nationalgrid

Stage 04: Code Administrator Consultation

Connection and Use of System Code (CUSC)

CMP250

‘Stabilising BSUoS with at least a twelve month notification period’

01	Initial Written Assessment
02	Workgroup Consultation
03	Workgroup Report
04	Code Administrator Consultation
05	Draft CUSC Modification Report
06	Final CUSC Modification Report

CMP250 seeks to eliminate BSUoS volatility and unpredictability by proposing to fix the value of BSUoS over the course of a season, with a notice period for fixing this value being at least 12 months ahead of the charging season.

This Code Administration Consultation contains the discussion and conclusions of the Workgroup which formed in September 2015 to develop and assess the proposal.

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High Impact:
Any Customer liable for BSUoS charges

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About this document

This document is the Code Administrator Consultation for CMP250 which includes the deliberations of the Workgroup, responses to the Workgroup Consultation and the conclusions of the Workgroup. The Code Administrator is seeking views from Industry parties on the Conclusions of the Workgroup.

An electronic version of this document and all other CMP250 related documentation can be found on the National Grid website via the following link:

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP250/ or http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP250/

Any Questions?

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Document Control

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1.0	16/11/2017	Code Administrator	Code Administrator Consultation to the Industry

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1 Summary

1.1 This document describes the Original CMP250 CUSC Modification Proposal (the Proposal), summarises the deliberations of the Workgroup and sets out the options for potential Workgroup Alternative CUSC Modifications (WACMs).

1.2 CMP250 was proposed by Drax Power and was submitted to the CUSC Modifications Panel for their consideration on 28 August 2015. A copy of this Proposal is provided within Annex 1. The Panel decided to send the Proposal to a Workgroup to be developed and assessed against the CUSC Applicable Objectives. The Workgroup consulted on the Proposal on 15 March 2016 for 20 working days to gain views from the wider industry. Following this Consultation, the Workgroup considered responses; developed the Proposal further and voted on the best solution to the defect. This Report presented the Workgroups conclusion back to the CUSC Panel.

1.3 The defect CMP250 attempts to address issues which relates to the fact that BSUoS is only known after the event (ex post) and is becoming significantly more volatile and unpredictable as a consequence of the dramatically changing generation mix. As a result, there is an increasing risk for market participants that their attempts to forecast the cost of BSUoS could be incorrect and could result in loss making and/or uncompetitive market activity. The unpredictability and volatility of BSUoS results in the application of risk premia in the market which will tend to inflate the costs borne by the end consumer. CMP250 aims to eliminate BSUoS volatility and unpredictability by proposing to fix the value of BSUoS over the course of a season (later changed to 12 months), with a notice period for fixing this value being at least 12 months ahead of the charging season. Any under or over recovery of BSUoS costs is then recovered/returned in a future period. It is argued this will reduce the BSUoS risk premium and deliver better value for money compared to the current charging arrangements.

1.4 In assessing the merits of the proposal and developing the specific options, the Workgroup has considered the following issues with subsequent high level conclusions reached:

BSUoS Volatility

There is agreement that BSUoS volatility has been increasing.

Competition

There are mixed views on how the proposal can be expected to impact on competition. Some consider that the current method of charging BSUoS means that there is little ability for parties to compete on the basis of superior BSUoS forecasting capability. This is because the determinants of BSUoS are too unpredictable particularly in trading timescales. However, others are of the contrary opinion that they are able to benefit from having a superior ability to forecast BSUoS.

BSUoS as a cost recovery and/or market signal

The majority view is that BSUoS is almost exclusively a cost recovery mechanism which does not provide any meaningful market signal for parties to respond to. However, a minority believe that BSUoS does provide a meaningful signal which if fixed for a length of time as proposed could result in inefficient dispatch.

Cash flow implications and financing costs

By in effect transferring the BSUoS risk from generators and suppliers to National Grid, it has been established that there will be a significant cash flow impact on National Grid associated with potential over and/or under recovery of BSUoS. Some consider that the impact may be lower where there is a specific incentive on National Grid to more

accurately forecast BSUoS charges. However, additional resource would be required to facilitate greater forecasting accuracy.

There is general preference from market participants that financing requirements for managing BSUoS risk under the proposal should sit with National Grid and should not be funded by an industry (generators and suppliers) guarantee. Nevertheless, the detailed arrangements are a matter for bilateral discussion between National Grid and Ofgem. For the avoidance of doubt, it is not the intention of the proposal that the cost of managing BSUoS risk should be borne by National Grid shareholders. It is the Workgroup's view that all costs associated with the implementation of a fixed BSUoS product should be recovered from industry whilst maintaining the principle of ex-ante pricing.

Risk Premia

The principle that the volatility and unpredictability of BSUoS results in market participants applying risk premia to their prices is generally accepted. There has though been difficulty in accurately quantifying the value of this risk premia. This is because parties' approach to BSUoS risk is commercially sensitive and therefore unknown. Moreover, quantification of risk premia is difficult as there is unlikely to be a homogenous approach to managing the risk amongst generators and suppliers. Nevertheless, high level analysis of the BSUoS risk premia has been undertaken based on publically available data. This analysis provides a high level indication of the level of risk premia that may exist although there is some debate about how conclusive the analysis is.

It is considered that to provide a more accurate representation of level of BSUoS risk premia; parties should provide details on their approach to managing BSUoS risk directly to Ofgem. Parties are encouraged to make representations to Ofgem directly as part of the Code Administrator consultation. This approach will ensure that the Authority is better placed to make a determination on CMP250 whilst also safeguarding commercially confidential information.

Workgroup Conclusion

1.5 Sixteen responses were received to the Workgroup Consultation. Following this Workgroup Consultation, as summarised in **Section 6** in this report, the Original Proposal and five options for potential Workgroup Alternative CUSC Modifications (WACMs) were proposed. At the Workgroup meeting held 30 October 17, the Workgroup agreed to support four of these options which became WACMs. The Original and four WACMs are clarified are follows;

- Original – 12 Months' Notice, 12 Month's Fixed
- WACM 1 – 12 Months' Notice, 6 Month's Fixed
- WACM 2 – 15 Months' Notice, 6 Month's Fixed
- WACM 3 – 15 Months' notice, 12 Month's Fixed
- WACM 4 – 9 Months' notice, 12 Month's Fixed

1.6 The Workgroup voted and three Workgroup members concluded that the Original Proposal is the best option. Two Workgroup members believed that WACM3 is best. WACM 1 and the Baseline received one vote each. The Baseline was concluded to be the best option by the National Grid Representative. The Workgroup agreed that during the Code Administrator Consultation, the Industry should be encouraged to share how Generators and Suppliers account for BSUoS risk in their pricing as this would support the Authority in making their determination.

National Grid View

1.7 Although fixing BSUoS charges may give some relief to market participants of a volatile cost this does not appropriately recognise the transition to a more dynamic system and the price signal that BSUoS will provide for smarter more flexible markets. National Grid consider that developing a BSUoS product ahead of the next SO price control which fixes those elements of BSUoS that form a residual cost and leaves variable those that provide a market signal is more suitable. Additionally, there is no suitable mechanism with the current price control to allow for the recovery of the costs and capital associated with the System Operators assuming this risk. It would be more appropriate to also consider these elements within the next price control. If a decision was taken to implement the modification significant changes to the NGET licence would be required to facilitate appropriate funding of financing costs incurred by the System Operator and over/under recovery arrangements. In addition, as noted in some detail in paragraph 5.2 a lead time would be required to allow National Grid to effectively implement the solution.

1.8 This Code Administration Consultation Report has been prepared in accordance with the terms of the CUSC. An electronic version of this document and all other CMP250 related documentation can be found on the National Grid website via the following link:

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP250/

Or

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP250/

2 Workgroup Discussions

Defect

2.1 Balancing Services Use of System (BSUoS) Charges are the means by which the System Operator (SO) recovers the costs associated with balancing the transmission system. BSUoS charges are levied on both generation and demand on a 50:50 split basis for each half hour settlement period mostly reflecting the actual costs incurred by the SO in each period. The charge is currently levied on an ex post basis (after the event).

2.2 The Proposer identified the defect as due to the growing unpredictability of BSUoS prices, industry participants have no real certainty of their BSUoS costs when forward contracting for power. This lack of certainty ahead of time can result in increasing risk premia being applied by Generators and Suppliers to their product sales, which are ultimately borne by the consumer. It was argued that participants are exposed to events beyond their control, trading prior to a known cost. The Proposer therefore suggests that an ex ante charge would better meet the CUSC objectives.

Proposal - Scope of the Modification

2.3 The Workgroup discussed key scoping assumptions that frame the context of the proposal:

1. No optionality – the Workgroup considered that the solution to the defect should be mandatory for all participants, and not optional. In other words, it would not be possible for some market participants to opt out of a fixed BSUoS price and remain exposed to an ex post half hourly charge, for example. Later in the Workgroup process an optional approach was revisited as discussed in Annex 9 although such an option was not taken forward.

2. One solution to reducing BSUoS volatility could be to make changes to the “Connect and Manage” regime. The Workgroup agreed that this modification is not about the absolute costs of BSUoS in terms of how it is incurred today, and that therefore an alternative proposal along these lines would be out of scope.

3. Another solution might be to allocate all the costs of BSUoS to demand, for example. The Workgroup agreed to look at the impact on market participants but changing the split of who pays BSUoS from 50:50 is out of scope. It is not a question of how to allocate the costs but whether the current ex-post charge is the best approach.

Components of BSUoS

2.4 Table 1 below shows a breakdown of the main categories that made up total BSUoS costs from 2014/15 to 2016/17.

	Total Cost (£m)		
	2014/15	**2015/16**	**2016/17**
Energy Imbalance	-11.8	-22.1	-80.4
Operating Reserve	80.7	75.0	176.3
Balancing Mechanism Start-up	1.1	0.9	6.5
Short Term Operating Reserve	62.3	49.0	72.2
Constraints	292.6	320.9	295.2
Foot room	7.4	2.0	24.3
Fast Reserve	130.1	117.0	93.6
Response	174.4	174.4	145.2
Reactive	72.0	75.7	86.1
Minor components	40.4	42.5	19.4
Internal costs	141.3	148.0	158.5
Balancing Services Incentive Scheme + Wind incentive	25.8	30.0	4.0
SBR/DSBR (including testing costs)	31.7	29.3	117.8
Total	**1048.0**	**1042.6**	**1114.6**

Table 1: Breakdown of BSUoS costs in 2014/15, 2015/16 and 2016/17. The total cost of BSUoS is expected to rise significantly by the end of the decade, potentially doubling to £2bn[1]. The actual total for 2016/17 is £1,280.7. The format of the MBSS has changed in 2016/17 resulting in different cost categories. The additional £166.1m is made up of £134.4m of black start and ROCOF (E&W) £31.7m.

Calculation of BSUoS

2.5 The precise calculation of BSUoS Charges is described in The Statement of the Balancing Services Use of System Charging Methodology Sections 14.29 to 14.32 within Section 14 of the CUSC. Simplified examples of how specific basic actions taken by the SO translate into a BSUoS price are shown in Annex 4 (How RCRC interacts with BSUoS prices).

[1] Julian Lewis, Head of Electricity Network Development at National Grid, was quoted in the Daily Telegraph on 27 June 2016 stating ""At the moment we are spending around £1bn a year and ever-increasing, and I think personally by the next five years or so that will be £2bn a year. This market of flexibility, providing these services to us, is only ever going to increase as we get to a more and more complex network with more distributed generation." http://www.telegraph.co.uk/business/2016/06/26/balancing-demand-could-cost-national-grid-2bn/

BSUoS Volatility

2.6 BSUoS accounts for varying proportions of the wholesale energy price, in some cases very large proportions. Figure 1 below shows BSUoS as a percentage of the wholesale power price (APX Mid P) in 2016-17. Please note that a small number of percentages are negative or infinite. Negative percentages occur where either the power price or BSUoS charge is negative. Infinite percentages occur where the power price equals £0/MWh. Less than 0.5% of settlement periods are affected so the high level conclusions are not impacted. The data shows that BSUoS tends to lie in region of between 2%-6% of the power price the majority of the time. However, it is not uncommon for BSUoS to represent much higher percentages of the power price for example being greater than 20% of the power price over three and a half percent of the time. This can occur where the power price falls significantly or where BSUoS charges are far greater than the average. As renewables increase as a proportion of the generation mix in future such instances can be expected to increase in frequency.

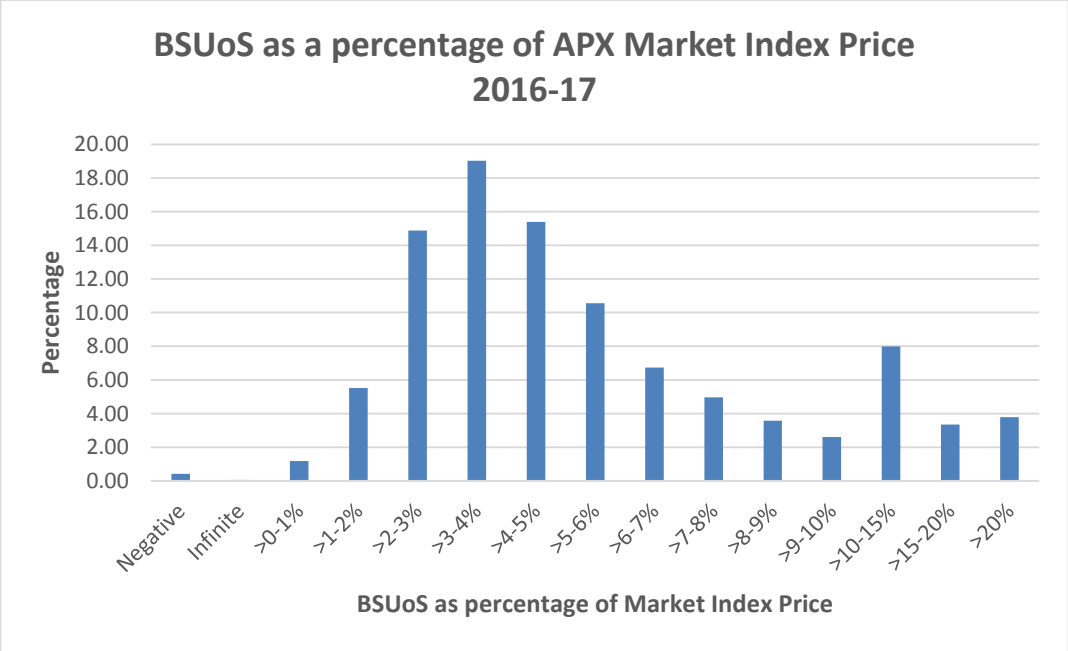


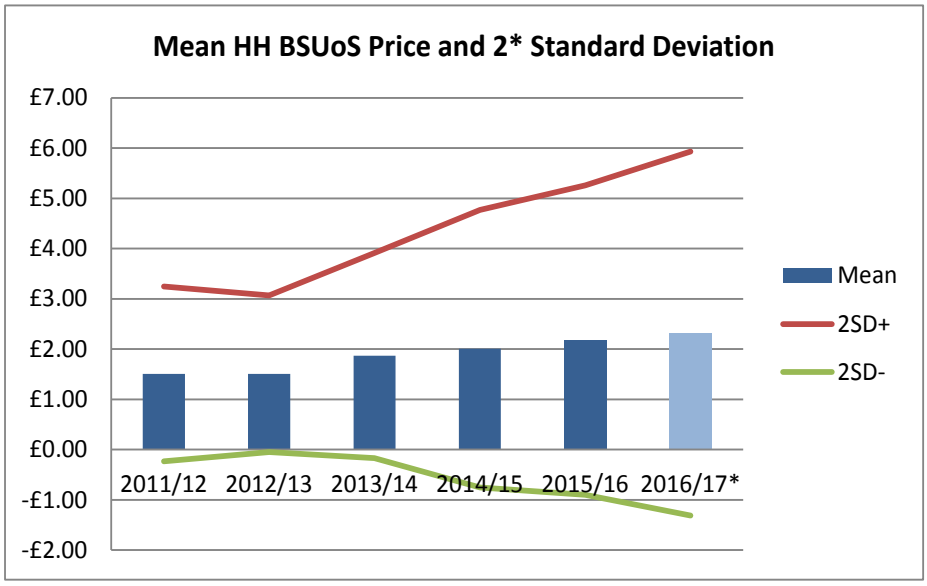
Figure 1: BSUoS as a percentage of wholesale power price

2.7 The average cost of BSUoS can also be compared to the average price of different wholesale power products. For example, the average cost of BSUoS in 2015 was £2.24/MWh and the average price of day ahead power in 2015 was £40.43/MWh. As such BSUoS constituted 5.54% of the average day ahead price for 2015. Moreover, the average Summer BSUoS cost in 2015 was £2.14/MWh. As the average summer 2015 power price at season ahead was £45.36, this means that the average BSUoS cost in summer 2015 constituted 4.71% of the season ahead average summer 2015 power price.

2.8 BSUoS is expected to become a more significant element of the wholesale price as the wholesale price falls with increased renewables penetration whilst the cost of balancing the system increases simultaneously. The Workgroup discussed analysis provided by National Grid showing increasing volatility in BSUoS prices. Table 2 below shows an increasing trend in the absolute price of BSUoS and increases in the standard deviation around the mean. The graph shows the expected range of BSUoS prices with 95% confidence assuming BSUoS prices are normally distributed.

Charging Year	Standard Deviation (from mean)	Mean HH BSUoS	SD as % of Mean
2011/12	£0.87	£1.50	57.8%
2012/13	£0.78	£1.51	51.7%
2013/14	£1.02	£1.86	54.9%
2014/15	£1.38	£2.01	68.7%
2015/16	£1.54	£2.18	70.6%
2016/17	£1.81	£2.47	73.4%

Table 2



*Incomplete year, data to Oct 2016

Figure 2: Expected range of BSUoS prices

2.9 The Table 3 and Figure 3 show how the number of incidences of higher price spikes has increased over the last four years.

Charging Year	> £5.00/MWh	> £7.50/MWh	> £10.00/MWh	< £0.00/MWh
2011/12	98	12	4	167
2012/13	51	3	0	124
2013/14	249	28	0	53
2014/15	701	190	59	33
2015/16	1136	210	19	133
2016/17	850	249	248	36

Table 3

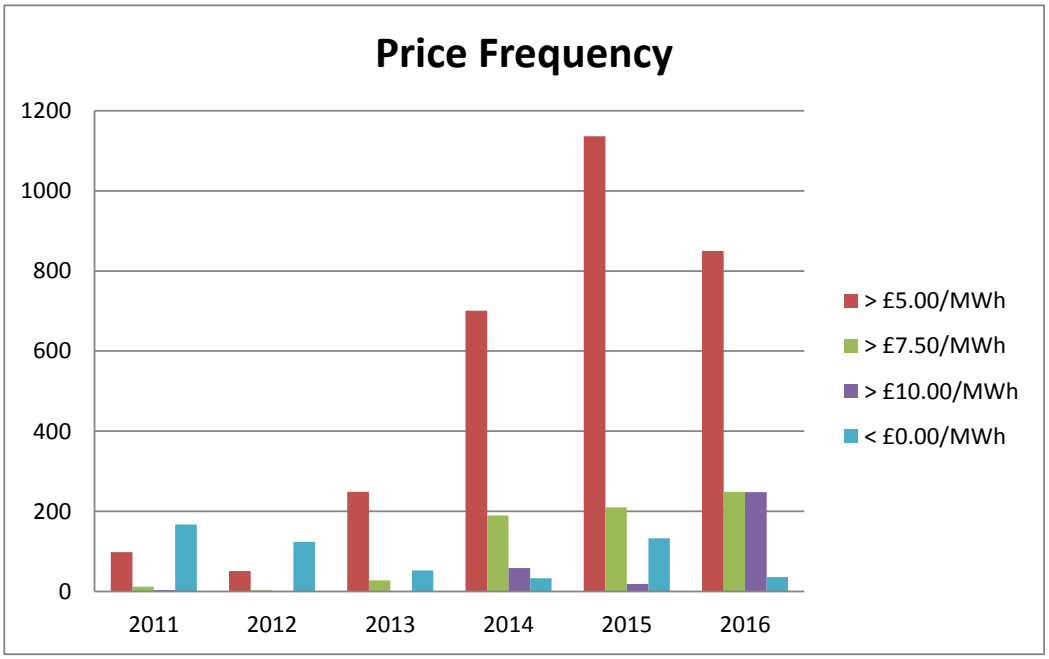


Figure 3: Price Frequency of BSUoS

2.10 There are three primary drivers for increasing half hourly prices:

- **<u>Falling transmission demand (including an increase in embedded generation) which is a key factor in the determination of the BSUoS price</u>**
- Increased constraint costs resulting from the "Connect and Manage" regime (where generators are permitted to connect to the transmission network ahead of reinforcement)
- A reduction in 'traditional' service providers resulting in a reduction in inertia, Black Start capability etc.

2.11 Figure 4 illustrates the BSUoS price distribution curves over the last six years:

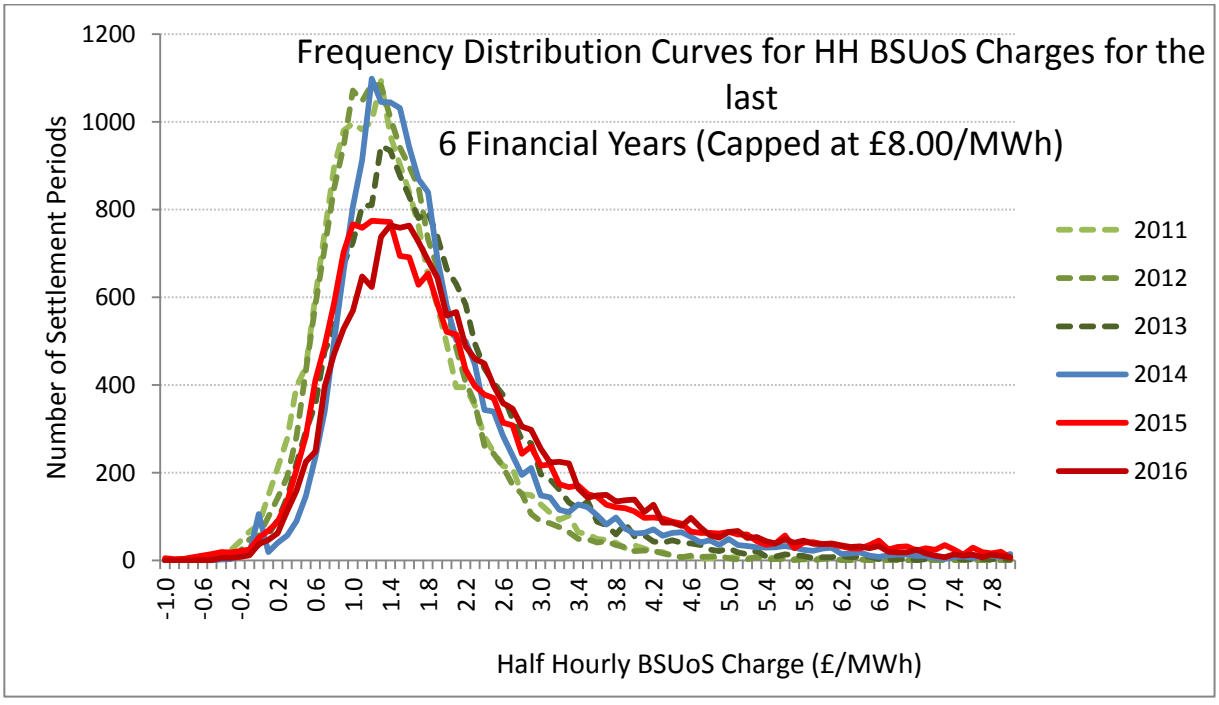


Figure 4: HH BSUoS Charge distribution curves

2.12 It can be seen that the tail of the distribution curve is getting longer with each passing year suggesting a wider price range for BSUoS prices and evidence for increased volatility.

2.13 Within Annex 4 of this document, there are four graphs showing Monthly BSUoS from 2011-2015. In the four graphs the following can be observed:

- **Little or no pattern in the overall monthly BSUoS costs, with higher aggregate costs possible in winter or summer seasons**

- **Falling transmission system demand over the past 5 years.**

2.14 The Workgroup invited the Industry to comment on BSUoS volatility within question 5 of the Workgroup Consultation document. The question asked whether market participants agreed BSUoS charges were becoming more volatile and to explain reasoning if not.

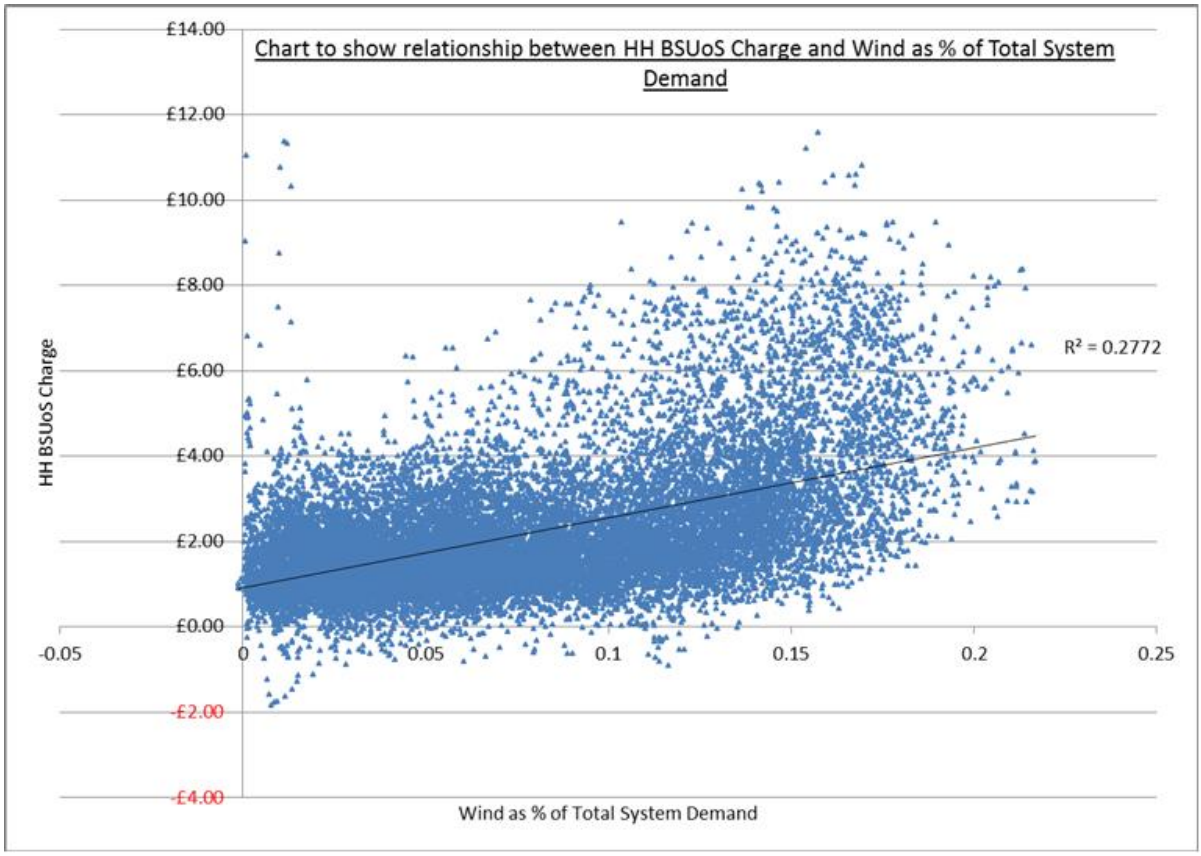
2.15 Of the sixteen responses received to the Workgroup consultation 2 were unable to comment. The majority of the remaining fourteen respondents agreed that BSUoS charges were becoming more volatile and agreed with evidence provided by the Workgroup within the Workgroup Consultation document. One response highlighted that although the report was able to demonstrate that BSUoS has become more volatile over recent years, consideration should be given to the impact on BSUoS in the future with upgrades to the Transmission network and changes to the generation mix.
The Workgroup noted this view and considered the potential impact that the HVDC Bootstrap and further solar capacity may have on BSUoS. One Workgroup member also noted the most recent Summer Outlook Report flagging the possibility of solar constraints in the future. The expectation of the Workgroup was that BSUoS volatility is likely to remain an ongoing feature.

2.16 The Workgroup also asked the Industry to provide their comments on how BSUoS volatility materially impacts their business within question 6 of the Workgroup Consultation document.

2.17 Of the sixteen responses received to the Workgroup Consultation, one respondent was unable to comment and one respondent stated that the material impact of BSUoS volatility was not inherently unmanageable. The remaining fourteen responses generally agreed that BSUoS volatility did have a material impact on their businesses and noted this increased the risk to their businesses. This could lead to them making uneconomic decisions resulting in a loss of competitiveness and ultimately higher costs for GB consumers.

2.18 The Workgroup acknowledged these responses and agreed that BSUoS volatility had a material impact on generators, suppliers and customers. The Workgroup also agreed to further explore the view expressed by the respondent that believed that this risk could be managed. The respondent cited the correlation of high wind output at times of higher BSUoS prices as a clear trend. The Workgroup gathered further evidence to establish the degree to which a correlation exists between BSUoS price and wind output.

2.19 In Figure 5 the graphs show half hourly BSUoS charges (£/MWh) against two variables relating to wind generation for the complete financial year 2015/16. The first graph shows BMU settlement metered wind as a percentage of total system demand plotted against half hourly BSUoS charges. The second chart shows BMU settlement metered wind (MWh) plotted against half hourly BSUoS price. There is some relationship between wind and balancing costs, but the correlation is not that strong, or at least not strong enough to be the only factor that needs to be considered when looking at half hourly BSUoS charging variability. Other factors being system demand and inflexible generation e.g. nuclear and CHP. This confirmed the view of the Workgroup that forecasting wind and demand alone are unlikely to offer a decisive competitive advantage to BSUoS forecasting.



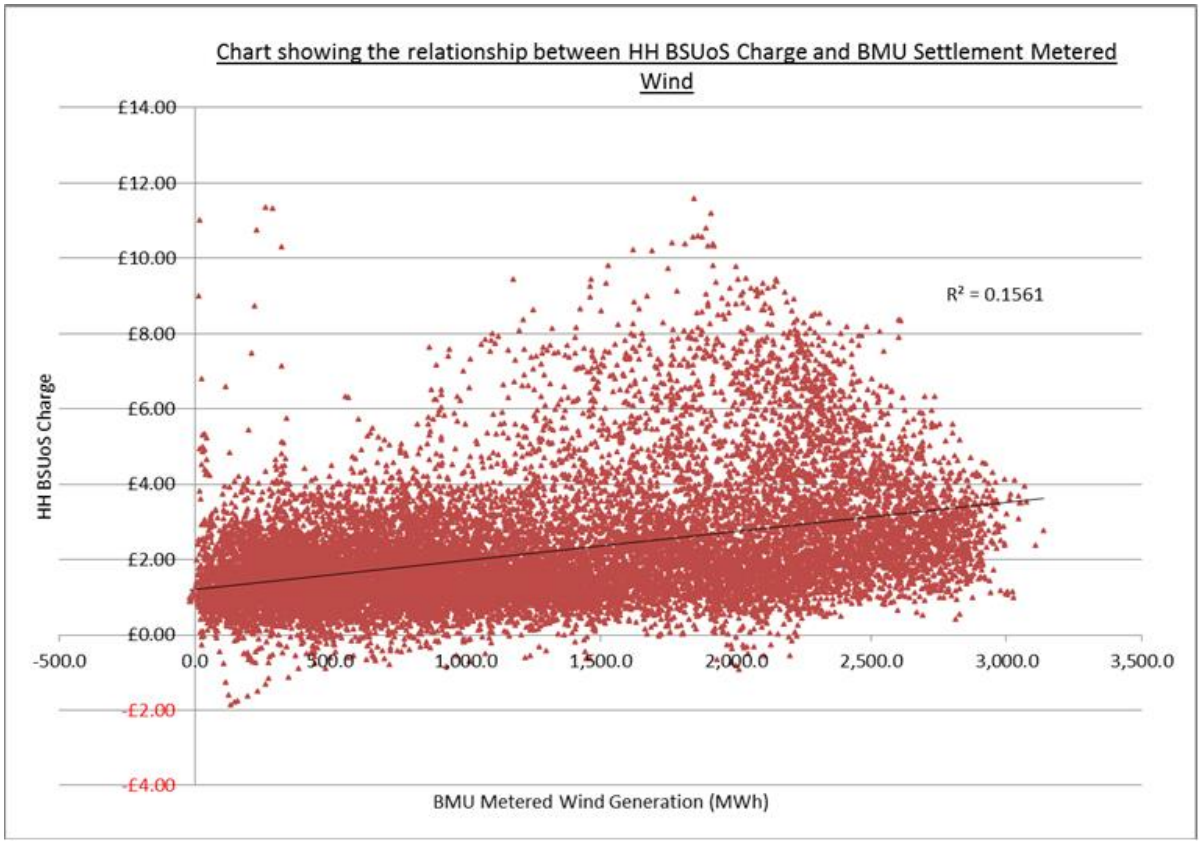


Figure 5: Charts showing relation between HH BSUoS Charge and Wind as % of Total wind Demand and then BMU Settlement Meter Wind

Modification Proposal Benefits

2.20 The Proposer envisages the following benefits to the modification proposal:

- An ex ante price allows generators to precisely reflect BSUoS costs in the Short Run Marginal Cost (SRMC) in wholesale power sales, bid and offer prices and ancillary services.
- An ex ante price with notice period allows Suppliers to forward contract with certainty, in effect longer term liquidity is assisted.

2.21 The product is not hedgeable and therefore it makes sense for the entity with the most control over the costs to assume the risk on behalf of industry.

2.22 One Workgroup member also noted a further requirement for Supplier certainty of BSUoS charges following the decision of the Competition and Markets Authority (CMA) energy market investigation which introduced a transitional price cap for domestic customers on pre-payment meters from 2017-20. Other Network Costs (DUoS, TNUoS etc) are known published tariffs during the time horizon of the cap. These tariffs will be reflected in the price cap. BSUoS, however, is different in that the prices are not known until after the event. The current methodology uses the average BSUoS price for the preceding 12 full calendar months available at the time the level of the cap is set. As historic costs are used to determine a future price, any change in BSUoS costs is not reflected in the level of the cap for at least 6 months.

2.23 Implementation of CMP250 would provide an accurate view of the BSUoS element in the Domestic Pre-Payment Cap, since the cap would use published BSUoS prices. This would bring BSUoS in line with the other Network Costs. Such certainty would ensure a cost-reflective calculation of the Domestic Pre-Payment Cap. This approach would also be beneficial if other tariff price caps are implemented in future.

Competition

2.24 The Proposer contends that it is not possible to compete with other parties on BSUoS, in that it is not possible to be better at forecasting BSUoS than other players. In other words there is no comparative advantage in this area. The fact that National Grid suggest their outage plan (which is not visible to market participants) is important for BSUoS forecasting supports this view. Moreover, the Proposer does not believe that BSUoS provides a useful signal to market participants. Firstly, BSUoS is extremely difficult to predict particularly when the prevalence of forward power contracting is recognised. Therefore it appears very difficult to react to, pretty much impossible where power has been sold far ahead of delivery. Secondly, BSUoS, even if it can be predicted, can provide perverse signals. For example, a high BSUoS charge could be caused by intermittent generation being bought down/off behind a transmission export constraint. However, the high BSUoS charge could conceivably incentivise flexible generation to turn down/off which may not be optimal in terms of system operation.

2.25 The Workgroup also asked the Industry if they considered BSUoS price forecasting to be a potential source of competitive advantage for their business in question 7 of the Workgroup Consultation document.

2.26 Of the sixteen responses received to the Workgroup Consultation, six respondents were unable to comment. Five respondents believed that this could provide a potential competitive advantage allowing better decisions to be made, although also noted that the current lack of information from the SO made it difficult to forecast as well as they would like to. Five respondents did not believe that BSUoS price forecasting was a potential source of competitive advantage due to there being too many unpredictable variables.

2.27 The Workgroup acknowledged these responses and recognised that different industry players had different needs – for some, volatility may be preferable for others certainty is preferred. The Workgroup also noted that it is difficult to spot particular patterns and trends, making it very difficult to gain a particular competitive advantage. The Proposer noted that generally customers preferred certainty over volatility.

2.28 One Workgroup member considered that the calculation of BSUoS charges on an ex post basis for each settlement period does provides a price signal, to which market participants can respond. Whether parties are able, or choose to respond to such a signal is another matter however. What is clear is that different classes of market participant will face different commercial drivers affecting how they might respond. Portfolio players will not

necessarily face the same risks as say a single site independent generator and peaking plant, “must run” CHP plant output, or wind generators will need to respond differently to changes in the market. Some market participants may be able to forecast BSUoS charges better than National Grid or other market participants. In a competitive market, the size of BSUoS risk premia that can be passed through to customers will depend on the ability of market participants to respond to pricing signals and the extent to which the parties that are best able to forecast BSUoS set market prices. Any apparent benefits from charge stability under CMP250 or any other suggested alternatives should be judged against the efficacy of existing pricing signals that would be removed and the loss of competitive advantage to those parties that are most skilled at forecasting BSUoS prices.

2.29 A Workgroup Member notes that small players may be at a greater disadvantage than bigger players in forecasting BSUoS as they have fewer resources to commit to accurately assessing the price risks. Smaller Suppliers may therefore be under-pricing the risk if they just use the year-ahead National Grid forecast.

2.30 One Workgroup member discussed comments on cost reflectivity of a fixed price BSUoS and the effect on some parties that may believe they have a competitive advantage from forecasting it. The Workgroup carried out further discussion with a split view on whether BSUoS is seen as a signal or cost recovery tool. The Workgroup agreed that the signal needs to be doing something good and positive for the system and that it would be beneficial to gain the views of the Industry on this area when the Workgroup Report is issued out to consultation.

2.31 The Workgroup noted that fixing BSUoS charges on an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. The industry were asked to describe how their businesses may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period and asked if the existing, ex post, BSUoS charges provide price signal with which they were able to respond to in question 8 of the Workgroup Consultation document.

2.32 Of the sixteen responses received to the Workgroup Consultation, four respondents did not provide any comments to this question. Three believe that existing BSUoS charges provide a sufficient signal enabling them to manage their businesses. This demographic also noted that by having a flat pricing signal this could lead to higher BSUoS charges due to inefficient despatch actions being carried out. Nine responses did not believe that the current BSUoS charging arrangements provided a suitable signal highlighting that the assessment carried out by the Workgroup demonstrated that the costs and benefits identified outweighed any additional cost incurred to the industry as existing BSUoS charges were inappropriate due to the levels of volatility observed. It was also noted that BSUoS charges were considered a cost recovery mechanism and not a market signal. The Proposer noted that:

a) It is unlikely that the signal, if one is able to predict it, would provide an efficient dispatch signal e.g. in low demand periods.

b) In any case, energy dispatch signals are provided by the wholesale market. Dispatch signals will continue to exist in the event that BSUoS is fixed ex ante.

2.33 The Workgroup acknowledged these responses and noted that only a fraction of the current BSUoS charges were actually cost reflective in the sense that they are costs incurred in the half hour itself. One particular respondent was invited to attend a following Workgroup meeting to explain their consultation response which was substantively different from other responses. This market participant presented data showing how different generation technology types were, as a result of their load factors, exposed to different BSUoS costs, and that therefore, if BSUoS prices were fixed, there would in effect be cross-subsidy between different technology types. The analysis considered data from 2015/16 and showed the following BSUoS costs:

Generation Technology	BSUoS Rate £/MWh
Coal	1.92
CCGT	1.83
Non-pumped storage	1.66
Nuclear	2.10
Wind	2.24
All 5 technologies above	1.95

Table 4: Comparison of BSUoS Cost by Generation Type

2.34 The presenter showed that wind technologies pay 15% more than the average and non-pumped storage 15% less than the average. The Workgroup noted the analysis, and concluded that the value of the cross-subsidy (estimated to be ~£3m to wind) was small compared to the overall ~£1bn total BSUoS costs and the benefits deriving from certainty of BSUoS price. Moreover, the value of the different BSUoS technology costs was considered low. The Workgroup was sceptical that any benefit is provided as it cannot be envisaged how these different costs can be expected to change market participants' behaviour and thus contribute to the achievement of a more efficient system. For customers on fixed contracts the Workgroup felt that this would not be an issue, however, for those customers who receive pass through costs they may incur costs different to their effect on the system in a similar manner to generators.

Risk Transfer

2.35 By providing a fixed price, the proposed modification effectively transfers cash flow risk from industry to the System Operator. The diagrams from paragraphs 2.142 to 2.152 show how cash flow risks is transferred to the SO, and other alternative approaches.

BSUoS as a Market Signal or Cost Recovery Mechanism?

2.36 When first developed, it was thought that BSUoS would generate some form of signal to market participants through the cost reflectivity of the charge itself. The Workgroup discussed whether BSUoS is a market signal or a cost recovery mechanism. As market participants are unable to respond to an ex post price, a majority of the group considered that the charge is a cost recovery mechanism and not a market signal.

2.37 Targeting BSUoS costs to individual half hours is only partially achieved:

- Constraint costs are smeared across all market participants, and not to those that cause them
- Only the following costs are actually allocated to specific half hours:

- Bid/ Offer Acceptances
- Trading Costs
- STOR week ahead availability costs. Balancing actions taken by the SO are not necessarily specific to the settlement period where the action is required due to specific plant dynamics i.e. the need for plant warming, ramp rates etc.

2.38 All other costs and incentive allowances are computed on a daily basis and allocated to settlement periods through volume weighting. This suggests that about a third of total spend can be allocated precisely by half hour. The rest of the costs are smeared across the day.

2.39 One Workgroup member stated that as far as reasonably possible, existing BSUoS charges seek to target the cost of day to day operation of the transmission system to relevant settlement periods in which such costs are incurred. Fixing BSUoS charges will result in a reallocation of costs between settlement periods. For example, any 'flattening' of charges across a day or longer period will, depending on the actual operating pattern of particular generation plant, alter the size of the BSUoS bill faced by such parties. For embedded generators for example, this change to BSUoS charges would be expected to reflect the level of embedded benefits passed through to them by Suppliers.

2.40 In addition, determining the current level of BSUoS charges on an ex-post basis means there can be an exact recovery of costs in the relevant charging year. However, any ex-ante fixing of charges under CMP250 necessarily leads to a 'misallocation' of costs from one year to another because of over or under-recovery of revenues. The speed with which these adjustments can be made also affects the appropriate cost allocation. Thus CMP250 or any of the alternatives suggested would make BSUoS charges inherently less cost reflective. Any apparent benefits of these proposals from charge stability should therefore be judged against any reduction in overall cost reflectivity.

Product

2.41 The group considered whether the fixed price should be profiled or just one flat number. The Workgroup recognised that the justification for any profiling would need to be clear in terms of what the signal would be designed to achieve and to whom. Historic data was examined to see whether there was an obvious natural profile.

2.42 Analysis of data from previous years suggests little obvious pattern in BSUoS prices by day or half hour. The monthly split of prices shown in the graph within Annex 4 of this document also illustrates how prices can be very different across the year. Table 5 below shows winter-summer seasonal splits:

EFA Year	Season	Total	Data Type
2011	Summer	£1.45	RF
2011	Winter	£1.56	RF
2012	Summer	£1.56	RF
2012	Winter	£1.46	RF
2013	Summer	£1.92	RF
2013	Winter	£1.79	RF
2014	Summer	£1.61	RF
2014	Winter	£2.41	RF
2015	Summer	£2.19	SF
2015	Winter	£2.17	SF

2016	Summer	£2.37	SF
2016	Winter	£2.56	SF
2017	Summer	£2.44	SF

Table 5: Winter-Summer seasonal splits (No 2017 winter data as yet)

2.43 Only 2014 exhibited a clear winter-summer seasonal split. However, further inspection of data shows some differences between Weekend and Weekday splits, and Overnight and Extended Peak (07:00-19:00) splits, as shown in Table 6 and Table 7 below:

Charging Year	WE-WD	ON-EP	Win-Sum	Data Type
2011/12	£0.25	£0.11	£0.11	RF
2012/13	£0.21	£0.23	-£0.11	RF
2013/14	£0.28	£0.18	-£0.13	RF
2014/15	£0.34	£0.60	£0.81	RF
2015/16	£0.72	£0.90	-£0.02	RF
2016/17	£0.47	£0.92	£0.20	SF
2017/18	-£0.41	£1.19	-	SF

Table 6: Weekend and weekday splits

Charging Year	Ex-Peak	Overnight	Difference	Data Type
2011/12	£1.47	£1.58	£0.11	RF
2012/13	£1.43	£1.66	£0.23	RF
2013/14	£1.80	£1.98	£0.18	RF
2014/15	£1.81	£2.41	£0.60	RF
2015/16	£1.88	£2.78	£0.90	RF
2016/17	£2.16	£3.08	£0.92	SF
2017/18 (to May)	£2.04	£3.23	£1.19	SF

Table 7: Overnight and extended peak splits

2.44 If any profiling is included in an ex ante price, weekend-weekday, and/or overnight-extended peak would be the most obvious candidates, based on historic observations.

2.45 However, the Workgroup noted that shaping BSUoS requires an extremely accurate view of market developments in the future. Assumptions on future profiles could be undone by changes in the market happening in timeframes after an ex-ante BSUoS price has been notified. One example might be the effect of the Western HVDC project which might be expected to decrease the level of constraint payments, which is one of the primary drivers for BSUoS volatility.

2.46 Profiling would only have value if the System Operator is able to forecast the shape, and history shows that there is no strong or consistent pattern of half hourly charge.

2.47 The Workgroup noted there may be merit in a profile of some kind if this can be shown to reduce the overall costs of ex ante pricing. The Workgroup also considered it may be appropriate to retain the flexibility to generate a profiled shape, even if at present, there may not be a case to profile BSUoS prices. On this basis, and for simplicity, the

Workgroup agreed to consider only options that are a flat fixed price (one number for each half hour).

2.48 The Workgroup asked the industry if they believed BSUoS to be a useful price signal in question 9 of the Workgroup Consultation document.

2.49 Of the sixteen responses received to the Workgroup Consultation, ten respondents did not believe that BSUoS to be a useful price signal as charges are not know with absolute certainty until many months after the SO has incurred the costs. Four respondents did believe that BSUoS provided a useful signal, when used within a level of tolerance considering seasonality and weighting between times of the day. Two respondents did not provide any comments.

2.50 The Workgroup acknowledged these responses and also were also mindful of the impact of DSR and Flexibility in the future and what it may mean to the implementation of this modification, in the sense that a fixed and flat BSUoS price may weaken signals for demand side response and flexibility. However, the Proposer was sceptical about the argument that flattening BSUoS may impact signals for DSR. This scepticism is informed by the comments noted in paragraph 2.32.

2.51 The Workgroup asked the industry if a fixed BSUoS price was implemented, should this be shaped/profiled or flat and if there should be a shape, can they describe a shape that would provide a signal to the industry in question 10 of the Workgroup Consultation document.

2.52 Of the sixteen responses received to the Workgroup Consultation, ten showed strong preference for a flat profile. Four supported a shaped profile and two respondents did not believe that any option is beneficial. The Workgroup acknowledged these responses and agreed to adopt a flat profile

Notification and Fixed Price Periods for a universally applied product

2.53 The diagram below shows a number of possible options and the interaction between notification and fixed price time periods. The options are defined by a combination of the notice period (shown in blue), the fixed price time period (shown in orange), and the formal reconciliation process following the relevant charge phase (shown in grey).

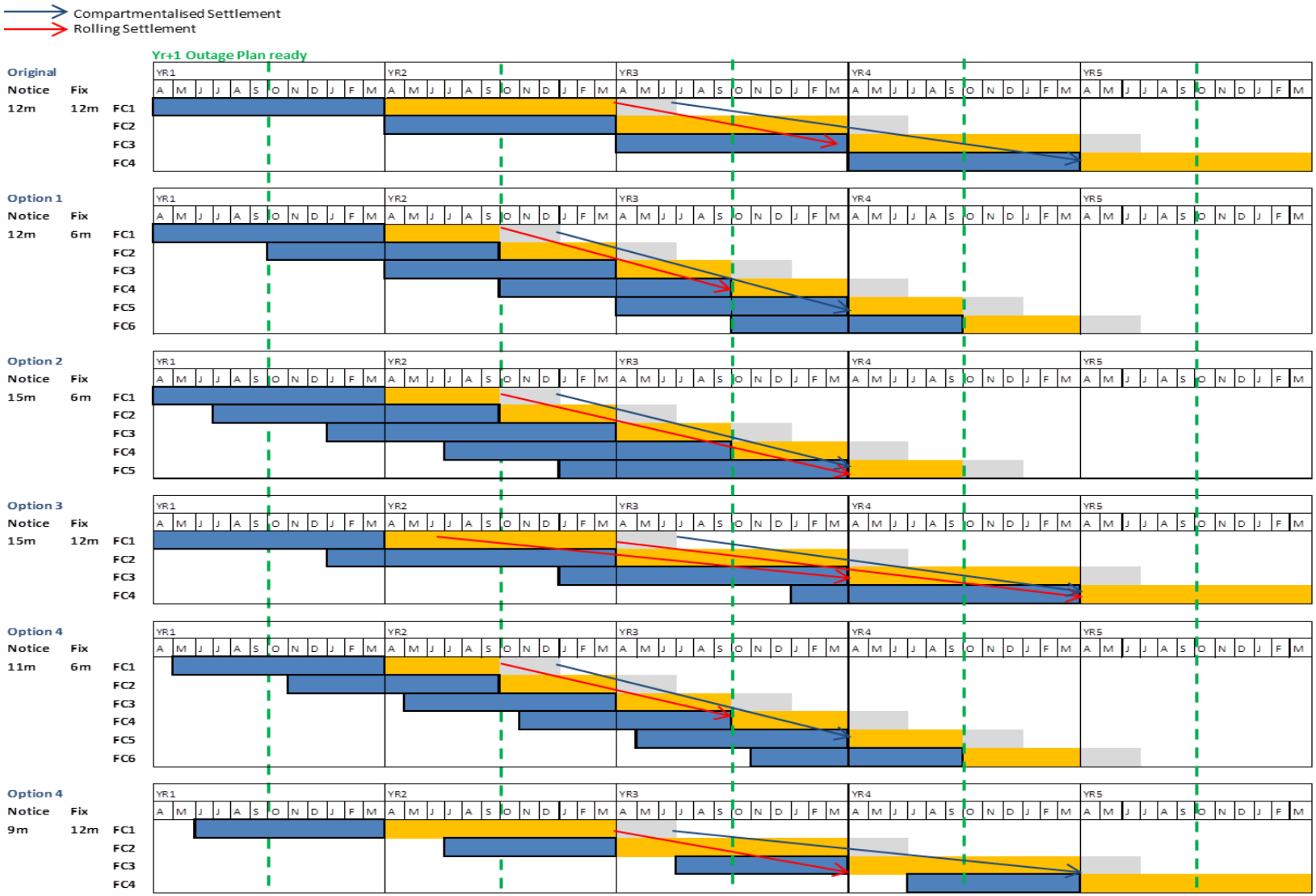


Figure 6: Original Proposal and WACMs

2.54 For the Original, the diagram shows a blue bar in Year 1 signalling the one year notice of the fixed price that would apply in the first 12 months of Year 2 (the gold bar). Depending on the approach to settlement (rolling or compartmentalised) any under or over recoveries will then be recovered in a future fixed price period. In the "rolling" settlement approach, the SO will immediately factor in any emerging over or under recoveries into the next available fixed price period, without waiting for a formal closure of the under/over recovery position (including agreed BSIS incentive scheme allowances). In the "compartmentalised" approach to settlement, the total over or under-recovery for a given fixed price period will be transferred in one go to the next possible fixed price period. It can be seen from the diagram that the rolling approach allows earlier transfer of over or under recoveries.

2.55 The Workgroup came to the conclusion that a rolling settlement approach is preferable. This is because rolling settlement will likely reduce the cash flow risk to National Grid relative to a compartmentalised approach. Following further discussion the National Grid representative confirmed that this would need to be an approach for licence drafting between National Grid and Ofgem. The National Grid representative proposed that an additional term would be incorporated into the legal text to allow National Grid to make a forecasted under/over recovery adjustment to the revenue to ensure that large cash flows could be managed more appropriately. The Workgroup agreed with this approach.

The Workgroup also agreed that it would be most appropriate for National Grid to incorporate an amount relating to the BSUoS financial incentives into the fixed price and to correct this in future years through the term described in paragraph 2.55.

2.56 The first point to note is that for options where the combined notification and fixed price period is more than 18 months, reconciliation of the cash flow over/under recovery cannot occur until yr+2 under rolling settlement and yr+3 under compartmentalised settlement. Reconciliation of the cash flow over/under recovery is possible in yr+1 with rolling settlement in the Option 1 and Option 4.

2.57 The Workgroup did consider whether it might be possible to have a fixed period of 11 months and 3 weeks or 5 months and 3 weeks to enable some late calculations that would deliver a yr+1 reconciliation. However National Grid advised that there is a 3 month process following each financial year where over or under recovery that results in a given year is adjusted through a "K" adjustment methodology approved by Ofgem. Condition B15 of the NGET Transmission Licence requires National Grid to comply with the Regulatory Instructions and Guidance which National Grid carries out through delivery of its Regulatory Reporting Pack by 31 July of each year. The principles elsewhere are that "K" is measured in the year and reported as part of the regulatory return in year 2. Such a mechanism would suggest a requirement for an additional process for options with a 6 month or greater fixed price period.

2.58 National Grid described the key variables driving any forecasting lead time. Generator TEC positions are generally known 12 months ahead, though TEC reductions could still happen after the cut-off date. The BSUoS energy component is relatively stable and reasonably well understood ahead of time. However volatility in BSUoS tends to arise from the constraints side of balancing costs which are mainly a consequence of:

(i) Transmission system outages

(ii) Intermittent wind generation.

2.59 One of the key pieces of information affecting any future BSUoS forecast would be the year-ahead outage plan. This is because constraints are such a large component of the overall BSUoS costs. Understanding when specific transmission circuits are to be switched out would remove a significant uncertainty in attempting to forecast a fixed price. The higher the uncertainty, the larger the cash flow financing provision will need to be, and hence increase overall costs to consumers. The outage plan is firmed-up mid-

October for the financial year ahead. However, it was noted that relevant European Network Code developments suggest a shift to a calendar year outage plan is likely.

2.60 It was recognised that Outage Plan timescales were unlikely to be adjusted to work to CMP250 preferred timescales. The Workgroup therefore acknowledged that any changes to the Outage Plans will be out of the scope of CMP250.

2.61 The diagram shows a green dotted line indicating the likely availability of an indicative outage plan for the following charging year that could be used to determine possible constraint costs. The key point to note is that the Option 1 and Option 4 would enable one of the two 6 month price fix periods within a year to benefit from an understanding of the outage plan, and therefore potentially minimise over/under-recovery from a more accurate fixed price forecast.

Benefits of a longer notice period

2.62 According to Ofgem's Wholesale Power Market Liquidity: Annual Report 2015 (9 September 2015), in Quarter 2 2015 approximately 50% of OTC baseload products were traded up to six months ahead of delivery (Baseload S+1). However, an approximately additional 20 percentage points of OTC baseload trading was undertaken up to 12 months ahead of delivery (Baseload S+2). The data can be seen in Figure 7 below. This represents the additional traded volumes which would benefit from a CMP250 solution that includes a 12 month as opposed to six month notice period.

2.63 A CMP250 solution with 12 months rather than six months' notice could be expected to reduce the BSUoS risk premium by an additional 20% (which could be valued at somewhere between £40m and £16m – please see the BSUoS risk premium section for the full results of this analysis - paragraph 2.100 – 2.127).

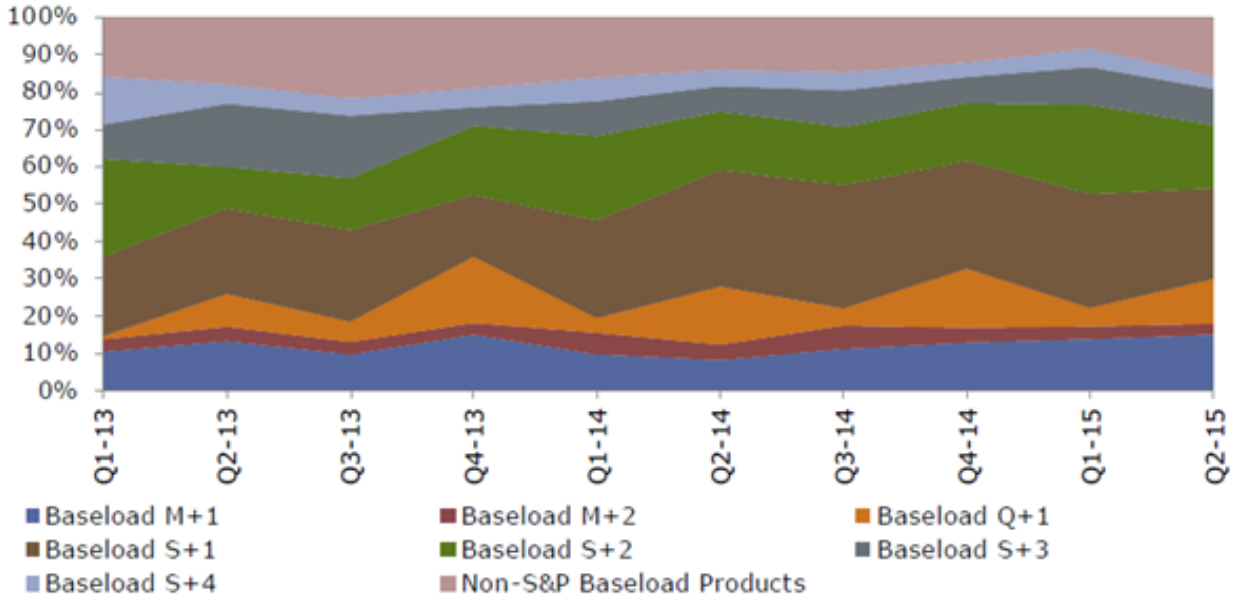


Figure 7: OTC baseload trading since Q1 2013

2.64 One Workgroup member noted the trade-off between the notification period and the size of the cash flow provision required to ensure sufficient finance is available in the event the fixed price forecast is inaccurate – the chances of which are higher, the longer the notification period.

2.65 The Workgroup asked the industry what was their preferred notification lead times, and what should be the length of the price fix period in question 11 of the Workgroup Consultation document.

2.66 Half of the sixteen responses received to the Workgroup Consultation supported the Original proposal of having a 12 month notice period and 6 month fixed. Three respondents were unable to comment and the remaining respondents provided a suggestion that has been acknowledged by the Workgroup and will be presented as an option for a WACM. The Workgroup acknowledged all responses to this question.

Cash flow Implications

2.67 The Workgroup considered how a fixed price mechanism may affect SO cash flow. Analysis was performed to examine how the SO cash flow position would have been affected if a fixed price mechanism had been in place for the last four years. It should be noted that the fixed price used in the analysis is one month ahead, as no longer term forecasts of BSUoS price exist. The analysis therefore does not consider the accuracy of BSUoS forecasting with longer notification lead times. It is purely an indication of the possible movement in cash flows that might be observed as a result of over or under-recoveries.

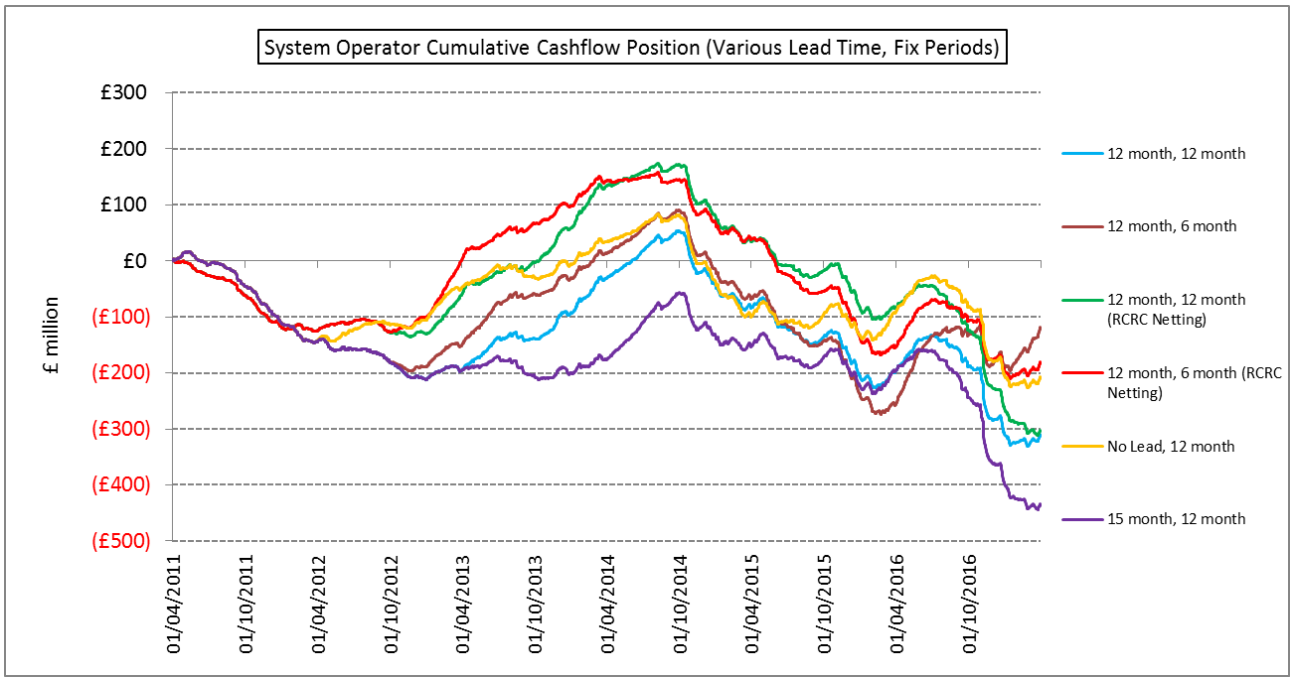


Figure 8: SO cumulative cash flow position

	BSUoS Year/6 Month Period	Annual Under/Over Recovery
No Lead, 12 month fi...	2011	-£144,127,414
	2012	-£50,690,831

	2013	£25,986,729
	2014	-£107,632,406
	2015	-£100,146,915
	2016	-£221,535,285

12 month Lead, 12 month Fix	2011	-£144,127,414
	2012	-£51,432,110
	2013	£17,982,609
	2014	-£112,444,268
	2015	-£102,219,169
	2016	-£226,789,530

12 month Lead, 6 month Fix	01/04/2011 - 30/09/2011	-£45,035,754
	01/10/2011 - 31/03/2012	-£99,091,660
	01/04/2012 - 30/09/2012	-£36,168,459
	01/10/2012 - 31/03/2013	-£15,263,391
	01/04/2013 - 30/09/2013	-£8,702,525
	01/10/2013 - 31/03/2014	£30,653,496
	01/04/2014 - 30/09/2014	£57,044,034
	01/10/2014 - 31/03/2015	-£167,113,035
	01/04/2015 - 30/09/2015	-£47,019,746
	01/10/2015 - 31/03/2016	-£55,878,878
	01/04/2016 - 30/09/2016	-£43,843,171
	01/10/2016 - 31/03/2017	-£35,070,405

12 month Lead, 12 month Fix (RCRC Netting)	2011	-£125,277,196
	2012	£65,398,780
	2013	£65,148,348
	2014	-£38,535,009
	2015	-£54,925,083
	2016	-£256,995,598

12 month Lead, 6 month Fix (RCRC Netting)	01/04/2011 - 30/09/2011	-£60,771,609
	01/10/2011 - 31/03/2012	-£64,505,587

	01/04/2012 - 30/09/2012	-£2,409,005
	01/10/2012 - 31/03/2013	£67,808,137
	01/04/2013 - 30/09/2013	-£1,225,208
	01/10/2013 - 31/03/2014	£69,987,123
	01/04/2014 - 30/09/2014	£67,830,092
	01/10/2014 - 31/03/2015	-£106,148,066
	01/04/2015 - 30/09/2015	-£23,608,076
	01/10/2015 - 31/03/2016	-£33,006,982
	01/04/2016 - 30/09/2016	-£58,890,414
	01/10/2016 - 31/03/2017	-£98,077,532

15 month Lead, 12 month Fix	2011	-£144,127,414
	2012	-£51,432,110
	2013	£18,948,459
	2014	-£35,236,610
	2015	-£34,223,737
	2016	-£280,287,133

6 month Lead, 12 month Fix	2011	-£144,127,414
	2012	-£51,432,110
	2013	£18,948,459
	2014	-£35,236,610
	2015	-£30,706,491
	2016	-£275,290,064

Table 8 – Supporting Data for SO cashflow table

2.68 Cash flow recovery is calculated by comparing actual half hourly balancing costs to the year ahead half hourly BSUoS forecast multiplied by total half hourly System Demand (multiplied by 2 to represent both generation and demand). Any differences between the Balancing Services Incentive Scheme (BSIS) costs included in the forecast and the outturn BSIS SO costs to the industry have been stripped out of the under/over-recovery figures. Any over/under-recoveries are assumed to be addressed in the next available period (rather than yr+2 as described above) except the 15m:12m scenario where recovery is in yr+2.

2.69 The analysis shows that the cash flow position can fluctuate significantly broadly +£175m or -£430m (as shown in Figure 8). However, it is also important to note that the analysis does not include consideration of any notification period, it just assumes a fixed price from the beginning of the charging year. (It is not possible to model a notification period, because no forecast is available to cover this). Therefore, the price forecasts above were made by reference to an outage plan, which would not be possible were the notification period to exceed 6 months, and therefore it is realistic to suggest the fluctuation parameters could be significantly wider.

2.70 The most positive cash flow scenarios are those where RCRC is netted out of the BSUoS calculation, and this is discussed further in paragraph 2.72 below. Generally, the longer the notification and fix period, the longer any over or under-recovery persists.

2.71 The Workgroup noted that the current state of potential under or over recovery by National Grid is likely to be over-stated as there is no incentive, either risk or reward based, on the SO to accurately forecast BSUoS over a longer time frame. Under any changes as a result of CMP250, BSUoS forecasting would become an issue that the SO would need to manage. The Workgroup considered that this would both be an exposure to risk which the SO would mitigate through improved forecasting and a potential incentive to ensure that under or over recovery was within a specific tolerance.

Impact of RCRC

2.72 Net Residual Cash-flow Reallocation Cash-flow (RCRC) is a term used to reallocate surpluses or deficits generated from a dual cash-out price. In the Balancing Mechanism, bids and offers have different prices so when the SO takes balancing actions to resolve energy imbalances these actions do not net to zero. As the system is generally long, a surplus is more usual, and this is reallocated to those parties that had balanced positions in the market.

2.73 It can be seen in the graph above that if RCRC was netted from the BSUoS price before being reallocated to market participants, the cash flow position would be significantly more positive, and therefore the cash flow costs of fixing a BSUoS price would be lower.

2.74 The Workgroup considered whether netting RCRC should be an additional feature of the modification proposal. Whilst carrying out its analysis, Balancing Code modification P305 was implemented on 5 November 2015. This modification included the implementation of a single cash out price. It is expected therefore that RCRC surpluses will significantly reduce following the implementation of this modification. The Workgroup kept this position under review, and the following data was captured:

FY	Month	Sum of ES_TRC_J_GBP
2013	1	9,950,743
2013	2	8,634,854
2013	3	-1,692,188
2013	4	2,823,387
2013	5	-8,828,717

2013	6	-9,913,301
2013	7	6,532,666
2013	8	813,417
2013	9	12,819,969
2013	10	8,182,749
2013	11	6,689,448
2013	12	4,730,488
2014	1	7,420,076
2014	2	10,702,501
2014	3	7,207,887
2014	4	2,855,836
2014	5	1,181,309
2014	6	-2,313,097
2014	7	219,252
2014	8	-557,893
2014	9	4,329,914
2014	10	14,543,042
2014	11	9,001,264
2014	12	10,198,149
2015	1	3,391,800
2015	2	1,220,190
2015	3	-1,228,281
2015	4	-8,918,802
2015	5	8,410,805
2015	6	4,035,811
2015	7	6,199,180
2015	8	9,536,008
2015	9	1,801,518
2015	10	7,130,053
2015	11	11,171,942
2015	12	-1,731,082
2016	4	124,457
2016	5	-5,669,592
2016	6	-2,083,689
2016	7	-4,524,325
2016	8	-5,101,950
2016	9	621,250
2016	10	-966,593

Table 9: RCRC Surpluses

2.75 Table 9 above shows a reasonable reduction in the level of RCRC since implementation of a single cash out price in November 2015. The graph below shows the sum of Total Residual Cash flow (TRC) for the period 5 November (commencement of single cash out) to 14 February (data as of March 2016) inclusive of these dates for the five financial years. The data suggests that the RCRC value is diminishing.

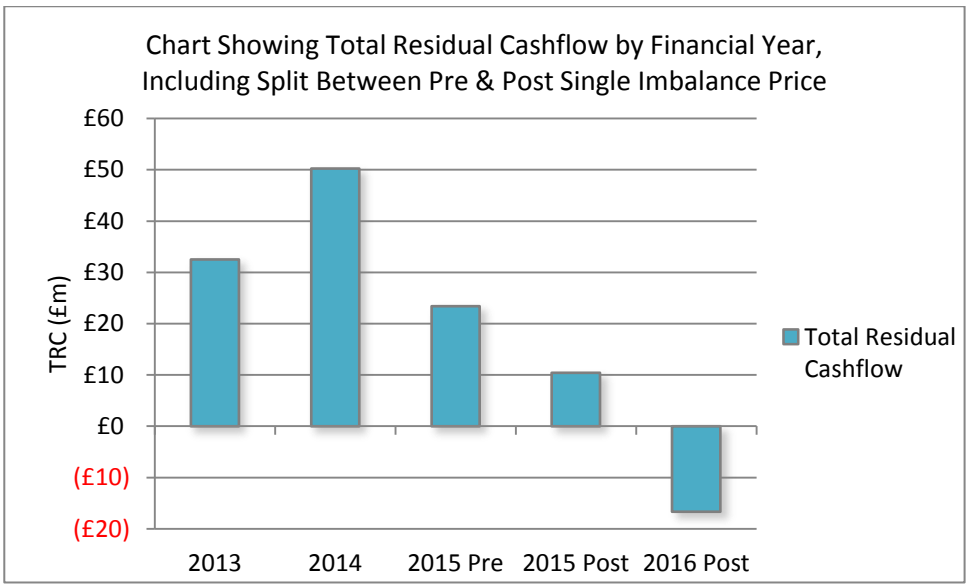


Figure 9: Total residual cash flow (TRC)

2.76 Figure 9 above excludes the month of October for all years so that the data is more comparable. At the time of writing there is very little settlement data for October 2016 as the data was taken at the start of November.

2.77 On the basis of the above information, the Workgroup agreed to leave RCRC calculations unchanged.

Impact of demand forecasting and unforeseen costs on future cash flow risk

2.78 Workgroup members noted that the cash flow analysis was conducted over a period when National Grid's demand forecasting had yet to take account of significant new market developments relating to embedded generation. This had the effect of exacerbating the under-recoveries in the analysis. Workgroup members were therefore interested in the effect improved demand forecasting could have on BSUoS cash flow exposures.

2.79 Whilst improvements are being made to demand forecasting modelling, demand forecasting (particularly for BSUoS applicable volume net of embedded generation) for the year ahead, 12-18 or 12-24 months ahead, can still be very difficult given a host of unknowns. Using solar PV as an example the SO and the market would have struggled to predict an ~2.5GW rush to solar PV in Q1 '15 prior to the government closing the >5MW Renewable Obligation scheme early. The DECC consultation announcement was made 13th May 2014 which would have been post BSUoS forecast for summer 2015.

2.80 There is also still a large portion of demand forecasting that is weather dependent, both in terms of temperature deviations and embedded renewable generation. Whilst better demand forecasting may improve the annual BSUoS forecast it does not improve the volatility in underlying half hourly demand movements resulting from swings in intermittent renewable generation. Therefore, even with a perfect annual demand forecast, large cost variations can still arise.

2.81 Further, during 2016/17 the SO has announced additional significant costs that will feed into BSUoS that were not foreseen at the beginning of the charging year. These relate to Black Start and SBR/DSBR costs and amount to a further 20% of total BSUoS costs. Clearly this has a huge impact on market participants, and in a fixed price BSUoS regime, these sums would be recovered in a following fixed price period, and provision would need to made for the cash flow costs.

2.82 Presented below is an illustration of the impact on market participants following a change in cost similar in magnitude to that seen with the Income Adjusting Event (IAE).

Ofgem has determined that an additional £113m can be recouped by National Grid as part of the IAE related to Black Start procurement[2]. This suggests a price impact of approximately £0.20/MWh (assuming a BSUoS charging base of 563TWh). The significance of a £0.20/MWh cost shock to market participants can be deduced by comparing this to the likely gross margin on power sales. From a generation perspective, current Clean Spark Spreads (CSSs) are published and are indicative of the gross margin that can be achieved by a CCGT. CSSs for different wholesale electricity products (forward seasonal products have been chosen as these tend to be relatively liquid) are shown below alongside the percentage that would be lost following a cost shock of £0.20/MWh.

[2] It is also worth mentioning that there was a high degree of uncertainty on what the final value of this would be, potentially being anything from £0 to £113m

CSS Product	CSS (spreads reported on 18 August 2016)	Percentage of margin lost following BSUoS cost shock
Winter 16	£8.78/MWh	2%
Summer 17	£4.56/MWh	4%
Winter 17	£4.82/MWh	4%
Summer 18	£2.06/MWh	10%
Winter 18	£2.15/MWh	9%
Summer 19	£0.56/MWh	36%

Table 10: BSUoS cost increase as percentage of gas generator gross margin

2.83 In addition, the CSS for summer 2016 was £3.89/MWh 1 year ahead i.e. August 2015 which indicates a percentage of lost margin equal to 5%.

2.84 Table 10 above illustrates that the greater the risk a cost shock is relative to the achieved gross margin, the more likely it will deter parties from trading in the market. This is likely to either have a dampening effect on wholesale market liquidity and/or require generators to demand a risk premium when selling power to protect themselves against the risk.

2.85 The impact of supplier EBITDA margins is also significant, probably more so. Using the Big Six Consolidated Segmental Accounts (2015)[3], average Big Six EBITDA margins can be calculated for both domestic and non-domestic retail supply. These EBITDA margins are illustrated below in Table 11:

Supply segment	Average Big Six EBITDA margin 2015	Percentage of margin lost following BSUoS cost shock
Domestic	£1.60/MWh	12.5%
Non-domestic	£0.90/MWh	22%

Table 11:BSUoS cost increase as percentage of retail EBITDA margin

Risk Premia

2.86 The Workgroup recognised that one of the key pieces of evidence for the success of the modification proposal would be establishing whether the costs associated with the existing regime were higher or lower than the proposed arrangement, and whether GB consumers would benefit overall. To this extent the Workgroup noted the difficulty in finding robust quantitative evidence for the risk premia currently attributed to BSUoS prices and suggested that this issue should be one of the questions in the Workgroup Consultation Report, and perhaps the subject of a separate Ofgem consultation, given the commercially sensitive nature of this information.

2.87 The modification proposal is clear that all balancing costs are reconciled. It is only the timing element of that reconciliation that changes. Presently, System Operator costs of balancing the system are reconciled ex post within 28 days of those costs being incurred, with a final reconciliation d+14 months when the majority of metering data and any Income Adjusting Events are known.

2.88 The proposal seeks to fix the BSUoS price ex ante thereby transferring cash flow risk from market participants to the System Operator. Cash flow risk is the money required to continue to function as an operating concern, the working capital. In other words, if the

[3] https://www.ofgem.gov.uk/system/files/docs/2016/07/energy_companies_consolidated_segmental_statements_css_july2016.pdf

BSUoS price is set too low, the System Operator would be required to borrow money to continue to procure services to balance the system, and if it is set too high, the System Operator will be in receipt of a considerable financial surplus. The challenge therefore is how to make available the cash to balance the system at least cost, and to optimise that level so that only an efficient amount of cash is required.

2.89 Industry participants made the point that for them there was real profit and loss at stake in the event their risk margins were set incorrectly, whereas moving to an ex ante regime and centralising the risk would just be a cash flow timing issue for the entity taking the risk. The National Grid representative later confirmed that although there was an assumption that the capital would be returned at a later date through the an under/over recovery mechanism this would only be risk free if the costs of funding that cash flow were also recovered by the entity in question.

2.90 The Workgroup attempted to quantify the absolute level of risk to which market participants are potentially exposed. One Group member noted that the risk margin is the price which market participants would be prepared to pay in order to have certainty over the BSUoS price.

2.91 It was noted that there were two risk components resulting from volatile BSUoS prices:

(i) The contractual risk faced by Suppliers; and

(ii) The wholesale risk faced by Generators

2.92 The Workgroup noted the difficulty in estimating and even discussing the risk premia applied by market participants given the commercially sensitive nature of the information. It was also noted that risk premia would be a function of a given company's risk appetite, and market competitiveness.

2.93 The Workgroup discussed at great length how the risk premia might be valued. A couple of different approaches are discussed below, though they lean on significant assumptions.

2.94 The Workgroup discussed how BSUoS price risk was different to other types of risk such as credit risk and volume risk. One key difference noted is that most types of risk can be hedged, but that is not possible with ex post BSUoS. It was also suggested that BSUoS price risk might have a diversification effect but the Group considered that BSUoS risk is not a diversifier.

2.95 The Workgroup discussed the extent to which competition might limit the application of risk premiums. The Group considered that the risk premium would be reflected in the market price, and since most Workgroup Members believe that no party had a competitive advantage in forecasting BSUoS, in theory all market participants should broadly have similar risk margins. It was noted that the lengthening tail of the most recent distribution curves in Figure 4 means that some small parties may not be able to transact because this risk is too large, and therefore may constitute a barrier to entry.

National Grid BSUoS forecast and supplier risk premium

2.96 The following graph shows the National Grid Year Ahead BSUoS Price Forecast versus actual outturn as of the end of March 2017.

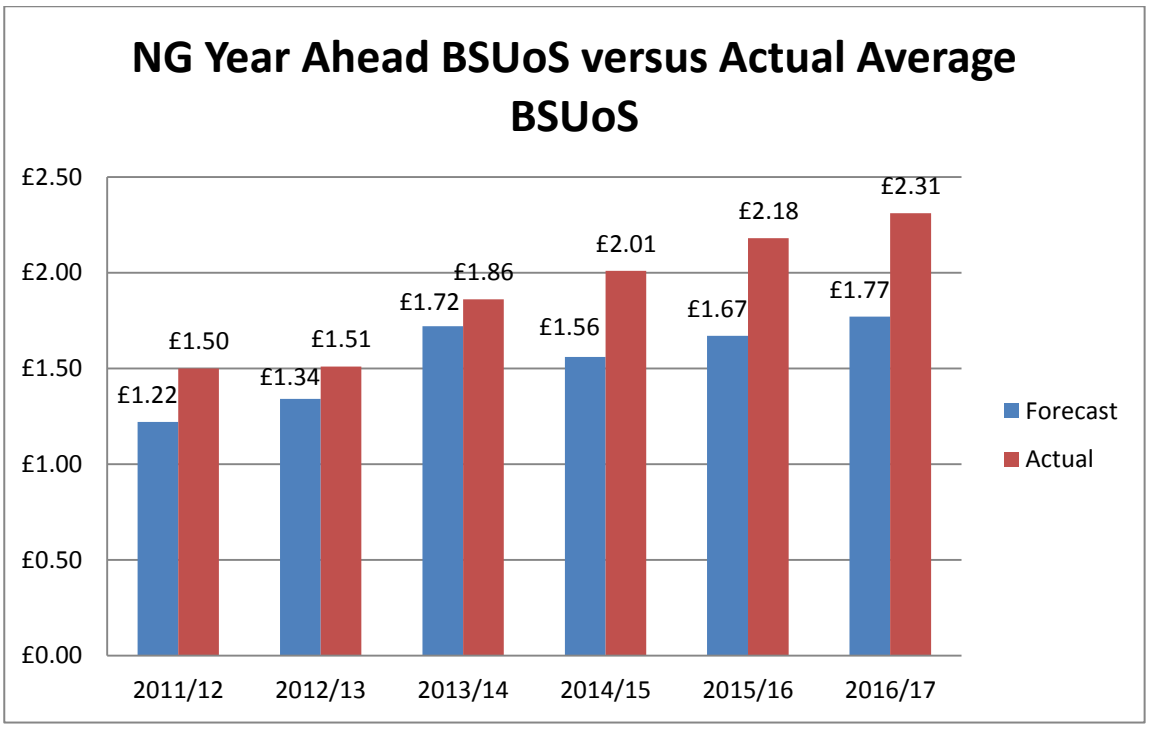


Figure 10: NG Year Ahead BSUoS Price Forecast v Actuals

2.97 Figure 10 shows that over recent years National Grid has tended to under-forecast the annual average BSUoS price, and if Suppliers are using the National Grid forecast without applying a risk margin, they are potentially exposed. The Workgroup discussed the degree to which the National Grid forecast was used, and it was argued that larger companies are perhaps more able to take their own view of BSUoS prices, whereas smaller participants are more likely to take the National Grid forecast at face value.

2.98 In an attempt to quantify the value of the "appropriate" risk margin that Suppliers should have applied if they had used the National Grid forecast and had perfect hindsight, then one could take the average difference between forecast and actuals over the period 2011/12 and 2014/15 which equates to £0.25/MWh. If multiplied by the demand base of approximately 300TWh, then the value of the Supplier risk premium is approximately £75m per annum. The Workgroup discussed the merits of this approach to quantifying the costs to consumers of ex post BSUoS pricing.

2.99 The Workgroup discussed whether it was appropriate to use 300TWh, as large customers are likely to have pass-through contracts with their Suppliers. It was however noted that large consumers would still need to manage this risk themselves. If one was to exclude broadly 100TWh of large industrial consumption, the value of the "appropriate" risk premium would be approximately £50m pa.

Generation and Supply BSUoS risk premium analysis

2.100 The following section sets out a method of quantifying the BSUoS risk premium that was undertaken in early 2016.

2.101 The Proposer explained what the BSUoS risk premium is and how it arises. Generators and suppliers do not know what the price of BSUoS will be in any half hour Settlement Period (SP) until after the event. National Grid provides a forecast of the mean average annual BSUoS charge ahead of time. However the price of BSUoS in any SP can deviate greatly from this average. If a generator or supplier assumes that it will be charged the average annual BSUoS cost when selling, there is a risk that the generator or supplier will face a higher cost where the BSUoS price outturns higher than the average. This is

particularly the case where a generator or supplier does not produce or 'consume' all year round.

2.102 To mitigate against this risk of higher than average BSUoS costs, a generator or supplier will add a risk premium to the price it is willing to sell into the market. This is particularly important to market participants with low profit margins (likely the marginal 'price setting' producers) as only a small increase in BSUoS prices above the average can wipe out any profit assumed and even result in a party incurring losses.

Calculating the BSUoS risk premium

2.103 The Proposer suggested that a statistic method could be employed to quantity the size of the BSUoS risk premium. This statistic method is explained below.

2.104 Firstly, distributions of outturn half hourly (HH) BSUoS prices for financial years 2011/12 to 2015/16 (noting 2015/16 is not yet complete) were established. To create these distributions, HH BSUoS data was obtained from the National Grid Website[4]. BSUoS Distributions were created for different trading periods within the five financial years. The following trading periods have been used to develop BSUoS distributions:

- Peak - 0700-1900, all week
- Extended Peak – 0700-2300, all week
- Block 5 – 1500-1900, all week
- Baseload – 2300-2300, all week

2.105 This means that BSUoS prices in settlement periods outside the trading period are not included in the specific BSUoS distribution. For example, a Peak BSUoS distribution does not contain HH BSUoS prices set between 1900-0700. These BSUoS Distributions were created by a software package. Two graphical examples of the BSUoS distributions are provided under (i) and (ii) of Annex 8 of this document.

2.106 With these BSUoS price distributions, different probabilistic values can be deduced to reflect different risk appetites (P numbers). For example P50 reflects the cost assumption that would need to be made to ensure that the market participant does not make a loss in 50% of applicable SPs, P60 relates to 60% of applicable SPs and so forth. P numbers are produced for risk mitigation strategies ranging from P10 (reflecting a very aggressive risk appetite) and P100 (reflecting a very conservative risk appetite).

2.107 So for example, if a generator selling peak electricity in 2014/15 wanted to ensure that it avoided the risk of losses in 70% of the trading period, it would need to assume a BSUoS cost of £1.96/MWh and price its power accordingly. All P values for different trading periods and financial years are presented in the tables under (iii) within Annex 8 of this document

2.108 Clearly a limitation with this approach is that it is backward looking, focussing on actual outturn BSUoS values. A market participant would not have foresight of these values when making pricing decisions on its trades ahead of delivery. But for the purposes of the analysis it gives an indication of the risk facing market participants and quantifies the costs that should be assumed to mitigate risk to varying degrees depending on individual risk appetite.

[4] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Historic-BSUoS-data/

Comparing P BSUoS Distribution Values with actual outturn average BSUoS values

2.109 The P values are then compared with the average outturn BSUoS for the relevant trading period. This shows the discount or premium that a market participant would need to apply to the outturn BSUoS average to adopt any of the P value risk mitigation approaches. So for example if a generator selling peak electricity in 2014/15 wanted to ensure that it avoided the risk of losses in 70% (P70) of the trading period, it would apply a premium of £0.21/MWh to the outturn average BSUoS in the peak trading period (£1.96/MWh minus £1.75/MWh).

2.110 The BSUoS discounts or premiums to outturn BSUoS values are presented in the tables under (iv) within Annex 8, along with the outturn BSUoS averages for the relevant trading periods under (v).

Estimating the impact of the BSUoS risk premium on total system costs

2.111 Finally, an attempt is made to determine the costs (or benefits) to the total system in terms of BSUoS cost over (or under) recovery associated with pursuing different risk strategies. Firstly, for the purpose of the analysis, it is assumed that there is a uniform approach to risk mitigation across the market. This is unlikely to be the case, but to assume a heterogeneous approach to risk appetite would be overly complicated to model/analyse.

2.112 Secondly, to estimate how these risk premia could impact the costs to the system and thus costs to the end consumer, we need to make assumptions on what generation and supply volumes these risk premia are likely to be applied to. As noted above, risk premia is more likely to be applied by those market participants operating on small profit margins and as such is an important determinant of the likely generation and supply volumes that will have a risk premium applied.

Generation output

2.113 In terms of the generation volume, while there is some variation in the profit margins being made by different technologies, with some having higher profit margins than others[5], it is the marginal source of production that determines the wholesale power price. As the 'marginal generator' is highly likely to be earning very slim profit margins (and this is borne out from historical experience), it is likely that it will apply a BSUoS risk premium. This will drive up the wholesale power price which will be received by all (or at least the vast majority) of generators. Therefore we assume that while certain generators can be classified as 'price takers' and therefore do not necessarily apply a risk premium themselves, as the marginal generator is likely to apply a risk premium this means the total generation volume will have a BSUoS risk premium attached to it.

2.114 However, we should also note that as power is transacted in multiple timescales in the wholesale market (for example thermal plant is likely to sell a large proportion of its output in the forward market, whereas this is less the case for wind plant) it may not be the case that all generation volume is subject to a BSUoS risk premium. Therefore, the assumption that all generation volume is subject to a risk premium will represent the upper limit on the volume that may be impacted. However, as the vast majority of power is sold ahead of delivery we expect that a large proportion of generation volume will be subject to a BSUoS risk premium.

[5] For example nuclear plant has higher gross profit margins than gas plant.

Supply volume

2.115 In terms of supply volume, as all suppliers are operating on small profit margins (at least relative to the potential variation in BSUoS costs), we expect that all supply volume will have a risk premium attached. However, the exception to this is that some customers have BSUoS cost pass through arrangements in their contracts (likely to be I&C Flex customers and Extra High Voltage Customers). As such we have not assumed that a risk premium is applied by suppliers to the volume consumed by these customers. We estimate this volume is approximately 60TWh.

2.116 However, it is important to note that whilst suppliers will not be applying a risk premium to I&C Flex and Extra High Voltage Customer volumes, these customers will still be exposed to the risk of BSUoS cost variation above the annual mean average. Therefore we expect that a risk premium is likely to be applied to the products and services these companies provide to their respective markets. In summary there is still likely to be a cost impact to the wider economy.

2.117 For the reasons given above we estimate that the following energy volumes will have a risk premium (or discount) attached to them.

	2011/12	2012/13	2013/14	2014/15	2015/16
Applicable Volume (TWh)	655	662	637	623	600

Table 12: Energy volumes to apply BSUoS risk premiums or discounts

2.118 Moreover, for trading periods (apart from Baseload) we only apply premiums and discounts to a proportion of the total energy volumes. These proportions are set out in the Table 11 below.

	Volume proportion
Peak	0.50
Extended Peak	0.67
Block 5	0.17
Baseload	1.00

Table 13: proportion of total energy volumes

2.119 To calculate the total system cost (or benefit), one should multiply the discount or premium to outturn BSUoS by the applicable volume multiplied by the trading volume proportion. So for example, if market participants adopted a risk mitigation strategy to ensure that they avoided BSUoS losses 70% of time (P70) in the peak trading period 2014/15, this would result in the market over recovering £67m from consumers (£0.21/MWh multiplied by 623/TWh multiplied by 0.5 (reflecting that the peak trading period covers half of the total financial year)). All the total system cost results are set out in the tables under (vi) within Annex 8 of this document.

Conclusions

2.120 The analysis suggests that if a market participant wished to ensure that in half of all periods (P50) it would not be exposed to losses associated with BSUoS, it would need to assume a BSUoS cost at a discount to the outturn average BSUoS of between £0.10/MWh and £0.36/MWh depending on the financial year and trading period. This could result in the market under recovering BSUoS from customers by between £74m and £224m. This indicates that a market participant is likely to price BSUoS to ensure that BSUoS loss making transactions are restricted to less than 50% of settlement periods.

2.121 For market participants to reduce their risk appetite by 20 percentage points (P70 – ensure that 70% of the time there would be no losses made attributable to BSUoS volatility), the premium above the average BSUoS outturn would need to increase to somewhere between £0.13/MWh and £0.42/MWh. Applying this risk mitigation strategy would result in an over recovery of BSUoS costs from consumers of somewhere between £81m and £201m.

2.122 The analysis above and the National Grid analysis (in 2.99 of the Report) show the estimated financial magnitude of under and over recoveries of BSUoS with perfect hindsight. It is likely that market participants and National Grid would either over or under recover BSUoS costs whichever takes on this risk. The data produced by both these pieces of analysis appear to be broadly consistent in terms of the value that could be expected to be over-recovered from consumers.

2.123 Importantly, in the long run over recovery is more likely to occur where the risk is placed on market participants rather than National Grid (under a CMP250 solution). This is because consistent under recovery is not financially sustainable in a liberalised market. Moreover, the view that over recovery is more likely than under recovery is consistent with the concept of loss aversion. There is a risk of a party foregoing opportunity if it over estimates BSUoS and there is a risk that a party will make a loss if it under estimates BSUoS. However, much of the academic literature suggests that losses are more powerful psychologically relative to gains.

2.124 Additionally, there is a general expectation that BSUoS will rise in future years, potentially doubling to £2bn in the next five years. There is a strong possibility that BSUoS will remain volatile and increase with large step changes as seen with this year's IAE costs. A market participant is likely to be biased towards a more risk averse than less risk averse strategy in this situation. However, if it were the case that BSUoS was expected to fall significantly, the contrary would probably apply i.e. a less risk averse strategy to forecasting BSUoS would be favourable.

2.125 Crucially though, under the current method of recovering BSUoS costs there is not a mechanism to recoup BSUoS under or over recoveries. This can weaken competition or result in consumers paying more or less than is necessary for balancing services.

2.126 However, the proposed CMP250 solution would provide a mechanism to ensure that any under or over recoveries of BSUoS are recouped in future years. This may be better for competition and may ensure that consumers pay no more than necessary for balancing services.

2.127 Moreover, while National Grid will incur a cost in managing the financial implications of BSUoS under recovery, market participants will similarly face a cost of under recovering BSUoS. This opportunity cost is accompanied by the risk of market exit. As the WACC for the industry will be higher than that for National Grid, the cost of managing over recovery is likely to lower under CMP250 than the current baseline, however, National Grid's existing WACC does not factor in the additional cash flow risk associated with this modification.

2.128 The Workgroup asked the industry for their thoughts on the methodology and calculation of possible industry risk premia as a result of ex post BSUoS and whether they were able

to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers in question 12 of the Workgroup Consultation document.

2.129 Of the sixteen responses received to the Workgroup Consultation four were unable to provide any comments to this question.

2.130 The Workgroup acknowledged these responses and in particular discussed the response from Engie that the assessment of BSUoS risk premiums without the additional consideration of RCRC does not fully cover the perceived risk exposure faced by the industry. The Workgroup considered that the single cash out price would have the effect of reducing the value of RCRC. As such it did not believe that further assessment explicitly including RCRC would materially impact the conclusions reached by the Workgroup.

2.131 The Workgroup asked the industry if their business used the National Grid BSUoS forecast as an input into trading costs either in isolation or in combination with other factors in question 13 of the Workgroup Consultation document.

2.132 Of the sixteen responses received to the Workgroup Consultation ten confirmed that they did use the National Grid forecast as an input into their forecasting processes. Two respondents did not provide any comments and four confirmed that they did not use the forecast. The Workgroup acknowledged these responses.

2.133 Following on from question 13 of the Workgroup Consultation, The Workgroup asked the industry if applicable, if they were able to share their approach to calculating risk premia in question 14 of the Workgroup Consultation.

2.134 Of the sixteen responses received to the Workgroup Consultation no respondent felt it appropriate to comment on this question. The Workgroup acknowledged this. In light of the difficulties in estimating existing risk premia, and the Ofgem decision on CMP244, one Workgroup member considered that it might be possible to develop an approach where market participants are given the choice to fix their BSUoS price ex ante in return for a SO management fee, or whether to remain on the existing ex post variable methodology. The relevant paragraph regarding risk premia from Ofgem's CMP244 decision is shown below:

2.135 **"Supplier risk premium:** The key advantage put forward for CMP244 is that it would reduce the risk premiums that suppliers add to their electricity prices for non-domestic, fixed-price, fixed-term contracts, and this would result in lower costs to non-domestic customers with these types of contracts. The Workgroup explored various approaches to quantifying this benefit in terms of an overall reduction of risk premiums. **However, industry was unable to provide the necessary data to the Workgroup due to its commercially sensitive nature**, and therefore, the Workgroup could only discuss this benefit qualitatively. The Workgroup put forward the possibility of Ofgem holding a data gathering exercise on supplier risk premiums instead. We carefully considered the pros and cons of undertaking such an exercise. The Workgroup had acknowledged that this would not provide full information as to what TNUoS-related risk premiums all industry participants charge, due to different parties' view of risk and their different ways of contracting. We understand that suppliers have different approaches to applying TNUoS-specific risk premiums to their prices, making it hard to quantify these and produce comparable data. Therefore, we do not believe that such an exercise would have provided us with any better information that that already provided by the Workgroup."

2.136 Whilst the CMP250 Workgroup has provided quantitative evidence of the value of the risk premium, they have also noted that Ofgem is better able to take account of confidential evidence in its decision making process where this is presented in writing to them. The Workgroup have discussed the best route to submit confidential evidence to Ofgem and concluded that this would be requested during the Code Administration Consultation phase of the process.

Future Consideration of BSUoS

2.137 The National Grid representative recognised that there may be potential value to consumers in fixing elements of the cost of BSUoS but did not consider a fully fixed product to be appropriate as ensuring that an appropriate price signal is given to the market for those elements that remain variable would promote smarter more flexible markets. The National Grid representative stated that they consider there should be a focused industry debate, either alongside or within Ofgem's charging review, to deliver changes within the next price control (RIIO T-2) when full considerations of the costs and operation of a product along the lines of the above can take place and should not be considered solely within a CUSC modification.

2.138 The National Grid representative explained that he would expect that this work would take place in the lead up to the next price control beginning in 2021 and informed the Workgroup that prior to this the System Operator is developing a work package to improve BSUoS charge forecasting and provide increased transparency around the balancing actions that are taken – this will be delivered over the remainder of 2017 and into 2018. This will include:

- Improvements to the current monthly average BSUoS forecast process and then further work to develop the tools required to provide a more granular forecast, along with all assumptions feeding into it.
- Trading activity will be published at near real time, including volumes
- Publication of a daily and monthly summary of balancing costs and volume, with a high level summary of system conditions
- We plan to create a separate BSUoS forecast report with scenarios and a range to the forecast, with explanation for the drivers. We will also provide explanation of any significant divergence between outturn and forecast
- We plan to make all underlying data available in excel format, from the Monthly Balancing Services Statement (MBSS), and market information reports for tendered ancillary services
- The MBSS and demand side balancing report will be combined into one report

2.139 The Proposer noted the National Grid view but disagreed with the National Grid view that CMP250 should not be implemented for the following reasons:

- It is uncertain what form a price signal could take. No assessment of such a proposal has been made so there is no way to judge the efficacy of such an option. It is particularly unclear whether it would represent a solution to the identified defect. Moreover, the recovery of Balancing Services costs and the promotion of flexible markets are not the same thing. The promotion of flexible markets will involve changes to incentivise CAPEX in new technologies and retrofitting of existing assets. This goes way beyond recovering costs incurred in the most effective manner.
- Further delay until RIIO T-2 would not allow the defect to be resolved in the timeliest manner especially if the SO will require a 12 month implementation period after decision.
- It is recognised that the CUSC process on its own is insufficient to implement the proposed solution but if the change is beneficial there should not be any reason to prevent the complementary changes being made i.e. changes to the Transmission Licence
- The proposal to improve National Grid's BSUoS forecasting is unproven and is not an alternative to CMP250. It should be undertaken regardless. Moreover, the initial work on improving transparency appears to be deficient e.g. no commitment made to identify BMUs repositioned under 7A Trades.

- These views were supported by all Workgroup members with the exception of National Grid.

Alternative approaches to managing BSUoS price risk

2.140 The Workgroup discussed where the cost of BSUoS price risk currently sits today and the following diagram illustrates how risk premia are effectively passed through to consumers.

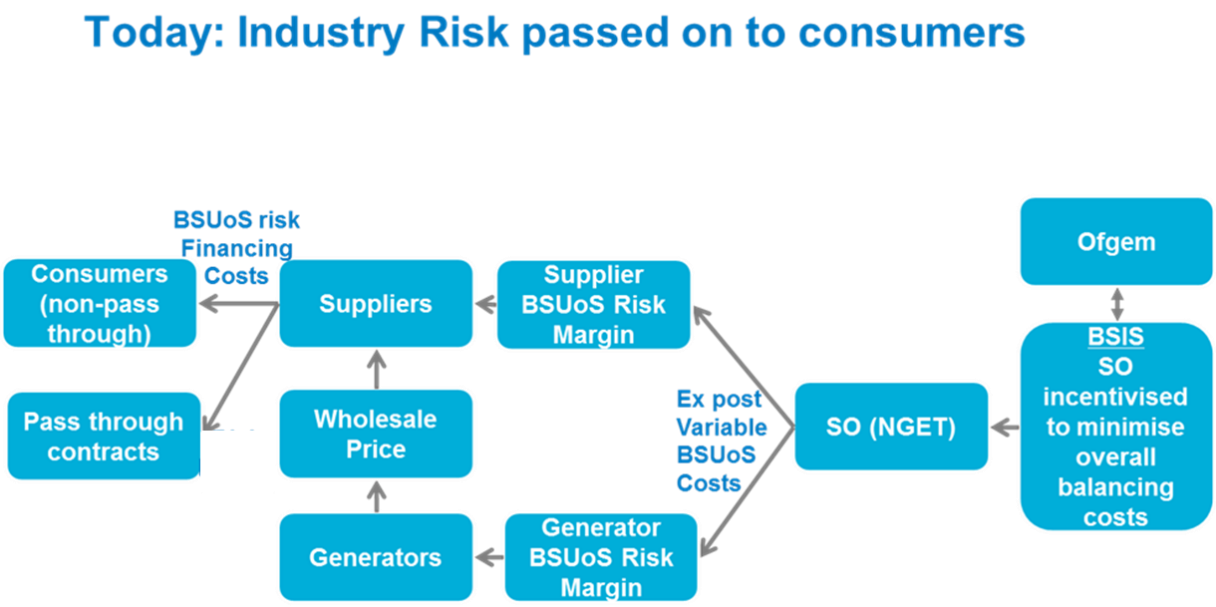


Figure 11: How risk premia is passed through to customers - today

2.141 The Workgroup discussed a number of scenarios describing how different entities could best manage the costs of the risk and the following scenarios were identified:

1 Transmission System Operator (the Original proposal)
2 Independent System Operator
3 Industry Consortium
4 All Transmission Owners

2.142 These options are described in the following flow charts for background information, though it is only the Original proposal (Scenario 1) that is currently being taken forward and forms the basis of CMP250.

2.143 If the move to an ex ante pricing mechanism requires finance to be provided (e.g. for a stability fund) then that finance will result in a cost being incurred. This cost will need to be remunerated. Additionally, there is an option of adding incentive arrangements to ensure the overall financing costs are as efficient as possible and do not have any other adverse effect on the entity's business.

2.144 Scenario 1 considers the SO providing a fixed BSUoS price and NGET as the licensed entity financing the cash flow required to manage it:

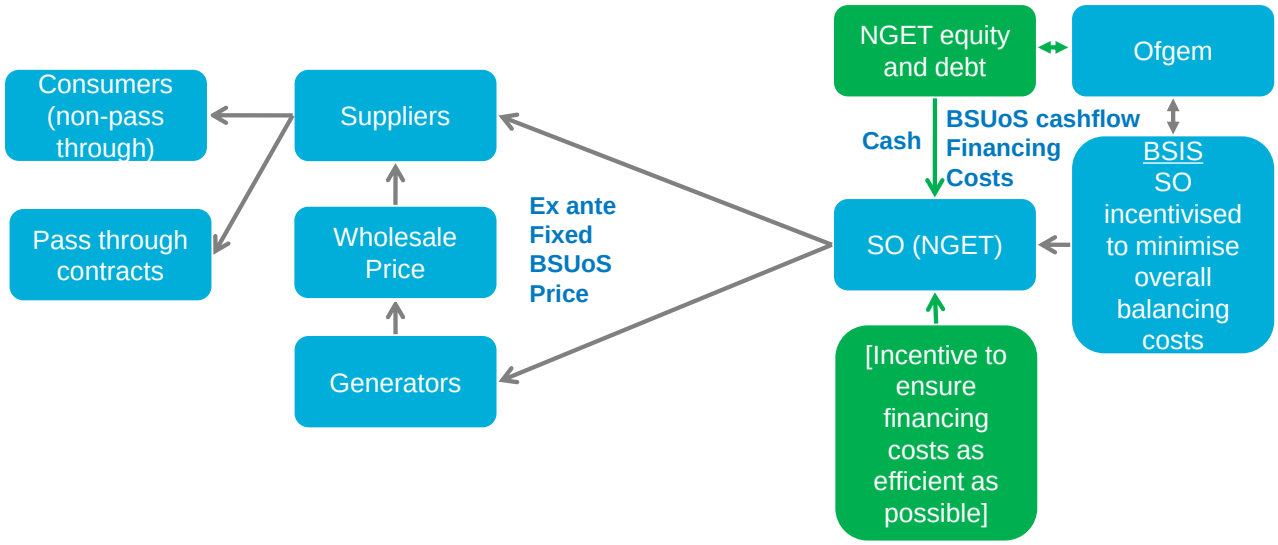


Figure 12: Scenario 1

2.145 The assumption in this scenario is that working capital financing is permitted under the NGET Transmission Licence.

2.146 Scenarios 2a and 2b contemplate the prospect of the SO managing the risk under separate Licence. These are relevant considerations given the ongoing industry discussions relating to the role of the System Operator. In Scenario 2a, equity (of ISO shareholders) and debt is used to finance the cash flow costs. The use of equity may be required to avoid excessive gearing.

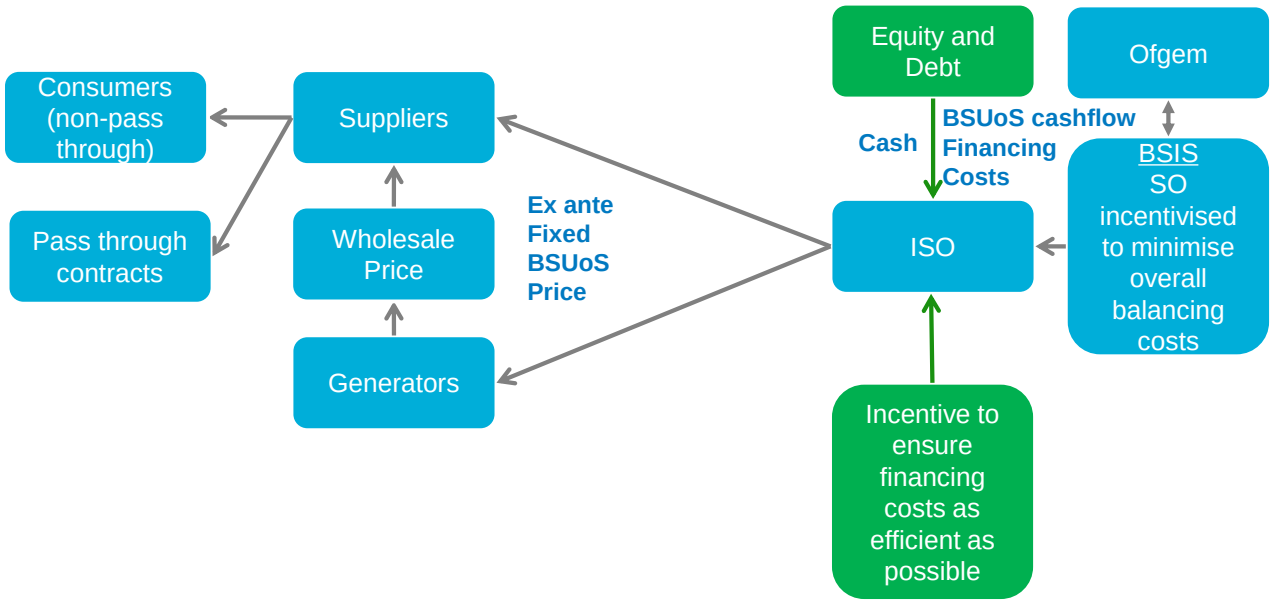


Figure 13: Scenario 2a

2.147 In Scenario 2b, the cash flow is only financed through debt. Given that an ISO would have next to no assets, the terms of any borrowing implications are unclear.

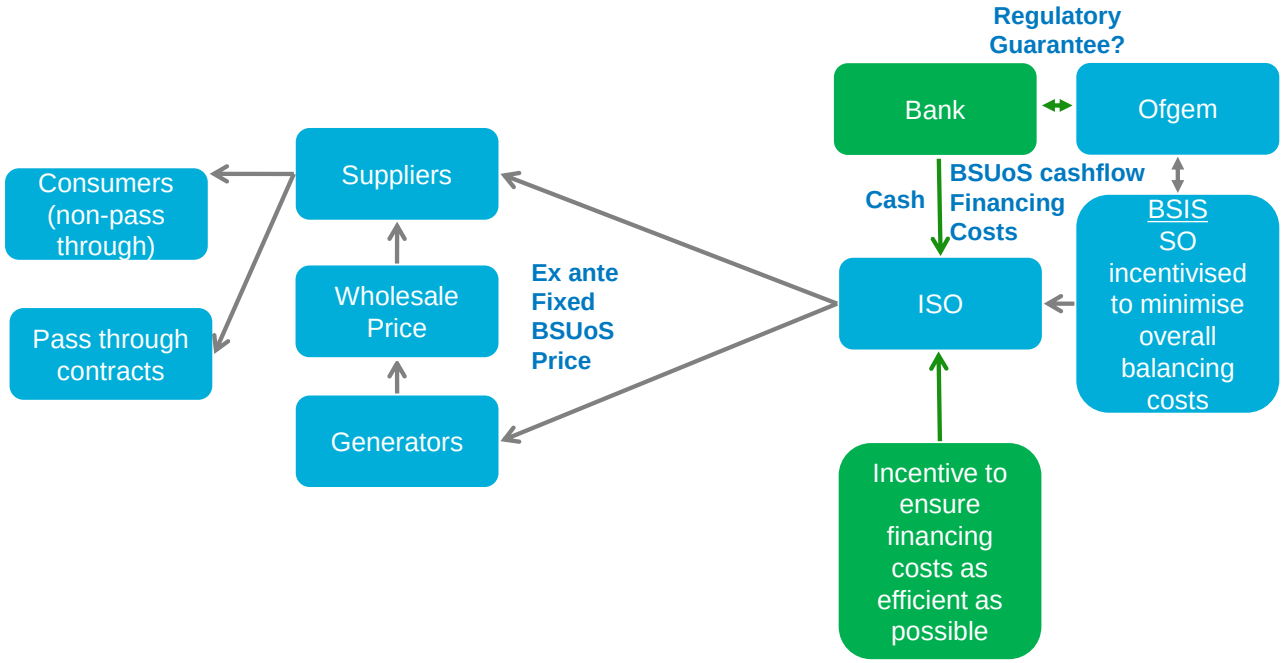


Figure 14: Scenario 2b

2.148 The Workgroup noted that "Regulatory Guarantee" means that the SO would be allowed to recover its costs i.e. a revenue guarantee rather than a financing guarantee.

2.149 Scenario 3 shows that market participants could form a consortium to put the finance in place to enable an ex ante BSUoS price:

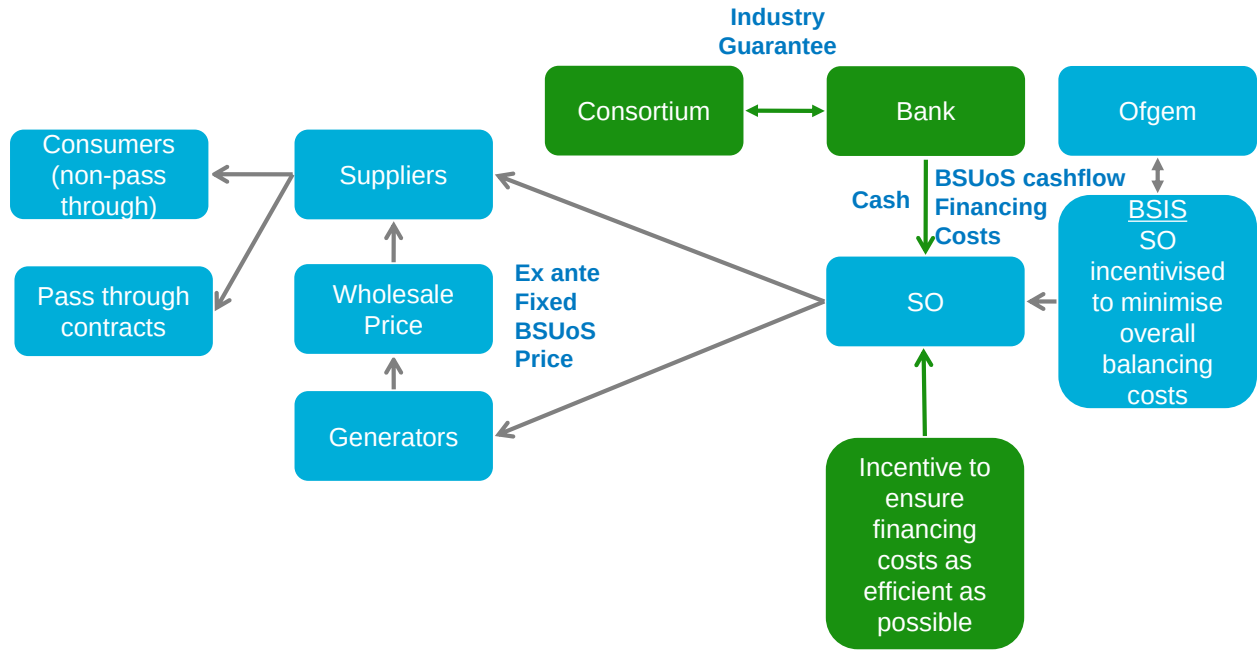


Figure 15: Scenario 3

2.150 Finally, Scenario 4 shows an option where all TOs collectively provide the financing. The rationale for this approach is that some Workgroup members considered that the entities with the lowest cost of capital should finance the cash flow risk as this represents the best deal for GB consumers. However, the cost of capital would have been different for these entities if this cash flow risk had been included, though as regulated entities, would still likely retain lower costs of capital than other market participants.

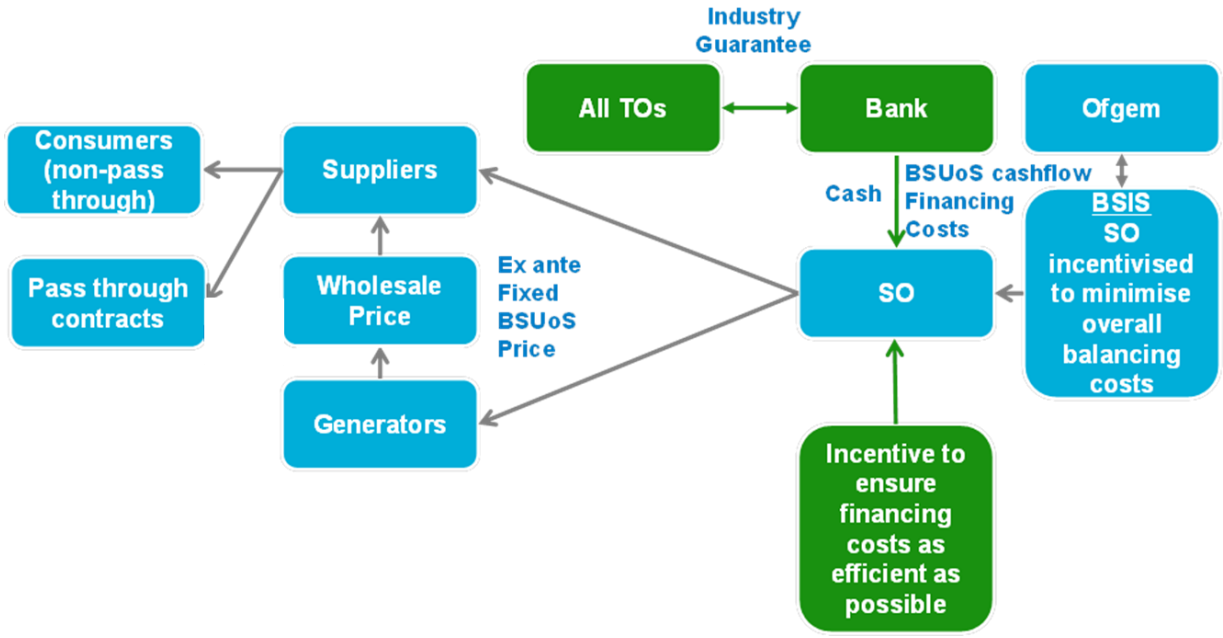


Figure 15: Scenario 4

2.151 Table 14 summarises the advantages and disadvantages of each entity financing the cash flow costs (not the advantages and disadvantages of an ex ante BSUoS price managed by the SO). These scenarios do not assess the full impact on the relevant licensee's business - for example any increase to the entities perceived risk profile.

Risk Owner	Scenario	Pros	Cons
Today		• No Funding issue for National Grid	• Market participants applying risk premia to manage unknown BSUoS costs ahead of time. • Consumers exposed to market participant cost of capital of between 8.2% and 11.5% according to the CMA – See Annex 5 (NGET nominal WACC is 7.5%)
National Grid as TSO (NGET Licence)	Scenario 1 - Financing costs (National Grid debt and equity) recovered though BSUoS	• Simplicity of one party financing the cash flow costs • Lower cost of capital	• Question around whether it is legal/ appropriate for the TSO to use its balance sheet to finance market participant costs.
ISO, still part of National Grid Group (but not NGET Licence)	2a – funded by National Grid debt and equity 2b – funded only by debt, backed by Regulatory	• Simplicity of one party financing the cash flow costs • ISO still has licence framework to recover costs • Potentially lower cost of capital due to regulatory	• SO doesn't own any assets therefore WACC potentially higher than for TSO.

	guarantee	guarantee/monopoly business	
Industry consortium	3 – Funded by debt, backed by industry guarantee	• Market participants continue to fund cash flow costs as today without the need to apply risk premia • Consortium borrowing rate lower than companies financing the cost individually	• Who owns the fund? Market share changes from year to year • More complex than one party doing it • Possible barrier to entry (further bureaucracy) • Administration costs • Higher cost of capital than regulated entity
TO consortium (including OFTOS, and Scottish TOs)	4 – Funded by TOs backed by an industry guarantee	• Consortium of TOs borrowing rate possibly lower than companies financing the cost individually	• TOs not financed for this purpose, therefore difficult to understand rationale for why they should finance this cost • National Grid TO would have the lion's share so why bother adding the complexity? • How would you divide contribution of shares (by RAV?) • More complex than one party doing it

Table 14: Advantages and disadvantages of each scenario

2.152 The Workgroup asked the industry who should bear this risk and did they think the risk should remain with market participants, sit with National Grid, or was there another entity that should be considered in question 15 of the Workgroup Consultation document.

2.153 Of the sixteen responses received to the Workgroup Consultation, ten agreed that National Grid should bear this risk; two agreed that the responsibility rested with market participants and four respondents did not provide any comments.

2.154 The Workgroup acknowledged these responses

Working Capital Financing Costs

2.155 Regardless of which entity is best placed to finance the cash flow to enable a universally applied fixed BSUoS price, there remains the issue of calculating how much this would cost, and how those costs are recovered. From National Grid's perspective broadly there are two options: on balance sheet options, and off balance sheet options

On National Grid Balance Sheet Options	Off National Grid Balance Sheet Options
Scenario 1: NGET Finance with equity and debt	Scenario 3: Debt Only Special Purpose Vehicle (SPV) – Loan facility
Scenario 2: Industry Finance by providing security up front	Scenario 4: Debt Only Special Purpose Vehicle (SPV) – Rolling credit facility
	Scenario 5: Partially capitalised SPV

Table 15: On National Grid balance sheet and off National Grid balance sheet options.

2.156 These options are described below:

1 In Option 1 NGET would finance the cost on balance sheet using equity and debt. The cost would be the maximum borrowing requirement * Rate of Return. It may also be appropriate to build in a within year incentive to ensure the principal sum is invested as efficiently as possible and a longer term incentive to ensure the principal sum is as small as possible. An alternative approach may be to estimate the cash flow cost and factor that into a future BSIS scheme. It is understood that Scenario 1 is the preferred financing approach in the Original Proposal.

2 In Option 2 NGET would finance the cost on balance sheet by first building up a surplus generated from a premium levied on each £/MWh until a sufficient credit has been built up to draw down when BSUoS costs are higher than the fixed price. The aim would be to target a surplus level so that NG shareholders' interests are not affected by the transfer of risk and there is no additional burden to the parent company's debt burden.

3 In Options 3, 4 and 5, SPVs are entities created for a specific, limited and normally temporary purpose. They are limited companies or partnerships to which debt is transferred. By transferring debt off balance sheet into an SPV, a company is able to isolate itself from any risk that the debt might pose. SPVs are often used in the securitisation of loans or other instruments. For example banks may issue a BSUoS backed security, the income from which is derived from repayments from a pool of market participants. The bank may wish to legally separate itself from the loans and does so by setting up an SPV and transferring the loans to it. This would allow BSUoS cash flow to be financed without affecting (NG) shareholders' interests or adding to the parent company's debt burden.

2.157 The Workgroup asked the industry their view on the above cash flow financing approach in question 16 of the Workgroup Consultation document.

2.158 Of the sixteen responses received to the Workgroup Consultation six respondents were unable to comment.

2.159 The Workgroup reviewed the remaining responses and acknowledged that two respondents had a preference for Option 1, one respondent preferred Option 2 and one respondent preferred Option 3. The National Grid representative stated that any eventual financing options would be discussed between National Grid and Ofgem as part of any licence changes.

2.160 Finally in question 17 of the Workgroup Consultation document, the Workgroup asked the industry their view what they would regard as good value to enable a fixed BSUoS. The Workgroup were interested in understanding how important fixing BSUoS was to each organisation. They also wanted to see how much would they would be willing to pay, if anything, in return for fixing BSUoS either 6 or 12 months in advance for a period of 12 months and if they were able to quantify this in £/MWh, i.e. a range of £0.06/MWh to £0.08/MWh for 6 months' notice, and £0.07/MWh to £0.09/MWh for 12 months' notice.

2.161 Of the sixteen responses received to the Workgroup Consultation four respondents were unable to comment and two did not agree with the premise of the question.

2.162 The Workgroup acknowledged all responses and noted that of those that did regard a fixed BSUoS as being good value, the majority of respondents expressed that they would be willing to pay a small proportion of the total BSUoS cost but did not wish to pay any more than £0.07/MWh. It was also acknowledged that the evidence within the Workgroup Consultation Report showed that the potential benefits of the modification outweighed the increase in costs that the industry may incur.

2.163 . The Workgroup noted that in the event CMP250 was approved, it understood the precise cash flow cost recovery was a matter for National Grid and Ofgem to agree. However, the Workgroup emphasised that the assumption is that any such costs should not exceed the lower end of the value of the existing annual risk premia, estimated in the analysis to be ~£80m, or about 8% of total BSUoS costs.

Recovery Mechanisms

2.164 It is anticipated that in a universal approach, any cash flow costs will be recovered through a flat £/MWh charge, or an adjustment made to the BSIS scheme or licence. Any under or over recoveries for the given fixed period would be rolled over into the next available fixed period, and the new fixed price would be adjusted accordingly.

Overall views on the Proposal

2.165 This section summarises the views of the Workgroup and the Industry that were provided after the Workgroup Consultation responses were received to the Standard Workgroup Consultation questions. The standard first four questions of the Workgroup Consultation request views on whether the proposal meets the applicable CUSC Objectives, if the implementation approach is supported and general comments including the requirement of any potential WACMs.

2.166 The responses to the question of whether the Original Proposal better facilitates the applicable CUSC Objectives revealed that eleven respondents did support the proposal and believed it did better meet Objective (a). The general view of these respondents was

they believed that the modification reduced uncertainty and unpredictability in the market thus benefiting competition.

2.167 Three respondents did not believe it better facilitated the CUSC Objectives and 1 respondent did not provide any comments to this question.

2.168 The Workgroup reviewed the responses and noted that three responses did not support the modification and did not believe that the proposal better met the Applicable CUSC Objectives. The Workgroup noted the respondents' reason being essentially that they believed the Proposal removed cost reflectivity by introducing a flat BSUoS value which could potentially remove the market signal for flexible generators thus reducing competition.

2.169 Whilst reviewing these responses, the Workgroup also noted wider initiatives taking place within the industry, in particular the work being initiated on Flexibility by Ofgem and the impact this may have on the implementation of this Proposal. The Workgroup expressed concern over the timings and as they did not want to introduce changes to the market that could need changing again in a short space of time. The Ofgem representative was able to confirm that the work on Flexibility was still within early stages of development and should not impact the progression of this proposal.

2.170 Since this discussion the National Grid representative highlighted that there has been significant progression on Flexibility as evidenced in Ofgem and BEIS' Smarter more flexible markets consultation[6] and National Grid's progression on their product strategy and simplification[7]. National Grid considered that it was not appropriate to make changes in this manner at this time. Please note the counter point to this view contained in para 2.140.

2.171 The Workgroup noted that responses had been received from different customer types and took this into consideration when reviewing all responses. This varied view allowed the Workgroup to assess the Proposal from different perspectives. One Workgroup member confirmed that feedback from their customers was that budget certainty over a longer term forecast was important to them and that this Proposal would support that. It was also noted by the Workgroup that there would also be a smaller proportion of customers that would have a preference for more dynamic pricing model and therefore do not require a long term forecast.

2.172 The Ofgem representative asked whether the Workgroup was going to consider the treatment of under and over recoveries in the report and it was agreed the principles on this area should be discussed. However, it was ultimately a matter for National Grid and Ofgem to agree financial arrangements.

2.173 The Workgroup reviewed the cost of implementing the modifications and recognised that additional FTEs would be required. Some Workgroup members believed that as the methodology already exists in current IT systems, no additional IT costs were envisaged. National Grid did not agree with this view. A shadow report would be required by the industry along with an extra line in the MBSS containing the shadow over/under recovery.

Post Workgroup Consultation Supporting Material

2.174 Another member commented that from a qualitative perspective it should be more efficient for this risk to be managed centrally and that financing costs should be cheaper for a

[6] https://www.ofgem.gov.uk/electricity/retail-market/market-review-and-reform/smarter-markets-programme/electricity-system-flexibility

[7] http://www2.nationalgrid.com/UK/Services/Balancing-services/Future-of-balancing-services/

solution backed with a regulatory settlement, which guaranteed that costs could be recovered in full, compared with the cost of capital of parties operating in the competitive market.

3 Workgroup Views

3.1 Following the Workgroup Consultation, the Workgroup reviewed the Original Proposal and five options as summarised in **Section 6** of this report. The Proposer confirmed that his Original would look to provide an option with a notice period was for 12 months and the fixed period for 12 months.

3.2 At the Workgroup meeting held 30 October 17, the Workgroup agreed to support four of these options which became Workgroup Alternative CUSC Modifications (WACMs).

3.3 The Workgroup voted against the Applicable CUSC Charging Objectives for the Original Proposal and four WACMs. The Workgroup voted and three Workgroup members concluded that the Original Proposal is the best option. Two Workgroup members believed that WACM3 is best. WACM 1 and the Baseline received one vote each. The Baseline was concluded to be the best option by the National Grid Representative. The Workgroup agreed that during the Code Administrator Consultation, the Industry should be encouraged to share how Generators and Suppliers account for BSUoS risk in their pricing as this would support the Authority in making their determination.

3.4 The Workgroup assessed the Proposal and WACMs against the Applicable CUSC Charging Objectives as shown below;

(a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

(b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);

(c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses*;

(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1; and

(e) Promoting efficiency in the implementation and administration of the CUSC arrangements.

*Objective (d) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).

Options for WACMs

Member	Option 1 12 months' notice 6 months fix	Option 2 15 months' notice 6 months fix	Option 3 15 months' notice 12 months fix	Option 4 11 months' notice 6 months fix	Option 5 9 months' notice 12 months fix
Supported by:	**Simon Vicary**	**Helen Inwood**	**Helen Inwood**	**Not supported by WG**	**Simon Vicary**
Jon Wisdom – National Grid	No	No	No		No
Cem Suleyman – Drax (Proposer)	Yes	Yes	Yes		Yes
Helen Inwood - npower	Yes	Yes	Yes		Yes
Garth Graham – SSE	Yes	No	No		Yes
Peter Bolitho - Waters Wye	Yes	Yes	Yes		Yes
Lee Taylor/Simon Lord – Engie – Not Present – no alternative					
Christopher Granby – Infinis – abstained from vote					
Paul Jones - Uniper	Yes	Yes	Yes		Yes
Simon Vicary - EDF	Yes	Yes	Yes		Yes
James Anderson – Scottish Power	Yes	Yes	Yes		Yes
Overall	7/8	6/8	6/8		7/8
Supported by Chair if applicable (yes / no)	n/a	n/a	n/a		n/a
WACM Reference	WACM1	WACM2	WACM3		WACM4

Vote 1 – ***does the original or WACM facilitate the objectives better than the Baseline?***

Workgroup Member	Better facilitates ACO (a)	Better facilitates ACO (b)?	Better facilitates ACO (c)?	Better facilitates ACO (d)?	Better facilitates ACO (e)?	Overall (Y/N)
Jon Wisdom – National Grid						
Original – 12/12	No	No	No	Neutral	Neutral	No
WACM1 12/6	No	No	No	Neutral	Neutral	No
WACM2 15/6	No	No	No	Neutral	Neutral	No
WACM3 15/12	No	No	No	Neutral	Neutral	No
WACM4 9/12	No	No	No	Neutral	Neutral	No
Voting Statement: Negative against (a), (b) and (c), neutral vs (d), and (e). (a) Although fixing BSUoS charges may give some relief to market participants of a volatile cost this does not appropriately recognise the transition to a more dynamic system and the price signal that BSUoS will provide for smarter more flexible markets. Therefore on balance a fully fixed BSUoS product does not better meet this objective at this time. Developing a BSUoS product ahead of the next SO price control which fixes those elements of BSUoS that form a residual cost and leaves variable those that provide a market signal is more suitable. (b) This objective is detrimentally impacted as the costs of BSUoS to market participants through the proposed charging methodology will not accurately reflect the costs incurred by National Grid. In addition costs incurred by the SO in particular settlement periods will not be passed through to those causing them. Finally, there is not a suitable mechanism within the current price control to allow for the recovery of costs and capital associated with the SO assuming this risk. (c) This objective is not better facilitated as the charging methodology, by fixing costs for a longer period, will not accurately reflect developments in balancing services and products and the costs of these to the market will not be accurately reflected in the immediate BSUoS price.						
Cem Suleyman – Drax						
Original – 12/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM1 12/6	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM2 15/6	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM3 15/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM4 9/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes
Voting Statement: The defect this modification seeks to address is that industry parties have no real certainty of their BSUoS costs when forward contracting their power. This is directly caused by the current BSUoS charging methodology alongside the substantial growth in renewables that produces a highly volatile and unpredictable cost. As a result, there is an increasing risk for market participants that their attempts to forecast the cost of BSUoS could be incorrect and could result in loss making and /or uncompetitive market activity. The unpredictability and volatility of BSUoS results in the application of risk premia in the market which will tend to inflate the costs borne by the end consumer. The analysis undertaken by the workgroup illustrates the cost of risk premia is likely to reside in the tens of millions of pounds						

far outweighing the costs of a central body managing the risk.

It should also be noted that BSUoS is a cost recovery mechanism and does not provide a useful market signal to market participants. In fact, BSUoS may be more likely to provide perverse signals to the market. This means that arguments suggesting that fixing the cost of BSUoS ahead of time will impact market efficiency have no substance.

The Original and all WACMs allow parties to know ahead of time what their BSUoS charge will be, and to reallocate this risk from those parties that are poorly placed to manage the risk, in particular smaller market participants, to a party that is more financially capable of dealing with it thereby better facilitating Applicable CUSC Charging Objective (a). Consequently, the total risk premium, and therefore total cost of BSUoS recovered from end consumers, will decrease, thereby increasing competition throughout the industry and benefiting consumers through lower costs and increased certainty surrounding their energy bills.

Helen Inwood - npower

Original – 12/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM1 12/6	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM2 15/6	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM3 15/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM4 9/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes

Voting Statement: I strongly believe that the original CMP250 proposal, and all WACMs, are better than the baseline. BSUoS is a volatile cost which is difficult for market participants to predict. Suppliers price 1, 2 or 3 years out and therefore need to use a forecast of BSUoS prices. For customers on non-pass through contracts (where BSUoS charges are built into the overall rate that the customer pays), suppliers will apply Risk Premia to cover for uncertainty in out-turn BSUoS costs. At a time of increased pressure to reduce costs going into customer bills, this modification has very clear benefits through the reduction in the need for suppliers to apply a risk premium for the period of the contract where prices are fixed. This will result in reduced costs to customers and prices will be more cost reflective of the actual BSUoS costs that will be incurred by suppliers. This modification also reduces the risk to customers on pass through contracts, providing with them with much more visibility and transparency of BSUoS costs for their own financial planning processes.

The original CMP250 proposal and WACMs facilitate better competition since it provides a more level playing field for suppliers to operate. CMP250 improves competition since it allows market participants to compete in areas where they should be competing on price (e.g. wholesale market hedging, cost to serve etc), and is not influenced by their ability (or inability) to forecast BSUoS prices which are outside of their control.

National Grid have all the information to be able to forecast BSUoS more accurately than market participants and are best placed to manage this. Under this modification, they will still receive the correct monies for BSUoS, adjusted for cash flow. They will therefore be financially neutral to these changes. It is simply spread over a longer period, with a 'k-factor' type adjustment similar to other regulated Network charges. This management of this within National Grid will be cheaper than the current baseline which is spread across many industry participants.

I have voted for WACM 3 as the best option since it gives the maximum notice / fixed period. These timescales also align with the DUoS publication timescales (implemented as a result of Ofgem's approval of DCP178).

Any of the options are better than the baseline and I would also support these alternatives.

Garth Graham – SSE						
Original – 12/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM1 12/6	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM2 15/6	No	Neutral	Neutral	Neutral	Neutral	No
WACM3 15/12	No	Neutral	Neutral	Neutral	Neutral	No
WACM4 9/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes

Voting Statement: The Original together with WACM1 and WACM4 better facilitate applicable objective (a) (and are neutral in terms of objectives (b)-(e)) as they facilitate effective competition in generation and supply by affording 9 months (WACM4) or 12 months (Original and WACM1) notice of the fixing of the level of BSUoS for a subsequent period of 12 months (Original and WACM4) or 6 months (WACM1) duration. This, when compared with the baseline, allows party to take this into account in their offering to purchasers of their products.

On the face of it WACM2 and WACM3 appear to have a similar characteristics. However, on balance, the additional notice period (of fifteen months) goes beyond the period where the costs elements can reasonably be forecasted / fixed without incurring an increase in risks that do not outweigh the cost impact for competition and consumers. Therefore these WACMs (2 and 3) do not better facilitate applicable objective (a) (and are neutral in terms of objectives (b)-(e)).

Peter Bolitho - Waters Wye						
Original – 12/12	Yes	No	Neutral	Neutral	Neutral	Yes
WACM1 12/6	Yes	No	Neutral	Neutral	Neutral	Yes
WACM2 15/6	Yes	No	Neutral	Neutral	Neutral	Yes
WACM3 15/12	Yes	No	Neutral	Neutral	Neutral	Yes
WACM4 9/12	Yes	No	Neutral	Neutral	Neutral	Yes

Voting Statement: For the foreseeable future it is clear that National Grid is in the best position to manage BSUoS forecasting risk and at much lower cost. Hence all proposals that fix BSUoS for a period, and notify the fix BSUoS charge in advance, provide greater certainty to generators selling power on a forward basis and suppliers offering fixed price tariffs to consumers. Overall competition (objective a) will be enhanced by any of these changes.

The market participant risk premiums that are reflected in power prices to cover exposure from BSUoS charge uncertainty can largely be avoided if National Grid manages this risk. There will be a cost this service however, which would be additional cash-flow costs with some limited investment required in improvements to forecasting and new billing systems. As a regulated network monopoly NG's cost of capital is much lower than that of market participants, so it is self-evident that it will be able to manage BSUoS risk more cheaply for the benefit of customers.

This inherent financing cost advantage means that under the current arrangements market participants would have to collectively manage BSUoS risk substantially better than National Grid to offer better value to customers. This assumes that BSUoS costs are essentially a pass-through cost and the market is not generally able to respond to BSUoS price signals

(e.g. to ensure more efficient plant dispatch decisions) – the evidence gathered by the workgroup generally supported this view.

Over the longer-term however, changes to the market may make it possible for market participant to improve their BSUoS forecasting capability and respond to BSUoS price signals better. Philosophically, there are also dangers in getting a monopoly to manage an activity just because that organisation has lower financing costs, than smaller competitive entities - this may ultimately stifle future innovation and in 'lock-in' inefficiencies.

All proposals are, by definition, less cost reflective (objective b) than the current baseline where variable BSUoS charges better target costs to the settlement periods in which those costs are incurred. This detriment is more than outweighed by the competitive benefits (objective a) from stabilising BSUoS.

Over the long-term it may be appropriate to progressively re-introduce variable BSUoS charges, if only for those cost elements that it can be demonstrated that market participants are able to forecast better than National Grid and/or provide market signals they can respond to.

On balance all proposals above are better than the baseline.

Paul Jones - Uniper

Original – 12/12	Yes	No	Neutral	Neutral	Neutral	Yes
WACM1 12/6	Yes	No	Neutral	Neutral	Neutral	Yes
WACM2 15/6	Yes	No	Neutral	Neutral	Neutral	Yes
WACM3 15/12	Yes	No	Neutral	Neutral	Neutral	Yes
WACM4 9/12	Yes	No	Neutral	Neutral	Neutral	Yes

Voting Statement: All options promote competition by removing an unmanageable risk associated with the current floating BSUoS price. The floating price has been shown during the workgroup's assessment of the modification not to provide economic signals which could drive more efficient behaviour by participants to reduce the cost of BSUoS. Therefore, the mechanism is simply recovering the costs from participants and should be done in the most efficient manner possible, which does not distort competition in the retail and wholesale markets in electricity. A fixed price BSUoS managed by a central party such as National Grid, backed by a regulatory settlement which ensures that the company managing the risk is held whole as a consequence, must be a cheaper option for customers than individual parties trying to forecast a very volatile number and managing that at a competitive cost of capital.

This option by definition reduces the cost reflectivity of the price, but it has been shown that this does not remove any economic signal as a consequence, as none is currently provided. Therefore, cost reflectivity is a false objective in this instance.

Overall, this should be an effective outcome for customers.

Simon Vicary - EDF

Original – 12/12	Yes	Neutral	Neutral	Neutral	Yes	Yes
WACM1 12/6	Yes	Neutral	Neutral	Neutral	Yes	Yes
WACM2 15/6	Yes	Neutral	Neutral	Neutral	Yes	Yes
WACM3	Yes	Neutral	Neutral	Neutral	Yes	Yes

15/12						
WACM4 9/12	Yes	Neutral	Neutral	Neutral	Yes	Yes
Voting Statement: All options better facilitate effective competition and promote efficiency for suppliers and generators in the administration of the CUSC compared to baseline.						
James Anderson – Scottish Power						
Original – 12/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM1 12/6	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM2 15/6	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM3 15/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM4 9/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes
Voting Statement: The ex-post nature and the observed volatility of BSUoS charges results in the risk that both generators and suppliers apply a risk premium to avoid exposure to unexpectedly high charges. By fixing BSUoS charges in advance, CMP250 removes this uncertainty and enables parties to price products in competitive markets taking account of the risks which they are able to control. This better facilitates competition (Applicable Charging Objective (A)). As the majority of costs within BSUoS are "smeared" and the charge is calculated ex-post, BSUoS does not send an effective price signal to which market participants can respond. Therefore, fixing the charge in advance will not reduce its cost-reflectivity and CMP250 is neutral against ACO (B). CMP250 is neutral against the other ACOs and overall better meets the Applicable Charging Objectives than the current baseline. There is a trade-off between the notice period before the fixed-price period and the time when charges will ultimately be reconciled with industry and the Original Proposal would appear to achieve the optimal solution between the notice period, fixed-price period, and time to reconcile charges.						

<u>Vote 2</u> – *does the WACM facilitate the objectives better than the Original?*

Workgroup Member	Better facilitates ACO (a)	Better facilitates ACO (b)?	Better facilitates ACO (c)?	Better facilitates ACO (d)?	Better facilitates ACO (e)?	Overall (Y/N)
Jon Wisdom – National Grid						

Voting Statement: Abstained From Vote – Not Better Than Baseline

Cem Suleyman – Drax						
WACM1 12/6	No	Neutral	Neutral	Neutral	Neutral	No
WACM2 15/6	No	Neutral	Neutral	Neutral	Neutral	No
WACM3 15/12	No	Neutral	Neutral	Neutral	Neutral	No
WACM4 9/12	No	Neutral	Neutral	Neutral	Neutral	No

Voting Statement: Generally, those options with relatively longer notice and fixed periods will provide greater certainty to market participants but on the other hand will be more difficult for a central body to manage the cash flow risk. The opposite is true for options with relatively shorter notice and fixed periods. Overall I consider the Original provides the best balance between these competing tensions and as such none of the WACMs are better than the Original albeit it by a small margin.

Helen Inwood - npower						
WACM1 12/6	No	Neutral	Neutral	Neutral	Neutral	No
WACM2 15/6	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM3 15/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM4 9/12	No	Neutral	Neutral	Neutral	Neutral	No

Voting Statement:

Garth Graham – SSE						
WACM1 12/6	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM2 15/6	No	Neutral	Neutral	Neutral	Neutral	No
WACM3 15/12	No	Neutral	Neutral	Neutral	Neutral	No
WACM4 9/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes

Voting Statement: WACM1 and WACM4 better facilitate applicable objective (a) (and are neutral in terms of objectives (b)-(e)) as they facilitate effective competition in generation and supply by affording 9 months (WACM4) or 12 months (WACM1) notice of the fixing of the level of BSUoS for a subsequent period of 12 months (WACM4) or 6 months (WACM1) duration. This, when compared with the baseline, allows party to take this into account in their offering to purchasers of their products.

On the face of it WACM2 and WACM3 appear to have a similar characteristics. However, on balance, the additional notice period (of fifteen months) goes beyond the period where the costs elements can reasonably be forecasted / fixed without incurring an increase in risks that do not outweigh the cost impact for competition and consumers. Therefore these WACMs (2 and 3) do not better facilitate applicable objective (a) (and are neutral in terms of objectives (b)-(e)).

Peter Bolitho - Waters Wye						
WACM1 12/6	No	Neutral	Neutral	Neutral	Neutral	No

WACM2 15/6	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM3 15/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM4 9/12	No	Neutral	Neutral	Neutral	Neutral	No

Voting Statement: Compared to the original WACM2 and WACM3 better fit with the precedent set under CP178 of 15 months' notice for DUoS. This will provide much greater certainty for suppliers setting fixed price tariffs and alignment with the DUoS charge notices allows these to be managed more effectively.

There is a downside risk of larger over and under-recovery BSUoS adjustments that are more likely with longer notice and fix periods, but these are more than outweighed by the competitive (objective a) benefits in terms of lower tariffs that can now potentially be offered by suppliers.

WACM3 is the best proposal as it aligns with the 15 months' notice for DUoS charges covering an annual period.

Paul Jones - Uniper

WACM1 12/6	No	Neutral	Neutral	Neutral	Neutral	No
WACM2 15/6	No	Neutral	Neutral	Neutral	Neutral	No
WACM3 15/12	No	Neutral	Neutral	Neutral	Neutral	No
WACM4 9/12	No	Neutral	Neutral	Neutral	Neutral	No

Voting Statement: There is a balance to be struck regarding the level of notice period and the period of fixing the price. The original provides the best balance. Others are less effective in promoting competition, either by seeking to fix for too long a period or for not fixing long enough.

Simon Vicary - EDF

WACM1 12/6	Yes	Neutral	Neutral	Neutral	Neutral	Yes
WACM2 15/6	No	Neutral	Neutral	Neutral	Neutral	No
WACM3 15/12	No	Neutral	Neutral	Neutral	Neutral	No
WACM4 9/12	Yes	Neutral	Neutral	Neutral	Neutral	Yes

Voting Statement: WACM's 1 and 4 are better than the original as they strike the best balance between notice period, duration of fix and likely cost.

James Anderson – Scottish Power

WACM1 12/6	No	Neutral	Neutral	Neutral	Neutral	No
WACM2 15/6	No	Neutral	Neutral	Neutral	Neutral	No
WACM3 15/12	No	Neutral	Neutral	Neutral	Neutral	No
WACM4 9/12	No	Neutral	Neutral	Neutral	Neutral	No

Voting Statement:

Vote 3 – *Which option is the best?*

Workgroup Member	BEST Option?
Jon Wisdom – National Grid	Baseline
Cem Suleyman – Drax (Proposer)	Original
Helen Inwood - npower	WACM3
Garth Graham – SSE	WACM1
Peter Bolitho - Waters Wye	WACM3
Paul Jones - Uniper	Original
Simon Vicary - EDF	WACM4
James Anderson – Scottish Power	Original

4 Impact and Assessment

Impact on the CUSC

4.1 Changes to Section 14 BSUoS Charging Methodology

Impact on Greenhouse Gas Emissions

4.2 None identified.

Impact on Core Industry Documents

4.3 Licence changes to ensure National Grid costs are recovered.

Impact on other Industry Documents

4.4 None identified.

5 Proposed Implementation and Transition

5.1 The Workgroup suggested implementation into the CUSC on 1 April 2018, this would mean the notification of a fixed price would be given on 1 April 2018 and that fixed price would commence on the 1 April 2019 for a period of 12 months ending 31st March 2020.

5.2 National Grid has confirmed, however, that they will require 12 months to implement the necessary system changes and will incur costs of approximately £1.5m for system implementation. In addition there would need to be an increase in FTE to take on the additional roles of forecasting BSUoS and managing the resultant business risks depending upon the final decision by Ofgem and option taken forward. The earliest date that a fixed price could be produced would be October 2018 and the earliest point that the fixed methodology could be implemented would be 1 April 2019. The National Grid representative also pointed out that were a decision to be received after the 31st March 2018 the earliest date of implementation would need to move to 1 April 2020 to allow for the start of the next financial year after system changes had been carried out.

5.3 A Workgroup member suggested that a two stage systems development may enable an earlier implementation;

(i) Stage 1 would deliver the billing system changes required to enable BSUoS billing utilising the fixed price and

(ii) Stage 2 would deliver the reconciliation process and calculation of any over or under recovery against actual BSUoS costs as calculated using the existing half-hourly BSUoS charging functionality. Development of Stage 2 functionality could continue during the first fixed BSUoS price period and delivery would not be required before the end of that first fixed period.

5.4 However, the National Grid representative informed the Working Group that the changes required to deliver Step 1 were also not feasible for 1 April 2018 implementation. The National Grid representative provided information to the Workgroup provided by the National Grid IT department. These have been summarised below;

1. Currently there is only one billing method - half hourly. CMP250 needs to cater for two billing methods (impacting the Billing engine) to achieve both half hourly billing and constant pricing for reconciliation purposes.
   System Change: Need to add new billing logic to achieve the requirement which will impact the current billing engine. This is challenging technically as it is a link to schema changes in a further part of the process.

2. CMP250 requires redistribution of charges and needs a different approach in the finance module to divide equally in 12 months.
   System Change: Redistribution of charges require logical changes and configuration.

3. The changes will lead to additional new reports and/or changes to existing reports.
   System Change: As we are changing the logic and adding new logic it will require changes for reporting within other systems.

4. Some CMP250 options require that the fixed values are calculated across two fluctuating periods. These are not exactly fixed adding greater complexity through having to use two settlement figures that need to be distributed accordingly across the annual period.

System Change: As the values are changing for two different periods the system needs to adjust the tariffs twice in a year for differing periods.

5.5 The National Grid representative informed the Workgroup that a go-live date would need to be established once a confirmation of any post-Workgroup activity had taken place including any Ofgem consultations and decisions. This would include any period to define licence changes. Taking both this and the implementation period into account 1 April 2019 go live date appeared a more reasonable timeframe from the National Grid representative's perspective.

5.6 The Workgroup considered the possibility of approval, by Ofgem, after 31 March 2018 and proposed that implementation should be at the earliest opportunity for the chosen option. The Workgroup also proposed that Ofgem may wish to use their judgement to instruct an implementation timescale ahead of the next 1 April. The Proposer suggested, and the majority of the Workgroup agreed, that following an Ofgem decision for the option chosen the notice period should be retained but if necessary the first fixed period should be shortened to fit into the financial year timescales, e.g. 12 month notice, 12 fixed – decision provided in 14 October 2018 – fixed period should be, in this example 5½ months, from 14 October 2019 to 31 March 2020. This example assumes that a fixed value will be produced on the same date as the decision from the Authority.

5.7 In terms of the licence changes that may arise from this proposal, a Workgroup member noted that, in the past, National Grid and Ofgem have on occasion progressed the licence changes in parallel with proposal changes and this would seem (in the view of some Workgroup members) appropriate in this case in order to achieve the benefits from the CMP250 proposal as soon as practicable.

6 Workgroup Consultation Responses

6.1 The Workgroup Consultation closed on 14th April 2016 and received ten responses. A summary of these responses can be found below; the full responses are included within Annex 6.

	1. Do you believe that CMP250 Original proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives?	2. Do you support the proposed implementation approach?	3. Do you have any other comments?	4. Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider? Please see 8.3.
Crown Commercial Services	Yes, as long as stability and low cost to customers is achieved in BSUoS charges.	No comment.	No.	No.
EDF Energy	Yes. We believe by stabilising BSUoS costs for participants it facilitates effective competition and thus meets CUSC objective a.	Yes. An implementation that would achieve an initial six months of stability from 1st April 2018 by 1st April 2017 is supported.	We have had many of our customers in the B2B sector tell us that they support this proposal and they have informed us that an implementation date as earlier as practicably possible would be favoured.	No.
ENGIE	No. The key issue relating to objective (b) is that introducing a flat BSUoS value removes the half hourly cost reflectivity of the charge and potentially removes a market signal for flexible generators to optimise running patterns. This would reduce costs for those who exacerbate the BSUoS volatility and share	No.	No.	N/A.

	the cost amongst all market participants, distorting the market.			
Gazprom Energy	Yes, better facilitates objective (a).	Yes. Implementation should be no later than April 2017.	No.	No.
Haven Power	Yes. The proposal would allow suppliers and generators to price their power more competitively, thereby better facilitating objectives (a). Further, reducing the risk will facilitate market entry thereby further increasing competition.	Yes.	No.	No.
Hudson Energy Supply UK	N/A.	Yes in principle.	N/A.	No.
InterGen	Yes.	Yes.	Whilst beyond the scope of this modification we believe that BSUoS charges should be recovered 100% from the demand side. This will bring the GB charging regime in line with the EU Third Package. BSUoS forecasting risk should reside with National Grid and not with market participants.	No.
Opus Energy	Yes, better facilitates objective (a).Transferring some of the BSUoS forecasting risk to National Grid will allow greater competition in the market as newer entrants with fewer resources to forecast BSUoS	Yes.	Opus Energy would suggest indicative charges for future periods or charging years should also be published periodically. As under and over recovery amounts build-up it is vital that National Grid keep suppliers	No.

	would be more able to compete.		informed of these accrued values and the expected impacts of these on future years charges. As we consider National Grid to be the best suited for forecasting BSUoS charges, providing indicative charges will help reduce the forecasting risks for future periods.	
RWE NPower	Yes, better facilitates objective (a). A fixed BSUoS will encourage competition by stabilising a volatile and unpredictable element of the cost stack that cannot be forecasted accurately, hedged or known ahead of out-turn. Fixing BSUoS prices ahead of time and allowing parties to accurately reflect these in their costs will improve competition allowing parties to compete effectively on pricing and reduce costs to consumers through the removal of risk premia. Although we accept that a fixed BSUoS cost could be considered less cost reflective on a half hour by half hour basis we consider that there is no meaningful price signal within BSUoS costs due to	Yes.	We would still require market information as provided currently by National Grid (MBSS and BSIS data) as well as HH BSUoS out-turn to enable us to predict future fixed rates and any K factors for longer dated contracts. We also assume that each fixed period will carry a shortfall (K) which will be rolled forward into future periods.	Yes. We prefer a 15 month notice period as this would allow us the opportunity to price the new information into any contracts. Considering the options in Annex 7 we propose that 15 month notice, 12 month fix with a 3 month reconciliation period should be adopted alongside a 15 month notice, 6 month fix with a 3 month reconciliation period.

	their volatility calling into question the need to accurately allocate costs to any single half-hour period.			
Scottish Power Energy Management	Yes, better facilitates objective (a) through reducing uncertainty and unpredictability in the level of BSUoS faced by both generators and suppliers when participating in the wholesale electricity market. Reduced uncertainty should facilitate more competitive pricing to the benefit of consumers.	Yes.	No.	No.
Smartest Energy Limited	No. We do not believe that CMP250 better facilitates any of the applicable CUSC objectives.	No.	No.	No. We would prefer that National Grid issues a range of (non binding) BSUoS forecasts which may help inform generation/supply as to expected BSUoS costs and allow more efficient price setting in spot and forwards markets e.g. 2 day ahead HH price, week ahead block prices, month and seasonal peak/base prices.
Tesco	Yes, better facilitates objective (a).	Yes.	No.	No.
Uniper UK / E.ON UK	Yes, better facilitates objective (a) as the proposal should benefit competition in the market.	Yes.	No.	No.
VPI Immingham	No, we do not believe the	We do not support the	Whilst we recognise/accept some	No response.

	proposal better facilitates the applicable CUSC objectives. The original proposal reduces competition across generators as an important element of cost reflectivity and relevant signal to the market is removed. As a result, there is reduced incentive to change behaviour in a specific settlement period which is likely to harm competition. In addition, the proposal does not reflect the charges as incurred by the SO in balancing the system.	implementation of this modification as currently worded.	of the issues outlined in the modification proposal, we do not support the proposed solution. We believe that the issues that need to be addressed go deeper than volatility of BSUoS charges and that a more fundamental review of the charge, what it consists of and how it is allocated is conducted. The proposed modification does nothing to fix the major issues with BSUoS. This is one of the reasons we do not support the modification.	
WM Morrison Supermarkets PLC	Yes, better facilitates objective (a). All suppliers charging BSUoS for a period of 12 months at the same rate enables us to choose more effectively.	Yes. Supports early implementation as facing significant uncertainty on costs arising from SBR and intermittent generators that appear to be increasing costs for the SO.	No.	No.

As well as the standard consultation questions above, the Workgroup also seek views on the thirteen specific questions below;

	5. Do you agree Balancing Services Use of System Charges are becoming more volatile?	**6. Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	**7. Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	**8. Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**
Crown Commercial Services	No comment.	Yes, this does have some impact on our business.	No comment.	No comment.
Drax	Yes, as seen in pages 5-8 of this report.	Yes. As BSUoS is not known until ex post and can be seen to be getting more volatile and unpredictable, industry participants include a risk premia in order to protect themselves in the event of a high BSUoS cost. If the	No. No party can predict how BSUoS varies therefore no party can have a competitive advantage, especially in forward trading timescales. There are far too many unpredictable variables.	If BSUoS is fixed, an over/under recovery of costs should not considerably impact an industry participant. The Workgroup has shown the benefits and cost savings CMP250 introduces far outweighs any additional cost incurred to the industry.

		BSUoS in a settlement period spikes, a previously profit-making sale could become loss-making.		There are no discernible price signals and therefore Drax considers the BSUoS charge a cost recovery mechanism and not a market signal. As BSUoS is ex post, generators cannot accurately predict BSUoS. Further, BSUoS can give potentially perverse signals. For example, a high BSUoS cost can result from system constraints caused by intermittent generation being bought down. The high BSUoS price associated with this may incentivise flexible generation to turn down which is not desirable in this circumstance.
EDF Energy	Yes. We have looked at BSUoS data since 2005 and the analysis is consistent with the information in the Workgroup Consultation report that demonstrates BSUoS is becoming more volatile.	Yes. For EDF Energy's supply business we need to be able to offer customers competitive prices whilst trying to forecasts costs that can vary considerably and are not known until after delivery.	No. We believe that no party has the ability to know in advance, with any degree of certainty, what the BSUoS costs are.	Many networks costs have an ex-ante approach in which an under or over recovery mechanism is used. As long as sufficient notice is given of adjustments we are comfortable with this approach. EDF Energy does not believe that BSUoS is a cost signal because it is unknown until after the cost has been incurred.
ENGIE	We would generally agree with the evidence provided in the Workgroup Report, which demonstrates that BSUoS has 'become' more volatile. However, there is little evidence in the report to suggest that BSUoS volatility will continue in the future. Upgrades to the transmission network and changes to the generation mix will impact this volatility in the future.	Yes. The more extreme BSUoS events can generally be forecast and plant optimised on this basis, reducing risk and therefore the impact on the business.	Yes, Extremes in BSUoS outturn can be forecast on short term timescales (within week) and running profiles can be optimised on this basis. Those who are unable to make BSUoS forecasts or who are unable to optimise generation during highly volatile BSUoS periods are subsequently penalised, therefore providing cost reflectivity and providing additional value to flexibility. Volatility should encourage	The reallocation of BSUoS costs away from settlement periods and into a flat, fixed period potentially removes the cost reflectivity from BSUoS and distorts the signals being sent to market participants. Removing any type of signal for flexibility in the market seems counterintuitive to the requirements of the system.

			innovation.	
Gazprom Energy	No response.	No response.	No response.	No response.
Haven Power	Yes.	Yes. As a Supplier, overestimating BSUoS could make us uncompetitive in the retail market. Where this is applied across the market, the cost will ultimately fall to the end customer. A fixed BSUoS charge will allow industry participants to more accurately price their power.	No. Too many unpredictable variables make BSUoS difficult to predict.	No. There are no obvious price signals and we consider the BSUoS charge a cost recovery mechanism and not a market signal. We believe that the benefits and cost savings through the reduction of the risk premia far outweigh any additional cost to the industry.
Hudson Energy Supply UK	Yes.	Yes – Volatility in BSUoS impacts pricing assumptions, leading to potential under recovery or competiveness.	Most big organisations/large generators have teams to model BSUoS forecast costs, so as a smaller supplier we feel we are at an unfair disadvantage.	Some form of Ex ante charging will benefit smaller suppliers in generating more stable and consistent returns verses planned budgets. Charge years should mirror financial periods and any over / under recovery in one charging year should then be reflected in the next year's charges. As a Supplier we don't currently have contractual arrangements in place that would allow an end user to respond to any price signals created by BSUoS activity in any HH.
InterGen	Yes.	Yes. InterGen is a non-vertically integrated independent generator. For our plant, which typically is dispatched for short timescales to capture value in peak periods we do not benefit	The more accurately you can forecast the BSUoS, the better the decisions you will make and the less risk you will need to price in to account for possible variance in BSUoS charges.	The existing ex post BSUoS charges are inappropriate for the levels of volatility now observed in BSUoS charges. With the increased penetration of intermittent renewable

		from smoothing /averaging of BSUoS over time. With increased volatility of BSUoS, our plants have been subject to very large spikes in BSUoS resulting in uneconomic dispatch of the plant. Due to increases in BSUoS we have lost money and with the benefit of hindsight would not have made the decision to dispatch the plant at certain points.	Thus a competitive advantage could be gained by BSUoS forecasting.	generation requiring frequent constraint management actions and more expensive balancing actions BSUoS has become highly volatile. National Grid's forecast of BSUoS at the day ahead stage it is often inaccurate and does not profile the charges across settlement periods. For flexible generation assets which typically will only run for short periods of the day in the peak periods or for 2-6 hours in the Balancing Mechanism the volatility in BSUoS can lead to loss making dispatch as the HH values of BSUoS can deviate significantly from the daily forecast average.
Opus Energy	Yes.	Yes. The volatility of BSUoS results in an inherent risk that needs to be captured in our pricing. As BSUoS is never known at the point of pricing there is a significant risk to both profitability and efficient customer pricing.	No comment.	Fixing BSUoS charges will provide additional assurance when contracting with customers for terms within the forecast period, by removing the inherent uncertainty over the BSUoS charges. However customers contracted for a longer period would still be subject to the same, if not greater, risks as they currently face, owing to the additional

				consideration of the over/under recovery from revenue from previous years. We still consider this modification to beneficial overall. Settlement period level BSUoS charges do not currently provide us with a cost signal to which we or our customers are able to respond.
RWE Npower	Yes and we consider that this will increase over the next several years due to the geographical diversification of the network, increase in intermittency of generation and closures of central capacity.	Yes. BSUoS costs across 2015 and 2014 were materially higher than in previous years. This causes additional costs to be incorporated into the cost stack to allow for the risk of out-turn costs being higher than forecast. In addition customers on pass-through deals have utilised NGET BSUoS forecasts and suffered volatility in their business planning as a result.	Not as such as the cost is extremely volatile and unpredictable. Some parties may be more capable than others in understanding the volatility in these costs and therefore factor in risk premia for this. However, this is not a competitive advantage as such as National Grid's BSUoS forecasting has been lower than out-turn BSUoS costs over a number of years. Parties who do not price for this volatility will therefore be exposed to losses and parties who do will not be as competitive from a pricing perspective.	We do not consider that this is an issue.
Scottish Power Energy Management	We agree that the analysis in section 2.6 to 2.13 of the report demonstrates an increasing volatility in HH BSUoS costs	Increasing volatility of BSUoS makes it likely that there could be an increasing number of periods when generation plant may be	No. All market participants have access to the same sources of data underlying BSUoS charges and each participant is free to	Currently there is not a useful price signal to which businesses can respond. Market participants have insufficient knowledge of

	which we would expect to increase further as the deployment of intermittent renewable generation continues.	dispatched uneconomically as actual BSUoS costs may exceed expected levels. A significant risk premium would have to be added to any central BSUoS forecast in order to achieve a reasonable level of certainty that dispatch would not be uneconomic. Suppliers would face similar problems in pricing customer contracts particularly where customer profiles resulted in a different load weighting than the mean load-weighted BSUoS value.	decide how much significance and resource to allocate to BSUoS price forecasting.	the current state of the electricity system and whether current conditions will persist or change into future settlement periods. Thus, the most recently published indicative BSUoS data is a relatively poor indicator of the charges which may be experienced in future periods. The reallocation of BSUoS charges within year will reduce uncertainty over the variability of the charge and reduce the potential of making uneconomic pricing decisions in the short term. The potential reallocation of BSUoS charges between years will be achieved with sufficient notice to participants that it will enable them to take account of this in their BSUoS forecasts and economic decisions.
Smartest Energy Limited	BSUoS reflects the reality of the system.	The volatility of BSUoS is not inherently unmanageable.	It is not appropriate for us to comment on the relative forecasting abilities of competitors.	Yes, in addition to comments for question 1, we add that we respond to price signals in BSUoS by tailoring BSUoS charges to customers dependent upon their consumption profile. Customers with higher forecast BSUoS costs have higher energy

				rates and vice versa.
Tesco	Yes. Analysis presented to us by our supplier has demonstrated that as more intermittent and embedded generators play a larger role, BSUoS costs ranges are becoming more extreme. This does not impact us day to day but it does play a consideration when we are deciding to fix or have BSUoS as a pass-through, ex-post reconciliation element within our contract terms.	To a degree. Tesco values budget certainty and knowing this cost in advance can enable us to make more effective decisions on how we treat this cost within our contract terms.	N/A	N/A
Uniper UK / E.ON UK	Yes. We also agree with the evidence in the Report. Values are becoming more difficult to forecast going forwards than has been the case historically, which is increasing risk for all parties exposed to BSUoS charges.	Yes. From a retail perspective it makes it more difficult to forecast future BSUoS levels and increases the risk associated with setting fixed rate tariffs. For those customers with BSUoS pass-through contracts, it increases the risk for them directly. From a generation perspective greater uncertainty makes it even more difficult to include the cost of BSUoS, which in principle is an avoidable cost, into prices offered into the market.	Some benefit is gained from forecasting BSUoS compared to an alternative of not putting any or putting little effort into forecasting. Nevertheless, the nature of the charge makes it difficult to spot particular patterns and trends, making it very difficult to gain a particular competitive advantage through more effective forecasting than other parties.	If there is no particular pattern to BSUoS charges it is difficult to predict how changes would alter the distribution of costs between parties in future. That is, you assess this on historic charges, but this is unlikely to be indicative of the effect going forwards. Given that BSUoS is calculated ex post and that there is no particular pattern to prices which can be identified and acted against in future periods, then it is difficult to see how it can act as a price signal. If it does provide a signal, it is not one which can be responded to by

				BSUoS payers to promote beneficial behaviour. Therefore, it can't be relied on to promote benefits to the system and ultimately lower customer costs.
VPI Immingham	The answer to this depends on your definition of volatile. We would argue that on a day to day basis charges are more volatile, but on a seasonal basis, whilst they are increasing, they are not necessarily becoming more volatile. BSUoS, however, is becoming increasingly difficult to forecast due to the changing nature of the system and the addition of costs that are virtually impossible to forecast, such as SBR utilisation costs	Yes. As a CHP with a "must run" element, we must always be generating to provide steam to the local refineries, Humber and Lindsey. Given current market conditions, BSUoS plays an important part of how we despatch the plant, particularly in the overnights when wholesale prices and spark spreads are very low, yet BSUoS may be very high if there are high constraint costs. We often have to despatch at a loss, partly driven by high levels of BSUoS.	Yes, we do. Given the nature of operation of our plant, we have invested considerable time and resources into building an accurate forecast of BSUoS charges which feeds straight into our decision making. We believe that our ability to accurately forecast BSUoS, the vast majority of time, enables us to ensure that we are making efficient despatch decisions. However, at the same time, the lack of transparency around some of the decisions that the System Operator is taking does make it difficult to get an accurate forecast 100% of the time. Whilst the absolute size of the BSUoS charges, as currently recovered can be difficult to forecast accurately, parties should be able to say with a firm degree of confidence what order of magnitude the charges may	We have concerns regarding fixing an ex ante BSUoS charge, particularly for periods of a year at a time. We believe that current estimates of BSUoS do incentivise different behaviour across the market and the cost reflectivity of the existing charges aids competition. For example, high BSUoS costs as a result of constraining wind in Scotland overnight may result in flexible plant switching off overnight when it may not be profitable to generate. However, having a flat price signal could result in additional generators staying on overnight with no meaningful price signal to switch off. Perversely, this in turn could lead to higher BSUoS charges as National Grid is forced to take more actions to balance the system, driving increasing costs. A fixed charge could impact the merit order and may not result in

			be before the settlement period itself.	the most efficient despatch due to the lack of appropriate cost reflectivity and signal. Whilst the absolute size of the BSUoS charges, as currently recovered can be difficult to forecast, parties should be able to say with a firm degree of confidence what order of magnitude the charges may be. We believe that this signal is important for efficient despatch and should remain in place. As outlined elsewhere in this consultation response, many of the current issues are a result of an increasing number of ancillary services recovered via BSUoS that are not directly related to balancing the system and that are virtually impossible to forecast. We believe that it would be more appropriate to conduct a full review of BSUoS as a cost recovery mechanism to address all of the issues associated with BSUoS and not just one small element.
WM Morrison Supermarkets PLC	Yes. We monitor the costs quite closely and with the assistance from our supplier the low and	Yes. We have to ensure that we forecast to the best of our ability all elements of costs that we are	Not applicable.	Not applicable.

	high case ranges are widening. This is as a result of more system actions we believe are being required to be taken by National Grid balancing a much different network than several years ago. We believe that this trend will continue in the future.	liable to pay. Having certainty of these costs a year in advance will enable us to budget more effectively. We are of the opinion that any additional stability to costs (such as longer notice period for TNUoS) allows us to have more budget certainty which is important to our business.		

	9. Do you believe BSUoS is a useful price signal?	**10. If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	**11. What are your thoughts on notification lead times and the length of the price fix period?**	**12. What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**
Crown Commercial Services	Unable to predict BSUoS hence not necessarily a strong price signal, however seasonality and weighting between times of the day can provide some benefit to some customers. Believe this can support demand shifting of load in particular.	Shaped BSUoS curve supported as it allows generators to dispatch stations with greater certainty. A flat shape penalises customers/generators and reduces the incentive for customers to demand shift load.	No comment.	No comment.
Drax	No, see response to Q8	The costs will be recovered over the year so it should not	Drax considers that a long notification period to be best	The methodology detailed through paragraphs 2.67 to

		matter. It can be seen from the table on page 11 of the Workgroup Report that there is no discernible pattern in BSUoS prices by day, half hour, or season. Given this we see no merit in profiling.	in order to allow parties to trade effectively along the forward curve. As the majority of wholesale power is sold 12-18 months ahead, the proposed 12 month lead time with 6 month price fix is optimal. Providing 12 months' notice will be more difficult in terms of forecasting compared to 6 months, however, the benefits of the longer notice period in reducing trading risk further along the curve outweighs any additional difficulty associated with forecasting.	2.85 is subject to a number of simplifying assumptions as the possible risk premia industry apply as a result of ex post BSUoS charging is difficult to model. However, the model gives a likely impact of the risk premia with the upper and lower bounds being above any additional cost that industry may incur through the impact of fixing BSUoS.
EDF Energy	No. It is not known with absolute certainty, for many months after the SO has incurred costs, what the actual charges are. The ability for Income Adjusting events to be retrospectively applied highlights that BSUoS is an ex-post signal which cannot be reasonably acted upon.	We believe that BSUoS should be profiled as a flat value. The mechanism under proposal is simply to determine a variance that needs to be adjusted in a future period. Adding the complexity of a shaped curve serves no purpose.	We support that a twelve-month notification period which sufficiently balances the period in which customers contract within and also the length of time contracts are signed for.	There is no possible way to determine a standard risk premia that is applied because of the way different suppliers treat this charge. We do not consider risk premia, in isolation, as an appropriate measure to judge benefits for customers. The wider competitiveness and transparency this will bring to customers is just as important.
ENGIE	Yes. More extreme changes in BSUoS can be forecast in short term timescales and plant can be optimised. Extremes in BSUoS act as a signal for flexibility from generation assets.	If a fixed price is to be implemented, then a flat price seems the most sensible approach. Historic BSUoS price shapes are not necessarily an indicator of future shapes, particularly as	The proposed notification / fixed BSUoS period seem reasonable. However, further consideration should be given to shorter term fixing periods (week or month ahead). This would potentially reduce the	The Workgroup Report correctly identifies that using historic BSUoS as a marker for future risk premiums is limited, as changes to the transmission network and generation mix will greatly

		the transmission network and generation mix change.	cash risk held by the SO (or industry/other) and allow NGC to provide the market with a more accurate forecast of BSUoS. Whilst the Workgroup Report acknowledges that longer term In addition, further consideration should be given to the length of the fixed period if the full potential benefit for consumers is realised.	impact the magnitude of BSUoS volatility. Different market participants may have different views on the future system and different risk appetites.
Gazprom Energy	No response.	In favour of a flat BSUoS rate because suppliers/consumers cannot respond to it and a flat rate is simpler. Profiled BSUoS may reward demand or generation decisions which do not necessarily benefit the system.	No response.	No response.
Haven Power	No.	If the cost is to be recovered over the year it wouldn't matter.	We feel that 12 months should be a minimum term. We would like to cite the relatively recent industry changes in both the DCUSA (DCP178) and the CUSC (CMP244) that have seen the respective notice periods for DUoS and TNUoS tariffs increase exponentially.	While we are not aware of an improved method of modelling, we welcome other potential modelling techniques.
Hudson Energy Supply UK	Only if it is predictable, we do not have the resource to understand this currently.	It should be shaped based on some understanding of the cost of actions taken to balance the system and when they are taken. Any reconciliation should then be	We would prefer a 12 month charging period issued 12 month in advance of the charging year.	Premia is acceptable – but the amount should be published and reconciled each year – benefit should passed on in following years.

		applied based on actual cost of balancing for each HH.		
InterGen	Only BSUoS pricing that will be fixed and provided ahead of trading will be useful.	Ideally, BSUoS pricing would be profiled to reflect settlement periods when balancing costs are highest/lowest. However, due to influence of this on intermittent generation this forecast will not be reflective if provided ahead of a charging year. A fixed 'curve' profile that reflected the variance across a day of BSUoS would not reflect the dynamic nature of balancing actions day to day. This profile would also be difficult to price into wholesale power price on the forward market as only Baseload and Peak products trade in any significant volume at greater than month ahead of delivery. For practical reasons it will be simplest to provide a single value. This will feed efficiently to the wholesale markets.	The prices could be fixed on a quarterly or seasonal basis (6 month terms to align with the wholesale market summer and winter products). This allows some adjustment by National Grid to reflect the different forecasted costs of balancing the system in summer and winter. The notification lead time needs to strike the right balance between providing an early signal to the market and allowing National Grid to minimise the significant variables that feed into the BSUoS calculation.	InterGen do include a risk premium for volatility in BSUoS which feeds into the SRMC for our power plants. As a result, the plants are not able to sell into the wholesale market or BM at their most efficient/competitive price point. If this behaviour is replicated across the market then it will result in uplift in wholesale prices with end consumer ultimately penalised. If BSUoS resided 100% on the demand side then generators would be able to exclude these charges and the associated risk and sell power at reduced levels.
Opus Energy	No comment.	The vast majority of customers of all sizes prefer a bundled product price that	As illustrated in Annex 7, the 12-month notice, 6-month fixed charge will provide the	No comment

		includes all costs. As such, a shaped BSUoS cost will provide no signal to the customer to change its behaviour. The reality of actual system costs will always be different than any shape so it would be misplaced effort. As most wholesale trading occurs in baseload products it would be logical to assume that generators take a similar approach to mid-term risk management where this change would be most impactful, so shaping would not reduce the risk premia further.	best coverage throughout a charging year. By year 2, at least 12 months of BSUoS charges would be known at any point during the year, which would reduce with any shorter notification period.	
RWE NPower	No.	We believe a single annual price would provide the best cost recovery mechanism. Any shaping or profiling of the price would be a purely artificial measure and we do not consider that it would lead to any benefits to market participants.	We believe that our suggestion of a 15 month period provides a much better price fix notice period encompassing a larger proportion of supplier contracting periods and aligning with the recently approved notice periods of DUoS charges.	We consider that all participants will include risk premia to a varying degree both generators and suppliers. This will increase costs for consumers. Prudent market operators will consider previous BSUoS out-turn as well as expected network events/market changes. The Workgroup has considered this risk as far as

				possible in an open forum and believe that some parties may give further detail to Ofgem in confidence.
Scottish Power Energy Management	No. Please see our response to Question 8.	The analysis in the Workgroup Report at 2.25 to 2.27 indicates only a very weak correlation between BSUoS and seasons or time periods (peak/off-peak; weekday/weekend). Therefore we do not believe that there is any empirical justification for introducing a shape to the fixed BSUoS price. The introduction of an erroneous price shape risks sending misleading price signals to the market and may lead to inefficient dispatch of generation.	Ideally we would seek a 12 month fixed period, compatible with annual traded products coupled with a 12 month notice period to coincide with the time frame in which as significant proportion of OTC products are traded However, as noted at 2.33 of the report and combination of fix and notice periods in excess of 18 months increases the reconciliation period to 3 years. We therefore believe that a 6 month fixed period with 12 months' notice would be an acceptable compromise solution.	We do not believe that there is a single method of determining an appropriate risk premium to be applied to BSUoS forecasts and that each industry participant will adopt a different approach according to its risk appetite. However, we believe that most methodologies adopted will consider the overall annual level of BSUoS costs, annual BSUoS volume, and the level of sensitivity around a derived annual BSUoS charge. This will be accompanied by consideration of the volatility of BSUoS on an individual Settlement Period basis in order to assess the risk associated with a particular contract profile. We believe that the approach demonstrated in Annex 8 provides one such method of assessing BSUoS volatility

				around a central forecast.
Smartest Energy Limited	Yes.	It should be shaped.	Given our contractual position and system set-up we would need at least two years.	No comment.
Tesco	No.	We do not have a preference as it would impact our supplier more, however given that the aim of this mod is to simply fix costs in advance with a post reconciliation we believe a flat shape is sufficient.	We are comfortable with the proposal.	We are very much reliant on third-party information to ensure that the BSUoS charges offered by suppliers are at an acceptable level. We are aware that our supplier provides us with the most informed BSUoS values available to them.
Uniper UK / E.ON UK	No	If BSUoS does not provide a signal at present, then it seems pointless to shape it in future as a proxy for a signal. If the cost was shaped it may illicit a response from parties, but it is highly unlikely that it would be one that would provide benefits to the system and customers. The focus should be on cost recovery instead which doesn't require a profile.	Clearly parties would like notification as far ahead as possible, but realistically this has to be balanced by what is practicable. Similarly, this is the case for the length of the fix period. The Workgroup preferred combination of a 12 month notice period and 6 month fix period is the one which seems to provide the best combination in terms of managing risk for parties and customers.	The analysis is inevitably limited as a result of it being backwards looking. The real issue is the risk that parties have looking forwards due to the huge amount of uncertainty about future BSUoS levels. Therefore, it is difficult to put a cost on this.
VPI Immingham	Yes, within a level of tolerance, we do believe that BSUoS can provide an	Should a fixed price be introduced, we believe that it should be shaped and	Should this change be implemented, we would support shorter price fix	Whilst the statistical methodology behind the analysis would appear to be

	effective price signal. The issue, as set out above, is that it has been polluted by the addition of an increasing number of charges that are increasingly volatile and impossible to forecast. Should these “polluting” elements be removed, we believe BSUoS could again provide a meaningful price signal and should be allowed to do so.	profiled. At the very least, we would advocate a seasonal split with a further peak / off peak split. The reason for this is due to the different profile of BSUoS and generators in these time periods and the different behaviour that National Grid should want to incentivise. However, any variation may just average out over the fix period. Additionally, the impact of intermittent generators is growing as the volume of installed capacity increases and this often has a direct impact on BSUoS costs. Shaping allows some reflection of the different actions that National Grid is taking to balance the system at different times of day. With increasing levels of solar penetration and subsequent balancing actions, this might become even more pronounced.	periods. We believe that drivers of the cost are highly seasonal and therefore, BSUoS should be fixed to reflect the true costs within a short time period. For example, SBR, a component of BSUoS, is only in place November to February and could be a key driver of costs in this time period. As with any fixed costs, the longer the notification period, the better able industry are to manage it and the more certainty is given.	sound, we do not believe that it reflects what actually happens and is overly simplistic with some limitation. With BSUoS costs driven by many external factors, such as the volume of intermittent generation on the system, or whether SBR is utilised, then we think that taking an average over a specific time period does not reflect the actual level of risk factored in by generators. In addition, as pointed out in the consultation document, the analysis is backward looking. We believe that any consideration of risk premia would be forward looking, particularly with the ever increasing cost of ancillary services now included, and consider actual market conditions at the time.
WM Morrison Supermarkets PLC	No. We are unable to act in advance to this signal.	We would prefer the stability of a flat shape. Introducing a shape to costs that are	12 months in advance is a suitable lead time as I am sure there is a balance	We are happy for the industry to derive the best value but we would not support any

	unknown does not seem add any value.	between remaining cost reflective but also being able to benefit from cost certainty. We would like to see a minimum of one years worth of fixed charges but a longer period would enable us to contract for a longer period of time if other network and low carbon charges (RO, FIT, CfD) were also fixed further in advance.	costs that would exceed £0.07/MWh annually. If it did then we would perhaps need to consider the merits of a lead time of between six to twelve months.

	13. Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?	**14. If applicable, are you able to share your approach to calculating risk premia?**	**15. Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	**16. What is your view on the above cash flow financing approaches?**	**17. What would you regard as good value to enable a fixed BSUoS price?**
Crown Commercial Services	No comment.	No comment.	No comment.	No comment.	Would value certainty of cost but unable to determine a suitable cost. Would pay a small proportion of the total BSUoS cost to achieve some certainty.

Drax	The National Grid BSUoS forecast can be used as a useful guide. However, we use certain different assumptions in our own forecast.	N/A.	We believe that the risk should sit with a party that has a low cost of capital and is financially capable of holding such a risk. This party will be able to fulfil this role more effectively and at a lower cost than industry participants. National Grid is a good candidate to fulfil this role. Further, National Grid also has a good view of the market with strong expertise in forecasting.	These options are still at an early stage of development. National Grid is encouraged to continue its dialogue with financial institution(s) to assist in designing the optimum option to finance the cash flow risk. Additionally, we have the following views on the options suggested: We initially consider that Option 1 will provide the most cost effective option. The SPV options may also have some attractions depending on the detailed arrangements. We do not consider that Option 2 will deliver a cost effective solution.	To justify this modification, the reduction in risk premia must outweigh any cost that the risk carrying party incurs. The evidence in the Workgroup Report from paragraph 2.53 shows that the potential benefits of CMP250 greatly outweighs any increase in cost that industry participants may incur.
EDF Energy	We use many different sources to determine what our BSUoS forecast may be.	No. Please see full response to question 12 in the Annex.	The SO is best placed to manage this risk as the costs of any actions taken are not visible to the industry until after the event.	We agree that a suitable loan facility is the best option. The right choice will all be dependent on value for money.	We would not expect the ability to fix BSUoS using a loan facility to be any higher than £0.04 - £0.07/MWh. We expect that over time the amount of loan facility

					will reduce as the variance between the forecast and actual amount spent improves.
ENGIE	No.	No.	Market participants are best placed to manage the risk. Current arrangements follow a reasonable simple set of rules which can allow market participants to optimise assets and react to volatility in BSUoS. Those parties willing and able to react to volatile BSUoS prices are not necessarily in a position to reduce it. The proposals suggest significant structural innovation, with a potentially large burden on either National Grid, market participants or another.	All funding costs require significant market innovation and, as highlighted in the report, the legality of the cash flow options needs further clarity.	No Comment.
Gazprom Energy	No response.	No response.	No response.	No response.	No response.
Haven Power	Yes. We use National Grid's Monthly Balancing Services Summary (MBSS) report and other certain assumptions in	N/A.	Transferring the risk from suppliers and generators to National Grid would be appropriate. National	We agree with any over/under recoveries should be redistributed through a higher/lower charge in a charging	To justify this modification, the reduction in risk premia will need to outweigh any cost that the risk

	our own forecast.		Grid has a better credit rating than suppliers and generators, a lower cost of capital to fund and vast experience in forecasting BSUoS.	season twelve months after the initial over-under recovery.	carrying party incurs. Evidence in paragraph 2.53 in report shows that the potential benefits of this mod outweighs increase in costs the industry may incur.
Hudson Energy Supply UK	Yes, but we'd like to see the BSUoS forecast improve.	N/A.	National Grid should hold the risk for the period.	Not sure what you mean by this question.	Not sure what you mean by this question.
InterGen	Yes, InterGen use the annual forecast for inclusion in our SRMC for making forward trading decisions in the wholesale markets. Also use the Day Ahead forecast provided by National Grid to update the SRMC for trading decisions close to delivery. Due to the high level of volatility observed around the daily average provided InterGen does look at the value in combination with other factors, including how the price might be profiled across the HH periods in	No.	This risk should not reside with generators / market participants. National Grid are best placed to forecast the costs incurred as they are taking the decisions to balance the system and have full sight of all of the procurement. If BSUoS resided 100% on the demand side then generators would be able to fully exclude these charges and the associated volatility risk and sell power at reduced levels.	No comment	No comment.

	correlation with the cost of balancing actions taken by National Grid.				
Opus Energy	The National Grid forecast has not been useful to us because it has been a material underestimation of actual BSUoS costs in recent years.	No comment	It is a system cost, that cannot be accurately placed against a particular part of the system, so should be best managed in one place rather than sliced to each company as happens now. The cost is ultimately governed by the level of uncertainty in the system and the cost of capital of the body providing cost stability. Provided the cost of capital used is sufficiently low, given the risk aggregation and guaranteed recovery; and National Grid is adequately controlled to ensure it does not simply add its own risk premium to the numbers if produces there should be a net benefit to customers in placing it with National Grid.	It is key that the financial cost of financing the cash flow does not increase the cost of BSUoS (in the short-term or the long-term) by an amount which exceeds the risk premiums that this modification will avoid. We would not support a solution which required suppliers to lodge credit cover by cash or letter of credit.	A forecast that is truly based around the expected value of the cost and does not include any premia.

RWE NPower	We use the MBSSS report as an indication of some costs. We consider that National Grid's forecast in isolation is consistently below out-turn and therefore does not provide a reliable indication of the cost of BSUoS.	Not at this time.	We consider that the cost should be stabilised by the SO and that they should explore appropriate mechanisms to fund this stabilisation. We consider that the SO should be exposed to some risk to provide an incentive to accurately forecast the rate in each year. In addition we consider that National Grid should be able to forecast BSUoS far more accurately than it currently does and therefore the risk will be far less than that currently faced by market participants.	We consider that the TO's who have far lower costs of capital than market participants should contribute to the SO's financing of BSUoS stabilisiation.	We consider that BSUoS should be fixed for a cost reflective value. This would provide best value as opposed to risk adjusted pricing carried out by many participants.
Scottish Power Energy Management	Our business makes use of all of the information on costs published by National Grid including BSUoS forecast when preparing our estimate of BSUoS costs / charges.	Please see our answer to Question 12.	We believe that the risk associated with forecasting BSUoS charges should lie with the National Grid as the SO who is in possession of information not available to market participants and is therefore better placed	Setting up SPVs would be administratively complex and would potentially increase overall costs to consumers. We believe that the least complex and most cost effective solution would be for National Grid to finance	No response provided.

			to manage this risk. This is supported by Annex 5.	with equity and debt.	
Smartest Energy Limited	Clearly, we take it into consideration.	No.	The risk should remain with market participants.	Building up a reserve through a premium is an inappropriate additional charge on consumers. We can equally understand that NGT do not wish to hold anything on their balance sheet or incur costs associated with any other funding. There is a reason why things are the way they are.	£0.00/MWh would represent good value but we don't agree with the premise of the question.
Tesco	Our supplier has shown us the National Grid forecast. Generally this is not a very reliable input for us as costs are generally not always up to date with the latest information.	No comment.	No comment.	No comment.	£0.07/MWh as mentioned in the report is really the highest it should be. Without any details of how this can be calculated we cannot comment any further.
Uniper UK / E.ON UK	The National Grid BSUoS forecast forms part of the information used to form our own forecast. National Grid's views, provided in its forecast and through	It is unlikely that a specific premium is applied per se to reflect this risk, but it is included implicitly in the costing/pricing decisions which people take in	Centrally managing the risk is inevitably going to be more efficient than individual parties doing so, particularly as there is no real mechanism for parties to hedge BSUoS	We would not support option 2 whereby the industry is clearly responsible for funding the cash flow. This would prevent the second of the benefits	It is difficult to determine how the value would be measured. However, we believe that in principle the proposal would deliver benefits to the market and ultimately

	other routes such as the Operational Forum, are an important source of information.	response to their forecast of BSUoS. That is, if a cost is known to be very volatile, forecasting scenarios used for costing purposes will reflect this. Of course, the market will ensure that suppliers are not too risk averse in this, so that they remain competitive.	in the open market. It would also seem to be more efficient for a single regulated entity to manage the cash-flows arising from the fixed price mechanism, if there is a regulatory settlement (licence condition) which allows that entity always to recover its money. This should attract a lower cost of capital than parties in the competitive market are able to do (i.e. present payers of BSUoS). This should reduce the cost to customers.	outlined in the answer to Q15 above from being realised. The other options should be pursued with a view to leveraging lower costs of capital, which should be forthcoming if the arrangement is underwritten through a regulatory settlement enshrined in National Grid's transmission licence.	customers as described in our responses to previous questions.
VPI Immingham	We use our own modelled assessment of BSUoS costs to feed into commercial decisions, but sense check it against the National Grid forecast on an ongoing basis.	We are not comfortable sharing this information believing it to be commercially sensitive.	We believe that National Grid are best placed to manage the risk having lower cost of capital and an existing methodology for forecasting BSUoS, plus existing mechanisms for cost recovery that could mirror the new arrangements.	We think it is appropriate to continue with the status quo and to conduct a more detailed analysis of what goes into BSUoS costs and how and from whom these are recovered. Therefore, we support the "today" position. Should the modification	We do not understand this question. However, as we do not support the modification as currently stands, we do not see any value associated with fixing BSUoS and would not support increasing costs in order to fix it.

			Whilst the Workgroup Consultation document refers to these costs as industry costs, we do not support this point of view. National Grid, as System Operator, makes all decisions regarding procurement and use of the services and therefore has full control over the costs. It just so happens that National Grid is then allowed to recover the costs from industry players.	be implemented, we think it appropriate that National Grid as System Operator finances the costs, with appropriate incentive schemes in place to ensure industry costs are managed efficiently.	
WM Morrison Supermarkets PLC	We are aware of National Grid's forecast as this is generally communicated to us via our supplier. We are conscious that there is generally a large disparity on the forecast provided by National Grid and the advice given by our supplier.	No comment.	No comment.	No comment.	As answered in question 12, we would accept that a value below £0.07/MWh would be an appropriate cost to enable certainty of BSUoS costs. We would expect however that over time the cost should start to naturally fall as improvements in forecasting are achieved through this process.

7 How to Respond

7.1 If you wish to respond to this Code Administrator Consultation, please use the response pro-forma which can be found under the 'Industry Consultation' tab via the following link;

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP250/

Or

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP250/

7.2 Responses are invited to the following questions;

1. Do you believe CMP250 or its alternative solution better facilitates the Applicable CUSC Objectives? Please include your reasoning.

2. Do you support the proposed implementation approach? If not, please provide reasoning why.

3. Do you have any other comments?

7.3 Views are invited on the proposals outlined in this consultation, which should be received by 5pm on 15 December 2017. Please email your formal response to:

CUSC.team@nationalgrid.com

7.4 If you wish to submit a confidential response, please note the following;

7.5 Information provided in response to this consultation will be published on National Grid's website unless the response is clearly marked 'Private & Confidential', we will contact you to establish the extent of this confidentiality. A response marked 'Private & Confidential' will be disclosed to the Authority in full by, unless agreed otherwise, will not be shared with the CUSC Modifications Panel or the industry and may therefore not influence the debate to the same extent as a non-confidential response.

7.6 Please note an automatic confidentiality disclaimer generated by your IT System will not in itself, mean that your response is treated as if it had been marked 'Private & Confidential'

7.7 Additionally, the Authority would encourage Industry participants to respond directly to them if participants have information which they consider may assist the Authority when making its determination but would prefer it not to be made publicly available (for example, how they forecast and apply risk premium within their businesses). Please respond directly to David.McCrone@ofgem.gov.uk by 31 January 2018 at the latest.

Annex 1 – CMP250 CUSC Modification Proposal Form

CUSC Modification Proposal Form (for Charging Methodology Proposals) CMP250

nationalgrid

Connection and Use of System Code (CUSC)

Title of the CUSC Modification Proposal

Stabilising BSUoS with at least a twelve month notification period

Submission Date

19/08/15

Description of the Issue or Defect that the CUSC Modification Proposal seeks to address

Balancing Service Use of System (BSUoS) Charges are the means by which the System Operator (SO) recovers the costs associated with balancing the transmission system. BSUoS charges are levied on both generation and demand on a 50:50 split basis. The value of BSUoS varies in each half hour settlement period reflecting the different costs incurred by the SO in each period.

Generators seek to recover the cost of BSUoS from prices available in the wholesale market. In effect the cost of BSUoS is one component of a generator's Short Run Marginal Cost (SRMC). Unfortunately, the cost of BSUoS is only known ex-post once values are published by the SO, so a generator can only estimate the cost of BSUoS. This has not been particularly problematic in the past as the cost of BSUoS was relatively stable. However, with a fast evolving generation mix, specifically the rapid increase in intermittent renewable generation, the costs of balancing the system are increasing and becoming much more volatile between settlement periods. This impact will persist and intensify with the drive to meet government environmental targets.

The lack of certainty ahead of time and increasing volatility is making it increasingly difficult for generators to estimate the cost of BSUoS. This unpredictability leads to two clear problems:

1. If the generator underestimates the cost of BSUoS there is a risk that the generator could sell power at a loss.
2. If the generator overestimates the cost of BSUoS it could result in the generator pricing itself out of the wholesale market.

Ultimately, increased volatility and unpredictability ahead of time can result in increasing risk premiums being applied by generators to their power and ancillary service sales. Where this is uniformly applied, it will result in an increased cost to the consumer.

Suppliers (and some generators) commit to power sales seasons in advance to match the length of customer contracts. Suppliers need to estimate the cost of BSUoS over the length of the customer contract. Suppliers may add a risk premium to their estimate of BSUoS, as underestimating BSUoS could result in loss making contracts owing to current low profit margins prevalent in the market. However, overestimating BSUoS could make a supplier

uncompetitive in the retail market and thus damage its competitive position, reducing profitability. Again, where risk premiums are applied uniformly in the retail market, the cost will ultimately be borne by the end consumer.

The defect this modification seeks to address is that industry parties have no real certainty of their BSUoS costs when forward contracting their power. This is directly caused by the current BSUoS charging methodology that produces a highly volatile and unpredictable cost. This modification allows parties to know ahead of time what their BSUoS charge will be, and to reallocate this risk from those parties that are poorly placed to manage the risk, in particular smaller market participants, to a party that is better suited to deal with it thereby better facilitating Applicable CUSC Charging Objective (a). Consequently, the total risk premium, and therefore total cost of BSUoS recovered from end consumers, will decrease, thereby increasing competition throughout the industry and benefiting consumers through lower costs and increased certainty surrounding their energy bills.

Description of the CUSC Modification Proposal

The best way to reduce the risk premia applied by market participants is to eliminate BSUoS volatility and unpredictability. We initially propose this be achieved by fixing the value of BSUoS over the course of a season (April – September, October – March). The length of the fix (initially suggested as a season) and the profile of how this is set is open to discussion by the workgroup. A notification period of at least 12 months ahead of the charging season should be introduced. A Working Group should evaluate the optimum notification period. The within season risk of over and under recovery of BSUoS revenues will be borne by the SO. This risk could be outsourced to a party with a large credit portfolio to appropriately manage the risk (e.g. a financial institution). The proposal transfers the forecasting risk from suppliers and generators to the SO. We consider this to be appropriate as the risk will be better managed by a regulated business with a better credit rating and lower cost of capital to fund. Further, the SO are already well placed to handle this responsibility as they have the resources and experience surrounding BSUoS and will be able to calculate and communicate the over/under recoveries to the rest of the industry.

BSUoS under/over recoveries would be redistributed through a higher/lower charge respectively in a charging season 12 months, or the length of the notification period, after the initial under/over recovery. For example, an under recovery in summer of the 15/16 charging year could be reflected in a higher BSUoS charge winter of the 16/17 charging year. The exact under/over arrangements should be determined by the Working Group.

Further, the current half hourly settlement of BSUoS should still be published in the spirit of openness and transparency. The publication of the cost of half hourly periods would allow the industry to better predict future BSUoS costs and allows for better transparency as to what has transpired.

Impact on the CUSC

Changes to section 14.

Do you believe the CUSC Modification Proposal will have a material impact on Greenhouse Gas Emissions? Yes / No

No

Impact on Core Industry Documentation. Please tick the relevant boxes and provide any supporting information

BSC ☐

Grid Code ☐

STC ☐

Other ☒

BSIS

It is possible that Ofgem may review some of the parameters in the RIIO-T1 price control to ensure that the SO can efficiently finance them given the need to stabilise revenues collected by BSUoS at least 12 months ahead. This may result in a need to change the Transmission Licence (subject to consultation).

A specific BSUoS incentive scheme (which may include an incentive to minimise BSUoS over/under recovery) may be necessary. A possible impact on SO incentive scheme may also need to be considered.

Documentation relating to BSUoS forecasting will need to be updated – potentially supplementing the CMP208 solution.

Urgency Recommended: Yes / No

No

Justification for Urgency Recommendation

N/A

Self-Governance Recommended: Yes / No

No

Justification for Self-Governance Recommendation

N/A

Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews?

No

Impact on Computer Systems and Processes used by CUSC Parties:

There will be an impact on computer systems used by CUSC parties and possibly a large impact to the SO's computer systems.

Details of any Related Modification to Other Industry Codes

N/A

Justification for CUSC Modification Proposal with Reference to Applicable CUSC Objectives for Charging:

Please tick the relevant boxes and provide justification for each of the Charging Methodologies affected.

Use of System Charging Methodology

☒ (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

☐ (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

☐ (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

☐ (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.
These are defined within the National Grid Electricity Transmission plc Licence under

Standard Condition C10, paragraph 1.

Objective (c) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).

Full justification:

Both suppliers and generators often sell power months or years ahead meaning a volatile and unpredictable BSUoS charge creates a financial risk which is ultimately passed onto the consumer. Fixing the BSUoS charge ahead of time and moving the risk onto a party that is more financially capable of dealing with it means suppliers and generators will be able to price their power more competitively, thereby better facilitating Applicable CUSC Objectives (charging) (a). Further, reducing the risk will facilitate market entry thereby further increasing competition.

Additional details

Details of Proposer: (Organisation Name)	Drax Power Limited
Capacity in which the CUSC Modification Proposal is being proposed: (i.e. CUSC Party, BSC Party or "National Consumer Council")	CUSC Party
Details of Proposer's Representative: Name: Organisation: Telephone Number: Email Address:	 Cem Suleyman Drax Power Limited 01757 612338 cem.suleyman@drax.com
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	 Joseph Underwood Drax Power Limited 01757 612736 joseph.underwood@drax.com
Attachments (Yes/No): No. **If Yes, Title and No. of pages of each Attachment:**	

Contact Us

If you have any questions or need any advice on how to fill in this form please contact the Panel Secretary:

E-mail cusc.team@nationalgrid.com

Phone: 01926 653606

For examples of recent CUSC Modifications Proposals that have been raised please visit the National Grid Website at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/Current/

Submitting the Proposal

Once you have completed this form, please return to the Panel Secretary, either by email to jade.clarke@nationalgrid.com copied to cusc.team@nationalgrid.com, or by post to:

Jade Clarke
CUSC Modifications Panel Secretary, TNS
National Grid Electricity Transmission plc
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

If no more information is required, we will contact you with a Modification Proposal number and the date the Proposal will be considered by the Panel. If, in the opinion of the Panel Secretary, the form fails to provide the information required in the CUSC, the Proposal can be rejected. You will be informed of the rejection and the Panel will discuss the issue at the next meeting. The Panel can reverse the Panel Secretary's decision and if this happens the Panel Secretary will inform you.

Annex 2 – CMP250 Terms of Reference

nationalgrid

Workgroup Terms of Reference and Membership
TERMS OF REFERENCE FOR CMP250 WORKGROUP

CMP250 aims to eliminate BSUoS volatility and unpredictability by proposing to fix the value of BSUoS over the course of a season, with a notice period for fixing this value being at least 12 months ahead of the charging season.

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP250 'Stabilising BSUoS with at least a twelve month notice period'** tabled by Drax Power at the CUSC Modifications Panel meeting on 28 August 2015.

2. The proposal must be evaluated to consider whether it better facilitates achievement of the Applicable CUSC Objectives. These can be summarised as follows:

   Use of System Charging Methodology

   (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity

   (b) that compliance with the use of system charging methodology results in charges which reflect, as far as practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

   (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

   (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

3. It should be noted that additional provisions apply where it is proposed to modify the CUSC Modification provisions, and generally reference should be made to the Transmission Licence for the full definition of the term.

Scope of work

4. The Workgroup must consider the issues raised by the Modification Proposal and consider if the proposal identified better facilitates achievement of the Applicable CUSC Objectives.

5. In addition to the overriding requirement of paragraph 4, the Workgroup shall consider and report on the following specific issues:

   a) *Implementation*
   b) *Review draft legal text*
   c) *Consider who picks up the costs of transferring the risk.*
   d) *Consider whether transferring the risk has a consumer benefit*
   e) *Can CMP250 be applied with an independent SO?*
   f) *Technical and commercial implementation for customers*
   g) *Consider effect of charging volatility/ predictability/ HH/ Day ahead/Year ahead/*
   h) *Minimum notification period required to make a material difference*

6. The Workgroup is responsible for the formulation and evaluation of any Workgroup Alternative CUSC Modifications (WACMs) arising from Group discussions which would, as compared with the Modification Proposal or the current version of the CUSC, better facilitate achieving the Applicable CUSC Objectives in relation to the issue or defect identified.

7. The Workgroup should become conversant with the definition of Workgroup Alternative CUSC Modification which appears in Section 11 (Interpretation and Definitions) of the CUSC. The definition entitles the Group and/or an individual member of the Workgroup to put forward a WACM if the member(s) genuinely believes the WACM would better facilitate the achievement of the Applicable CUSC Objectives, as compared with the Modification Proposal or the current version of the CUSC. The extent of the support for the Modification Proposal or any WACM arising from the Workgroup's discussions should be clearly described in the final Workgroup Report to the CUSC Modifications Panel.

8. Workgroup members should be mindful of efficiency and propose the fewest number of WACMs possible.

9. All proposed WACMs should include the Proposer(s)'s details within the final Workgroup report, for the avoidance of doubt this includes WACMs which are proposed by the entire Workgroup or subset of members.

10. There is an obligation on the Workgroup to undertake a period of Consultation in accordance with CUSC 8.20. The Workgroup Consultation period shall be for a period of 3 weeks as determined by the Modifications Panel.

11. Following the Consultation period the Workgroup is required to consider all responses including any WG Consultation Alternative Requests. In undertaking an assessment of any WG Consultation Alternative Request, the Workgroup should consider whether it better facilitates the Applicable CUSC Objectives than the current version of the CUSC.

As appropriate, the Workgroup will be required to undertake any further analysis and update the original Modification Proposal and/or WACMs. All responses including any WG Consultation Alternative Requests shall be included within the final report including a summary of the Workgroup's deliberations and conclusions. The report should make it clear where and why the Workgroup chairman has exercised his right under the CUSC to progress a WG Consultation Alternative Request or a WACM against the majority views of Workgroup members. It should also be explicitly stated where, under these circumstances, the Workgroup chairman is employed by the same organisation who submitted the WG Consultation Alternative Request.

12. The Workgroup is to submit its final report to the Modifications Panel Secretary on 23 March 2017 for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on 31 March 2017.

Membership

13. It is recommended that the Workgroup has the following members:

Role	Name	Representing
Chairman	~~Nikki Jamieson~~ **John Martin**	Code Administrator
*National Grid Representative**	~~Nick Pittarello~~ / **Jon Wisdom**	National Grid
*Industry Representatives**	Garth Graham	SSE
	~~Jon Wisdom~~ / **Helen Inwood**	Npower
	Peter Bolitho	Waters Wye
	Lee Taylor	Engie
	Christopher Granby	Infinis
	Cem Suleyman (proposer)	Drax Power
	Paul Jones	Uniper
	~~Binoy Dharsi~~ / **Simon Vicary**	EDF
	James Anderson	Scottish Power
Authority Representatives	Donald Smith	Ofgem
Technical secretary	Heena Chauhan	Code Administrator
Observers		

NB: A Workgroup must comprise at least 5 members (who may be Panel Members). The roles identified with an asterisk in the table above contribute toward the required quorum, determined in accordance with paragraph 14 below.

14. The Chairman of the Workgroup and the Modifications Panel Chairman must agree a number that will be quorum for each Workgroup meeting. The agreed figure for CMP250 is that at least 5 Workgroup members must participate in a meeting for quorum to be met.

15. A vote is to take place by all eligible Workgroup members on the Modification Proposal and each WACM. The vote shall be decided by simple majority of those present at the meeting at which the vote takes place (whether in person or by teleconference). The Workgroup chairman shall not have a vote, casting or otherwise. There may be up to three rounds of voting, as follows:

- Vote 1: whether each proposal better facilitates the Applicable CUSC Objectives;
- Vote 2: where one or more WACMs exist, whether each WACM better facilitates the Applicable CUSC Objectives than the original Modification Proposal*;*
- Vote 3: which option is considered to BEST facilitate achievement of the Applicable CUSC Objectives. For the avoidance of doubt, this vote should include the existing CUSC baseline as an option.

The results from the vote and the reasons for such voting shall be recorded in the Workgroup report in as much detail as practicable.

16. It is expected that Workgroup members would only abstain from voting under limited circumstances, for example where a member feels that a proposal has been insufficiently developed. Where a member has such concerns, they should raise these with the Workgroup chairman at the earliest possible opportunity and certainly before the Workgroup vote takes place. Where abstention occurs, the reason should be recorded in the Workgroup report.

17. Workgroup members or their appointed alternate are required to attend a minimum of 50% of the Workgroup meetings to be eligible to participate in the Workgroup vote.

18. The Technical Secretary shall keep an Attendance Record for the Workgroup meetings and circulate the Attendance Record with the Action Notes after each meeting. This will be attached to the final Workgroup report.

19. The Workgroup membership can be amended from time to time by the CUSC Modifications Panel.

Appendix 1 – Indicative Workgroup Timetable

The following timetable is indicative for CMP250

7 September 2015	Deadline for comments on Terms of Reference / nominations for Workgroup membership
7 October 2015	Workgroup meeting 1
20 October 2015	Workgroup meeting 2
2 November 2015	Workgroup meeting 3
3 December 2015	Workgroup meeting 4
19 January 2016	Workgroup meeting 5
29 February 2016	Workgroup meeting 6
7 March 2016	Workgroup Consultation issued for 1 week Workgroup comment
14 March	Deadline for comment
15 March 2016	Workgroup Consultation published (for 20 working days)
14 April 2016	Deadline for responses

w/c 18 April 2016	Workgroup meeting 7 (Review consultation comments)
April 16 to October 17	Workgroup meeting 8 – 18 Report Development
30 October 2017	Workgroup meeting 19 (Workgroup vote)
8 November 2017	Circulate draft Workgroup Report
14 November 2017	Deadline for comment
16 November 2017	Submit final Workgroup Report to Panel
24 November 2017	Present Workgroup Report at CUSC Modifications Panel

Post Workgroup modification process

24 November 2017	Code-Administrator Consultation published (15 days)
15 December 2017	Deadline for responses
3 January 2018	Draft FMR published
10 January 2018	Deadline for comments
18 January 2018	Draft FMR issued to CUSC Panel
26 January 2018	CUSC Panel Recommendation vote
2 February 2018	Final CUSC Modification Report submitted to Authority
9 March 2018	Indicative Decision Date
1 April 2018	Implementation in CUSC *(assuming decision provided before 31 March 2018, if decision provided after 31 March 2018 then Implementation will take place 1 April 2019)*

Annex 3 – Workgroup attendance register

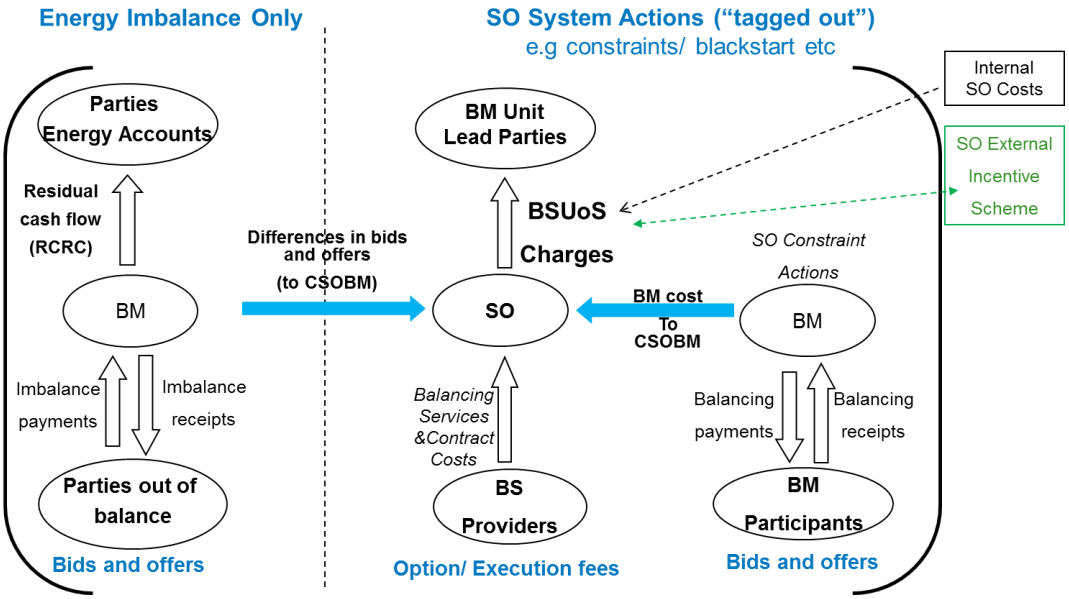
A – Attended
X – Absent
O – Alternate
D – Dial-in

			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Organisation	Role	Name	7/10/15	23/10/15	2/11/15	3/12/15	19/01/16	29/02/16	22/4/16	10/05/16	8/6/16	24/6/16	18/7/16	01/8/16	17/10/16	16/11/16	02/5/17	13/6/17	10/7/17	3/10/17	30/10/17
National Grid	Chair	(Mtg1-Pat Hynes) Nikki Jamieson till 16/11/16 John Martin till 30/10/17	A	A	O	A	A	D	A	O (Wayne Mullins	O (Paul Wakeley)	O (Paul Wakeley)	O (Paul Wakeley)	O (Paul Wakeley)	O (John Martin)	A	A	D	D	A	A
National Grid	Tech Sec	Heena Chauhan (Alternate is Jade Clarke)	A	A	A	A	A	O D	A	A	A	A	A	A	A	A	A	D	D	A	A
Drax Power	Proposer	Cem Suleyman	A	A	A	A	A	D	A	A	A	A	A	A	A	A	A	D	D	A	A
National Grid	Workgroup member	Nick Pittarello till 16 Oct/ Jon Wisdom from 17 Oct 2016	A	A	A	A	A	D	A	A	A	A	A	A	A	A	A	D	D	A	A
N	Workgroup	Jonathan	A	A	A	A	A	D	A	A	A	A	A	A	A	A	D	D	D	A	A

Power	member	Wisdom till 17 Jul 2016 Helen Inwood from 18 Jul 2016																			
SSE	Workgroup member	Garth Graham (Alternate is John Tindall)	A	A	D	X	O D	O D	A	D	D	A	A	D	X	X	D	D	D	D	D
Waters Wye	Workgroup member	Peter Bolitho	A	A	A	A	A	D	A	X	A	A	A	A	X	A	A	D	X	A	A
GDF Suez	Workgroup member	Lee Taylor (Alternate is Simon Lord / Jonathan Kane)	A	X	D	A	O D (Simon Lord)	D	X	D	D	X	X	D	X	O (Jonathan Kane)	D	X	D	D	X
EON	Workgroup member	Paul Jones (Alternate is Guy Phillips)	A	X	X	A	A	O D	A	A	A	A	A	A	A	A	A	D	D	A	A
EDF Energy	Workgroup member	Binoy Dharsi (Alternate is Simon Vicary) till 16 Oct/ Simon Vicary from 17 Oct 2016	A	A	O	A	A	D	A	A	X	A	A	X	A	A	D	D	D	A	A
Scottish Power	Workgroup member	James Anderson	A	A	A`	D	A	D	A	X	A	A	X	D	X	A	D	D	D	X	A
Infinis	Workgroup member	Christopher Granby	A	X	X	X	D	D	A	A	A	A	A	A	X	X	A	X	X	X	A
Ofgem	Authority Representative	Donald Smith	D	A	A	X	A	D	D	D	D	X	D	D	D	D	D	D	D	D (Charlie Friel)	X

The Workgroup attendance register tracks the attendance of the Workgroup so that you can see how many people have attended when it comes to the Workgroup vote. In order to vote, Workgroup members need to have attended at least 50% of Workgroup meetings (either in person, teleconference or by sending an alternate) to be eligible to vote.

Annex 4 – How RCRC interacts with BSUoS prices



Balancing Services Use of System Charges are made up of a number of component parts, but they fall into two camps, either those costs relating purely to energy imbalance – whether the market is long or short, and those costs relating to actions taken by the SO for resolving constraints and maintaining system integrity – holding reserve generation, voltage control, and black start.

Looking at energy imbalance, any costs incurred by the SO to resolve energy imbalance become part of CSOBM (Costs to the SO taken in the BM). However any imbalance payments made by out of balance market participants are redistributed across all market participants.

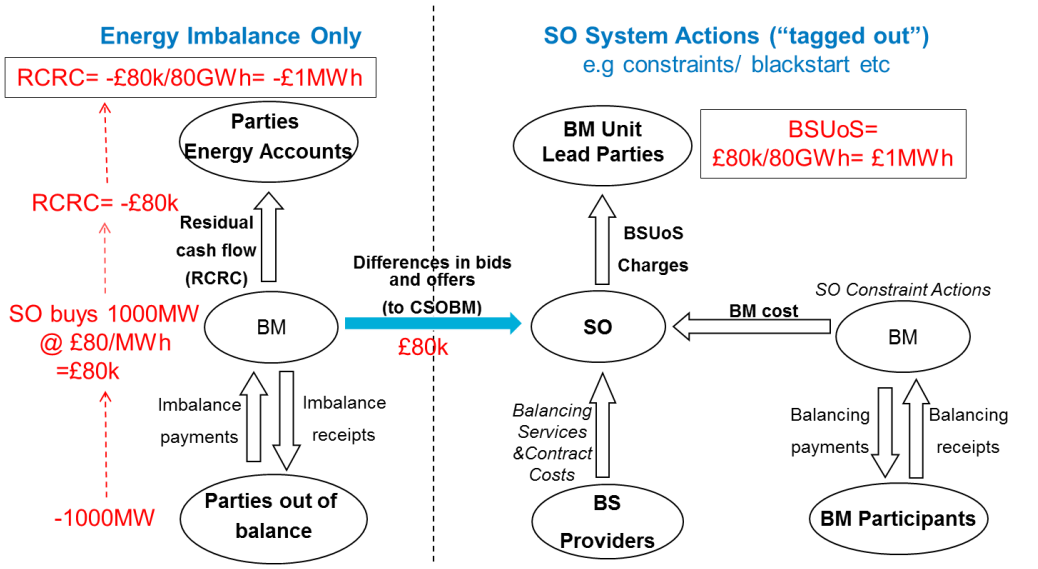
The SO may also take actions in the BM to resolve constraints, reducing output from power stations behind constrained boundaries and replacing that energy in zones not affected by that constraint. This costs money and these costs feed through to CSOBM.

Finally, the SO also signs contracts with parties to provide specific services, and these option and execution fees are apportioned across relevant settlement periods.

BSUoS charges also include internal SO costs – which would include our control rooms and my salary, and an external incentive scheme also known as BSIS (Balancing Services Incentive Scheme) where National Grid is incentivised to keep costs to a minimum. The current scheme has a 30% sharing factor, so for every £1 saved against the target price, £0.70 is shared with industry, up to a cap of £30m either way.

Example 1 – Simple Imbalance

- Supplier under-contracted by 1000MW (SO incurs £80k,Supplier pays £80k)
- Total demand for the half hour = 80GWh, SBP £80/MWh

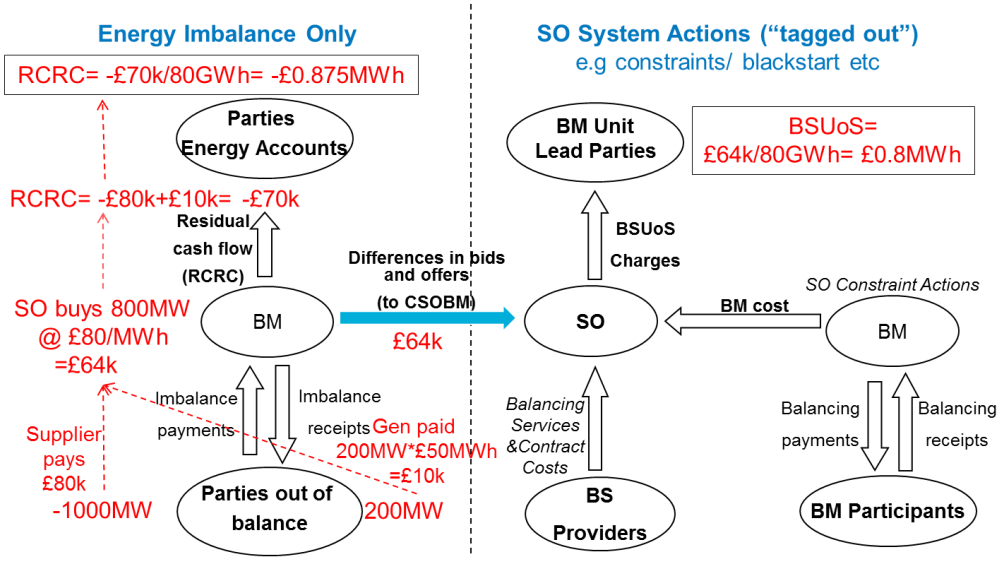


RCRC and BSUoS net to zero, 3rd parties not exposed

The following slides explain some simple scenarios. In this example we have a supplier under-contracted by 1000MW. The SO would need to resolve that imbalance and would buy 1000MW in the market at £80/MWh and incur a cost of £80k. The Supplier would pay an imbalance payment of £80k and this would go into the RCRC pot. RCRC would then be -£1/MWh. Similarly, if this was the only action that the SO had taken, market participants would be charged £1/MWh. So clearly the two net to zero, and only the out of balance supplier forks out. This acts as an incentive for market participants to balance their positions.

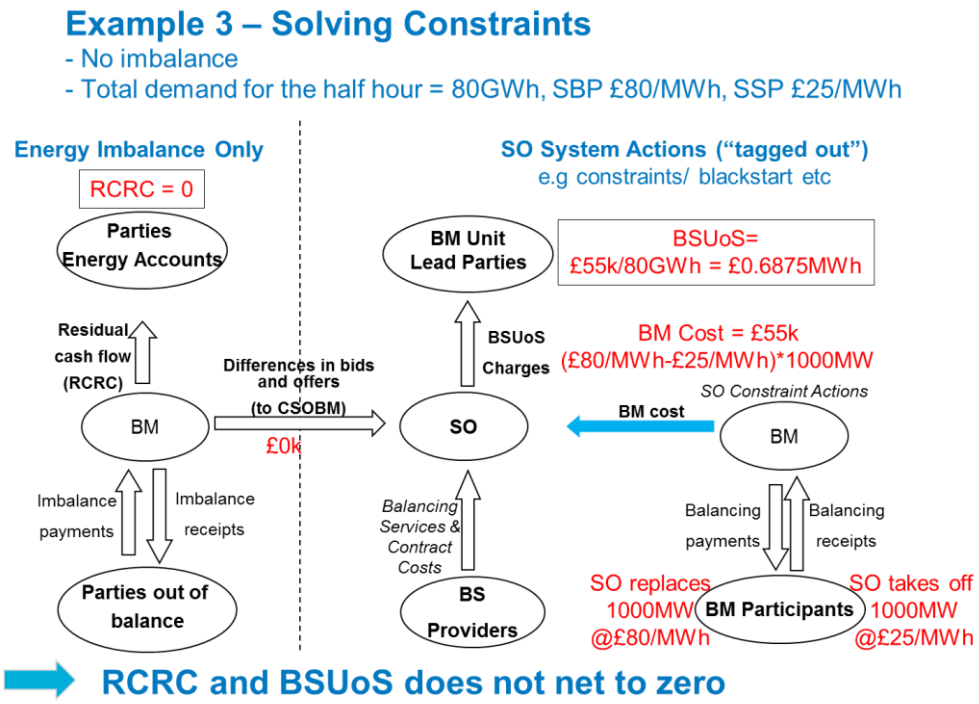
Example 2 – Dual Imbalance

- Supplier under-contracted by 1000MW, Generator spills 200MW
- Total demand for the half hour = 80GWh, SBP £80/MWh, SSP £50/MWh



RCRC and BSUoS are not related

If a party is now added that is spilling onto the system, they would be cashed out at SSP (System Sell Price), in this example £50/MWh and receive £10k. Combined with the £80k of our out of balance Supplier, the RCRC pot would be a bit lower at £70k. The SO however would only need to procure 800MW and would spend £64k in the BM. In this case, RCRC and BSUoS are not the same and do not net-off.



Finally, in this example, there is perfect energy balance, but the SO needs to resolve a constraint. With RCRC equal to zero as there is no energy imbalance, the BSUoS charge is the cost of resolving the constraint.

Appendix 10.4: Cost of capital

Contents

Page

Introduction 1
General approach to estimating the WACC 2
CMA estimation of WACC 4
Interpretation of WACC 32

Introduction

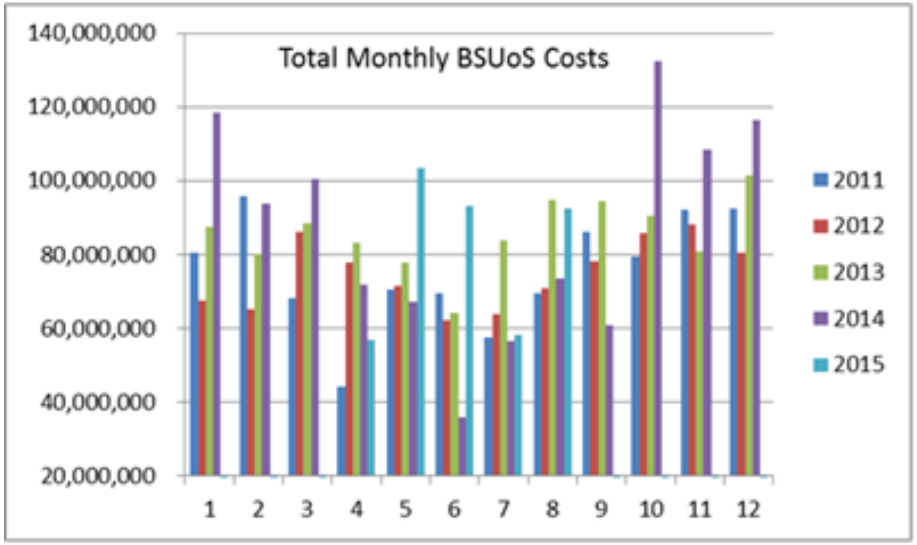
1. The approach to assessing profitability, as set out in the Guidelines,[1] is to compare the profits earned with an appropriate cost of capital. In this appendix, we set out our estimate of the nominal pre-tax weighted average cost of capital (WACC) for the various elements of the energy value chain in Great Britain (GB), based on data for the period January 2007 to March 2014.

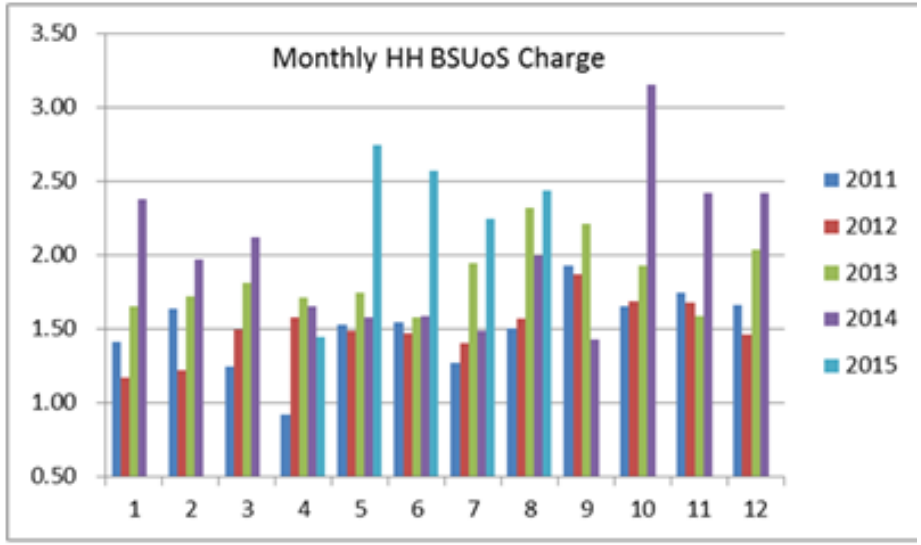
2. Our estimate of the WACC of a stand-alone electricity generator is between 8.2 and 10.0%, while a retail supply business would be entirely equity funded with a cost of equity of 9.3 to 11.5%.

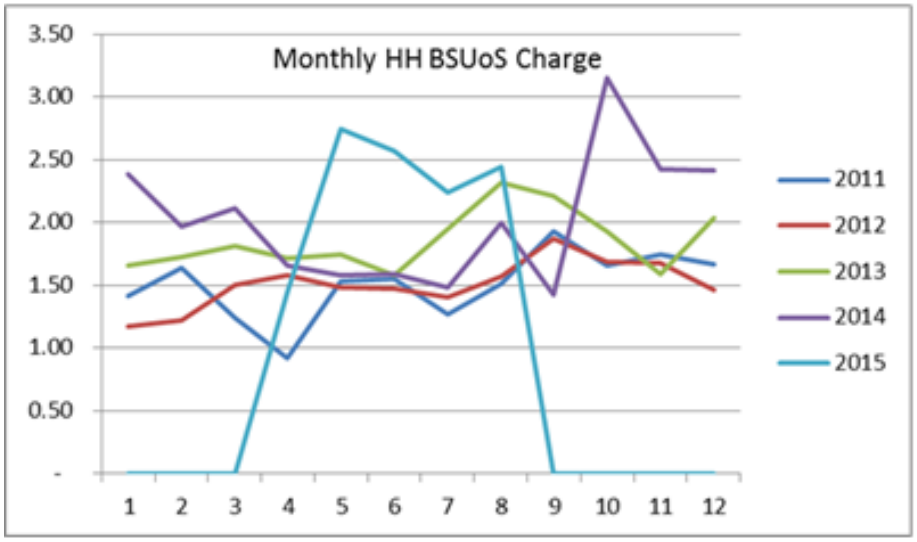
Table 1: CMA estimates of the WACC for the elements of the energy value chain

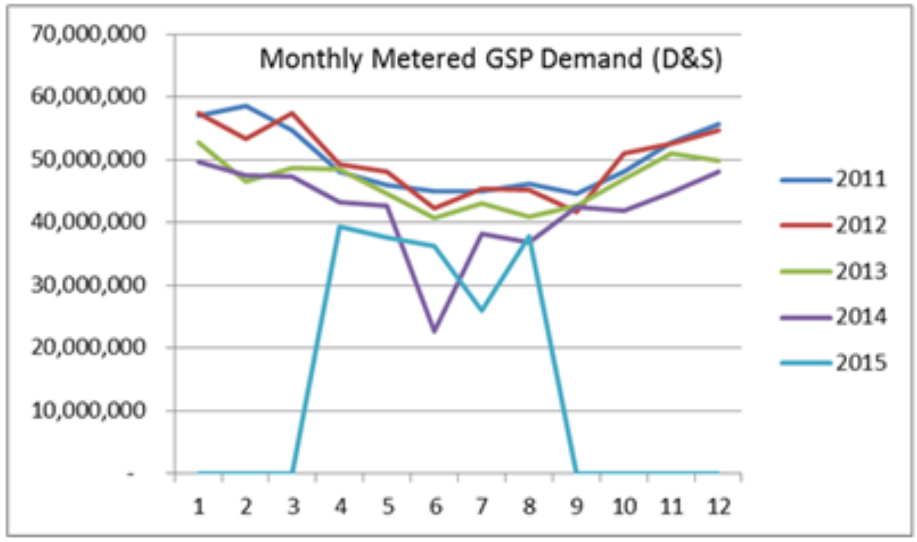
	Generation	*Retail supply*
Real risk-free rate (%)	1.0	1.0
Nominal risk-free rate (%)	4.0	4.0
Equity risk premium (%)	4.0–5.5	4.0–5.5
Asset beta	0.5–0.6	0.7–0.8
Pre-tax Ke (%)	9.1–10.4	9.3–11.5
Pre-tax cost of debt (Kd) (%)	6.0–7.0	-
Gearing (%)	10.0–30.0	0
Tax rate (%)	27.0	27.0
Pre-tax WACC (%)	**8.2–10.0**	**9.3–11.5**

Annex 6 – Monthly BSUoS charts 2011-2015

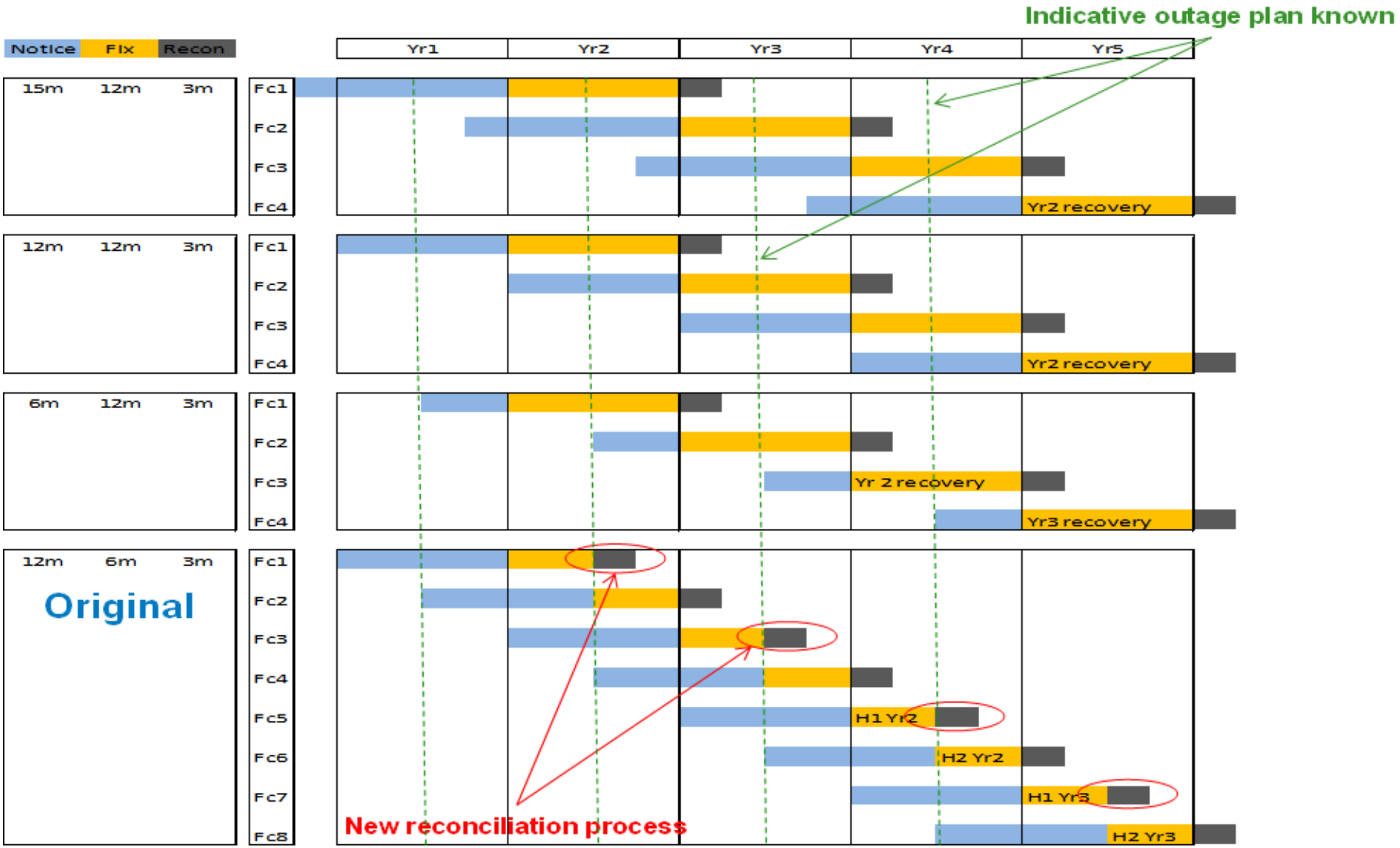






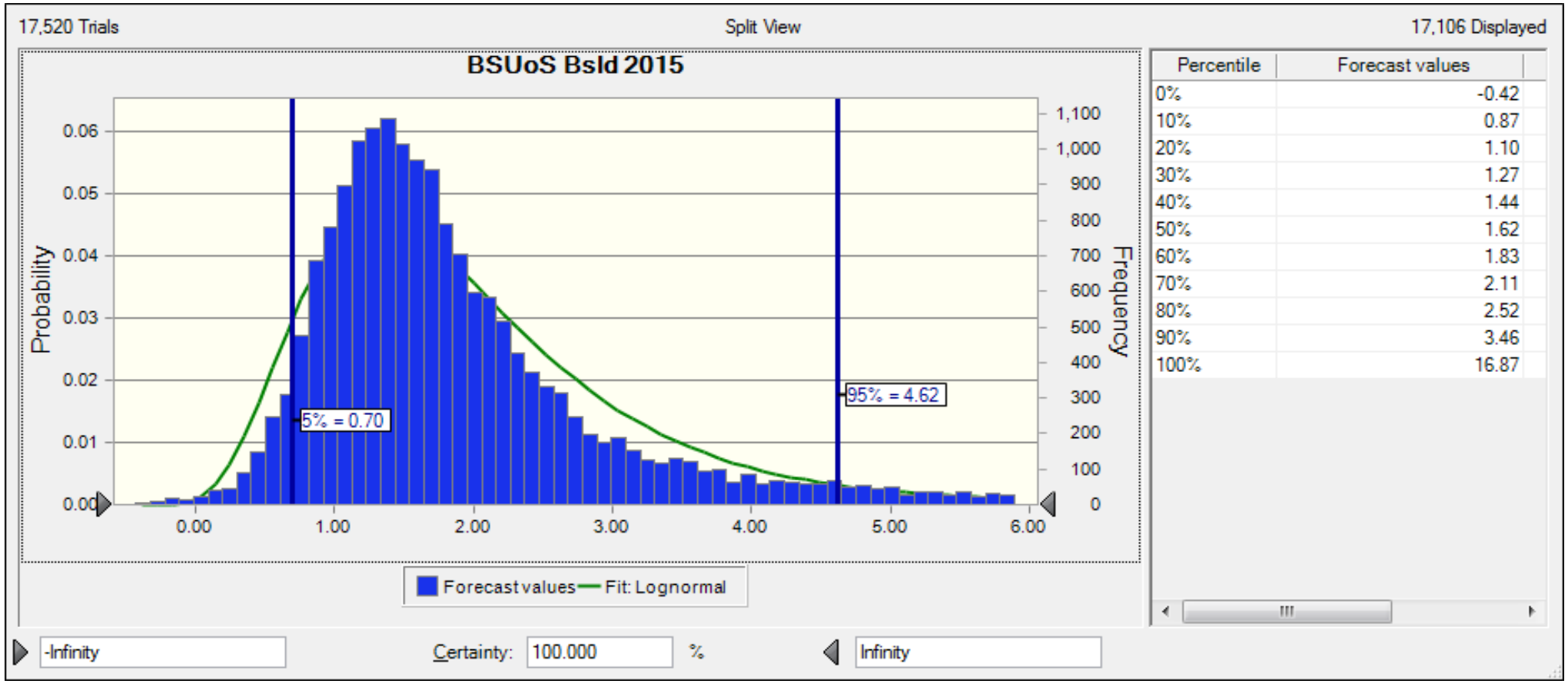


Annex 7 – Interaction between notification and fixed price time periods



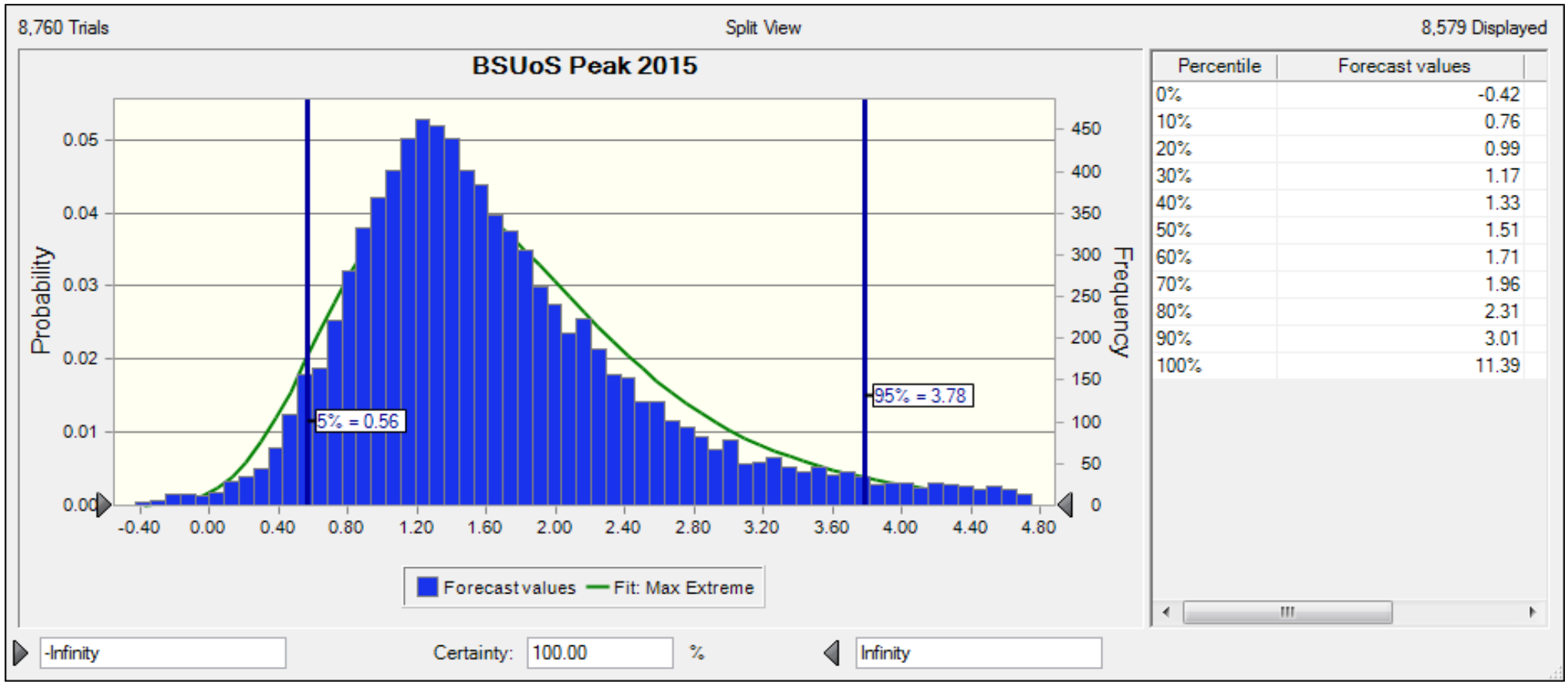
Annex 8 – Generation and Supply BSUoS risk premium analysis

(i) BSUoS Distribution for Baseload trading period in 2014/15



Percentile	Forecast values
0%	-0.42
10%	0.87
20%	1.10
30%	1.27
40%	1.44
50%	1.62
60%	1.83
70%	2.11
80%	2.52
90%	3.46
100%	16.87

(ii) BSUoS Distribution for Peak trading period in 2014/15



(iii) BSUoS Distributions

2011/12 P Values (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	0.58	0.84	1.02	1.20	1.37	1.55	1.77	2.08	2.54	2.99	6.97
Extended Peak	0.60	0.85	1.04	1.22	1.38	1.55	1.77	2.05	2.50	2.94	6.97
Block 5	0.50	0.77	0.97	1.17	1.34	1.55	1.77	2.11	2.66	3.06	6.65
Baseload	0.60	0.85	1.04	1.22	1.39	1.57	1.78	2.08	2.60	3.13	10.65

2012/13 P Values (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	0.51	0.75	0.94	1.11	1.29	1.49	1.73	2.01	2.46	2.91	6.64
Extended Peak	0.55	0.79	0.98	1.14	1.32	1.51	1.73	2.00	2.45	2.88	7.29
Block 5	0.42	0.69	0.89	1.07	1.25	1.48	1.76	2.12	2.60	3.15	6.64
Baseload	0.62	0.86	1.05	1.21	1.39	1.58	1.80	2.06	2.50	2.96	8.56

2013/14 P Values (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	0.66	0.96	1.20	1.42	1.64	1.86	2.12	2.48	3.02	3.59	9.56
Extended Peak	0.73	1.02	1.25	1.45	1.66	1.87	2.13	2.47	3.00	3.57	9.56
Block 5	0.60	0.92	1.15	1.38	1.64	1.89	2.21	2.58	3.14	3.73	9.10
Baseload	0.78	1.07	1.29	1.49	1.69	1.91	2.17	2.51	3.08	3.72	9.56

2014/15 P Values (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	0.76	0.99	1.17	1.33	1.51	1.71	1.96	2.31	3.01	3.78	11.39
Extended Peak	0.81	1.05	1.22	1.38	1.55	1.75	1.99	2.34	3.00	3.75	11.39
Block 5	0.78	1.02	1.20	1.38	1.57	1.77	2.07	2.47	3.20	3.98	9.41
Baseload	0.87	1.10	1.27	1.44	1.62	1.83	2.11	2.52	3.46	4.62	16.87

2015/16 P Values (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	0.56	0.93	1.18	1.41	1.62	1.87	2.19	2.64	3.38	4.13	11.57
Extended Peak	0.66	0.99	1.24	1.46	1.67	1.93	2.24	2.67	3.39	4.11	11.57
Block 5	0.53	0.90	1.15	1.40	1.62	1.88	2.19	2.62	3.36	4.00	9.33
Baseload	0.77	1.10	1.36	1.58	1.83	2.12	2.50	3.04	4.01	5.38	11.57

(iv) BSUoS premiums and discounts compared to outturn BSUoS

2011/12 Percentiles (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	-0.91	-0.65	-0.47	-0.29	-0.12	0.06	0.28	0.59	1.05	1.50	5.48
Extended Peak	-0.88	-0.63	-0.44	-0.26	-0.10	0.07	0.29	0.57	1.02	1.46	5.49
Block 5	-0.98	-0.71	-0.51	-0.31	-0.14	0.07	0.29	0.63	1.18	1.58	5.17
Baseload	-0.92	-0.67	-0.48	-0.30	-0.13	0.05	0.26	0.56	1.08	1.61	9.13

2012/13 Percentiles (£/MWh)	P10	P20	P30	P40	P50	P60	P70	80	P90	P95	P100
Peak	-0.90	-0.66	-0.47	-0.30	-0.12	0.08	0.32	0.60	1.05	1.50	5.23
Extended Peak	-0.88	-0.64	-0.45	-0.29	-0.11	0.08	0.30	0.57	1.02	1.45	5.86
Block 5	-1.00	-0.73	-0.53	-0.35	-0.17	0.06	0.34	0.70	1.18	1.73	5.22
Baseload	-0.88	-0.64	-0.45	-0.29	-0.11	0.08	0.30	0.56	1.00	1.46	7.06

2013/14 Percentiles (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	-1.12	-0.82	-0.58	-0.36	-0.14	0.08	0.34	0.70	1.24	1.81	7.78
Extended Peak	-1.06	-0.77	-0.54	-0.34	-0.13	0.08	0.34	0.68	1.21	1.78	7.77
Block 5	-1.19	-0.87	-0.64	-0.41	-0.15	0.10	0.42	0.79	1.35	1.94	7.31
Baseload	-1.07	-0.78	-0.56	-0.36	-0.16	0.06	0.32	0.66	1.23	1.87	7.71

2014/15 Percentiles (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	-0.99	-0.76	-0.58	-0.42	-0.24	-0.04	0.21	0.56	1.26	2.03	9.64
Extended Peak	-0.97	-0.73	-0.56	-0.40	-0.23	-0.03	0.21	0.56	1.22	1.97	9.61
Block 5	-1.04	-0.80	-0.62	-0.44	-0.25	-0.05	0.25	0.65	1.38	2.16	7.59
Baseload	-1.11	-0.88	-0.71	-0.54	-0.36	-0.15	0.13	0.54	1.48	2.64	14.89

2015/16 Percentiles (£/MWh)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	-1.29	-0.92	-0.67	-0.44	-0.23	0.02	0.34	0.79	1.53	2.28	9.72
Extended Peak	-1.23	-0.90	-0.65	-0.43	-0.22	0.04	0.35	0.78	1.50	2.22	9.68
Block 5	-1.29	-0.92	-0.67	-0.42	-0.20	0.06	0.37	0.80	1.54	2.18	7.51
Baseload	-1.42	-1.09	-0.83	-0.61	-0.36	-0.07	0.31	0.85	1.82	3.19	9.38

(v) Outturn BSUoS

Average BSUoS Outturns (£/MWh)	2011/12	2012/13	2013/14	2014/15	2015/16
Peak	1.49	1.41	1.78	1.75	1.85
Extended Peak	1.48	1.43	1.79	1.78	1.89
Block 5	1.48	1.42	1.79	1.82	1.82
Baseload	1.52	1.50	1.85	1.98	2.19

(vi) Total system costs – under or over recovery

2011/12 Percentiles (£m)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	298)	(213)	(154)	(95)	(39)	20	92	193	344	491	1,794
Extended Peak	(386)	(277)	(194)	(116)	(46)	28	124	247	443	635	2,394
Block 5	(106)	(77)	(55)	(33)	(15)	8	32	69	129	173	565
Baseload	(603)	(440)	(315)	(197)	(86)	32	169	366	706	1,053	5,976

2012/13 Percentiles (£m)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	(298)	(219)	(156)	(100)	(40)	26	105	198	347	495	1,729
Extended Peak	(387)	(281)	(197)	(127)	(47)	37	134	253	451	641	2,586
Block 5	(110)	(81)	(59)	(39)	(19)	6	37	77	130	191	575
Baseload	(583)	(425)	(299)	(193)	(74)	52	197	369	660	965	4,669

2013/14 Percentiles (£m)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	(355)	(260)	(183)	(113)	(43)	27	110	225	397	578	2,481
Extended Peak	(452)	(329)	(231)	(146)	(57)	32	143	287	512	755	3,300
Block 5	(126)	(92)	(68)	(43)	(16)	11	45	84	144	206	777
Baseload	(685)	(500)	(360)	(233)	(105)	35	201	418	781	1,189	4,911

2014/15 Percentiles (£m)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	(307)	(236)	(180)	(130)	(74)	(11)	67	176	394	633	3,004
Extended Peak	(403)	(303)	(233)	(166)	(95)	(12)	87	233	507	818	3,991
Block 5	(108)	(83)	(65)	(46)	(26)	(6)	26	67	143	224	788
Baseload	(692)	(548)	(443)	(337)	(224)	(94)	81	336	922	1,644	9,275

2015/16 Percentiles (£m)	P10	P20	P30	P40	P50	P60	P70	P80	P90	P95	P100
Peak	(386)	(275)	(200)	(131)	(68)	7	103	238	460	685	2,917
Extended Peak	(493)	(361)	(261)	(173)	(89)	15	139	311	599	887	3,871
Block 5	(129)	(92)	(67)	(42)	(20)	6	37	80	54	218	751
Baseload	(854)	(656)	(500)	(368)	(218)	(44)	184	508	1,090	1,912	5,626

Annex 9 – Elective Approach

The Workgroup discussed an Elective Approach which was later discounted. For completeness, this view is shown below;

In view of the difficulty in establishing the risk premia currently applied by industry, and therefore establishing the cost benefit of an universally applied fixed BSUoS price, one Workgroup member suggested that giving industry participants the choice of whether to fix their BSUoS price for a fee, might be viewed as a preferable approach as each participant would be able to make an independent choice over whether it was cost effective.

The key aspect of this approach is that BSUoS costs would have to be split between those participants remaining on the ex post variable price as today, and those electing the ex-ante fixed price. Over or under recoveries for the "fixed" participants would be factored into the fixed price in future charging years, and so it would be important to ensure the appropriate parties were exposed to those over or under recoveries.

At the beginning of a notification period, the SO would declare a fixed BSUoS price including management fee to apply for the relevant fixed price period. Market participants would choose whether to go fixed or variable and the Workgroup discussed how this could be done in one of 3 possible ways:

- A market participant would nominate a volume, by BMU to which the ex-ante fixed price would be applied
- A market participant would nominate a percentage of its volume by BMU to which the ex-ante fixed price would apply
- A market participant (Supplier or Generator) would make an indefinite one-off decision to be either 100% fixed or 100% variable.

Some Workgroup members thought that declaring a volume would prove difficult for generators because it would not be possible to accurately identify plant generation volumes 15-11 months ahead after balancing actions had been taken into account. Further, if a power station broke down, then the question arises whether they should be liable for the fixed price against the initial volume declared. There is a risk of creating perverse barriers to exist which could be detrimental to competition.

By declaring a percentage of the total volume by BMU, some Workgroup members considered that it might be possible for market participants to move volume between Supplier IDs within or between years, one registered as fixed and the other as variable. In this way, it might be possible to avoid BSUoS costs to which they should be liable, depending on the original election decision.

To avoid the above disadvantages it was suggested Suppliers or Generators should make an indefinite one-off decision for all of their volume to be either fixed or variable, which would address the above disadvantages.

A spreadsheet model was discussed which could illustrate how the variable and fixed price "pots" would be managed under a number of scenarios, showing clearly that only those that elect to fix the BSUoS price during a charging year are exposed to any over/under recoveries between years. As this option was not supported as a viable solution to this defect by the Workgroup, a model was not developed.

Annex 10 – Workgroup Consultation Responses

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **14th April 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Kashif Afsar (*kashif.afsar@crowncommercial.gov.uk)
Company Name:	*Crown Commercial Service*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Yes on the understanding that this proposal achieves stability of BSUoS charges at a low cost to customers.
2	**Do you support the proposed implementation approach?**	No comment.
3	**Do you have any other comments?**	No.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	No comment.
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	BSUoS volatility does have some impact on our business.
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	No comment.

Q	Question	Response
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	No comment.
9	**Do you believe BSUoS is a useful price signal?**	Whilst we are unable to predict BSUoS and hence it would not necessarily be a strong price signal, the seasonality and weighting between times of the day can provide some benefit for certain participants. We believe this can support the demand shifting of load in particular.
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	We are inclined to support a shaped BSUoS curve. A shaped HH BSUoS curve is more desirable than a flat shape as: o A flat shape penalises customers/ generators with a flatter shape o A flat BSUoS shape reduces the incentive for customers to demand shift load. o A shaped BSUoS curve would still allow generators to dispatch stations with greater certainty
11	**What are your thoughts on notification lead times and the length of the price fix period?**	No comment.

Q	Question	Response
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	No comment.
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	No comment.
14	**If applicable, are you able to share your approach to calculating risk premia?**	No comment.
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	No comment.
16	**What is your view on the above cashflow financing approaches?**	No comment.
17	**What would you regard as good value to enable a fixed BSUoS price?**	We value certainty of costs but are unable to determine a suitable cost. We would pay a very small proportion of the total BSUoS cost to achieve some cost certainty.

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

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Please send your responses by **14th April 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Joe Underwood– Joseph.Underwood@drax.com– 01757 612736*
Company Name:	*Drax*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
16	**What is your view on the above cashflow financing approaches?**	We recognise these options are still at an early stage of development and would encourage National Grid to continue its dialogue with financial institution(s) to assist in designing the optimum option to finance the cashflow risk. Whilst recognising this point, we have the following views on the options suggested: We do not consider that Option 2 is likely to be the optimum solution. This is because this will involve relying on the cost of capital of market participants, which in the vast majority of cases is likely to be greater than National Grid's cost of capital. This is unlikely to keep the costs borne by consumers to a minimum. Conversely, the need to keep costs to a minimum means we have an initial preference for Option 1. We believe this will allow for the use of National Grid's superior cost of capital with respect to industry. We consider that, depending on the tenor of the required funding, a revolving credit facility as opposed to a term loan may offer the more cost effective option and may better meet the risks associated with BSUoS over/under recovery. However, there may be merit in exploring a longer term facility to allow access to alternative sources of debt. Further investigation should be undertaken to determine the most cost effective approach. With regards to the Special Purpose Vehicle (SPV) options, we consider that the merits of these options will depend to a great extent on the exact recourse arrangements. A better understanding of the regulatory treatment of such an option would also be helpful. At a high level, we would expect that the SPV options are likely to be more costly compared to Option 1. This is because the financial institution may consider that the real risk of a failure to repay lies with market participants rather than the SPV. However, on the other hand, SPVs are typically able to take on a greater degree of leverage which may help reduce costs. We'd also note that SPVs will always require some level of equity from the sponsor. In conclusion, we initially consider that Option 1 will provide the most cost effective option. The SPV options may also have some attractions depending on the detailed arrangements. We do not consider that Option 2 will deliver a cost effective solution.

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Yes. The defect this modification seeks to address is that industry parties have no real certainty of their BSUoS costs when forward contracting their power. This is directly caused by the current BSUoS charging methodology that produces a highly volatile and unpredictable cost. This modification allows parties to know ahead of time what their BSUoS charge will be, and to reallocate this risk from those parties that are poorly placed to manage the risk, in particular smaller market participants, to a party that is more financially capable of dealing with it thereby better facilitating Applicable CUSC Charging Objective (a). Consequently, the total risk premium, and therefore total cost of BSUoS recovered from end consumers, will decrease, thereby increasing competition throughout the industry and benefiting consumers through lower costs and increased certainty surrounding their energy bills.
2	**Do you support the proposed implementation approach?**	Yes
3	**Do you have any other comments?**	No
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	Yes, as seen in pages 5-8 of the workgroup report.
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	Yes. As BSUoS is not known until ex post and can be seen to be getting more volatile and unpredictable, industry participants include a risk premia in order to protect themselves in the event of a high BSUoS cost. If the BSUoS in a settlement period spikes, a previously profit-making sale could become loss-making. A fixed BSUoS charge will allow industry participants to more keenly price their wholesale power.

Q	Question	Response
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	No. No party can predict how BSUoS varies therefore no party can have a competitive advantage, especially in forward trading timescales. There are far too many unpredictable variables e.g. demand, wind output, etc.
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	Drax considers that, provided BSUoS is fixed for a given period of time, an over/under recovery of costs should not considerably impact an industry participant. Drax considers that the workgroup has shown the benefits and cost savings through the reduction of the risk premia CMP250 will introduce far outweighs any additional cost incurred to the industry. It should also be noted that a lot of costs that are included in the BSUoS charged are smeared across half hour periods already. There are no discernible price signals and therefore Drax considers the BSUoS charge a cost recovery mechanism and not a market signal. As BSUoS is ex post, generators cannot accurately predict BSUoS. Further, BSUoS can give potentially perverse signals. For example, a high BSUoS cost can result from system constraints caused by intermittent generation being bought down. The high BSUoS price associated with this may incentivise flexible generation to turn down which is not desirable in this circumstance.
9	**Do you believe BSUoS is a useful price signal?**	No. Please see answer to question 8 above.
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry? Please explain your reasons.**	The costs will be recovered over the year so it should not matter. It can be seen from the table on page 11 of the workgroup report that there is no discernible pattern in BSUoS prices by day, half hour, or season. Given this we see no merit in profiling. However, if a strong argument is brought forward we will be happy to consider.

Q	Question	Response
11	**What are your thoughts on notification lead times and the length of the price fix period?**	Drax considers that a long notification period to be best in order to allow parties to trade effectively along the forward curve. As the majority of wholesale power is sold 12-18 months ahead, the proposed 12 month lead time with 6 month price fix is optimal. We accept providing 12 months' notice as oppose to 6 months' notice will be more difficult in terms of forecasting. However, the benefits of the longer notice period in reducing trading risk further along the curve outweighs any additional difficulty associated with forecasting (as demonstrated in figure 5 of the workgroup report).
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	The methodology detailed through paragraphs 2.67 to 2.85 is subject to a number of simplifying assumptions as the possible risk premia industry apply as a result of ex post BSUoS charging is difficult to model. However, the model gives a likely impact of the risk premia with the upper and lower bounds being above any additional cost that industry may incur through the impact of fixing BSUoS. While we are not aware of an improved method of modelling this risk premia, we welcome other suggested potential modelling techniques.
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	The National Grid BSUoS forecast can be used as a useful guide. However, we use certain different assumptions in our own forecast.
14	**If applicable, are you able to share your approach to calculating risk premia?**	N/A
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	We believe that the risk should sit with a party that has a low cost of capital and is financially capable of holding such a risk. This party will be able to fulfil this role more effectively and at a lower cost than industry participants. National Grid is a good candidate to fulfil this role. Further, National Grid also has a good view of the market with strong expertise in forecasting.

Q	Question	Response
17	**What would you regard as good value to enable a fixed BSUoS price?**	To justify this modification, the reduction in risk premia must outweigh any cost that the risk carrying party incurs. The evidence in the workgroup report from paragraph 2.53 shows that the potential benefits of CMP250 greatly outweighs any increase in cost that industry participants may incur.

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

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Please send your responses by **14th April 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Binoy Dharsi (binoy.dharsi@edfenergy.com)*
Company Name:	*EDF Energy*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Yes. We believe by stabilising BSUoS costs for participants it facilitates effective competition and thus meets CUSC objective a. We also believe that whilst not all BSUoS costs are currently allocated specifically in the period in which the cost was incurred the adjustment of future years with an under or over recovery would not adversely impact CUSC objective b and on balance be neutral.
2	**Do you support the proposed implementation approach?**	Yes. An implementation that would achieve an initial six months of stability from 1st April 2018 by 1st April 2017 is supported.
3	**Do you have any other comments?**	We have had many of our customers in the B2B sector tell us that they support this proposal and they have informed us that an implementation date as earlier as practicably possible would be favoured.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	Yes. We have looked at BSUoS data since 2005 and the analysis is consistent with the information in the workgroup consultation report that demonstrates BSUoS is becoming more volatile. We find that providing our customers with potential BSUoS ranges is also increasing. Something they have pointed out to us makes it more difficult in deciding what types of contract terms (pass-through or fixed) to consider.
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	Yes. For EDF Energy's supply business we need to be able to offer customers competitive prices whilst trying to forecasts costs that can vary considerably and are not known until after delivery.
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	No. We believe that no party has the ability to know in advance, with any degree of certainty, what the BSUoS costs are.

Q	Question	Response
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	Many networks costs have an ex-ante approach in which an under or over recovery mechanism is used. As long as sufficient notice is given of adjustments we are comfortable with this approach. EDF Energy does not believe that BSUoS is a cost signal because it is unknown until after the cost has been incurred.
9	**Do you believe BSUoS is a useful price signal?**	No. It is not known with absolute certainty, for many months after the System Operator has incurred costs, what the actual charges are. The ability for Income Adjusting events to be retrospectively applied highlights that BSUoS is an ex-post signal which cannot be reasonably acted upon.
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	We believe that BSUoS should be profiled as a flat value. The mechanism under proposal is simply to determine a variance that needs to be adjusted in a future period. Adding the complexity of a shaped curve serves no purpose.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	We support that a twelve-month notification period which sufficiently balances the period in which customers contract within and also the length of time contracts are signed for.

Q	Question	Response
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	There is no possible way to determine a standard risk premia that is applied because of the way different suppliers treat this charge. Suppliers are able to use Terms and Conditions to effectively give a risk premium of zero but then retrospectively re-bill customers if the actual value outturns higher than they had forecast. Some suppliers do not look to add risk premiums but forecast as accurately as possible. These suppliers will either benefit if their forecast is lower than the actual out turn or face increase in costs by under forecasting. Conversely the opportunity to win business with a forecast higher than the actual outturn lowers the chance of winning a contract whereas a forecast lower than the actual cost could mean acquiring business at a lower than expected margins or even a loss. There is also a timing risk premium that suppliers may wish to add. If a customer was offered a contract before information relating to a SBR tender was concluded the forecast could carry an element of risk associated with that outcome. If that same customer was offered a contract after the costs associated with the SBR tender was known this risk could well be reduced or negated. We therefore do not consider risk premia, in isolation, as an appropriate measure to judge benefits for customers. The wider competitiveness and transparency this will bring to customers is just as important.
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	We use many different sources to determine what our BSUoS forecast may be.
14	**If applicable, are you able to share your approach to calculating risk premia?**	No. Please see response to question 12.
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	The System Operator is best placed to manage this risk. The costs of any actions taken are not visible to the industry until after the event.

Q	Question	Response
16	**What is your view on the above cashflow financing approaches?**	We agree that a suitable loan facility is the best option. The right choice will all be dependent on value for money.
17	**What would you regard as good value to enable a fixed BSUoS price?**	We would not expect the ability to fix BSUoS using a loan facility to be any higher than £0.04 - £0.07/MWh. We expect that over time the amount of loan facility will reduce as the variance between the forecast and actual amount spent improves.

CUSC Workgroup Consultation Response Proforma

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Please send your responses by **14th April 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

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Respondent:	*Lee Taylor (lee.taylor@engie.com)*
Company Name:	*ENGIE*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	**No** – The key issue relating to the CUSC objective (b) is that introducing a flat BSUoS value removes the half hourly cost reflectivity of the charge and potentially removes a market signal for flexible generators to optimise running patterns. This would reduce costs for those who exacerbate the BSUoS volatility and share the cost amongst all market participants, distorting the market.
2	**Do you support the proposed implementation approach?**	No
3	**Do you have any other comments?**	No
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at cusc.team@nationalgrid.com*

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	We would generally agree with the evidence provided in the workgroup report, which demonstrates that BSUoS has 'become' more volatile. However, there is little evidence in the report to suggest that BSUoS volatility will continue in the future. Upgrades to the transmission network and changes to the generation mix will impact this volatility in the future.
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	Yes. The more extreme BSUoS events can generally be forecast and plant optimised on this basis, reducing risk and therefore the impact on the business.

[1] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/

Q	Question	Response
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	Yes, Predominantly from a generation perspective in the short term markets. Extremes in BSUoS outturn can be forecast on short term timescales (within week) and running profiles can be optimised on this basis. Those who are unable to make BSUoS forecasts (these are generally fairly simplistic and should be within the scope of most generator operators) or who are unable to optimise generation during highly volatile BSUoS periods are subsequently penalised, therefore providing cost reflectivity and providing additional value to flexibility. Volatility should encourage innovation.
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	The reallocation of BSUoS costs away from settlement periods and into a flat, fixed period potentially removes the cost reflectivity from BSUoS and distorts the signals being sent to market participants. Highly volatile BSUoS prices are typically *currently* correlated to high RES output and system constraint conditions. Plant which are unable to operate flexibly or that choose not to flex are essentially exposed to the high BSUoS. Those which can flex avoid such conditions and can factor this risk into running costs, therefore valuing the flexibility of those types of generators. Removing any type of signal for flexibility in the market seems counterintuitive to the requirements of the system.
9	**Do you believe BSUoS is a useful price signal?**	Yes. More extreme changes in BSUoS can be forecast in short term timescales and plant can be optimised. Extremes in BSUoS act as a signal for flexibility from generation assets.
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	If a fixed price is to be implemented, then a flat price seems the most sensible approach. Historic BSUoS price shapes are not necessarily an indicator of future shapes, particularly as the transmission network and generation mix change.

Q	Question	Response
11	**What are your thoughts on notification lead times and the length of the price fix period?**	From a generation perspective, the proposed notification and fixed BSUoS period seem reasonable. However, further consideration should be given to shorter term fixing periods (week or month ahead). This would potentially reduce the cash risk held by the SO (or industry/other) and allow NGC to provide the market with a more accurate forecast of BSUoS. Whilst the workgroup report acknowledges that longer term In addition, further consideration should be given to the length of the fixed period if the full potential benefit for consumers is realised. Whilst fairly short term contracts would benefit from the certainty given from fixing BSUoS on a 12 month notice/6 month fix, any longer term deals would have an element of BSUoS forecast – reflecting any over or under charges.
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	The workgroup report correctly identifies that using historic BSUoS as a marker for future risk premiums is limited, as changes to the transmission network and generation mix will greatly impact the magnitude of BSUoS volatility. Different market participants may have different views on the future system and different risk appetites. The report also acknowledges that power is transacted in multiple timescales, so recovering the risk premium from a single power transaction, without optimising the position closer to delivery, seems unlikely and potentially over estimates the premium added. In addition, the assessment of BSUoS risk premiums without the additional consideration of RCRC does not seem to fully cover the perceived risk exposure to balancing costs which the industry faces. The workgroup report correctly identifies that RCRC values have been diminishing since single cashout, although it is possible that additional volatility could occur in RCRC under very tight system conditions. Therefore, it does not seem that a robust baseline for the costs of the current system has been established. This means that evaluating alternatives is difficult.
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	No.

Q	Question	Response
14	**If applicable, are you able to share your approach to calculating risk premia?**	No.
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	Market participants are best placed to manage the risk. As indicated in previous questions, current arrangements follow a reasonable simple set of rules which can allow market participants to optimise assets and react to volatility in BSUoS. The key issue is that those parties that are willing and able to react to volatile BSUoS prices are not necessarily in the right place to reduce it. The proposals in the workgroup report suggest significant structural innovation, with a potentially large burden on either National Grid, market participants or another. The report is not clear on how a changing customer base (generators closing or new generators entering the market) would be treated under the proposed arrangements.
16	**What is your view on the above cashflow financing approaches?**	All funding costs require significant market innovation and, as highlighted in the report, the legality of the cashflow options needs further clarity.
17	**What would you regard as good value to enable a fixed BSUoS price?**	No Comment

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

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Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

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Respondent:	*Tom Breckwoldt* *tom.breckwoldt@gazprom-energy.com*
Company Name:	*Gazprom Energy*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We are supportive of CMP250. We agree with the proposer that BSUoS has becoming increasingly volatile and unpredictable in recent years, with National Grid's forecast not being accurate enough to rely upon. We believe greater certainty for suppliers of BSUoS costs will aid price setting for contracts where the cost of BSUoS is built in, as it will reduce the forecast error risk. This should benefit applicable CUSC objective A. We expect this will also be welcomed by pass-through customers who can see with more certainty and transparency ahead of delivery, the costs that they will be subject to in regards to BSUoS. For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging

	methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Yes CMP250 better facilitates CUSC objective A.
2	**Do you support the proposed implementation approach?**	Yes. We think implementation should be no later than April 2017.
3	**Do you have any other comments?**	
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	

Q	Question	Response
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	
9	**Do you believe BSUoS is a useful price signal?**	
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	We are in favour of a flat BSUoS rate because suppliers/consumers cannot respond to it and a flat rate is simpler. A profiled BSUoS may reward demand or generation decisions which do not necessarily benefit the system.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	

Q	Question	Response
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	
14	**If applicable, are you able to share your approach to calculating risk premia?**	
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	
16	**What is your view on the above cashflow financing approaches?**	
17	**What would you regard as good value to enable a fixed BSUoS price?**	

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

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Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

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Respondent:	*Richard Mawdsley – richard.mawdsley@havenpower.com*
Company Name:	*Haven Power*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Yes. We believe that the proposal would allow suppliers and generators to price their power more competitively, thereby better facilitating Applicable CUSC Objectives (a). Further, reducing the risk will facilitate market entry thereby further increasing competition.
2	**Do you support the proposed implementation approach?**	Yes.
3	**Do you have any other comments?**	No.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	Yes.
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	Yes. From a supplier perspective, overestimating BSUoS could make us uncompetitive in the retail market. Where this is applied across the market, the cost will ultimately fall to the end customer. A fixed BSUoS charge will allow industry participants to more accurately price their power.
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	No. Too many unpredictable variables make BSUoS difficult to predict.

Q	Question	Response
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	No. There are no obvious price signals and we consider the BSUoS charge a cost recovery mechanism and not a market signal. We believe that the benefits and cost savings through the reduction of the risk premia far outweigh any additional cost to the industry.
9	**Do you believe BSUoS is a useful price signal?**	No.
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	If the cost is to be recovered over the year it wouldn't matter.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	We feel that 12 months should be a minimum term. We would like to cite the relatively recent industry changes in both the DCUSA (DCP178) and the CUSC (CMP244) that have seen the respective notice periods for DUoS and TNUoS tariffs increase exponentially.

Q	Question	Response
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	While we are not aware of an improved method of modelling, we welcome other potential modelling techniques.
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	Yes. We use National Grid's Monthly Balancing Services Summary (MBSS) report and other certain assumptions in our own forecast.
14	**If applicable, are you able to share your approach to calculating risk premia?**	N/A
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	Transferring the risk from suppliers and generators to National Grid would be appropriate. National Grid has a better credit rating than suppliers and generators, a lower cost of capital to fund and vast experience in forecasting BSUoS.
16	**What is your view on the above cashflow financing approaches?**	We agree with any over/under recoveries should be redistributed through a higher/lower charge in a charging season twelve months after the initial over-under recovery.
17	**What would you regard as good value to enable a fixed BSUoS price?**	To justify this modification, the reduction in risk premia will need to outweigh any cost that the risk carrying party incurs. The evidence from paragraph 2.53 in the workgroup report shows that the potential benefits of CMP250 outweigh the increase in costs that industry may incur.

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

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Respondent:	*Richard Mawdsley – richard.mawdsley@havenpower.com*
Company Name:	*Haven Power*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Yes. We believe that the proposal would allow suppliers and generators to price their power more competitively, thereby better facilitating Applicable CUSC Objectives (a). Further, reducing the risk will facilitate market entry thereby further increasing competition.
2	**Do you support the proposed implementation approach?**	Yes.
3	**Do you have any other comments?**	No.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	Yes.
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	Yes. From a supplier perspective, overestimating BSUoS could make us uncompetitive in the retail market. Where this is applied across the market, the cost will ultimately fall to the end customer. A fixed BSUoS charge will allow industry participants to more accurately price their power.
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	No. Too many unpredictable variables make BSUoS difficult to predict.

Q	Question	Response
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	No. There are no obvious price signals and we consider the BSUoS charge a cost recovery mechanism and not a market signal. We believe that the benefits and cost savings through the reduction of the risk premia far outweigh any additional cost to the industry.
9	**Do you believe BSUoS is a useful price signal?**	No.
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	If the cost is to be recovered over the year it wouldn't matter.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	We feel that 12 months should be a minimum term. We would like to cite the relatively recent industry changes in both the DCUSA (DCP178) and the CUSC (CMP244) that have seen the respective notice periods for DUoS and TNUoS tariffs increase exponentially.

Q	Question	Response
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	While we are not aware of an improved method of modelling, we welcome other potential modelling techniques.
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	Yes. We use National Grid's Monthly Balancing Services Summary (MBSS) report and other certain assumptions in our own forecast.
14	**If applicable, are you able to share your approach to calculating risk premia?**	N/A
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	Transferring the risk from suppliers and generators to National Grid would be appropriate. National Grid has a better credit rating than suppliers and generators, a lower cost of capital to fund and vast experience in forecasting BSUoS.
16	**What is your view on the above cashflow financing approaches?**	We agree with any over/under recoveries should be redistributed through a higher/lower charge in a charging season twelve months after the initial over-under recovery.
17	**What would you regard as good value to enable a fixed BSUoS price?**	To justify this modification, the reduction in risk premia will need to outweigh any cost that the risk carrying party incurs. The evidence from paragraph 2.53 in the workgroup report shows that the potential benefits of CMP250 outweigh the increase in costs that industry may incur.

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

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Respondent:	*Ricky Cheng / John McPate* *rcheng@hudsonenergy.co.uk / jmpacte@hudsonenergy.co.uk*
Company Name:	*Hudson Enrgy*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	BSUoS has become more volatile and represents an increasing proportion of the overall cost of supplying energy to homes and businesses. The result is that it has become increasingly difficult for suppliers (especially the smaller suppliers) to forecast accurately. As such we are at risk of under recovery of our BSUoS costs. Fixing BSUoS charges will result in fewer discrepancies between actual BSUoS costs and related revenue recovery in any given period.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	N/A
2	**Do you support the proposed implementation approach?**	Yes in principle

Q	Question	Response
3	**Do you have any other comments?**	N/A
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	Yes
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	Yes – Volatility in BSUoS impacts pricing assumptions, leading to potential under recovery or competiveness
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	Most Big6 organisations and large generators will have teams to model BSUoS forecast costs, so as a smaller supplier we feel we are at an unfair disadvantage.

Q	Question	Response
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	Some form of Ex ante charging will benefit smaller suppliers in generating more stable and consistent returns verses planned budgets. Charge years should mirror financial periods and any over / under recovery in one charging year should then be reflected in the next years charges As a Supplier we don't currently have contractual arrangements in place that would allow an end user to respond to any price signals created by BSUoS activity in any HH
9	**Do you believe BSUoS is a useful price signal?**	Only if it is predictable, we do not have the resource to understand this currently
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	It should be shaped based on some understanding of the cost of actions taken to balance the system and when they are taken. Any reconciliation should then be applied based on actual cost of balancing for each HH
11	**What are your thoughts on notification lead times and the length of the price fix period?**	We would prefer a 12 month charging period issued 12 month in advance of the charging year

Q	Question	Response
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	Premia is acceptable – but the amount should be published and reconciled each year – benefit should passed on in following years
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	Yes, but we'd like to see the BSUoS forecast improve
14	**If applicable, are you able to share your approach to calculating risk premia?**	N/A
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	National Grid should hold the risk for the period
16	**What is your view on the above cashflow financing approaches?**	Not sure what you mean
17	**What would you regard as good value to enable a fixed BSUoS price?**	Not sure what you mean

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

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Respondent:	*Please insert your name and contact details (phone number or email address)*
Company Name:	*Please insert Company Name*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Yes.
2	**Do you support the proposed implementation approach?**	Yes.
3	**Do you have any other comments?**	Whilst beyond the scope of this modification we believe that BSUoS charges should be recovered 100% from the demand side. This will bring the GB charging regime in line with the EU Third Package. BSUoS forecasting risk should reside with National Grid and not with market participants.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at cusc.team@nationalgrid.com*

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	Yes.

[1] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/

Q	Question	Response
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	Yes. InterGen is a non-vertically integrated independent generator. InterGen operate and dispatch three CCGTs in the GB market amounting to approximately 2.5GW of capacity. BSUoS is a variable portion of the operating costs of these plants. Under the current regime this element is only known after the fact creating an unknown contribution to the costs of dispatching the plant. The MWs generated by the plants are largely hedged through the forward wholesale market at anything up to three years ahead of delivery. At this stage, an assumption is used for BSUoS, namely National Grid's most recent annual forecast. This results in opening up risk versus the out-turn BSUoS values which cannot be reasonably predicted with any level of accuracy over that timescale. For our plant, which typically is dispatched for short timescales to capture value in peak periods we do not benefit from smoothing/averaging of BSUoS over time. As such, we are exposed to the variance between the forecast BSUoS value provided by National Grid and the actual HH out-turn values. With the increased volatility of BSUoS, InterGen's plants have been subject to very large spikes in BSUoS resulting in uneconomic dispatch of the plant. In other words, due to increases in BSUoS we have lost money and with the benefit of hindsight would not have made the decision to dispatch the plant. Whilst National Grid do now provide a day ahead BSUoS forecast, this includes no HH profiling. It is also subject to a degree of inaccuracy. Across March 2016, there have been two occasions where the day ahead forecast has deviated from the average HH out-turn by over £1.00 (£1.50/MWh on the 22nd March). The £1.50/MWh increase in BSUoS versus the Day-Ahead forecast would result in a £27,000 increase in costs for one of our plants running baseload on that day.

Q	Question	Response
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	Whilst National Grid do now provide a day ahead BSUoS forecast, this includes no HH profiling. With the increasing number of constraint management actions required to be undertaken by National Grid, largely as a result of the renewable generation fleet generating at times of low demand, the forecasting of Grid's balancing actions is a necessary part of the dispatch decision, especially for marginal plant. The more accurately you can forecast the BSUoS, the better the decisions you will make and the less risk you will need to price in to account for possible variance in BSUoS charges. Thus a competitive advantage could be gained by BSUoS forecasting.
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	The existing ex post BSUoS charges are inappropriate for the levels of volatility now observed in BSUoS charges. With the increased penetration of intermittent renewable generation requiring frequent constraint management actions and more expensive balancing actions BSUoS has become highly volatile. Whilst National Grid provide a forecast of BSUoS at the day ahead stage it is often inaccurate and does not profile the charges across settlement periods. For flexible generation assets which typically will only run for short periods of the day in the peak periods or for 2-6 hours in the Balancing Mechanism the volatility in BSUoS can lead to loss making dispatch as the HH values of BSUoS can deviate significantly from the daily forecast average. It follows that this type of plant is dispatched in the Balancing Mechanism at times when Grid is incurring the greatest cost to balance the system and therefore the potential rise in BSUoS is highest also.
9	**Do you believe BSUoS is a useful price signal?**	Only BSUoS pricing that will be fixed and provided ahead of trading will be useful.

Q	Question	Response
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	Ideally, the BSUoS princing would be profiled to reflect the settlement periods when balancing costs are highest/lowest. However, due to the influence on this of intermittent generation this forecast will not be reflective if provided ahead of a charging year. Clearly, a fixed 'curve' profile that reflected the variance across a day of BSUoS would not reflect the dynamic nature of balancing actions day to day. This profile would also be quite difficult to price into the wholesale power price on the forward market as only Baseload and Peak products trade in any significant volume at greater than month ahead of delivery. For practical reasons it will be simplest to provide a single value. This will feed through efficiently to the wholesale markets.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	The prices could be fixed on a quarterly or seasonal basis (6 month terms to align with the wholesale market summer and winter products). This would allow some adjustment by National Grid to reflect the different forecasted costs of balancing the system in summer and winter. The notification lead time needs to strike the right balance between providing an early signal to the market and allowing National Grid to minimise the significant variables that feed into the BSUoS calculation.
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	InterGen do include a risk premium for volatility in BSUoS which feeds into the SRMC (short run marginal cost) for our power plants. As a result, the plants are not able to sell into the wholesale market or Balancing Mechanism at their most efficient/competitive price point. If this behaviour is replicated across the market then it will result in an uplift in wholesale prices with the end consumer ultimately penalised. If BSUoS resided 100% on the demand side then generators would be able to exclude these charges and the associated risk and sell power at reduced levels.

Q	Question	Response
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	Yes, InterGen use the annual forecast for inclusion in our SRMC for making forward trading decisions in the wholesale markets. InterGen also uses the Day Ahead forecast provided by National Grid to update the SRMC for trading decisions close to delivery. Due to the high level of volatility observed around the daily average provided InterGen does look at the value in combination with other factors, including how the price might be profiled across the HH periods in correlation with the cost of balancing actions taken by National Grid.
14	**If applicable, are you able to share your approach to calculating risk premia?**	No.
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	This risk should not reside with generators/market participants. National Grid are best placed to forecast the costs incurred as they are taking the decisions to balance the system and have full sight of all of the procurement involved from SBR and STOR through to real time Balancing Mechanism actions. If BSUoS resided 100% on the demand side then generators would be able to fully exclude these charges and the associated volatility risk and sell power at reduced levels.
16	**What is your view on the above cashflow financing approaches?**	No comment
17	**What would you regard as good value to enable a fixed BSUoS price?**	No comment

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **14th April 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Please insert your name and contact details (phone number or email address)*
Company Name:	*Opus Energy*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Yes, this modification is positive against applicable objective a). Transferring some of the BSUoS forecasting risk to National Grid will allow greater competition in the market as newer entrants with fewer resources to forecast BSUoS would be more able to compete.
2	**Do you support the proposed implementation approach?**	Yes
3	**Do you have any other comments?**	Opus Energy would suggest indicative charges for future periods or charging years should also be published periodically. As under and over recovery amounts build up it is vital that National Grid keep suppliers informed of these accrued values and the expected impacts of these on future years charges. As we consider National Grid to be the best suited for forecasting BSUoS charges, providing indicative charges will help reduce the forecasting risks for future periods.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at cusc.team@nationalgrid.com*

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	Yes.
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	Yes. The volatility of BSUoS results in an inherent risk that needs to be captured in our pricing. As BSUoS is never known at the point of pricing there is a significant risk to both profitability and efficient customer pricing.

[1] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/

Q	Question	Response
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	No comment
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	Fixing BSUoS charges will provide additional assurance when contracting with customers for terms within the forecast period, by removing the inherent uncertainty over the BSUoS charges. However customers contracted for a longer period would still be subject to the same, if not greater, risks as they currently face, owing to the additional consideration of the over/under recovery from revenue from previous years. We still consider this modification to beneficial overall. Settlement period level BSUoS charges do not currently provide us with a cost signal to which we or our customers (to the best of our knowledge) are able to respond. Typically customers have a bundled price for supply which is fixed over a period of time to give them budget certainty, so there is no notable impact on them to which they can respond.
9	**Do you believe BSUoS is a useful price signal?**	No comment

Q	Question	Response
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	The vast majority of customers of all sizes prefer a bundled product price that includes all costs. As such, a shaped BSUoS cost will provide no signal to the customer to change its behaviour. The value of this change is to reduce the cost of funding BSUoS through aggregating at a national level to a party with a low cost of capital, so applying any shaping is at best an approximation based on assumed 'average' conditions. The reality of actual system costs will always be different than any shape so it would be misplaced effort. As most wholesale trading occurs in baseload products it would be logical to assume that generators take a similar approach to mid-term risk management where this change would be most impactful, so shaping would not reduce the risk premia further.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	As illustrated in Annex 7, the 12-month notice, 6-month fixed charge will provide the best coverage throughout a charging year. By year 2, at least 12 months of BSUoS charges would be known at any point during the year, which would reduce with any shorter notification period.
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	No comment
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	The National Grid forecast has not been useful to us because it has been a material underestimation of actual BSUoS costs in recent years.
14	**If applicable, are you able to share your approach to calculating risk premia?**	No comment

Q	Question	Response
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	Fundamentally, the causes of balancing costs are the nature of the physical product, so it makes little difference to the actual cost where the risk sits. It is a system cost, that cannot be accurately placed against a particular part of the system, so should be best managed in one place rather than sliced to each company as happens now. The cost is ultimately governed by the level of uncertainty in the system (broadly linked to growing intermittent generation at this point) and the cost of capital of the body providing cost stability (if a customer product is fixed price, or a generator sales a fixed profile wholesale product). Provided the cost of capital used is sufficiently low, given the risk aggregation and guaranteed recovery; and National Grid is adequately controlled to ensure it does not simply add its own risk premium to the numbers if produces there should be a net benefit to customers in placing it with National Grid.
16	**What is your view on the above cashflow financing approaches?**	It is key that the financial cost of financing the cash flow does not increase the cost of BSUoS (in the short-term or the long-term) by an amount which exceeds the risk premiums that this modification will avoid. We would not support a solution which required suppliers to lodge credit cover by cash or letter of credit.
17	**What would you regard as good value to enable a fixed BSUoS price?**	A forecast that is truly based around the expected value of the cost and does not include any premia.

SCUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

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Please send your responses by **14th April 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Jonathan Wisdom – jonathan.wisdom@npower.com* *07584 491508*
Company Name:	*npower ltd*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	We believe that CMP250 better facilitates objective (a) as fixed BSUoS will encourage competition by stabilising a volatile and unpredictable element of the cost stack that cannot be forecasted accurately, hedged or known ahead of out-turn. Fixing BSUoS prices ahead of time and allowing parties to accurately reflect these in their costs will improve competition allowing parties to compete effectively on pricing and reduce costs to consumers through the removal of risk premia. Although we accept that a fixed BSUoS cost could be considered less cost reflective on a half hour by half hour basis we consider that there is no meaningful price signal within BSUoS costs due to their volatility calling into question the need to accurately allocate costs to any single half-hour period.
2	**Do you support the proposed implementation approach?**	Yes
3	**Do you have any other comments?**	We would still require market information as provided currently by National Grid (MBSS and BSIS data) as well as HH BSUoS out-turn to enable us to predict future fixed rates and any K factors for longer dated contracts. We also assume that each fixed period will carry a shortfall (K) which will be rolled forward into future periods.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	Yes. We prefer a 15 month notice period as this would allow us the opportunity to price the new information into any contracts. Considering the options in Annex 7 we propose that 15 month notice, 12 month fix with a 3 month reconciliation period should be adopted alongside a 15 month notice, 6 month fix with a 3 month reconciliation period

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	Yes and we consider that this will increase over the next several years due to the geographical diversification of the network, increase in intermittency of generation and closures of central capacity.

Q	Question	Response
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	Yes. BSUoS costs across 2015 and 2014 were materially higher than in previous years. This causes additional costs to be incorporated into the cost stack to allow for the risk of out-turn costs being higher than forecast. In addition customers on pass-through deals have utilised NGET BSUoS forecasts and suffered volatility in their business planning as a result.
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	Not as such as the cost is extremely volatile and unpredictable. We consider that some parties may be more capable in terms of understanding the volatility in these costs and therefore factor in risk premia to allow for this. However, this is not a competitive advantage as such as National Grid's BSUoS forecasting has been lower than out-turn BSUoS costs over a number of years. Parties who do not price for this volatility will therefore be exposed to losses and parties who do will not be as competitive from a pricing perspective.
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	We do not consider that this is an issue.
9	**Do you believe BSUoS is a useful price signal?**	No

Q	Question	Response
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	We believe a single annual price would provide the best cost recovery mechanism. Any shaping or profiling of the price would be a purely artificial measure and we do not consider that it would lead to any benefits to market participants.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	We believe that our suggestion of a 15 month period provides a much better price fix notice period encompassing a larger proportion of supplier contracting periods and aligning with the recently approved notice periods of DUoS charges.
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	We consider that all participants will include risk premia to a varying degree both generators and suppliers. This will increase costs for consumers. Prudent market operators will consider previous BSUoS out-turn as well as expected network events/market changes (PV increases, generation connection etc). We are satisfied that the workgroup has considered this risk as far as possible in an open forum. We consider though that in more confidential responses parties may give further detail to Ofgem.
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	We use the MBSSS report as an indication of some costs. We consider that National Grid's forecast in isolation is consistently below out-turn and therefore does not provide a reliable indication of the cost of BSUoS.
14	**If applicable, are you able to share your approach to calculating risk premia?**	Not at this time.
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	We consider that the cost should be stabilised by the System Operator and that the SO should explore appropriate mechanisms to fund this stabilisation. We consider that the SO should be exposed to some risk to provide an incentive to accurately forecast the rate in each year. In addition we consider that National Grid should be able to forecast BSUoS far more accurately than it currently does and therefore the risk will be far less than that currently faced by market participants.
16	**What is your view on the above cashflow financing approaches?**	We consider that the TO's who have far lower costs of capital than market participants should contribute to the SO's financing of BSUoS stabilisiation.
17	**What would you regard as good value to enable a fixed BSUoS price?**	We consider that BSUoS should be fixed for a cost reflective value. This would provide best value as opposed to risk adjusted pricing carried out by many participants.

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **14th April 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*James Anderson* *james.anderson@scottishpower.com*
Company Name:	*ScottishPower Energy Management*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	We believe that the Proposal overall better meets the Applicable Charging Objectives than the current baseline. The Proposal better meets applicable Charging Objective (a) through reducing uncertainty and unpredictability in the level of BSUoS faced by both generators and suppliers when participating in the wholesale electricity market. Reduced uncertainty should facilitate more competitive pricing to the benefit of consumers. The current ex-post BSUoS charging methodology attempts to reflect costs into the appropriate settlement periods but it contains a number of non cost-reflective cost allocation methodologies and, being ex-post, does not provide a signal to which market participants can respond. Therefor we believe that the Proposal is largely neutral against Applicable Charging Objective (b). We believe that he Proposal is neutral against Applicable Objectives (c) and (d).
2	**Do you support the proposed implementation approach?**	We support the implementation approach outlined in section 5 of the workgroup report.
3	**Do you have any other comments?**	No.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	We agree that the analysis in section 2.6 to 2.13 of the workgroup report demonstrates an increasing volatility in half-hourly BSUoS costs which we would expect to increase further as the deployment of intermittent renewable generation continues.

Q	Question	Response
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	Increasing volatility of BSUoS makes it likely that there could be an increasing number of periods when generation plant may be dispatched uneconomically as actual BSUoS costs may exceed expected levels. As demonstrated in Annex 8 of the report, a significant risk premium would have to be added to any central BSUoS forecast in order to achieve a reasonable level of certainty that dispatch would not be uneconomic. Suppliers would face similar problems in pricing customer contracts particularly where cutomer profiles resulted in a different load weighting than the mean load-weighted BSUoS value.
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	No. All market participants have access to the same sources of data underlying BSUoS charges and each participant is free to decide how much significance and resource to allocate to BSUoS price forecasting.
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	The existing ex-post, BSUoS charge do not provide a useful price signal to which businesses can respond. Market participants have insufficient knowledge of the current state of the electricity system and whether current conditions will persist or change into future settlement periods. Thus, the most recently published indicative BSUoS data is a relatively poor indicator of the charges which may be experienced in future periods. The reallocation of BSUoS charges within year will reduce uncertainty over the variability of the charge and reduce the potential of making uneconomic pricing decisions in the short term. The potential reallocation of BSUoS charges between years will be achieved with sufficient notice to participants that it will enable them to take account of this in their BSUoS forecasts and economic decisions.
9	**Do you believe BSUoS is a useful price signal?**	No. Please see our response to Question 8.

Q	Question	Response
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	The analysis in the workgroup report at 2.25 to 2.27 indicates only a very week correlation between BSUoS and seasons or time periods (peak/off-peak; weekday/weekend). Therefore we do not believe that there is any empirical justification for introducing a shape to the fixed BSUoS price. The introduction of an erroneous price shape risks sending misleading price signals to the market and may lead to inefficient dispatch of generation.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	Ideally we would seek a 12 month fixed period, compatible with annual traded products coupled with a 12 month notice period to coincide with the time frame in which as significant proportion of OTC products are traded (Figure 5, Workgroup Report). However, as noted at 2.33 of the report and combination of fix and notice periods in excess of 18 months increases the reconciliation period to 3 years. We therefore believe that a 6 month fixed period with 12 months' notice would be an acceptable compromise solution.
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	We do not believe that there is a single method of determining an appropriate risk premium to be applied to BSUoS forecasts and that each industry participant will adopt a different approach according to its risk appetite. However, we believe that most methodologies adopted will consider the overall annual level of BSUoS costs, annual BSUoS volume, and the level of sensitivity around a derived annual BSUoS charge. This will be accompanied by consideration of the volatility of BSUoS on an individual Settlement Period basis in order to assess the risk associated with a particular contract profile. We believe that the approach demonstrated in Annex 8 provides one such method of assessing BSUoS volatility around a central forecast.
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	Our business makes use of all of the information on system operation costs published by National Grid including the BSUoS forecast in preparing our own estimate of BSUoS costs and charges.
14	**If applicable, are you able to share your approach to calculating risk premia?**	Please see our answer to Question 12.
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	We believe that the risk associated with forecasting BSUoS charges should lie with the National Grid as the System Operator who is in possession of information not available to market participants and is therefore better placed to manage this risk. Annex 5 indicates that National Grid is best placed to finance any cashflow movements at the lowest cost to consumers.

Q	Question	Response
16	**What is your view on the above cashflow financing approaches?**	Setting up SPVs would be administratively complex and would potentially increase overall costs to consumers. There is a potential issue with ownership of any surplus built up through a premium levied on BSUoS i.e. to whom would the surplus belong if market shares change and would the surplus be refunded if a party decide to exit the market? There is a potential discrimination issue with current market participants being required to contribute to a surplus to which future participants who would not be required to contribute and who could potentially receive a refund from the surplus. On this basis, we believe that the least complex and most cost effective solution would be Scenario 1: NGET finance with equity and debt.
17	**What would you regard as good value to enable a fixed BSUoS price?**	

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **14th April 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*James Anderson* *james.anderson@scottishpower.com*
Company Name:	*ScottishPower Energy Management*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	We believe that the Proposal overall better meets the Applicable Charging Objectives than the current baseline. The Proposal better meets applicable Charging Objective (a) through reducing uncertainty and unpredictability in the level of BSUoS faced by both generators and suppliers when participating in the wholesale electricity market. Reduced uncertainty should facilitate more competitive pricing to the benefit of consumers. The current ex-post BSUoS charging methodology attempts to reflect costs into the appropriate settlement periods but it contains a number of non cost-reflective cost allocation methodologies and, being ex-post, does not provide a signal to which market participants can respond. Therefor we believe that the Proposal is largely neutral against Applicable Charging Objective (b). We believe that he Proposal is neutral against Applicable Objectives (c) and (d).
2	**Do you support the proposed implementation approach?**	We support the implementation approach outlined in section 5 of the workgroup report.
3	**Do you have any other comments?**	No.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	We agree that the analysis in section 2.6 to 2.13 of the workgroup report demonstrates an increasing volatility in half-hourly BSUoS costs which we would expect to increase further as the deployment of intermittent renewable generation continues.

Q	Question	Response
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	Increasing volatility of BSUoS makes it likely that there could be an increasing number of periods when generation plant may be dispatched uneconomically as actual BSUoS costs may exceed expected levels. As demonstrated in Annex 8 of the report, a significant risk premium would have to be added to any central BSUoS forecast in order to achieve a reasonable level of certainty that dispatch would not be uneconomic. Suppliers would face similar problems in pricing customer contracts particularly where cutomer profiles resulted in a different load weighting than the mean load-weighted BSUoS value.
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	No. All market participants have access to the same sources of data underlying BSUoS charges and each participant is free to decide how much significance and resource to allocate to BSUoS price forecasting.
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	The existing ex-post, BSUoS charge do not provide a useful price signal to which businesses can respond. Market participants have insufficient knowledge of the current state of the electricity system and whether current conditions will persist or change into future settlement periods. Thus, the most recently published indicative BSUoS data is a relatively poor indicator of the charges which may be experienced in future periods. The reallocation of BSUoS charges within year will reduce uncertainty over the variability of the charge and reduce the potential of making uneconomic pricing decisions in the short term. The potential reallocation of BSUoS charges between years will be achieved with sufficient notice to participants that it will enable them to take account of this in their BSUoS forecasts and economic decisions.
9	**Do you believe BSUoS is a useful price signal?**	No. Please see our response to Question 8.

Q	Question	Response
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	The analysis in the workgroup report at 2.25 to 2.27 indicates only a very week correlation between BSUoS and seasons or time periods (peak/off-peak; weekday/weekend). Therefore we do not believe that there is any empirical justification for introducing a shape to the fixed BSUoS price. The introduction of an erroneous price shape risks sending misleading price signals to the market and may lead to inefficient dispatch of generation.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	Ideally we would seek a 12 month fixed period, compatible with annual traded products coupled with a 12 month notice period to coincide with the time frame in which as significant proportion of OTC products are traded (Figure 5, Workgroup Report). However, as noted at 2.33 of the report and combination of fix and notice periods in excess of 18 months increases the reconciliation period to 3 years. We therefore believe that a 6 month fixed period with 12 months' notice would be an acceptable compromise solution.
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	We do not believe that there is a single method of determining an appropriate risk premium to be applied to BSUoS forecasts and that each industry participant will adopt a different approach according to its risk appetite. However, we believe that most methodologies adopted will consider the overall annual level of BSUoS costs, annual BSUoS volume, and the level of sensitivity around a derived annual BSUoS charge. This will be accompanied by consideration of the volatility of BSUoS on an individual Settlement Period basis in order to assess the risk associated with a particular contract profile. We believe that the approach demonstrated in Annex 8 provides one such method of assessing BSUoS volatility around a central forecast.
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	Our business makes use of all of the information on system operation costs published by National Grid including the BSUoS forecast in preparing our own estimate of BSUoS costs and charges.
14	**If applicable, are you able to share your approach to calculating risk premia?**	Please see our answer to Question 12.
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	We believe that the risk associated with forecasting BSUoS charges should lie with the National Grid as the System Operator who is in possession of information not available to market participants and is therefore better placed to manage this risk. Annex 5 indicates that National Grid is best placed to finance any cashflow movements at the lowest cost to consumers.

Q	Question	Response
16	**What is your view on the above cashflow financing approaches?**	Setting up SPVs would be administratively complex and would potentially increase overall costs to consumers. There is a potential issue with ownership of any surplus built up through a premium levied on BSUoS i.e. to whom would the surplus belong if market shares change and would the surplus be refunded if a party decide to exit the market? There is a potential discrimination issue with current market participants being required to contribute to a surplus to which future participants who would not be required to contribute and who could potentially receive a refund from the surplus. On this basis, we believe that the least complex and most cost effective solution would be Scenario 1: NGET finance with equity and debt.
17	**What would you regard as good value to enable a fixed BSUoS price?**	

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **14th April 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Colin Prestwich*
Company Name:	*SmartestEnergy Limited*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We are opposed to this code modification proposal as it fundamentally dilutes the principle of cost reflective charging. In our view BSUoS has clear trends as to its cost and just levying a blunt flat rate will change the balance of who pays more/less than other people. The biggest impact is negative for competition in generation/wholesale market prices. Whilst it is true that flat rate BSUoS would level the playing field for generators' cost forecasting, the correlation of wind generation to times of higher BSUoS price means that the flatter/lower BSUoS prices for transmission connected wind resulting from this modification would be a subsidy which would dilute the effectiveness of the wholesale market for setting appropriate price signals to generation and demand. Similarly, we note that for embedded generation a flat rate BSUoS price would increase the benefits paid to solar generators at the expense of generators who respond to price signals in the wholesale market and balancing mechanism. Similarly for consumers, a flat rate BSUoS cost disincentives engagement in demand management and load shifting in response to price signals, which will increase costs in the medium term. Additionally, in the (likely) instance that BSUoS is set above forecast cost for the year, consumers will be funding another needless cash reserve in the energy sector.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	We do not believe that CMP250 better facilitates any of the applicable CUSC objectives. For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.
2	**Do you support the proposed implementation approach?**	No
3	**Do you have any other comments?**	No

Q	Question	Response
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No. We would prefer that National Grid issues a range of (non binding) BSUoS forecasts which may help inform generation/supply as to expected BSUoS costs and allow more efficient price setting in spot and forwards markets e.g. 2 day ahead HH price, week ahead block prices, month and seasonal peak/base prices.

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	BSUoS reflects the reality of the system
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	The volatility of BSUoS is not inherently unmanageable.
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	It is not appropriate for us to comment on the relative forecasting abilities of competitors.

Q	Question	Response
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	Yes, in addition to the comments for question 1, we would add that we respond to the price signals in BSUoS by tailoring the BSUoS charges to customers dependent upon their consumption profile. Customers with higher forecast BSUoS costs have higher energy rates and vice versa.
9	**Do you believe BSUoS is a useful price signal?**	Yes
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	It should be shaped.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	Given our contractual position and system set-up we would need at least two years.

Q	Question	Response
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	No comment
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	Clearly, we take it into consideration.
14	**If applicable, are you able to share your approach to calculating risk premia?**	No
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	The risk should remain with market participants
16	**What is your view on the above cashflow financing approaches?**	Building up a reserve through a premium is an inappropriate additional charge on consumers. We can equally understand that NGT do not wish to hold anything on their balance sheet or incur costs associated with any other funding. There is a reason why things are the way they are.
17	**What would you regard as good value to enable a fixed BSUoS price?**	£0.00/MWh would represent good value but we don't agree with the premise of the question.

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

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Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

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Respondent:	*Colin Prestwich*
Company Name:	*SmartestEnergy Limited*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We are opposed to this code modification proposal as it fundamentally dilutes the principle of cost reflective charging. In our view BSUoS has clear trends as to its cost and just levying a blunt flat rate will change the balance of who pays more/less than other people. The biggest impact is negative for competition in generation/wholesale market prices. Whilst it is true that flat rate BSUoS would level the playing field for generators' cost forecasting, the correlation of wind generation to times of higher BSUoS price means that the flatter/lower BSUoS prices for transmission connected wind resulting from this modification would be a subsidy which would dilute the effectiveness of the wholesale market for setting appropriate price signals to generation and demand. Similarly, we note that for embedded generation a flat rate BSUoS price would increase the benefits paid to solar generators at the expense of generators who respond to price signals in the wholesale market and balancing mechanism. Similarly for consumers, a flat rate BSUoS cost disincentives engagement in demand management and load shifting in response to price signals, which will increase costs in the medium term. Additionally, in the (likely) instance that BSUoS is set above forecast cost for the year, consumers will be funding another needless cash reserve in the energy sector.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	We do not believe that CMP250 better facilitates any of the applicable CUSC objectives. For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.
2	**Do you support the proposed implementation approach?**	No
3	**Do you have any other comments?**	No

Q	Question	Response
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No. We would prefer that National Grid issues a range of (non binding) BSUoS forecasts which may help inform generation/supply as to expected BSUoS costs and allow more efficient price setting in spot and forwards markets e.g. 2 day ahead HH price, week ahead block prices, month and seasonal peak/base prices.

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	BSUoS reflects the reality of the system
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	The volatility of BSUoS is not inherently unmanageable.
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	It is not appropriate for us to comment on the relative forecasting abilities of competitors.

Q	Question	Response
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	Yes, in addition to the comments for question 1, we would add that we respond to the price signals in BSUoS by tailoring the BSUoS charges to customers dependent upon their consumption profile. Customers with higher forecast BSUoS costs have higher energy rates and vice versa.
9	**Do you believe BSUoS is a useful price signal?**	Yes
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	It should be shaped.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	Given our contractual position and system set-up we would need at least two years.

Q	Question	Response
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	No comment
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	Clearly, we take it into consideration.
14	**If applicable, are you able to share your approach to calculating risk premia?**	No
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	The risk should remain with market participants
16	**What is your view on the above cashflow financing approaches?**	Building up a reserve through a premium is an inappropriate additional charge on consumers. We can equally understand that NGT do not wish to hold anything on their balance sheet or incur costs associated with any other funding. There is a reason why things are the way they are.
17	**What would you regard as good value to enable a fixed BSUoS price?**	£0.00/MWh would represent good value but we don't agree with the premise of the question.

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

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Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	Jim Conlin (james.conlin@uk.tesco.com)
Company Name:	*Tesco*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Yes Tesco believe that the original proposal allows for better competition and therefore satisfies CUSC objective a.
2	**Do you support the proposed implementation approach?**	Tesco are comfortable with the implementation approach which could see BSUoS charged begin being fixed on the 1st April 2017 for the following year.
3	**Do you have any other comments?**	
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	Yes. Analysis presented to us by our supplier has demonstrated that as more intermittent and embedded generators play a larger role, BSUoS costs ranges are becoming more extreme. This does not impact us day to day but it does play a consideration when we are deciding to fix or have BSUoS as a pass-through, ex-post reconciliation element within our contract terms.
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	To a degree. Tesco values budget certainty and knowing this cost in advance can enable us to make more effective decisions on how we treat this cost within our contract terms.
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	Not applicable.

Q	Question	Response
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	Not applicable.
9	**Do you believe BSUoS is a useful price signal?**	No.
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	We do not have a preference as our supplier would be the ones more impacted. However given that the aim of this modification is to simply fix costs in advance with a post reconciliation we believe a flat shape is sufficient.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	We are comfortable with the proposal which sets out twelve months in advance the initial six month period of fixed BSUoS charges then followed up by a further six months of fixed charges as a rolling mechanism.

Q	Question	Response
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	We are very much reliant on third-party information to ensure that the BSUoS charges offered by suppliers are at an acceptable level. We are aware that our supplier provides us with the most informed BSUoS values available to them. Other suppliers can use their Terms and Conditions to pass-through costs that have not been initially covered by their forecast. We like the idea of more certainty around costs to avoid us trying to determine which approach is the best.
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	Our supplier has shown us the National Grid forecast which is available on their website. Generally this is not a very reliable input for us as the costs are generally not always up to date with the latest information.
14	**If applicable, are you able to share your approach to calculating risk premia?**	No comment.
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	No comment.
16	**What is your view on the above cashflow financing approaches?**	No comment.
17	**What would you regard as good value to enable a fixed BSUoS price?**	We expect that between the workgroup members and National Grid a reasonable cost can be determined. £0.07/MWh as mentioned in the report is really the highest it should be. Without any detailed calculation as to how this can be calculated we can not comment any further.

CUSC Workgroup Consultation Response Proforma

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Please send your responses by **14th April 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Paul Jones paul.jones@uniper.energy*
Company Name:	*Uniper UK / E.ON UK*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Yes the proposal should benefit competition in the market and therefore better meet objective a). Arguably cost reflectivity is reduced, but cost reflectivity is important if it provides signals which can be acted upon to benefit customers and the system. Therefore, we do not expect a significant impact on objective b). It is likely to have a neutral impact on objectives c) and d).
2	**Do you support the proposed implementation approach?**	Yes.
3	**Do you have any other comments?**	No thank you.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at cusc.team@nationalgrid.com* No thank you.

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	Yes and we agree that the evidence in the consultation paper suggests so too. Values are becoming more difficult to forecast going forwards than has been the case historically, which is increasing risk for all parties exposed to BSUoS charges.
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	Yes. From a retail perspective it makes it more difficult to forecast future BSUoS levels and increases the risk associated with setting fixed rate tariffs. For those customers with BSUoS pass-through contracts, it increases the risk for them directly of course. From a generation perspective greater uncertainty makes it even more difficult to include the cost of BSUoS, which in principle is an avoidable cost, into prices offered into the market.

[1] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/

Q	Question	Response
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	Some benefit is gained from forecasting BSUoS compared to an alternative of not putting any or putting little effort into forecasting. Nevertheless, the nature of the charge makes it difficult to spot particular patterns and trends, making it very difficult to gain a particular competitive advantage through more effective forecasting than other parties.
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	If there is no particular pattern to BSUoS charges it is difficult to predict how changes would alter the distribution of costs between parties in future. That is, you assess this on historic charges, but this is unlikely to be indicative of the effect going forwards. Given that BSUoS is calculated ex post and that there is no particular pattern to prices which can be identified and acted against in future periods, then it is difficult to see how it can act as a price signal. If it does provide a signal, it is not one which can be responded to by BSUoS payers to promote beneficial behaviour. Therefore, it can't be relied on to promote benefits to the system and ultimately lower customer costs.
9	**Do you believe BSUoS is a useful price signal?**	No.
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	If BSUoS does not provide a signal at present, then it seems pointless to shape it in future as a proxy for a signal. If the cost was shaped it may illicit a response from parties, but it is highly unlikely that it would be one that would provide benefits to the system and customers. The focus should be on cost recovery instead which doesn't require a profile.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	Clearly parties would like notification as far ahead as possible, but realistically this has to be balanced by what is practicable. Similarly, this is the case for the length of the fix period. The workgroup preferred combination of a 12 month notice period and 6 month fix period is the one which seems to provide the best combination in terms of managing risk for parties and customers.

Q	Question	Response
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	The analysis is inevitably limited as a result of it being backwards looking. The real issue is the risk that parties have looking forwards due to the huge amount of uncertainty about future BSUoS levels. Therefore, it is difficult to put a cost on this.
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	The National Grid BSUoS forecast forms part of the information used to form our own forecast. National Grid's views, provided in its forecast and through other routes such as the Operational Forum, are an important source of information.
14	**If applicable, are you able to share your approach to calculating risk premia?**	It is unlikely that a specific premium is applied per se to reflect this risk, but it is included implicitly in the costing/pricing decisions which people take in response to their forecast of BSUoS. That is, if a cost is known to be very volatile, forecasting scenarios used for costing purposes will reflect this. Of course, the market will ensure that suppliers are not too risk averse in this, so that they remain competitive.
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	The benefits of fixing BSUoS centrally comes to two issues: who best placed to manage the risk; and who is best placed to fund cash-flow differences which occur as a result of the fixed price inevitably not recovering exactly what is required to cover outturn balancing costs? Centrally managing the risk is inevitably going to be more efficient than individual parties doing so, particularly as there is no real mechanism for parties to hedge BSUoS in the open market. It would also seem to be more efficient for a single regulated entity to manage the cash-flows arising from the fixed price mechanism, if there is a regulatory settlement (licence condition) which allows that entity always to recover its money. This should attract a lower cost of capital than parties in the competitive market are able to do (i.e. present payers of BSUoS). This should reduce the cost to customers.

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **14th April 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Mary Teuton (mteuton@vpi-i.com; 0207 312 4469)*
Company Name:	*VPI Immingham*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	No, we do not believe that the proposal better facilitates the applicable CUSC objectives, notably objectives (a) and (b). We think the original proposal, as written, reduces competition across generators as an important element of cost reflectivity and relevant signal to the market is removed. As a result, there is reduced incentive to change behaviour in a specific settlement period which is likely to harm competition. In addition, the proposal does not reflect the charges as incurred by the System Operator in balancing the system. In fact, it moves considerably away from cost reflective charges within each settlement period and so the current status quo better delivers the CUSC objectives.
2	**Do you support the proposed implementation approach?**	We do not support the implementation of this modification as currently worded.
3	**Do you have any other comments?**	Whilst we recognise and accept some of the issues outlined in the modification proposal, we do not support the proposed solution. We believe that the issues that need to be addressed go deeper than volatility of BSUoS charges and that a more fundamental review of the charge, what it consists of and how it is allocated is conducted. The proposed modification does nothing to fix the major issues with BSUoS and that is one of the reasons we do not support the modification. BSUoS in its purest form should provide some form of cost reflective market signal. The issues arise from BSUoS now being used to collect an increasing volume and size of costs that are not truly for balancing, i.e. the price signal is being "polluted" by an increasing number of other costs. For example, we do not believe that either black start costs, nor SBR should be collected via BSUoS. Therefore, we would advocate a more detailed review of BSUoS and the potential to separate out those charges that represent an effective price signal and those that are purely cost recovery.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at cusc.team@nationalgrid.com*

[1] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	The answer to this depends on your definition of volatile. We would argue that on a day to day basis charges are more volatile, but on a seasonal basis, whilst they are increasing, they are not necessarily becoming more volatile. BSUoS, however, is becoming increasingly difficult to forecast due to the changing nature of the system and the addition of costs that are virtually impossible to forecast, such as SBR utilisation costs.
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	Yes. As a CHP with a "must run" element, we must always be generating to provide steam to the local refineries, Humber and Lindsey. Given current market conditions, BSUoS plays an important part of how we despatch the plant, particularly in the overnights when wholesale prices and spark spreads are very low, yet BSUoS may be very high if there are high constraint costs. We often have to despatch at a loss, partly driven by high levels of BSUoS.
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	Yes, we do. Given the nature of operation of our plant, we have invested considerable time and resources into building an accurate forecast of BSUoS charges which feeds straight into our decision making. We believe that our ability to accurately forecast BSUoS, the vast majority of time, enables us to ensure that we are making efficient despatch decisions. However, at the same time, the lack of transparency around some of the decisions that the System Operator is taking does make it difficult to get an accurate forecast 100% of the time. Whilst the absolute size of the BSUoS charges, as currently recovered can be difficult to forecast accurately, parties should be able to say with a firm degree of confidence what order of magnitude the charges may be before the settlement period itself.

Q	Question	Response
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	We have concerns regarding fixing an ex ante BSUoS charge, particularly for periods of a year at a time. We believe that current estimates of BSUoS do incentivise different behaviour across the market and the cost reflectivity of the existing charges aids competition. For example, high BSUoS costs as a result of constraining wind in Scotland overnight may result in flexible plant switching off overnight when it may not be profitable to generate. However, having a flat price signal could result in additional generators staying on overnight with no meaningful price signal to switch off. Perversely, this in turn could lead to higher BSUoS charges as National Grid is forced to take more actions to balance the system, driving increasing costs. A fixed charge could impact the merit order and may not result in the most efficient despatch due to the lack of appropriate cost reflectivity and signal. Whilst the absolute size of the BSUoS charges, as currently recovered can be difficult to forecast, parties should be able to say with a firm degree of confidence what order of magnitude the charges may be. We believe that this signal is important for efficient despatch and should remain in place. As outlined elsewhere in this consultation response, many of the current issues are a result of an increasing number of ancillary services recovered via BSUoS that are not directly related to balancing the system and that are virtually impossible to forecast. We believe that it would be more appropriate to conduct a full review of BSUoS as a cost recovery mechanism to address all of the issues associated with BSUoS and not just one small element.
9	**Do you believe BSUoS is a useful price signal?**	Yes, within a level of tolerance, we do believe that BSUoS can provide an effective price signal. The issue, as set out above, is that it has been polluted by the addition of an increasing number of charges that are increasingly volatile and impossible to forecast. Should these “polluting” elements be removed, we believe BSUoS could again provide a meaningful price signal and should be allowed to do so.

Q	Question	Response
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	Should a fixed price be introduced, we believe that it should be shaped and profiled. At the very least, we would advocate a seasonal split with a further peak / off peak split. The reason for this is due to the different profile of BSUoS and generators in these time periods and the different behaviour that National Grid should want to incentivise. However, any variation may just average out over the fix period. Additionally, the impact of intermittent generators is growing as the volume of installed capacity increases and this often has a direct impact on BSUoS costs. Shaping allows some reflection of the different actions that National Grid is taking to balance the system at different times of day. With increasing levels of solar penetration and subsequent balancing actions, this might become even more pronounced.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	Should this change be implemented, we would support shorter price fix periods. We believe that drivers of the cost are highly seasonal and therefore, BSUoS should be fixed to reflect the true costs within a short time period. For example, SBR, a component of BSUoS, is only in place November to February and could be a key driver of costs in this time period. As with any fixed costs, the longer the notification period, the better able industry are to manage it and the more certainty is given.
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	Whilst the statistical methodology behind the analysis would appear to be sound, we do not believe that it reflects what actually happens and is overly simplistic with some limitation. With BSUoS costs driven by many external factors, such as the volume of intermittent generation on the system, or whether SBR is utilised, then we think that taking an average over a specific time period does not reflect the actual level of risk factored in by generators. In addition, as pointed out in the consultation document, the analysis is backward looking. We believe that any consideration of risk premia would be forward looking, particularly with the ever increasing cost of ancillary services now included, and consider actual market conditions at the time.

Q	Question	Response
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	We use our own modelled assessment of BSUoS costs to feed into commercial decisions, but sense check it against the National Grid forecast on an ongoing basis.
14	**If applicable, are you able to share your approach to calculating risk premia?**	We are not comfortable sharing this information believing it to be commercially sensitive.
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	We believe that National Grid are best placed to manage the risk having lower cost of capital and an existing methodology for forecasting BSUoS, plus existing mechanisms for cost recovery that could mirror the new arrangements. Whilst the workgroup consultation document refers to these costs as industry costs, we do not support this point of view. National Grid, as System Operator, makes all decisions regarding procurement and use of the services and therefore has full control over the costs. It just so happens that National Grid is then allowed to recover the costs from industry players.
16	**What is your view on the above cashflow financing approaches?**	We think it is appropriate to continue with the status quo and to conduct a more detailed analysis of what goes into BSUoS costs and how and from whom these are recovered. Therefore, we support the “today” position. Should the modification be implemented, we think it appropriate that National Grid as System Operator finances the costs, with appropriate incentive schemes in place to ensure industry costs are managed efficiently.
17	**What would you regard as good value to enable a fixed BSUoS price?**	We do not understand this question. However, as we do not support the modification as currently stands, we do not see any value associated with fixing BSUoS and would not support increasing costs in order to fix it.

CUSC Workgroup Consultation Response Proforma

CMP250 'Stabilising BSUoS with at least a twelve month notification period'

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **14th April 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Heena Chauhan at heena.chauhan@nationalgrid.com

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Adam Garbutt (adam.garbutt@morrisonsplc.co.uk)*
Company Name:	*Wm Morrison Supermarkets PLC*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP250 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Morrisons believes that if all suppliers charged BSUoS for a period of twelve months at the same rate it would enable us to choose more effectively. We therefore believe this will satisfy CUSC Objective a. the facilitation of more effective competition.
2	**Do you support the proposed implementation approach?**	We support the implementation as proposed. The earlier the implementation the better for Morrisons as we are facing significant uncertainty on costs arising from SBR and intermittent generators that appear to be increasing costs for the System Operator, National Grid.
3	**Do you have any other comments?**	
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP250

Q	Question	Response
5	**Do you agree Balancing Services Use of System Charges are becoming more volatile?**	Yes. We monitor the costs quite closely and with the assistance from our supplier the low and high case ranges are widening. This is as a result of more system actions we believe are being required to be taken by National Grid balancing a much different network than several years ago. We believe that this trend will continue in the future.
6	**Does the volatility of BSUoS have a material impact on your business? Please provide comments on how this impacts you.**	Yes. We have to ensure that we forecast to the best of our ability all elements of costs that we are liable to pay. Having certainty of these costs a year in advance will enable us to budget more effectively. We are of the opinion that any additional stability to costs (such as longer notice period for TNUoS) allows us to have more budget certainty which is important to our business.
7	**Do you consider BSUoS price forecasting to be a potential source of competitive advantage for your business?**	Not applicable.

Q	Question	Response
8	**Fixing BSUoS charges an ex ante basis will result in a reallocation of costs between settlement periods and, because of over or under-recovery of revenues, between charging years. Please describe how your business may be affected by any within day, weekly, monthly, seasonal or year to year re-distributional effects arising from setting uniform BSUoS for a fixed period. Do the existing, ex post, BSUoS charges provide price signals which your business is able to respond to? If your answer is YES please describe how you respond to such signals.**	Not applicable.
9	**Do you believe BSUoS is a useful price signal?**	No. We are unable to act in advance to this signal.
10	**If we had a fixed price should this be shaped/profiled or flat? If there should be a shape, can you describe a shape that would provide a signal to the industry. Please explain your reasons.**	We would prefer the stability of a flat shape. Introducing a shape to costs that are unknown does not seem add any value.
11	**What are your thoughts on notification lead times and the length of the price fix period?**	Twelve months in advance is a suitable lead time as I am sure there is a balance between remaining cost reflective but also being able to benefit from cost certainty. We would like to see a minimum of one years worth of fixed charges but a longer period would enable us to contract for a longer period of time if other network and low carbon charges (RO, FIT, CfD) were also fixed further in advance.

Q	Question	Response
12	**What are your thoughts on the methodology and calculation of possible industry risk premia applied as a result of ex post BSUoS? Are you able to suggest other approaches to calculate how much volatile BSUoS prices materially affect consumers?**	We are happy for the industry to derive the best value but we would not support any costs that would exceed £0.07/MWh annually. If it did then we would perhaps need to consider the merits of a lead time of between six to twelve months.
13	**Does your business use the National Grid BSUoS forecast as an input in to trading costs either in isolation or in combination with other factors?**	We are aware of National Grid's forecast as this is generally communicated to us via our supplier. We are conscious that there is generally a large disparity on the forecast provided by National Grid and the advice given by our supplier.
14	**If applicable, are you able to share your approach to calculating risk premia?**	No comment.
15	**Who should bear the risk? Do you think the risk should remain with market participants, sit with National Grid or is there another entity that should be considered? Please explain your reasoning.**	No comment.
16	**What is your view on the above cashflow financing approaches?**	No comment.
17	**What would you regard as good value to enable a fixed BSUoS price?**	As answered in question 12, we would accept that a value below £0.07/MWh would be an appropriate cost to enable certainty of BSUoS costs. We would expect however that over time the cost should start to naturally fall as improvements in forecasting are achieved through this process.

Annex 11 – Draft Legal Text

Original Proposal

Section 2 – The Statement of the Balancing Services Use of System Charging Methodology

14.29 Principles

14.29.1 The Transmission Licence allows The Company to derive revenue in respect of the Balancing Services Activity through the Balancing Services Use of System (BSUoS) charges. This statement explains the methodology used in order to calculate the BSUoS charges.

14.29.2 The Balancing Services Activity is defined in the Transmission Licence as the activity undertaken by The Company as part of the Transmission Business including the operation of the transmission system and the procuring and using of Balancing Services for the purpose of balancing the transmission system.

14.29.3 The Company in its role as System Operator keeps the electricity system in balance (energy balancing) and maintains the quality and security of supply (system balancing). The Company is incentivised on the procurement and utilisation of services to maintain the energy and system balance and other costs associated with operating the system. Users pay for the cost of these services and any incentivised payment/receipts through the BSUoS charge.

14.29.4 All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement Period.

14.29.5 BSUoS charges ~~comprise~~ recover the following costs:

(i) The Total Costs of the Balancing Mechanism
(ii) Total Balancing Services Contract costs
(iii) Payments/Receipts from National Grid incentive schemes
(iv) Internal costs of operating the System
(v) Costs associated with contracting for and developing Balancing Services
(vi) Adjustments
(vii) Costs invoiced to The Company associated with Manifest Errors and Special Provisions.
(viii) BETTA implementation costs
(ix) Any under/over recovery amounts resulting from the Fixed BSUoS Price
~~(viii)~~(x) Financing costs associated with the Fixed BSUoS Price

14.29.6 BSUoS charges are calculated and levied on a fixed price £/MWh (the "Fixed BSUoS Price") per Settlement Period basis set for a period of twelve months (the "Fixed Price Period") and notified to Users twelve months in advance. The Fixed BSUoS Price will be applied to each User's actual metered volumes (including all relevant losses) to derive that User's BSUoS charge.

14.29.7 Any over or under recovery during a Fixed Price Period will be included in the calculation of the Fixed BSUoS Price £/MWh for the next available Fixed Price Period

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14.29.8 This methodology is divided into three sections:

a. Calculation of the Daily BSUoS charge
b. Calculation of the Fixed BSUoS Price
c. Volume settlement of BSUoS

14.30 PART A Calculation of the Daily Balancing Services Use of System charge

Calculation of the Daily Balancing Services Use of System charge

14.30.1 The BSUoS charge payable by customer c, on Settlement Day d, will be calculated in accordance with the following formula:

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} BSUoSTOT_{ij}$$

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} FixedBSUoSTOT_{ij}$$

Where:

i	-	refers to the individual BM Unit
j	-	refers to an individual Settlement Period
$\sum_{i \in c} \sum_{j \in d}$	-	refers to the sum over all BM units 'i', for which customer 'c' is the Lead Party* summed over all Settlement Periods 'j' on a Settlement Day 'd'

14.30.2 A customer's charge is based on their proportion of BM Unit Metered Volume for each Settlement Period relative to the total BM Unit Metered Volume for each Settlement Period, adjusted for transmission losses by the application of the relevant Transmission Losses Multiplier.

For all liable importing and exporting BM Units in delivering Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = FixedBSUoSPrice_t * QMBSUoS_{ij} * TLM_{ij}$$

$$BSUoSTOT_{ij} = \frac{BSUoSTOT_j * QMBSUoS_{ij} * TLM_{ij}}{\left\{\left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}$$

For all liable importing and exporting BM Units in offtaking Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = -1 * FixedBSUoSPrice_t * QMBSUoS_{ij} * TLM_{ij}$$

$$BSUoSTOT_{ij} = \frac{-1 * BSUoSTOT_j * QMBSUoS_{ij} * TLM_{ij}}{\left\{\left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}$$

Where:

$FixedBSUoSTOT_{ij}$	Total BSUoS Charge for BM Unit i for Settlement Period j
$FixedBSUoSPrice_t$	As defined in Part B
$QMBSUoS_{ij}$	BM Unit Metered Volume (QM_{ij})** for BSUoS Liable BM Units
TLM_{ij}	Transmission Loss Multiplier **

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* or CUSC party associated with the BMUnits (listed in Appendix C of the BEGA) who is exempt from also being a BSC Party

** Detailed definition in Balancing and Settlement Code Annex X2 – Technical Glossary

$\sum^{+}$ - refers to the sum over all BM Units that are in delivering Trading Units in Settlement Period 'j'

$\sum^{-}$ - refers to the sum over all BM Units that are in offtaking Trading Units in Settlement Period 'j'

'delivering' and 'offtaking' in relation to Trading Units have the meaning set out in the Balancing and Settlement Code (excluding all Interconnector BMUs and Trading Units)

14.30.3 For the avoidance of doubt, BM Units that are registered in Trading Units will be charged on a net Trading Unit basis i.e. if a BM Unit is exporting to the system and is within a Trading Unit that is offtaking from the system then the BM Unit in essence would be paid the BSUoS charge. Conversely, if a BM Unit is importing from the system in a delivering Trading Unit then the BM Unit in essence would pay the BSUoS charge.

Interconnector BM Units

14.30.4 BM Unit and Trading Units associated with Interconnectors, including those associated with the Interconnector Error Administrator, are not liable for BSUoS charges.

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PART B - Calculation of the Fixed BSUoS price

Fixed BSUoS Price Calculation

The Fixed BSUoS -Price for the Fixed Price Period is calculated as follows to give a £/MWh figure:

$$FixedBSUoSPrice_t = \left(\frac{FcBSUoSTOT_t + KB_{t-x}}{FcBSUoSVol_t} \right)$$

where:

$FixedBSUoSPrice_t$	Fixed BSUoS Price £/MWh for the Fixed Price Period t
$FcBSUoSTOT_t$	Forecast Total BSUoS Revenue applicable for Fixed Price Period t including all forecast BSUoSExt and BSUoSInt costs as per paragraph 14.30.1
$FcBSUoSVol_t$	Forecast Volume in MWh of all offtaking and ontaking BM Units, i, adjusted for Transmission Losses within the relevant Fixed Price Period t as forecast by The Company
KB_{t-x}	Adjustment for financing costs and any difference between the Fixed BSUoS Price cost recovery and the actual Total BSUoS costs incurred by The Company in a previous period t-x.

Comment [A1]: Need to this as formala says its STOT divided by vol?? As comment below in formal above show stot as + KB and define KB in formula list??

ForecastSTOT is our forecast of BSUoSEXT and BSUoSINT for the relevant period t (so means we still need the defined licence terms as per table, otherwise have no purpose in sec 14?

Purpose of BSUoS Sot (in table) in sec 14 ?

KB = difference between forecast SEXT and SINT for fixed price period and actual sext and sint plus financing??

Forecast Total BSUoS Revenue (Internal + External)

14.30.1 The Forecast Total BSUoS Revenue for the relevant Fixed Price Period ($FcBSUoSTOT_t$) is calculated by (a) summing the external BSUoS Forecast

~~r~~Revenue (ForecastBSUoSEXT$_t$) and internal BSUoS Forecast ~~r~~Revenue (ForecastBSUoSINT$_t$) expected to be incurred for that Fixed Price Period including all associated incentives.~~.~~

$$FcBSUoSTOT_t = ForecastBSUoSEXT_t + ForecastBSUoSINT_t$$

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Where

ForecastBSUoSExt$_t$ Forecast for Fixed Price Period t of all relevant External BSUoS costs as defined by the Transmission Licence.

ForecastBSUoSInt$_t$ Forecast for Fixed Price Period t of all relevant Internal BSUoS costs as defined by the Transmission Licence

~~Total BSUoS Charge (Internal + External) for each Settlement Period (BSUoSTOT$_{jd}$)~~

~~The Total BSUoS charges for each Settlement Period (BSUoSTOT$_{jd}$) for a particular day are calculated by summing the external BSUoS charge (BSUoSEXT$_{jd}$) and internal BSUoS charge (BSUoSINT$_{jd}$) for each Settlement Period.~~

$$BSUoSTOT_{jd} = BSUoSEXT_{jd} + BSUoSINT_{jd}$$

~~External BSUoS Charge for each Settlement Period (BSUoSEXT$_{jd}$)~~

~~The External BSUoS Charges for each Settlement Period (BSUoSEXT$_{jd}$) are calculated by taking each Settlement Period System Operator BM Cash Flow (CSOBM$_j$) and Balancing Service Variable Contract Cost (BSCCV$_j$) and allocating the daily elements on a MWh basis across each Settlement Period in a day.~~

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd}$$
$$+\left[(IncpayEXT_d + BSCCA_d + ET_d - OM_d + FIIR_d + BSC_d + SOTOC_d + LBS_d) \right.$$
$$*\left\{ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd}) + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right| \right\} /\right.$$
$$\left.\sum_{j \in d} \left\{ \left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij}) \right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right| \right\} \right]$$

~~Calculation of the daily External Incentive Payment (IncpayEXT$_d$)~~

~~In respect of each Settlement Day d, IncpayEXTd is calculated as the difference between the new total incentive payment (FKIncpayEXTd) and the incentive payment that has been made to date for the previous days from the commencement of the scheme ($\sum$k=1=d-1IncpayEXTk):~~

$$IncpayEXT_d = FKIncpayEXT_d - \sum_{k=0}^{d-1} IncpayEXT_k$$

~~The forecast incentive payment made to date (from the commencement of the scheme) (FKIncpayEXT$_d$) is calculated as the ratio of total forecast external incentive payment across the duration of the scheme: the number of days in the scheme, multiplied by the sum of the profiling factors to date.~~

$$FKIncpayEXT_d = \frac{FYIncpayEXT_d}{NDS} * \sum_{k=1}^{d} PFT_k$$

Inclusion of Profiling Factors

Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_d are assumed to be one for the duration of the current external incentive scheme.

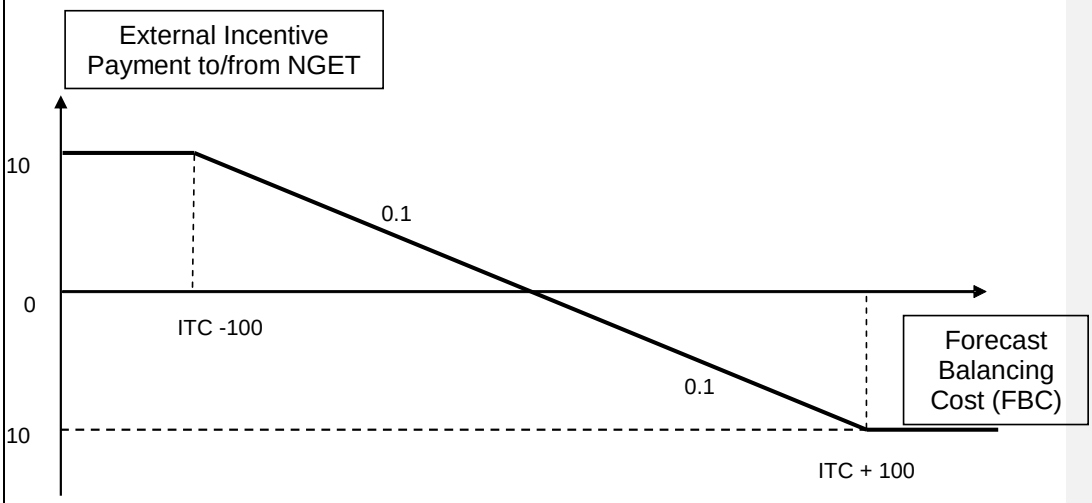
The forecast External incentive payment for the duration of the External incentive scheme ($FYIncpayEXT_d$) is calculated as the difference between the External Scheme target (M_t) and the forecast Balancing cost (FBC) subject to sharing factors (SF_t) and a cap/collar (CB_t).

$$FYIncpayEXT_d = SF_t * (M_t - FBC_d) + CB_t$$

The relevant value of the External incentive payment (BSUoSEXT) can then be calculated by reference to Table 9.1 and the selection and application of the appropriate sharing factors and offset dependent upon the value of the forecast Balancing Services cost (FBC).

Table 9.1

Forecast Balancing Cost (FBC)	M_t £m	SF_t	CB_t £m
FBC < (Incentive Target Cost – 100)	0	0	10
(Incentive Target Cost -100) <= FBC < (Incentive Target Cost)	Incentive Target Cost	10	0
Incentive Target Cost = FBC	FBC	0	0
(Incentive Target Cost) < FBC <= (Incentive Target Cost + 100)	Incentive Target Cost	10	0
(Incentive Target Cost + 100)	0	0	10



In respect of each Settlement Day d, the forecast incentivised Balancing Cost (FBC_d) will be calculated as follows:

$$FBC_d = \frac{\sum_{k=1}^{d} IBC_k}{\sum_{k=1}^{d} PFT_k} * NDS$$

Where:

NDS = Number of days in Scheme.

Daily Incentivised Balancing Cost (IBC_d) is calculated as follows:

~~**Internal BSUoS Charge for each Settlement Period ($BSUoSINT_{id}$)**~~

~~The Internal BSUoS Charges ($BSUoSINT_{id}$) for each Settlement Period j for a particular day are calculated by taking the incentivised and non-incentivised SO Internal Costs for each Settlement Day allocated on a MWh basis across each Settlement Period in a day.~~

$$BSUoSINT_{jd} = [(SOPU_d + SOMOD_d + SOEMR_d + SOEMRCO_d + SOTRU_d) * RPIF_t]$$
$$* \{ \left| \sum^{+} (QMBSUoS_{ijd} * TLM_{ijd}) \right| + \left| \sum^{-} (QMBSUoS_{ijd} * TLM_{ijd}) \right| \}$$
$$/ \sum_{j \in d} \{ \left| \sum^{+} (QMBSUoS_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QMBSUoS_{ij} * TLM_{ij}) \right| \}$$

~~**Inclusion of Profiling Factors**~~

~~Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_k are assumed to be one for the duration of the current external incentive scheme~~

14.31 PART C Volume Settlement of BSUoS

Settlement and Reconciliation of BSUoS charges

14.31.1 There are two stages of the reconciliation of BSUoS charges described below:

- Initial Settlement (SF)
- Final Reconciliation (RF)

Initial Settlement of BSUoS

14.31.2 The Company will calculate initial settlement (SF) BSUoS charges in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Initial Settlement Run and the Initial Volume Allocation Run.

Reconciliation of BSUoS Charges

14.31.3 Final Reconciliation will result in the calculation of a reconciled charge for each settlement day in the scheme year. The Company will calculate Final Reconciliation (RF) BSUoS charges (with the inclusion of interest as defined in the CUSC) in accordance with the methodology set out in ~~section 14.30~~Part A above, ~~using the applicable latest available data,~~ including data from the Final Reconciliation Settlement Run and the Final Reconciliation Volume Allocation Run.

Unavailability of Data

14.31.4 If any of ~~the elements~~volume data required to calculate the BSUoS charges in respect of any Settlement Day have not been notified to The Company in time for it to do the calculations then The Company will use volume data for the corresponding Settlement Day in the previous week. If no such values for the previous week are available to The Company then The Company will substitute such ~~variables~~ volume data as it shall, at its reasonable discretion, think fit and calculate Balancing Services Use of System charges on the basis of these values. When the actual volume data becomes available a reconciliation run will be undertaken.

Disputes

14.31.5 If The Company or any customer identifies any error which would affect the total Balancing Services Use of System charge on a Settlement Day then The Company will recalculate the charges following resolution of the error. Revised invoices and/or credit notes will be issued for the change in charges, plus interest as set out in the CUSC. The charge recalculation and issuing of revised invoices and/or credit notes will not take place for any day where the total change in the Balancing Services charge is less than £2000.

Relationship between the Statement of the Use of System Charging Methodology and the Transmission Licence

14.31.6 BSUoS charges are made on a daily basis and as such ~~of~~ this Statement sets out the details of the calculation of such charges on a daily basis and the Fixed BSUoS Price used to derive the charge. Customers may, when verifying charges for Balancing Services Use of System refer to the Transmission Licence which sets out the maximum allowed revenue that The Company may recover in respect of the Balancing Services Activity.

14.31.7 The Company has, where possible and appropriate, attempted to ensure that acronyms allocated to variables within the Balancing Services charging software, and associated reporting, match with the acronyms given to those variables used within this statement.

14.31.8 Balancing Services Use of System Acronym Definitions

For the avoidance of doubt "as defined in the BSC" relates to the Balancing and Settlement Code as published from time to time.

EXPRESSION	ACRONYM	Unit	Definition
BETTA Preparation Costs	BI	£	As defined in the Transmission Licence
Balancing Mechanism Unit	BM Unit or BMU		As defined in the BSC
~~Black Start Costs~~	~~BSC~~	~~£~~	~~As defined in the Transmission Licence (means he allowed revenue from and associated with Black Start services in accordance with paragraph 4G.5 of Special Condition 4G (Black Start Allowed Revenue Cost Incentive))~~
~~Balancing service contract costs – non-Settlement Period specific~~	~~$BSCCA_{d}$~~	~~£~~	~~Non Settlement Period specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
~~Balancing Service Contract Cost~~	~~$BSCC_{j}$~~	~~£~~	~~Balancing Service Contract Cost from purchasing Ancillary services applicable to a Settlement Period j less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
~~Balancing service contract costs – Settlement Period specific~~	~~$BSCCV_{jd}$~~	~~£~~	~~Settlement Period j specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
External Balancing Services Use of System charge	$BSUoSEXT_{jd}$	£	External System Operator (SO) Balancing Services Use of System charge ~~applicable to Settlement Period j for settlement day d~~
Internal Balancing Services Use of System charge	$BSUoSINT_{jd}$	£	Internal System Operator (SO) Balancing Services Use of System charge ~~applicable to Settlement Period j for settlement day d~~
Total Balancing Services Use of System charge	$BSUoSTOT_{cd}$	£	The sum determined for each customer, c, in accordance with this Statement and payable by that customer in respect of each Settlement Day d, in accordance with the terms of the Supplemental Agreement
~~Total Balancing Services Use of System charge~~	~~$BSUoSTOT_{j}$~~	~~£~~	~~Total Balancing Services Use of System Charge applicable for Settlement Period j~~

EXPRESSION	ACRONYM	Unit	Definition
~~System Operator BM Cash Flow~~	~~$CSOBM_i$~~	~~£~~	~~As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001 less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
Daily balancing services adjustment	ET_d	£	Is the contribution on Settlement Day, d, to the value of ET_t where ET_t is determined pursuant to part B of Special Condition 4C of the Transmission Licence
~~Forecast incentivised Balancing Cost~~	~~FBC_d~~	~~£~~	~~Forecast incentivised Balancing Cost for duration of the Incentive Scheme as at settlement day d~~
~~SO Forecasting Incentive Payment~~	~~FIIR~~	~~£~~	~~As defined in the Transmission Licence~~ ~~(means the incentive payment which the licensee may derive from the forecasting incentive for Wind Generation Output and National Demand Wind Generation Forecasting Incentive in accordance with Special Condition 4H (Wind Generation Forecasting Incentive))~~
~~External Incentive payment to date~~	~~$FKIncpayEXT_d$~~	~~£~~	~~Total External Incentive Payment to date up to and including settlement day d~~
~~Total Forecast External incentive payment~~	~~$FYIncpayEXT_d$~~	~~£~~	~~Total forecast External incentive payment for the entire duration of the incentive scheme as at settlement day d~~
Allowed Income Adjustment relating to the SO-TO Code	IAT	£	As defined in the Transmission Licence
~~Daily Incentivised Balancing Cost~~	~~IBC_d~~	~~£~~	~~Is equal to that value calculated in accordance with paragraph 14.30.13 of Part 2 of this Statement~~
~~Daily External incentive payment~~	~~$IncpayEXT_d$~~	~~£~~	~~External Incentive payment for Settlement Day d~~
~~Demand Side Balancing Reserve and Supplementary Balancing Reserve costs~~	~~LBS~~	~~£~~	~~As defined in the Transmission Licence~~
~~Cost associated with the Provision of Balancing Services to others~~	~~OM_d~~	~~£~~	~~Is the contribution on Settlement Day, d, to the value of OM_t where OM_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence~~
Outage change allowance amount	ON	£	As defined in the Transmission Licence

Comment [A2]: Legacy definition

Comment [A3]: Legacy definition

Comment [A4]: Legacy definition

EXPRESSION	ACRONYM	Unit	Definition
~~Incentivised Balancing Cost daily profiling factor~~	~~PFT_d~~		~~The daily profiling factor used in the determination of forecast Incentivised Balancing Cost for settlement day d~~
BM Unit Metered Volume	QM_{ij}	MWh	As defined in the BSC
BSUoS Liable BM Unit Metered Volume	$QMBSUoS_{ij}$	MWh	QM_{ij} for all BM Units liable for BSUoS
~~Retail Price Index Adjustment Factor~~	~~RPIF~~		~~As defined in the Transmission Licence~~
Balancing services deemed costs	RT_d	£	Is the contribution on Settlement Day, d, to the value of RT_t where RT_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
~~SOEMR Preparation Costs~~	~~SOEMR~~	~~£~~	~~As defined in the Transmission Licence~~
~~SOEMR Preparation Costs Adjustment~~	~~SOEMRCO~~	~~£~~	~~As defined in the Transmission Licence~~
~~Incremental change from SO Opening Base Revenue Allowance~~	~~SOMOD~~		~~As defined in the Transmission Licence~~
~~SO Opening Base Revenue Allowance~~	~~SOPU~~		~~As defined in the Transmission Licence~~
~~SO-TO funding allowance~~	~~SOTOC~~	~~£~~	~~As defined in the Transmission Licence~~ ~~(means the SO-TO Mechanism cost allowance calculated in accordance with 4C.29 Special Condition 4J (SO-TO Mechanism))~~
~~Revenue Adjustment with respect to actual and assumed RPI values~~	~~SOTRU~~		~~As defined in the Transmission Licence~~
Tax Allowance	T	£	As defined in the Transmission Licence
Transmission Loss Multiplier	TLM_{ij}		As defined in the BSC
Total System Energy Imbalance Volume	$TQEI_j$	MWh	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001

Comment [A5]: Legacy definition

Comment [A6]: Legacy definition

Comment [A7]: Legacy definition

EXPRESSION	ACRONYM	Unit	Definition
Final Reconciliation Settlement Run			As defined in the BSC
Final Reconciliation Volume Allocation Run			As defined in the BSC
Initial Settlement Run			As defined in the BSC
Initial Volume Allocation Run			As defined in the BSC
Lead Party			As defined in the BSC
Fixed BSUoS Price	FixedBSUoSPrice		Fixed BSUoS Price in £/MWh for the Fixed Price Period
Fixed Price Period			The period for which the Fixed BSUoS price has been calculated.
$FixedBSUoSTot_{ij}$	$FixedBSUoSTot_{ij}$		The Fixed BSUoS cost for the relevant settlement period j for the relevant BM Unit j
$FcBSUoSTOT_t$	$FcBSUoSTOT_t$		Forecast Total BSUoS Revenue applicable for Fixed Price Period t including all forecast BSUoSExt and BSUoSInt costs
$FcBSUoSVol_t$	$FcBSUoSVol_t$		Forecast Volume in MWh of all offtaking and ontaking BM Units, i,adjusted for Transmission Losses within the relevant Fixed Price Period t as forecast by The Company
KB_{t-x}	KB_{t-x}		Adjustment for financing costs and any difference between the Fixed BSUoS Price cost recovery and the actual Total BSUoS costs incurred by The Company in a previous period t-x
$ForecastBSUoSExt_t$	$ForecastBSUoSExt_t$		Forecast for Fixed Price Period t of all relevant External BSUoS costs as defined by the Transmission Licence.
$ForecastBSUoSInt_t$	$ForecastBSUoSInt_t$		Forecast for Fixed Price Period t of all relevant Internal BSUoS costs as defined by the Transmission Licence

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14.32 Examples of Balancing Services Use of System (BSUoS) Daily Charge Calculations

This example illustrates the operation of the Balancing Services Use of System Daily charge formula. The parameters used are for illustrative purposes only and have been chosen for ease of calculation. They do not relate to the agreed scheme for any particular year. The actual scheme parameters are shown in the main text.

To calculate the daily BSUoS charge applicable to each User in each Ssettlement Period the below formulae are used for each Trading Unit.

For all liable importing and exporting BM Units in delivering Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = FixedBSUoSPrice_{t} * QMBSUoS_{ij} * TLM_{ij}$$

Where a User delivered 360MWh
£817.29= £2.25*360*1.009

For all liable importing and exporting BM Units in off-taking Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = -1 * FixedBSUoSPrice_{t} * QMBSUoS_{ij} * TLM_{ij}$$

Where a User offtook 360MWh
£822.15= -1*£2.25*-360*1.0015

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~~The example is divided into the calculation of the External System Operator cost and Internal System Operator cost elements. All daily profiling factors (PFT_d) have been assumed to be one for this example.~~

~~Day 1~~

~~Calculation of the Daily External SO Incentive Scheme Payment~~

~~The first step is to calculate the Daily Incentivised Balancing Cost (IBC_1 for day one) for that day using the following formula. These are the daily incentivised cost elements used to calculate the external SO incentive payment.~~

$$IBC_1 = CSOBM_1 + BSCCA_1 + BSCCV_1 - OM_1 - RT_1$$

$$= £800,000 + £500,000 + £250,000 - £0 - £0$$

$$= £1,550,000$$

~~Assuming that $CSOBM_1$ = £800,000~~
~~$BSCCA_1$ = £500,000~~
~~$BSCCV_1$ = £250,000~~
~~OM_1 = £0~~
~~RT_1 = £0~~

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~~**Now that we know IBC_1, it is possible to calculate Forecast Balancing Services Cost (FBC_1) from that day's outturn as follows:**~~

$$FBC_1 = \frac{\sum_{k=1}^{d=1} IBC_k}{\sum_{k=1}^{d=1} PFT_k} * NDS$$

$$= \frac{£1{,}550{,}000}{1} * 365$$

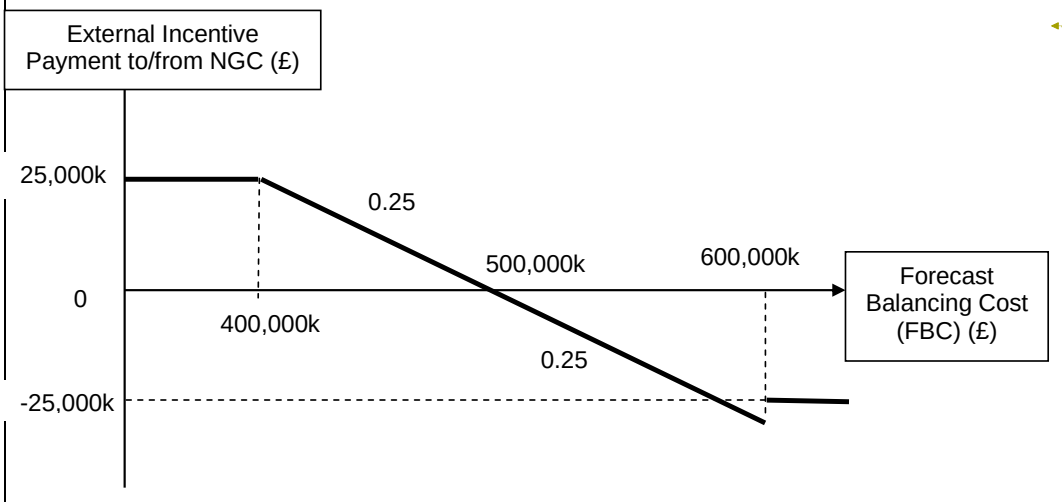
$$= £565{,}750{,}000$$

~~**The values of SF_t and CB_t can now be read off table BS1 below. (**These values are used purely for illustrative purposes based on an incentive target of £500,000,000~~**). As FBC_1 is £565,750,000, SF_t is 0.25, CB_t is £0 and M_t is £500,000,000.**~~

~~Table BS1~~

~~Forecast Balancing Cost (FBC_d)~~	~~M_t~~	~~SF_t~~	~~CB_t~~
~~**£400,000,000 < FBC**~~	~~**£0**~~	~~**0**~~	~~**£25,000,000**~~
~~**£400,000,000 <= FBC < £500,000,000**~~	~~**£500,000,000**~~	~~**0.25**~~	~~**£0**~~
~~**FBC = £500,000,000**~~	~~**£500,000,000**~~	~~**0**~~	~~**£0**~~
~~**£500,000,000 < FBC <= £600,000,000**~~	~~**£500,000,000**~~	~~**0.25**~~	~~**£0**~~
~~**FBC > £600,000,000**~~	~~**£0**~~	~~**0**~~	~~**- £25,000,000**~~

~~**The table describes the external incentive scheme, which can also be illustrated by the graph below.**~~



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~~Using the values set out in the table above, the external SO incentive payment for the duration of the scheme (FYIncpayEXT) can be calculated as follows:~~

$$FYIncpayEXT_1 = SF_t * (M_t - FBC_1) + CB_t$$

~~$= 0.25 * (£500,000,000 - £565,750,000) + £0$~~

$$= -£16,437,500$$

~~In this case the incentive payment is negative (£16,437,500) i.e. a payment from The Company.~~

~~The external SO incentive payment for the entire duration of the incentive scheme (FYIncpayEXT) is then used to calculate the total incentive payment to date (FKIncpayEXT), shown as follows:~~

$$FKIncpayEXT_1 = \frac{FYIncpayEXT_1}{NDS} * \sum_{k=1}^{d=1} PFT_k$$

$$= \frac{-£16,437,500}{365} * 1$$

$$= -£45,034$$

~~Where:~~

~~NDS = Number of days in the external incentive scheme~~

~~The final step is to calculate today's external incentive payment (IncpayEXT$_1$ for day one), shown as follows:~~

$$IncpayEXT_1 = FKIncpayEXT_1 - \sum_{k=0}^{d-1=0} IncpayEXT_k$$

$$= -£45,034 - £0$$

$$= -£45,034$$

~~Calculating the External Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~The External Balancing Services Use of System (BSUoS) charge for Settlement Period 1 on this Settlement Day 1 can now be calculated using the following formula:~~

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd}$$
$$+ \left[(IncpayEXT_d + BSCCA_d + ET_d - OM_d + FIIR_d + BSC_d + SOTOC_d + LBS_d) \right.$$
$$* \left\{ \left| \sum^{+} (QM_{i1,1} * TLM_{i1,1}) + \left| \sum^{-} (QM_{i1,1} * TLM_{i1,1}) \right| \right\} /$$
$$\left. \sum_{j \in 1} \left\{ \left| \sum^{+} (QM_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QM_{ij} * TLM_{ij}) \right| \right\} \right]$$

~~For simplicity, the BSUoS applicable BM Unit Metered Volume (QMBSUoS$_{ij}$ * TLM$_{ij}$) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48) i.e. the multiplier at the end of the equation.~~

~~The illustration below shows the external BSUoS charge (BSUoSEXT$_{11}$) for Settlement Period one of Settlement Day 1.~~

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~~The costs of the external SO Settlement Period variables are as follows (these are the daily values included in the IBC_t equation divided by 48 Settlement Periods).~~

~~CSOBM = £16,667~~
~~BSCCV = £5,208~~
~~$FIIR_t$, BSC_t, $SOTOC_t$ and LBS_t are all zero.~~

~~The costs of the external SO Settlement Day variables are as follows:~~

~~IncpayEXT = £-45,034~~
~~BSCCA = £500,000~~
~~ET = £0~~
~~OM = £0~~

$$BSUoSEXT_{11} = £16,667 + £5,208 + [(-£45,034 + £500,000 + £0 - £0 + £0 + £0 + £0)/48]$$
$$= £16,667 + £5,208 + £9,478$$
$$= £31,353$$

~~Calculating the Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~Table BS2 below shows the annual Internal SO costs assumed for this example:~~

~~Table BS2~~

~~Internal SO Cost Variable~~	~~Annual Cost (£m)~~
~~$SOPU_t$~~	~~75,873,280~~
~~$SOMOD_t$~~	~~18,250,000~~
~~$SOEMR_t$~~	~~0~~
~~$SOEMRCO_t$~~	~~0~~
~~$SOTRU_t$~~	~~18,250,000~~

~~$RPIF_t = 1$~~

~~The Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period 1 of Settlement Day 1 can be calculated using the following formula:~~

$$BSUoSINT_{11} = \left[\{(SOPU_1 + SOMOD_1 + SOEMR_1 + SOEMRCO_1 + SOTRU_1)/NDS\} * RPIF_1\right]$$
$$* \left\{ \left|\sum^{+}(QM_{i1,1} * TLM_{i1,1})\right| + \left|\sum^{-}(QM_{i1,1} * TLM_{i1,1})\right| \right\} / \sum_{j \in 1} \left\{ \left|\sum^{+}(QM_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QM_{ij} * TLM_{ij})\right| \right\}$$

~~As with the external BSUoS charge, for simplicity, the BSUoS applicable BM Unit Metered Volume ($QMBSUoS_{ij} * TLM_{ij}$) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48).~~

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$$BSUoSINT_{11} = \left[(75{,}873{,}280 + 18{,}250{,}000 + 0 + 0 + 18{,}250{,}000)/365\right] * 1/48$$
$$= £6414$$

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Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period 1

The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{11}$) for a Settlement Period 1 on Settlement Day 1.

$$BSUoSTOT_{11} = BSUoSEXT_{11} + BSUoSINT_{11}$$
$$= £31{,}353 + £6{,}414$$
$$= £37{,}767$$

~~Day 2~~

~~Calculation of the Daily External SO Incentive Scheme Payment~~

~~Again, the first step is to calculate the Daily Incentivised Balancing Cost for day 2 (IBC_2) using the following formula:~~

$$IBC_2 = CSOBM_2 + BSCCA_2 + BSCCV_2 - OM_2 - RT_2$$

$$= £600,000 + £150,000 + £100,000 - £0 - £0$$

$$= £850,000$$

~~Assuming that $CSOBM_2$ = £600,000~~
~~$BSCCA_2$ = £150,000~~
~~$BSCCV_2$ = £100,000~~
~~OM_2 = £0~~
~~RT_2 = £0~~

~~With IBC_d known for day one, it is possible to calculate Forecast Balancing Services Cost (FBC_2) from the outturn to date as follows:~~

$$FBC_2 = \frac{\sum_{k=1}^{d=2} IBC_k}{\sum_{k=1}^{d=2} PFT_k} * NDS$$

$$= \frac{(£1,550,000 + £850,000)}{2} * 365$$

$$= £438,000,000$$

~~The values of SF_t, M_t and CB_t can now be read off table BS1 given previously. As FBC_2 is £438,000,000, SF_t is now 0.25, M_t is £500,000,000 and CB_t is 0, calculated as follows:~~

$$FYIncpayEXT_2 = SF_t * (M_t - FBC_2) + CB_t$$

$$= 0.25 * (£500,000,000 - £438,000,000) + £0$$

$$= £15,500,000$$

~~The external SO incentive payment for the entire duration of the incentive scheme ($FYIncpayEXT_2$) is then used to calculate the total incentive payment to date ($FKIncpayEXT_2$), shown as follows:~~

$$FKIncpayEXT_2 = \frac{FYIncpayEXT_2}{NDS} * \sum_{k=1}^{d=2} PFT_k$$

$$= \frac{£15,500,000}{365} * 2$$

$$= £84,932$$

~~Where:~~

~~NDS = Number of days in the incentive scheme~~

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~~In this case the incentive payment forecast for the year is £84,932.~~

~~Again, the final step is to calculate today's external incentive payment (IncpayEXT$_2$ for day two), shown as follows:~~

$$IncpayEXT_2 = FKIncpayEXT_2 - \sum_{k=0}^{d-1=1} IncpayEXT_k$$
$$= £84{,}932 - -£45{,}034$$
$$= £129{,}966$$

~~The costs of the external SO Settlement Period variables are as follows:~~

~~CSOBM = £12,500~~
~~BSCCV = £2,083~~

~~FIIR$_2$, BSC$_2$, SOTOC$_2$ and LBS$_2$ are all zero.~~

~~The costs of the external SO Settlement Day variables are as follows:~~

~~IncpayEXT = £129,966~~
~~BSCCA = £150,000~~
~~ET = £0~~
~~OM = £0~~

$$BSUoSEXT_{12} = £12{,}500 + £2{,}083$$
$$+ [(£129{,}966 + £150{,}000 + £0 - £0 + £0 + £0 + £0 + £0)/48]$$
$$= £12{,}500 + £2{,}083 + £5{,}833$$
$$= £20{,}416$$

~~Annual internal SO costs assumed for this example have been listed in table BS2 above.~~

~~RPIF$_j$ = 1~~

$$BSUoSINT_{12} = [(75{,}873{,}280 + 18{,}250{,}000 + 0 + 0 + 18{,}250{,}000)/365]*1/48$$
$$= £6{,}414$$

~~Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~The final step is to calculate the Total Balancing Services Use of System (BSUoSTOT$_{12}$) for Settlement Period 1 on Settlement Day 2.~~

$$BSUoSTOT_{12} = BSUoSEXT_{12} + BSUoSINT_{12}$$
$$= £20{,}416 + £6414$$
$$= £26{,}830$$

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Day 365

If we now move to the end of the year, then once again the first step is to calculate the Daily Incentivised Balancing Cost for the final day (IBC_{365}) using the formula below:

Calculation of the Daily External SO Incentive Scheme Payment

$$IBC_{365} = CSOBM_{365} + BSCCA_{365} + BSCCV_{365} - OM_{365} - RT_{365}$$

$$= £700{,}000 + £200{,}000 + £150{,}000 + £200{,}000 - £0 - £0$$

$$= £1{,}050{,}000$$

Assuming that $CSOBM_{365}$ = £700,000
$BSCCA_{365}$ = £200,000
$BSCCV_{365}$ = £150,000
OM_{365} = £0
RT_{365} = £0

With $\sum_{364} IBC_d$ assumed to be £432,000,000 for the previous 364 days, it is possible to calculate Forecast Balancing Services Cost (FBC_{365}) from the outturn to date as follows:

$$FBC_{365} = \frac{\sum_{k=1}^{d=365} IBC_k}{\sum_{k=1}^{d=365} PFT_k} * NDS$$

$$= \frac{£432{,}000{,}000 + £1{,}050{,}000}{365} * 365$$

$$= £433{,}050{,}000$$

The values of SF_t, M_t and CB_t can now be read off table BS1. As FBC_{365} is £433,050,000, SF_t is now 0.25, M_t is £500,000,000 and CB_t is 0. Therefore $FYIncpayEXT_{365}$ is calculated as follows:

$$FYIncpayEXT_{365} = SF_t * (M_t - FBC_{365}) + CB_t$$

$$= 0.25 * (£500{,}000{,}000 - £433{,}050{,}000) + £0$$

$$= £16{,}737{,}500$$

The external SO incentive payment for the entire duration of the incentive scheme (FYincpayEXT) is then used to calculate the total incentive payment to date (FKIncpayEXT), shown as follows:

$$FKIncpayEXT_{365} = \frac{FYIncpayEXT_{365}}{NDS} * \sum_{k=1}^{d=365} PFT_k$$

$$= \frac{£16{,}737{,}500}{365} * 365$$

$$= £16{,}737{,}500$$

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~~**Where:**~~

~~**NDS = Number of days in the incentive scheme**~~

~~**In this case the incentive payment is positive (£16,737,500) i.e. a payment to The Company. As this is the last day of the scheme this represents the overall incentive payment due to The Company i.e. with reference to the graph with Table BS1 25% of the difference between £500,000,000 and £433,050,000.**~~

~~**Again, the final step is to calculate today's external incentive payment (IncpayEXT$_{365}$ for day 365), shown as follows:**~~

~~**It has been assumed that the total incentive payments for the previous 364 days ($\sum_{k=0}^{d-1=364} IncpayEXT_k$) is £16,461,800.**~~

$$IncpayEXT_{365} = FKIncpayEXT_{365} - \sum_{k=0}^{d-1=364} IncpayEXT_k$$
$$= £16{,}737{,}500 - £16{,}461{,}800$$
$$= £275{,}700$$

~~**The costs of the external SO Settlement Period variables are as follows:**~~

~~**CSOBM = £14,583**~~
~~**BSCCV = £3,125**~~

~~**FIIR$_{365}$, BSC$_{365}$, SOTOC$_{365}$ and LBS$_{365}$ are all zero.**~~

~~**The costs of the external SO Settlement Day variables are as follows:**~~

~~**IncpayEXT = £275,700**~~
~~**BSCCA = £200,000**~~
~~**ET = £0**~~
~~**OM = £0**~~

$$BSUoSEXT_{365} = £14{,}583 + £3{,}125$$
$$+ (£275{,}700 + £200{,}000 + £0 - £0 + £0 + £0 + £0 + £0)/48$$
$$= £14{,}583 + £3{,}125 + £9{,}910$$
$$= £27{,}618$$

~~**Annual internal SO costs assumed for this example have been listed in Table BS2 above.**~~

~~**RPIF$_t$ = 1**~~

$$BSUoSINT_{1,365} = \left[(£75{,}873{,}280 + £18{,}250{,}000 + 0 + 0 + £18{,}250{,}000)/365\right] * 1/48$$
$$= £6{,}414$$

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~~**Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period i**~~

~~**The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{1365}$) for Settlement Period 1 on Settlement Day 365**~~

$$BSUoSTOT_{1,365} = BSUoSEXT_{1,365} + BSUoSINT_{1,365}$$

$$= £27{,}618 + £6{,}414$$

$$= £34{,}032$$

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Section 2 – The Statement of the Balancing Services Use of System Charging Methodology

14.29 Principles

14.29.1 The Transmission Licence allows The Company to derive revenue in respect of the Balancing Services Activity through the Balancing Services Use of System (BSUoS) charges. This statement explains the methodology used in order to calculate the BSUoS charges.

14.29.2 The Balancing Services Activity is defined in the Transmission Licence as the activity undertaken by The Company as part of the Transmission Business including the operation of the transmission system and the procuring and using of Balancing Services for the purpose of balancing the transmission system.

14.29.3 The Company in its role as System Operator keeps the electricity system in balance (energy balancing) and maintains the quality and security of supply (system balancing). The Company is incentivised on the procurement and utilisation of services to maintain the energy and system balance and other costs associated with operating the system. Users pay for the cost of these services and any incentivised payment/receipts through the BSUoS charge.

14.29.4 All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement Period.

14.29.5 BSUoS charges ~~comprise~~ recover the following costs:

(i) The Total Costs of the Balancing Mechanism
(ii) Total Balancing Services Contract costs
(iii) Payments/Receipts from National Grid incentive schemes
(iv) Internal costs of operating the System
(v) Costs associated with contracting for and developing Balancing Services
(vi) Adjustments
(vii) Costs invoiced to The Company associated with Manifest Errors and Special Provisions.
(viii) BETTA implementation costs
(ix) Any under/over recovery amounts resulting from the Fixed BSUoS Price
~~(viii)~~(x) Financing costs associated with the Fixed BSUoS Price

14.29.6 BSUoS charges are calculated and levied on a fixed price £/MWh (the "Fixed BSUoS Price") per Settlement Period basis set for a period of six months (the "Fixed Price Period") and notified to Users twelve months in advance. The Fixed BSUoS Price will be applied to each User's actual metered volumes (including all relevant losses) to derive that User's BSUoS charge.

14.29.7 Any over or under recovery during a Fixed Price Period will be included in the calculation of the Fixed BSUoS Price £/MWh for the next available Fixed Price Period

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14.29.8 This methodology is divided into three sections:

a. Calculation of the Daily BSUoS charge
b. Calculation of the Fixed BSUoS Price
c. Volume settlement of BSUoS

14.30 PART A Calculation of the Daily Balancing Services Use of System charge

Calculation of the Daily Balancing Services Use of System charge

14.30.1 The BSUoS charge payable by customer c, on Settlement Day d, will be calculated in accordance with the following formula:

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} BSUoSTOT_{ij}$$

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} FixedBSUoSTOT_{ij}$$

Where:

i	-	refers to the individual BM Unit
j	-	refers to an individual Settlement Period
$\sum_{i \in c} \sum_{j \in d}$	-	refers to the sum over all BM units 'i', for which customer 'c' is the Lead Party* summed over all Settlement Periods 'j' on a Settlement Day 'd'

14.30.2 A customer's charge is based on their proportion of BM Unit Metered Volume for each Settlement Period relative to the total BM Unit Metered Volume for each Settlement Period, adjusted for transmission losses by the application of the relevant Transmission Losses Multiplier.

For all liable importing and exporting BM Units in delivering Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = FixedBSUoSPrice_t * QMBSUoS_{ij} * TLM_{ij}$$

$$BSUoSTOT_{ij} = \frac{BSUoSTOT_j * QMBSUoS_{ij} * TLM_{ij}}{\left\{\left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}$$

For all liable importing and exporting BM Units in offtaking Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = -1 * FixedBSUoSPrice_t * QMBSUoS_{ij} * TLM_{ij}$$

$$BSUoSTOT_{ij} = \frac{-1 * BSUoSTOT_j * QMBSUoS_{ij} * TLM_{ij}}{\left\{\left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}$$

Where:

$FixedBSUoSTOT_{ij}$	Total BSUoS Charge for BM Unit i for Settlement Period j
$FixedBSUoSPrice_t$	As defined in Part B
$QMBSUoS_{ij}$	BM Unit Metered Volume (QM_{ij})** for BSUoS Liable BM Units
TLM_{ij}	Transmission Loss Multiplier **

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* or CUSC party associated with the BMUnits (listed in Appendix C of the BEGA) who is exempt from also being a BSC Party

** Detailed definition in Balancing and Settlement Code Annex X2 – Technical Glossary

$\sum^{+}$ - refers to the sum over all BM Units that are in delivering Trading Units in Settlement Period 'j'

$\sum^{-}$ - refers to the sum over all BM Units that are in offtaking Trading Units in Settlement Period 'j'

'delivering' and 'offtaking' in relation to Trading Units have the meaning set out in the Balancing and Settlement Code (excluding all Interconnector BMUs and Trading Units)

14.30.3 For the avoidance of doubt, BM Units that are registered in Trading Units will be charged on a net Trading Unit basis i.e. if a BM Unit is exporting to the system and is within a Trading Unit that is offtaking from the system then the BM Unit in essence would be paid the BSUoS charge. Conversely, if a BM Unit is importing from the system in a delivering Trading Unit then the BM Unit in essence would pay the BSUoS charge.

Interconnector BM Units

14.30.4 BM Unit and Trading Units associated with Interconnectors, including those associated with the Interconnector Error Administrator, are not liable for BSUoS charges.

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PART B - Calculation of the Fixed BSUoS price

Fixed BSUoS Price Calculation

The Fixed BSUoS -Price for the Fixed Price Period is calculated as follows to give a £/MWh figure:

$$FixedBSUoSPrice_t = \left(\frac{FcBSUoSTOT_t + KB_{t-x}}{FcBSUoSVol_t} \right)$$

where:

$FixedBSUoSPrice_t$	Fixed BSUoS Price £/MWh for the Fixed Price Period t
$FcBSUoSTOT_t$	Forecast Total BSUoS Revenue applicable for Fixed Price Period t including all forecast BSUoSExt and BSUoSInt costs as per paragraph 14.30.1
$FcBSUoSVol_t$	Forecast Volume in MWh of all offtaking and ontaking BM Units, i, adjusted for Transmission Losses within the relevant Fixed Price Period t as forecast by The Company
KB_{t-x}	Adjustment for financing costs and any difference between the Fixed BSUoS Price cost recovery and the actual Total BSUoS costs incurred by The Company in a previous period t-x.

Comment [A1]: Need to this as formala says its STOT divided by vol?? As comment below in formal above show stot as + KB and define KB in formula list??

ForecastSTOT is our forecast of BSUoSEXT and BSUoSINT for the relevant period t (so means we still need the defined licence terms as per table, otherwise have no purpose in sec 14?

Purpose of BSUoS Sot (in table) in sec 14 ?

KB = difference between forecast SEXT and SINT for fixed price period and actual sext and sint plus financing??

Forecast Total BSUoS Revenue (Internal + External)

14.30.1 The Forecast Total BSUoS Revenue for the relevant Fixed Price Period ($FcBSUoSTOT_t$) is calculated by (a) summing the external BSUoS Forecast

rRevenue (ForecastBSUoSEXT$_t$) and internal BSUoS Forecast rRevenue (ForecastBSUoSINT$_t$) expected to be incurred for that Fixed Price Period including all associated incentives.r

$$FcBSUoSTOT_t = ForecastBSUoSEXT_t + ForecastBSUoSINT_t$$

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Where

ForecastBSUoSExt$_t$ Forecast for Fixed Price Period t of all relevant External BSUoS costs as defined by the Transmission Licence.

ForecastBSUoSInt$_t$ Forecast for Fixed Price Period t of all relevant Internal BSUoS costs as defined by the Transmission Licence

Total BSUoS Charge (Internal + External) for each Settlement Period (BSUoSTOT$_{jd}$)

The Total BSUoS charges for each Settlement Period (BSUoSTOT$_{jd}$) for a particular day are calculated by summing the external BSUoS charge (BSUoSEXT$_{jd}$) and internal BSUoS charge (BSUoSINT$_{jd}$) for each Settlement Period.

$$BSUoSTOT_{jd} = BSUoSEXT_{jd} + BSUoSINT_{jd}$$

External BSUoS Charge for each Settlement Period (BSUoSEXT$_{jd}$)

The External BSUoS Charges for each Settlement Period (BSUoSEXT$_{jd}$) are calculated by taking each Settlement Period System Operator BM Cash Flow (CSOBM$_j$) and Balancing Service Variable Contract Cost (BSCCV$_j$) and allocating the daily elements on a MWh basis across each Settlement Period in a day.

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd}$$
$$+\left[(IncpayEXT_d + BSCCA_d + ET_d - OM_d + FIIR_d + BSC_d + SOTOC_d + LBS_d) \right.$$
$$*\left\{ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd}) + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right| \right\} /\right.$$
$$\left.\sum_{j \in d} \left\{ \left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij}) \right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right| \right\} \right]$$

Calculation of the daily External Incentive Payment (IncpayEXT$_d$)

In respect of each Settlement Day d, IncpayEXTd is calculated as the difference between the new total incentive payment (FKIncpayEXTd) and the incentive payment that has been made to date for the previous days from the commencement of the scheme ($\sum$k=1=d-1IncpayEXTk):

$$IncpayEXT_d = FKIncpayEXT_d - \sum_{k=0}^{d-1} IncpayEXT_k$$

The forecast incentive payment made to date (from the commencement of the scheme) (FKIncpayEXT$_d$) is calculated as the ratio of total forecast external incentive payment across the duration of the scheme: the number of days in the scheme, multiplied by the sum of the profiling factors to date.

$$FKIncpayEXT_d = \frac{FYIncpayEXT_d}{NDS} * \sum_{k=1}^{d} PFT_k$$

Inclusion of Profiling Factors

Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_d are assumed to be one for the duration of the current external incentive scheme.

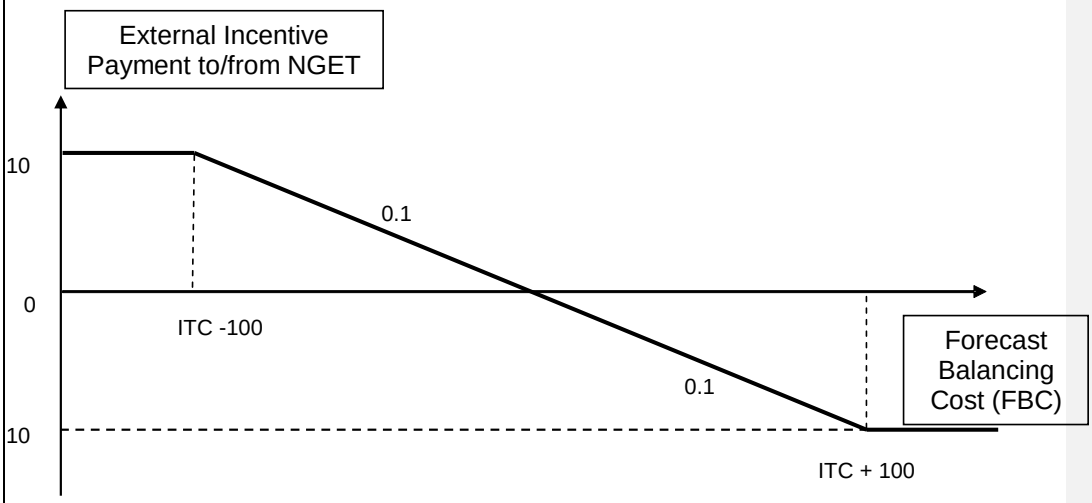
The forecast External incentive payment for the duration of the External incentive scheme ($FYIncpayEXT_d$) is calculated as the difference between the External Scheme target (M_t) and the forecast Balancing cost (FBC) subject to sharing factors (SF_t) and a cap/collar (CB_t).

$$FYIncpayEXT_d = SF_t * (M_t \quad FBC_d) + CB_t$$

The relevant value of the External incentive payment (BSUoSEXT) can then be calculated by reference to Table 9.1 and the selection and application of the appropriate sharing factors and offset dependent upon the value of the forecast Balancing Services cost (FBC).

Table 9.1

Forecast Balancing Cost (FBC)	M_t £m	SF_t	CB_t £m
FBC < (Incentive Target Cost – 100)	0	0	10
(Incentive Target Cost -100) <= FBC < (Incentive Target Cost)	Incentive Target Cost	10	0
Incentive Target Cost = FBC	FBC	0	0
(Incentive Target Cost) < FBC <= (Incentive Target Cost + 100)	Incentive Target Cost	10	0
(Incentive Target Cost + 100)	0	0	10



In respect of each Settlement Day d, the forecast incentivised Balancing Cost (FBC_d) will be calculated as follows:

$$FBC_d = \frac{\sum_{k=1}^{d} IBC_k}{\sum_{k=1}^{d} PFT_k} * NDS$$

Where:

NDS = Number of days in Scheme.

Daily Incentivised Balancing Cost (IBC_d) is calculated as follows:

~~**Internal BSUoS Charge for each Settlement Period ($BSUoSINT_{jd}$)**~~

~~The Internal BSUoS Charges ($BSUoSINT_{jd}$) for each Settlement Period j for a particular day are calculated by taking the incentivised and non-incentivised SO Internal Costs for each Settlement Day allocated on a MWh basis across each Settlement Period in a day.~~

$$BSUoSINT_{jd} = [(SOPU_d + SOMOD_d + SOEMR_d + SOEMRCO_d + SOTRU_d) * RPIF_t]$$
$$* \{ \left| \sum^{+} (QMBSUoS_{ijd} * TLM_{ijd}) \right| + \left| \sum^{-} (QMBSUoS_{ijd} * TLM_{ijd}) \right| \}$$
$$/ \sum_{j \in d} \{ \left| \sum^{+} (QMBSUoS_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QMBSUoS_{ij} * TLM_{ij}) \right| \}$$

~~**Inclusion of Profiling Factors**~~

~~Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_k are assumed to be one for the duration of the current external incentive scheme~~

14.31 PART C Volume Settlement of BSUoS

Settlement and Reconciliation of BSUoS charges

14.31.1 There are two stages of the reconciliation of BSUoS charges described below:

- Initial Settlement (SF)
- Final Reconciliation (RF)

Initial Settlement of BSUoS

14.31.2 The Company will calculate initial settlement (SF) BSUoS charges in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Initial Settlement Run and the Initial Volume Allocation Run.

Reconciliation of BSUoS Charges

14.31.3 Final Reconciliation will result in the calculation of a reconciled charge for each settlement day in the scheme year. The Company will calculate Final Reconciliation (RF) BSUoS charges (with the inclusion of interest as defined in the CUSC) in accordance with the methodology set out in ~~section 14.30~~Part A above, ~~using the applicable latest available data,~~ including data from the Final Reconciliation Settlement Run and the Final Reconciliation Volume Allocation Run.

Unavailability of Data

14.31.4 If any of ~~the elements~~volume data required to calculate the BSUoS charges in respect of any Settlement Day have not been notified to The Company in time for it to do the calculations then The Company will use volume data for the corresponding Settlement Day in the previous week. If no such values for the previous week are available to The Company then The Company will substitute such ~~variables~~ volume data as it shall, at its reasonable discretion, think fit and calculate Balancing Services Use of System charges on the basis of these values. When the actual volume data becomes available a reconciliation run will be undertaken.

Disputes

14.31.5 If The Company or any customer identifies any error which would affect the total Balancing Services Use of System charge on a Settlement Day then The Company will recalculate the charges following resolution of the error. Revised invoices and/or credit notes will be issued for the change in charges, plus interest as set out in the CUSC. The charge recalculation and issuing of revised invoices and/or credit notes will not take place for any day where the total change in the Balancing Services charge is less than £2000.

Relationship between the Statement of the Use of System Charging Methodology and the Transmission Licence

14.31.6 BSUoS charges are made on a daily basis and as such ~~of~~ this Statement sets out the details of the calculation of such charges on a daily basis and the Fixed BSUoS Price used to derive the charge. Customers may, when verifying charges for Balancing Services Use of System refer to the Transmission Licence which sets out the maximum allowed revenue that The Company may recover in respect of the Balancing Services Activity.

14.31.7 The Company has, where possible and appropriate, attempted to ensure that acronyms allocated to variables within the Balancing Services charging software, and associated reporting, match with the acronyms given to those variables used within this statement.

14.31.8 Balancing Services Use of System Acronym Definitions

For the avoidance of doubt "as defined in the BSC" relates to the Balancing and Settlement Code as published from time to time.

EXPRESSION	ACRONYM	Unit	Definition
BETTA Preparation Costs	BI	£	As defined in the Transmission Licence
Balancing Mechanism Unit	BM Unit or BMU		As defined in the BSC
~~Black Start Costs~~	~~BSC~~	~~£~~	~~As defined in the Transmission Licence (means he allowed revenue from and associated with Black Start services in accordance with paragraph 4G.5 of Special Condition 4G (Black Start Allowed Revenue Cost Incentive))~~
~~Balancing service contract costs – non-Settlement Period specific~~	~~$BSCCA_{id}$~~	~~£~~	~~Non Settlement Period specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
~~Balancing Service Contract Cost~~	~~$BSCC_{j}$~~	~~£~~	~~Balancing Service Contract Cost from purchasing Ancillary services applicable to a Settlement Period j less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
~~Balancing service contract costs – Settlement Period specific~~	~~$BSCCV_{jd}$~~	~~£~~	~~Settlement Period j specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
External Balancing Services Use of System charge	$BSUoSEXT_{jd}$	£	External System Operator (SO) Balancing Services Use of System charge ~~applicable to Settlement Period j for settlement day d~~
Internal Balancing Services Use of System charge	$BSUoSINT_{jd}$	£	Internal System Operator (SO) Balancing Services Use of System charge ~~applicable to Settlement Period j for settlement day d~~
Total Balancing Services Use of System charge	$BSUoSTOT_{cd}$	£	The sum determined for each customer, c, in accordance with this Statement and payable by that customer in respect of each Settlement Day d, in accordance with the terms of the Supplemental Agreement
~~Total Balancing Services Use of System charge~~	~~$BSUoSTOT_{j}$~~	~~£~~	~~Total Balancing Services Use of System Charge applicable for Settlement Period j~~

EXPRESSION	ACRONYM	Unit	Definition
~~System Operator BM Cash Flow~~	~~$CSOBM_j$~~	~~£~~	~~As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001 less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
Daily balancing services adjustment	ET_d	£	Is the contribution on Settlement Day, d, to the value of ET_t where ET_t is determined pursuant to part B of Special Condition 4C of the Transmission Licence
~~Forecast incentivised Balancing Cost~~	~~FBC_d~~	~~£~~	~~Forecast incentivised Balancing Cost for duration of the Incentive Scheme as at settlement day d~~
~~SO Forecasting Incentive Payment~~	~~FIIR~~	~~£~~	~~As defined in the Transmission Licence~~ ~~(means the incentive payment which the licensee may derive from the forecasting incentive for Wind Generation Output and National Demand Wind Generation Forecasting Incentive in accordance with Special Condition 4H (Wind Generation Forecasting Incentive))~~
~~External Incentive payment to date~~	~~$FKIncpayEXT_d$~~	~~£~~	~~Total External Incentive Payment to date up to and including settlement day d~~
~~Total Forecast External incentive payment~~	~~$FYIncpayEXT_d$~~	~~£~~	~~Total forecast External incentive payment for the entire duration of the incentive scheme as at settlement day d~~
Allowed Income Adjustment relating to the SO-TO Code	IAT	£	As defined in the Transmission Licence
~~Daily Incentivised Balancing Cost~~	~~IBC_d~~	~~£~~	~~Is equal to that value calculated in accordance with paragraph 14.30.13 of Part 2 of this Statement~~
~~Daily External incentive payment~~	~~$IncpayEXT_d$~~	~~£~~	~~External Incentive payment for Settlement Day d~~
~~Demand Side Balancing Reserve and Supplementary Balancing Reserve costs~~	~~LBS~~	~~£~~	~~As defined in the Transmission Licence~~
~~Cost associated with the Provision of Balancing Services to others~~	~~OM_d~~	~~£~~	~~Is the contribution on Settlement Day, d, to the value of OM_t where OM_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence~~
Outage change allowance amount	ON	£	As defined in the Transmission Licence

Comment [A2]: Legacy definition

Comment [A3]: Legacy definition

Comment [A4]: Legacy definition

EXPRESSION	ACRONYM	Unit	Definition
~~Incentivised Balancing Cost daily profiling factor~~	~~PFT_d~~		~~The daily profiling factor used in the determination of forecast Incentivised Balancing Cost for settlement day d~~
BM Unit Metered Volume	QM_{ij}	MWh	As defined in the BSC
BSUoS Liable BM Unit Metered Volume	$QMBSUoS_{ij}$	MWh	QM_{ij} for all BM Units liable for BSUoS
~~Retail Price Index Adjustment Factor~~	~~RPIF~~		~~As defined in the Transmission Licence~~
Balancing services deemed costs	RT_d	£	Is the contribution on Settlement Day, d, to the value of RT_t where RT_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
~~SOEMR Preparation Costs~~	~~SOEMR~~	~~£~~	~~As defined in the Transmission Licence~~
~~SOEMR Preparation Costs Adjustment~~	~~SOEMRCO~~	~~£~~	~~As defined in the Transmission Licence~~
~~Incremental change from SO Opening Base Revenue Allowance~~	~~SOMOD~~		~~As defined in the Transmission Licence~~
~~SO Opening Base Revenue Allowance~~	~~SOPU~~		~~As defined in the Transmission Licence~~
~~SO-TO funding allowance~~	~~SOTOC~~	~~£~~	~~As defined in the Transmission Licence~~ ~~(means the SO-TO Mechanism cost allowance calculated in accordance with 4C.29 Special Condition 4J (SO-TO Mechanism))~~
~~Revenue Adjustment with respect to actual and assumed RPI values~~	~~SOTRU~~		~~As defined in the Transmission Licence~~
Tax Allowance	T	£	As defined in the Transmission Licence
Transmission Loss Multiplier	TLM_{ij}		As defined in the BSC
Total System Energy Imbalance Volume	$TQEI_j$	MWh	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001

Comment [A5]: Legacy definition

Comment [A6]: Legacy definition

Comment [A7]: Legacy definition

EXPRESSION	ACRONYM	Unit	Definition
Final Reconciliation Settlement Run			As defined in the BSC
Final Reconciliation Volume Allocation Run			As defined in the BSC
Initial Settlement Run			As defined in the BSC
Initial Volume Allocation Run			As defined in the BSC
Lead Party			As defined in the BSC
Fixed BSUoS Price	FixedBSUoSPrice		Fixed BSUoS Price in £/MWh for the Fixed Price Period
Fixed Price Period			The period for which the Fixed BSUoS price has been calculated.
$FixedBSUoSTot_{ji}$	$FixedBSUoSTot_{ji}$		The Fixed BSUoS cost for the relevant settlement period j for the relevant BM Unit j
$FcBSUoSTOT_t$	$FcBSUoSTOT_t$		Forecast Total BSUoS Revenue applicable for Fixed Price Period t including all forecast BSUoSExt and BSUoSInt costs
$FcBSUoSVol_t$	$FcBSUoSVol_t$		Forecast Volume in MWh of all offtaking and ontaking BM Units, i,adjusted for Transmission Losses within the relevant Fixed Price Period t as forecast by The Company
KB_{t-x}	KB_{t-x}		Adjustment for financing costs and any difference between the Fixed BSUoS Price cost recovery and the actual Total BSUoS costs incurred by The Company in a previous period t-x
$ForecastBSUoSExt_t$	$ForecastBSUoSExt_t$		Forecast for Fixed Price Period t of all relevant External BSUoS costs as defined by the Transmission Licence.
$ForecastBSUoSInt_t$	$ForecastBSUoSInt_t$		Forecast for Fixed Price Period t of all relevant Internal BSUoS costs as defined by the Transmission Licence

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14.32 Examples of Balancing Services Use of System (BSUoS) Daily Charge Calculations

This example illustrates the operation of the Balancing Services Use of System Daily charge formula. The parameters used are for illustrative purposes only and have been chosen for ease of calculation. They do not relate to the agreed scheme for any particular year. The actual scheme parameters are shown in the main text.

To calculate the daily BSUoS charge applicable to each User in each Ssettlement Period the below formulae are used for each Trading Unit.

For all liable importing and exporting BM Units in delivering Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = FixedBSUoSPrice_{t} * QMBSUoS_{ij} * TLM_{ij}$$

Where a User delivered 360MWh
£817.29= £2.25*360*1.009

For all liable importing and exporting BM Units in off-taking Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = -1 * FixedBSUoSPrice_{t} * QMBSUoS_{ij} * TLM_{ij}$$

Where a User offtook 360MWh
£822.15= -1*£2.25*-360*1.0015

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~~The example is divided into the calculation of the External System Operator cost and Internal System Operator cost elements. All daily profiling factors (PFT_d) have been assumed to be one for this example.~~

~~Day 1~~

~~Calculation of the Daily External SO Incentive Scheme Payment~~

~~The first step is to calculate the Daily Incentivised Balancing Cost (IBC_1 for day one) for that day using the following formula. These are the daily incentivised cost elements used to calculate the external SO incentive payment.~~

$$IBC_1 = CSOBM_1 + BSCCA_1 + BSCCV_1 - OM_1 - RT_1$$

$$= £800,000 + £500,000 + £250,000 - £0 - £0$$

$$= £1,550,000$$

~~Assuming that $CSOBM_1$ = £800,000~~
~~$BSCCA_1$ = £500,000~~
~~$BSCCV_1$ = £250,000~~
~~OM_1 = £0~~
~~RT_1 = £0~~

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~~**Now that we know IBC_1, it is possible to calculate Forecast Balancing Services Cost (FBC_1) from that day's outturn as follows:**~~

$$FBC_1 = \frac{\sum_{k=1}^{d=1} IBC_k}{\sum_{k=1}^{d=1} PFT_k} * NDS$$

$$= \frac{£1{,}550{,}000}{1} * 365$$

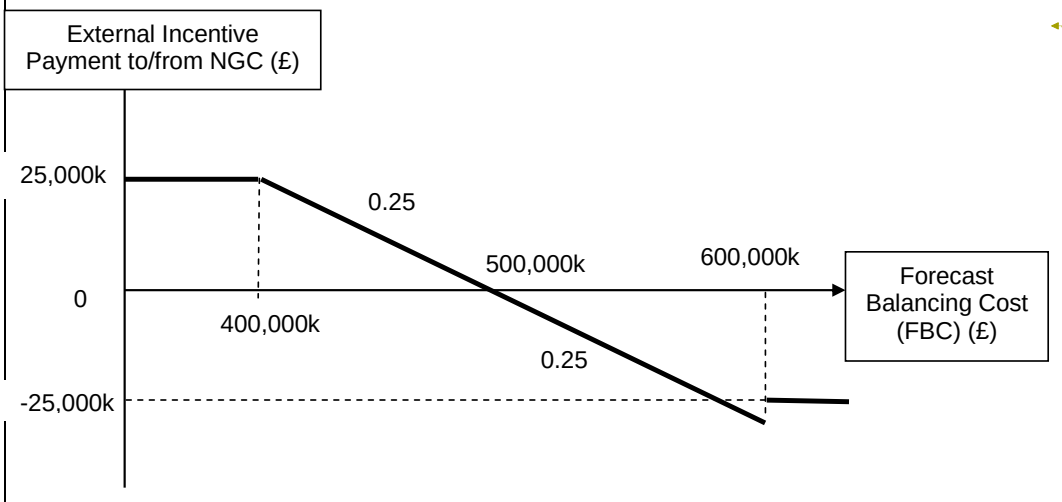
$$= £565{,}750{,}000$$

~~**The values of SF_t and CB_t can now be read off table BS1 below. (**These values are used purely for illustrative purposes based on an incentive target of £500,000,000~~**). As FBC_1 is £565,750,000, SF_t is 0.25, CB_t is £0 and M_t is £500,000,000.**~~

~~Table BS1~~

~~Forecast Balancing Cost (FBC_d)~~	~~M_t~~	~~SF_t~~	~~CB_t~~
~~**£400,000,000 < FBC**~~	~~**£0**~~	~~**0**~~	~~**£25,000,000**~~
~~**£400,000,000 <= FBC < £500,000,000**~~	~~**£500,000,000**~~	~~**0.25**~~	~~**£0**~~
~~**FBC = £500,000,000**~~	~~**£500,000,000**~~	~~**0**~~	~~**£0**~~
~~**£500,000,000 < FBC <= £600,000,000**~~	~~**£500,000,000**~~	~~**0.25**~~	~~**£0**~~
~~**FBC > £600,000,000**~~	~~**£0**~~	~~**0**~~	~~**- £25,000,000**~~

~~**The table describes the external incentive scheme, which can also be illustrated by the graph below.**~~



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~~Using the values set out in the table above, the external SO incentive payment for the duration of the scheme (FYIncpayEXT) can be calculated as follows:~~

$$FYIncpayEXT_1 = SF_t * (M_t - FBC_1) + CB_t$$

~~$$= 0.25 * (£500,000,000 - £565,750,000) + £0$$~~

$$= -£16,437,500$$

~~In this case the incentive payment is negative (£16,437,500) i.e. a payment from The Company.~~

~~The external SO incentive payment for the entire duration of the incentive scheme (FYincpayEXT) is then used to calculate the total incentive payment to date (FKIncpayEXT), shown as follows:~~

$$FKIncpayEXT_1 = \frac{FYIncpayEXT_1}{NDS} * \sum_{k=1}^{d=1} PFT_k$$

~~$$= \frac{-£16,437,500}{365} * 1$$~~

$$= -£45,034$$

~~Where:~~

~~NDS = Number of days in the external incentive scheme~~

~~The final step is to calculate today's external incentive payment (IncpayEXT$_1$ for day one), shown as follows:~~

$$IncpayEXT_1 = FKIncpayEXT_1 - \sum_{k=0}^{d-1=0} IncpayEXT_k$$

$$= -£45,034 - £0$$

$$= -£45,034$$

~~Calculating the External Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~The External Balancing Services Use of System (BSUoS) charge for Settlement Period 1 on this Settlement Day 1 can now be calculated using the following formula:~~

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd}$$

$$+ \left[(IncpayEXT_d + BSCCA_d + ET_d - OM_d + FIIR_d + BSC_d + SOTOC_d + LBS_d) \right.$$

$$* \left\{ \left| \sum^{+} (QM_{i1,1} * TLM_{i1,1}) + \left| \sum^{-} (QM_{i1,1} * TLM_{i1,1}) \right| \right\} /$$

$$\left. \sum_{j \in 1} \left\{ \left| \sum^{+} (QM_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QM_{ij} * TLM_{ij}) \right| \right\} \right]$$

~~For simplicity, the BSUoS applicable BM Unit Metered Volume (QMBSUoS$_{ij}$ * TLM$_{ij}$) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48) i.e. the multiplier at the end of the equation.~~

~~The illustration below shows the external BSUoS charge (BSUoSEXT$_{11}$) for Settlement Period one of Settlement Day 1.~~

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~~The costs of the external SO Settlement Period variables are as follows (these are the daily values included in the IBC_1 equation divided by 48 Settlement Periods).~~

~~CSOBM = £16,667~~
~~BSCCV = £5,208~~
~~$FIIR_1$, BSC_1, $SOTOC_1$, and LBS_1 are all zero.~~

~~The costs of the external SO Settlement Day variables are as follows:~~

~~IncpayEXT = £-45,034~~
~~BSCCA = £500,000~~
~~ET = £0~~
~~OM = £0~~

$$BSUoSEXT_{11} = £16,667 + £5,208 + [(-£45,034 + £500,000 + £0 - £0 + £0 + £0 + £0)/48]$$
$$= £16,667 + £5,208 + £9,478$$
$$= £31,353$$

~~Calculating the Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~Table BS2 below shows the annual Internal SO costs assumed for this example:~~

~~Table BS2~~

~~Internal SO Cost Variable~~	~~Annual Cost (£m)~~
~~$SOPU_t$~~	~~75,873,280~~
~~$SOMOD_t$~~	~~18,250,000~~
~~$SOEMR_t$~~	~~0~~
~~$SOEMRCO_t$~~	~~0~~
~~$SOTRU_t$~~	~~18,250,000~~

~~$RPIF_t = 1$~~

~~The Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period 1 of Settlement Day 1 can be calculated using the following formula:~~

$$BSUoSINT_{11} = \left[\{(SOPU_1 + SOMOD_1 + SOEMR_1 + SOEMRCO_1 + SOTRU_1)/NDS\} * RPIF_1\right]$$
$$* \left\{ \left|\sum^{+}(QM_{i1,1} * TLM_{i1,1})\right| + \left|\sum^{-}(QM_{i1,1} * TLM_{i1,1})\right| \right\} / \sum_{j\in 1} \left\{ \left|\sum^{+}(QM_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QM_{ij} * TLM_{ij})\right| \right\}$$

~~As with the external BSUoS charge, for simplicity, the BSUoS applicable BM Unit Metered Volume ($QMBSUoS_{ij} * TLM_{ij}$) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48).~~

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$$BSUoSINT_{11} = \left[(75{,}873{,}280 + 18{,}250{,}000 + 0 + 0 + 18{,}250{,}000)/365\right] * 1/48$$
$$= £6414$$

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Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period 1

The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{11}$) for a Settlement Period 1 on Settlement Day 1.

$$BSUoSTOT_{11} = BSUoSEXT_{11} + BSUoSINT_{11}$$
$$= £31{,}353 + £6{,}414$$
$$= £37{,}767$$

~~Day 2~~

~~Calculation of the Daily External SO Incentive Scheme Payment~~

~~Again, the first step is to calculate the Daily Incentivised Balancing Cost for day 2 (IBC_2) using the following formula:~~

$$IBC_2 = CSOBM_2 + BSCCA_2 + BSCCV_2 - OM_2 - RT_2$$

$$= £600,000 + £150,000 + £100,000 - £0 - £0$$

$$= £850,000$$

~~Assuming that $CSOBM_2$ = £600,000~~
~~$BSCCA_2$ = £150,000~~
~~$BSCCV_2$ = £100,000~~
~~OM_2 = £0~~
~~RT_2 = £0~~

~~With IBC_d known for day one, it is possible to calculate Forecast Balancing Services Cost (FBC_2) from the outturn to date as follows:~~

$$FBC_2 = \frac{\sum_{k=1}^{d=2} IBC_k}{\sum_{k=1}^{d=2} PFT_k} * NDS$$

$$= \frac{(£1,550,000 + £850,000)}{2} * 365$$

$$= £438,000,000$$

~~The values of SF_t, M_t and CB_t can now be read off table BS1 given previously. As FBC_2 is £438,000,000, SF_t is now 0.25, M_t is £500,000,000 and CB_t is 0, calculated as follows:~~

$$FYIncpayEXT_2 = SF_t * (M_t - FBC_2) + CB_t$$

$$= 0.25 * (£500,000,000 - £438,000,000) + £0$$

$$= £15,500,000$$

~~The external SO incentive payment for the entire duration of the incentive scheme ($FYIncpayEXT_2$) is then used to calculate the total incentive payment to date ($FKIncpayEXT_2$), shown as follows:~~

$$FKIncpayEXT_2 = \frac{FYIncpayEXT_2}{NDS} * \sum_{k=1}^{d=2} PFT_k$$

$$= \frac{£15,500,000}{365} * 2$$

$$= £84,932$$

~~Where:~~

~~NDS = Number of days in the incentive scheme~~

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~~In this case the incentive payment forecast for the year is £84,932.~~

~~Again, the final step is to calculate today's external incentive payment (IncpayEXT$_2$ for day two), shown as follows:~~

$$IncpayEXT_2 = FKIncpayEXT_2 - \sum_{k=0}^{d-1=1} IncpayEXT_k$$
$$= £84{,}932 - -£45{,}034$$
$$= £129{,}966$$

~~The costs of the external SO Settlement Period variables are as follows:~~

~~CSOBM = £12,500~~
~~BSCCV = £2,083~~

~~FIIR$_2$, BSC$_2$, SOTOC$_2$ and LBS$_2$ are all zero.~~

~~The costs of the external SO Settlement Day variables are as follows:~~

~~IncpayEXT = £129,966~~
~~BSCCA = £150,000~~
~~ET = £0~~
~~OM = £0~~

$$BSUoSEXT_{12} = £12{,}500 + £2{,}083$$
$$+ [(£129{,}966 + £150{,}000 + £0 - £0 + £0 + £0 + £0 + £0)/48]$$
$$= £12{,}500 + £2{,}083 + £5{,}833$$
$$= £20{,}416$$

~~Annual internal SO costs assumed for this example have been listed in table BS2 above.~~

~~RPIF$_j$ = 1~~

$$BSUoSINT_{12} = [(75{,}873{,}280 + 18{,}250{,}000 + 0 + 0 + 18{,}250{,}000)/365]*1/48$$
$$= £6{,}414$$

~~Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~The final step is to calculate the Total Balancing Services Use of System (BSUoSTOT$_{12}$) for Settlement Period 1 on Settlement Day 2.~~

$$BSUoSTOT_{12} = BSUoSEXT_{12} + BSUoSINT_{12}$$
$$= £20{,}416 + £6414$$
$$= £26{,}830$$

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Day 365

If we now move to the end of the year, then once again the first step is to calculate the Daily Incentivised Balancing Cost for the final day (IBC_{365}) using the formula below:

Calculation of the Daily External SO Incentive Scheme Payment

$$IBC_{365} = CSOBM_{365} + BSCCA_{365} + BSCCV_{365} - OM_{365} - RT_{365}$$

$$= £700{,}000 + £200{,}000 + £150{,}000 + £200{,}000 - £0 - £0$$

$$= £1{,}050{,}000$$

Assuming that $CSOBM_{365}$ = £700,000
$BSCCA_{365}$ = £200,000
$BSCCV_{365}$ = £150,000
OM_{365} = £0
RT_{365} = £0

With $\sum_{364} IBC_d$ assumed to be £432,000,000 for the previous 364 days, it is possible to calculate Forecast Balancing Services Cost (FBC_{365}) from the outturn to date as follows:

$$FBC_{365} = \frac{\sum_{k=1}^{d=365} IBC_k}{\sum_{k=1}^{d=365} PFT_k} * NDS$$

$$= \frac{£432{,}000{,}000 + £1{,}050{,}000}{365} * 365$$

$$= £433{,}050{,}000$$

The values of SF_t, M_t and CB_t can now be read off table BS1. As FBC_{365} is £433,050,000, SF_t is now 0.25, M_t is £500,000,000 and CB_t is 0. Therefore $FYIncpayEXT_{365}$ is calculated as follows:

$$FYIncpayEXT_{365} = SF_t * (M_t - FBC_{365}) + CB_t$$

$$= 0.25 * (£500{,}000{,}000 - £433{,}050{,}000) + £0$$

$$= £16{,}737{,}500$$

The external SO incentive payment for the entire duration of the incentive scheme (FYincpayEXT) is then used to calculate the total incentive payment to date (FKIncpayEXT), shown as follows:

$$FKIncpayEXT_{365} = \frac{FYIncpayEXT_{365}}{NDS} * \sum_{k=1}^{d=365} PFT_k$$

$$= \frac{£16{,}737{,}500}{365} * 365$$

$$= £16{,}737{,}500$$

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~~**Where:**~~

~~**NDS = Number of days in the incentive scheme**~~

~~**In this case the incentive payment is positive (£16,737,500) i.e. a payment to The Company. As this is the last day of the scheme this represents the overall incentive payment due to The Company i.e. with reference to the graph with Table BS1 25% of the difference between £500,000,000 and £433,050,000.**~~

~~**Again, the final step is to calculate today's external incentive payment (IncpayEXT$_{365}$ for day 365), shown as follows:**~~

~~**It has been assumed that the total incentive payments for the previous 364 days ($\sum_{k=0}^{d-1=364} IncpayEXT_k$) is £16,461,800.**~~

$$IncpayEXT_{365} = FKIncpayEXT_{365} - \sum_{k=0}^{d-1=364} IncpayEXT_k$$
$$= £16{,}737{,}500 - £16{,}461{,}800$$
$$= £275{,}700$$

~~**The costs of the external SO Settlement Period variables are as follows:**~~

~~**CSOBM = £14,583**~~
~~**BSCCV = £3,125**~~

~~**FIIR$_{365}$, BSC$_{365}$, SOTOC$_{365}$ and LBS$_{365}$ are all zero.**~~

~~**The costs of the external SO Settlement Day variables are as follows:**~~

~~**IncpayEXT = £275,700**~~
~~**BSCCA = £200,000**~~
~~**ET = £0**~~
~~**OM = £0**~~

$$BSUoSEXT_{365} = £14{,}583 + £3{,}125$$
$$+ (£275{,}700 + £200{,}000 + £0 - £0 + £0 + £0 + £0 + £0)/48$$
$$= £14{,}583 + £3{,}125 + £9{,}910$$
$$= £27{,}618$$

~~**Annual internal SO costs assumed for this example have been listed in Table BS2 above.**~~

~~**RPIF$_t$ = 1**~~

$$BSUoSINT_{1,365} = \left[(£75{,}873{,}280 + £18{,}250{,}000 + 0 + 0 + £18{,}250{,}000)/365\right] * 1/48$$
$$= £6{,}414$$

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~~**Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period i**~~

~~**The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{1365}$) for Settlement Period 1 on Settlement Day 365**~~

$$BSUoSTOT_{1,365} = BSUoSEXT_{1,365} + BSUoSINT_{1,365}$$

$$= £27{,}618 + £6{,}414$$

$$= £34{,}032$$

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Section 2 – The Statement of the Balancing Services Use of System Charging Methodology

14.29 Principles

14.29.1 The Transmission Licence allows The Company to derive revenue in respect of the Balancing Services Activity through the Balancing Services Use of System (BSUoS) charges. This statement explains the methodology used in order to calculate the BSUoS charges.

14.29.2 The Balancing Services Activity is defined in the Transmission Licence as the activity undertaken by The Company as part of the Transmission Business including the operation of the transmission system and the procuring and using of Balancing Services for the purpose of balancing the transmission system.

14.29.3 The Company in its role as System Operator keeps the electricity system in balance (energy balancing) and maintains the quality and security of supply (system balancing). The Company is incentivised on the procurement and utilisation of services to maintain the energy and system balance and other costs associated with operating the system. Users pay for the cost of these services and any incentivised payment/receipts through the BSUoS charge.

14.29.4 All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement Period.

14.29.5 BSUoS charges ~~comprise~~ recover the following costs:

(i) The Total Costs of the Balancing Mechanism
(ii) Total Balancing Services Contract costs
(iii) Payments/Receipts from National Grid incentive schemes
(iv) Internal costs of operating the System
(v) Costs associated with contracting for and developing Balancing Services
(vi) Adjustments
(vii) Costs invoiced to The Company associated with Manifest Errors and Special Provisions.
(viii) BETTA implementation costs
(ix) Any under/over recovery amounts resulting from the Fixed BSUoS Price
~~(viii)~~(x) Financing costs associated with the Fixed BSUoS Price

14.29.6 BSUoS charges are calculated and levied on a fixed price £/MWh (the "Fixed BSUoS Price") per Settlement Period basis set for a period of six months (the "Fixed Price Period") and notified to Users fifteen months in advance. The Fixed BSUoS Price will be applied to each User's actual metered volumes (including all relevant losses) to derive that User's BSUoS charge.

14.29.7 Any over or under recovery during a Fixed Price Period will be included in the calculation of the Fixed BSUoS Price £/MWh for the next available Fixed Price Period

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14.29.8 This methodology is divided into three sections:

a. Calculation of the Daily BSUoS charge
b. Calculation of the Fixed BSUoS Price
c. Volume settlement of BSUoS

14.30 PART A Calculation of the Daily Balancing Services Use of System charge

Calculation of the Daily Balancing Services Use of System charge

14.30.1 The BSUoS charge payable by customer c, on Settlement Day d, will be calculated in accordance with the following formula:

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} BSUoSTOT_{ij}$$

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} FixedBSUoSTOT_{ij}$$

Where:

i	-	refers to the individual BM Unit
j	-	refers to an individual Settlement Period
$\sum_{i \in c} \sum_{j \in d}$	-	refers to the sum over all BM units 'i', for which customer 'c' is the Lead Party* summed over all Settlement Periods 'j' on a Settlement Day 'd'

14.30.2 A customer's charge is based on their proportion of BM Unit Metered Volume for each Settlement Period relative to the total BM Unit Metered Volume for each Settlement Period, adjusted for transmission losses by the application of the relevant Transmission Losses Multiplier.

For all liable importing and exporting BM Units in delivering Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = FixedBSUoSPrice_t * QMBSUoS_{ij} * TLM_{ij}$$

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$$BSUoSTOT_{ij} = \frac{BSUoSTOT_j * QMBSUoS_{ij} * TLM_{ij}}{\left\{\left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}$$

For all liable importing and exporting BM Units in offtaking Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = -1 * FixedBSUoSPrice_t * QMBSUoS_{ij} * TLM_{ij}$$

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$$BSUoSTOT_{ij} = \frac{-1 * BSUoSTOT_j * QMBSUoS_{ij} * TLM_{ij}}{\left\{\left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}$$

Where:

$FixedBSUoSTOT_{ij}$	Total BSUoS Charge for BM Unit i for Settlement Period j
$FixedBSUoSPrice_t$	As defined in Part B
$QMBSUoS_{ij}$	BM Unit Metered Volume (QM_{ij})** for BSUoS Liable BM Units
TLM_{ij}	Transmission Loss Multiplier **

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* or CUSC party associated with the BMUnits (listed in Appendix C of the BEGA) who is exempt from also being a BSC Party

** Detailed definition in Balancing and Settlement Code Annex X2 – Technical Glossary

$\sum^{+}$ - refers to the sum over all BM Units that are in delivering Trading Units in Settlement Period 'j'

$\sum^{-}$ - refers to the sum over all BM Units that are in offtaking Trading Units in Settlement Period 'j'

'delivering' and 'offtaking' in relation to Trading Units have the meaning set out in the Balancing and Settlement Code (excluding all Interconnector BMUs and Trading Units)

14.30.3 For the avoidance of doubt, BM Units that are registered in Trading Units will be charged on a net Trading Unit basis i.e. if a BM Unit is exporting to the system and is within a Trading Unit that is offtaking from the system then the BM Unit in essence would be paid the BSUoS charge. Conversely, if a BM Unit is importing from the system in a delivering Trading Unit then the BM Unit in essence would pay the BSUoS charge.

Interconnector BM Units

14.30.4 BM Unit and Trading Units associated with Interconnectors, including those associated with the Interconnector Error Administrator, are not liable for BSUoS charges.

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PART B - Calculation of the Fixed BSUoS price

Fixed BSUoS Price Calculation

The Fixed BSUoS -Price for the Fixed Price Period is calculated as follows to give a £/MWh figure:

$$FixedBSUoSPrice_t = \left(\frac{FcBSUoSTOT_t + KB_{t-x}}{FcBSUoSVol_t} \right)$$

where:

$FixedBSUoSPrice_t$	Fixed BSUoS Price £/MWh for the Fixed Price Period t
$FcBSUoSTOT_t$	Forecast Total BSUoS Revenue applicable for Fixed Price Period t including all forecast BSUoSExt and BSUoSInt costs as per paragraph 14.30.1
$FcBSUoSVol_t$	Forecast Volume in MWh of all offtaking and ontaking BM Units, i, adjusted for Transmission Losses within the relevant Fixed Price Period t as forecast by The Company
KB_{t-x}	Adjustment for financing costs and any difference between the Fixed BSUoS Price cost recovery and the actual Total BSUoS costs incurred by The Company in a previous period t-x.

Comment [A1]: Need to this as formala says its STOT divided by vol?? As comment below in formal above show stot as + KB and define KB in formula list??

ForecastSTOT is our forecast of BSUoSEXT and BSUoSINT for the relevant period t (so means we still need the defined licence terms as per table, otherwise have no purpose in sec 14?

Purpose of BSUoS Sot (in table) in sec 14 ?

KB = difference between forecast SEXT and SINT for fixed price period and actual sext and sint plus financing??

Forecast Total BSUoS Revenue (Internal + External)

14.30.1 The Forecast Total BSUoS Revenue for the relevant Fixed Price Period ($FcBSUoSTOT_t$) is calculated by (a) summing the external BSUoS Forecast

rRevenue (ForecastBSUoSEXT$_t$) and internal BSUoS Forecast rRevenue (ForecastBSUoSINT$_t$) expected to be incurred for that Fixed Price Period including all associated incentives.r

$$FcBSUoSTOT_t = ForecastBSUoSEXT_t + ForecastBSUoSINT_t$$

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Where

ForecastBSUoSExt$_t$ Forecast for Fixed Price Period t of all relevant External BSUoS costs as defined by the Transmission Licence.

ForecastBSUoSInt$_t$ Forecast for Fixed Price Period t of all relevant Internal BSUoS costs as defined by the Transmission Licence

Total BSUoS Charge (Internal + External) for each Settlement Period (BSUoSTOT$_{jd}$)

The Total BSUoS charges for each Settlement Period (BSUoSTOT$_{jd}$) for a particular day are calculated by summing the external BSUoS charge (BSUoSEXT$_{jd}$) and internal BSUoS charge (BSUoSINT$_{jd}$) for each Settlement Period.

$$BSUoSTOT_{jd} = BSUoSEXT_{jd} + BSUoSINT_{jd}$$

External BSUoS Charge for each Settlement Period (BSUoSEXT$_{jd}$)

The External BSUoS Charges for each Settlement Period (BSUoSEXT$_{jd}$) are calculated by taking each Settlement Period System Operator BM Cash Flow (CSOBM$_j$) and Balancing Service Variable Contract Cost (BSCCV$_j$) and allocating the daily elements on a MWh basis across each Settlement Period in a day.

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd}$$
$$+\left[(IncpayEXT_d + BSCCA_d + ET_d - OM_d + FIIR_d + BSC_d + SOTOC_d + LBS_d) \right.$$
$$*\left\{ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd}) + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right| \right\} /\right.$$
$$\left.\sum_{j \in d} \left\{ \left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij}) \right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right| \right\} \right]$$

Calculation of the daily External Incentive Payment (IncpayEXT$_d$)

In respect of each Settlement Day d, IncpayEXTd is calculated as the difference between the new total incentive payment (FKIncpayEXTd) and the incentive payment that has been made to date for the previous days from the commencement of the scheme ($\sum$k=1=d-1IncpayEXTk):

$$IncpayEXT_d = FKIncpayEXT_d - \sum_{k=0}^{d-1} IncpayEXT_k$$

The forecast incentive payment made to date (from the commencement of the scheme) (FKIncpayEXT$_d$) is calculated as the ratio of total forecast external incentive payment across the duration of the scheme: the number of days in the scheme, multiplied by the sum of the profiling factors to date.

$$FKIncpayEXT_d = \frac{FYIncpayEXT_d}{NDS} * \sum_{k=1}^{d} PFT_k$$

Inclusion of Profiling Factors

Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_d are assumed to be one for the duration of the current external incentive scheme.

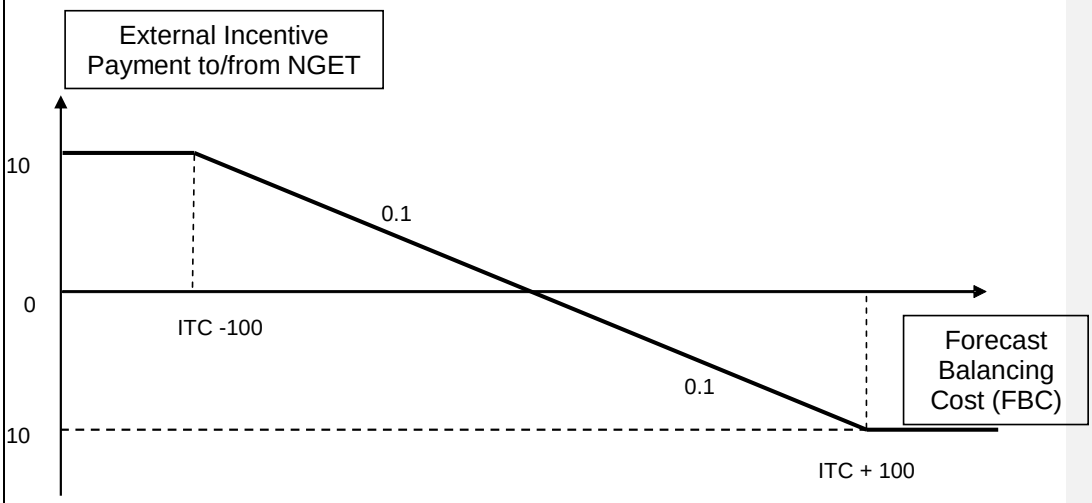
The forecast External incentive payment for the duration of the External incentive scheme ($FYIncpayEXT_d$) is calculated as the difference between the External Scheme target (M_t) and the forecast Balancing cost (FBC) subject to sharing factors (SF_t) and a cap/collar (CB_t).

$$FYIncpayEXT_d = SF_t * (M_t \quad FBC_d) + CB_t$$

The relevant value of the External incentive payment (BSUoSEXT) can then be calculated by reference to Table 9.1 and the selection and application of the appropriate sharing factors and offset dependent upon the value of the forecast Balancing Services cost (FBC).

Table 9.1

Forecast Balancing Cost (FBC)	M_t £m	SF_t	CB_t £m
FBC < (Incentive Target Cost – 100)	0	0	10
(Incentive Target Cost -100) <= FBC < (Incentive Target Cost)	Incentive Target Cost	10	0
Incentive Target Cost = FBC	FBC	0	0
(Incentive Target Cost) < FBC <= (Incentive Target Cost + 100)	Incentive Target Cost	10	0
(Incentive Target Cost + 100)	0	0	10



In respect of each Settlement Day d, the forecast incentivised Balancing Cost (FBC_d) will be calculated as follows:

$$FBC_d = \frac{\sum_{k=1}^{d} IBC_k}{\sum_{k=1}^{d} PFT_k} * NDS$$

Where:

NDS = Number of days in Scheme.

Daily Incentivised Balancing Cost (IBC_d) is calculated as follows:

~~**Internal BSUoS Charge for each Settlement Period ($BSUoSINT_{id}$)**~~

~~The Internal BSUoS Charges ($BSUoSINT_{id}$) for each Settlement Period j for a particular day are calculated by taking the incentivised and non-incentivised SO Internal Costs for each Settlement Day allocated on a MWh basis across each Settlement Period in a day.~~

$$BSUoSINT_{jd} = [(SOPU_d + SOMOD_d + SOEMR_d + SOEMRCO_d + SOTRU_d) * RPIF_t]$$
$$* \{ \left| \sum^{+} (QMBSUoS_{ijd} * TLM_{ijd}) \right| + \left| \sum^{-} (QMBSUoS_{ijd} * TLM_{ijd}) \right| \}$$
$$/ \sum_{j \in d} \{ \left| \sum^{+} (QMBSUoS_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QMBSUoS_{ij} * TLM_{ij}) \right| \}$$

~~**Inclusion of Profiling Factors**~~

~~Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_k are assumed to be one for the duration of the current external incentive scheme~~

14.31 PART C Volume Settlement of BSUoS

Settlement and Reconciliation of BSUoS charges

14.31.1 There are two stages of the reconciliation of BSUoS charges described below:

- Initial Settlement (SF)
- Final Reconciliation (RF)

Initial Settlement of BSUoS

14.31.2 The Company will calculate initial settlement (SF) BSUoS charges in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Initial Settlement Run and the Initial Volume Allocation Run.

Reconciliation of BSUoS Charges

14.31.3 Final Reconciliation will result in the calculation of a reconciled charge for each settlement day in the scheme year. The Company will calculate Final Reconciliation (RF) BSUoS charges (with the inclusion of interest as defined in the CUSC) in accordance with the methodology set out in ~~section 14.30~~Part A above, ~~using the applicable latest available data,~~ including data from the Final Reconciliation Settlement Run and the Final Reconciliation Volume Allocation Run.

Unavailability of Data

14.31.4 If any of ~~the elements~~volume data required to calculate the BSUoS charges in respect of any Settlement Day have not been notified to The Company in time for it to do the calculations then The Company will use volume data for the corresponding Settlement Day in the previous week. If no such values for the previous week are available to The Company then The Company will substitute such ~~variables~~ volume data as it shall, at its reasonable discretion, think fit and calculate Balancing Services Use of System charges on the basis of these values. When the actual volume data becomes available a reconciliation run will be undertaken.

Disputes

14.31.5 If The Company or any customer identifies any error which would affect the total Balancing Services Use of System charge on a Settlement Day then The Company will recalculate the charges following resolution of the error. Revised invoices and/or credit notes will be issued for the change in charges, plus interest as set out in the CUSC. The charge recalculation and issuing of revised invoices and/or credit notes will not take place for any day where the total change in the Balancing Services charge is less than £2000.

Relationship between the Statement of the Use of System Charging Methodology and the Transmission Licence

14.31.6 BSUoS charges are made on a daily basis and as such ~~of~~ this Statement sets out the details of the calculation of such charges on a daily basis and the Fixed BSUoS Price used to derive the charge. Customers may, when verifying charges for Balancing Services Use of System refer to the Transmission Licence which sets out the maximum allowed revenue that The Company may recover in respect of the Balancing Services Activity.

14.31.7 The Company has, where possible and appropriate, attempted to ensure that acronyms allocated to variables within the Balancing Services charging software, and associated reporting, match with the acronyms given to those variables used within this statement.

14.31.8 Balancing Services Use of System Acronym Definitions

For the avoidance of doubt "as defined in the BSC" relates to the Balancing and Settlement Code as published from time to time.

EXPRESSION	ACRONYM	Unit	Definition
BETTA Preparation Costs	BI	£	As defined in the Transmission Licence
Balancing Mechanism Unit	BM Unit or BMU		As defined in the BSC
~~Black Start Costs~~	~~BSC~~	~~£~~	~~As defined in the Transmission Licence (means he allowed revenue from and associated with Black Start services in accordance with paragraph 4G.5 of Special Condition 4G (Black Start Allowed Revenue Cost Incentive))~~
~~Balancing service contract costs – non-Settlement Period specific~~	~~$BSCCA_{id}$~~	~~£~~	~~Non Settlement Period specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
~~Balancing Service Contract Cost~~	~~$BSCC_{j}$~~	~~£~~	~~Balancing Service Contract Cost from purchasing Ancillary services applicable to a Settlement Period j less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
~~Balancing service contract costs – Settlement Period specific~~	~~$BSCCV_{jd}$~~	~~£~~	~~Settlement Period j specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
External Balancing Services Use of System charge	$BSUoSEXT_{jd}$	£	External System Operator (SO) Balancing Services Use of System charge ~~applicable to Settlement Period j for settlement day d~~
Internal Balancing Services Use of System charge	$BSUoSINT_{jd}$	£	Internal System Operator (SO) Balancing Services Use of System charge ~~applicable to Settlement Period j for settlement day d~~
Total Balancing Services Use of System charge	$BSUoSTOT_{cd}$	£	The sum determined for each customer, c, in accordance with this Statement and payable by that customer in respect of each Settlement Day d, in accordance with the terms of the Supplemental Agreement
~~Total Balancing Services Use of System charge~~	~~$BSUoSTOT_{j}$~~	~~£~~	~~Total Balancing Services Use of System Charge applicable for Settlement Period j~~

EXPRESSION	ACRONYM	Unit	Definition
~~System Operator BM Cash Flow~~	~~$CSOBM_j$~~	~~£~~	~~As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001 less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
Daily balancing services adjustment	ET_d	£	Is the contribution on Settlement Day, d, to the value of ET_t where ET_t is determined pursuant to part B of Special Condition 4C of the Transmission Licence
~~Forecast incentivised Balancing Cost~~	~~FBC_d~~	~~£~~	~~Forecast incentivised Balancing Cost for duration of the Incentive Scheme as at settlement day d~~
~~SO Forecasting Incentive Payment~~	~~FIIR~~	~~£~~	~~As defined in the Transmission Licence~~ ~~(means the incentive payment which the licensee may derive from the forecasting incentive for Wind Generation Output and National Demand Wind Generation Forecasting Incentive in accordance with Special Condition 4H (Wind Generation Forecasting Incentive))~~
~~External Incentive payment to date~~	~~$FKIncpayEXT_d$~~	~~£~~	~~Total External Incentive Payment to date up to and including settlement day d~~
~~Total Forecast External incentive payment~~	~~$FYIncpayEXT_d$~~	~~£~~	~~Total forecast External incentive payment for the entire duration of the incentive scheme as at settlement day d~~
Allowed Income Adjustment relating to the SO-TO Code	IAT	£	As defined in the Transmission Licence
~~Daily Incentivised Balancing Cost~~	~~IBC_d~~	~~£~~	~~Is equal to that value calculated in accordance with paragraph 14.30.13 of Part 2 of this Statement~~
~~Daily External incentive payment~~	~~$IncpayEXT_d$~~	~~£~~	~~External Incentive payment for Settlement Day d~~
~~Demand Side Balancing Reserve and Supplementary Balancing Reserve costs~~	~~LBS~~	~~£~~	~~As defined in the Transmission Licence~~
~~Cost associated with the Provision of Balancing Services to others~~	~~OM_d~~	~~£~~	~~Is the contribution on Settlement Day, d, to the value of OM_t where OM_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence~~
Outage change allowance amount	ON	£	As defined in the Transmission Licence

Comment [A2]: Legacy definition

Comment [A3]: Legacy definition

Comment [A4]: Legacy definition

EXPRESSION	ACRONYM	Unit	Definition
~~Incentivised Balancing Cost daily profiling factor~~	~~PFT_d~~		~~The daily profiling factor used in the determination of forecast Incentivised Balancing Cost for settlement day d~~
BM Unit Metered Volume	QM_{ij}	MWh	As defined in the BSC
BSUoS Liable BM Unit Metered Volume	$QMBSUoS_{ij}$	MWh	QM_{ij} for all BM Units liable for BSUoS
~~Retail Price Index Adjustment Factor~~	~~RPIF~~		~~As defined in the Transmission Licence~~
Balancing services deemed costs	RT_d	£	Is the contribution on Settlement Day, d, to the value of RT_t where RT_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
~~SOEMR Preparation Costs~~	~~SOEMR~~	~~£~~	~~As defined in the Transmission Licence~~
~~SOEMR Preparation Costs Adjustment~~	~~SOEMRCO~~	~~£~~	~~As defined in the Transmission Licence~~
~~Incremental change from SO Opening Base Revenue Allowance~~	~~SOMOD~~		~~As defined in the Transmission Licence~~
~~SO Opening Base Revenue Allowance~~	~~SOPU~~		~~As defined in the Transmission Licence~~
~~SO-TO funding allowance~~	~~SOTOC~~	~~£~~	~~As defined in the Transmission Licence~~ ~~(means the SO-TO Mechanism cost allowance calculated in accordance with 4C.29 Special Condition 4J (SO-TO Mechanism))~~
~~Revenue Adjustment with respect to actual and assumed RPI values~~	~~SOTRU~~		~~As defined in the Transmission Licence~~
Tax Allowance	T	£	As defined in the Transmission Licence
Transmission Loss Multiplier	TLM_{ij}		As defined in the BSC
Total System Energy Imbalance Volume	$TQEI_j$	MWh	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001

Comment [A5]: Legacy definition

Comment [A6]: Legacy definition

Comment [A7]: Legacy definition

EXPRESSION	ACRONYM	Unit	Definition
Final Reconciliation Settlement Run			As defined in the BSC
Final Reconciliation Volume Allocation Run			As defined in the BSC
Initial Settlement Run			As defined in the BSC
Initial Volume Allocation Run			As defined in the BSC
Lead Party			As defined in the BSC
Fixed BSUoS Price	FixedBSUoSPrice		Fixed BSUoS Price in £/MWh for the Fixed Price Period
Fixed Price Period			The period for which the Fixed BSUoS price has been calculated.
$FixedBSUoSTot_{ji}$	$FixedBSUoSTot_{ji}$		The Fixed BSUoS cost for the relevant settlement period j for the relevant BM Unit j
$FcBSUoSTOT_t$	$FcBSUoSTOT_t$		Forecast Total BSUoS Revenue applicable for Fixed Price Period t including all forecast BSUoSExt and BSUoSInt costs
$FcBSUoSVol_t$	$FcBSUoSVol_t$		Forecast Volume in MWh of all offtaking and ontaking BM Units, i,adjusted for Transmission Losses within the relevant Fixed Price Period t as forecast by The Company
KB_{t-x}	KB_{t-x}		Adjustment for financing costs and any difference between the Fixed BSUoS Price cost recovery and the actual Total BSUoS costs incurred by The Company in a previous period t-x
$ForecastBSUoSExt_t$	$ForecastBSUoSExt_t$		Forecast for Fixed Price Period t of all relevant External BSUoS costs as defined by the Transmission Licence.
$ForecastBSUoSInt_t$	$ForecastBSUoSInt_t$		Forecast for Fixed Price Period t of all relevant Internal BSUoS costs as defined by the Transmission Licence

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14.32 Examples of Balancing Services Use of System (BSUoS) Daily Charge Calculations

This example illustrates the operation of the Balancing Services Use of System Daily charge formula. The parameters used are for illustrative purposes only and have been chosen for ease of calculation. They do not relate to the agreed scheme for any particular year. The actual scheme parameters are shown in the main text.

To calculate the daily BSUoS charge applicable to each User in each Ssettlement Period the below formulae are used for each Trading Unit.

For all liable importing and exporting BM Units in delivering Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = FixedBSUoSPrice_{t} * QMBSUoS_{ij} * TLM_{ij}$$

Where a User delivered 360MWh
£817.29= £2.25*360*1.009

For all liable importing and exporting BM Units in off-taking Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = -1 * FixedBSUoSPrice_{t} * QMBSUoS_{ij} * TLM_{ij}$$

Where a User offtook 360MWh
£822.15= -1*£2.25*-360*1.0015

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~~The example is divided into the calculation of the External System Operator cost and Internal System Operator cost elements. All daily profiling factors (PFT_d) have been assumed to be one for this example.~~

~~Day 1~~

~~Calculation of the Daily External SO Incentive Scheme Payment~~

~~The first step is to calculate the Daily Incentivised Balancing Cost (IBC_1 for day one) for that day using the following formula. These are the daily incentivised cost elements used to calculate the external SO incentive payment.~~

$$IBC_1 = CSOBM_1 + BSCCA_1 + BSCCV_1 - OM_1 - RT_1$$

$$= £800,000 + £500,000 + £250,000 - £0 - £0$$

$$= £1,550,000$$

~~Assuming that $CSOBM_1$ = £800,000~~
~~$BSCCA_1$ = £500,000~~
~~$BSCCV_1$ = £250,000~~
~~OM_1 = £0~~
~~RT_1 = £0~~

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~~**Now that we know IBC_1, it is possible to calculate Forecast Balancing Services Cost (FBC_1) from that day's outturn as follows:**~~

$$FBC_1 = \frac{\sum_{k=1}^{d=1} IBC_k}{\sum_{k=1}^{d=1} PFT_k} * NDS$$

$$= \frac{£1{,}550{,}000}{1} * 365$$

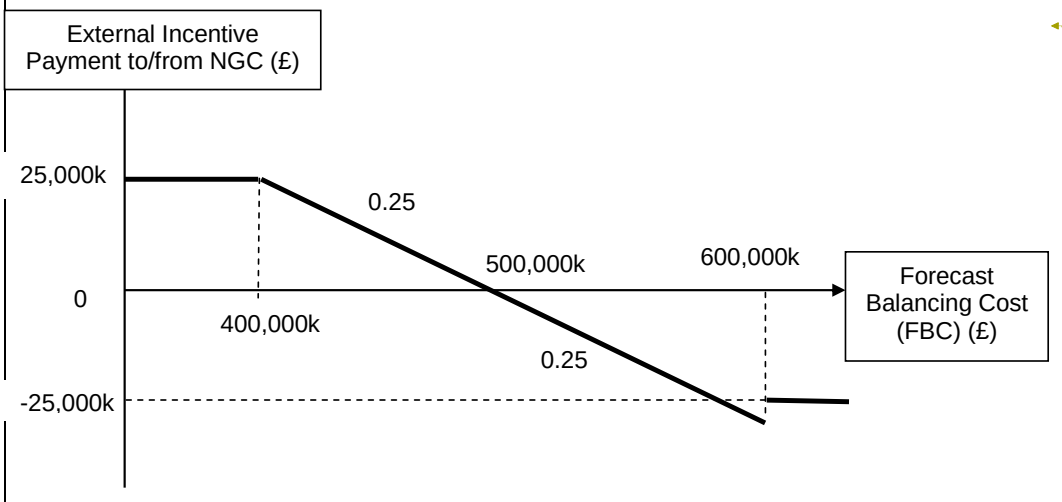
$$= £565{,}750{,}000$$

~~**The values of SF_t and CB_t can now be read off table BS1 below. (**These values are used purely for illustrative purposes based on an incentive target of £500,000,000**). As FBC_1 is £565,750,000, SF_t is 0.25, CB_t is £0 and M_t is £500,000,000.**~~

~~Table BS1~~

~~Forecast Balancing Cost (FBC_d)~~	~~M_t~~	~~SF_t~~	~~CB_t~~
~~**£400,000,000 < FBC**~~	~~**£0**~~	~~**0**~~	~~**£25,000,000**~~
~~**£400,000,000 <= FBC < £500,000,000**~~	~~**£500,000,000**~~	~~**0.25**~~	~~**£0**~~
~~**FBC = £500,000,000**~~	~~**£500,000,000**~~	~~**0**~~	~~**£0**~~
~~**£500,000,000 < FBC <= £600,000,000**~~	~~**£500,000,000**~~	~~**0.25**~~	~~**£0**~~
~~**FBC > £600,000,000**~~	~~**£0**~~	~~**0**~~	~~**- £25,000,000**~~

~~**The table describes the external incentive scheme, which can also be illustrated by the graph below.**~~



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~~Using the values set out in the table above, the external SO incentive payment for the duration of the scheme (FYIncpayEXT) can be calculated as follows:~~

$$FYIncpayEXT_1 = SF_t * (M_t - FBC_1) + CB_t$$

~~$$= 0.25 * (£500,000,000 - £565,750,000) + £0$$~~

$$= -£16,437,500$$

~~In this case the incentive payment is negative (£16,437,500) i.e. a payment from The Company.~~

~~The external SO incentive payment for the entire duration of the incentive scheme (FYincpayEXT) is then used to calculate the total incentive payment to date (FKIncpayEXT), shown as follows:~~

$$FKIncpayEXT_1 = \frac{FYIncpayEXT_1}{NDS} * \sum_{k=1}^{d=1} PFT_k$$

~~$$= \frac{-£16,437,500}{365} * 1$$~~

$$= -£45,034$$

~~Where:~~

~~NDS = Number of days in the external incentive scheme~~

~~The final step is to calculate today's external incentive payment (IncpayEXT$_1$ for day one), shown as follows:~~

$$IncpayEXT_1 = FKIncpayEXT_1 - \sum_{k=0}^{d-1=0} IncpayEXT_k$$

$$= -£45,034 - £0$$

$$= -£45,034$$

~~Calculating the External Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~The External Balancing Services Use of System (BSUoS) charge for Settlement Period 1 on this Settlement Day 1 can now be calculated using the following formula:~~

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd}$$
$$+ \left[(IncpayEXT_d + BSCCA_d + ET_d - OM_d + FIIR_d + BSC_d + SOTOC_d + LBS_d) \right.$$
$$* \left\{ \left| \sum^{+} (QM_{i1,1} * TLM_{i1,1}) + \left| \sum^{-} (QM_{i1,1} * TLM_{i1,1}) \right| \right\} /$$
$$\left. \sum_{j \in 1} \left\{ \left| \sum^{+} (QM_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QM_{ij} * TLM_{ij}) \right| \right\} \right]$$

~~For simplicity, the BSUoS applicable BM Unit Metered Volume (QMBSUoS$_{ij}$ * TLM$_{ij}$) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48) i.e. the multiplier at the end of the equation.~~

~~The illustration below shows the external BSUoS charge (BSUoSEXT$_{11}$) for Settlement Period one of Settlement Day 1.~~

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~~The costs of the external SO Settlement Period variables are as follows (these are the daily values included in the IBC_1 equation divided by 48 Settlement Periods).~~

~~CSOBM = £16,667~~
~~BSCCV = £5,208~~
~~$FIIR_1$, BSC_1, $SOTOC_1$, and LBS_1 are all zero.~~

~~The costs of the external SO Settlement Day variables are as follows:~~

~~IncpayEXT = £-45,034~~
~~BSCCA = £500,000~~
~~ET = £0~~
~~OM = £0~~

$$BSUoSEXT_{11} = £16,667 + £5,208 + [(-£45,034 + £500,000 + £0 - £0 + £0 + £0 + £0)/48]$$
$$= £16,667 + £5,208 + £9,478$$
$$= £31,353$$

~~Calculating the Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~Table BS2 below shows the annual Internal SO costs assumed for this example:~~

~~Table BS2~~

~~Internal SO Cost Variable~~	~~Annual Cost (£m)~~
~~$SOPU_t$~~	~~75,873,280~~
~~$SOMOD_t$~~	~~18,250,000~~
~~$SOEMR_t$~~	~~0~~
~~$SOEMRCO_t$~~	~~0~~
~~$SOTRU_t$~~	~~18,250,000~~

~~$RPIF_t = 1$~~

~~The Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period 1 of Settlement Day 1 can be calculated using the following formula:~~

$$BSUoSINT_{11} = \left[\{(SOPU_1 + SOMOD_1 + SOEMR_1 + SOEMRCO_1 + SOTRU_1)/NDS\} * RPIF_1\right]$$
$$* \left\{ \left| \sum^{+} (QM_{i1,1} * TLM_{i1,1}) \right| + \left| \sum^{-} (QM_{i1,1} * TLM_{i1,1}) \right| \right\} / \sum_{j \in 1} \left\{ \left| \sum^{+} (QM_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QM_{ij} * TLM_{ij}) \right| \right\}$$

~~As with the external BSUoS charge, for simplicity, the BSUoS applicable BM Unit Metered Volume ($QMBSUoS_{ij} * TLM_{ij}$) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48).~~

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$$BSUoSINT_{11} = \left[(75{,}873{,}280 + 18{,}250{,}000 + 0 + 0 + 18{,}250{,}000)/365\right] * 1/48$$
$$= £6414$$

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Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period 1

The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{11}$) for a Settlement Period 1 on Settlement Day 1.

$$BSUoSTOT_{11} = BSUoSEXT_{11} + BSUoSINT_{11}$$
$$= £31{,}353 + £6{,}414$$
$$= £37{,}767$$

~~Day 2~~

~~Calculation of the Daily External SO Incentive Scheme Payment~~

~~Again, the first step is to calculate the Daily Incentivised Balancing Cost for day 2 (IBC_2) using the following formula:~~

$$IBC_2 = CSOBM_2 + BSCCA_2 + BSCCV_2 - OM_2 - RT_2$$

$$= £600,000 + £150,000 + £100,000 - £0 - £0$$

$$= £850,000$$

~~Assuming that $CSOBM_2$ = £600,000~~
~~$BSCCA_2$ = £150,000~~
~~$BSCCV_2$ = £100,000~~
~~OM_2 = £0~~
~~RT_2 = £0~~

~~With IBC_d known for day one, it is possible to calculate Forecast Balancing Services Cost (FBC_2) from the outturn to date as follows:~~

$$FBC_2 = \frac{\sum_{k=1}^{d=2} IBC_k}{\sum_{k=1}^{d=2} PFT_k} * NDS$$

$$= \frac{(£1,550,000 + £850,000)}{2} * 365$$

$$= £438,000,000$$

~~The values of SF_t, M_t and CB_t can now be read off table BS1 given previously. As FBC_2 is £438,000,000, SF_t is now 0.25, M_t is £500,000,000 and CB_t is 0, calculated as follows:~~

$$FYIncpayEXT_2 = SF_t * (M_t - FBC_2) + CB_t$$

$$= 0.25 * (£500,000,000 - £438,000,000) + £0$$

$$= £15,500,000$$

~~The external SO incentive payment for the entire duration of the incentive scheme ($FYIncpayEXT_2$) is then used to calculate the total incentive payment to date ($FKIncpayEXT_2$), shown as follows:~~

$$FKIncpayEXT_2 = \frac{FYIncpayEXT_2}{NDS} * \sum_{k=1}^{d=2} PFT_k$$

$$= \frac{£15,500,000}{365} * 2$$

$$= £84,932$$

~~Where:~~

~~NDS = Number of days in the incentive scheme~~

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~~In this case the incentive payment forecast for the year is £84,932.~~

~~Again, the final step is to calculate today's external incentive payment (IncpayEXT$_2$ for day two), shown as follows:~~

$$IncpayEXT_2 = FKIncpayEXT_2 - \sum_{k=0}^{d-1=1} IncpayEXT_k$$
$$= £84{,}932 - -£45{,}034$$
$$= £129{,}966$$

~~The costs of the external SO Settlement Period variables are as follows:~~

~~CSOBM = £12,500~~
~~BSCCV = £2,083~~

~~FIIR$_2$, BSC$_2$, SOTOC$_2$ and LBS$_2$ are all zero.~~

~~The costs of the external SO Settlement Day variables are as follows:~~

~~IncpayEXT = £129,966~~
~~BSCCA = £150,000~~
~~ET = £0~~
~~OM = £0~~

$$BSUoSEXT_{12} = £12{,}500 + £2{,}083$$
$$+ [(£129{,}966 + £150{,}000 + £0 - £0 + £0 + £0 + £0 + £0)/48]$$
$$= £12{,}500 + £2{,}083 + £5{,}833$$
$$= £20{,}416$$

~~Annual internal SO costs assumed for this example have been listed in table BS2 above.~~

~~RPIF$_1$ = 1~~

$$BSUoSINT_{12} = [(75{,}873{,}280 + 18{,}250{,}000 + 0 + 0 + 18{,}250{,}000)/365]*1/48$$
$$= £6{,}414$$

~~Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~The final step is to calculate the Total Balancing Services Use of System (BSUoSTOT$_{12}$) for Settlement Period 1 on Settlement Day 2.~~

$$BSUoSTOT_{12} = BSUoSEXT_{12} + BSUoSINT_{12}$$
$$= £20{,}416 + £6414$$
$$= £26{,}830$$

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Day 365

If we now move to the end of the year, then once again the first step is to calculate the Daily Incentivised Balancing Cost for the final day (IBC_{365}) using the formula below:

Calculation of the Daily External SO Incentive Scheme Payment

$$IBC_{365} = CSOBM_{365} + BSCCA_{365} + BSCCV_{365} - OM_{365} - RT_{365}$$

$$= £700{,}000 + £200{,}000 + £150{,}000 + £200{,}000 - £0 - £0$$

$$= £1{,}050{,}000$$

Assuming that $CSOBM_{365}$ = £700,000
$BSCCA_{365}$ = £200,000
$BSCCV_{365}$ = £150,000
OM_{365} = £0
RT_{365} = £0

With $\sum_{364} IBC_d$ assumed to be £432,000,000 for the previous 364 days, it is possible to calculate Forecast Balancing Services Cost (FBC_{365}) from the outturn to date as follows:

$$FBC_{365} = \frac{\sum_{k=1}^{d=365} IBC_k}{\sum_{k=1}^{d=365} PFT_k} * NDS$$

$$= \frac{£432{,}000{,}000 + £1{,}050{,}000}{365} * 365$$

$$= £433{,}050{,}000$$

The values of SF_t, M_t and CB_t can now be read off table BS1. As FBC_{365} is £433,050,000, SF_t is now 0.25, M_t is £500,000,000 and CB_t is 0. Therefore $FYIncpayEXT_{365}$ is calculated as follows:

$$FYIncpayEXT_{365} = SF_t * (M_t - FBC_{365}) + CB_t$$

$$= 0.25 * (£500{,}000{,}000 - £433{,}050{,}000) + £0$$

$$= £16{,}737{,}500$$

The external SO incentive payment for the entire duration of the incentive scheme (FYincpayEXT) is then used to calculate the total incentive payment to date (FKIncpayEXT), shown as follows:

$$FKIncpayEXT_{365} = \frac{FYIncpayEXT_{365}}{NDS} * \sum_{k=1}^{d=365} PFT_k$$

$$= \frac{£16{,}737{,}500}{365} * 365$$

$$= £16{,}737{,}500$$

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~~**Where:**~~

~~**NDS = Number of days in the incentive scheme**~~

~~**In this case the incentive payment is positive (£16,737,500) i.e. a payment to The Company. As this is the last day of the scheme this represents the overall incentive payment due to The Company i.e. with reference to the graph with Table BS1 25% of the difference between £500,000,000 and £433,050,000.**~~

~~**Again, the final step is to calculate today's external incentive payment (IncpayEXT$_{365}$ for day 365), shown as follows:**~~

~~**It has been assumed that the total incentive payments for the previous 364 days ($\sum_{k=0}^{d-1=364} IncpayEXT_k$) is £16,461,800.**~~

$$IncpayEXT_{365} = FKIncpayEXT_{365} - \sum_{k=0}^{d-1=364} IncpayEXT_k$$
$$= £16{,}737{,}500 - £16{,}461{,}800$$
$$= £275{,}700$$

~~**The costs of the external SO Settlement Period variables are as follows:**~~

~~**CSOBM = £14,583**~~
~~**BSCCV = £3,125**~~

~~**FIIR$_{365}$, BSC$_{365}$, SOTOC$_{365}$ and LBS$_{365}$ are all zero.**~~

~~**The costs of the external SO Settlement Day variables are as follows:**~~

~~**IncpayEXT = £275,700**~~
~~**BSCCA = £200,000**~~
~~**ET = £0**~~
~~**OM = £0**~~

$$BSUoSEXT_{365} = £14{,}583 + £3{,}125$$
$$+ (£275{,}700 + £200{,}000 + £0 - £0 + £0 + £0 + £0 + £0)/48$$
$$= £14{,}583 + £3{,}125 + £9{,}910$$
$$= £27{,}618$$

~~**Annual internal SO costs assumed for this example have been listed in Table BS2 above.**~~

~~**RPIF$_t$ = 1**~~

$$BSUoSINT_{1,365} = \left[(£75{,}873{,}280 + £18{,}250{,}000 + 0 + 0 + £18{,}250{,}000)/365\right] * 1/48$$
$$= £6{,}414$$

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~~**Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period i**~~

~~**The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{1365}$) for Settlement Period 1 on Settlement Day 365**~~

$$BSUoSTOT_{1,365} = BSUoSEXT_{1,365} + BSUoSINT_{1,365}$$

$$= £27{,}618 + £6{,}414$$

$$= £34{,}032$$

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Section 2 – The Statement of the Balancing Services Use of System Charging Methodology

14.29 Principles

14.29.1 The Transmission Licence allows The Company to derive revenue in respect of the Balancing Services Activity through the Balancing Services Use of System (BSUoS) charges. This statement explains the methodology used in order to calculate the BSUoS charges.

14.29.2 The Balancing Services Activity is defined in the Transmission Licence as the activity undertaken by The Company as part of the Transmission Business including the operation of the transmission system and the procuring and using of Balancing Services for the purpose of balancing the transmission system.

14.29.3 The Company in its role as System Operator keeps the electricity system in balance (energy balancing) and maintains the quality and security of supply (system balancing). The Company is incentivised on the procurement and utilisation of services to maintain the energy and system balance and other costs associated with operating the system. Users pay for the cost of these services and any incentivised payment/receipts through the BSUoS charge.

14.29.4 All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement Period.

14.29.5 BSUoS charges ~~comprise~~ recover the following costs:

(i) The Total Costs of the Balancing Mechanism
(ii) Total Balancing Services Contract costs
(iii) Payments/Receipts from National Grid incentive schemes
(iv) Internal costs of operating the System
(v) Costs associated with contracting for and developing Balancing Services
(vi) Adjustments
(vii) Costs invoiced to The Company associated with Manifest Errors and Special Provisions.
(viii) BETTA implementation costs
(ix) Any under/over recovery amounts resulting from the Fixed BSUoS Price
~~(viii)~~(x) Financing costs associated with the Fixed BSUoS Price

14.29.6 BSUoS charges are calculated and levied on a fixed price £/MWh (the "Fixed BSUoS Price") per Settlement Period basis set for a period of twelve months (the "Fixed Price Period") and notified to Users fifteen months in advance. The Fixed BSUoS Price will be applied to each User's actual metered volumes (including all relevant losses) to derive that User's BSUoS charge.

14.29.7 Any over or under recovery during a Fixed Price Period will be included in the calculation of the Fixed BSUoS Price £/MWh for the next available Fixed Price Period

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14.29.8 This methodology is divided into three sections:

a. Calculation of the Daily BSUoS charge
b. Calculation of the Fixed BSUoS Price
c. Volume settlement of BSUoS

14.30 PART A Calculation of the Daily Balancing Services Use of System charge

Calculation of the Daily Balancing Services Use of System charge

14.30.1 The BSUoS charge payable by customer c, on Settlement Day d, will be calculated in accordance with the following formula:

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} BSUoSTOT_{ij}$$

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} FixedBSUoSTOT_{ij}$$

Where:

i	-	refers to the individual BM Unit
j	-	refers to an individual Settlement Period
$\sum_{i \in c} \sum_{j \in d}$	-	refers to the sum over all BM units 'i', for which customer 'c' is the Lead Party* summed over all Settlement Periods 'j' on a Settlement Day 'd'

14.30.2 A customer's charge is based on their proportion of BM Unit Metered Volume for each Settlement Period relative to the total BM Unit Metered Volume for each Settlement Period, adjusted for transmission losses by the application of the relevant Transmission Losses Multiplier.

For all liable importing and exporting BM Units in delivering Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = FixedBSUoSPrice_{t} * QMBSUoS_{ij} * TLM_{ij}$$

$$BSUoSTOT_{ij} = \frac{BSUoSTOT_{j} * QMBSUoS_{ij} * TLM_{ij}}{\left\{\left|\sum\nolimits^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum\nolimits^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}$$

For all liable importing and exporting BM Units in offtaking Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = -1 * FixedBSUoSPrice_{t} * QMBSUoS_{ij} * TLM_{ij}$$

$$BSUoSTOT_{ij} = \frac{-1 * BSUoSTOT_{j} * QMBSUoS_{ij} * TLM_{ij}}{\left\{\left|\sum\nolimits^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum\nolimits^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}$$

Where:

$FixedBSUoSTOT_{ij}$	Total BSUoS Charge for BM Unit i for Settlement Period j
$FixedBSUoSPrice_{t}$	As defined in Part B
$QMBSUoS_{ij}$	BM Unit Metered Volume (QM_{ij})** for BSUoS Liable BM Units
TLM_{ij}	Transmission Loss Multiplier **

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* or CUSC party associated with the BMUnits (listed in Appendix C of the BEGA) who is exempt from also being a BSC Party

** Detailed definition in Balancing and Settlement Code Annex X2 – Technical Glossary

$\sum^{+}$ - refers to the sum over all BM Units that are in delivering Trading Units in Settlement Period 'j'

$\sum^{-}$ - refers to the sum over all BM Units that are in offtaking Trading Units in Settlement Period 'j'

'delivering' and 'offtaking' in relation to Trading Units have the meaning set out in the Balancing and Settlement Code (excluding all Interconnector BMUs and Trading Units)

14.30.3 For the avoidance of doubt, BM Units that are registered in Trading Units will be charged on a net Trading Unit basis i.e. if a BM Unit is exporting to the system and is within a Trading Unit that is offtaking from the system then the BM Unit in essence would be paid the BSUoS charge. Conversely, if a BM Unit is importing from the system in a delivering Trading Unit then the BM Unit in essence would pay the BSUoS charge.

Interconnector BM Units

14.30.4 BM Unit and Trading Units associated with Interconnectors, including those associated with the Interconnector Error Administrator, are not liable for BSUoS charges.

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PART B - Calculation of the Fixed BSUoS price

Fixed BSUoS Price Calculation

The Fixed BSUoS -Price for the Fixed Price Period is calculated as follows to give a £/MWh figure:

$$FixedBSUoSPrice_t = \left(\frac{FcBSUoSTOT_t + KB_{t-x}}{FcBSUoSVol_t} \right)$$

where:

$FixedBSUoSPrice_t$	Fixed BSUoS Price £/MWh for the Fixed Price Period t
$FcBSUoSTOT_t$	Forecast Total BSUoS Revenue applicable for Fixed Price Period t including all forecast BSUoSExt and BSUoSInt costs as per paragraph 14.30.1
$FcBSUoSVol_t$	Forecast Volume in MWh of all offtaking and ontaking BM Units, i, adjusted for Transmission Losses within the relevant Fixed Price Period t as forecast by The Company
KB_{t-x}	Adjustment for financing costs and any difference between the Fixed BSUoS Price cost recovery and the actual Total BSUoS costs incurred by The Company in a previous period t-x.

Comment [A1]: Need to this as formala says its STOT divided by vol?? As comment below in formal above show stot as + KB and define KB in formula list??

ForecastSTOT is our forecast of BSUoSEXT and BSUoSINT for the relevant period t (so means we still need the defined licence terms as per table, otherwise have no purpose in sec 14?

Purpose of BSUoS Sot (in table) in sec 14 ?

KB = difference between forecast SEXT and SINT for fixed price period and actual sext and sint plus financing??

Forecast Total BSUoS Revenue (Internal + External)

14.30.1 The Forecast Total BSUoS Revenue for the relevant Fixed Price Period ($FcBSUoSTOT_t$) is calculated by (a) summing the external BSUoS Forecast

£Revenue (ForecastBSUoSEXT$_t$) and internal BSUoS Forecast £Revenue (ForecastBSUoSINT$_t$) expected to be incurred for that Fixed Price Period including all associated incentives.

$$FcBSUoSTOT_t = ForecastBSUoSEXT_t + ForecastBSUoSINT_t$$

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Where

ForecastBSUoSExt$_t$ Forecast for Fixed Price Period t of all relevant External BSUoS costs as defined by the Transmission Licence.

ForecastBSUoSInt$_t$ Forecast for Fixed Price Period t of all relevant Internal BSUoS costs as defined by the Transmission Licence

Total BSUoS Charge (Internal + External) for each Settlement Period (BSUoSTOT$_{jd}$)

The Total BSUoS charges for each Settlement Period (BSUoSTOT$_{jd}$) for a particular day are calculated by summing the external BSUoS charge (BSUoSEXT$_{jd}$) and internal BSUoS charge (BSUoSINT$_{jd}$) for each Settlement Period.

$$BSUoSTOT_{jd} = BSUoSEXT_{jd} + BSUoSINT_{jd}$$

External BSUoS Charge for each Settlement Period (BSUoSEXT$_{jd}$)

The External BSUoS Charges for each Settlement Period (BSUoSEXT$_{jd}$) are calculated by taking each Settlement Period System Operator BM Cash Flow (CSOBM$_{jd}$) and Balancing Service Variable Contract Cost (BSCCV$_{jd}$) and allocating the daily elements on a MWh basis across each Settlement Period in a day.

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd}$$
$$+\left[(IncpayEXT_d + BSCCA_d + ET_d - OM_d + FIIR_d + BSC_d + SOTOC_d + LBS_d) \right.$$
$$*\left\{ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right| \right\} /$$
$$\left.\sum_{j \in d}\left\{ \left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right| \right\} \right]$$

Calculation of the daily External Incentive Payment (IncpayEXT$_d$)

In respect of each Settlement Day d, IncpayEXTd is calculated as the difference between the new total incentive payment (FKIncpayEXTd) and the incentive payment that has been made to date for the previous days from the commencement of the scheme (ξk=1=d-1IncpayEXTk):

$$IncpayEXT_d = FKIncpayEXT_d - \sum_{k=0}^{d-1} IncpayEXT_k$$

The forecast incentive payment made to date (from the commencement of the scheme) (FKIncpayEXT$_d$) is calculated as the ratio of total forecast external incentive payment across the duration of the scheme: the number of days in the scheme, multiplied by the sum of the profiling factors to date.

$$FKIncpayEXT_d = \frac{FYIncpayEXT_d}{NDS} * \sum_{k=1}^{d} PFT_k$$

Inclusion of Profiling Factors

Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_d are assumed to be one for the duration of the current external incentive scheme.

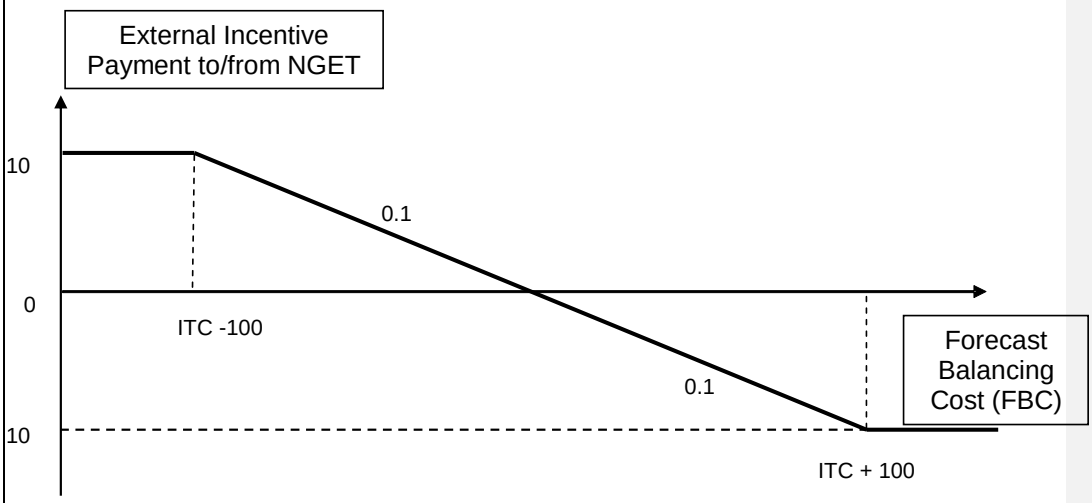
The forecast External incentive payment for the duration of the External incentive scheme ($FYIncpayEXT_d$) is calculated as the difference between the External Scheme target (M_t) and the forecast Balancing cost (FBC) subject to sharing factors (SF_t) and a cap/collar (CB_t).

$$FYIncpayEXT_d = SF_t * (M_t - FBC_d) + CB_t$$

The relevant value of the External incentive payment (BSUoSEXT) can then be calculated by reference to Table 9.1 and the selection and application of the appropriate sharing factors and offset dependent upon the value of the forecast Balancing Services cost (FBC).

Table 9.1

Forecast Balancing Cost (FBC)	M_t £m	SF_t	CB_t £m
FBC < (Incentive Target Cost – 100)	0	0	10
(Incentive Target Cost -100) <= FBC < (Incentive Target Cost)	Incentive Target Cost	10	0
Incentive Target Cost = FBC	FBC	0	0
(Incentive Target Cost) < FBC <= (Incentive Target Cost + 100)	Incentive Target Cost	10	0
(Incentive Target Cost + 100)	0	0	10



In respect of each Settlement Day d, the forecast incentivised Balancing Cost (FBC_d) will be calculated as follows:

$$FBC_d = \frac{\sum_{k=1}^{d} IBC_k}{\sum_{k=1}^{d} PFT_k} * NDS$$

Where:

NDS = Number of days in Scheme.

Daily Incentivised Balancing Cost (IBC_d) is calculated as follows:

~~**Internal BSUoS Charge for each Settlement Period ($BSUoSINT_{id}$)**~~

~~The Internal BSUoS Charges ($BSUoSINT_{id}$) for each Settlement Period j for a particular day are calculated by taking the incentivised and non-incentivised SO Internal Costs for each Settlement Day allocated on a MWh basis across each Settlement Period in a day.~~

$$BSUoSINT_{jd} = [(SOPU_d + SOMOD_d + SOEMR_d + SOEMRCO_d + SOTRU_d) * RPIF_t]$$
$$* \{ \left| \sum^{+} (QMBSUoS_{ijd} * TLM_{ijd}) \right| + \left| \sum^{-} (QMBSUoS_{ijd} * TLM_{ijd}) \right| \}$$
$$/ \sum_{j \in d} \{ \left| \sum^{+} (QMBSUoS_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QMBSUoS_{ij} * TLM_{ij}) \right| \}$$

~~**Inclusion of Profiling Factors**~~

~~Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_k are assumed to be one for the duration of the current external incentive scheme~~

14.31 PART C Volume Settlement of BSUoS

Settlement and Reconciliation of BSUoS charges

14.31.1 There are two stages of the reconciliation of BSUoS charges described below:

- Initial Settlement (SF)
- Final Reconciliation (RF)

Initial Settlement of BSUoS

14.31.2 The Company will calculate initial settlement (SF) BSUoS charges in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Initial Settlement Run and the Initial Volume Allocation Run.

Reconciliation of BSUoS Charges

14.31.3 Final Reconciliation will result in the calculation of a reconciled charge for each settlement day in the scheme year. The Company will calculate Final Reconciliation (RF) BSUoS charges (with the inclusion of interest as defined in the CUSC) in accordance with the methodology set out in ~~section 14.30~~Part A above, ~~using the applicable latest available data,~~ including data from the Final Reconciliation Settlement Run and the Final Reconciliation Volume Allocation Run.

Unavailability of Data

14.31.4 If any of ~~the elements~~volume data required to calculate the BSUoS charges in respect of any Settlement Day have not been notified to The Company in time for it to do the calculations then The Company will use volume data for the corresponding Settlement Day in the previous week. If no such values for the previous week are available to The Company then The Company will substitute such ~~variables~~ volume data as it shall, at its reasonable discretion, think fit and calculate Balancing Services Use of System charges on the basis of these values. When the actual volume data becomes available a reconciliation run will be undertaken.

Disputes

14.31.5 If The Company or any customer identifies any error which would affect the total Balancing Services Use of System charge on a Settlement Day then The Company will recalculate the charges following resolution of the error. Revised invoices and/or credit notes will be issued for the change in charges, plus interest as set out in the CUSC. The charge recalculation and issuing of revised invoices and/or credit notes will not take place for any day where the total change in the Balancing Services charge is less than £2000.

Relationship between the Statement of the Use of System Charging Methodology and the Transmission Licence

14.31.6 BSUoS charges are made on a daily basis and as such ~~of~~ this Statement sets out the details of the calculation of such charges on a daily basis and the Fixed BSUoS Price used to derive the charge. Customers may, when verifying charges for Balancing Services Use of System refer to the Transmission Licence which sets out the maximum allowed revenue that The Company may recover in respect of the Balancing Services Activity.

14.31.7 The Company has, where possible and appropriate, attempted to ensure that acronyms allocated to variables within the Balancing Services charging software, and associated reporting, match with the acronyms given to those variables used within this statement.

14.31.8 Balancing Services Use of System Acronym Definitions

For the avoidance of doubt "as defined in the BSC" relates to the Balancing and Settlement Code as published from time to time.

EXPRESSION	ACRONYM	Unit	Definition
BETTA Preparation Costs	BI	£	As defined in the Transmission Licence
Balancing Mechanism Unit	BM Unit or BMU		As defined in the BSC
~~Black Start Costs~~	~~BSC~~	~~£~~	~~As defined in the Transmission Licence (means he allowed revenue from and associated with Black Start services in accordance with paragraph 4G.5 of Special Condition 4G (Black Start Allowed Revenue Cost Incentive))~~
~~Balancing service contract costs – non-Settlement Period specific~~	~~$BSCCA_{id}$~~	~~£~~	~~Non Settlement Period specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
~~Balancing Service Contract Cost~~	~~$BSCC_{j}$~~	~~£~~	~~Balancing Service Contract Cost from purchasing Ancillary services applicable to a Settlement Period j less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
~~Balancing service contract costs – Settlement Period specific~~	~~$BSCCV_{jd}$~~	~~£~~	~~Settlement Period j specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
External Balancing Services Use of System charge	$BSUoSEXT_{jd}$	£	External System Operator (SO) Balancing Services Use of System charge ~~applicable to Settlement Period j for settlement day d~~
Internal Balancing Services Use of System charge	$BSUoSINT_{jd}$	£	Internal System Operator (SO) Balancing Services Use of System charge ~~applicable to Settlement Period j for settlement day d~~
Total Balancing Services Use of System charge	$BSUoSTOT_{cd}$	£	The sum determined for each customer, c, in accordance with this Statement and payable by that customer in respect of each Settlement Day d, in accordance with the terms of the Supplemental Agreement
~~Total Balancing Services Use of System charge~~	~~$BSUoSTOT_{j}$~~	~~£~~	~~Total Balancing Services Use of System Charge applicable for Settlement Period j~~

EXPRESSION	ACRONYM	Unit	Definition
~~System Operator BM Cash Flow~~	~~$CSOBM_j$~~	~~£~~	~~As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001 less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
Daily balancing services adjustment	ET_d	£	Is the contribution on Settlement Day, d, to the value of ET_t where ET_t is determined pursuant to part B of Special Condition 4C of the Transmission Licence
~~Forecast incentivised Balancing Cost~~	~~FBC_d~~	~~£~~	~~Forecast incentivised Balancing Cost for duration of the Incentive Scheme as at settlement day d~~
~~SO Forecasting Incentive Payment~~	~~FIIR~~	~~£~~	~~As defined in the Transmission Licence~~ ~~(means the incentive payment which the licensee may derive from the forecasting incentive for Wind Generation Output and National Demand Wind Generation Forecasting Incentive in accordance with Special Condition 4H (Wind Generation Forecasting Incentive))~~
~~External Incentive payment to date~~	~~$FKIncpayEXT_d$~~	~~£~~	~~Total External Incentive Payment to date up to and including settlement day d~~
~~Total Forecast External incentive payment~~	~~$FYIncpayEXT_d$~~	~~£~~	~~Total forecast External incentive payment for the entire duration of the incentive scheme as at settlement day d~~
Allowed Income Adjustment relating to the SO-TO Code	IAT	£	As defined in the Transmission Licence
~~Daily Incentivised Balancing Cost~~	~~IBC_d~~	~~£~~	~~Is equal to that value calculated in accordance with paragraph 14.30.13 of Part 2 of this Statement~~
~~Daily External incentive payment~~	~~$IncpayEXT_d$~~	~~£~~	~~External Incentive payment for Settlement Day d~~
~~Demand Side Balancing Reserve and Supplementary Balancing Reserve costs~~	~~LBS~~	~~£~~	~~As defined in the Transmission Licence~~
~~Cost associated with the Provision of Balancing Services to others~~	~~OM_d~~	~~£~~	~~Is the contribution on Settlement Day, d, to the value of OM_t where OM_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence~~
Outage change allowance amount	ON	£	As defined in the Transmission Licence

Comment [A2]: Legacy definition

Comment [A3]: Legacy definition

Comment [A4]: Legacy definition

EXPRESSION	ACRONYM	Unit	Definition
~~Incentivised Balancing Cost daily profiling factor~~	~~PFT_d~~		~~The daily profiling factor used in the determination of forecast Incentivised Balancing Cost for settlement day d~~
BM Unit Metered Volume	QM_{ij}	MWh	As defined in the BSC
BSUoS Liable BM Unit Metered Volume	$QMBSUoS_{ij}$	MWh	QM_{ij} for all BM Units liable for BSUoS
~~Retail Price Index Adjustment Factor~~	~~RPIF~~		~~As defined in the Transmission Licence~~
Balancing services deemed costs	RT_d	£	Is the contribution on Settlement Day, d, to the value of RT_t where RT_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
~~SOEMR Preparation Costs~~	~~SOEMR~~	~~£~~	~~As defined in the Transmission Licence~~
~~SOEMR Preparation Costs Adjustment~~	~~SOEMRCO~~	~~£~~	~~As defined in the Transmission Licence~~
~~Incremental change from SO Opening Base Revenue Allowance~~	~~SOMOD~~		~~As defined in the Transmission Licence~~
~~SO Opening Base Revenue Allowance~~	~~SOPU~~		~~As defined in the Transmission Licence~~
~~SO-TO funding allowance~~	~~SOTOC~~	~~£~~	~~As defined in the Transmission Licence~~ ~~(means the SO-TO Mechanism cost allowance calculated in accordance with 4C.29 Special Condition 4J (SO-TO Mechanism))~~
~~Revenue Adjustment with respect to actual and assumed RPI values~~	~~SOTRU~~		~~As defined in the Transmission Licence~~
Tax Allowance	T	£	As defined in the Transmission Licence
Transmission Loss Multiplier	TLM_{ij}		As defined in the BSC
Total System Energy Imbalance Volume	$TQEI_j$	MWh	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001

Comment [A5]: Legacy definition

Comment [A6]: Legacy definition

Comment [A7]: Legacy definition

EXPRESSION	ACRONYM	Unit	Definition
Final Reconciliation Settlement Run			As defined in the BSC
Final Reconciliation Volume Allocation Run			As defined in the BSC
Initial Settlement Run			As defined in the BSC
Initial Volume Allocation Run			As defined in the BSC
Lead Party			As defined in the BSC
Fixed BSUoS Price	FixedBSUoSPrice		Fixed BSUoS Price in £/MWh for the Fixed Price Period
Fixed Price Period			The period for which the Fixed BSUoS price has been calculated.
$FixedBSUoSTot_{ji}$	$FixedBSUoSTot_{ji}$		The Fixed BSUoS cost for the relevant settlement period j for the relevant BM Unit i
$FcBSUoSTOT_t$	$FcBSUoSTOT_t$		Forecast Total BSUoS Revenue applicable for Fixed Price Period t including all forecast BSUoSExt and BSUoSInt costs
$FcBSUoSVol_t$	$FcBSUoSVol_t$		Forecast Volume in MWh of all offtaking and ontaking BM Units, i,adjusted for Transmission Losses within the relevant Fixed Price Period t as forecast by The Company
KB_{t-x}	KB_{t-x}		Adjustment for financing costs and any difference between the Fixed BSUoS Price cost recovery and the actual Total BSUoS costs incurred by The Company in a previous period t-x
$ForecastBSUoSExt_t$	$ForecastBSUoSExt_t$		Forecast for Fixed Price Period t of all relevant External BSUoS costs as defined by the Transmission Licence.
$ForecastBSUoSInt_t$	$ForecastBSUoSInt_t$		Forecast for Fixed Price Period t of all relevant Internal BSUoS costs as defined by the Transmission Licence

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14.32 Examples of Balancing Services Use of System (BSUoS) Daily Charge Calculations

This example illustrates the operation of the Balancing Services Use of System Daily charge formula. The parameters used are for illustrative purposes only and have been chosen for ease of calculation. They do not relate to the agreed scheme for any particular year. The actual scheme parameters are shown in the main text.

To calculate the daily BSUoS charge applicable to each User in each Ssettlement Period the below formulae are used for each Trading Unit.

For all liable importing and exporting BM Units in delivering Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = FixedBSUoSPrice_t * QMBSUoS_{ij} * TLM_{ij}$$

Where a User delivered 360MWh
£817.29= £2.25*360*1.009

For all liable importing and exporting BM Units in off-taking Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = -1 * FixedBSUoSPrice_t * QMBSUoS_{ij} * TLM_{ij}$$

Where a User offtook 360MWh
£822.15= -1*£2.25*-360*1.0015

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~~The example is divided into the calculation of the External System Operator cost and Internal System Operator cost elements. All daily profiling factors (PFT_d) have been assumed to be one for this example.~~

~~Day 1~~

~~Calculation of the Daily External SO Incentive Scheme Payment~~

~~The first step is to calculate the Daily Incentivised Balancing Cost (IBC_1 for day one) for that day using the following formula. These are the daily incentivised cost elements used to calculate the external SO incentive payment.~~

$$IBC_1 = CSOBM_1 + BSCCA_1 + BSCCV_1 - OM_1 - RT_1$$

$$= £800,000 + £500,000 + £250,000 - £0 - £0$$

$$= £1,550,000$$

~~Assuming that $CSOBM_1$ = £800,000~~
~~$BSCCA_1$ = £500,000~~
~~$BSCCV_1$ = £250,000~~
~~OM_1 = £0~~
~~RT_1 = £0~~

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~~**Now that we know IBC_1, it is possible to calculate Forecast Balancing Services Cost (FBC_1) from that day's outturn as follows:**~~

$$FBC_1 = \frac{\sum_{k=1}^{d=1} IBC_k}{\sum_{k=1}^{d=1} PFT_k} * NDS$$

$$= \frac{£1{,}550{,}000}{1} * 365$$

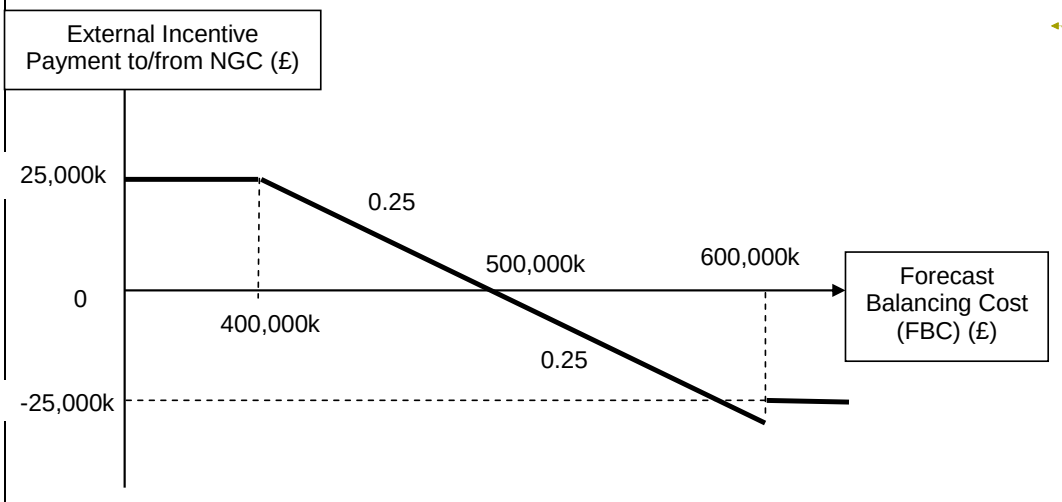
$$= £565{,}750{,}000$$

~~**The values of SF_t and CB_t can now be read off table BS1 below. (**These values are used purely for illustrative purposes based on an incentive target of £500,000,000**). As FBC_1 is £565,750,000, SF_t is 0.25, CB_t is £0 and M_t is £500,000,000.**~~

~~Table BS1~~

~~Forecast Balancing Cost (FBC_d)~~	~~M_t~~	~~SF_t~~	~~CB_t~~
~~**£400,000,000 < FBC**~~	~~**£0**~~	~~**0**~~	~~**£25,000,000**~~
~~**£400,000,000 <= FBC < £500,000,000**~~	~~**£500,000,000**~~	~~**0.25**~~	~~**£0**~~
~~**FBC = £500,000,000**~~	~~**£500,000,000**~~	~~**0**~~	~~**£0**~~
~~**£500,000,000 < FBC <= £600,000,000**~~	~~**£500,000,000**~~	~~**0.25**~~	~~**£0**~~
~~**FBC > £600,000,000**~~	~~**£0**~~	~~**0**~~	~~**- £25,000,000**~~

~~**The table describes the external incentive scheme, which can also be illustrated by the graph below.**~~



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~~Using the values set out in the table above, the external SO incentive payment for the duration of the scheme (FYIncpayEXT) can be calculated as follows:~~

$$FYIncpayEXT_1 = SF_t * (M_t - FBC_1) + CB_t$$

~~$$= 0.25 * (£500{,}000{,}000 - £565{,}750{,}000) + £0$$~~

$$= -£16{,}437{,}500$$

~~In this case the incentive payment is negative (£16,437,500) i.e. a payment from The Company.~~

~~The external SO incentive payment for the entire duration of the incentive scheme (FYIncpayEXT) is then used to calculate the total incentive payment to date (FKIncpayEXT), shown as follows:~~

$$FKIncpayEXT_1 = \frac{FYIncpayEXT_1}{NDS} * \sum_{k=1}^{d=1} PFT_k$$

~~$$= \frac{-£16{,}437{,}500}{365} * 1$$~~

$$= -£45{,}034$$

~~Where:~~

~~NDS = Number of days in the external incentive scheme~~

~~The final step is to calculate today's external incentive payment (IncpayEXT$_1$ for day one), shown as follows:~~

$$IncpayEXT_1 = FKIncpayEXT_1 - \sum_{k=0}^{d-1=0} IncpayEXT_k$$

$$= -£45{,}034 - £0$$

$$= -£45{,}034$$

~~Calculating the External Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~The External Balancing Services Use of System (BSUoS) charge for Settlement Period 1 on this Settlement Day 1 can now be calculated using the following formula:~~

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd}$$
$$+ \left[(IncpayEXT_d + BSCCA_d + ET_d - OM_d + FIIR_d + BSC_d + SOTOC_d + LBS_d) \right.$$
$$* \left\{ \left| \sum\nolimits^{+} (QM_{i1,1} * TLM_{i1,1}) + \left| \sum\nolimits^{-} (QM_{i1,1} * TLM_{i1,1}) \right| \right\} /$$
$$\left. \sum_{j \in 1} \left\{ \left| \sum\nolimits^{+} (QM_{ij} * TLM_{ij}) \right| + \left| \sum\nolimits^{-} (QM_{ij} * TLM_{ij}) \right| \right\} \right]$$

~~For simplicity, the BSUoS applicable BM Unit Metered Volume (QMBSUoS$_{ij}$ * TLM$_{ij}$) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48) i.e. the multiplier at the end of the equation.~~

~~The illustration below shows the external BSUoS charge (BSUoSEXT$_{11}$) for Settlement Period one of Settlement Day 1.~~

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~~The costs of the external SO Settlement Period variables are as follows (these are the daily values included in the IBC_1 equation divided by 48 Settlement Periods).~~

~~CSOBM = £16,667~~
~~BSCCV = £5,208~~
~~$FIIR_1$, BSC_1, $SOTOC_1$ and LBS_1 are all zero.~~

~~The costs of the external SO Settlement Day variables are as follows:~~

~~IncpayEXT = £-45,034~~
~~BSCCA = £500,000~~
~~ET = £0~~
~~OM = £0~~

$$BSUoSEXT_{11} = £16,667 + £5,208 + [(-£45,034 + £500,000 + £0 - £0 + £0 + £0 + £0)/48]$$
$$= £16,667 + £5,208 + £9,478$$
$$= £31,353$$

~~Calculating the Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~Table BS2 below shows the annual Internal SO costs assumed for this example:~~

~~Table BS2~~

~~Internal SO Cost Variable~~	~~Annual Cost (£m)~~
~~$SOPU_t$~~	~~75,873,280~~
~~$SOMOD_t$~~	~~18,250,000~~
~~$SOEMR_t$~~	~~0~~
~~$SOEMRCO_t$~~	~~0~~
~~$SOTRU_t$~~	~~18,250,000~~

~~$RPIF_t = 1$~~

~~The Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period 1 of Settlement Day 1 can be calculated using the following formula:~~

$$BSUoSINT_{11} = \left[\{(SOPU_1 + SOMOD_1 + SOEMR_1 + SOEMRCO_1 + SOTRU_1)/NDS\} * RPIF_1\right]$$
$$* \left\{ \left|\sum\nolimits^{+}(QM_{i1,1} * TLM_{i1,1})\right| + \left|\sum\nolimits^{-}(QM_{i1,1} * TLM_{i1,1})\right| \right\} / \sum_{j\in 1} \left\{ \left|\sum\nolimits^{+}(QM_{ij} * TLM_{ij})\right| + \left|\sum\nolimits^{-}(QM_{ij} * TLM_{ij})\right| \right\}$$

~~As with the external BSUoS charge, for simplicity, the BSUoS applicable BM Unit Metered Volume ($QMBSUoS_{ij} * TLM_{ij}$) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48).~~

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$$BSUoSINT_{11} = \left[(75{,}873{,}280 + 18{,}250{,}000 + 0 + 0 + 18{,}250{,}000)/365\right] * 1/48$$
$$= £6414$$

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Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period 1

The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{11}$) for a Settlement Period 1 on Settlement Day 1.

$$BSUoSTOT_{11} = BSUoSEXT_{11} + BSUoSINT_{11}$$
$$= £31{,}353 + £6{,}414$$
$$= £37{,}767$$

~~Day 2~~

~~Calculation of the Daily External SO Incentive Scheme Payment~~

~~Again, the first step is to calculate the Daily Incentivised Balancing Cost for day 2 (IBC_2) using the following formula:~~

$$IBC_2 = CSOBM_2 + BSCCA_2 + BSCCV_2 - OM_2 - RT_2$$

$$= £600,000 + £150,000 + £100,000 - £0 - £0$$

$$= £850,000$$

~~Assuming that $CSOBM_2$ = £600,000~~
~~$BSCCA_2$ = £150,000~~
~~$BSCCV_2$ = £100,000~~
~~OM_2 = £0~~
~~RT_2 = £0~~

~~With IBC_d known for day one, it is possible to calculate Forecast Balancing Services Cost (FBC_2) from the outturn to date as follows:~~

$$FBC_2 = \frac{\sum_{k=1}^{d=2} IBC_k}{\sum_{k=1}^{d=2} PFT_k} * NDS$$

$$= \frac{(£1,550,000 + £850,000)}{2} * 365$$

$$= £438,000,000$$

~~The values of SF_t, M_t and CB_t can now be read off table BS1 given previously. As FBC_2 is £438,000,000, SF_t is now 0.25, M_t is £500,000,000 and CB_t is 0, calculated as follows:~~

$$FYIncpayEXT_2 = SF_t * (M_t - FBC_2) + CB_t$$

$$= 0.25 * (£500,000,000 - £438,000,000) + £0$$

$$= £15,500,000$$

~~The external SO incentive payment for the entire duration of the incentive scheme ($FYIncpayEXT_2$) is then used to calculate the total incentive payment to date ($FKIncpayEXT_2$), shown as follows:~~

$$FKIncpayEXT_2 = \frac{FYIncpayEXT_2}{NDS} * \sum_{k=1}^{d=2} PFT_k$$

$$= \frac{£15,500,000}{365} * 2$$

$$= £84,932$$

~~Where:~~

~~NDS = Number of days in the incentive scheme~~

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~~In this case the incentive payment forecast for the year is £84,932.~~

~~Again, the final step is to calculate today's external incentive payment (IncpayEXT$_2$ for day two), shown as follows:~~

$$IncpayEXT_2 = FKIncpayEXT_2 - \sum_{k=0}^{d-1=1} IncpayEXT_k$$
$$= £84{,}932 - -£45{,}034$$
$$= £129{,}966$$

~~The costs of the external SO Settlement Period variables are as follows:~~

~~CSOBM = £12,500~~
~~BSCCV = £2,083~~

~~FIIR$_2$, BSC$_2$, SOTOC$_2$ and LBS$_2$ are all zero.~~

~~The costs of the external SO Settlement Day variables are as follows:~~

~~IncpayEXT = £129,966~~
~~BSCCA = £150,000~~
~~ET = £0~~
~~OM = £0~~

$$BSUoSEXT_{12} = £12{,}500 + £2{,}083$$
$$+ [(£129{,}966 + £150{,}000 + £0 - £0 + £0 + £0 + £0 + £0)/48]$$
$$= £12{,}500 + £2{,}083 + £5{,}833$$
$$= £20{,}416$$

~~Annual internal SO costs assumed for this example have been listed in table BS2 above.~~

~~RPIF$_j$ = 1~~

$$BSUoSINT_{12} = [(75{,}873{,}280 + 18{,}250{,}000 + 0 + 0 + 18{,}250{,}000)/365] * 1/48$$
$$= £6{,}414$$

~~Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~The final step is to calculate the Total Balancing Services Use of System (BSUoSTOT$_{12}$) for Settlement Period 1 on Settlement Day 2.~~

$$BSUoSTOT_{12} = BSUoSEXT_{12} + BSUoSINT_{12}$$
$$= £20{,}416 + £6414$$
$$= £26{,}830$$

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Day 365

If we now move to the end of the year, then once again the first step is to calculate the Daily Incentivised Balancing Cost for the final day (IBC_{365}) using the formula below:

Calculation of the Daily External SO Incentive Scheme Payment

$$IBC_{365} = CSOBM_{365} + BSCCA_{365} + BSCCV_{365} - OM_{365} - RT_{365}$$

$$= £700{,}000 + £200{,}000 + £150{,}000 + £200{,}000 - £0 - £0$$

$$= £1{,}050{,}000$$

Assuming that $CSOBM_{365}$ = £700,000
$BSCCA_{365}$ = £200,000
$BSCCV_{365}$ = £150,000
OM_{365} = £0
RT_{365} = £0

With $\sum_{364} IBC_d$ assumed to be £432,000,000 for the previous 364 days, it is possible to calculate Forecast Balancing Services Cost (FBC_{365}) from the outturn to date as follows:

$$FBC_{365} = \frac{\sum_{k=1}^{d=365} IBC_k}{\sum_{k=1}^{d=365} PFT_k} * NDS$$

$$= \frac{£432{,}000{,}000 + £1{,}050{,}000}{365} * 365$$

$$= £433{,}050{,}000$$

The values of SF_t, M_t and CB_t can now be read off table BS1. As FBC_{365} is £433,050,000, SF_t is now 0.25, M_t is £500,000,000 and CB_t is 0. Therefore $FYIncpayEXT_{365}$ is calculated as follows:

$$FYIncpayEXT_{365} = SF_t * (M_t - FBC_{365}) + CB_t$$

$$= 0.25 * (£500{,}000{,}000 - £433{,}050{,}000) + £0$$

$$= £16{,}737{,}500$$

The external SO incentive payment for the entire duration of the incentive scheme (FYincpayEXT) is then used to calculate the total incentive payment to date (FKIncpayEXT), shown as follows:

$$FKIncpayEXT_{365} = \frac{FYIncpayEXT_{365}}{NDS} * \sum_{k=1}^{d=365} PFT_k$$

$$= \frac{£16{,}737{,}500}{365} * 365$$

$$= £16{,}737{,}500$$

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~~**Where:**~~

~~**NDS = Number of days in the incentive scheme**~~

~~**In this case the incentive payment is positive (£16,737,500) i.e. a payment to The Company. As this is the last day of the scheme this represents the overall incentive payment due to The Company i.e. with reference to the graph with Table BS1 25% of the difference between £500,000,000 and £433,050,000.**~~

~~**Again, the final step is to calculate today's external incentive payment (IncpayEXT$_{365}$ for day 365), shown as follows:**~~

~~**It has been assumed that the total incentive payments for the previous 364 days ($\sum_{k=0}^{d-1=364} IncpayEXT_k$) is £16,461,800.**~~

$$IncpayEXT_{365} = FKIncpayEXT_{365} - \sum_{k=0}^{d-1=364} IncpayEXT_k$$
$$= £16{,}737{,}500 - £16{,}461{,}800$$
$$= £275{,}700$$

~~**The costs of the external SO Settlement Period variables are as follows:**~~

~~**CSOBM = £14,583**~~
~~**BSCCV = £3,125**~~

~~**FIIR$_{365}$, BSC$_{365}$, SOTOC$_{365}$ and LBS$_{365}$ are all zero.**~~

~~**The costs of the external SO Settlement Day variables are as follows:**~~

~~**IncpayEXT = £275,700**~~
~~**BSCCA = £200,000**~~
~~**ET = £0**~~
~~**OM = £0**~~

$$BSUoSEXT_{365} = £14{,}583 + £3{,}125$$
$$+ (£275{,}700 + £200{,}000 + £0 - £0 + £0 + £0 + £0 + £0)/48$$
$$= £14{,}583 + £3{,}125 + £9{,}910$$
$$= £27{,}618$$

~~**Annual internal SO costs assumed for this example have been listed in Table BS2 above.**~~

~~**RPIF$_t$ = 1**~~

$$BSUoSINT_{1,365} = \left[(£75{,}873{,}280 + £18{,}250{,}000 + 0 + 0 + £18{,}250{,}000)/365\right] * 1/48$$
$$= £6{,}414$$

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~~**Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period i**~~

~~**The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{1365}$) for Settlement Period 1 on Settlement Day 365**~~

$$BSUoSTOT_{1,365} = BSUoSEXT_{1,365} + BSUoSINT_{1,365}$$

$$= £27{,}618 + £6{,}414$$

$$= £34{,}032$$

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Section 2 – The Statement of the Balancing Services Use of System Charging Methodology

14.29 Principles

14.29.1 The Transmission Licence allows The Company to derive revenue in respect of the Balancing Services Activity through the Balancing Services Use of System (BSUoS) charges. This statement explains the methodology used in order to calculate the BSUoS charges.

14.29.2 The Balancing Services Activity is defined in the Transmission Licence as the activity undertaken by The Company as part of the Transmission Business including the operation of the transmission system and the procuring and using of Balancing Services for the purpose of balancing the transmission system.

14.29.3 The Company in its role as System Operator keeps the electricity system in balance (energy balancing) and maintains the quality and security of supply (system balancing). The Company is incentivised on the procurement and utilisation of services to maintain the energy and system balance and other costs associated with operating the system. Users pay for the cost of these services and any incentivised payment/receipts through the BSUoS charge.

14.29.4 All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement Period.

14.29.5 BSUoS charges ~~comprise~~ recover the following costs:

(i) The Total Costs of the Balancing Mechanism
(ii) Total Balancing Services Contract costs
(iii) Payments/Receipts from National Grid incentive schemes
(iv) Internal costs of operating the System
(v) Costs associated with contracting for and developing Balancing Services
(vi) Adjustments
(vii) Costs invoiced to The Company associated with Manifest Errors and Special Provisions.
(viii) BETTA implementation costs
(ix) Any under/over recovery amounts resulting from the Fixed BSUoS Price
~~(viii)~~(x) Financing costs associated with the Fixed BSUoS Price

14.29.6 BSUoS charges are calculated and levied on a fixed price £/MWh (the "Fixed BSUoS Price") per Settlement Period basis set for a period of twelve months (the "Fixed Price Period") and notified to Users nine months in advance. The Fixed BSUoS Price will be applied to each User's actual metered volumes (including all relevant losses) to derive that User's BSUoS charge.

14.29.7 Any over or under recovery during a Fixed Price Period will be included in the calculation of the Fixed BSUoS Price £/MWh for the next available Fixed Price Period

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14.29.8 This methodology is divided into three sections:

a. Calculation of the Daily BSUoS charge
b. Calculation of the Fixed BSUoS Price
c. Volume settlement of BSUoS

14.30 PART A Calculation of the Daily Balancing Services Use of System charge

Calculation of the Daily Balancing Services Use of System charge

14.30.1 The BSUoS charge payable by customer c, on Settlement Day d, will be calculated in accordance with the following formula:

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} BSUoSTOT_{ij}$$

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} FixedBSUoSTOT_{ij}$$

Where:

i	-	refers to the individual BM Unit
j	-	refers to an individual Settlement Period
$\sum_{i \in c} \sum_{j \in d}$	-	refers to the sum over all BM units 'i', for which customer 'c' is the Lead Party* summed over all Settlement Periods 'j' on a Settlement Day 'd'

14.30.2 A customer's charge is based on their proportion of BM Unit Metered Volume for each Settlement Period relative to the total BM Unit Metered Volume for each Settlement Period, adjusted for transmission losses by the application of the relevant Transmission Losses Multiplier.

For all liable importing and exporting BM Units in delivering Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = FixedBSUoSPrice_t * QMBSUoS_{ij} * TLM_{ij}$$

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$$BSUoSTOT_{ij} = \frac{BSUoSTOT_j * QMBSUoS_{ij} * TLM_{ij}}{\left\{\left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}$$

For all liable importing and exporting BM Units in offtaking Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = -1 * FixedBSUoSPrice_t * QMBSUoS_{ij} * TLM_{ij}$$

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$$BSUoSTOT_{ij} = \frac{-1 * BSUoSTOT_j * QMBSUoS_{ij} * TLM_{ij}}{\left\{\left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}$$

Where:

$FixedBSUoSTOT_{ij}$	Total BSUoS Charge for BM Unit i for Settlement Period j
$FixedBSUoSPrice_t$	As defined in Part B
$QMBSUoS_{ij}$	BM Unit Metered Volume (QM_{ij})** for BSUoS Liable BM Units
TLM_{ij}	Transmission Loss Multiplier **

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* or CUSC party associated with the BMUnits (listed in Appendix C of the BEGA) who is exempt from also being a BSC Party

** Detailed definition in Balancing and Settlement Code Annex X2 – Technical Glossary

$\sum^{+}$ - refers to the sum over all BM Units that are in delivering Trading Units in Settlement Period 'j'

$\sum^{-}$ - refers to the sum over all BM Units that are in offtaking Trading Units in Settlement Period 'j'

'delivering' and 'offtaking' in relation to Trading Units have the meaning set out in the Balancing and Settlement Code (excluding all Interconnector BMUs and Trading Units)

14.30.3 For the avoidance of doubt, BM Units that are registered in Trading Units will be charged on a net Trading Unit basis i.e. if a BM Unit is exporting to the system and is within a Trading Unit that is offtaking from the system then the BM Unit in essence would be paid the BSUoS charge. Conversely, if a BM Unit is importing from the system in a delivering Trading Unit then the BM Unit in essence would pay the BSUoS charge.

Interconnector BM Units

14.30.4 BM Unit and Trading Units associated with Interconnectors, including those associated with the Interconnector Error Administrator, are not liable for BSUoS charges.

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PART B - Calculation of the Fixed BSUoS price

Fixed BSUoS Price Calculation

The Fixed BSUoS -Price for the Fixed Price Period is calculated as follows to give a £/MWh figure:

$$FixedBSUoSPrice_t = \left(\frac{FcBSUoSTOT_t + KB_{t-x}}{FcBSUoSVol_t} \right)$$

where:

$FixedBSUoSPrice_t$	Fixed BSUoS Price £/MWh for the Fixed Price Period t
$FcBSUoSTOT_t$	Forecast Total BSUoS Revenue applicable for Fixed Price Period t including all forecast BSUoSExt and BSUoSInt costs as per paragraph 14.30.1
$FcBSUoSVol_t$	Forecast Volume in MWh of all offtaking and ontaking BM Units, i, adjusted for Transmission Losses within the relevant Fixed Price Period t as forecast by The Company
KB_{t-x}	Adjustment for financing costs and any difference between the Fixed BSUoS Price cost recovery and the actual Total BSUoS costs incurred by The Company in a previous period t-x.

Comment [A1]: Need to this as formala says its STOT divided by vol?? As comment below in formal above show stot as + KB and define KB in formula list??

ForecastSTOT is our forecast of BSUoSEXT and BSUoSINT for the relevant period t (so means we still need the defined licence terms as per table, otherwise have no purpose in sec 14?

Purpose of BSUoS Sot (in table) in sec 14 ?

KB = difference between forecast SEXT and SINT for fixed price period and actual sext and sint plus financing??

Forecast Total BSUoS Revenue (Internal + External)

14.30.1 The Forecast Total BSUoS Revenue for the relevant Fixed Price Period ($FcBSUoSTOT_t$) is calculated by (a) summing the external BSUoS Forecast

rRevenue (ForecastBSUoSEXT$_t$) and internal BSUoS Forecast rRevenue (ForecastBSUoSINT$_t$) expected to be incurred for that Fixed Price Period including all associated incentives.r

$$FcBSUoSTOT_t = ForecastBSUoSEXT_t + ForecastBSUoSINT_t$$

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Where

ForecastBSUoSExt$_t$ Forecast for Fixed Price Period t of all relevant External BSUoS costs as defined by the Transmission Licence.

ForecastBSUoSInt$_t$ Forecast for Fixed Price Period t of all relevant Internal BSUoS costs as defined by the Transmission Licence

Total BSUoS Charge (Internal + External) for each Settlement Period (BSUoSTOT$_{jd}$)

The Total BSUoS charges for each Settlement Period (BSUoSTOT$_{jd}$) for a particular day are calculated by summing the external BSUoS charge (BSUoSEXT$_{jd}$) and internal BSUoS charge (BSUoSINT$_{jd}$) for each Settlement Period.

$$BSUoSTOT_{jd} = BSUoSEXT_{jd} + BSUoSINT_{jd}$$

External BSUoS Charge for each Settlement Period (BSUoSEXT$_{jd}$)

The External BSUoS Charges for each Settlement Period (BSUoSEXT$_{jd}$) are calculated by taking each Settlement Period System Operator BM Cash Flow (CSOBM$_j$) and Balancing Service Variable Contract Cost (BSCCV$_j$) and allocating the daily elements on a MWh basis across each Settlement Period in a day.

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd}$$
$$+\left[(IncpayEXT_d + BSCCA_d + ET_d - OM_d + FIIR_d + BSC_d + SOTOC_d + LBS_d) \right.$$
$$*\left\{ \left|\sum^{+}(QMBSUoS_{ijd} * TLM_{ijd}) + \left|\sum^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right| \right\} /\right.$$
$$\left.\sum_{j \in d} \left\{ \left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij}) \right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right| \right\} \right]$$

Calculation of the daily External Incentive Payment (IncpayEXT$_d$)

In respect of each Settlement Day d, IncpayEXTd is calculated as the difference between the new total incentive payment (FKIncpayEXTd) and the incentive payment that has been made to date for the previous days from the commencement of the scheme ($\sum$k=1=d-1IncpayEXTk):

$$IncpayEXT_d = FKIncpayEXT_d - \sum_{k=0}^{d-1} IncpayEXT_k$$

The forecast incentive payment made to date (from the commencement of the scheme) (FKIncpayEXT$_d$) is calculated as the ratio of total forecast external incentive payment across the duration of the scheme: the number of days in the scheme, multiplied by the sum of the profiling factors to date.

$$FKIncpayEXT_d = \frac{FYIncpayEXT_d}{NDS} * \sum_{k=1}^{d} PFT_k$$

Inclusion of Profiling Factors

Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_d are assumed to be one for the duration of the current external incentive scheme.

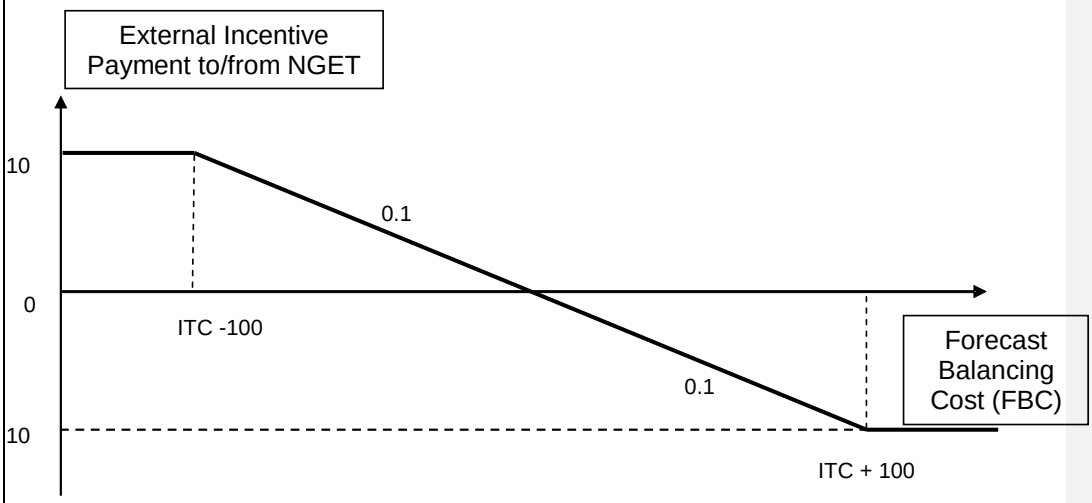
The forecast External incentive payment for the duration of the External incentive scheme ($FYIncpayEXT_d$) is calculated as the difference between the External Scheme target (M_t) and the forecast Balancing cost (FBC) subject to sharing factors (SF_t) and a cap/collar (CB_t).

$$FYIncpayEXT_d = SF_t * (M_t \quad FBC_d) + CB_t$$

The relevant value of the External incentive payment (BSUoSEXT) can then be calculated by reference to Table 9.1 and the selection and application of the appropriate sharing factors and offset dependent upon the value of the forecast Balancing Services cost (FBC).

Table 9.1

Forecast Balancing Cost (FBC)	M_t £m	SF_t	CB_t £m
FBC < (Incentive Target Cost – 100)	0	0	10
(Incentive Target Cost -100) <= FBC < (Incentive Target Cost)	Incentive Target Cost	10	0
Incentive Target Cost = FBC	FBC	0	0
(Incentive Target Cost) < FBC <= (Incentive Target Cost + 100)	Incentive Target Cost	10	0
(Incentive Target Cost + 100)	0	0	10



In respect of each Settlement Day d, the forecast incentivised Balancing Cost (FBC_d) will be calculated as follows:

$$FBC_d = \frac{\sum_{k=1}^{d} IBC_k}{\sum_{k=1}^{d} PFT_k} * NDS$$

Where:

NDS = Number of days in Scheme.

Daily Incentivised Balancing Cost (IBC_d) is calculated as follows:

~~**Internal BSUoS Charge for each Settlement Period ($BSUoSINT_{id}$)**~~

~~The Internal BSUoS Charges ($BSUoSINT_{id}$) for each Settlement Period j for a particular day are calculated by taking the incentivised and non-incentivised SO Internal Costs for each Settlement Day allocated on a MWh basis across each Settlement Period in a day.~~

$$BSUoSINT_{jd} = [(SOPU_d + SOMOD_d + SOEMR_d + SOEMRCO_d + SOTRU_d) * RPIF_t]$$
$$* \{ \left| \sum^{+} (QMBSUoS_{ijd} * TLM_{ijd}) \right| + \left| \sum^{-} (QMBSUoS_{ijd} * TLM_{ijd}) \right| \}$$
$$/ \sum_{j \in d} \{ \left| \sum^{+} (QMBSUoS_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QMBSUoS_{ij} * TLM_{ij}) \right| \}$$

~~**Inclusion of Profiling Factors**~~

~~Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_k are assumed to be one for the duration of the current external incentive scheme~~

14.31 PART C Volume Settlement of BSUoS

Settlement and Reconciliation of BSUoS charges

14.31.1 There are two stages of the reconciliation of BSUoS charges described below:

- Initial Settlement (SF)
- Final Reconciliation (RF)

Initial Settlement of BSUoS

14.31.2 The Company will calculate initial settlement (SF) BSUoS charges in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Initial Settlement Run and the Initial Volume Allocation Run.

Reconciliation of BSUoS Charges

14.31.3 Final Reconciliation will result in the calculation of a reconciled charge for each settlement day in the scheme year. The Company will calculate Final Reconciliation (RF) BSUoS charges (with the inclusion of interest as defined in the CUSC) in accordance with the methodology set out in ~~section 14.30~~Part A above, ~~using the applicable latest available data,~~ including data from the Final Reconciliation Settlement Run and the Final Reconciliation Volume Allocation Run.

Unavailability of Data

14.31.4 If any of ~~the elements~~volume data required to calculate the BSUoS charges in respect of any Settlement Day have not been notified to The Company in time for it to do the calculations then The Company will use volume data for the corresponding Settlement Day in the previous week. If no such values for the previous week are available to The Company then The Company will substitute such ~~variables~~ volume data as it shall, at its reasonable discretion, think fit and calculate Balancing Services Use of System charges on the basis of these values. When the actual volume data becomes available a reconciliation run will be undertaken.

Disputes

14.31.5 If The Company or any customer identifies any error which would affect the total Balancing Services Use of System charge on a Settlement Day then The Company will recalculate the charges following resolution of the error. Revised invoices and/or credit notes will be issued for the change in charges, plus interest as set out in the CUSC. The charge recalculation and issuing of revised invoices and/or credit notes will not take place for any day where the total change in the Balancing Services charge is less than £2000.

Relationship between the Statement of the Use of System Charging Methodology and the Transmission Licence

14.31.6 BSUoS charges are made on a daily basis and as such ~~of~~ this Statement sets out the details of the calculation of such charges on a daily basis and the Fixed BSUoS Price used to derive the charge. Customers may, when verifying charges for Balancing Services Use of System refer to the Transmission Licence which sets out the maximum allowed revenue that The Company may recover in respect of the Balancing Services Activity.

14.31.7 The Company has, where possible and appropriate, attempted to ensure that acronyms allocated to variables within the Balancing Services charging software, and associated reporting, match with the acronyms given to those variables used within this statement.

14.31.8 Balancing Services Use of System Acronym Definitions

For the avoidance of doubt "as defined in the BSC" relates to the Balancing and Settlement Code as published from time to time.

EXPRESSION	ACRONYM	Unit	Definition
BETTA Preparation Costs	BI	£	As defined in the Transmission Licence
Balancing Mechanism Unit	BM Unit or BMU		As defined in the BSC
~~Black Start Costs~~	~~BSC~~	~~£~~	~~As defined in the Transmission Licence (means he allowed revenue from and associated with Black Start services in accordance with paragraph 4G.5 of Special Condition 4G (Black Start Allowed Revenue Cost Incentive))~~
~~Balancing service contract costs – non-Settlement Period specific~~	~~$BSCCA_{id}$~~	~~£~~	~~Non Settlement Period specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
~~Balancing Service Contract Cost~~	~~$BSCC_{j}$~~	~~£~~	~~Balancing Service Contract Cost from purchasing Ancillary services applicable to a Settlement Period j less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
~~Balancing service contract costs – Settlement Period specific~~	~~$BSCCV_{jd}$~~	~~£~~	~~Settlement Period j specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
External Balancing Services Use of System charge	$BSUoSEXT_{jd}$	£	External System Operator (SO) Balancing Services Use of System charge ~~applicable to Settlement Period j for settlement day d~~
Internal Balancing Services Use of System charge	$BSUoSINT_{jd}$	£	Internal System Operator (SO) Balancing Services Use of System charge ~~applicable to Settlement Period j for settlement day d~~
Total Balancing Services Use of System charge	$BSUoSTOT_{cd}$	£	The sum determined for each customer, c, in accordance with this Statement and payable by that customer in respect of each Settlement Day d, in accordance with the terms of the Supplemental Agreement
~~Total Balancing Services Use of System charge~~	~~$BSUoSTOT_{j}$~~	~~£~~	~~Total Balancing Services Use of System Charge applicable for Settlement Period j~~

EXPRESSION	ACRONYM	Unit	Definition
~~System Operator BM Cash Flow~~	~~$CSOBM_j$~~	~~£~~	~~As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001 less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve~~
Daily balancing services adjustment	ET_d	£	Is the contribution on Settlement Day, d, to the value of ET_t where ET_t is determined pursuant to part B of Special Condition 4C of the Transmission Licence
~~Forecast incentivised Balancing Cost~~	~~FBC_d~~	~~£~~	~~Forecast incentivised Balancing Cost for duration of the Incentive Scheme as at settlement day d~~
~~SO Forecasting Incentive Payment~~	~~FIIR~~	~~£~~	~~As defined in the Transmission Licence~~ ~~(means the incentive payment which the licensee may derive from the forecasting incentive for Wind Generation Output and National Demand Wind Generation Forecasting Incentive in accordance with Special Condition 4H (Wind Generation Forecasting Incentive))~~
~~External Incentive payment to date~~	~~$FKIncpayEXT_d$~~	~~£~~	~~Total External Incentive Payment to date up to and including settlement day d~~
~~Total Forecast External incentive payment~~	~~$FYIncpayEXT_d$~~	~~£~~	~~Total forecast External incentive payment for the entire duration of the incentive scheme as at settlement day d~~
Allowed Income Adjustment relating to the SO-TO Code	IAT	£	As defined in the Transmission Licence
~~Daily Incentivised Balancing Cost~~	~~IBC_d~~	~~£~~	~~Is equal to that value calculated in accordance with paragraph 14.30.13 of Part 2 of this Statement~~
~~Daily External incentive payment~~	~~$IncpayEXT_d$~~	~~£~~	~~External Incentive payment for Settlement Day d~~
~~Demand Side Balancing Reserve and Supplementary Balancing Reserve costs~~	~~LBS~~	~~£~~	~~As defined in the Transmission Licence~~
~~Cost associated with the Provision of Balancing Services to others~~	~~OM_d~~	~~£~~	~~Is the contribution on Settlement Day, d, to the value of OM_t where OM_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence~~
Outage change allowance amount	ON	£	As defined in the Transmission Licence

Comment [A2]: Legacy definition

Comment [A3]: Legacy definition

Comment [A4]: Legacy definition

EXPRESSION	ACRONYM	Unit	Definition
~~Incentivised Balancing Cost daily profiling factor~~	~~PFT_d~~		~~The daily profiling factor used in the determination of forecast Incentivised Balancing Cost for settlement day d~~
BM Unit Metered Volume	QM_{ij}	MWh	As defined in the BSC
BSUoS Liable BM Unit Metered Volume	$QMBSUoS_{ij}$	MWh	QM_{ij} for all BM Units liable for BSUoS
~~Retail Price Index Adjustment Factor~~	~~RPIF~~		~~As defined in the Transmission Licence~~
Balancing services deemed costs	RT_d	£	Is the contribution on Settlement Day, d, to the value of RT_t where RT_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
~~SOEMR Preparation Costs~~	~~SOEMR~~	~~£~~	~~As defined in the Transmission Licence~~
~~SOEMR Preparation Costs Adjustment~~	~~SOEMRCO~~	~~£~~	~~As defined in the Transmission Licence~~
~~Incremental change from SO Opening Base Revenue Allowance~~	~~SOMOD~~		~~As defined in the Transmission Licence~~
~~SO Opening Base Revenue Allowance~~	~~SOPU~~		~~As defined in the Transmission Licence~~
~~SO-TO funding allowance~~	~~SOTOC~~	~~£~~	~~As defined in the Transmission Licence~~ ~~(means the SO-TO Mechanism cost allowance calculated in accordance with 4C.29 Special Condition 4J (SO-TO Mechanism))~~
~~Revenue Adjustment with respect to actual and assumed RPI values~~	~~SOTRU~~		~~As defined in the Transmission Licence~~
Tax Allowance	T	£	As defined in the Transmission Licence
Transmission Loss Multiplier	TLM_{ij}		As defined in the BSC
Total System Energy Imbalance Volume	$TQEI_j$	MWh	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001

Comment [A5]: Legacy definition

Comment [A6]: Legacy definition

Comment [A7]: Legacy definition

EXPRESSION	ACRONYM	Unit	Definition
Final Reconciliation Settlement Run			As defined in the BSC
Final Reconciliation Volume Allocation Run			As defined in the BSC
Initial Settlement Run			As defined in the BSC
Initial Volume Allocation Run			As defined in the BSC
Lead Party			As defined in the BSC
Fixed BSUoS Price	FixedBSUoSPrice		Fixed BSUoS Price in £/MWh for the Fixed Price Period
Fixed Price Period			The period for which the Fixed BSUoS price has been calculated.
$FixedBSUoSTot_{ji}$	$FixedBSUoSTot_{ji}$		The Fixed BSUoS cost for the relevant settlement period j for the relevant BM Unit j
$FcBSUoSTOT_t$	$FcBSUoSTOT_t$		Forecast Total BSUoS Revenue applicable for Fixed Price Period t including all forecast BSUoSExt and BSUoSInt costs
$FcBSUoSVol_t$	$FcBSUoSVol_t$		Forecast Volume in MWh of all offtaking and ontaking BM Units, i,adjusted for Transmission Losses within the relevant Fixed Price Period t as forecast by The Company
KB_{t-x}	KB_{t-x}		Adjustment for financing costs and any difference between the Fixed BSUoS Price cost recovery and the actual Total BSUoS costs incurred by The Company in a previous period t-x
$ForecastBSUoSExt_t$	$ForecastBSUoSExt_t$		Forecast for Fixed Price Period t of all relevant External BSUoS costs as defined by the Transmission Licence.
$ForecastBSUoSInt_t$	$ForecastBSUoSInt_t$		Forecast for Fixed Price Period t of all relevant Internal BSUoS costs as defined by the Transmission Licence

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14.32 Examples of Balancing Services Use of System (BSUoS) Daily Charge Calculations

This example illustrates the operation of the Balancing Services Use of System Daily charge formula. The parameters used are for illustrative purposes only and have been chosen for ease of calculation. They do not relate to the agreed scheme for any particular year. The actual scheme parameters are shown in the main text.

To calculate the daily BSUoS charge applicable to each User in each Ssettlement Period the below formulae are used for each Trading Unit.

For all liable importing and exporting BM Units in delivering Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = FixedBSUoSPrice_{t} * QMBSUoS_{ij} * TLM_{ij}$$

Where a User delivered 360MWh
£817.29= £2.25*360*1.009

For all liable importing and exporting BM Units in off-taking Trading Units in a Settlement Period:

$$FixedBSUoSTOT_{ij} = -1 * FixedBSUoSPrice_{t} * QMBSUoS_{ij} * TLM_{ij}$$

Where a User offtook 360MWh
£822.15= -1*£2.25*-360*1.0015

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~~The example is divided into the calculation of the External System Operator cost and Internal System Operator cost elements. All daily profiling factors (PFT_d) have been assumed to be one for this example.~~

~~Day 1~~

~~Calculation of the Daily External SO Incentive Scheme Payment~~

~~The first step is to calculate the Daily Incentivised Balancing Cost (IBC_1 for day one) for that day using the following formula. These are the daily incentivised cost elements used to calculate the external SO incentive payment.~~

$$IBC_1 = CSOBM_1 + BSCCA_1 + BSCCV_1 - OM_1 - RT_1$$

$$= £800,000 + £500,000 + £250,000 - £0 - £0$$

$$= £1,550,000$$

~~Assuming that $CSOBM_1$ = £800,000~~
~~$BSCCA_1$ = £500,000~~
~~$BSCCV_1$ = £250,000~~
~~OM_1 = £0~~
~~RT_1 = £0~~

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~~**Now that we know IBC_1, it is possible to calculate Forecast Balancing Services Cost (FBC_1) from that day's outturn as follows:**~~

$$FBC_1 = \frac{\sum_{k=1}^{d=1} IBC_k}{\sum_{k=1}^{d=1} PFT_k} * NDS$$

$$= \frac{£1{,}550{,}000}{1} * 365$$

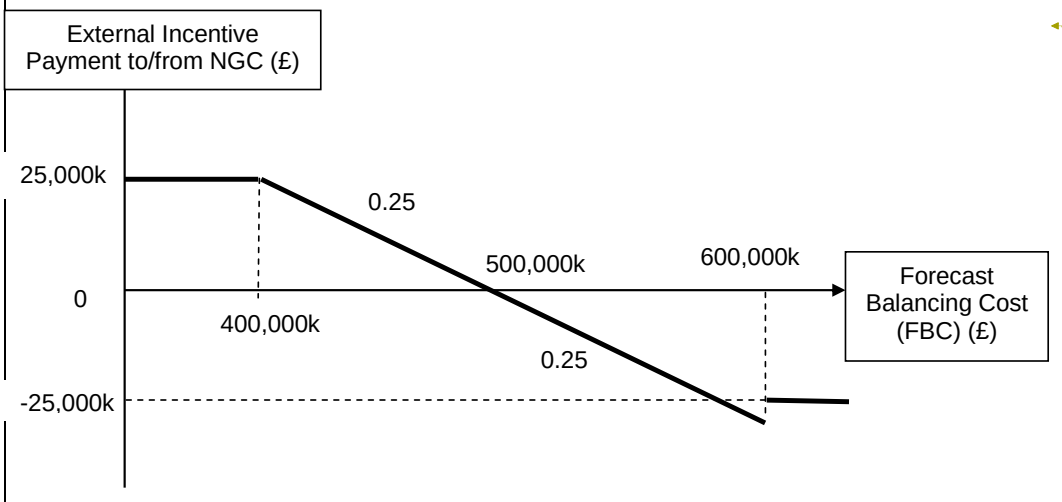
$$= £565{,}750{,}000$$

~~**The values of SF_t and CB_t can now be read off table BS1 below. (**These values are used purely for illustrative purposes based on an incentive target of £500,000,000**). As FBC_1 is £565,750,000, SF_t is 0.25, CB_t is £0 and M_t is £500,000,000.**~~

~~Table BS1~~

~~Forecast Balancing Cost (FBC_d)~~	~~M_t~~	~~SF_t~~	~~CB_t~~
~~**£400,000,000 < FBC**~~	~~**£0**~~	~~**0**~~	~~**£25,000,000**~~
~~**£400,000,000 <= FBC < £500,000,000**~~	~~**£500,000,000**~~	~~**0.25**~~	~~**£0**~~
~~**FBC = £500,000,000**~~	~~**£500,000,000**~~	~~**0**~~	~~**£0**~~
~~**£500,000,000 < FBC <= £600,000,000**~~	~~**£500,000,000**~~	~~**0.25**~~	~~**£0**~~
~~**FBC > £600,000,000**~~	~~**£0**~~	~~**0**~~	~~**- £25,000,000**~~

~~**The table describes the external incentive scheme, which can also be illustrated by the graph below.**~~



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~~Using the values set out in the table above, the external SO incentive payment for the duration of the scheme (FYIncpayEXT) can be calculated as follows:~~

$$FYIncpayEXT_1 = SF_t * (M_t - FBC_1) + CB_t$$

~~$$= 0.25 * (£500,000,000 - £565,750,000) + £0$$~~

$$= -£16,437,500$$

~~In this case the incentive payment is negative (£16,437,500) i.e. a payment from The Company.~~

~~The external SO incentive payment for the entire duration of the incentive scheme (FYincpayEXT) is then used to calculate the total incentive payment to date (FKIncpayEXT), shown as follows:~~

$$FKIncpayEXT_1 = \frac{FYIncpayEXT_1}{NDS} * \sum_{k=1}^{d=1} PFT_k$$

~~$$= \frac{-£16,437,500}{365} * 1$$~~

$$= -£45,034$$

~~Where:~~

~~NDS = Number of days in the external incentive scheme~~

~~The final step is to calculate today's external incentive payment (IncpayEXT$_1$ for day one), shown as follows:~~

$$IncpayEXT_1 = FKIncpayEXT_1 - \sum_{k=0}^{d-1=0} IncpayEXT_k$$

$$= -£45,034 - £0$$

$$= -£45,034$$

~~Calculating the External Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~The External Balancing Services Use of System (BSUoS) charge for Settlement Period 1 on this Settlement Day 1 can now be calculated using the following formula:~~

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd}$$
$$+ \left[(IncpayEXT_d + BSCCA_d + ET_d - OM_d + FIIR_d + BSC_d + SOTOC_d + LBS_d) \right.$$
$$* \left\{ \left| \sum^{+} (QM_{i1,1} * TLM_{i1,1}) + \left| \sum^{-} (QM_{i1,1} * TLM_{i1,1}) \right| \right\} /$$
$$\left. \sum_{j \in 1} \left\{ \left| \sum^{+} (QM_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QM_{ij} * TLM_{ij}) \right| \right\} \right]$$

~~For simplicity, the BSUoS applicable BM Unit Metered Volume (QMBSUoS$_{ij}$ * TLM$_{ij}$) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48) i.e. the multiplier at the end of the equation.~~

~~The illustration below shows the external BSUoS charge (BSUoSEXT$_{11}$) for Settlement Period one of Settlement Day 1.~~

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~~The costs of the external SO Settlement Period variables are as follows (these are the daily values included in the IBC_1 equation divided by 48 Settlement Periods).~~

~~CSOBM = £16,667~~
~~BSCCV = £5,208~~
~~$FIIR_1$, BSC_1, $SOTOC_1$, and LBS_1 are all zero.~~

~~The costs of the external SO Settlement Day variables are as follows:~~

~~IncpayEXT = £-45,034~~
~~BSCCA = £500,000~~
~~ET = £0~~
~~OM = £0~~

$$BSUoSEXT_{11} = £16,667 + £5,208 + [(-£45,034 + £500,000 + £0 - £0 + £0 + £0 + £0)/48]$$
$$= £16,667 + £5,208 + £9,478$$
$$= £31,353$$

~~Calculating the Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~Table BS2 below shows the annual Internal SO costs assumed for this example:~~

~~Table BS2~~

~~Internal SO Cost Variable~~	~~Annual Cost (£m)~~
~~$SOPU_t$~~	~~75,873,280~~
~~$SOMOD_t$~~	~~18,250,000~~
~~$SOEMR_t$~~	~~0~~
~~$SOEMRCO_t$~~	~~0~~
~~$SOTRU_t$~~	~~18,250,000~~

~~$RPIF_t = 1$~~

~~The Internal Balancing Services Use of System (BSUoS) charge for a Settlement Period 1 of Settlement Day 1 can be calculated using the following formula:~~

$$BSUoSINT_{11} = \left[\{(SOPU_1 + SOMOD_1 + SOEMR_1 + SOEMRCO_1 + SOTRU_1)/NDS\} * RPIF_1\right]$$
$$* \left\{ \left| \sum^{+} (QM_{i1,1} * TLM_{i1,1}) \right| + \left| \sum^{-} (QM_{i1,1} * TLM_{i1,1}) \right| \right\} / \sum_{j \in 1} \left\{ \left| \sum^{+} (QM_{ij} * TLM_{ij}) \right| + \left| \sum^{-} (QM_{ij} * TLM_{ij}) \right| \right\}$$

~~As with the external BSUoS charge, for simplicity, the BSUoS applicable BM Unit Metered Volume ($QMBSUoS_{ij} * TLM_{ij}$) is assumed to be the same in all half hour Settlement Periods in a Settlement Day. Therefore the daily BSUoS charge will be evenly allocated to each Settlement Period (1/48).~~

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$$BSUoSINT_{11} = \left[(75{,}873{,}280 + 18{,}250{,}000 + 0 + 0 + 18{,}250{,}000)/365\right] * 1/48$$
$$= £6414$$

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Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period 1

The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{11}$) for a Settlement Period 1 on Settlement Day 1.

$$BSUoSTOT_{11} = BSUoSEXT_{11} + BSUoSINT_{11}$$
$$= £31{,}353 + £6{,}414$$
$$= £37{,}767$$

~~Day 2~~

~~Calculation of the Daily External SO Incentive Scheme Payment~~

~~Again, the first step is to calculate the Daily Incentivised Balancing Cost for day 2 (IBC_2) using the following formula:~~

$$IBC_2 = CSOBM_2 + BSCCA_2 + BSCCV_2 - OM_2 - RT_2$$

$$= £600,000 + £150,000 + £100,000 - £0 - £0$$

$$= £850,000$$

~~Assuming that $CSOBM_2$ = £600,000~~
~~$BSCCA_2$ = £150,000~~
~~$BSCCV_2$ = £100,000~~
~~OM_2 = £0~~
~~RT_2 = £0~~

~~With IBC_d known for day one, it is possible to calculate Forecast Balancing Services Cost (FBC_2) from the outturn to date as follows:~~

$$FBC_2 = \frac{\sum_{k=1}^{d=2} IBC_k}{\sum_{k=1}^{d=2} PFT_k} * NDS$$

$$= \frac{(£1,550,000 + £850,000)}{2} * 365$$

$$= £438,000,000$$

~~The values of SF_t, M_t and CB_t can now be read off table BS1 given previously. As FBC_2 is £438,000,000, SF_t is now 0.25, M_t is £500,000,000 and CB_t is 0, calculated as follows:~~

$$FYIncpayEXT_2 = SF_t * (M_t - FBC_2) + CB_t$$

$$= 0.25 * (£500,000,000 - £438,000,000) + £0$$

$$= £15,500,000$$

~~The external SO incentive payment for the entire duration of the incentive scheme ($FYIncpayEXT_2$) is then used to calculate the total incentive payment to date ($FKIncpayEXT_2$), shown as follows:~~

$$FKIncpayEXT_2 = \frac{FYIncpayEXT_2}{NDS} * \sum_{k=1}^{d=2} PFT_k$$

$$= \frac{£15,500,000}{365} * 2$$

$$= £84,932$$

~~Where:~~

~~NDS = Number of days in the incentive scheme~~

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~~In this case the incentive payment forecast for the year is £84,932.~~

~~Again, the final step is to calculate today's external incentive payment (IncpayEXT$_2$ for day two), shown as follows:~~

$$IncpayEXT_2 = FKIncpayEXT_2 - \sum_{k=0}^{d-1=1} IncpayEXT_k$$
$$= £84{,}932 - -£45{,}034$$
$$= £129{,}966$$

~~The costs of the external SO Settlement Period variables are as follows:~~

~~CSOBM = £12,500~~
~~BSCCV = £2,083~~

~~FIIR$_2$, BSC$_2$, SOTOC$_2$ and LBS$_2$ are all zero.~~

~~The costs of the external SO Settlement Day variables are as follows:~~

~~IncpayEXT = £129,966~~
~~BSCCA = £150,000~~
~~ET = £0~~
~~OM = £0~~

$$BSUoSEXT_{12} = £12{,}500 + £2{,}083$$
$$+ [(£129{,}966 + £150{,}000 + £0 - £0 + £0 + £0 + £0 + £0)/48]$$
$$= £12{,}500 + £2{,}083 + £5{,}833$$
$$= £20{,}416$$

~~Annual internal SO costs assumed for this example have been listed in table BS2 above.~~

~~RPIF$_1$ = 1~~

$$BSUoSINT_{12} = [(75{,}873{,}280 + 18{,}250{,}000 + 0 + 0 + 18{,}250{,}000)/365]*1/48$$
$$= £6{,}414$$

~~Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period j~~

~~The final step is to calculate the Total Balancing Services Use of System (BSUoSTOT$_{12}$) for Settlement Period 1 on Settlement Day 2.~~

$$BSUoSTOT_{12} = BSUoSEXT_{12} + BSUoSINT_{12}$$
$$= £20{,}416 + £6414$$
$$= £26{,}830$$

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Day 365

If we now move to the end of the year, then once again the first step is to calculate the Daily Incentivised Balancing Cost for the final day (IBC_{365}) using the formula below:

Calculation of the Daily External SO Incentive Scheme Payment

$$IBC_{365} = CSOBM_{365} + BSCCA_{365} + BSCCV_{365} - OM_{365} - RT_{365}$$

$$= £700{,}000 + £200{,}000 + £150{,}000 + £200{,}000 - £0 - £0$$

$$= £1{,}050{,}000$$

Assuming that $CSOBM_{365}$ = £700,000
$BSCCA_{365}$ = £200,000
$BSCCV_{365}$ = £150,000
OM_{365} = £0
RT_{365} = £0

With $\sum_{364} IBC_d$ assumed to be £432,000,000 for the previous 364 days, it is possible to calculate Forecast Balancing Services Cost (FBC_{365}) from the outturn to date as follows:

$$FBC_{365} = \frac{\sum_{k=1}^{d=365} IBC_k}{\sum_{k=1}^{d=365} PFT_k} * NDS$$

$$= \frac{£432{,}000{,}000 + £1{,}050{,}000}{365} * 365$$

$$= £433{,}050{,}000$$

The values of SF_t, M_t and CB_t can now be read off table BS1. As FBC_{365} is £433,050,000, SF_t is now 0.25, M_t is £500,000,000 and CB_t is 0. Therefore $FYIncpayEXT_{365}$ is calculated as follows:

$$FYIncpayEXT_{365} = SF_t * (M_t - FBC_{365}) + CB_t$$

$$= 0.25 * (£500{,}000{,}000 - £433{,}050{,}000) + £0$$

$$= £16{,}737{,}500$$

The external SO incentive payment for the entire duration of the incentive scheme (FYincpayEXT) is then used to calculate the total incentive payment to date (FKIncpayEXT), shown as follows:

$$FKIncpayEXT_{365} = \frac{FYIncpayEXT_{365}}{NDS} * \sum_{k=1}^{d=365} PFT_k$$

$$= \frac{£16{,}737{,}500}{365} * 365$$

$$= £16{,}737{,}500$$

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~~**Where:**~~

~~**NDS = Number of days in the incentive scheme**~~

~~**In this case the incentive payment is positive (£16,737,500) i.e. a payment to The Company. As this is the last day of the scheme this represents the overall incentive payment due to The Company i.e. with reference to the graph with Table BS1 25% of the difference between £500,000,000 and £433,050,000.**~~

~~**Again, the final step is to calculate today's external incentive payment (IncpayEXT$_{365}$ for day 365), shown as follows:**~~

~~**It has been assumed that the total incentive payments for the previous 364 days ($\sum_{k=0}^{d-1=364} IncpayEXT_k$) is £16,461,800.**~~

$$IncpayEXT_{365} = FKIncpayEXT_{365} - \sum_{k=0}^{d-1=364} IncpayEXT_k$$
$$= £16{,}737{,}500 - £16{,}461{,}800$$
$$= £275{,}700$$

~~**The costs of the external SO Settlement Period variables are as follows:**~~

~~**CSOBM = £14,583**~~
~~**BSCCV = £3,125**~~

~~**FIIR$_{365}$, BSC$_{365}$, SOTOC$_{365}$ and LBS$_{365}$ are all zero.**~~

~~**The costs of the external SO Settlement Day variables are as follows:**~~

~~**IncpayEXT = £275,700**~~
~~**BSCCA = £200,000**~~
~~**ET = £0**~~
~~**OM = £0**~~

$$BSUoSEXT_{365} = £14{,}583 + £3{,}125$$
$$+ (£275{,}700 + £200{,}000 + £0 - £0 + £0 + £0 + £0 + £0)/48$$
$$= £14{,}583 + £3{,}125 + £9{,}910$$
$$= £27{,}618$$

~~**Annual internal SO costs assumed for this example have been listed in Table BS2 above.**~~

~~**RPIF$_t$ = 1**~~

$$BSUoSINT_{1,365} = \left[(£75{,}873{,}280 + £18{,}250{,}000 + 0 + 0 + £18{,}250{,}000)/365\right] * 1/48$$
$$= £6{,}414$$

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~~**Calculating the Total Balancing Services Use of System (BSUoS) charge for a Settlement Period i**~~

~~**The final step is to calculate the Total Balancing Services Use of System ($BSUoSTOT_{1365}$) for Settlement Period 1 on Settlement Day 365**~~

$$BSUoSTOT_{1,365} = BSUoSEXT_{1,365} + BSUoSINT_{1,365}$$

$$= £27{,}618 + £6{,}414$$

$$= £34{,}032$$

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