RIIO-ED1 RIGs Environment and Innovation Commentary

2019-20

Electricity North West

Contents

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 £1,248. 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 categoies were newly introduced that year. Primary spend drivers have now been established to enable this data to be captured. So that the total cost in cell U21 matches cell V17 of table CV22 in the C&V pack, credit adjustments for small tools and equipment, changes in contractor and increased pension costs, of £3,820 were subtracted from cell U12. **Fluid Filled Cables**

The total for fluid filled cable in service (cell AL24) was calculated by adding together the asset volumes for 2019/20 for 33kV UG Cable (Oil) and 132kV UG Cable (Oil) from table V1. The volumes were 238.73km of 33kV cable (cell BU86 of V1) and 144.5km of 132kV cable (cell BU116 of V1) giving a total for fluid filled cable in service of 383.23km.
 	
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:
 	
➢ 238.73km of 33 kV cable = 208.73km of three core and 30km of single core
  o 30km of single core x 1,560 litres per km = 46,800 litres of oil
  o 208.73km of three core x 1,300 litres per km = 271,349 litres of oil
  o 238.73km of 33kV cable x 1.1835 tanks per km x 173.525 litres per tank = 49,027.23 litres of oil
 	
➢ 144.5km of 132kV cable = 100.5km of three core and 44km of single core
  o 44km of single core x 4,800 litres per km = 211,200 litres of oil
  o 100.5km of three core x 4,000 litres per km = 402,000 litres of oil
  o 144.5km of 132kV cable x 1.7605 tanks per km x 337.985 litres per tank = 85,980.76 litres of oil
 	
➢ Total of 46,800 + 271,349 + 49,027.23 + 211,200 + 402,000 + 85,980.76 = 1,066,356.99 litres of oil in service (cell AL25).
 	
The figure for fluid used to top up cables (21,616 litres) (cell AL26) 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.
16 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 2019-20.

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.
N/A

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 2019-20. 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 2019-20. 7 oil mitigation schemes were undertaken relating to work on: • Bispham BSP GT2 • Longridge • Lancaster Broadway • Ardwick • Ancoats • Higgins Lane, Burscough • Strawberry Bank 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 nominal distances are used of 4.8 kilometres one-way and 9.6 kilometres return. 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.

[1] Greenhouse gas protocol

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. 2019 were used in calculations.

Expiry:	31/07/2020	**Factor set:**	Standard set
Version:	1.0	**Year:**	2019

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 Government Conversion Factors for Company Reporting* were used:

Activity	Country	Unit	Year	kg CO_2e
Electricity generated	Electricity: UK	kWh	2019	0.2556

For 2019/20 the calculation is as follows:

- Consumption = 4,663,158.59 kWh x 0.2556/1,000 = 1,191.9 tCO2e.

To ensure this figure was the 2020 entry in table E3 a scalar of 0.0002556 (cell BC14) was used:

- Total consumption 2019/20 = 4,663,158.59 kWh (cell BS14) x 0.0002556 = 1,191.9 (cell AH14).

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	2019	0.2556

For 2019/20 the calculation is as follows:

- Consumption = 14,293,911.99 kWh x 0.2556/1,000 = 3,653.52 tCO2e.

To ensure this figure was the 2020 entry in table E3 a scalar of 0.0002556 (cell BC16) was used:

- Total consumption 2019/20 = 14,293,911.99 kWh (cell BS16) x 0.0002556 = 3,653.52 (cell AH16).

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	2.59411

For 2019/20 the calculation is as follows:

- Consumption = 1,617,962.00 litres x 2.59411 /1,000 = 4,197.17 tCO2e.

To ensure this figure was the 2020 entry in table E3 a scalar of 0.00259411 (cell BC22) was used:

- Total consumption 2019/20 = 1,617,962.00 litres (cell BS22) x 0.00259411 = 4,197.17 (cell AH22).

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	0.22868	0.24736
	Medium car	miles	0.27459	0.30945
	Large car	miles	0.33713	0.45536

For 2019/20 the calculation is as follows:

- Small petrol car: 634,222.00 miles x 0.24736/1,000 = 156.88 tCO2e.
- Medium petrol car: 650,846.00 miles x 0.30945/1,000 = 201.4 tCO2e.
- Large petrol car: 281,695.00 miles x 0.45536/1,000 = 128.27 tCO2e.
- Small diesel car: 1,104,743.00 miles x 0.22868/1,000 = 252.63 tCO2e.
- Medium diesel car: 985,823.00 miles x 0.27459/1,000 = 270.7 tCO2e.
- Large diesel car: 987,960.00 miles x 0.33713/1,000 = 333.07 tCO2e.

This gives a total of 1,342.96 tCO2e. To ensure this figure was the 2020 entry in table E3 a scalar of 0.000289102 (cell BC32) was used:

- Total consumption 2019/20 = 4,645,289.00 miles (cell BS32) x 0.000289102 = 1,342.96 (cell AH32).

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 LNER carbon calculator website. The mileages are then converted into kilometres for calculating the tCO2e.

To calculate the London Underground element of rail journey nominal distances are used of 4.8 kilometres one-way and 9.6 kilometres return.

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	0.04115
	London Underground	passenger.km	0.03084

For 2019/20 the calculation is as follows:

- National Rail: 519,957.46 km x 0.04115/1,000 = 21.39 tCO2e.
- London Underground: 8,179.6 km x 0.03084/1,000 = 0.25 tCO2e.

This gives a total of 21.64 tCO2e. To ensure this figure was the 2020 entry in table E3 a scalar of 0. 00004098 (cell BC33) was used:

- Total consumption 2019/20 = 528,137.06 km (cell BS33) x 0.00004098 = 21.64 (cell AH33).

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	0.25493
	Short-haul, to/from UK	Economy class	passenger.km	0.15573
	Long-haul, to/from UK	Business class	passenger.km	0.43446

For 2019/20 the calculation is as follows:

- Domestic, to/from UK, average passenger: 11,738.00 km x 0.25493/1,000 = 2.99 tCO2e.
- Short-haul, to/from UK, economy class: 121,175.00km x 0.15573/1,000 = 18.87 tCO2e.
- Long-haul, to/from UK, business class: 178,107.00 km x 0.43446/1,000 = 77.38 tCO2e.

This gives a total of 99.25 tCO2e. To ensure this figure was the 2020 entry in table E3 a scalar of 0.000319112 (cell BC35) was used:

- Total consumption 2019/20 = 311,020 km (cell BS35) x 0.000319112 = 99.25 (cell AH35).

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 2019/20 the calculation is as follows:

- 77.73 kg x 22,800/1000 = 1,772.24 tCO2e

To ensure this figure was the 2020 entry in table E3 a scalar of 22.80 (cell BC46) was used:

- Total emissions 2019/20 = 77.73kg (cell BS46) x 22.80 = 1,772.24 (cell AH46).

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
	R32	kg	675

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 2019/20 is recorded in the 'FY20 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: 0.233 tCO2e.
- R407C: 1.344 tCO2e.
- R410A: 14.445 tCO2e.
- R32: 0.019 tCO2e.

This gives a total of 16.041 tCO2e.

The total calculated refrigerant loss over the year was 7.832 kg

To ensure this figure was the 2020 entry in table E3 a scalar of 2.05 (cell BC47) was used:

- Total emissions 2019/20 = 7.832 kg (cell BS47) x 2.05 = 16.04 (cell AH47).

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	2.59411

For 2019/20 the calculation is as follows:

Consumption: 26,846.00 litres x 2.59411/1,000 = 69.64 tCO2e.

To ensure this figure was the 2020 entry in table E3 a scalar of 0.00259411 (cell BC53) was used:

- Total consumption 2019/20 = 26,846.00 litres (cell BS53) x 0.00259411 = 69.64 (cell AH53).

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	2.75821
	Petrol (average biofuel blend)	litres	2.20904

For 2019/20 the calculation is as follows:

- Petrol consumption: 20,080.00 litres (average biofuel petrol) x 2.20904/1,000 = 44.357 tCO_2e.
- Gas oil consumption: 52,376.00 litres x 2.75821/1,000 = 144.464 tCO_2e

This gives a total of 188.82 tCO_2e. To ensure this figure was the 2020 entry in table E3 a scalar of 0.00260601 (cell BC55) was used:

- Total consumption 2019/20 = 72,456.00 litres (cell BS55) x 0.00260601 = 188.82 (cell AH55).

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 V1.0 2019 were used in calculations.

Expiry:	31/07/2020	**Factor set:**	Standard set
Version:	1.0	**Year:**	2019

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 tCO_2e 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	2.59411

For 2019/20 the calculation is as follows:

Consumption = 1,232,134.76 litres x 2.59411/1,000 = 3,196.29 tCO2e.

To ensure this figure was the 2020 entry in table E3 a scalar of 0.00259411 (cell BC74) was used:

- Total consumption 2019/20 = 1,232,134.76 litres (cell BS74) x 0. 00259411 = 3,196.29 (cell AH74).

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	1.5226

Activity	Fuel	Unit	kg CO_2e
Liquid fuels	Gas oil	litres	2.75821
	Petrol (average biofuel blend)	litres	2.20904

For 2019/20 the calculation is as follows:

- Petrol consumption = 13,055.65 litres (average biofuel petrol) x 2.20904/1,000 = 28.84 tCO2e.
- Gas oil consumption = 814,567.7 litres x 2.75821/1,000 = 2,246.75 tCO2e
- LPG consumption = 16,908.93 litres x 1.5226/1,000 = 25.75 tCO2e.

This gives a total of 2,301.33 tCO2e. To ensure this figure was the 2020 entry in table E3 a scalar of 0.002724976 (cell BC101) was used:

- Total consumption 2019/20 = 844,532.28 litres (cell BS101) x 0.002724976 = 2,301.33 (cell AH101).

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* V1.0 2019 were used.

Expiry:	31/07/2020	**Factor set:**	Standard set
Version:	1.0	**Year:**	2019

Activity	Country	Unit	Year	kg CO_2e
Electricity generated	Electricity: UK	kWh	2019	0.2556

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 (2020) submission is based on the same assumptions as the 2015 Losses Strategy.

<u>Technical Losses</u>

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 0.7701.

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 0.2917.

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 are 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)

Five primary transformers were delivered in 2019-2020.

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 are 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.

Non-Technical Losses

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 2019-2020 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 lower than costs during 2019-2020 we report a positive 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.

Technical Losses

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 300mm2 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 2019-2020 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 less 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 300mm2 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.

Non-Technical Losses

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	2020 Install 300sqmm HV Cable versus 185sqmm HV
Opportunistic installation with 300mm^2 LV cable	Other	2020 Install 300sqmm LV Cable versus 185sqmm LV
Proactive replacement of 1000kVA ground mounted transformers	Equipment to manage losses	2020 Proactive 1000kVA GMT Replacement CV21
Opportunistic installation of primary transformers (33kV/HV)	Other	2020 Programme 23MVA Replacement
Relevant Theft of Electricity	Other	2020 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 £2.5m Smart Meter Communication Licensee Costs for 2019-20 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 £0.5m compared to last year as a result of the DCC increasing the monthly fixed charges for Electricity Distributors.

Smart Meter Information Technology Costs

The £1.4m IT costs incurred in 2019-20 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 £0.4m as there has been less of a requirement for integration work than in the previous period.

Development work has taken place to cater for changes in scope, including DCC Release3 (SMETS1 adoption).

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. In the longer term, we expect benefits from the use of this non-elective data procured as part of the Smart Meter Communication Licensee Costs. This will enable us to manage our network more effectively and efficiently for customers.

DNO's have previously assessed the benefits of non-elective 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 approximately 122,000 SMETS1 and SMETS2 meters enrolled in our region (as at June 2020). This represents approximately 5% penetration of exit points within our footprint. Supplier installations in the North of the country continue to lag behind the Southern and Central regions.

Since November 2019, there has been a gradual increase in the volume of SMETS2 meters being installed in our area, although this has been disrupted by the Covid-19 pandemic. Communications problems continue, especially in the area of power outage and restoration alerts and these are areas where benefits are envisaged.

Elective communication services

Our DCC user interface provides for access to half-hourly readings and meter logs. 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.

Work continues 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 (DSR)

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 (ie under a fault situation), as the demand exceeds the transfer firm capacity. Deferring the reinforcement by 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, and £17,050 for years FY20 - 23 as ENWL has purchased 3 MVA of DSR for 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. This 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 populated with information on the number of LV ways fitted with reclosing devices during 2019–20, 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) enables 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 G98 notifications received during 2019-20. 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 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 2019 to March 2020 (ie RIIO-ED1, year 5).

Innovative Solutions

There are five Innovative Solutions which form part of our business as usual activities during 2019/20:

- Demand Side Response (Catterall)
- Transformer regeneration (combined with 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 below as separate projects; however for the purpose of the CBA (Transformer Regeneration) they are brought together in combination to provide the innovative solution, to avoid double counting of the associated costs and benefits.

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 transformer or the circuit supplying the 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 mitigate the need for 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.

LV Fault Management – Fault Support Centre

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.

LV Fault Management – Smart Fuse Devices

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 lower reinforcement costs recovered through lower DUoS charges. Environmental benefits also accrue because 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 included in 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.

LV Fault Management

The CBA is informed by the number of phases on LV ways fitted with reclosing devices during 2019/20, 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 enables 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 G98 notification received during 2019/20. This year we have reviewed the assumptions in the baseline methodology of the CBA as the potential intervention (altering of 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 availability 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.

Capacity to Customers

Both EHV and HV costs and benefits are claimed within the financial year of energisation of the scheme. This is because the benefits of the scheme (ie the difference between innovative solution and the counterfactual) are not realised until the scheme is energised. The counterfactual scheme is only developed and the associated costs calculated when the actual scheme is energised as it is only then that the total actual scheme costs are known; this ensures clarity on the derivation of the counterfactual values rather than artificially being split over multiple years.

For the eight schemes connected at EHV, the actual connections costs are the total of the connection costs for an N-0 solution paid by the customer. The benefits were calculated by studying the counterfactual solution required to provide additional connection security for each scheme.

ENWL deploys 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 included an additional solution type under which we report the impact of this innovative solution as these schemes include Sole Use elements of reinforcement that had been avoided; the final figures for these solutions have been reported on separate lines (ie Customer, Sole Use Customer and DUoS), whereas we had previously only reported Customer and DUoS avoided costs.

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 FY20 RIIO ED1 CBA V1.0
Demand Side Response FY20 RIIO ED1 CBA v2.0
LV fault management FY20 RIIO ED1 CBA v1.0
PV Connect & Manage FY20 RIIO ED1 CBA V1.0
TX Regen CBA FY20 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 2019/20 was filtered from the Date Approved / Received with any blank entries not counted.

Using this filter the following volumes were identified:

354 units of total heat pump size of 2314.16 kVA.

To convert the kVA to MW a conversion factor of 1 kVA = 0.001 MW was used to give a total of 2.3 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 2019/20 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: 81 units
From the IDNO - EV Table: 0 units (up to 16A)

Total 2019/20 = 81 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 0.3 MW (81 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 2019/20 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: 944 units (greater than 16A)
From the IDNO - EV Table: 10 units (greater than 16A)

Total 2019/20 = 954 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 6.678 MW (954 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 2019/20 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: 942 units totalling 2,767.05 kW
From IDNO SSEGs tab: 32 units totalling 46.34 kW
From SSEG + Battery tab: 6 units totalling 65.77kW

The total number of units installed is 942 + 32 + 6 = 980
The total kW installed is 2767.05 + 46.34 + 65.77= 2879.16

To convert the kVA to MW a conversion factor of 1 kVA = 0.001 MW was used to give a total of 2.87916 MW.

LCTs Installed – Other DG (G83)

The DG database provided by Connections indicated that no G83 generation other than photovoltaic was installed in 2019/20.

LCTs Installed – Secondary Networks DG (non G83)

From the information within the DG database the number of units installed was:

Low voltage network 43
High voltage network 5

Total units connected = 43 + 5 = 48

From the information within the DG database the MW connected was:

Low voltage network 3.42 MW
High voltage network 4.05 MW

Total MW connected =3.42 + 4.05 = 7.47

LCTs Installed – Primary Networks DG (non G83)

From the information within the DG database units installed at 33 kV and above was 10 with 193.86 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 decreased in 2019/20 compared to 2018/19. This is assumed to be associated with the deadline for the removal of the feed-in-tariff support. However the number of heat pumps and electric vehicles has increased significantly compared to 2018/19.

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.