Environment Report 2022/23
Detailed Commentary Associated with the Annexes

Overview

This file contains the commentary associated with Annexes 1 to 7 to the Environment and Innovation 2022/23 report. In the context of the regulatory reporting process, the purpose of this commentary is to provide to the regulator, Ofgem, information supporting the data that we submit in the Environment and Innovation Reporting Pack (i.e. Annexes 1 to 7).

Annexes 1 to 7 and this associated commentary are an edited copy[1] of our annual submission to the regulator. The structure and content of this document reflect their specific purpose, and as a result are not suited for the reader looking for some general information. For that reader, we recommend the Environment Report.

Date of publication: October 2023

Associated documents:

- Environment Report 2022/23, Northern Powergrid, October 2023
- Annexes to the Environment report 2022/23, Northern Powergrid, October 2023
- Cost benefit analysis Tables, October 2023
- Regulatory Instructions and Guidance (RIGs) for RIIO-ED1, Ofgem, May 2021, available from: https://www.ofgem.gov.uk/publications/direction-make-modifications-regulatory-instructions-and-guidance-rigs-riio-ed1-version-70

Contents

[1] The edits consist in formatting changes to ease navigation and redaction of content that we agreed with the regulator was inappropriate for publication.

E1 – Visual Amenity

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
We have updated Table E1, where the workload refers to the undergrounding of overhead lines within or around the borders of the national parks/areas of outstanding natural beauty that form our designated areas. We are reporting 2.67km of overhead line removed in the Northeast and 11.05km in Yorkshire during 2022/23.This brings our ED1 programme to a successful close, undergrounding over 100km of overhead lines across our nine designated AONBs. We have work programmes specifically used for recording costs and volumes of undergrounding work in our regions' designated areas, which allow us to separate the costs and activities of visual amenity from other undergrounding work. We have examined individual schemes to determine the correct voltage and the amounts of overhead conductor removed and cable installed. Other assets involved with the work, such as the count of overhead services and poles removed, and underground services installed have been noted in the asset register listing included in Table CV20. All the work undertaken is on LV or HV overhead circuits. On examination of the schemes undertaken in 2022/23, we are able to confirm that all costs recorded arose from work carried out within the designated area. The schemes we have undertaken are within the boundary of the designated area concerned or are within the tolerance allowed.

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.
There have been no new designated areas created or extended in 2022/23 nor, to our knowledge, any change in the geographical size of any individual area.

E2 – Environmental Reporting

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
Table E2 provides volumetric performance statistics against a number of environmental drivers. *Cost and Volumes categories* • In absolute terms, expenditure reported in E2 is low compared to some other tables, but this belies the fact that the overall investment made and outputs achieved in asset replacement (where the replacement of fluid-filled cables is reported), in flooding and in asbestos mitigation projects all produce important environmental benefits.

- We have reported contaminated land clean up costs associated with an oil spill at 8 sites in the Northeast at a cost of £0.03m and 13 in Yorkshire (cost of £0.03m).

- We have also recorded one noise pollution intervention in Yorkshire in the year – details are given in the specific 'Noise Pollution' section below.

- We have recorded two sites where oil mitigation measures were employed (both Northeast) and one site for SF6 Mitigation – details are provided in the relevant section below.

- In 2022/23 we also commenced our PCB Oil testing programme on a sample of our ground mounted transformer population in the Northeast. Twenty sites were selected for testing for PCBs and if over the threshold, the oil was changed and re-tested. As a result of the testing, oil was changed in 16 sites.

Volumetric Measures

- Table E2 also includes a number of categories, against which we record Northern Powergrid's environmental performance.

- We recorded nine incidents requiring reporting to the Environment Agency (none of the incidents resulted in civil sanction); Six in Yorkshire and three in the Northeast, all related to fluid filled cables. All incidents were appropriately addressed in consultation with the Environment Agency.

- On SF_6 leakage, Table E2 records SF_6 emitted as a proportion of the total gas bank. We have updated the amount of our overall gas bank with the net asset additions in each licence. We have also applied the amount of gas emissions, which we record on our source systems, and the table calculates a gas emitted ratio of 0.134% in Northeast and 0.52% in Yorkshire in 2022/23. This represents a slight reduction in performance in the Northeast and no movement in Yorkshire. We will continue to utilise our SF_6 camera to further reduce our SF_6 loss in both licence areas

- For fluid used statistics we record circuit kilometres, oil fluid litres and the amounts of oil top ups and recoveries. In order to calculate the fluid totals, we calculate the average value for litre per km for each cable core and voltage, taking account of a range of variables, including cable type, cable manufacturers' specifications and different types of site works. We have taken the circuit lengths of oil-filled cable at each voltage, using data taken from the asset register.

We have also reported the audited values for net fluid used for top ups and fluid recovered that are recorded on our source systems. When these are entered on to Table E2, the result is that our ratios of fluid tops ups to the total in service is 0.84% for Northeast and 1.34% for Yorkshire in 2022/23. This represents a slight decrease in performance in the Northeast but an increase in our performance in Yorkshire.

DNOs must provide some analysis of any emerging trends in the environmental data and any areas of trade-off in performance.
The overall number of environmental events (those reportable to the Environment Agency and those that fall outside this category) has reduced from 97 in the 2012/13 regulatory year (Northeast & Yorkshire combined) to 45 in the 2021/22 regulatory year to 30 this year. Changing weather patterns and third party interference (such as reductions in vandalism and theft) play a large role in this trend. Fluid loss is on a continuing downward trend and gas loss is has started to increase. We have developed a management strategy that has been implemented to stem and ultimately reduce gas loss and bring it back in line with target.

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.
We have completed the row in Table E2 relating to noise complaints. Of those calls, there are a number that result in formal complaints and remedial action in terms of mitigation schemes that are reported in Table E2. Noise complaints are considered objectively, by performing site surveys and measuring sound levels across the audible spectrum at various points in the area the complaint was raised. A noise complaint is justified if specified noise levels, especially in the 100Hz range, are exceeded. We examine each case in detail: this involves personal attendance at the site, taking the necessary readings and making an assessment of the best means of dealing with the nuisance. A variety of mitigation solutions are possible: acoustic doors, acoustic roof panels, acoustic louvres, anti-vibration pads – but we have faced situations where poor ventilation or restricted space between substation doors and the electrical equipment inside does not allow us to install the acoustic solution (indeed these sometimes might pose a risk as a climbing aid). In those circumstances we are left with re-siting the equipment (for pole mounted transformers) or full replacement of the transformer at a distribution substation, mindful of course for opportunities for other work at the site. Any work at primary sites is, by the very nature of the assets being treated; a much more specialised, complicated and expensive exercise and as such, noise complaints involving primary sites can take time to resolve. We have reported one Northeast scheme in our volumes in Table E2: • *Esh Green Court, Durham* Following a customer complaint we installed acoustic lining and modified a number of the air vents. We have noted 47 new noise enquiries in Table E2, in line with the volumes reported in 2021/22.

Where reported in the Regulatory Year under report, DNOs must provide details of any Non-Undergrounding Visual Amenity Schemes undertaken.
We can confirm that we have no non-undergrounding visual amenity schemes to report.

Any Undergrounding for Visual Amenity should be identified including details of the activity location, including whether it falls within a Designated Area.
No work has been undertaken other than under the Visual Amenity programme identified in Table E1.

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.
We recorded nine incidents requiring reporting to the Environment Agency (none of the incidents resulted in enforcement actions or penalties); All incidents relate to fluid filled cables and all were appropriately addressed in consultation with the Environment Agency.

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 ISO14001:2015 and have been subject to one surveillance audit and a full recertificaion audit during the regulatory year under report and no major non-conformances were identified.

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.
We have three bespoke permits and four standard oil only permits. We are a registered upper tier waste carrier, broker and dealer.

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.
Oil mitigation involved the replacement of transformer bunds at Toronto Primary, Bishop Auckland and High Barmston Primary, Washington, both sites in the Northeast. The SF6 mitigation scheme targeted the 66kV circuit breaker at Balby that had required a number of top-ups in early 2022 and as such was identified as one of the worst performing circuit breakers with regard to SF6 loss. This scheme involved the invasive examination of, and the undertaking of any subsequent works to repair defects on the circuit breaker at a cost of £0.03m. Whilst we seek to protect and prevent interference as our top priority, it is recognised that the management of incidents is an inevitable outcome and therefore pollution containment measures are essential in reducing environmental, financial and reputational damage to Northern Powergrid. To ensure effective remediation we have a 24 hour environmental response

support contract in place to attend for any and all environmental incidents as required.

E3 –BCF

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

Data entry is in the form of base measurement and conversion factors. Such factors are the factors published by DEFRA in place on 31 March of the regulatory period being reported.

Where multiple conversion factors were required to calculate BCF within a particular category (e.g. due to use of both diesel and petrol vehicles), a weighted average of these factors has been entered.

Variations in volume of each fuel type between Yorkshire and the Northeast will result in different weighted average conversion factors for similar categories. E.g. in Yorkshire a lower quantity of petrol was used for business transport and a larger quantity of diesel was used. Therefore the resultant overall weighted average conversion factor for this category for Yorkshire will be different to that of Northeast.

All Contractor figures are actual returns.

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.

- All figures relate to the activities of the regulated business. All data is collected in a form where it is attributed to one of the licensed distribution businesses. Corporate categories are allocated on a 50:50 basis.
- Business travel by bus, taxi and ferry have not been included as it believed not to be material.
- Refrigerant gas loss from air conditioning units has not been included. The amount is not believed to be material.
- Energy use at substations has been estimated.

- The company is audited on an annual basis to ensure compliance with the ISO 14064-1:2018 standard. This tests the management, reporting and verification of our greenhouse gas inventory.

BCF process The reporting methodology for BCF must be compliant with the principles of the Greenhouse Gas Protocol.[2] 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.
The reporting methodology for BCF is compliant with the principles of the Greenhouse Gas Protocol.

Commentary required for each category of BCF

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

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

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

<u>Building energy usage</u>

- Data from electricity and gas bills relating to all the licensee's non-operational properties is collated by the facilities department. For non-half-hourly metered bills, the amount included is that billed in the quarter even if based on an estimated reading. A small number of buildings that are

[2] Greenhouse gas protocol

owned by a landlord are excluded. For gas the conversion factor for gross calorific value has been used.

- The volume of energy is converted in tonnes of carbon dioxide using the "Electricity – generation" (scope 2) and also "Electricity – T&D" (Scope 3) factors as outlined in Defra guidance.
- Own use at substations has been estimated and the figures have been built bottom up from the various components (heating, lighting, etc.), although the contribution of each component is an engineering judgement rather than a direct or sample measurement.
- It should be note that the 2021/22 substation energy figures were found to be incorrect due to an administrative error and we have re-stated the reduced revised figures in this years submission. The variance (Northeast and Yorkshire combined) results in a reduction of our previously posted energy figures by 506,507 kWh which equates to a total reduction in emissions of 117.06 tCO2e. A full breakdown of the variances are presented below.

2021/22 Substation Energy

NPg Total	**Original**	**Revised**	**Variance**	**Variance %**
Sub energy kWh	19,211,315	18,704,808	-506,507	-2.64%
Sub energy tCO2e	4,440	4,323	-117.06	-2.64%
BCF excl Contractors tCO2e	14,467	14,350	-117.06	-0.81%
BCF incl Contractors tCO2e	33,498	33,381	-117.06	-0.35%

NPgN	**Original**	**Revised**	**Variance**	**Variance %**
Sub energy kWh	7,658,963	7,702,686	43,723	0.57%
Sub energy tCO2e	1,770	1,780	10.11	0.57%
BCF excl Contractors tCO2e	6,028	6,038	10.11	0.17%
BCF incl Contractors tCO2e	17,099	17,109	10.11	0.06%

NPgY	**Original**	**Revised**	**Variance**	**Variance %**
Sub energy kWh	11,552,352	11,002,122	-550,230	-4.76%
Sub energy tCO2e	2,670	2,543	-127.17	-4.76%
BCF excl Contractors tCO2e	8,439	8,311	-127.17	-1.51%
BCF incl Contractors tCO2e	16,399	16,272	-127.17	-0.78%

<u>Operational Transport</u>

- The main source of fuel reported here is used by the company's fleet, and data is collected from company fuel card use. Figures are collated for petrol, diesel, and LPG (when used).
- Other usage of fuel includes that used by contractors for their fleet and generators. Data on contractors' usage is compiled from monthly metric returns sent in by the contractors as part of contract reporting. See comments under Contractors.

<u>Business Transport</u>

- Business transport - road

Data is collected from business miles claimed by staff monthly on their expense claim forms. The data is split between diesel and petrol according to the information provided on the claim forms. Corporate staff mileage is split 50:50

between licensees (to reflect the fact that such travel is undertaken on behalf of both licensees equally).

- Business transport – rail and air

Staff wishing to make a business journey by train or air must formally request approval. Data from these requests is transferred to a spreadsheet where the mileage for each journey is calculated and then collated according to rail, domestic flights, short-haul international, and long-haul international. As mentioned above, figures relating to corporate staff are attributed 50:50 between licensees.

Fugitive Emissions

These figures are the same as those used in Table E2 and are the SF_6 emissions from the network.

Fuel combustion

This is the fuel used for generators by our contractors.

Losses

- This data stream uses the figures derived under the Balancing and Settlement Code arrangements and reported regularly to Ofgem.
- The volume of energy is converted in tonnes of carbon dioxide using the "Electricity – generation" (scope 2) factor provided by DEFRA.

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.

Contractor figures are derived from actual returns provided by contractors utilised to undertake work on behalf of Northern Powergrid.

BCF variation 2019/20 NPgY

		original 2020	revised 2020		original 2020	revised 2020		original 2020	revised 2020
Operational Transport Road	tCO2e	4,110.43	4,110.43	Scalar	0.0017098	0.0025846	Litres	2,404,030.74	1,590,346.22
Fuel Combustion Diesel	tCO2e	3,922.14	3,922.14	Scalar	0.0029543	0.0025941	Litres	1,327,601.40	1,511,941.85

BCF variation 2019/20 NPgN

		original 2020	revised 2020		original 2020	revised 2020		original 2020	revised 2020
Operational Transport Road	tCO2e	4,010.03	4,010.03	Scalar	0.0021490	0.0025858	Litres	1,866,029.16	1,550,803.16
Fuel Combustion Diesel	tCO2e	4,549.83	4,549.83	Scalar	0.0023676	0.0025941	Litres	1,921,743.60	1,753,907.15

Building energy usage
Natural gas, Diesel and other fuels are all categorised as fuel combustion and must be converted to tCO2e on either a Gross Calorific Value (Gross CV) or Net Calorific Value (Net CV) basis. The chosen approach should be explained, including whether it has been adapted over time.

Substation Electricity must be captured under Buildings Energy Usage. Please explain the basis on which energy supplied has been assessed.

Own use at substations has been estimated and the figures have been built bottom up from the various components (heating, lighting, etc.), although the contribution of each component is an engineering judgement rather than a direct or sample measurement.

E4 – Losses Snapshot

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

E4 includes:

- Activities where the costs incurred principally relate to managing distribution losses.
    - In practice at this time this will be restricted to actions to deal with relevant theft of electricity as we have no other investments solely to reduce losses.
- Activities where some of the costs incurred relate to managing distribution losses (but where losses are not the principal reason for the expenditure) excepting activities that may help to manage losses but where distribution losses are not associated with the DNOs decision to undertake the activity and where any losses benefits are purely coincidental. At present, we are focusing on two activities:

1) Quantifying losses savings between installing the 185mm^2 underground (UG) 11kV and LV cables and upsizing the size to 300mm^2.
We have been pursuing this option in our investment plans throughout ED1.

2) Quantifying losses savings of targeted replacement of pre-1958 distribution transformers with a Health Index of 3.
Our analysis shows that the costs associated with replacing a pre-1958 transformer with a more efficient modern transformer would be offset by the future losses cost savings within ten years of its replacement. Therefore we have decided to prioritise the replacement of pre-1958 distribution transformers as part of our existing asset replacement work programmes.
This supports our on-going drive to reduce technical losses on the network and supports an approach to the targeted replacement of pre-1958 distribution transformers identified by other DNOs within their business plans.

a. Underground cables

Volumes

The cable volumes were obtained from Information Management (rather than estimation used in prior years, therefore the volumes for 2019 onwards have been updated in the E4 table). It is assumed that 80% of the volume of installed cable are of size 300mm^2, and to be inputted into the CBA.

Costs

- The estimated total costs in the E4 table are taken from the unit cost for cable replacement, and multiply the unit cost with the cable lengths installed.
- The differential between the 300mm^2 cable and 185mm^2 cable is known. Together with the lengths of each type, the unit cost specific to each type can be calculated.
- This calculation is done for our underground 11kV cable and LV cables on both our Northeast (NPgN) and Yorkshire (NPgY) licences, giving four cost lines in total.
- Incremental costs associated with the losses initiative are taken from the CBA cost per meter and the volumes of 300mm^2 cable.

Losses benefits

Losses benefits (MWh) associated with the losses initiative are taken from the CBA losses benefit per meter and the volumes of the LV and 11kV UG 300mm^2 cables respectively.

Cost-benefit analysis (CBA)

The CBAs are based on the submitted RIIO-ED1 CBAs reviewed in line with the financial data (WACC) from the ED1-RIIO settlement and actual cable lengths involved.

The CBA has now been updated to reflect the actual volume of cables installed onto the network as obtained by Information Management.

By entering the actual cable lengths in the actual year of installation onto the Ofgem CBA tool, RIIO-ED1 benefit and a 45-year benefit can be obtained.

b. Pre-1958 distribution transformers

Costs

- The estimated total costs in the E4 table are taken from the unit cost for the transformer replacement (assumed £15,000), and multiply the unit cost with the total volume of the transformers replaced. The baseline cost is assumed zero in this case.
- This calculation is done for units on both our Northeast (NPgN) and Yorkshire (NPgY) licences, giving two cost lines in total.
- Incremental costs associated with the losses initiative are taken from the CBA cost per unit and the volumes of transformers.

Volumes

- Total transformer volumes are taken from the data provided by Investment Planning and Delivery and Systems Engineering teams.

Losses benefits

- Losses benefits (MWh) associated with the losses initiative are taken from the CBA losses benefit per unit and the volumes of the units.

Cost-benefit analysis (CBA)

The CBA is similar to the one described for cables, the only difference is that the input data is the numbers of units replaced in the actual year. We have improved and updated our CBA table (and updated our assumptions in the methodology statement) to consider the standard size of new transformers. For 200kVA and 300kVA pre-1958 transformers, they are replaced with 315kVA unit (the smallest standard size). For 750kVA, it is replaced with 800kVA.

Programme/Project Title

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

Underground cables

The benefits of low loss design have usually been in the form of oversizing conductors (relative to existing utilisation levels), which can have the added benefit of improving network performance (i.e. voltage drop, current carrying capacity and earth loop impedance).

LV cable oversizing

At low voltage (230/400V), the use of 300mm^2 aluminium cables has been adopted as standard cable size for all mains other than teed network carrying less than 120A per phase (e.g. in cul-de-sac areas), in line with our RIIO-ED1 business plan submissions.

11kV *cable oversizing*

At 11kV, the use of 185mm^2 aluminium has been adopted as a standard network feeder size, with 300mm^2 aluminium used for the first leg from the primary substation and highly loaded feeders. In line with our RIIO-ED1 business plan submissions we are implementing the policy of installing a minimum cable size of 300mm^2 at 11kV where practical (e.g. if bending radii and termination arrangements allow).The use of 95mm^2 is only recommended in special circumstances, as it becomes uneconomical in terms of lifetime losses at greater than 100A peak loading.

Pre-1958 distribution transformer replacement
Our analysis shows that the costs associated with replacing a pre-1958 transformer with a more efficient modern transformer would be offset by the future losses cost savings within ten years of its replacement. Therefore we have decided to prioritise the replacement of pre-1958 distribution transformers as part of our existing asset replacement work programmes. This supports our on-going drive to reduce technical losses on the network and supports an approach to the targeted replacement of pre-1958 distribution transformers identified by other DNOs within their business plans.

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

Cables are replaced or installed as part of activities such as asset replacement, reinforcement, connections, visual amenity and faults volumes. The pre-1958 transformers are replaced as part of asset replacement activities. These are the primary drivers for the respective activities.

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

Underground cables
The baseline scenario assumed each metre of cable actually installed as 300mm^2 was installed as 185mm^2.
Volumes were restricted to 300mm^2 cable which would otherwise have been 185mm^2. Any cable actually installed at a smaller size or that would have been the larger in any event was excluded.
On the CBA, only incremental costs were included so the baseline was a blank sheet.

Pre-1958 distribution transformer replacement
The baseline scenario assumed that the pre-1958 distribution transformers are still under service. They will only be replaced under the existing work programme due to poor health index (where the Health Index ≥ HI4) and/or as a consequence of other works at site, e.g. due to the condition of the LV board and/or HV switchgear and/or building and/or if it's closely coupled, i.e. where there are secondary drivers.

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.

Ofgem's version 4 CBA from the RIIO-ED1 business plan submissions was used. This is understood to be Ofgem's current version.

All CBAs show a positive benefit over 45 years.

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

Cost benefit analysis additional information Please include a reference to the file name and location of any additional relevant evidence submitted to support the costs and benefits inputted into this worksheet. This should include the most recent CBA for each activity reported in column C in the Regulatory Year under report.
The CBA tables are saved in on zip file called "CBA E4 Losses 22_23" and are individually called: • NE RRP 2022-23 11kV 300 cable CBA RIIO ED1 • NE RRP 2022-23 LV 300 wf cable CBA RIIO ED1 • NE RRP 2022-23 Pre-1958 transformers CBA RIIO ED1 • YE RRP 2022-23 11kV 300 cable CBA RIIO ED1 • YE RRP 2022-23 LV 300 wf cable CBA RIIO ED1 • YE RRP 2022-23 Pre-1958 transformers CBA RIIO ED1

E5 – Smart Metering

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
Worksheet E5 records the following information: • Pass-through Smart Meter Communication Licensee Costs and pass-through Smart Meter Information Technology Costs, plus any Elective Communication Services costs or Smart Meter Communication Licensee Costs outside of the price control, and • DNOs' estimates of the benefits of smart metering for domestic and non-domestic customers using the categories set out in DECC's January 2014 Impact Assessment.

Commentary regarding pass-through Smart Meter Communication Licensee Costs and pass-through Smart Meter Information Technology Costs, plus any Elective Communication Services costs or Smart Meter Communication Licensee costs that are outside of the price control:

Smart Metering Communication Licensee Costs consist only of the monthly charges levied by the Data Communications Company (DCC). These are recorded against dedicated account codes in our financial recording systems allowing us to separate these costs from any other cost items.

We have not incurred any Elective Communication Services costs. These costs would be payable to the DCC in respect of Elective Communication Services, which include services to or from a Smart Metering System that relate solely to the Supply of Energy (or its use), and services that are provided by DCC pursuant to a Bilateral Agreement (rather than the DCC User Interface Services Schedule).

We have not incurred any Smart Meter Communication Licensee costs that are outside of the price control. These costs would be payable to the DCC in respect of optional data transaction fees relating to the use of Smart Meters that are at a DNO's discretion and may extend beyond the Smart Meter roll-out period.

Our 2022/23 Smart Metering Information Technology Costs consequently covered the:

- Licence support costs for our Oracle database software.
- Software and hardware support and maintenance costs for our smart metering IT user gateway.
- Cost of maintaining a Registration Data Provider (RDP) service.
- Costs incurred on our project to integrate our main smart metering IT user gateway with our distribution network management system in order to allow our despatch staff, who assign our engineering repair teams to work activities, to check the supply status of smart meters at premises potentially affected by a power cut.
- Costs to develop and implement an Intelligent Filter that analyses smart metering outage data alongside network monitoring data to identify unknown power loss events.
- Costs to develop a Data Privacy Module providing the functionality to collect and aggregate half-hourly consumption data prior to storage in line with our Data Privacy Plan.

The projects listed below are all stand-alone capital projects. This means that we are able to separately record the costs for each project and segregate these from the costs incurred by other smart metering and non-smart metering activities.

- The integration of our smart metering IT user gateway to work with our network management system to support fault location, and
- The development of an Intelligent Filter to enable smart metering outage data to supplement network monitoring, and
- The development of a Data Privacy Module to provide the aggregation necessary to be complaint with our Data Privacy Plan.

Licence update and supports costs for our Oracle database software have been taken from US dollar invoice values, adjusted to Sterling using agreed corporate exchange rates.

IT user gateway software and hardware support and maintenance costs have been taken directly from purchase order values, with the only allocation and apportionment having been the division of the invoice value by 12 (to identify a monthly cost) followed by the splitting these costs equally between our two licences.

RDP costs have been taken directly from purchase order values; hence no estimation, allocation or apportionments have been undertaken save from splitting these costs equally between our two licences.

Commentary regarding DNO's estimates of the benefits of smart metering for domestic and non-domestic customers using the categories set out in DECC's January 2014 Impact Assessment:

Smart Metering Estimated Benefits for the 2022/23 regulatory year are nil.

This is because each of the seven benefit categories set out in DECC's original Impact Assessment require an appropriate volume of reliable smart metering data to be available to us as an essential input to the delivery of benefits.

The data that is available to us is not yet reliable, nor is it available with sufficient coverage in any given geographic area to support benefit delivery.

In particular:

- The deployment rate of SMETS2 meters in the DCC's Communication Service Provider North (CSP N) area, which is where our customers are located, has been materially lower than that in the DCC's Communication Service Provider Central & Southern (CSP C&S) area. As such the number of SMETS2 and SMETS1 meters enrolled in Data Communications Company (DCC) systems in our licence areas up to the end of the 2022/2023 regulatory year account for circa 33% of our domestic and small non-domestic customers (profile classes 1-4). Over 50% of the meters are SMETS1.
- There are a number of technical issues in the CSP N area that mean that communications with meters are frequently intermittent.
- Success rates of smart metering DCC service requests that collect voltage data (SR4.10) are particularly poor.
- Where voltage data can be retrieved it is not always recorded in meters on a consistent basis. I.e. it should be recorded for 30 minute periods to 4 significant figures; however it is often recorded for periods as low as 10 minutes and is sometimes recorded to 3 or 5 significant figures.
- Success rates of service smart metering DCC service requests that confirm the power supply status at a meter point (SR7.4) are variable.
- Power Outage Alerts and Power Restoration Alerts are erratic and not sufficiently reliable to be consumed by customer-facing business processes. SMETS1 meters enrolled in the DCC do not provide outage alarms.
- Meters from different manufacturers sometimes behave differently to one another.

- Communications with meters that were previously reliable can stop when the communications hub becomes 'deaf'.

Also, we are not yet in a position to deliver benefits from aggregated consumption data.

- Our Data Privacy Plan was accepted by Ofgem in December 2020, however our licence prohibits us from accessing such data (except in the case of a very small number of Northern Powergrid employees where we have their explicit permission) until we have added a data aggregation module to our smart metering IT user gateway. Whilst we have implemented Phase 1 of this module we aware the resolution of key defects in Phase 2, which has a dependency on the platform refresh. We expect the full functionality to be available within Q2 2024.

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.

The expenditure reported under Smart Meter Information Technology Costs has being used to support, maintain and upgrade our smart metering IT user gateway; to provide our RDP service; to support the integration of our smart metering IT user gateway with our distribution network management system, and to support the sharing of an overall view of premises affected by power cuts with corporate customer-facing applications.

- The expenditure on our smart metering IT user gateway allows us to receive smart meter alerts, execute service requests to send commands to smart meters, and execute service requests to send commands to the DCC. The IT user gateway system is as an essential enabler for the delivery of smart meter benefits.

- The expenditure on our RDP service supports the wider smart metering programme's security model by providing details to the DCC of each of our customer's registered suppliers.

- The expenditure being used to fund the integration of our smart metering IT user gateway with our distribution network management system will provide our despatch staff with the ability to check the supply status of smart meters at premises potentially affected by power cuts. This will help them to gain insights into customers without power, customers whose power has been restored, and the potential extent of incidents on non-telemetered parts of our HV network.

- The expenditure being used to develop an Intelligent Filter which support visibility of all premises affected by power cuts with other corporate customer-facing applications. The Intelligent Filter will help us to use power cut information obtained from smart meters to inform customers that we are aware of their situation and are working to restore their power.

- The expenditure being used to develop the Data Privacy Module with enable us to store aggregated demand data sets, providing more information to the decision makers in our asset management team.

No Elective Communication Services have been procured from the DCC.

No Smart Meter Communication Licensee services that are outside of the price control have been procured from the DCC.

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.

Smart Metering Estimated Benefits for the 2022/23 regulatory year are nil.

This is because the RIGs require us to estimate the "gross financial benefits delivered in the Regulatory Year from the use of smart metering data" against each of the seven benefit categories set out in DECC's January 2014 Impact Assessment.

The continuing modest level of smart meters enrolled in DCC systems that are in our licence area, the poor performance of the DCC systems, and the variation in behaviours from different meter types, means that reliable smart metering data, as an essential input to the delivery of benefits, is not yet available.

In addition, we have limited access to consumption data. Once we have delivered Phase 2 of the data aggregation module to our smart metering IT user gateway we will explore the retrieval, and potential utilisation, of consumption data.

As such no meaningful smart metering data, from which benefits could realistically be derived, has been available to us in 2022/23.

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

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

E6 – Innovative Solutions

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

The Regulatory Instructions and Guidance published by Ofgem in April 2016 planned for a working group to be established to clarify instructions and guidance on:

- the definition of a unit for different solutions
- consistency in reporting of Innovative Solutions definitions
- consistency in reporting methods with regards to impacts.

Since the working group has not yet been formed, we have followed the guidance in the RIGs, responded to informal feedback from Ofgem and made assumptions that are explained in the commentary below.

In previous years, we have reported on five areas which we have now ceased to report on:

- Load capacity release
- Generation capacity release
- Telematics in operational vehicles
- Fire retardant workwear
- Farm safety

We believe these are innovative and are continuing to provide benefit. However, we understand that Ofgem have ruled that they do not meet the specific definition of "Innovative Solutions" employed for the purposes of regulatory reporting.

If Ofgem revise this guidance we will provide benefits for these lines.
We have not removed the 2015/16 and 2016/17 benefits for these lines as these have been accepted previously.

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.

Increase Network Capacity/Optimise Utilisation

Voltage Reduction – We have continued to receive complaints of high voltage on our network as the amount of embedded generation increases. Our programme of reducing the set point voltage at 11kV busbars of our primary substations is benefitting this situation. This is the first step in a revision to our voltage control policy which is being amended as a result of the learning from the CLNR project. The basic assessment involved determining whether the tapping range at the substation is adequate for the expected load flows and voltages on the network, whilst still leaving room for an OC6 voltage reduction. The assessment assumed that the reduction in statutory voltage limit on the LV network (from 225.6V to 216.2V) would provide the necessary voltage leg-room to lower the target voltage at the primary substation by 200V. Reducing the target 11kV voltage by 200V results in a voltage reduction of approximately 4.5V at the LV terminals of a distribution transformer. These actions are designed to create the voltage headroom to cater for the connection of PV without creating voltage complaints.

In 2022/23, we completed a further 13 sites under the Voltage Reduction program bringing the total to 511.
.
It is estimated that these actions have released 4,599MVA of voltage headroom to date, allowing connection of more distributed generation such as domestic solar PV to the LV network fed from each primary substation.

HV automation - We are currently rolling out Automatic Power Restoration System (APRS) across our High Voltage distribution network. This has been deployed across 51 primary substations in 2022/23; 6 in the Northeast & 45 in Yorkshire bringing the total to 407 since 2014. It is designed to identify and isolate faulted sections of the network and then restore healthy sections of network within 3 minutes. This restores supplies to many customers automatically and also enables fault restoration/repair staff to be directed towards the faulted section of network more quickly, both of which enhance the customer experience. Note, whenever a new APRS installation occurs, it is entered as an addition. Subsequently, where we have upgraded a system from advisory to executable, we have removed it from the year of original installation and inserted it as an addition in the upgrade year. The CML figures are not adjusted.

LV Technology Programme - We have continued with our pro-active approach to LV network intermittent faults by use of new technology, this centres on the concurrent deployment of over 1000 smart LV devices on the LV network. The intention is to restore intermittent (Non Damage) faults within 3 minutes and thus enhance customer experience. Over time, this allows the pro-active location and repair of persistently active intermittent faults before customers experience a longer, permanent unplanned interruption (Damage Fault). These devices improve customer service and reduce costs associated with service failures as well as reducing overtime payments due to the ability to programme fuse replacements in normal working time.

We have continued to refine the methodology and identified the potential for overstating the benefits by including fault location benefits which were not part of the original CBA and is not the primary purpose of the devices. An additional peer review of the methodology determined that the gross Estimated Customer Interruption (CI) Impact had been overstated by a factor of 100. Both of these have been amended in this years return with figures from 2016 restated using the corrected method.

In 2022/23 it is estimated that the smart LV devices have saved estimated gross avoided costs of £1.32m, over 25,195 customer interruptions and 3.02m customer minutes lost.

Improve asset life cycle management

HV circuit breaker retrofit - Retrofitting refers to the replacement of the moving portion and its carriage with a modern equivalent. The fault current interruption medium used in recovered units is likely to be oil; the replacement units will typically employ a vacuum to extinguish the arc.

Retrofitting extends the asset life significantly and provides network performance benefits with reduced capital investment compared to replacement.

The replacement of a complete switchboard would normally require an off-line build, involving the construction of a new switchroom adjacent to the existing building. This option presents significant building, civil and cabling costs and adjacent land may not be available. Retrofitting mitigates the most significant risks associated with the existing switchboard, but retains the fixed portion and associated cabling, auxiliary wiring and instruments, thus incurring significantly lower capital investment.

In 2022/23 we retrofitted 27 units, 19 in Yorkshire and 8 in the North East.

Transformer insulating oil regeneration - Acidity and moisture are products of the degradation of the insulation systems and their presence will accelerate the further deterioration of the paper insulation. Treatment of the insulating oil to remove acidity and moisture will extend the transformer life significantly.

On-line regeneration of the oil has significant benefits over an oil change including:

- More effective removal of particles and sludge;
- Longer term improvement of the insulating oil;
- Negates the need to drain the transformer;
- Negates the need to pull a vacuum on the transformer;
- Significantly reduces the quantity of insulating oil that needs to be transported to site and reduces the associated safety risk and cost; and
- Overall reduction of Northern Powergrid's carbon footprint.

Life extension of the transformer will only be realised if all the components of the unit remain serviceable. Oil regeneration shall only be undertaken following an assessment of tap changer serviceability and main tank integrity, and subject to satisfactory oil dissolved gas analysis results.

In 2022/23 we regenerated the insulating oil in 18 power transformers, all in the Yorkshire region. It is estimated that the regeneration and associated refurbishment will extend the serviceability of the transformers by 17 years.

Improve Environmental Impact

Silent Power - Northern Powergrid has deployed three electric Silent Power fleet vans (ENV200s) into BAU operation. The vehicles, developed through an innovation trial, each contain on-board electrical energy storage systems (EESS), with a 40kVa output and can be deployed during a power cut or essential maintenance work. The vehicles support customers while reducing noise pollution, local air pollution and carbon emissions typically associated with a conventional diesel generator.
In 2022-23 the silent power vehicles were deployed 145 times, saving 7,105 litres of diesel, 17.88 tonnes of CO_2 and £102,084 compared to the deployment of a standard diesel generator.

Fluid filled cable leak location (PFT) - ***Fluid filled cable leak location (PFT)*** – Up until 2020/21 we had reported on deployment of PFT leak detection techniques to locate and repair EHV fluid filled cable circuits. With the current process having ceased and due to be replaced in ED2, we have not reported figures in 2022/23. We have not removed the previous years' benefits for this innovation from the table as these have been accepted previously.

Improve Connection Performance

AutoDesign was launched on 31/01/2020. It is an innovative online tool that can help customers identify the best locations to secure new LV demand connections up to 210KVA. Local authorities, installers, developers and consultants are now regularly using AutoDesign and benefitting from the visibility it offers through providing indicative connections costs in minutes rather than the usual 10 day turnaround. In 2022/2023, AutoDesign was used 2837 times, resulting in estimated gross avoided costs of £310,560 in connection offer expenses.
There were implementation costs associated with transfer of the completed NIA product into BAU, however, these were minimal and have not been captured.

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.

It should be noted that none of the initiatives reported in this return were initially justified by using the Ofgem CBA table. The information in our own CBAs has therefore been transcribed into the Ofgem CBA as best as reasonably practicable.
Any expenditure incurred for example in 2016, for benefits realised in 2017 and projected beyond 2017, has been shown as 2017 expenditure. CBAs have been completed in this way for the following items:

- LV technology programme (Kelvatek)
- HV automation (APRS)
- Cable fluid leak location
- Oil Regeneration

We have not completed CBAs for capacity recovery or constrained generation. For capacity recovery, the costs are quite low but the payback can be quite random. For constrained generation connections, the CBA really lies with the connectee who has to consider the risks of occasional constraints on future cash flows vs. the reduction in connection costs that can be achieved through these arrangements.

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.

Voltage Reduction – The benefits for generators, as a result of lowering the target 11kV (or 20kV) voltage at the primary substation will vary depending upon the local network topology. Each Primary substation level bar reduction =1 on the table. We have undertaken a desktop study of 166 existing LV feeders to identify the potential increase in generation export capacity if the voltage at the distribution substation was lowered.

Lowering the LV bar at a 11,000/400V distribution substation by 4V (from 252V to 248V) the average export capability per household increases significantly but the starting and revised export capability varies significantly by network, as follows:

	No. of customers on feeder	Max kW generation per customer at 252V	Max kW generation per customer at 248V	Total kW permitted generation at 252V	Total kW permitted generation at 248V
Average	*46*	*0.88*	*4.40*	*26.00*	*129.80*
Max	*106*	*3.18*	*15.86*	*59.66*	*298.30*
Min	*14*	*0.07*	*0.34*	*6.09*	*29.58*

From the above studies, the average increase in permitted generation export is 3.5kW per customer. However, after accounting for voltage rise in the HV network it would be prudent to reduce the expected increase in capability to, say, 1.5kW per customer.

Northern Powergrid has 654 primary substations and 3.96 million customers. With an average of 6,050 customers per primary substation, the average increase in LV generation capacity is estimated to be 9MW per primary substation.

***HV automation* (APRS)** - For CI, the benefits are taken directly from the number of customers whose supplies were restored within three minutes. For

CML, the counterfactual is based on long-run historical fault data, which shows that remote switching from the control centre took, on average, five minutes.

***LV Technology Programme* (Kelvatek)** – Estimate of CI / CML savings on substations where the smart LV devices have been located and successfully operated on an intermittent fault, calculated from the avoidance of an over 3 minute interruption. An estimate of avoided overtime due to a reduction in fuse replacements during overtime and a reduction in EGS2 payments due to better fault location information reducing restoration times on permanent faults.

HV circuit breaker retrofit – Retrofitting the moving (active) portion of the circuit breaker significantly reduced the safety risk associated with oil and reduces the network risk presented by deteriorated mechanisms. Civil works and cable jointing are avoided. The unit cost of a retrofitted circuit breaker is assumed to be £20k compared to the installed unit cost of a new HV primary circuit breaker of £40k. The fixed portion is assessed and expected to remain in a serviceable condition for at least 10 years.

Transformer insulating oil regeneration - Oil regeneration activity has an average unit cost of £50k and defers a £700k transformer replacement by ten years. For more detailed calculations, please refer to the CBA.

***Autodesign* -** In table E6 the figures for are based on the number of uses of Autodesign multiplied by the cost of the assessment and design fee which would otherwise have been applied through the standard connections process. Note that only a proportion of the additions reported resulted in an avoided cost but for completeness, all uses of Autodesign are recorded as additions.

***Silent Power* -** Cost savings per deployment are taken as the cost of the generator hire plus fuel, minus the cost of charging the EESS.
The CO_2 saved per deployment = kg CO_2 associated with diesel generator operation - kg CO_2 associated with payload charge.
* values taken from 2021 UK Government GHG Conversion Factors for Company Reporting

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.

There have been no significant changes to the business cases for the work we have been undertaking in these areas and the CBAs are therefore still valid. We have made no further investment in the LV Technology programme, therefore although the benefits have changed, a review of the the CBA for investment is not appropriate.

The CBA tables are saved in on zip file called "CBA tables Table E6 InnovativeSolutions 20_21" and are individually called:

- NPg RRP 2015-16 Table E6 CBA (APRS).xlsx
- NPg RRP 2015-16 Table E6 CBA (LV technology).xlsx
- NPg RRP 2015-16 Table E6 CBA (PFT).xlsx
- NPg RRP 2016-17 Table E6 CBA (OilRegeneration).xls

E7 – LCTs

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
The methodology used to report the data has allowed allocating the LCTs to the relevant Northern Powergrid licence with a good level of accuracy. Our processes to derive the data reported include some assumptions, which are outlined in the section below. We have assumed that no heat pumps or DG (G83) were connected to the primary network.

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.

<u>Heat pumps</u>
Heat pump data for 2022-23 has been sourced from the connection notifications that the installers send to Northern Powergrid. No assumptions or estimations were made on this data.
 	
The source of data for heat pump installation and capacity for reporting periods up to and including 2020-21 is Ofgem's (Renewable Heat Incentive installation data, received in 2021).
 	
By adopting this report in 2020-21, we made the following adjustments:
• ***Commissioned date*** corresponds to the connection date of the LCT.
• ***Installed capacity*** corresponds to the size of the LCT installed. As it is given in kW_{th}, a mean seasonal performance factor (SPF) (in line with table 2.6. of *Non-Domestic and Domestic Renewable Heat Incentive (RHI) monthly deployment data: April 2021, for New&Legacy installations*) is applied to determine the capacity connected in kW. Mean SPF as of April 2021 was as follows:
   ○ 3.2 for air source heat pumps
   ○ 3.5 for air source heat pumps
   ○ In addition, a SPF of 2.5 was assumed for non-domestic RHI installations as it is the minimum SPF for installation to be eligible.
Installations for which *Installed capacity* was omitted or zero were excluded. Domestic heat pump installations with capacity of 0 kW(th) or above 160 kW(th), as well as one non-domestic heat pump installation with capacity in excess of 400,000 kW(th), were excluded as outliers. We are awaiting a response from Ofgem to confirm whether this data is accurate.
 	
• Installations for which supply MPAN information was unavailable were cross-referenced with a list of Northern Powergrid's postcode districts. A similar issue pertaining to *Feed In Tariff* (FiT) datasets has been highlighted to Ofgem in previous years.

Where a postcode district corresponded to both Northern Powergrid Yorkshire and Northern Powergrid North East, the installations were not included in Table E7 as they represented a negligible variation (please refer to our 2021 Commentary for more detail on variation).

We have used this blend of Ofgem RHI data for earlier years and Northern Powergrid data for the latest 2021/22 year as the recent 2022 Ofgem dataset received has significant unexplained variances to the previous year's dataset. Until such time as these variances can be explained by Ofgem then we have held off using this data.

Electric vehicle chargers

The source for Electric Vehicle chargers data is the connection notifications that the installers send to Northern Powergrid. No assumptions or estimations were made on this data.

PV (G98) and Other DG (G98):

The data for DG connected under G98 (previously G83) standard for 2019-20, 2020-21, 2021-22 and 2022-23 has been sourced from the connection notifications that the installers send to Northern Powergrid. No assumptions or estimations were made on this data.

All DG (G98) data for up to 2018-19 was sourced from Ofgem (e-serve). Customers who install small renewable generation have been incentivised to declare it to Ofgem through the Feed-In-Tariff (FiT) scheme. This has resulted in a higher level of accuracy for this data source compared to that held by Northern Powergrid. We have made the following low-risk assumptions whilst using the data source:

- ***Commissioned date*** corresponds to the connection date of the LCT.
- ***Declared capacity*** corresponds to the size of the LCT installed, we use it to filter the G98 from non-G98. We have assumed that installations with capacity smaller and up to 4kW can be classified as G98 (previously G83) generation, irrespectively of their FiT tag.

In 2020-21 and 2021-22, we did not restate the volumes reported in previous years. This data was last analysed and restated in 2019-20. As FiT closed in 2019, and, we have assumed that any changes in data would be negligible.

DG (non G98)

The source for DG (non G98) data is the connection request database held in Northern Powergrid. CHP installations where fuel had not been determined have been included in the report (none such installations in 2022-23). Fossil-fuel powered CHP installations excluded from E7 Table in 2022-23 are as follows:

CHP	Northeast	Yorkshire
Volume	10	13
Capacity, MW	7.91	2.94

Where Solar PV has been co-located with the battery, we have only taken into account the PV capacity, and excluded battery capacity altogether only where the PV had already been connected.

Notes:

- Where we are using connection notifications received from installers to populate the table, we expect these present and underestimation of all connections made. This has been reinforced by comparing our connection data with the Renewable Heat Incentive and Feed-In Tariff installation data from Ofgem for the past reporting periods.

We have counted the number of connections as *Volumes*; some connections might include more than one LCT (e.g. heat pump or an EV charging point).

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.

Our forecast of LCT uptake in our licence areas, over the RIIO-ED1 period was quantified in our submission back to Ofgem of Table CV103 in 2014.

The rate of LCT uptake is highly sensitive to the Government's stimuli and also depends on the market's ability to find profitable business models.

- During the regulatory year 2015-16, a reduction took place on FiT and RHI, and Renewable Obligation (RO) closed for new onshore wind operators.
- In 2017, the Government announced its plans to ban new petrol and diesel car sales from 2040, later bringing it forward to 2030.
- On 31 March 2019, the Government closed the FiT scheme and decided to introduce the Smart Export Guarantee from 1 January 2020.
- On 31 March 2022, the Domestic Renewable Heat Incentive (RHI) closed to new applicants. The Non-Domestic RHI closed on 31 March 2021.
- In May 2022, the Chancellor announced in the Spring Budget that the VAT rate applicable to the installation of energy saving materials and technologies will be reduced to 0%, effective from 1 April 2022 until 31 March 2027.

As a result of these changes, the uptake of LCTs has generally been slow, although we have seen an upwards trend in uptake of electric vehicle chargers for the past few years and have now started to observe an upwards trend for other the LCTs in 2022.

We expect a further increase in low carbon technologies in response to energy price increases, increased awareness of Net Zero targers, and the Government's removal of VAT for energy efficiency solutions, including Solar PV, to materialise during 2022-23 regulatory reporting period.

We expect to continue to see an increase in the number of heat pumps connected, as the Government has revised its building standards for new buildings which support the uptake of low-carbon heating in the form of heat pumps; however we don't expect significant increase unless policy for building standards in existing buildings would change to strongly support the uptake of heat pumps.

LCT uptake data comparison with forecasts (ED1 and DECC scenarios)

Heat pumps
Our LCT growth projection for the 2015-23 period was based on a Low HP forecast scenario. In Yorkshire and the Northeast, the actuals are well below forecast (both in terms of number of installations and input electrical capacity).

Electric vehicle chargers
Our LCT growth projection was again based on Low EV forecast scenario.
The volumes of EV chargers were largely behind forecast, except for the fast charging points in Yorkshire, where the actuals for 2021-22 were one and a half times the forecast for the same period. In terms of connected capacity, it was below forecast for slow chargers but exceeded the forecast for fast chargers in both licence areas three to four times.

Photovoltaic (G98 and non-G98)
Our LCT growth projection was based on the low DECC forecast for HV and EHV, and the medium DECC forecast for LV. In Yorkshire and the Northeast, the actuals are well below forecast both in terms of volumes and capacity.

Other DG (non G98)
For other, non-G98 DG, the volumes were above the forecast and the electrical capacity was below the forecast.