locational basis to BM Unit i in Settlement Period j.*

P229 – ALTERNATIVE DRAFT LEGAL TEXT

SECTION E: BSC AGENTS (version 4.0)

Paragraph 1.2.5 shall be amended by adding the following:

TLF Determination	Transmission Loss Factor Agent	TLFA

SECTION H: GENERAL (version 15)

Paragraph 1.2.4 shall be amended by adding the following:

(f) Communications Requirements Documents; ~~and~~

(g) the Reporting Catalogue; and

(h) the LFM Specification.

SECTION T: SETTLEMENT AND TRADING CHARGES (version 18)

The following paragraph 1.3.9 shall be added to Section T:

1.3.9 Data required from the TLFA are Transmission Loss Factors for all BM Units.

The following paragraph 1.12 shall be added to Section T:

1.12 **Annex T–2**

1.12.1 Annex T–2 shall apply for the purposes of the determination of Transmission Loss Factors.

Paragraph 2.2.1 shall be amended to read:

2.2.1 For the purposes of the Code, the Transmission Loss Factor ~~for each BM Unit,~~ and factor α~~,~~ shall be as follows:

(a) for each BM Unit TLF_{ij} shall be determined in accordance with Annex T-2;~~= 0 for all BM Units,~~ and

(b) $\alpha = 0.45$.

The following Annex T-2 shall be added:

ANNEX T-2

TRANSMISSION LOSS FACTORS

1. Introduction

1.1 This Annex T-2 sets out the basis for determining Transmission Loss Factors.

1.2 Transmission Loss Factors will be determined by the TLFA:

(a) by reference to Nodal TLFs determined by the application of the Load Flow Model in accordance with paragraph 8.2; and

(b) in accordance with the further provisions of paragraph 8.

1.3 For the purposes of this Annex T-2:

(a) a "**node**" is a point on an electrical network at which:

(i) a power flow on to or off the network can occur; or

(ii) two or more circuits (forming part of the network) meet;

(b) a "**load flow model**" is a mathematical model of an electrical network which represents power flows between pairs of adjacent nodes on the network, and from which nodal TLFs can be determined for each node for given power flows;

(c) a "**nodal TLF**", in relation to a node on a network and a given power flow at the node, is the rate of change of electrical losses on the network with respect to a change of power flow at that node, with network balance being maintained by the slack node;

(d) the "**Load Flow Model**" is the load flow model established and adopted by the TLFA in accordance with paragraph 3;

(e) the "**slack node**" is a node that acts:

(i) for the purposes of a load flow model, as a sink for power flow surpluses or as a source for power flow deficits arising from inaccuracies in the load flow model; and

(ii) in relation to each pair of adjacent nodes in a load flow model, as the reference node for calculating the phase angle of the power flow between the nodes;

(f) the "**total calculated heating losses**" are the total level of electrical losses calculated by the Load Flow Model using the Load Flow Model power flows referred to in paragraph 2.2;

(g) in relation to a BSC Year, BSC Spring shall be considered to be the periods 1st April to 31st May and 1st March to 31st March in that BSC Year; and

(h) in relation to the BSC Year (the "**first effective BSC Year**") in which the Relevant Implementation Date falls:

(i) unless the Relevant Implementation Date is 1st April:

(1) a reference to a BSC Year shall, where the context requires, be construed as a reference to the period from the Relevant Implementation Date to the end of the first effective BSC Year; and

(2) each of the dates specified in paragraphs 4.4(a)(ii), 4.4(b)(ii), 4.4(c), 7.3, 8.2(a), 8.2(b), 8.2(c), 8.2(d), 8.7(a), 8.7(b), 8.8(b) and 8.8(c) shall be extended by the period from the start of the first effective BSC Year to the Relevant Implementation Date; and

(ii) for the avoidance of doubt, this Annex T-2 shall take effect so as to require to be done anything necessary to be done before the Relevant Implementation Date in order to give effect to this Annex T-2 with effect on and from the Relevant Implementation Date.

2. LFM Specification

2.1 The Panel shall, in consultation with the Transmission Company and other Parties and the Authority, establish (to form part of the BSC Service Description for the TLFA) a specification ("**LFM Specification**") for a load flow model for the Transmission System, to operate based on the data inputs specified in paragraph 8.2(f), and consistent with the requirements in paragraph 2.2.

2.2 The LFM Specification shall provide for the following assumptions and approximations to be made in the load flow model:

(a) only electrical losses associated with power flows between adjacent nodes (forming part of the network) ("**Load Flow Model power flows**") will be used in determining nodal TLFs; and

(b) in respect of the power flow between adjacent nodes it is assumed:

(i) there is no Reactive Power component;

(ii) the ratio of the change of power flow over a circuit to the injection of power at a given node is not dependent on the overall electrical load on the network;

(iii) the sine of the voltage phase angle is equal to the phase angle (as measured in radians); and

(iv) the power flow in a circuit is equal to the difference in the voltage phase angles across the circuit multiplied by the circuit susceptance.

3. Load Flow Model

3.1 The TLFA shall establish, and (subject to paragraph 3.2) adopt and from time to time modify, a load flow model which implements and complies with the LFM Specification.

3.2 The TLFA shall not adopt such load flow model or a modification thereof unless the model reviewer has reported to the Panel (in such terms, and as to such materiality, as the Panel may decide) that such model or modification complies with the LFM Specification and the Panel accepts such model or modification; and the TLFA shall not modify the Load Flow Model except as the Panel may instruct or agree.

3.3 The Panel shall appoint, and may from time to time reappoint or replace, an independent expert (the "**model reviewer**") for the following purposes:

(a) to inspect and test the Load Flow Model and report to the Panel as to the compliance of the Load Flow Model with the LFM Specification or any particular aspect of the LFM Specification:

(i) before the Load Flow Model is first used for the purposes of this Annex T-2;

(ii) upon any modification of the Load Flow Model (whether upon a change to the LFM Specification or otherwise); and

(iii) on any other occasion on which the Panel decides to obtain such a report; and

(b) to verify and report to the Trading Disputes Committee as to whether Nodal TLFs were determined in accordance with the Load Flow Model, on any occasion on which it is necessary to do so for the purposes of any Trading Dispute.

3.4 Any report produced by the model reviewer on Nodal TLFs for the Trading Disputes Committee shall be final and binding on all Parties (save in the case of fraud or manifest error) and if a Party refers a Trading Dispute to arbitration under Section W3.6, then save in the case of fraud or manifest error, the arbitrator(s) appointed in accordance with Section H7 shall not have the power to open up, review or in any way revise the model reviewer's report on whether Nodal TLFs were, or were not, determined in accordance with the Load Flow Model.

3.5 BSCCo shall enter into a contract of engagement (for the term for which the model reviewer is appointed) with the model reviewer, which shall, inter alia:

(a) provide terms of reference set or approved by the Panel for the model reviewer; and

(b) require the model reviewer to enter into a confidentiality undertaking in favour of the TLFA in such terms as the Panel shall reasonably require or approve.

3.6 To ensure the integrity of the Load Flow Model:

(a) the TLFA shall deposit a copy of the Load Flow Model in escrow with an escrow agent in such form and on such terms and conditions as BSCCo may require; and

(b) the TLFA shall be responsible for the payment of all fees due to the escrow agent.

3.7 The TLFA shall be required to make the Load Flow Model (and any details thereof) available to the model reviewer and the BSC Auditor (and as may be required by the arbitral tribunal in connection with any arbitration); but shall not be required to make available or disclose the Load Flow Model or details thereof to the Panel, any Panel Committee or Parties other than to BSCCo as required for the provision of the reports set out in Table 9 in Annex V-1.

3.8 Subject to paragraph 3.4, once the Load Flow Model (or any modification thereof) has been adopted by the TLFA, Nodal TLFs which are properly determined by the Load Flow Model shall be definitive; and accordingly:

(a) (without prejudice to any question as to whether such Nodal TLFs were in fact properly determined) no Party may challenge or question on any grounds the validity of any Nodal TLF which was so determined; and

(b) any modification of the Load Flow Model shall have effect only prospectively, that is for the purposes of determining Transmission Loss Factors in respect of BSC Years for which (at the time the modification was made) Transmission Loss Factors have not already been determined in accordance with paragraph 8.

3.9 For the purposes of paragraph 3.8(a), Nodal TLFs are properly determined if they are determined by and only by the application of the Load Flow Model on the basis of data input in compliance with the further provisions of this Annex T-2.

4. Zones, Nodes and Mapping

4.1 For the purposes of this Annex T-2:

(a) a "**Zone**" is the geographic area:

(i) in which the following lie:

(1) a GSP Group (there being no more than one GSP Group in any one Zone);

(2) any part of an Offshore Transmission System which connects directly to that GSP Group; and/or

(3) any part of an Offshore Transmission System which connects to the onshore Transmission System at a point within the geographic area of that GSP Group; and

(ii) which is determined by the Panel (applying such criteria as it shall decide in its discretion) but so that the Zones are mutually exclusive and are contained within the area specified in Schedule 1 of the Transmission Licence;

(b) the Panel may from time to time review and upon reasonable notice to Parties change its determination of any Zones where there is any change in the GSP Group, any change to a part of the Transmission System contained within the Zone, upon the application of a Party or otherwise on its own initiative; provided that a change in the determination of any Zone(s) shall be effective only in relation to BSC Years for which (at the time the change was made) Transmission Loss Factors have not already been determined in accordance with paragraph 8;

(c) the Panel may, but shall not be required to, consult any Party on the determination of any part of the boundary of a Zone where it considers there is material doubt as to such boundary; and

(d) the Panel shall publish a description of the Zones from time to time (but may do so by referring to any other document which describes or identifies the geographic areas determined by the Panel to be the Zones).

4.2 For the purposes of this Annex T-2:

(a) a "**Node**" is a node on the Transmission System;

(b) the Transmission Company shall:

(i) identify each Node and prepare, keep up-to-date, and maintain, a list of all Nodes, each identified or capable of being identified geographically; and

(ii) provide to BSCCo, as soon as practicable, each updated list of Nodes; and

(c) BSCCo shall publish the same on the BSC Website.

4.3 For the purposes of this Annex T-2:

(a) a "**network mapping statement**" is a statement of the following:

(i) for each Volume Allocation Unit (other than a GSP Group, or BM Unit embedded in a Distribution System), the Node which represents or best represents that Volume Allocation Unit or (as the case may be) the Boundary Point(s) at which that Volume Allocation Unit is connected to the Transmission System (it being recognised that one Node may represent several such points); and

(ii) for each Node which represents or best represents a Volume Allocation Unit in accordance with paragraph 4.3(a)(i), the Zone in which the Node lies or should best be considered to lie; and

(iii) for each BM Unit, the Zone in which the BM Unit lies, in accordance with what has been established under paragraphs (i) and (ii), except that:

(1) Interconnector BM Units lie in the Zone in which (in accordance with paragraph (ii)) the Node for the relevant Interconnector lies; and

(2) Supplier BM Units and other BM Units embedded in a Distribution System lie in the Zone which incorporates the geographical area of the corresponding GSP Group; and

(b) in relation to each BSC Year:

(i) the "**reference network mapping statement**" is the version of the network mapping statement approved by the Panel under paragraph 4.4(b);

(ii) for the purposes of determining Nodal power flows under paragraph 8.2(e) the reference network mapping statement shall be used and any update thereof under paragraph 4.4(d) shall have no effect;

(iii) the "**prevailing network mapping statement**" is the reference network mapping statement as from time to time updated by BSCCo under paragraph 4.4(d); and

(iv) the prevailing network mapping statement shall be used to determine the Zone in which each BM Unit is located for the purposes of determining from time to time the Transmission Loss Factor applicable to such BM Unit under paragraph 8.8(a).

4.4 For each BSC Year:

(a) BSCCo shall:

(i) prepare (on the basis of data relating to the Reference Year, and taking account of the prevailing network mapping statement for the preceding BSC Year) a draft reference network mapping statement;

(ii) provide a copy of the draft reference network mapping statement to the Panel and each Party, wherever practicable not later than 31st August in the preceding BSC Year; and

(iii) submit to the Panel any representations or comments on the draft statement which were received from Parties within ten Business Days after the statement was provided under paragraph (ii);

(b) the Panel shall approve the draft reference network mapping statement with such amendments (if any) as the Panel may decide, taking into account (inter alia):

(i) any representations and comments submitted to it under paragraph (a)(iii); and

(ii) any determination made by the Panel under paragraph 4.5 in relation to a question or dispute which was raised with the Panel within the 10 Business Days referred to in paragraph 4.4(a)(iii) in the preceding BSC Year;

(c) BSCCo shall, no later than 19th October in the preceding BSC Year, provide the approved reference network mapping statement to the TLFA and the Transmission Company and publish the same on the BSC Website; and

(d) following the approval of the reference network mapping statement under paragraph (b) BSCCo shall:

(i) from time to time update the reference network mapping statement (or prevailing network mapping statement as the case may be) so as to reflect any changes to, or in respect of, the list of Nodes, the definition of any Zone, BM Units, Transmission System Boundary Points or Systems Connection Points and any determination by the Panel under paragraph 4.5 (such updated reference network mapping statement being the prevailing network mapping statement); and

(ii) publish each such update of the prevailing network mapping statement on the BSC Website.

4.5 Any question or dispute as to the matters in sub-paragraphs (i) and (ii) of paragraph 4.3(a) shall be determined by the Panel in its discretion, after consultation with the Transmission Company and the Lead Party(ies) of the BM Unit(s) affected by such question or dispute, having regard (so far as appears to the Panel to be relevant) to the parts of the Transmission System in which power flows are typically most influenced by changes in power flows at the relevant Node or (as the case may be) the relevant BM Unit.

4.6 The Transmission Company, each Distribution System Operator, the CRA and the CDCA shall cooperate with and provide information as may be required to BSCCo and the Panel in connection with the preparation of each network mapping statement and the determination of any question or dispute under paragraph 4.5.

5. Transmission Network Data

5.1 For the purposes of this Annex T-2:

(a) "**Transmission Network Data**" means the following data relating to the Transmission System:

(i) the identity of each pair of adjacent Nodes; and

(ii) for each such pair of Nodes, values of the resistance and the reactance between the Nodes; and

(b) Transmission Network Data shall be established on the assumption of an 'intact network', that is disregarding any planned or other outage of any part of the Transmission System.

5.2 The Transmission Company shall determine Transmission Network Data in good faith and based on its operational knowledge of the Transmission System, and in accordance with any relevant assumption made in the LFM Specification, but in the absence of a manifest error no Party may challenge or question the validity or correctness of the Transmission Network Data determined by the Transmission Company.

5.3 The Transmission Company and the TLFA shall cooperate so as to ensure that the form and medium in which Transmission Network Data is provided by the Transmission Company is compatible with the Load Flow Model and the BSC Agent System on which the Load Flow Model operates.

6. Distribution Network Data

6.1 For the purposes of this Annex T-2:

(a) "**Distribution Network Data**" means the following data showing power flows from an Offshore Transmission Connection Point to other Grid Supply Points on a Distribution System:

(i) the identity of each Node that represents an Offshore Transmission Connection Point (an "**Offshore Transmission Connection Point Node**");

(ii) the identity of each Node on a Distribution System (representing a Grid Supply Point) to which power flows from an Offshore Transmission Connection Point Node (a "**corresponding Node**"); and

(iii) the percentage of net energy received by each corresponding Node, of the total energy flowing from the Offshore Transmission Connection Point Node, as an estimated average value for each Reference Year; and

(b) Distribution Network Data shall be established on the assumption of an 'intact network', that is disregarding any planned or other outage of any part of a Distribution System.

6.2 Each Distribution System Operator shall determine Distribution Network Data in good faith for each Distribution System that it operates, based on the operation of that Distribution System and in accordance with any relevant assumption made in the LFM Specification.

6.3 Each Distribution System Operator and the TLFA shall cooperate so as to ensure that the form and medium in which Distribution Network Data is provided by the Distribution System Operator is compatible with the Load Flow Model and the BSC Agent System on which the Load Flow Model operates.

6.4 Any question or dispute as to the determination of Distribution Network Data pursuant to paragraph 6.2 shall be determined by the Panel in its discretion, after consultation with the relevant Distribution System Operator, the Transmission Company and the Lead Party(ies) of the BM Unit(s) affected by such question or dispute, having regard (so far as appears to the Panel to be relevant) to the parts of the Total System in which power flows are typically most influenced by changes in power flows at the relevant Node(s) or (as the case may be) the relevant BM Unit.

6.5 Each Distribution System Operator, the Transmission Company, the CRA and the CDCA shall cooperate with and provide information as may be required to BSCCo and the Panel in connection with the determination of any question or dispute under paragraph 6.4.

7. Sample Settlement Periods

7.1 For each BSC Year, Transmission Loss Factors shall be determined by reference to Nodal TLFs for sample Settlement Periods in the 12 month period (a "**Reference Year**") ending 31st August in the preceding BSC Year.

7.2 For the purposes of so determining Transmission Loss Factors, the Panel, after consultation with the Transmission Company and other Parties:

(a) shall divide the Reference Year into a number of different periods (each a "**Load Period**"), representing (in the opinion of the Panel) typically different levels of load on the Transmission System, defined by time of day, day of week, season and such other factors as the Panel considers relevant, such that every Settlement Period in the Reference Year falls into one and only one Load Period;

(b) shall specify, for each Load Period, a representative (in the opinion of the Panel) number of sample Settlement Periods (each a "**Sample Settlement Period**") within that Load Period; and

(c) will revise the specification of Load Periods or Sample Settlement Periods (if required) for each BSC Year.

7.3 BSCCo shall, not later than 31st August in the preceding BSC Year, notify the specification of each Load Period and the Sample Settlement Periods to the TLFA, the Transmission Company and the CDCA, and publish such specification on the BSC Website.

8. Determination of TLFs

8.1 For each BSC Year, Transmission Loss Factors for each BM Unit shall be determined in accordance with this paragraph 8.

8.2 For each Sample Settlement Period:

(a) the Transmission Company shall, not later than 5th October in the preceding BSC Year, send to BSCCo the Transmission Network Data;

(b) each Distribution System Operator shall, not later than 5th October in the preceding BSC Year, send to BSCCo the Distribution Network Data;

(c) the CDCA shall, not later than 5th October in the preceding BSC Year, send to BSCCo Metered Volumes for each Volume Allocation Unit (other than GSP Groups and BM Units embedded in a Distribution System);

(d) BSCCo shall, not later than 19th October in the preceding BSC Year, send to the TLFA:

(i) the information received by BSCCo pursuant to paragraphs 8.2(a), 8.2(b) and 8.2(c); and

(ii) each of the sum of the Metered Volumes for all delivering Trading Units and the sum of the Metered Volumes for all offtaking Trading Units for each Zone, for each Sample Settlement Period;

(e) the TLFA shall translate the Metered Volume data provided by BSCCo to power flows (on the assumption they are constant in a Settlement Period) for each Node by applying the reference network mapping statement ("**Nodal power flows**"); and

(f) the TLFA shall input into the Load Flow Model the Transmission Network Data under paragraph (a), the Distribution Network Data under paragraph (b) and Nodal power flows under paragraph (e), and apply the Model to derive a nodal TLF for each Node ("**Nodal TLF**").

8.3 For each Sample Settlement Period, the TLFA shall determine the Zonal TLF (TLF_{Zj}) for each Zone according to the following formula:

$$TLF_{Zj} = \Sigma_N (TLF_{Nj} * QM_{Nj}) / \Sigma_N QM_{Nj}$$

where for that Settlement Period, and for each Node in that Zone (determined by the TLFA on the basis of the reference network mapping statement):

TLF_{Nj} is the value of Nodal TLF; and

QM_{Nj} is the absolute value of the Nodal power flow; and

where Σ_N is summation by Node in a Zone.

8.4 For each BSC Season (the "**relevant BSC Season**") in each BSC Year, the TLFA shall determine the Seasonal Zonal TLF (TLF_{Zs}) for each Zone according to the following formula:

$$TLF_{Zs} = \Sigma_p ((\Sigma_s TLF_{Zj} / S_{ps}) * J_{ps}) / \Sigma_p J_{ps}$$

where (in relation to the Reference Year):

S_{ps} is the number of Sample Settlement Periods within a Load Period which fall within the relevant BSC Season;

J_{ps} is the total number of Settlement Periods falling within a Load Period which fall within the relevant BSC Season;

Σ_s is summation by Sample Settlement Periods within a Load Period which fall within the relevant BSC Season; and

Σ_p is summation by Load Period within the relevant BSC Season.

8.5 For each Sample Settlement Period the TLFA shall determine the Delivering Scaling Factor (β^+_j), the Offtaking Scaling Factor (β^-_j) and the Settlement Period Scaling Factor (β_j) according to the following formulae:

$$\beta^+_j = \min(1, \alpha * VL_j / [\text{Max}_Z(TLF_{Zs}) * \Sigma_Z(QM^+_{Zj}) – \Sigma_Z TLF_{Zs} * QM^+_{Zj})])$$

$$\beta^-_j = \min(1, (1-\alpha) * VL_j / [\text{Min}_Z(TLF_{Zs}) * \Sigma_Z(QM^-_{Zj}) - \Sigma_Z(TLF_{Zs} * QM^-_{Zj})])$$

$$\beta_j = \min(\beta^+_j , \beta^-_j)$$

where for that Settlement Period:

$\text{Max}_Z(TLF_{Zs})$ is the maximum value of TLF_{Zs} for any Zone for the BSC Season in which the Sample Settlement Period falls;

$\text{Min}_Z(TLF_{Zs})$ is the minimum value of TLF_{Zs} for any Zone for the BSC Season in which the Sample Settlement Period falls;

VL_j is the total calculated heating losses;

Σ_Z is summation over all Zones;

QM^+_{Zj} is the sum of the Metered Volumes for all delivering Trading Units for each Zone; and

QM^-_{Zj} is the sum of the Metered Volumes for all offtaking Trading Units for each Zone.

8.6 For each BSC Season in each BSC Year the TLFA shall determine the Seasonal Scaling Factor (β_s) according to the following formula:

$$\beta_s = \Sigma_p ((\Sigma_s \beta_j / S_{ps}) * J_{ps}) / \Sigma_p J_{ps}$$

where (in relation to the Reference Year):

S_{ps} is the number of Sample Settlement Periods within a Load Period which fall within the relevant BSC Season;

J_{ps} is the total number of Settlement Periods falling within a Load Period which fall within the relevant BSC Season;

Σ_s is summation by Sample Settlement Periods within a Load Period which fall within the relevant BSC Season; and

Σ_p is summation by Load Period within the relevant BSC Season.

8.7 For each BSC Year:

(a) the TLFA shall, not later than 30th November in the preceding BSC Year:

(i) determine the Adjusted Seasonal Zonal TLF ($ATLF_{Zs}$) for each Zone and each BSC Season according to the following formula:

$$ATLF_{Zs} = TLF_{Zs} * \beta_s$$

(ii) send the Adjusted Seasonal Zonal TLFs and the Seasonal Scaling Factors β_s to BSCCo; and

(b) BSCCo shall, not later than 31st December in the preceding BSC Year, publish the Adjusted Seasonal Zonal TLF ($ATLF_{Zs}$) for each Zone and each BSC Season and the Seasonal Scaling Factor β_s for each BSC Season on the BSC Website.

8.8 For each BSC Season in each BSC Year:

(a) the Transmission Loss Factor (TLF_{ij}) for each BM Unit shall be the Adjusted Seasonal Zonal TLF ($ATLF_{Zs}$) for the Zone in which that BM Unit is located (allocated on the basis of the prevailing network mapping statement) and for that BSC Season;

(b) the TLFA shall, not later than 30th November in the preceding BSC Year, determine and send the Transmission Loss Factors for each BM Unit to BSCCo;

(c) BSCCo shall, not later than 31st December in the preceding BSC Year, send such Transmission Loss Factors to the CRA; and

(d) upon any revision of the network mapping statement under paragraph 4.4(d), in relation to any BM Unit affected by such revision, BSCCo shall determine the new or revised Transmission Loss Factors (in accordance with the prevailing network mapping statement) and send such Transmission Loss Factors to the CRA.

8.9 The CRA shall maintain in CRS, as BM Unit registration data, the Transmission Loss Factors for each BM Unit.

SECTION V: REPORTING (version 25)

Amend the number of the heading to the following paragraph as follows:

3.~~1~~2 Reports

Amend paragraph 3.2.5 as follows:

3.2.5 Reports are to be provided:

(a) to Parties by the means specified in Section ~~0~~O; and

(b) to persons other than Parties by such means as the Panel may from time to time determine.

Insert new paragraph 4.6 as follows:

4.6 Transmission Loss Factor Data

4.6.1 BSCCo shall arrange for the report(s) and data set out in Table 9 in Annex V-1 to be made available as set out in that table.

4.6.2 Paragraph 3.2 shall apply for the purposes of paragraph 4.6.1 as if references in paragraph 3.2:

(a) to BSC Agents included BSCCo; and

(b) to Tables in Annex V-1 included Table 9.

The following text shall be deleted at Table 9 of Annex V-1:

~~THIS TABLE IS INTENTIONALLY LEFT BLANK~~

Insert as Table 9 at Annex V-1 the following:

TABLE 9 – TRANSMISSION LOSS FACTOR DATA

Name of Report(s) / Category of Data	Frequency	Recipient	General Description

Distribution Network Data	Annually	Any Party (on request)	Reports containing the Distribution Network Data for each Distribution System determined by the relevant Distribution System Operator in accordance with, and in the format specified in, paragraph 6 of Annex T-2.
Transmission Network Data	Annually	Any Party (on request)	A report containing the Transmission Network Data determined by the Transmission Company in accordance with, and in the format specified in, paragraph 5 of Annex T-2.
Metered Volumes	Annually	Any Party (on request)	A report containing the Metered Volume data provided to or determined by BSCCo in accordance with paragraph 8.2 of Annex T-2.
Nodal TLFs	Annually	Any Party (on request)	For each Node, a report providing Nodal TLFs as determined by the TLFA in accordance with paragraph 8.2 of Annex T-2.
Nodal power flows	Annually	Any Party (on request)	A report providing Nodal power flows as determined by the TLFA in accordance with paragraph 8.2 of Annex T-2.
Load Flow Model power flows	Annually	Any Party (on request)	A report containing the power flows which the LFM Specification provides for and upon which the Load Flow Model is established as described in paragraph 2.2 of Annex T-2.
total calculated heating losses	Annually	Any Party (on request)	A report containing the total calculated heating losses (as defined in paragraph 1.3(f) of Annex T-2) calculated by the Load Flow Model using the Load Flow Model power flows.

SECTION X-1: GENERAL GLOSSARY (version 45)

The following new definitions shall be inserted in alphabetical order in Annex X-1:

"Distribution Network Data":	has the meaning given to that term in paragraph 6.1 of Annex T-2;
"Load Flow Model":	has the meaning given to that term in paragraph 1.3 of Annex T-2;
"Load Flow Model Specification" or **"LFM Specification"**:	has the meaning given to that term in paragraph 2.1 of Annex T-2;
"Load Period":	has the meaning given to that term in paragraph 7.2 of Annex T-2;
"Node":	has the meaning given to that term in paragraph 4.2 of Annex T-2;
"Reference Year":	has the meaning given to that term in paragraph 7.1 of Annex T-2;
"Sample Settlement Period":	has the meaning given to that term in paragraph 7.2 of Annex T-2;
"Transmission Network Data":	has the meaning given to that term in paragraph 5.1 of Annex T-2;
"Transmission Loss Factor Agent" or "TLFA":	means the BSC Agent for TLF Determination in accordance with Section E1.2.5;
"Zone":	has the meaning given to that term in paragraph 4.1 of Annex T-2;

The following definition in Annex X-1 shall be amended as follows:

"Trading Data":	means any data of a kind listed in Annex V-1, Tables 2-7and 9;

ANNEX X–2: TECHNICAL GLOSSARY (version 29)

The following new Subscripts shall be inserted in alphabetical order in Table X-1:

N		Node
Z		Zone

The following new definitions shall be inserted in alphabetical order in Table X-2:

Delivering Scaling Factor	β^{+}_{j}		Is the factor determined as such in accordance with paragraph 8.5 of Annex T-2. *A factor used in determining the Seasonal Scaling Factor* *(β_{S}).*
Offtaking Scaling Factor	β^{-}_{j}		Is the factor determined as such in accordance with paragraph 8.5 of Annex T-2.

			A factor used in determining the Seasonal Scaling Factor (β_s).
Seasonal Scaling Factor	β_s		Is the factor determined as such in accordance with paragraph 8.6 of Annex T-2. *A factor used in determining TLF_{ij}.*

The following definition in Table X – 2 shall be amended as follows:

Transmission Loss Factor	TLF_{ij}		The factor specified in Section T2.2.1(a).~~, being equal to zero.~~ *The Transmission Loss Factor is that factor used to allocate transmission losses on a locational basis to BM Unit i in Settlement Period j.*

The following new Acronyms shall be inserted in alphabetical order in Table X-3:

β^{+}_{j}		Delivering Scaling Factor
β^{-}_{j}		Offtaking Scaling Factor
β_s		Seasonal Scaling Factor