nationalgrid

Stage 06: Final CUSC Modification Report

Connection and Use of System Code (CUSC)

# CMP209 and CMP210 Allow Suppliers' submitted forecast demand to be export.

These two proposals seek to modify the CUSC in order to allow Suppliers to submit a negative demand forecast and receive the embedded benefit payments on a monthly basis throughout the year. Two separate proposals have been raised in order to assess both the potential CUSC changes and the Charging Methodology changes against the relevant CUSC Objectives.

What stage is this document at?

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

**Submitted on:** **12 December 2012**

***The CUSC Modifications Panel recommends:***
That the CMP209 and CMP210 Original Proposal best meet the Applicable CUSC Objectives and so should be implemented.

***High Impact:***
Suppliers, Exemptible embedded units with a Bilateral Embedded Generation Agreement

***Medium Impact:***
National Grid

***Low Impact:***
Other parties that pay TNUoS charges

## Contents




**Any Questions?**

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## About this document

This is the Final CUSC Modification Report which has been prepared and issued by National Grid under the rules and procedures specified in the CUSC. The purpose of this document is to assist the Authority in their decision whether to implement CMP209 and CMP210.

## Document Control

| Version | Date | Author | Change Reference |
|---|---|---|---|
| 0.1 | 14 November 2012 | Code Administrator | Version to Industry |
| 0.2 | 21 November 2012 | Code Administrator | Version for Panel Vote |
| 0.3 | 4 December 2012 | Code Administrator | Version for Panel Comment |
| 1.0 | 12 December 2012 | Code Administrator | Version for Submission to Authority |

# 1 Summary

1.1 This document summarises the deliberations of the Workgroup and describes the CMP209 and CMP210 Modification Proposals.

1.2 CMP209 and CMP210 were proposed by Opus Energy and submitted to the CUSC Modifications Panel for their consideration on 19 April 2012. CMP209 and CMP210 address the same issue but have been raised as two separate proposals due to the different set of objectives that apply to (i) the Charging Methodologies and (ii) the rest of the CUSC. The CUSC Panel determined that the proposals should be considered by a Workgroup and that they should report back to the CUSC Modifications Panel in September 2012 following a period of 20 working days for the Workgroup Consultation.

1.3 The Workgroup held two initial meetings on 20 June 2012 and 4 July 2012. At the first meeting the members accepted the Terms of Reference. A copy of the Terms of Reference for both proposals is provided in Annex 1. The Workgroup considered the issues raised by the two CUSC Modification Proposals and worked through the Terms of Reference.

1.4 The Workgroup Consultation closed on 22nd August 2012 and 5 responses were received. These responses can be found in Volume 2 of the draft Final Modification Report. A final Workgroup meeting was held on 6th September 2012 and the 5 Workgroup Members present voted by a majority of 3 to 2 that the CMP209 and CMP210 Original and WACM1 better facilitates the Applicable CUSC Objectives, with a preference for the Original. Further details of the Workgroup vote can be found in Section 7.

| View against Applicable CUSC Objectives | Better than CUSC baseline | Better than CMP209 and CMP210 original | Best |
|---|---|---|---|
| CUSC baseline | N/A | 2 | 2 |
| Original | 3 | N/A | 3 |
| WACM1 | 3 | 1 | 0 |

1.5 The Code Administrator Consultation closed on 1 November 2012 and received 7 responses. These can be found alongside the Workgroup Consultation responses in Volume 2.

1.6 During the Code Administrator Consultation, one Workgroup Member identified some minor improvements to the legal text to assist in providing further clarification to the industry. The Workgroup agreed that they were happy with the suggestions and that they were minor changes which provided further clarity. The CUSC Panel agreed at their meeting on 30 November 2012 that the changes are minor and can be included as part of the legal text provided to the Authority. The legal text can be found in Annex 9 and 10 in this document.

1.7 This CUSC Modification Report has been prepared in accordance with the terms of the CUSC. An electronic copy can be found on the National Grid website at www.nationalgrid.com/uk/Electricity/Codes, along with the CUSC Modification Proposal form

## CUSC Modifications Panel's View

1.8 The Panel voted by majority that the CMP209 Original Proposal best facilitates the Applicable CUSC Objectives for Charging and so should be implemented

1.9 The Panel voted by majority that the CMP210 Original Proposal best facilitates the Applicable CUSC Objectives and so should be implemented.

## Workgroup Conclusion

1.10 The Workgroup voted by majority that CMP209 and CMP210 Original and WACM 1 better facilitates the Applicable CUSC Objectives. The majority of the Workgroup expressed a preference for the Original.

## National Grid Opinion

1.11 National Grid does not believe that either the Original proposal or the Alternative better facilitate the Applicable CUSC or Charging Methodology Objectives. There are wider competition issues with embedded benefits that need to be addressed separately. National Grid believes that these proposed modifications would not help address these broader issues, and indeed could enhance the disparity between embedded and directly connected generation which would therefore represent a move against competition. In addition, National Grid understand the Original would require changes to be made to industry IS systems and forecasting processes. A BSC modification proposal would also be required to ensure gross metering data is received by the Company. National Grid believe that making such changes ahead of a broader embedded review is not efficient use of industry time and resource. National Grid prefers the Original over the proposed Alternative as the provision of gross information allows for forecasts to be validated appropriately and believe that a net alternative poses a risk to industry, and consequently consumers.

## 2 Why Change?

2.1 Currently, Suppliers are charged monthly for Transmission Network Use of System (TNUoS) based on the Balancing Mechanism (BM) Unit level Half Hourly (HH) and Non Half Hourly (NHH) demand forecasts they provide to National Grid. The data provided by Suppliers is different for HH and NHH

- For HH this consists of the kW demand expected during the Triad periods.
- For NHH this is the yearly kWh demand in settlement periods 33-38.

2.2 The forecasts provided by each Supplier are net, with distribution connected generation netted off against demand. Therefore in normal circumstances embedded generation reduces a Supplier's TNUoS bills giving them an 'embedded benefit'.

2.3 This works without problems for Suppliers who net import in all BM Units. However, the CUSC currently prevents a Supplier's forecast from being below zero for any BM Unit. Therefore if a Supplier's net exports in a BM Unit; i.e. their demand is below zero; they will not receive this portion of their embedded benefits in the monthly TNUoS invoices they receive from National Grid.

2.4 Instead such Suppliers will receive payment for these TNUoS embedded benefits in June/July of the following charging year, once the initial reconciliation of the demand charges has been undertaken by National Grid.

2.5 It is noted that whilst Suppliers are referred to predominantly in this report, this Modification Proposal would also impact on exemptible embedded generators with a Bilateral Embedded Generation Agreement (BEGA) who currently also receive embedded benefits at reconciliation.

2.6 As a Supplier's forecast is capped at zero, the monthly charges cannot reflect the annual liability if a Supplier has more export than import in a BM Unit. Suppliers are also unable to provide National Grid with an accurate forecast if their net volume is less than zero.

**What is TNUoS?**

Transmission Network Use of System Charges recover the Transmission Owner costs. It covers installing and maintaining the National Electricity Transmission System assets required to allow the transfer of power between connection sites and to provide transmission security. Tariffs are split annually by National Grid and are split into zones.

## 3 Solution

3.1 CMP209 and CMP210 propose that Suppliers should be allowed to submit a negative demand forecast for the charging year and receive the embedded benefits payments on a monthly basis within that charging year rather than wait to have the money credited back at the annual reconciliation (which occurs in the June/July of the next charging year).

## 4 Summary of Workgroup Discussions

### Presentation of Proposals

4.1 The CMP209 and CMP210 Proposer presented the two proposals to the Workgroup at the first meeting and gave the background as to why they were raised.

4.2 The National Grid representative gave an overview to the Workgroup on the current arrangements in comparison to the proposed changes resulting from CMP209 and CMP210.

4.3 The National Grid representative clarified that currently, negative demand payments are made at initial reconciliation. The process takes place around June each year, approximately three months after the end of the charging year. Payments are then made one month after this. The Proposer noted that Triad period data is published by National Grid in the preceding March and that shortly afterward this is when benefits are normally paid to generators by Suppliers (depending on their contract). One member of the Workgroup felt the lag between the publication of the Triad periods (in March) and final reconciliation (in June) was problematic as there was an expectation from generators that they would be paid as soon as the Triad periods are published. This could be easier for large Suppliers who may be more able to stick to tighter timescales for payment (i.e. before receiving the benefit at reconciliation). The Workgroup considered that a large proportion of contracts (between embedded generators and Suppliers) would only be paid after the publication of the Triads periods and noted that Suppliers are free to set their own payment terms with the generators.

4.4 Respondents to the Workgroup Consultation identified that they had contracts with embedded generators and that the terms were variable, but of those that stated specifics, the majority paid at reconciliation.

4.5 The Workgroup considered whether negative forecasts provided by Suppliers are an issue for Half Hourly (HH) metered demand only or whether it also applied to Non-Half Hourly metered (NHH). The National Grid representative explained that payments are not currently made for NHH (not that the charging methodology prevents such a scenario). One Workgroup member felt that these two proposals were an issue primarily for half hourly (HH) metered generation. Another member of the Workgroup noted that for NHH, there was likely to be minimal cash flow impact. The Workgroup felt that NHH net demand may become an issue in the future, for example if there were to be an increasing take-up of micro-generation (e.g. domestic solar panels) as a result of the Feed In Tariff.

4.6 If negative NHH forecasts were to be considered as part of these two Modification Proposals, additional information would be required. The generation profile across the year would be required to assess the Supplier security liabilities (discussed in section 4.17). One Workgroup member also suggested that Suppliers may not be able to supply gross generation capacity

**What is Triad Demand?**

Triad demand is measured as the average demand on the system over three half hours between November and February in a financial year. These three half hours comprise the half hour of system demand peak and the two other half hours of highest system demand which are separated from system demand peak and each other by at least 10 days.

and forecasts for their NHH customer base (discussed for HH in section 4.38). The Workgroup were not aware of any issues resulting from NHH negative forecasts and respondents to the consultation felt that it was not an issue.

4.7 Following discussions in the Workgroup, the Proposer decided not to include NHH in the original so CMP209 and CMP210 applies to HH only.

4.8 After the initial discussions on the two Proposals, the Workgroup then worked through the scope of work as listed in the Terms of Reference (see Annex 1).

**Whether, and the extent to which, CMP209 and CMP210 would create perverse incentives on Suppliers to submit incorrect demand forecasts to improve their cashflow.**

4.9 One member of the Workgroup advised that the CUSC Panel had a concern about the principle that a Supplier could provide inaccurate forecasts in order to obtain credit / improved cashflow (i.e. provide an 'inflated' negative demand forecast figure). This is because interest levied by National Grid on (over)payments to Suppliers (in this scenario) at reconciliation is lower than standard bank lending rates. This would mean that National Grid could be effectively funding these Suppliers, instead of a financial institution. It was noted by the Proposer that accuracy of demand forecasting is a consequential issue within these two proposals (as discussed under Term of Reference (b).

4.10 One Workgroup member expressed another concern that, under these two proposals, if a Supplier had over-forecasted their demand there could be a situation where, at the end of the year, a large reconciliation payment would need to be levied by National Grid on that Supplier.

4.11 The Workgroup discussed that one way of reducing the risk of over-forecasting of negative demand is for Supplier forecasts to be verified by National Grid, and arrangements for this are currently in place for positive demand forecasts (see Section 3.12 of the CUSC). However, it was suggested that it would be useful if all Suppliers provided their export and import forecasts separately in order to monitor the reliability of forecasts more accurately. In addition to this, gross metering information would enable National Grid to verify the accuracy of forecasts based on previous years would be required. This would require a modification to data flows received under the BSC (see section 5.4).

4.12 It was suggested that providing export and import forecasts separately would apply to all Suppliers including those who currently net their embedded generation from positive demand forecasts to ensure all Suppliers are treated equally.

4.13 The Proposer suggested that Suppliers could be asked to provide information to justify their forecasts if National Grid felt this was necessary, replicating arrangements in place currently for positive demand forecasts. It was noted however, that a Supplier could submit what they believe are accurate forecasts but due to unexpected circumstances (for example, lack of wind output or plant failure over the Triad peaks) these forecasts may prove to be incorrect by a large margin.

4.14 One member of the Workgroup highlighted another risk with over-forecasting by Suppliers of negative demand is that if such a Supplier defaults, then the risk falls on the rest of the industry, as these monies would need to be recovered from them (rather than the defaulting Supplier). The Proposer suggested that this risk was not significantly different from that currently with under-forecasting positive demand. However, some Workgroup members gave the view that the difference is around the cash flow direction and that if such a Supplier were to go out of business, then National Grid would have to recover the money, and that this is a risk placed on the remaining TNUoS paying parties. Given the special administration arrangements that are in place for National Grid (under sections 154-159 of the Energy Act 2004[1]), Suppliers would continue to receive payments from the NETSO if they (National Grid) enter financial difficulty. There are no such protections on Suppliers, meaning payments to National Grid from a defaulting Supplier would cease. The Proposer clarified that whilst he was not arguing this point, he believed that there were only slightly increased perverse incentives with this proposal to the status quo for positive demand forecasting.

4.15 The graph below (Figure 1) represents the cumulative monthly payments by Suppliers through the charging year, and the liability confirmation at Triad under the current arrangements. The Value at Risk (VAR) is the red shaded area which represents the proportion of the year for which liability has been incurred but payments have not yet been made.

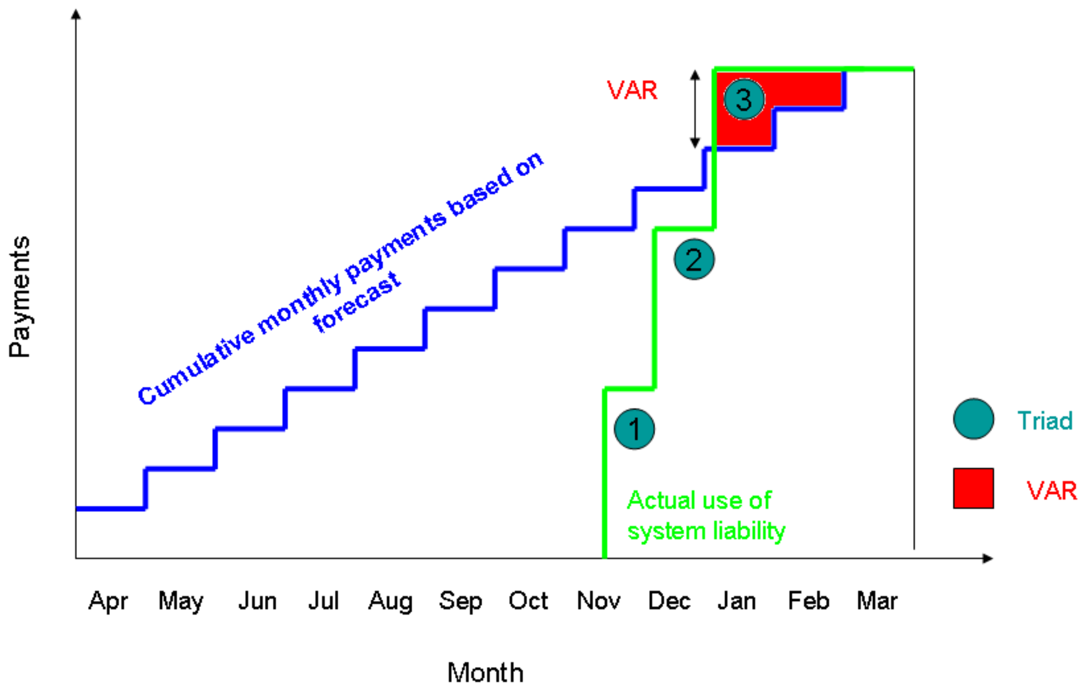



Figure 1 Positive HH Demand – Value At Risk (VAR) Profile

4.16 The National Grid representative confirmed that the VAR for Suppliers' negative demand forecasts is the gap between what has been paid and the accrual of benefits, and is demonstrated in Figure 2 below. This assumes that payments are made in equal instalments throughout the charging year. A relatively larger

[1] http://www.legislation.gov.uk/ukpga/2004/20/part/3/chapter/3

VAR in comparison with the positive demand forecast occurs because Triad takes place during the winter. This means that benefits aren't accrued until this point, but the payments are made all (charging) year round. Another Workgroup member added that the process is built for peak demand but that National Grid cannot be certain which Suppliers will participate in the Triad market and if they will continue to do so every charging year.

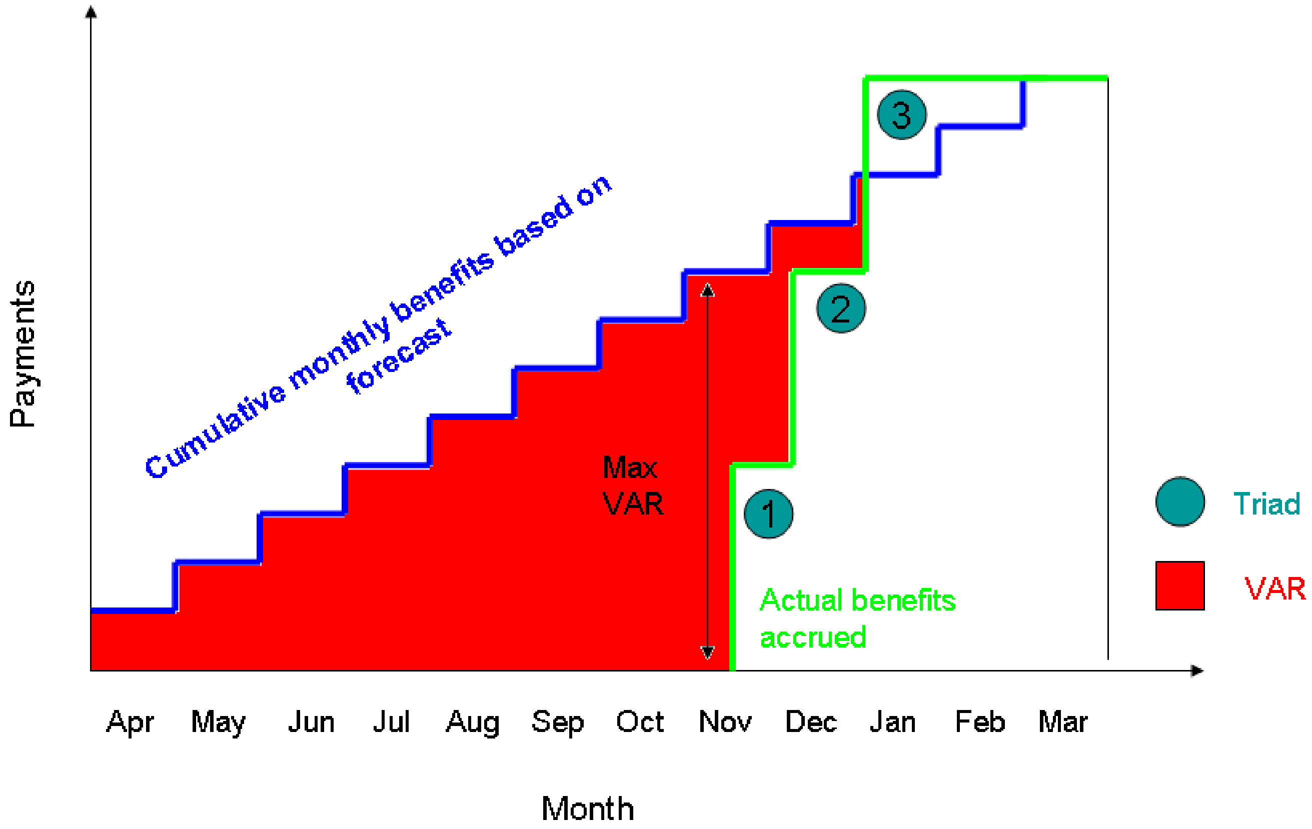



Figure 2 Negative HH Demand – VAR Profile

4.17 VAR is used to calculate the amount of securities required for TNUoS liabilities, and a base percentage is produced for each of the four security periods in a charging year. The Workgroup referred to the tables in the Section 3 of the CUSC (replicated below in Tables 1 and 2) that show the base VAR percentages for positive demand forecasts.

Table 1 Base Value At Risk for positive HH demand forecasts

| ***Security Period Start Date (inclusive)*** | ***Security Period End Date (inclusive)*** | ***HH Base Percentage*** |
|---|---|---|
| *1st April* | *30th June* | *-8.4%* |
| *1st July* | *30th September* | *-33.4%* |
| *1st October* | *31st December* | *-49.1%* |
| *1st January* | *31st March* | *7.0%* |

Table 2 Base Value At Risk for positive NHH demand forecasts

| ***Security Period Start Date (inclusive)*** | ***Security Period End Date (inclusive)*** | ***(i) NHH Base Percentage*** |
|---|---|---|
| *1st April* | *30th June* | *(ii) 4.3%* |
| *1st July* | *30th September* | *(iii) -1.5%* |
| *1st October* | *31st December* | *(iv) -2.8%* |
| *1st January* | *31st March* | *(v) 3.7%* |

4.18 The National Grid representative explained that these percentages are not appropriate for Suppliers' negative demand forecasts as they reflect a different set of Values at Risk, and they also include assumptions regarding missed payment delays in the base calculations. Base VAR percentages were calculated for HH negative demand using a similar methodology to that used for positive demand without the additional assumptions. This works out as the average VAR within a security period which is shown in the Table 3 below. These figures should be treated as illustrative at this stage.

Table 3 Illustrative Base Value At Risk for negative HH demand forecasts

| ***Security Period Start Date (inclusive)*** | ***Security Period End Date (inclusive)*** | ***HH Base Percentage*** |
|---|---|---|
| *1st April* | *30th June* | *-12.82%* |
| *1st July* | *30th September* | *-37.77%* |
| *1st October* | *31st December* | *-58.61%* |
| *1st January* | *31st March* | *-9.16%* |

4.19 For demand forecasts resulting in a net receipt for Suppliers (i.e. payments to Suppliers from National Grid) and incorporating positive NHH demand elements, the NHH Base Percentages have been calculated as follows to reflect the average VAR per security period. The positive base percentage for NHH cannot be used as this includes assumptions such as missed payments in the calculation which are inappropriate for demand forecasts resulting in a net receipt for Suppliers. These figures should be treated as illustrative at this stage.

Table 4 Illustrative Base Value At Risk for positive NHH demand forecasts with overall net receipt for Suppliers

| ***Security Period Start Date (inclusive)*** | ***Security Period End Date (inclusive)*** | ***NHH Base Percentage*** |
|---|---|---|
| *1st April* | *30th June* | *-2.30%* |
| *1st July* | *30th September* | *-7.81%* |
| *1st October* | *31st December* | *-10.12%* |
| *1st January* | *31st March* | *-4.51%* |

4.20 Should Supplier NHH negative demand forecasts be identified as a possibility (as per section 4.5-4.6), then base VAR percentages would need to be developed for NHH negative demand forecasts. This additional table is not required for HH as demand and liability are both calculated based on Triad. However, it is assumed that the generation and demand profiles for NHH vary somewhat. However, as discussed in section 4.5, generation profile data for NHH is not currently received by National Grid.

4.21 The VAR base percentage tables to be used in calculation of securities will vary depending on whether the forecast is based on import or export components, and the payment direction between National Grid and Suppliers. The tables to be used in each scenario are summarised in Annex 7. An example security calculation is shown in Annex 6.

4.22 The Proposer acknowledged that there are measures in place currently to prevent Suppliers from submitting incorrect positive forecasts. A Supplier's forecast accuracy is measured and a Forecasting Performance value is added to the VAR.

4.23 The National Grid representative considered that these could be replicated with CMP209 and CMP210 to reduce the risks associated with Suppliers over forecasting negative demand forecasts. However, due to the additional risk under the two proposals there may be more that could be done in addition to this. One member of the Workgroup highlighted that whilst it is good to have mitigating factors in place, they felt that this issue was not a major concern and added that the benefit of the two proposals outweighs this problem.

4.24 The Proposer outlined the two issues regarding this area: (i) the Supplier attempts to submit a correct negative demand forecast but unintentionally gets it wrong; and (ii) the Supplier purposefully submits an incorrect negative demand forecast in order to gain a cash flow benefit.

4.25 The Chair acknowledged the range of views within the Workgroup on these two issues, and the point that there could be good reasons for incorrect negative demand forecasts by Suppliers was accepted as was the point that there was a risk of incorrect negative demand forecast being submitted by Suppliers in order to gain a cash flow benefit. The National Grid representative asked the Workgroup how new Suppliers would be treated as they do not have any historical demand forecast data. It was suggested that these Suppliers could be asked to support their demand forecasts with evidence and that the Suppliers could be asked to revise their monthly / quarterly updates if it looks like their charging year forecast is going to be incorrect. The Workgroup agreed that a solution for new entrants was required in order to prevent creating an incentive for new entrants to over-forecast their negative demand.

4.26 In conclusion, the Workgroup agreed that CMP209 and CMP210 had the potential to create perverse incentives, but it is debateable to what extent this would be. The Workgroup agreed that there were four potential mitigation measures to deal with this issue:

(i) Use a Supplier negative forecasting performance percentage added to the VAR, using a comparable methodology to that currently used for positive demand forecasts.

(II) Allowing Supplier forecast increases to only rise by a fixed percentage before additional justification is requested (by National Grid) to support a rise above this level.

(III) Placing limits on the extent of Supplier's negative demand forecast or preventing it for the next charging year if they over forecast by a gross amount in the previous charging year.

(IV) National Grid receive extra data from Suppliers via a new methodology to enable them to better validate the negative demand forecasts that Suppliers provide

For (ii) and (iii) allowable increases and measures of error would need to be defined in the CUSC.

These could be used alongside the existing means of mitigating risk:

I. Larger negative demand forecasts require more credit (for a net importer an under forecast reduces a Supplier's credit requirement as well as their invoices)
II. Incorrect negative demand forecasts increase future Supplier credit requirements through the forecasting risk methodology
III. National Grid have powers to reject any Supplier forecast they feel is unreasonable and cannot be justified under the amendments to the CUSC made relating to CAP55.

4.27 Views on the suggested mitigation measures were requested from respondents to the Workgroup consultation. There were mixed opinions; some respondents felt that some of the measures may be an administrative burden, whereas some of them could be helpful

4.28 The Proposer decided that the Original Proposal would include the measures identified in (i) and (iv) above and not include (ii) or (iii) from the first list, and that the existing means of mitigating risk in the second list would be retained.

**Whether interest should be levied on overpayment**

4.29 The National Grid representative advised that interest is charged on underpayments by Suppliers (for example, if a Supplier should have paid National Grid £1 and paid 90p, then interest is paid (by the Supplier) on the 10p) in line with the Barclays base rate [currently at 0.5%]. This rate is usually, but not always in line with the Bank of England base rate. The National Grid Workgroup member confirmed that any interest on any over payment (i.e. the Supplier receives £1.10p from National Grid but, after reconciliation, it is determined it should have received £1 and interest is paid (by the Supplier) on the 10p) would be levied on the Supplier at the time of reconciliation (in June), via a lump sum.

4.30 One Workgroup member suggested that as a result of the perverse incentive discussed above, a higher interest rate should be levied for Suppliers over-forecasting negative demand. One Workgroup member suggested that this should work both ways, for under and over payment and that the two should not be differentiated. The National Grid representative noted that whilst this could be considered for both, in general the risk of over-forecasting negative demand is higher because the payments are made before any benefits have been accrued. The other Workgroup member felt that it was not different in terms of net position.

4.31 The Workgroup consultation provided mixed views on this issue, with some respondents believing that interest should be calculated on the same basis as that for positive demand for consistency and fairness, and others feeling that an uplift to a penal rate may be appropriate. The majority of respondents felt that overpayment for negative demand and underpayment for positive demand should be treated equally.

4.32 The Proposer decided to keep the interest at Barclays' base rate for the Original Proposal and not to propose an uplift to ensure consistency with current arrangements.

**Whether Suppliers with significant amounts of intermittent generation are able to submit accurate demand forecasts.**

4.33 The definition of 'intermittent' in terms of the legal text was considered and it was agreed that the definition in the Grid Code was the most appropriate:

*Intermittent Power Source: The primary source of power for a Generating Unit that can not be considered as controllable, e.g wind, wave or solar.*

4.34 The Workgroup began by considering if this was a particular issue for new entrants. One Workgroup member advised that intrinsically it would be more difficult for new entrants to submit accurate data as they may have less experience and familiarity with the industry. However, the Workgroup felt the accuracy of intermittent forecasts was still an issue across all Suppliers. Although short-term forecasts for intermittent generation can be accurate, charging forecasts are in the longer term and are therefore less likely to be accurate due to the variability of the primary source of power.

4.35 The Chair summarised that it is very difficult to submit forecasts for intermittent generation and whilst National Grid would aim to verify if a forecast has a reasonable probability of being correct, this is not always possible with intermittent generation forecasts. One member of the Workgroup suggested that there could be a requirement for National Grid to calculate and publish a figure for average intermittent output over the Triad periods as far back as the data is available and that this could be used to create a discount factor for an allowable proportion of capacity forecasts for intermittent generation. The Workgroup noted that geographic dispersion might not be able to be considered in such an analysis. The National Grid representative confirmed that currently the output and capacity data for transmission connected generation is available, but not for distribution connected generation. However, transmission connected wind is a suitable proxy for these purposes. It was considered that this would give a best-case scenario baseline as transmission connected intermittent generation is often more likely to output during the winter peak period than embedded intermittent generation.

4.36 The Workgroup considered the question of whether it is National Grid's responsibility to take a policing role to try and establish the accuracy of this type of data. The Workgroup also considered whether this scenario would cause Suppliers to submit data that they think National Grid would accept, rather than what they believe to be true. One Workgroup member concluded that there is justification as to why intermittent generation should be treated differently and that National Grid need a mechanism to deal with this, namely that they would have the ability to ask the Supplier to provide evidence to support their forecast data. The National Grid representative advised that in order to assess a Supplier's negative demand forecast accuracy they would require a breakdown of what that Supplier's intermittent generation was in terms of both capacity and forecast.

4.37 The majority of the Workgroup agreed that all Suppliers should submit their negative demand forecasts as a split of conventional and intermittent generation. In order to validate the intermittent portion of this, National Grid would use the historical Triad transmission output information mentioned in section 4.35 above. The conventional portion of this could be validated through examination of historical gross metering data.

4.38 In summary, the majority of the Workgroup agreed that Supplier demand forecasts would need to include the following information:

(i) Generation forecast for HH – conventional generation

(ii) Generation forecast for HH – intermittent generation

(iii) Demand forecast for HH

(iv) HH installed conventional generation capacity

(v) HH installed intermittent generation capacity

(vi) Net forecast for NHH

4.39 It was agreed to keep the information in (i) to (vi) as part of the Original Proposal.

4.40 The Workgroup discussed the potential issues for Suppliers that may be caused by submitting their demand forecast data in this way but some members of the Workgroup felt that this would not be an issue as it could be a case of extracting the data from an existing spreadsheet. However, it was felt by some that this is not an essential element of CMP209 and CMP210 and if there were Supplier IS / IT system implications, it would be more of a priority to continue progressing CMP209 and CMP210 and instead consider a manual workaround whilst system changes are implemented.

4.41 There would also be a likely IS system implication from National Grid's perspective which may impact on the implementation timeline and costs of the two Modifications.

4.42 A methodology would also need to be developed demonstrating the process by which National Grid's forecast would be produced for negative demand (similar to the current CUSC section 14.27 for positive forecasts).

4.43 Most respondents to the consultation advised that changes to information required would have no impact on their IS systems. One respondent advised that a lead time of up to 6 months, and another advised up to three months would be required to implement the changes.

4.44 National Grid advised that changes to their IS systems would require in the region of 6-9 months minimum to capture changes required as a result of implementation of the original proposal.

**Whether Feed In Tariff metering data can be used to justify Supplier demand forecasts**

4.45 The Proposer felt that this information was not usable data and another member of the group felt that this would only be a partial solution. Another member of the Workgroup noted that as this data is already submitted to Ofgem (in order to claim the Feed in Tariff) that this could be a useful source of data if made available to National Grid to verify Suppliers demand forecasts. The Workgroup noted that Smart Metering may provide the data required in the future and it may be sensible to review the potential changes from CMP209 and CMP210 after Smart Metering has been rolled out.

**Appropriate credit arrangements to recognise that Suppliers would receive payments that may not be accurate and would require reconciliation**

4.46 The possibility of undertaking HH reconciliation earlier than June after the end of each charging year was discussed by the Workgroup. The National Grid representative confirmed that the reconciliation is carried out at the time that it is due to when metering data is received. It is done when NHH data is also available to enable HH and NHH forecasts to be undertaken for the same Supplier concurrently. Splitting these two reconciliation processes would likely require additional resource within National Grid and would mean that Suppliers would receive reconciliations for HH and NHH separately.

4.47 It was envisaged that credit arrangements currently in place for Suppliers could be maintained for these two proposals. The Proposer highlighted that a Suppliers' payment history would provide a certain amount of allowed credit but it might be harder for Suppliers to build up credit when they are being paid (in the case of negative demand forecasts). The National Grid representative noted that TNUoS was only one type of payment, and that payment history could be built up by Suppliers liable for other types of payment (e.g. BSUoS). Also, this is not an issue for Suppliers with an Approved Credit Rating, whose credit allowances are calculated related to their credit rating.

4.48 The Workgroup considered some example case studies regarding payment histories in terms of credit cover. It is anticipated that the current credit cover arrangements for Suppliers would stand, and these differ for companies who are rated as opposed to those who are unrated (for full details see section 3.26 of the CUSC). Some worked examples of this being applied in practice are contained as Annex 8.

**Whether Suppliers would have an obligation under CMP209 and CMP210 to provide the energy that they would be paid for**

4.49 One Workgroup member commented that the issue concerns whether payment should be made by a Supplier (to National Grid) when they have submitted an incorrect over-forecast negative demand figure. Another member of the Workgroup noted that if an obligation is placed on export, then the same should be done for demand. However, it was added that this would not be workable for demand. The Workgroup felt that placing an obligation on Suppliers to provide the energy would not be practically achievable. Responses to the Workgroup consultation all agreed with the view of the Workgroup.

**Whether the existing IS systems can cope with negative demand forecast data**

4.50 At the first Workgroup meeting, the National Grid representative advised that their initial view is that this is workable and that their IS systems would only require minor changes should information be received in current 'net' format with negative integers. However, should more extensive changes be required as a result of the two proposals, this would need to be revisited. Respondents to the Workgroup Consultation advised that they believed their existing IS systems would cope with providing negative demand forecast data.

**To what extent the current arrangements are a barrier to entry to embedded generators and/or to Suppliers specialising in embedded generation.**

4.51 The Proposer felt that there is an impact on Suppliers in terms of cash flow and how competitive they can be and that these implications could deter new Suppliers who wish to specialise in embedded generation.

4.52 When considering the current arrangements, the National Grid representative confirmed that for the 2011-12 charging year, there were 19 Suppliers that provided zero forecasts, including subsidiaries and received embedded benefits.

4.53 The majority of responses to the Workgroup Consultation advised that the current arrangements are not generally a barrier to entry to suppliers specialising in embedded generation, however two respondents felt that cashflow may cause constraints for small suppliers.

**Overview of CMP209 and CMP210 Original Proposal**

4.54 At the post-consultation meeting, the Proposer confirmed the key elements of his proposal. These are as follows:

- Applicable to HH only
- To include the following mitigation measures:
    - Use a Supplier negative forecasting performance percentage added to the VAR, using a comparable methodology to that currently used for positive demand forecasts.
    - Require the following information in supplier demand forecasts:
        - Generation forecast for HH – conventional generation
        - Generation forecast for HH – intermittent generation
        - Demand forecast for HH
        - HH installed conventional generation capacity
        - HH installed intermittent generation capacity
    - National Grid apply a fixed load factor to validate the intermittent portion of the forecast, published in the annual charging statement.
- To levy interest on overpayment made by National Grid to suppliers at the Barclays base rate, consistent with current practice for positive demand.
- Include appropriate variations of current security, credit arrangements and forecasting performance measures currently used for positive demand as per the legal text. The legal text is contained as Annex 9 and 10 of this document.

**Workgroup Alternative CUSC Modifications**

4.55 The Workgroup considered that a potential Workgroup Alternative CUSC Modification (WACM) could be to receive net negative demand forecast Supplier data. This has the advantage of simplicity as it requires less IS / IT system changes. One Workgroup member suggested that it would not be possible for National Grid to monitor the accuracy of these forecasts.

4.56 One Workgroup member suggested a potential alternative of having the same arrangements as in the two Original Modifications for Suppliers to provide negative demand forecasts throughout the charging year, but for the associated payments (from National Grid to Suppliers) to occur after the Triad period data is published, by National Grid, in March which is when payments (to generators) fall due on Suppliers. The Workgroup member clarified that under this WACM, all Suppliers would submit forecasts on a gross basis and would be treated the same in terms of forecasting their negative demand. Overall the Workgroup member felt this alternative might be considered to better address the defect (as it would facilitate payments from Suppliers to embedded generators around the time those payments fell due (from March onwards each charging year, after the Triad periods are published) whilst minimising the duration of the risks identified by the Workgroup between payment from National Grid to Suppliers (in March) and the eventual reconciliation (in June / July) whilst at the same time ensuring negative demand forecasts can be provided by Suppliers.

4.57 Another potential WACM is similar to the proposal above, but allows for those who currently net embedded benefits from their positive demand to continue doing so. This would also address the defects highlighted in 4.56. However, the Proposer commented that this would still mean unequal treatment for Suppliers that are not net negative.

4.58 Another potential option for a WACM was suggested in the Workgroup where gross forecasts are received from all Suppliers and embedded benefits are paid to all Suppliers at reconciliation. This would meet the objective of treating all Suppliers equally. However, it was acknowledged this might prove rather unpopular with Suppliers who currently receive benefits within year and would not address the CMP209 and CMP210 defect in terms of improving Supplier demand forecast accuracy. Rather, it would run counter to the aims of the two proposals as instead of seeking to facilitate Supplier negative demand forecasting it would seek to exacerbate the defect by requiring all Suppliers to submit inaccurate demand forecasts.

4.59 There was general support at consultation for the potential WACM in 4.55 and mixed support for the second option in 4.56. The third WACM suggested in 4.57 was not generally supported and the option in 4.58 for all to be paid at reconciliation was not supported by any respondents

4.60 The Workgroup discussed the potential options for WACMs in order to reach a decision on which options, if any, should be progressed as formal WACMs.

4.61 The Workgroup discussed the first option regarding receiving net negative demand forecast supplier data, which was supported in the majority of consultation responses. The Proposer felt that this option addresses the defect and therefore is a valid option. Another Workgroup member felt that there is not an issue to start with. This member felt that, the situation would be made worse for suppliers as it raises the expectation of generators they would be paid throughout the year, which would force suppliers to take on a credit risk from the generator, which would be anti-competitive. The Workgroup member also added that it would be an administrative burden to Suppliers. Another Workgroup member felt that their contracted generators would not demand different payment terms as a result of this option and therefore would support this as a WACM. The National Grid representative agreed that this option would create a risk for Suppliers as well as a risk to Industry of Supplier payment default that does not exist currently. This representative felt that the alternative option is worse than the original because receiving forecast information net does not enable National Grid to validate forecasts.

4.62 The Chair held a vote and there was a majority of 3 to 2 support for the first option, therefore this was progressed as a formal WACM.

4.63 The group then discussed the second option where the payments are brought forward from June to March. The National Grid representative advised that this option would require two reconciliations, but that paying after triad reduces the risk inherent in paying throughout the year for negative demand, therefore they believe that overall it is a better option than the original. The Proposer and two other Workgroup members felt that it does not address the defect and is not better than the Original or baseline. One Workgroup member felt that it was marginally better than the baseline and therefore should be progressed. Overall, 3 out of the 5 Workgroup Members present felt that this potential alternative should not be progressed, therefore by majority it was not progressed as a WACM.

4.64 The Workgroup were unanimously against progressing the third option which allows those who currently net embedded benefits from their positive demand to continue doing so, whilst those with forecasts that fall net below 0 would be required to submit gross forecasts. As a result, this option was not progressed any further.

4.65 The fourth option where gross forecasts are received from all suppliers and embedded benefits are paid to all suppliers at reconciliation was rejected by all but one of the Workgroup Members. The Workgroup member in favour of this option felt that it addresses the defect by paying everyone at the same time and thus providing equitable treatment. This option was not progressed as a formal WACM.

4.66 Therefore, out of the four potential options considered by the Workgroup and taking into account the views of the Workgroup Consultation respondents, it was agreed to progress the first option as the only WACM for CMP209 and CMP210. The proposed legal text for WACM1 can be found in Annex 10.

# 5 Impacts & Costs

## Impact on the CUSC

5.1 CMP209 requires amendments to Section 14 of the CUSC to remove the references to the forecasts having to be positive.

5.2 CMP210 requires amendments to Section 11 and Section 3 of the CUSC.

## Impact on Greenhouse Gas Emissions

5.3 Neither the proposer nor the Workgroup identified any material impact on Greenhouse Gas emissions.

## Impact on Core Industry Documents

5.4 Metering data for HH customers is currently received by Net Period BMU Allocated Volume. In order to add gross demand and gross generation data elements to the TNUoS Report (P0210), a BSC Modification would be required. This could be processed as a consequential change and its implementation could follow that of CMP209/210. A BSC modification (P260) was raised previously to obtain this data as it was anticipated that it may be required in the future. It was rejected by the Authority at the time as the report was unclear about the purposes for which the data was needed at the time. The Authority's rejection letter and all related documentation can be found at http://www.elexon.co.uk/mod-proposal/p260-extension-to-data-provided-to-the-transmission-company-in-the-tuos-report/.

5.5 The Workgroup discussed the timings for raising a potential BSC modification and noted that with an implementation date of April 2014, there would be sufficient time to raise a modification. The Workgroup also noted that a potential option could be to raise a modification now and withdraw if the modification is then not required. It was concluded that National Grid would raise a modification if necessary at a suitable point.

## Impact on other Industry Documents

5.6 Neither the proposer nor the Workgroup identified any impacts on other Industry Documents.

## Costs

| **Code administration costs** | |
|---|---|
| Resource costs | **£5,445** - 3 Workgroup meetings<br>**£125** - Catering |
| Total Code Administrator costs | **£5,570** |

| Industry costs (Standard CMP) | |
|---|---|
| Resource costs | **£16,335** - 3 Workgroup meetings<br>**£10,890** – 2 Consultations<br><br>• 3 Workgroup meetings<br>• 6 Workgroup members<br>• 1.5 man days effort per meeting<br>• 1.5 man days effort per consultation response<br>• 12 consultation respondents |
| Total Industry Costs | **£27,225** |

## 6 Proposed Implementation

6.1 As these two proposals contain modifications to the Charging Methodologies it should be noted that in normal circumstances the CUSC only foresees the implementation dates for Charging Methodology changes being at the start of a charging year; i.e. 1st April

6.2 For the Original, large-scale IS changes may be required to National Grid's charging system. It should be noted that IS changes may take at least 6-9 months and therefore CMP209 and CMP210 would be implemented in April 2014. There is currently an ongoing project to replace the National Grid charging system and implementation is due to take place in 2013-2014 financial year. If the original was approved by December 2012 costs of changes would be significantly lower than if a decision was made at a later point.

6.3 For WACM 1, the IT changes would be on a smaller scale but would not be made in time for an implementation in April 2013 (based on receiving an Authority Decision in January 2013) and therefore if WACM 1 was approved, this would also be implemented in April 2014.

# 7 Views

## Workgroup Conclusion

7.1 On 6th September 2012 the Workgroup voted by majority that the CMP209 and CMP210 Original and WACM 1 better facilitates the Applicable CUSC Objectives, with a preference for the Original. Details of these can be found in the tables below.

7.2 For reference the CUSC Objectives for the Use of System Charging Methodology are:

(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.

7.3 For reference the Applicable CUSC Objectives for the CUSC are:

(a) the efficient discharge by the licensee of the obligations imposed upon it under the Act and by this licence;

(b) facilitating effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the sale, distribution and purchase of electricity.

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

CMP209

### Vote 1: Whether each proposal better facilitates ACOs (against CUSC baseline)

**a) Original Proposal**

| | (a) | (b) | (c) | Overall |
|---|---|---|---|---|
| Phil Hayward | Yes, it is more effective for competition. | Yes, forecasts are more accurate. | Yes, small benefit as it reflects the increase in embedded generation. | Yes |

| | | | | |
|---|---|---|---|---|
| Adelle McGill | No, there is no proof that suppliers pass through cost benefits from netting throughout the year to generators. There are wider competition issues with embedded benefits that are going to be addressed separately. The proposal enhances the disparity between embedded and directly connected generation and therefore is a move against competition | Neutral. | Neutral. | No |
| Chris Greer | Yes, it levels the playing field so promotes competition. | Yes, it corrects current forecasts. | Neutral. | Yes |
| Esther Sutton | Yes, same arguments as Phil. | Yes, same reason as Phil. | Yes, same as Phil. | Yes |
| Alan Goodbrook | No, it results in issues for suppliers from generators expecting to be paid throughout the year, so does not benefit competition. | Neutral. | Neutral. | No |

**b) WACM 1**

| | **(a)** | **(b)** | **(c)** | **Overall** |
|---|---|---|---|---|
| Phil Hayward | Yes, it promotes competition. | Neutral. | Neutral. | Yes |
| Adelle McGill | No, it is worse for competition. | No, as NG cannot validate their forecasts. | Neutral. | No |
| Chris Greer | Yes, same as for Original. | Neutral. | Neutral. | Yes |
| Esther Sutton | Yes, it helps competition. | Yes, forecasts are more accurate. | Yes | Yes |
| Alan Goodbrook | No, same as for Original | Neutral | Neutral | No |

## Vote 2: Whether each WACM better facilitates the ACOs than the ORIGINAL

**a) WACM1**

| | **(a)** | **(b)** | **(c)** | **Overall** |
|---|---|---|---|---|
| Phil Hayward | Neutral, it is as good as the Original. | No, not easy to validate the forecasts. | No, not as efficient. | No |

| | | | | |
|---|---|---|---|---|
| Adelle McGill | Neutral. | No, as NG won't be able to validate the forecasts. | | No |
| Chris Greer | Neutral. | No, same argument as Phil. | Neutral. | No |
| Esther Sutton | Marginally no. | No, same as Phil. | No. | No |
| Alan Goodbrook | Yes, data requirements are less. | Neutral | Neutral | Yes |

### Vote 3: Which option BEST facilitates achievement of the ACOs? (inc. CUSC baseline)

**CUSC Baseline**
**CMP209 Original**
**WACM 1**

| Name | Preference |
|---|---|
| Phil Hayward | Original |
| Adelle McGill | Baseline |
| Chris Greer | Original |
| Esther Sutton | Original |
| Alan Goodbrook | Baseline |

CMP210

### Vote 1: Whether each proposal better facilitates ACOs (against CUSC baseline)

**a) Original Proposal**

| | (a) | (b) | (c) | Overall |
|---|---|---|---|---|
| Phil Hayward | Yes, more accurate forecasts so more efficient. | Yes, promotes effective competition. | Neutral. | Yes |

| | | | | |
|---|---|---|---|---|
| Adelle McGill | No, makes it more inefficient for NG to make large scale changes when embedded benefits are to be addressed as an issue separately. It also creates a credit risk for Suppliers and Industry. | No, there is no proof that suppliers pass through cost benefits from netting throughout the year to generators. There are wider competition issues with embedded benefits that are going to be addressed separately. The proposal enhances the disparity between embedded and directly connected generation and therefore is a move against competition | Neutral. | No |
| Chris Greer | Neutral | Yes, it promotes competition | Neutral. | Yes |
| Esther Sutton | Neutral | Yes | Neutral. | Yes |
| Alan Goodbrook | Neutral | No, worse for competition. | Neutral | No |

**b) WACM 1**

| | (a) | (b) | (c) | Overall |
|---|---|---|---|---|
| Phil Hayward | Neutral | Yes, helps competition. | Neutral | Yes |
| Adelle McGill | No, as for Original. | No, as for Original. | Neutral | No |
| Chris Greer | Neutral | Yes | Neutral | Yes |
| Esther Sutton | Neutral | Yes | Neutral | Yes |
| Alan Goodbrook | Neutral | No | Neutral | No |

## Vote 2: Whether each WACM better facilitates the ACOs than the ORIGINAL

**b) WACM1**

| | (a) | (b) | (c) | Overall |
|---|---|---|---|---|
| Phil Hayward | No, not as efficient | Neutral | Neutral | No |
| Adelle McGill | No, not as efficient due to inability to validate forecasts. | Neutral | Neutral | No |
| Chris Greer | Neutral | No | Neutral | No |

| | | | | |
|---|---|---|---|---|
| Esther Sutton | No, less efficient | Neutral | Neutral | No |
| Alan Goodbrook | Neutral | Yes, better for competition. | Neutral | Yes |

## Vote 3: Which option BEST facilitates achievement of the ACOs? (inc. CUSC baseline)

**CUSC Baseline**
**CMP210 Original**
**WACM 1**

| Name | Preference |
|---|---|
| Phil Hayward | Original |
| Adelle McGill | Baseline |
| Chris Greer | Original |
| Esther Sutton | Original |
| Alan Goodbrook | Baseline |

## National Grid View

7.4 National Grid does not believe that either the Original proposal or the Alternative better facilitate the Applicable CUSC or Charging Methodology Objectives. National Grid prefers the Original over the proposed Alternative as the provision of gross information allows for forecasts to be validated appropriately and believe that a net alternative poses a risk to industry, and consequently consumers.

## CUSC Panel Recommendation

7.5 The Panel voted by majority that the CMP209 and CMP210 Original Proposal best facilitates the Applicable CUSC Objectives and so should be implemented. The tables below show a breakdown of each Panel Member's vote and the rational for their vote:

**<u>CMP209 Original</u>**

| Panel Member | Better facilitates ACO (a)? | Better facilitates ACO (b)? | Better facilitates ACO (c)? | Overall (Y/N) |
|---|---|---|---|---|
| Garth Graham | No. Mindful of views of smaller parties regarding concerns over cash flow – generators might ask for money upfront from suppliers so shifts the risk on to suppliers. | Neutral. | Neutral. | No. |

| | | | | |
|---|---|---|---|---|
| Bob Brown | Yes. Defect exists and is fixable, solution is proportionate to issue.<br>Better monitoring and information provision. Change is appropriate given changes in embedded generation. More accurate cash requirements mean less credit risk for participants and makes market entry easier. | Yes. NGET will be getting a cash flow which is more accurate. | Neutral. | Yes. |
| Simon Lord | Yes. Help competition and encourage more accurate forecasts. | Yes. Would incentivise more accurate forecasts. | Neutral. | Yes. |
| James Anderson | Yes. Improving cash flow to net exporters will improve competition. | Yes, marginally better as improved forecast data should improve cost reflectivity of charges. | Neutral. | Yes. |
| Paul Jones | Yes. Benefit is improving the cash flow for net exporters and putting them on a similar basis to those parties that don't have a net export. | Neutral. Charges are unaffected, just their timing. | Neutral. | Yes. |
| Paul Mott | Yes, marginally better. The defect does exist for net exporters. Risk of creating another defect of inaccurate submission and credit risk. | Yes, marginally better. | Neutral. | Yes. |
| Duncan Carter | Yes. Defect does exist in CUSC. Reduces exposure to cash flow imbalances to those parties who are exporting and National Grid can take safeguards to prevent potential abuse of credit opportunities | Neutral. | Neutral. | Yes. |
| Ian Pashley | No. Not clear from consultation responses that competition is improved. Creates credit risk for suppliers. NGET has a licence obligation to consider embedded generation separately. | Neutral. | Neutral. | No. |

**CMP209 WACM 1**

| Panel Member | Better facilitates ACO (a)? | Better facilitates ACO (b)? | Better facilitates ACO (c)? | Overall (Y/N) |
|---|---|---|---|---|
| Garth Graham | No. Same as for Original. | Neutral. | Neutral. | No. |
| Bob Brown | Yes. Same reasoning as for Original but Original better due to quality of information. | Yes. Same as for Original. | Neutral. | Yes. |
| Simon Lord | Neutral. | Yes. Same as for original. | Neutral. | Yes. |
| James Anderson | Yes. Same cash flow benefit as Original. | No. Does not have improved forecast data of Original | Neutral. | No. |
| Paul Jones | Yes. Same benefit on cash flow as the original, but makes it harder for National Grid to validate. | Neutral. Same reasoning as for the original. | Neutral. | Yes. |
| Paul Mott | No. Enhances competition but makes it harder for National Grid to validate. | Neutral. | Neutral. | No. |

| | | | | |
|---|---|---|---|---|
| Duncan Carter | Yes. Same as for Original. | Neutral. | Neutral. | Yes. |
| Ian Pashley | No. Same as for Original and using net approach further muddies the water. | Neutral. | Neutral. | No. |

**BEST**

| | |
|---|---|
| Garth Graham | Baseline |
| Bob Brown | Original |
| Simon Lord | Original |
| James Anderson | Original |
| Paul Jones | Original |
| Paul Mott | Original |
| Duncan Carter | WACM1 – lower cost of implementation |
| Ian Pashley | Baseline |

**CMP210 Original**

| Panel Member | Better facilitates ACO (a)? | Better facilitates ACO (b)? | Better facilitates ACO (c)? | Overall (Y/N) |
|---|---|---|---|---|
| Garth Graham | Neutral. | No. Mindful of views of smaller parties regarding concerns over cash flow – generators might ask for money upfront from suppliers so shifts the risk on to suppliers. | Neutral. | No. |
| Bob Brown | Neutral. | Yes. Facilitates competition. | Neutral. | Yes. |
| Simon Lord | Neutral. | Yes. Promotes competition. | Neutral. | Yes. |
| James Anderson | Neutral. | Yes. Promotes competition due to improved cash flow to net exporters. | Neutral. | Yes. |
| Paul Jones | Neutral. | Yes. Due to improved cash flow for net exporters. | Neutral. | Yes. |
| Paul Mott | Yes. | Yes. Due to cash-flow benefit. | Neutral. | Yes. |
| Duncan Carter | Neutral. | Yes. Promotes competition | Neutral. | Yes. |
| Ian Pashley | No. Embedded issue due to be addressed, potential additional changes could be inefficient at this point in time. | No. Not clear from consultation responses that competition is improved. Creates credit risk for suppliers. NGET licence obligation to consider embedded generation separately. | Neutral. | No. |

**CMP210 WACM 1**

| Panel Member | Better facilitates ACO (a)? | Better facilitates ACO (b)? | Better facilitates ACO (c)? | Overall (Y/N) |
|---|---|---|---|---|
| Garth Graham | Neutral. | No. Due to cash-flow issues. | Neutral. | No. |
| Bob Brown | Yes. Better for new market entrants. | Yes. | Neutral. | Yes. |
| Simon Lord | Neutral. | Yes. Helps competition. | Neutral. | Yes. |
| James Anderson | Neutral. | No. Credit risk issues not countered by improved forecast data. | Neutral. | No. |
| Paul Jones | Neutral. | Yes. Due to improved cash flow for net exporters, but more difficult for National Grid to validate. | Neutral. | Yes. |
| Paul Mott | No. Harder for NGET to validate. | No. | Neutral. | No. |
| Duncan Carter | Neutral. | Yes. | Neutral. | Yes. |
| Ian Pashley | No. Same as for Original. | No. Same as for Original. | Neutral. | No. |

**BEST**

| | |
|---|---|
| Garth Graham | Baseline |
| Bob Brown | Original |
| Simon Lord | Original |
| James Anderson | Original |
| Paul Jones | Original |
| Paul Mott | Original |
| Duncan Carter | WACM1 |
| Ian Pashley | Baseline |

## 8 Workgroup Consultation Response Summary

8.1 5 responses were received to the Workgroup Consultation. These responses are contained in Volume 2 the draft Final Modification Report. The following table provides an overview of the representations received:

**Question 1.** Do you have any contracts with generators to pass through embedded benefits? If so, what proportion of these contracts pay at reconciliation (i.e. June), only after the Triads are known (i.e. March), or consistently throughout the year?

**Question 2.** To what extent do you believe that NHH negative forecasts are an issue? Are Suppliers able to submit gross NHH generation and demand capacity and forecast information? Is there any data available on generation profiles across the year for NHH technologies?

**Question 3.** What are your views on the two issues summarised in section 4.22 and the suggested mitigation measures shown in section 4.24? Are there any additional issues or mitigation measures you'd like to bring to the attention of the Workgroup?

**Question 4.** Do you believe that interest should be levied on overpayment made by National Grid to Suppliers and if so, should this be at the Barclays base rate, or as an uplift?

**Question 5.** What are your views on whether overpayment for negative demand and underpayment for positive demand should be treated differently?

**Question 6.** What do you believe the impacts on your IS/ IT systems would be, if any, if the data is broken down in the way described in 4.9 and 4.32 and what are the timescale implications for any IS / IT system changes?

**Question 7.** Do you agree with the view in 4.40 regarding Suppliers having an obligation to provide the energy they have been paid for, or do you have any evidence to say otherwise?

**Question 8.** Can your existing IS systems cope with providing negative demand forecast data?

**Question 9.** Do you feel the current arrangements are a barrier to entry and/or to Suppliers specialising in embedded generation?

**Question 10.** What are your views on the potential WACMs suggested?

| | Centrica | E.ON | EDF | Good Energy | Smartest Energy |
|---|---|---|---|---|---|
| **Initial Views** | Welcome changes, current method is outdated. | Support but note some work may be required from parties to provide information. | Report identifies all the issues and considerations. | Not a market need for this. We favour the WACM in 4.44 which provides a simpler solution to the alleged defect. | Not keen on this replacing the current arrangements but not averse to it being an option for other participants. |
| **Views against ACO's.** | Support (b) – improves competition. | Support (a) and (b) and to some extent (c) due to increase for embedded. | Better meets (a) and (b) and neutral for (c). | Do not support, counter to (a) as additional costs to suppliers. | No real competition or efficiency issues so does not better facilitate ACOs. |
| **Implementation** | Support. | Support. | Support. | Do not support the proposal. | No comment. |
| **Q1** | Have contracts with embedded generators but terms vary. | Yes, 100% after triads are known. | Yes but only small proportion of demand so we wouldn't benefit from this proposal. | All our contracts (around 120) are with generators which pay at reconciliation. | Yes, pay all generators at reconciliation. |
| **Q2** | Not an issue for us. A negative PN to NG is possible. | Not an issue at present. For HH it could require some work to produce stand-alone intermittent generation forecast. | The report clearly identifies an issue for at least 1 supplier. | NHH forecasts are not an issue for the foreseeable future. Relevant profiles are available from the SAA. | Do not believe it is an issue worthy of further discussion. |
| **Q3** | Option (i) will remove benefits of suppliers artificially inflating volume data. Other options do not allow enough flexibility for year on year movements. | More likely forecast is incorrect due to issues outside suppliers control rather than deliberate. (i) could be useful, (iii) could be unhelpful and (iv) is difficult to assess. | Issues in 4.22 reflect our own concerns. The proposal does not prevent a supplier submitting an erroneous forecast in error or deliberately. NG should have powers to reject any forecast to reject any forecast they believe is inaccurate. Like to see these checks and balances included in the mod. | Due to difficulty in forecasting export from intermittent generation, we consider it prudent to be conservative in our forecasts and would be unrealistic to do otherwise. Would be unfair to be penalised for under-forecasting export. | Option (ii) seems the best. Options (i) and (iii) have issue as portfolios change over time. (ii) and (iv) are unnecessary and administrative burden. |
| **Q4** | Yes, and calculated on same basis as current scheme. | Consistent approach seems fair. Charging at Barclays base rate would be appropriate. | This would add complexity but may also provide an incentive to ensure accuracy. | Yes, but rate should not be penal. Should be at an uplift to Barclays base rate to reflect the higher risk to NG. | Not convinced it is practical to charge an uplift but if so, it should work both ways and NG should apply same uplift to the base rate for payments they make under reconciliation. |
| **Q5** | Should be treated equally to avoid cashflow imbalance. | Consistent approach preferable. | As above. | Should be treated differently. | No difference. |
| **Q6** | No impact. | Some changes required, perhaps 3-6 months. | Seems disproportionate to require this of all suppliers | No impact of providing import and export forecasts | None. |

| | | | | | |
|---|---|---|---|---|---|
| | | | when most will never have a negative demand forecast. | separately. Limited impact of providing split for intermittent, would need 3 months notice. There would be an unacceptable cost burden of providing further disaggregation of export forecasts. | |
| **Q7** | Agree with Workgroup, not practical. | Agree it would be one-sided and impractical. | Agree it is not practically achievable. | No justification for obligation. | Does not make sense. |
| **Q8** | Yes. | Tbc. | Yes. | Yes. | Unable to provide this info. |
| **Q9** | Yes, cashflow may cause constraints for small suppliers. | Not significantly, but recognise Proposer's arguments. | See answer to views against ACOs. | No, current arrangements reflect fact that export is more difficult to forecast that import. | No, generators accept they have to wait until June before they receive payments. |
| **Q10** | Not answered. | 4.44 and 4.45 have merit but 4.46 would not solve problem and 4.47 is inefficient. | Agree with WG on WACM to receive net negative demand forecast supplier data. Also agree with WG on WACM where embedded benefits are only paid at reconciliation, but would not address defect. | Prefer WACM in 4.44 combined with an interest at an uplift to Barclays base rate for over-payment due to over-forecast of negative demand. | Not averse to WACM where NG receive net negative demand forecast data. There is a netting advantage whether net negative or positive and is appropriate this should remain. Not in favour of WACM where gross forecasts are received and embedded benefits are paid to all suppliers at reconciliation. |

## 9 Code Administrator Consultation Response Summary

9.1 7 responses were received to the Code Administrator Consultation. These responses are contained within Volume 2 of the draft Final Modification Report. The following table provides an overview of the representations received.

| Company | Supportive | Comments |
|---|---|---|
| E.ON UK | Yes | • Provides a more level playing field with competitors and provide clearer visibility of forecast demand<br>• Support implementation approach |
| EDF Energy | Yes | • Neutral against (a) and (b) as understand the defect that the Proposer is trying to address, but there is the risk that a supplier could input a negative erroneous demand forecast and gain a cash flow advantage, which could result in a loss if that supplier fails financially.<br>• Support implementation approach<br>• WACM is worse than Original as is makes it harder for National Grid to validate forecasts |
| Good Energy | No | • Creates financial risk to parties and creates cash flow risk to all concerned but particularly small suppliers, and thus restrains competition.<br>• Support implementation approach<br>• Current BSC modification which may result in the changing dynamics between HH and NHH needing to be reviewed. |
| Opus Energy | Yes | • Strongly facilitates competition objectives<br>• Disagree with National Grid's argument<br>• This proposal will lead to more efficient and accurate calculations of forecast load and initial supplier TNUoS bills<br>• Support implementation approach |
| Scottish Power | Yes | • Better facilitates (a) as improved cash flow will benefit competition and improves the cost reflectivity of transmission charges<br>• Support implementation approach |
| Smartest Energy | No | • CUSC Objectives not relevant to this proposal<br>• No real competition or efficiency issues with the current process and no compliance issues with European Codes.<br>• Would require IT changes and also an administrative burden |
| SSE | No | • Detrimental to competition<br>• Broadly support implementation approach – IT changes would be required<br>• Note National Grid's intention to propose a CUSC change regarding embedded benefits, which would be a more comprehensive and holistic approach. |

## Annex 1 – Terms of Reference

## TERMS OF REFERENCE FOR CMP209 WORKGROUP

### Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal CMP209 "Allow Suppliers' submitted forecast demand to be export", tabled by Opus Energy at the CUSC Modifications Panel meeting on 27 April 2012.

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 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.

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) Whether, and the extent to which, CMP209 would create perverse incentives on Suppliers to submit incorrect demand forecasts to improve their cashflow;

   b) Whether Suppliers with significant amounts of intermittent generation are able to submit accurate demand forecasts;

   c) Whether Feed In Tariff metering data be used to justify Supplier demand forecasts;

   d) Appropriate credit arrangements to recognise that Suppliers would receive payments that may not be accurate and would require reconciliation;

   e) Whether Suppliers would have an obligation under CMP209 to provide the energy that they would be paid for;

   f) Whether interest should be levied on overpayment;

   g) Whether the existing IS systems can cope with negative demand forecast data;

   h) To what extent the current arrangements are a barrier to entry to embedded generators and/or to Suppliers specialising in embedded generation;

   i) Review the illustrative legal text

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 4 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 20 September 2012 for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on 28 September.

## Membership

13. The Workgroup has the following members:

| Role | Name | Representing |
|---|---|---|
| Chairman | Alex Thomason | Code Administrator |
| National Grid Representative* | Adelle McGill | National Grid |
| Industry Representatives* | Phil Hayward | Opus Energy (Proposer) |
| | Garth Graham | SSE |
| | Esther Sutton | E.ON |
| | Alan Goodbrook | Good Energy |
| | Chris Greer | Garsington Energy Ltd |
| | | |
| Authority Representatives | Abid Sheikh<br>Scott Hamilton<br>Antony Mungall | |
| Technical secretary | Emma Clark | 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 CMP209 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.

The following timetable is indicative for the CMP209 Workgroup.

| | |
|---|---|
| w/c 30 April | Send out request for WG nominations |
| w/c 11 June or 18 June | First Workgroup meeting |
| w/c 25 June or 2 July | Second Workgroup meeting |
| 12 July | Issue draft Workgroup Consultation for Workgroup comment (5 working days) |
| 19 July | Deadline for comments on draft Workgroup Consultation |
| 23 July | Publish Workgroup consultation (for 4 weeks) |
| 20 August | Deadline for responses to Workgroup consultation |
| w/c 27 August | Post-consultation Workgroup meeting |
| 10 September | Circulate draft Workgroup Report |
| 17 September | Deadline for comment on Workgroup report |
| 20 September | Submit final Workgroup report to Panel Secretary |
| 28 September | Present Workgroup report to CUSC Modifications Panel |

# TERMS OF REFERENCE FOR CMP210 WORKGROUP

## Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal CMP210 "Allow Suppliers' submitted forecast demand to be export", tabled by Opus Energy at the CUSC Modifications Panel meeting on 27 April 2012.

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

   (a) the efficient discharge by the Licensee of the obligations imposed on it by the Act and the Transmission Licence; and

   (b) facilitating effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the sale, distribution and purchase of electricity.

   (c) 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) Whether, and to what extent, CMP210 would create perverse incentives on Suppliers to submit incorrect demand forecasts to improve their cashflow;

   b) Whether Suppliers with significant amounts of intermittent generation are able to submit accurate demand forecasts;

   c) Whether Feed In Tariff metering data be used to justify Supplier demand forecasts;

   d) Appropriate credit arrangements to recognise that Suppliers would receive payments that may not be accurate and would require reconciliation;

e) Whether Suppliers would have an obligation under CMP210 to provide the energy that they would be paid for;

f) Whether interest should be levied on overpayment;

g) Whether the existing IS systems can cope with negative demand forecast data;

h) To what extent the current arrangements are a barrier to entry to embedded generators and/or to Suppliers specialising in embedded generation;

i) Review the illustrative legal text

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 4 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 20 September 2012 for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on 28 September 2012.

## Membership

13. The Workgroup has the following members:

| Role | Name | Representing |
|---|---|---|
| Chairman | Alex Thomason | Code Administrator |
| National Grid Representative* | Adelle McGill | National Grid |
| Industry Representatives* | Phil Hayward | Opus Energy (Proposer) |
| | Garth Graham | SSE |
| | Esther Sutton | E.ON |
| | Alan Goodbrook | Good Energy |
| | Chris Greer | Garsington Energy Ltd |
| | | |
| Authority Representatives | Abid Sheikh<br>Scott Hamilton<br>Antony Mungall | |
| Technical secretary | Emma Clark | 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 CMP210 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.

The following timetable is indicative for the CMP210 Workgroup.

| | |
|---|---|
| w/c 30 April | Send out request for WG nominations |
| w/c 11 June or 18 June | First Workgroup meeting |
| w/c 25 June or 2 July | Second Workgroup meeting |
| 12 July | Issue draft Workgroup Consultation for Workgroup comment (5 working days) |
| 19 July | Deadline for comments on draft Workgroup Consultation |
| 23 July | Publish Workgroup consultation (for 4 weeks) |
| 20 August | Deadline for responses to Workgroup consultation |
| w/c 27 August | Post-consultation Workgroup meeting |
| 10 September | Circulate draft Workgroup Report |
| 17 September | Deadline for comment on Workgroup report |
| 20 September | Submit final Workgroup report to Panel Secretary |
| 28 September | Present Workgroup report to CUSC Modifications Panel |

## Annex 2 – CMP209 Proposal Form

| **CUSC Modification Proposal Form (for Charging Methodology proposals)** | **CMP209** |
|---|---|
| | |

**Title of the CUSC Modification Proposal**: *(mandatory by Proposer)*

Allow Suppliers' submitted forecast demand to be export

**Submission Date** *(mandatory by Proposer)*

*19/04/12*

**Description of the CUSC Modification Proposal** *(mandatory by Proposer)*

Currently suppliers who net import in a BM Unit receive the transmission benefit from their generation sites on a monthly basis – as they are netted off their transmission bill. Suppliers who net export do not receive these benefits until the annual reconciliation which can be up to 7 months after TRIAD periods for HH sites and 15 months for NHH. We propose to correct this disparity

**Description of Issue or Defect that CUSC Modification Proposal seeks to Address:** *(mandatory by Proposer)*

Currently, the monthly TNUoS charging is based on the HH and NHH demand forecasts that suppliers provide. As a suppliers forecast is capped at 0, the monthly charges can't reflect the annual liability if a supplier has more export than import in a BM Unit. As the proportion of embedded generation increases this is becoming more and more of an issue.

Suppliers are incentivised to make their forecasts as accurate as possible, as National Grid benefit from having an accurate picture of forecast demand. The current system prevents the supplier from provide an accurate forecast if their volume is less than 0

**Impact on the CUSC** *(this should be given where possible)*

Section 14 contains several references to the forecast having to be positive, e.g. 14.17.16, 14.24

These references would need removing / rewriting for clarity

This won't affect the way that the charging is calculated, as the calculations are already set up to allow for negatives at the reconciliation runs.

**Do you believe the CUSC Modification Proposal will have a material impact on Greenhouse Gas Emissions? Yes/No** *(mandatory by Proposer. Assessed in accordance with Authority Guidance – see guidance notes for website link)*

No

| |
|---|
| **Impact on Core Industry Documentation. Please tick the relevant boxes and provide any supporting information** *(this should be given where possible)*<br><br>**BSC** ☐<br><br>**Grid Code** ☐<br><br>**STC** ☐<br><br>**Other** ☐<br><br>*(please specify)* |
| **Urgency Recommended: Yes / No** *(optional by Proposer)*<br>*No* |
| **Justification for Urgency Recommendation** *(mandatory by Proposer if recommending progression as an Urgent Modification Proposal)* |
| **Self-Governance Recommended: Yes / No** *(mandatory by Proposer)*<br>*No* |
| **Justification for Self-Governance Recommendation** *(Mandatory by Proposer if recommending progression as Self-governance Modification Proposal)* |
| **Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews?** *(Mandatory by Proposer in order to assist the Panel in deciding whether a Modification Proposal should undergo a SCR Suitability Assessment)*<br>*Yes* |
| **Impact on Computer Systems and Processes used by CUSC Parties:** *(this should be given where possible)* |
| **Details of any Related Modification to Other Industry Codes** *(where known)*: |

**Justification for CUSC Modification Proposal with reference to Applicable CUSC Objectives:** *(mandatory by proposer)*

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

Use of System Charging Methodology

☒x (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;**

☒x (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.**

**Full justification:**

A)

The current methodology results in suppliers that net export in a BM Unit receiving an initial transmission bill of zero, when they should receive a credit. They will have this money credited back in the reconciliation; however, until this time the supplier is at a commercial disadvantage, the impact of which discriminates against small suppliers. Furthermore, standard generation contracts are set up to pass TNUoS benefit through to the customer once the TRIAD data is published, exacerbating the issue.

Suppliers who have a sufficiently large import portfolio (e.g. the incumbent ‘big 6’ players) are able to do this without any problems as they have already received the benefit through netting against their initial bill. Therefore, this disproportionately impacts smaller, niche, suppliers, especially suppliers who choose to specialise wholly or partially in generation customers as they have no, or smaller, import portfolio to net it off against. This discourages new start-ups in that area, because it places them at a commercial disadvantage, and thereby damages competition in a sector that the government is very keen to encourage

B)

It would also improve the accuracy of forecast data that National Grid have to work with, as suppliers forecasts won’t artificially be capped at 0 and will be free to reflect their demand more accurately.

Allowing this to go below 0 will not involve significant extra risks to national grid as it is has essentially the same impact as the established system of allowing suppliers to net export against import

| | |
|---|---|
| **Details of Proposer:** (Organisation Name) | Opus Energy 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: | Philip Hayward<br>Opus Energy Limited<br>0845 4379406<br>**Philip.hayward@opusenergy.com** |
| **Details of Representative's Alternate:** Name: Organisation: Telephone Number: Email Address: | David Soper<br>Opus Energy Limited<br>0845 4379403<br>David.soper@opusenergy.com |
| **Attachments (Yes/No):**<br>**If Yes, Title and No. of pages of each Attachment:**<br>**No** | |

## Annex 3 – CMP210 Proposal Form

| CUSC Modification Proposal Form | CMP210 |
|---|---|
| | |
| **Title of the CUSC Modification Proposal**: *(mandatory by Proposer)*<br>Allow Suppliers' submitted forecast demand to be export | |
| **Submission Date** *(mandatory by Proposer)*<br>*19/04/12* | |
| **Description of the CUSC Modification Proposal** *(mandatory by Proposer)*<br>Currently suppliers who net import in a BM Unit receive the transmission benefit from their generation sites on a monthly basis – as they are netted off their transmission bill. Suppliers who net export do not receive these benefits until the annual reconciliation which can be up to 7 months after TRIAD periods for HH sites and 15 months for NHH. We propose to correct this disparity | |
| **Description of Issue or Defect that CUSC Modification Proposal seeks to Address:** *(mandatory by Proposer)*<br>Currently, the monthly TNUoS charging is based on the HH and NHH demand forecasts that suppliers provide. As a suppliers forecast is capped at 0, the monthly charges can't reflect the annual liability if a supplier has more export than import in a BM Unit. As the proportion of embedded generation increases this is becoming more and more of an issue.<br>Suppliers are incentivised to make their forecasts as accurate as possible, as National Grid benefit from having an accurate picture of forecast demand. The current system prevents the supplier from provide an accurate forecast if their volume is less than 0 | |
| **Impact on the CUSC** *(this should be given where possible)*<br>Section 11 assumes supplier non-half-hourly demand and supplier half-hourly demand are positive and import. This is not the case and needs amending.<br>Section 3.12 may end up being amended, although at present it does not mention that a forecast must be positive. | |
| **Do you believe the CUSC Modification Proposal will have a material impact on Greenhouse Gas Emissions? Yes/No** *(mandatory by Proposer. Assessed in accordance with Authority Guidance – see guidance notes for website link)*<br>No | |
| **Impact on Core Industry Documentation. Please tick the relevant boxes and provide any supporting information** *(this should be given where possible)* | |

| |
|---|
| **BSC** ☐<br><br>**Grid Code** ☐<br><br>**STC** ☐<br><br>**Other** ☐<br><br>*(please specify)* |
| **Urgency Recommended: Yes / No** *(optional by Proposer)*<br>*No* |
| **Justification for Urgency Recommendation** *(mandatory by Proposer if recommending progression as an Urgent Modification Proposal)* |
| **Self-Governance Recommended: Yes / No** *(mandatory by Proposer)*<br>*No* |
| **Justification for Self-Governance Recommendation** *(Mandatory by Proposer if recommending progression as Self-governance Modification Proposal)* |
| **Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews?** *(Mandatory by Proposer in order to assist the Panel in deciding whether a Modification Proposal should undergo a SCR Suitability Assessment)*<br>*Yes* |
| **Impact on Computer Systems and Processes used by CUSC Parties:** *(this should be given where possible)* |
| **Details of any Related Modification to Other Industry Codes** *(where known)*: |

**Justification for CUSC Modification Proposal with Reference to Applicable CUSC Objectives:** *(mandatory by proposer)*

Please tick the relevant boxes and provide justification:

☒ (a) the efficient discharge by The Company of the obligations imposed upon it by the Act and the Transmission Licence

It would improve the accuracy of forecast data that National Grid have to work with, as suppliers forecasts won't artificially be capped at 0 and will be free to reflect their demand more accurately.

Allowing this to go below 0 will not involve significant extra risks to national grid as it is has essentially the same impact as the established system of allowing suppliers to net export against import

☒ **(**b) facilitating effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the sale, distribution and purchase of electricity.

The current methodology results in suppliers that net export in a BM Unit receiving an initial transmission bill of zero, when they should receive a credit. They will have this money credited back in the reconciliation; however, until this time the supplier is at a commercial disadvantage, the impact of which discriminates against small suppliers. Furthermore, standard generation contracts are set up to pass TNUoS benefit through to the customer once the TRIAD data is published, exacerbating the issue.

Suppliers who have a sufficiently large import portfolio (e.g. the incumbent 'big 6' players) are able to do this without any problems as they have already received the benefit through netting against their initial bill. Therefore, this disproportionately impacts smaller, niche, suppliers, especially suppliers who choose to specialise wholly or partially in generation customers as they have no, or smaller, import portfolio to net it off against. This discourages new start-ups in that area, because it places them at a commercial disadvantage, and thereby damages competition in a sector that the government is very keen to encourage.

☐ **(c) 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

| | |
|---|---|
| **Details of Proposer:** (Organisation Name) | Opus Energy 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:**<br>Name:<br>Organisation:<br>Telephone Number:<br>Email Address: | Philip Hayward<br>Opus Energy Limited<br>0845 4379406<br>**Philip.hayward@opusenergy.com** |
| **Details of Representative's Alternate:**<br>Name:<br>Organisation:<br>Telephone Number:<br>Email Address: | David Soper<br>Opus Energy Limited<br>0845 4379403<br>David.soper@opusenergy.com |
| **Attachments (Yes/No):**<br>**If Yes, Title and No. of pages of each Attachment:**<br>**No** | |

## Annex 4 - Workgroup Attendance Register

| Name | Organisation | Role | 20/06/12 Attended? | 04/07/12 Attended? | 06/09/12 Attended? |
|---|---|---|---|---|---|
| Alex Thomason | National Grid | Chairman | Yes | Yes | Yes |
| Emma Clark | National Grid | Technical Secretary | Yes | Yes | Yes |
| Adelle McGill | National Grid | National Grid representative | Yes | Yes | Yes |
| Phil Hayward | Opus Energy | Proposer | Yes | Yes | Yes |
| Anthony Mungall | Ofgem | Authority Representative | Teleconference | No | No |
| Scott Hamilton | Ofgem | Authority Representative | Teleconference | Teleconference | No |
| Esther Sutton | E.ON | Workgroup Member | Yes | No | Yes |
| Garth Graham | SSE | Workgroup Member | Yes | Yes | No |
| Alan Goodbrook | Good Energy | Workgroup Member | Yes | Yes | Yes |
| Chris Greer | Green Energy | Workgroup Member | No | Yes | Yes |

## Annex 5 – Glossary of Terms

| | |
|---|---|
| BM | Balancing Mechanism |
| BMU | Balancing Mechanism Unit |
| CALF | Credit Assessment Load Factor |
| HH | Half Hourly |
| NETS | National Electricity Transmission System |
| NHH | Non Half Hourly |
| NGET | National Grid Electricity Transmission plc |
| TEC | Transmission Entry Capacity |
| TNUoS | Transmission Use of System Charges |
| VAR | Value At Risk |
| WACM | Workgroup Alternative CUSC Modification |

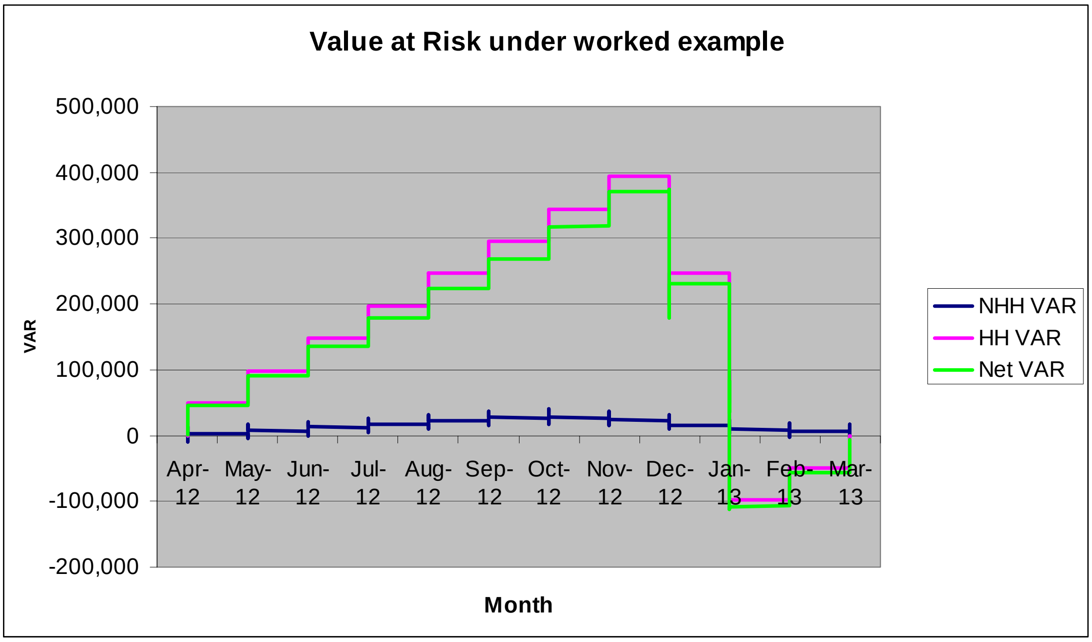
## Annex 6 – Worked example 1 for calculation of securities

***Assumptions***

| | |
|---|---|
| Annual HH benefit | -£590,800 |
| Annual NHH liability | £370,255 |
| Net payment direction | National Grid to pay Supplier |

In this example, the payment direction is from National Grid to the Supplier, with an export forecast for HH and import forecast from NHH.

Securities are required to cover the Value at Risk (VAR) as explained in (4.17-4.19). In the example above, a proportion of the export HH VAR would be offset by the import NHH VAR. This would reduce the net level of VAR over the year. The profile of the HH VAR, NHH VARs and the reduced net VAR are shown in the graph below.




The security liability calculation takes this reduced liability into account by netting the NHH liability (calculated using the NHH base VAR percentage table in 4.19) from the HH liability (calculated using the HH base VAR percentage table in 4.18) for each security period.

Therefore, in this example the securities required for each period are shown below.

| Security period | Securities required |
|---|---:|
| Period 1 (Apr-Jun) | £67,210.54 |
| Period 2 (Jul-Sep) | £194,221.70 |
| Period 3 (Oct - Dec) | £308,797.00 |
| Period 4 (Jan - Mar) | £37,420.23 |

## Annex 7 – Guidance to choice of VAR tables in the calculation of securities

The table below demonstrates which base percentage Value at Risk table should be used as part of security calculations. Different base VAR tables are used depending on whether the forecast is based on import or export components, and the payment direction between National Grid and Suppliers.

| | **HH import**<br>**NHH import** | **HH export**<br>**NHH import** |
|---|---|---|
| **Forecast resulting in overall payment from Supplier to National Grid** | Calculation of HH securities using table 1<br>**+**<br>Calculation of NHH securities using table 2 | Calculation of NHH securities using table 2<br>**+**<br>Calculation of HH securities using table 1 |
| **Forecast resulting in overall payment from National Grid to Supplier** | N/A | Calculation of HH securities using table 3<br>**+**<br>Calculation of NHH securities using table 4 |

***Summary of VAR percentage tables***

- **Table 1** – existing HH Base percentages as defined in section 3 of the CUSC for positive demand forecast
- **Table 2** – existing NHH Base percentages as defined in section 3 of the CUSC for positive demand forecasts
- **Table 3** – new proposed table for HH Base percentages for negative demand forecasts (see section 4.18).
- **Table 4** – new proposed table for NHH Base percentages for negative demand forecasts (see section 4.19)

## Annex 8 – Credit Cover Case Studies

***Example 1 – rated company***

Company A wishes to get a credit limit with National Grid. Company A is awarded a credit rating of BBB+ from Standard & Poor's and A3 from Moody's KMV. National Grids RAV is £7,640.1m.
The calculation applied to establish Company A's credit limit is as follows:

% Credit Allowance x 2% of RAV
0.20 x (0.02 x 7,640,100,000)
= £30,560,400

The percentage credit allowance is 20% as the lower credit rating of BBB+ is applied.
Company A is therefore awarded an unsecured credit amount of £30.6m

***Example 2 – unrated company***

Company B is unrated but has been paying all invoices on time for exactly two years.
Their credit limit would be calculated as follows:
No of years perfect payment history x (0.4% x (maximum credit limit))
Which equates to:
2 x (0.004 x 152,800,000)
This equals £1,222,400.
Providing the payment record remained perfect this would increase by £50,933 each month for the next three years giving a credit allowance of £3,056,000 after five years. This can then not increase any further but can decrease should a payment be missed.

***Example 3 – unrated company***

Company B from the above example is used as a starting point for this example.
Company B now has five years perfect payment history and therefore a credit allowance of £3,056,000. If they miss a payment the credit allowance gets reduced immediately to £1,528,000. Providing they don't miss any more payments in the next twelve months then their credit limit will have increased to £2,139,200 thirteen months after the missed payment date (as they don't start accruing again until the month after the missed payment). After another twelve months the credit limit would be £2,750,400 and then after six additional months it would reach £3,056,000. Again it can not go above this value.
Whilst a Supplier is building up a payment history it will be very likely that some other form of security will need to be in place. As the payment history allowance gains value the security required will be reviewed and adjusted if necessary.

For ease of reference, the proposed deleted text is shown in red strikethrough, and any proposed additional text is shown in blue font.

# CUSC – Section 3

3.22.7 Revision of **Deemed HH Forecasting Performance**

If the **User** has experienced a significant increase in the amount of **Demand** taken by its **Customers** during the last five months of the previous **Financial Year** and believes that this has had a significant effect on their **Deemed HH Forecasting Performance**, then no later than one month from the date of the notification given to the **User** under paragraph 3.22.5, the **User** may request that **The Company** revises the **Deemed HH Forecasting Performance**. Upon raising such a request, the **User** must provide information to **The Company** relating to the size of the reported **Demand** increase and the **Reported Period(s) of Increase**. Where for any **Reported Period of Increase** the resulting increase in **Demand** equates to a level that is in excess of one percent of the **Actual Amount** of **HH Charges** in respect of the previous **Financial Year**, **The Company** shall, within one month of receiving such a request, recalculate the **Deemed HH Forecasting Performance** on the basis set out in Appendix 2 Paragraph ~~4~~6. A **User** shall not be entitled to raise more than one request by reference to any period or part period covered in another **Reported Period of Increase** in respect of which a request has been raised under this Paragraph.

3.22.8 Revision of **Deemed NHH Forecasting Performance**

If the **User** has experienced a significant increase in the amount of **Demand** taken by its **Customers** during the last five months of the previous **Financial Year** and believes that this has had a significant effect on their **Deemed NHH Forecasting Performance**, then no later than one month from the date of the notification given to the **User** under paragraph 3.22.6, the **User** may request that **The Company** revises the **Deemed NHH Forecasting Performance**. Upon raising such a request, the **User** must provide information to **The Company** relating to the size of the reported **Demand** increase and the **Reported Period(s) of Increase**. Where for any **Reported Period of Increase** the resulting increase in **Demand** equates to a level that is in excess of one percent of the **Actual Amount** of **NHH Charges** in respect of the previous **Financial Year**, **The Company** shall within one month of receiving such a request, recalculate the **Deemed NHH Forecasting Performance** on the basis set out in Appendix 2 Paragraph ~~7~~9. A **User** shall not be entitled to raise more than one request by reference to any period or part period covered in another **Reported Period of Increase** in respect of which a request has been raised under this Paragraph.

**APPENDIX 2**

Base Value At Risk

1. For each **Security Period** within a **Financial Year**, where a **User's Demand Forecast** results in an overall positive **Transmission Network Use of System Demand Charge** in respect of that **Financial Year**, the **HH Base Percentage** used in determining the **User's HH Base Value at Risk** shall be determined by reference to the following table:

Table 1:

(i)

| Security Period Start Date (inclusive) | Security Period End Date (inclusive) | HH Base Percentage |
|---|---|---|
| 1st April | 30th June | -8.4% |
| 1st July | 30th September | -33.4% |
| 1st October | 31st December | -49.1% |
| 1st January | 31st March | 7.0% |

2. For each **Security Period** within a **Financial Year**, where a **User's Demand Forecast** results in an overall negative **Transmission Network Use of System Demand Charge** in respect of that **Financial Year**, the **HH Base Percentage** used in determining the **User's HH Base Value at Risk** shall be determined by reference to the following table:

Table 2:

| Security Period Start Date (inclusive) | Security Period End Date (inclusive) | HH Base Percentage |
|---|---|---|
| 1st April | 30th June | -12.82% |
| 1st July | 30th September | -37.77% |
| 1st October | 31st December | -58.61% |
| 1st January | 31st March | -9.16% |

3. For each **Security Period** within a **Financial Year**, where a **User's Demand Forecast** results in an overall positive **Transmission Network Use of System Demand Charge** in respect of that **Financial Year**, the **NHH Base Percentage** used in determining the **User's NHH Base Value at Risk** shall be determined by reference to the following table:

Table 3:

| Security Period Start Date (inclusive) | Security Period End Date (inclusive) | NHH Base Percentage |
|---|---|---|
| 1st April | 30th June | 4.3% |
| 1st July | 30th September | -1.5% |
| 1st October | 31st December | -2.8% |

| | | |
|---|---|---|
| 1st January | 31st March | 3.7% |

4. For each **Security Period** within a **Financial Year**, where a **User's Demand Forecast** results in an overall negative **Transmission Network Use of System Demand Charge** in respect of that **Financial Year**, the **NHH Base Percentage** used in determining the **User's NHH Base Value at Risk** shall be determined by reference to the following table:

Table 4:

| **Security Period Start Date (inclusive)** | **Security Period End Date (inclusive)** | **NHH Base Percentage** |
|---|---|---|
| 1st April | 30th June | -2.30% |
| 1st July | 30th September | -7.81% |
| 1st October | 31st December | -10.12% |
| 1st January | 31st March | -4.51% |

5. The following table demonstrates how the **Base Value at Risk** will be calculated for varying types of **User Demand Forecasts**:

| | **HH import**<br>**NHH import** | **HH export**<br>**NHH import** |
|---|---|---|
| **Demand Forecast** resulting in overall positive **Transmission Network Demand Charge** (payment to **The Company**) | **HH Base Value At Risk** calculated using table 1<br>+<br>**NHH Base Value At Risk** calculated using table 3 | **HH Base Value At Risk** calculated using table 1<br>+<br>NHH Base Value At Risk calculated using table 3 |
| **Forecast** resulting in overall negative **Transmission Network Demand Charge** (payment to the **User**) | N/A | **HH Base Value At Risk** calculated using table 2<br>+<br>**NHH Base Value At Risk** calculated using table 4 |

Deemed HH Forecasting Performance and Revision

~~3~~6. **Deemed HH Forecasting Performance**, $FPP_{HH}$, shall be calculated as set out in the following formulae:

(a) Where the **Actual Amount** of **User's HH Charges** for the previous **Financial Year** is positive:

$$FPP_{HH} = \max\left(0, \frac{5}{1333}\sum_{m=8}^{12}\left(\frac{AA_{HH} - IA_{HH,m}}{AA_{HH}} * W_{HH,m}\right) - CA_{HH}\right)$$

or

(b) Where the **Actual Amount** of **User's HH Charges** for the previous **Financial Year** is negative:

$$FPP_{HH} = \max\left(0, \frac{5}{1333}\sum_{m=8}^{12}\left(\frac{IA_{HH} - AA_{HH,m}}{AA_{HH}} * W_{HH,m}\right) - CA_{HH}\right)$$

Where:

$AA_{HH}$ is the **Actual Amount** of **User's HH Charges** for the previous **Financial Year**

$IA_{HH,m}$ is the **Indicative Annual HH TNUoS charge** calculated using the **Demand Forecast** used to determine **Transmission Network Use of System Demand Charges** made during month *m* of the previous **Financial Year**.

$W_{HH,m,}$ The forecast weighting to be applied for each month, *m* by reference to the following:

| ***m*** | **Invoice Month** | **Forecast weighting, $W_{HH,m}$** |
|---|---|---|
| 8 | November | 33.3 |
| 9 | December | 33.3 |
| 10 | January | 33.3 |
| 11 | February | 66.7 |
| 12 | March | 100 |

$CA_{HH,}$ is an allowance for extreme conditions equal to 0.06.

47. The revised Deemed HH Forecasting Performance, shall be calculated on the basis of Paragraph 3 above, substituting the Indicative Annual HH TNUoS Charge for each month, *m* prior to the end of the Reported Period of Increase with the Revised Indicative Annual HH TNUoS charge, $RIA_{HH,m}$

~~5~~8. The **Revised Indicative Annual HH TNUoS charge,** $RIA_{HH,m}$ shall be derived as follows:

$$RIA_{HH,m} = \min\left( \max\left( \frac{DUA_{HH,p}}{DUB_{HH,p}} - \frac{DSA_{HH,p}}{DSB_{HH,p}}, 0 \right) * RD_{HH,p} + IA_{HH,m}, IA_{HH,p} \right)$$

Where:

$DUA_{HH,p}$ is the average half-hourly metered demand taken by the **User's Customers** during the period 17:00 to 17:30 on the twenty **Business Days** prior to the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22nd December.

$DUB_{HH,p}$ is the average half-hourly metered demand taken by the **User's Customers** during the period 17:00 to 17:30 on the twenty **Business Days** following the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22nd December.

$DSA_{HH,p}$ is the average demand taken by **Total System Chargeable HH Demand** during the period 17:00 to 17:30 on the twenty **Business Days** prior to the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22nd December.

$DSB_{HH,p}$ is the average demand taken by **Total System Chargeable HH Demand** during the period 17:00 to 17:30 on the twenty **Business Days** following the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22nd December.

$RD_{HH,p}$ is the forecast proportion of **HH Charges** remaining for the previous **Financial Year** from the first day of the month in which the **Reported Period of Increase**, *p* commences by reference to the following:

| Month in which **Reported Period of Increase commences** | Remaining proportion of **HH Charges** |
|---|---|
| October | 100% |
| November | 100% |
| December | 100% |
| January | 66.7% |
| February | 33.3% |

$IA_{HH,m}$ is the **Indicative Annual HH TNUoS charge** calculated using the **Demand Forecast** used to determine **Transmission Network Use of System Demand Charges** made during month *m* of the previous **Financial Year**.

$IA_{HH,p}$ in the case that the the **Reported Period of Increase**, *p* ends prior to the 10th February of the previous **Financial Year**, is set equal to the **Indicative Annual HH TNUoS charge** calculated using the **Demand Forecast** used to determine **Transmission Network Use of System Demand Charges** made during the month immediately following

**Reported Period of Increase** of the previous **Financial Year,** otherwise is set to infinity.

Deemed NHH Forecasting Performance and Revision

~~6~~9. **Deemed NHH Forecasting Performance**, $FPP_{NHH}$, shall be calculated as set out in the following formula:

$$FPP_{NHH} = \max\left(0, \frac{1}{300}\sum_{m=8}^{12}\left(\frac{AA_{NHH} - IA_{NHH,m}}{AA_{NHH}} * W_{NHH,m}\right) - CA_{NHH}\right)$$

Where:

$AA_{NHH}$ is the **Actual Amount** of **User's NHH Charges** for the previous **Financial Year**.

$IA_{NHH,m}$ is the **Indicative Annual NHH TNUoS charge** calculated using the **Demand Forecast** used to determine **Transmission Network Use of System Demand Charges** made during month *m* of the previous **Financial Year**.

$W_{NHH,m,}$ The forecast weighting to be applied for each month, *m* by reference to the following:

| ***m*** | **Invoice Month** | **Forecast weighting, $W_{NHH,m}$** |
|---|---|---|
| 8 | November | 41 |
| 9 | December | 49 |
| 10 | January | 59 |
| 11 | February | 70 |
| 12 | March | 81 |

$CA_{NHH,}$ is an allowance for extreme conditions equal to 0.03.

~~7~~10**.** The revised Deemed NHH Forecasting Performance shall be calculated on the basis of Paragraph 6 above, substituting the Indicative Annual NHH TNUoS Charge for each month, *m* prior to the end of the Reported Period of Increase with the Revised Indicative Annual NHH TNUoS charge, $RIA_{NHH,m}$.

~~8~~11. The **Revised Indicative Annual NHH TNUoS charge,** $RIA_{NHH,m}$ shall be derived as follows:

$$RIA_{NHH,m} = \min\left(\max\left(\frac{DUA_{NHH,p}}{DUB_{NHH,p}} - \frac{DSA_{NHH,p}}{DSB_{NHH,p}}, 0\right) * RD_{NHH,p} + IA_{NHH,m}, IA_{NHH,p}\right)$$ Wher

e:

$DUA_{NHH,p}$ is the average non-half-hourly metered demand taken by the **User's Customers** during the period 16:00 to 19:00 on the twenty **Business Days** prior to the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22nd December.

$DUB_{NHH,p}$ is the average non-half-hourly metered demand taken by the **User's Customers** during the period 16:00 to 19:00 on the twenty **Business Days** following the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22nd December.

$DSA_{NHH,p}$ is the average demand taken by **Total System Chargeable NHH Demand** during the period 16:00 to 19:00 on the twenty **Business Days** prior to the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22nd December.

$DSB_{NHH,p}$ is the average demand taken by **Total System Chargeable NHH Demand** during the period 16:00 to 19:00 on the twenty **Business Days** following the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22nd December.

$RD_{NHH,p}$ is the forecast proportion of **NHH Charges** remaining for the previous **Financial Year** from the first day of the month in which the **Reported Period of Increase**, *p* commences by reference to the following:

| Month in which **Reported Period of Increase commences** | Remaining proportion of **NHH Charges** |
|---|---|
| October | 59% |
| November | 51% |
| December | 41% |
| January | 30% |
| February | 19% |

$IA_{NHH,m}$ is the **Indicative Annual NHH TNUoS charge** calculated using the **Demand Forecast** used to determine **Transmission Network Use of System Demand Charges** made during month *m* of the previous **Financial Year**.

$IA_{NHH,p}$ in the case that the the **Reported Period of Increase**, *p* ends prior to the 10th February of the previous **Financial Year**, is set equal to the **Indicative Annual NHH TNUoS charge** calculated using the **Demand Forecast** used to determine **Transmission Network Use of System Demand Charges** made during the month immediately following **Reported Period of Increase** of the previous **Financial Year,** otherwise is set to infinity.

**END OF SECTION 3**

# CUSC - SECTION 11

## INTERPRETATION AND DEFINITIONS

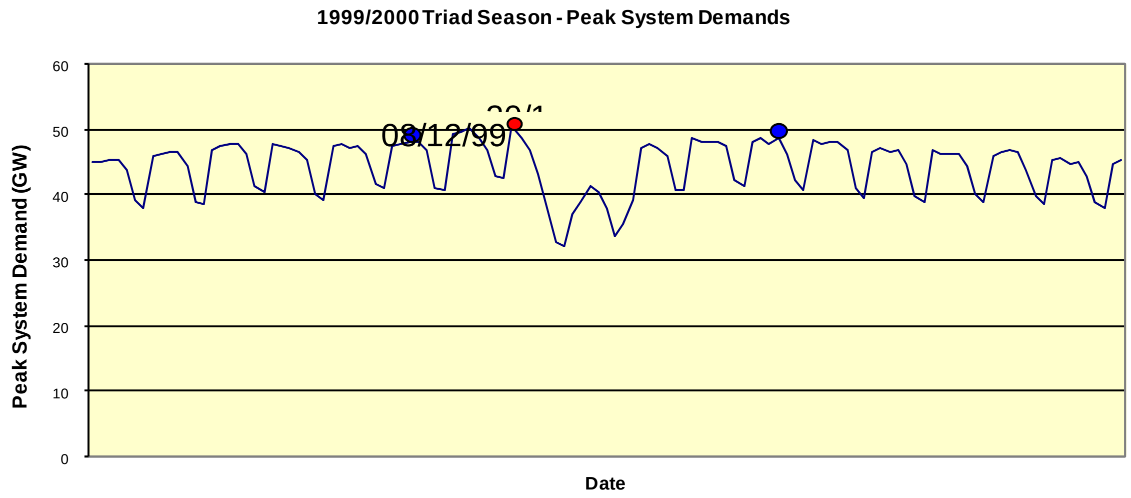
| | |
|---|---|
| **"Demand Forecast"** | a **User's** forecast of its **Demand**, either positive or negative submitted to **The Company** in accordance with paragraphs 3.10, 3.11 and 3.12. In the case of negative forecasts, this will take account of output from **Exemptible Generation** associated with **Supplier BM Units**, and **Exemptible Generation** and **Derogated Distribution Interconnectors** with a **Bilateral Embedded Generation Agreement**; |
| **"Derogated Distribution Interconnector"** | A **Distribution Interconnector** which has been granted a derogation by the BSC panel |
| **"HH Demand"** | **Half-hourly metered Demand** for which **HH Charges** are paid; |
| **"Intermittent Generation"** | as defined in the **Grid Code**; |
| **"NHH Demand"** | **Non-half-hourly metered Demand** for which **NHH Charges** are paid; |

# CUSC - Section 14

## Charging Methodologies

### The Triad

14.17.13 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak demand and the two half hour settlement periods of next highest demand, which are separated from the system peak demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak demand. An illustration is shown below.




## Half-hourly metered demand charges

14.17.14 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered volume over the Triad results in an import, the Chargeable Demand Capacity will be positive resulting in the BMU being charged. If the average half-hourly metered volume over the Triad results in an export, the Chargeable Demand Capacity will be negative resulting in the BMU being paid. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for a negative demand credit.

## ~~Netting off within a BM Unit~~

~~14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.~~

## Monthly Charges

14.17.1~~6~~5 Throughout the year Users' monthly demand charges will be based on their forecasts of:

- half-hourly metered demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing an import from the system) will be accepted.

14.17.13 14.17.1~~7~~6 Users shall~~ould~~ submit reasonable D~~d~~emand F~~f~~orecasts in accordance with sections 3.10-3.12. ~~in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.~~ These may be expressed as either a positive figure, resulting in an overall TNUoS charge to the User, or a negative figure, resulting in an overall payment to the User. For any of the information below, a User should submit a forecast of zero (0) where no applicable data exists.

Each Demand Forecast shall incorporate the following information;

- Gross import forecast for HH Demand
- Gross export forecast for HH Demand due to conventional generation
- Gross export forecast for HH Demand due to Intermittent Generation
- The sum of the kW capacities of the individual Generating Units which are Embedded within a Supplier BM Unit for export HH Demand due to conventional generation
- The sum of the kW capacities of the individual Generating Units which are Embedded within a Supplier BM Unit for export HH Demand due to Intermittent Generation
- Net forecast of NHH Demand

where export and import have the same definitions as defined in the BSC, and conventional generation is the sum of all generation other than Intermittent Generation within that Supplier BM Unit associated with Exemptible Generation or Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement.

14.17.17 ~~Users should submit reasonable demand forecasts in accordance with the CUSC.~~ The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with ~~the CUSC~~ section 3.12, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad demand for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) demand in the Financial Year to date is compared to the equivalent average demand for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH demand at Triad in the preceding Financial Year to derive a forecast of the User's HH demand at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

iii) National Grid will apply a load factor to the submitted capacity of export HH. Demand due to Intermittent Generation to derive maximum allowable figure for the forecast of export HH Demand due to Intermittent Generation. This load factor will be derived from an average load factor of on-shore transmission connected windfarms for the previous three Triad periods, and will be published in the Statement of Use of System Charges. Where the User has provided a forecast of export HH Demand due to Intermittent Generation above this level, further justification for this forecast will be required.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

~~ii~~iv) The User's average weekday settlement period 35 half-hourly metered (HH) demand over the last complete month for which The Company has settlement data is calculated. Total system average HH demand for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH demand at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH demand for weekday settlement period 35 over the last month to derive a forecast of the User's HH demand at Triad for this Financial Year.

~~iv~~v) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

~~iv~~vi) National Grid will apply a load factor to the submitted capacity of export HH Demand due to Intermittent Generation to derive maximum allowable figure for the forecast of export HH Demand due to Intermittent Generation. This load factor will be derived from an average load factor of on-shore transmission connected windfarms for the previous three Triad periods, and will be published in the Statement of Use of System Charges. Where the User has provided a forecast of export HH Demand due to Intermittent Generation above this level, further justification for this forecast will be required.

14.17.14 14.27 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

## 14.24 Reconciliation of Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

## Monthly Charges

Suppliers provide half-hourly (HH) and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW and 1.20p/kWh, is as follows:

| | Forecast HH Triad Demand $HHD_F$(kW) | HH Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | 15,000,000 | 15,000 | 25,000 |
| May | 12,000 | 10,000 | 15,000,000 | 15,000 | 25,000 |
| Jun | 12,000 | 10,000 | 15,000,000 | 15,000 | 25,000 |
| Jul | 12,000 | 10,000 | 18,000,000 | 19,000 | 29,000 |
| Aug | 12,000 | 10,000 | 18,000,000 | 19,000 | 29,000 |
| Sep | 12,000 | 10,000 | 18,000,000 | 19,000 | 29,000 |
| Oct | 12,000 | 10,000 | 18,000,000 | 19,000 | 29,000 |
| Nov | 12,000 | 10,000 | 18,000,000 | 19,000 | 29,000 |
| Dec | 12,000 | 10,000 | 18,000,000 | 19,000 | 29,000 |
| Jan | 7,200 | (6,000) | 18,000,000 | 19,000 | 13,000 |
| Feb | 7,200 | (6,000) | 18,000,000 | 19,000 | 13,000 |
| Mar | 7,200 | (6,000) | 18,000,000 | 19,000 | 13,000 |
| Total | | 72,000 | | 216,000 | 288,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad demand forecast, and hence paid HH monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

## Initial Reconciliation (Part 1)

The Supplier's outturn HH triad demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = $(HHD_A - HHD_F) \times$ £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

~~Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.~~

~~As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.~~

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge $= \dfrac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \dfrac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \dfrac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,000 (£18,000 - £12,000).

### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad demand and NHH energy consumption values were 9,500kW and 16,500,000kWh, respectively.

Final HH Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW

= £5,000

Final NHH Reconciliation Charge = $\dfrac{(16{,}700{,}000\text{kWh} - 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,400.

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

~~Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.~~

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Demand (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**£/kW Tariff** = The £/kW Demand Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.27 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1$^{st}$ April to 31$^{st}$ March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User - demand

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH demand at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH demand at Triad in the preceding Financial Year

D = User's average half hourly metered demand in settlement period 35 in the Financial Year to date

P = User's average half hourly metered demand in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH demand at Triad in the Financial Year minus two

D = User's average half hourly metered demand in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered demand in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

F = 10,000 * 13,200 / 12,000

F = 11,000 kWh

where:

T = 10,000 kWh (period November 2003 to February 2004)

D = 13,200 kWh (period 1st April 2004 to 15th February 2005#)

P = 12,000 kWh (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Half-Hourly (HH) Metered Demand Forecast – Existing User - embedded generation

F = CF + (ICC * ILF)

Where

ICC= Installed capacity for intermittent generation (current year)

ILF = Intermittent generation load factor (calculated as per 14.17.17)

CF= Conventional Forecast

Where

CF = T * (MMVC – MILFC * MICC) / (MMVP – MILFP * MICP)

Where

T = User's HH output at Triad in the preceding Financial Year

MMVC= Monthly metered output volume in the most recent month for which settlement data is available

MILFC= Intermittent load factor for the most recent month for which settlement data is available

MICC = Maximum potential output for intermittent generation in the most recent month for which settlement data is available

MMVP= Monthly metered output volume in the same month in the preceding financial year

MILFP= Intermittent load factor for in the same month in the preceding financial year

MICP = Maximum potential output for intermittent generation in the same month in the preceding financial year

**Example**

The Company calculates an HH demand with embedded generation forecast for an existing user, using the above methodology on 10th March for the period 1st April – 31st March in the following financial year. It is assumed that the last month for which metering data is available has 31 days, and thus 744 hours.

F = 846 + (100 * 15%)

F = 861 kW

Where

CF = 900 * (576,000 – 15% * 74,400) / (612,000 - 15% * 74,400)

CF= 900 * 0.940083882564410

CF= 846 kW

Where

T = 900 kW

MMVC = 576,000 kWh (equates to average monthly output of 800 kW)

MILFC = 15%

MICC = 74,400 kWh (100 kW installed capacity * 744 hours in month)

MMVP = 612,000 kWh (equates to an average monthly output of 850 kW)

MILFC = 15%

MICP = 74,400 kWh (100 kW installed capacity * 744 hours in month)

### iii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ June 2005 for the period 1$^{st}$ April 2005 to 31$^{st}$ March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1$^{st}$ April 2004 to 31$^{st}$ March 2005)

D = 4,400,000 kWh (period 1$^{st}$ April 2005 to 15$^{th}$ May 2005#)

P = 4,000,000 kWh (period 1$^{st}$ April 2004 to 15$^{th}$ May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### ~~ii~~iv) Half-Hourly (HH) Metered Demand Forecast – New User - demand

F = M * T/W

where:

F = Forecast of User's HH metered demand at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH demand at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2004 to 31$^{st}$ March 2006.

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kWh

where:

M = 1,000 kWh (period 1$^{st}$ July 2005 to 31$^{st}$ July 2005)

T = 17,000,000 kWh (period November 2004 to February 2005)

W = 18,888,888 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ July 2004)

**~~i~~v) Half-Hourly (HH) Metered Demand Forecast – New User - embedded generation**

F = CF + (ICC * ILF)

Where

ICC= Installed capacity for intermittent generation (current year)

ILF = Intermittent generation load factor (calculated as per 14.17.17)

CF= Conventional Forecast

Where

CF = XST * (MMVC – MILFC * MICC) / (XMMVP – MILFP * TICP)

Where

XST = HH output at Triad in the preceding Financial Year for all HH negative demand

MMVC= Monthly metered output volume in the most recent month for which settlement data is available

MILFC= Intermittent load factor for the most recent month for which settlement data is available

MICC = Maximum potential output for intermittent generation in the most recent month for which settlement data is available

XMMVP= Monthly metered output volume in the same month in the preceding financial year for all HH negative demand

MILFP= Intermittent load factor for in the same month in the preceding financial year

TICP = Maximum potential output for intermittent generation in the previous financial year for all HH negative demand

**Example**

The Company calculates a HH demand with embedded generation forecast for a new user, using the above methodology on 10th March for the period 1st April – 31st March in the following financial year. It is assumed that the last month for which metering data is available has 31 days, and thus 744 hours.

F = 770 + (100 * 15%)

F = 785 kW

Where

ICC= 100 kW

CF = 19,000,000 * (372,000 – 15% * 74,400) / (8,928,000,000 – 15% * 148,800,000)

CF 19,000,000 * 0.000040517961571

CF = 770

Where

XST = 19,000,000 kW

MMVC = 372,000 kWh

MILFC = 15%

MICC = 74,400 kWh (100kW installed capacity * 744 hours in month)

XMMVP = 8,928,000,000 kWh (equates to an average monthly output of 12,000,000 Kw)

MILFP = 15%

TICP = 1,468,800,000 kWh (200,000kW installed capacity * 744 hours in month)

### ~~iv~~vi) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

## Annex 10 – Legal Text for Workgroup Alternative CUSC Modification

# CUSC – Section 3

3.22.7 Revision of **Deemed HH Forecasting Performance**

If the **User** has experienced a significant increase in the amount of **Demand** taken by its **Customers** during the last five months of the previous **Financial Year** and believes that this has had a significant effect on their **Deemed HH Forecasting Performance**, then no later than one month from the date of the notification given to the **User** under paragraph 3.22.5, the **User** may request that **The Company** revises the **Deemed HH Forecasting Performance**. Upon raising such a request, the **User** must provide information to **The Company** relating to the size of the reported **Demand** increase and the **Reported Period(s) of Increase**. Where for any **Reported Period of Increase** the resulting increase in **Demand** equates to a level that is in excess of one percent of the **Actual Amount** of **HH Charges** in respect of the previous **Financial Year**, **The Company** shall, within one month of receiving such a request, recalculate the **Deemed HH Forecasting Performance** on the basis set out in Appendix 2 Paragraph ~~4~~6. A **User** shall not be entitled to raise more than one request by reference to any period or part period covered in another **Reported Period of Increase** in respect of which a request has been raised under this Paragraph.

3.22.8 Revision of **Deemed NHH Forecasting Performance**

If the **User** has experienced a significant increase in the amount of **Demand** taken by its **Customers** during the last five months of the previous **Financial Year** and believes that this has had a significant effect on their **Deemed NHH Forecasting Performance**, then no later than one month from the date of the notification given to the **User** under paragraph 3.22.6, the **User** may request that **The Company** revises the **Deemed NHH Forecasting Performance**. Upon raising such a request, the **User** must provide information to **The Company** relating to the size of the reported **Demand** increase and the **Reported Period(s) of Increase**. Where for any **Reported Period of Increase** the resulting increase in **Demand** equates to a level that is in excess of one percent of the **Actual Amount** of **NHH Charges** in respect of the previous **Financial Year**, **The Company** shall within one month of receiving such a request, recalculate the **Deemed NHH Forecasting Performance** on the basis set out in Appendix 2 Paragraph ~~7~~9. A **User** shall not be entitled to raise more than one request by reference to any period or part period covered in another **Reported Period of Increase** in respect of which a request has been raised under this Paragraph.

**APPENDIX 2**

Base Value At Risk

1. For each **Security Period** within a **Financial Year**, where a **User's Demand Forecast** results in an overall positive **Transmission Network Use of System Demand Charge** in respect of that **Financial Year**, the **HH Base Percentage** used in determining the **User's HH Base Value at Risk** shall be determined by reference to the following table:

Table 1:

| (ii) **Security Period Start Date (inclusive)** | **Security Period End Date (inclusive)** | **HH Base Percentage** |
|---|---|---|
| 1st April | 30th June | -8.4% |
| 1st July | 30th September | -33.4% |
| 1st October | 31st December | -49.1% |
| 1st January | 31st March | 7.0% |

2. For each **Security Period** within a **Financial Year**, where a **User's Demand Forecast** results in an overall negative **Transmission Network Use of System Demand Charge** in respect of that **Financial Year**, the **HH Base Percentage** used in determining the **User's HH Base Value at Risk** shall be determined by reference to the following table:

Table 2:

| **Security Period Start Date (inclusive)** | **Security Period End Date (inclusive)** | **HH Base Percentage** |
|---|---|---|
| 1st April | 30th June | -12.82% |
| 1st July | 30th September | -37.77% |
| 1st October | 31st December | -58.61% |
| 1st January | 31st March | -9.16% |

3. For each **Security Period** within a **Financial Year**, where a **User's Demand Forecast** results in an overall positive **Transmission Network Use of System Demand Charge** in respect of that **Financial Year**, the **NHH Base Percentage** used in determining the **User's NHH Base Value at Risk** shall be determined by reference to the following table:

Table 3:

| **Security Period Start Date (inclusive)** | **Security Period End Date (inclusive)** | **NHH Base Percentage** |
|---|---|---|
| 1st April | 30th June | 4.3% |
| 1st July | 30th September | -1.5% |

| | | |
|---|---|---|
| 1st October | 31st December | -2.8% |
| 1st January | 31st March | 3.7% |

4. For each **Security Period** within a **Financial Year**, where a **User's Demand Forecast** results in an overall negative **Transmission Network Use of System Demand Charge** in respect of that **Financial Year**, the **NHH Base Percentage** used in determining the **User's NHH Base Value at Risk** shall be determined by reference to the following table:

Table 4:

| **Security Period Start Date (inclusive)** | **Security Period End Date (inclusive)** | **NHH Base Percentage** |
|---|---|---|
| 1st April | 30th June | -2.30% |
| 1st July | 30th September | -7.81% |
| 1st October | 31st December | -10.12% |
| 1st January | 31st March | -4.51% |

5. The following table demonstrates how the **Base Value at Risk** will be calculated for varying types of **User Demand Forecasts**:

| | **HH import**<br>**NHH import** | **HH export**<br>**NHH import** |
|---|---|---|
| **Demand Forecast** resulting in overall positive **Transmission Network Demand Charge** (payment to **The Company**) | **HH Base Value At Risk** calculated using table 1<br>**+**<br>**NHH Base Value At Risk** calculated using table 3 | **HH Base Value At Risk** calculated using table 1<br>**+**<br>**NHH Base Value At Risk** calculated using table 3 |
| **Forecast** resulting in overall negative **Transmission Network Demand Charge** (payment to the **User**) | N/A | **HH Base Value At Risk** calculated using table 2<br>**+**<br>**NHH Base Value At Risk** calculated using table 4 |

~~3~~6. **Deemed HH Forecasting Performance**, $FPP_{HH}$, shall be calculated as set out in the following formulae:

(a) Where the **Actual Amount** of **User's HH Charges** for the previous **Financial Year** is positive:

$$FPP_{HH} = \max\left(0, \frac{5}{1333}\sum_{m=8}^{12}\left(\frac{AA_{HH} - IA_{HH,m}}{AA_{HH}} * W_{HH,m}\right) - CA_{HH}\right)$$

or

(b) Where the **Actual Amount** of **User's HH Charges** for the previous **Financial Year** is negative:

$$FPP_{HH} = \max\left(0, \frac{5}{1333}\sum_{m=8}^{12}\left(\frac{IA_{HH} - AA_{HH,m}}{AA_{HH}} * W_{HH,m}\right) - CA_{HH}\right)$$

Where:

$AA_{HH}$ is the **Actual Amount** of **User's HH Charges** for the previous **Financial Year**

$IA_{HH,m}$ is the **Indicative Annual HH TNUoS charge** calculated using the **Demand Forecast** used to determine **Transmission Network Use of System Demand Charges** made during month *m* of the previous **Financial Year**.

$W_{HH,m}$, The forecast weighting to be applied for each month, *m* by reference to the following:

| ***m*** | **Invoice Month** | **Forecast weighting, $W_{HH,m}$** |
|---|---|---|
| 8 | November | 33.3 |
| 9 | December | 33.3 |
| 10 | January | 33.3 |
| 11 | February | 66.7 |
| 12 | March | 100 |

$CA_{HH}$, is an allowance for extreme conditions equal to 0.06.

47. The revised Deemed HH Forecasting Performance, shall be calculated on the basis of Paragraph 3 above, substituting the Indicative Annual HH TNUoS Charge for each month, *m* prior to the end of the Reported Period of Increase with the Revised Indicative Annual HH TNUoS charge, $RIA_{HH,m}$

~~5~~8. The **Revised Indicative Annual HH TNUoS charge,** $RIA_{HH,m}$ shall be derived as follows:

$$RIA_{HH,m} = \min\left(\max\left(\frac{DUA_{HH,p}}{DUB_{HH,p}} - \frac{DSA_{HH,p}}{DSB_{HH,p}}, 0\right) * RD_{HH,p} + IA_{HH,m}, IA_{HH,p}\right)$$

Where:

$DUA_{HH,p}$ is the average half-hourly metered demand taken by the **User's Customers** during the period 17:00 to 17:30 on the twenty **Business Days** prior to the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22nd December.

$DUB_{HH,p}$ is the average half-hourly metered demand taken by the **User's Customers** during the period 17:00 to 17:30 on the twenty **Business Days** following the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22nd December.

$DSA_{HH,p}$ is the average demand taken by **Total System Chargeable HH Demand** during the period 17:00 to 17:30 on the twenty **Business Days** prior to the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22nd December.

$DSB_{HH,p}$ is the average demand taken by **Total System Chargeable HH Demand** during the period 17:00 to 17:30 on the twenty **Business Days** following the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22nd December.

$RD_{HH,p}$ is the forecast proportion of **HH Charges** remaining for the previous **Financial Year** from the first day of the month in which the **Reported Period of Increase**, *p* commences by reference to the following:

| Month in which **Reported Period of Increase commences** | Remaining proportion of **HH Charges** |
|---|---|
| October | 100% |
| November | 100% |
| December | 100% |
| January | 66.7% |
| February | 33.3% |

$IA_{HH,m}$ is the **Indicative Annual HH TNUoS charge** calculated using the **Demand Forecast** used to determine **Transmission Network Use of System Demand Charges** made during month *m* of the previous **Financial Year**.

$IA_{HH,p}$ in the case that the the **Reported Period of Increase**, *p* ends prior to the 10th February of the previous **Financial Year**, is set equal to the **Indicative Annual HH TNUoS charge** calculated using the **Demand Forecast** used to determine **Transmission Network Use of System Demand Charges** made during the month immediately following **Reported Period of Increase** of the previous **Financial Year,** otherwise is set to infinity.

Deemed NHH Forecasting Performance and Revision

~~6~~9. **Deemed NHH Forecasting Performance**, $FPP_{NHH}$, shall be calculated as set out in the following formula:

$$FPP_{NHH} = \max\left(0, \frac{1}{300}\sum_{m=8}^{12}\left(\frac{AA_{NHH} - IA_{NHH,m}}{AA_{NHH}} * W_{NHH,m}\right) - CA_{NHH}\right)$$

Where:

$AA_{NHH}$ is the **Actual Amount** of **User's NHH Charges** for the previous **Financial Year**.

$IA_{NHH,m}$ is the **Indicative Annual NHH TNUoS charge** calculated using the **Demand Forecast** used to determine **Transmission Network Use of System Demand Charges** made during month *m* of the previous **Financial Year**.

$W_{NHH,m,}$ The forecast weighting to be applied for each month, *m* by reference to the following:

| *m* | Invoice Month | Forecast weighting, $W_{NHH,m}$ |
|---|---|---|
| 8 | November | 41 |
| 9 | December | 49 |
| 10 | January | 59 |
| 11 | February | 70 |
| 12 | March | 81 |

$CA_{NHH,}$ is an allowance for extreme conditions equal to 0.03.

~~7~~10. The revised Deemed NHH Forecasting Performance shall be calculated on the basis of Paragraph 6 above, substituting the Indicative Annual NHH TNUoS Charge for each month, *m* prior to the end of the Reported Period of Increase with the Revised Indicative Annual NHH TNUoS charge, $RIA_{NHH,m}$.

~~8~~11. The **Revised Indicative Annual NHH TNUoS charge,** $RIA_{NHH,m}$ shall be derived as follows:

$$RIA_{NHH,m} = \min\left(\max\left(\frac{DUA_{NHH,p}}{DUB_{NHH,p}} - \frac{DSA_{NHH,p}}{DSB_{NHH,p}}, 0\right) * RD_{NHH,p} + IA_{NHH,m}, IA_{NHH,p}\right)$$

Where:

$DUA_{NHH,p}$ is the average non-half-hourly metered demand taken by the **User's Customers** during the period 16:00 to 19:00 on the twenty **Business Days** prior to the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22$^{nd}$ December.

$DUB_{NHH,p}$ is the average non-half-hourly metered demand taken by the **User's Customers** during the period 16:00 to 19:00 on the twenty **Business Days** following the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22$^{nd}$ December.

$DSA_{NHH,p}$ is the average demand taken by **Total System Chargeable NHH Demand** during the period 16:00 to 19:00 on the twenty **Business Days** prior to the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22nd December.

$DSB_{NHH,p}$ is the average demand taken by **Total System Chargeable NHH Demand** during the period 16:00 to 19:00 on the twenty **Business Days** following the **Reported Period of Increase,** *p*, that do not fall between the two week period commencing 22nd December.

$RD_{NHH,p}$ is the forecast proportion of **NHH Charges** remaining for the previous **Financial Year** from the first day of the month in which the **Reported Period of Increase**, *p* commences by reference to the following:

| Month in which **Reported Period of Increase commences** | Remaining proportion of **NHH Charges** |
|---|---|
| October | 59% |
| November | 51% |
| December | 41% |
| January | 30% |
| February | 19% |

$IA_{NHH,m}$ is the **Indicative Annual NHH TNUoS charge** calculated using the **Demand Forecast** used to determine **Transmission Network Use of System Demand Charges** made during month *m* of the previous **Financial Year**.

$IA_{NHH,p}$ in the case that the the **Reported Period of Increase**, *p* ends prior to the 10th February of the previous **Financial Year**, is set equal to the **Indicative Annual NHH TNUoS charge** calculated using the **Demand Forecast** used to determine **Transmission Network Use of System Demand Charges** made during the month immediately following **Reported Period of Increase** of the previous **Financial Year,** otherwise is set to infinity.

**END OF SECTION 3**

# CUSC - SECTION 11

# INTERPRETATION AND DEFINITIONS

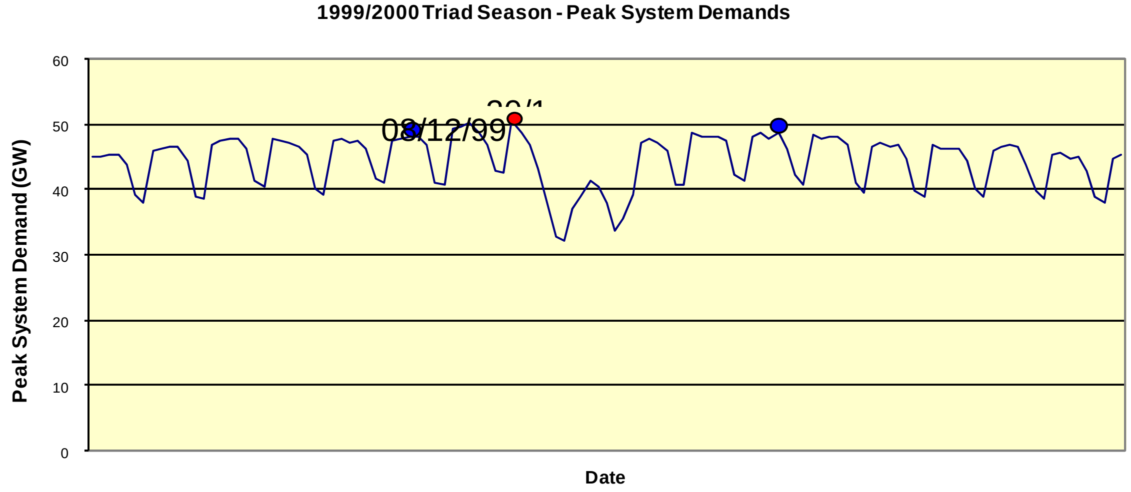
| | |
|---|---|
| **"Demand Forecast"** | a **User's** forecast of its **Demand**, either positive or negative submitted to **The Company** in accordance with paragraphs 3.10, 3.11 and 3.12. In the case of negative forecasts, this will take account of output from **Exemptible Generation** associated with **Supplier BM Units**, and **Exemptible Generation** and **Derogated Distribution Interconnectors** with a **Bilateral Embedded Generation Agreement**; |
| **"Derogated Distribution Interconnector"** | A **Distribution Interconnector** which has been granted a derogation by the **BSC panel**; |

# CUSC - Section 14

## Charging Methodologies

### The Triad

14.17.16 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak demand and the two half hour settlement periods of next highest demand, which are separated from the system peak demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak demand. An illustration is shown below.




### Half-hourly metered demand charges

14.17.17 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered volume over the Triad results in an import, the Chargeable Demand Capacity will be positive resulting in the BMU being charged. If the average half-hourly metered volume over the Triad results in an export, the Chargeable Demand Capacity will be negative resulting in the BMU being paid. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for a negative demand credit.

### Netting off within a BM Unit

14.17.18 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.

### Monthly Charges

14.17.19 Throughout the year Users' monthly demand charges will be based on their forecasts of:

- half-hourly metered demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. ~~For the avoidance of doubt, only positive demand forecasts (i.e. representing an import from the system) will be accepted.~~

14.17.20 Users should submit reasonable demand forecasts in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad demand for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) demand in the Financial Year to date is compared to the equivalent average demand for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH demand at Triad in the preceding Financial Year to derive a forecast of the User's HH demand at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iv) The User's average weekday settlement period 35 half-hourly metered (HH) demand over the last complete month for which The Company has settlement data is calculated. Total system average HH demand for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH demand at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH demand for weekday settlement period 35 over the last month to derive a forecast of the User's HH demand at Triad for this Financial Year.

v) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.21 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.