RIIO-ED1 RIGs Environment and Innovation Commentary, version 0.0

[2022-2023]

[Electricity North West Limited]

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.

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.

Oil Filled Cables

The total for oil filled cable in service (cell AO26) was calculated by adding together the asset volumes for 2022/23 for 33kV UG Cable (Oil) and 132kV UG Cable (Oil) from table V1. The volumes were 204km of 33kV cable and 142km of 132kV cable giving a total for fluid filled cable in service of 3.46km.

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:

- 204km of 33 kV cable = 174km of three core and 30km of single core
  - 30km of single core x 1,560 litres per km = 46,800 litres of oil
  - 174km of three core x 1,300 litres per km = 226,200 litres of oil
  - 204km of 33kV cable x 1.1835 tanks per km x 173.525 litres per tank = 41,894 litres of oil

- 142km of 132kV cable = 98km of three core and 44km of single core
  - 44km of single core x 4,800 litres per km = 211,200 litres of oil
  - 98km of three core x 4,000 litres per km = 392,000 litres of oil
  - 142km of 132kV cable x 1.7605 tanks per km x 337.985 litres per tank = 84,493 litres of oil

- Total of 46,800 + 226,200 + 41,894 + 211,200 + 392,000 + 84,493 = 1,002,587 litres of oil in service (cell AO27).

The figure for fluid used to top up cables (13,217 litres) (cell AO28) 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.
N/A

Where reported in the Regulatory Year under report, DNOs must provide details of any Non-Undergrounding Visual Amenity Schemes undertaken.
N/A

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 2022-23. 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 2022-23.

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.

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

[1] Greenhouse gas protocol

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 V2. 2022 were used in calculations.

Expiry:	08/06/2023	**Factor set:**	Condensed set
Version:	2.0	**Year:**	2022

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	2022	0.19338

For 2022/23 the calculation is as follows:

- Consumption = 4,176,472.67 kWh x 0.19338/1,000 = 807.65 tCO2e.

To ensure this figure was the 2023 entry in table E3 a scalar of 0.00019338 (cell BF14) was used:

- Total consumption 2022/23 = 4,176,472.67 kWh (cell BV14) x 0.00019338 = 807.65 (cell AK14).

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	2022	0.19338

For 2022/23 the calculation is as follows:

- Consumption = 13,323,598.51 kWh x 0.19338/1,000 = 2,576.52 tCO2e.

To ensure this figure was the 2023 entry in table E3 a scalar of 0.00019338 (cell BF16) was used:

- Total consumption 2022/23 = 13,323,598.51 kWh (cell BV16) x 0.00019338 = 2,576.52 (cell AK16).

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	2.55784

For 2022/23 the calculation is as follows:

- Consumption = 1,680,865.75 litres x 2.55784/1,000 = 4,299.39 tCO2e.

To ensure this figure was the 2023 entry in table E3 a scalar of 0.00255784 (cell BF22) was used:

- Total consumption 2022/23 = 1,680,865.75 litres (cell BV22) x 0.00255784 = 4,299.39 (cell AK22).

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	Hybrid	PHEV	EV
Activity	Type	Unit	kg CO_2e	kg CO_2e	kg CO_2e	kg CO_2e	kg CO_2e
Cars (by size)	Small car	miles	0.22514	0.2358	0.16628	0.03567 0.04481	
	Medium car	miles	0.27039	0.29724	0.17702	0.10421 0.03126	
	Large car	miles	0.33722	0.4448	0.24929	0.11924 0.04039	
	Average car	Miles					0.07578

For 2022/23 the calculation is as follows:

- Small petrol car: 430,297.00 miles x 0.2358/1,000 = 101.46 tCO2e.
- Medium petrol car: 177,283.00 miles x 0.29724/1,000 = 52.70 tCO2e.
- Large petrol car: 22,070.00 miles x 0.4448/1,000 = 9.82 tCO2e.
- Small diesel car: 413,808.00 miles x 0.22514/1,000 = 93.16 tCO2e.
- Medium diesel car: 446,127.00 miles x 0.27039/1,000 = 120.63 tCO2e.
- Large diesel car: 708,184.00 miles x 0.33722/1,000 = 238.81 tCO2e.
- Small hybrid car: 2,161.00 miles x 0.16628/1000 = 0.36 tCO2e.
- Medium hybrid car: 230,911.60 miles x 0.17702/1000 = 40.88 tCO2e.
- Large hybrid car: 219,804.00 miles x 0.24929/1000 = 54.79 tCO2e.
- Small PHEV car: 7,306.00 miles:
  - Combustion engine: 7,306.00 miles x 0.03567/1000 = 0.26 tCO2e.
  - EV motor: 1,461.20 miles x 0.04481/1000 = 0.07 tCO2e

        - Combined: 0.26 + 0.07 = 0.33 tCO2e
- Medium PHEV car: 52,129.00 miles:
    - Combustion engine: 52,129.00 miles x 0.10421/1000 = 5.43 tCO2e.
    - EV motor: 10,425.80 miles x 0.03126/1000 = 0.33 tCO2e.
        - Combined: 5.43 + 0.33 = 5.76 tCO2e
- Large PHEV car: 48,356.00 miles:
    - Combustion engine: 48,356.00 miles x 0.11924/1000 = 5.77 tCO2e.
    - EV motor: 9,671.20 miles x 0.04039/1000 = 0.39 tCO2e
        - Combined: 5.77 + 0.39 = 6.16 tCO2e
- Average EV car: 104,385.80 miles x 0.07578/1000 = 7.91 tCO2e

To calculate the EV element for PHEV and EV until we have further data around charging habits, we are applying the Pareto principle and assuming 80% of charging takes place at one of our depots and will be included in our Buildings Electricity with the remaining 20% being included here.

This gives a total of 732.76 tCO2e. To ensure this figure was the 2023 entry in table E3 a scalar of 0.000254044 (cell BF32) was used:

- Total consumption 2022/23 = 2,884,380.6 miles (cell BV32) x 0.000254044 = 732.76 (cell AK32).

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	0.03549
	London Underground	passenger.km	0.02781

For 2022/23 the calculation is as follows:

- National Rail: 138,046.47 km x 0.03549/1,000 = 4.90 tCO2e.
- London Underground: 1,771.20 km x 0.02781/1,000 = 0.05 tCO2e.

This gives a total of 4.95 tCO2e. To ensure this figure was the 2023 entry in table E3 a scalar of 0.0000354038 (cell BF33) was used:

- Total consumption 2022/23 = 139,817.67 km (cell BV33) x 0.0000354038 = 4.95 (cell AK33).

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	0.24587
	Short-haul, to/from UK	Economy class	passenger.km	0.15102
	Long-haul, to/from UK	Business class	passenger.km	0.42882

For 2022/23 the calculation is as follows:

- Domestic, to/from UK, average passenger: 10,124.00 km x 0.24587/1,000 = 2.49 tCO2e.
- Short haul, to/from UK, economy class: 73,268.00 km x 0.15102/1,000 = 11.06 tCO2e.
- Long haul, to/from UK, business class: 0 km x 0.42882/1,000 = 0 tCO2e.

This gives a total of 13.55 tCO2e. To ensure this figure was the 2023 entry in table E3 a scalar of 0.000162486 (cell BF35) was used:

- Total consumption 2022/23 = 83,392.00km (cell BV35) x 0.000162486 = 13.55 (cell AK35).

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 2022/23 the calculation is as follows:

- 38.24 kg x 22,800/1000 = 871.87 tCO2e

To ensure this figure was the 2023 entry in table E3 a scalar of 22.80 (cell BF46) was used:

- Total emissions 2022/23 = 38.24kg (cell BV46) x 22.80 = 871.87 (cell AK46).

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 2021/22 is recorded in the ‘FY22 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: 1.344 tCO2e.
- R410A: 14.99 tCO2e.
- R32: 0.005 tCO2e.

This gives a total of 16.60 tCO2e.

The total calculated refrigerant loss over the year was 8.10 kg.

To ensure this figure was the 2023 entry in table E3 a scalar of 2.0495 (cell BF47) was used:

- Total emissions 2022/23 = 8.10 kg (cell BV47) x 2.0495 = 16.60 (cell AK47).

DNO Emissions: Fuel Combustion – Diesel

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

Note: These fuel cards are no longer used, and this consumption is included in 'Operational Transport – Road'

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	2.55784

For 2022/23 the calculation is as follows:

Consumption: 0 litres x 2.55784/1,000 = 0 tCO2e.

To ensure this figure was the 2023 entry in table E3 a scalar of 0.00255784 (cell BF53) was used:

- Total consumption 2022/23 = 0 litres (cell BV53) x 0.00255784 = 0 (cell AK53).

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	2.75857
	Petrol (average biofuel blend)	litres	2.16185

For 2022/23 the calculation is as follows:

- Petrol consumption: 20,519.29 litres (average biofuel petrol) x 2.16185/1,000 = 44.36 tCO2e.
- Gas oil consumption: 0 litres x 2.75857/1,000 = 0 tCO2e

This gives a total of 44.36 tCO2e. To ensure this figure was the 2023 entry in table E3 a scalar of 0.00216187 (cell BF55) was used:

- Total consumption 2022/23 = 20,519.29 litres (cell BV55) x 0.00216187 = 44.36 (cell AK55).

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 V2.0 2022 were used in calculations.

Expiry:	08/06/2023	**Factor set:**	Condensed set
Version:	2.0	**Year:**	2022

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	2.55784

For 2022/23 the calculation is as follows:

Consumption = 738,993.63 litres x 2.55784/1,000 = 1,890.23 tCO2e.

To ensure this figure was the 2023 entry in table E3 a scalar of 0.00255784 (cell BF74) was used:

- Total consumption 2022/23 = 738,993.63 litres (cell BV74) x 0.00255784 = 1,890.23 (cell AK74).

Contractor Emissions: Fuel Combustion – Diesel

The fuel combustion diesel figure is calculated from fuel litres used data provided by contractors in relation to their generator usage on our behalf.

In previous years generators were fuelled by gas oil and would have been included in 'Contractor Emissions: Fuel Combustion – Other'. This change took place following legislation changes restricting the entitlement to use gas oil (red diesel) which took place from April 2022.

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	2.55784

For 2022/23 the calculation is as follows:

Consumption = 1,006,135.00 litres x 2.55784/1,000 = 2,573.53 tCO2e.

To ensure this figure was the 2023 entry in table E3 a scalar of 0.00255784 (cell BF99) was used:

- Total consumption 2022/23 = 1,006,135.00 litres (cell BV99) x 0.00255784 = 2,573.53 (cell AK99).

Contractor Emissions: Fuel Combustion – Other

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

In previous years this would have also included gas oil (red diesel) in relation to generator usage on our behalf. These emissions are now included in 'Contractor Emissions: Fuel Combustion – Diesel'. This change took place following legislation changes restricting the entitlement to use gas oil (red diesel) which took place from April 2022

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	1.55709

Activity	Fuel	Unit	kg CO_2e
Liquid fuels	Gas oil	litres	2.75857
	Petrol (average biofuel blend)	litres	2.16185

For 2022/23 the calculation is as follows:

- Petrol consumption = 73,469.38 litres (average biofuel petrol) x 2.16185/1,000 = 158.83 tCO2e.
- Gas oil consumption = 0 litres x 2.75857/1,000 = 0 tCO2e
- LPG consumption = 0 litres x 1.55709/1,000 = 0 tCO2e.

This gives a total of 158.83 tCO2e. To ensure this figure was the 2023 entry in table E3 a scalar of 0.00216185 (cell BF101) was used:

- Total consumption 2022/23 = 73,469.38 litres (cell BV101) x 0.00216185 = 158.83 (cell AK101).

Building energy usage
Natural gas, Diesel and other fuels are all categorised as fuel combustion and must be converted to tCO_2e 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 2021 were used.

Expiry:	08/06/2023	**Factor set:**	Condensed set
Version:	2.0	**Year:**	2022

Activity	Country	Unit	Year	kg CO_2e
Electricity generated	Electricity: UK	kWh	2022	0.19338

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 (March 2021). 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 (March 2021) are listed in the Snapshot Table E4. They are however still being carried out, in line with the decision in our Losses Strategy (March 2021). The excluded initiatives are:

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

This RRP (2023) submission is based on the same assumptions as the Losses Strategy (March 2021).

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 (March 2021).

The Losses Snapshot, Table E4, includes the technical losses reduction initiatives detailed in our Losses Strategy (March 2021) 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 0.8233.

The baseline solution and losses reduction activity unit costs are the same as those assumed for our Losses Strategy (March 2021) 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 0.4060.

The baseline solution and losses reduction activity unit costs are the same as those assumed for our Losses Strategy (March 2021) 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 Losses Strategy (March 2021) 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)

Six primary transformers were delivered in 2022-2023.

The baseline solution and losses reduction activity unit costs are the same as those assumed for our Losses Strategy (March 2021) 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.

<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 2022-2023 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 higher than costs during 2022-2023 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.

<u>Non-Technical Losses</u>

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 2022-2023 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 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.

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'.

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 Volumes 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 £2.799m Smart Meter Communication Licensee Costs for 2022-23 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 £0.263m compared to last year as a result of the DCC increasing the monthly fixed charges for Electricity Distributors.

Smart Meter Information Technology Costs

The £1.692m IT costs incurred in 2022-23 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; work required to ensure systems remain compatible with the uplifts to the DCC User Interface Specification (DUIS) v5.1 specifications; the integration of Power Outage and Power Restoration Alerts with our Network Management System (NMS); integration of 'Ping' (Read Supply Status) requests with NMS, STORM (automated customer call handling) and Customer website self-service channels; and establishing a foundational Management Information (MI) capability in the Microsoft Azure cloud.

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).

Since our gateway became live in December 2017, we have approximately 551,135 SMETS1 and 525,038 SMETS2 meters enrolled in our region (as at end March 2023). This represents approximately 45% penetration of exit points within our footprint. There are approximately 276,365 SMETS1 meters installed in our distribution area which are yet to be either enrolled by DCC or upgraded to the SMETS2 specification. As SMETS1 devices, these do not provide power outage alert functionality.

Previously developed proof of concept implementations of Power Outage / Power Restore functionality have now successfully upgraded and integrated with our Production NMS system. This means that they can be used in automated decision making, although the reliability and consistency of this information is still being assessed. Work is currently completing to integrate 'Ping' functionality with NMS, STORM (automated customer call handling) and Customer website self-service channels. This should allow us to better triage a customer call and aid in fault restoration.

A foundational MI/Analytics capability is being implemented in the Microsoft Azure cloud which will give access to modern data analysis and reporting tools. These can be used to interrogate smart meter and other data at scale, supporting identification of possible new uses for smart meter data and helping to manage the quality of both asset and transactional data.

Whilst we continue to explore use cases and integrate smart meter data into our operations, significant concerns have been raised by ourselves and other DNO's with regards to the ability of the CSP-N communication network to support smart meter data at volume. This is particularly noticeable when requesting anything more than a few days of voltage or consumption data from meters which are in relatively close geographic proximity to each other. This introduces complexity to our integration and uncertainty into the efficacy and reliability of our processes. There is concern that this issue will be further exacerbated by the requirement of the Market-Wide Half-Hourly Settlement (MHHS) programme to read half hour consumption data from all smart meters nationally. We have raised our concerns in response to industry consultations in this area and strongly recommended that a holistic view of requirements be taken across both the smart meter and MHHS programmes. A reliable and efficient communication service is critical to being able to optimise investment and realise benefits.

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.

Whilst the smart meter roll out programme is now gathering momentum, it is not yet at a volume where benefits are quantifiable.

There has been a Smart Energy Code performance target change for the delivery of Power Outage Alerts (they can now take much longer than the original 60 seconds) owing to the poor performance of the CSP-N communication network with no technical solution for improving it.

A number of common issues relating to both Device and DCC functionality have been raised and are being managed by industry groups. These, along with concerns about the communication network, have potential to negatively impact current benefits realisation forecasts.

We have worked with other DNOs and industry parties to attempt to resolve issues with the smart meter system. These span a number of areas including: significant volumes of false positive alert notifications; extremely high volumes of nuisance alerts; and incorrect/inconsistent meter functionality.

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

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) P2/7, 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 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 P2/7.

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 2022–23, 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 2022-23. 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.

The avoided sole use costs have also been modelled to demonstrate the additional savings to the connecting customer of being offered a smart solution.

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 2022 to March 2023 (i.e. RIIO-ED1, year 8).

Innovative Solutions:

There are five Innovative Solutions which form part of our business as usual activities during 2022/23:

- Demand Side Response (Catterall)
- LV Fault Management (Fault Support Centre and Smart Fuse Devices)
- Connection and Management of PV Clusters (LV Smart Joint)
- Long and Crawford switchgear modifications
- Smart Street IRM

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) P2/7. 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 (i.e. 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 P2/7 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 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. The full costs and benefits are claimed within the year of completion.

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.

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 (i.e. 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 five years there has been a prioritisation of the 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 (i.e. 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.

Long & Crawford switchgear modification

What the solution is:

The urban parts within the ENWL operating area have HV networks operating predominantly at 6.6kV. A proportion of the switchgear in these areas is fault rated at 13.1kA below our design standard of 21.9kA. Although the current fault level may not exceed this design rating, the lower rated switchgear often represents a significant barrier for new connections, particularly low carbon technologies (LCTs) and distributed generation (DG).

Type testing undertaken by KEMA of Long & Crawford (L&C) 6.6kV switchgear resulted in an innovative technique which allows the use of enhanced fault ratings following a defined modification on specified L&C switchgear types to be implemented.

How the solution is being used

Two upgrade kits/procedures were developed by Long Controls Limited of St Helens and included in the test series. Such upgrades extend the short circuit withstand capabilities of J3 Ring Switches and T3GF3 Ring Main Units from 13.1kA at 6.6kV to 20kA at 6.6kV for 3 seconds.

This solution enhances the fault level capability of this lower-rated switchgear from the network to coincide with increased penetration of LCT which may otherwise be constrained or unacceptably delayed.

How the solution is delivering benefits

L&C 6.6kV switchgear represents 31% of ENWL's total switching assets, which shows the prevalence of L & C switchgear and the prioritisation of these sites to achieve maximum impact in alleviating these fault level constraints.

Smart Street Innovation Roll-Out

What the solution is:

The full solution is designed to reduce customer bills by reducing the total amount of energy consumed when supplied to customers. This involves reducing the energy consumed in losses in the ENWL network by reducing energy distributed to customers and by meshing the LV network; reduced carbon emissions flow as a result of these energy reductions and capacity released to connect new LCT technologies by improving control of the LV network.

The Innovation Roll-out Mechanism project (18 October 2019 award from Ofgem) focusses on areas of high fuel poverty to deliver benefits to those most in need. In those targeted areas it will replace 180 distribution fix tap transformers with on load tap changing (OLTC) equivalents and by using LV fuse way circuit breakers (LVCB) and link box switches enable the LV network supplied from these sites to be meshed with adjacent LV networks.

All these new devices will ultimately be autonomously controlled by our central network management system (NMS), periodically optimising the network configuration for maximum benefit.

How the solution is being used

When all technology elements are complete it will operate autonomously in the background, unless operational activity curtail its operation for safety reasons. The equipment is remotely operated by connection to the central NMS and the autonomous software takes control of the remote operation to deliver the full benefits described in the IRM bid submission.

Each OLTC transformer is being recorded as a distribution transformer (additional detail is captured in ENWL Asset systems). The LVCB are single phase devices, with three required for each LV way/Feeder. Each single-phase unit is being counted as an individual LVCB. No LV linkbox switches have yet to be installed

How the solution is delivering benefits

The project will deliver the benefits as described out above, however these will not be realised until all counterparts of the solution are installed at each site. The IRM bid outlined anticipated saving and methodology for the complete solution which has yet to be implemented.

Note: The savings, against previous operational practise, will vary every time the optimisation model is run and the network re configured.

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.

ENWL confirms that the RIIO-ED1 CBA tool has been used consistently throughout ED1 to show the costs and benefits of the innovative solutions it has employed ie the fixed data has remained constant throughout ED1, even though the carbon data was updated in 2021 by HMG, which has been adopted for the RIIO-ED2 CBA.

All costs used in the CBAs have been deflated to a 2012/13 price base for the purpose of this modelling and for consistency where these values contributed to tother mechanisms such as the load related reopener. References to the outturn cost for each relevant cost table are provided within each CBA.

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.

<u>Demand Side Response:</u>

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.

Transformer regeneration:

During 2022/23 three grid transformers had oil regeneration activities completed.

The costs 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 2022/23, 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. Data provided from the Fault Support Centre confirms whether the devices have reclosed within this 3 minute timeslot and therefore whether a saving has been achieved. 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 2022/23. Again, this year we have included within the baseline methodology of the CBA the altering of transformer taps from single applications had not been included prior to 2022. 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.

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 (i.e. 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 those 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, operational in RIIO-ED1.

The Sole Use elements of reinforcement that have been avoided are included as an additional solution type and reported on a separate line within the table. The calculation of these values follows the same process as above for EHV and HV respectively.

Long & Crawford switchgear modification

The costs of the innovative solution are derived from CV3 – fault level reinforcement and the procedure for undertaking this refurbishment is documented within ENWL's Code of Practice 390 (Fault Level Upgrades of Long and Crawford Switchgear).

This solution is being rolled out to facilitate further LCT connection onto the distribution network through increasing the fault level of existing assets. This is an alternative to traditional reinforcement of the assets, and the modification extends the life of the existing asset by up to 25 years, while increasing the fault level capacity to 20kA.

Smart Street Innovation Roll Out

No benefits have been quantified for the year 2022-2023 as the Smart Street Optimisation software was undergoing testing throughout the year, and will be implemented in the beginning of RIIO-ED2, allowing ENWL to optimise installed counterparts.. All counterparts including the software need to be installed at the specific sites before assets can be optimised and benefits can begin to be realised, Therefore this years' submission details only the costs incurred for the counterparts that were installed within the year.

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:

- Demand Side Response FY23 RIIO ED1 CBA v1.0
- LV fault management FY23 RIIO ED1 CBA v1.0
- PV Connect & Manage FY23 RIIO ED1 CBA V1.0
- TX Regen CBA FY23 RIIO ED1_v1.0
- Long Crawford FY23 RIIO ED1 CBA V1.0
- Smart Street IRM FY23 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 ENWL's Data Management and Connections teams. With regards to all of the G98 records, all reporting involved making reasonable assessments about missing date or capacity data. As such, the totals are an approximation, to provide the most accurate totals possible, detailed in the Methodology document.

LCTs Installed – Secondary Networks Heat Pumps (G98)

From the Data Management Heat Pumps database, the number of heat pump units installed in 2022/23 was filtered from the 'Date Registered on Database' column with any blank entries counted where they fell in sequence between the dates of the financial year in comparing 'Date Email Received' with 'Date Registered on Database' where there was crossover. Where the value was null the average value was applied (i.e., 822 units totalled 4680.23kVA, so 89 blanks thus applied average for sub total of 506.74kVA equalling 5186.97kVA).

911 units with total Heat Pump kVA of **5,186.97 kVA.**

To convert the kVA to MW a conversion factor of 1 kVA = 0.001 MW was used to give a total of **5.187 MW**.

LCTs Installed – Secondary Networks EV Slow Charge (up to 16A/3.7kW draw-down) (G98)

From the Data Management EV Database, the secondary networks EV slow charge units installed in 2022/23 were identified using the following:

- The EVCP table was analysed by filtering on the 'Financial Year' of installation and 'Charging Point Rating kVA'.
- No IDNO data was available for the year to Apr-23.

5 units were identified totalling **18.40 kVA**.

To convert the Charging Point Rating kVA total to maximum export allowed in MW a draw-down of 3.7kW for each 16A units was assumed to give a total of **0.018 MW**.

LCTs Installed – EV Fast Charge (above 16A/3.7kW draw-down) (G98)

From the Data Management EV Database, the secondary networks EV fast charge units installed in 2022/23 were identified using the following:

- The EVCP table was analysed by filtering on the 'Date of Installation', 'Charging Point Rating kVA', and 'Registration Date (ENWL)' where no installation date was available. Where the installed date had FY24 in the 'Financial Year' column they were added to the count as installed in FY23, and where they had a FY22 assignment, they were discounted as being assumed to have been counted in the previous year's reports. A new column 'RRP Reported' groups these together for easy reference next year. Blanks in 'Date of Installation' were counted according to the 'Registration Date (ENWL)' column that fell into FY23 dates, to approximate their commissioned dates. This totalled 1572 units. It should be noted that there is missing data for 1571 units in a sequence of entries in both the installation and registration columns, included in that total; these were placed firmly in the registration dates for FY23, and so were labelled as FY23 in the 'Financial Year' column and included in this count.
- No IDNO data was available for the year to Apr-23.

12,450 units were identified totalling **92,030.88kVA**.

To convert the Charging Point Rating kVA total to MW, a conversion factor of 1 kVA = 0.001 MW was used to give a total of **92.031MW**.

LCTs Installed – Secondary Networks PVs (G98)

From the Data Management SSEG database (SSEG, IDNO SSEGs and SSEG + Battery tables) the PV units installed in 2022/23 was filtered by the Commissioned Date and Plant Capacity kW, with any blank entries included where they were evaluated by reasonable assumption to have fallen in sequence between the FY23 dates in the surrounding fields. In this count there were 26 blank 'Plant kW' values. In these instances the average value taken from the recorded values against their total number was applied to these blank fields (i.e. 3746 units totalling 12417.11 kW, so 26 blanks thus applied average for sub total of 86.18389 kW equalling 12503.29389 kW).

3,772 units with installation dates were identified totalling **12,503.29 kW**.

0 of these were IDNO sites.

The SSEGs data capacities are recorded in kW to give a total of **12.503 MW**.

LCTs Installed – Other DG (G98)

The data within the Data Management spreadsheet SSEG database was analysed to identify the number of installations completed in 2022/23. Any blank entries were included where they were evaluated by reasonable assumption to have fallen in sequence between the FY23 dates in the surrounding fields.

1,221 units were identified totalling **4,435.57 kW**.

The SSEGs data capacities are recorded in kW and give a total of **4.435 MW**.

LCTs installed – Secondary Networks DG (G99)

From the information within the DG database the number of units installed was determined by filtering on the 'Financial Year' of installation, with any blank entries included where they fell in sequence of the DG reference column:

Low voltage network connections volume is **264**.

High voltage network connections volume is **12**.

Total units connected = **276**.

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

Low voltage network connection volume is **3,410.63 kW**.

High voltage network connection volume is **8,183.00 kW**.

Total MW connected = **11.594 MW.**

LCTs installed – Primary Networks DG (G99)

The information for this data was taken from the Embedded Capacity Register (ECR) spreadsheet.

Filtering in the 'Register Part 1 - >= 1MW' worksheet, by 'Date Connected' values that fell within the FY23 range, this identified that **2** projects totalling **38 MW**, that qualify by voltage as Primary Network, were connected during the financial year.

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.
Following several years of decreasing LCT volumes, the year 2021-22 has seen a sharp increase in installations. Installations of non G83/98 technologies has remained low following delays from COVID-19, however the number of heat pumps and electric vehicles has increased significantly in the last few years, which are trends we expect to see continue in RIIO-ED2. 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 period that is significantly below the forecast.

E8 – Smart Street Innovation Rollout Mechanism (IRM)

Project Background:

The IRM is a funding mechanism that allows new technologies to be transitioned from innovation to Business as usual. Following a project application, Ofgem, in a letter dated 18 October 2019, awarded £15.09m (£18.02m current prices) to deliver the IRM application between April 2020 and March 2023. The award stated that "Smart Street is expected to deliver long-term benefits to ENWL's consumers through reduced bills, avoided reinforcement costs, and reduced network losses." ENWL will report on the following key performance indicators:

- Annual reporting of costs - through RIGs Table E8
    - Table E8 in Annex J of the Environment and Innovation pack in the RIIO-ED1 RIGs.
- If expected benefits from roll-out have been achieved - through RIGs Table E6
    - Table E6 in Annex J of the Environment and Innovation pack in the RIIO-ED1 RIGs

To deliver the above benefits, the project will deliver a series of physical equipment installations. As some of this equipment is novel, categorisation under the appropriate asset classes will be clarified. The physical equipment includes: On Load Tap Changing (OLTC) distribution transformers, replacing standard Distribution transformers, Weezap LV circuit breakers replacing LV fuses and Relink link box switches inserted into empty link boxes.

The project interfaces these new asset types to the ENWL control system (NMS) and then enhances NMS to allow autonomous operation using periodic optimisation algorithms.

The whole system, then allows improved management the LV network leading to the benefits of reduced customer bills, avoided reinforcement costs, and reduced network losses.

Project Progress:

As reported last year additional work and delays due to the development and testing of Low voltage link box switches continued, whilst the final integration of plant and software into the new NMS system also took longer than anticipated, with additional testing cycles required before final system acceptance.

LV link box switches have been heavily delayed due to electronic supply chain shortages with the first pre-production unit being sent in March for initial ENWL testing. Type testing for the units, at a third-party test facility, is being confirmed for summer 23, for site installation commencing autumn 23.
To resolve the ability to retrofit these units a programme of new link box installations has commenced.
All LV CB have been delivered, with installation matching OLTC and Linkbox installation programmes. All OLTC have been delivered, 176 have been installed with a handful of sites experiencing unexpected installation issues. All equipment has been commissioned in "local" mode with the OLTC providing active voltage control and the LV CB providing full protection of meshed feeders together with power, voltage and current measurements.

During the year remote operation via ENWL Scada has been tested for both OLTC and LV CB. Initial unit commissioning was undertaken and operations from using the central control system achieved.

The Smart Street Optimisation Software has been through a series of extensive System Acceptance Testing, including integration testing with the BAU control software and its continuing enhancement. The added complexity has taken longer than anticipated but was completed at year end.

The focus of the project is to deliver the remaining items as soon as possible in Fy24. These items being:

- Commissioning of final OLTCs and LV CBs to the central control system and optimisation software
- Type testing of ReLink device, final manufacture, and installation of units (including SCADA commission)

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

Costs (E8) – Costs are tracked as per any other capital expenditure within ENWL corporate finance and programme management systems. All IRM expenditure is being reported under PCFM cost type Non-load related capex other. This is the best match of IRM to available categories. Smart Street is the only entry on table E8.

Within year only OLTC transformers and LV CB have been installed. Additions and disposals are as recorded in our asset systems.

Benefits (E6) – The significant benefits from Smart Street start to accrue once the full integrated solution is in place. This requires primary equipment to be fitted, full commissioning to, and control via the central control system, then the implementation of the optimisation software within the control system. The equipment installed to date is operating in a basic mode, awaiting control system changes, and is therefore not yet delivering significant Smart Street benefits.

With the completion of the Smart Street optimisation software, and the number of OLTCs commissioned through SCADA the benefits from Smart Street will continue to build through 2023-2024 and will maximise once the LV meshing is activated.