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Electricity Distribution Price Control Network Asset Data and Performance Reporting - Regulatory Instructions and Guidance: Version 1

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Target audience: Electricity Distribution Network Operators, Independent Distribution Network Operators, Electricity Suppliers, consumers and consumer representatives

Overview:

This document provides instructions and guidance to Electricity Distribution Network Operators to enable them to complete the reporting requirements associated with the new price control arrangements (DPCR5) which run from 1 April 2010 to 31 March 2015.

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Context

This document contains the Electricity Distribution Price Control Network Asset Data and Performance Reporting Regulatory Instructions and Guidance (RIGs).

The purpose of this document is to provide a framework to allow Ofgem to collect accurate and consistent asset data and performance information from the Electricity Distribution Network Operators (DNOs). A number of licence conditions require the DNOs to provide us with this information. The key licence conditions for the purposes of this document are standard conditions 15A (Connection Policy and Connection Performance), 44A (Network outputs regime), 44B (Distribution Losses Reporting Regime), 45 (Incentive scheme for quality of service), 45A (Incentive scheme for Transmission Connection Point Charges), 46 (Incentive schemes for innovation funding and Distributed Generation) and 46A (Business Carbon Footprint Reporting) of the electricity distribution licence.

This version of the guidance will apply for reporting for the year ending 31 March 2011. Revised versions of the guidance may apply for subsequent years.

This document is one of four which together form the entire RIGs associated with DPCR5. The three further documents cover:

- Electricity Distribution Price Control Cost and Revenue Reporting RIGs,
- Electricity Distribution Price Control Customer Service Reporting RIGs, and
- Glossary of terms.

Associated Documents

- Electricity Distribution Price Control Review Final Proposals (144/09)

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Summary

The Electricity Distribution Price Control Review[1] (DPCR5) sets the maximum amount of revenue that Distribution Network Operators (DNOs) can recover from customers over a five-year period from 1 April 2010 and places a number of incentives and obligations on the DNOs. We collect data annually to allow us to monitor DNO performance against their incentives, monitor compliance with their price control obligations and to allow analysis between price controls and at the subsequent price control review. Annual data collection also allows Ofgem to identify issues of performance ahead of the next price control review and provide us with a more robust understanding of the DNO business.

The Regulatory Instructions and Guidance (RIGs) provide a framework that enables Ofgem to collect data from DNOs in a consistent format. The RIGs inform DNOs about the information we plan to collect, guide them on how to provide this information and enable the DNOs to put the systems in place to collect the data to the detail we require.

Since we introduced the annual regulatory reporting arrangements in 2005 there have been significant improvements in the quality of data DNOs have provided to us annually and as part of their Forecast Business Plan Questionnaire (FBPQ) submissions. These improvements allowed us to carry out more robust cost comparisons and cost assessments at DPCR5. However, there are still inconsistencies in the data provided to us by DNOs and we will be looking for further improvements in the lead up to the next price control review.

As part of DPCR5 we introduced a number of new incentives and obligations, many of which require us to collect new data from the DNOs. In designing the RIGs associated with DPCR5 we have looked to streamline the approach to collecting the data to avoid duplication and overlaps between data requests.

Rather than establish new RIGs for each of the new price control mechanisms, which would lead to a proliferation of RIGs and a risk of duplication of data requests, we have grouped the data collection according to whether it relates to financial data (i.e. cost or revenue data), data on network assets and outputs and activity volumes, such as connection, quality of service and environmental volumes, or data related to quality of service including the guaranteed standards of service reporting.

For each of these three areas we have established separate RIGs documents. This means we will collect data on areas such as connections through returns relating to all three RIGs documents depending on whether it is cost, volume or service related.

In our annual reports on DNO performance, we will bring together data from across all three areas to provide stakeholders with a complete view of performance against each of the DPCR5 mechanisms. We intend to widen the scope of our annual reports

[1] Electricity Distribution Price Control Review Final Proposals, December 2009. Ref: 114/09

to include information on DNOs' costs and revenues, an overview of financial issues, an update on delivery against agreed network outputs and performance against environmental targets, connections and quality of service standards.

There are a number of conditions in the electricity distribution licences that require the DNOs to provide the information set out in the RIGs. These licence conditions also provide a procedure by which we can amend the RIGs. We intend to keep the RIGs reporting obligations under review and may seek to change them in light of the recommendations arising from the RPI-X@20 review, experience of reporting and analysing data from the new RIGs and where we identify duplication or gaps in the RIGs data.

1. Introduction

Background

1.1. As part of DPCR5 we introduced a number of incentives and obligations on the DNOs. These include a requirement on the DNOs to commit to deliver a predetermined set of network investment outputs, new standards of performance in providing connections, a requirement to report on the company's business carbon footprint and new incentives related to customer satisfaction with the DNOs' performance.

1.2. We need to collect data to allow us to monitor DNO performance against these additional incentives and obligations and to ensure compliance against the overall price control. The Regulatory Instructions and Guidance (RIGs) provide a framework that enables Ofgem to collect data from DNOs in a consistent format. The RIGs informs DNOs about the information we plan to collect, guide them on how to provide this information and enable the DNOs to put the systems in place to collect the data to the detail we require.

1.3. Towards the end of 2009 we commenced a review of our information reporting arrangements to ensure we could collect the information we need without placing an undue burden on the DNOs or introducing duplication in the data we request. We also considered that there was merit in bringing all the information that we collect from the DNOs into the RIGs framework such as the data requirements for conducting the annual Connections Industry Review.

1.4. Instead of creating a separate RIGs document for each price control mechanism we have grouped the reporting obligations depending on whether the data is financially related, volume related or performance related. We have decided to create RIGs for each of the following areas:

- Cost and revenue reporting - this includes all data of a financial nature including: DNO performance against the cost baselines we have set as part of the price control review process (looking separately at costs associated with network investment, other direct and indirect expenditure and spending on connections, quality of service and environmental obligations); DNO performance against the revenue allowance we have set as part of DPCR5; and DNO costs associated with pensions, tax and other financial commitments,

- Network asset data and performance reporting - this includes data associated with the type, scale and performance of the physical network. It covers reporting on the new network investment output measures that we have introduced as part of DPCR5 and also covers data on asset volumes, activity volumes and the number and types of connections, environmental and quality of service outputs, and

- Customer service reporting - this includes performance against the new broad measure of community satisfaction that we have introduced as part of DPCR5 and

against the telephony standards. We have also included guidance for the guaranteed standards of service to ensure that all DNO reporting obligations are in one place. Currently this guidance does not extend to standards related to connection services. We will include this guidance in the customer service reporting RIGs in 2011.

1.5. Structuring the RIGs in this way means that data relating to a number of different areas (such as connections) appears in all three RIGs. For example, connection costs will be reported under the cost and revenue reporting RIGs, connection volumes under the network asset data and performance reporting RIGs and connection performance reporting will be in the customer service reporting RIGs. While this approach means that the scope for duplication is minimised, we recognise that the full picture on any aspect of DPCR5 will involve bringing data together from across the three areas. We will address this in the way that we report on DNO performance.

Legal framework

1.6. There are a number of different licence obligations that requires the DNOs to provide Ofgem with information. For the network asset data and performance reporting RIGs the following legal framework applies:

- Standard licence condition (SLC) 15A (Connection Policy and Connection Performance) places obligations for connections reporting as set out in chapter 5,
- SLC 44A (Network outputs regime) places obligations for reporting on network outputs as set out in chapter 2,
- SLC 44B (Distribution Losses Reporting Regime) places obligations for reporting on losses as set out in chapter 5,
- SLC 45 (Incentive scheme for quality of service) places obligations for reporting on quality of service as set out in chapter 4,
- SLC 45A (Incentive scheme for Transmission Connection Point Charges) places obligations for reporting on transmission connection point charges as set out in chapter 5,
- SLC 46 (Incentive schemes for innovation funding and Distributed Generation), and places obligations for reporting on innovation funding and distributed generation as set out in chapter 5, and
- SLC46A (Business Carbon Footprint Reporting) places obligations for reporting on the business carbon footprint as set out in chapter 5.

1.7. The RIGs include definitions and related instructions and guidance for preparing the annual information submissions. For the avoidance of doubt, these RIGs are subordinate to the licence conditions. Consequently, the RIGs will not change any definitions or obligations contained within the electricity distribution licences applicable to the DNOs and in the event of any dispute, the licence conditions will always take precedence.

Timescales for reporting under the RIGs.

Reporting year

1.8. The relevant reporting year for the provision of information required under SLCs 15A, 44A, 44B, 45, 45A and 46 runs from 1 April to 31 March of the following calendar year. SLC 46A allows licensees to define their reporting period for business carbon footprint, which must be approved by Ofgem.

Submission dates

1.9. With the exception of the data set out in Table 1.1 and data associated with Network outputs DNOs must provide the information required under SLCs 15A, 44A, 44B, 45, 45A, 46 and 46A as soon as reasonably practicable and in any event, not later than 31 July following the end of the relevant reporting year to which such information relates. This is the latest date that DNOs can submit the information unless the Authority has previously consented otherwise in writing.

1.10. The submission must be accompanied by a letter signed by a director on behalf of the licensee confirming that the data has been provided in accordance with the RIGs.

1.11. With regards to the submission of data for network outputs reporting Table 2.3 sets out the reporting timetable.

1.12. Table 1.1 below sets out the timescales for the submission of reporting data for interruptions and faults.

Table 1.1 Timescales for the submission of data for interruptions and faults

RIGs workbook reference	Reporting data to be provided	Date of submission
QoS interruptions reporting workbook and QoS interruptions stage data reporting workbook	Interruptions	30 April
Network outputs reporting workbook	Data, commentary and analysis for the health index, fault rate record and load index	30 September (31 July for 2014)
QoS HV disaggregation reporting workbook	High Voltage disaggregation data	31 May

Resubmissions

1.13. Ofgem's agreement is required before any resubmission of information set out in a report produced in accordance with these RIGs can be made and in any such instance the report concerned must be resubmitted in full. The resubmission must

only be accompanied by a letter signed by a director where significant changes have been made and Ofgem or the licensee decide such a letter is required.

1.14. In addition for each resubmission a separate explanation must be provided listing each and every cell that has been amended and sufficient commentary to explain the reasons.

Review

1.15. Once the DNOs have submitted the information to the Authority, Ofgem or a person nominated by the Authority ('a reviewer') will undertake a detailed review of the information. Such a review may include a visit to each DNO for discussion of the information submitted. Such visits will be agreed with the licensees in advance.

1.16. Where a reviewer has been nominated, then in accordance with SLC 48.10, the reviewer will enter into an agreement with the licensee to maintain confidentiality on reasonable terms.

Appointing an examiner

1.17. In accordance with SLC 44A.12, SLC 45.8 and SLC46.8 the licensee must permit a person nominated by the Authority to examine the systems, processes and procedures for measuring the specified information, the specified information collected by the licensee and the extent to which the systems, process and procedures and the specified information complies with the RIGs.

Auditing interruptions reporting

1.18. Appendix 1 sets out the audit requirements for interruptions reporting.

The RIGs workbooks

1.19. There are six workbooks for the network asset data and performance reporting RIGs. Below is a summary of these workbooks and the worksheets that are contained within them where relevant:

- Network Asset Data and Performance reporting workbook A1-A27 and A36-44 for reporting on network asset data in chapter 3 and A28-35 for reporting on environmental data as specified in chapter 5,
- Network Outputs reporting workbook for reporting on network outputs as specified in chapter 2,
- Network Outputs reporting workbook HI tracking for reporting on network outputs as specified in chapter 2,
- QoS HV Disaggregation reporting workbook for reporting on quality of service as specified in chapter 4,

- QoS Interruptions reporting workbook for reporting on quality of service as specified in chapter 4, and
- QoS Interruptions stage data reporting workbook for reporting on quality of service as specified in chapter 4.

1.20. In chapters 3 and 5 we refer to the worksheets contained in the workbooks, for example in chapter 5 we refer to worksheets A28 to A35 in the network asset data and performance reporting workbook, and in chapters 2 and 4 we refer to the workbooks themselves, for example we refer to the network outputs.

Completing the RIGs workbooks

Template

1.21. In the RIGs workbooks all the cells that DNOs are required to complete are coloured yellow. Cells with pre inputted values and checking cells are coloured orange and cells which have auto calculations or are totals are coloured green. Cells which are linked to other sheets are coloured blue.

1.22. Values must be entered in the column corresponding to the Regulatory Year under report. For example, values reported in respect of Regulatory Year 2010-11 must be entered in the column headed "2011".

1.23. Instructions for the electronic submission of the workbooks will be circulated to the licensee regulation managers in advance of each submission deadline. However, if there is any doubt about the method of submission, the licensee must contact the Costs and Outputs team at Ofgem.

Accuracy of reporting

1.24. In the RIGs worksheets the numbers will be displayed to two decimal places. However, the DNOs are required to provide this data to the highest level of accuracy available with the minimum being two decimal places, unless otherwise indicated in the worksheets or the guidance. Where a reportable value is zero or not applicable to the licensee then a zero must be input rather than the cell being left blank.

Provision of historic data

1.25. For each reporting year DNOs will be required to report a complete set of historic reporting data using this version of the workbooks for the full period of DPCR4 i.e. for each year commencing 2005-6. Ofgem will confirm in writing the

level of detail that we will require for the historic data. The open letter that accompanies these RIGs clarifies that historic data is not required for the 2009-10 submission[2].

Provision of forecast data

1.26. In each reporting year DNOs are also required to provide a full set of forecast reporting data for each of the subsequent five years. Therefore, for example, by 31 July 2011 DNOs will be required to submit a full set of reporting data for 2010-11 and also forecast data for 2011-12 to 2015-16 unless the Authority has previously consented otherwise in writing. The open letter that accompanies these RIGs clarifies that forecast data is not required for the 2009-10 submission[3].

Glossary

1.27. The glossary of terms is the fourth document in the RIGs pack and provides a definitive list of definitions for all three RIGs documents but excludes terms set out in the licence conditions. Where a term is defined in a RIGs document it can also be found in the glossary of terms.

1.28. For the avoidance of doubt the glossary of terms are subordinate to the licence conditions therefore if a term is defined in both the licence and the glossary the licence takes precedence.

Document Structure

1.29. The document contains the following chapters:

- Chapter 2 – sets out the instructions for completing network outputs reporting,
- Chapter 3 – sets out the instructions for completing asset data reporting,
- Chapter 4 – sets out the instructions for completing quality of service outputs reporting, and
- Chapter 5 – sets out the instructions for completing environmental reporting.

1.30. The appendices consist of the following:

- Appendix 1 – sets out the quality of service appendix,
- Appendix 2 – sets out the asset replacement unit cost scope,

[2] Electricity Distribution Price Control Review 5 (DPCR5): Version 1 of the regulatory instructions and guidance, 26 May 2010.
[3] Electricity Distribution Price Control Review 5 (DPCR5): Version 1 of the regulatory instructions and guidance, 26 May 2010.

- Appendix 3 – sets out the Authority's powers and duties, and
- Appendix 4 – sets out the feedback questionnaire.

2. Instructions for completing network outputs reporting

Introduction

2.1. The purpose of this chapter is to provide a framework for the collection and provision of accurate and consistent Network Outputs information from the electricity Distribution Network Operators (DNOs) and to set out a process for the assessment of performance.

2.2. This chapter covers the following areas:

- Use of Network Outputs reporting,
- Definitions and reporting categories,
- Reporting timetable,
- Annual reporting of Network Outputs,
- Network Outputs mid-period review,
- Network Outputs performance assessment, and
- Instructions and guidance for completing Network Outputs reporting workbook.

2.3. The Network Outputs reporting is intended to form the basis for informed discussions both during and at the end of a price control period on the benefits delivered by the level of investment undertaken during the price control period. The Network Outputs will make an important contribution to determining whether a DNO has delivered the change in the level of network risk funded by customers as part of the DPCR5 settlement, and will help establish whether any cost savings achieved by a DNO are due to efficiencies achieved during the price control period.

2.4. The Network Outputs specified in this RIG have been developed such that they are:

- measurable, controllable, auditable and replicable over time,
- sufficiently aligned with the underlying business processes that are used to plan and operate the network,
- sensitive to the level of investment, and
- able to capture outputs or outcomes such as performance, asset health, network capacity or headroom and network risk.

2.5. Network Outputs are not intended to constrain innovation or encourage inappropriate goal-orientated behaviour. Network Outputs are intended to help demonstrate, track and encourage improvements in asset management over time, the benefits of which should be realised by all interested parties. The Network Outputs developed as part of the settlement may be suitable not only for Ofgem in determining whether customers receive value for money, but also as a useful internal planning and management tool for the DNOs themselves.

2.6. It is recognised that the Network Outputs formulated for these purposes are at an early stage of development, and further improvement is encouraged over the period. The impact on output performance of any new information received during the DPCR5 price control period (e.g. changes to Health Index modelling), will be taken into account by Ofgem in forming an opinion on any financial consequences to apply in the event that the Delivered Network Outputs are different to those originally forecast (adjusted for the changes that occur over the period).

Use of Network Outputs

2.7. References in this document to the Agreed Network Outputs are references to the outputs (measured in terms of the Load Index, the Health Index and the Fault Rate Record) that form the baseline against which the DNO's future performance will be assessed. Those outputs were specified for the DNO in the Authority's decision document published on 7 December 2009 and are deemed to have been accepted by the DNO by virtue of the Authority's modification, with the licensee's consent, of the Charge Restriction Conditions of the distribution licence effective from 1 April 2010.

2.8. While the Agreed Network Outputs are not a 'hard target' for DNOs to meet, they will form the baseline against which each individual DNO's future performance will be assessed at an overall level by Ofgem. There will be financial consequences for a DNO that Ofgem qualitatively determines has not Delivered Network Outputs which reflect the change in the level of network risk funded by customers via the DPCR5 settlement.

2.9. The Agreed Network Outputs come in the form of metrics representing the DNOs':

- current assessments of network health (or fault rates) and utilisation,
- forecasts of network health and utilisation at the end of the price control period in the absence of network Intervention, and
- forecasts of network health (or fault rates) and utilisation at the end of the price control period as a consequence of their proposed load and non-load related network Interventions.

2.10. These initial Network Outputs have been developed against a common methodology and further refinement is expected and encouraged over the course of the price control period.

2.11. The Agreed Network Outputs developed for the DPCR5 price control period will be used:

- as the basis for informed discussions with Ofgem during DPCR5 and at DPCR6 on the level of investment undertaken and planned by a DNO during the DPCR5 period and to assess the likelihood of the DNO delivering the agreed package of

Network Outputs, (or equivalent), in return for the revenues collected from customers,

- to distinguish between those companies that have innovated and delivered what customers need more efficiently, and those that have deferred investment at the expense of delivering the agreed levels of network health and/or utilisation (noting that the different internal asset management approaches of each individual DNO means that Network Outputs cannot at this stage be used to compare DNOs directly),

- to demonstrate, monitor and encourage improvements and evolution in DNOs' asset risk management techniques over DPCR5, and

- as the foundation for further improvements in Network Outputs capabilities in DPCR6 (e.g. the development of high level network risk or 'tier one' Network Outputs).

2.12. As part of the DPCR6 process Ofgem is to conduct a Network Outputs performance assessment. The purpose of the performance assessment is to determine whether or not a DNO has satisfactorily delivered a package of outputs consistent with the change in the level of risk funded by its customers through the DPCR5 settlement. At a high level, this requires DNOs to provide information to demonstrate that the program of work actually delivered over DPCR5 was in customer's best interests, and for Ofgem to qualitatively determine whether or not this is the case.

Definitions and reporting categories

Definitions

2.13. This section sets out definitions and related instructions and guidance for the reporting of Network Outputs information under the common methodology. The definitions set out below are consistent with, and expand upon, those specified in paragraph A21 of SLC 44A. The following definitions can be found in the glossary:

- **Adjusted network outputs,**
- **Agreed network outputs,**
- **Annual submission,**
- **Delivered network outputs,**
- **Demand group,**
- **Demand group categories,**
- **Distribution asset,**
- **Distribution asset categories,**
- **Fault rate,**
- **Fault rate asset category,**
- **Fault rate record,**
- **Health index,**
- **Health index asset category,**
- **Intervention,**

- **Load index,**
- **Load index logic,**
- **Material change,**
- **Material change log,**
- **Mid-period review submission,**
- **Network outputs,**
- **Network outputs gap,**
- **Network outputs submission,**
- **Tier 1 network output measure,**
- **Tier 2 network output measure, and**
- **Tier 3 network output measure.**

Reporting categories

2.14. This section sets out the reporting categories for Network Outputs. DNOs must as a minimum provide updated information for all those reporting categories which are included in the Agreed Network Outputs, in accordance with the agreed reporting dates contained at section 2.18 of this RIG.

2.15. Unless otherwise specified, DNOs are required to report Health Index information for the Health Index Asset Categories set out in table 2.1 below. Table 2.1 expresses a preferred level of granularity, acknowledging that there may be minor variations between DNOs.

Table 2.1: Health Index Asset Categories and corresponding Distribution Asset Categories

Health Index Asset Category	Distribution Asset Category
LV OHL Support	LV Support
LV Switchgear and Other*	LV Pillar (ID) LV Pillar (OD) LV Board (WM)
LV UGB*	LV UGB
HV OHL Support - Poles	6.6/11 kV Support 20 kV Support
HV UG Cable*	6.6/11kV UG Cable 20kV UG Cable
HV Switchgear (GM) - Primary	6.6/11 kV CB (GM) [Primary] 20 kV CB (GM) [Primary]
HV Switchgear (GM) - Distribution	6.6/11 kV CB (GM) [Distribution] 6.6/11 kV Switch (GM) 6.6/11 kV RMU 20 kV CB (GM) [Distribution] 20 kV Switch (GM) 20 kV RMU
HV Transformer (GM)*	6.6/11 kV Transformer (GM) 20 kV Transformer (GM)
EHV OHL Fittings and Conductors (Tower Lines)*	33kV OHL (Tower Line)

	66kV OHL (Tower Line)
EHV OHL Support - Poles	33kV Pole 66kV Pole
EHV OHL Support - Towers	33kV Tower 66kV Tower
EHV UG Cable (Non pressurised)*	33kV UG Cable (Non Pressurised) 66kV UG Cable (Non Pressurised)
EHV UG Cable (Oil)*	33kV UG Cable (Oil) 66kV UG Cable (Oil)
EHV UG Cable (Gas)*	33kV UG Cable (Gas) 66kV UG Cable (Gas)
EHV Switchgear	33 kV CB (ID) 33 kV CB (OD) 33 kV Switch (GM) 33 kV RMU 66 kV CB (ID & OD)
EHV Transformer	33 kV Transformer (GM) 66 kV Transformer
132kV OHL Fittings and Conductors (Tower Lines)	132kV OHL Conductor (Tower Line)
132kV OHL Support - Tower	132kV Tower
132kV UG Cable (Non pressurised)*	132kV UG Cable (Non Pressurised)
132kV UG Cable (Oil)*	132kV UG Cable (Oil)
132kV UG Cable (Gas)*	132kV UG Cable (Gas)
132kV CBs	132kV CB (ID & OD)
132kV Transformer	132 kV Transformer
Submarine Cables*	HV Sub Cable EHV Sub Cable 132 kV Sub Cable

* DNOs to report a Fault Rate Record instead of Health Index information if:
the DNO does not presently have Health Index capability, and / or
it is not economic or practical to collect a full set of Health Index data.

2.16. Unless otherwise specified, DNOs are required to report a Fault Rate Record for the Fault Rate Asset Categories set out in table 2.2 below.

Table 2.2: Fault Rate Asset Categories and corresponding Distribution Asset Categories

Fault Rate Asset Category	Distribution Asset Category
LV Main (OHL)	LV Main (OHL)
LV Service	LV Service (OHL)
LV Main (UG Consac)	LV Main (UG Consac)
LV Main (UG non-Consac)	LV Main (UG Plastic) LV Main (UG Paper)
LV Service (UG)	LV Service (UG)
LV Switchgear*	LV Pillar (ID) LV Pillar (OD) LV Board (WM) LV UGB LV Fuses (PM) LV Fuses (TM)
HV OHL	6.6/11 kV OHL (Open) 6.6/11 kV OHL (Covered) 20 kV OHL (Open) 20 kV OHL (Covered)
HV UG Cable*	6.6/11 kV UG Cable 20 kV UG Cable
HV Switchgear (PM)	6.6/11 kV CB (PM) 20 kV CB (PM)
HV Transformer (PM) HV Transformer (GM)	6.6/11 kV Transformer (PM) 20 kV Transformer (PM) 6.6/11 kV Transformer (GM) 20 kV Transformer (GM)
EHV OHL Fittings and Conductors*	33 kV OHL (Pole Line) 33 kV OHL (Tower Line) 66 kV OHL (Pole Line) 66 kV OHL (Tower Line)
EHV UG Cable*	33 kV UG Cable (Non Pressurised)
	33kV UG Cable (Oil) 33 kV UG Cable (Gas) 66 kV UG Cable (Non Pressurised) 66 kV UG Cable (Oil) 66 kV UG Cable (Gas)
132kV UG Cable*	132 kV UG Cable (Non Pressurised) 132 kV UG Cable (Oil) 132 kV UG Cable (Gas)
Submarine Cables*	HV Sub Cable EHV Sub Cable 132 kV Sub Cable

* DNOs to report a Fault Rate Record instead of Health Index information only if:
- the DNO does not presently have Health Index capability, and / or
- it is not economic or practical to collect a full set of Health Index data.

Note 1: If Health Index information is provided for this category, DNOs to report a fault rate for 'Tower Lines' only (not 'Pole lines').

2.17. Unless otherwise agreed, DNOs are required to report Load Index information for each of the following Demand Group Categories:

- Substations (132kV to EHV),
- Substations (132kV to HV),
- Substations (EHV to EHV),
- Substations (EHV to HV), and
- Interconnected substation groups (with secondary voltage at HV or above). [4]

Reporting timetable

2.18. DNOs are required to provide a Network Outputs Submission for each year of the price control period, which must contain the required information as at 31 March of that year.

2.19. The reporting timetable for Network Outputs (to September 2015) is set out in table 2.3 below.

[4] For the purposes of the Agreed Network Outputs, DNOs only reported Load Index information for interconnected substation groups where there was expenditure forecast at the group level, but may have opted to provide this information for groups considered to be of relevance to a current or future general reinforcement decision.

Table 2.3: Reporting timetable – Network Outputs

Date	Submission due
7 December 2009	DPCR5 Agreed Network Outputs Submission (as published with Final Proposals)
30 September 2010	Annual Submission[5] - (for LI and HI true up only). No additional forecast is required
30 September 2011	Annual Submission
30 September 2012	Mid-Period Review submission
30 September 2013	Annual Submission
tbc	Initial Performance Assessment Submission
30 September 2014	Final Performance Assessment Submission
30 September 2015	Annual Submission[6]

Material Changes

2.20. It is important that the reasons for changes in the outputs delivered over DPCR5 relative to the Agreed Network Outputs are tracked and well understood through constructive dialogue between the DNOs and Ofgem. There could be a number of legitimate reasons to explain variations in outturn performance which could be considered Material Changes, including:

- Changes to input data,
- Changes to the assessment techniques/calculation methodology,
- Changes due to external factors, and/or
- Changes to DNO asset management strategy and approach, which could include a change in attitude to risk overall, or a shift in priorities from one risk to another as a result of one of the changes identified in the bullets above.[7]

2.21. Information on Material Changes relative to the Agreed Network Outputs is to be reported by DNOs as part of a Network Outputs Submission, and is relevant for

[5] This submission will provide an actual snapshot as at the start of DPCR5.
[6] This submission will provide an actual snapshot as at the end of DPCR5 (start of DPCR6), and will be used to 'true-up' the Network Outputs revenue adjustment (if required). See paragraphs 2.122 to 2.124 for details.
[7] It is recognised that the changes to highlight in the annual submission for years 1 and 2 of DPCR5 will likely focus only on changes to input data or the calculation method.

the purposes of determining the Adjusted Network Outputs. The nature and content of discussions between Ofgem and DNOs on the Material Changes identified and addressed through re-prioritisation is to be recorded in the Material Change Log.

Changes due to input data

2.22. Changes to input data are particularly likely with respect to the Health Index given that most DNOs continue to work towards a full dataset throughout DPCR5. The information provided on changes due to input data must be auditable, and include details of and reasons for, all Material Changes in the DNO's data collection methodology, assumptions, or in the underlying quality of the data set.

2.23. Material Changes in this category may be due (but are not limited) to:

- an exogenous change in data (e.g. due to a type fault identified),
- unexpected changes in data (e.g. asset health degradation being better or worse than forecast), and/or
- a conscious business decision regarding the data collection methodology which causes a change in data accuracy for the relevant measure.

2.24. As an example, a change to the equipment rating would constitute a change to input data (along with any consequent change to firm capacity as defined), whereas a change to the DNO's definition of firm capacity would constitute a change to the assessment technique / calculation methodology.

Changes to the assessment technique/calculation methodology

2.25. Changes to the assessment techniques/calculation methodologies applied by the DNOs are possible given that the methodology for Network Outputs is still relatively new. On this basis it is recognised that a DNO's outputs delivered may diverge from the Agreed Network Outputs as new asset information or new and innovative asset management techniques are adopted. The information provided on changes to the assessment techniques used for individual outputs or the calculation and data collection methodologies must be auditable, and include details of, and reasons for, all those changes that produce a different set of outputs for a given set of inputs.

2.26. Material Changes in this category may include (but are not limited to):

- development of innovative (condition) assessment technique for an individual Network Output,
- changes to asset degradation assumptions,
- change to the definition of firm (n-1) capacity,
- introduction of a new or improved Health Index methodology,
- a conscious business decision regarding key data requirements, causing a change in the data items used for the output measure, and/or
- legitimate changes to data interpretation (e.g. weightings/thresholds).

Changes due to external factors

2.27. Changes in output delivery may occur due to external factors. The Material Changes in this category may include (but are not limited to):

- exceptional events (e.g. floods),
- speed of economic recovery (e.g. load growth different than forecast),
- legislative changes (e.g. greater focus placed on developing networks for a low carbon future),
- resource constraints (e.g. availability of human and plant resources in marketplace)
- significant changes in input prices, and/or
- planning constraints.

Asset management strategy

2.28. DNOs are expected to continuously optimise their asset risk management and this is likely to cause rebalancing of relative risks to optimise interventions. In doing so DNOs must take into account the change in the level of risk that customers have funded through the price control settlement. The information provided on changes to a DNO's asset management strategy must include details of and reasons for any deliberate decision to alter the relative or aggregate level of network risk faced.

2.29. Material Changes that may drive a need to reprioritise activities could arise for a number of reasons, including (but not limited to) any of those examples discussed above in paragraphs 2.56 to 2.58.

2.30. DNOs may provide information on their asset management approach as part of an Annual Submission however this is not expected to be a focus of discussions with Ofgem until the mid-period review. A full re-forecast of Network Outputs data, taking into account all forecast asset management Interventions, is not required until the mid-period review.

Annual reporting of Network Outputs

2.31. DNOs are required to provide an annual submission for Network Outputs in accordance with the timetable set out in table 2.3 above. The Annual Submission must include data in the reporting workbook for the following:

- Load Index – current LI profile (i.e. as at 1 April), and updated forecast LI profile without further Intervention (i.e. as at 31 March 2015),

- Health Index – current HI profile and commentary on HI data quality (i.e. as at 1 April), and updated forecast HI profile without further Intervention (i.e. as at 31 March 2015),

- Fault Rate Record – an updated actual Fault Rate for each relevant Fault Rate Asset Category.[8]

2.32. Section 2.125 of this RIG sets out detailed instructions and guidance for completing the reporting workbook.

2.33. In accordance with SLC44A Ofgem may appoint an Examiner to review the accuracy and integrity of the outputs data provided.

2.34. In addition to the information reported in the workbook, as part of the annual submission DNOs are required to provide commentary on all Material Changes that have occurred in the year since the previous submission.

2.35. It is important that the reasons for changes in the outputs delivered during DPCR5 relative to the Agreed Network Outputs are tracked and well understood through constructive dialogue between the DNOs and Ofgem. There could be a number of legitimate reasons to explain variations in outturn performance which could be considered Material Changes, including:

a) Changes to input data,
b) Changes to the assessment techniques/calculation methodology,
c) Changes due to external factors, and
d) Changes to DNO asset management strategy and approach, which could include a change in attitude to risk overall, or a shift in priorities from one risk to another as a result of one of the changes identified in (a), (b), and (c) above.[9]

2.36. Details on the nature of these Material Changes are contained in paragraphs 2.54 to 2.61 of this RIG.

2.37. The nature of any discussions between Ofgem and the DNOs with respect to the Material Changes identified and reported in an Annual Submission must be recorded in the Material Change Log.

2.38. The information contained in an Annual Submission will be reviewed by Ofgem and recorded in the Material Change Log. However it should be noted that the contents of the Annual Submission will not be approved by Ofgem in the sense that a formal declaration of the acceptability or otherwise will be issued. Ofgem reserves the right to assess a DNO's performance in delivering its outputs across the full period as part of the end-of-period performance assessment.

[8] For the avoidance of doubt, an updated 31 March 2015 (with further Intervention) profile for Network Outputs is not required as part of the Annual Submission.
[9] It is recognised that the changes to highlight in the annual submission for years 1 and 2 of DPCR5 will likely focus only on changes to input data or the calculation method.

2.39. It is acknowledged, however, that there is a clearly established intent to work bi-laterally in developing the use of outputs during the DPCR5 period and the inappropriate use of hindsight in judging performance at DPCR6 is to be avoided. DNOs can expect a substantive discussion with Ofgem following provision of each Annual Submission, during the course of which Ofgem will set out its opinion at that time on the progress being made in the context of the 5 year outcomes being pursued.

Network Outputs mid-period review

2.40. The purpose of the mid-period review is for DNOs to explain their progress towards achieving the Agreed Network Outputs. As part of the mid-period review a DNO must provide an updated forecast of their Network Outputs with further Intervention (i.e. as at 31 March 2015), which represents the DNO's interim view of the Adjusted Network Outputs. Ofgem will note the data and commentary in the Mid-Period Review Submission for price control discussions, provide guidance to DNOs on their progress and highlight any areas of concern at a high-level.

2.41. In accordance with the timetable set out in table 2.3, DNOs are required to provide a Mid-Period Review Submission by no later than 30 September 2012. The mid-period review is to take place in the period October-December 2012.

2.42. The Mid-Period Review Submission must include a full re-population of the reporting workbook, which comprises the following:

- Load Index – current LI profile (i.e. as at 31 March 2012), an updated forecast LI profile as at 31 March 2015 without further Intervention, and an updated forecast LI profile as at 31 March 2015 with further Intervention,
- Health Index – current HI profile and commentary on HI data quality (i.e. as at 31 March 2012), an updated forecast HI profile as at 31 March 2015 without further Intervention, and an updated forecast HI profile as at 31 March 2015 with further Intervention, and
- Fault Rate Record – current fault rate, and an updated forecast Fault Rate for each relevant Fault Rate Asset Category for each year to 31 March 2015.

2.43. Section 2.125 of this RIG sets out detailed instructions and guidance for completing the reporting workbook.

2.44. In accordance with SLC 44A Ofgem may appoint an Examiner to review the accuracy and integrity of the outputs data provided.

2.45. In addition to the information reported in the workbook, as part of the Mid-Period Review Submission DNOs are required to provide commentary on all Material Changes that have occurred in the year since the previous submission, as well as a

recap of previously reported Material Changes. It is expected that the DNO responses to these Material Changes will then be reflected in the updated forecasts.

2.46. There could be a number of reasons to explain variations in outturn performance which could be considered Material Changes, including:

a) Changes to input data,
b) Changes to the assessment techniques/calculation methodology,
c) Changes due to external factors, and
d) Changes to DNO asset management strategy and approach, which could include a change in attitude to risk overall, or a shift in priorities from one risk to another as a result of one of the changes identified in (a), (b) and (c) above.

2.47. The nature of these Material Changes is explained further in paragraph 2.20 of this RIG.

2.48. It is recognised that the Material Changes identified under paragraphs 2.46(a), 2.46(b) and 2.46(c) may directly impact the current profile (i.e. as at 31 March 2012) and the forecast profile as at 31 March 2015 without further intervention, whereas the DNO's asset management response to these Material Changes (i.e. paragraph 2.46(d)) will wrap all these changes up to produce a forecast profile as at 31 March 2015 with further Intervention. It is also recognised that Material Changes due to external factors identified under paragraph 2.46(c) may directly impact the forecast profile as at 31 March 2015 with further Intervention.

2.49. As part of the mid-period review, a DNOs must provide a high-level assessment of performance and progress against the Agreed Network Outputs. This assessment must take into account each of the Material Changes identified in paragraph 2.46 above, the impact on the Agreed Network Outputs and the response taken or forecast to be taken. At this time Ofgem may provide specific guidance on those aspects of the submission it considers could be relevant for the purposes of setting the Adjusted Network Outputs as part of the end-of-period performance assessment process, including any specific concerns.

2.50. The nature of any discussions between Ofgem and the DNOs with respect to the Material Changes identified and reported in the Mid-Period Review Submission, including any guidance provided by Ofgem, must be recorded in the Material Change Log. It should be noted however that the information provided by the DNOs as part of the Mid-Period Review Submission will not be approved by Ofgem in the sense that a formal declaration of the acceptability or otherwise of DNO actions will be issued. Ofgem reserve the right to assess a DNO's performance in delivering its outputs across the full period as part of the end-of-period Network Outputs performance assessment.

2.51. The specific timeframes for the provision of DPCR6 Network Outputs information are to be agreed as part of the mid-period review.

Network Outputs performance assessment

2.52. As part of the DPCR6 process Ofgem is to conduct a Network Outputs performance assessment. The purpose of the performance assessment is to determine whether or not a DNO has satisfactorily delivered a package of outputs consistent with the change in the level of risk funded by its customers through the DPCR5 settlement. At a high level, this requires DNOs to provide information to demonstrate that the program of work actually (and forecast to be) delivered over DPCR5 was in customer's best interests, and for Ofgem to qualitatively determine whether or not this is the case. In making this assessment Ofgem accepts that the Delivered Network Outputs will differ from the Agreed Network Outputs in detail due to the impact of Material Changes.

2.53. The specific timetable for provision of the Initial Performance Assessment Submission is to be determined as part of the DPCR6 process. The final Performance Assessment Submission is to be provided by no later than 30 September 2014. The performance assessment is to take place over the course of the DPCR6 review.

2.54. The performance assessment process is summarised as follows:

- As part of its Performance Assessment Submission, a DNO must provide information to demonstrate that the Delivered Network Outputs are in customers' best interests, taking into account all Material Changes that have occurred over the price control period which have impacted outturn delivery relative to the Agreed Network Outputs.

- Based on this information, Ofgem is to qualitatively determine at a high level:
  - the Adjusted Network Outputs, and
  - whether or not a DNO has met its Adjusted Network Outputs.

- If Ofgem determines that a DNO has not satisfactorily delivered its Adjusted Network Outputs, a financial adjustment is to be applied to DPCR6 revenues, which is to be calculated as follows:
  - Value the difference between the DNO's Delivered Network Outputs and the Adjusted Network Outputs (i.e. the 'Network Outputs Gap'), and
  - Apply a sharing factor to the Network Outputs Gap to calculate a revenue adjustment (the 'Network Outputs revenue adjustment').

- In the event that Ofgem applies the Network Outputs revenue adjustment to a DNO's DPCR6 revenues, there may be a requirement for a 'true-up' at the end of the first year of DPCR6, once the final year of Network Outputs data for DPCR5 is received.

2.55. For the avoidance of misunderstanding, allowances for DPCR6 will be based upon the network need at the time and any under-delivery of DPCR5 outputs will be catered for by the revenue adjustment and not by reducing future allowances.

2.56. This section is structured as follows:

- Performance assessment submission,
- Qualitative performance assessment process,
- Revenue adjustment for failure to deliver Adjusted Network Outputs, and
- Correction to Network Outputs revenue adjustment during DPCR6.

Performance assessment submission

2.57. The performance assessment submission must include a full re-population of the reporting workbook, which comprises the following:

- Load Index – current LI profile (i.e. as at 31 March 2014), an updated forecast LI profile as at 31 March 2015 without further intervention and an updated forecast LI profile 31 March 2015 with further intervention,

- Health Index – current HI profile and commentary on HI data quality (i.e. as at 31 March 2014), an updated forecast HI profile 31 March 2015 without further intervention and an updated forecast HI profile 31 March 2015 with further intervention, and

- Fault Rate Record – current fault rate, and an updated forecast Fault Rate for each relevant Fault Rate Asset Category for each year to 31 March 2015.

2.58. Section 2.125 of this RIG sets out detailed instructions and guidance for completing the reporting workbook.

2.59. In accordance with SLC 44A Ofgem may appoint an Examiner to review the accuracy and integrity of the outputs data provided.

2.60. In addition to the information reported in the workbook, as part of the Performance Assessment Submission DNOs are required to provide commentary on all Material Changes that have impacted performance relative to the Agreed Network Outputs. The commentary provided on Material Changes can cross-reference previous submissions. There could be a number of reasons to explain variations in outturn performance which could be considered Material Changes, including:

a) Changes to input data,
b) Changes to the assessment techniques/calculation methodology,
c) Changes due to external factors, and
d) Changes to DNO asset management strategy and approach, which could include a change in attitude to risk overall, or a shift in priorities from one risk to another as a result of one of the changes identified in (a), (b) and (c) above.

2.61. The nature of these Material Changes is explained further in paragraphs 2.54 to 2.61 of this RIG.

2.62. In their Performance Assessment Submission DNOs are required to provide evidence to demonstrate and explain:

- the nature of all Material Changes identified under paragraphs 2.94(a), 2.94(b) and 2.94(c),
- the impact of these Material Changes on output performance as at 31 March 2014,
- the impact of these Material Changes on forecast output performance as at 31 March 2015 before taking into account any further Intervention,

- the impact of the asset management decisions taken to address these Material Changes, as well as any other deliberate decisions affecting the level of network risk, on the Delivered Network Outputs, and
- taking into account all this information, the reasons why the Delivered Network Outputs represent the best outcome for customers, and specifically why they represent the Adjusted Network Outputs – by delivering an equivalent change in the level of risk as that implied by the Agreed Network Outputs.

2.63. It is recognised that the Material Changes identified under paragraphs 2.94(a), 2.94(b) and 2.94(c) may directly impact the current profile (i.e. as at 31 March 2014) and the forecast profile as at 31 March 2015 without further Intervention, whereas the DNO's asset management response to these Material Changes (i.e. paragraph 2.94(d)) will wrap all these changes up to produce the Delivered Network Outputs. It is also recognised that Material Changes due to external factors identified under paragraph 2.94(c) may directly impact the Delivered Network Outputs.

2.64. As part of the Performance Assessment Submission DNOs must refer to the information previously provided on Material Changes, as contained in the Material Change Log.

2.65. The following examples illustrate the type of changes that could occur over the period, and possible DNO asset management decisions in response:

- During the period a type-specific fault is identified for a particular Distribution Asset Category which impacts HI rankings and causes the DNO to reprioritise asset replacement away from lower (relative) risk Distribution Asset Categories to this higher (relative) risk Distribution Asset Category.

- Higher than expected load growth in a particular part of the network causes the DNO to reprioritise general reinforcement expenditure to this part of the network and away from other parts of the network which experience lower than expected load growth.

- Further work on asset degradation techniques during the period identifies some Distribution Assets as degrading slower than initially forecast, leading to a reprioritisation of asset replacement expenditure away from these lower (relative) risk Distribution Assets.

- A quicker than expected economic recovery leads to higher load growth and significantly higher input prices, causing the DNO to increasingly examine short term lower cost solutions such as load transfers, demand side management and increased use of life-extending refurbishment.

2.66. Ofgem recognises that while the Tier 2 Network Output Measures developed for asset replacement and general reinforcement provide a good indication of investment priorities, they do not capture all the critical elements of a DNO's investment decision. This is because they are not holistic measures of 'network risk' (i.e. Tier 1 Network Output Measures) – they are measures of the probability of failure/overload, which do not yet fully incorporate the consequences of failure and other strategic considerations. In the absence of holistic Tier 1 Network Output Measures, the efficient trade-off of Tier 2 Network Output Measures will need to be demonstrated by DNOs (and assessed by Ofgem) qualitatively. While a qualitative assessment is reasonable for DPCR5, we consider that the development of Tier 1 Network Output Measures over time represents a logical evolution of this process, and is in the interests of both parties. Ofgem will work with the DNOs to develop Tier 1 Network Output Measures over the DPCR5 period, by building on or aggregating the site and asset specific Tier 2 Network Output Measures which have been developed for the DPCR5 settlement.[10]

2.67. It is recognised that a DNO's views on the Adjusted Network Outputs may not perfectly coincide with the Delivered Network Outputs it has reported in its Performance Assessment Submission. Such a divergence may occur as a result of a Material Change due to an external factor. For example, planning constraints may delay projects, which in itself does not change the underlying need for Intervention at these sites, but impacts upon the DNO's ability to meet its Agreed Network Outputs. In this case a DNO may submit that the Adjusted Network Outputs have not been delivered due to circumstances beyond its control.

2.68. There should be few surprises in the performance assessment submission – a consistent story is expected to develop over the period with respect to output performance, based on the information from previous submissions as well as that recorded in the Material Changes Log.

Qualitative performance assessment process

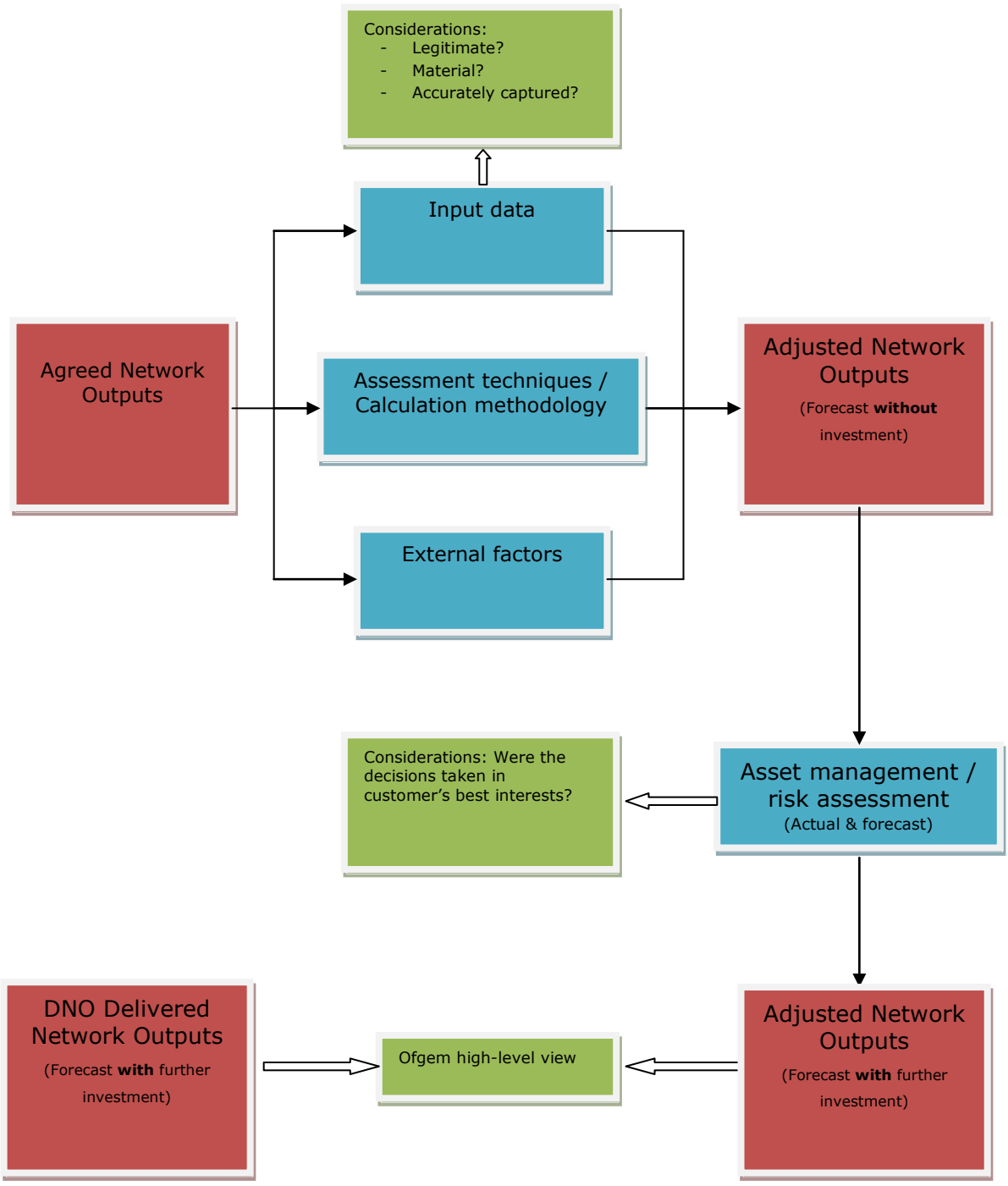
2.69. Based on the information provided by the DNO in its Performance Assessment Submission, Ofgem is to undertake a qualitative assessment to determine:

- the Adjusted Network Outputs, and
- whether a DNO has met its Adjusted Network Outputs.

2.70. This assessment is to be undertaken in a number of distinct steps, as described in figure 2.1 below.

[10] As an interim step towards development of holistic network-wide risk metrics, DNOs may develop quantitative measures to assess the relative risk between two or more Tier 2 Network Output Measures (referred to here as 'tier 1.5 network output measures').

Figure 2.1: Network Outputs qualitative performance assessment process



2.71. Ofgem is to examine the information presented by the DNO in its Performance Assessment Submission on each of the Material Changes identified as being due to:

- Input data,
- Assessment techniques/calculation methodology, and
- External factors.

2.72. Ofgem is to have regard to the information contained in the Material Change Log in undertaking its assessment at paragraph 2.71.

2.73. In doing so, Ofgem is to qualitatively assess the information provided on each of these Material Changes to determine whether:

- the change/event identified is legitimate and did not appear in the forecast,
- the change/event has a material impact on the DNO's achievement of the Agreed Network Outputs, and
- the impact of the change/event has been accurately captured.

2.74. Based on this assessment, Ofgem is to qualitatively determine the Adjusted Network Outputs without further Intervention (i.e. as at 31 March 2015).

Adjusted Network Outputs

2.75. The Adjusted Network Outputs with further Intervention (i.e. as at 31 March 2015) are the outputs that a DNO's Delivered Network Outputs are to be assessed against by Ofgem as part of the performance assessment. The Adjusted Network Outputs are the Agreed Network Outputs, adjusted for Ofgem's view of an efficient and reasonable response to all Material Changes that occur over the price control period.

2.76. Ofgem is to assess the efficiency and efficacy of the asset management decisions taken by the DNO in response to the Material Changes identified. In doing so the overriding objective is to ensure that the resulting Adjusted Network Outputs reflect the best network risk outcome for customers given: (a) the impact of all Material Changes; and (b) the change in the level of network risk funded by customers via the DPCR5 settlement.

2.77. Ofgem's assessment is to be informed by, and must be consistent with, its previous discussions with the DNO, as recorded in the Material Change Log.

2.78. Taking into account all this information, Ofgem is to qualitatively determine the Adjusted Network Outputs and then qualitatively assess whether or not, at an overall level, the DNO has met its Adjusted Network Outputs.

2.79. Ofgem is to apply the following high-level principles in determining whether or not a DNO has met its Adjusted Network Outputs:

- Efficient reprioritisation of activities is expected and encouraged – the key consideration is the change in the overall level of network risk provided by the

DNO's Delivered Network Outputs compared to the change in the level of network risk implicit in the Agreed Network Outputs.[11]

- The conclusion is to be a qualitative 'pass/fail' at the overall level, however it is to be informed by the data and commentary provided for the individual Tier 2 Network Output Measures.

- There is to be no specific and quantitative thresholds adopted to identify areas for further consideration – the outputs data is intended to be a useful resource to assist DNOs in justifying, and for Ofgem in assessing, the efficiency and efficacy of asset management decisions.

- Further improvement and innovation in asset management techniques should be encouraged and not hindered by the performance assessment process.

- The efficiency of significant decisions related to the timing of interventions (e.g. replacement/refurbishment; reinforcement/load transfers) must be justified where appropriate through whole-of-life NPV analysis.

- There needs to be significant and material issues identified with the Delivered Network Outputs at the overall level before it can be qualitatively determined that a DNO has not delivered, or is not expected to deliver, the Adjusted Network Outputs.

2.80. If Ofgem qualitatively determines that a DNO has satisfactorily met its Adjusted Network Outputs, there will be no further action under this RIG.

2.81. If Ofgem qualitatively determines that a DNO has not satisfactorily met its Adjusted Network Outputs, a revenue adjustment is to apply (see below).

Revenue adjustment for failure to deliver Adjusted Network Outputs

2.82. If Ofgem qualitatively determines that a DNO has not satisfactorily met its Adjusted Network Outputs, an adjustment is to be applied to DPCR6 revenues. The revenue adjustment is to be calculated as follows:

- Value the difference between the DNO's Delivered Network Outputs and the Adjusted Network Outputs (i.e. the 'Network Outputs Gap'), and

- Apply a sharing factor to the Network Outputs Gap to calculate a revenue adjustment (the 'Network Outputs revenue adjustment').

[11] This highlights the need for development of Tier 1 Network Output Measures over DPCR5, which will better allow DNOs to make the case that their asset management decisions represent the best outcome for customers.

Network Outputs Gap

2.83. On a line-by-line basis, Ofgem is to calculate the difference in volumes implicit in the DNO's Delivered Network Outputs with the volumes implicit in the Adjusted Network Outputs. For the HI this is to be in terms of the number of assets replaced for each Health Index Asset Category, and for the LI this is to be in terms of the Distribution Asset volumes delivered by the general reinforcement schemes carried out. In determining the volume gap on a line-by-line basis, Ofgem is to remove the impact of any volumes implicit in the DNO's Delivered Network Outputs that are deemed to be unjustified based on network need.

2.84. Then, for the volumes calculated at paragraph 2.83, Ofgem is to determine the appropriate unit cost assumption to apply (i.e. £/Distribution Asset Category), which is to be the higher of:

- The DNO's outturn unit costs, and
- Ofgem's forecast unit costs (underpinning the DPCR5 allowance) adjusted for outturn RPI.[12]

2.85. To calculate the Network Outputs Gap, Ofgem is to take the sum of the volume differences in paragraph 2.83 multiplied by the relevant unit costs assumption determined in paragraph 2.84.

Network Outputs revenue adjustment

2.86. The Network Outputs revenue adjustment is equal to the value of the Network Outputs Gap multiplied by the Network Outputs incentive rate, which for DPCR5 is the IQI incentive rate multiplied by a factor of 1.025. The DPCR5 Network Outputs incentive rate is set out for each DNO in table 2.4 below.

[12] A reasonable unit cost timing assumption to apply is to take an average over the price control period. Where feasible, Ofgem is to value the gap for general reinforcement on a scheme-by-scheme basis, based on forecast and actual scheme costs.

Table 2.4: DPCR5 Network Outputs incentive rate – by DNO

DNO	Network Outputs incentive rate
CN_West	48%
CN_East	48%
ENW	46%
CE_NEDL	49%
CE_YEDL	49%
WPD_S_Wales	52%
WPD_S_West	52%
EDFE_LPN	46%
EDFE_SPN	46%
EDFE_EPN	46%
SP_Distribution	46%
SP_Manweb	46%
SSE_Hydro	50%
SSE_Southern	50%

2.87. The Network Outputs revenue adjustment is to be applied as part of the final settlement for DPCR6.

Correction to Network Outputs revenue adjustment during DPCR6

2.88. The Performance Assessment Submission contains Year 4 actual data, and a 31 March 2015 forecast, which means that Ofgem in practice is required to determine the Adjusted Network Outputs on the basis of a one-year forecast.

2.89. Therefore Ofgem is to apply a correction to the Network Outputs revenue adjustment based on the information provided by the DNO in its final Annual Submission for DPCR5 (on 30 September 2015). The correction is to be calculated using the same methodology as described in paragraphs 2.83 to 2.86.

2.90. The correction is to be applied as a revenue adjustment with effect from 1 April 2016.

Instructions and guidance for completing Network Outputs reporting workbook

2.91. This section provides guidance for completing the Network Outputs reporting workbook and may need to be updated for future versions of the workbook.

2.92. The Network Output reporting workbook is produced in Microsoft Excel (2003). It includes the following sheets:

- Version & Contents,
- LI logic,
- LI data,
- LI charts,
- HI data,
- HI charts,
- Fault rate data,
- MTP all incidents,
- MTP one-off ee's only,
- MTP severe weather ee's only,
- MTP excluding all ee's,
- Fault rate charts, and
- Volume reconciliation.

LI sheets

2.93. These sheets capture and display Load Index (LI) data. The LI is a Tier 2 network output measure related to network utilisation. It is a framework for collating information on the utilisation of the Distributed Assets supplying each Demand Group and for tracking changes in their utilisation over time.

2.94. The LI will be used to inform an assessment of the efficacy of the DNO's general reinforcement decisions over the price control period.

HI sheets

2.95. These sheets capture and display Health Index (HI) data. The Health Index is a Tier 2 network output measure related to asset condition. It is a framework for collating information on the health (or condition) of Distribution Assets and for tracking changes in their condition over time.

2.96. The HI will be used to inform an assessment of the efficacy of the DNOs' asset management decisions over the price control period.

Fault rate and MTP sheets

2.97. These sheets capture and display fault rate data. The MTP sheets capture the number of recorded incidents for asset categories. This data will be used in conjunction with the A1 Total sheet to provide fault rates for each asset category.

Volume reconciliation sheet

2.98. The volume reconciliation sheet provides details of the mapping process from Distribution Asset Categories to Health Index Asset Categories and Fault Rate Asset Categories. This sheet is for reference only.

Version and Contents

2.99. This sheet provides a version history for each Network Outputs Submission, as well as links to each of the other outputs worksheets.

2.100. In the yellow input cells provided, DNOs are required to enter:

- the DNO name to which the submission applies (cell B7),
- the submission number (column B, rows 12-19),
- for each submission, the date submitted (column C, rows 12-19), and
- for each submission, the changes made from the previous submission (column D, rows 13-19).

LI logic

2.101. This sheet provides for input of the individual DNO's Load Index Logic (i.e. decision criteria) for assigning Demand Groups a Load Index ranking LI1 to LI5, in accordance with the high-level common definitions contained at paragraph 2.33 of this RIG. The allocation is dependent on the individual DNO's views regarding the level of and interaction between the following drivers for a site-specific demand-related Intervention:

- Demand driver: measure of the maximum demand of the Demand Group relative to the firm (n-1) capacity of the Demand Group, and
- Duration driver: measure of the hours/energy at risk per annum brought about by the capacity utilisation for the Demand Group.

Description of Logic

2.102. In the 'Description of Logic' section, enter the maximum demand as a percentage of the firm capacity applicable to each ranking LI1 to LI5 (column C, rows 8-32); and the number of hours or MVA at risk applicable to each ranking LI1 to LI5 (column D, rows 8-32). For example, in table 2.5 below the DNO has defined 'LI5' as a Demand Group with either:

- Maximum demand as a percentage of firm capacity of 100-110% and >200 hours at risk per annum, or
- Maximum demand as a percentage of firm capacity of greater than 110%.

Table 2.5: LI logic sheet – Description of logic (example)

	B	C	D
7		**Demand driver**	**Duration driver**
8	LI1	0-60%	
9			
10			
11			
12			
13	LI2	60-80%	
14			
15			
16			
17			
18	LI3	80-100%	
19			
20			
21			
22			
23	LI4	100-110%	0-200 hours
24			
25			
26			
27			
28	LI5	100-110%	>200 hours
29		>110%	
30			
31			
32			

Logic Thresholds

2.103. In the 'Logic Thresholds' section, enter the lower and upper bounds of each threshold for the 'Demand driver' (columns G-H, rows 8-12) and the 'Duration driver' (columns G-H, rows 13-16). An example is provided in table 2.6 below, which contains the same logic as in table 2.5.

Table 2.6: LI logic sheet – Logic Thresholds (example)

	F	G	H
7		**Lower bound**	**Upper bound**
8	Demand driver	0.00	0.60
9		0.60	0.80
10		0.80	1.00
11		1.00	1.10
12		1.10	
13	Duration driver	0	200
14		200	
15			
16			

Logic VLOOKUP Tables

2.104. The DNO-specific data to be entered in the 'Logic VLOOKUP Tables' section must be entered in consultation with Ofgem. Broadly, in the 'Demand driver' table (column G, rows 21-24), DNOs need to enter the rankings "LI1" to "LI5" applicable to each threshold for the 'Demand driver'. These values need to be entered in the cells adjacent and directly to the right of the lower bound thresholds (i.e. column F, rows 21-24). For LI rankings in which both drivers operate, DNOs need to enter "Duration" in the relevant cells of the 'Demand driver' table (column G, rows 21-24). Then, in the 'Duration driver' table (column G, rows 27-29), DNOs need to enter the rankings "LI1" to "LI5" applicable to each threshold for the 'Duration driver'.

2.105. For example, in table 2.7 below, for a Demand group with maximum demand as a percentage of firm capacity of 100-110%, the DNO has entered "Duration" in cell G24, which triggers the 'Duration driver'. The values entered by the DNO in the 'Duration driver' table for this example indicate that:

- A Demand Group is defined as "LI4" if maximum demand as a percentage of firm capacity is between 100-110%, and there are 0-200 hours at risk per annum (cell G28), and
- A Demand Group is defined as "LI5" if maximum demand as a percentage of firm capacity is between 100-110%, and there are greater than 200 hours at risk per annum (cell G29).

Table 2.7: LI logic sheet – Logic VLOOKUP Tables (example)

19	F	G
20	**Demand**	
21	0.00	LI1
22	0.60	LI2
23	0.80	LI3
24	1.00	Duration
25	1.10	LI5
26		
27	**Duration**	
28	0	LI4
29	200	LI5
30		

LI data

2.106. The LI data sheet contains the full set of input data used to generate the LI profile for each Demand Group, and is split into two sections:

- Individual substations (rows 6-812), and
- Substation groups (rows 816-1222).

2.107. The following section explains the requirements for data to be entered into the relevant yellow input cells, for each of the columns of the LI data sheet. As explained in Table 2.3 of this RIG, there are different reporting requirements at different points in time over the price control period. For the LI data sheet:

- All the relevant yellow input cells will have been populated for the purposes of defining the Agreed Network Outputs (i.e. the baseline),
- For an Annual Submission, all yellow input cells except those in columns Z to AI must be populated, and
- All the relevant yellow input cells must be populated for the purposes of the Mid-Period Review Submission and the Performance Assessment Submission.

Demand Group description
Substation name (column C)

2.108. Please enter the name of the substation, where possible by reference to its geographic location. For interconnected substation groups (rows 816-1222), in column C, please enter a name for the group and the names of the individual substations which make up the group.

Category (column D)

2.109. Please enter the primary and secondary voltage levels supplying each Demand Group, as follows:

- 132kV – EHV,
- 132kV – HV,
- EHV – EHV, or
- EHV – HV.

No. of customers (column E)

2.110. For each Demand group, please enter the number of customers supplied. In addition, please manually enter the total number of customers supplied in the DNO region at cell E811 and cell E1221.

Percentage of customers supplied by substation (column F)

2.111. This column automatically calculates the number of customers for each Demand group as a percentage of the total number of customers. Note that the total number of customers supplied by all substations will exceed the total number of customers supplied by the network (i.e. the value in cell F811 exceeds 100%), given that any individual customer may be supplied by more than one substation, at different voltages.

Load Index – Current (as at 31 March)
Current substation firm capacity under single circuit outage conditions (column G)

2.112. For each Demand Group, please enter the firm (n-1) capacity in MVA units as at 31 March of the current year. The data in this column provides a snapshot of the actual firm capacity for each Demand Group.

Season of Most Onerous Demand and Limiting Factor (column H)

2.113. Please provide the season of most onerous demand for each Demand Group. In addition please provide the limiting factor relevant to each Demand Group, classified as one of the following:

- Cyclic rating of a transformer
- Rating of the incoming circuit(s)
- Capacity of normally connected secondary interconnection
- Rating of the secondary switchboard
- Rating of any ancillary equipment
- Voltage regulation
- Substation or network configuration
- Rating of the primary switchgear or busbars
- Redundant substation
- Meshed network circuit capacity
- Customer connection agreement

Substation current Maximum Demand (column I)

2.114. For each Demand Group, please enter the maximum MVA demand for the year ending 31 March of the current year. The data in this column provides a snapshot of the actual maximum demand for each Demand Group.

Substation current maximum demand as % of Substation firm capacity (column J)

2.115. This column automatically calculates, for each Demand Group, the current maximum demand as a percentage of firm capacity. This constitutes the 'Demand driver' for each Demand Group as at 31 March of the current year.

Current hours / energy at risk (column K)

2.116. Please indicate in the tick-box provided (cell K8) whether the 'Duration driver' is based on a measure of "Duration" or "MVAh", and correspondingly in cell K9. Then, for each Demand Group, in column K please enter the current hours / MVAh at risk (if any). The data in this column constitutes the 'Duration driver' for each Demand Group for the year ending 31 March of the current year.

Load index ranking (column L)

2.117. This column takes the current 'Demand driver' (column J) and the 'Duration driver' (column K) and assigns a Load Index ranking LI1 to LI5 using the decision criteria contained in the VLOOKUP tables in the LI logic sheet. This provides a snapshot of the LI ranking as at 31 March of the current year.

Forecast load information
Historic and forecast max demand – excluding forecast Intervention (columns M to V)

2.118. For each Demand Group, please enter the actual and forecast maximum demand (MVA) over the 10 year period specified, excluding the impact of any forecast Intervention.

Load index – 31 March 2015 (with no further DPCR5 Intervention)
31 March 2015 Substation Maximum Demand as % of Substation firm capacity – with no further DPCR5 Intervention (column W)

2.119. This column automatically calculates, for each Demand Group, maximum demand forecast as at 31 March 2015 (column V) as a percentage of current firm capacity. This constitutes the 'Demand driver' for each Demand Group as at 31 March 2015 with no further DPCR5 Intervention.

31 March 2015 forecast energy / hours at risk – with no further DPCR5 Intervention (column X)

2.120. For each Demand Group, in column X please enter the forecast hours/MVAh at risk (if any), as at 31 March 2015, assuming no further DPCR5 intervention. The data in this column constitutes the 'Duration driver' for each Demand Group as at 31 March 2015 with no further DPCR5 Intervention.

Load index ranking (column Y)

2.121. This column takes the 'Demand driver' (column W) and the 'Duration driver' (column X) as at 31 March 2015 with no further DPCR5 Intervention, and assigns a Load Index ranking LI1 to LI5 using the decision criteria contained in the VLOOKUP tables in the LI logic sheet. This provides a forecast of the LI ranking as at 31 March 2015 with no further DPCR5 Intervention.

Load index – 31 March 2015 (with further DPCR5 Intervention)
Is there expenditure contained within the FBPQ relating to a general reinforcement scheme which will increase firm capacity for this demand group over DPCR5? (column Z)

2.122. Each DNO will have populated this column (i.e. "Yes"/"No") as part of providing its Agreed Network Outputs at the start of the price control period. As part of the DPCR5 process, the data provided by DNOs in column Z was used to reconcile the LI data with the general reinforcement schemes listed in Table LR4 of the FBPQ – to ensure that the Agreed Network Outputs reconciled with the revenue allowance for general reinforcement. The data in this column will be locked for the duration of the price control period.

2.123. While it is recognised that the outcome of a general reinforcement scheme may constitute more than an increase to firm capacity for a Demand Group (i.e. it may also include permanent load transfers), this column seeks only to identify those Demand Groups where there is an increase in capacity planned. See paragraph 2.81 below for reporting of changes to maximum demand as a result of permanent load transfers.

Is a reinforcement to increase firm capacity for this demand group underway or planned over DPCR5 (i.e. after reprioritisation)? (column AA)

2.124. As part of the mid-period review submission and the performance assessment submission, DNOs must enter "Yes" or "No" in column AA. This must provide the DNO's updated best view of the reinforcement work undertaken or planned over DPCR5.

31 March 2015 Substation firm capacity under single circuit outage conditions – with further DPCR5 Intervention (column AB)

2.125. As part of the Mid-Period Review Submission and the Performance Assessment Submission, for each Demand Group please enter the forecast firm (n-1) capacity in MVA units as at 31 March 2015 with further DPCR5 Intervention. The data in this column provides an update of the forecast capacity for each Demand Group, and is relevant to the setting of the Adjusted Network Outputs.

31 March 2015 Substation Maximum Demand after permanent load transfers (column AC)

2.126. As part of the Mid-Period Review Submission and the Performance Assessment Submission, for each Demand Group please enter the forecast maximum demand in MVA units as at 31 March 2015, after accounting for expected permanent load transfers (if any).

31 March 2015 substation current maximum demand as % of Substation firm capacity – with further DPCR5 Intervention (column AD)

2.127. This column will automatically calculate, for each Demand Group, the forecast of maximum demand as a percentage of firm capacity as at 31 March 2015 after permanent load transfers (column AC) (with further DPCR5 Intervention). This constitutes the 'Demand driver' for each Demand Group as at 31 March 2015 (with further DPCR5 Intervention), and is relevant to the setting of the Adjusted Network Outputs.

31 March 2015 forecast energy / hours at risk – with further DPCR Intervention (column AE)

2.128. As part of the Mid-Period Review Submission and the Performance Assessment Submission, for each Demand Group, in column AE please enter the forecast hours/MVAh at risk (if any) as at 31 March 2015, after accounting for further forecast DPCR5 Intervention. The data in this column constitutes the 'Duration driver' for each Demand Group as at 31 March 2015 (with further DPCR5 Intervention), and is relevant to the setting of the Adjusted Network Outputs.

Load index ranking (column AF)

2.129. This column takes the 'Demand driver' (column AD) and the 'Duration driver' (column AE) as at 31 March 2015 with further DPCR5 Intervention, and assigns a Load Index ranking LI1 to LI5 using the decision criteria contained in the VLOOKUP tables in the LI logic sheet. This provides a forecast of the LI ranking as at 31 March 2015 with further DPCR5 intervention, and is relevant to the setting of the Adjusted Network Outputs.

For those demand groups in which a reinforcement to increase firm capacity is underway or planned over DPCR5, please indicate the demand driver for the project (column AG)

2.130. As part of the Mid-Period Review Submission and the Performance Assessment Submission, in this column DNOs are required to enter "Organic load growth" or "One-off customer connection" for each Demand group in which "Yes" is entered in column AA (see paragraph 2.79 above). The information in this column may be used to inform discussions during the price control period on a DNO's structure of charges.

Risk Management

Risk management/operational measures in places as at 31 March 2015 – may include manual transfers in operation or planned, DG, DSR, etc. (column AH)

2.131. As part of the Mid-Period Review Submission and the Performance Assessment Submission, in this column DNOs will be provided the opportunity to enter commentary on any operational or risk management measures forecast to be in place (as at 31 March 2015) which are relevant for the Demand Group. Commentary in column AH may also relate to expected developments for which it is not possible to accurately forecast the impact on either capacity or demand (e.g. Distributed Generation, demand-side management activities).

2.132. It is recognised that although such measures will not have a permanent impact on the either the firm (n-1) capacity or the maximum demand for the Demand Group (or this impact cannot be reliably estimated), they represent common asset management practices and may have a material impact on the decision on whether or not to undertake investment.[13]

P2/6 Compliance

Is a derogation or self-derogation against P2/6 in place, or planned? (column AI)

2.133. As part of the Mid-Period Review Submission and the Performance Assessment Submission, in this column DNOs must indicate whether there is a derogation against P2/6 in place or planned for the Demand Group. This provides an

[13] Over the course of DPCR5, Ofgem is to work with the DNOs to explore how such measures and developments can be more fully integrated into the common methodology.

opportunity to highlight compliance issues that may impact the decision to undertake (and the timing for) investment.[14]

Changes to firm capacity from previous year

Previous year substation firm capacity – as at 31 March (column AK)

2.134. For each Demand Group, please enter the firm (n-1) capacity as at 31 March of the previous year, as presented in the previous year's submission.

Previous year substation firm capacity (as at 31 March) - after accounting for Material Changes (column AL)

2.135. For each Demand Group, please enter the firm (n-1) capacity as at 31 March of the previous year, adjusted for any Material Changes that occurred in the year since the previous submission.

Current substation firm capacity under single circuit outage conditions - as at 31 March (column AM)

2.136. This column provides the current firm capacity for each Demand Group as at 31 March, taken from column G.

Change in substation firm capacity from previous year due to Material Changes (column AN)

2.137. This column automatically calculates, for each Demand Group, the changes to firm capacity as a result of Material Changes that have occurred since the previous submission.

Change in substation firm capacity from previous year due to Intervention (column AO)

2.138. This column automatically calculates, for each Demand Group, the changes to firm capacity as a result of Interventions that have occurred since the previous submission.

[14] Over the course of DPCR5, Ofgem would like to work with the DNOs to more fully integrate P2/6 compliance issues into the common methodology.

Briefly explain the nature/category of any Material Change affecting Firm Capacity for this Demand Group (column AP)

2.139. For each Demand Group, please provide a brief explanatory note for the Material Changes to firm capacity that have occurred since the previous submission (as calculated in column AN). Please provide details of the nature and impact of Material Changes (at an overall level) in the commentary accompanying the submission.

Forecast of current substation maximum demand from previous year (column AQ)

2.140. For each Demand Group, please enter the forecast of current maximum demand from the previous year's submission.

Current substation maximum demand - after accounting for Material Changes (column AR)

2.141. For each Demand Group, please enter the forecast of current maximum demand from the previous year's submission, adjusted for any Material Changes that occurred in the year since the previous submission.

Substation current maximum demand (column AS)

2.142. This column provides the current maximum demand for each Demand Group as at 31 March, taken from column I.

Change in substation maximum demand from previous year due to Material Changes (column AT)

2.143. This column automatically calculates, for each Demand Group, the changes to maximum demand as a result of Material Changes that have occurred since the previous submission.

Change in substation maximum demand from previous year due to Intervention – e.g. permanent load transfers, DSR, DG (column AU)

2.144. This column automatically calculates, for each Demand Group, the changes to maximum demand as a result of Interventions that have occurred since the previous submission.

Briefly explain the nature/category of any Material Change affecting maximum demand for this Demand Group (column AV)

2.145. For each Demand Group, please provide a brief explanatory note for the Material Changes to maximum demand that have occurred since the previous

submission (as calculated in column AT). Commentary in this column needs only to be provided by exception (e.g. for once-off changes to demand). Please provide details of the nature and impact of Material Changes (at an overall level) in the commentary accompanying the submission.

Hours/energy at risk from previous year (column AW)

2.146. For each Demand Group, please enter the hours/energy at risk as at 31 March of the previous year, as presented in the previous year's submission.

Current hours/energy at risk (column AX)

2.147. This column provides the current hours/energy at risk for each Demand Group as at 31 March, taken from column K.

Change in hours/energy at risk from previous year due to Material Changes (column AY)

2.148. For each Demand Group, please enter the change in hours/energy at risk from the previous year's submission due to any Material Changes that occurred in the year since the previous submission.

Briefly explain the nature/category of any Material Change affecting hours / energy at risk for this Demand Group (column AZ)

2.149. For each Demand Group, please provide a brief explanatory note for the Material Changes to hours/energy at risk that have occurred since the previous submission (as presented in column AY). Please provide details of the nature and impact of Material Changes (at an overall level) in the commentary accompanying the submission.

LI charts

2.150. The LI charts sheet presents the Load Index Network Outputs. This sheet contains a series of buttons which when pressed produce charts from the LI data sheet, for each of the following:

- All substations,
- Substations (132kV primary to EHV secondary),
- Substations (EHV primary and secondary),
- Substations (EHV primary to HV secondary),
- Substations (132kV primary to HV secondary), and
- Substation groups.

2.151. Each of the charts displays the following:

- Current Load Index profile,
- 31 March 2015 Load Index profile (with no DPCR5 Intervention), and
- 31 March 2015 Load Index profile (with DPCR5 Intervention).

2.152. At the start of the price control period, each DNO will have provided the three Load Index profiles referred to above, with the 31 March 2015 (with DPCR5 Intervention) LI profile representing the Agreed Network Output for the Load Index.

HI data

2.153. The HI data sheet contains the full set of input data used to generate the HI profile for each Health Index Asset Category, as well as important information on HI data source and quality.

2.154. The following section explains the requirements for data to be entered into the relevant yellow input cells, for each of the columns of the HI data sheet. As explained in Table 2.3 of this RIG, there are different reporting requirements at different points in time over the price control period. For the HI data sheet:

- All the relevant yellow input cells will have been populated for the purposes of defining the Agreed Network Outputs,
- For the purposes of annual reporting, only columns C, E to N and U to Y need to be populated (i.e. columns D and O to S are not required),
- All the relevant yellow input cells must be populated for the purposes of the Mid-Period Review Submission and the Performance Assessment Submission.

Asset register

Current – as at 31 March (column C)

2.155. In this column, for each Health Index Asset Category DNOs must enter the asset volumes contained in the asset register as at 31 March of the current year. For each Health Index Asset Category these volumes must reconcile with the asset volumes for the corresponding Distribution Asset Categories (see paragraph 2.14).

Forecast – as at 31 March 2015 (column D)

2.156. As part of the Mid-Period Review Submission and the Performance Assessment Submission, in this column DNOs must enter the forecast asset volumes for each Heath Index Asset Category as 31 March 2015 (i.e. end of DPCR5).

Health Index – Current (as at 31 March)

HI 1 to HI 5 (columns E to I)

2.157. For each relevant Heath Index Asset Category, please enter the number of assets/kms of line that are ranked HI 1 to HI 5 as at 31 March of the current year. While these allocations are to be based on the DNO's internal asset management practices, they must be made in accordance with the agreed common HI definitions contained in table 2.1 of this RIG.

Health Index – 31 March 2015 (with no further DPCR5 Intervention)

HI 1 to HI 5 (columns J to N)

2.158. For each relevant Heath Index Asset Category please enter the number of assets / kms of line that are forecast to be ranked HI 1 to HI 5 as at 31 March 2015 (with no further DPCR5 Intervention). While these allocations are to be based on the DNO's internal asset management practices, they must be made in accordance with the agreed common HI definitions contained in table 2.1 of this RIG.

This provides a forecast of the HI ranking as at the end of DPCR5 with no further Intervention, which is effectively an indication of the impact of forecast degradation and routine (non life-extending) maintenance for each Health Index Asset Category.

Health Index – 31 March 2015 (with DPCR5 actual and forecast Intervention)

HI 1 to HI 5 (columns O to S)

2.159. As part of the Mid-Period Review Submission and the Performance Assessment Submission, for each relevant Heath Index Asset Category please enter the number of assets / kms of line that are forecast to be ranked HI 1 to HI 5 as at 31 March 2015 (with actual and forecast DPCR5 Intervention). While these allocations are to be based upon the DNO's internal asset management practices, they must be made in accordance with the agreed common HI definitions contained in table 2.1 of this RIG.

2.160. This provides a forecast of the HI ranking as at the end of DPCR5 after taking into account actual and forecast Intervention, which when compared with the updated HI profile as at 31 March 2015 without DPCR5 Intervention, provides an indication of the impact of actual and forecast DNO asset replacement and (life-extending) refurbishment on the HI ranking for each Health Index Asset Category.

Data Quality – Current (as at 31 March)

Number of assets included for HI asset category (column T)

2.161. This column automatically calculates, for each Health Index Asset Category, the total number of assets/kms of line that have been assigned a HI ranking as at

the current date (i.e. sum of values in columns E to I). Unless otherwise agreed, the values in this column must reconcile with the asset register volumes entered at column C.

Primary form of measure (column U)

2.162. In this column, for each Health Index Asset Category please enter the primary form of measure currently used internally by the DNO assign HI rankings. Please enter one of the following:

- Health,
- Condition,
- Age, or
- Other.

2.163. It is recognised that the data in column U may change over time as DNOs further develop their internal Health Index capabilities.

Percentage of assets actually observed (column V)

2.164. In this column, for each Health Index Asset Category, please enter the proportion of the total asset volumes (i.e. column T) for which the current HI ranking is based upon an actual observation. This data provides an indication of the extent of sampling undertaken by the DNO to assign HI rankings to their assets.

Average age of data used (column W)

2.165. In this column, for each Health Index Asset Category please enter the average age (in years) of the data underlying the HI rankings. For example, if the data for a particular Health Index Asset Category is collected over a 10 year cycle, a value of "5" must be entered for that category in column W. This data provides an indication of:

- the extent to which the HI data incorporates the latest information, and
- the frequency with which the HI data is updated by the DNO.

Description of the form of measure used to assign a HI, the quality of data used, and any other relevant information (column X)

2.166. In this column, for each Health Index Asset Category DNOs may enter commentary to describe in more detail the quality of the current HI data. It is expected that the commentary entered in column X will build upon the data entered in columns U to W.

Degradation assumption adopted (column Y)

2.167. In this column, for each Health Index Asset Category please describe the assumptions currently adopted to forecast degradation out to the end of the period. It is recognised that DNOs' degradation assumptions may change over time as internal Health Index capabilities are further developed and improved.

HI charts

2.168. The HI charts sheet presents the Health Index Network Outputs. This sheet contains a series of buttons which when pressed produce charts from the HI data sheet for each of the 23 Health Index Asset Categories.

2.169. For each of the Health Index Asset Categories, the charts display the following:

- Current Health Index profile,
- 31 March 2015 Health Index profile (with no DPCR5 Intervention), and
- 31 March 2015 Health Index profile (with DPCR5 Intervention).

2.170. At the start of the price control period, each DNO will have provided the three Health Index profiles referred to above, with the HI profile as at 31 March 2015 (with DPCR5 Intervention) representing the Agreed Network Output for the Health Index.

Medium-term performance (MTP)

2.171. This section sets out definitions and related instructions and guidance for the reporting of information that Ofgem requires for monitoring the medium-term performance of distribution networks. Ofgem intends to collect information on the incidents and causes on electric lines and electrical plant. At future price control reviews Ofgem will want to understand the impact of future expenditure (both capital and operating) on MTP.

2.172. There are four worksheets which show MTP information:

- MTP all incidents. DNO input is required for this sheet,
- MTP one-off ee's only - containing only those incidents which are attributable to one-off exceptional events for which exemptions have been requested and which meet the criteria set out in CRC8 of the distribution licence. DNO input is required for this sheet,
- MTP severe weather ee's only - containing only those incidents which are attributable to severe weather exceptional events for which exemptions have been requested and which meet the criteria set out in CRC8 of the distribution licence. DNO input is required for this sheet, and
- MTP excluding all ee's –This sheet is calculated my deducting MTP one-off ee's and MTP severe weather ee's from MTP all incidents. No DNO input required.

Reporting the number of unplanned incidents

2.173. DNOs are required to report the number of damage faults and total number of unplanned incidents that have occurred on the LV, HV, EHV and 132kV networks. For each voltage level the number of damage faults and total number of unplanned incidents must be disaggregated into the number of unplanned incidents occurring on each of the categories in the workbook.

2.174. Only initial unplanned incidents on the DNO's own network are to be included in the medium-term performance report. Pre-arranged incidents and incidents on other connected systems are to be excluded. Incidents which are raised simply to record supply interruptions which occur as a result of manual switching more than 3/18 hours after all customers' supplies are restored are also to be excluded.

2.175. DNOs must explain any changes that have been made to the definitions or measurement over the period that have led to a change in the reported figures.

2.176. The MTP worksheets also captures the volumes for the following assets for unplanned incidents:

- Streetlights/Street furniture,
- Cut outs,
- Overhead services (no customers interrupted – e.g. bracket repair), and
- Cut out fuses only.

2.177. The worksheets also captures the following occurrences:

- Abortive calls,
- Meters,
- Responding to critical safety calls (e.g. substations), and
- Pilot wire failures.

Fault rate data

2.178. The Fault Rate data sheet contains the full set of input data used to generate the Fault Rate Record for each relevant Fault Rate Asset Category. The MTP worksheets also captures the volumes for unplanned incidents in the following categories:

- Damage fault rates – all incidents (rows 91 to 130), and
- Damage fault rates – excluding exceptional events (rows 131 to 169).

2.179. The Agreed Network Output is the forecast for 'Damage fault rates - all incidents'.

2.180. As explained in section 2.18 of this RIG, there are different reporting requirements at different points in time over the price control period. For the Fault Rate data:

- All the relevant yellow input cells will have been populated for the purposes of defining the Agreed Network Outputs,
- For the purposes of annual reporting, actual Fault Rate data will be collected in the workbook, and
- All the relevant yellow input cells must be populated for the purposes of the Mid-Period Review Submission and the Performance Assessment Submission.

Fault rate charts

2.181. The Fault Rate charts sheet presents the Fault Rate Record for each Fault Rate Asset Category. This sheet contains a series of buttons which, when pressed, produce charts from the Fault Rate data sheet, for each of the 14 Fault Rate Asset Categories. For each of the Fault Rate Asset Categories, the charts display the following:

- Damage fault rates – all incidents (actual),
- Damage fault rates – excluding exceptional events (actual),
- Damage fault rates – all incidents (forecast), and
- Damage fault rates – excluding exceptional events (forecast).

2.182. As part of the mid-period review and performance assessment, Ofgem is to compare forecast Fault Rates (i.e. the Agreed Network Output) with the actual Fault Rates recorded over the period.

Volume reconciliation

2.183. The volume reconciliation sheet provides details of the mapping process from Distribution Asset Categories to Health Index Asset Categories and Fault Rate Asset Categories, consistent with paragraphs 2.14 and 2.15 of this RIG. There is no requirement to enter data in this sheet – it is provided for reference only.

HI tracking

2.184. The HI tracking sheet breaks down, for each Health Index Asset Category, the changes to the HI profile over DPCR5. A DNO must provide an updated HI tracking sheet each year which reconciles to the HI data sheet. The section below provides guidance for a number of specific line items required in this sheet.

Impact on volumes of data cleansing (before Material Changes)

2.185. In this row, please enter the changes from the previous year's HI profile due to data cleansing.[15] The impact of these changes must be entered relative to the previous year's HI profile, before accounting for any Material Changes.

Impact of deterioration (before Material Changes)

2.186. In this row, please enter the impact on the HI profile of deterioration from the previous year's submission. This must reflect the normal path of deterioration assumed as at the previous submission, before accounting for any Material Changes that have occurred during the year (e.g. change to degradation assumptions).

Variance due to Material Changes

2.187. In this row, please enter the overall impact on the HI profile of all Material Changes impacting that Health Index Asset Category. Details on the nature and impact of Material Changes must be contained in commentary accompanying the submission.

Asset register movements for asset replacement

2.188. In this row, please enter the changes to the HI profile resulting from any asset replacement Interventions that have occurred during the year. These numbers will reconcile with relevant volumes in the asset register.

Asset register movements for other investment

2.189. In this row please enter the changes to the HI profile that reflect any other investment not captured under asset replacement (e.g. load-related).

[15] Data cleansing is defined as the act of detecting and correcting (or removing) corrupt or inaccurate records from the HI data set.

3. Instructions for completing network asset data reporting

Introduction

3.1. The purpose of this chapter is to provide instructions and guidance for the collection of consistent and accurate network asset data. The data will be used in conjunction with the cost data in order to set allowances for the DPCR6 price control period.

3.2. This chapter deals with the collection of the following data:

- volume of network assets for which the DNOs are responsible (including assets installed as a result of a new generation connection (DG) or funded by the Low Carbon Networks fund),
- age profile of network assets, and
- volume of network activities undertaken by the DNOs.

3.3. Definitions for terms used within this chapter can be found in the glossary. Further information can also be found within the Appendix 2, 'Asset replacement unit cost scope appendix'.

(A1-A20) Asset register

3.4. The purpose of the asset register is to collect volume data, and the number of additions and disposals for each asset type. The information provided will be used in conjunction with the cost data to provide information regarding the unit cost for assets, and will enable modelling for DPCR6.

3.5. The asset register is a collection of worksheets which shows the total number of network assets for each year and the number of network assets added and removed from the network each year. The asset register is not linked to any of the Activity worksheets. For each work driver (e.g. asset replacement, general reinforcement etc.), a worksheet has been added to allow each asset addition or disposal to be recorded against the driver.

3.6. Definitions for terms used within the asset register can be found within the glossary (2. Asset register definitions).

3.7. DNOs must input the current year's asset total in the A1 Total worksheet, For example, in the July 2010 submission DNOs must input into column J the assets in commission at the end of the 31st March 2010 reporting year. In July 2011 DNOs must input into column K the assets in commission at the end of the 31st March 2011 reporting year.

3.8. Each year the DNOs must input the additions and disposals for each asset in worksheets A4 to A18.

3.9. The total assets in commission for historic and future years are auto-calculated in worksheet A1 using the asset additions and disposals data in conjunction with the most recent reporting year and assets in commission data.

3.10. A cleansing worksheet has been added to record any corrections to the total asset count from the previous year. The cleansing sheet must be populated when there is a difference between the total asset count (A1 total) for the same year in the current year's submission and the previous year's submission. For example, if in the July 2010 submission, the total number of HV transformers in commission at the end of the 31st March 2010 was reported as 400 and during the reporting year 1st April 2010 to 31st March 2011, there were no additions or disposals, but new data has revealed that at the end of 31st March 2011 there were 425 HV transformers in commission then the July 2011 submission must report 425 HV transformers in column K of the A1 total sheet, and 25 HV transformers in year 2010 (column J) in the A19 Cleansing worksheet.

3.11. This data will be used in conjunction with data collected through the cost and revenue RIGs to help us get a better understanding of unit costs across the industry, and to inform DPCR6 modelling.

3.12. The age profile register will be used in conjunction with the asset data reports to help us get a better understanding of the asset replacement practices of DNOs and to inform DPCR6 modelling.

3.13. The activity volumes report provides data for activities undertaken by the DNO. The data provided will be used in conjunction with the cost reports to inform allowances for DPCR6.

A1 Total

Guidance

3.14. DNOs are required to input the closing balance for each asset, as defined within the glossary, for the current reporting year.

3.15. This total must include any assets installed as a result of DG connections or funded by the Low Carbon Network fund. The closing balance for previous years is calculated from the current closing balance minus the total additions plus the total disposals for the current reporting year.

3.16. The closing balance for future years is calculated by adding the next years total additions and deducting next years total disposals from the current years closing balance.

3.17. The total count for the following assets within the Other assets section of A1 must be populated and include:

- LV Fuses (PM),
- LV Fuses (GM) (TM),
- Switching points with remote control/automation facility,
- GM substations with batteries, and
- GM substations without batteries.

A2 Total additions

3.18. This worksheet shows the total number of additions for each asset category (summation of the asset additions in tables A4 to A18).

3.19. DNO input is only required to show the annual additions for the following asset categories:

- LV Fuses (PM),
- LV Fuses (GM) (TM),
- Pilot wire overhead,
- Pilot wire underground,
- GM substations with batteries, and/ or
- GM substations without batteries.

A3 Total disposals

3.20. This worksheet shows the total number of disposals for each asset (summation of the asset disposals in tables A4 to A18).

3.21. DNO input is only required to show the annual disposals for the following asset categories:

- LV Fuses (PM),
- LV Fuses (GM) (TM),
- Pilot wire overhead,
- Pilot wire underground,
- GM substations with batteries, and
- GM substations without batteries.

A4-A18 Additions & disposals

3.22. Additions and disposals are categorised according to the driver of the activity. The drivers are shown below:

- Demand connections,

- Diversions,
- General reinforcement,
- Fault level,
- ESQCR,
- Asset replacement,
- Asset replacement (Consequential),
- Rising & Lateral Mains (RLM),
- AONB (Inside boundary),
- AONB (Outside boundary),
- High Value Projects (HVP),
- Generation connections (DG),
- Low Carbon Networks fund (LCN), and
- Other.

3.23. The addition and/or disposal of an individual asset must be recorded in one of these sheets according to the workload driver.

3.24. DNOs must input the asset quantities for additions and disposals from the network. Both additions and disposals must be input as positive numbers. All network lengths must be reported as circuit length (in km) rather than route lengths.

3.25. Asset additions and disposals must be input for historic years, the current year and future years unless otherwise indicated.

3.26. For current and historic years, asset additions must only appear in this table once they are energised on the network rather than once the assets are installed on site. Forecast asset additions must show the number of (energised) assets which are expected to be added to the network.

3.27. Assets under construction must not be included in this table.

3.28. Strategic spares must not be included in this table until installed and energised on the system.

3.29. Assets which are de-energised during the year but are available for re-commissioning (e.g. pressure-assisted cables) must be entered as disposals.

3.30. Asset data must be disclosed by operating, and not by construction, voltage. Where asset data is available only at construction voltage then this must be stated in the commentary.

3.31. The old HV Switchgear Other (GM), EHV Switchgear (other) and 132kV Switchgear (other) categories are discontinued. Their previous counts do not need to be absorbed in other categories.

A4 Demand connections

3.32. This sheet records asset additions and disposals due to Demand connections.

A5 Diversions

3.33. This sheet records asset additions and disposals due to Diversions.

A6 General reinforcement

3.34. This sheet records asset additions and disposals due to general reinforcement of the network.

A7 Fault level

3.35. This sheet records asset additions and disposals due to fault level reinforcement of the network.

A8 ESQCR

3.36. This sheet records asset additions and disposals to comply with ESQCR regulations.

A9 Asset replacement

3.37. Asset replacement, additions and disposals of prime assets (i.e. installed assets which are the prime reason for the activity) must be recorded in the "A9_Asset_Replacement" sheet.

3.38. Appendix 2 ' Asset Replacement Unit Cost Scope Appendix' shows the asset replacement categories and details which assets must be classed as prime assets and which must be classed as consequential assets.

3.39. Pole-mounted circuit breakers or transformers replaced at the same time and location as HV poles, must also be reported as prime assets.

A10 Asset replacement (Consequential)

3.40. Consequential assets (i.e. other assets included within the scope of work) must be recorded within the consequential asset replacement sheet ("A10_Asset_Repl_(Consequential)").

3.41. Appendix 2 shows the asset replacement categories and details which assets must be classed as prime assets and which must be classed as consequential assets.

3.42. Pole-mounted circuit breakers or transformers replaced at the same time and location as HV poles, must also be reported as prime assets.

A11 Asset replacement (Memo)

3.43. The Asset replacement (Memo) table has been added to record the different types of transformer and cable which have been added. This table does not feed into the A1 Total sheet, therefore any asset additions in this table must also appear in the relevant asset register sheet.

A13 AONB (Inside boundary)

3.44. This sheet is to record additions and disposals of assets which have been funded by the AONB allowance and which are sited within the boundary of the AONB.

A14 AONB (Outside boundary)

3.45. This sheet is to record additions and disposals of assets which have been funded by the AONB allowance and which are sited outside the boundary of the AONB.

A15 High Value Projects (HVP)

3.46. This sheet is to record assets which are added or disposed of as part of a High Value Project.

3.47. Where the addition or disposal of an asset could be classed as both a High Value Project and another driver, the assets must only be recorded in the High Value Projects worksheet. Further information regarding the HVP must be provided in the narrative.

A16 Generation connections (DG)

3.48. The Generation connections (DG) sheet records all assets installed or replaced as part of a DG connection.

A17 Low Carbon Networks (LCN)

3.49. The LCN sheet records additions and disposals of assets which have been funded by the Low Carbon Networks (LCN) Fund. We note that the LCN Fund does

not fund assets for RAV purposes, since funding is provided up front. However, where physical assets are purchased via the LCN Fund (whether First or Second Tier) their addition (and subsequent disposal) must be recorded here. This ensures the total asset register tables include all assets even though LCN assets do not feed into the RAV calculations.

A18 Other

3.50. Where the driver for the asset installation does not fit into any of the categories in worksheets A4 to A17, the addition or disposal must be recorded in the "A18_Other" sheet. Examples of drivers of work which would be recorded in this worksheet are HILP, Faults and Non Trading Rechargeable Diversions.

3.51. Assets installed by ICPs and adopted by DNOs must be entered in this worksheet.

A19 Cleansing

3.52. The purpose of the cleansing worksheet is to highlight any differences in the total asset count (A1 Total) from the previous year's submission.

3.53. In worksheet A19 Cleansing, the DNO must input the difference between asset totals in the A1 Total worksheet for this year's submission and the previous year's submission. For example, if in the July 2010 submission, the total number of HV transformers in commission at the end of the 31st March 2010 was reported as 400 and during the reporting year, 1st April 2010 to 31st March 2011, there were no additions or disposals but new data has revealed that at the end of 31st March 2011 there were 425 HV transformers in commission then the July 2011 submission must report 425 HV transformers in column K of the A1 total sheet, and 25 HV transformers in year 2010 (column J) in the A19 Cleansing worksheet.

3.54. For each year that there is a difference, a cleansing figure must be populated (e.g. If, in the example above, it was not discovered until reporting year 2011, that HV transformers had been under-reported by 25 units, then 25 must be populated in A19 for all years from 2006 to 2010).

3.55. If an asset has been over-reported in previous years, a negative value must be populated in the A19 Cleansing worksheet.

3.56. The A19 Cleansing worksheet does not feed into the A1 Totals worksheet. The A1 Totals worksheet calculations only require the current year's asset total and additions and disposals for each year to provide the asset totals for historic and future years.

3.57. Where cleansing has been recorded, the DNO must provide further information within the commentary.

A20 Age profile

3.58. DNOs must input the existing asset quantities (by asset type as specified in the table) in the Regulatory Year in which they were added to the network.

3.59. DNOs must input the average asset lives for the assets and the standard deviation of asset lives in the asset replacement profile section. Average asset lives are defined as the "expected average age at replacement as experienced by DNO for the asset population (this is the mean value of the asset age replacement profile of the particular asset)".

3.60. Assets must only appear in this table once they are energised on the network. Assets which have been re-energised must appear in the year in which the asset was originally installed.

3.61. Assets under construction must not be included in the age profile.

3.62. Strategic spares must not be included in this table until installed and energised on the system.

3.63. Assets which are de-energised during the year but are available for re-commissioning (e.g. pressure assisted cables) must not be entered in the age profile.

3.64. Asset data must be disclosed by operating, and not by construction, voltage. Where asset data is available only at construction voltage then this must be stated in the commentary.

A21 Fault levels

Purpose

3.65. This table captures information on fault level issues and the resulting impact on measures of system fault level issues.

Guidance

Fault level system measures

3.66. DNOs must input:

- the number of switchboards (nodes) by busbar voltage,
- the number of switchboards where fault levels are greater than 95% of switchgear rating, and
- the total number of switchboards with operational restrictions due to fault level issues.

3.67. The HV column refers only to switchboards on the secondary side of transformers (i.e. excludes distribution substations). For the purposes of this table a switchboard is equivalent to a node for which data is reported in the Long Term Development Statement (LTDS).

Fault level schemes

3.68. DNOs must input the number of fault level schemes by voltage against switchboards, transformers and other schemes.

A22 Connections

Purpose

3.69. This table shows actual connection volumes for connections with no element funded via the apportionment rule, connections with an element funded via the apportionment rule and total unmetered connections. Alongside these values, DNOs are required to forecast the relevant volumes of connections for the years ahead.

Guidance

3.70. The detailed connections reporting workbook (tables CN1-CN16) will auto populate this table with the relevant actuals for the current reporting year and the next reporting year. In addition to this, DNOs must forecast volumes of connections activity across the relevant categories, as defined in the glossary, for all subsequent years within the table. Where the actual values for a future year differs substantially from the previous year's forecast, Ofgem would expect DNOs to readjust subsequent forecasts accordingly.

A23 Diversions

Purpose

3.71. This table collects volumes for non-rechargeable diversions to assess expenditure for DPCR6. Diversions are divided into the following three areas:

- conversion of wayleaves to easements, easements, injurious affection,
- diversions due to wayleave terminations, and
- diversions for highways (funded as detailed in NRSWA).

Guidance

Conversion of wayleaves to easements, easements and injurious affection

3.72. DNOs are required to input the number of claims settled (or forecast to be settled) for each year at each voltage level without physical work being carried out on the network and where the settlement is at the company's expense and is not chargeable to third parties.

3.73. Where the work covers more than one voltage level, then the claim must be recorded against the higher voltage.

3.74. The activity includes the conversion of wayleaves to easements, injurious affection settlements and related costs.

3.75. Volumes must only be recorded once the claim is settled.

Diversions due to wayleave terminations

3.76. DNOs are required to input the closing balance each year for the number of alterations or diversions at each voltage level which have, or are forecast to have, been carried out in response to a notice of wayleave termination at the Company's expense and not chargeable to third parties.

3.77. This activity includes the rerouting, raising or undergrounding of a circuit and assets.

3.78. Where a diversion requires work at more than one voltage level, then the diversion must be recorded against the higher voltage.

3.79. This activity excludes those included under Diversions for Highways and those carried out to achieve compliance with ESQCR.

3.80. Volumes must only be recorded once the diversion is completed.

Diversions for highways (funded as detailed in NRSWA)

3.81. DNOs are required to input the number of diversions at each voltage level which have been carried out and funded as detailed in NRSWA.

3.82. This activity includes the rerouting, raising or undergrounding of a circuit and assets.

3.83. Where a diversion covers work at more than one voltage level, then the claim must be recorded against the higher voltage.

3.84. Volumes must only be recorded once the diversion is completed.

A24 ESQCR 43-8 safety clearance volumes

Purpose

3.85. This worksheet collects volume data regarding the number of sites where ESQCR 43-8 safety clearance work has taken place which will be used in conjunction with the cost reports to set allowances for DPCR6.

Guidance

3.86. The table must only contain information relating to buildings and structures and excludes clearance infringements caused by vegetation and associated costs.

3.87. The ESQCR 43-8 safety clearance table is split by horizontal and vertical clearance data.

3.88. Horizontal refers to activity to remove or prevent horizontal clearance infringements. DNOs must input the total number of horizontal sites which do not meet the requirements of ESQCR 43-8 regulation as at the 31st March of the relevant year.

3.89. Vertical refers to activity to remove or prevent vertical clearance infringements. DNOs must input the total number of vertical sites which do not meet the requirements of ESQCR 43-8 regulation as at the 31st March of the relevant year.

3.90. Site affected is defined as the number of sites that have one or more low-risk clearance infringements.

3.91. DNOs must input the number of sites where permanent shrouding of conductors was required to remove hazard. This includes the use of plastic ducts to prevent contact with conductors.

3.92. DNOs must input the number of sites for the following categories, where the hazard is removed:

- by a diversion (This includes raising or rerouting a circuit),
- by undergrounding,
- by replacing bare conductor with covered conductor,
- as a result of other planned work, e.g. overhead line refurbishment, undergrounding for environmental reasons, a diversion as a result of a wayleave termination claim, or
- by rebuilding the line.

3.93. DNOs must input the number of sites with vertical clearance issues that are resolved by obtaining derogation from HSE/DECC.

A25 Legal & Safety

Purpose

3.94. This worksheet collects volume data for site security, asbestos management, safety climbing fixtures, substation fire protection and earthing upgrades. Other lines have been added which allow manual entry for DNOs to specify legal and safety issues against which work is forecast. This data will enable analysis of costs for DPCR6 requirements.

Guidance

Site security

3.95. DNOs must input the number of sites where site security work has been carried out.

3.96. This relates to specific security-related improvement to Grid, Primary and Distribution substation sites in response to trespass, unauthorised entry and fly-tipping.

3.97. These measures include the use of additional physical barriers to vehicular access, upgraded site security lighting, enhanced anti-climbing measures and enhanced access control systems.

3.98. This must not include any measures associated with Critical National Infrastructure.

Asbestos management - Substations

3.99. DNOs must input the number of sites where work to manage asbestos in substations has been carried out.

3.100. This activity includes the removal and disposal of asbestos from substations and other measures to control an asbestos hazard.

Asbestos management - Meter positions

3.101. DNOs must input the number of sites where work to manage asbestos on meter positions has been carried out.

3.102. This activity includes the removal and disposal of asbestos from meter boards and other measures to control an asbestos hazard.

Safety climbing fixtures

3.103. DNOs must input the number of sites where work on this activity has taken place.

3.104. This activity includes the provision of support or plant-mounted fixtures or devices as an aid to improving the safety for operators.

Substation fire protection

3.105. DNOs must input the number of sites where work on this activity has taken place.

3.106. This activity includes provision of fire detection systems or the installation of fire preventative measures such as ablative coatings or fire barriers and fire protection system improvements including emulsifier and inert gas systems or replacement or upgrading of CO_2 systems.

Earthing upgrades

3.107. DNOs must input the number of sites where work on this activity has taken place. This includes work at both substation sites and customer premises.

3.108. This activity includes earthing system improvements to reduce earth resistivity.

3.109. This excludes the replacement of missing earth conductor.

Other

3.110. These rows are to enable DNOs to separately identify any activity volumes undertaken in response to additional legal & safety requirements. The DNO is to identify the relevant measure (e.g. no. of sites) and report accordingly. Additional clarification, where relevant, is to be provided within the commentary.

A26 BT21C

Purpose

3.111. This worksheet collects volumes of work carried out relating to the BT 21st century project.

Guidance

3.112. DNOs are to input the number of circuits (or group of circuits) which have had commissioned protection communication circuits replaced due to BT21C or, where BT21C issues have been compensated for by operational measures.

3.113. Operational measures refer to measures which do not involve investment in their own replacement circuits (e.g. leasing alternative communication circuits from another provider).

A27 Flood mitigation (site)

Purpose

3.114. This worksheet collects volumes and levels of expenditure on work to mitigate the risk of flooding.

3.115. The information provided will also be shared with DECC.

Guidance

3.116. Within tables A26 and A27, the probability of flooding, as identified as part of the ENA Substation Resilience to Flooding Task Group, is to be measured as a "return period" in years to the nearest whole number, i.e. the longest period in years that will pass without the site flooding. For example, if there is a risk of a substation flooding once in 20 years, this must be categorised as a flood risk of 1/20 (to be measured to the nearest whole number). Where this level of analysis is not available and/or the risk has been identified from the EA/SEPA indicative flood maps, enter 1/100 for the 1/100 years contour, 1/200 for the 1/200 years contour or 1/1000 for the 1/1000 years contour. (These categories must be mutually exclusive, e.g. substations at 1/100 years risk must not also be categorised as 1/200 years or 1/1000 years risk – put the substation in the highest level of risk faced).

3.117. In Table 1, DNOs must input the number of Primary, BSP and SGP sites that are presently considered to be unmitigated for a risk of flooding. These volumes must be disaggregated by the following risk of flooding bands (1/ 100, 1/200 & 1/1000), where a risk of 1/100 or less must be categorised as 1/100, 1/101 to 1/200 as 1/200 and 1/201 to 1/1000 as 1/1000.

3.118. The second half of the table must be completed on the same basis for those sites that will still have flood risk unmitigated on the 31st March 2015.

3.119. In Table 2, DNOs must input data requested for individual substations where work to mitigate flood risk is to be carried out in DPCR5, or has already taken place in DPCR4.

3.120. In Table 3, DNOs must input data requested for individual substations where there is a flood risk but no work is planned to be carried in DPCR5, or has previously taken place in DPCR4.

A28 Flood mitigation (summary)

Purpose

3.121. This worksheet collects data on the number of substations where the flooding risk has been mitigated at each risk level.

3.122. The information provided will also be shared with DECC.

Guidance

3.123. DNOs must input the number of assets in each risk category which have had, or are forecast to have, flood mitigation work carried out.

A37 Inspections & Maintenance (I&M)

Purpose

3.124. This worksheet collects volumes of inspections and maintenance activities and frequency of inspections and maintenance visits to inform assessment of costs and benchmarking.

Guidance

3.125. DNOs must input data for each category of inspections and maintenance as per the activity description given below.

3.126. If a single site is visited four times during any reporting year, this counts as four site inspections and this is the number which must be entered into the report.

Overhead Line (Inspections)

3.127. This is the patrol and inspection of overhead lines (all voltages) includes foot, climbing and helicopter patrols and inspections. This also includes ad hoc repair carried out at the same time as the inspection.

Overhead Line (Surveys)

3.128. This includes non-routine asset condition surveys (all voltages).

Overhead Line (Repair & Maintenance)

3.129. This is the repair and maintenance of all OHL types (all voltages) including anti climbing device repairs, stay and stay insulator repairs, insulation and fittings repairs, steelwork repairs, ad hoc replacement and earthing repairs (i.e. all overhead line expenditure not reported under OHL refurbishment expenditure).

Overhead Line (Shrouding)

3.130. This is the provision and removal of temporary shrouding.

LV Switchgear & UG Cable (Inspection)

3.131. This refers to the inspection of LV switchgear including substation located switchgear, feeder pillars, link boxes and connected cabling.

LV Switchgear & UG Cable (Repair & Maintenance)

3.132. This refers to the repair and maintenance of LV switchgear including substation located switchgear, feeder pillars, link boxes and connected cabling.

Rising & lateral mains - Surveys

3.133. DNOs must input the number of sites surveyed. The survey includes the identification under an asset data collection exercise of multi-occupancy buildings each served by a network of rising mains and for which the company accepts asset management responsibility.

3.134. DNOs must input the number of properties surveyed. The activity includes the identification of properties, each with a service (or looped service) connected to a rising main or lateral, within multi-occupancy buildings for which the company accepts asset management responsibility.

Substation (Inspection)

3.135. This includes the inspection of substation/switching station fencing, buildings, site and assets (HV, EHV, 132kV).

Plant - RMU X-type (Repair & Maintenance)

3.136. This refers to expenditure on X-Type RMU including electrical and mechanical maintenance of main and tee-off switching devices and associated protection, control and metering equipment. This includes testing, repair and preventative maintenance.

Plant - RMU Other type (Repair & Maintenance)

3.137. This refers to expenditure on HV and EHV RMUs (excluding X type) including electrical and mechanical maintenance of main and tee-off switching devices and associated protection and control equipment. This includes testing, repair and preventative maintenance.

Plant – Other switchgear (Repair & Maintenance)

3.138. This refers to expenditure on switchgear (HV, EHV, 132kV) including circuit breakers and switches but excluding RMUs. This includes testing, repair and preventative maintenance. This also includes expenditure on associated switchgear protection, control and metering equipment and integral CTs and VTs.

Plant – Switchgear All types (EHV) (Repair & Maintenance)

3.139. This refers to expenditure on EHV switchgear including electrical and mechanical maintenance of main and tee-off switching devices and associated protection and control equipment. This includes testing, repair and preventative maintenance.

Plant - Transformers (Repair & Maintenance)

3.140. This refers to expenditure on transformers, including reactor transformers, and associated earthing transformers and NERS (HV, EHV, 132kV) including testing, oil testing, filtration and replacement, tap changer maintenance, bushing or other ad hoc replacement, maintenance of silica gel breathers. This includes expenditure on associated cooling plant and equipment. This excludes painting.

Plant - Batteries at substations (Repair & Maintenance)

3.141. This refers to expenditure on substation batteries (HV, EHV, 132kV). This includes testing, repair and preventative maintenance.

Civils - Substations (Repair and Maintenance)

3.142. This is the repair and maintenance of substation buildings (all voltages) including doors, windows, roofs, lighting and heating systems, dehumidifying equipment and painting. This excludes plant and equipment painting and asset replacement activity.

Underground Cable (Inspection)

3.143. This includes monitoring of pressurised cables and pressurising plant and equipment (HV, EHV, 132kV). This excludes cable testing and inspections of cable tunnels and bridges.

Underground Cable (Repair & Maintenance)

3.144. This is the maintenance expenditure on cables (all voltages) including diagnostic cable testing, e.g. partial discharge testing, sheath testing. This includes sheath repairs, repressurising cable or repairs to pressurising equipment. This excludes work on cable bridges and tunnels.

Cable Tunnels (Inspections)

3.145. This is the routine inspections of cable tunnels (all voltages) including fixtures and fittings and associated plant, e.g. sump pumps, lighting etc.

Cable Tunnels (Repair & Maintenance)

3.146. This includes civil, electrical and mechanical work, repairs and painting (all voltages).

Cable Bridges (Inspections)

3.147. This is the routine inspection of cable bridges (all voltages) including fixtures and fittings and associated plant, e.g. access arrangements and lighting etc.

Cable Bridges (Repair & Maintenance)

3.148. This includes civil, electrical and mechanical work , repairs and painting (all voltages).

Civils - Grounds and Fencing (Repair & Maintenance)

3.149. This is the repair and maintenance of substation grounds and fencing (all voltages) including painting, substation weeding and maintenance of security lighting and perimeter security systems. This excludes plant and equipment painting, and asset replacement activity.

Plant - Protection, SCADA (Repair & Maintenance)

3.150. This refers to expenditure on substation located protection, control and SCADA equipment (HV, EHV, 132kV). This includes testing, repair and preventative maintenance. This also includes protection of conventional circuit breakers.

Plant - Other (Repair & Maintenance)

3.151. This includes painting of transformers, painting and maintenance of free standing VTs and CTs (HV, EHV, 132kV).

A38 Tree cutting

Purpose

3.152. This worksheet collects data regarding tree cutting as part of ENATS 43-8 and ETR 132

Guidance

ENATS 43-8: Tree cutting

3.153. Data collected for ENATS 43-8 tree cutting is divided into three areas; networks parameters, tree cutting policy and volume.

3.154. DNOs must provide data for these three areas as detailed below for each voltage level.

3.155. In the “Network parameters” section of the table, enter the total number of kilometres of network, the total number of spans, the average length of spans and the number of spans affected by trees (split by high and low density of trees).

3.156. This excludes the felling or trimming of vegetation as part of a Capital Scheme.

3.157. In the “Tree Cutting Policy” section, enter if there is a reactive or a proactive approach to tree cutting by entering "R" or "P" respectively in each cell in the row.

3.158. For "Cut cycle", please input the number of years it would take the DNO to complete the cut cycle for the network.

3.159. In the "Volume" section, DNOs must input the number of "Spans inspected and managed".

3.160. This includes all spans that are inspected and managed to meet DNO policy. This may include spans which require tree cutting and spans that are inspected but don't require any cutting as adequate clearance is already achieved.

ETR 132 Tree cutting

3.161. DNOs must provide the following tree cutting activity data to comply with ETR132.

3.162. DNOs must enter the total kilometres cleared split by:

- ETR 132 undertaken as a standalone programme of work,
- ETR 132 undertaken as an extension to 43-8 tree cutting, and
- ETR 132 undertaken at the same time as OHL refurbishment (including rebuild work).

A39 Refurbishment

Purpose

This worksheet collects information regarding assets which have been refurbished.

Guidance

Pole refurbishment

3.163. DNOs must input the number of poles which have been refurbished.

Tower refurbishment

3.164. DNOs must input the number of towers which have been refurbished. This includes tower painting.

Foundation refurbishment

3.165. DNOs must input the number of towers which have had foundations (one or more legs) refurbished or replaced.

LV underground service transfers

3.166. DNOs must input the number of services that have been reconnected in association with cable overlaying programmes.

Transformers

3.167. DNOs must populate the number of transformers where only refurbishment work has been carried out.

Civils

3.168. DNOs must input the number of sites where refurbishment work has been undertaken.

3.169. Refurbishment activities are shown in Table 3.1 below.

Table 3.1: Refurbishment activities

Voltage	Asset	Name	Scope
HV	Civils	GM Indoor Substation	Above or below ground brick, GRP, steel housing – refurbishment or replacement. Modification, replacement or temporary installation of plinth.
		GM Outdoor Substation	Grounds refurbishment replacement – fence or ground covering
HV	Civils	GM Mixed Substation[16]	Above or below ground brick, GRP, steel housing – refurbishment or replacement. Modification, replacement or temporary installation of plinth. grounds refurbishment, replacement – fence or ground covering.
HV	Civils	GM Third Party Substation	Modification, replacement or temporary installation of plinth
EHV	Civils	Total EHV Substations	Refurbishment or replacement of – concrete structures, cable troughs and covers. Replacement of existing palisade fence or installation. Construct or refurbish oil bund. Dismantlement/reconstruction of/Modification of noise enclosures. Blast walls.
132kV	Civils	Total 132kV Substations	Refurbishment or replacement of – concrete structures, cable troughs and covers. Replacement of existing palisade fence or installation. Construct or refurbish oil bund. Demolition and removal of existing

			civils. Dismantlement/reconstruction of/Modification of noise enclosures. Blast walls.
Other	Civils	Cable Tunnels	Refurbishment or replacement.
Other	Civils	Cable Bridges	Refurbishment or replacement

A40 Dismantlement

Purpose

3.170. This worksheet provides visibility of the volumes of dismantlement work undertaken.

Guidance

3.171. DNOs must input the total number of assets (at each voltage level) where dismantlement, recovery and disposal work has taken place.

3.172. Dismantlement refers to the physical activity of de-energising, disconnecting and removing (where appropriate) network assets where the cost of dismantlement is not chargeable to a third party and no new assets are to be installed.

A41 Streetworks

Purpose

3.173. This worksheet collects data regarding volumes associated with Streetworks. This includes permit numbers, permitting penalties, notifications, notification penalties, inspections, lane rentals and overstay fines.

Guidance

3.174. DNOs must input the volumes of permits, penalties, notifications, inspections, lane rentals and fines.

3.175. The volume of each of these must be categorised according to:

- Demand connections - DUoS funded,
- Network investment, and
- Network operating costs.

A42 QoS schemes annual

Purpose

3.176. This worksheet provides details of discretionary improvement schemes driven by improving IIS performance as well as the likely impacts on CI and CML performance and estimated lifespan of these improvements (this column must be left blank for improvements that do not have a specific lifespan and will instead continue to improve performance indefinitely). This information will be collected on an annual basis.

3.177. This will provide visibility on an annual basis of any schemes that have been undertaken where the main driver was to improve CI/CML performance.

Guidance

3.178. Each scheme requires a unique scheme ID (identification number). Where schemes roll over into subsequent years, the scheme ID must remain constant with the expenditure and description reflective of the actual work phase and expenditure that has been undertaken within the particular reporting year. Work schemes which are concentrated on a particular section of network/circuit must be grouped together under a specific scheme ID where possible, even where elements of the schemes may differ significantly. Where DNOs approach the defining and naming of schemes in a different way, relevant commentary is to be provided.

Table 1- CI/CML schemes

3.179. This table is to be completed with the scheme details of "CI/CML schemes"- that is, discretionary schemes primarily aimed at improving CI and/or CML performance. Against each scheme ID, DNOs must enter a description of the work phase undertaken within the particular reporting year and enter the expenditure undertaken in the year being reported on, the estimated impacts on annual CI/CML rates and the estimated lifespan of the specific improvements.

Table 2- Operational changes

3.180. This table must be completed with a description of any operational changes which are aimed at improving IIS performance. Against each operational change, the level of relevant investment undertaken within the year being reported on must be split and entered under the following table headings:

- Fault costs (£m),
- Closely associated indirects,
- Business support (£m), or
- Non-operational Capex (£m).

A43 QoS CI & CML improvements

Purpose

3.181. This worksheet shows any CI/CML performance improvements resulting from discretionary IIS improvement schemes.

3.182. This will identify those CI and CML improvements which are deemed to have been derived from identifiable CI/CML improvement driven schemes or operational changes.

Guidance

Definitions

3.183. CI refers to the Customers Interrupted metric, where 1 CI equates to 1 interruption per every 100 customers on a DNOs network.

3.184. CML refers to the Customer Minutes Lost metric, where 1 CML equates to 1 minute of interruption (where interruptions last at least 3 minutes in duration) affecting each of the network's customers.

3.185. CI & CML schemes refers to discretionary schemes primarily aimed at improving CI and/or CML performance. The relevant improvements detailed in the table must relate to schemes identified in the QoS_schemes_annual Table 1 or Table 2, with the scheme specific improvements not outlasting the specific scheme's estimated "Lifetime of improvement".

Table 1- CI improvement

3.186. Each year the estimated impact of ongoing IIS improvement-based schemes (including operational changes as identified within the "QoS schemes annual" sheet) on annual CI performance levels must be reported against the relevant year, and where necessary, subsequent forecasts of future improvements must be included/amended. The improvement will be measured in CIs.

Table 2- CML improvement

3.187. Each year the estimated impact of ongoing IIS improvement-based schemes (including operational changes as identified within the "QoS schemes annual" sheet) on annual CML performance levels must be reported against the relevant year, and where necessary, subsequent forecasts of future improvements must be included/amended. The improvement is to be measured in CMLs.

A44 WSC schemes

Purpose

3.188. We will annually collect WSC scheme information, details of predicted improvements as well as forecast expenditure information on a scheme-by-scheme basis.

3.189. We need to collect this data to determine the eligibility and success of Worst Served Customer schemes undertaken by DNOs.

Guidance

3.190. Each scheme requires a unique scheme ID (identification number). Where schemes roll over into subsequent years the scheme ID must remain constant, with the expenditure and description of relevant predicted improvements, etc. reflective of the actual work phase and expenditure that has been undertaken within the particular reported year. Work schemes which are concentrated on a particular "worst served" section of network must be grouped together under a specific scheme ID, even where the elements of the schemes may differ significantly. Where DNOs approach the defining and naming of schemes in a different way, relevant commentary is to be provided. The "Total cost of scheme" column must be completed with the total cost of an individual scheme across the years in which it is active. For example, for the first year of a project, the in-year costs and total cost must be equal. After 2 years, the total cost of the scheme must be equal to the first year's in year costs plus the second year's in-year cost.

Table 1- Worst Served customer

3.191. Against each numbered and named potential Worst Served Customer scheme enter the type of scheme, year of implementation, location, cost, voltage and customers on that circuit (all customers and worst-served customers). For each scheme there must be a designated number of worst served customers that are expected to benefit from the scheme. For these worst-served customers expected to benefit from a scheme the following will need to be provided on an average per annum basis:

- the current three year average number of higher voltage interruptions experienced by the worst served customers expected to benefit,
- the predicted improvement in average number of higher voltage interruptions experienced by the worst served customers expected to benefit, and
- the predicted life of improvements.

3.192. Please also include any resultant CI and/or CML improvement (although this must not be the driver).

3.193. In order to capture the year-on-year actual change in average annual interruption DNOs are to calculate the actual average annual interruptions per worst served customer in the subsequent three years after the scheme has been implemented.

4. Instructions for completing quality of service outputs reporting

QoS Interruptions

Introduction

4.1. The purpose of this chapter is to provide instructions and guidance for quality of service outputs reporting.

4.2. This chapter sets out definitions and related instructions and guidance for the reporting of:

- the number of customers interrupted (CIs),
- the duration of interruptions to supply (CMLs),
- the number of customers interrupted by short interruptions (SIs), and
- the number of customers re-interrupted (RIs).

4.3. The quality of service tables are designed to monitor DNO performance against compliance with the interruptions incentive scheme (IIS) and to provide the underlying data to assist with target setting as part of DPCR6.

Information sources

4.4. Most DNOs use the National Fault and Interruption Reporting Scheme (NaFIRS) which is administered by the Energy Networks Association (ENA) - or an equivalent system - to collect information on the number of customers interrupted and duration of interruptions to supply. For the purpose of reporting under SLC 45, DNOs are instructed to use the definitions contained in this guidance.

Definitions of output measures

4.5. Definitions to be applied for reporting on the number of customers interrupted and duration of interruptions to supply, the number of customers interrupted by short interruptions and the number of customers re-interrupted are shown below. Further definitions, instructions and guidance and output reporting requirements are set out later in this chapter.

- the number of customers interrupted per year (CI) – the number of customers whose supplies have been interrupted per 100 customers per year over all incidents,

where an interruption of supply lasts for three minutes or longer, excluding re-interruptions to the supply of customers previously interrupted during the same incident (see below for further details). It is calculated as:

$$\frac{\text{The sum of the number of customers interrupted for all incidents} * 100}{\text{The total number of customers}}$$

- the duration of interruptions to supply per year (CML) - average customer minutes lost per customer per year, where an interruption of supply to customer(s) lasts for three minutes or longer, calculated as:

$$\frac{\text{The sum of the customer minutes lost for all restoration stages for all incidents}}{\text{The total number of customers}}$$

- the number of customers interrupted by short interruptions per year (SI) –the number of customers whose supplies have been interrupted by a short interruption per 100 customers per year over all short interruptions, where the initial interruption to supply is restored in less than three minutes, calculated as:

$$\frac{\text{The sum of the number of customers interrupted by short interruptions} * 100}{\text{The total number of customers}}$$

- the number of customers re-interrupted per year (RI) – the number of customers whose supplies have been re-interrupted per 100 customers per year, calculated as:

$$\frac{\text{The sum of the number of customers re-interrupted} * 100}{\text{The total number of customers}}$$

Further definitions

Distribution System

4.6. "Distribution System" is defined in SLC 1 of the distribution licence. Transmission activities in Scotland encompass 132 kV electric lines and plant; therefore references to reporting on 132 kV in the RIGs are not applicable to the two Scottish DNOs[17].

[17] SP Distribution Limited, Scottish Hydro-Electric Power Distribution Limited

SLC 45 voltages/systems

4.7. Incidents at the following voltage levels must be included in reporting under SLC 45 following these instructions and guidance:

- 132 kV systems,
- extra high voltage (EHV) systems (i.e. all voltages above 20kV up to but excluding 132 kV),
- HV systems (i.e. all voltages above 1kV up to and including 20kV),
- LV systems (i.e. voltages of 1 kV and below), and
- LV services.

4.8. The upper and lower boundaries associated with these voltages are defined in Appendix 1.

4.9. It should be noted that incidents on cut-outs and all wiring and equipment after cut-outs, including cut-out fuse operations, are excluded from reporting under SLC 45 even where such incidents have resulted in the operation of a fuse at the DNO's substation, and the definition of LV services therefore excludes this equipment.

Higher voltages

4.10. For the purposes of reporting under SLC 45, higher voltages include HV, EHV and 132 kV networks[18].

Definition - Customer

4.11. For the purposes of SLC 45, charge restriction condition CRC8 and the NADPR RIGs only, customer means in relation to any energised or de-energised entry or exit point to the DNO's Distribution System, where metering equipment is used for the purpose of calculating charges for electricity consumption, the person who is providing or is deemed to be providing a supply of electricity through that entry point, or the person who is taking or is deemed to be taking a supply of electricity through that exit point.

4.12. Customers should be identified from Metering Point Administration Numbers (MPANs)[19], such that an individual customer is identified at each connection point.

[18] See Appendix 1 – SLC 45 Voltage boundaries

[19] The Master Registration Agreement (MRA) is an agreement that sets out, amongst other things, the terms for metering point administration services and the requirements for the change of supplier process. Schedule 5 of the MRA sets out the form in which a supplier is

Guidance – Customer

4.13. Only one customer should be identified at each connection point. This means that multiple (or secondary) MPANs which arise due to the type of "tariff" (or equivalent) and/or metering arrangements (e.g. import/export meters), but are associated with a single connection point, must not be counted.

4.14. In some cases (e.g. flats), the connection point may be from the Distribution System to wiring owned by a landlord or a facilities manager. In such cases, individual customers supplied by such wiring are classed as customers of the Distribution System where they are identifiable from MPANs.

4.15. Any changes to the method used by DNOs to identify customers from MPANs must be agreed in advance with Ofgem. Ofgem will want to ensure that, as far as possible, DNOs use a consistent method for identifying customers.

Definition - Total number of customers

4.16. The total number of customers is defined as the total number of customers whose supplies are connected to the DNO's distribution network as at 30 September in the relevant reporting year. Guidance on counting customers is set out in paragraphs 4.11 to 4.13.

Definition - Total number of new customers

4.17. The total number of new customers is defined as customers whose supplies have been connected between 1 October in the previous year and 30 September in the relevant year.

Definition - Total number of disconnected customers

4.18. The total number of disconnected customers is defined as customers whose supplies have been disconnected between 1 October in the previous year and 30 September in the relevant year. This count must also include any data cleansing of MPANs that has occurred between 1 October in the previous year and 30 September in the relevant year.

obliged to print the supply number (attributed to a metering point) on a customer's bill. Within the industry the supply number is known as the metering point administration number (MPAN).

4.19. New and disconnected customers should be identified from MPANs such that the number of new and disconnected customers corresponds with the number of new and disconnected connection points on the Distribution System.

Definition - Incident

4.20. Incident is defined as any occurrence on the DNO's Distribution System or other connected distributed generation, transmission or Distribution System, which:

- results in an interruption of supply to customer(s) for three minutes or longer, or
- prevents a circuit or item of equipment from carrying normal load current or being able to withstand "through fault current" for three minutes or longer.

Guidance - Incident

4.21. Occurrences that are classed as an incident lasting three minutes or longer include:

- any physical break in the circuit upstream of the customers interrupted (or circuit affected), due to automatic or manual operation of switchgear or fusegear, or due to any other open circuit condition,
- the unprogrammed isolation of any circuit or item of equipment, energised at power system voltage, which has not been classified as a pre-arranged incident,
- failures of non-system equipment (e.g. pilot cables, oil and gas alarms, voltage control equipment etc) which result in the disconnection of equipment energised at power system voltage,
- incorrect operations of protection equipment which result in the disconnection of a circuit energised at power system voltage,
- failure of protection equipment to operate. This includes incidents where the main protection fails to operate and a fault clearance is initiated by back-up protection or protection at another point on the network,
- the loss of infeed from other connected systems, including those owned by NGET/transmission companies (in Scotland), other distribution companies and distributed generators, and
- the pre-arranged isolation of any circuit or item of equipment energised at power system voltage that results in loss of supply.

4.22. Occurrences that would not lead to an incident are as follows:

- maintenance outages and malfunctions of non-system equipment (e.g. pilot cables, etc) which do not result in the disconnection of a circuit or item of equipment energised at power system voltage,

- failures and overloads on customers' equipment or another connected system, which are cleared by the correct operation of the DNO's protection and which do not interrupt the supply to other customers of the DNO,

- pre-arranged works affecting customers for the purposes of meter changes, voltage standardisation and work on service cables and distributors' fuses, and

- interruptions to supply resulting from load shedding in compliance with statutory and/or licence obligations following upstream incidents relating to either transmission or generation activities.

4.23. Any additional incidents which affect part of the network and/or customers already affected by an incident must also be reported as additional incidents. Two or more incidents may then be active concurrently and the number and duration of interruptions and the number of re-interruptions must be calculated accordingly.

Incident start

4.24. The incident start time is the earlier of the date and time at which:

- the first report is received of a loss of supply[20,21] or other abnormality which prevents a circuit or other item of equipment from carrying normal load current or being able to withstand "through fault current" for three minutes or longer, or

- the relevant circuit is automatically, deliberately or otherwise disconnected.

Report received time

4.25. The report received time is the earliest time that a DNO became aware of a loss of supply, an abnormality or a suspected abnormality. It must be the earliest of the date and time at which:

- a customer (or other person) first contacted the DNO to advise of no-supply, an abnormality or suspected abnormality,

[20] Neutral alarms or indication of reduced feeder load should not be taken as the start time.
[21] Where a customer reports "low volts" then this should not be treated as a loss of supply, until the DNO confirms that the customer is off supply. Equally, where a report of "reverse polarity" is received by the DNO, the customer should be considered "on supply" until the DNO confirms that the customer is off supply, or needs to be disconnected in order to carry out repairs to the DNO's network.

- an alarm was received by the DNO indicating a loss of supply, abnormality or suspected abnormality, or
- a DNO employee or agent identified the existence of a loss of supply, abnormality or suspected abnormality.

4.26. For reports that are associated with a loss of supply or other abnormality which prevents a circuit or other item of equipment from carrying normal load current or being able to withstand "through fault current" for three minutes or longer, the report received time will coincide with the incident start time. For other reports the report received time may precede the incident start time, for example:

- when deliberate disconnection is undertaken some time after the report is received, or
- when some faults are held by arc suppression.

4.27. In respect of loss of supply, some DNOs wait for a second report before initiating action. However, for the purposes of reporting under SLC 45 the incident start time must be based on the time of the first report received. The date and time of an incident is the time at which the DNO first becomes aware of the incident by any means.

Incident completion

4.28. The determination of when an incident is considered complete is dependent on whether or not a temporary supply arrangement[22] has been used to restore supplies.

4.29. Where a temporary supply arrangement has not been used to restore supplies, an incident is considered complete when supplies have been restored to all customers involved in the incident for a period of at least 3 hours. This does not require the restoration of the normal network configuration and open points.

4.30. Where a temporary supply arrangement has been used to restore supplies, an incident is considered complete when supplies have been restored to all customers involved in the incident for a period of at least 18 hours.

4.31. In both of the above cases, any interruptions to supply caused by the removal of a temporary supply to reconnect, where done within 18 hours of restoring supplies via that temporary connection, must be counted as a re-interruption to supply. Any failures of a temporary supply arrangement, such as a generator running out of fuel,

[22] Defined in paragraph 4.60

must be treated as a new interruption to supply and reported accordingly if this takes place after the temporary supply arrangement has been in place for more than 18 hours, otherwise this must be treated as a re-interruption.

4.32. In both of the above cases, if there is a further loss of supply due to an unrelated occurrence, e.g. an incident on an adjacent circuit, to some or all of the same customers before incident completion, then this must be treated as a separate incident and the losses of supply must be counted as interruptions.

4.33. In both of the above cases and for any reason, if there is a further loss of supply to some or all of the same customers after incident completion, this must be treated as a separate incident and the losses of supply must be treated as interruptions.

4.34. Where an incident start time and completion time/date span two reporting years, the incident must be allocated to the year in which it started.

Definition - Unplanned incident on the Distribution System

4.35. Any incident arising on the licensee's Distribution System, where statutory notification[23] has not been given to all customers affected at least 48 hours before the commencement of the earliest interruption (or such notice period of less than 48 hours where this has been agreed with the customer(s) involved).

Definition - Pre-arranged incident

4.36. Any incident arising from the pre-arranged isolation of any circuit or item of equipment energised at power system voltage that results in loss of supply and where statutory notification has been given to all customers affected at least 48 hours before the commencement of the earliest interruption (or such notice period of less than 48 hours where this has been agreed with the customer(s) involved), and where the loss of supply start time is not before that notified to customers.

Guidance – Pre-arranged incident

4.37. A pre-arranged incident which requires a number of switching operations involving an interruption to supply to customers must be treated as a single incident, provided that the outage start time is within the period stated on the notification provided to the customer(s). Whether or not the outage restoration time is outside the period stated on the notification provided to the customer(s), the full length of the outage must be recorded as part of the planned incident. A record must also be

[23] SI 2010 No. 698 The Electricity (Standards of Performance) Regulations 2010 Regulation 14

kept of the times notified to the customer(s) and the actual interruption times. Where the affected customers have agreed to a shorter notice period for a pre-arranged interruption or this interruption starts before the original notice period at the request of customers, the interruptions to these customers must be recorded as pre-arranged incidents, but only where there is auditable evidence, e.g. a note in the incident log detailing the revised interruption time.

4.38. Where the outage start time is before the period stated on the notification provided to the customer(s) and the affected customers have not agreed to or requested the earlier start time, the interruption of supply to the customer(s) must be recorded as an unplanned incident.

4.39. Where statutory notification has not been provided to one or more customers or the customer(s) has not agreed a shorter notice period, then the customer(s) must be recorded separately as part of an unplanned incident. The interruption to supply of all of the customers that received statutory notice (or agreed a shorter notice period) must still be reported as a pre-arranged incident.

Definition - Incident on other systems

4.40. Any incident arising on other connected electricity systems which leads to the interruption of supply to the customers of the licensee, including:

- National Grid Company (NGET) or transmission companies (in Scotland),
- distributed generators, and
- any other connected systems – which must be identified.

Definition - Non-damage incident

4.41. A non-damage incident is defined as any unplanned incident where supply can be restored from the original source by network switching and without the need for the repair of equipment. For example:

- the remote or manual operation of a pole mounted auto recloser that had previously completed its duty cycle and locked out, to restore supplies, is regarded as network switching,
- the changing of a blown fuse is regarded as network switching and is therefore not considered to be a repair of equipment, and
- the removal of trees from an otherwise healthy overhead line is not considered to be the repair of equipment.

Definition - Damage incident

4.42. A damage incident is defined as any unplanned incident where it is necessary to repair equipment. For example, the changing of a damaged insulator is considered to be a repair.

Definition – Interruption

4.43. An interruption is defined as the loss of supply of electricity to one or more customers due to an incident but excluding voltage quality[24] and frequency abnormalities, such as dips, spikes or harmonics.

Guidance – Interruption

Interruption sequences

4.44. An incident may include both a loss of supply of less than 3 minutes' duration and a loss of supply of 3 minutes or longer. Under such circumstances, where the loss of supply of less than 3 minutes' duration occurs first, it must be reported as a short interruption. Where an interruption lasts for 3 minutes or longer, further losses of supply of less than 3 minutes' duration during the course of the same incident must not be recorded either as part of the incident or as a short interruption.

4.45. In determining interruption sequences above, restorations of less than 3 minutes must be ignored, i.e. the interruption sequence would be determined as if there had been no such restoration. For example, where a customer is interrupted for 2 minutes, restored for 2 minutes, then interrupted for 30 minutes and subsequently restored for 3 minutes or more, the duration of the interruption would be 34 minutes.

Definition - Short interruption

4.46. Short interruptions are defined as the loss of supply of electricity to one or more customers due to automatic, manual or remote control operation of switchgear or fusegear on the Distribution System or other systems, upstream of the customers interrupted, where supply is restored in less than three minutes. (Note an initial loss

[24] Where a customer reports "low volts" then this should not be treated as a loss of supply, until the DNO confirms that the customer is off supply. Equally, where a report of "reverse polarity" is received by the DNO, the customer should be considered "on supply" until the DNO confirms that the customer is off supply, or needs to be disconnected in order to carry out repairs to the DNO's network.

of supply of electricity for less than 3 minutes must be treated as a short interruption rather than an interruption.)

Guidance – Short interruption

4.47. In the case of multi-shot reclosing schemes, only one short interruption is to be counted where the successful restoration is achieved by a sequence of multiple operations in less than three minutes, where these are identifiable. Where the sequence of operations is not identifiable, a simple count of all operations of automatic reclosing devices could be used, excluding those operations recorded elsewhere, e.g. those associated with other incidents or routine switching.

4.48. The number of customers interrupted must be identified in the same way as for incidents (i.e. those situations where customers are off supply for three minutes or longer). If a DNO uses periodic counts of recloser operations to calculate the number of short interruptions, the number of customers interrupted will be based on an estimate of those customers who would have been interrupted. The DNO must base this estimate on the assumption that the circuit affected was configured normally, unless the DNO has robust information that there were abnormal feeding arrangements in place at the time.

4.49. The dates and times of short interruptions are not required. Where short interruptions are identified from a periodic count of circuit breaker operations, the counters must be read annually between 1 January and 31 March to ensure a reasonable approximation to a 12-month total.

Definition - Re-interruption

4.50. A re-interruption is defined as the loss of supply of electricity to one or more customers, for a period of 3 minutes or longer, where those same customers have experienced an interruption during previous restoration stages of the same incident.

Definition - Restoration stage

4.51. A restoration stage is defined as a stage of an incident, at the end of which supply to some or all customer(s) is restored and/or a circuit or part of a circuit is re-energised, excluding any restoration/re-energisation which is followed within 3 minutes by a circuit trip.

Guidance – Restoration stage

4.52. Where a customer's supply is restored for a period of less than three minutes, the calculation of the duration of interruptions to supply must ignore the time for which customers' supplies were restored, i.e. the minutes for which the customers are restored will be included in the count of minutes lost as if there were no restoration.

4.53. There must be no limit to the number of restoration stages for an incident.

Start of a restoration stage

4.54. The start of a restoration stage is the date and time at which supply to customer(s) is interrupted and/or a circuit or part of a circuit is de-energised.

End of a restoration stage

4.55. The end of a restoration stage is the date and time at which customer(s) have their supply restored and/or a circuit or part of a circuit is re-energised.

Customers involved in a restoration stage

4.56. The customers involved in a restoration stage are defined as the customers connected to that part of the DNO's distribution network restored in the restoration stage, including restorations from mobile generators and temporary connections.

4.57. The number of customers interrupted for single-phase and two-phase LV incidents may be calculated on a pro rata basis, i.e. 1/3 or 2/3 of the total number of customers connected to the LV circuit, or part of circuit, affected. Customers with a three-phase LV supply (where these can be identified) are considered to be interrupted when supply is interrupted to one or more of the three phases. Individual customer phase connections do not need to be identified for the purpose of reporting under SLC 45. It might be helpful, in terms of the audit process, if DNOs recorded the number and phases of fuses that have operated in the event of an incident on the LV system.

4.58. For HV incidents, in the interest of simplicity and consistent reporting, if one phase of a three-phase circuit is disconnected it must be considered that two-thirds of customers connected downstream of the point of disconnection had their supplies interrupted.

4.59. Where a connectivity model is in place it must be used consistently[25] to derive the number of customers interrupted on a particular element (e.g. LV feeder) of the network modelled. Where the section of network involved is a subset of a modelled network element (e.g. LV service), the number of customers interrupted may be derived from records or from information available on site, supported by an

[25] As such where the number of calls exceeds the number of customers predicted as being off supply the DNO must adhere to the model, taking account of any three-phase LV customers, although Ofgem would expect to see robust processes in place to identify and correct mis-allocated customers.

appropriate audit trail, e.g. the property numbers involved, the location of the open circuit fault.

4.60. Customers involved for HV, EHV and 132 kV must take account of the real-time changes to 132 kV/EHV/HV network configuration during restoration, which may be identified from a connectivity model.

4.61. Customers involved in each restoration stage may be identified from a connectivity model in which customer information is individually linked with the appropriate section of network to which they are connected.

4.62. The date and time of interruption and the date and time of restoration must be recorded for each restoration stage. The numbers of customers involved and the elapsed time in each restoration stage will be used to calculate the number of customers interrupted and duration of interruptions to supply.

Definition - Temporary supply arrangement

4.63. A temporary supply arrangement is the use of temporary connections, temporary disconnections or mobile generation in order to provide temporary restoration of supplies during an incident.

Definition - Temporary connection

4.64. A temporary connection is a connection (made without using normal switching devices) which is not to become a permanent feature of the Distribution System, but which is used solely to provide a temporary restoration of supplies during an incident.

Guidance – Temporary connection

4.65. An LV backfeed that is a permanent feature of the Distribution System must not be treated as a temporary connection. The bunching of two phases or the use of a temporary loop service are to be treated as temporary connections.

Definition - Temporary disconnection

4.66. A temporary disconnection is a deliberate break in the continuity of a circuit, which is not to become a permanent feature of the Distribution System, but is used solely to facilitate the temporary restoration of supplies during an incident.

Definition – Clock stopping

4.67. Clock stopped is defined as the ability, in circumstances as described in paragraphs 4.65 to 4.68, to legitimately stop the count of the number of minutes that customers are off supply even though supply has not been restored.

Guidance – Clock stopping

4.68. Where access to customers' premises necessary to restore supplies is not available, the DNO must stop the clock for the period where access is not available. The clock must be restarted as soon as access is available. The DNO must keep appropriate audit records of the inability to gain access and the associated delay.

4.69. Where a customer requests that restoration work be delayed, the DNO must stop the clock for the period requested by the customer. The clock must be restarted at the time agreed with the customer that the delay in restoration work would end. The DNO must keep appropriate audit records of the customer request and agreed delay.

4.70. Where access necessary to restore supplies is explicitly prevented by the emergency services, government authorities or other utilities (e.g. gas and water) (and supplies cannot be restored through other means such as remote switching or network reconfiguration and the use of temporary generation is not economic), the DNO must stop the clock for the period where access is denied. The DNO must keep auditable records detailing orders given by the emergency services or government authorities and the times of the orders. The clock must be restarted as soon as access is available.

4.71. Where the DNO is in a position to restore supplies but the customer either requests to be left off supply, or they have to reset their own equipment, then the DNO must treat the time they were able to restore supplies, but prevented from doing so by customer request, as the restoration time and classify this as a temporary supply arrangement.

Updating the connectivity model

4.72. It is important that the connectivity model is kept up to date. The accuracy with which the number and duration of interruptions to supply are reported is, in part, determined by the frequency with which the connectivity model is updated. A reasonable timeframe for updating the connectivity model is likely to be within 14 days of the DNO being formally notified of any permanent changes to the network or customer connections. (For example, a change expected to be in place for at least 28 consecutive days may be regarded as a permanent change). In addition, the numbers of customers in the model could be reconciled with the total number of connected customers on a monthly basis.

Output reporting requirements

Customers

4.73. DNOs are required to report information on the number of customers according to the following categories:

- total number of customers,
- total number of new customers, and
- total number of disconnected customers.

Disaggregation of incidents

4.74. It is necessary to collect information on the number of customers interrupted and duration of interruptions to supply at a disaggregated level. This will help in comparing performance across DNOs, setting performance targets and determining appropriate audit samples, and could be used for making adjustments within the incentive scheme. There are five types of mutually exclusive disaggregation required, these are:

- by incident and restoration stage,
- by source, voltage level and main equipment involved (MEI),
- by duration band (both pre-arranged and unplanned CI),
- by frequency band (higher voltage unplanned CI only), and
- by HV circuit.

Disaggregation by both incident and restoration stage

4.75. In addition to reporting on the effect on customers of all incidents arising on the Distribution System, the number of customers interrupted and duration of interruptions to supply must be reported separately by incident and restoration stage.

Disaggregation by "source", voltage level and main equipment involved (MEI)

4.76. In addition to the above the number of customers interrupted and duration of interruptions to supply arising from the following categories must be separately identified:

- unplanned incidents on the Distribution System in total and by the following classifications:

- 132 kV non-damage,
- 132 kV damage,
- EHV non-damage,
- EHV damage,
- HV non-damage,
- HV damage,
- LV non-damage,
- LV overhead mains damage,
- LV underground mains damage,
- LV switchgear damage,
- LV services overhead, and
- LV services underground.

4.77. DNOs are required to provide cause code and MEI information for every unplanned damage incident. For incidents at HV DNOs must also provide the unique circuit identification number as set out in paragraph 4.83.

4.78. DNOs are required to identify pre–arranged incidents on the Distribution System by the following classifications:

- EHV,
- HV pole-mounted or overhead,
  - Load related,
  - Non-load related,
  - Inspection, maintenance and repair, and
  - Tree cutting.
- HV ground-mounted or underground,
  - Load related,
  - Non-load related,
  - Inspection, maintenance and repair, and
  - Tree cutting.
- LV pole-mounted or overhead,
  - Load related,
  - Non-load related,
  - Inspection, maintenance and repair, and
  - Tree cutting.
- LV ground-mounted or underground,
  - Load related,
  - Non-load related,
  - Inspection, maintenance and repair, and
  - Tree cutting.

4.79. DNOs are also required to provide incident and stage information relating to:

- incidents on the systems of NGET or the transmission companies (in Scotland),
- incidents on the systems of distributed generators, and
- incidents on any other connected systems – which must be identified.

Disaggregation by duration band (pre-arranged and unplanned CI only)

4.80. DNOs are required to separately disaggregate both the pre-arranged and unplanned number of customers interrupted (including all voltage levels) by duration band in order to provide a better understanding of how customer minutes lost are made up and of DNOs' effectiveness in restoring customers' supplies following an interruption. The customer minutes lost used for this disaggregation must be post any clock stopping.

4.81. DNOs must report separately both the pre-arranged and unplanned number of customers interrupted (excluding re-interruptions and re-interruptions only) by the following duration bands:

- 3 minutes up to but excluding 1 hour,
- 1 hour up to but excluding 2 hours,
- 2 hours up to but excluding 3 hours,
- 3 hours up to but excluding 6 hours, and
- 6 hours up to but excluding 12 hours etc.

in 6-hour bands up to and including the longest time any customers have been recorded as being off supply. Time bands with no customers interrupted must be reported with a zero count.

Disaggregation by frequency band (higher voltage unplanned CI only)

4.82. DNOs must report the unplanned number of customers interrupted (excluding re-interruptions) by frequency band starting with customers experiencing zero higher voltage interruptions and rising in single increments up to customers experiencing 10 higher voltage interruptions. The DNO must also identify the total number of customers experiencing more than 10 higher voltage interruptions and the largest number of higher voltage interruptions experienced by any customer. (Higher voltage interruptions include HV, EHV and 132 kV interruptions).

Disaggregation by HV circuit

4.83. The number of unplanned incidents, customers interrupted and duration of interruptions to supply arising on HV systems need to be reported by HV circuit to support work on comparing quality of supply performance.

4.84. For each HV circuit DNOs must report the following circuit characteristics and performance information:

- the unique circuit identifier (where possible this must be the same as for previous years so that comparisons can be made over time),
- the voltage level (e.g. 6.6 kV, 11 kV, 20 kV),
- the number of connected customers (on 31 March),
- the length of overhead line in kilometres (on 31 March),
- the length of underground cable in kilometres (on 31 March),
- the number of incidents affecting the circuit,
- the total number of customer minutes lost, and
- the total number of customers interrupted (excluding re-interruptions).

4.85. Two versions of the HV circuit information must be provided:

- containing all HV incidents and associated customers interrupted and customer minutes lost, and
- excluding HV incidents, customers interrupted and customer minutes lost for the duration of events for which exemptions have been requested and which meet the criteria set out in special condition CRC8 of the distribution licence. The approach to treating such events must be agreed with Ofgem in advance of the data being provided. DNOs must provide summary data for the events which have been excluded including: the number of days' performance which has been removed, the number of incidents, customers interrupted and customer minutes lost[26].

4.86. DNOs must also provide total number of incidents, total number of customers interrupted and total number of customer minutes lost for any incidents that are not attributable to specific circuits. These must be grouped into one of the two following categories (see reporting workbook for more detail):

- changes to HV topology or misallocation (e.g. circuit removed during the reporting period), and

[26] The performance figures excluding exceptional events plus the summary data for those events should reconcile with the information containing all incidents requested in paragraph 4.84.

- loss of HV circuit infeed (e.g. a fault on an 11 kV bus-bar).

4.87. In addition to the above, for each loss of HV circuit infeed, the number of customers interrupted and number of customer minutes lost for each incident must be provided.

4.88. The incidents, total number of customers interrupted and total number of customer minutes lost for the disaggregated reporting for HV circuits plus unattributable HV performance must reconcile with the total HV performance.

Definition of a HV circuit

4.89. The DNOs have submitted their existing mix of circuit types to Ofgem. Any change in the definition of "HV circuits" to be used when reporting performance on a disaggregated circuit-by-circuit basis must be agreed with Ofgem in advance of the data being provided.

Circuits with non-zero length and non-zero connected customers

4.90. These are valid circuits and must be included in the HV circuit dataset submitted by DNOs.

Circuits with non-zero length and zero connected customers

4.91. These are valid circuits that would normally be used to provide alternative supplies to one or more customers. These circuits must be included in the HV dataset submitted by DNOs. However, customers interrupted and customer minutes lost per customer would be inconsistent with zero connected customers. Therefore it will be necessary for DNOs to re-attribute any incidents, customers interrupted and customer minutes lost as if the network were normally configured.

Circuits with zero length and non-zero connected customers

4.92. This classification of circuits is present for two reasons;

- a circuit exists but there is actually no circuit length, e.g. the exit point of a customer's connection is the circuit breaker, or

- a circuit exists and there is actual circuit length that is not being reported by the functionality of the mapping system or GIS.

4.93. In both cases, these are valid circuits that must be included in the HV circuit dataset submitted by DNOs. However, in order to include such circuits in the dataset, a nominal circuit length of 100 metres must be attributed to each of these circuits.

Circuits with zero length and zero connected customers

4.94. These HV circuits are not valid and must not be included in the HV circuit dataset submitted by DNOs. Where appropriate any incidents, customers interrupted and customer minutes lost must be re-attributed as if the network were normally configured.

Short interruptions

4.95. For the purpose of reporting under SLC 45, DNOs are required to report the total number of short interruptions and disaggregated number of short interruptions by the following four causes:

- due to the automatic operation of distribution network switchgear where the supplies of some or all of the customers involved are successfully restored by automatic switching within less than three minutes of the first interruption,
- due to the automatic operation of distribution network switchgear where the supplies of some or all of the customers involved are successfully restored by manual or remote control switching within less than three minutes of the first interruption. This definition includes only the initial restoration. Further short interruptions during subsequent stages of fault sectionalising are not to be reported,
- due to the manual or remote operation of distribution network switchgear for reasons such as deliberate disconnection for operational or emergency reasons, and
- due to the operation of switchgear on the networks of NGET/transmission companies (in Scotland) or other connected systems and distributed generators.

4.96. Short interruptions do not need to be disaggregated by voltage or by HV circuit. Where DNOs make significant use of automatic reclosing devices and automatic switching at the LV level, the number of short interruptions at this voltage level must be included in the appropriate short interruption categories identified above.

Required level of accuracy for reporting interruptions data

4.97. Ofgem considers that it is important that information used to implement the incentive scheme is sufficiently accurate to enable comparisons to be made over time and if appropriate between DNOs. Ofgem has specified minimum levels of accuracy for the reporting of:

- the number of customers interrupted – at the 132kV and EHV, the HV and LV levels, and

- the duration of interruptions to supply – at the 132kV and EHV, the HV and LV levels.

4.98. Table 4.1 below specifies the minimum levels of accuracy required for the reporting of the number of customers interrupted and duration of interruptions to supply. DNOs are required to meet the minimum levels of accuracy for the three voltage categories shown below. Meeting one of the required levels of accuracy is not sufficient to satisfy the requirements set out in SLC 45.

Table 4.1 Accuracy thresholds

Voltage	Overall accuracy	Initial stage accuracy (smaller sample)
EHV and 132kV	97 per cent	99 per cent
HV	95 per cent	97 per cent
LV	90 per cent	93 per cent

5. Instructions for completing environmental data reporting

Introduction

5.1. The purpose of this chapter is to provide a framework for the collection and provision of accurate and consistent information on environmental measures. The data is required in order to monitor performance under the different measures, as well as monitoring key drivers of that performance.

5.2. This chapter includes both measures introduced in DPCR4 and the new measures introduced in DPCR5. Some incentives, such as losses and business carbon footprint require specific information to be provided and manipulated in a very specific manner – and we have provided detailed guidance for these areas.

5.3. The environmental data referred to in this chapter is reported in worksheets A28-35 in the Network Asset Data and Performance reporting workbook.

5.4. The following terms are used in this chapter, and are defined in the Glossary:

- Balancing Mechanism Unit (BMU) Connection Point
- Business Carbon Footprint (BCF)
- Biomass & energy crops (not CHP)
- Bulk Supply Point (BSP)
- Business energy usage
- Business transport
- Charged DG
- DG Voltage Level
- Distributed Generation (DG)
- Distribution Systems Connection Point (DSCP)
- Environmental Agency (EA)
- Fugitive Emissions
- Grid Supply Point (GSP)
- Half-hourly Settled Connection Point
- Hydro
- Landfill gas, sewage gas, biogas (not CHP)
- Large CHP (>=50MW)
- Medium CHP (>=5MW, <50MW)
- Micro CHP (domestic)
- Mini CHP (<1MW)
- No. of GSPs reinforced – total
- No. of new GSPs – total
- No. of GSPs refurbished
- No. of GSPs reinforced - licensee requirement
- No. of new GSPs - licensee requirement
- Non-DSP Connection Point
- Non-half-hourly Settled Connection Point
- Non-relevant BMU
- Non-relevant DCSP

- Offshore wind
- Onshore wind
- Other Generation
- Photovoltaic
- Post-2005 DG
- Pre-2005 DG
- Registered Power Zone (RPZ)
- Relevant BMU Connection Point
- Relevant DSCP
- SF6
- SF6 Leakage
- Small CHP (>=1MW, <5MW)
- tC02e
- Tidal stream & wave power
- Transmission Connection Points
- Waste incineration (not CHP)

A33, A34, A35 – Losses Reporting

Overview

5.5. The losses reporting worksheets (A33, A34 and A35) provide the data to enable us to monitor the DNOs' performance in relation to the Distribution Losses Incentive Scheme.

5.6. The losses reporting methodology is described first, with specific instructions for completing worksheet A33. The instructions for A34 and A35 are provided separately, and are followed by a description of the general reporting requirements and timescales for all three worksheets (A33, A34 and A35)

A33 – Losses

Overview of losses reporting methodology

5.7. As part of DPCR5 a consistent measure of losses was implemented across all DNOs to improve the comparability and transparency of DNOs' performance against the incentive. The common calculation of losses is based on the following principles:

- common reporting across all DNOs – to ensure that the reporting of losses is consistent and comparable,
- the use of Settlement data – which is compiled, validated and audited in accordance with agreed industry processes,
- minimal (and pre authorised) DNO manipulation of data,
- the use of actual energy entering and exiting the networks at network boundary points – so that the calculation of losses and the evaluation of performance is not masked by unnecessary adjustments that are made for Settlement purposes,

- where possible the use of Settlement data flows already used by the DNOs (to avoid costly changes to their systems), and
- use of a two year reporting lag – to enable the Settlement reconciliation process (data will be used at Run Final, RF), to increase the accuracy of the losses calculation.

5.8. This means that in reporting losses, DNOs will not use provision accounts or adjust Settlement data in any way other than the specific calculations we have detailed.

Guidance for calculating distribution losses

5.9. In accordance with SLC 44B, DNOs must measure, record and provide Specified Information to the Authority. In particular, the Specified Information comprises the System Entry Volumes and Units Distributed, which are the primary inputs into the calculation of Adjusted Distribution Losses for the purpose of CRC 8 ('Adjustment of licensee's revenues to reflect distribution losses performance').

5.10. The calculation of energy entering (System Entry Volumes) and exiting (Units Distributed) a DNO's network must take account of all sources and uses of energy entering and leaving the network at different types of network connection point. All connection points (except for Non-Distribution Service Provider (DSP) connection points) are registered in Settlement, meaning that the energy flows at these boundary points are recorded, validated and used in accordance with the Balancing and Settlement Code (BSC). Depending on the technical details of boundary points the energy flowing through them is either recorded in Central Volume Allocation (CVA) or Supplier Volume Allocation (SVA)[27].

5.11. Details of energy flows at boundary points registered in Settlement are communicated to BSC Parties, Central Agents and Party Agents using data flows that are provided by the BSC. These data flows are described in the Interface Definition and Design document (which relates to CVA data) and Data Transfer Catalogue (which relates to SVA data). Throughout the following sections, the relevant data flows will be identified by the standard Settlement reference (e.g. CDCA IO30).

5.12. The following detailed definitions and instructions describe what the Specified Information is and how it must be calculated.

[27] Boundary points registered in CVA are defined by BSC Section K2.1.1; all other boundary points are registered in SVA, in accordance with BSC Section K2.4.1.

Detailed definitions and instructions - System Entry Volumes and Units Distributed

5.13. In the sections below we describe the different data elements according to the network connection point. In the RIGs tables, this data is reported according to whether it is entering (System Entry Volumes) or exiting (Units Distributed) the network and according to the network connection point.

5.14. When calculating volumes of energy, DNOs must pay particular attention to relevant Aggregation Rules – for more information see the sub-section below, which is entitled 'Additional Instructions and Guidance'.

GSP, non-relevant DCSP and non-relevant BMU

5.15. Energy entering or exiting the DNO's Distribution System via GSPs, non-relevant DCSPs and non-relevant BMUs in a Regulatory Year is calculated as the net total energy reported on all CDCA IO30 flows for all GSPs, non-relevant DCSPs and non-relevant BMUs to the DNO's Distribution System over the course of the relevant Regulatory Year. In calculating the units entering or exiting the DNO must:

- for each GSP and non-relevant DCSP, record the most up to date CDCA IO30 data flows that relate to each day of the relevant Regulatory Year.
- for each non-relevant BMU, record the most up to date CDCA IO42 data flows that relate to each day of the relevant Regulatory Year.
- for each GSP sum together the daily volumes of energy entering reported in the CDCA IO30s to calculate an annual volume of energy entering.
- similarly, sum together the daily volumes of energy exiting reported in the CDCA IO30s to calculate an annual volume of energy exiting.
- for each non-relevant DCSP sum together the daily volumes of energy entering reported in the CDCA IO30s to calculate an annual volume of energy entering. Similarly, sum together the daily volumes of energy exiting reported in the CDCA IO30s to calculate an annual volume of energy exiting.
- for each non-relevant BMU sum together the daily volumes of energy entering reported in the CDCA IO42s to calculate an annual volume of energy entering. Similarly, sum together the daily volumes of energy exiting reported in the CDCA IO30s to calculate an annual volume of energy exiting.
- sum together the annual volumes of energy entering GSPs, non-relevant DSCPs and non-relevant BMUs (taking account of the direction of flow). Similarly, sum together the annual volumes of energy exiting GSPs, non-relevant DSCPs and non-relevant BMUs (taking account of the direction of flow).
- subtract the annual volume of energy exiting from the annual volume of energy entering.
- if the difference is positive, the value must be entered in Worksheet A33 against the 'Units entering via GSPs' for the relevant Regulatory Year. If the product is negative, the value must be entered in Worksheet A33 against the 'Units distributed via GSPs' for the relevant Regulatory Year.

Relevant DSCP

5.16. Energy entering or exiting the DNO's Distribution System via relevant DSCPs is the gross total energy entering or exiting that is reported on all CDCA IO12 and IO14 flows for all relevant DSCPs to the DNO's Distribution System over the course of the relevant Regulatory Year. In calculating the units entering or exiting the DNO must:

- for each relevant DSCP record the most up to date CDCA IO12 and IO14 data flows that relate to each day of the relevant Regulatory Year,
- sum together the daily volumes of energy entering reported in the IO12 and IO14s to calculate a gross annual volume of energy entering via relevant DCSPs. This value must be entered in Worksheet A33 against the 'Units entering via relevant DCSPs' for the relevant Regulatory Year, and
- sum together the daily volumes of energy exiting reported in the IO12 and IO14s to calculate a gross annual volume of energy exiting via relevant DCSPs. This value must be entered in Worksheet A33 against the 'Units distributed via relevant DCSPs' for the relevant Regulatory Year.

Relevant BMU Connection Point

5.17. Energy entering or exiting the DNO's Distribution System via 'relevant' BMUs is the gross total energy entering or exiting that is reported on all CDCA IO12 and IO14 flows for all 'relevant' BMUs to the DNO's Distribution System over the course of the relevant Regulatory Year. In calculating the units entering or exiting the DNO must:

- for each relevant BMU record the most up to date CDCA IO12 and IO14 data flows that relate to each day of the relevant Regulatory Year,
- sum together the daily volumes of energy entering reported in the IO12 and IO14s to calculate gross annual volumes of energy entering via relevant BMUs. This value must be entered in Worksheet A33 against the 'Units entering via relevant BMUs' for the relevant Regulatory Year, and
- sum together the daily volumes of energy exiting reported in the IO12 and IO14s to calculate a gross annual volume of energy exiting via relevant BMUs. This value must be entered in Worksheet A33 against the 'Units distributed via relevant BMUs' for the relevant Regulatory Year.

Half-hourly Settled Connection Point (HHSCP)

5.18. Energy entering or exiting the DNO's Distribution System via HHSCPs is the gross total energy entering or exiting that is reported on SVA D0036 or D0275 data flows for all HHSCPs to the DNO's Distribution System over the course of the relevant Regulatory Year. In calculating the units entering or exiting via HHSCPs, the DNO must:

- for each HHSCP record the most up to date D0036 or D0275 data flows that relate to each day of the relevant Regulatory Year,

- sum together the daily volumes of energy entering reported in the D0036 or D0275s to calculate gross annual volumes of energy entering via HHSCPs. This value must be entered in Worksheet A33 against the 'Units entering via HHSCPs' for the relevant Regulatory Year, and
- sum together the daily volumes of energy exiting reported in the D0036 or D0275s to calculate gross annual volumes of energy exiting via HHSCPs. This value must be entered in Worksheet A33 against the 'Units distributed via HHSCPs' for the relevant Regulatory Year.

NHHSCP

5.19. Energy entering or exiting the DNO's Distribution System via NHHSCPs is the gross total energy entering or exiting that is reported on SVA D0030 data flows for all NHHSCPs to the Distribution System over the course of the relevant Regulatory Year. In calculating the units entering or exiting the DNO must:

- for each NHHSCP record the most up to date D0030 data flows that relate to each day of the relevant Regulatory Year for all NHHSCPs with the Distribution System,
- sum together the daily volumes of energy entering reported in the D0030s to calculate gross annual volumes of energy entering via NHHSCPs. This value must be entered in Worksheet A33 against the 'Units entering via NHHSCPs' for the relevant Regulatory Year, and
- sum together the daily volumes of energy exiting reported in the D0030s to calculate gross annual volumes of energy exiting via NHHSCPs. This value must be entered in Worksheet A33 against the 'Units distributed via NHHSCPs' for the relevant Regulatory Year.

Non-DSP Connection Point

5.20. Energy entering or exiting at a Non-DSP Connection Point is calculated in the same way that the DNO calculates energy for billing the IDNO for use of the DNO's network. For the relevant Regulatory Year, the DNO must report to the Authority, in accordance with the losses table, the amount of energy that has entered and exited their Distribution System at the Non-DSP Connection Point.

Additional instructions and guidance

Inset networks and Convenience Customers

5.21. Energy entering or exiting a DNO's Distribution System because of a Convenience Customer or Inset Network must be attributed to the DNO's Distribution System that customer or Inset Network is connected to, not the DNO whose region they may be located within by virtue of geography.

Use of Aggregation Rules

5.22. The direction of energy flowing across GSPs, DSCPs and BMU Connection Points is determined in accordance with Aggregation Rules that are submitted by the DNO to the CDCA.

5.23. DNOs must therefore use these Aggregation Rules to correctly determine the direction of energy to or from their Distribution Systems when calculating System Entry Volumes and Units Distributed.

Use of IO12s and IO14s

5.24. CDCA IO12 and IO14 data flows report raw and estimated metered data in relation to the energy entering and exiting the Distribution System at connection points registered in CVA.

5.25. For a particular CVA connection point on any given day in a relevant Regulatory Year, the DNO must use the energy reported in the most up to date validated IO12. Only if an IO12 is not sent by the CDCA, received by the DNO or fails validation in accordance with the BSC, then the DNO must use the energy reported in the IO14 flow that corresponds to that day.

Sources excluded from the calculation of losses

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.

Substation energy usage

5.27. DNOs must register their substation usage with a supplier so that it is properly taken account of in the Settlement process and will therefore be reported using one of the CVA or SVA data flows described above.

5.28. DNOs who do not register their substation usage in Settlement cannot include this usage in the calculation of losses.

5.29. It should be noted that the substation usage (as registered with suppliers) is to be reported in the Costs and Revenue Reporting RIGs, against Substation Electricity in worksheet C75 NOCs Other.

A34 – Losses DG Adjustment (LAG)

5.30. In accordance with CRC7.10 (b), DNOs are allowed to make an adjustment to the calculation of Adjusted Distribution Losses to take account of the effect caused by distributed generators connected to the Distribution System with a loss adjustment factor less than 0.997.

5.31. Distributed generators connected to the Distribution System with a loss adjustment factor less than 0.997 must be listed individually, with the site name and the loss adjustment factor identified in each Regulatory Year.

5.32. In calculating the value of LAG for each relevant distributed generator the DNO must apply the loss adjustment factors used in the relevant settlement procedure of the Balancing and Settlement Code in respect of the distributed generator in question to the units for that generator for each half hour of the regulatory year, and then divide the sum of those loss adjusted units by the total number of units entering the licensee's network from that generator in that year.

A35 – Losses DG Adjustment (DGV)

5.33. To calculate the adverse effect (DGV) of distributed generators in accordance with CRC7, the DNO must follow the same instructions described above for calculating volumes of energy entering their network and report the total adjustment calculated for each Regulatory Year.

5.34. The same sites as identified in Worksheet A34, must be identified by name with the units entering the DNO's Distribution System from that site for each Regulatory Year.

Reporting requirements and timescales for A33, A34 and A35

Timescales and reporting lag

5.35. Losses data will be reported with a lag of two regulatory years so that the RF Settlement data can be included and allocated to the year in which it was incurred.

5.36. This is the final data, reported using RF Settlement data. Therefore in any year, the final data will be reported for the losses that occurred two years before. Data must be reported against the year in which it was incurred.

5.37. It should be noted that the values reported as final data in Worksheets A33, A34 and A35 must have matching values reported in the Input Page (R5) and DG Losses Input Page (R6) of the Price Control Revenue Information within the Cost and Revenue Reporting RIGs. However, these values will be reported in different years for the two sets of RIGs. As explained above, in Worksheets A33, A34 and A35 in

Regulatory Year t final values are entered for Regulatory Year t-2, and are entered in the Regulatory Year t-2 column. In the Price Control Revenue Information final values are entered for Regulatory Year t-2, but are entered in the Regulatory Year t column. This is because the Price Control Revenue is calculating the losses incentive to be included in the current year Allowed Revenue, based on the final losses data (from two years before).

5.38. For example, for the RIGs reporting in July 2013, A32, A33, A34 and R5 will all report the losses that occurred in 2010/11. However, for A33, A34, A35 the values will be entered against 2010/11 whereas for R5 the values will be entered against 2012/13.

A28 – Business Carbon Footprint (BCF)

5.39. This provides a quantification of all aspects of a DNOs' Business Carbon Footprint (in tonnes of CO2 equivalent) in order for us to assess the carbon footprint across all the DNOs, and in order that we can compile a league table showing year on year percentage change.

5.40. The performance league table will be based on the subtotal of the BCF not including losses.

5.41. Losses are not included in the league table since they are already incentivised under the losses incentive. However we have included losses in the total BCF in Worksheet A28 in order to provide an annual estimate of total BCF that will align with other environmental reports produced by the company. This will enable us to present the total BCF across all DNOs, but will not be used in the performance league table.

5.42. The associated commentary must contain the methodology used, including detailed emission tables for each of the sections below, and further information on the methodology adopted.

5.43. It is not expected that DNOs must enter historic data, prior to the data they reported to Ofgem for 2009.

5.44. As stated below, a DNO can select the 12 month period that it intends to use as its confirmed reporting year. This confirmed reporting year must have prior approval from Ofgem. We expect the confirmed reporting year to align with the statutory or regulatory accounts.

General principles of the reporting methodology

5.45. The reporting methodology must be compliant with the principles of the Greenhouse Gas Protocol[28] ("GHG Protocol"). In summary[29], the BCF reporting must be:

- Relevant: the inventory must reflect the substance and economic reality of the company's business relationships, not merely its legal form,
- Complete: all relevant emission sources must be included (although in practice lack of data or cost of gathering could be a limiting factor),
- Consistent: accounting approaches, inventory boundary and calculation methodology must be applied consistently over time,
- Transparent: information on the processes, procedures, assumptions and limitations of the BCF reporting must be disclosed in a clear, factual, neutral and understandable manner, enabling internal and external verifiers to attest to its credibility, and
- Accurate: GHG measurements, estimates, or calculations must be systemically neither over nor under the actual emissions value, as far as can be judged, and that uncertainties be reduced as far as practicable.

Reporting boundaries

5.46. DNOs must report on all Scope 1 and Scope 2 emissions (and a subset of Scope 3 emissions, as detailed below) on an "operational control" basis, i.e. report all emissions from operations on which the DNO has full authority to introduce and implement its operating policy.

5.47. DNOs must also report on a subset of Scope 3 emissions (business travel and external contractors), to ensure that the reporting captures all of the emissions arising from the development and operation of the licensee's Distribution System, regardless of the legal entity carrying out each activity. According to this, we consider it valuable to focus on contractors emissions relating to the operational transport fleet and mobile power plants.

5.48. DNOs that form part of a larger corporate group must provide a brief introduction outlining the structure of the group. The commentary must detail which organisations' are considered to be within the reporting boundary for the purpose of this exercise.

5.49. Apportionment of emissions across a corporate group to the DNO business units must be made clear in the commentary.

[28] http://www.ghgprotocol.org/
[29] For further details, please refer to "GHG Protocol – A corporate Accounting and Reporting Standard", available at: http://www.ghgprotocol.org/files/ghg-protocol-revised.pdf

Contractors

5.50. The exclusion of any contractors must be justified and any thresholds used for exclusion must be stated in the commentary.

5.51. The commentary must also include an indication of what proportion of contractors have been excluded. This figure could be calculated based on contract value.

5.52. As far as possible, DNOs must try to ensure that data provided from different contractors is based on consistent assumptions.

Detailed reporting requirements

5.53. DNOs are given flexibility to set their own standards for:

- reporting year. We expect this generally to align with the statutory or regulatory accounts;
- the use of estimates rather than direct measurement[30], and any exclusion from the reporting based on (lack of) materiality considerations[31]. Any assumptions used to make estimates must be included in the commentary. It is anticipated that data will need to be estimated under two scenarios:
- when the type of emissions is not measured.
- when there is measurement data, but an estimate is required as the data is not at the same level of granularity as required by the summary BCF worksheet.

5.54. As a general principle, DNOs must focus more on the first type of estimation.

5.55. The commentary must include data tables for each area of emissions (ideally at the same level of granularity as the Defra conversion factors) containing the following information:

- the DNO in question,
- the level of emissions (in tCO2e),
- the data source and collection process[32],

[30] In accordance with the principles of the GHG protocol and ISO14001, we expect a process of continual improvement, so that estimates are progressively replaced by direct measurement. More attention must be given to those estimates of emissions, which are likely to be significant.
[31] In cases where emissions have not been estimated, it is important that this is transparently documented and justified in the methodology.
[32] Collection processes requiring a more detailed explanation must be elaborated upon elsewhere in the commentary.

- the relevant physical units e.g. miles,
- the emission conversion factor used,
- the source of the emission conversion factor (this shall be Defra unless there is a compelling case for using another conversion factor),
- the Scope of the emissions i.e. Scope 1, 2 or 3,
- whether the emissions have been measured or estimated,
- any tools used in the calculation, and
- whether the emissions stem from contractors.

5.56. The commentary must also include details of any auditing a DNO has performed to verify their emissions data.

Apportionment across Distribution Service Areas

5.57. When the emissions data is not available for individual Distribution Service Areas then the apportionment factor used must be transparent. The basis for calculating the apportionment factor must also be included in the commentary.

5.58. We expect that the basis for calculating the apportionment factor will vary according to the area of emissions. The table below gives the preferred basis for determining the apportionment factor. Other methodologies can be used, but they must be justified.

Table 5.1: Apportionment factor determination

Area of emissions	Basis for apportionment factor
Building usage	Head count
Operational Transport	Network length or km2 of the DSA.
Business transport	Head count, or like operational transport
Substations usage	Number of substations
Diesel mobile generation	CML or CI or number of interventions

Guidance on completing the worksheet

Buildings energy usage

5.59. Emission for electricity usage in buildings must be converted according to the factor for the "Grid Rolling Average".

5.60. Natural Gas, Diesel and other fuels are all categorised as fuel combustion and must be converted to tCO2e on either a Gross Calorific Value (Gross CV) or Net Calorific Value (Net CV) basis. We expect that this element of the chosen approach is clearly stated in the commentary and that this is consistently applied over time.

5.61. Electricity usage in substations must be captured under "Buildings energy usage". All substation consumption must be treated as energy supplied rather than losses. It is recognised that not all substations will be metered; rather, it is expected

that licensees will in time register all substation as unmetered supplies and develop a common method for estimating consumption. Each licensee must include in its methodology (included in the commentary) the basis on which energy supplied has been assessed. Estimation could be based on a bottom-up approach, whereby the substation energy usage is split into estimates of its constituent parts, such as heating and lighting etc.

Transport

5.62. Defra guidelines provide for a range of emission conversion factors for transport means, with the aim to provide the best possible estimate of emissions from the vehicle portfolio owned and/or operated by the company. The reporting must, as far as reasonably practicable, use the full range of emission conversion factors available (as applicable to the range of means of transport actually used by the company).

5.63. Defra allows for transport to be entered in terms of both mileage and fuel consumption. Reporting must be based upon mileage, using conversion factors at the greatest level of disaggregation that is reasonably practicable. Reporting can be based on fuel consumption only where detailed and reliable data is available, e.g. through fuel cards.

5.64. In cases where emission factors for specific transport means are not available (we are aware of this issue for helicopters, but there may be some other instances) the equivalent tonnes of carbon dioxide (tCO2e) must be estimated and summed to the closest means of transport (e.g. "air" for helicopters). The methodology and assumptions used for estimating/measuring these emissions must be included in the commentary.

5.65. Operational Transport is the transportation (often a fleet of vehicles) used in the day to day operation of the business – i.e. in the inspection and maintenance of the network.

5.66. Business Transport is that undertaken by staff travelling to locations that are other than their normal place of work or moving between sites for purposes such as meetings.

Fugitive emissions

5.67. This category caters for GHG emissions from a range of gases that may be relevant to the DNO business. We anticipate that this will mainly include SF6 emissions, but other gases may be included (e.g. HFC from air conditioning). SF6 emissions must be reported in accordance with ENA-ER S38, using Defra conversion factors.

5.68. The commentary must identify which fugitive emissions have not been calculated or estimated.

Fuel combustion (non-building)

5.69. This is to cover for non-building fuel usage, such as mobile plants and the stand-by diesel mobile generators that are deployed from time to time in response to planned outages or faults. Defra emissions factors must be used. All mobile plant and generation used by the licensee, related and affiliate undertakings, contactors and sub-contractors must be included in so far as it is reasonably practicable. The methodology must describe the degree of estimation, and decisions to exclude any sources of emissions, applied.

Losses

5.70. This is to consider DNO's responsibility towards losses as a Scope 2 emission, using the same Defra conversion factor "Grid Rolling Average" that was used for buildings emissions. Substation electricity usage must be excluded from the reported emissions for network losses, so that it is not double-counted.

5.71. The BCF losses are reported on a different basis to the losses reported in Worksheet A33. In Worksheet A33 losses are reported with a two year lag, whilst in the BCF table the losses must be estimated for the current year. Worksheet A33 will also contain an estimate of the current year's losses, however it is recognised that this may not match the losses reported under BCF due to the fact that the reporting period for the BCF does not necessarily match the Regulatory Year.

5.72. As explained above, an estimate of losses is required because it is important for Ofgem to have an indication of the overall BCF for a company and across all DNOS, however the BCF losses estimate is not included in the BCF performance assessment as reported in the league table.

A29 –Transmission Connection Points

5.73. The purpose of this table is to collect information relating to the demand and supply capacity at the GSPs substations and to identify new and expanded capacity, in order to monitor and inform the Transmission Connection Point Charges incentive scheme.

5.74. All assumptions must be included in the commentary.

5.75. It is acceptable to use fractions to indicate a shared GSP; where the fraction must indicate what proportion of the Transmission Connection Point Charges for that GSP the licensee pays for. However, an explanation of how the apportionment has been calculated must be included in the commentary.

5.76. Data elements are defined in the glossary, with additional explanation for the Number of substations within (demand/capacity) % bands set out below.

Number of substations within (demand/capacity) % bands

5.77. For both Peak demand / intact capacity and Maintenance period demand / n-2 capacity - >300MW demand groups only, the number of GSP substations within each utilisation percentage band must be reported, where:

- peak demand is the maximum demand of the demand group at the substation,
- maintenance period demand is as defined in the Security and Quality of Supply Standard, and
- for n-2 capacity - >300MW demand groups only, the second circuit outage condition as set out in the SQSS – only applicable for substations where the peak group demand is greater than 300MW.

A30 – Distributed Generation (DG)

5.78. These tables support and inform the DG scheme and also provide information relevant to use of system charges for DG.

5.79. The accompanying commentary must include ranges of uncertainty for all forecasts of number of projects and MW.

DG network unavailability (MWh)

5.80. This is the sum, for all Charged DG, of the products resulting from the multiplication of the network interruption duration, experienced during the reporting year, by the Charged DG capacity for each installation experiencing the interruption.

5.81. It only refers to that DG eligible for network unavailability payments – and therefore where the generator has agreed to the standard condition.

Network interruption duration

5.82. This is, for a Charged DG in the relevant year and connected at HV or above, the total duration of all occurrences on the DNO's Distribution System, within the reporting year, each of which involves a physical break in the circuit between the DG and the rest of the system or any other open circuit condition, which prevents that DG from exporting power for a consecutive period of three minutes or longer. It excludes:

- 50 per cent of the total duration of cases where DNO takes pre-arranged outages of its equipment for which the statutory notification has been given to the DG,
- cases where the relevant agents for DG had specific exemption agreements with the DNO in the connection and use of system agreement(s), (relevant agents being parties such as the generator owner, relevant suppliers, meter registrant or independent distribution network operator who enters into the connection and use of system agreement(s) with the DNO on behalf of the generator), and

- cases where the network interruption was caused primarily by severe weather or other events as more fully described in Appendices 2 and 3 respectively of CRC 8.

5.83. The start time of a network interruption is the earlier of the time at which:

- the first report, whether from DG, DNO's own alarm system, employee or agent, is received of a loss of connection or other abnormality which prevents a circuit or other item of equipment from carrying output from DG or being able to withstand "through fault current", or
- the relevant circuit is automatically, deliberately or otherwise disconnected.

5.84. The completion of a network interruption is the time when the connection is restored from the network to the DG so that the DG is able to generate at its agreed capacity.

Baseline network interruption duration

5.85. This is the total network interruption duration in a reporting year for a Charged DG, above which the network unavailability rebate will apply.

Pre-2005 DG (MW)

5.86. This is the highest active electrical power that could be generated (or the relevant incremental change of this amount in cases of the expansion of existing DG plant) by Pre-2005 DG that is still energised in the reporting year, with a generator capacity of 5MW(/MVA) or above, according to the connection and use of system agreement(s) in force on 31 March of the relevant year or notification in cases of generation covered by Engineering Recommendation G83/1.

Pre-2005 DG – No. of projects

5.87. This is the number of separate DG plant classified as Pre-2005 DG that are still energised in the reporting year, with a generator capacity of 5MW(/MVA) or above.

Pre-2005 charged DG – MW

5.88. This is the highest active electrical power that could be generated (or the relevant incremental change of this amount in cases of the expansion of existing DG plant) by Pre-2005 DG, according to the connection and use of system agreement(s) in force on 31 March of that relevant year or notification in cases of generation covered by Engineering Recommendation G83/1 and that is subject to use of system charges in the reporting year.

Pre-2005 charged DG - No of projects

5.89. This is the number of separate DG plant classified as Pre-2005 DG that are still energised as the reporting year, with a generator capacity of 5MW(/MVA) or above that are subject to use of system charges in the reporting year.

Post-2005 DG

5.90. Post-2005 DG is reported by technology type, DG voltage level, no of projects and MW connected.

Technology type

5.91. This is classified according to the table below:

Table 5.2: Technology type

Type	Description
1	Onshore wind
2	Offshore wind
3	Tidal stream & wave power
4	Biomass & energy crops (not CHP)
5	Hydro
6	Landfill gas, sewage gas, biogas (not CHP)
7	Waste incineration (not CHP)
8	Photovoltaic
9	Micro CHP (domestic)
10	Mini CHP (<1MW)
11	Small CHP (>=1MW,<5MW)
12	Medium CHP (>=5MW, <50MW)
13	Large CHP (>=50MW)
14	Other generation

Voltage level

5.92. This is the voltage level at the point of metering the DG, and is classified as either LV, HV, EHV or 132kV.

No. of Projects

5.93. This is the number of separate DG plant.

MW connected

5.94. This is the highest active electrical power that could be generated (or the relevant incremental change of this amount in cases of the expansion of existing DG

plant) by a DG for the reporting year, according to the connection and use of system agreement(s) in force on 31 March of that relevant year or notification in cases of generation covered by Engineering Recommendation G83/1.

A31 – Registered Power Zones (RPZ)

5.95. This table collects all the information about Registered Power Zones (RPZ).

5.96. Each individual RPZ should be listed by name, along with the starting year and the RPZ DG capacity connected (or forecast to be connected) in the relevant year where:

- RPZ starting year is the reporting year in which the RPZ was first registered; and
- RPZ DG capacity is the sum of Post-2005 DG capacity (in MW) of all the Post-2005 DG whose connection point is contained in a RPZ.

A32 – Other Environmental

5.97. This section sets out guidance for the reporting of other environmental performance information to Ofgem.

5.98. It is not intended that these requirements should be any more onerous than would be required by current reporting or management practices. It is therefore expected that DNOs will use existing information systems to report these measures (including those introduced to support the Operating Code on the Management of Fluid Filled Cable Systems).

5.99. To support the reporting of these indicators, DNOs must include in their commentary:

- discussion of any emerging trends in the environmental data and areas of trade-off in performance,
- further details of any reportable incidents or prosecutions,
- details of any Environmental Management System (EMS) accredited under ISO or other recognised accreditation scheme, and
- Ofgem continues to take an interest in Schedule 9 matters and DNOs are also encouraged to send Ofgem copies of their Schedule 9 statements, for instance, after a review or update.

5.100. The table below sets out the "other" environmental performance measures for the distribution networks that are to be reported.

Table 5.3: Other environmental performance measures

Performance indicator	Reportable measures
Loss of SF6	Weight of SF6 in service in kg Weight of SF6 lost (i.e. top-ups used) in kg
Loss of insulating fluid	Volume of fluid used to top-up cables in litres Volume of fluid recovered in litres Number of reportable incidents Number of prosecutions Number of warnings Number of cautions

5.101. General Environmental Management is the percentage of all DNO activities covered by a certified Environmental Management System (EMS scheme)[33]

[33] It is not a mandatory requirement for DNOs to have a certified or accredited EMS.

Appendices

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Appendix 1 – Quality of Service Appendix

Purpose of SLC 45 information

1.1. The table below sets out the purpose for which the specified information as set out in SLC 45, and described in detail in chapter 4 of this document, will be used. It does not specify how this information will be used in the incentive scheme.

Information relating to number of customers interrupted and duration of interruptions	**Purpose**	
	Incentive scheme	**Other**
Number of customers interrupted by short interruptions of less than three minutes, including disaggregated by "cause"		Yes
Number of customers interrupted for three minutes or more	Yes	
Duration of interruptions to supply of three minutes or more	Yes	
Number of customers interrupted and duration of interruptions to supply of three minutes or more disaggregated by: incident and restoration stage; source, voltage level and MEI; duration band; frequency of interruption; and HV circuit.	 Yes Yes	 Yes Yes Yes Yes
Aggregate number of customers re-interrupted		Yes

Formulae for the purposes of reporting

1.2. This appendix sets out formulaic expressions for:

- the number of customers interrupted in the relevant year t (excluding re-interruptions), and
- the duration of interruptions to supply in the relevant year t.

Definitions
CIt = the number of customers interrupted in the relevant year t, **excluding re-interruptions.**

CMLt = the duration of interruptions to supply in the relevant year t, **including re-interruptions.**

i = an unplanned incident on the distribution system.

j = a pre-arranged incident on the distribution system.

k = an incident on a transmission system such as the systems of NGET or transmission companies in Scotland.

l = an incident on a distributed generator's system.

m = an incident on any other connected system.

r = a restoration stage in any incident i,j,k,l,m.

t = relevant year (that financial year for the purposes of which any calculation falls to be made).

TCt = total connected customers in the relevant year t.

TRrit = the restoration time of restoration stage r of an unplanned incident i in the relevant year t.

TRrjt = the restoration time of restoration stage r of a pre-arranged incident j in the relevant year t.

TRrkt = the restoration time of restoration stage r of an incident k on NGET's system or a transmission company's system in Scotland in the relevant year t.

TRrlt = the restoration time of restoration stage r of an incident l on a distributed generator's system in the relevant year t.

TRrmt = the restoration time of restoration stage r of an incident m on any other connected system in the relevant year t.

TIrit = the interruption time prior to the restoration time of restoration stage r of an unplanned incident i in the relevant year t.

TIrjt = the interruption time prior to the restoration time of restoration stage r of a pre-arranged incident j in the relevant year t.

TIrkt = the interruption time prior to the restoration time of restoration stage r of an incident k on NGET's system or a transmission company's system in Scotland in the relevant year t.

TIrlt = the interruption time prior to the restoration time of restoration stage r of an incident l on a distributed generator's system in the relevant year t.

TIrmt = the interruption time prior to the restoration time of restoration stage r of an incident m on any other connected system in the relevant year t.

and:

NDrit = Number of customers interrupted in restoration stage r of an unplanned incident i in the relevant year t, excluding re-interruptions to supply.

NDrjt = Number of customers interrupted in restoration stage r of a pre-arranged incident j in the relevant year t, excluding re-interruptions to supply.

NDrkt = Number of customers interrupted in restoration stage r of an incident k on NGET's system or a transmission company's system in Scotland in the relevant year t, excluding re-interruptions to supply.

NDrlt = Number of customers interrupted in restoration stage r of an incident l on a distributed generator's system in the relevant year t, excluding re-interruptions to supply.

NDrmt = Number of customers interrupted in restoration stage r of an incident m on any other connected system in the relevant year t, excluding re-interruptions to supply.

NNrit = Number of customers interrupted in each restoration stage r of an unplanned incident i in the relevant year t, including re-interruptions to supply.

NNrjt = Number of customers interrupted in restoration stage r of a pre-arranged incident j in the relevant year t, including re-interruptions to supply.

NNrkt = Number of customers interrupted in restoration stage r of an incident k on NGET's system or a transmission company's system in Scotland in the relevant year t, including re-interruptions to supply.

NNrlt = Number of customers interrupted in each restoration stage r of an incident l on a distributed generator's system in the relevant year t, including re-interruptions to supply.

NNrmt = Number of customers interrupted in restoration stage r of an incident m on any other connected system in the relevant year t, including re-interruptions to supply.

Formulae

CIt is the number of customers interrupted per year in the relevant year t and is derived from the following formula: $CI_t = CIA_t + CIB_t + CIC_t + CID_t + CIE_t$

Where

CIAt is the number of customers interrupted per year arising from unplanned incidents on the distribution system in the relevant year t and is derived from the following formula:

$$CIA_t = \frac{\left(\sum_i \sum_r ND_{rit}\right) * 100}{TC_t}$$

CIBt is the number of customers interrupted per year arising from pre-arranged incidents on the distribution system in the relevant year t and is derived from the following formula:

$$CIB_t = \frac{\left(\sum_j \sum_r ND_{rjt}\right) * 100}{TC_t}$$

CICt is the number of customers interrupted per year arising from incidents on the systems of NGET or transmission companies in Scotland in the relevant year t and is derived from the following formula:

$$CIC_t = \frac{\left(\sum_k \sum_r ND_{rkt}\right) * 100}{TC_t}$$

CIDt is the number of customers interrupted per year arising from incidents on the systems of distributed generators in the relevant year t and is derived from the following formula:

$$CID_t = \frac{\left(\sum_l \sum_r ND_{rlt}\right) * 100}{TC_t}$$

CIEt is the number of customers interrupted per year arising from incidents on any other connected systems in the relevant year t and is derived from the following formula:

$$CIE_t = \frac{\left(\sum_m \sum_r ND_{rmt}\right) * 100}{TC_t}$$

Each of the terms CIAt, CIBt, CICt, CIDt and CIEt should be separately identified.

CMLt is the duration of interruptions to supply in the relevant year t and is derived from the following formula:

$$CML_t = CMLA_t + CMLB_t + CMLC_t + CMLD_t + CMLE_t$$

CMLAt is the duration of interruptions from unplanned incidents on the distribution system in the relevant year t and is derived from the following formula:

$$CMLA_t = \frac{\sum_i \sum_r (NN_{rit} * (TR_{rit} - TI_{rit}))}{TC_t}$$

CMLBt is the duration of interruptions from pre-arranged incidents on the distribution system in the relevant year t and is derived from the following formula:

$$CMLB_t = \frac{\sum_j \sum_r (NN_{rjt} * (TR_{rjt} - TI_{rjt}))}{TC_t}$$

CMLCt is the duration of interruptions arising from incidents on the systems of NGET or transmission companies in Scotland in the relevant year t and is derived from the following formula:

$$CMLC_t = \frac{\sum_k \sum_r (NN_{rkt} * (TR_{rkt} - TI_{rkt}))}{TC_t}$$

CMLDt is the duration of interruptions arising from incidents on the systems of distributed generators in the relevant year t and is derived from the following formula:

$$CMLD_t = \frac{\sum_l \sum_r (NN_{rlt} * (TR_{rlt} - TI_{rlt}))}{TC_t}$$

CMLEt is the duration of interruptions arising from incidents on any other connected systems in the relevant year t and is derived from the following formula:

$$CMLE_t = \frac{\sum_m \sum_r (NN_{rmt} * (TR_{rmt} - TI_{rmt}))}{TC_t}$$

Each of the terms CMLAt, CMLBt, CMLCt, CMLDt and CMLEt should be separately identified.

Other formulae

1.3. This section sets out formulaic expressions for:

- the number of customers interrupted by short interruptions in the relevant year t (excluding re-interruptions), and
- the number of customers re-interrupted in the relevant year t.

Definitions

RIt = the number of customers re-interrupted in the relevant year t.

n = a short interruption due to the automatic operation of distribution network switchgear where the supplies of some or all of the customers involved are successfully restored by automatic switching within less than three minutes of the first interruption.

o = a short interruption due to the automatic operation of distribution network switchgear where the supplies of some or all of the customers involved are successfully restored by manual or remote control switching within less than three minutes of the first interruption.

p = a short interruption due to the manual or remote operation of distribution network switchgear for reasons such as deliberate disconnection for operational or emergency reasons.

q = a short interruption due to the operation of switchgear on the networks of NGET/transmission companies (in Scotland) or other connected systems and distributed generators.

SIt = the number of short interruptions to supply in the relevant year t.

NSnt = the number of customers interrupted by a short interruption in category n in the relevant year t.

NSot = the number of customers interrupted by a short interruption in category o in the relevant year t.

NSpt = the number of customers interrupted by a short interruption in category p in the relevant year t.

NSqt = the number of customers interrupted by a short interruption in category q in the relevant year t.

Formulae

SIt is the number of customers interrupted by short interruptions in the relevant year t and is derived from the following formula:

$$SI_t = SIA_t + SIB_t + SIC_t + SID_t$$

where:

SIAt is the number of customers interrupted by short interruptions in the relevant year t due to the automatic operation of distribution network switchgear where the supplies of some or all of the customers involved are successfully restored by automatic switching within less than three minutes of the first interruption and is derived from the following formula:

$$SIA_t = \frac{\left(\sum_n NS_{nt}\right) * 100}{TC_t}$$

SIBt is the number of customers interrupted by short interruptions in the relevant year t due to the automatic operation of distribution network switchgear where the supplies of some or all of the customers involved are successfully restored by manual or remote control switching within less than three minutes of the first interruption and is derived from the following formula:

$$SIB_t = \frac{\left(\sum_o NS_{ot}\right) * 100}{TC_t}$$

SICt is the number of customers interrupted by short interruptions in the relevant year t due to the manual or remote operation of distribution network switchgear for reasons such as deliberate disconnection for operational or emergency reasons and is derived from the following formula:

$$SIC_t = \frac{\left(\sum_p NS_{pt}\right) * 100}{TC_t}$$

SIDt is the number of customers interrupted by short interruptions in the relevant year t due to the operation of switchgear on the networks of NGET/transmission companies (in Scotland) or other connected systems and distributed generators and is derived from the following formula:

$$SID_t = \frac{\left(\sum_q NS_{qt}\right) * 100}{TC_t}$$

Each of the terms SIAt, SIBt, SICt and SIDt should be separately identified.

RIt is the number of customers re-interrupted in the relevant year t and is derived from the following formula:

$$RI_t = RIA_t + RIB_t + RIC_t + RID_t + RIE_t$$

where:

RIAt is the number of customers re-interrupted in the relevant year t arising from unplanned incidents on the distribution system and is derived from the following formula:

$$RIA_t = \frac{\left(\sum_i \sum_r (NN_{rit} - ND_{rit})\right) * 100}{TC_t}$$

RIBt is the number of customers re-interrupted in the relevant year t arising from pre-arranged incidents on the distribution system and is derived from the following formula:

$$RIB_t = \frac{\left(\sum_j \sum_r (NN_{rjt} - ND_{rjt})\right) * 100}{TC_t}$$

RICt is the number of customers re-interrupted in the relevant year t arising from incidents on the systems of NGET or transmission companies in Scotland and is derived from the following formula:

$$RIC_t = \frac{\left(\sum_k \sum_r (NN_{rkt} - ND_{rkt})\right) * 100}{TC_t}$$

RIDt is the number of customers re-interrupted in the relevant year t arising from incidents on the systems of distributed generators and is derived from the following formula:

$$RID_t = \frac{\left(\sum_l \sum_r (NN_{rlt} - ND_{rlt})\right) * 100}{TC_t}$$

RIEt is the number of customers re-interrupted in the relevant year t arising from incidents on any other connected systems and is derived from the following formula:

$$RIE_t = \frac{\left(\sum_m \sum_r (NN_{rmt} - ND_{rmt})\right) * 100}{TC_t}$$

SLC 45 Voltage boundaries

1.4. This section sets out the definition of voltage boundaries.

132 kV systems

1.5. The "lower boundary" of the 132 kV[34] system should be taken as the supply terminals of the DNO's customers supplied at 132 kV or the load-side terminals of switchgear controlling the secondary (lower voltage) side of 132 kV transformers. If no switchgear exists between the secondary side of the 132 kV transformer and the primary side of an EHV or HV system transformer, the "lower boundary" should be taken as the secondary-side terminals of the 132 kV transformer. The lower voltage busbars and their protection equipment at 132 kV/lower voltage substations are not included.

1.6. The "upper boundary" of the 132 kV system should be taken as the point at which ownership of the 132 kV circuit or plant becomes the responsibility of the DNO.

EHV systems

1.7. For the purposes of reporting under SLC 45, extra high voltage (EHV) includes all voltage levels above 20kV up to but excluding 132kV. The "lower boundary" of EHV systems should be taken as the supply terminals of customers supplied at EHV, and in other situations as the load-side terminals of protection equipment connected to the secondary side (lower voltage) of EHV transformers. The "upper boundary" should in general be taken as the busbar side of lower voltage switchgear of transformers whose primary voltage is 132kV or above and whose secondary voltage is EHV. If no secondary switchgear exists, the "upper boundary" should be taken as the secondary-side terminals of the 132 kV or above transformer: incidents on the system connected to the secondary voltage terminals of the transformer should be reported as EHV incidents and not as 132kV incidents.

HV systems

1.8. For the purposes of reporting under SLC 45, high voltage (HV) includes all voltage levels above 1,000 volts up to and including 20kV. The "lower boundary" of HV systems should be taken as the supply terminals of customers supplied at HV, and in other situations as the load-side terminals of the protection equipment connected to the secondary side (lower voltage) of distribution transformers respectively. Where the transformer does not have any secondary-side protection equipment, the boundary must be the bolted connection between the transformer tail and the lower voltage busbar. The "upper boundary" should in general be taken as the busbar side of lower voltage switchgear of transformers whose primary voltage is EHV or above and whose secondary voltage is HV. If no secondary switchgear exists, the "upper boundary" should be taken as the secondary-side terminals of the EHV or above transformer: incidents on the system connected to the secondary voltage terminals of the transformer should be reported as HV incidents and not as EHV or 132 kV incidents.

LV systems

[34] See chapter 4 paragraph 4.4 in relation to the reporting of incidents in Scotland

1.9. For the purposes of reporting under SLC 45, a low voltage (LV) system is one that operates at a nominal voltage of 1000 V or less.

1.10. The upper boundary should be taken as the load-side terminals of the protection equipment connected to the secondary side (low voltage) of distribution transformers. Where the transformer does not have any secondary-side protection equipment, the boundary must be the bolted connection between the transformer tail and the LV busbar. The lower boundary should be taken as the points of connection associated with LV services.

LV services

1.11. For the purpose of reporting under SLC 45, LV services are defined as the service line from the LV distributing main to the DNO's protection device situated upon the customer's premises, including the joint and associated components connecting the service line to the distributing main. It should be noted that incidents on cut-outs and all wiring and equipment after cut-outs, including cut-out fuse operations, are excluded from reporting under the Quality of Service Incentive Scheme (even where this results in the operation of a fuse at the DNO's substation) and the definition of LV services therefore excludes this equipment.

Auditing and estimating the accuracy of interruptions reporting

Audit preparation

1.12. At the end of the reporting year each DNO must submit information on CI and CML at each voltage by incident and restoration stage.

1.13. Ofgem will then select a sample of 150 incidents, split between 132kV and EHV, HV and LV according to the respective contribution to CI and CML (with a minimum of 50 LV incidents). A proportion of the sample will be held back until the time of the audit, and where a DNO agrees, the entire sample will be held back.

Audits

1.14. The audits of interruption reporting accuracy for the purposes of the scheme will then involve the following steps:

Stage 1 – Calculation of MPAN accuracy[35]

[35] True feeders are feeders which can generate CI and CML.

1.15. The HV MPAN accuracy will be calculated using the following formula:

$$\left(\frac{\text{Total number of primary traded MPANs assigned to true feeders at HV}}{\text{Total number of primary traded MPANs}}\right)\times 100$$

1.16. The LV MPAN accuracy will be calculated using the following formula:

$$\left(\frac{\text{Total number of primary traded MPANs assigned to true feeders at LV}}{\text{Total number of primary traded MPANs}}\right)\times 100$$

1.17. The 132kV and EHV MPAN accuracy will be calculated using the following formula:

$$\left(\frac{\text{Total number of primary traded MPANs assigned to true feeders at 132kV and EHV}}{\text{Total number of primary traded MPANs}}\right)\times 100$$

Stage 2

1.18. Ofgem's auditors will audit 50 HV and above incidents and 30 LV incidents[36].

1.19. The auditors will then calculate the mean, standard deviation and mean plus/minus 4 standard deviations of the errors in the reported restoration stage figures.

1.20. The auditors will exclude any incidents containing outlier restoration stages (i.e. where the errors of any stage are outside the mean plus/minus 4 standard deviations).

1.21. The auditors will then calculate the accuracy of incident reporting for CI and CML for the 132kV and EHV, HV and LV data sets using the following formula:

[36] Where incidents that are "too difficult" to audit are substituted by a relevant spare incident.

$$\frac{\text{Sum of reported CI/CML for remaining restoration stages}}{\text{Sum of audited CI/CML for remaining restoration stages}}$$

1.22. The auditors will calculate the combined MPAN and incident reporting accuracies (for each of the three voltage categories) using the following formula:

[MPAN accuracy* accuracy of incident reporting]* 100

1.23. This is expressed as a percentage less than 100 using the following formula:

100 - modulus[100 - combined accuracy]

1.24. If the 132kV and EHV accuracy results are greater than or equal to 99 per cent, the DNO will be deemed to have met the accuracy levels set out in the rigs. If not, the remaining 132kV and EHV sample will be audited at Stage 3.

1.25. If the HV accuracy results are greater than or equal to 97 per cent, the DNO will be deemed to have met the accuracy levels set out in the RIGs. If not, the remaining HV sample will be audited at Stage 3.

1.26. If the LV accuracy results are greater than or equal to 93 per cent, then the DNO will be deemed to have met the accuracy levels set out in the RIGs. If not, the remaining LV sample will be audited at Stage 3.

Stage 3

1.27. If appropriate, the auditors will audit the remaining incidents in the 132kV and EHV, HV and LV samples and recalculate the incident reporting accuracies and combined accuracies using the same method as set out in Stage 2.

1.28. If the DNO fails to meet the 97 per cent minimum 132kV and EHV level of accuracy required for the reporting of the number of customers interrupted and duration of interruptions set out in table 4.1 in chapter 4, Ofgem will make the appropriate adjustments[37] to performance.

1.29. If the DNO fails to meet the 95 per cent minimum HV level of accuracy required for the reporting of the number of customers interrupted and duration of

[37] Where data is found to fail the 97 per cent minimum 132kV and EHV level of accuracy, the data will be made 100 per cent accurate.

interruptions set out in table 4.1 in chapter 4, Ofgem will make the appropriate adjustments[38] to performance.

1.30. If the DNO fails to meet the 90 per cent minimum LV level of accuracy required for the reporting of the number of customers interrupted and duration of interruptions set out in table 4.1 in chapter 4, Ofgem will make the appropriate adjustments[39] to performance.

[38] Where data is found to fail the 95 per cent minimum HV level of accuracy, the data will be made 100 per cent accurate.
[39] Where data is found to fail the 90 per cent minimum LV level of accuracy, the data will be made 100 per cent accurate.

Appendix 2 – Asset replacement unit cost scope

Asset replacement Category (Cost Reporting Table)

The following tables present the DNO agreed scope of work for each of the asset replacement activities. The table shows the minimum scopes of work which must be carried out when each asset type is replaced to ensure consistency of workload and cost reporting. It also provides guidance to indicate where assets should be classed as prime or consequential.

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET REPLACEMENT	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN ADDITION OR DISPOSAL OF ASSET
LV	**Overhead Pole Line**	**LV Main (OHL) Conductor**						
Dismantle, remove and dispose of existing LV OH line conductor			Yes	Yes				
Supply and erect replacement LV OH line conductor			Yes	Yes				
Undertake any necessary tree cutting			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Remove and dispose of existing LV insulators						Yes		Yes
Supply and fit replacement LV insulators						Yes		Yes
Replacement of poles						Yes	Yes	
Installation of additional poles						Yes	Yes	
LV	**Overhead Pole Line**	**Services**						
Dismantle, remove and dispose of existing LV OH service flight			Yes					
Dismantle, remove and dispose of existing LV OH undereaves wiring			Yes	Yes				
Supply and install replacement LV OH service flight			Yes					
Supply and install replacement LV OH undereaves wiring			Yes	Yes				
Dismantle, remove and dispose of existing LV cut out (including meter board where required)			Yes		Yes			
Supply & install replacement LV cut out (including meter board where required)			Yes		Yes			

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET REPLACEMENT	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN ADDITION OR DISPOSAL OF ASSET
LV	**Overhead Pole Line**	**LV Poles**						
Dismantle, remove and dispose of existing pole (where applicable)			Yes	Yes				
Excavate pole hole			Yes					
Dress and erect new pole (including insulators etc)			Yes	Yes				
Disconnect/reconnect/re-erect LV OH service flights			Yes					
Replace undereaves service wiring			Yes					
Disconnect/reconnect/re-erect streetlight			Yes					
Undertake any necessary tree cutting			Yes					
Excavate stay holes			Yes					
Renew stays (where required)			Yes					
Dismantle, remove and dispose of existing LV UG cable and associated pole box (where appropriate)			Yes		Yes			
Excavate joint hole (where appropriate)			Yes					
Supply and make of replacement LV UG cable pole box (where appropriate)			Yes					
Supply and make of LV UG cable joint at base of pole (where appropriate)			Yes					
Supply and erect LV UG cable and associated pole box (where appropriate)			Yes		Yes			
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
LV	**Overhead Pole Line**	**Pole Refurbishment**						
Principle here is that the costs collected relate to activities that does not result in the addition or disposal of a pole. When number of qualifying task are undertaken on single pole, the activity count would be one refurbished pole.								
Tasks that qualify as pole refurbishment include:								
Remove and dispose of existing LV insulators (when undertaken independently of pole replacement)						Yes		Yes
Supply and fit replacement LV insulators (when undertaken independently of pole replacement)						Yes		Yes
Supply and install a replacement stay (when undertaken independently of pole replacement)						Yes		Yes
Supply & fit pole bandages/splints etc						Yes		Yes
Tasks that do not qualify as pole refurbishment include:								
Replacement of signs, notices and anti-climbing guards when undertaken independently of tasks that qualify as pole refurbishment						Yes		
Insertion of boron rods when undertaken independently of tasks that qualify as pole refurbishment						Yes		

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN
LV	**Cable**	**LV Main (UG Plastic)**						
Supply & Install replacement LV UG Mains Cable			Yes	Yes				
Disconnect and abandon existing LV cable (where applicable)			Yes	Yes				
All trench excavation, backfilling & reinstatement (including joint holes) associated with LV mains UG cable			Yes					
Supply & installation of cable ducting as required			Yes					
Supply & Make Off LV Mains/mains Joint(s)			Yes					
Dismantle existing LV overhead line (where applicable)			Yes	Yes				
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Supply & Install replacement LV UG Service Cable						Yes		Yes
All trench excavation, backfilling & reinstatement (including joint holes) associated with LV UG service cable						Yes		Yes
Supply & Make Off LV Mains/service Joint(s)						Yes		Yes
Supply & Make Off LV service/service Joint(s)						Yes		Yes
Associated replacement of LV UG link box						Yes	Yes	
LV	**Cable**	**Rising Mains**						
Disconnect and remove existing rising & lateral mains cabling systems including busbars / cabling / containment systems and distribution boards			Yes	Yes				
Installation of new distribution board(s) and connecting cables to building supply intake point			Yes					
Installlation of rising and lateral cabling systems from distribution board(s) to each individual premise , including making ways in building, installing cables, (& busbars (if required)) and installation of cable containment & support systems plus mechanical protection (incl making good any cable ways)			Yes	Yes				
Installation of cableheads / disconnection capabilities at each premise & all cable termination work			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Replacement of UG service cable to multi-occupancy building						Yes	Yes	

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET REPLACEMENT	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN ADDITION OR DISPOSAL OF ASSET
LV	**Cable**	**LV Service (UG)**						
Supply and install LV service cable			Yes	Yes				
Disconnect and abandon existing LV UG service cable			Yes	Yes				
All trench excavation, backfilling & reinstatement (including joint holes) associated with LV UG service cable			Yes					
Supply & installation of cable ducting as required			Yes					
Supply and make off LV mains/LV UG service joint (where appropriate)			Yes					
Supply and make off LV UG service/LV UG service joint (where appropriate)			Yes					
Pot end existing LV UG service (where appropriate)			Yes					
Supply and make off LV UG service/LV UG service joint (where appropriate)			Yes					
Dismantle, remove and dispose of existing LV cut out (including meter board where required)			Yes		Yes			
Supply & install replacement LV cut out (including meter board where required)			Yes		Yes			
Dismantle, remove and dispose of existing LV overhead service flight (where appropriate)			Yes					
Dismantle, remove and dispose of existing LV undereaves service (where appropriate)			Yes		Yes			
LV	**Cable**	**LV Service Associated With Rising and Lateral Mains**						
LV	**Cable**	**LV Service Transfers Associated With LV UG Cable Replacement**						
Supply & Install replacement LV UG Service Cable						Yes		Yes
All trench excavation, backfilling & reinstatement (including joint holes) associated with LV UG service cable						Yes		Yes
Supply & Make Off LV Mains/service Joint(s)						Yes		Yes
Supply & Make Off LV service/service Joint(s)						Yes		Yes
LV	**Switchgear**	**LV Circuit Breaker**						
Dismantle, remove and dispose of existing LV CB			Yes	Yes				
Supply & Install Replacement LV CB			Yes	Yes				
Supply and install LV cable			Yes		Yes			
Supply and make off LV connections			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of mechanical aids to facilitate installation			Yes					

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET REPLACEMENT	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN ADDITION OR DISPOSAL OF ASSET
LV	**Switchgear**	**LV Pillar (ID)**						
Dismantle, remove and dispose of existing LV switchgear (e.g. LV pillar, LV Board (WM) including any integral LV circuit breaker)			Yes	Yes				
Supply & Install Replacement LV Pillar			Yes	Yes				
Supply & Install LV UG Cable			Yes		Yes			
Disconnect and abandon existing LV UG cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off Permanent Joint			Yes					
Supply & Make Off Temporary Joints (if required)			Yes					
Terminate LV UG cables into replacement LV pillar			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
LV	**Switchgear**	**LV Pillar (OD)**						
Dismantle, remove and dispose of existing LV switchgear (e.g. LV pillar, LV Board (WM) including any integral LV circuit breaker)			Yes	Yes				
Supply & Install Replacement LV Pillar			Yes	Yes				
Supply & Install LV UG Cable			Yes		Yes			
Disconnect and abandon existing LV UG cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off Permanent Joint			Yes					
Supply & Make Off Temporary Joints (if required)			Yes					
Terminate LV UG cables into replacement LV pillar			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET REPLACEMENT	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN ADDITION OR DISPOSAL OF ASSET
LV	**Switchgear**	**LV Board (WM)**						
Dismantle, remove and dispose of existing LV switchgear (e.g. LV pillar, LV Board (WM) including any integral LV circuit breaker)			Yes	Yes				
Supply & Install Replacement LV Board (WM)			Yes	Yes				
Supply & Install LV UG Cable			Yes		Yes			
Disconnect and abandon existing LV UG cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off Permanent Joint			Yes					
Supply & Make Off Temporary Joints (if required)			Yes					
Terminate LV UG cables into replacement LV pillar			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
LV	**Switchgear**	**LV UGB**						
Supply and install replacement LV UG ink box			Yes	Yes				
Dismantle, remove and dispose of existing LV Switchgear (e.g. UG link box or LV pillar)			Yes	Yes				
Excavate for link box			Yes					
Install new prefabricated pit, frame and cover			Yes					
Supply & Install LV UG Cable			Yes		Yes			
Disconnect and abandon existing LV UG cable			Yes		Yes			
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply and make off LV UG cable terminations			Yes					
Supply and make off LV UG cable joints			Yes					
LV	**Switchgear**	**Metered Cutout**						
Dismantle, remove and dispose of existing LV cut out (including meter board where required)			Yes	Yes				
Supply & install replacement LV cut out (including meter board where required)			Yes	Yes				

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET REPLACEMENT	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN ADDITION OR DISPOSAL OF ASSET
LV	**Switchgear**	**LV Board (WM)(X Type Network)**						
Dismantle, remove and dispose of existing LV switchgear (e.g. LV pillar, LV Board (WM) including any integral LV circuit breaker)			Yes	Yes				
Supply & Install Replacement LV Board (WM)(X Type Network)			Yes	Yes				
Supply & Install LV UG Cable			Yes		Yes			
Disconnect and abandon existing LV UG cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off Permanent Joint			Yes					
Supply & Make Off Temporary Joints (if required)			Yes					
Terminate LV UG cables into replacement LV pillar			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
HV	**Overhead Pole Line**	**6.6/11 kV OHL (Conventional Conductor)**						
Dismantle, remove and dispose of existing HV OH line conductor			Yes	Yes				
Supply and erect replacement HV OH line conductor			Yes	Yes				
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Undertake any necessary tree cutting			Yes					
Remove and dispose of existing HV insulators						Yes		Yes
Supply and fit replacement HV insulators						Yes		Yes
Replacement of poles						Yes	Yes	
Installation of additional poles						Yes	Yes	
HV	**Overhead Pole Line**	**6.6/11 kV OHL (BLX or similar Conductor)**						
Dismantle, remove and dispose of existing HV OH line conductor			Yes	Yes				
Supply and erect replacement HV OH line BLX or similar conductor			Yes	Yes				
Undertake any necessary tree cutting			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Remove and dispose of existing HV insulators						Yes		Yes
Supply and fit replacement HV insulators						Yes		Yes
Replacement of poles						Yes	Yes	
Installation of additional poles						Yes	Yes	

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET REPLACEMENT	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN ADDITION OR DISPOSAL OF ASSET
HV	**Overhead Pole Line**	**20kV OHL (Conventional Conductor)**						
Dismantle, remove and dispose of existing HV OH line conductor			Yes	Yes				
Supply and erect replacement HV OH line conductor			Yes	Yes				
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Undertake any necessary tree cutting			Yes					
Remove and dispose of existing HV insulators						Yes		Yes
Supply and fit replacement HV insulators						Yes		Yes
Replacement of poles						Yes	Yes	
Installation of additional poles						Yes	Yes	
HV	**Overhead Pole Line**	**20kV OHL (BLX or similar Conductor)**						
Dismantle, remove and dispose of existing HV OH line conductor			Yes	Yes				
Supply and erect replacement HV OH line BLX or similar conductor			Yes	Yes				
Undertake any necessary tree cutting			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Remove and dispose of existing HV insulators						Yes		Yes
Supply and fit replacement HV insulators						Yes		Yes
Replacement of poles						Yes	Yes	
Installation of additional poles						Yes	Yes	
HV	**Overhead Pole Line**	**6.6/11 kV Pole**						
Dismantle, remove and dispose of existing pole (where appropriate)			Yes	Yes				
Excavate pole hole			Yes					
Dress and erect new (additional or replacement) pole (including cross arm and insulators etc)			Yes	Yes				
Undertake any necessary tree cutting			Yes					
Excavate stay holes			Yes					
Renew stays (where required)			Yes					
Dismantle, remove and dispose of existing HV UG cable and associated pole box (where appropriate)			Yes		Yes			
Excavate joint hole (where appropriate)			Yes					
Supply and make of replacement HV UG cable pole box (where appropriate)			Yes					
Supply and make of HV UG cable joint at base of pole (where appropriate)			Yes					
Supply and erect HV UG cable and associated pole box (where appropriate)			Yes		Yes			
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN
HV	**Overhead Pole Line**	**20 kV Pole Replacement**						
Dismantle, remove and dispose of existing pole (where appropriate)			Yes	Yes				
Excavate pole hole			Yes					
Dress and erect new (additional or replacement) pole (including cross arm and insulators etc)			Yes	Yes				
Undertake any necessary tree cutting			Yes					
Excavate stay holes			Yes					
Renew stays (where required)			Yes					
Dismantle, remove and dispose of existing HV UG cable and associated pole box (where appropriate)			Yes		Yes			
Excavate joint hole (where appropriate)			Yes					
Supply and make of replacement HV UG cable pole box (where appropriate)			Yes					
Supply and make of HV UG cable joint at base of pole (where appropriate)			Yes					
Supply and erect HV UG cable and associated pole box (where appropriate)			Yes		Yes			
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
HV	**Overhead Pole Line**	**6.6/11 kV Pole Refurbishment**						
Principle here is that the costs collected relate to activities that does not result in the addition or disposal of a pole. When number of qualifying task are undertaken on single pole, the activity count would be one refurbished pole.								
Tasks that qualify as pole refurbishment include:								
Remove and dispose of existing cross arm and insulators (when undertaken independently of pole replacement)						Yes		Yes
Supply and fit replacement cross arm and insulators (when undertaken independently of pole replacement)						Yes		Yes
Supply and install a replacement stay (when undertaken independently of pole replacement)						Yes		Yes
Supply & fit pole bandages/splints etc						Yes		Yes
Tasks that do not qualify as pole refurbishment include:								
Replacement of signs, notices and anti-climbing guards when undertaken independently of tasks that qualify as pole refurbishment						Yes		
Insertion of boron rods when undertaken independently of tasks that qualify as pole refurbishment						Yes		

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HV	**Overhead Pole Line**	**6.6/11 kV Pole Refurbishment**						
Principle here is that the costs collected relate to activities that does not result in the addition or disposal of a pole. When number of qualifying task are undertaken on single pole, the activity count would be one refurbished pole.								
Tasks that qualify as pole refurbishment include:								
Remove and dispose of existing cross arm and insulators (when undertaken independently of pole replacement)						Yes		Yes
Supply and fit replacement cross arm and insulators (when undertaken independently of pole replacement)						Yes		Yes
Supply and install a replacement stay (when undertaken independently of pole replacement)						Yes		Yes
Supply & fit pole bandages/splints etc						Yes		Yes
Tasks that do not qualify as pole refurbishment include:								
Replacement of signs, notices and anti-climbing guards when undertaken independently of tasks that qualify as pole refurbishment						Yes		
Insertion of boron rods when undertaken independently of tasks that qualify as pole refurbishment						Yes		
HV	**Cable**	**6.6/11kV UG Cable**						
Supply & Install 6.6/11 kV UG Cable			Yes	Yes				
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & installation of cable ducting as required			Yes					
Supply & Make Off 6.6/11 kV Joint(s)			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
HV	**Cable**	**20kV UG Cable**						
Supply & Install 20 kV UG Cable			Yes	Yes				
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & installation of cable ducting as required			Yes					
Supply & Make Off 20 kV Joint(s)			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					

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HV	**Cable**	**HV Sub Cable**						
Supply and install HV submarine cable			Yes	Yes				
Sdisconnect and abandon existing HV submarine cable			Yes	Yes				
Vessel mobilisation/demobilisation			Yes					
Dive team mobilisation/demobilisation			Yes					
Environmental studies			Yes					
Jointers mobilisation/demobilisation			Yes					
Ploughing or post lay burial jetting.			Yes					
Protection where burial not achieved.			Yes					
Transistion Jointing on shore			Yes					
Shore end protection burial			Yes					
Tide and weather delays			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
HV	**Switchgear**	**6.6/11 kV CB (PM)**						
Supply and install replacement 6.6/11 kV pole mounted circuit breaker			Yes	Yes				
Dismantle, remove and dispose of 6.6/11 kV pole mounted circuit breaker			Yes	Yes				
Supply and install HV earthwire (assuming original CB was unearthed)			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Replace existing HV pole (if required and irrespective of driver)						Yes	Yes	
Dismantle, remove and dispose of existing radio and RTU for remote control functionality (where radio and RTU existed previously)			Yes					
Supply and install radio and RTU for remote control functionality (where radio and RTU existed previously)			Yes					
Supply and install radio and RTU for remote control functionality (where no radio or RTU existed previously)						Yes		

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HV	**Switchgear**	**6.6/11 kV CB (GM) Primary**						
Supply and install replacement 6.6/11 kV GM circuit breaker (including protection relays and SCADA interface)			Yes	Yes				
Dismantle, remove and dispose of existing 6.6/11 kV GM circuit breaker (including protection relays and SCADA interface)			Yes	Yes				
Supply & Install 6.6/11 kV UG Cable			Yes		Yes			
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & installation of cable ducting as required			Yes					
Supply & Make Off 6.6/11 kV Joint(s)			Yes					
Terminate 6.6/11 kV UG cable into circuit breaker			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Supply & install replacement battery and associated charger			Yes		Yes			
Dismantle, remove and dispose of existing battery and associated charger			Yes		Yes			
Construction of new switchroom/demolition of existing switchroom/Modification to switchroom						Yes		
Modification to concrete plinth/base (including where appropriate complete new plinths and break of existing plinth)						Yes		
Modify substation surround/Supply and install substation enclosure						Yes		

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HV	**Switchgear**	**6.6/11 kV CB (GM) Secondary**						
Supply and install replacement 6.6/11 kV GM circuit breaker (including protection relays)			Yes	Yes				
Dismantle, remove and dispose of existing 6.6/11 kV GM circuit breaker (including protection relays)			Yes	Yes				
Supply & Install 6.6/11 kV UG Cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off 6.6/11 kV Joint(s)			Yes					
Terminate 6.6/11 kV UG cable into circuit breaker			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Supply & install replacement battery and associated charger (where applicable)			Yes		Yes			
Dismantle, remove and dispose of existing battery and associated charger (where applicable)			Yes		Yes			
Construction of new switchroom/demolition of existing switchroom/Modification to switchroom						Yes		
Modification to concrete plinth/base (including where appropriate complete new plinths and break of existing plinth)						Yes		
Modify substation surround/Supply and install substation enclosure						Yes		
Install SCADA interface and associated telecommunications (i.e. as an enhancement)						Yes		
HV	**Switchgear**	**6.6/11 kV Switch (PM)**						
Dismantle, remove and dispose of existing sectionaliser								
Supply and install new sectionaliser								
Supply and install HV earthwire (assuming original CB was unearthed)			Yes					
Dismantle, remove and dispose of existing radio and RTU for remote control functionality (where radio and RTU existed previously)			Yes					
Supply and install radio and RTU for remote control functionality (where radio and RTU existed previously)			Yes					
Supply and install radio and RTU for remote control functionality (where no radio or RTU existed previously)						Yes		

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HV	**Switchgear**	**6.6/11 kV Other PM Switchgear**						
Dismantle, remove and dispose of existing Other HV PM switchgear (e.g. ABI, ABSD, ASL & HV PM fuse)								
Supply and install new Other HV PM Switchgear (e.g. ABI, ABSD, ASL & HV PM fuse)								
HV	**Switchgear**	**6.6/11 kV Switch (GM)**						
Supply and install replacement 6.6/11 kV GM switch			Yes	Yes				
Dismantle, remove and dispose of existing 6.6/11 kV switchgear (e.g. GM switch, RMU & GM CB)			Yes	Yes				
Supply & Install 6.6/11 kV UG Cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off 6.6/11 kV Joint(s)			Yes					
Terminate 6.6/11 kV UG cable into GM switch			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Modification to concrete plinth/base (including where appropriate complete new plinths and break of existing plinth)						Yes		
Modify substation surround/Supply and install substation enclosure						Yes		
Fit actuator, RTU etc for remote operation						Yes		

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HV	**Switchgear**	**6.6/11 kV RMU**						
Supply and Install Replacement 6.6/11 kV RMU			Yes	Yes				
Dismantle, remove and dispose of existing 6.6/11 kV switchgear (e.g. GM switch, RMU & GM CB)			Yes	Yes				
Supply & Install 6.6/11 kV UG Cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off 6.6/11 kV Joint(s)			Yes					
Terminate 6.6/11 kV UG cable into RMU			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Modification to concrete plinth/base (including where appropriate complete new plinths and break of existing plinth)						Yes		
Modify substation surround/Supply and install substation enclosure						Yes		
Fit actuator, RTU etc for remote operation						Yes		
HV	**Switchgear**	**6.6/11kV X type RMU**						
Supply and Install Replacement 6.6/11 kV X-type RMU including 2 sets of unit protection CTs			Yes	Yes				
Dismantle, remove and dispose of existing 6.6/11 kV switchgear (e.g. GM switch, RMU & GM CB)			Yes	Yes				
Supply & Install 6.6/11 kV UG Cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off 6.6/11 kV Joint(s)			Yes					
Terminate 6.6/11 kV UG cable into RMU			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Modification to concrete plinth/base (including where appropriate complete new plinths and break of existing plinth)						Yes		
Modify substation surround/Supply and install substation enclosure						Yes		
Replace unit protection equipment at substation plus remote circuit end & recommission			Yes					
Muticore cabling - remove & replace existing cabling (including all retermination)			Yes					
Breakdown transformer end box and replace CTs. Install CTs in Transformer endbox, remake and recomission			Yes					

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HV	**Switchgear**	**20 kV CB (PM)**						
Supply and install replacement 20 kV pole mounted circuit breaker			Yes	Yes				
Dismantle, remove and dispose of 20 kV pole mounted circuit breaker			Yes	Yes				
Supply and install HV earthwire (assuming original CB was unearthed)			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Replace existing HV pole (if required and irrespective of driver)						Yes	Yes	
Dismantle, remove and dispose of existing radio and RTU for remote control functionality			Yes					
Supply and install radio and RTU for remote control functionality (where radio and RTU existed previously)			Yes					
Supply and install radio and RTU for remote control functionality (where no radio or RTU existed previously)						Yes		
HV	**Switchgear**	**20 kV CB (GM) Primary**						
Supply and install replacement 20 kV GM circuit breaker (including protection relays and SCADA interface)			Yes	Yes				
Dismantle, remove and dispose of existing 20 kV GM circuit breaker (including protection relays and SCADA interface)			Yes	Yes				
Supply & Install 20 kV UG Cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off 20 kV Joint(s)			Yes					
Terminate 6.6/11 kV UG cable into circuit breaker			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Supply & install replacement battery and associated charger			Yes		Yes			
Dismantle, remove and dispose of existing battery and associated charger			Yes		Yes			
Construction of new switchroom/demolition of existing switchroom/Modification to switchroom						Yes		
Modification to concrete plinth/base (including where appropriate complete new plinths and break of existing plinth)						Yes		
Modify substation surround/Supply and install substation enclosure						Yes		

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HV	**Switchgear**	**20 kV CB (GM) Distribution**						
Supply and install replacement 20 kV GM circuit breaker (including protection relays)			Yes	Yes				
Dismantle, remove and dispose of existing 20 kV GM circuit breaker (including protection relays)			Yes	Yes				
Supply & Install 20 kV UG Cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off 20 kV Joint(s)			Yes					
Terminate 20 kV UG cable into circuit breaker			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Supply & install replacement battery and associated charger (where applicable)			Yes		Yes			
Dismantle, remove and dispose of existing battery and associated charger (where applicable)			Yes		Yes			
Construction of new switchroom/demolition of existing switchroom/Modification to switchroom						Yes		
Modification to concrete plinth/base (including where appropriate complete new plinths and break of existing plinth)						Yes		
Modify substation surround/Supply and install substation enclosure						Yes		
Install SCADA interface and associated telecommunications (i.e. as an enhancement)						Yes		
HV	**Switchgear**	**20 kV Switch (PM)**						
Dismantle, remove and dispose of existing sectionaliser								
Supply and install new sectionaliser								
Supply and install HV earthwire (assuming original CB was unearthed)			Yes					
Dismantle, remove and dispose of existing radio and RTU for remote control functionality (where radio and RTU existed previously)			Yes					
Supply and install radio and RTU for remote control functionality (where radio and RTU existed previously)			Yes					
Supply and install radio and RTU for remote control functionality (where no radio or RTU existed previously)						Yes		

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HV	**Switchgear**	**20 kV Other PM Switchgear**						
Dismantle, remove and dispose of existing Other HV PM switchgear (e.g. ABI, ABSD, ASL & HV PM fuse)								
Supply and install new Other HV PM Switchgear (e.g. ABI, ABSD, ASL & HV PM fuse)								
HV	**Switchgear**	**20 kV Switch (GM)**						
Supply and install replacement 20 kV GM switch			Yes	Yes				
Dismantle, remove and dispose of existing 20 kV switchgear (e.g. GM switch, RMU & GM CB)			Yes	Yes				
Supply & Install 20 kV UG Cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off 20 kV Joint(s)			Yes					
Terminate 20 kV UG cable into GM switch			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Modification to concrete plinth/base (including where appropriate complete new plinths and break of existing plinth)						Yes		
Modify substation surround/Supply and install substation enclosure						Yes		
Fit actuator, RTU etc for remote operation						Yes		
HV	**Switchgear**	**20 kV RMU**						
Supply and Install Replacement 20 kV RMU			Yes	Yes				
Dismantle, remove and dispose of existing 20 kV switchgear (e.g. GM switch, RMU & GM CB)			Yes	Yes				
Supply & Install 20 kV UG Cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off 20 kV Joint(s)			Yes					
Terminate 20 kV UG cable into RMU			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Modification to concrete plinth/base (including where appropriate complete new plinths and break of existing plinth)						Yes		
Modify substation surround/Supply and install substation enclosure						Yes		
Fit actuator, RTU etc for remote operation						Yes		

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HV	**Transformer**	**6.6/11 kV Transformer (PM)**						
Dismantle existing 6.6/11 kV transformer (either pole mounted or ground mounted)			Yes	Yes				
Supply and installl replacement pole mounted 6.6/11 kV transformer			Yes	Yes				
Renew LV fusegear and associated wiring			Yes					
Make off HV & LV connections			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Replace existing HV pole (if required and irrespective of driver)						Yes	Yes	
HV	**Transformer**	**6.6/11 kV Transformer (GM)**						
Dismantle existing 6.6/11 kV transformer (either pole mounted or ground mounted)			Yes	Yes				
Supply and install replacement 6.6/11 kV GM transformer			Yes	Yes				
Connect LV switchgear/equipment to transformer (e.g. cable box or transformer mounted pillar)			Yes					
Connect HV switchgear/equipment to transformer (e.g. cable box or transformer mounted RMU)			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Modification to concrete plinth/base (including where appropriate complete new plinths and break of existing plinth)						Yes		
Modify substation surround/Supply and install substation enclosure						Yes		
HV	**Transformer**	**20 kV Transformer (PM)**						
Dismantle existing 20 kV transformer (either pole mounted or ground mounted)			Yes	Yes				
Supply and installl replacement pole mounted 20 kV transformer			Yes	Yes				
Renew LV fusegear and associated wiring			Yes					
Make off HV & LV connections			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Replace existing HV pole (if required and irrespective of driver)						Yes	Yes	

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HV	**Transformer**	**20 kV Transformer (GM)**						
Dismantle existing 6.6/11 kV transformer (either pole mounted or ground mounted)			Yes	Yes				
Supply and install replacement 6.6/11 kV GM transformer			Yes	Yes				
Connect LV switchgear/equipment to transformer (e.g. cable box or transformer mounted pillar)			Yes					
Connect HV switchgear/equipment to transformer (e.g. cable box or transformer mounted RMU)			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Modification to concrete plinth/base (including where appropriate complete new plinths and break of existing plinth)						Yes		
Modify substation surround/Supply and install substation enclosure						Yes		
EHV	**Overhead Pole Line**	**33 kV Wood Pole Overhead Line Conductor Replacement**						
Dismantle, remove and dispose of existing EHV wood pole OH line conductor			Yes	Yes				
Supply and erect replacement EHV wood pole OH line conductor			Yes	Yes				
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Undertake any necessary tree cutting			Yes					
Remove and dispose of existing EHV insulators						Yes		Yes
Supply and fit replacement EHV insulators						Yes		Yes
Replacement of poles						Yes	Yes	
Installation of additional poles						Yes	Yes	

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EHV	**Overhead Pole Line**	**33 kV Pole Replacement**						
Dismantle, remove and dispose of existing pole (where appropriate)			Yes	Yes				
Excavate pole hole			Yes					
Dress and erect new (additional or replacement) pole (including cross arm and insulators etc)			Yes	Yes				
Undertake any necessary tree cutting			Yes					
Excavate stay holes			Yes					
Renew stays (where required)			Yes					
Dismantle cross bracing (on H poles)			Yes					
Supply and fit replacement cross bracing (on H poles)			Yes					
Dismantle, remove and dispose of existing 33 kV UG cable and associated pole box (where appropriate)			Yes		Yes			
Excavate joint hole (where appropriate)			Yes					
Supply and make of replacement 33 kV UG cable pole box (where appropriate)			Yes					
Supply and make of 33 kV UG cable joint at base of pole (where appropriate)			Yes					
Supply and erect 33 kV UG cable and associated pole box (where appropriate)			Yes		Yes			
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
EHV	**Overhead Pole Line**	**66 kV Wood Pole Overhead Line Conductor Replacement**						
Dismantle, remove and dispose of existing EHV wood pole OH line conductor			Yes	Yes				
Supply and erect replacement EHV wood pole OH line conductor			Yes	Yes				
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Undertake any necessary tree cutting			Yes					
Remove and dispose of existing EHV insulators						Yes		Yes
Supply and fit replacement EHV insulators						Yes		Yes
Replacement of poles						Yes	Yes	
Installation of additional poles						Yes	Yes	

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EHV	**Overhead Pole Line**	**66 kV Pole Replacement**						
Dismantle, remove and dispose of existing pole (where appropriate)			Yes	Yes				
Excavate pole hole			Yes					
Dress and erect new (additional or replacement) pole (including cross arm and insulators etc)			Yes	Yes				
Undertake any necessary tree cutting			Yes					
Excavate stay holes			Yes					
Renew stays (where required)			Yes					
Dismantle cross bracing (on H poles)			Yes					
Supply and fit replacement cross bracing (on H poles)			Yes					
Dismantle, remove and dispose of existing 66 kV UG cable and associated pole box (where appropriate)			Yes		Yes			
Excavate joint hole (where appropriate)			Yes					
Supply and make of replacement 66 kV UG cable pole box (where appropriate)			Yes					
Supply and make of 66 kV UG cable joint at base of pole (where appropriate)			Yes					
Supply and erect 66 kV UG cable and associated pole box (where appropriate)			Yes		Yes			
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
EHV	**Overhead Pole Line**	**33 kV Pole Refurbishment**						
Principle here is that the costs collected relate to activities that does not result in the addition or disposal of a pole. When number of qualifying task are undertaken on single pole, the activity count would be one refurbished pole.								
Tasks that qualify as pole refurbishment include:								
Remove and dispose of existing cross arm and insulators (when undertaken independently of pole replacement)						Yes		Yes
Supply and fit replacement cross arm and insulators (when undertaken independently of pole replacement)						Yes		Yes
Supply and install a replacement stay (when undertaken independently of pole replacement)						Yes		Yes
Supply & fit pole bandages/splints etc						Yes		Yes
Tasks that do not qualify as pole refurbishment include:								
Replacement of signs, notices and anti-climbing guards when undertaken independently of tasks that qualify as pole refurbishment						Yes		
Insertion of boron rods when undertaken independently of tasks that qualify as pole refurbishment						Yes		

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET REPLACEMENT	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN ADDITION OR DISPOSAL OF ASSET
EHV	**Overhead Pole Line**	**66 kV Pole Refurbishment**						
Principle here is that the costs collected relate to activities that does not result in the addition or disposal of a pole. When number of qualifying task are undertaken on single pole, the activity count would be one refurbished pole.								
Tasks that qualify as pole refurbishment include:								
Remove and dispose of existing cross arm and insulators (when undertaken independently of pole replacement)						Yes		Yes
Supply and fit replacement cross arm and insulators (when undertaken independently of pole replacement)						Yes		Yes
Supply and install a replacement stay (when undertaken independently of pole replacement)						Yes		Yes
Supply & fit pole bandages/splints etc						Yes		Yes
Tasks that do not qualify as pole refurbishment include:								
Replacement of signs, notices and anti-climbing guards when undertaken independently of tasks that qualify as pole refurbishment						Yes		
Insertion of boron rods when undertaken independently of tasks that qualify as pole refurbishment						Yes		

EHV	**Overhead Tower Line**	**33kV OHL (Tower Line) Conductor Replacement**						
Dismantle, remove and dispose of existing EHV tower line OH conductor			Yes	Yes				
Supply and erect replacement EHV tower line OH conductor			Yes	Yes				
Dismantle, remove and dispose of existing aerial earthwire			Yes					
Supply and erect replacement areial earth wire			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Undertake any necessary tree cutting			Yes					
Remove and dispose of existing EHV insulator sets			Yes		Yes			
Supply and fit replacement EHV insulator sets			Yes		Yes			
Provision and use of mechanical aids, scaffolding etc			Yes					

EHV	**Overhead Tower Line**	**33 kV Tower Line Fittings**						
Dismantle, remove and dispose of existing insulator sets			Yes	Yes				
Supply and erect new or replacement insulator sets			Yes	Yes				
Undertake any necessary tree cutting			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Provision and use of mechanical aids, scaffolding etc			Yes					

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET REPLACEMENT	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN ADDITION OR DISPOSAL OF ASSET
EHV	**Overhead Tower Line**	**33kV Tower (Complete Replacement)**						
Dismantle, remove and dispose of existing tower			Yes					
Supply erect new or replacmement tower			Yes					
Dismantle, remove and dispose of existing insulator sets			Yes		Yes			
Supply and erect new or replacement insulator sets			Yes		Yes			
Undertake any necessary tree cutting			Yes					
Break up existing foundations and make good ground (where appropriate)			Yes					
Excavate and install new or replacement tower foundations (where appropriate)			Yes					
Lower and re-erect existing conductors (where appropriate)			Yes					
Temporarily divert existing conductors			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Provision and use of mechanical aids, scaffolding etc			Yes					
EHV	**Overhead Tower Line**	**66kV OHL (Tower Line) Conductor Replacement**						
Dismantle, remove and dispose of existing EHV tower line OH conductor			Yes	Yes				
Supply and erect replacement EHV tower line OH conductor			Yes	Yes				
Dismantle, remove and dispose of existing aerial earthwire			Yes					
Supply and erect replacement areial earth wire			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Undertake any necessary tree cutting			Yes					
Remove and dispose of existing EHV insulator sets			Yes		Yes			
Supply and fit replacement EHV insulator sets			Yes		Yes			
Provision and use of mechanical aids, scaffolding etc			Yes					
EHV	**Overhead Tower Line**	**66 kV Tower Line Fittings**						
Dismantle, remove and dispose of existing insulator sets			Yes	Yes				
Supply and erect new or replacement insulator sets			Yes	Yes				
Undertake any necessary tree cutting			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Provision and use of mechanical aids, scaffolding etc			Yes					

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EHV	**Overhead Tower Line**	**66kV Tower (Complete Replacement)**						
Dismantle, remove and dispose of existing tower			Yes					
Supply erect new or replacmement tower			Yes					
Dismantle, remove and dispose of existing insulator sets			Yes		Yes			
Supply and erect new or replacement insulator sets			Yes		Yes			
Undertake any necessary tree cutting			Yes					
Break up existing foundations and make good ground (where appropriate)			Yes					
Excavate and install new or replacement tower foundations (where appropriate)			Yes					
Lower and re-erect existing conductors (where appropriate)			Yes					
Temporarily divert existing conductors			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Provision and use of mechanical aids, scaffolding etc			Yes					
EHV	**Overhead Tower Line**	**33 kV Tower (Refurbishment)**						
Principle here is that the costs collected relate to activities that does not result in the addition or disposal of a tower. When number of qualifying task are undertaken on single tower, the activity count would be one refurbished tower.								
Tasks that qualify as tower refurbishment include:								
Remove and dispose of existing defective steelwork						Yes		Yes
Supply and fit replacement steelwork						Yes		Yes
Tasks that do not qualify as tower refurbishment include:								
Replacement of signs, notices and anti-climbing guards when undertaken independently of tasks that qualify as tower refurbishment						Yes		
Tower painting						Yes		
Strengthening of foundations						Yes		
EHV	**Overhead Tower Line**	**66 kV Tower (Refurbishment)**						
Principle here is that the costs collected relate to activities that does not result in the addition or disposal of a tower. When number of qualifying task are undertaken on single tower, the activity count would be one refurbished tower.								
Tasks that qualify as tower refurbishment include:								
Remove and dispose of existing defective steelwork						Yes		Yes
Supply and fit replacement steelwork						Yes		Yes
Tasks that do not qualify as tower refurbishment include:								
Replacement of signs, notices and anti-climbing guards when undertaken independently of tasks that qualify as tower refurbishment						Yes		
Tower painting						Yes		
Strengthening of foundations						Yes		

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EHV	**Overhead Tower Line**	**33 kV Tower Foundation Strengthening**						
Break up existing foundations and make good ground (where appropriate)						Yes		Yes
Excavate and install new or replacement tower foundations (where appropriate)						Yes		Yes
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)						Yes		Yee
Provision and use of mechanical aids, scaffolding etc						Yes		Yes
EHV	**Overhead Tower Line**	**66 kV Tower Foundation Strengthening**						
Break up existing foundations and make good ground (where appropriate)						Yes		Yes
Excavate and install new or replacement tower foundations (where appropriate)						Yes		Yes
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)						Yes		Yee
Provision and use of mechanical aids, scaffolding etc						Yes		Yes
EHV	**Cable**	**33kV UG Cable (Non Pressurised)**						
Supply & Install 33 kV non pressurised UG Cable			Yes	Yes				
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & installation of cable ducting as required			Yes					
Supply & Make Off 33 kV Joint(s) and terminations			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Fully decommission redundant 33 kV cable (pressurised and non pressurised)			Yes	Yes				
Dismantle, remove and dispose of pressurised oil tanks etc.			Yes					
Supply and install 19 pair pilot cable			Yes		Yes			
Supply and make off pilot cable joints and terminations			Yes					
EHV	**Cable**	**66kV UG Cable (Non Pressurised)**						
Supply & Install 66 kV non pressurised UG Cable			Yes	Yes				
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & installation of cable ducting as required			Yes					
Supply & Make Off 66 kV Joint(s) and terminations			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Fully decommission redundant 66 kV cable (pressurised and non pressurised)			Yes	Yes				
Dismantle, remove and dispose of pressurised oil tanks etc.			Yes					
Supply and install 19 pair pilot cable			Yes		Yes			
Supply and make off pilot cable joints and terminations			Yes					

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EHV	**Cable**	**EHV Sub Cable**						
Supply and install EHV submarine cable			Yes	Yes				
Vessel mobilisation/demobilisation			Yes					
Dive team mobilisation/demobilisation			Yes					
Environmental studies			Yes					
Jointers mobilisation/demobilisation			Yes					
Ploughing or post lay burial jetting.			Yes					
Protection where burial not achieved.			Yes					
Transistion Jointing on shore			Yes					
Shore end protection burial			Yes					
Tide and weather delays			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
EHV	**Switchgear**	**33 KV CB (ID)**						
Supply and install replacement 33 kV Indoor circuit breaker (including protection relays and SCADA interface)			Yes	Yes				
Dismantle, remove and dispose of existing 33 kV CB (either indoor or outdoor including protection relays and SCADA interface)			Yes	Yes				
Supply & Install 33 kV UG Cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off 33 kV Joint(s)			Yes					
Terminate 33 kV UG cable into circuit breaker			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Supply and install replacement multicore cable			Yes					
Make off multicore terminations			Yes					
Dismantle, remove and dispose of existing multicore cable			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Supply & install replacement battery and associated charger			Yes		Yes			
Dismantle, remove and dispose of existing battery and associated charger			Yes		Yes			
Construction of new switchroom/demolition of existing switchroom/Modification to switchroom						Yes		

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EHV	**Switchgear**	**33 kV CB (OD)**						
Dismantle, remove and dispose of existing 33 kV CB and associated structures			Yes	Yes				
Dismantle, remove and dispose of 33 kV isolators and associated structures			Yes					
Dismantle, remove and dispose of existing 33 kV busbars and associated structures			Yes					
Supply and install replacement 33 kV outdoor circuit breaker and associated structures			Yes	Yes				
Modification to concrete plinth/base (including where appropriate complete new plinths and break of existing plinth)						Yes		
Supply and install 33 kV isolators and associated structures			Yes					
Supply and install 33 kV busbars and associated structures			Yes					
Supply and install replacement multicore cable			Yes					
Make off multicore terminations			Yes					
Dismantle, remove and dispose of existing multicore cable			Yes					
Supply and install replacement control/protection panel			Yes					
Remove existing control/protection panel			Yes					
Supply & install replacement battery and associated charger			Yes		Yes			
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
EHV	**Switchgear**	**33 kV Switch (GM)**						
Supply and install replacement 33 kV GM switch (including SCADA interface)			Yes	Yes				
Dismantle, remove and dispose of existing 33 kV switchgear			Yes	Yes				
Supply & Install 33 kV UG Cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off 33 kV Joint(s)			Yes					
Terminate 33 kV UG cable into switch			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Construction of new switchroom/demolition of existing switchroom/Modification to switchroom/Modification to plinth						Yes		

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EHV	**Switchgear**	**33 kV Switch (PM)**						
						Yes		
						Yes		
						Yes		
						Yes		
						Yes		
						Yes		
EHV	**Switchgear**	**33 kV RMU**						
Supply and install replacement 33 kV RMU (including SCADA interface)			Yes	Yes				
Dismantle, remove and dispose of existing 33 kV switchgear			Yes	Yes				
Supply & Install 33 kV UG Cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off 33 kV Joint(s)			Yes					
Terminate 33 kV UG cable into RMU			Yes					
Supply and install replacement multicore cable			Yes					
Make off multicore terminations			Yes					
Dismantle, remove and dispose of existing multicore cable			Yes					
Supply and install replacement control/protection panel			Yes					
Remove existing control/protection panel			Yes					
Supply & install replacement battery and associated charger			Yes		Yes			
Dismantle, remove and dispose of existing battery and associated charger			Yes		Yes			
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Construction of new switchroom/demolition of existing switchroom/Modification to switchroom/Modification to plinth						Yes		

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EHV	**Switchgear**	**66 KV CB (ID)**						
Supply and install replacement 66 kV Indoor circuit breaker (including protection relays and SCADA interface)			Yes	Yes				
Dismantle, remove and dispose of existing 66 kV CB (either indoor or outdoor including protection panels, relays and SCADA interface)			Yes	Yes				
Supply & Install 66 kV UG Cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off 66 kV Joint(s)			Yes					
Terminate 66 kV UG cable into circuit breaker			Yes					
Supply and install replacement multicore cable			Yes					
Make off multicore terminations			Yes					
Dismantle, remove and dispose of existing multicore cable			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Supply & install replacement battery and associated charger			Yes		Yes			
Dismantle, remove and dispose of existing battery and associated charger			Yes		Yes			
Construction of new switchroom/demolition of existing switchroom/Modification to switchroom						Yes		
EHV	**Switchgear**	**66 KV CB (OD)**						
Dismantle, remove and dispose of existing 66 kV CB and associated structures			Yes	Yes				
Dismantle, remove and dispose of 66 kV isolators and associated structures			Yes					
Dismantle, remove and dispose of existing 66 kV busbars and associated structures			Yes					
Supply and install replacement 66 kV outdoor circuit breaker and associated structures			Yes	Yes				
Modification to concrete plinth/base (including where appropriate complete new plinths and break of existing plinth)						Yes		
Supply and install 66 kV isolators and associated structures			Yes					
Supply and install 66 kV busbars and associated structures			Yes					
Supply and install replacement multicore cable			Yes					
Make off multicore terminations			Yes					
Dismantle, remove and dispose of existing multicore cable			Yes					
Supply and install replacement control/protection panel			Yes					
Remove existing control/protection panel			Yes					
Supply & install replacement battery and associated charger			Yes		Yes			
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					

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EHV	**Transformer**	**33 kV Transformer (PM)**						
Dismantle existing 33 kV transformer (either pole mounted or ground mounted)			Yes	Yes				
Supply and installl replacement pole mounted 33 kV transformer			Yes	Yes				
Renew LV fusegear and associated wiring			Yes					
Make off EHV & LV connections			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Replace existing HV pole (if required and irrespective of driver)						Yes	Yes	

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EHV	**Transformer**	**33 kV Transformer (GM)**						
Supply and install 33 kV GM power transformer			Yes	Yes				
Dismantle, remove and dispose of existing power transformer			Yes	Yes				
Supply and install 33 kV earthing transformer/reactor/resistor			Yes					
Dismantle existing earthing transformer/reactor/resistor			Yes					
Supply and install replacement multicore cable			Yes					
Make off multicore terminations			Yes					
Remove existing multicore cable			Yes					
Supply and install replacement AVC/control & protection panel			Yes					
Remove existing AVC/control & protection panel			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab etc to aid plant installation			Yes					
For cable connected transformers						Yes		
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Install 33 kV Interplant cables			Yes		Yes			
Supply & make off 33 kV cable terminations			Yes					
Supply & make off 33 kV cable joints			Yes					
Supply & install secondary interplant cables (6.6 kV, 11 kV & 20 kV)			Yes		Yes			
Supply & make off secondary cable terminations (6.6 kV, 11 kV & 20 kV)			Yes					
Supply & make off secondary cable joints (6.6 kV, 11 kV & 20 kV)			Yes					
For overhead connected transformers						Yes		
Dismantle, remove and dispose of existing 33 kV OH terminations (inc busbars and supports)			Yes					
Supply & Make Off 33 kV OH terminations (inc busbars and supports)			Yes					
Dismantle, remove and dispose of existing secondary OH terminations (inc busbars and supports)			Yes					
Supply & Make Off secondary OH terminations (inc busbars and supports)			Yes					
Modification to concrete plinths/bases (including where appropriate complete new plinths and break of existing plinths)						Yes		
Construct/refurbish oil bund						Yes		
Dismantlement/modification/reconstruction of noise enclosures						Yes		
Modification of site walls						Yes		

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EHV	**Transformer**	**66 kV Transformer**						
Supply and install 66 kV GM power transformer			Yes	Yes				
Dismantle, remove and dispose of existing power transformer			Yes	Yes				
Supply and install 66 kV earthing transformer/reactor/resistor			Yes					
Dismantle existing earthing transformer/reactor/resistor			Yes					
Supply and install replacement multicore cable			Yes					
Make off multicore terminations			Yes					
Remove existing multicore cable			Yes					
Supply and install replacement AVC/control & protection panel			Yes					
Remove existing AVC/control & protection panel			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab etc to aid plant installation			Yes					
For cable connected transformers						Yes		
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Install 66 kV Interplant cables			Yes		Yes			
Supply & make off 66 kV cable terminations			Yes					
Supply & make off 66 kV cable joints			Yes					
Supply & install secondary interplant cables (6.6 kV, 11 kV & 20 kV)			Yes		Yes			
Supply & make off secondary cable terminations (6.6 kV, 11 kV & 20 kV)			Yes					
Supply & make off secondary cable joints (6.6 kV, 11 kV & 20 kV)			Yes					
For overhead connected transformers						Yes		
Dismantle, remove and dispose of existing 66 kV OH terminations (inc busbars and supports)			Yes					
Supply & Make Off 66 kV OH terminations (inc busbars and supports)			Yes					
Modification to concrete plinths/bases (including where appropriate complete new plinths and break of existing plinths)						Yes		
Construct/refurbish oil bund						Yes		
Dismantlement/modification/recoonstruction of noise enclosures						Yes		
Modification of site walls						Yes		

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132kV	**Overhead Pole Line**	**132kV OHL Conductor (Pole Line) Conductor Replacement**						
Dismantle, remove and dispose of existing 132 kV wood pole OH line conductor			Yes	Yes				
Supply and erect replacement 132 kV wood pole OH line conductor			Yes	Yes				
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Undertake any necessary tree cutting			Yes					
Remove and dispose of existing 132 kV insulators						Yes		Yes
Supply and fit replacement 132 kV insulators						Yes		Yes
Replacement of poles						Yes	Yes	
Installation of additional poles						Yes	Yes	
132kV	**Overhead Pole Line**	**132kV Pole Replacement**						
Dismantle, remove and dispose of existing pole (where appropriate)			Yes	Yes				
Excavate pole hole			Yes					
Dress and erect new (additional or replacement) pole (including cross arm and insulators etc)			Yes	Yes				
Undertake any necessary tree cutting			Yes					
Excavate stay holes			Yes					
Renew stays (where required)			Yes					
Dismantle cross bracing (on H poles)			Yes					
Supply and fit replacement cross bracing (on H poles)			Yes					
Dismantle, remove and dispose of existing 132 kV UG cable and associated cable termination (where appropriate)			Yes		Yes			
Excavate joint hole (where appropriate)			Yes					
Supply and make off replacement 132 kV pole top UG cable termination (where appropriate)			Yes		Yes			
Supply and make of 132 kV UG cable joint at base of pole (where appropriate)			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					

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132kV	**Overhead Pole Line**	**132kV Pole Refurbishment**						
Principle here is that the costs collected relate to activities that does not result in the addition or disposal of a pole. When number of qualifying task are undertaken on single pole, the activity count would be one refurbished pole.								
Tasks that qualify as pole refurbishment include:								
Remove and dispose of existing cross arm and insulators (when undertaken independently of pole replacement)						Yes		Yes
Supply and fit replacement cross arm and insulators (when undertaken independently of pole replacement)						Yes		Yes
Supply and install a replacement stay (when undertaken independently of pole replacement)						Yes		Yes
Supply & fit pole bandages/splints etc						Yes		Yes
Tasks that do not qualify as pole refurbishment include:								
Replacement of signs, notices and anti-climbing guards when undertaken independently of tasks that qualify as pole refurbishment						Yes		
Insertion of boron rods when undertaken independently of tasks that qualify as pole refurbishment						Yes		

132kV	**Overhead Tower Line**	**132kV OHL (Tower Line) Conductor Replacement**						
Dismantle, remove and dispose of existing 132 kV tower line OH conductor			Yes	Yes				
Supply and erect replacement 132 kV tower line OH conductor			Yes	Yes				
Dismantle, remove and dispose of existing aerial earthwire			Yes					
Supply and erect replacement areial earth wire			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Undertake any necessary tree cutting			Yes					
Remove and dispose of existing 132 kV insulator sets			Yes		Yes			
Supply and fit replacement 132 kV insulator sets			Yes		Yes			
Provision and use of mechanical aids, scaffolding etc			Yes					

132kV	**Overhead Tower Line**	**132kV Tower (Complete Replacement)**						
Dismantle, remove and dispose of existing tower			Yes					
Supply erect new or replacmement tower			Yes					
Dismantle, remove and dispose of existing insulator sets			Yes		Yes			
Supply and erect new or replacement insulator sets			Yes		Yes			
Undertake any necessary tree cutting			Yes					
Break up existing foundations and make good ground (where appropriate)			Yes					
Excavate and install new or replacement tower foundations (where appropriate)			Yes					
Lower and re-erect existing conductors (where appropriate)			Yes					
Temporarily divert existing conductors			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Provision and use of mechanical aids, scaffolding etc			Yes					

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET REPLACEMENT	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN ADDITION OR DISPOSAL OF ASSET
132kV	**Overhead Tower Line**	**132kV Fittings (Tower Line)**						
Dismantle, remove and dispose of existing insulator sets			Yes	Yes				
Supply and erect new or replacement insulator sets			Yes	Yes				
Undertake any necessary tree cutting			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Provision and use of mechanical aids, scaffolding etc			Yes					
132kV	**Overhead Tower Line**	**132kV Tower (Refurbishment)**						
Principle here is that the costs collected relate to activities that does not result in the addition or disposal of a tower. When number of qualifying task are undertaken on single tower, the activity count would be one refurbished tower.								
Tasks that qualify as tower refurbishment include:								
Remove and dispose of existing defective steelwork						Yes		Yes
Supply and fit replacement steelwork						Yes		Yes
Tasks that do not qualify as tower refurbishment include:								
Replacement of signs, notices and anti-climbing guards when undertaken independently of tasks that qualify as tower refurbishment						Yes		
Tower painting						Yes		
Strengthening of foundations						Yes		
132kV	**Overhead Tower Line**	**132kV Tower Foundation Strengthening**						
Break up existing foundations and make good ground (where appropriate)						Yes		Yes
Excavate and install new or replacement tower foundations (where appropriate)						Yes		Yes
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)						Yes		Yee
Provision and use of mechanical aids, scaffolding etc						Yes		Yes
132kV	**Cable**	**132kV UG Cable (Non Pressurised)**						
Supply & Install 132 kV non pressurised UG Cable			Yes	Yes				
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & installation of cable ducting as required			Yes					
Supply & Make Off 132 kV Joint(s) and terminations			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Fully decommission redundant pressurised 132 kV cable			Yes	Yes				
Supply and install 19 pair pilot cable						Yes		
Supply and make off pilot cable joints and terminations						Yes		

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET REPLACEMENT	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN ADDITION OR DISPOSAL OF ASSET
132kV	**Cable**	**132kV UG Cable (Oil)**						
Not applicable								
132kV	**Cable**	**132kV UG Cable (Gas)**						
Not applicable								
132kV	**Switchgear**	**132 kV CB (ID)**						
Supply and install replacement 132 kV Indoor circuit breaker (including protection relays and SCADA interface)			Yes	Yes				
Dismantle, remove and dispose of existing 132 kV CB (either indoor or outdoor including protection panels, relays and SCADA interface)			Yes	Yes				
Supply & Install 132 kV UG Cable			Yes		Yes			
Supply & installation of cable ducting as required			Yes					
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Make Off 132 kV Joint(s)			Yes					
Terminate 132 kV UG cable into circuit breaker			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab to aid plant installation			Yes					
Supply & install replacement battery and associated charger			Yes		Yes			
Dismantle, remove and dispose of existing battery and associated charger			Yes		Yes			
Construction of new switchroom/demolition of existing switchroom/Modification to switchroom						Yes		

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET REPLACEMENT	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN ADDITION OR DISPOSAL OF ASSET
132kV	**Switchgear**	**133 kV CB (OD)**						
Dismantle, remove and dispose of existing 132 kV CB and associated structures			Yes	Yes				
Dismantle, remove and dispose of 132 kV isolators and associated structures			Yes					
Dismantle, remove and dispose of existing 132 kV busbars and associated structures			Yes					
Supply and install replacement 132 kV outdoor circuit breaker and associated structures			Yes	Yes				
Modification to concrete plinth/base (including where appropriate complete new plinths and break of existing plinth)						Yes		
Supply and install 132 kV isolators and associated structures			Yes					
Supply and install 132 kV busbars and associated structures			Yes					
Supply and install replacement multicore cable			Yes					
Make off multicore terminations			Yes					
Remove existing multicore cable			Yes					
Supply and install replacement control/protection panel			Yes					
Remove existing control/protection panel			Yes					
Supply & install replacement battery and associated charger			Yes		Yes			
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					

			COSTS WITHIN SCOPE OF REPLACING PRIME ASSET	REPORT AS PRIME ASSET	REPORT AS CONSEQUENTIAL ASSET	COSTS OUTSIDE SCOPE OF REPLACING PRIME ASSET	REPORT COSTS AND ACTIVITY AS SEPARATE PRIME ASSET REPLACEMENT	REPORT COSTS AND ACTIVITY AS SEPARATE ACTIVITY THAT DOES NOT RESULT IN ADDITION OR DISPOSAL OF ASSET
132kV	**Transformer**	**132 kV Transformer**						
Supply and install 132 kV power transformer			Yes	Yes				
Dismantle, remove and dispose of existing power transformer (either 132 kV, 66 kv or 33 kV)			Yes	Yes				
Supply and install 132 kV earthing transformer/reactor/resistor			Yes					
Dismantle existing earthing transformer/reactor/resistor (either 33 kV , 66 kV or 33 kV)			Yes					
Supply and install replacement multicore cable			Yes					
Make off multicore terminations			Yes					
Remove existing multicore cable			Yes					
Supply and install replacement AVC/control & protection panel			Yes					
Remove existing AVC/control & protection panel			Yes					
Associated network operations (Switching, linking, use of mobile generation, issuing safety documentation, pre-commissioning tests and energisation)			Yes					
Delivery of plant to site and use of crane/hiab etc to aid plant installation			Yes					
						Yes		
For cable connected transformers						Yes		
All trench excavation, backfilling & reinstatement (including joint holes)			Yes					
Supply & Install 132 kV Interplant cables			Yes		Yes			
Supply & make off 132 kV cable terminations			Yes					
Supply & make off 132 kV cable joints			Yes					
Supply & install secondary interplant cables (66 kV, 33 kV & 11 KV)			Yes		Yes			
Supply & make off secondary cable terminations (66 kV, 33 kV & 11 KV)			Yes					
Supply & make off secondary cable joints (66 kV, 33 kV & 11 KV)			Yes					
						Yes		
For overhead connected transformers						Yes		
Dismantle, remove and dispose of existing 132 kV OH terminations (inc busbars and supports)			Yes					
Supply & Make Off 132 kV OH terminations (inc busbars and supports)			Yes					
Dismantle, remove and dispose of existing secondary OH terminations (inc busbars and supports)			Yes					
Supply & Make Off secondary OH terminations (inc busbars and supports)			Yes					
						Yes		
						Yes		
Modification to concrete plinths/bases (including where appropriate complete new plinths and break of existing plinths)						Yes		
Construct/refurbish oil bund						Yes		
Dismantlement/modification/recoonstruction of noise enclosures						Yes		
Modification of site walls						Yes		

Appendix 3 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[40]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[41].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of existing and future consumers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- the need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- the need to secure that all reasonable demands for electricity are met;
- the need to secure that licence holders are able to finance the activities which are the subject of obligations on them[42];
- the need to contribute to the achievement of sustainable development; and

[40] entitled "Gas Supply" and "Electricity Supply" respectively.
[41] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[42] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.

- the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[43]

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- promote efficiency and economy on the part of those licensed[44] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity; and
- secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- the effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[45] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[43] The Authority may have regard to other descriptions of consumers.
[44] or persons authorised by exemptions to carry on any activity.
[45] Council Regulation (EC) 1/2003

Appendix 4 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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