Meeting name	BSC Panel
Date of meeting	10 February 2011
Paper title	Standing Issue 39 Report
Purpose of paper	For Information
Synopsis	Standing Issue 39 considered different options for improving how unrecorded units are entered into Settlement under the BSC. The Issue 39 Group developed three solution options and obtained impact assessments to inform a future proposal. The majority of the Group favours a Settlement Cost Smearing scheme (though Ofgem has some concerns around this approach) but note that it is important that any BSC change aligns with the relevant DCUSA arrangements.

1 Introduction

1.1 E.ON UK raised Standing Issue 39 to investigate how unrecorded units identified by a Revenue Protection Service (RPS) should be submitted into Settlement. A Change Proposal under the Distribution Connection and Use of System Agreement (DCUSA), DCP 054, is considering Revenue Protection and settling unrecorded units. The DCP 054 Working Group recognised that while the DCUSA may cover obligations around estimating and agreeing unrecorded units, requirements for processing such unrecorded units in Settlement fall under the BSC.

1.2 DCP 054 and Technical Assurance (TA) Checks conducted by ELEXON identified issues with the current processes for entering unrecorded units into Settlement. These issues are outlined in Standing Issue 39. The DCP 054 Working Group believed there was no single, clear solution for processing unrecorded units in Settlement. Therefore E.ON UK raised Standing Issue 39 on behalf of the DCP 054 Working Group to explore different options to resolve the existing issues and optimise the processes with respect to the outcome of DCP 054.

1.3 The Standing Issue 39 Group developed, impact assessed and considered three options for improving the processes for entering unrecorded units into Settlement. It is intended that the results of Issue 39, as set out in this paper and its attachments, will inform the proposal of any subsequent change in this area. Such a change may be either a Modification or a Change Proposal, depending on the solution.

1.4 We will feed the results of Standing Issue 39 into Ofgem's ongoing work on unrecorded units and energy theft.

2 Solution Options

2.1 Issue 39 suggested that processing unrecorded units in Settlement could be improved by:

- Tracking unrecorded units from the Data Collector to the Supplier Volume Allocation Agent (SVAA), such that they can be reported on the D0030 NHH DUoS Report; or
- Using a 'Settlement Cost Smearing Scheme' whereby unrecorded units to account for units outside the standard Settlement processes for the purposes of Distribution Price Control.

2.2 The Issue 39 Group ('the Group') developed the following three potential solutions:

- Option 1 – address the TA Check findings by enhancing the current process;
- Option 2 – end-to-end tracking of Revenue Protection adjustments; and
- Option 3 – Settlement Cost Smearing.

2.3 These options are detailed in the Issue 39 Draft Solution document (Attachment B). The Draft Solution document also details the current process, the areas of impact and issues associated with each solution. The Group did not make any changes to the solution options following the impact assessment. However, the Group did consider and note areas for further assessment which any Party raising a change based on Issue 39 should take into account.

3 Impact Assessment

3.1 The results of the impact assessment of Issue 39 by industry participants, ELEXON and the BSC Agent Service Providers are summarised in the table below. Option 2 has the highest impact on industry participants and centrally. Option 3 has the least impact on industry participants and option 1 has the lowest central impact.

3.2 The results of the impact assessments are discussed in detail in the full Issue 39 Report (Attachment A), and the collated industry responses are provided in Attachment C. A new and separate impact assessment of any subsequent change would be required.

Option	Industry impact	Indicative ELEXON impact	Indicative BSC Agent impact
1.	Impacts range from minimal to significant system impacts Impact on materially affected Parties ranges from **6-12 months/£25,000-£250,000** Some identified costs of £20,000 per annum	Approximately **30 Man Days** (around **£7,000**) No ongoing operational effort	**No impact**
2.	Impacts range from minimal to significant system impacts Impact on materially affected Parties ranges from **6-12 months/£30,000-£250,000** Some identified costs of £20,000 per annum	Approximately **180 Man Days** (around **£43,000**) No ongoing operational effort Implementation as option 1, plus management of significant software change	**10 months[1]/£281,000** Significant software change; Impacts on NHHDA, SVAA, MDD Significant testing requirements identified
3.	Some Parties not impacted Impact on materially affected Parties ranges from **6-12 months/up to £100,000** Impacts dependent on detail of solution, but less than those	Approximately **75 Man Days** (around **£18,000**) if ELEXON is central administrator (if not, **30 Man Days/£7,000**) Ongoing effort: risk audit (if ELEXON is administrator)	**No impact** (unless BSCCo fulfils the administrative role) Service Providers need to reassess if ELEXON as central administrator is progressed One Service Provider gave

[1] This is an aggregate of the two Service Providers' assessments, so the actual lead time to implement is likely to be less than this as they can work in parallel.

Option	Industry impact	Indicative ELEXON impact	Indicative BSC Agent impact
	under options 1 or 2.	Implementation as option 1, with additional management if BSCCo acts is administrator	indicative assessment, based on a similar change, of **10 weeks/£39,000** (if ELEXON acts as administrator)

4 Conclusions

4.1 The full discussions of the Issue 39 Group are detailed in Attachment A.

4.2 The majority of the Group support option 3 because it would cover more types of unrecorded units than option 1 or 2, such as theft in conveyance[2], and would reduce a disincentive on Suppliers to actively detect theft. Impact assessment respondents also supported option 3.

4.3 However, there are concerns about the compatibility of option 3 with the Distribution Price Control Review 5 (DPCR5) methodology, and Ofgem has made it clear that satisfactory reporting and governance arrangements would be required for option 3 to be potentially viable. These concerns should be taken into consideration both before and during any BSC change to introduce a cost smearing scheme as set out under option 3. If option 3 is removed from the potential choices option 1 becomes the Group's majority preference.

4.4 Industry impacts varied substantially among respondents, but the costs, impacts and timescales associated with options 1 and 2 appear to be similar, with those for option 2 slightly higher. The impact of option 3 on industry participants is less than that of the other options.

4.5 The central impact of option 1 is low, consisting of minimal ELEXON implementation activities only, with no central system impacts. Option 2 has a substantial impact, due to its impact on NHHDA, SVAA and MDD. Option 3 has a greater impact than option 1, but much less than option 2, though this mainly relates to changes to Central Services operation if ELEXON performs a central administrative function. If ELEXON does not perform this role the costs of option 3 would be comparable with those of option 1 (though if a central administrator is still required, the relevant organisation would be impacted instead).

4.6 Though the Group favoured option 3 (both in principle and considering its indicative associated impacts), they agreed that it was important that any BSC change in this area is consistent with the related DCUSA arrangements, i.e. those resulting from DCP 054. The Group also identified other areas it believed should be considered as part of any subsequent change (depending on what solution is progressed), as follows:

- The outcome and ramifications of DCUSA Change Proposal 054;
- Any relevant information resulting from Ofgem's questionnaire on theft of electricity or other source;
- Where data interfaces are required between participants, the volumes of data concerned and the impacts and benefits of using the DTN;
- The appropriate oversight, governance and validation of the process and/or data; and
- Any relevant views expressed by Ofgem.

[2] The definition of 'theft in conveyance' is currently in question and is being discussed as part of DCP 054.

5 Recommendations

5.1 The Panel is invited to:

a) **NOTE** the discussions and conclusions of the Issue 39 Group;

b) **NOTE** that a BSC change (Modification or Change Proposal as applicable) raised to amend the process of entering unrecorded units into Settlement should be coordinated with DCUSA CP 054; and

c) **NOTE** that the Issue 39 Group developed and impact assessed three potential options for such a change, and its majority preference is option 3, 'Settlement Cost Smearing', though Ofgem have concerns about such an approach at present.

Dean Riddell

Change Analyst

Attachments:
Attachment A: Report on Standing Issue 39
Attachment B: Draft Solution to Identify Impacts
Attachment C: Collated Industry Impact Assessment Responses

Report on Standing Issue 39 'Processing Unrecorded Units identified by Revenue Protection Services'

1 Summary

Standing Issue 39 considered different options for improving how unrecorded units are entered into Settlement under the BSC. The Issue 39 Group developed three solution options and obtained impact assessments to inform a future proposal. The majority of the Group favours a Settlement Cost Smearing scheme (option 3) though there are some concerns around this approach, but it is important that any BSC change aligns with the relevant DCUSA arrangements.

2 Background

E.ON UK raised Standing Issue 39 to investigate how unrecorded units identified by a Revenue Protection Service (RPS) should be submitted into Settlement. A Change Proposal under the Distribution Connection and Use of System Agreement (DCUSA), DCP 054, is considering Revenue Protection and settling unrecorded units. The DCP 054 Working Group recognised that while the DCUSA may cover obligations around estimating and agreeing unrecorded units, requirements for processing such unrecorded units in Settlement fall under the BSC.

DCP 054 and Technical Assurance (TA) Checks conducted by ELEXON identified issues with the current processes for entering unrecorded units into Settlement. These issues are outlined in Standing Issue 39. The DCP 054 Working Group believed there was no single, clear solution for processing unrecorded units in Settlement. Therefore E.ON UK raised Standing Issue 39 on behalf of the DCP 054 Working Group to explore different options to resolve the existing issues and optimise the processes with respect to the outcome of DCP 054.

The Standing Issue 39 Group developed, impact assessed and considered three options for improving the processes for entering unrecorded units into Settlement. It is intended that the results of Issue 39, as set out in this paper and its attachments, will inform the proposal of any subsequent change in this area. Such a change may be either a Modification or a Change Proposal, depending on the solution.

We will feed the results of Standing Issue 39 into Ofgem's ongoing work on unrecorded units and energy theft.

3 Solution Options

Issue 39 suggested that processing unrecorded units in Settlement could be improved by:

- Tracking unrecorded units from the Data Collector to the Supplier Volume Allocation Agent (SVAA), such that they can be reported on the D0030 NHH DUoS Report; or
- Using a 'Settlement Cost Smearing Scheme' whereby unrecorded units to account for units outside the standard Settlement processes for the purposes of Distribution Price Control.

The Issue 39 Group ('the Group') developed the following three solution options:

- Option 1 – address the TA Check findings by enhancing the current process;
- Option 2 – end-to-end tracking of Revenue Protection adjustments; and
- Option 3 – Settlement Cost Smearing.

These options are detailed in the Issue 39 Draft Solution document (Attachment B). The Draft Solution document also details the current process, the areas of impact and issues associated with each solution. The Group did not make any changes to the solution options following the impact assessment. However, the Group did consider and note areas for further assessment which any Party raising a change based on Issue 39 should take into account.

4 Impact Assessment

Summary

The results of the impact assessment of Issue 39 by industry participants, ELEXON and the BSC Agent Service Providers are summarised in the table below. Option 2 has the highest impact on industry participants and centrally. Option 3 has the least impact on industry participants and option 1 has the lowest central impact. Much or the information obtained is high-level and indicative as impact assessment was constrained by the level of detail available at this stage.

The collated responses to the industry impact assessment can be found in Attachment C. A new and separate impact assessment of any subsequent change would be required.

Option	Industry impact	Indicative ELEXON impact	Indicative BSC Agent impact
1.	Impacts range from minimal to significant system impacts Impact on materially affected Parties ranges from **6-12 months/£25,000-£250,000** Some identified cost of £20,000 per annum	Approximately **30 Man Days** (around **£7,000**) No ongoing operational effort	**No impact**
2.	Impacts range from minimal to significant system impacts Impact on materially affected Parties ranges from **6-12 months/£30,000-£250,000** Some identified cost of £20,000 per annum	Approximately **180 Man Days** (around **£43,000**) No ongoing operational effort Implementation as option 1, plus management of significant software change	**10 months[1]/£281,000** Significant software change; Impacts on Non Half Hourly Data Aggregation software (NHHDA), Supplier Volume Allocation Agent (SVAA), Market Domain Data (MDD) Significant testing requirements identified

[1] This is an aggregate of the two Service Providers' assessments, so the actual lead time to implement is likely to be less than this as they can work in parallel.

Option	Industry impact	Indicative ELEXON impact	Indicative BSC Agent impact
3.	Some Parties not impacted Impact on materially affected Parties ranges from **6-12 months/up to £100,000** Impacts dependent on detail of solution, but less than those under options 1 or 2.	Approximately **75 Man Days** (around **£18,000**) if ELEXON is central administrator (if not, **30 Man Days/£7,000**) Ongoing effort: risk audit (if ELEXON is administrator) Implementation as option 1, with additional management if BSCCo acts is administrator	**No impact** (unless BSCCo fulfils the administrative role) Service Providers need to reassess if ELEXON as central administrator is progressed One Service Provider gave indicative assessment, based on a similar change, of **10 weeks/£39,000** (if ELEXON acts as administrator)

Industry Impact Assessment

Issue 39 was issued for impact assessment by industry participants. As well as details of the impacts of the different solution options, the impact assessment sought information to assist the Group, such as the proportion of unrecorded units that fall outside the 14 month Settlement window. A new and separate impact assessment of any subsequent change would be conducted by industry participants, ELEXON and the BSC Service Providers.

12 responses were received; all respondents were Distributors, Suppliers or Party Agents (e.g. Non Half Hourly Data Collector (NHHDC), Non Half Hourly Data Aggregator (NHHDA)), or operate in more than one of these roles.

11 respondents confirmed option 1 would impact their organisation; one respondent identified no significant impact. Identified impacts range from minimal (new reports, testing; low associated costs and timescales) to significant system impacts with associated costs of up to £250,000 and 12 months required for implementation (based on a high level assessment). Most participants identified probable implementation lead times of 6 - 9 months.

Some respondents identified an additional operational cost of the magnitude of around £20,000 per annum for new processes and/or to handle increased volumes of adjustments, with additional staff possibly being required. This applied to both option 1 and option 2.

All 12 respondents confirmed option 2 would impact them. Cost and impacts were comparable with those for option 1, or slightly increased. Two respondents suggested using some kind of hybrid of options 1 and 2 (to achieve visibility of both input and output data) but such a solution would have a higher cost/impact than either option 1 or 2, likely to be approximately the sum of the costs and impacts of both.

Nine respondents confirmed option 2 would impact them, two stated it would not, and one identified a possible impact on billing systems, depending on how agreed adjustments are provided to LDSOs. Impacts and costs identified for option 3 were generally less than those for options 1 or 2.

ELEXON and BSC Agent Service Provider Impact Assessments

The results of the ELEXON and BSC Agent Service Provider impact assessments are summarised in the table below. The Service Providers' ability to deliver impact assessments was constrained by the level of detail available at this stage, and their assessments are therefore indicative, to a varying degree. ELEXON's impact assessment of the solution options was constrained by the unavailability of definitive Service Provider assessments, and is therefore also indicative.

Option	Indicative ELEXON impact	Indicative BPO Service Provider impact	Indicative AMD Service Provider impact
1.	Approximately **30 Man Days** (around **£7,000**) No ongoing operational effort Implementation: Manage BSC Release (no software change), documentation changes, audit requirements, update qualification documents, support participants	**No impact** No changes required to operation of BSC Central Services; Revenue Protection adjustments would continue to be indistinguishable from normal consumption in data received by the SVAA (i.e. from BPO perspective)	**No impact**
2.	Approximately **180 Man Days** (around **£43,000**) No ongoing operational effort Implementation: as option 1, plus management of significant software change	**10 weeks/£46,000** Significant change required to SVAA software, including: Format of D0041 files from participants to SVAA SVAA flat file database and SVAA output reports Testing requirements identified	**8 months/£235,000** Impacts on NHHDA, SVAA, MDD Significant testing requirements identified
3.	Approximately **75 Man Days** (around **£18,000**), ***if ELEXON acts as central administrator*** (otherwise circa **30 Man Days/£7,000**) Ongoing operational effort: Minimal risk audit (only if ELEXON is administrator) Implementation: as option 1, with additional management if BSCCo acts is administrator	**10 weeks/£39,000** (if ELEXON is administrator) May involve changes to BSC Central Services operation if ELEXON performs Central Administrator role ***Indicative assessment based on similar change introducing new PARMS Serials (CP1334)***	**No impact** (unless BSCCo fulfils the administrative role) If ELEXON is the central administrator a new application would be required for reporting RP adjustments – more detailed specification of requirements needed for a useful impact assessment

5 Discussions of the Issue 39 Group

5.1 Initial Discussions

The Group discussed how unrecorded unit data would enter Settlement. Under all of the options under consideration, data would come from a Revenue Protection Service (RPS). The RPS and relevant Supplier would assess and agree the unrecorded units under DCUSA governance before it reaches any BSC process.

The Group considered the different sources of unrecorded units, and what should be included in the scope of an Issue 39 solution. The Group considered that as well as theft, discrepancies in recorded units arise due to errors in data processing. For example, errors in the energy associated with Unmetered Supplies due to incorrect inventory information or discrepancies arising from energisation status errors. However, processes exist to address such data errors - corrections can be made to inventories and energisation status (up to RF). Ultimately a dispute can be raised to resolve errors, if necessary.

The Group agreed that where processes exist to address errors they should be used. It may be possible to improve these processes, but this is outside the scope of Issue 39. The Group identified the following causes of unrecorded units resulting from theft, which it believed should be taken into account when considering Issue 39 solutions:

- Theft by meter bypass;
- Theft in conveyance; and
- Unrecorded units without associated Supplier.

The Group believed that of these three, theft in conveyance is the cause of a large proportion of unrecorded units, and noted that only option 3 would address theft in conveyance.

Option 1

The Group noted that the current process in BSCP504 'Non Half Hourly Data Collection for SVA Metering Systems Registered in SMRS' refers to adjusting the meter advance. However, an alternative approach is to adjust the meter reading. TA Checks found that in practice this alternative approach is usually employed. Where unrecorded units are identified the meter is often (but not always) replaced at the same time the meter reading is adjusted. The Group noted that meters are not always replaced in cases of theft, and that considerations under DCP 054 had led to the conclusion that meter changes could not be mandated.

If the meter is not exchanged then the adjustment can be lost the next time a meter reading is taken. The Group agreed that the process going forward should be to adjust the meter reading if a meter exchange also takes place and to adjust the meter reading and use a 'dummy meter exchange' if no actual exchange occurs. Under a dummy meter exchange the Meter is not replaced, but the NHHDC creates Final and Initial Readings to simulate a Meter replacement within BSC Systems. This allows a meter reading to be adjusted to account for unrecorded units without impacting subsequent consumption for the Metering System.

The Group considered whether Smart metering would impact this approach, and believed that the agreed process would work despite the differences between conventional and Smart meters.

The Group agreed that to facilitate using adjusted readings a change should be raised to the Data Transfer Catalogue (DTC) to add a new value for Revenue Protection Adjustments to the valid set for Reading Type.

The Group considered how the adjustment should be applied to meter advance periods across the period of units being unrecorded (i.e. usually due to theft), i.e. whether the adjustment should be:

- Made to the reading taken on meter replacement (or dummy exchange); or
- Spread over all advances during the period of theft.

A Group member suggested that only the final meter reading should be adjusted, arguing that this was a simple and pragmatic approach and matched the existing process. Another member contended that this would affect the associated annualised advance; spreading the adjustment over the entire period of theft would promote Settlement accuracy. This would require that the DC is told how to allocate the information on unrecorded units from the RPS.

There is currently no defined flow for transfer of information between RPS and DC. Such transfer is done manually using spreadsheets. The Group agreed that this method was acceptable. If it is considered necessary in future to have a defined flow for this purpose (e.g. data volumes prove to be great enough to justify an automated flow) then a DTC change can be raised.

The Group therefore agreed that adjustments should be spread over the period across which units had gone unrecorded and that this would be done on the basis of information from the RPS in the form of manually communicated spreadsheets. A Group member noted that while this would not give absolute accuracy it would be less inaccurate than the present approach of adjusting only the final meter reading.

The Group agreed that where the period of theft falls (partly or completely) outside the 14 month Final Reconciliation (RF) window, adjustments should be made up to RF to deal with unrecorded units within the 14 month window. The Disputes process would address any unrecorded units falling outside the window.

The Group noted that they did not have information on the length of periods of theft. Some work had been done under DCP 054 to investigate magnitude of theft in energy terms, but not duration of theft periods. Information on the length of theft periods would be useful to determine the materiality of units falling outside the Final Reconciliation window. The Group asked a question on this in the industry impact assessment.

Option 2

This option does not account for theft against Half Hourly meters. Under Option 2 the SVAA will receive Revenue Protection adjustments via the D0041 'Supplier Purchase Matrix Data File', which will be profiled and adjusted for line losses in the same way as other Non Half Hourly (NHH) consumption. The values will be aggregated using a new Consumption Component Class (CCC) and will therefore be separately identified on the D0030 'Non Half Hourly DUoS Report'. To cover Half Hourly theft a similar solution would be required for adjustments to Half Hourly Metering Systems.

The Group believed that unrecorded units associated with Half Hourly Metering Systems are less prevalent than Non Half Hourly systems, but noted that Automatic Meter Reading (AMR) and Smart metering could affect this. The Group agreed not to include a solution for adjustments to Half Hourly Metering Systems as part of Option 2, but decided to ask a question on this as part of the impact assessment.

Option 3

Under this option the RPS could notify unrecorded units (outside Settlement processes) to a central 'Revenue Protection Administrator' (RPA), or multilateral data flows could be employed. The RPA role could be performed by ELEXON, Ofgem, a National Revenue Protection Service (NRPS - depends on other developments) or another organisation. The Group did not have a view on who should perform the RPA role, and considered that the views of impact assessment respondents would inform a decision on this.

The Group considered what frequency of reporting should be used and whether a reconciliation process is required. They agreed that the process would be monthly and a reconciliation process would not be required.

Ofgem commented that they would prefer not to remove units from Settlement, but they would consider the impacts and benefits of this possible approach. Ofgem had separately issued a questionnaire seeking information on electricity theft.

5.2 Further discussions following impact assessment of Issue 39

Following the Issue 39 impact assessment the Group reconsidered the solution options in light of the responses.

Solution Scope (interaction of BSC and DCUSA)

A respondent suggested it would be clearer to include all Revenue Protection activities in a single BSC Procedure (BSCP). They considered that if the process is changed so RP data is received from the Supplier, there will be no reference under the BSC to RPSs. However, the Group agreed that the processes for calculating and agreeing RP figures should form part of the Revenue Protection Code of Practice which, subject to agreement as part of DCP 054, will sit under the DCUSA. The BSC is concerned only with the process of entering unrecorded units into Settlement after they have been agreed under DCUSA processes.

A respondent suggested that introducing the option 1 process would penalise Parties that currently follow the current process correctly (i.e. communicate adjustments between RPS and NHHDC). Such Parties will need to make more system changes than those that incorrectly submit RP data via the Supplier. The respondent believed that having the RPS pass RP data to both NHHDC and Supplier would allow either process to be used, minimising the impact. The Group was concerned that allowing a choice would lead to process inconsistencies. They noted that the RPS does not always have all relevant information, and if the Supplier receives data from the RPS it can add to/adjust the data if necessary before passing it to the NHHDC. The Group noted that the DCUSA governs Supplier/RPS interactions, and therefore agreed that it was important that the BSC and DCUSA are consistent and therefore any solution under the BSC must align with the outcome of DCP 054.

Data Interfaces (options 1 and 2)

Some respondents were concerned that the proposal to use a manual interface (e.g. email spreadsheets) would not be adequately secure and would be more prone to errors and process failures than an automated interface employing the DTN. The Group noted that Ofgem's recent questionnaire on theft of electricity should provide better information on instances of theft, and could inform a decision on whether a manual or automated interface should be used. The majority of the Group believed that the cost of using the DTN would not be justified by the volume of data, and a manual interface should be employed. However, the Group agreed that the progression of any subsequent BSC change should further consider the data volumes and the impact of potentially using the DTN.

A respondent suggested that it would be more sensible to deal with RP information as data is received, rather than on a monthly basis, to avoid adding unnecessary delays to adjustments. The Group agreed this should be discussed under the DCUSA and any BSC change should reflect the outcome.

Audit and Validation (options 1 and 2)

A respondent suggested that the BSC Audit should cover the agreement of unrecorded units and their processing in Settlement. The Group believed the concern was primarily around the agreement of RP units, which lies under the DCUSA, and is therefore not relevant to Issue 39. If this issue needs to be addressed, it should be done under the DCUSA (i.e. as part of DCP 054). It might be possible for DCUSA audit requirements to be discharged via the BSC Audit (with associated costs falling outside the BSC), but this is not relevant to Issue 39.

A respondent noted that under option 1 LDSOs must agree adjustments, but do not have visibility of the adjusted data. They therefore believed option 1 would be more effective if the LDSO and Supplier receive an output report in addition to the normal NHH DUoS report. The Group believed some participants want an aggregated view of data to enable them to check D0010 'Meter Readings' flows received. Options 1 and 2 differ in this area:

- Option 1 would give details of individual Metering Point Administration Numbers (MPANs) entering the process, but not aggregated output data; and
- Option 2 would provide aggregated output data, but not individual input MPAN details.

Unrecorded Units beyond Final Reconciliation

The impact assessment sought information on the proportion of Revenue Protection incidents in which the period between the date that theft is deemed to have started, and the date that unrecorded units are estimated and agreed, exceed 14 months. On average, respondents estimated that just under a quarter (23.9%) of cases exceed 14 months.

The Group agreed that, in progressing a change subsequent to Issue 39, consideration should be given to investigating and taking into account the volume of energy that exceeds the 14 month Settlement window. The responses to Ofgem's questionnaire may provide some information on this.

Under options 1 and 2, the only recourse for RP volumes that exceed 14 months would be either the disputes process or an amendment to the Gross Volume Correction (GVC) process, which both had drawbacks. One of the benefits of option 3 is that the reporting process need not be constrained by the Settlement timetable. The Group noted that it would be possible to employ a 'hybrid' solution using option 1 (or 2) for volumes within 14 months and an option 3 approach for volumes in excess of 14 months, though the impacts and costs of such an approach would be expected to be significant compared with those of the individual options.

Half Hourly Metering Systems

Most respondents agreed that the incidence of theft for Half Hourly Metering Systems is too low to warrant significant changes to the Half Hourly processes. A respondent suggested that the HH market could see an increase in theft due to the potential move of all Profile Class 5-8 customers (164,000) to HH when the necessary meters are installed, and that it may therefore be prudent to review the HH process prior to this potential move. But the Group did not believe this affected the conclusion that present HH theft is too low to justify a change as part of an Issue 39 solution.

Central Administration and Ofgem Concerns (option 3)

Respondents were split as to whether a centrally administered scheme for reporting Revenue Protection adjustments or multilateral reporting between Suppliers and LDSOs (under the governance of the DCUSA) should be used under option 3. Having recently introduced a losses incentive methodology under Distribution Price Control Review 5 (DPCR5), where targets and outcomes are based on Settlement outputs, Ofgem would need to vary this methodology to take into account Revenue Protection adjustments reported under option 3.

Ofgem would therefore need reassurance that a robust reporting process and appropriate governance is in place for option 3 before considering this reporting under DPCR5. For instance, they would not favour applying a manual/spreadsheet type method for option 3. In principle, Ofgem tend to favour option 1 or 2 over option 3. At this stage, it is understood that option 3 would need to have central management and proper oversight for Ofgem to potentially feel comfortable with it.

Note that the 'Electricity Distribution Price Control Network Asset Data and Performance Reporting - Regulatory Instructions and Guidance' is available on Ofgem's website[2]. Special Condition CRC7 of the Electricity Distribution Licence requires distribution losses to be measured and reported under the Distribution Losses Reporting Regulatory Instructions and Guidance (RIGs). On page 104, the RIGs state:

5.26. Any data source that is not accounted for in Settlement or does not arise from a connected IDNO network within the timescales set out below must not be included in the calculation of losses. This includes, but is not limited to:

- *Data relating to theft of energy not entered into Settlement,*
- *Embedded distributed generation not registered in Settlement,*
- *Own site use (e.g. substation usage, which is described further below) not registered in Settlement, and*
- *Any known or perceived anomalies that are not captured in Settlement.*

The Group noted Ofgem's views, but when considering what a central administer would actually do, some Group members believed the practical necessity of a central administration would depend on the complexity of the methodology. Participants could carry out simple aggregation of units via multilateral arrangements, but a more complicated methodology might benefit from central administration.

The Group believed that the primary benefit of central administration, particularly in light of Ofgem's views, would be validation of outputs and of the process itself. The option 3 process would effectively operate apart from the Settlement process, implying HH values would not be used, but the Group believed that there would be benefit in validating against MPANs.

On the question of who should perform the central administration role, respondents were split between BSCCo, DCUSA or, if introduced, a National Revenue Protection Service (NRPS). Views on funding varied depending on respondents' preference to fulfil the central administrator role. The Group was unable to make a decision on this, particularly in light of the split views from respondents. Fulfilment of the central administration role (if required) and funding of its activities would need to be considered as part of any subsequent change progressing solution option 3. This may be facilitated by further information being available on the likelihood and form of an NRPS.

Theft in Conveyance

The definition of 'theft in conveyance' is currently in question and is being discussed as part of DCP 054. In its initial discussions the Group considered 'theft in conveyance' to be theft that cannot be directly allocated to a Metering System (and hence a Supplier). Three respondents provided data despite the ongoing debate around the definition of theft in conveyance. Their estimates of theft in conveyance were fairly consistent, at 20%, 24% and 30% of total detected theft. The Group noted that the proportion of theft that is theft in conveyance may be greatly affected by the outcome of the debate about the meaning of the term. This could affect the benefits associated with different solution options, and should therefore be considered in the progression of any subsequent change.

The Group noted that only option 3 handles theft in conveyance. A Group member believed that this raised concerns with options 1 and 2 because they do not cover volumes associated with theft in conveyance, which is a significant proportion of theft.

[2] http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/Electricity%20Distribution%20NADPR%20RIGs.pdf

New Connections

Respondents believed units taken prior to the registration of a Supplier for a new connection should be included within the scope of reporting under option 3. This category of unrecorded units will not necessarily fall within the scope of Revenue Protection Services. Group members disagreed about the prevalence of such unrecorded units, and therefore whether it was important to include them in reporting under option 3.

Preferred Solution

Respondents were split on the question of preferred solution option, but the majority favoured option 3. The Group broadly concurred with respondents' views, with the majority preferring option 3, subject to Ofgem's concerns. Ofgem's current stance on option 3 throws doubt on its viability. A Group member noted that Ofgem are further developing the methodologies in the Distribution Price Control Review 5 (DPCR5), and the reporting requirements should be taken into account as part of the progression of a subsequent change.

A Group member suggested that in the current climate of Smart rollout it would be imprudent to develop change to data and flows (as options 1 and 2) since the industry will be subject to a great degree of change in the short to medium term. A simpler solution as set out in Option 3, allied with robust reporting and governance, could provide a stable solution for the medium term.

The Group gave their views, taking into consideration the consultation responses and their further discussions, on their preferred solutions. This was not a formal vote to determine the Group's overall views, as would be taken under a Modification, and anyone in attendance was invited to give their view if they wished; the rigours of Modification Group voting did not apply.

Assuming Ofgem would be prepared to accept option 3, the majority of the Group favoured option 3. Both option 1 and option 2 (two members each) had some minority support. One member, whose first preference was option 1, was not opposed to option 3, but believed option 2 should not be introduced. Another member, whose first preference was option 2, supported all three solutions because they believed all would improve on the present arrangements.

Ruling out option 3, the majority of the Group preferred option 1. A minority favoured option 2, but one declined to give a preference between options 1 and 2 because they felt unable to support either (this member did support option 3).

6 Conclusions

The majority of the Group support option 3 because it would cover more types of unrecorded units than option 1 or 2, such as theft in conveyance, and would reduce a disincentive on Suppliers to actively detect theft. Impact assessment respondents also supported option 3.

However, there are concerns about the compatibility of option 3 with the Distribution Price Control Review 5 (DPCR5) methodology, and Ofgem has made it clear that satisfactory reporting and governance arrangements would be required for option 3 to be potentially viable. These concerns should be taken into consideration both before and during any BSC change to introduce a cost smearing scheme as set out under option 3. If option 3 is removed from the potential choices option 1 becomes the Group's majority preference.

Industry impacts varied substantially among respondents, but the costs, impacts and timescales associated with options 1 and 2 appear to be similar, with those for option 2 slightly higher. The impact of option 3 on industry participants is less than that of the other options.

The central impact of option 1 is low, consisting of minimal ELEXON implementation activities only, with no central system impacts. Option 2 has a substantial impact, due to its impact on NHHDA, SVAA and MDD. Option 3 has a greater impact than option 1, but much less than option 2, though this mainly relates to changes to Central Services operation if ELEXON performs a central administrative function. If ELEXON does not perform this role the costs of option 3 would be comparable with those of option 1 (though if a central administrator is still required, the relevant organisation would be impacted instead).

Though the Group favoured option 3 (both in principle and considering its indicative associated impacts), they agreed that it was important that any BSC change in this area is consistent with the related DCUSA arrangements, i.e. those resulting from DCP 054. The Group also identified other areas it believed should be considered as part of any subsequent change (depending on what solution is progressed), as follows:

- The outcome and ramifications of DCUSA Change Proposal 054;
- Any relevant information resulting from Ofgem's questionnaire on theft of electricity or other source;
- Where data interfaces are required between participants, the volumes of data concerned and the impacts and benefits of using the DTN;
- The appropriate oversight, governance and validation of the process and/or data; and
- Any relevant views expressed by Ofgem.

7 Issue 39 Meeting Participation

Member	Organisation	2/11/10	11/1/11
Andrew Wright	ELEXON (Chairman)	✓	✓
Dean Riddell	ELEXON (Lead Analyst)	✓	✓
Jon Spence	ELEXON (Technical expert)	✓	✓
Lizzie Montgomerie	ELEXON (Technical expert)	✓	X
Glen Sheern	E•ON (Proposer)	✓	✓
Colette Baldwin	E•ON	X	✓
Paul Coyle	Scottish Power	☎	✓
Graham Smith	Western Power	✓	✓
Kevin Woollard	British Gas	✓	☎
Tony Savka	Electricity North West	✓	✓
Heath Watts-Robinson	Central Networks	☎	☎
Emma Cottle	CE Electric UK	☎ (part)	☎
Mike Blake	UK power networks (previously EDF Energy Networks)	✓	✓
Kevin Kerrigan	Teccura Ltd	✓	X
Jonathan Wisdom	npower	✓	✓
Els Demets	Teccura Ltd	☎	☎
Cesar Coelho	Ofgem	✓	✓
Walter Hood	Accenture (on behalf of Scottish Power Distribution)	-	✓
Allan Hendry	SP Distribution Ltd	-	✓

8 Attachments

Attachment B: Draft Solution to Identify Impacts

Attachment C: Collated Industry Impact Assessment Responses

Standing Issue: Draft Solution to Identify Impacts

This document sets out the solutions options under consideration

Standing Issue 39: Processing Unrecorded Units identified by Revenue Protection Services

Standing Issue 39 has been raised to consider and develop options for the processing of unrecorded units identified by Revenue Protection Services.

High Impact:

- All options: Suppliers, Data Collectors, LDSOs
- Option dependent: NHHDA, SVAA, BSCCo/DCUSA/MRASCo/ National Revenue Protection Service

Contents

About this document:

This document is the Draft Solution to Identify Impacts for Standing Issue 39. It summarises the solution options developed by the Volume Allocation Standing Modification Group (VASMG), and the changes - to the extent the group has been able to identify them - that will be required to participants' systems, BSC Central Systems, Code Subsidiary Documents and Configurable Items to implement the various solution options.

The purpose of this document is to facilitate assessment of the impact of implementing the various solution options.

You should assess impacts and submit responses in accordance with the Change Proposal Circular (CPC) or other covering documents supplied with this Draft Solution.

Any questions?

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1 Summary

Why Change?

Standing Issue 39 is investigating how unrecorded units identified by Revenue Protection Services should be submitted into Settlement.

What are unrecorded units?

Unrecorded units usually arise due to energy theft.

They represent energy that has not been correctly metered and entered into Settlement.

Background

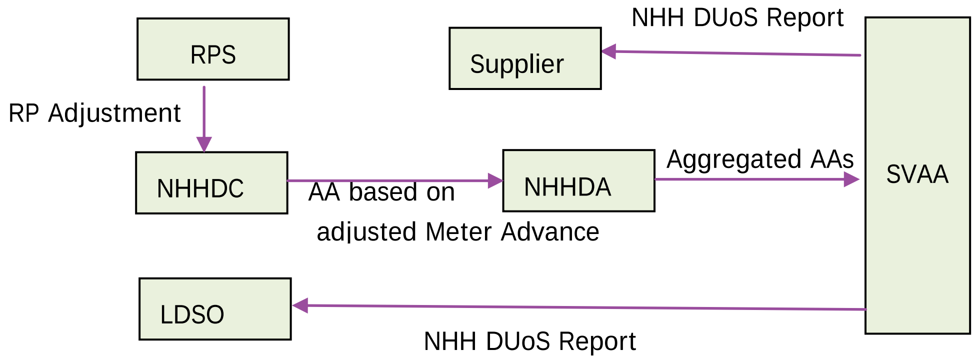
In October 2009 a party to the Distribution Connection and Use of System Agreement (DCUSA) raised Change Proposal DCP 054 'Revenue Protection/Unrecorded Units into Settlements'. The DCP 054 Working Group was set up to consider the Change Proposal. This group continues to hold regular meetings and the Change Proposal is in the 'definition' phase.

The DCP 054 Working Group has recognised that, whilst the DCUSA could include obligations relating to how unrecorded units are estimated and agreed, the requirements for how these unrecorded units are then processed in Settlement fall within the scope of the BSC. As there is no single clear solution for processing unrecorded units in Settlement, E.ON UK raised Standing Issue 39 'Processing Unrecorded Units identified by Revenue Protection Services' on behalf of the DCP 054 Working Group to allow various options to be considered.

The current process

The process for applying Non Half Hourly Revenue Protection adjustments in Settlement is defined in BSCP504 'Non Half Hourly Data Collection for SVA Metering Systems Registered in SMRS' 3.6 'Revenue Protection'. "When informed by the Revenue Protection Service that there is evidence of tampering with a SVA Metering System", the Non Half Hourly Data Collector (NHHDC) is required to "record an Adjustment to the meter advance based on the unrecorded units estimated by the Revenue Protection Service" and to "calculate a new EAC and AA based on the adjusted meter advance and send the new EAC/AA" to the NHHDA.

Figure 1: Current process for inputting Non Half Hourly Revenue Protection adjustments in Settlement



The current process is described in greater detail in Attachment A.

Technical Assurance Checks

Between November 2009 and February 2010, ELEXON visited seven NHHDCs and five NHH Suppliers to perform Technical Assurance (TA) checks on the processing of revenue protection reads. The results were published in 'Findings from the Technical Assurance Checks on the Processing of Revenue Protection Reads' (PAB111/05).

The key findings of the TA Checks were that:

- The current BSC obligations are not defined in detail and are not being applied consistently;
- There is a lack of engagement between Suppliers, NHHDCs and Revenue Protection Services (RPS) regarding the processing of Revenue Protection units; and
- Little evidence was found that units identified by Revenue Protection Services are being processed by NHHDCs.

The impact of not processing Revenue Protection adjustments using the current BSCP504 process is that unrecorded units identified by the RPS are allocated to all Suppliers in proportion to their Non Half Hourly market share, via the GSP Group Correction process (i.e. in the same way as undetected theft is settled).

Further details about issues with the current process can be found in Attachment A.

Settlement Risk

The risk that "stolen energy notified by Revenue Protection units is not used in calculations by Suppliers and NHHDCs" (Settlement Risk SR0073) is one of the "Top Ten" risks identified in the Risk Evaluation Register (RER). The Technical Assurance Checks described above related to this Settlement Risk. No other Performance Assurance Techniques have been applied due to a lack of information about the levels of adjustments being made.

Solution Options

Three solution options have been developed by the Standing Issue 39 Group ('the Group') at its first meeting, on 2 November.

- **Solution Option 1 – address the TA Check findings by enhancing the current process**
- **Solution Option 2 – end-to-end tracking of Revenue Protection adjustments**
- **Solution Option 3 – Settlement Cost Smearing**

These solutions are detailed on pages 5 to 21.

Impacts & Costs

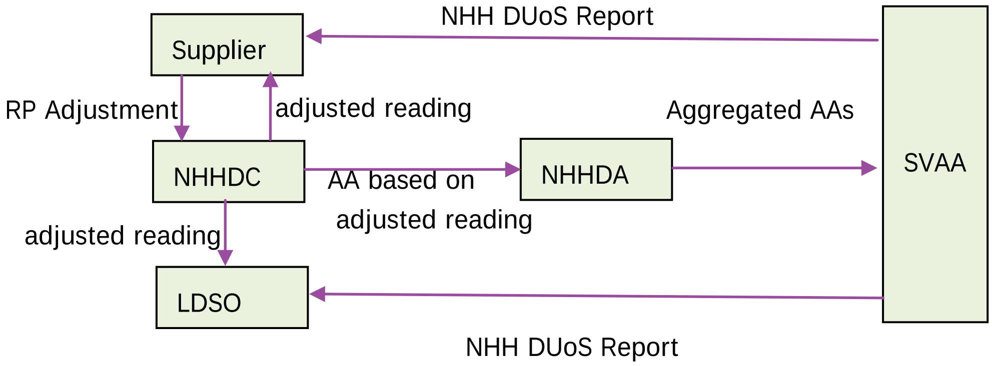
Costs will be established using the results of this impact assessment. We request that you assess the impact of each option on your organisation.

2 Solution Option 1 – address the TA Check findings by enhancing the current process

Summary

Option 1 is to enhance the current process in order to address the issues identified by the TA Checks.

- Revenue Protection adjustments will be provided to the NHHDC by the Supplier (rather than by the RPS, as currently specified);
- Revenue Protection adjustments must be applied by adjusting Meter readings and using "dummy Meter exchanges" must be used where the Meter is not replaced; and
- A Master Registration Agreement (MRA) Change Proposal will be raised to introduce a new value of Reading Type for Revenue Protection adjusted readings.



Question 1

Would Option 1 impact your organisation? If so please describe the impacts, costs and required implementation timescales (from the point of approval).

Detailed Requirements

Changes to BSC Systems

No changes to the BSC Systems would be needed.

Changes to Party and Party Agents' processes

Requirement 1.1 – Suppliers to provide Revenue Protection adjustments to the NHHDC

Suppliers will send Revenue Protection adjustments to NHHDCs. This will include the Metering System Id, the volume of unrecorded units and the start and end dates of the period of theft. The Supplier will provide the date of the meter replacement, where applicable. Where the meter has not been replaced, the Supplier will provide a reading and the date on which it was taken. It is assumed that where a Meter is not replaced after an episode of theft, that a reading will be taken.

The interface between the Supplier and the NHHDC will be manual (the Group invites your views on this - see Question 2). The contents of the flow will be defined in a new P-flow in the SVA Data Catalogue. For the purposes of this impact assessment, please assume that adjustments are sent monthly in the form of spreadsheets.

Question 2

Do you agree that a manual interface (e.g. monthly spreadsheets sent by email) is appropriate for Suppliers to send Revenue Protection adjustments to NHHDCs, given the likely volume of data?

There will be a requirement on Suppliers to process all agreed units identified by the RPS. However, the process for agreeing Revenue Protection adjustments between the Supplier, RPS and LDSO will be under the governance of the DCUSA and so is outside the scope of this solution. The Group invites your views on this. See Question 3.

Question 3

Do you agree that a requirement on Suppliers to process all agreed Revenue Protection adjustments, together with a process under the governance of the DCUSA for agreeing these adjustments, will be sufficient to ensure that all agreed units are accounted for? If not, what additional steps can be taken to ensure that all Revenue Protection adjustments are accounted for?

The Group believes it will be relatively rare for periods of theft to span more than one Supplier Registration. Where this does occur, it is assumed that the allocation of missing units between the relevant Suppliers will be agreed between the RPS, Suppliers and LDSO as part of the above process for agreeing adjustments.

Requirement 1.2 – NHHDC to receive Revenue Protection adjustments from the Supplier and adjust the closing reading on the old meter

NHHDCs will receive Revenue Protection adjustments from Suppliers on a monthly basis. These will be stored for audit purposes. The NHHDC will determine whether the Meter was replaced as a result of the Revenue Protection incident, using the Meter replacement date provided by the Supplier and the Non Half-hourly Meter Technical Details (D0150) flow received from the Meter Operator.

If the Meter was replaced, the NHHDC will withdraw the final reading on the old Meter and replace it with a new adjusted reading. The adjusted final reading will be set to the original reading plus the estimate of unrecorded units received from the Supplier. The adjusted final reading will be sent to the Supplier and LDSO a 'Meter Readings' (D0010) dataflow using a new Reading Type. A revised AA will be calculated using the adjusted reading and sent to the NHHDA in the normal way.

What is a dummy Meter exchange?

A Meter is not replaced, but the NHHDC creates Final and Initial Readings to simulate a Meter replacement within the BSC Systems. This allows a meter reading to be adjusted to account for unrecorded units without impacting subsequent consumption for the Metering System.

Requirement 1.3 – NHHDC to carry out a "dummy Meter exchange" in the event that the Meter wasn't replaced following the intervention of the Revenue Protection Service

Where the Meter has not been replaced, the NHHDC will use a "dummy Meter exchange" – i.e. will artificially create a revised Final Reading (adjusted to take into account the estimated unrecorded units provided by the Supplier) and an Initial Reading (with the pre-adjustment value). This will ensure that the adjustment is not erased when the meter is next read.

The readings will be sent to the Supplier and LDSO on a 'Meter Readings' (D0010) dataflow. The adjusted Final Reading will use the new Reading Type. A revised AA will be calculated using this adjusted reading and sent to the NHHDA in the normal way.

Requirement 1.4 – NHHDC to attempt to allocate energy over the correct period, so far as is practicable

The Group believes that Metering Systems that have been subject to theft will not have been read regularly, so the NHHDC will usually only need to adjust one Meter reading. However, to promote Settlement accuracy the adjustment should be spread over the maximum possible number of Meter readings across the applicable time period. A requirement will therefore be placed on NHHDCs to attempt to allocate energy over the correct period, so far as is practicable, by applying the adjustment over multiple readings, where such readings exist. Where the adjustment needs to be applied over multiple readings and the Meter is not replaced, only the last reading would need a "dummy Meter exchange".

Adjustments can only be made within the 14 month Final Reconciliation window. The Group suggests that adjustments should be made only to account for unrecorded units that fall within this window, i.e. adjustments would not be applied to readings within the 14 month window to account for energy stolen over longer timescales. Unrecorded units that fall outside the window may be addressed via the Trading Disputes process. However, the Group's view on this may be affected by information from respondents. You are therefore invited to supply views on the appropriateness of this approach and the proportion of incidents where the period between the date when theft is deemed to have started and the date when the estimated stolen units have been agreed is greater than 14 months (see Question 4).

Question 4

In what proportion of Revenue Protection incidents does the period between the date theft is deemed to have started and the date unrecorded units have been estimated and agreed exceed 14 months?

NB: quantitative data would be appreciated if available, but estimates and qualitative assessments would also be useful.

Requirement 1.5 – Suppliers to provide Revenue Protection adjustments to the HHDC

References to the Half Hourly Data Collector (HHDC) receiving data from the RPS will be amended to refer to Revenue Protection adjustments received from Suppliers. Otherwise no changes will be made to the Half Hourly arrangements.

Impacts of Solution Option 1

The impact on ELEXON will be determined by internal impact assessment, in parallel with the industry impact assessment.

Impact on BSC Parties and Party Agents
Change to Supplier processes to send monthly spreadsheets of Revenue Protection adjustments to Data Collectors.
Change to Data Collector processes to receive and process monthly spreadsheets of Revenue Protection adjustments, adjust readings and report revised readings using new Reading Type.
Revised Supplier and LDSO processes to receive Meter Readings (D0010) flows with new Reading Type for adjusted readings.

Impact on Code Subsidiary Documents	
CSD	Potential impact
BSCP504 'Non Half Hourly Data Collection for SVA Metering Systems Registered in SMRS'	Section 3.6 to be amended to reflect changes described in requirements 1.1 to 1.4.
BSCP502 'Half Hourly Data Collection for SVA Metering Systems Registered in SMRS'	References to Revenue Protection Services in Section 4.2 to be replaced by Supplier (as per requirement 1.5).
SVA Data Catalogue	New P-flow to define manual interface between Supplier and NHHDC for Revenue Protection adjustments.

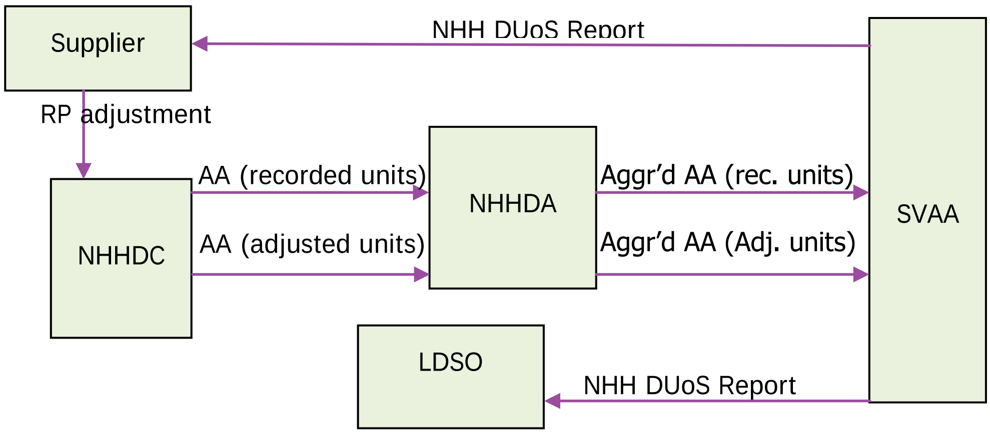
Impact on Core Industry Documents and other documents	
Document	Potential impact
Data Transfer Catalogue	New value for adjusted Revenue Protection reading in valid set for Data Item J0171 'Reading Type'.

3 Solution Option 2 – end-to-end tracking of Revenue Protection adjustments

Summary

Option 2 is to amend NHHDC, NHHDA and SVAA processes such that Revenue Protection adjustments are processed as separate quantities from any recorded units.

- Revenue Protection adjustments will be provided to the NHHDC by the Supplier (rather than by RPS, as currently specified);
- These adjustments will be applied as Meter Advances and will be separately identifiable from any recorded consumption on the same Meter;
- The adjusted units will be traceable from NHHDC to SVAA via a new instruction Type Code (on the NHHDC to NHHDA interface) and a new data item on the Supplier Purchase Matrix (on the NHHDA to SVAA interface); and
- The aggregated volume of adjusted units will be reported to Suppliers and LDSOs as a separate line item on the Non Half Hourly DUoS Report (D0030) and will be allocated a distinct Consumption Component Class (CCC).



Question 5
Would Option 2 impact your organisation? If so please describe the impacts, costs and required implementation timescales (from the point of approval).

Detailed Requirements

Changes to Party and Party Agents' processes

Requirement 2.1 – Suppliers to provide Revenue Protection adjustments to the NHHDC

NB: this requirement is the same as Requirement 1.1 for Option 1.

Suppliers will send Revenue Protection Adjustments to NHHDCs. This will include the Metering System Id, the volume of unrecorded units and the start and end dates of the period of theft.

The interface between the Supplier and the NHHDC will be manual (see Question 2). The contents of the flow will be defined in a new P-flow in the SVA Data Catalogue. For the purposes of this impact assessment, please assume that adjustments are sent monthly in the form of spreadsheets.

There will be a requirement on Suppliers to process all agreed units identified by the RPS. However, the process for agreeing Revenue Protection adjustments between the Supplier, RPS and LDSO will be under the governance of the DCUSA and so is outside the scope of this solution.

The Group believes it will be relatively rare for periods of theft to span more than one Supplier Registration. Where this does occur, it is assumed that the allocation of missing units between the relevant Suppliers will be agreed between the RPS, Suppliers and LDSO as part of the above process for agreeing adjustments.

Requirement 2.2 – NHHDC to receive, store and allocate Revenue Protection adjustments from the Supplier

NHHDCs will receive Revenue Protection adjustments from Suppliers on a monthly basis. NHHDCs will store these for audit purposes.

The Group suggests that adjustments should be made only to account for unrecorded units that fall within the Final Reconciliation window, i.e. adjustments would not be applied to Meter Advance Periods within the current 14 month window to account for energy stolen over longer timescales. Unrecorded units that fall outside the window may be addressed via the Disputes process. However, the Group's view on this may be affected by information from respondents. You are therefore invited to supply views on the appropriateness of this approach and the proportion of incidents where the period between the date when theft is deemed to have started and the date when the estimated stolen units have been agreed is greater than 14 months (see Question 4).

Requirement 2.3 – NHHDC to calculate an Annualised Advance, based on the adjustment provided by the Supplier, and store it within a new table in its database

The NHHDC will then submit the Meter Advance (representing the Revenue Protection adjustment) and the relevant settlement details for the Metering System (Profile Class, Standard Settlement Configuration (SSC) etc) to the EAC/AA calculator. The Meter Advance will not be added to any recorded units for the Metering System, but will be treated as a distinct quantity. NHHDCs will need to submit revenue protection adjustments to the EAC/AA calculator in separate batches from normal meter advances, i.e. as a separate monthly batch run.

The NHHDC will store the resultant AA for audit purposes in a distinct table within its database. There is no need to store the EAC because the Revenue Protection adjustment will be applied via the AA.

Requirement 2.4 – NHHDC to send the Annualised Advance to the NHHDA using a new Instruction Type

The NHHDC will submit the AA to the NHHDA using the existing 'Metering System EAC/AA data' (D0019) flow. Currently, all D0019 flows between the NHHDC and the NHHDA have an instruction Type Code of NH09. Revenue Protection AAs will have a new Type Code (say 'NH10').

The data items for the new Type Code will be the same as a standard 'NH09' instruction. The EAC groups 'EAH' and 'EAD' will be null (which is already supported by the D0019).

Requirement 2.5 – Suppliers to provide Revenue Protection adjustments to the HHDC

References to the Half Hourly Data Collector (HHDC) receiving data from the RPS will be amended to refer to the HHDC receiving Revenue Protection adjustments from Suppliers. Otherwise, Option 2 does not cover theft associated with Half Hourly Meters. This would require changes to Half Hourly arrangements equivalent to those described to the Non-Half Hourly arrangements set out in this section. The Group believes that this approach is appropriate on the basis that theft in the Half Hourly sector is rare. The Group invites your views on this (see Question 6).

Question 6

Do you agree that the incidence of theft for Half Hourly Metering Systems is too low to warrant significant changes to the Half Hourly processes?

Changes to BSC Systems

Requirement 2.6 – NHHDA to receive and validate the new D0019 Instruction Type

The NHHDA will receive and validate D0019 flows with the new NH10 instruction Type Code.

There will be no cross-validation of data received in an NH10 instruction and that received in NH09 instructions in respect of the same Metering System. For example, the Meter Advance Period in the NHO9 doesn't have to correspond to an existing Meter Advance Period for the same Metering System, and the Profile Class, SSC etc need not be the same.

Any data loaded from valid NH10 instructions will however be validated against the SMRS view of the Metering System data (as described in Requirement 2.7 below).

If an EAC is included in a NH10 instruction, it will be ignored and no exception will be reported. Similarly any Settlement attributes (SSC, Profile Class etc) which end before the start date of the earliest Meter Advance Period will be ignored and no exception will be reported. Otherwise the instruction will be rejected and a Failed Instruction (D0023) flow sent, where any of the following conditions apply:

- The instruction includes a change of Supplier or SSC within a Meter Advance Period;
- The instruction includes attributes with duplicate start dates;
- Settlement attributes are missing at the start of the earliest Meter Advance Period;
- Supplier, DC or other Settlement attributes are not included in valid standing data;
- The instruction contains overlapping Meter Advance Periods;
- The instruction contains attribute values for a Supplier Registration that doesn't exist in the NHHDA database;
- AA values are missing (or duplicated) for one or more registers associated with the Metering System's SSC or are provided for registers which are not valid for the Metering System's SSC;
- The Meter Advance Period end date is earlier than the Meter Advance Period start date.

If the NH10 instruction passes validation, any existing adjustments which start after or overlap with the Significant Date in the instruction will be deleted and replaced with the contents of the new D0019.

The NHHDA will store any AAs (and associated Settlement details) received with a Type Code of NH10, that pass validation, in a separate database table.

Requirement 2.7 – NHHDA to aggregate Revenue Protection AAs and allocate to a new field in the Supplier Purchase Matrix Data Flow (D0041)

The aggregation run will sum the values in the new database table and report them separately to the SVAA. This will require a new data item in the 'Supplier Purchase Matrix Data File' (D0041).

Where there is an inconsistency between the adjustment record and the SMRS view of the data, the following rules will apply:

- Where there is a mismatch on Supplier Id or Standard Settlement Configuration Id (SSC) the Revenue Protection adjustment AA will NOT be included in the aggregation run;
- Where the NHHDA is not appointed to the Metering System on the day in question, the Revenue Protection adjustment AA will NOT be included in the aggregation run;
- Where the NHHDC has not been appointed to the Metering System at any time within the Supplier Registration effective on the day in question, the Revenue Protection adjustment AA will NOT be included in the aggregation run;
- Where there is a mismatch on Energisation Status or Measurement Class Id, the Revenue Protection adjustment AA will be included in the aggregation run (in relation to the Measurement Class, there will not be separate categories for metered/unmetered adjustments);
- Where there is a mismatch on Profile Class Id or GSP Group Id, the Revenue Protection adjustment AA will be included in the aggregation run and will be allocated to the Profile Class/GSP Group according to the SMRS view;
- Where overlapping Revenue Protection adjustment AAs have been provided by more than one NHHDC, the value provided by the latest NHHDC appointed within the Supplier Registration will be used.

Where the above exceptions are identified as part of the 'Check Data Collector Data' function, exceptions will be reported on the Non Half Hourly Data Aggregation Exception Report (D0095).

Requirement 2.8 – SVAA to process Revenue Protection adjustment data as a separate data quantity

The SVAA will receive annualised Revenue Protection adjustments as a separate data item in the D0041. These will be profiled and adjusted for line losses in the same way as other NHH consumption. The values will be aggregated using new Consumption Component Classes (CCC) for consumption and line losses.

Requirement 2.9 – SVAA to report Revenue Protection adjustment data as a separate data quantity

The SVAA will report Revenue Protection adjustments as a separate data quantity:

- Changes will be required to the format of the Non Half Hourly DUoS Report (D0030) and Supplier Purchase Matrix Report (D0082) to include the new Revenue Protection adjustment data item;
- The Supplier Half Hourly Demand Report (D0081), GSP Group Consumption Totals Report (D0276) and Supplier BM Unit Report (D0296) will include the new data, by virtue of the new Consumption Component Classes, but will not need format changes;

- Revenue Protection adjustments will be included in the totals that are already reported in the Supplier Deemed Take Report (D0043) and the Supplier Purchase Report (D0079), but the format of these reports will be unchanged.

Impacts of Solution Option 2

The impact on ELEXON will be determined by internal impact assessment, in parallel with the industry impact assessment.

Impact on BSC Systems and process	
BSC System/Process	Potential impact
NHHDA	• Receive and validate annualised Revenue Protection adjustments via a new instruction type on the D0019 flow; • Sum these values (by Settlement Class) and report to the SVAA as a new item(s) in the D0041 flow.
SVAA	• Receive new data item(s) for Revenue Protection adjustments in D0041 flow; • Profile aggregated AAs for Revenue Protection adjustments and calculate line losses in the same way as ordinary aggregated AAs; • Report total annualised (and/or profiled) Revenue Protection adjustments as a new data item on the D0030 and D0082 flows • Report Revenue Protection adjustments against new Consumption Component Classes on the D0081, D0276 and D0296 flows.

Impact on BSC Parties and Party Agents
Change to Supplier processes to send monthly spreadsheets of Revenue Protection adjustments to Data Collectors.
Change to Data Collector processes to receive and process monthly spreadsheets of Revenue Protection adjustments, store adjustments, submit adjustments to the EAC/AA calculator, store resultant AAs and submit to the NHHDA using a new instruction Type Code.
NHHDA impacts are described under 'Impact on BSC Systems and process' above.
Revise Supplier processes to receive D0030 and D0082 in new format and (optionally) to process new Consumption Component Class data on D0081, D0276 and D0296.
Change LDSO processes to receive D0030 in new format and process Revenue Protection adjustments for DUoS billing and Distribution Price Control purposes.

Impact on Code	
Code section	Potential impact
Section S-2	Change to S-2 4.3 to reflect requirement on NHHDC to calculate a separate AA for Revenue Protection adjustments. Change to S-2 4.4 to reflect requirement on NHHDA to separately aggregate Revenue Protection adjustments. Potential change to 5.1.12 to 5.1.16 to include/exclude adjustments in Average Fraction of Yearly Consumption (AFYC) and GSP Group Profile Class Average Estimated Annual Consumption (GGPCAEAC) calculations.
Section X-2 Table X-6	Definition of new data items for Annualised Advance (RP Adjustment) and Total Annualised Advance (RP Adjustment)
Section X-2 Table X-8	Definition of three new Consumption Component Classes for Revenue Protection adjustments (for consumption, metering system specific losses and metering system non-specific losses).

Impact on Code Subsidiary Documents	
CSD	Potential impact
BSCP504 'Non Half Hourly Data Collection for SVA Metering Systems Registered in SMRS'	Section 3.6 to be amended to reflect changes described in requirements 2.1 to 2.4.
BSCP505 'Non Half Hourly Data Aggregation for SVA Metering Systems Registered in SMRS'	Changes to reflect requirements 2.6 and 2.7.
BSC Procedure for Supplier Volume Allocation Agent (BSCP508)	Changes to reflect requirements 2.8 and 2.9.
BSCP502 'Half Hourly Data Collection for SVA Metering Systems Registered in SMRS'	References to Revenue Protection Services in Section 4.2 to be replaced by Supplier (as per requirement 2.5).
NHH Instruction Processing Specification	Definition of requirements for processing new instruction type for Revenue Protection Adjustments.
SVA Data Catalogue	New P-flow to define manual interface between Supplier and NHHDC for Revenue Protection adjustments.

Impact on Core Industry Documents and other documents	
Document	Potential impact
Data Transfer Catalogue	New data items in Supplier Purchase Matrix Data File (D0041), Non Half Hourly DUoS Report (D0030) and Supplier Purchase Matrix Report (D0082)

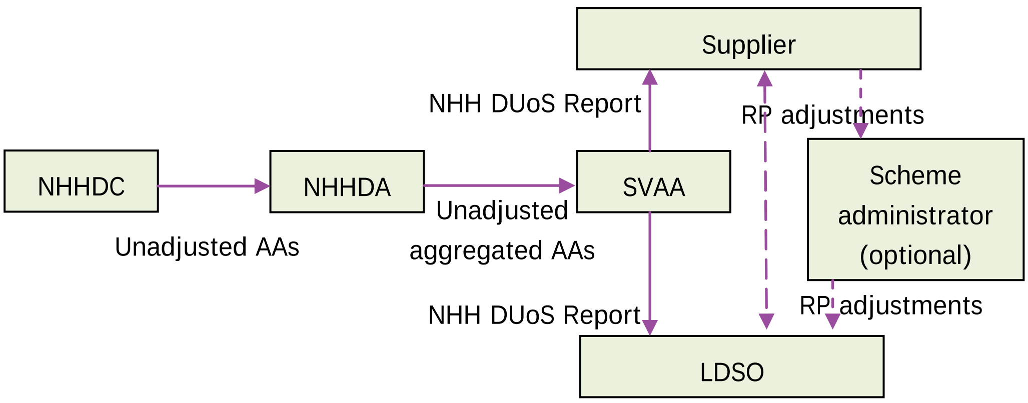
Summary

If Revenue Protection adjustments are recorded against the Metering System where theft is discovered, the Supplier for that Metering System will incur the full energy costs for the assessed unrecorded units. This acts as a disincentive on Suppliers to actively discover cases of theft, as the likelihood of fully recovering charges from the thief is very low.

Under Option 3 Revenue Protection adjustments are processed outside the NHHDC-NHHDA-SVAA systems, resulting in unrecorded units being 'smeared' across Suppliers.

- The requirements in BSCP502 and BSCP504 will be removed;
- All unrecorded units will be smeared across all Suppliers in proportion to their NHH market share (i.e. via the GSP Group Correction process);
- Revenue Protection adjustments will be agreed between RPS, Suppliers and LDSOs;
- Agreed adjustments will be utilised by LDSOs for DUoS charging and are reported to Ofgem for the purposes of the Distribution Price Control (subject to Ofgem agreeing such an approach);
- Adjusted units could be reported between RPS, Suppliers and LDSOs via a monthly reporting process, under the governance of the DCUSA;
- Alternatively, these adjustments could be collated centrally by an administrator. This could be the National Revenue Protection Service (if this is set up following consultations by the Gas Forum and Ofgem) or another central organisation, such as BSCCo, the DCUSA or MRASCo. If BSCCo were to fulfil this centralised administrative role, it would seem appropriate to introduce governance arrangements under the BSC, which would require a Modification (an equivalent change to the relevant governance arrangements would be required for another central organisation to fulfil this role).

Please note that unrecorded units are currently being allocated via GSP Group Correction to a large extent, as a result of failures to process Revenue Protection adjustments.



Question 7

Would Option 3 impact your organisation? If so please describe the impacts, costs and required implementation timescales (from the point of approval).

How does Option 3 impact the Distribution Price Control?

As part of Distribution Price Control Review number 5 (DPCR5), calculations are based exclusively on outputs from Settlement. Taking account of units reported outside the usual Settlement processes is dependent on Ofgem being willing to vary the DPCR5 methodology.

Detailed Requirements

Changes to BSC Systems

No changes would need to be made to the BSC Systems, although a new application would need to be developed if BSCCo fulfils the role of administrator under the centrally-administered sub-option.

Changes to Party and Party Agents' processes

Requirement 3.1 – remove requirement on NHHDCs and HHDCs to process Revenue Protection adjustments

Under Option 3 the requirement on NHHDCs to process Revenue Protection adjustments in BSCP504 3.6 is removed; the requirement on HHDCs to process Revenue Protection adjustments in BSCP502 4.2 is also removed. This will have the effect that all unrecorded units are smeared across all Suppliers in proportion to their NHH market share (i.e. via the GSP Group Correction process).

Requirement 3.2 – Revenue Protection Services to report Revenue Protection adjustments to Suppliers

RPS will report identified units to Suppliers on a monthly basis. This will include all units identified within the reporting month, regardless of the period of theft. The adjustments will be reviewed by Suppliers.

Requirement 3.3 – Suppliers to report and agree Revenue Protection adjustments with LDSOs

The Group suggests there should be a cut-off point (to be defined) after which adjustments cannot be made. Suppliers will report agreed adjustments on a monthly basis to LDSOs, having excluded any units deemed to have been taken before the cut-off point.

LDSOs will have the opportunity to dispute the reported units and Suppliers will report revised values, where agreed. The monthly report from Suppliers to LDSOs will thus include both new values and revised values from previous reporting periods.

LDSOs may wish to use the reports from Suppliers (in conjunction with the Non Half Hourly DUoS Report (D0030) and data from Half Hourly Data Collectors) to calculate revised DUoS charges. There may need to be an agreed process to enable LDSOs to include reported units in their DUoS billing and to enable Suppliers to validate the adjusted bills. However, it is assumed that reporting for DUoS charging purposes and its associated governance falls under the DCUSA rather than the BSC.

Requirement 3.4 – LDSOs to report aggregated and agreed Revenue Protection adjustments to Ofgem

LDSOs will report aggregated adjustments (from the reports agreed with Suppliers) to Ofgem for the purposes of the Distribution Price Control (subject to Ofgem agreeing such an approach).

Reporting and Governance Options

The reporting processes described above could be carried out on a multi-lateral basis between RPS, Suppliers and LDSOs (i.e. without a central administrator). The reporting process would need to be subject to governance arrangements, which would appear to best sit within the DCUSA.

Alternatively, reporting could be carried out via a central scheme administrator. This could be the National Revenue Protection Service (if this is set up following consultations by the Gas Forum and Ofgem) or another central organisation, such as BSCCo, the DCUSA or MRASCo. If BSCCo were to fulfil this centralised administrative role, it would seem appropriate to introduce governance arrangements under the BSC, which would require a Modification (an equivalent change to the relevant governance arrangements would be required for another central organisation to fulfil this role). Questions 8 and 9 seek your views on the reporting and governance under Option 3.

Question 8

Under Option 3 would you favour a centrally administered scheme for reporting Revenue Protection adjustments or multilateral reporting between Suppliers and LDSOs under the governance of the DCUSA?

Please provide details of the relative costs and benefits of these two sub-options.

Question 9

Under a central administered scheme:

- Who do you believe should perform this role (subject, of course, to their willingness to do so) - National Revenue Protection Service; BSCCo; the DCUSA; MRASCo; or another organisation (please specify)?
- How do you believe such a scheme should be funded?

Scope Options

Under the normal Supplier Volume Allocation (SVA) processes, energy can only be allocated to a Supplier via a Metering System or through the GSP Group Correction process. As such, Options 1 and 2 can only assign assessed unrecorded units to a particular Metering System. Under Option 3 there is the flexibility to report by Metering System (e.g. where the Meter has been by-passed or tampered with) or to include unrecorded units that cannot be allocated to a Supplier (e.g. theft in conveyance). The latter can be taken into account for Distribution Price Control reporting, though not for DUoS charging. The relative merit of Option 3, compared to the other options, is partly dependent on the extent to which theft in conveyance contributes to the overall volume of detected theft. The Group invites your views on this (see question 10).

Question 10

Approximately what proportion of detected theft would you estimate to be 'theft in conveyance', i.e. theft that cannot be directly allocated to a Metering System (and hence a Supplier)?

Where unrecorded units are the result of a Settlement error (for example, Metering Systems incorrectly registered as de-energised), it is assumed that these can be corrected using existing processes, within Final Reconciliation timescales, and by means of a Trading Dispute, outside Final Reconciliation timescales (so long as the criteria for a valid Trading Dispute are met). As such, the scope of Option 3 does not extend to all unrecorded units. Rather it only includes those units identified by RPS.

An exception is the situation where a Metering System is energised without being registered to a Supplier. Under this scenario, unrecorded units cannot be allocated to an individual Supplier. However, these units are not usually identified by a RPS, so arguably fall outside the scope of this solution. Question 11 below seeks your views on this type of unrecorded energy.

Question 11
Should units taken prior to the registration of a Supplier for a new connection be included within the scope of reporting under Option 3? If so, how should these units to fed into the reporting process, given that they are not usually identified by Revenue Protection Services?

Impacts of Solution Option 3

The full impact on ELEXON will be determined by internal impact assessment, in parallel with the industry impact assessment.

Impact on BSC Systems and process	
BSC System/Process	Potential impact
New	New application would be required if BSCCo to fulfil central administrator role for reporting Revenue Protection adjustments.

Impact on BSC Agent/service provider contractual arrangements	
BSC Agent/service provider contract	Potential impact
New (potentially the SVAA)	New contractual arrangements for Revenue Protection adjustment reporting, in the event that BSCCo fulfils central administrator role.

Impact on BSC Parties and Party Agents
Removal of requirement on NHHDCs and HHDCs to account for assessed unrecorded units.
New reporting requirements for Suppliers (and new LDSO processes for verifying Supplier reports).
Changes to DUoS billing systems for LDSOs (and changes to Supplier systems for validating DuoS charges).
New LDSO processes for reporting aggregated Revenue Protection adjustments as part of Distribution Price Control.

Impact on ELEXON	
Area of ELEXON's business	Potential impact
BSC Operations	Contractual and operational management of new reporting function, in the event that BSCCo fulfils the central administrator role.

Impact on Code	
Code section	Potential impact
Sections S, Annex S-2 and X	New obligations on the SVAA (under Section S) and associated definitions under Section X, if BSCCo fulfils the central administrator role (and assuming that the reporting process is undertaken by the SVAA).

Impact on Code Subsidiary Documents	
CSD	Potential impact
BSCP504 'Non Half Hourly Data Collection for SVA Metering Systems Registered in	Removal of Section 3.6

SMRS'	
BSCP502 'Half Hourly Data Collection for SVA Metering Systems Registered in SMRS'	Removal of references to Revenue Protection Services in Section 4.2
New (or BSCP508 'Supplier Volume Allocation Agent')	New reporting processes for the SVAA, if BSCCo fulfils the central administrator role (and assuming that reporting process is undertaken by the SVAA).
SVA Data Catalogue	New P-flows to define reports between SVAA, Suppliers and LDSOs, if BSCCo undertakes the central administrator role

Impact on Core Industry Documents and other documents	
Document	Potential impact
Distribution Connection and Use of System Agreement	New rules around Revenue Protection Service, Supplier and LDSO reporting of Revenue Protection adjustments

Summary of Impacts

The following table highlights the key differences between the three options (and their sub-options). Question 12 asks for your views on the weight that should be given to these factors, and whether you have a preferred solution option.

	Option 1 – enhancements to current process	**Option 2 – end-to-end tracking**	**Option 3 – Settlement Cost Smearing**
Change Management			
Modification Required?	No	Yes	Yes (if BSCCo administers)
Impact on other Codes	DTC change	DTC changes	New governance around scheme administration in DCUSA, unless BSCCo administers
Scope			
Theft at meter (by-passing meter /tampering).	Yes	Yes	Yes
Theft in Conveyance.	No	No	Yes
Energised Metering Systems with no Supplier appointed.	No	No	Potentially (see Question 8)
Includes theft for Half Hourly metered Supplies	Yes	No	Yes
Incentives			
Reduces disincentive to detect theft.	No	No	Yes
Audit and Performance Assurance			
Auditable?	Only to the extent that adjusted readings can be mapped to RP cases	Yes	Yes
Supports monitoring of Settlement Risk SR0073.	No	Yes	Potentially, if reports sent to ELEXON by Suppliers/ administrator

LDSO Requirements			
Supports Distribution Price Control reporting	Yes (but not as a separately identifiable quantity)	Yes	Yes
Supports DUoS billing	Yes (but not as a separately identifiable quantity)	Yes	Yes
Allocation of Energy			
Allocates energy to period of theft	Depends on application of process	Depends on application of process	Yes
Allocates energy to correct Half Hours/Settlement Periods	No	No	Yes (via GSP Group Correction)
Allocates energy to correct Supplier	Yes (partly depends on application of process)	Yes (partly depends on application of process)	Only for DUoS. Not for Settlement
Supports adjustments outside RF	No (Adjustments outside RF should only be made as part of an authorised Trading Dispute)	No (Adjustments outside RF should only be made as part of an authorised Trading Dispute)	Yes (not constrained by Settlement Calendar)

Question 12

Of the factors listed in the table are there any that you believe the Group should give particular weight to? (or, conversely, which you believe are not important)

What is your preferred solution option, if any?

Are there any other solution options you believe the Group should consider?

6 Further Information

More information is available in:

Attachment A: Current BSC Process for Revenue Protection Adjustments

This information includes:

- A description of the current process
- A description of issues relating to the current process.

Attachment B: Impact Assessment Response Form

All Issue 39 documentation is available on the Issue 39 page of the ELEXON website.

Standing Issue 39 Impact Assessment Responses

Impact Assessment issued on 1 December 2010

We received responses from:

Company	No. and role of Parties/non-Parties represented
Western Power Distribution	2/1; Distributor, MOA
Electricity North West Limited	1/0; Distributor
The Electricity Network Company Limited	1/0; Distributor
CE Electric UK	2/0; Distributor
Siemens Metering Services	0/1; Party Agent
RWE npower	9/0; Supplier/Party Agent
G4S Utility Services	0/1; Party Agent – NHHDC,NHHDA, MOp
Central Networks	1/0; Distributor
UK Power Networks	4/0; Distributor
E.ON UK	5/0; Supplier
British Gas	1/0; Supplier
Accenture Services Limited (for and on behalf of Scottish Power)	7/0; Supplier / Generator / Trader / Consolidator / Exemptible Generator / Distributor

Question 1: Would Option 1 impact your organisation?

Summary

Yes	No	Neutral/Other
11	1	0

Responses

Respondent	Response	Rationale
WPD	Yes	The only impacts on our systems and processes will be new reports, should we choose to take advantage of the new reading type for "stolen" units. Costs and implementation timescales will be low.
ENW Ltd	Yes	We are impacted from two perspectives: From a Revenue Protection Service (RPS) we would no longer have to provide data to the Data Collector. It is assumed that we would continue to undertake the calculation and provide to the Supplier; and

Respondent	Response	Rationale
		From a Distributor perspective we will start to receive adjusted readings. Prior to commenting on both we believe it would be more helpful to include the RPS process within the diagrams and the BSCPs so that a full process is understood. The BSCP504 ref 3.6.1 starts at the data already having been received from the RPS. To change this to receipt from the Supplier will lose any reference to the RPS undertaking such an activity and the BSCP would then be oblivious to their involvement in the process. RPS is a market participant in their own right and as such should be recognised within this section of the BSCP. Since the RPS send the data by e-mail to both the Supplier and Data Collector the impact will be to amend who they send the data to. This will therefore have no financial impact. From a Distributor perspective we will be receiving an adjusted reading from the NHHDC. The impact will be the requirement to accept an additional 'reading type' within the D0010 as a consequence of the MRA change proposal. This would be classed as a medium impact with a lead time of six months from approval.
NEC Ltd	No	No real impact.
CE Electric UK	Yes	Yes – very minor impact. Testing of the new D0010 data would be required, this would require minor system changes estimated to take approximately 6 months.
SMS	Yes	This would have a significant impact on our current processes, and is likely to require a new job role creating. The costs for this would be in the region of £25k upwards as an initial cost, then an ongoing annual cost of approx £20k. The implementation timescales would be approximately 10 months (following approval).
RWE npower	Yes	There would be significant impact on internal systems including NHHDC and Supplier registration and billing. New processes would need to be developed including flow management and reporting. We anticipate that it would require up to 12 months from point of approval for these changes to be incorporated. We assume that these costs may reach £250,000, however, we have not been able to perform any detailed costings.
G4S Utility Services	Yes	Option 1 would require some change to our NHHDC system to allow the use of the new reading type. Other than that the process is as our current processes are setup – however we would anticipate an increase in volume of adjustments if option 1 was approved therefore we may require extra staff to process these. We estimate there is about 10 person days of work to make the changes to our systems and processes. Implementation timescales would be 6 months for the

Respondent	Response	Rationale
		new read type.
Central Networks	Yes	There will be minimal impact with a requirement to adjust local systems to be able to identify a new read type value for the adjusted readings via the d0010 flow. There is a need for an agreed method of calculation for the assessment of lost units for Revenue Protection teams. This will facilitate easier discussion and agreement between suppliers and RP teams when settlement figures have to be agreed before submission to NHHDC. The agreed method of assessment will require a period of training. Additional staff resource may be required to facilitate the discussions required between suppliers and the clerical teams at the supporting RP service. The lead time required for this would be xxx months from approval.
UKPN	Yes	We would need to be able to receive in our systems an additional reading type. We believe our existing systems could handle this with minimal change. Additionally we would need to put in place manual processes to monitor and reconcile the number of adjustments against information provided by the RPS.
E.ON UK	Yes	This would be a small change for us as this is the method that E.ON supply and NHHDC currently use when entering units into settlement. By introducing a new meter reading type this process would be more transparent to other parties.
British Gas	Yes	We estimate that the additional process changes would cost an additional £20k per annum to complete
Accenture (for Scottish Power)	Yes	The initial impact will be to ensure that a robust process is put in place for the Revenue Protection adjustments to be sent from the Revenue Protection Service (RPS) prior to being sent to NHHDC. We do not understand why this additional process has been suggested as it just adds another layer to the overall process. It may be more efficient to get the RPS to simultaneously pass any Revenue Protection adjustment to both the NHHDC and relevant Supplier. It should also be noted in this option that BSC parties that currently follow the correct process and communicate adjustments between RPU and NHHDC will be burdened with making more changes to their existing processes than those that do not. As stated above, having both channels available when the RPU sends the adjustments would ensure either process could be adopted and minimise the impact on parties currently following the existing process.

Respondent	Response	Rationale
		With regard to use of 'dummy meter exchanges, we believe it is preferable to always exchange a meter when a revenue protection adjustment is required, as we have in the past encountered system difficulties when implementing a 'dummy meter exchange process'. We have no issue with the proposal to create a new value of Reading Type for RP adjusted readings as this will allow a ready view of units identified as being discovered as part of the Revenue Protection process. However as this will potentially require system changes it will require an implementation timescale between 6 and 9 months.

Question 2: Do you agree that a manual interface (e.g. monthly spreadsheets sent by email) is appropriate for Suppliers to send Revenue Protection adjustments to NHHDCs, given the likely volume of data?

Summary

Yes	No	Neutral/Other
7	4	1

Responses

Respondent	Response	Rationale
WPD	No	The DTN provides a secure, robust and auditable transfer mechanism for the purpose of sending information from one Market Participant to another and it should be used. The information being transferred would be classed as personal under the data protection act. Email spreadsheets do not provide an adequate level of security unless encryption and passwords are used and the overhead of doing this makes the manual system less efficient.
ENW Ltd	Yes	Requirement 1.1 The start and end dates of the theft – this should be the supplier's period of theft impact rather than the theft start and end dates. This is applicable where there is a change of supplier i.e. on one change of supplier the start date may be with supplier A and the end date with supplier B so the values that are being sent need not be the full start and end date of the theft period. On the point raised over meter replacement, whilst it is accepted that this date will be included in the manual process between Supplier and DC, this should also have been provided by the MOp (via RPS on the D0239 to a D0149/D0150 being sent) and dependant upon when the data is sent is likely to be already known by the DC. We need to consider whether the first supplier in the

Respondent	Response	Rationale
		chain (where a CoS has taken place) would need to provide such information since the removal date would be when they are not responsible for the supply. The D0239 can process the meter reading that has been taken were no meter has been removed but this flow only goes to the Supplier and MOp. This is a mandated data item so should be provided. This information therefore should be provided both as a meter reading during the investigation irrespective of whether the meter is removed or not. Regarding the manual interface via monthly spreadsheets, it would make more sense to deal with these as and when the data is received from the RPS i.e. we need to say x days after receipt from the RPS this data will be sent to the DC. This avoids having any unnecessary delays in handling such adjustments. This will need to be catered for under the proposed DCUSA change.
ENC Ltd	N/A	No Comment. Suppliers and NHHDC to answer.
CE Electric UK	No	No – Where possible the interface should be automated to avoid error and process failures. If the manual interface is adopted then generic templates and targets should be included to reduce the risk of ineffective processes.
SMS	No	Although we cannot be certain of the volume of data involved, we would not favour a manual interface, as this is would be more open to error and risk.
RWE npower	Yes	We agree that a manual interface is appropriate. A long term goal would be to enable transmission over the DTN however, until some method of tracking theft is enabled we believe the cost/benefits case for this will not be robust enough to consider implementation. Also in the first instance amounts of data transfer is likely to be on the lower side. Actual figures of RP discovery and investigation will be available through the Ofgem consultation RFI.
G4S Utility Services	Yes	Assuming the volume is relatively low a manual interface would appear to be the most cost effective solution
Central Networks	Yes	Upon approval this is probably the best and most cost effective option available currently. Distributors would also benefit from receiving this information when sent to the NHHDCs for audit purposes. Visibility of the units being submitted at the end of each month by the suppliers would give the distributor the opportunity to check the submitted data against their own records, although there will be a capability to run reports to check against the new 'read type'.
UKPN	No	An electronic solution would be better. This would be in the form of a standard template used throughout the

Respondent	Response	Rationale
		industry.
E.ON UK	Yes	Yes it works at present and we see no reason to change the process.
British Gas	Yes	Given the volume of data we are happy with a manual interface
Accenture (for Scottish Power)	Yes	We refer to comment made in Q1 – we believe that a manual interface could be sent simultaneously by the RPS to the relevant Supplier, NHHDC and the Distributor if required. We are also in support of the interface being manual with set criteria agreed for what is to be contained in the spreadsheets.

Question 3: Do you agree that a requirement on Suppliers to process all agreed Revenue Protection adjustments, together with a process under the governance of the DCUSA for agreeing these adjustments, will be sufficient to ensure that all agreed units are accounted for? If not, what additional steps can be taken to ensure that all Revenue Protection adjustments are accounted for?

Summary

Yes	No	Neutral/Other
5	6	1

Responses

Respondent	Response	Rationale
WPD	Yes	If option one is taken forward then we believe these arrangements are sufficient.
ENW Ltd	No	There is still a lack of a specific BSC audit in this area. It should be a requirement to make this a mandated audit area and be covered off within the necessary BSCP. Such an audit needs to cover off end to end processes across market participants. Ideally, there should be a separate BSCP for Revenue Protection Services.
ENC Ltd	Yes	We agree that there should be a process under the governance of the DCUSA for agreeing adjustments and for mandating Suppliers to process the information given to them by the RPS and by any other parties who have identified unrecorded units.
CE Electric UK	No	No - Under option 1, LDSOs are required to agree the adjustments before they are made, however under the option the LDSO does not get any visibility of the final results, i.e. the adjusted data, therefore reconciliation will be difficult unless a summated report is produced using D0010 information. This option would be more feasible if the LDSO and supplier received an output report in addition to the normal NHH DUoS report.

Respondent	Response	Rationale
SMS	Yes	-
RWE npower	No	We believe that it would be prudent to put in place an audit framework to ensure that Suppliers are not selectively submitting units. This should be an independent body and governed under the BSC. We would also expect an units identified by the Distribution Network Operator as theft in conveyance to be submitted to this body also.
G4S Utility Services	-	No opinion.
Central Networks	No	If the process was run under the governance of the BSC then an end to end audit of the processes would have to be agreed and implemented. The units submitted should be as agreed with the RP service provider who should also be included in future audit processes.
UKPN	No	It would be beneficial if there was a robust BSC requirement on Suppliers to process all agreed Revenue Protection adjustments, with Performance assurance validation checks. Such a requirement would ensure that all adjustments entered the process but must also ensure that the adjustments reflect the actual units. There should be an industry standard template/interface for the RPS to notify the Supplier and the LDSO of lost units. To minimise the interaction and potential for disputes there should be a methodology used by the RPS for calculating units (eg in a governed RP Code of Practice)
E.ON UK	Yes	We believe that suppliers should process all revenue protection units when a supplier's equipment has been interfered with. For units where theft has been in conveyance and the Distributors equipment has been interfered with, then they should be responsible for entering those units into settlement. The governance for these activities should sit under the DCUSA.
British Gas	Yes	A DCUSA working group is working on a Revenue Protection Code of Practice (COP). This COP will specify the acceptable methods a supplier can use to calculate the stolen units. We agree that the DCUSA governance are sufficient to ensure all agreed units are accounted for.
Accenture (for Scottish Power)	No	We believe that a supplier should process all unrecorded units into the settlement process not just revenue protection adjustments. However with regard to the revenue protection adjustments we believe that the governance of such should be strengthened and be included in both the DCUSA and BSC. The reasoning behind this view is that elements of revenue protection impact on both. The DCUSA should focus on the actual revenue protection activity, whereas the BSC should

Respondent	Response	Rationale
		focus on the recording and entering of the units into the settlement process.

Question 4: In what proportion of Revenue Protection incidents does the period between the date theft is deemed to have started and the date unrecorded units have been estimated and agreed exceed 14 months?

Responses

Respondent	Response	Rationale
WPD	-	We do not have any information that would enable us to provide an answer to this question.
ENW Ltd		Between January 2010 and Nov 2010 we have the following: Number of cases – 1452 <14 months period of unrecorded units– 698 >14 months period of unrecorded units – 754. If the suggestion is to push through those above 14 months through the Trading Dispute Procedure this will increase the workload for the Trading Dispute committee in this area. It would be useful if the criteria for a trading dispute were reviewed and consideration given to the reconciliation process being based on the current GVC process.
ENC Ltd		As a distributor we are not aware of any such incidents reported to us. As a start up IDNO we still have only a relatively small number of MPANs.
CE Electric UK		Using information from assessments performed on behalf of Suppliers in Dec 10, 94.2 % of the assessments are within 14 months, 5.8% exceeding 14 months. It would be useful if the criteria for a trading dispute was reviewed if this would be the process for getting the units that exceed 14 months processed.
SMS		We are unable to provide data on this.
RWE npower		We believe that cases that exceed 14 months make up around 20% of all revenue protection activity. We are including detailed information regarding this in our response to Ofgem on their theft detection consultation.
G4S Utility Services		We currently receive too few adjustments so do not have sufficient information to base an answer to this question on.
Central Networks		Where we have found domestic and commercial meter interference there are very few instances (around 15%) where theft is deemed to have been taking place over 14 months. This is probably because suppliers identify leads through data analysis / non payments etc and passes the report through to RP services. Domestic thefts especially

Respondent	Response	Rationale
		tend to be short term / repeated offences with the consumer swapping suppliers every couple of months. Central Networks attended 4000 cases of interference in the period Jan to Nov 2010 92% is accounted for by domestic / commercial theft by meter interference. The other 8% is largely made up of cannabis factories directly connected to the network. These are more likely to be longer term projects usually between 12 and 18 months. Option 1 does not support the settlement of units from network losses and so fall out of the remit of this question.
UKPN		For 2010, 1579 theft cases were for periods > 14 months
E.ON UK		We do not hold data on this. However we have had start dates in the past going back for up to five years.
British Gas		We estimate that the proportion of theft that exceeds 14 months is around 28%. This is based on analysis of our theft cases for 2010.
Accenture (for Scottish Power)		It is our belief that any adjustments should be included in the process regardless of when it has been found and what period it relates to including any period falling outside the settlement window as it's inclusion could have a material impact on Distribution losses, however we recognise that a further mechanism may be required for these units to be accounted for. We also believe that any adjustments that are made should follow the same guidelines that were set out within CP1310, CP1311 and CP1312. These changes looked to clarify the process for using Gross Volume Correction and set clear guidelines around the timescales that this can be applied. So, any guidelines around timescales for RPU should look to follow the same process as the recently updated GVC process

Question 5: Would Option 2 impact your organisation?

Summary

Yes	No	Neutral/Other
12	0	0

Responses

Respondent	Response	Rationale
WPD	Yes	The only impacts on our systems and processes will be new reports, should we choose to take advantage of the new reading type for "stolen" units. Costs and

Respondent	Response	Rationale
		implementation timescales will be low.
ENW Ltd	Yes	We are impacted from two perspectives: From a Revenue Protection Service (RPS) we would no longer have to provide data to the Data Collector. It is assumed that we would continue to undertake the calculation and provide to the Supplier; and From a Distributor perspective we will start to receive an amended D0030. As per our response to Q1 we believe that the RPS should form part of the process diagram. Since the RPS sends the data by e-mail to both the Supplier and Data Collector the impact will be to amend who they send the data to. This will therefore have no financial and lead time impact. From a Distributor perspective we will be receiving an amended D0030 from the SVAA. The impact will be the requirement to accept the amended data flow as a consequence of the MRA change proposal. This would be classed as a medium impact with a lead time of six months from approval. The above however does not show us what is being entered into settlements without trawling through the D0019's (needle in a haystack) that is only available to Distributors on a quarterly basis if requested by them in the first place. In our opinion, when considering option 1 and option 2 we would suggest that both the D0010 and the D0030 amendments are undertaken together with a BSC audit requirement to audit across market participants i.e. take data from the RPS and ensure that the unrecorded units enter settlements by checking at each point (supplier/DC/DA/SVVA) that each has undertaken their part of the process.
ENC Ltd	Yes	Option 2 would impact our organisation by way of the identification of unrecorded units, and the entry of such units into the settlement process, reducing distribution losses.
CE Electric UK	Yes	Yes – This would have a medium/high impact upon our business. We would need to make changes to the billing systems to receive and process the new D0030. Timescales (would require IT confirmation) are likely to take up to 9-12 months, this includes implementation timescales; costs would require impact assessment from our IT provider.
SMS	Yes	This would have a significant system and process impact. The process changes would be similar to Option 1, but with the additional system change requirements, the timescales for implementation would be around 12 months, and the cost would be approximately £35k upwards, with an ongoing annual increase of approx £20k.

Respondent	Response	Rationale
RWE npower	Yes	Option 2 would have a significant impact across all of our organisation and would require changes to supply/registration/billing/settlement and NHHDC systems. It is likely that implementation would require at least 12 months from the date of approval. We anticipate that any change would be in excess of £250,000, however, we have not been able to perform any detailed costing. We would require detailed business rules and requirements as to how the industry process would work in practice.
G4S Utility Services	Yes	Option 2 would require a large amount of change to our NHHDC system, it would also require changes to NHHDA system which we would need to test. The changes to our NHHDC system would include changes to the database structure and major processes like requesting and loading EAC/AA data and production of D0019s as well as new GUI feature to allow the meter advances to be entered. These are significant changes and therefore be like to trigger a re-qualification processes as well. Although centrally maintained the changes to NHHDA to process the new AAs for adjustment units would mean we would have to carry out full testing of the new NHHDA release. We estimate there is about 100 person days of work to make the changes to our systems and processes. Implementation timescales would be 1 year for option 2.
Central Networks	Yes	There will be minimal impact with a requirement to adjust local systems to be able to accept the amended d0030 data flow. There is little visibility on the units entering settlement in this option. Central Networks would like to have visibility of the units entering settlement and will require RP services to provide this data as agreed with suppliers before submitting for settlement. As with option 1 this process requires all parties to be subject to a mandatory audit by the BSC to ensure accuracy. The lead time required for this would be xxx months from approval.
UKPN	Yes	We would receive an amended D0030. We believe our existing systems could handle this with minimal change provided the data was presented in a consistent format with other D0030 data. To enable a reconciliation of the D0030 data to all the individual jobs completed by the RPS, an industry process would be required whereby all RPS services provided details to the Distributor
E.ON UK	Yes	This solution has far ranging impacts on our systems as

Respondent	Response	Rationale
		well as central systems. Development of these changes would require a minimum of 9 months to implement. Although we do not have firm costs for these changes, experience shows that costs will typically run into tens of thousands of pounds.
British Gas	Yes	Same impacts as option 1 plus We will need to change our internal systems as a result of proposed changes to dataflows. We estimate these changes to cost around £30k
Accenture (for Scottish Power)	Yes	It is our belief that Option 2 provides the most suitable option in that it provides clear transparency and sight of RP adjustments throughout the process, which will also allow an auditable trail to be easily created. However, where there are changes to existing processes, such changes and any information provided by these changes must be readily identifiable and extractable from any flows. The specific costs associated with this option will depend on the changes that will be required on the NHHDC side as these will have to be funded within ScottishPower. We envisage significant cost and system change required to implement this option both internally for BSC parties and for Industry governance. Any changes to existing processes will need a minimum 6-9 month lead time to ensure all implementation and testing is in place.

Question 6: Do you agree that the incidence of theft for Half Hourly Metering Systems is too low to warrant significant changes to the Half Hourly processes?

Summary

Yes	No	Neutral/Other
8	1	3

Responses

Respondent	Response	Rationale
WPD	Don't know	We suspect this is the correct conclusion but we do not have any evidence that would enable us to provide a definite answer to this question.
ENW Ltd	Yes	A manual process is sufficient as long as there is a BSC audit in this area as per our response to Q3.
ENC Ltd	-	To focus RPS on "theft" is too narrow. The focus should be on detecting unrecorded units. For example, in the case of HH supplies metered via CTs, it is possible for a connection to be energised without metering being fitted, CTs to be incorrectly recorded or for CT fuses to fail.

Respondent	Response	Rationale
CE Electric UK	Yes	Yes – we agree that the incidence of theft for HH metering systems is too low to warrant significant changes to the HH processes.
SMS	Yes	-
RWE npower	Yes	-
G4S Utility Services	-	No opinion
Central Networks	Yes	Theft from Half Hourly metering systems is very low and can be largely handled using current processes.
UKPN	Yes	Half hourly adjustments can be processed as re-transmissions of HH data. However these also should be subject to auditability to prove reconciliation/completeness of data between RPS and Supplier. The method used must enable data to be processed promptly, especially for cases that might be on the point of falling outside the settlement window.
E.ON UK	Yes	-
British Gas	Yes	At this time we do not have any material evidence to support the argument that significant changes should be made to Half Hourly processes. This is an area that we have not concentrated on in the past. We do intend to look at this area in the future and will make proposals if we feel these are warranted in due course.
Accenture (for Scottish Power)	No	Given the current Elexon/PSRG initiative to potentially move to all PC5-8 customers (164,000) to HH once AMR meters have been installed would suggest that the HH market could see an increase in the incidence of theft. Given this possibility it may be prudent to review the HH process at this time prior to this potential move.

Question 7: Would Option 3 impact your organisation?

Summary

Yes	No	Neutral/Other
9	2	1

Responses

Respondent	Response	Rationale
WPD	Yes	We would need to introduce new processes and, possibly, undertake some systems development to be able to process data from Suppliers or from the Central Agent. The costs and implementation timescales would be dependent upon the end to end solution agreed under the associated DCUSA change process. We could end up with a simple solution where, for example, we receive one monthly total of lost units per

Respondent	Response	Rationale
		supplier and we use this to calculate a manual monthly charge for DUoS at a single per unit rate. We would use the sum of all lost units to make a simple adjustment to our losses statement. In this best case scenario implementation costs and timescales would be minimal, as would the ongoing operating costs. Alternatively we could be required to introduce a system which merged data with D0030 flows. This would require a change to our DUoS billing system and would potentially cost tens of thousands of pounds and take up to a year to implement.
ENW Ltd	Yes	We are impacted from two perspectives: From a Revenue Protection Service (RPS) we would no longer have to provide data to the Data Collector. It is assumed that we would continue to undertake the calculation and provide to the Supplier and also to provide the data to the Distributor; and From a Distributor perspective we will have to agree adjustments for DUoS billing and reporting for losses. In the opening remarks to this section it was stated that suppliers have a disincentive to chase theft since they pick up the full energy costs rather than have them smeared across suppliers if they remain as unrecorded units. It would make more sense to continue the theme of smeared costs by socialising DUoS costs as well i.e. we don't bill DUoS for the agreed adjustments to the Supplier but through amended prices over the 5 year period up to the price cap thereby each supplier picking up their share of unrecorded units based on their proportion of market share. By such an introduction we then remove any barrier to promoting theft initiatives across all market participants. There is however a requirement that such identified losses, that are agreed with Suppliers and RPS' are submitted as part of each distributor's reporting of losses to Ofgem. The impact is more on business process rather than amending IT systems.
ENC Ltd	Possibly	It is difficult to understand how "agreed adjustments" would be provided to LDSOs. If this information was to be provided other than through amended D0030 flows, for example, we would need to modify our billing systems to enable input of such data. Suppliers may then need to validate their DUoS validation systems.
CE Electric UK	Yes	Yes – We would require new processes to bill out RPS adjustments as an additional activity to NHH DUoS billing. The impact however would be minimal. If this option is implemented, further consideration needs to be taken in respect of overall losses reporting to Ofgem.

Respondent	Response	Rationale
SMS	No	-
RWE npower	Yes	Option 3 would have a medium impact on our organisation. We believe that this would be around £100,000. However we feel that it is the most prudent option in terms of cost/benefit as wholesale system change is avoided. We would require clarity and detailed business rules on the DUoS charging elements of this option and in particular we would require time to assess any impact this would have on our settlement payment systems.
G4S Utility Services	No	No changes would be required for us.
Central Networks	Yes	The impact of this option on the distributor is minimal. A stated earlier I think that there is a requirement for an agreed method of calculation for the assessment of lost units for Revenue Protection teams. This will facilitate easier discussion and agreement between suppliers and RP teams when settlement figures have to be agreed before submission to scheme administrator. If Ofgem are willing to vary the DPCR5 methodology allowing units that are not 'visible' to enter into settlements then this is a viable option. If the RP service can submit adjustments to the scheme administrator where no supplier has a responsibility for the stolen units then this method could also be used to account for units stolen from the network.
UKPN	Yes	Option 3 would need to be sufficiently robust so that OFGEM were able to recognise the units in their losses methodology This solution would need agreement from Suppliers that the data format provided would enable them to validate Duos bills based upon the same data This impact would be around changes to business processes and would need around 6 months to prepare for implementation
E.ON UK	Yes	This would have an impact on our DUOS validation systems and the creation of new reporting. Although we do not have firm costs for these changes, experience shows that costs will likely to be lower than Option 2.
British Gas	Yes	Option 3 would have the minimum impact on our organisation. This is our preferred option as it removes the disincentive on Suppliers to identify cases of theft. We already provide reports to each distribution business containing details of each theft case we deal with on a monthly basis.

Respondent	Response	Rationale
		This option has the advantage that units assessed as stolen before the cut-out "theft in conveyance" can be easily incorporated into the Distribution Price Control reporting. This is important as we estimate that around 24% of the value of stolen units are related to "theft in conveyance" We do not envisage any material additional costs in implementing this option.
Accenture (for Scottish Power)	Yes	We do not believe that Option 3 provides a viable solution given that for it to proceed requires Ofgem to vary the DPCR5 methodology, a scenario which we believe to be unlikely given that Ofgem have indicated in the past that they would prefer that all units are entered into the formal settlement process. However, should Ofgem alter their current position it is expected that the major impacts will fall mainly on the Distribution businesses in respect of their Distribution Price Control and Losses incentive. In addition there will also be an impact with regard to change of governance from the BSC to governance within the DUCUSA.

Question 8: Under Option 3 would you favour a centrally administered scheme for reporting Revenue Protection adjustments or multilateral reporting between Suppliers and LDSOs under the governance of the DCUSA?

Summary

Centrally administered	Multilateral reporting	Neutral/ Other
6	5	1

Responses

Respondent	Response	Rationale
WPD	Multilateral	We favour a multilateral approach but, as for question 7, this will depend on the complexity of the end to end solution. Provided that the end to end solution is kept simple then we do not see a need for a central agent to administer the scheme. Provided Suppliers retain sufficient information to enable the values they provide to LDSOs to be audited, and the information sent is, for example, a simple monthly total of stolen units found by that Supplier then we don't need any third party intervention. However, if data pertaining to stolen units needs to be formatted to facilitate a complex DUoS billing solution then this may warrant a central agent being appointed to

Respondent	Response	Rationale
		do it.
ENW Ltd	Multilateral	We would prefer a multi-lateral arrangement. The Revenue Protection Code of Practice should be embedded within DCUSA as suggested under DCP054. This should include the rules around estimating and the reporting of unrecorded consumption together with consideration given to lead generation and reporting requirements. By introducing a new administrator you are increasing the costs of administering theft.
ENC Ltd	Central	We would support a centrally administered scheme. However, this is dependent on the difference in costs which we would incur for other options. The benefits are that you would receive the information by standard process and standard data structure.
CE Electric UK	Central	A centrally administered scheme certainly would allow for consistency and monitoring across the industry although is likely to be costly. Multilateral reporting allows greater flexibility for process arrangements between LDSOs and suppliers but would compromise the process consistency. Therefore a centrally administered scheme would be favourable.
SMS	Central	-
RWE npower	Central	We favour a centrally administered scheme. Although this may take more effort to establish in the short term it would allow the industry as a whole to view and discuss theft and provide analysis on whether theft is causing particular parties substantial disadvantage.
G4S Utility Services	-	No opinion
Central Networks	Multilateral	To keep the costs of identifying theft down a multilateral approach would be preferred. The introduction of an administrator is the introduction of higher costs to identifying theft. With the code of practice brought under the governance of the DCUSA all parties should benefit from a consistency of approach. The introduction of rules around the method of assessment for calculating stolen units and the communications required by all market participants is required.
UKPN	Central	A central scheme would give integrity and robustness to the data being exchanged
E.ON UK	Central	A centrally administered scheme for reporting would be our favoured approach under the governance of the DCUSA. We do not have details at this time of the costs, but typically there are benefits of a central process against multilateral arrangements.
British Gas	Multilateral	We would favour a multilateral reporting system between

Respondent	Response	Rationale
		Suppliers and LDSO's under the governance of DCUSA. We see this as a lower cost option that procuring a centrally administered scheme.
Accenture (for Scottish Power)	Multilateral	While we do not believe that Option 3 is viable, we believe that Multilateral reporting between Suppliers and LDSO's will give each company control of their Revenue Protection adjustments. Multilateral reporting will also ensure that a clear separation of responsibility is in place for reporting and tracking purposes.

Question 9: Under a central administered scheme:

• Who do you believe should perform this role (subject, of course, to their willingness to do so) - National Revenue Protection Service; BSCCo; the DCUSA; MRASCo; or another organisation (please specify)?

• How do you believe such a scheme should be funded?

Summary

National Revenue Protection Service	BSCCo	The DCUSA	MRASCo	Other organisation	Neutral/ other
2	4[1]	5	0	0	2

Responses

Respondent	Response	Rationale
WPD	DCUSA	On the assumption that the governance will be under DCUSA then we would favour DCUSA undertaking the task. It should be funded jointly by Suppliers and Distributors in line with other normal DCUSA services.
ENW Ltd	DCUSA	DCUSA since the RPS code of practice may sit within the code (subject to the outcome of DCP054)
ENC Ltd	BSCCo	• We would support the central scheme being performed by BSCCo because it is settlement information which is provided The National Revenue Protection Service has no governance arrangements with distributors, DCUSA is an administration agent rather than a central service provider and for MRASCo to perform this role would not be consistent with its' objectives. • We believe that the scheme should be funded as part of the BSC funding.
CE Electric UK	BSCCo	Since this is a settlements issue, the BSCCo would be best placed to administer the scheme. The scheme should be funded by suppliers.
SMS	-	-

[1] One respondent stated either BSCCo or DCUSA; this has been recorded as a preference for both BSCCo and DCUSA (i.e. this is why the sum of the various responses does not equal the number of respondents).

Respondent	Response	Rationale
RWE npower	BSCCo	• We have no strong views on the responsible party but feel it should be closely linked to the BSC as the aim is to increase the accuracy of settlement. Also as the governance for this seems likely to fall under the remit of the BSC it seems appropriate that the central administration role rest with the BSCCo. • It should be centrally funded by demand side participants including Distributors and Suppliers. We recognise that this may require change to the current BSC funding share arrangements to allow Distributors to contribute.
G4S Utility Services	-	No opinion
Central Networks	DCUSA	If a centrally administered scheme were to be accepted the DCUSA should take up this role as per the proposal to enter the code of practice into the DCUSA (DCP054).
UKPN	NRPS	We believed this would be best carried out by a National RPS The scheme should be funded by Suppliers
E.ON UK	NRPS	This central role would seem a fit the potential remit of a National Revenue Protection service. The scheme should be funded by all parties based on their market share.
British Gas	BSCCo/ DCUSA	Notwithstanding our response to question 8, we would see this carried out by either BSCCo or DCUSA and these would seem the most appropriate organisations to carry out this role. The scheme should be funded by both suppliers and distributors as distributors will benefit through their losses incentive and option 3 will give them the ability to account for units that are stolen in conveyance. Supplier share of the costs should be based on total energy throughput by each Supplier.
Accenture (for Scottish Power)	DCUSA	Again similar to our comments in Q7 we do not believe Option 3 is viable for the reasons previously stated, however, if it is to be a central administered scheme then it should be under DCUSA as this already contains elements within it with respect to Revenue Protection. A scheme could be funded by a small addition to the daily pence per mpan charge, however this would mean all customers would be paying for theft, though it could be argued that customers are paying for theft through the current smearing process carried out via the Group correction factor.

Question 10: Approximately what proportion of detected theft would you estimate to be 'theft in conveyance', i.e. theft that cannot be directly allocated to a Metering System (and hence a Supplier)?

Responses

Respondent	Rationale
WPD	We suspect it will be low but do not have any evidence that would enable us to provide a definite answer to this question.
ENW Ltd	The understanding of 'theft in conveyance' is currently being debated and consulted on by DCUSA as part of DCP054. Such a question therefore requires the outcome of that debate before we understand exactly what such a percentage is. For completeness, we should like to provide our view on the meaning of 'theft in conveyance': Our understanding of the electricity act that covers conveyance and is also contained within our DCP54 response is as follows: Where electricity is abstracted at premises for which no supplier has been appointed (paragraph 4(2) of Schedule 6) or outside of a premise (paragraph 4(1) of schedule 6) then this is the abstraction in conveyance: *"4.(1) Where any person takes a supply of electricity which is in the course of being conveyed by an electricity distributor, the distributor shall be entitled to recover from that person the value of the electricity so taken.* *(2) Where* *(a)any person at premises at which a connection has been restored in contravention of paragraph 5(1) takes a supply of electricity which has been conveyed to those premises by an electricity distributor; and* *(b)the supply is taken otherwise than in pursuance of a contract made with an authorised supplier, or of a contract deemed to have been made with an electricity supplier by virtue of paragraph 3 above or paragraph 23 (former tariff customers) of Schedule 7 to the Utilities Act 2000,* *the distributor shall be entitled to recover from that person the value of the electricity so taken."* The key to this interpretation is the definition of premises. Premises is defined in s64(1) of the Electricity Act and includes any land, buildings or structure. The appropriate interpretation is therefore, if electricity is abstracted from the meter or other assets including cables owned by the Distributor on the customer's premises for which a Supplier is responsible it is no longer in the course of being conveyed by the licensed Distributor.
ENC Ltd	Not known.
CE Electric UK	At present every case of theft is assigned to a Supplier. There are ongoing discussion groups where theft in conveyance is being discussed however the debate on this is still underway. Until we have direction we will continue to assign every case to a Supplier. Given an approximation 30% would be classed as theft in conveyance and 70% allocated direct to a metering system and Supplier.

Respondent	Rationale
SMS	We are unable to provide data on this.
RWE npower	We believe that there are substantial amounts of theft that is in conveyance however, due to continuing legal discussions around this (led by the DCP054 working group) we do not consider it appropriate to give detailed comments at this time. However, if Distributors are finding instance of theft in conveyance these should be reported to the central framework as well as all Supplier detected theft.
G4S Utility Services	No opinion
Central Networks	The answer to this question depends on the definition of 'theft in conveyance'. This needs to be established before figures can be given and is currently being consulted on by DCUSA as a part of the DCP054.
UKPN	The definition of theft in conveyance is currently being debated by the industry
E.ON UK	Of all cases of potential theft investigated by our Revenue Protection team in 2010 20% were theft in conveyance. This rises to 24% for cases that were actual confirmed tampers with equipment.
British Gas	We estimate theft in conveyance to be around 24% of the value of all theft cases identified. This is based on analysis of cases handled in 2010.
Accenture (for Scottish Power)	The majority of cases reviewed by the RPU are found to be theft that is associated with a specific metering system. It is very difficult to detect theft in conveyance and as such we cannot put a value on this type of theft.

Question 11: Should units taken prior to the registration of a Supplier for a new connection be included within the scope of reporting under Option 3?

If so, how should these units to fed into the reporting process, given that they are not usually identified by Revenue Protection Services?

Summary

Yes	No	Neutral/Other
9	0	3

Responses

Respondent	Response	Rationale
WPD	Yes	As is the case for units found to have been stolen directly form the distribution system, units consumed in this manner can not normally be attributed to a Supplier or corrected through the BSC processes. They are not true distribution system losses so they should be reported separately and taken out of the value of losses reported by LDSOs to the Authority. The LDSO should be responsible for collating and

Respondent	Response	Rationale
		reporting these units. Where they are detected by another party, that party should report them directly to the Distributor.
ENW Ltd	Yes	By socialising theft this should pick up such instances as No MPAN and New MPAN. That said we need to review the process of appointing a supplier who may not wish to pick up such instances. This may include a requirement to invoke a supplier of Last resort. Such instances in our distribution area do include RPS in the process because we have such a service. The losses however are not calculated and DUoS not recovered because the existing processes include settlements. Without a supplier being appointed we cannot enter data into settlements and suppliers are wary of accepting a new customer who is known to be taking electricity illegally. By taking this outside of the settlement arena we have an opportunity to fully reflect the impact that this area is having on our business by reporting such losses in line with the RPS calculations that are in the Revenue Protection Code of Practice. Such calculations can be undertaken and verified by the new supplier appointed and their RPS to agree the value of unrecorded units. The issue of the recovery of lost DUoS is catered for within the Electricity Act as indicated in our earlier response (Schedule 6, Para 4(1)).
ENC Ltd	Yes	Units taken prior to registration of a Supplier will have no appointed supplier and, therefore, no DC. As such, a mechanism needs to be established for LDSOs to input such units to BSCCo.
CE Electric UK	Yes	Yes – it is our experience that there are sites currently consuming energy where a supplier has failed to register liability, we are continuing to investigate these sites and have spoken with Elexon on the matter. One of our primary objectives is getting the units into settlements going forwards.
SMS	-	In theory these units should be captured in the scope of this solution, however we are not sure how it would be possible to report on this.
RWE npower	Yes	Any units identified in this manner should be fed in as it will give an indication of theft that a Supplier cannot be expected to easily identify. We believe that more active participation by the Distributors in theft detection and reporting of this will contribute to building a holistic picture of the issue within the industry.
G4S Utility Services	-	No opinion
Central Networks	Yes	The units being used by consumers that have unregistered supplies are investigated by the RP services

Respondent	Response	Rationale
		at Central Networks. The RP service should have the capability to enter units into settlement where no supplier can be identified, as with stolen units from the network.
UKPN	Yes	These could be reported as "No Supplier". This would give visibility of the units involved and the units could count against losses (subject to OFGEM agreement) Upon identification of such units, the Distributor would feed these into the reporting using the same process/template as an RPS and send the details to the Central Administrator
E.ON UK	-	All units that are not entered into settlement will artificially distort the DNOs losses incentive. There should be an obligation for DNOs to at least report these missing units along with the cause of the energisation error.
British Gas	Yes	We agree that units taken prior to registration should be included within the scope of option 3. These units should be agreed by both the new Supplier and the respective distributor and included on the report that is submitted to Ofgem as part of the Losses Incentive reporting.
Accenture (for Scottish Power)	Yes	All unrecorded units that are found regardless of whether it is theft or otherwise should be entered into the settlement process. This should always be the case regardless of which of the options outlined in the paper is ultimately chosen going forward.

Question 12: Of the factors listed in the table are there any that you believe the Group should give particular weight to? (or, conversely, which you believe are not important)

What is your preferred solution option, if any?

Are there any other solution options you believe the Group should consider?

Summary

Option 1	Option 2	Option 3	Neutral/ Other
3[2]	2	7[2]	1

Responses

Respondent	Response	Rationale
WPD	Option 3	We believe particular weight should be given to: Distribution Price Control reporting. DUoS Billing. Addressing of units stolen in conveyance. Reduction of the current disincentive to detect theft.

[2] One respondent stated 'not Option 2' – this has been recorded as a preference for both option 1 and 3 (i.e. this is why the sum of the various responses does not equal the number of respondents).

Respondent	Response	Rationale
		Auditable solution. Supports adjustment outside RF. We prefer option 3 as it provides the most complete solution to the issue. However, as this will require manual adjustment to losses reporting we would require Authority consent to this. In the absence of such consent then we would favour option 2.
ENW Ltd	Option 3	Option 3 is preferred, then Option 1 and finally option 2. That said we believe that Option 3 can be improved as suggested in our response, and that Option 2 and 1 should be combined. The biggest hurdle to unrecorded units is the costs that theft has on the supplier. This acts as a disincentive to promote theft initiatives. By socialising all DUoS and settlement costs it gives suppliers an incentive to start to chase theft, and Distributors a better reporting mechanism for losses.
ENC Ltd	-	The key factor which we believe should be given particular weight to is supporting adjustment outside RF. We believe that what is required is for the D0030 to be amended to allow for the adjusted units and for a process to be established for the supplier to recover those appropriate charges.
CE Electric UK	Option 1	Our preferred solution is option 1 (with a report to the LDSO of adjusted units)
SMS	Option 3	We believe that the aim to reduce the disincentive on Suppliers to detect theft should be prioritised. Option 3 is our preferred option as it addresses all of the issues raised, to a much greater extent than options 1 or 2. As an alternative option, have the group considered addressing this from an MOA perspective, rather than the NHHDC? A solution similar to Option 1 could be investigated, but with Suppliers notifying the NHHMO (instead of the DC), asking them to carry out the dummy meter exchange and advise them of the new reading to be used.
RWE npower	Option 3	Our preferred solution is option 3 as until accurate quantification all theft has taken place in an industry environment where the robust nature of that reporting can be guaranteed we believe that there is an insufficient business case to pursue option 1 or option 2. RWE npower also believe that in the current climate of Smart rollout it would be imprudent to develop change to data and flows as in option 1/2 as the industry will be subject to a great degree of change in the short to medium term that might supersede any activity under

Respondent	Response	Rationale
		option 1 and 2. Therefore a simpler solution as laid out in Option 3 with robust reporting and governance provides a stable solution for the medium term.
G4S Utility Services	Not option 2	Of the three option 2 is our least preferred because the changes required to our systems are much larger and more complicated for what we assume is a relatively small amount of energy.
Central Networks	Option 3 (see response to question 13)	The issue around the definition of theft in conveyance and how that will impact that will have on the choices people make has some importance to distributors and suppliers. The chosen option should be auditable with clarity for all market participants. Should support the monitoring of settlement risk as outlined by OFGEM.
UKPN	Option 2	Our preferred solution is Option 2. We would like to see a process which ensures that all theft units enter the process. This would provide recognition of theft units in settlements and from this, data reporting could be developed to consider incentives on Revenue Protection. This would also provide industry data which could be examined looking for trends in theft activity over time.
E.ON UK	Option 1	We believe there are merits in looking at all factors listed. Our preferred Option at present would be Option 1 as it is least change although there are merits in Option 3. We believe Option 2 to be too much change and expense and to be an inferior solution to the other two options.
British Gas	Option 3	We believe the most important factors are 1. Removes any dis-incentives on Suppliers to accurately calculate and report stolen units 2. Scope enables all categories of theft to be accounted for 3. Supports IDSO requirements 4. Allows energy to be correctly allocated within settlements Our preferred option is Option 3
Accenture (for Scottish Power)	Option 2	In order for Revenue Protection arrangements to work the system must be robust and must ensure that no party is disadvantaged. So from a Distribution perspective the Distributor must get full benefit from any Revenue Protection adjustments to ensure that they assist in the reduction of losses, which will in turn impact on the Distribution Price Control set by Ofgem possibly to their benefit. Suppliers should also not be disadvantaged when they report their Revenue Protection findings and as such

Respondent	Response	Rationale
		they should be incentivised to report and submit all Revenue Protection adjustments for entry into the settlement process. We also believe particular focus should be given to 'Reducing disincentive to detect theft' as this was one of the key areas reviewed as part of the initial DCUSA DCP054 working group and should remain a key aim of any changes implemented to the RPU process. Also, with the potential increase in HH sites following Elexon's PSRG analysis, their consideration should be given to the factor 'Allocate energy to correct half hour / Settlement periods' as this will complement the key goal of the PSRG to improve Settlements accuracy. Our preferred solution is Option 2, given that we do not believe Ofgem will alter the distribution price control methodology for Option 3. We believe that this option will provide full visibility at all stages of revenue protection adjustments throughout the whole process, from entering the process at NHHDC level through to both the Supplier Purchase Matrix and Distribution Use of System Report. It will also enable the Distribution companies to have a fully auditable trail of RP adjustments which can be utilised to provide Ofgem with relevant information in respect of the losses incentive that are part of the current Distribution Price Control (DPCR5). In addition, we believe that Option 2 provides an enhanced level of governance in respect of Revenue Protection going forward.

Question 13: Any further comments on Issue 39?

Responses

Respondent	Rationale
WPD	We consider that the critical element in any BSC, DCUSA or MRA change that is proposed is the agreement by the Authority that LDSOs can take the benefit from reduced losses that improvements in the revenue protection area will provide. This will provide the funds to enable enhanced revenue protection services which will be of overall benefit to all customers.
ENW Ltd	Suppliers need a monitoring process in place to cover the end to end process from the source of a lead to the outcome of the investigation. This process should from part of the BSC Audit. The raising of leads and success of them needs to be reported on by suppliers but we suspect that this is more a DCUSA issue rather than a BSC one.
RWE npower	One of our main concerns relates to customer billing as it is possible that a customer who has stolen will look to change supply if they receive the RP investigation notice. This is due to a misunderstanding on their part as the RP is separate in most cases to supply. However,

Respondent	Rationale
	consideration needs to be given to how to reimburse the original supplier when a customer who has stolen leaves and the new supplier corrects the old supply period. Additionally we would like to emphasise that all industry participants need to co-operate to maximise theft detection and look at this as an important step forward. However, there needs to be a holistic approach and possibly development of capability to allow Distributors to accurately report and manage theft in conveyance within the settlement arrangements.
G4S Utility Services	If option 2 is looked at in more detail some more consideration should be given to how NHHDA handles this data – are new D0023 and D0095 exception codes required? – If new data is received from the NHHDC that doesn't include NH10 instructions are the NH10 instructions superseded? – What happens if data is received from more than one NHHDC that is different (eg after a CoDC event). – Additional for an NHHDC – what would the requirements be on NHHDCs to transfer these adjustment AA details on a CoDC? – Would these AAs need to be used (with the AAs for the recorded units) when calculating an NH09 EAC or deeming a following read?
Central Networks	Option 3 is preferable if OFGEM is willing to vary the DCPCR5 methodology. It appears to be the most cost effective. Option 1 would work for theft where a supplier has been appointed to the premises where abstraction is taking place, but does not account for all instances of theft. Option 2 is the least preferable as the costs to implement this change will be high. The lack of visibility of the settled units may cause problems for distributors and cases where there is no appointed supplier cannot be settled using this method.
UKPN	All Options remove the RPS – NHHDC interface. This potentially creates scope for mismatches between RPS and NHHDC data.
Accenture (for Scottish Power)	In addressing a solution for Issue 39 the industry must put in place a robust solution that ensures that no party is disadvantaged throughout the whole Revenue Protection process. Issue 39 on its own, while providing some answers does not provide a complete solution, considerable work has also been put in by the DCUSA DCP054 working group and this work should not be ignored. In taking this issue forward it would seem sensible to bring the two groups together to allow them to work out a complete rather than piecemeal solution to resolve a major industry problem that has been around for a long time.