ELEXON

Stage 03: Assessment 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 Modification Group recommends **rejection** of Proposed and Alternative Modification P229 'Introduction of a seasonal Zonal Transmission Losses scheme'

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)

Contents

About this document

This document is the P229 Assessment Report which ELEXON will present to the Panel on 11 February 2010 on behalf of the P229 Modification Group. The Panel will consider the recommendations in this report and agree an initial view on whether or not this change should be made.

There are two parts to this document. This is Part 1, which details the solution, impacts, costs, benefits and the potential implementation activities associated with P229. Part 2 (Attachment A) is the detailed assessment of P229, which sets out the Modification Group's discussions leading to the P229 solutions and the Group's views on P229.

Any questions?

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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) would be a significant project for ELEXON, and 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 Group's recommended Implementation Date for P229 (Proposed or 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 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 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 P229 Group's recommendation is that the P229 Proposed and Alternative Modifications should not be made.

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

The Group's majority view is that compared with the current baseline both P229 Proposed and P229 Alternative would not better facilitate the Applicable BSC Objectives, and that both:

- 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).

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 Proposed 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.

4 Alternative Solution

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):

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

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

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

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;
- $\Sigma^+(QM)$ and $\Sigma^-(QM)$ are the total metered volumes for BM Units in delivering and offtaking Trading Units respectively; and
- $\Sigma^+(QM*TLF)$ and $\Sigma^-(QM*TLF)$ 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.

7 Implementation

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.

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 Recommendations

The P229 Modification Group invites the Panel to:

- AGREE an initial recommendation that Proposed Modification P229 should not be made;
- AGREE an initial recommendation that Alternative Modification P229 should not be made;
- AGREE 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;
- AGREE the draft legal text for Proposed Modification P229;
- AGREE the draft legal text for Alternative Modification P229;
- AGREE that Modification Proposal P229 be submitted to the Report Phase; and
- AGREE that ELEXON should issue the P229 draft Modification Report for consultation and submit results to the Panel to consider at its meeting on 11 March 2010.

10 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

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

- Responses to the P229 industry 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.