RIIO-ED1 RIGs Environment and Innovation Commentary, version 5.0

2018-19

Electricity North West

Contents

Summary – Information Required	1
Worksheet by worksheet commentary	1
E1 – Visual Amenity	2
E2 – Environmental Reporting	2
E3 –BCF	5
E4 – Losses Snapshot	15
E5 – Smart Metering	21
E6 – Innovative Solutions	24
E7 – LCTs	33

Summary – Information Required

One Commentary document is required per DNO Group. Respondents should ensure that comments are clearly marked to show whether they relate to all the DNOs in the group or to which DNO they relate.

Commentary is required in response to specific questions included in this document. DNO's may include supporting documentation where they consider it necessary to support their comments or where it may aid Ofgem's understanding. Please highlight in this document if additional information is provided.

The purpose of this commentary is to provide the opportunity for DNOs to set out further supporting information related to the data provided in the Environment and Innovation Reporting Pack. It also sets out supporting data submissions that DNOs must provide to us.

Worksheet by worksheet commentary

At a worksheet by worksheet level there is one standard question to address, where appropriate, as follows:

- **Allocation and estimation methodologies**: DNOs should detail estimates, allocations or apportionments used in reaching the numbers submitted in the worksheets.

  This is required for all individual worksheets (ie not an aggregate level), where relevant. Not all tables will have used allocation or estimation methods to reach the numbers. Where this is the case simply note "NA".

  Note: this concerns the methodology and assumptions and not about the systems in place to check their accuracy (that is for the NetDAR). This need to be completed for all worksheets, where an allocation or estimation technique was used.

In addition to the standard commentary questions, some questions specific to each worksheet are asked.

E1 – Visual Amenity

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
All expenditure on Electricity North West Limited projects is allocated on a percentage basis to a series of investment drivers. Allocations are calculated by Project Managers based on the respective costs of project deliverables. Volumes are also recorded on projects in a way that indicates the driver. Undergrounding for Visual Amenity is identified as a separate driver and specific projects are raised for these schemes of work. The costs recorded in our project management database differed from those recorded in CV20 by £4,300. The value in cell V58 of table E1 has been reduced by this amount to ensure that the two tables match.

Explanation of the increase or decrease in the total length of OHL inside designated areas for reasons other than those recorded in worksheet E1. For example, due to the expansion of an existing, or creation of a new, Designated Area.
N/A

E2 – Environmental Reporting

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
All expenditure on Electricity North West Limited projects is allocated on a percentage basis to a series of investment drivers including environment. Cost allocations are calculated by Project Managers based on the respective costs of project deliverables. Volumes are also recorded on projects in a way that indicates the driver. Environmental investment is identified as a separate driver within the classification system with associated costs and volumes allocated accordingly. Data associated with the new categories of persistent organic pollutants was not captured in 2018-19 as these categories are new. Primary spend drivers will be established to capture it going forward. So that the total cost in cell T21 matches cell U17 of table CV22 in the C&V pack, credit adjustments for small tools and equipment, changes in contractor and increased pension costs, of £3,396 were subtracted from cell T12. **Fluid Filled Cables** The total for fluid filled cable in service (cell AK24) was calculated by adding together the asset volumes for 2018/19 for 33kV UG Cable (Oil) and 132kV UG Cable (Oil) from table V1. The volumes were 249.97km of 33kV cable (cell BT86 of V1) and 146.65km of 132kV cable (cell BT116 of V1) giving a total for fluid filled cable in service of 396.62km.

To calculate the volume of oil in service, the following assumptions were used:

- 33kV single core cable = 1,560 litres per km
- 33kV three core cable = 1,300 litres per km
- 33kV cable = 1.1835 tanks per km
- 33kV average volume per tank of 173.525 litres
- 30km only of 33kV single core cable
- 132kV single core cable = 4,800 litres per km
- 132kV three core cable = 4,000 litres per km
- 132kV cable = 1.7605 tanks per km
- 132kV average volume per tank of 337.985 litres
- 44km only of 132kV single core cable

The oil in service in cables was then calculated as follows:

- 249.97km of 33 kV cable = 219.97km of three core and 30km of single core
    - 30km of single core x 1,560 litres per km = 46,800 litres of oil
    - 219.97km of three core x 1,300 litres per km = 285,961 litres of oil
    - 249.97km of 33kV cable x 1.1835 tanks per km x 173.525 litres per tank = 51,335.55 litres of oil

- 146.65km of 132kV cable = 102.65km of three core and 44km of single core
    - 44 km of single core x 4,800 litres per km = 211,200 litres of oil
    - 102.65km of three core x 4,000 litres per km = 410,600 litres of oil
    - 146.65km of 132kV cable x 1.7605 tanks per km x 337.985 litres per tank = 87,260.06 litres of oil

- Total of 46,800 + 285,961 + 51,335.55 + 211,200 + 410,600 + 87,260.06 = 1,093,156.61 litres of oil in service (cell AK25).

The figure for fluid used to top up cables (55,829 litres) (cell AK26) is held in our top-ups database.

DNOs must provide some analysis of any emerging trends in the environmental data and any areas of trade-off in performance.
No significant emerging trends were identified in terms of environmental data.

Where reported in the Regulatory Year under report, DNOs must provide discussion of the nature of any complaints relating to Noise Pollution and the nature of associated measures undertaken to resolve them.
40 noise complaints were received in the year all of which related to substation noise. No ex-gratia payments were made.

Where reported in the Regulatory Year under report, DNOs must provide details of any Non-Undergrounding Visual Amenity Schemes undertaken.
No additional Non-undergrounding for visual amenity schemes were undertaken

in 2018-19.

Any Undergrounding for Visual Amenity should be identified including details of the activity location, including whether it falls within a Designated Area.

N/A

Where reported in the Regulatory Year under report, DNOs must provide discussion of details of any reportable incidents or prosecutions associated with any of the activities reported in the worksheet.

The value in cell AJ20 of table E2 has been amended from zero to one. Whilst in the process of replacing a cable to the Winter Hill transmitter, the excavation machinery caused damage to peat. This resulted in a voluntary undertaking being agreed with Natural England.

Where reported in the Regulatory Year under report, DNOs must provide discussion of details of any Environmental Management System (EMS) certified under ISO or other recognised accreditation scheme.

We are certified to the ISO 14001 Environmental Management System Standard and successfully retained its certification in 2018-19.

In addition, we are certified to the ISO 50001 Energy Management Systems Standard.

DNOs must provide a brief description of any permitting, licencing, registrations and permissions, etc related to the activities reported in this worksheet that you have purchased or obtained during the Regulatory Year.

N/A

DNOs must include a description of any SF6 and Oil Pollution Mitigation Schemes undertaken in the Regulatory Year including the cost and benefit implications and how these were assessed.

No SF_6 mitigation schemes were undertaken in 2018-19.

11 oil mitigation schemes were undertaken relating to work on:

- Installation of new bunds for Morton Park substation T11 and T12 transformers;
- Transformer bund and drainage improvements for oil containment on GT1 at Timpell substation;
- Installation of new bunds for existing T11 & T12 transformer bays at Failsworth Primary substation;
- Installation of new bunds for existing T11 & T12 transformer bays at Mount Street Primary substation;
- Installation of new bunds for existing T11 & T12 transformer bays at South Park Primary substation;

- Improvements to Lancaster substation GT1 bund; and
- Replacement of leaking distribution transformer with a high PCB content at Macclesfield Cricket Club substation.

E3 –BCF

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.

To calculate buildings electricity usage we use data provided by the business energy suppliers and/or landlords for whole buildings or parts of buildings that we occupy. Within this data some estimates for energy usage have been made where half hourly metering is not installed.

To calculate substation electricity usage we use data provided by the business energy suppliers for metered supplies and the estimated consumption figure as submitted in the unmetered MPAN certificate. Within the metered data, some estimates for energy usage have been made by where half hourly metering is not installed and all of the unmetered supplies are estimates.

To calculate the London Underground element of rail journey distances nominal mileages were used for unspecified Zone 1, 2 and 3+ journeys based on typical locations visited by our staff. Zone 1 journeys were taken to be a three miles one-way, Zone 2, six miles one-way and Zone 3, nine miles one-way.

To calculate the fugitive emissions from air conditioning units an estimated leakage rate is taken from Table 8B in Annex 8 of the *2012 Guidelines to Defra/DECC's GHG Conversion Factors for Company Reporting*. To determine which leakage rate applies, the units were compared with the sizing guide in the December 2011 ICF document *Development of the GHG Refrigeration and Air Conditioning Model Final Report*. All units were judged to be "Small Stationary Air Conditioning" units. The time used by each unit was calculated as 24% of time available in the year based on an assumed usage of eight hours per day, five days per week = 40 hours per week/168 hours in week= 24%.

The reported losses figure is a snapshot of received data as of the date of this report and will change as further settlement reconciliation runs are carried out (up to 28 months after each relevant settlement date).

BCF reporting boundary and apportionment factor
DNOs that are part of a larger corporate group must provide a brief introduction outlining the structure of the group, detailing which organisations are considered within the reporting boundary for the purpose of BCF reporting.

Any apportionment of emissions across a corporate group to the DNO business units must be explained and, where the method for apportionment differs from the method proposed in the worksheet guidance, justified.

N/A

BCF process

The reporting methodology for BCF must be compliant with the principles of the Greenhouse Gas Protocol.[1] Accounting approaches, inventory boundary and calculation methodology must be applied consistently over time. Where any processes are improved with time, DNOs should provide an explanation and assessment of the potential impact of the changes.

N/A

Commentary required for each category of BCF

For **each** category of BCF in the worksheet (ie Business Energy Usage, Operation Transport etc) DNOs must, where applicable, provide a description of the following information, ideally at the same level of granularity as the Defra conversion factors:

- the methodology used to calculate the values, outlining and explaining any specific assumptions or deviations from the Greenhouse Gas Protocol
- the data source and collection process
- the source of the emission conversion factor (this shall be Defra unless there is a compelling case for using another conversion factor. Justification should be included for any deviation from Defra factors.)
- the Scope of the emissions ie, Scope 1, 2 or 3
- whether the emissions have been measured or estimated and, if estimated the assumptions used and a description of the degree of estimation
- any decisions to exclude any sources of emissions, including any fugitive emissions which have not been calculated or estimated
- any tools used in the calculation
- where multiple conversion factors are required to calculate BCF (eg, due to use of both diesel and petrol vehicles), DNOs should describe their methodology in commentary
- where multiple units are required for calculation of volumes in a given BCF category (eg, a mixture of mileage and fuel volume for transport), DNOs should describe their methodology in commentary, including the relevant physical units, eg miles.

DNOs may provide any other relevant information here on BCF, such as commentary on the change in BCF, and should ensure the baseline year for reference in any description of targets or changes in BCF is the Regulatory Year 2014-15. DNOs should make clear any differences in the commentary that relate to DNO and contractor emissions.

UK Government GHG conversion factors for company reporting V1.01 2018 were used in calculations.

Expiry:	31/07/2019	**Factor set:**	Full set
Version:	1.01	**Year:**	2018

DNO Emissions: Buildings Energy usage - Buildings Electricity

The buildings-electricity energy usage figure is calculated using the kWh usage data provided by the business energy suppliers and/or landlords for whole buildings or parts of buildings that we occupy.

To convert the usage into tCO2e the following conversion factors from the *UK*

[1] Greenhouse gas protocol

Government Conversion Factors for Company Reporting were used:

Activity	Country	Unit	Year	kg CO_2e
Electricity generated	Electricity: UK	kWh	2018	0.28307

For 2018/19 the calculation is as follows:

- Consumption = 4,848,335.82 kWh x 0.28307/1,000 = 1,372.42 tCO2e.

To ensure this figure was the 2019 entry in table E3 a scalar of 0.00028307 (cell BB14) was used:

- Total consumption 2018/19 = 4,848,335.82 kWh (cell BR14) x 0.00028307 = 1,372.42 (cell AG14).

DNO Emissions: Buildings Energy Usage - Substation Electricity

The substation electricity usage data is calculated from kWh usage data provided by the business energy suppliers for metered supplies and the estimated consumption figure as submitted in the unmetered MPAN certificate.

To convert the usage into tCO2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting* were used:

Activity	Country	Unit	Year	kg CO_2e
Electricity generated	Electricity: UK	kWh	2018	0.28307

For 2018/19 the calculation is as follows:

- Consumption = 15,548,640.72 kWh x 0.28307/1,000 = 4,401.35 tCO2e.

To ensure this figure was the 2019 entry in table E3 a scalar of 0.00028307 (cell BB16) was used:

- Total consumption 2018/19 = 15,548,640.72 kWh (cell BR16) x 0.00028307 = 4,401.35 (cell AG16).

DNO Emissions: Operational Transport – Road

The operational transport figure is calculated from fuel litres purchased data provided by the business fuel card suppliers. All the operational vehicles that we own have diesel engines.

To convert the usage into tCO2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting* were used:

Activity	Fuel	Unit	kg CO_2e
Liquid fuels	Diesel (average biofuel blend)	litres	2.62694

For 2018/19 the calculation is as follows:

- Consumption = 1,530,309.00 litres x 2.62694 /1,000 = 4,020.03 tCO2e.

To ensure this figure was the 2019 entry in table E3 a scalar of 0.00262694 (cell BB22) was used:

- Total consumption 2018/19 = 1,530,309.00 litres (cell BR22) x 0.00262694 = 4,020.03 (cell AG22).

DNO Emissions: Business Transport – Road

The business transport figure for road travel is calculated from the mileages claimed back through the corporate expenses system.

To convert the usage into tCO2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting* were used:

			Diesel	Petrol
Activity	Type	Unit	kg CO_2e	kg CO_2e
Cars (by size)	Small car	miles	0.23389	0.25049
	Medium car	miles	0.27927	0.31200
	Large car	miles	0.34634	0.45723

For 2018/19 the calculation is as follows:

- Small petrol car: 562,985.00 miles x 0.25049/1,000 = 141.022 tCO2e.
- Medium petrol car: 505,376.00 miles x 0.31200/1,000 = 157.677 tCO2e.
- Large petrol car: 187,632.00 miles x 0.45723/1,000 = 85.791 tCO2e.
- Small diesel car: 1,357,960.00 miles x 0.23389/1,000 = 317.613 tCO2e.
- Medium diesel car: 958,215.00 miles x 0.27927/1,000 = 267.601 tCO2e.
- Large diesel car: 1,007,114.00 miles x 0.34634/1,000 = 348.804 tCO2e.

This gives a total of 1,318.508 tCO2e. To ensure this figure was the 2019 entry in table E3 a scalar of 0.0002879289 (cell BB31) was used:

- Total consumption 2018/19 = 4,579,282.00 miles (cell BR31) x 0.0002879289 = 1,318.508 (cell AG31).

DNO Emissions: Business Transport – Rail

The business transport figure for rail is calculated using details provided by our travel supplier of rail journeys undertaken by our employees. The mileage for each journey is calculated using the distances between stations published on the Virgin Trains carbon calculator website. The mileages are then converted into kilometres for calculating the tCO2e.

For London Underground journeys, nominal mileages are used for Zone 1, 2 and 3+ journeys. Zone 1 journeys were taken to be 3 miles one-way, Zone 2, 6 miles one-way and Zone 3, 9 miles one-way.

Excluded from the rail journey calculations are any journeys booked by employees directly and claimed back through the corporate expenses system as these are minimal and the details not specific enough to make a valid calculation.

To convert the usage into tCO2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting* were used:

Activity	Type	Unit	kg CO_2e
Rail	National rail	passenger.km	0.04424
	London Underground	passenger.km	0.03760

For 2018/19 the calculation is as follows:

- National Rail: 504,730.11 km x 0.04424/1,000 = 22.33 tCO2e.
- London Underground: 207.61 km x 0.03760/1,000 = 0.01 tCO2e.

This gives a total of 22.34 tCO2e. To ensure this figure was the 2019 entry in table E3 a scalar of 0. 00004424308 (cell BA32) was used:

- Total consumption 2018/19 = 504,937.71 km (cell BR32) x 0.00004424308 = 22.34 (cell AG32).

DNO Emissions: Business Transport – Air

The business transport figure for air travel is calculated using details provided by our travel supplier of air journeys undertaken by our employees. The journey details are split into domestic, short haul international and long-haul international and the kilometres travelled for each journey calculated using the air journey distance calculator on the www.webflyer.com website.

To convert the usage into tCO2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting* were used:

Activity	Haul	Class	Unit	kg CO_2e
Flights	Domestic, to/from UK	Average passenger	passenger.km	0.29832
	Short-haul, to/from UK	Economy class	passenger.km	0.15970
	Long-haul, to/from UK	Business class	passenger.km	0.47208

For 2018/19 the calculation is as follows:

- Domestic, to/from UK, average passenger: 12,443.00 km x 0.29832/1,000 = 3.71 tCO2e.
- Short-haul, to/from UK, economy class: 50,058.00km x 0.15970/1,000 = 7.99 tCO2e.
- Long-haul, to/from UK, business class: 68,014.00 km x 0.47208/1,000 = 32.11 tCO2e.

This gives a total of 43.81 tCO2e. To ensure this figure was the 2019 entry in table E3 a scalar of 0.0003356702 (cell BB34) was used:

- Total consumption 2018/19 =130,515 km (cell BR34) x 0.0003356702 = 43.81 (cell AG34).

DNO Emissions: Fugitive Emissions - SF6

The amount of sulphur hexafluoride (SF_6) emitted is calculated using the actual mass of SF_6 used when topping up or replacing distribution network apparatus with low gas or gas loss. The top-up amounts are the actual amounts recorded by the engineers on-site when topping up. The loss amounts for apparatus that has been replaced as a result of gas loss are the amounts of gas held by those units less that recovered during the disposal process.

To convert the usage into tCO2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting* were used:

Activity	Emission	Unit	kg CO_2e
Kyoto protocol – standard	Sulphur hexafluoride (SF6)	kg	22800

For 2018/19 the calculation is as follows:

- 38.03 kg x 22,800/1000 = 867.08 tCO2e

To ensure this figure was the 2019 entry in table E3 a scalar of 22.80 (cell BB40) was used:

- Total emissions 2018/19 = 38.03kg (cell BR40) x 22.80 = 867.08 (cell AG40).

DNO Emissions: Fugitive Emissions - Gases Other

The "gases other" figure is calculated using data held on the capacity and type of HFC gases contained in air conditioning units in use within our occupied offices.

An estimated leakage rate is taken from Table 8B in Annex 8 of the *2012 Guidelines to Defra/DECC's GHG Conversion Factors for Company Reporting*. To determine which leakage rate applies the units were compared with the sizing guide in the December 2011 ICF document *Development of the GHG Refrigeration and Air Conditioning Model Final Report*. All units were judged to be "Small Stationary Air Conditioning" units.

The time used by each unit was calculated as 24% of time available in the year based on an assumed usage of 8 hours per day, 5 days per week = 40 hours per week/168 hours in week= 24%.

To convert the usage into tCO2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting* were used:

Activity	Emission	Unit	kg CO_2e
Montreal protocol - standard	HCFC-22/R22 = chlorodifluoromethane	kg	1810

Activity	Emission	Unit	kg CO_2e
Kyoto protocol- blends	R407C	kg	1774
	R410A	kg	2088

The capacity for each HFC type is multiplied by the time used percentage, the annual leak rate and the global warming potential conversion factor to provide the tCO2e number.

The data for the calculation for 2018/19 is recorded in the 'FY19 refrigerant tracker' database. It is calculated each month as follows and then the 12 monthly results summated.

Monthly calculation: Total stock held in kg/1000 x 24% usage x 3% leakage rate x conversion factor x 1/12.

This gave the following results:

- R22: 0.261 tCO2e.
- R407C: 1.462 tCO2e.
- R410A: 14.572 tCO2e.

This gives a total of 16.295 tCO2e.

The total calculated refrigerant loss over the year was 7.947 kg

The failure of one system led to a total gas loss. This resulted in the need to recharge the unit with 34.4kg of R410A. The whole of this recharge, less an allowance for the calculated losses over the last 3 years, has also been included. The calculation for the contribution is as follows:

System recharge contribution = 34.4kg x 2088/1000 = 71.83 tCO2e
Previous losses = 34.4kg x 2088/1000 x 0.24 usage x 0.03 leakage rate x 3 years x = 1.55 tCO2e
Contribution from system failure = 71.83 – 1.55 = 70.28 tCO2e

The total refrigerant loss over the year was 7.947 kg + 34.4kg = 42.347 kg.

The total tCO2e was 16.295 + 70.28 = 86.575 tCO2e

To ensure this figure was the 2019 entry in table E3 a scalar of 2.04442 (cell BB41) was used:

- Total emissions 2018/19 = 42.347kg (cell BR41) x 2.04442 = 86.575 (cell AG41).

DNO Emissions: Fuel Combustion – Diesel

The fuel combustion - diesel figure is calculated from fuel litres purchased data provided by the business plant card supplier.

To convert the usage into tCO2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting* were used:

Activity	Fuel	Unit	kg CO_2e
Liquid fuels	Diesel (average biofuel blend)	litres	2.62694

For 2018/19 the calculation is as follows:

Consumption: 48,086.00 litres x 2.62694/1,000 = 126.32 tCO2e.

To ensure this figure was the 2019 entry in table E3 a scalar of 0.00262694 (cell BB47) was used:

- Total consumption 2018/19 = 48,086.00 litres (cell BR47) x 0.00262694

= 126.32 (cell AG47).

DNO Emissions: Fuel Combustion – Other

The fuels other figure is calculated from fuel litres purchased data provided by the business fuel and fuel card suppliers.

To convert the usage into tCO2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting* were used:

Activity	Fuel	Unit	kg CO_2e
Liquid fuels	Gas oil	litres	2.97049
	Petrol (average biofuel blend)	litres	2.20307

For 2018/19 the calculation is as follows:

- Petrol consumption: 21,484.00 litres (average biofuel petrol) x 2.20307/1,000 = 47.331 tCO2e.
- Gas oil consumption: 87,977.00 litres x 2.97049/1,000 = 261.335 tCO2e

This gives a total of 308.666 tCO2e. To ensure this figure was the 2019 entry in table E3 a scalar of 0.0028198719 (cell BB49) was used:

- Total consumption 2017/18 = 109,461.00 litres (cell BR49) x 0.0028198719 = 308.666 (cell AG49).

DNO Emissions: Losses

Losses occur in all electricity networks, and for GB distribution companies typically represent 5-10% of energy distributed to end customers. Losses are usually divided into two categories: technical and non-technical. Technical losses can be further divided into fixed losses (e.g. transformer iron losses) and variable losses which are dependent on power flows in circuits, both of which have a direct carbon impact. Non-technical losses include unregistered or illegal connections, theft, meter inaccuracies, meter settlement errors and other settlement data issues.

Losses are measured as the difference between energy entering (generation) and energy exiting the network (demand), as recorded under the Balancing and Settlement Code (BSC) arrangements. Reported losses therefore do not distinguish between technical and non-technical losses.

The reported figure is a snapshot of received data as of the date of this report and will change as further settlement reconciliation runs are carried out (up to 28 months after each relevant settlement date).

To convert the usage into tCO2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting* were used:

Activity	Country	Unit	Year	kg CO_2e
Electricity generated	Electricity: UK	kWh	2018	0.28307

For 2018/19 the calculation is as follows:

- Reported losses = 1,225,880,935.60 kWh x 0.28307/1,000 = 347,010.12 tCO2e.

To ensure this figure was the 2019 entry in table E3 a scalar of 0.00028307 (cell BB55) was used:

- Total consumption 2018/19 = 1,225,880,935.60 kWh (cell BR55) x 0.00028307= 347,010.12 (cell AG55).

Contractors
When reporting BCF emissions due to contractors in the second half of the worksheet please:

- Explain, and justify, the exclusion of any contractors and any thresholds used for exclusion.
- Provide an indication of what proportion of contractors have been excluded. This figure could be calculated based on contract value.

Please provide a description of contractors' certified schemes for BCF where a breakdown of the calculation for their submitted values is not provided in the worksheet.

If a DNO's accredited contractor is unable to provide a breakdown of the calculation and has entered a dummy volume unit of '1' in the worksheet please provide details of the applicable accredited certification scheme which applies to the reported values.

For the BCF emissions due to contractors, only Operational Transport – Road and fuels other have been calculated.

The fuel usage figure from contractors includes the usage by the larger framework contractors only and excludes any usage by smaller, low volume sub-contractors where the collation of data is impractical.

UK Government GHG conversion factors for company reporting V1.01 2018 were used in calculations.

Expiry:	31/07/2019	**Factor set:**	Full set
Version:	1.01	**Year:**	2018

Contractor Emissions: Operational Transport – Road

The contractor operational transport figure is calculated using road fuel litres used data provided by contractors in relation to their fleet usage on our behalf.

The fuel usage figure from contractors includes the usage by the larger framework contractors only and excludes any usage by smaller, low volume sub-contractors where the collation of data is impractical.

To convert the usage into tCO2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting* were used:

Activity	Fuel	Unit	kg CO_2e

Liquid fuels	Diesel (average biofuel blend)	litres	2.62694

For 2018/19 the calculation is as follows:

Consumption = 1,465,589.27 litres x 2.62694/1,000 = 3,850.02 tCO2e.

To ensure this figure was the 2019 entry in table E3 a scalar of 0.00262694 (cell BB68) was used:

- Total consumption 2018/19 = 1,465,589.27 litres (cell BR68) x 0. 00262694 = 3,850.02 (cell AG68).

Contractor Emissions: Fuel Combustion – Other

The fuels other figure is calculated from fuel litres used data provided by contractors in relation to their generator and plant usage on our behalf.

To convert the usage into tCO2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting* were used:

Activity	Fuel	Unit	kg CO_2e
Gaseous fuels	LPG	litres	1.51906

Activity	Fuel	Unit	kg CO_2e
Liquid fuels	Gas oil	litres	2.97049
	Petrol (average biofuel blend)	litres	2.20307

For 2018/19 the calculation is as follows:

- Petrol consumption = 19,529.02 litres (average biofuel petrol) x 2.20307/1,000 = 43.024 tCO2e.
- Gas oil consumption = 1,324,361.83 litres x 2.97049/1,000 = 3,934.003 tCO2e
- LPG consumption = 14,851.00 litres x 1.51906/1,000 = 22.560 tCO2e.

This gives a total of 3,999.587 tCO2e. To ensure this figure was the 2019 entry in table E3 a scalar of 0.0029435959 (cell BB95) was used:

- Total consumption 2018/19 = 1,358,741.85 litres (cell BR95) x 0.0029435959 = 3,999.59 (cell AG95).

Building energy usage 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. The chosen approach should be explained, including whether it has been adapted over time. Substation Electricity must be captured under Buildings Energy Usage. Please explain the basis on which energy supplied has been assessed.

We only use electricity as our energy source for buildings and substations.

The buildings and substation electricity energy usage figures are calculated using kWh usage data. To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting* V1.01 2018 were used.

Expiry:	31/07/2019	**Factor set:**	Full set
Version:	1.01	**Year:**	2018

Activity	Country	Unit	Year	kg CO_2e
Electricity generated	Electricity: UK	kWh	2018	0.28307

E4 – Losses Snapshot

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.

The Losses Snapshot Table E4 has been completed based on the losses reduction initiatives detailed in our current Losses Strategy (April 2015). Other work may have helped to reduce Distribution Losses but the decision to undertake the activity was not driven by losses benefit, therefore this activity is not reported in Table E4.

The table format restricts reporting to two examples for each category and so not all initiatives detailed in our Losses Strategy (April 2015) are listed in the Snapshot Table E4. They are however still being carried out, in line with the decision in our Losses Strategy (April 2015). The excluded initiatives are:

- Proactive replacement of 800kVA ground mounted transformers
- Opportunistic replacement of pre-1970 200kVA pole mounted transformers

This RRP (2019) submission is based on the same assumptions as the 2015 Losses Strategy.

Technical Losses

All costs reported in Table E4 (Columns V: AK) and those costs contained within the supporting CBA workbooks are reported in 2012-13 price base to be consistent with our Losses Strategy (April 2015).

The losses Snapshot, Table E4, includes the technical losses reduction initiatives detailed in our Losses Strategy (April 2015) as follows:

- Opportunistic installation with 300mm^2 HV cable
- Opportunistic installation with 300mm^2 LV cable
- Proactive replacement of 1000kVA ground mounted transformers
- Opportunistic installation of primary transformers (33kV/HV)

The following provides the detail of any estimates, allocations or apportionments made when calculating the numbers submitted for each of the initiatives.

All Technical Losses Initiatives

Where the primary driver (column E) is detailed as 'Other', the base volume number is taken from C&V Tables CV1, CV2, CV3, CV5, CV6, CV7 CV13, CV14, CV15, CV16, CV18, CV19, CV20, CV22, CV23, CV24, CV25, CV26, CV27, CV28, CV29, CV36, CV38, CV39, V3 and V4.

Where the primary driver (column E) is detailed as 'Equipment to manage losses', the base volume number is taken from C&V Table CV21.

For all initiatives it was assumed that there were no losses saving in the first year (2015-16) and the full losses saving in the following years.

Opportunistic installation with 300mm^2 HV cable

We purchase HV cable in the following standard sizes; 95mm^2, 185mm^2 and 300mm^2. Our corporate Capital Programme Management system (CPM) does not record the size of cable installed and asset data systems do not associate an asset with a scheme or spend category. Therefore, the volumes of 300mm^2 HV cable (km) installed and contributing to the losses reduction is calculated to be the aggregate volume from the appropriate CV Table (per driver) apportioned in the ratio of 300mm^2 HV cable booked out of our stores:total HV cable booked out of our stores. The ratio used is 0.7971.

The baseline solution and losses reduction activity unit costs are the same as those assumed for our 2015 Losses Strategy and are expressed on 2012-13 prices.

The unit (1km) losses benefit was calculated as the losses saved by replacing a 185mm^2 HV cable with 300mm^2 HV cable. The peak current was assumed to be the thermal rating of the 185mm^2 cable. A typical (for ENWL) load factor of 0.53 was assumed across the network leading to a calculated loss load factor of approximately 0.3.

Opportunistic installation with 300mm^2 LV cable

We purchase LV cable in the following standard sizes; 95mm^2, 185mm^2 and 300mm^2. Our corporate Capital Programme Management system (CPM) does not record the size of cable installed and asset data systems do not associate an asset with a scheme or spend category. Therefore, the volumes of 300mm^2 LV cable (km) installed and contributing to the losses reduction is calculated to be the aggregate volume from the appropriate CV Table (per driver) apportioned in the ratio of 300mm^2 LV cable booked out of our stores:total LV cable booked out of our stores. The ratio used is 0.2593.

The baseline solution and losses reduction activity unit costs are the same as those assumed for our 2015 Losses Strategy and are expressed on 2012-13 prices.

The unit (1km) losses benefit was calculated as the losses saved by replacing a 185mm^2 LV cable with 300mm^2 LV cable. The peak current was assumed to be the thermal rating of the 185mm^2 cable. A typical (for ENWL) load factor of 0.53 was assumed across the network leading to a calculated loss load factor of approximately 0.3.

Proactive replacement of 1000kVA ground mounted transformers

The volume of ground mounted transformers replaced proactively (Equipment to manage losses) is reported in CV21. The recorded volume consists of both 1000kVA and 800kVA units. The volume split between the 1000kVA and the 800kVA units is established by inspection of our asset data system, Ellipse.

The baseline solution and losses reduction activity unit costs are the same as those assumed for our 2015 Losses Strategy and are expressed on 2012-13 prices.

The losses calculations is based on transformer resistance values. The peak current was assumed to be the thermal rating of the of the transformer type. A typical (for ENWL) load factor of 0.53 was assumed across the network leading to a calculated loss load factor of approximately 0.3.

Opportunistic installation of primary transformers (33kV/HV)

Twelve primary transformers were delivered in 2018-19.

The baseline solution and losses reduction activity unit costs are the same as those assumed for our 2015 Losses Strategy and are expressed on 2012-13 prices.

The losses calculations is based on transformer resistance values. The peak current was assumed to be half (because primary transformers are installed as pairs for resilience) the thermal rating of the of the transformer type. A typical (for ENWL) load factor of 0.53 was assumed across the network leading to a calculated loss load factor of approximately 0.3.

<u>Non-Technical Losses</u>

The costs associated with Relevant Theft of Electricity activities are taken directly from C&V Tables CV21, C9 and I5. These costs included the costs of investigating all reported or suspected instances of Relevant Theft of Electricity. Many of these are not ultimately found to be cases of Relevant Theft of Electricity, and therefore have no losses benefit associated with them, but costs are included to reflect the full cost of operating a Relevant Theft of Electricity activity.

The income associated with Relevant Theft of Electricity activities is also taken directly from C&V Tables CV21, C9 and I5. This income represents all income received during 2018-19 and will include some payments received from instances of theft identified in prior years (for example where a customer agrees to a payment plan and pays the debt over several years). We make no adjustment in our CBA to reflect the lag in receiving income.

The net of costs and associated income is reported within the losses snapshot table. As income was slightly higher than costs during 2018-19 we report a negative value for this year.

We estimate the losses benefit associated with identifying and remedying instances of Relevant Theft of Electricity as follows:

- For sites where we have billed the customer for the value of electricity for 12 months of theft (our usual approach), we quantify losses based on the invoiced amount of electricity used. We assume that this full losses benefit is achieved in the year that we identify the theft, reflecting the fact that the full 12 months has been invoiced. We assume this whether or not the customer has yet paid anything against the invoice; this reflects the benefit associated with there being no ongoing theft.

- For sites where we have billed the customer for the value of electricity for less than 12 months of theft (for example if the customer has not lived in the property for a year), we quantify losses benefit in year 1 based on the invoiced amount of electricity used. For subsequent years we increase the losses benefit to a full 12 month effect – reflecting the full amount of electricity that will no longer be being stolen. We assume this whether or not the customer has yet paid anything against the invoice; this reflects the benefit associated with there being no ongoing theft.

- For sites where we have identified theft but have not raised an invoice, for example where we have no reasonable expectation of recovering the costs, where the values involved are very small (for example where a customer has only just moved into a property) or where all lost units will be recovered via a supplier (following registration of a new MPAN) we assume a losses benefit of 10kWh per day for domestic properties and 30kWh a day for commercial properties. We assume that none of this losses benefit is achieved in the year that we identify the theft, with 100% of the benefit achieved from year 2 onwards.

These losses benefits reflect the fact that electricity is no longer being stolen – either the theft has ceased or the units are being entered into settlements.

In all cases we assume that the losses benefits persist on an ongoing basis, ie that the customer continues to use electricity at the rate we assumed, that the customer does not revert to stealing electricity and that the site is not disconnected.

Programme/Project Title
Please provide a brief summary and rationale for each of the activities in column C which you have reported against.

<u>Technical Losses</u>

Opportunistic installation with 300mm^2 HV cable

Opportunistic installation of large cross-section cables (300mm^2) at high voltage (HV – 6.6kV and 11kV) as standard, instead of a mix of smaller (95mm^2 and 185mm^2) cables. This will reduce circuit resistance, reduce losses and provides a positive business case.

Opportunistic installation with 300mm^2 LV cable

Opportunistic installation of large cross-section cables (300mm^2) at low voltage

(LV – 430/240V) as standard, instead of a mix of smaller ($95mm^2$ and $185mm^2$) cables. This will reduce circuit resistance, reduce losses and provides a positive business case.

Proactive replacement of 1000kVA ground mounted transformers

Proactively replace old (pre-1990) 1000kVA, ground mounted, secondary network transformers with lower loss EU Eco Design 2015 specification transformers. The old transformers have particularly high losses such that there is a positive business case for proactive replacement of these units.

Opportunistic installation of primary transformers (33kV/HV)

When installing or replacing a primary transformer, a lower loss unit which complies with the latest European Union standard (EU Eco Design 2015) specification will be installed. The lower loss units can now be procured at the same cost as the old (higher losses) specification units; therefore there is a positive business case for opportunistic replacement of these units.

Non-Technical Losses

Proactive investigation of Relevant Theft of Electricity. Identifying of instances of theft, rectifying the theft so that electricity is no longer stolen and, where appropriate, seeking to recover the value of electricity stolen and any associated costs from the customer. During 2018-19 we identified many instances of Relevant Theft of Electricity, delivering significant losses benefits by preventing further theft or ensuring units are correctly captured in settlements. We recovered associated monies from customers that totalled slightly more than our associated costs.

Primary driver of activity
If, in column E, you have selected 'Other' as the primary driver of the activity, please provide further explanation.

In respect of Technical Losses initiatives 'Other' has been selected as a primary driver (in column E) where the initiative is an opportunistic investment. Opportunistic initiatives are changes in policy affecting all business as usual activities. So for example installing larger cross-section HV cable as standard will affect reinforcement, asset replacement, fault level and any other activity that requires HV cable.

In respect of Relevant Theft of Electricity activity 'Other' has been selected as a primary driver (in column E) because it does not apply to reinforcement, asset replacement and fault level activities.

Baseline Scenario
Please provide a brief description of the 'Baseline Scenario' inputted in column K for each activity.

Technical Losses

Opportunistic installation with $300mm^2$ HV cable

The baseline scenario is to continue to install $95mm^2$ and $185mm^2$ cables. In the

CBA analysis the baseline scenario assumed activity was all $185mm^2$ cable producing a conservative estimate of losses reduced.

Opportunistic installation with $300mm^2$ LV cable

The baseline scenario is to continue to install $95mm^2$ and $185mm^2$ cables. In the CBA analysis the baseline scenario assumed activity was all $185mm^2$ cable producing a conservative estimate of losses reduced.

Proactive replacement of 1000kVA ground mounted transformers

The baseline scenario assumed that the high loss 1000kVA transformer units remained in service and were not replaced.

Opportunistic installation of primary transformers (33kV/HV)

The baseline scenario assumed that primary transformers that complied with ENWL's old standard would be installed.

<u>Non-Technical Losses</u>

The baseline scenario assumes that no Relevant Theft of Electricity activity is undertaken.

We set the baseline losses assumption to be equal to the benefits associated with theft identified during the year. In reality it is likely that the losses associated with ongoing theft is greater than this – but it is impossible for us to quantify this. As CBA modelling works on a marginal basis this approach should appropriately reflect the benefits gained.

Use of the RIIO-ED1 CBA Tool

DNOs should use the latest version of the RIIO-ED1 CBA Tool for each of the activities reported in column C. Where the RIIO-ED1 CBA Tool cannot be used to justify an activity, DNOs should explain why and provide evidence for how they have derived the equivalent figures for the worksheet. The most up-to-date CBA for each activity reported in the Regulatory Year under report must be submitted.

RIIO-ED1 CBA Tool version 'Template CBA RIIO ED1 v4' has been used for all CBA analysis associated with this submission.

We have not changed the assumptions from those contained within 'Template CBA RIIO ED1 v4'.

Changes to CBAs If, following an update to the CBA used to originally justify the activity in column C, the updated CBA shows: • a negative net benefit for an activity, but the DNO decides it is in the best interests of consumers to continue the activity, or • a substantively different NPV from that used to justify an activity that has already begun. the DNO should include an explanation of what has changed and why the DNO is continuing the activity. For example, where the carbon price used in the RIIO-ED1 CBA Tool has changed from that used to inform the decision such that the activity no longer has a positive NPV.
N/A

Cost benefit analysis additional information Please include a reference to the file name and location of any additional relevant evidence submitted to support the costs and benefits inputted into this worksheet. This should include the most recent CBA for each activity reported in column C in the Regulatory Year under report.
The table below lists the Losses initiative and the name of its relevant CBA:

Losses Initiative	Primary Driver of Activity	CBA Name
Opportunistic installation with 300mm^2 HV cable	Other	2019 Install 300sqmm HV Cable versus 185sqmm HV
Opportunistic installation with 300mm^2 LV cable	Other	2019 Install 300sqmm LV Cable versus 185sqmm LV
Proactive replacement of 1000kVA ground mounted transformers	Equipment to manage losses	2019 Proactive 1000kVA GMT Replacement CV21
Opportunistic installation of primary transformers (33kV/HV)	Other	2019 Programme 23MVA Replacement
Relevant Theft of Electricity	Other	2019 CBA for E4 Theft of Electricity

E5 – Smart Metering

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
This is a pass through cost and the vast majority of costs reflect actual invoicing. Any allocation or estimation is considered with table C22 in the Costs and Volume reporting pack.

Actions to deliver benefits

Detail what activities have been undertaken in the relevant regulatory year to produce benefits of smart metering where efficient and maximise benefits overall to consumers. At a minimum this should include:

- A description of what the expenditure reported under Smart Meter Information Technology Costs is being used to procure and how it expects this to deliver benefits for consumers.
- A description of the benefits expected from the non-elective data procured as part of the Smart Meter Communication Licensee Costs. The DNO should set out how it has used this data.
- A description of the Elective Communication Services being procured, how it has used these services, and a description of the benefits the DNO expects to achieve.

Smart Meter Communication Licensee Costs

The £2.0m Smart Meter Communication Licensee Costs for 2018-19 are those costs payable by us to the Data and Communications Company (DCC), as required by the Smart Energy Code and defined by DCC's published charging methodology statement. The costs have increased by £0.7m compared to last year as a result of the DCC increasing the monthly fixed charges for Electricity Distributors.

Smart Meter Information Technology Costs

The £1.8m IT costs incurred in 2018-19 covered: the continued support and maintenance of the gateway infrastructure connecting our IT systems to the DCC central systems as part of the Smart Meter Implementation Programme (SMIP) and required by the Smart Energy Code; plus additional design work required for the uplift of systems to be compatible with the DCC User Interface Specification (DUIS) to v2.0 and v3.0 specifications. The costs have decreased since last year by £0.1m as there has not been the same requirement for infrastructure build activities as the previous period.

Benefits expected from use of non-elective data

Connection to DCC's central systems facilitates access to smart meter data, generated from alerts and service requests. We expect benefits from the use of this non-elective data procured as part of the Smart Meter Communication Licensee Costs in the longer term to enable us to manage our network more effectively and cost efficiently for customers. DNO's have previously assessed the benefits of Half Hour Consumption data as being attained once a smart meter installation level approaching 70% penetration is reached (noting that there may be some geographic clustering which in some cases may allow us to begin achieving benefits earlier).

However, since our gateway became live in December 2017, we have only approx 10k SMETS2 meters installed in our region (as at June 2019). This represents approximately 1% of all SMETS2 meters installed nationally and an even smaller fraction of exit points within our footprint. Supplier installations in the North of the country continue to lag significantly behind the Southern and Central regions.

Due to the decline in installations under the SMIP and disparity between installations in the north and south, we do not expect an increase in SMETS2 installations in the north region and our share of the market to level with other DNOs until the north region communications problems are resolved.

As per our licence, we will not use any household-level data from smart meters which relates to a period of less than one month before approval of our Data Privacy Plan. We have submitted future plans to Ofgem which include details stating that we expect to be able to submit our Data Privacy Plan by March 2020.

It should be noted that further development work is required to cater for changes in scope, including DCC Release3 (SMETS1 adoption) and to define integration of the available smart meter data into our internal systems.

Calculation of benefits

Explain how the benefits have been calculated, including all assumptions used and details of the counterfactual scenario against which the benefits are calculated.

The Smart Meter programme has not yet rolled out to the extent that benefits are identifiable. A number of common issues relating to both Device and DCC functionality have been raised which have high potential to negatively impact benefits realisation.

Current issues span a number of areas including significant volumes of false positive alert notifications, extremely high volumes of nuisance alerts and incorrect/inconsistent meter functionality. In conjunction with other DNO's we are liaising with industry parties to attempt to resolve these in order to be able to move forward with systems integration and business transformation plans.

Use of the RIIO-ED1 CBA Tool

DNOs should use the latest version of the RIIO-ED1 CBA Tool for each solution reported in the worksheet in the Regulatory Year under report. Where the RIIO-ED1 CBA Tool cannot be used to justify a solution, DNOs should explain why and provide evidence for how they have derived the equivalent figures for the worksheet. The most up-to-date CBA for each activity reported in the Regulatory Year under report which are used to complete the worksheet must be submitted.

N/A

Cost benefit analysis additional information

Please include a reference to the file name and location of any additional relevant evidence submitted to support the costs and benefits inputted into this worksheet. This should include the most recent CBA for each solution reported in the Regulatory Year under report.

N/A

E6 – Innovative Solutions

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.

Demand Side Response

Catterall Primary substation is compliant with ENA Engineering Recommendation (ER) P2/6, as we have contracted DSR for when the system is operating abnormally. A non-compliance issue would exist, without the DSR, when the system is operating abnormally (i.e under a fault situation), as the demand exceeds the transfer firm capacity. Deferring the reinforcement and entering into a commercial contract with a local water company to purchase the demand at Catterall allows us to monitor Catterall's primary demand patterns and enables us to be compliant with ER P2/6.

Catterall Primary substation has a single 7.5 MVA transformer and a firm capacity of 5 MVA, limited by High Voltage transfer capability. The peak demand at Catterall Primary is 7.41 MVA, which exceeds the firm capacity by 2.41 MVA.

The CBA uses the agreed commercial costs of £13,500 per MVA for years FY17-19, in which ENWL has purchased 3 MVA of DSR under such fault conditions. The CBA was informed by actual costs as referenced in table CV1 and the losses were calculated based on load projections up to 2061.

Transformer regeneration

The standard solution for 132kV and 33kV transformers which have a Health Index (HI) of 5 is to replace them, whilst transformers with a HI of 4 are often refurbished. The innovative regeneration solution is to replace transformers at HI5 with a criticality of 2-4 only and refurbish those at HI5 with a criticality of 1 and HI4 with a criticality of 2-4. The costs used in the CBA are derived from the CV9 table within the Costs and Volumes pack.

LV Fault Management

The CBA is informed by the number of LV ways fitted with reclosing devices during 2018–19, the number of times the devices operated prior to the fault being located and repaired, and the number of customers fed off each way. It was assumed faults occurred linearly throughout the week and therefore costs for the baseline case include premium time working. Each callout to replace a fuse was costed at three hours and it was assumed that customers would be without supply for at least 90 minutes.

Repairs were assumed to commence immediately a fault became permanent. It was assumed that the installation of reclosing devices removed the requirement for fuse replacement and as supplies were restored within three minutes, the Customer Interruptions and Customer Minutes Lost were reduced. The input from the Fault Support Centre (FSC) allowed faults to be located prior to becoming permanent and it was assumed that all faults were repaired during normal working hours. The cost of setting up the FSC was included in year 1 of the CBA.

Connection and Management of PV Clusters

The volumes used for this CBA were based on the numbers of customers added to the Feed-In Tariff database during 2018-19. For the baseline scenario, it was assumed that there would be a requirement to purchase a tool for LV system analysis and that clusters of PV would consist of 24 properties covering 20% of the total. The remaining 80% would have an average 1.5 properties per application. Planning time was allocated at 12 hours per scheme for larger schemes and one hour per scheme for smaller schemes.

Solutions for the schemes were split between LV cable overlay (5%), transformer change (5%) and altering transformer taps (40%). It was assumed that for 50% of the larger schemes and all of the smaller schemes that the PV demand was approved.

For the Connect & Manage scenario, it was assumed that 20% of the applications would lead to LV system monitoring being installed and 20% of the total number requiring further planning. Of those that require planning and monitoring, it was assumed that only 10% would require any reinforcement works, and of this 10%, 10% would require an LV cable overlay and 90% would require the tap positioning to be altered.

Capacity to Customers

The actual costs were the total of the connection cost for an N-0 solution paid by the customer for schemes energised within the year. The benefits were calculated by assessing the avoided reinforcement costs of those EHV schemes that were energised within the year, and by applying an assumed reinforcement element for HV sites, varying depending on size of connection. These costs would be apportioned as per the Common Connections Charging Methodology (CCCM).

The gross connection cost is the total cost of the connection. For an N-1 (baseline) scenario, this includes the cost the connecting customer paid, plus the additional reinforcement cost of the solution (both customer contribution and DUoS costs). Whereas for an N-0 solution, the gross connection cost is purely the value paid by the customer, as no additional expenditure is incurred by ENWL.

Within the baseline scenario, the total DUoS funded investment is identified through the calculation of subtracting the customer's reinforcement contribution away from the gross connection cost. In the chosen N-0 solution, the additional cost of the connection (both DUoS funded and customer funded elements) is avoided, and no investment is required by ENWL as the full cost of the N-0 connection is paid for by the customer.

General

For each of the solutions please explain:

- In detail what the solution is, linking to external documents where necessary.
- How this is being used, and how it is delivering benefits.
- What the volume unit is and what you have counted as a single unit.
- How each of the impacts have been calculated, including what assumptions have been relied upon.

Introduction:

This commentary and the associated CBAs contain details of the innovative solutions which have incurred expenditure and delivered outputs during the period April 2018 to March 2019 (ie RIIO-ED1, year 4).

Innovative Solutions:

There are five Innovative Solutions which form part of our business as usual activities during 2018/19:

- Demand Side Response (Catterall)
- Transformer regeneration (Oil Regeneration and Online Transformer Monitoring)
- LV Fault Management (Fault Support Centre and Smart Fuse Devices)
- Connection and Management of PV Clusters (LV Smart Joint)
- Capacity to Customers (C2C).

Oil Regeneration and Online Transformer Monitoring are presented as separate projects. However, to avoid double counting of the associated costs and benefits, for the purpose of the CBA, they are brought together in combination to form a new and innovative solution referred to as Transformer Regeneration.

Demand Side Response:

What the solution is:

Catterall Waterworks Primary Substation has a single 7.5 MVA transformer and a firm capacity of 5 MVA, limited by High Voltage transfer capacity. The peak demand at the substation is 7.41 MVA, which exceeds the firm capacity by 2.41 MVA causing a compliance issue with ENA Engineering Recommendation (EREC) P2/6.The non-compliance issue only exists when the system is operating abnormally due to the loss of the circuit supplying the transformer or transformer (ie under a fault situation), as the demand exceeds the transfer capacity.

By entering into a commercial agreement for the purchasing of DSR services, ENWL is able to defer the reinforcement of this primary substation and maintain compliance with EREC P2/6 as it ensures that the demand does not exceed the capacity when the system is abnormal.

How it is being used:

Under system abnormal conditions, ENWL will switch out a circuit at Catterall Waterworks primary to reduce the demand at the customer's site, to the enable the restoration of supplies connected to Catterall primary so the transfer capacity of 5 MVA is not exceeded. The customer has agreed to have their demand reduced by 3 MVA for up to eight hours to allow time for ENWL to identify and resolve the issue.

How it is delivering benefits:

Demand Side Response limits the demand on Catterall Waterworks primary which is constrained by the transfer capacity for the loss of the transformer. With continuous monitoring, this provides the opportunity to defer or carry out reinforcement in the future if demand increases or arrangements change.

Transformer regeneration

What the solution is:

The condition of the oil in the transformer main tank is a good proxy of the general condition of the transformer as a whole. It has been shown from recent research that via unique application of transformer oil regeneration (a process whereby transformer oil is cleaned through an on-site process) can result in an improvement in overall condition of the transformer. When this is used in conjunction with enhanced transformer monitoring, this can improve the Health Index and extend the expected life of the transformer.

How it is being used:

Transformer regeneration is being used as an alternative to traditional asset replacement. The regeneration activities are being undertaken on those assets which are categorised as 'end of life' due to their Health Index and/or criticality level. Regeneration activities are also being undertaken on those transformers categorised as 'mid life' in order to determine the optimum point in a transformer's life cycle to implement oil regeneration activities to further extend the life of the asset.

How it is delivering benefits:

The financial benefits from this innovative solution are derived from transformer life extension and hence deferment of asset replacement costs. Other benefits include quality of supply benefits which relate to improved understanding of the risk of failure of older transformers and a better insight into the oil ageing process. The environmental benefits result from extending the life of an existing transformer and its oil therefore reducing the requirement for disposal of and/or recycling of used oil and scrapping the transformer. However additional losses are incurred due to the delayed implementation of modern equivalent transformers.

This is used in conjunction with the Online Transformer Monitoring (described below).

Online Transformer Monitoring

What the solution is:

As transformer life is extended through the use of techniques such as transformer oil regeneration, network operators must be certain that the refurbished units will continue to operate both safely and reliably. To support this, a real-time condition monitoring system has been developed which provides us with enhanced information on each refurbished transformer via an on-line information dashboard.

How it is being used:

Transformer monitoring is being fitted to all transformers which have had their oil regenerated in RIIO-ED1 for a period of time to confirm (via observable data) that both the initial condition of the transformer is improved and that this improved condition is maintained thereafter. The solution is being used as part of our intervention plan to extend the life of a large number of 132kV and 33kV transformers. The technology is fitted to targeted transformers for a short period prior to the commencement of the oil regeneration process and continues for a defined period thereafter.

How it is delivering benefits:

The condition monitoring provides us with confirmation that the transformer regeneration process has been successful in improving the condition of the transformer oil and thus the main tank. The combined online transformer monitoring is a key enabling technology for the refurbishment of large volumes of 132kV and 33kV transformers under the transformer regeneration innovative solution.

<u>LV Fault Management – Fault Support Centre</u>

What the solution is:

The Fault Support Centre (FSC) is an enhanced Low Voltage network fault management solution which makes use of the increased penetration of intelligent devices such as the Bidoyng coupled with an innovative commercial partnership with a third party provider (Kelvatek). The FSC provides a real-time operational management of low voltage networks to allow for the proactive management of faults. The data obtained can be further used to target areas of the network which would benefit from asset replacement.

How it is being used:

This solution is being used as the business-as-usual approach for how all transient faults are managed. In the event that a transient fault is detected, a smart fuse device such as the Bidoyng or Weezap is fitted to the suspect LV network. Kelvatek is informed of the installation event and data recorded by the Bidoyng/Weezap in real-time to monitor the suspect network.

Kelvatek will continue to monitor the affected networks until they have determined the potential location of the fault causing the transient supply interruption and issued an instruction to our field teams to investigate with the aim of locating and removing the fault or proving that the transient fault is no longer active. In both cases, the equipment will be recovered and redeployed elsewhere.

How it is delivering benefits:

The Fault Support Centre allows for the proactive management of LV transient faults. Our customer engagement activities have shown that these types of fault are one of the biggest cause of customer dissatisfaction. The ability to repair these faults before they have chance to progress into a permanent fault will significantly reduce the number of associated faults and reduce customer disruption accordingly.

Further benefits flow from the reduced CI and CML and associated fault costs that the proactive management of faults delivers.

<u>LV Fault Management – Smart Fuse Devices</u>

What the solution is:

The smart fuse devices produced by Kelvatek such as the Bidoyng and the Weezap act as an innovative replacement for the standard low voltage fuse. They provide a multi-shot re-close feature as opposed to the single operation offered by the standard fuse. This means that customer supplies can be automatically restored in the event of a transient fault, reducing the number of customer interruptions and customer minutes lost and the costs associated with managing our response to a loss of supply. This enhanced approach to LV faults also improves customer satisfaction.

In addition, this equipment provides increased network visibility via its ability to measure and transmit to our Network Management System key network parameters and make this available in near real-time.

How it is being used:

These smart fuse devices are used to reduce the customer impacts of faults, facilitate increased understanding of the impact of the connection of low carbon technologies and improve the management of network faults.
These devices are acting as enablers for a number of innovation solutions and applications. In particular, they are a key tool in the management of low voltage transient faults. These faults are intermittent in nature and are often difficult to find and repair. The Bidoyng is used to both minimise the customer disruption associated with a fault (ie by automatic restoration of supplies) and to help engineers to locate the fault (using travelling wave technology built into the smart device) thus allowing proactive repair of the fault.

How it is delivering benefits:

The Bidoyng smart fuse is a key enabling technology. It is being used as the main technology deployed on faulty parts of the LV network as part of the Fault Support Centre. In addition, it is providing information on the performance of the network to facilitate the application of the Connect & Manage approach to domestic PV clusters connected to the LV network.

Over the last two years there has been a further roll out of Weezap smart fuses. These devices have the capacity for five auto-recloses, whereas the Bidoyng has the capacity for only two. The further recloses offered by the Weezap saves additional subsequent customer interruptions while providing us with further information regarding the fault location enabled through the monitoring service managed by the FSC.

Connection and Management of PV Clusters

What the solution is:

As a result of the learning outcomes of the LCN Fund Tier 1 Project – Low Voltage Network Solutions (LVNS), we have been able to successfully implement a streamlined approach to the connection of domestic scale PV systems to the LV network. These systems are often connected in clusters and can give rise to associated network voltage and thermal issues.

Traditionally, a network operator would undertake detailed and time consuming network assessments to be performed in advance of allowing the connection to proceed. These assessments are aimed at understanding if the connection could give rise to any of the aforementioned problems. However, as a result of the research that was undertaken as part of the LVNS project and the sophisticated network modelling that underpinned it we have adopted the alternative approach of connecting PV and monitoring the LV network.

We have successfully shown that up to a certain threshold (ie percentage of customers with PV systems) it is acceptable to allow the connections to proceed. Once the threshold is met however we will install network monitors to assess, using actual recorded data, if the network requires a further intervention.

How it is being used:

The solution is being actively used across our network. We use this to avoid the often costly and time consuming network assessments that can accompany generation connections. We have established a business process supported by internal policy that provides for continued monitoring of the PV volumes. Specific actions are triggered when these volumes exceed pre-determined limits and follow up actions are performed as appropriate.

How it is delivering benefits:

The solution delivers benefits to customers in the form of avoided waiting times associated with the connection of PV systems to the LV network. We have also been able to avoid expensive and resource intensive network connection studies, thus reducing internal costs and freeing up resources to concentrate of other parts of our connection services.

Capacity to Customers

What the solution is:

Managed connections provide customers wishing to connect to the network with a lower cost connection and reduced waiting times versus traditional network reinforcement based connection arrangements. It utilises advances in network automation and communications alongside innovative commercial terms. It is a form of Active Network Management (ANM) which may seek to disconnect managed customers from the network for agreed periods when the network is running abnormally.

How the solution is being used

Managed connections are now the standard connection offer provided to all generation customers connecting to the HV and EHV network. Managed connections afford customers a lower cost connection and as such have become the default connection offer provided to all Distributed Generation (DG) customers.

To support decision making by customers, information on the potential 'curtailment factor' (ie the typical period of time that a customer could expect to be at risk of disconnection) is provided alongside the connection offer.

Customers may choose to reject the managed connection offer and instead opt for a more traditional connection arrangement without the managed elements.

How the solution is delivering benefits

Managed connections are providing a number of benefits. Economic benefits flow to connection customers from lower reinforcement costs and reduced time to connect. Benefits also flow to all customers from from lower reinforcement costs recovered through lower DUoS charges. Environmental benefits also accrue as a result of removing barriers to support the connection of low carbon generation such as solar/wind farms.

Use of the RIIO-ED1 CBA Tool

DNOs should use the latest version of the RIIO-ED1 CBA Tool for each solution reported in the Regulatory Year under report. Where the RIIO-ED1 CBA Tool cannot be used to justify a solution, DNOs should explain why and provide evidence for how they have derived the equivalent figures for the worksheet. The most up-to-date CBA for each solution reported in the Regulatory Year under report which are used to complete the worksheet must be submitted.

N/A

Changes to CBAs
If, following an update to the CBA used to originally justify the activity in column C, the updated CBA shows a negative net benefit for an activity, but the DNO decides it is in the best interests of consumers to continue the activity, the DNO should include an explanation of what has changed and why the DNO is continuing the activity.

N/A

Calculation of benefits
Explain how the benefits have been calculated, including all assumptions used and details of the counterfactual scenario against which the benefits are calculated.

Demand Side Response:

No additional benefits are being claimed within this reporting year, as the avoided cost of reinforcement was recorded in the 2016/17 submission. However costs have been incurred in the year as the customer has received their annual payment for the demand side response services that they provide. These costs are derived from CV1. It is assumed that the customer will extend the demand side response agreement indefinitely.

This year we have revised how we report the Estimated Gross Avoided Costs and Estimated Losses Impact by reporting the full avoided cost for the additional substation capacity, without deducting the cost of losses from greater utilisation of the existing assets.

Transformer regeneration:

The costs used in the CBA are derived from table CV9 of the Costs and Volumes pack. The losses impact is calculated in terms of the increase in losses seen annually for each year in which the life of the transformer has been extended in comparison to the losses of a modern equivalent transformer.

The cost of oil regeneration at those sites which are 'mid-life' have been accounted for, however the avoided cost of the replacement transformer has not been included. This is because we are not necessarily extending the life of the asset, but conducting regeneration at different points within the life cycle in order to identify the optimum timing for regeneration activities.

This year we have made an adjustment to the costs in FY18 reported under the Estimated Gross Avoided Costs category as we had misallocated a primary site as a grid site in the baseline scenario. This reduced the savings by £0.6m in 2018. A corresponding change has made to the 2018 losses figures in the Estimated Losses Impact category and a revised value has been submitted for the 2017 losses figure to correct a reporting error.

LV Fault Management:

The CBA is informed by the number of phases on LV ways fitted with reclosing devices during 2018/19, the number of times the devices operated prior to the fault being located and repaired, and the number of customers fed off each phase of each way. It is assumed faults occurred linearly throughout the week and therefore costs for the baseline case include premium time working. Each callout to replace a fuse is costed at three hours and it is assumed that customers are without supply for at least 90 minutes.

Repairs are assumed to commence immediately a fault becomes permanent. It is assumed that the installation of reclosing devices removes the requirement for fuse replacement and as supplies are restored within three minutes, the Customer Interruptions and Customer Minutes Lost are reduced. The input from the Fault Support Centre allows faults to be located prior to becoming permanent and it is assumed that all faults were repaired during normal working hours. The cost of setting up the FSC was included in year 1 of the CBA.

PV Connect & Manage:

The volumes used for this CBA were based on the numbers of customers added to the Feed-In Tariff database during 2018/19. This year we have reviewed the assumptions in the baseline methodology of the CBA as the potential intervention (altering the transformer taps) from single applications had not been previously included. For the baseline scenario, it was assumed that there would be a requirement to purchase a tool for LV system analysis and that clusters of PV would consist of 24 properties covering 20% of the total number of applications. The remaining 80% would be single applications. Planning time was allocated at 12 hours per scheme for larger schemes and one hour per scheme for smaller schemes.

Traditional intervention solutions for the clusters were split between LV cable overlay (5%), transformer change (5%) and altering transformer taps (40%), with 50% not requiring any intervention. For single applications it was assumed that 1% of applications would require transformer taps to be altered.

For the Connect & Manage scenario, it was assumed that 20% of the applications would lead to LV system monitoring being installed and 20% of the total number would require further planning. Of those that require planning and monitoring, it was assumed that only 10% would require any reinforcement works, and of this 10%, 10% would require an LV cable overlay and 90% would require the tap positioning to be altered. There has been a significant increase in the availablility of monitoring technology due to increased competition which has reduced the cost of monitoring equipment this year and so the costs of installing this equipment have been revised downwards going forward.

These methodological changes have had the impact of revising previously reported values. These are in the catergories of: Estimated Gross Avoided Costs (increase); Estimated CI Impact (decrease); and Estimated CML Impact (decrease) from 2016 to 2018 as the altering of transformer taps requires a substation outage which interrupts customers.

In the CBA calculations the Feed-In Tariff number was provided by Ofgem. This number (1,159) differs from the PV installed number in table E7 (1,052) which is the number of installations that we had been informed of.

Capacity to Customers:

The actual connections costs are the total of the connection costs for an N-0 solution paid by the customer for the four schemes connected at EHV. The benefits were calculated by assuming that the reinforcement would consist of simply looping in the supply with unit costs of £300 per metre and £200k for a primary switchboard change. It was also assumed that the customer would pay 100% of the additional costs as the increased security is wholly for their benefit.

This year ENWL has introduced a methodology for estimating the avoided costs of HV distributed generation schemes that also benefit from the capacity to customers solution. This is an extension to the current approach applied to new EHV distributed generation connections as we recognise that the C2C solution has been applied more frequently to HV connected distributed generation than EHV connected distributed generation. The benefits were calculated by applying an assumed reinforcement element for HV sites, varying by size of generation. These values were determined by ENWL undertaking a review of schemes energised and defining the number that triggered reinforcement, and of those schemes, the number that were defined as sole use, and the costs that would have been apportioned between the connecting customer and DUoS customers. These costs would be apportioned as per the CCCM.

This year we have revised the heading category that we report the impact of the this innovative solution as these schemes included DUoS funded elements of reinforcement that had been avoided; the final figures for these solutions have been reported on separate lines (ie customer and DUoS) within the reporting pack under the heading of Improving Connections Performance. Whereas we had previously categorised these under the heading of Increasing Network Capacity / Utilisation.

Cost benefit analysis additional information
Please include a reference to the file name and location of any additional relevant evidence submitted to support the costs and benefits inputted into this worksheet. This should include the most recent CBA for each solution reported in the Regulatory Year under report.

The relevant CBAs are contained in the following Excel files:

C2C CBA FY19 RIIO ED1 CBA V1.0
Demand Side Response FY19 RIIO ED1 CBA v1.0
LV fault management FY19 RIIO ED1 CBA v1.0
PV Connect & Manage FY19 RIIO ED1 CBA V1.0
TX Regen CBA FY19 RIIO ED1_v1.0

E7 – LCTs

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.

The ENW definition of secondary (up to 11kV) and primary (33kV and above) networks was used to disaggregate between the types of networks connected on to.

LCT – Processes used to report data (i) Please explain processes used to calculate or estimate the number and size of each type of LCT. (ii) If any assumptions have been made in calculating or estimating either of these values, these must be noted and explained.

The number of secondary network low carbon technologies installed was provided by the Data Management and Connections teams.

LCTs Installed – Secondary Networks Heat Pumps

From the Data Management Heat Pumps database the number of heat pump units installed in 2018/19 was filtered from the Date Approved / Received with any blank entries not counted.

Using this filter the following volumes were identified:

88 units of total heat pump size of 798.08 kVA.

To convert the kVA to MW a conversion factor of 1 kVA = 0.001 MW was used to give a total of 0.79808 MW.

LCTs Installed – Secondary Networks EV Slow Charge (up to 16A/3.7kW draw-down)

From the Data Management SSEG database (EV NEW, HP & EV and IDNO – EV tables) the secondary networks EV slow charge units installed in 2018/19 was identified:

- EV New worksheet by filtering on the date of installation and size with any blank or non-numeric data not counted.
- IDNO – EVs worksheet by energisation date and size with any blank data not counted. Only addresses within the ENW distribution area were counted.

From the EV NEW Table: 4 units
From the IDNO - EV Table: 0 units (up to 16A)

Total 2018/19 = 4 EV slow charge units installed.

To convert the size to maximum export allowed in MW a draw down of 3.7kW for each 16A units was assumed to give a total of 0.0148 MW (4 x 3.7 / 1000).

LCTs Installed – EV Fast Charge (above 16A/3.7kW draw-down)

From the Data Management SSEG database (EV NEW and IDNO-EV'S tables) the secondary networks EV fast charge units installed in 2018/19 was identified:

- EV New worksheet by filtering on the date of installation and size with any blank or non-numeric data not counted.
- IDNO – EVs worksheet by energisation date and size with any blank or non-numeric data not counted. Only addresses within the ENW distribution area were counted.

From the EV NEW Table: 67 units (greater than 16A)
From the IDNO - EV Table: 0 units (greater than 16A)

Total 2018/19 = 67 EV fast charge units installed.

To convert the size to maximum export allowed in MW a draw down of 7kW for each unit was assumed to give a total of 0.469 MW (67 x 7 / 1000).

LCTs Installed – Secondary Networks PVs (G83)

From the Data Management SSEG database (SSEG, IDNO SSEGs and SSEG + Battery tables) the PV units installed in 2018/19 was filtered by the Energisation Date with any blank entries not counted. Only those in the ENW distribution area were counted.

Using this filter the following volumes were identified:

From SSEG tab: 948 units totalling 2,986.791 kW
From IDNO SSEGs tab: 104 units totalling 158.975 kW
From SSEG + Battery tab: 0 units

The total number of units installed is 948 + 104 = 1,052
The total kW installed is 2,986.791 + 158.975 = 3,145.766

To convert the kVA to MW a conversion factor of 1 kVA = 0.001 MW was used to give a total of 3.145766 MW.

LCTs Installed – Other DG (G83)

The DG database provided by Connections indicated that no G83 generation other than photovoltaic was installed in 2018/19.

LCTs Installed – Secondary Networks DG (non G83)

From the information provided by Connections the number of units installed was:

Low voltage network 61
High voltage network 22.

Total units connected = 61 + 22 = 83

From the information provided by Connections the MW connected was:

Low voltage network 3.62 MW
High voltage network 65.47 MW

Total MW connected =3.62 + 65.47 = 69.09

LCTs Installed – Primary Networks DG (non G83)

From the information provided by Connections, the units installed at 33 kV and above was 1 with 50 MW connected.

LCT - Uptake
Please explain how the level of LCT uptake experienced compares to the forecast in your RIIO-ED1 Business Plan and the DECC low carbon scenarios. This must also include any expectation of changes in the trajectory for each LCT over the next Regulatory Year in comparison to actuals to date.

Overall, the volume of LCTs installed has been decreasing. However, the data relies on installers accurately reporting installations to Electricity North West and may not reflect actual installations.

The volume of small photovoltaic installations has increased in 2018/19 compared to 2017/18. There was a spike towards the end of the year. This is assumed to be associated with the deadline for the removal of the feed-in-tariff support.

In our RIIO-ED1 Business Plan we concluded that the DECC Low scenario was the most probable estimate for our region over the period. The uptake in the first two years of the RIIO-ED1 period is indicating an overall uptake at the end of the persio that is significantly below the forecast.