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 Consultation. This attachment provides additional detail on the Cost Benefit Analysis and Load Flow Modelling undertaken and the Modification Group's discussions and provisional views.

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?

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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.

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.	Consultation document
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
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 consultation 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.

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[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).

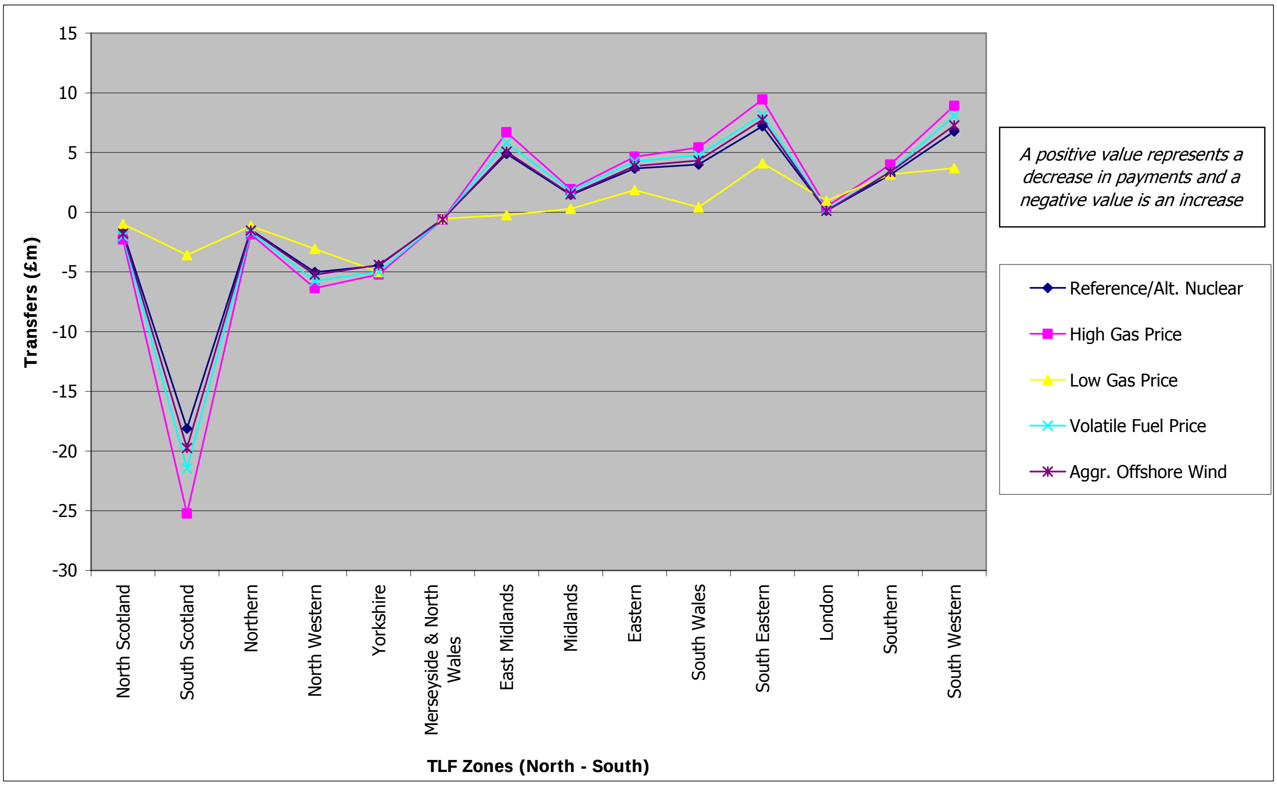
These areas comprise the following TLF Zones:

- **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).

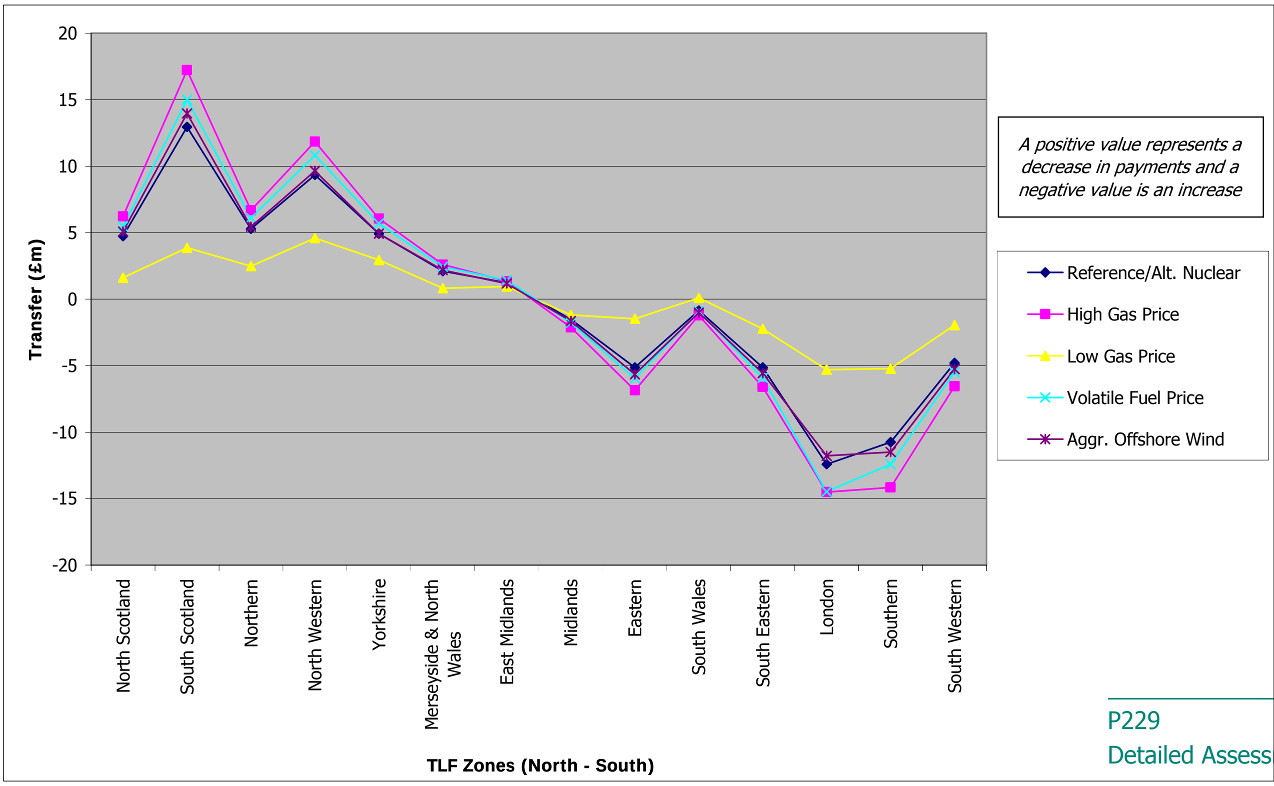
Again, the figures are the totals across all generators or Suppliers in each area and do not take account of portfolio effects. Note that they are also net totals, as some Zones in the South experienced an increase in charges while others experienced a decrease. These totals will therefore be different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

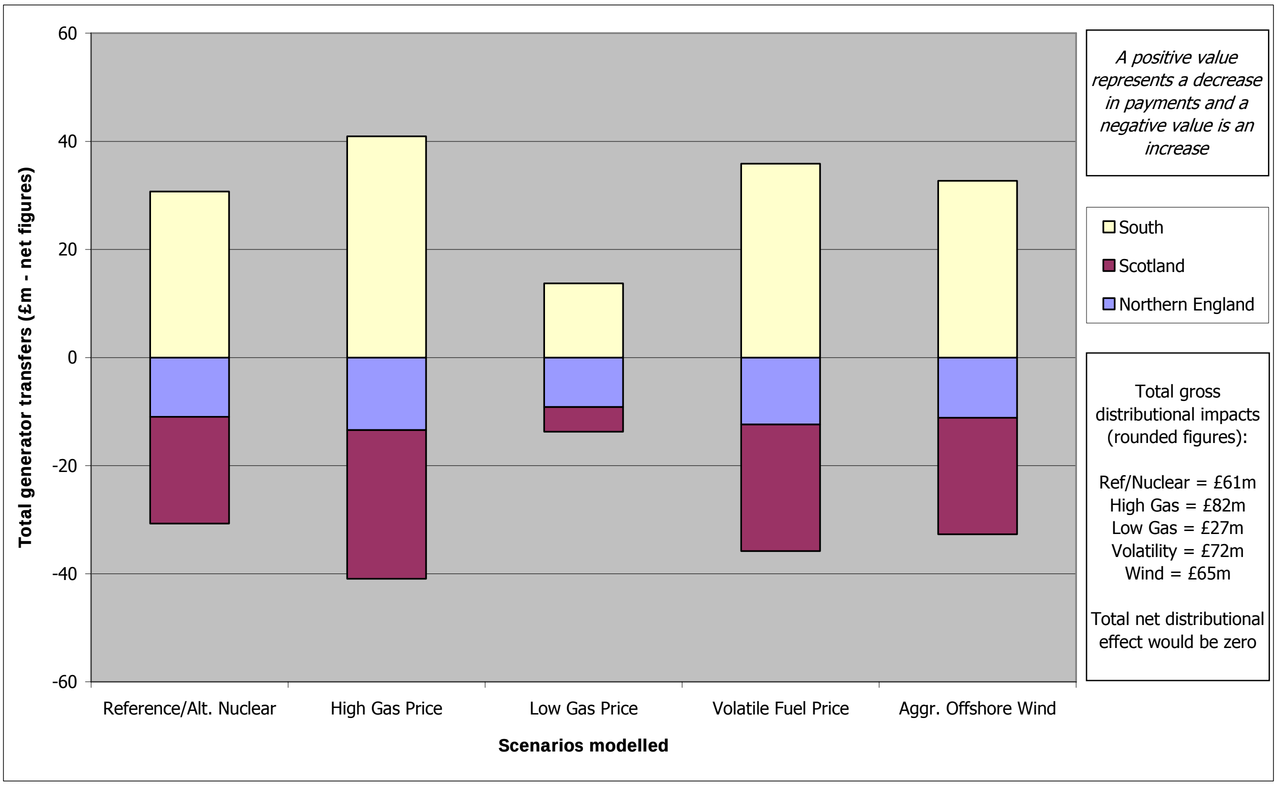
Graph 1 – Annualised distributional impacts on generators by TLF Zone (2011/12)



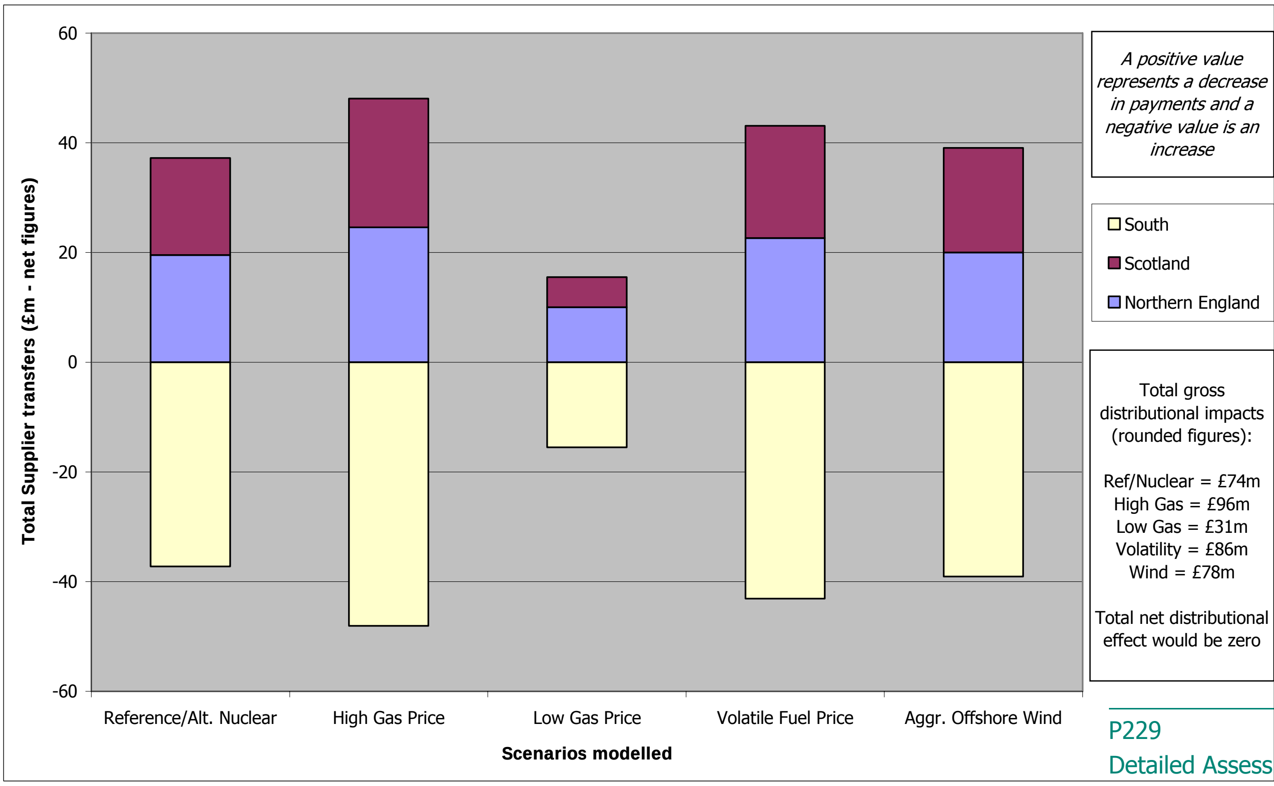
Graph 2 – Annualised distributional impacts on Suppliers by TLF Zone (2011/12)



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



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

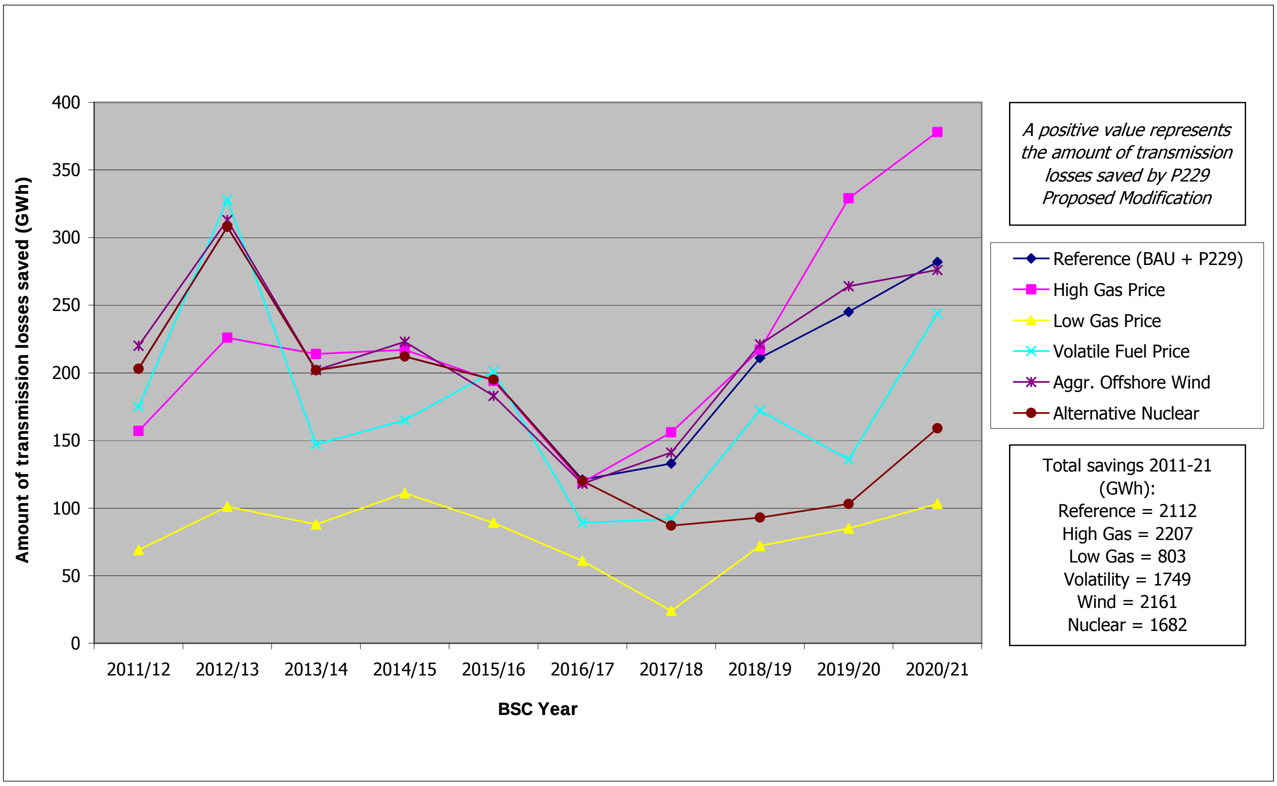


Impact on generation and transmission losses

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.

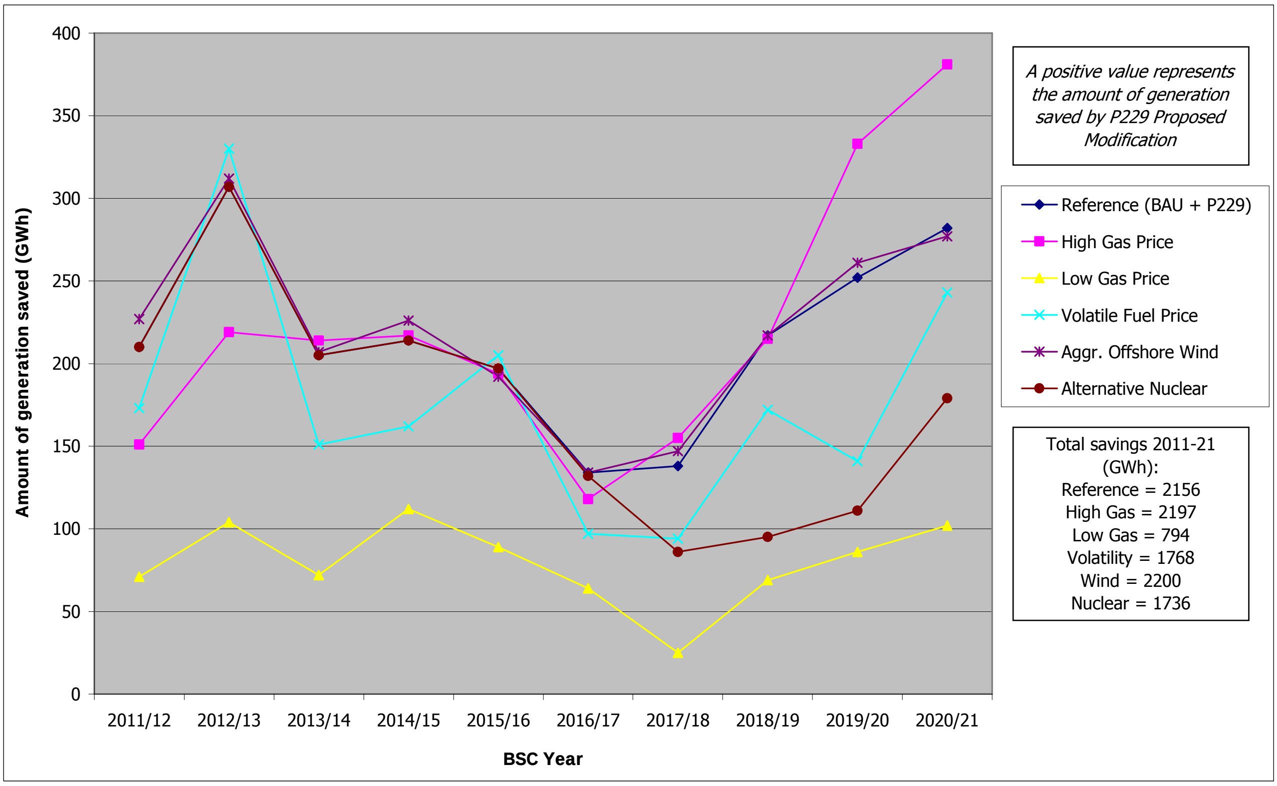
Graph 6 shows the amount (volume of energy in GWh) of generation which would be saved by Proposed Modification P229.

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.

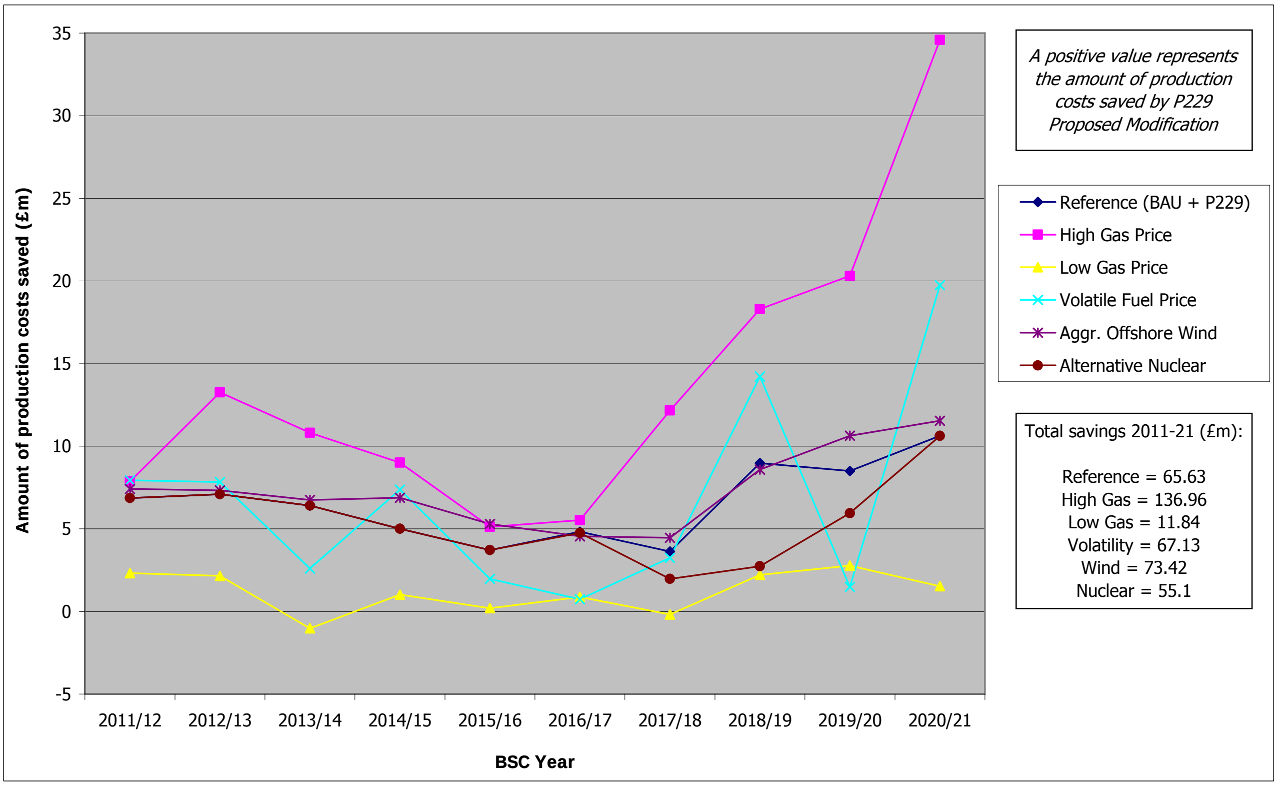
Again, the figures for each scenario are the difference between production costs under the current uniform charging and under seasonal zonal TLFs. You can find the figures behind this graph in Section 7.2.3 of LE/Ventyx's report.

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

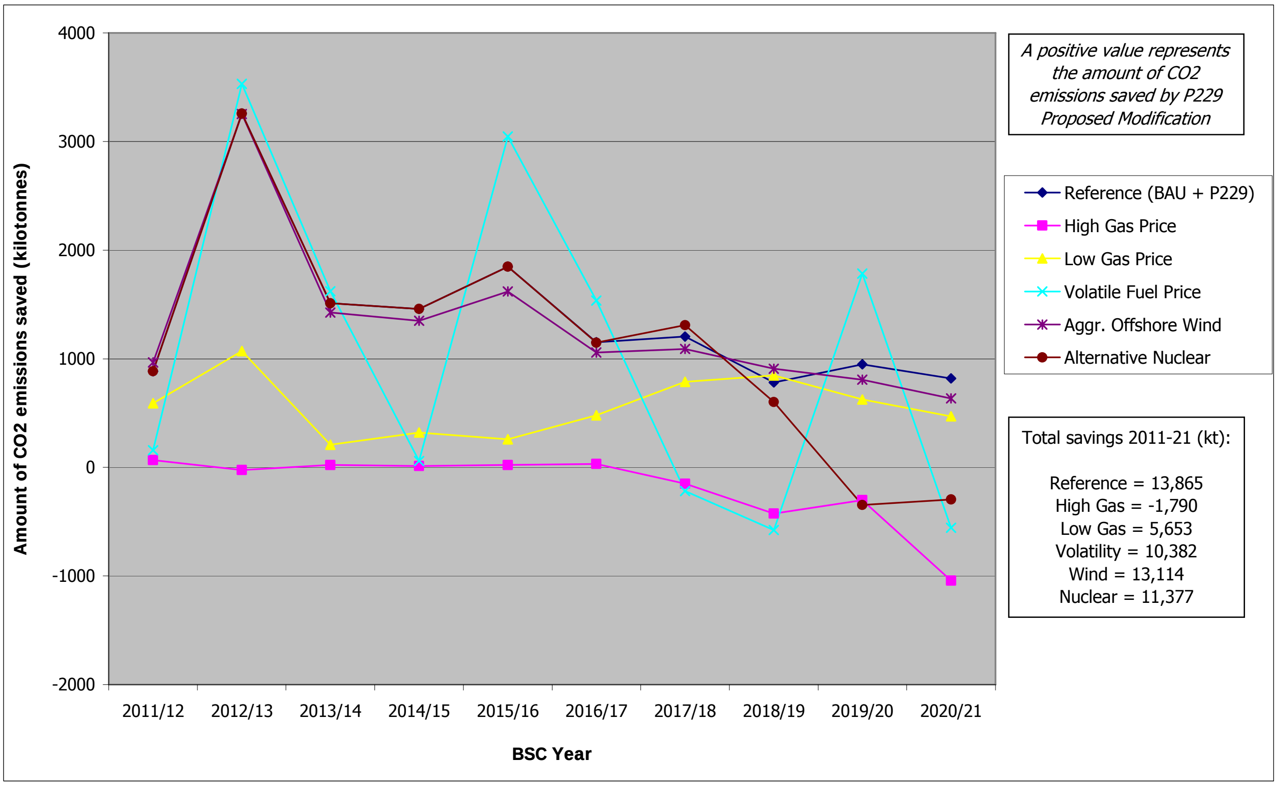
Graphs 8, 9 and 10 show the impact of Proposed Modification P229 on the amount of CO_2, NOx and SOx emissions respectively. Savings are shown as positive values.

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.

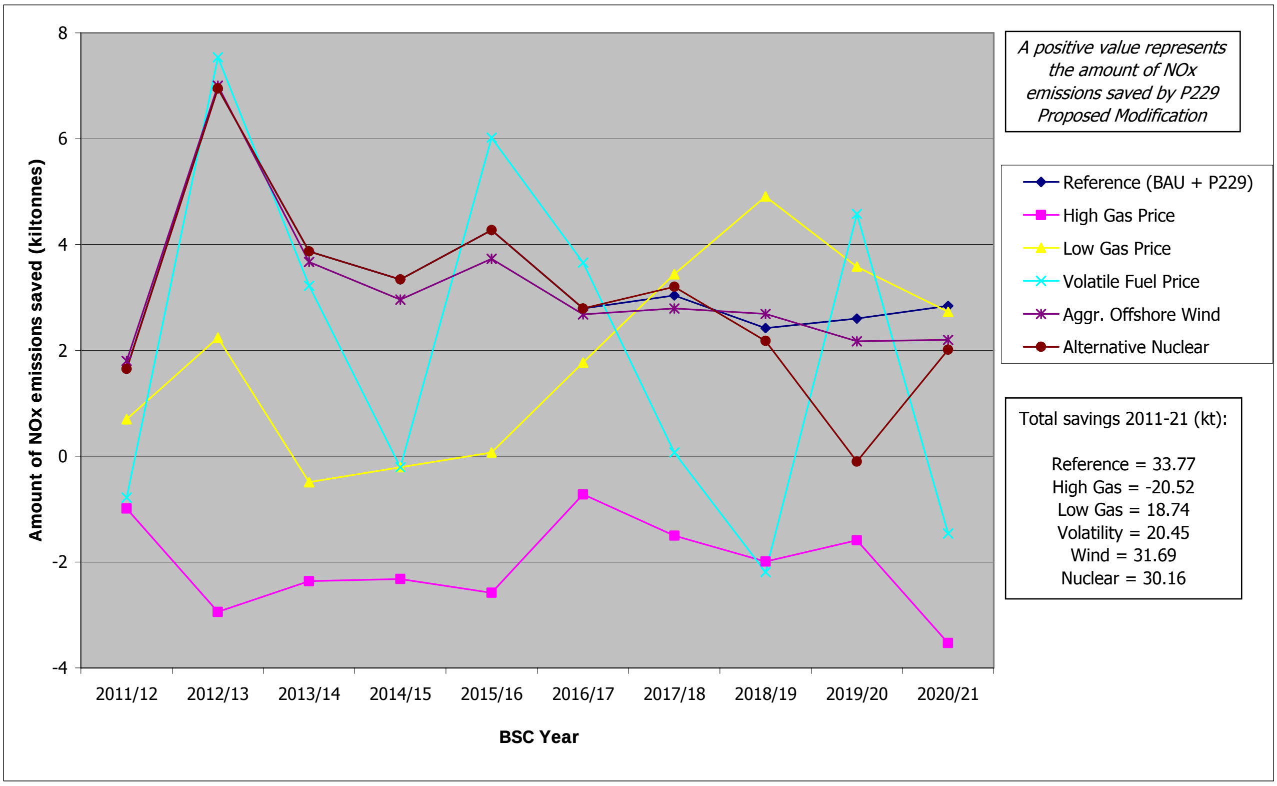
The financial benefit of CO_2 reductions is priced according to the EU ETS and is therefore included in the production cost savings shown in Graph 7. The treatment of CO_2 output is therefore similar to that of fuel input. Marginal abatement costs of £1,319 per tonne and £2,493 per tonne were used to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

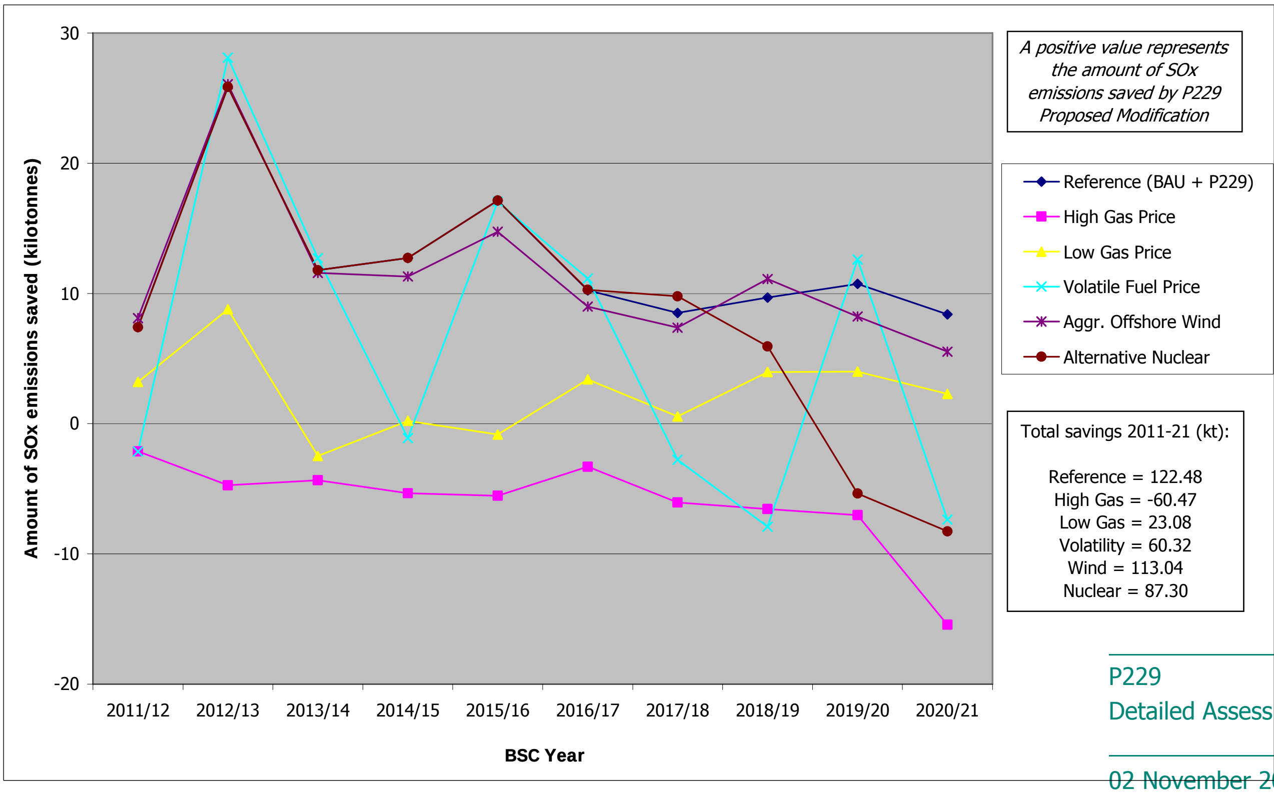
Graph 8 – Amount of CO_2 emissions saved by Proposed Modification P229 (kilotonnes)



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.

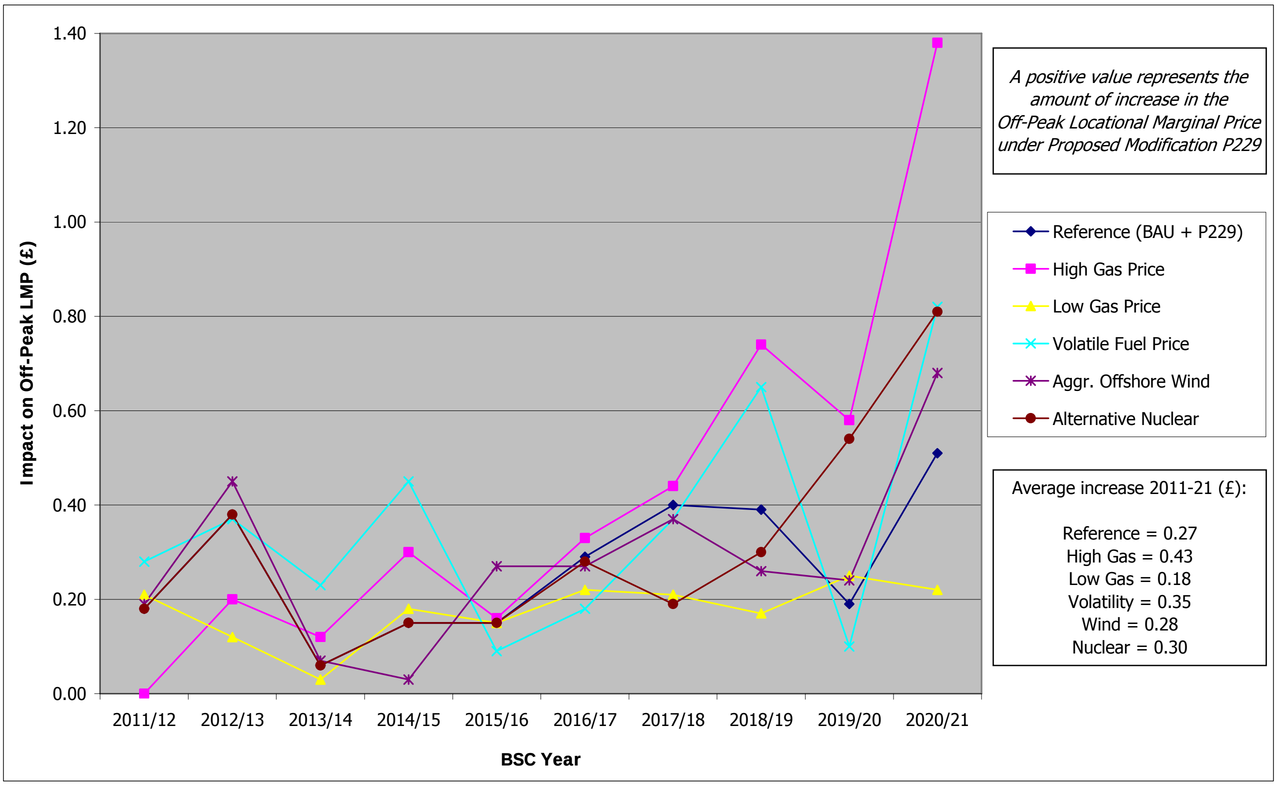
Since LE/Ventyx assumed competitive despatch and competitive pricing, the prices used in this analysis are the locational marginal costs from the despatch (LMPs), and are the load weighted-average of the hourly simultaneous optimisation of despatch and transmission.

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.

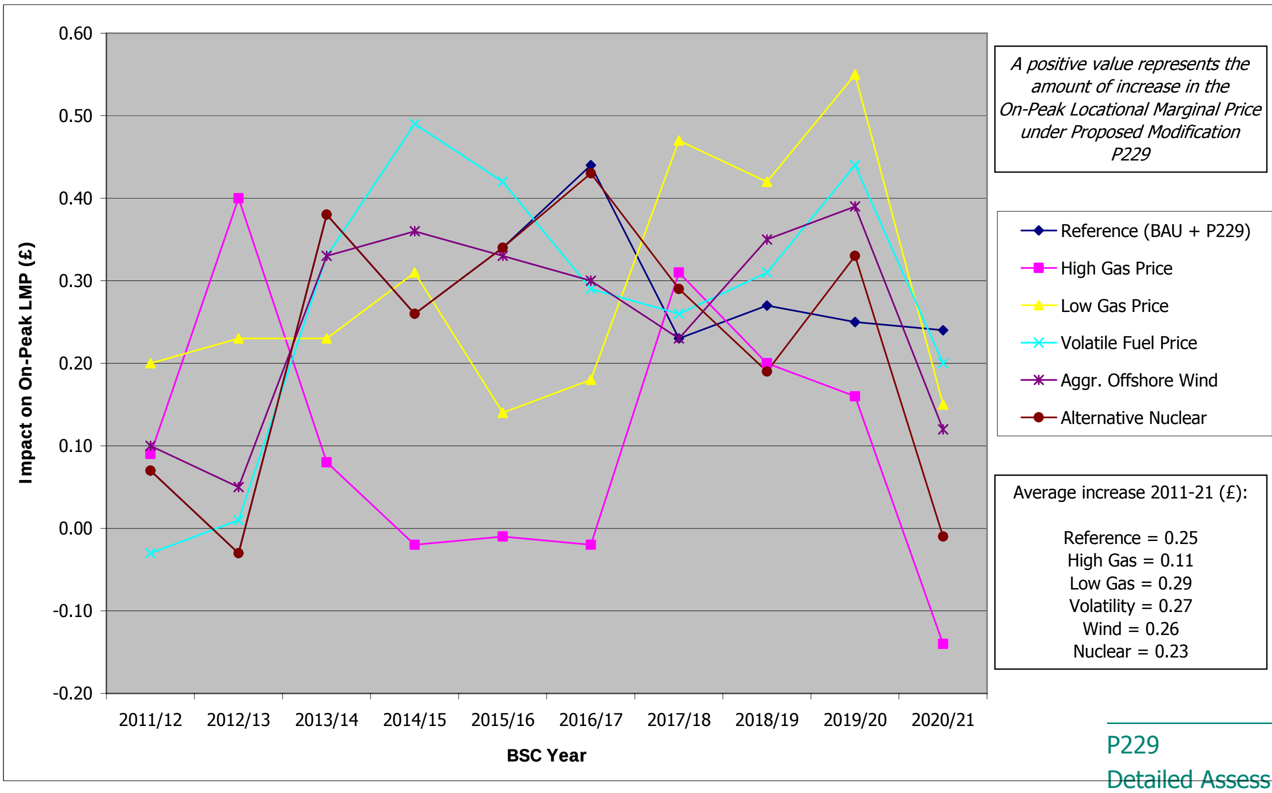
In general, the LMPs are higher under the Proposed Modification. This is intuitive as the pure despatch cost, ignoring transmission losses, should be optimal with respect to cost minimising without transmission losses. Therefore, optimising over both despatch and losses, while minimising cost on the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

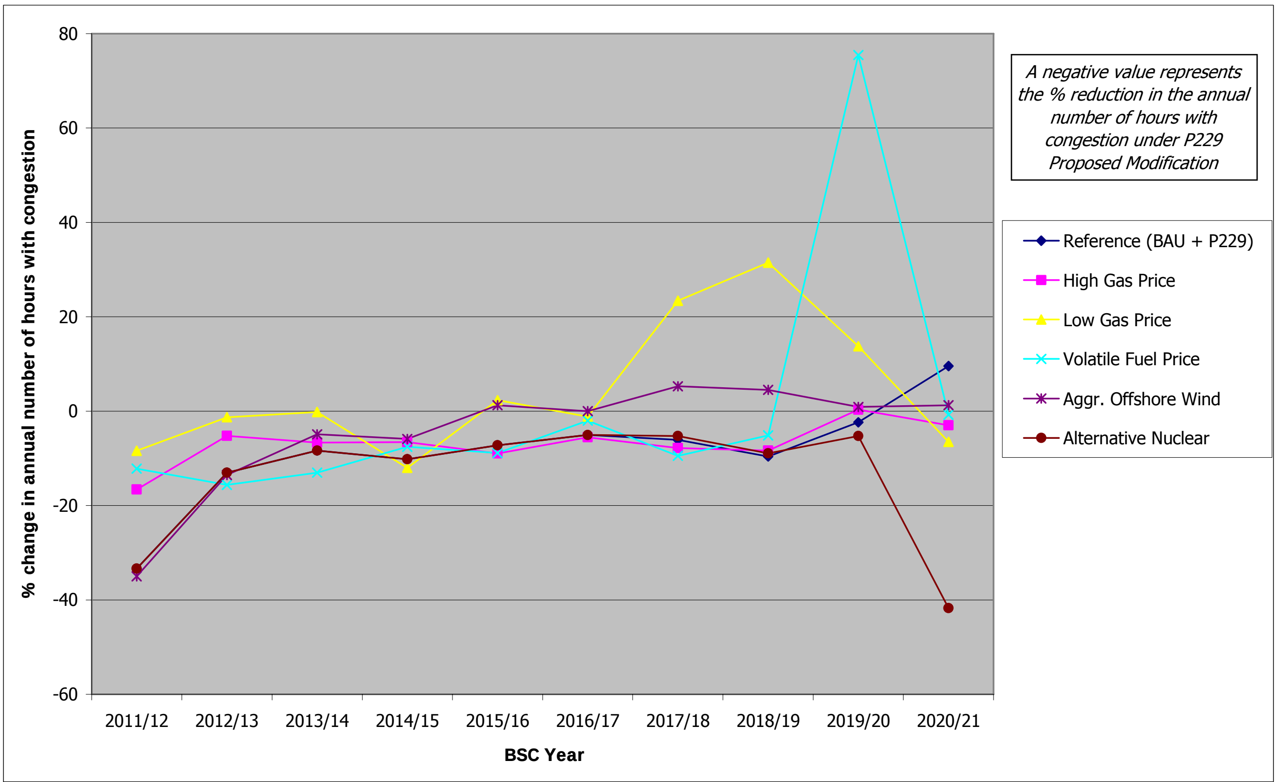
The exception to this trend is the Alternative Nuclear Scenario, where the introduction of new nuclear base-load from 2017 reduces the total number of congested hours.

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 is in 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

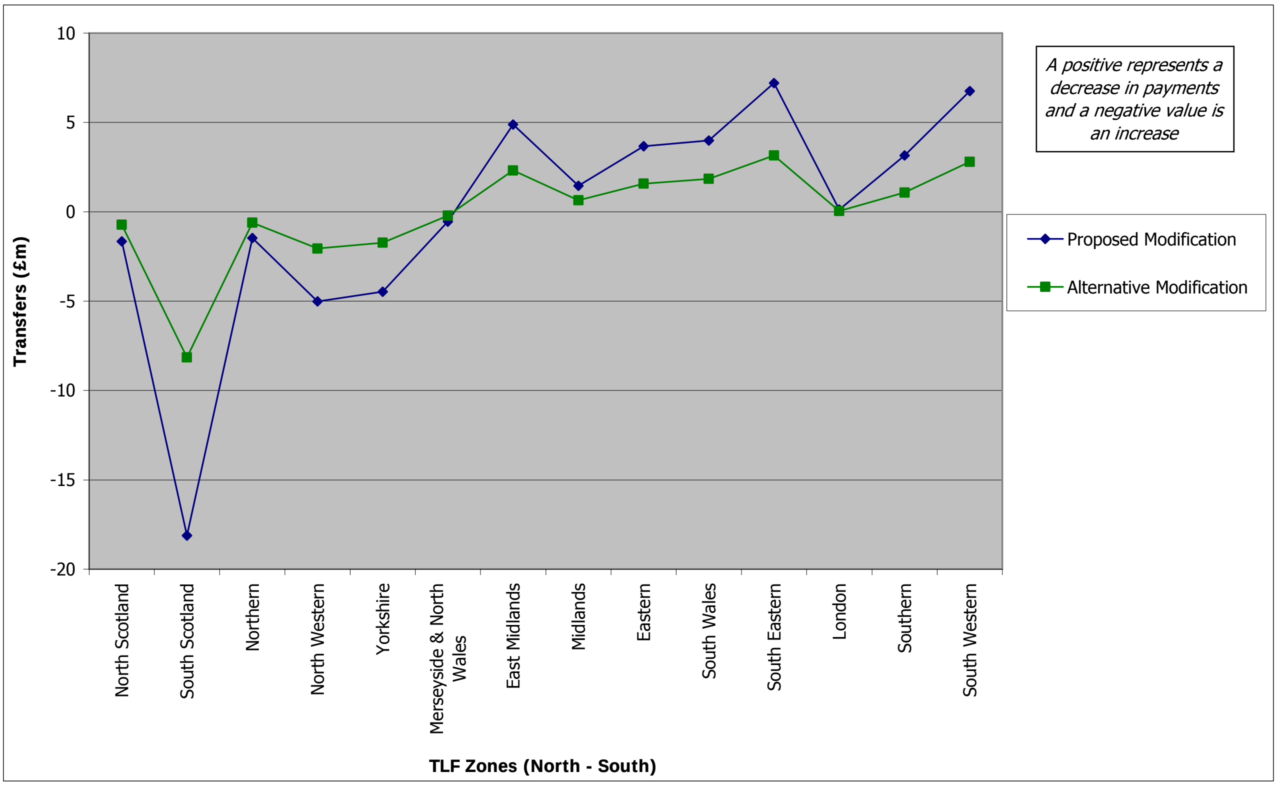
Graphs 13 and 14 show the total annualised distributional impacts for 2011/12 under the Alternative Modification (Reference Scenario), compared with the Proposed Modification (Reference Scenario).

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

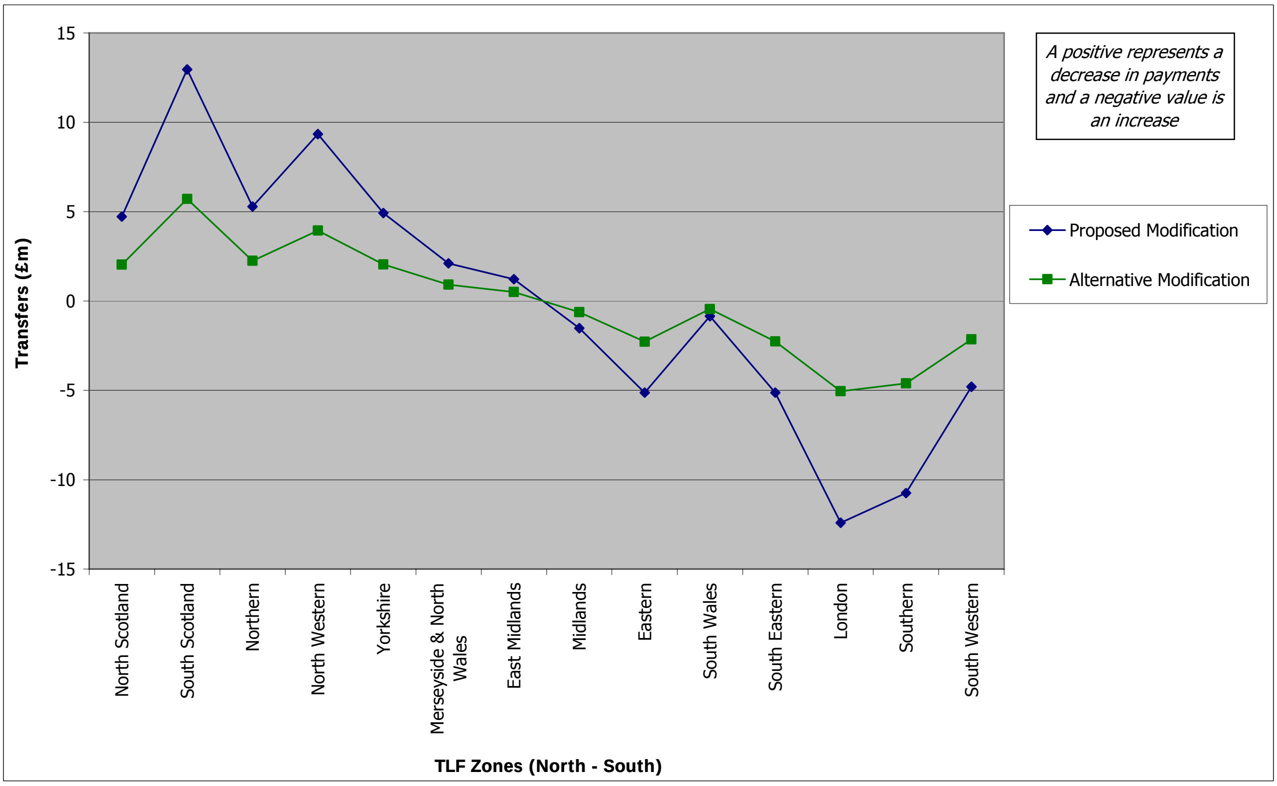
The basis for these figures is identical to Graphs 1-4. You can find the Alternative Modification figures in Section A1.3.8 of LE/Ventyx's report.

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.

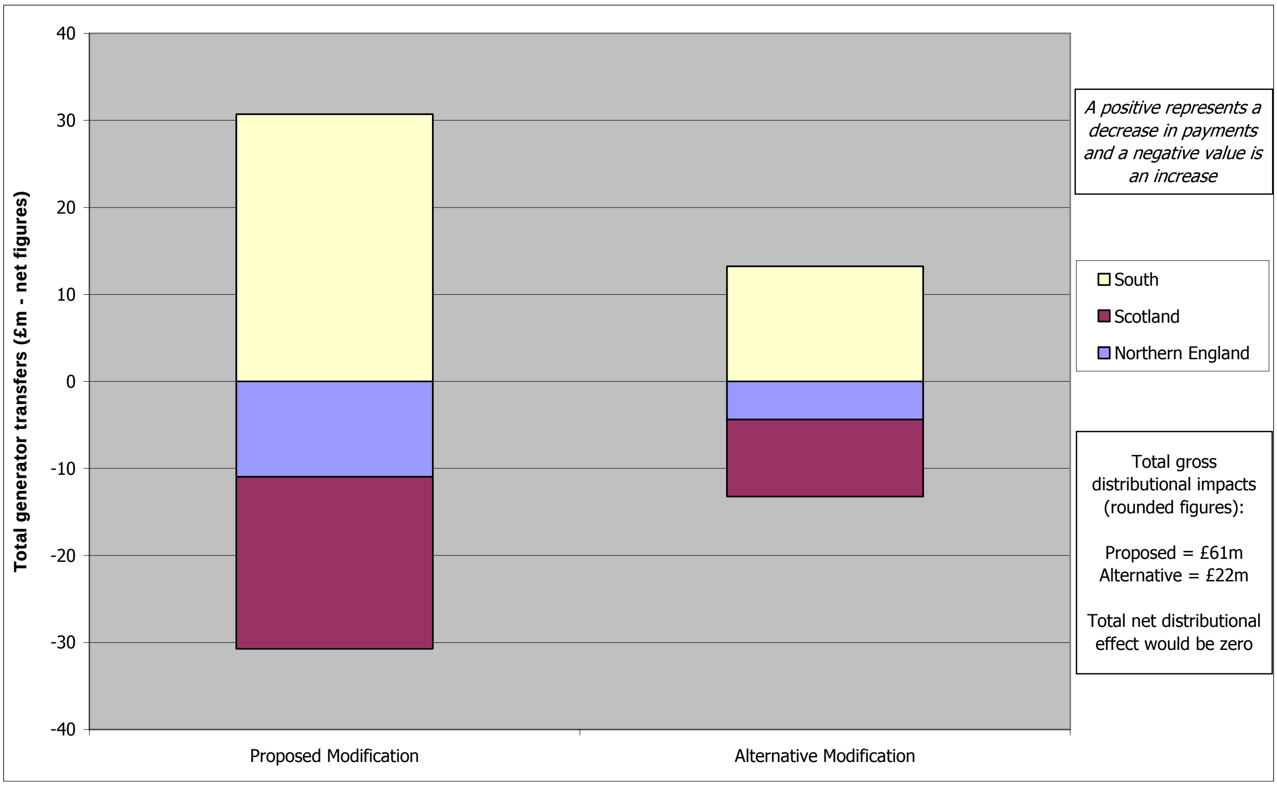
Graph 14 – Annualised distributional impacts on generators by TLF Zone (2011/12)



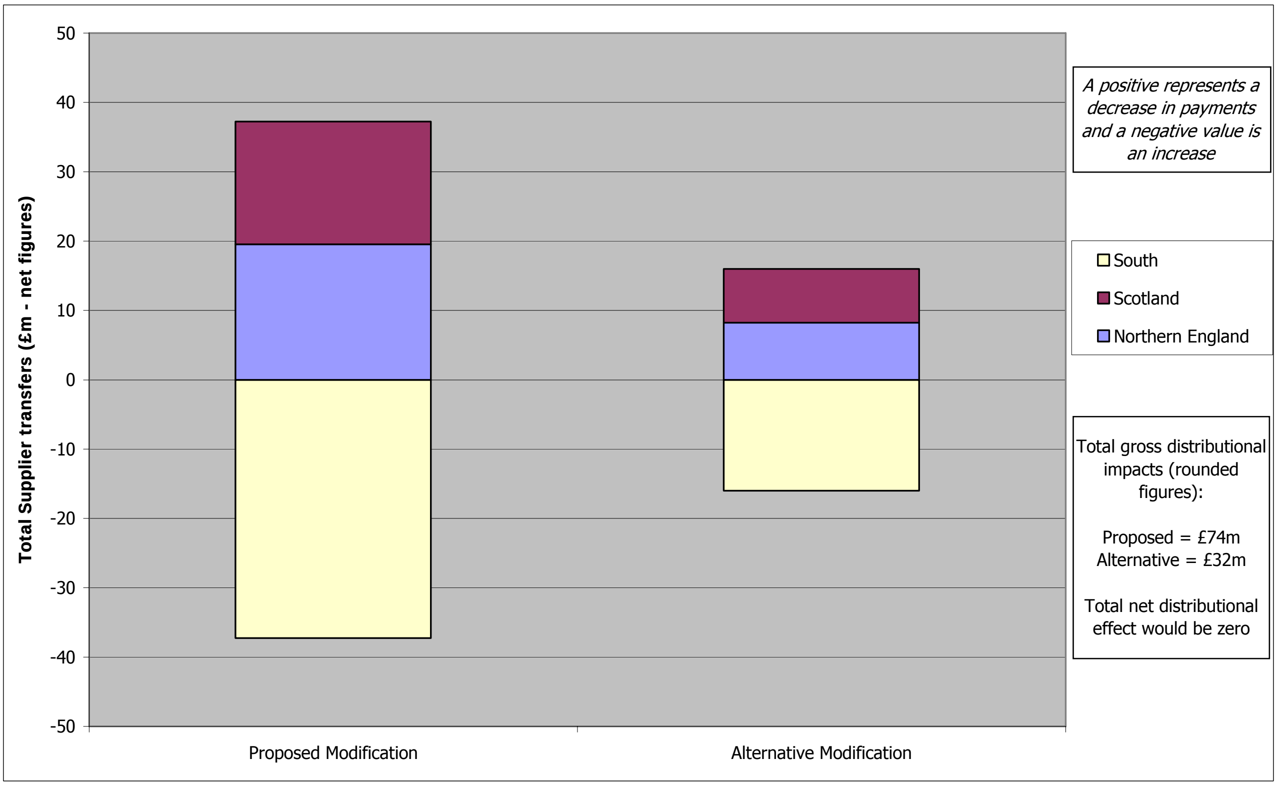
Graph 15 – Annualised distributional impacts on Suppliers by TLF Zone (2011/12)



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

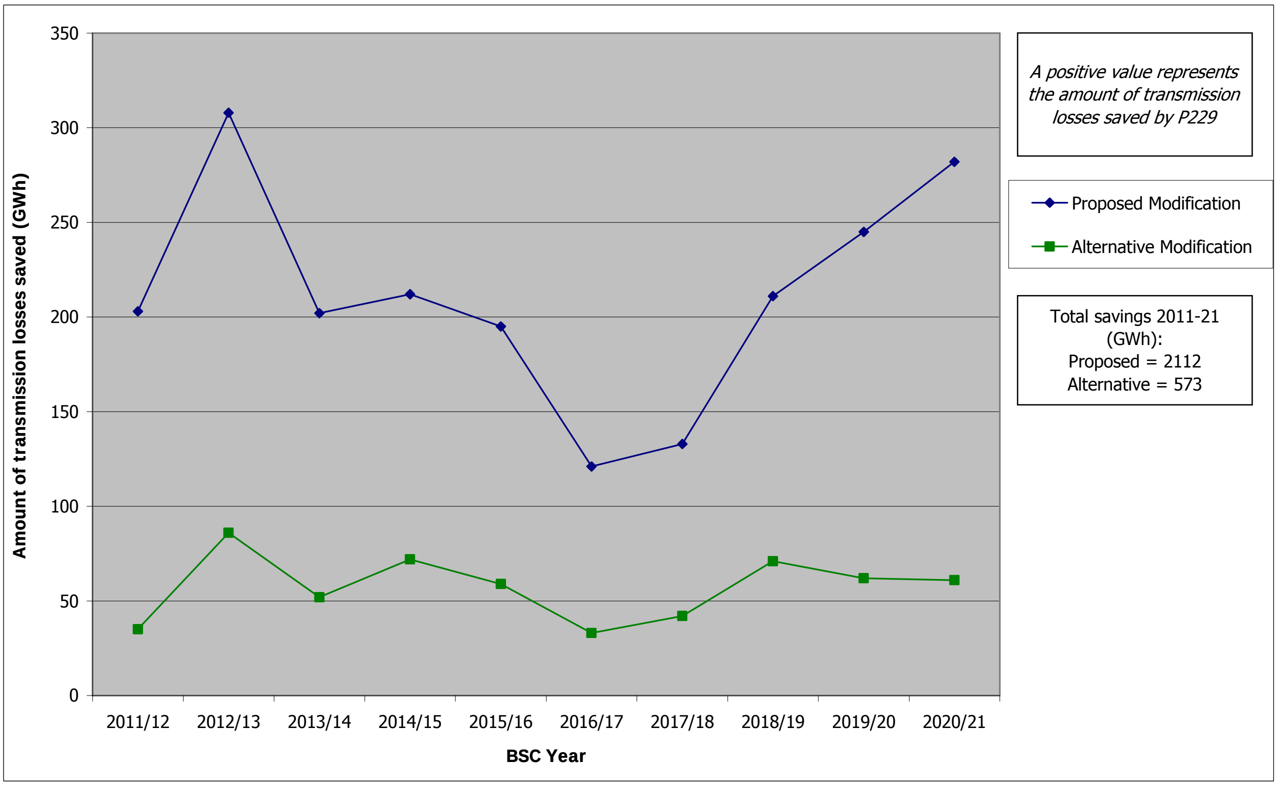
Graph 17 shows the amount of transmission losses which would be saved under the Alternative Modification (Reference Scenario) compared with the Proposed Modification (Reference Scenario).

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.

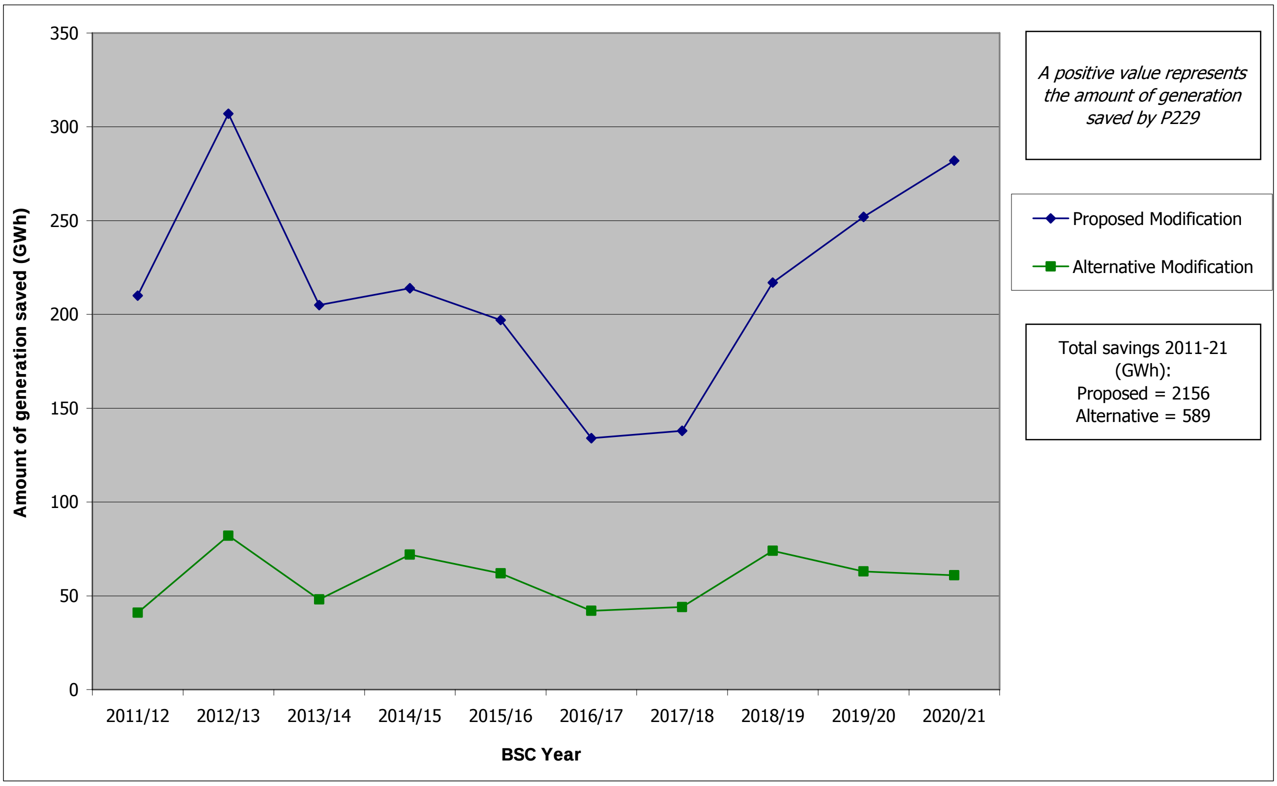
The basis for these figures is identical to Graphs 5, 6 and 7. You can find the Alternative Modification figures in Annex 2 of LE/Ventyx's report, Comparison of Results (Table A2.1).

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.

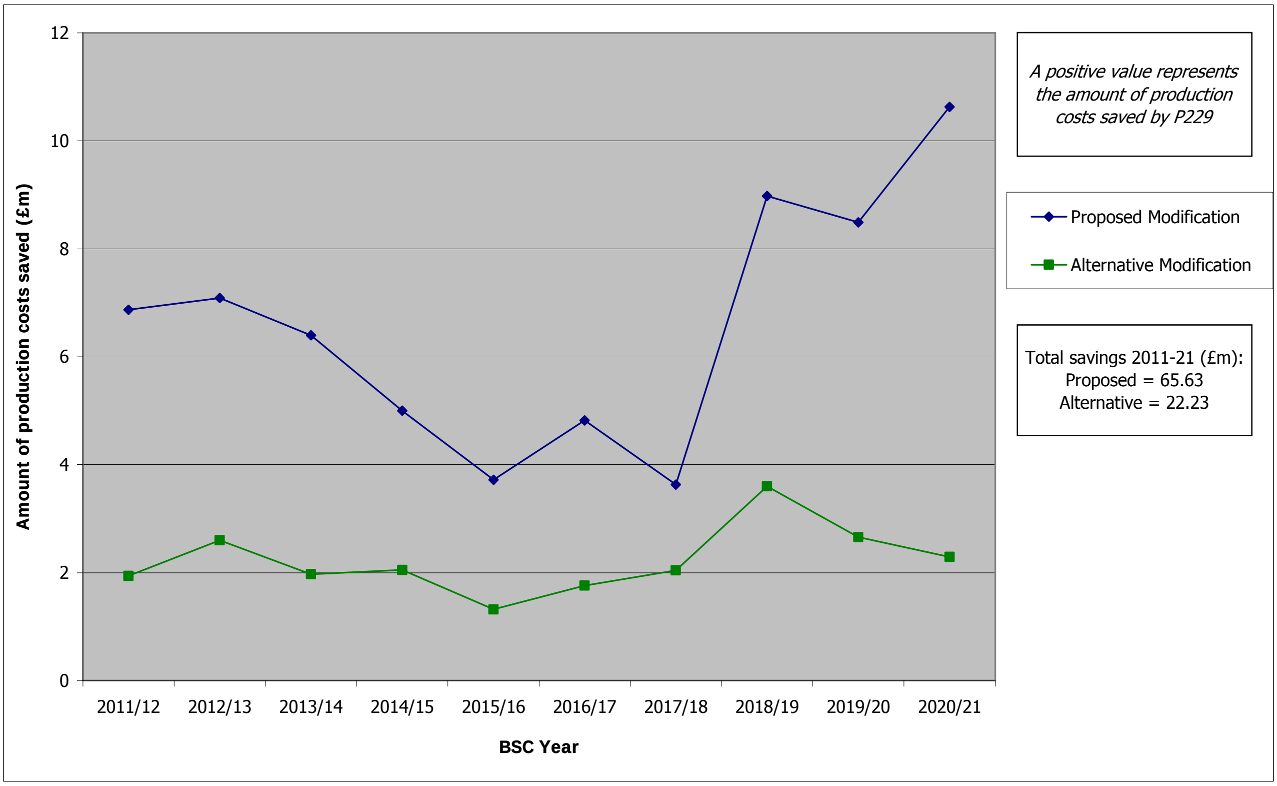
Graph 18 – Amount of transmission losses saved by Alternative Modification P229 (GWh)



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

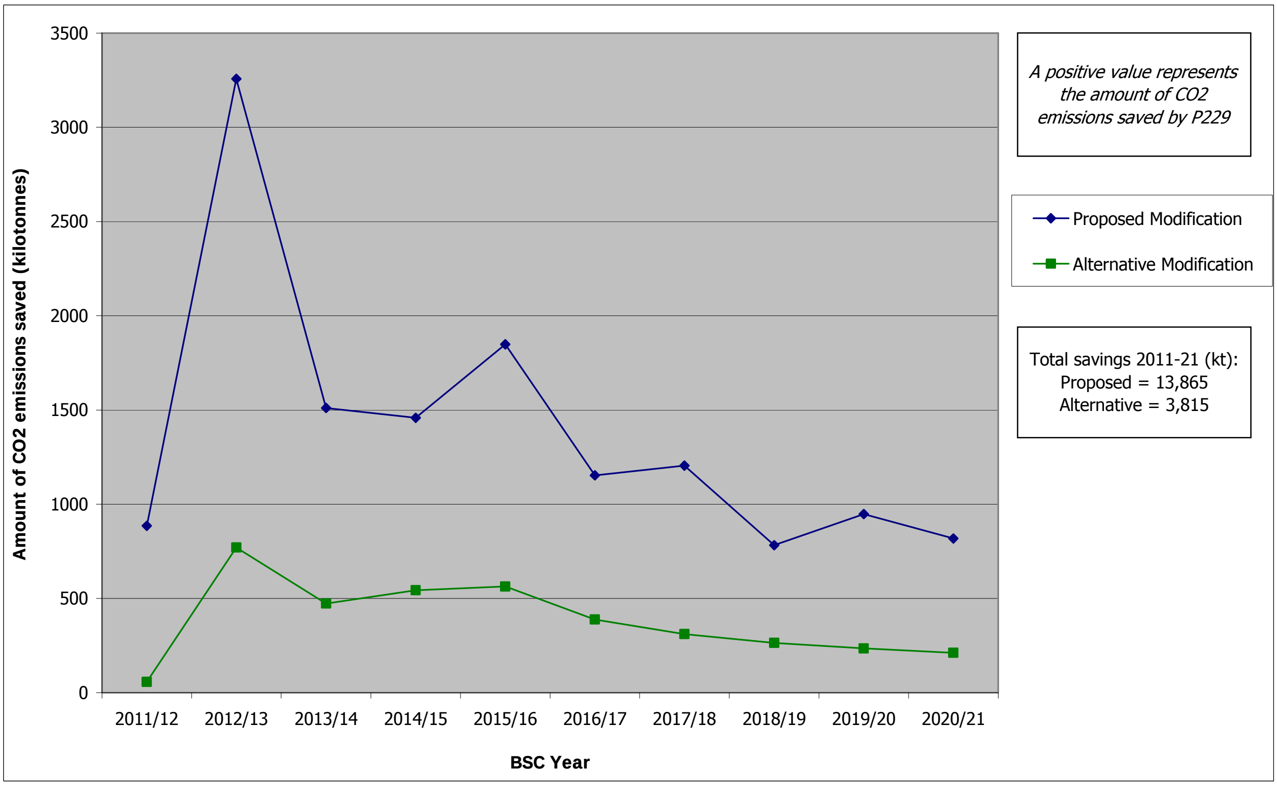
Graphs 20, 21 and 22 compare the impacts of the Alternative Modification (Reference Scenario) and Proposed Modification (Reference Scenario) on the amount of CO_2, NOx and SOx emissions.

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).

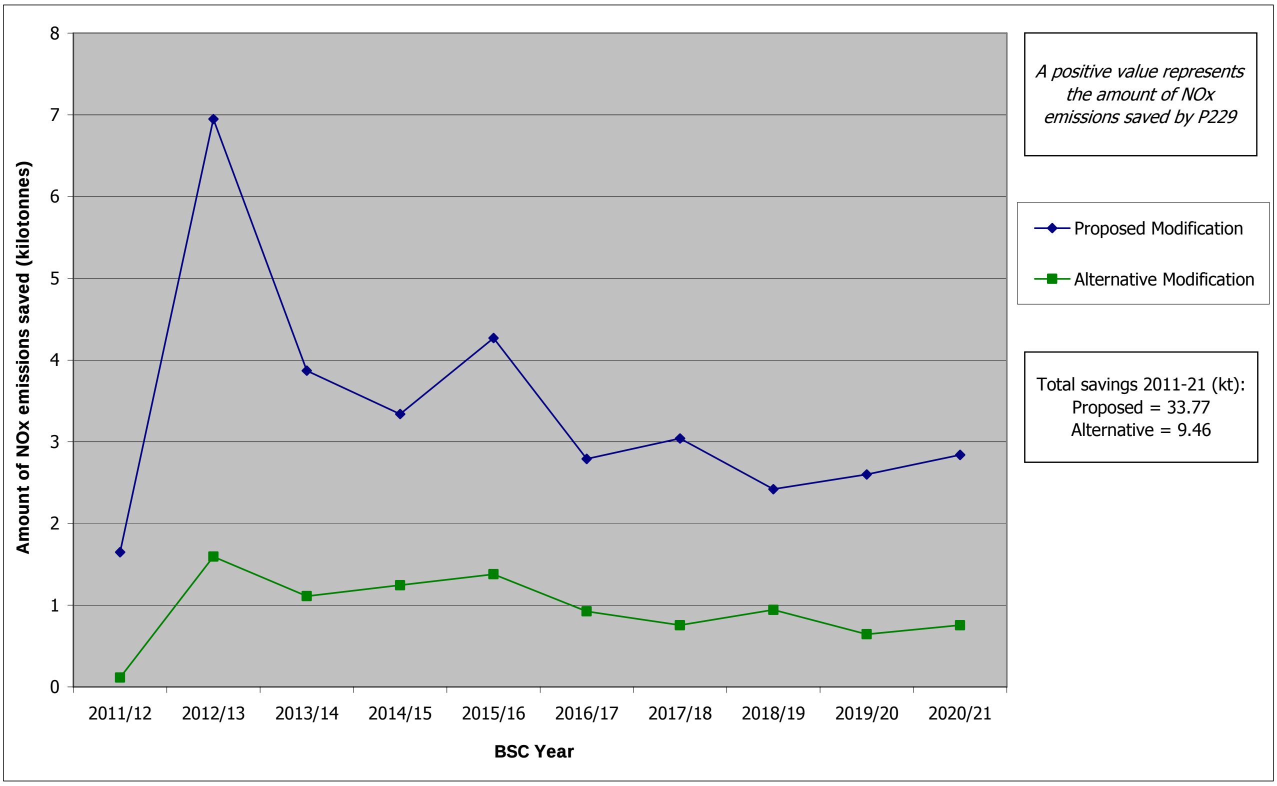
Savings follow a similar trend under the Alternative to the Proposed Modification, but are smaller overall.

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.

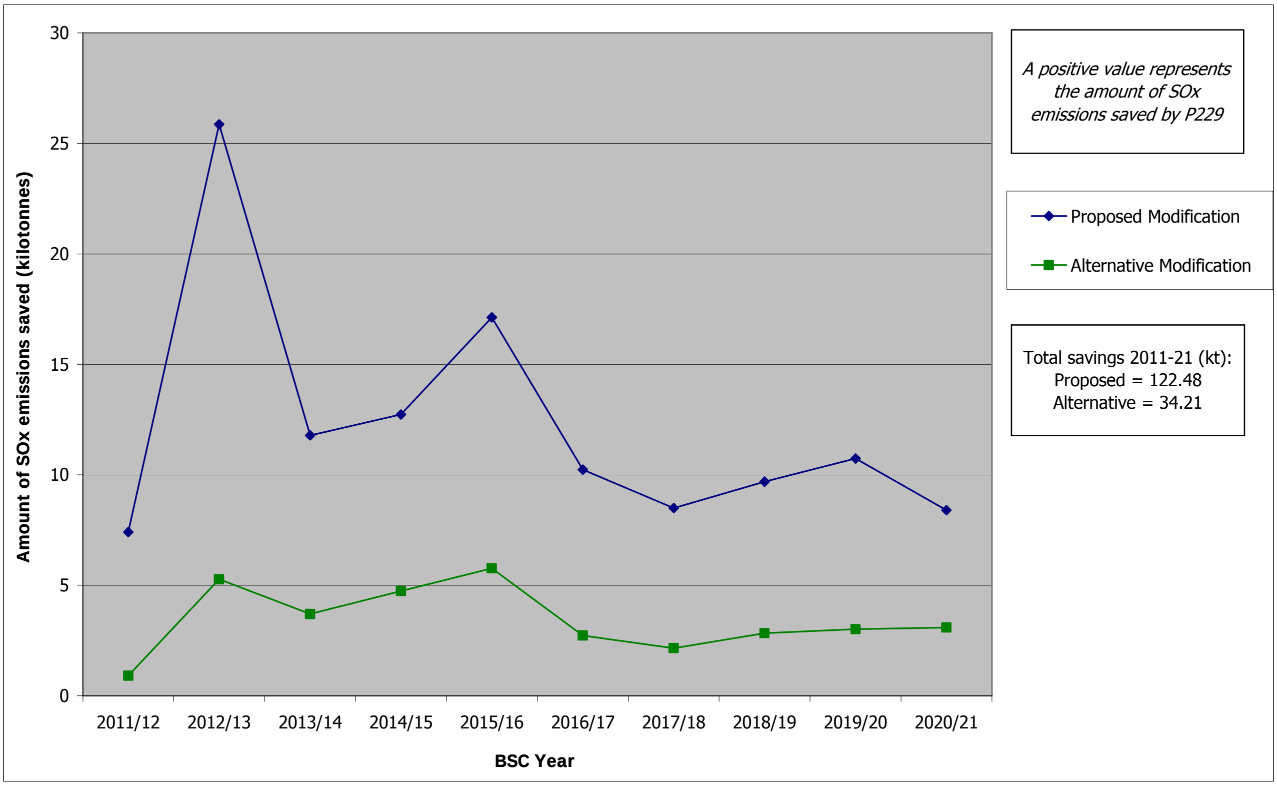
Graph 21 – Amount of CO_2 emissions saved by Alternative Modification P229 (kilotonnes)



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



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



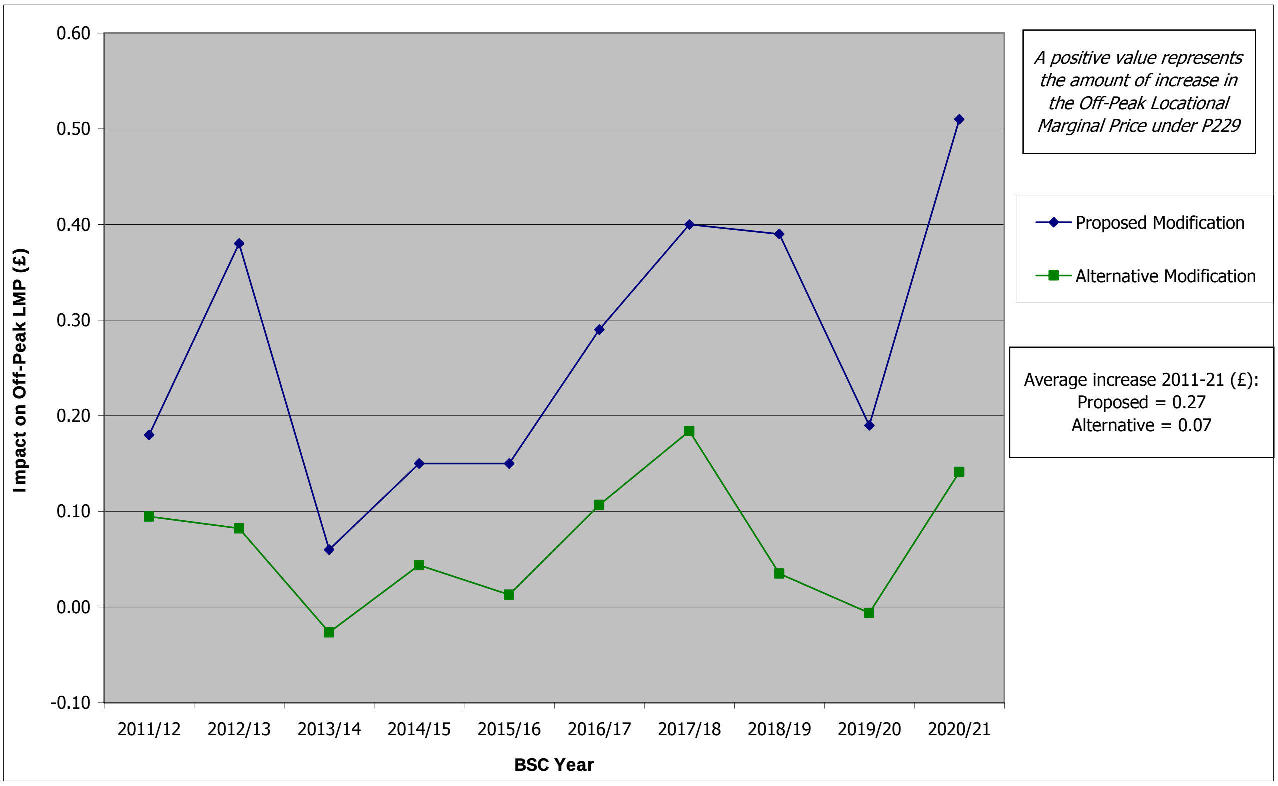
Impact on market prices

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).

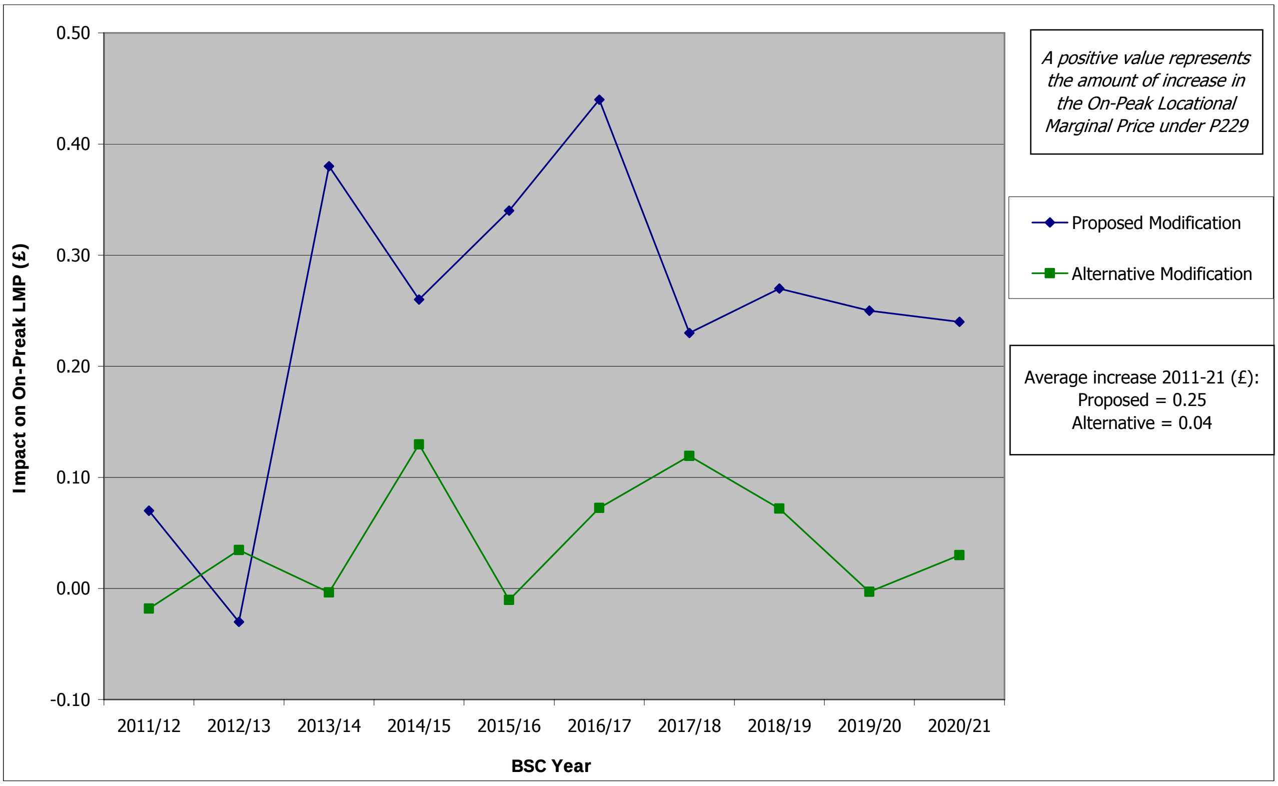
The basis for these figures is identical to Graphs 11 and 12. You can find the Alternative Modification figures in Annex 2 of LE/Ventyx's report, Comparison of Results (Table A2.1).

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.

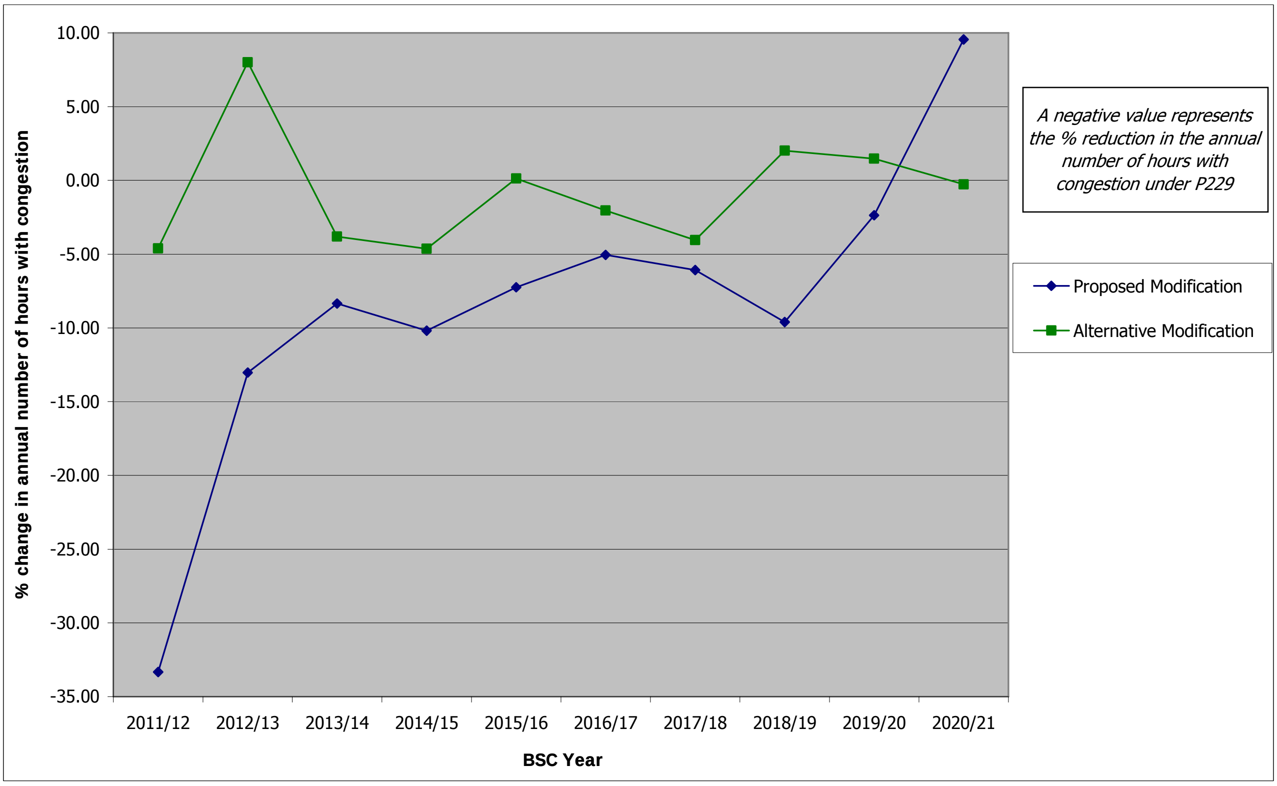
Savings are again greatest on the 400kV voltage lines, and the pattern of reduction is consistent with the Proposed Modification. However, the size of the savings is smaller under the Alternative. You can find the specific figures in Section A1.3.9 of LE/Ventyx's report.

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 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.

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

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 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 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.

[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 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.

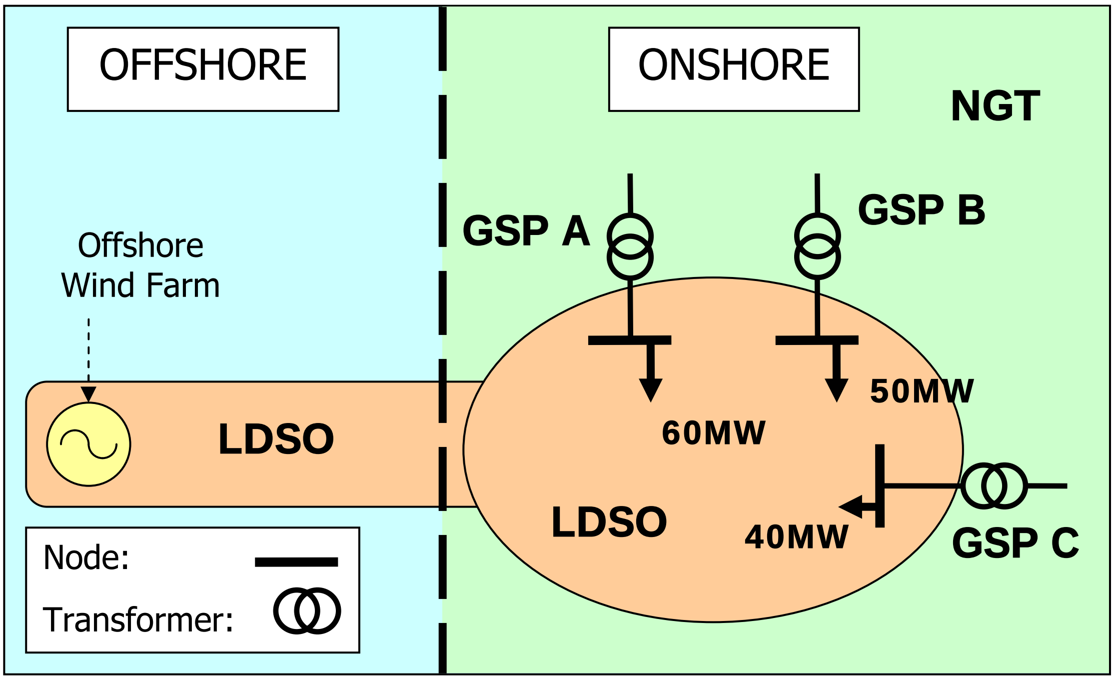


Figure 1: Present case

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.

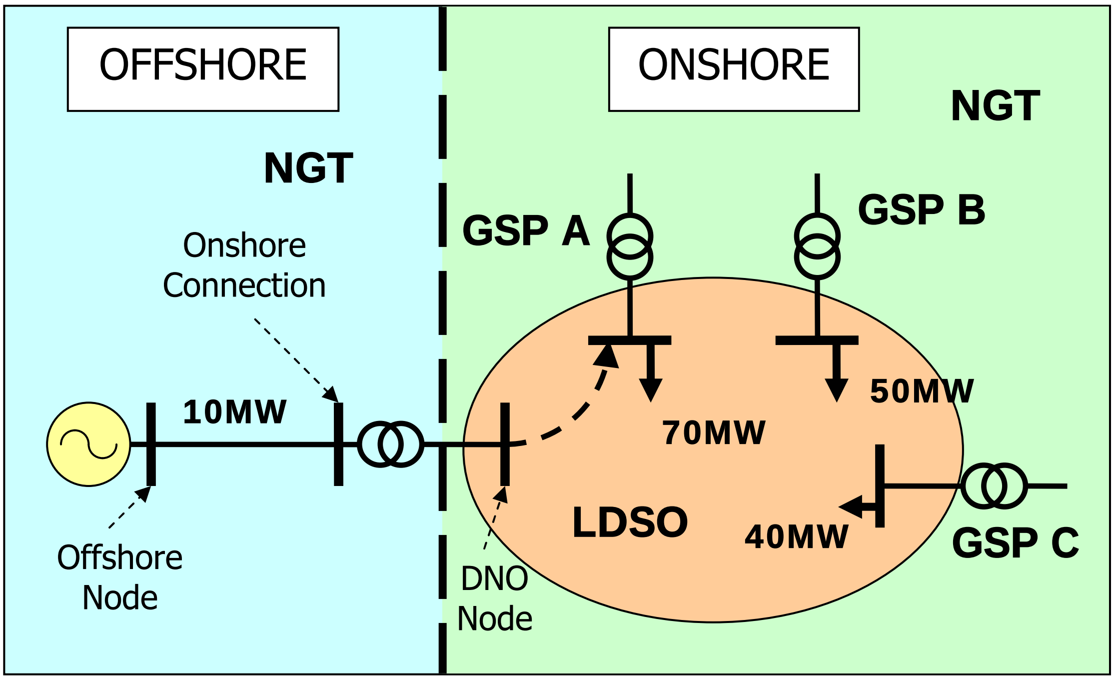


Figure 2: Model under Offshore Transmission

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.

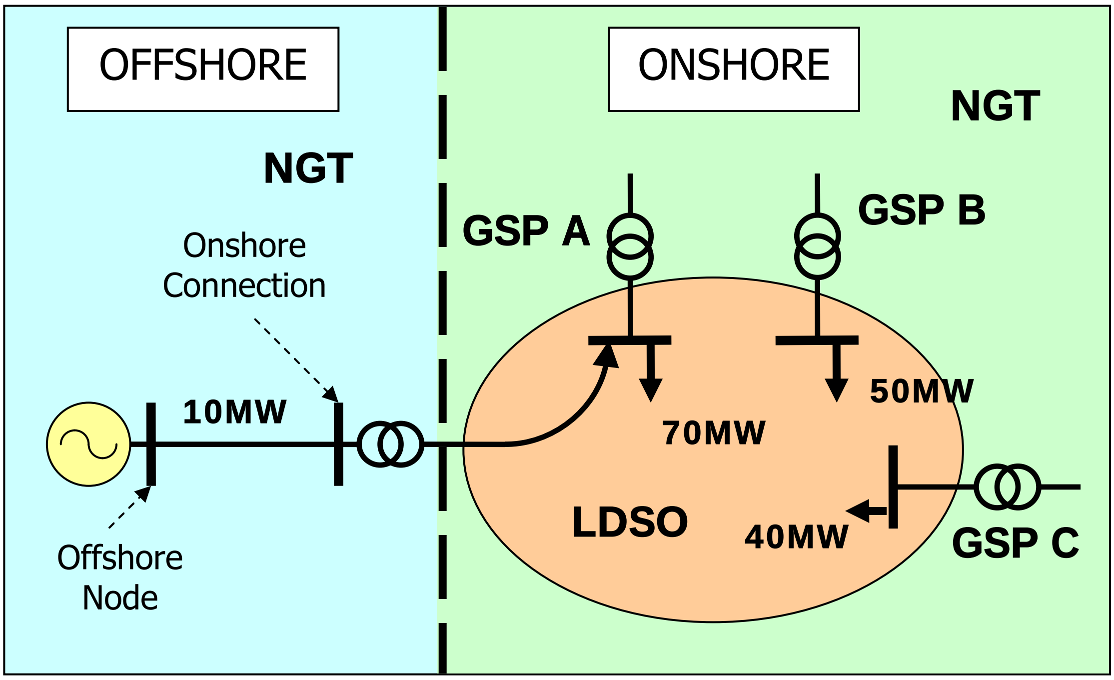


Figure 3: Model for P229

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. Is it the 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

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:
    - o 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;
    - o 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).

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 be affected only to the extent that they would need to provide any additional information that ELEXON and/or the Panel may require to prepare the Network Mapping Statement.

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.

10 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
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	√	√	√	√	√	√	√	√	√
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
Kathryn Coffin	ELEXON (DA)	-	-	-	-	-	-	-	-	-	√
Justin Andrews	ELEXON Operational	√ (part)	X	X	X	X	X	X	X	X	X
Steve Wilkin	ELEXON Operational	-	√	√	√	√	√	√	X	X	X

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

11 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.