Access and Forward-looking charges

Report on Network Cost Drivers

Cost drivers Subgroup

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Related Documents

Reference 1	Electricity Industry Access and Forward-Looking Charging Review - Significant Code Review launch statement and decision on the wider review – Ofgem publication
Reference 2	

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1 Executive summary

1.1 This report was prepared by the Cost Drivers subgroup and seeks to answer the questions posed in the product description produced by Ofgem and set out in Annex 2. The subgroup mainly used data provided to Ofgem as part of the regulatory reporting packs, but also identified examples of issues within their networks to provide additional evidence. The areas of focus in the product description, which were considered were:

- **Cost categories** – the network companies classified their cost categories as primary, secondary or tertiary, based on their materiality, whether they are likely to have a locational element, or can be attributed to certain customer groups. For both transmission and distribution, the significant majority of costs have been classified as 'secondary', which means they are material and have either a locational or customer attributable element. Although forward looking charges are focused on incremental costs, significant cost categories include asset replacement and closely associated indirects (opex).
- **Peak driven costs** – although the TOs assess wider network reinforcement across the whole year, rather than the focus being on peak conditions, they were still able to provide examples of investments that were still peak driven. For the DNOs, only 6.3% of RIIO-ED1 allowances are for load related capex (i.e. peak related reinforcement). The DNOs also identified whether primary substation investment was driven by summer or winter peaks.
- **User segmentation** – the network companies identified a number of ways that it might be possible to segment customers, including those relating to specific agreements (e.g. domestic or industrial demand), boundary location and general splits (e.g. rural/urban and tree growth rates). The subgroup noted that there may be some costs that should be levied on all users (e.g. licence fees, which are levied based on MPANs).
- **Upstream and downstream costs** – in 2017/18, the majority of the grid supply points (GSPs) in Scottish Power's distribution areas exported onto the transmission network, suggesting that, in some instances, embedded generators may be driving costs on the upstream transmission networks. For example, the effect of reverse power flows on SHE Transmission's network in 2017/18 included 74% of GSPs exporting at 275/33kV and 132/33kV and 60% of GSPs exported at either GB peak or GB minimum demand. Although the DNOs noted the impact of downstream local distribution network operators (LDNOs), any issues can be resolved over time or as part of ongoing network management.
- **Energy consumption and customer numbers** – the TOs identified that the volume of customers can have an impact on network costs, due to their relationship with network constraints. In addition, the Network Output Measures methodology includes a duty factor that is related to maximum and average demand placed on a transformer. The DNOs did not identify a direct link between network costs and energy consumed. However, the DNOs did identify several costs, which have a direct link with customer numbers, including licence fees that are shared on an MPAN basis.
- **Losses and reactive power** – although both TOs and DNOs are required to manage losses on their networks under their price controls and they are taken into consideration when planning investments, they do not consider losses to be drivers of network costs. For the TOs, a significant factor relating to reactive power is the issue of voltage management, which requires actions including the ESO procuring additional reactive power and the TOs investing in reactive compensation devices. The DNOs noted that customers with a poor power factor may result in them utilising additional network

capacity. However, there are no cited examples of poor power factor driving reinforcement.

- **Emerging technologies** – the ESO has identified, as part of the System Operability Framework, solutions for the ESO to maintain operability against voltage control, stability and thermal challenges (among others). The DNOs noted that, if price signals are insufficiently strong, they may not encourage customer behaviour to create diversity, increasing demand at peak times.

1.2 Although, as summarised above, the subgroup has used data from several sources to answer the questions, there are several areas where further work will be required to uncover more granular data. This will be undertaken during the next phase and will focus especially on providing more evidence of locational variations in costs, additional case studies demonstrating how issues have manifested in practice and more work on the impact of emerging technologies on the networks.

2 Introduction

Significant Code Review

2.1 This report will inform the Ofgem led Electricity Network Access and Forward-looking Charging Significant Code Review ('Access SCR', 'SCR') and is one of a suite of reports produced by the Access SCR Delivery Group.

2.2 Ofgem launched the SCR on 18 December 2018. The overarching objective of the SCR is to ensure that electricity networks are used efficiently and flexibly, reflecting users' needs and allowing consumers to benefit from new technologies and services while avoiding unnecessary costs on energy bills in general. The outputs of the SCR will inform decisions on future changes to the industry codes that govern the way in which different users can connect to and utilise our electricity networks.

Drivers for the SCR - the changing energy system

2.3 Decarbonisation and new technologies are driving rapid change in the way in which energy is produced, with growth in distributed and locally connected energy resources. At the same time the take up of new technologies and solutions such as behind the meter generation, electric vehicles, electric heating, smart meters and energy storage is increasing, and users are seeing greater choice and control over the way in which they use energy. These changes could lead to significant increases in peak demand and create constraints on some parts of the electricity network. Network reinforcement to address constraints can be costly, time consuming and disruptive, and could therefore present a barrier to the take-up of new technologies and changing patterns of usage.

2.4 The pace of change can be expected to hasten over the next decade and beyond, bringing unprecedented challenges in the way in which electricity networks are designed, operated and managed. By extension this also points to the need for change in the commercial, regulatory and technical arrangements that govern the way in which different users (for example domestic households (including vulnerable users); large and small generators; and large and small commercial demand users) connect to and utilise the electricity networks.

2.5 It is crucial that networks continue to meet the needs of all users, and continue to be managed in a way that is in the interests of current and future users. Central to this is ensuring that current network capacity is most effectively and efficiently utilised and that appropriate economically efficient signals indicate where there is need for new investment in networks, including traditional reinforcements. Important to this is ensuring there is a level playing field for different types of energy service providers to compete on and any undue differential treatment is avoided. Put simply, it is increasingly important that the use of network capacity is managed over all timescales in a way which minimises the costs to users as a whole.

2.6 Having consulted, Ofgem believes there is broad consensus across that industry that the current electricity network access arrangements and forward-looking charges will not efficiently facilitate these changes in our energy system. The SCR therefore identifies a number of key issues with the current arrangements and priority options for change. Consistent with this, the SCR includes:

- a review of the definition and choice of access rights for transmission and distribution users
- a wide-ranging review of distribution network charges (Distribution Use of System (DUoS) charges); and

- a review of the distribution connection charging boundary.

The Delivery Group

2.7 To deliver the SCR, a Delivery Group has been established to provide input to Ofgem for its consideration in developing its SCR conclusions. The Group is chaired by Ofgem, with members including the Electricity System Operator (ESO), distribution network operators (DNOs), transmission owners (TOs), the Energy Networks Association (ENA), relevant code administrators (e.g. DCUSA and CUSC), and a representative for independent DNOs. The purpose of the Delivery Group is to provide knowledge and experience of how the networks are planned and operated, to help develop and assess options. The Delivery Group has formed a number of subgroups to consider and report on specific aspects of the SCR, and will form more as needed going forward. In the current phase, three subgroups have been established, to focus on access rights, cost drivers and locational granularity of charges.

The Challenge Group

2.8 To provide ongoing wider stakeholder input into the Access SCR, a Challenge Group has been established. The Challenge Group provide a challenge function to the work of the Delivery Group (and that of any working groups it commissions), ensuring policy development takes into account a wide range of perspectives and is sufficiently ambitious in considering the potential for innovation and new technologies to offer new solutions. The Challenge Group’s feedback on the draft reports has been reflected in this report, where applicable.

Scope and purpose

2.9 This report has been prepared by the Cost Drivers subgroup, which was established to undertaken foundational analysis of the drivers of network costs to help shape the choice and analysis of charging and access rights. In particular, the report contains information on the level of seasonality and locational pricing to enable consideration of charge design that will better manage times of peak congestion. The full product description for the cost drivers report has been set out in Annex 2.

2.10 The subgroup membership comprises representatives from the DNOs, ESO and TOs and is chaired by Ofgem. Secretariat support is provided by the ENA.

Guiding principles

2.11 As part of Ofgem’s Access SCR launch statement, three guiding principles were set out. These are outlines below, and better-defined access rights should support these:

1. Arrangements support efficient use and development of the energy system.
2. Arrangements reflect the needs of consumers as appropriate for an essential service.
3. Any changes are practical and proportionate.

Exclusions and dependencies

2.12 This report does not include forecasts or assumptions regarding potential changes to loads on the networks due to the electrification of heat and transport and changes in the mix of costs. Forecast data will be identified and obtained, as part of the Analytical Framework workstream, which will develop the assumptions and modelling to support the impact assessment.

2.13 This report does not contain options or recommendations and instead presents evidence that will help to inform the reports being prepared by the other subgroups on access rights and locational granularity. As such, this report should be read in conjunction with the other subgroup reports.

2.14 The evidence will also inform the separate work Ofgem is undertaking with industry on the design of future network charges and modelling the impact of potential charges. It should be noted that potential future changes to both cost categories (e.g. procurement of flexibility) and cost drivers (e.g. increases in electric vehicles) will be considered, as part of development of scenarios for modelling.

3 Cost categories

3.1 This section contains the subgroup's assessment of the network companies' cost categories to determine those that require additional analysis, due to their significance as drivers of costs. In order to do this, the network companies applied the following criteria to classify their costs:

- Primary – if material in value, and satisfies both the locational and customer attribution criteria
- Secondary – if material, and satisfies one of the locational or customer attribution criteria
- Tertiary – if not material.

3.2 Those costs identified as primary will be investigated further, those identified as secondary will be considered on a case-by-case basis and those classified as tertiary are not considered to require further analysis.

3.3 A key focus of the investigation will be to identify which cost categories have a forward-looking component, as this will determine those costs should potentially be included in the 'non-residual' component of charges.

Transmission

3.4 For the TOs, cost categories were considered to have a location element if they were known drivers in specific larger regions. These regions were defined by each TO using the boundaries from the Electricity Ten Year Statement (ETYS). A map of these regions can be found in Annex 4.

3.5 Categories were deemed attributable to customers if they were as driven by an individual generator or demand user, either embedded or directly connected to the transmission system

3.6 Due to the differences in the TOs, the assessment of 'materiality' has been more subjective and was based on the subgroup's view on whether the scale of the cost meant it was material. The outcomes of the assessment are set out in Annex 2 and Table 1 below summarises the percentage split of cost categories between the classifications.

Table 1: Percentage of TO costs by classification

Priority cost type	% of total
Primary	13.2
Secondary	73.7
Tertiary	13.2

3.7 The transmission costs in this report cover a smaller range of categories when compared to the distribution section, which is primarily due to the level of detailed reporting requested by Ofgem. TOs are requested to focus on reporting categories of high materiality, those with relatively small costs are not reported on, due to the scale of difference in spending.

Distribution

3.8 In order to determine distribution costs, the subgroup built upon the DNOs' response to Ofgem's request for information (RFI), which identified the cost categories from the cost and volumes regulatory reporting packs, which are provided annually to Ofgem:

- The DNOs' M16s (Cost History and Future Forecast for rest of ED1 by cost segment) were collated and summarised to show total costs for each category reported in RIIO-ED1.
- From these totals, a cost per DNO, a cost per DNO by year and the proportion of total costs for each cost category were derived.
- The totals per DNO per year for RIIO-ED1 were used to identify those costs, which were over a £1m per year on average threshold determined by the subgroup.

3.9 It should be noted that the subgroups initial assessment of whether a cost category was locational or could be attributed to a customer group was based on whether the group considered it to be probable that the cost category met those criteria. Further analysis will be required to determine whether it is possible to robustly identify the locational or attributable component of costs.

3.10 Table 2 below contains the collated M16 data for all the DNOs.

Table 2: Total DNO costs disaggregated by category

			Total	Per DNO	Per DNO Per Year	Proportion
Load related	Connections within the price control	£'m	362.3	25.9	3.2	1.1%
	Reinforcement (Primary Network)	£'m	965.1	68.9	8.6	2.9%
	Reinforcement (Secondary Network)	£'m	519.6	37.1	4.6	1.6%
	Fault Level Reinforcement	£'m	112.9	8.1	1.0	0.3%
	New Transmission Capacity Charges	£'m	98.3	7.0	0.9	0.3%
	Total load related costs	**£'m**	**2,058.2**	**147.0**	**18.4**	**6.3%**
Non-load capex (excluding non-op capex)	Diversions (Excluding Rail Electrification)	£'m	601.4	43.0	5.4	1.8%
	Diversions (Rail Electrification)	£'m	19.7	1.4	0.2	0.1%
	Asset Replacement	£'m	4,258.4	304.2	38.0	13.0%
	Refurbishment no SDI	£'m	349.5	25.0	3.1	1.1%
	Refurbishment SDI	£'m	232.6	16.6	2.1	0.7%
	Civil Works Condition Driven	£'m	363.4	26.0	3.2	1.1%
	Operational IT and telecoms	£'m	446.9	31.9	4.0	1.4%
	Blackstart	£'m	65.5	4.7	0.6	0.2%
	BT21CN	£'m	71.0	5.1	0.6	0.2%
	Legal & Safety	£'m	261.3	18.7	2.3	0.8%
	QoS & North of Scotland Resilience	£'m	197.3	14.1	1.8	0.6%
	Flood Mitigation	£'m	92.3	6.6	0.8	0.3%
	Physical Security	£'m	3.5	0.3	0.0	0.0%
	Rising and Lateral Mains	£'m	151.2	10.8	1.3	0.5%
	Overhead Line Clearances	£'m	350.8	25.1	3.1	1.1%
	Worst Served Customers	£'m	17.6	1.3	0.2	0.1%
	Visual Amenity	£'m	56.9	4.1	0.5	0.2%
	Losses	£'m	30.9	2.2	0.3	0.1%
	Environmental Reporting	£'m	63.7	4.5	0.6	0.2%
	Total non-load capex (excluding Non-op capex)	**£'m**	**7,633.9**	**545.3**	**68.2**	**23.3%**
Non-op Capex	IT and Telecoms (Non-Op)	£'m	466.4	33.3	4.2	1.4%
	Property (Non-Op)	£'m	142.8	10.2	1.3	0.4%
	Vehicles and Transport (Non-Op)	£'m	233.8	16.7	2.1	0.7%
	Small Tools and Equipment	£'m	173.9	12.4	1.6	0.5%
	Total non-op capex	**£'m**	**1,016.9**	**72.6**	**9.1**	**3.1%**
HVP	High Value Projects DPCR5	£'m	72.5	5.2	0.6	0.2%
	High Value Projects RIIO-ED1	£'m	95.8	6.8	0.9	0.3%
	Total high value projects	**£'m**	**168.3**	**12.0**	**1.5**	**0.5%**
Moorside	Moorside	£'m	-	-	-	0.0%
	Total Moorside	**£'m**	**-**	**-**	**-**	**0.0%**
Network Operating Costs	Faults	£'m	2,349.6	167.8	21.0	7.2%
	Severe Weather 1 in 20	£'m	68.2	4.9	0.6	0.2%
	ONIs	£'m	644.3	46.0	5.8	2.0%
	Tree Cutting	£'m	890.8	63.6	8.0	2.7%
	Inspections	£'m	262.5	18.8	2.3	0.8%
	Repair and Maintenance	£'m	713.8	51.0	6.4	2.2%
	Dismantlement	£'m	13.9	1.0	0.1	0.0%
	Remote Generation Opex	£'m	27.7	2.0	0.2	0.1%
	Substation Electricity	£'m	147.7	10.6	1.3	0.5%
	Smart Metering Roll Out	£'m	207.9	14.8	1.9	0.6%
	Network Operating Costs	**£'m**	**5,326.4**	**380.5**	**47.6**	**16.3%**

Closely associated Indirects	Core CAI	£'m	4,685.6	334.7	41.8	14.3%
	Wayleaves	£'m	499.3	35.7	4.5	1.5%
	Operational Training (CAI)	£'m	529.7	37.8	4.7	1.6%
	Vehicles and Transport (CAI)	£'m	568.1	40.6	5.1	1.7%
	Closely Associated Indirects	**£'m**	**6,282.7**	**448.8**	**56.1**	**19.2%**
Business Support Costs	Core BS	£'m	1,316.6	94.0	11.8	4.0%
	IT& Telecoms (Business Support)	£'m	1,018.4	72.7	9.1	3.1%
	Property Mgt	£'m	432.5	30.9	3.9	1.3%
	Total Business Support Costs	**£'m**	**2,767.5**	**197.7**	**24.7**	**8.5%**
Other costs within Price Control	Atypicals Non Sev Weather	£'m	332.7	23.8	3.0	1.0%
	Atypicals Non Sev Weather (excluded from Totex)	£'m	5.0	0.4	0.0	0.0%
	Network Innovation Allowance (NIA)	£'m	111.9	8.0	1.0	0.3%
	Network Innovation Competition (NIC)	£'m	67.9	4.9	0.6	0.2%
	IFI & Low Carbon Network Fund	£'m	34.1	2.4	0.3	0.1%
	Other costs within Price Control	**£'m**	**551.6**	**39.4**	**4.9**	**1.7%**
	Total Costs within Price Control	**£'m**	**25,805.6**	**1,843.3**	**230.4**	**78.8%**
Costs outside Price Control	Connection costs outside of the price control	£'m	- 1,238.8	- 88.5	- 11.1	-3.8%
	Other cost outside of the price control	£'m	1,301.1	92.9	11.6	4.0%
	Total Costs outside Price Control	**£'m**	**62.4**	**4.5**	**0.6**	**0.2%**
Total Non Activity Based costs		**£'m**	**6,870.6**	**490.8**	**61.3**	**21.0%**
	Total DNO	**£'m**	32,738.5	2,338.5	292.3	100.0%

3.11 Table 3 below contains a summary of the outcomes of the classification as primary, secondary and tertiary costs. The detailed assessment of each cost category to determine the classification is set out in Annex 3.

Table 3: Total DNO costs by classification

Priority cost type	Value (£m)	% of total
Primary	56.87	19.5
Secondary	226.36	77.4
Tertiary	9.07	3.1
Average Cost per DNO per Year	**292.31**	**100**

3.12 The primary costs are made up of load related costs, asset replacements costs, and rising and lateral mains costs (see definition in Annex 3), which add up to approximately 20% of the total costs.

3.13 Although a number of costs have been identified as having a locational element, it can be very difficult to identify the customers these relate to. However, if these can be identified, they may relate to several different locational groups. For example, the reinforcement locational groups would be very different to the asset replacement which in turn would be very different to tree cutting groups. This may lead to a charging approach where the DNO is split into several different base groups and the cost applied to each group is based on its geographical/electrical cost or type of segmentation.

4 Peak driven costs

4.1 The purpose of this section is to provide evidence of the link between network loading / flows and network costs and consider whether this is likely to change in the future. The section also considers the impact that a user's location or the timing of their usage has on network costs.

Transmission (400kV, 275kV (in Scotland))

4.2 TOs and the ESO are licence obligated to develop an efficient, coordinated, and economic system of electricity transmission, consistent with the National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS). This is facilitated through the ESO's publication of Future Energy Scenarios (FES), ETYS, Network Options Assessment (NOA) which all provide important information for the TOs to reach investment decisions on transmission reinforcements for transmission capacity:

- The FES is used to produce the ETYS by determining the power flow requirements across the transmission network. For the ETYS, the network is divided into boundaries; while these do not physically exist, power flows can be measured over each adjacent boundary to determine the most constrained areas of the network in need of reinforcement.
- After the requirements have been defined, the ESO and the TOs work together to assess a wide range of options that could meet the future system requirements for submission to the NOA process. The ESO may also propose alternative options for TO consideration and submit potential operational or commercial options at this stage of the process.
- Following the receipt of these options, the 'optimisation' process can begin. This involves the ESO performing an economic assessment on each of the possible options weighing up the capital cost to implement them versus the constraint cost saving over time. A constraint cost is a monetary value incurred in limiting the bulk power flow over a given boundary. Constraint costs represent part of the Balancing Services Use of System (BSUoS) charges, whereas capital costs will influence Transmission Network Use of System (TNUoS) charges.

4.3 It is important to note that the ESO's economic assessment in the NOA is a year-round assessment analysing the total system constraints for every hour of every year. Consistent with the requirements of the NETS SQSS, wider network reinforcement or wider works projects are not only driven by specific peak conditions, instead their need is assessed and evaluated across the entire year. Whilst the NOA demonstrates a shift away from peak driven reinforcement, there are some examples of network reinforcements which were driven by peak conditions.

4.4 Table 4, 5 and 6 below summarises both the historic and planned types of peak driven and wider system investment across the different transmission networks across the RIIO T1 period for three main categories:

- Connection and Local Infrastructure – To cover for Enabling and sole-use connection costs, including Load Related Expenditure (LRE) - sole-use Local Enabling (Entry - Sole Use), Local Enabling (Entry) Sole-Use Infrastructure and Local Enabling (Entry) Shared-Use Infrastructure in our RIIO mechanism.
- GSP – To cover for works associated with providing capacity at GSPs including Local Enabling (Exit – Sole Use) and Local Enabling (Exit) Schemes not subject to uncertainty mechanisms.

- Wider – To cover for works associated with creating wider Main Interconnected Transmission System (MITS) capacity, including Baseline Wider Works, Wider Works Schemes not subject to uncertainty mechanisms and Strategic Wider Works (SWW).

It should be noted that, as later in the report, TOs' investment decisions are made on the balance of a number of factors, including peak system needs, reinforcement costs, earliest in service dates and year-round operational constraint costs.

4.5 Table 4 below sets out **SHE Transmission's** expenditure across three categories of capex, as reported to Ofgem in Table 4.2 of the RRP.

Table 4: Summary of peak driven investment across SHE Transmission's network

Investment Type	Number of schemes	RIIO T1 Spend
Connection and Local Infrastructure	134	£1092m
GSP	26	£84m
Wider	43	£1761m
Grand Total	**203**	**£2937m**

4.6 Table 5 below sets out **SP Transmission's** expenditure across three categories of capex, as reported to Ofgem in Table 4.2 of the RRP.

Table 5: Summary of peak driven investment across SP Transmission's network

Investment Type	Number of schemes	RIIO-T1 Spend
Connection and Local Infrastructure	245	£611m
GSP	53	£83m
Wider	52	£563m
Grand Total	**350**	**£1,258m**

4.7 Table 5 below sets out **NGET's** expenditure across three categories of capex, as reported to Ofgem in Table 4.2 of the RRP.

Table 5: Summary of peak driven investment across NGET's network

Investment Type	Number of schemes	RIIO T1 Spend
Connection and Local Infrastructure	161	£646m
GSP	114	£692m
Wider	169	£2259m
Grand Total	**444**	**£3598m**

4.8 Following are some detailed examples of different types of investment and the key drivers behind them.

SHE Transmission – Beauly – Corriemoillie (Local reinforcement)

4.9 The Beauly – Corriemoillie 132kV transmission reinforcement is driven by local peak flows caused by a number of hydro and wind plant in the region. The driver is a combination of both transmission and distribution connected generation totalling ~330MW. The Beauly – Corriemoillie reinforcement is justified under Chapter 2 of the NETS SQSS, Peak Generation Conditions, which states that there should be no overloads, unacceptable voltages or system instability under pre-fault conditions and defined outage events, including single circuit outages, double circuit outages and busbar outages. In addition, Chapter 4 of the NETS SQSS states that with an intact system and with background conditions as expected at Average Cold Spell

(ACS) peak demand, that should be no overloads, unacceptable voltages or system instability following a secured event (e.g. single circuit faults, double circuit faults and busbar faults).

SHE Transmission – Coupar Angus (GSP reinforcement)

4.10 Coupar Angus is a new 132kV GSP comprising two 132/33kV transformers. This reinforcement was driven by an increase of low carbon generation within the region. The generation mix is mostly wind and solar and made up entirely of distribution connected generation. The Coupar Angus reinforcement is justified under Chapter 2 of the NETS SQSS because, without this reinforcement, the network would not be compliant under planned or unplanned outage conditions.

SHE Transmission / SP Transmission – East Coast upgrades (Wider reinforcement)

4.11 The East Coast upgrade reinforcement works is a two-stage project, initially reprofiling and later uprating major transmission routs to 400kV. This reinforcement is driven by the large volumes of predominately low carbon generation situated in the North of Scotland with limited capacity to transfer this power to England. The East Coast reinforcement cannot be attributable to any one generator or customer, the need is driven by approximately 60 Transmission connected, over 130 distribution connected generators and an interconnector. This wider works project has been assessed against Chapter 4 of the NETS SQSS and analysed in the NOA, based on year-round expected conditions for the Economy Planned Transfer and meeting peak demand for the Security Planned Transfer. The ESO has recommended this project is proceeded to a SWW assessment where it will be studied in much greater detail to ensure the most economical solution is built.

SP Transmission – Dunbar (GSP reinforcement)

4.12 Dunbar is an existing 132/33kV GSP comprising two 60MVA 132/33kV transformers. Reinforcement of Dunbar GSP, comprising the installation of two new 132/33kV 90MVA transformers (while retaining the two original 60MVA units), is currently in delivery, driven by the significant penetration of new embedded wind and waste to energy generation. The Dunbar reinforcement is justified under Chapter 2 of the NETS SQSS.

National Grid Electricity Transmission – West Burton (GSP reinforcement)

4.13 This investment is required due to NETS SQSS non-compliance caused by an increase in demand across the West Burton area (WPD East Midlands network). West Burton 132kV substation is fed through two 240MVA transformers supporting the DNO demand group and West Burton 'A' Station demand. The DNO demand is forecast to increase from 2018/19 to 2021/22, with the station demand remaining consistent during operation. Following a single fault causing an outage on either of the current transformers (SGT 1 or 2) the remaining in service SGT is overloaded above its short term ratings. This was managed by transferring demand within the DNO group. WPD have informed NGET that due to the growth of embedded generation in the group this interim operational measure can no longer be maintained. Therefore, the investment of additional SGT becomes the most economic and efficient solution to resolve the capacity need during peak condition at the site.

National Grid Electricity Transmission – Kemsley – Littlebrook Reconductoring (Wider reinforcement)

4.14 With a number of generator and interconnector connections in the south east coast of England and Thames Estuary area, there is an increasing need for network capacity to cope with power flow conditions during peak and year around operation of the network in the area. Existing conductors on the double overhead line route are struggling to meet the need for customer connections agreement and energy scenarios from ESO's FES publication. This investment decision by NGET to reinforce the double circuit route with combination of highly rated conductors will significantly increase the boundary capabilities across a list of system boundaries in the area. Delivery of the reconductoring scheme is needed as soon as 2020 to significantly reduce system constraints in the Thames Estuary area.

Distribution (132kV and below)[1]

4.15 DNOs hold distribution licences and are responsible for the operation and maintenance of a public electricity distribution network. The Distribution Code covers the technical aspects relating to the connection and use of the electricity distribution licensees' distribution networks (e.g. by generators).

4.16 The DNOs have a licence obligation to plan and develop their networks in accordance to engineering recommendation P2 which is focused around ensuring sufficient capacity is available to meet peak demand and, in general, ensures the system is engineered to meet present customer requirements and some element of future requirements and expectations.

4.17 DNOs identify the most constrained areas of the network in need of reinforcement through a number of processes, including load flow analysis, which includes all customers expected to connect, regulatory analysis for submissions (e.g. Reinforcement Load Index (LI) reporting packs),[2] Long Term Development Statements (LTDS) and new connections and outputs from the EHV Distribution Charging Methodology (forward cost pricing approach). Load flow analysis looks at the winter peak which drive demand reinforcement and all the seasons which drive generation reinforcement. The DNOs create detailed forecasts for reinforcement at EHV, which include the type of reinforcement, for example, generation/demand led, and customer driven/ general reinforcement. However, these forecasts are subject to change. Load flow analysis is also done when a connection offer is made to a customer interested in connecting to the network.

4.18 The historical approach to investment in the network has involved network costs that are driven by peak demand levels which relate to peak power flows and the requirement for additional network infrastructure. The load related (LR) system reinforcement capital programme is an important element of this investment.

4.19 The networks are in the early stage of having to provide for EVs and heat pumps, both of which are predicted to have significant impacts on the load profile and network maximum demand. These emerging technologies, coupled with further growth in residential housing stock and more energy efficient electric devices, create the potential for major upheavals in distribution systems in the coming years. The increasing number of embedded generation sites have had a significant impact on the DNO systems already, including causing reverse power flows at some GSPs, which in turn impact the transmission network. For example, the effect of reverse power flows on SHE Transmission's network in 2017/18 included 74% of GSPs exporting at 275/33kV and 132/33kV and 60% of GSPs exported at either GB peak or GB minimum demand. In total, 19 GSPs exported half-hourly between April and September and 24 between October and March.

4.20 The most notable impact from peak driven costs relates to the level of reinforcement. The reinforcement can initially be broken down into two types, general reinforcement (including thermal, and, potentially, voltage/reactive, fault level and power quality) and customer driven. The customer driven reinforcement is subject to the apportionment rules, which mean that part

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[1] 132kV is transmission voltage in Scotland. Please refer to the Transmission section above for relevant information on the process
[2] Annual data on ongoing and completed primary reinforcement schemes are reported in the Reinforcement LI reporting packs. The pack identifies substations and substation groups by substation names, voltage levels and number of customers connected

of the cost is paid for by the customer who is connecting, and part of the cost is paid for by the DNO. As a result, reinforcement costs are ultimately paid for by all customers through direct contribution or DUoS charges.

4.21 Spreadsheet M16 of the DNOs' cost and volumes pack[3] reported to Ofgem has been summarised in Table 3 and identifies the actual and forecast expenditure (for the eight year RIIO-ED1 period) for all the cost categories from the 2017/18 Regulatory Instructions and Guidance (RIGs) submission. The main cost drivers relate to network capacity constraints, which are captured within the load related costs. As identified below in Table 6, the proportion of total RIIO-ED1 costs (including actual and forecast costs) that relate to "Load Related Reinforcement" is 6.3%.

Table 6: *Load Related Expenditure for RIIO-ED1*

	Type of Reinforcement	**% of LRE in ED1**	**All DNO LRE as % of Total ED1 allowance**
General Reinforcement	Primary Reinforcement	2.9%	**6.3%**
	Secondary Reinforcement	1.6%	
	Fault Level Reinforcement	0.3%	
	Network Transmission Capacity Charges	0.3%	
	High Value Project ED1	0.3%	
Customer triggered Reinforcement	Generation		
	Demand		
Customer Connection	Generation	1.1%	
	Demand		

4.22 System Peak events vary across different network areas. These can be found in the data used for determining peaking probabilities that are used under Common Distribution Charging Methodology (CDCM) for setting charges. The level of variation depends on whether the peak demand is residential, commercial or industry led, and whether the cold weather or summer high temperatures, which generally drive the peak, occurs uniformly across the network areas. It also depends on the level and frequency of cold and hot weather events within given year(s).

4.23

4.24 Table 7 below shows the number of GSPs for eleven of the DNO licence areas that have had peak demands for each month in 2017/18. It also includes the total number of bulk supply points (BSPs) and primary substations. This information was collated from Table 3 of the CDCM network models on peaking probabilities. The peaking probabilities help to determine the proportion of assets that have their time of maximum load during each distribution time band.

4.25 The purpose of Table 7 is to show the monthly split of when peak demand was achieved per month in 2017/18 for the DNO licence areas. This information has the advantage of going down to a more granular level than the LI packs by showing how many GSPs peak in a particular month, which helps to identify more accurately the seasonality of peaks across all four seasons and not just winter and summer. The seasonality of the peaks could even be further disaggregated by considering how the peaks vary by location i.e. by DNO licence area.

[3] There is detail on historical reinforcement and forecast reinforcement in the Costs and Volumes pack. However, the historical information in the costs and volumes pack is split by voltage level but not by location. The forecast reinforcement in the Costs and Volumes pack is in the M16 sheet and contains only a DNO total.

4.26 Table 7 shows that the highest proportion of peaks typically occur in winter, however, a significant number of GSPs, BSPs and primary substations had their peaks occurring in March. This was due to the ‘Beast from The East’.

Table 7: *Total count of peaking GSPs for 11 DNO licence areas by month*

	April	**May**	**June**	**July**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**March**
GSP	7	4	2	0	3	2	5	14	63	51	28	88
BSP	67	31	31	12	5	19	19	77	253	137	188	208
Primary	484	112	171	72	32	65	69	214	790	615	498	1254

4.27 Table 8 below summarises the RIIO-ED1 peak driven investment costs across DNOs’ network for different drivers of primary reinforcement. The data in this table was collated from the DNOs’ Regulatory Reporting LI packs for primary reinforcement schemes at 33kV and above.[4,5] The table shows that the majority of primary reinforcement schemes in the first three years of RIIO-ED1 are peak demand driven and make up 65% of "primary reinforcement costs".

Table 8: Historic and planned peak driven investment identified by cost driver

Specific Driver (Locational indicator)	**Substation primary voltage**	**Season of most onerous demand**	**Sum of DPRC5 Costs Prior to ED1 (£m)**	**Sum of Total Actual Spend ED1 (£m)**	**Number of schemes**	**Comments**	**Unit costs *£m/no. of schemes* (ED1)**
Improved security of supply	132kV	Summer	0	9.1	5		1.83
	132kV	Winter	0	14.5	9		1.61
	EHV	Winter	0	8.4	8		1.05
	No Voltage provided	No season provided	0	3.3	2		1.66
Total Improved Security of supply			**0**	**35.4**	**24**		**1.50**
Peak demand flow	132kV	Summer	0	30.8	13		2.37
	132kV	Winter	1.2517	39.8	36		1.11
	EHV	Summer	0	6.3	24		0.26
	EHV	Winter	0	104.2	154		0.68
	EHV	Winter		0.0	1	Load Transfers	0.02
	EHV	No season provided		3.5	2		1.75
	EHV	Winter	1.226	2.4	3		0.79
	No Voltage provided	No season provided	0	0.9	4		0.24
Total Peak demand flow			**2.5**	**188.0**	**237**		**1.00**
Wider network issues	132kV	Summer		9.0	3		2.99
	132kV	Winter	0	33.5	8		4.19
	132kV	No season provided	0	8.9	2		4.44
	EHV	Summer	0	2.6	2		1.30
	EHV	Winter	0	8.0	11		0.73
	EHV	Winter		0.0	2	Load Transfers	0.00
Total Wider network issues			**0**	**61.9**	**28**		**2.27**
Local network issues	132kV	Summer	0	2.2	1		2.18
	132kV	Winter		0.0	3	Reverse power flow	0.01
	132kV	Winter	0.1	0.1	1		0.09
	EHV	Winter		0.2	12	Reverse power flow	0.02
	EHV	Winter	0.0	2.6	7		0.38
	EHV	Winter	0.0	0.0	1		0.00
Total Local network issues			**0.09**	**5.1**	**25**		**0.44**
Total Primary Reinforcement Expenditure			**2.6**	**290.5**	**314**		**1.24**

4 Excludes HVPs because only 2 DNOs have reported HVPs in their LI submissions so the HVP schemes have not been included in the above LI table summary. They've been included in the Cost and Volumes summary table which is the main table that collects HVP costs and volumes annually.

5 Where DNOs have reported costs but not indicated the season and/or voltage that the peak occurred, it's been indicated in the table that "No season provided" and/or "No voltage provided".

4.28 Further observations from Table 8 shows that winter has the highest demand, as identified in further detail below in Table 9.

Table 9: Percentage split of substation peaks between winter and summer

	EHV	132kV	Overall
% of Substations with peaks occurring in **summer** (of schemes with intervention)	8%	7%	16%
% of Substations with peaks occurring in **winter** (of schemes with intervention)	65%	19%	84%

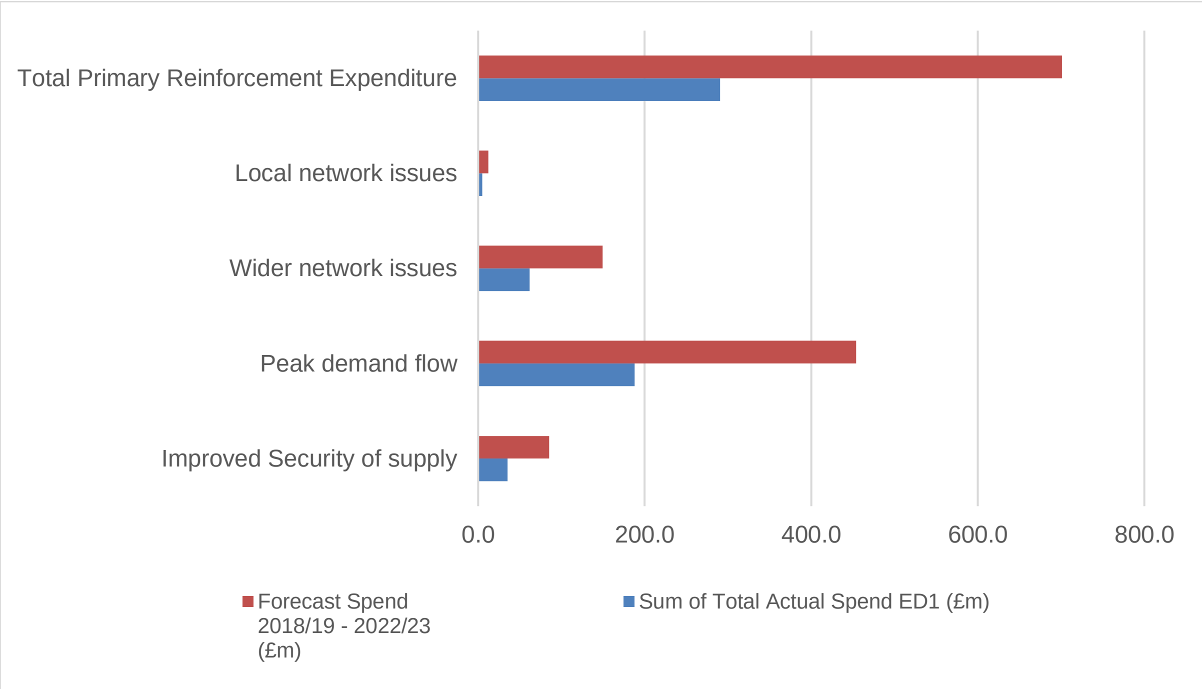
4.29 The forward looking peak driven costs for the future years of RIIO-ED1 have been estimated using the forecast primary reinforcement costs provided in Table M16 of the cost and volume pack – 2017/18 submission. A simplistic cost apportionment method was used where a percentage split was derived for each cost driver by calculating the ratio between the actual costs in the first three years of RIIO-ED1 (from Table 8) and the total primary reinforcement expenditure. The percentage split for each cost driver was applied to the total forecast primary reinforcement costs in the M16 table to derive an estimate cost for each cost driver.

4.30 Table 10 and Figure 1 show that the estimated forecast primary reinforcement costs have been broken down by specific cost drivers and they only cover the remaining years of the RIIO-ED1 price control period and not a longer time horizon. The season of maximum demand is assumed to be predominantly winter. The costs haven't taken account of any assumptions that DNOs may have made in providing for the growth of EVs and heat pumps both of which are predicted to have significant impacts on the load profile, diversity and network maximum demand. Further analysis is required to project how reinforcement costs should change over time including the of modelling different scenarios of technology take up that will impact reinforcement costs.

Table 10: Estimated forward looking peak driven investment by cost driver

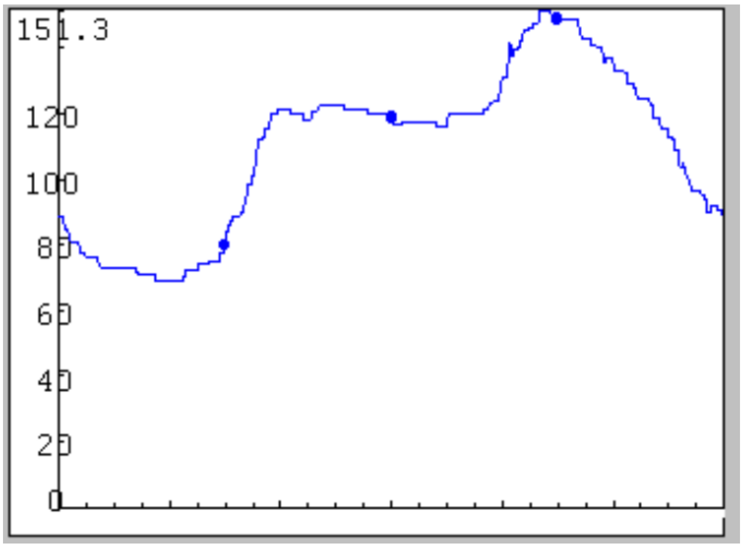
Specific Driver (Locational indicator)	Sum of Total Actual Spend ED1 (£m)	Actual Spend as a % of Total Actual Primary Reinforcement expenditure	Forecast Spend 2018/19 - 2022/23 (£m)	Forecast Spend as a % of Total Forecast Primary reinforcement expenditure
Improved Security of supply	35.4	12.2%	85.4	12.2%
Peak demand flow	188.0	64.7%	453.8	64.7%
Wider network issues	61.9	21.3%	149.4	21.3%
Local network issues	5.1	1.8%	12.4	1.8%
Total Primary Reinforcement Expenditure	**290.5**		**701.0**	

Figure 1: Estimated forward-looking costs for Primary Reinforcement



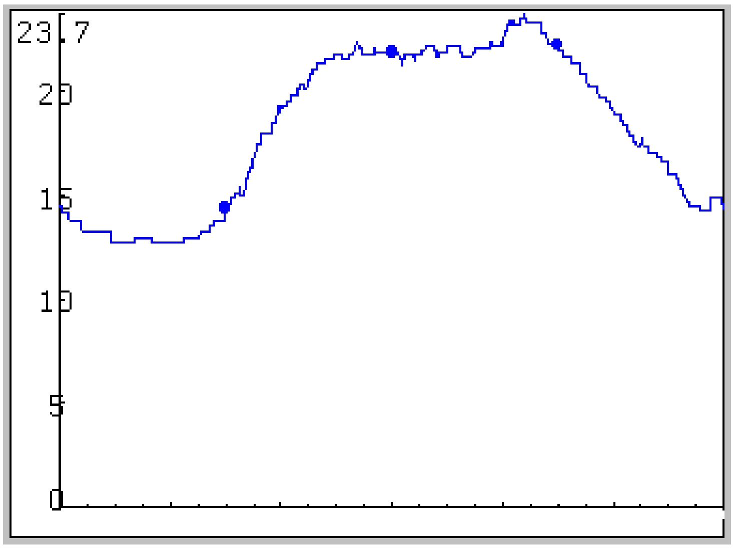
4.31 Peak demand flows usually occur over short periods. For instance, demand is highly variable over the course of the day and this is further impacted depending on the season. Figure 2 shows typical load profiles for urban 132/33kV substations every half hour over a 24-hour period from midnight to midnight.

Figure 2: Typical 12/33kV Substation Load profile (midnight – midnight)



4.32 Figure 3 shows a typical daily profile for 33/11kV substations. Note that both of these graphs were sourced from Appendix 2 of SSEN's 2018 LTDS.

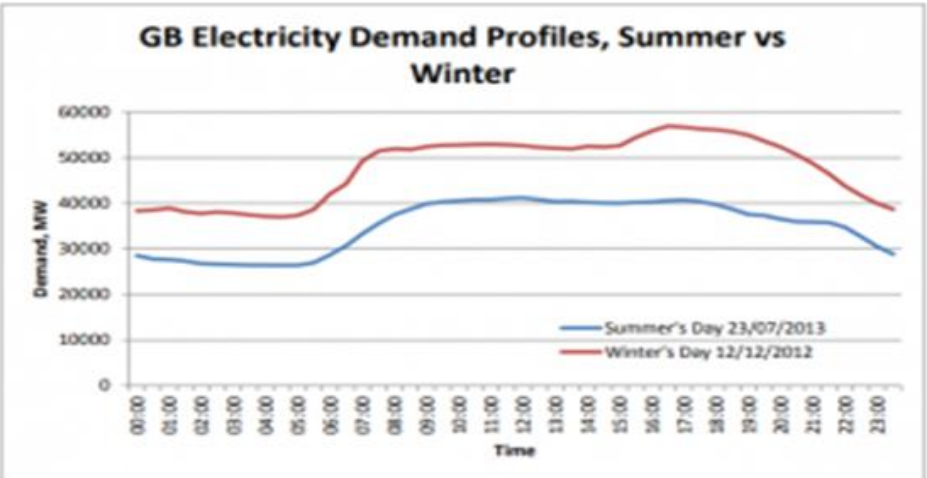
Figure 3: Typical 33/11kV Substation Load profile (midnight – midnight)



4.33 The former Government Department of Energy & Climate Change[6] (DECC) produced a report in March 2014, which compared electricity demand for a week in December 2012 (i.e. winter) and a week in July 2013 (i.e. summer). The report noted that electricity demand fluctuates, based on a number of factors, particularly weather conditions.

4.34 Demand for electricity tends also to fluctuate over the course of the day, determined by human activity. This is demonstrated in Figure 4, which compares demand profiles on a winter's day and a summer's day. The two lines both show a similar trend, but with the winter's day showing a higher demand for all of the 48 half-hour periods. On average, the demand on the winter's day was 36% higher than on a summer's day.

Figure 4: Comparison of GB's national electricity demand between summer and winter



4.35 There are regulatory requirements that put obligations on DNOs to inform the ESO of peak demand flow on their networks. On an annual basis, the ESO informs DNOs of when the GB system peak occurred and the DNOs provide Week 24 submissions, which include the value of their demand at the time of system peak. This information enables the ESO to work out the DNOs' contribution to GB system peak. In the Week 24 submissions, the DNOs provide the ESO with the value of the peak demand flow for each of their GSPs, as well as the time of day and season that the peak occurred.

[6] Now the Department for Business, Energy and Industrial Strategy (BEIS)

4.36 The cost and volumes pack that are submitted to Ofgem annually in July also collect cost and volume data relating to reinforcement activities. Table 11 below shows historical and RIIO-ED1 costs and volumes.

Table 11: load related expenditure for all DNOs

Types of Load Related Expenditure	Activities	Primary Voltage	DPCR5 Spend	RIIO-ED1 Spend	DPCR5 No of Schemes	ED1 No of Schemes
			£m	£m	#	#
Connections within Price control	Customer funded		140.2	48.3		
	DUoS Funded		166.2	198.6		
	Connections within Price control Totals		**306.4**	**247.0**		
General Reinforcement (Primary)	**Capacity constraints affecting substations (n-1/n-2)**					
	Substation_n-1	EHV	195.6	121.8		
	Circuit_n-1	EHV	92.9	120.3		
	Innovation_n-1	EHV	0.3	0.1		
	Substation_n-1	132kV	129.8	79.1		
	Circuit_n-1	132kV	41.0	25.0		
	Innovation_n-1	132kV	0.0	0.0		
	Substation_n-2	EHV	2.2	1.1		
	Circuit_n-2	EHV	3.4	23.1		
	Innovation_n-2	EHV	0.4	0.0		
	Substation_n-2	132kV	19.5	10.5		
	Circuit_n-2	132kV	25.0	49.8		
	Innovation_n-2	132kV	0	0		
	Capacity constraints Totals		**510.0**	**430.7**		
	Other substation constraints					
	Conventional - substation		12.34	2.05		
	Conventional - circuit		2.23	5.89		
	Innovative		0.00	0.03		
	Other substation Totals		**14.6**	**8.0**		
	Other Reinforcement Activities					
	Protection enhancements		1.99	3.58	11	22
	HILP		0.00	0.07	0	0
	Settlement Metering Project		0.00	0.10	0	1
	NGT Related		22.65	0.37	1	2
	Network Security		0.00	0.20	0	0
	Power Flow Monitoring		0.00	0.35	0	0
	Other Reinforcement Activities Totals		**24.6**	**4.7**	**12**	**25**
	Primary Reinforcement Totals		**549.2**	**443.4**	**12**	**25**
General Reinforcement (Secondary)	Substation constraints	HV	145.9	67.5	135.2	81.7
	Circuit constraints	HV	79.6	70.2	0	0
	Power Quality		13.9	20.0	0	0
	Secondary Reinforcement Totals		**239.5**	**157.8**	**135.2**	**81.7**
General Reinforcement (Fault Level)	Switchboard constraints	HV	9.2	6.8	72	14
		EHV	29.4	32.5	24	28
		132kV	15.5	0.2	2	0
	Switchboard constraints Totals		**54.1**	**39.4**	**98**	**42**
	Circuit constraints	HV	2.0	1.6	3	3
		EHV	0.2	1.1	0	0
		132kV	0.0	0.0	0	0
	Circuit constraints Totals		**2.2**	**2.7**	**3**	**3**
	Other constraints		0.9	0.0	16	4
	Fault Level Reinforcement Totals		**57.2**	**42.2**	**117**	**49**
New Transmission Capacity Charges (NTCC)	General Reinforcement		0.0	0.5	0	0
	New Asset		11.2	2.4	9	0
	NTCC Totals		**11.2**	**2.9**	**9**	**0**
General Reinforcement (High Value Projects)	ENW HVP (DPCR5)	132kV	16.7		1	
	NPG HVP (DPCR5)		9.6	26.0	1	
	SPM HVP (DPCR5)		9.7	1.8	1	
	EMID HVP1 (DPCR5)		24.8	0.17	1	
	EMID HVP2 (DPCR5)		0.5	0.00	1	
	LPN HVP1 (DPCR5)		31.8	10.3	1	
	LPN HVP2 (DPCR5)	132kV	18.0	4.8	1	
	LPN HVP3 (DPCR5)	132kV	23.6	5.8	1	
	LPN HVP4 (DPCR5)	132kV	2.2	3.9	1	
	SPN HVP (DPCR5)	33kV	9.04	0.0	1	
	EPN HVP (ED1)			0.5		1
	LPN HVP (ED1)			7.3		1
	SEPD High Value Projects (ED1)	132kV		17.3		1
	HVP Totals		**145.9**	**77.9**	**10**	**3**
	TOTAL		**1,309.4**	**971.1**	**283.2**	**158.7**

4.37 The analysis undertaken on the LI tables, as presented in Table 8, concludes that the reported costs relate to schemes that are largely driven by traditional winter peak demand flows. However, it should be noted that:

- There are other network conditions that create limitations on the distribution networks but are not reported in the LI packs. These conditions include periods of maximum distributed generation at times of minimum demand (e.g. in the summer predominantly on parts of the distribution network that have a lot of DG connected).
- Whilst the cost and volumes pack captures the expenditure and volumes related to generation connections (both customer driven and cost apportioned), it only does so at an asset level, rather than by scheme, and does not identify the specific driver.

4.38 On the transmission networks, peak distributed generation flows are driving reinforcement schemes at GSPs and radial circuits on the network. A proportion of the reinforcements done by the TOs are driven by exporting GSPs from the 33kV network. The costs shown in Tables 4-6show that the majority of spend is due to reinforcing the wider transmission network due to multiple generation and demand connections. In the SHE Transmission and SP Transmission network areas this is predominately low carbon generation connections in the north, which are driving wider boundary reinforcements to enable economic bulk power transfer to demand centres located in the south of GB.

Other cost drivers

4.39 In addition to reinforcement costs, asset replacement costs are a significant cost to DNOs. Although these costs are not associated with peak demand or peak generation drivers, they are locational, material enough and stable and will be considered when scheme costs become available. Asset replacement costs for all DNOs, account for 13% of total RIIO-ED1 costs. There are other significant cost drivers like Operational IT and Telecoms and BT21CN[7] (see definition in Annex 3), that are not locational, but where some DNOs are spending a lot of money at certain locations on the network. However, a lot of this expenditure is central and the costs will fall away once the infrastructure is in place.

4.40 Diversity assumptions are made by DNOs in planning and operating their network and the issue is considered in detail in the network Access subgroup's report with analysis provided to show that diversity is greatest at the LV domestic level. This is because there are lots of different peaks due to import/export requirements not being defined and sporadic energy flows. On the question of whether changes in diversity are a driver for peak driven costs, consider a scenario where a high proportion of primary substations in an area of the network that has a high diversity experiences a high penetration of EVs charging at a similar time. This might lead to the network experiencing low diversity because the nature of the loads is similar, the peaks occur close together and this could lead to the need to reinforce the network.

[7] BT 21st Century Network

5 Cost variation by user segmentation

5.1 This section contains the subgroup's initial assessment of the potential to separate users into segments, which reflect the way their characteristics influence costs. This information will help support consideration by the access subgroup of planning approaches and the locational granularity subgroup of whether it is possible to identify different groups for charging.

Transmission

5.2 The customers of a TO network are currently apportioned into groups determined by a combination of customer type – demand or generation, directly connected Users or embedded within a DNO network whilst impacting on the TO network – and voltage of connection. However, customers could be segmented in a similar manner to the proposals outlined below for Distribution customers.

5.3 The subgroup has investigated different ways of segmenting the customer profile, determining whether these splits have different costs associated with them and how identifiable the groups are.

5.4 SHE Transmission has no evidence of reinforcement costs solely driven by fault level increase. However, it is noteworthy that the connection of generation to the SP Distribution system has in some cases led to the need for works to ensure that the system can continue to be operated safely, and that short circuit duties imposed on some equipment, in particular 33kV circuit breakers at GSPs, do not exceed equipment ratings. In some circumstances a transmission solution can be the most economic and efficient means of resolving a fault infeed affecting distribution equipment.

5.5 Table 12 below contains the subgroup's initial thoughts on user segmentation. Note that the list is not exhaustive and so there may be other segmentations than those that have been identified, in addition to the outcomes of the work that has been undertaken by the locational granularity subgroup.

Table 12: Transmission user segmentation types

Segmentation types	Is the Segment Identifiable	Cost Drivers
Demand		
Large Directly Connected (Code of Practice (COP) 1 or COP 2 HH Metered)	Relevant Agreement/ Contract	No recent evidence of demand driven reinforcement. Asset replacement schemes benefit demand customers
Small DNO Connected (COP 3 HH Metered)	Relevant Agreement/ Contract	As above
Domestic Demand (NHH Metered)	Relevant Agreement/ Contract	As above
Commercial Demand (HH or NHH Metered)	Relevant Agreement/ Contract	As above
Industrial Demand (HH or NHH Metered)	Relevant Agreement/ Contract	As above
Flexible Demand (HH or NHH Metered)	Relevant Agreement/ Contract	As above
Storage (HH or NHH Metered)	Relevant Agreement/ Contract	As above

Segmentation types	Is the Segment Identifiable	Cost Drivers
Generators		
Directly Connected (COP 1 or COP 2 HH Metered)	Identified on Transmission Entry Capacity Register	Connection asset works, peak and wider reinforcement driven by directly connected generation.
Embedded (COP 2 or 3 HH Metered)	Relevant Agreement - may be on Embedded Register dependent on size and Transmission access rights	As per directly connected.
Synchronous	Identified on relevant Agreement	As per directly connected.
Asynchronous Intermittent	Identified on relevant Agreement	As per directly connected.
Steam, Wind, Hydro, Gas Turbine	Identified on relevant Agreement	As per directly connected.
Low Carbon Generator	Identified on relevant Agreement	As per directly connected.
BM Participant (COP 1, 2 or 3 HH Metered)	Identified on relevant Agreement	As per directly connected.
Large	Identified on relevant Agreement	As per directly connected.
Small	Identified on relevant Agreement	As per directly connected.
Flexible Access - Non Firm/ ANM	Identified on relevant Agreement	As per directly connected although tends to reduce costs by nature of design requirement and solution
General - Applicable to Demand and Generation		
Urban/ Rural	Difficult to define and to apportion costs to demand or generation network users	Asset replacement, connection and reinforcement costs
Noise Pollution Areas	Known noise pollution mitigation schemes completed at substations as a result of customer complaints. For transmission there are also rural noise mitigation schemes at urban locations where sites are surrounded by housing and rural substations where there are large assets such as SGTs and Reactive Compensation Schemes against a lower background noise level.	Environmental Reporting. Asset replacement, connection and reinforcement cost elements
Boundary Zone - North of B0	Generator location within Relevant Agreement	Evidence of peak and wider reinforcement costs driven by generation connected north of the B0 boundary.
Boundary Zone - Located North of B4	Generator location within Relevant Agreement	Evidence of peak and wider reinforcement costs driven by generation connected north of the B4 boundary.
Coastal or Corrosive Environment	There is evidence of a small number of transformers in SHE Transmission licenced area in north of Scotland island locations which have required replacement before design life. These amount	Asset Replacement

Segmentation types	Is the Segment Identifiable	Cost Drivers
	to less than 0.5% of overall SHE Transmission expenditure.	
Voltage Level	Recorded in Relevant Agreements	Asset replacement, connection and reinforcement costs
Overall Usage	Usage recorded for Balancing Mechanism participants and other HH metered customers	Reinforcement costs
Peak Usage	Usage recorded for Balancing Mechanism participants and other HH metered customers	Reinforcement costs
Tree Growth Rates	The growth rates of certain types of trees are more advanced than others. TOs in general use technology such as Lidar to inspect transmission networks and there will be different profiles of growth across the country.	Tree cutting

5.6 As identified above, there are many ways to segment groups of customers, including continuing to apply some of the existing segmentation in the future. The subgroup considered that segmentation by other factors such as rural/urban or levels of usage would be subjective in many cases and careful consideration would need to be given to how the different segments are identified.

5.7 In the case of generators of any size, the subgroup felt that connecting these onto the networks in specific locations would incur extra costs, with evidence of these costs at a transmission level. However, note that the costs incurred to connect low carbon generators north of the B4 and B0 boundaries and to reinforce the transmission boundaries to enable transport of this generation south to meet demand have wider societal benefits in terms of helping to meet climate change targets.

Distribution

5.8 In future, DNOs will need to better understand their customers, and that is where user segmentation is important. Segmentation separates the wider population into smaller groups with similar needs and preferences through the use of demographics or specific characteristics, which can also be measured through energy usage, where such data is available.

5.9 Now and increasingly in the future, traditional customer labels do not accurately describe the diverse customer groups. An example would be low income residential customers which will include a mixture of large families and home based businesses, as well as elderly people, all would have very different patterns of energy usage.

5.10 The customers of a DNO network are currently apportioned into groups determined by a combination of customer type and voltage of connection.

5.11 The subgroup has considered different ways of segmenting the full customer profile and determining whether these splits have different costs associated with them and how identifiable the groups are.

5.12 Generally, diversity of the different requirements of customer groups tends to spread the peaks of the networks, however the traditional teatime peak (4-7pm weekdays) is often the highest on the networks. The exception is in major cities (London, Manchester, Birmingham, etc) where the highest demand is often during the working day (11-2pm weekdays), largely due to air conditioning load.

5.13 Certain network costs are driven by specific users, however, although this cost is clear where the customer is on a dedicated piece of the network (such as an EHV customer), this is not always the case, because, as stated above, diversity generally addresses the networks peaks across different users.

5.14 While directly-coupled motors used by demand customers contribute to fault levels, their contribution is relatively small. Increasing fault levels on the distribution networks are primarily caused by the connection of new generation. However, the fault level contribution from generation is a function of both the capacity and the type of generation being connected. For example, inverter-connected generation, such as solar panels may only contribute 1-2 times their rated capacity, while traditional synchronous generation may contribute 6-10 times their rated capacity, depending on the customer's installation and the local network configuration.

5.15 Fault level-related reinforcement solutions triggered by the connection of generation normally involve installing higher rated switchgear to cater for the higher fault level, or installing higher impedance transformers to reduce the local fault level. Under the current cost apportionment rules in the Common Connection Charging Methodology, a proportion of the reinforcement cost is borne by the generation customer, with the majority of the cost being socialised.

Reinforcement works driven by generation connections at Distribution

5.16 Fault level driven reinforcement has been identified by SP Energy Networks as one of the most significant challenges faced across the SP Manweb and SP Distribution networks.

5.17 On the SP Manweb network there are currently requirements to carry out 33kV RMU replacements at 18 sites plus 33kV board replacements at 4 grid sites, including:

1. New DG triggering two 33kV RMU replacements and a 33kV board replacement on a grid site (total cost £3.77m)
2. New DG triggering six 33kV RMU replacements and subject to completion of planned reinforcement in the group (total cost £2.28m).

5.18 On the SP Distribution network there are currently multiple examples of DG projects triggering the requirement for both transmission system works (>14 GSPs impacted) and DG projects triggering the requirement for distribution system works (>7 sites); including new DG triggering the installation of a new 33kV switchboard and a 45MVA bus-section reactor (total cost £2.5m).

5.19 Table 13 below contains the subgroup's initial thoughts on user segmentation for distribution customers. Note that there is a large degree of crossover between the potential segmentation that could be applied for distribution and transmission users.

Table 13: Distribution user segmentation types

Segmentation Types	Is the segment Identifiable?	Cost Drivers
Urban/ Rural	Very difficult, first would need to define urban/ rural and then apportion customers into the groups	Asset replacement, rising and lateral mains, visual amenity, tree cutting
Noise pollution areas	Known noise pollution mitigation schemes completed at substations as a result of customer complaints.	Environment reporting
Voltage level	Yes, already in current charging methodology	Asset replacement, asset value
Distance from GSP	Almost impossible, first need to define the distances, calculate them, and then apportion customers into the groups	Asset replacement, rising and lateral mains, visual amenity, tree cutting
Places where assets deteriorate more quickly	Very difficult, first need to define these places and then apportion customers into the groups and apportion the cost ratio	Asset replacement, refurbishment no SDI
Generation/ Demand	Yes, already in current charging methodology	Reinforcement
Levels of Overall Usage	Suitable for HH but DNOs do not hold the data for NHH customers	Reinforcement, asset replacement
Levels of peak Usage	Suitable for HH but DNOs do not hold the data for NHH customers	Reinforcement
Higher growth rate of certain types of trees	The growth rates of certain types of trees are more advanced than others. Will need to identify the areas and use technology such as Lidar to inspect the network as there will be different profiles of growth across the country.	Tree cutting

5.20 There are many ways to segment groups of customers, and it is likely that some of the existing segmentation used would continue to be utilised in future. The existence of some customers with smart meters alongside customers who do not choose to have them, will present a challenge when ensuring that all customers receive a fair charge, relating to their impact upon the network.

5.21 Depending upon what type of user segmentation is utilised, consideration of additional costs which could be relevant in specific locations, such as the higher deterioration of assets on coastal or more exposed regions would need to be considered.

5.22 However, there are some costs faced by the networks which are appropriate to be levied on all users, some examples of these costs are customer call centres, DCC costs and industry licence fees. Although the size of these costs will be impacted by the number of customers connected to a network, the costs may not change with only a small increase in customers (as an example an additional ten customers will not require a further call centre employee to be recruited), however a licence fee which is paid on a per MPAN basis would increase with each single additional customer.

5.23 At a future point in time, the majority of customers can expect to be HH settled, which will allow for more granular DUoS tariffs which is likely in turn to reduce the need for customer segmentation as the price for a consumer type at a given time will be the same.

5.24 Customers who have requirements above a defined threshold (such as those who have an EV or heat pump) cause additional costs to the networks, as their electricity demands will be greater, however, concerns were raised as to whether it would be possible for the DNO to have a robust process in place to be aware that these additional requirements were at specific properties. Should a robust process be identified to enable DNOs to identify properties with EV, heat pumps, etc, then segmentation of these customers should be considered further.

5.25 In the case of generators of any size, it was felt that connecting these onto the networks, certainly in specific locations, would incur extra costs. Where a customer exports onto the network (rather than using generation on site to offset their demand) at any level, it was felt appropriate to consider additional costs, which would likely be seen on the units exported, rather than as a fixed cost.

Example: Low Carbon London

5.26 In 2014, UK Power Networks (UKPN) completed an innovation trial known as 'Low Carbon London' (LCL), which was a £28m, four-year innovation project to investigate the impact of a wide range of low carbon technologies on London's electricity distribution network. LCL was delivered successfully in accordance with the requirements of Ofgem's Low Carbon Networks Fund, facilitating the development of viable solutions for DNOs to support the low carbon transition in the UK.

5.27 LCL focused on two main areas: how smart meter data can be used to better understand the way in which customers contribute to network load, and the potential savings from energy efficient appliances, both at the household level and at scale. This analysis provided new understanding of network performance and delivered an insight into how DNOs will benefit from using smart meter data in the future. Household demand groups were also reclassified, based on current demographics and technology use. In the conclusion of the work, UKPN recommended that the consumer specific load and efficiency savings profiles from LCL should be applied to the unique consumer demographics of each DNO to enhance future network planning.

5.28 From analysis of the LCL smart meter trial data it has been determined that there are material differences between the peak energy consumption of different categories of customer. The categorisation can be based on data available to a DNO at the time of connection of new load, which allows this difference to be taken advantage of when assessing the impacts of the new connection.

5.29 Similar analysis to that shown in the LCL report could be carried out on further data sets more regularly, when they become available through the national smart meter roll-out. This analysis could be achieved without the need to expose individual customer consumption, which would avoid the need for customer consent under data privacy regulations, meaning that a large number of customers' profiles could be included.

5.30 Further information on LCL is available via this link.

5.31 The specifics of the trial referred to above is found in Report C1 'Use of smart meter information for network planning and operation' which is available via this link.

6 Upstream vs. downstream network costs

6.1 Conventionally, distribution network charges have been based on costs of the network at and above the voltage level to which the user is connected. This section seeks to identify whether there are any downstream costs, which can also be impacted by the behaviour of upstream users (or the opposite for reverse powerflow). In addition, the section considers the potential impact on upstream costs of downstream customers - in particular, it is expected that the would be evidence of distributed generation impacts on transmission network costs.

Transmission

6.2 At the interfaces between transmission and distribution or GSPs, sole use connection assets are funded directly by the DNOs through transmission connection charges. These assets and charges are identified in accordance with the charging methodology in the CUSC.

6.3 Reinforcement works are identified and agreed between TOs and DNOs to create the required capacity to facilitate power flows in either direction at these interfaces, commensurate with network operators' obligations to develop networks economically efficiently. These decisions are made jointly through Wk24 process defined in the Grid Code and Modification Application process in the CUSC. Note the CUSC process allows clarity for transmission investment required due to embedded generation connected at distribution.

6.4 In the year 2017/18, half of all the GSPs in both the SP Distribution and SP Manweb network areas were found to export onto the transmission network. Details as follows:

- SP Manweb:
  - 0/14 GSP network groups exported for the majority of the time.
  - 7/14 GSP network groups exported some of the time.
  - 7/14 GSP network groups exported none of the time.
- SP Distribution:
  - 14/90 GSPs exported for the majority of the time.
  - 31/90 GSPs exported some of the time. (In total 45/90 GSPs exported)
  - 45/90 GSPs exported none of the time

6.5 During this time period, 22% of GSPs in the SP Distribution network area exported at times of summer minimum and 18% at times of GB winter peak. SP Distribution currently has 6 GSPs with export restrictions.

6.6 Over the same time period, 60% of GSPs in the SHEPD network area exported at time of winter peak / GB summer minimum. In total, 74% of GSPs exported at some point during 2017/18.

6.7 Following are examples of works driven by power flows across the distribution to transmission networks.

Reinforcement works driven by connections at Distribution only

6.8 New distributed generation at SHE Transmission's Dunoon 132kV substation necessitates an uprating of the 132kV shared circuit between Dunoon and the tee into the Sloy-Windyhill circuit. SP Transmission's portion of the circuit runs between tower CM01 and mid span between CM13/14. The circuit presently uses 125mm2 ACSR Tiger conductor.

6.9 It is proposed that SP Transmission uprate the double circuit to Poplar 200mm^2 conductor from CM1 to CM12. SHE Transmission will uprate over the boundary span between CM14 and

CM13, terminating at tower CM12. The estimated total capital cost associated with the SP Transmission reinforcement works is £3.5m.

6.10 69 MW of new distributed generation behind Coupar Angus GSP has resulted in grid transformer upgrades from 2x45MVA to 2x120MVA units. The estimated total capital cost associated with the SHE Transmission reinforcement works is £10.3m.

Reinforcement works driven by connections at both Transmission and Distribution

6.11 In the SP Transmission network area, there are two 132kV circuits from Coalburn 132kV substation, which supply Linnmill 132/33kV GSP. Contracted renewable generation at Linnmill GSP has reached a level where the thermal uprating of the 132kV underground cable section, on the Coalburn to Linnmill GSP No.1 132kV circuit, is required to ensure compliance with the NETS SQSS.

6.12 It is proposed to replace the 3.2km 132kV underground cable section on the Coalburn to Linnmill No.1 132kV circuit with a 2000mm Cu XLPE cable having a continuous summer rating of 1285A (293MVA). The estimated total capital cost associated with the SP Transmission reinforcement works is £9m.

Reinforcement works driven by connections at Distribution only (Scottish Islands)

6.13 Orkney Islands – distributed generation is driving significant works on the transmission system for connectivity to the mainland (including subsea cable works). The estimated total capital cost associated with the SHE Transmission reinforcement works is £260m.

6.14 In conclusion, it has been evidenced that distributed generation projects connected to the EHV and HV networks in Scotland and in other parts of Great Britain are driving the requirement for reinforcement of the transmission network. The full extent of the impact of the larger volume of lower voltage distributed generation connections has not been completed at this stage.

Distribution

Embedded networks

6.15 From the point of view of a DNO network, embedded Independent Distribution Network Operators (IDNOs), DNOs operating out-of-area and private networks impact major network costs in the same manner as any other customer connected at the same voltage, with the same powerflow at the point of connection.

6.16 IDNOs and out-of-area DNOs are collectively known as LDNOs. Settlement meters for customers connected to both LDNO networks and DNO networks are funded by suppliers. Metering is not currently required at the boundary between DNO and LDNO networks, as LDNOs are billed for their customers' use of the DNO network on a portfolio basis.

6.17 Additional metering to monitor power flows at the DNO to LDNO boundary may be installed by either the LDNO (e.g. to ensure the LDNO network as a whole operates within the agreed capacity in the relevant BCA for the network with the DNO) or the DNO (e.g. for network monitoring purposes). Such metering would be installed at the cost of whichever network operator installs it, but is not required for regulatory compliance. Where boundary meters are not installed the only metering for a site is located at the end customer exit points from the system in compliance with standard settlements requirements.

6.18 As neither the LDNO nor the DNO is required to install a meter at the DNO to LDNO boundary, there is no cost saving compared to where there is a piece of new DNO network connected to the DNO's existing network. From a whole system point of view, comparing LDNO arrangements to DNO only networks, the same number of meters overall are required and would be located at end customer's premises at the same overall cost.

6.19 A further difference in LDNO sites arises due to the existence of an agreed capacity at the DNO/LDNO boundary which would not exist on a DNO only network. Situations can arise where DNOs are required to reserve an amount of unutilised capacity for LDNO networks which under current arrangements is not funded by ongoing DUoS, as it would be with a non-LDNO customer. In some instances, this level of LDNO unutilised reserved capacity has required DNOs to consider more expensive reinforcement schemes to facilitate the addition of new capacity. This issue arises only because of differences in the billing arrangements for LDNOs and DNO connected customers, which do not currently always provide an economic incentive for LDNOs to release unused capacity, and as such does not indicate DNO costs being driven by LDNO activity. Such issues can arise during the build out phase of a development and so will be resolved in time; alternatively, these issues could be resolved by mutual agreement as part of the ongoing management of the network.

7 Energy consumption and customer numbers

7.1 The SCR is considering a range of different charging designs, including seasonal time-of-use (ToU), capacity based and critical peak pricing. However, the review will also consider whether to retain some volumetric or fixed charges. This section sets out the subgroup's findings regarding whether costs are driven by energy consumption or customer numbers.

Transmission

7.2 The TOs and the ESO incur several ongoing costs whilst running a network. The volume of customers (both generation or demand) can have an impact on network costs due to their direct relationship with network constraints and therefore the need for boundary reinforcement. As an example, if generation in Scotland doubled, there would be a need to reinforce the boundary between Scotland and England. Likewise, if demand in Scotland significantly increased, the need for further boundary reinforcement may be reduced.

7.3 In addition, the TOs' Network Output Measures methodology includes a duty factor, which is included in the driver for asset probability of failure as a measure of asset health. This factor provides an end of life modifier, reflecting the accelerated degradation dependent on transformer loading. This factor is related to the maximum and average demand placed on the transformer. This methodology has been recently developed and agreed and has not yet resulted in asset replacement driven during RIIO-T1.

7.4 The ESO incurs several costs in the day-to-day operation of the NETS, depending on the balancing actions taken by the ESO. Balancing Services Charges (also called BSUoS) recover those costs. A Balancing Services Charges Task Force, led by the ESO, has been launched in January 2019 with the objective to provide analysis to support decisions on the future direction of BSUoS and to publish a final report in May 2019. The objective of the Task Force is to assess whether there is value in seeking to improve cost-reflective signals through BSUoS, or whether BSUoS should be treated as a cost-recovery charge (more information available on the Charging Futures website here: http://chargingfutures.com/charging-reforms/task-forces/balancing-services-charges-task-force/resources/).

Distribution

7.5 Although the DNOs incur several ongoing costs while running a network, most of these are not linked to the units of energy used by customers. This was highlighted during preparation of the cost driver table:

- A process was undertaken to link all the DNOs' reported costs with factors that affect them – the only ones identified that bear a relationship to units used were replacement costs, refurbishment costs and civil works.
- However, other factors identified as driving asset replacement costs, refurbishment costs, and civil works included the level of environmental salinity, time, maintenance, and weather.
- These costs were also identified as having a locational element, but this could be mostly circumstantial only.
- These costs equal approximately 16% of the total cost.

7.6 There are a small number of costs driven by customer numbers. These include:

- Ofgem licence fees, which are worked out by Ofgem and then shared out on a by MPAN basis. Licence fees are part of the pass through costs and are material

- Call centre costs, which are driven by the volume of customer calls.

7.7 These also include Quality of Service (QoS) as some DNOs have in their design standards a limit to the number of customers that can be connected to HV and LV circuits for the purpose of improving service levels to customers. Please see below extracts from some DNOs planning standards.

Northern Powergrid – Underground and overhead mains

LV underground and overhead mains shall be designed and selected to meet the design demand, load growth and credible future connections. Asset ratings are defined in the Code of Practice for Guidance on the Selection of Overhead Line Ratings, IMP/001/011 and the Code of Practice for Guidance on the Selection of Underground Cable Ratings, IMP/001/013.

The system shall be laid out so as not to exceed the maximum permissible value:

- For voltage drop as specified in section 3.3.3;
- Of 120 customers per LV feeder;
- For phase-neutral loop impedance as specified in section 3.3.5; and
- For fusing, such that a fault at the end of any service cable will be cleared within 60s.

HV circuits shall normally be operated as radial circuits with the open point selected for ease of operational access and to minimise the number of customer interruptions and customer minutes lost, whilst taking account of the need to minimise system losses and optimise voltage regulation. When open points are planned to be moved consideration shall be given to primary protection settings with respect to eh reconfigured circuit. The HV system shall be configured such that the number of customers normally supplied from each HV circuit does not exceed 2000. Further restrictions apply to the number of customers between switching points as set out on sections 3.5.2 and 3.5.3 below.

SSEN – LV Planning Standards for radial feeders

A maximum of 75 customers shall be connected to a radial LV feeder. Bunching of LV cores or parallel cables are not acceptable methods of reducing the EFLI. This also apply to risers in high rise building, i.e. the maximum number of customer per riser will be limited to 75.

An IDNO network is considered as one customer.

Interconnection is required where there are more than 75 customers connected to a single radial feeder. Interconnection will normally be via a 2-way link box or street pillar. The system would normally run with links / fuses on interconnected circuit removed. This provision is also required where there is more than one transformer being proposed to supply a multi-occupancy building.

Where a new distributor is to be connected onto an existing radial cable and the combined number of customers will exceed 75 then a 4-way link box shall be installed unless the new distributor can be connected to an alternative source of supply.

Total kW rating of EV charging point should be added to the ADMD values for domestic properties, unless there is more than 20 number of EV charging points on the feeder where half the total kW rating can be used:

- ≤ 20 EV charging points, EV demand = total kW rating
- > 20 EV charging points, EV demand = 0.5 x the total kW rating
- Consumer type (EATL WinDEBUT) – URHC.

Western Power Distribution

In the interest of reducing Customer Minutes Lost (CMLs) and Customer Interruptions (CIs), WPD's network shall be designed so that the number of customers (including the number of individual IDNO customers connection via an Embedded Network) left disconnected following a fault and after the network has been sectionalised using automated and/or tele-controlled switchgear, shall be no higher than 1500. For the purpose of this requirement, only the first circuit outage (N-1 conditions) shall be considered.

7.8 However, there are several more costs with a factor related to network size, and network size is itself a function of customer numbers, max demand, usage and topology of the network. Therefore, there is a link, although it should be noted that it is tenuous. This does lead to an argument that the sunk costs, which are the costs of building the network, have a link to units of electricity used, max demand and customer numbers. These are not ongoing but had to be incurred at some stage in order to build the network.

7.9 The current method of charging recognises these costs in the form of a hypothetical 500MW model, which reflects most of the cost of building a totally new network using the topology of each DNO's individual network.

8 Losses and reactive power

8.1 As electricity is transferred across the energy networks, a percentage of it is lost, which can have significant financial impacts. This section considers the impact that such losses have on the network companies' investment decisions.

8.2 In addition to losses, this section also considers the impact of reactive power, which uses capacity on the network to transfer electricity and can drive issues, such as with local network voltage, which require network companies and users to intervene in order to manage.

Transmission

Losses

8.3 Transmission losses are commonly divided into two types of losses:

- Fixed losses – occur when transmission assets are energised and are independent of loading conditions.
- Variable losses – occur when transmission assets carry load and are proportional to square current loading.

8.4 Transmission owners are obliged by their licence conditions to setup and publish their strategy[8,9] to manage losses on the transmission network. The employment of their losses strategies ensures that losses associated with equipment specifications are taken into consideration, as part of standard procurement practice, as one of the factors in cost benefit analysis. Investment decisions are made, based on the outcome of the overall economic and efficient case.

8.5 The ESO also takes losses into consideration for the operation of the transmission network and publishes on its website an annual report[10] on losses management and measurements. It should be noted that losses are only one of the factors that the ESO considers and is not the dominant driver of the way in which the transmission network is operated.

8.6 There is no significant evidence from TOs and the ESO showing that such losses are driving network costs in their licensed transmission areas or operation of the transmission network. It is also difficult to identify costs specifically linked to managing losses, as other factors in transmission licensees' activities can outweigh the consideration of losses in cost benefit analysis.

Reactive power

8.7 Transmission of active power needs the support of reactive power in order to maintain transmission network voltage within defined limits in the SQSS.[11] These limits are classified by the nature of voltage phenomenon on the transmission network into steady state voltage and step change voltage, both in planning and operation timescales. There are also maximum and minimum limits to each of these voltage limits to ensure the secure and safe operation of the transmission network. Reactive power absorption and injection are closely linked with voltage control requirements on the transmission network and, due to the alternating current (AC) nature of electricity transmission, are most effective at locations where voltage control is needed.

[8] https://www.nationalgrid.com/sites/default/files/documents/36718-Transmission%20Losses%20Strategy.pdf
[9] https://www.ssen.co.uk/TransmissionPriceControlReview/
[10] https://www.nationalgrideso.com/document/46771/download
[11] https://www.nationalgrideso.com/codes/security-and-quality-supply-standards?overview

8.8 Since being noted in the first publication of the System Operability Framework[12] in 2014, TOs and DNOs have been tackling voltage management, especially managing high voltage, as one of the challenging issues caused when energy transitions across transmission and distribution networks. Statistics show that the ratios between reactive and active power at interface points between distribution and transmission networks are declining. Although evidence demonstrates that this is caused by multiple factors, it is worthwhile noting the significance impact related to the technical requirements of generation activities on low voltage networks, which was identified as part of the REACT trial.[13] This is also aggravated by the amount of activities which are forecast by the ESO to further increase in the future under the FES.[14]

8.9 Actions currently taken at transmission voltage level to tackle voltage issues (especially high voltage issues) include:

- The ESO's actions to procure reactive power beyond Grid Code requirements from transmission connected generation
- In some cases, the above also requires ESO's actions in the balancing mechanism to make generation available at the minimum technical active output
- Switching voltage control circuits according to loading levels
- Asset investment in reactive compensation devices such as shunt reactors.

8.10 There are balancing service and capital investment costs associated with the ESO and TO actions described above to procure reactive power absorption and injection at the most economic and efficient timing and locations. Reactive compensation devices (mostly transmission voltage level reactors for high voltage issues) have been installed following assessments jointly commissioned by TOs and the ESO to provide voltage management and control at necessary locations. Further work is also underway as a pathfinder project under the NOA[15] in search of whole system solutions to ensure sufficient reactive power support for the safe, secure and economic operation of the transmission network.

Distribution

Losses

8.11 Typically, the losses incurred on the distribution networks to supply low voltage customers are in the order of 5-11% [16] of the power consumed by the end user, while the losses for customers connected at higher voltages will generally be lower, as they are located electrically closer to the traditional power source.

8.12 Losses on their own generally do not constitute a substantive network cost driver, but once a need is identified, any solution must include consideration of the lowest possible lifetime cost (including the long term cost of losses), while meeting the primary need. As utilisation levels increase on the network going forwards, the overall losses will also increase, which may increase the significance of losses as a network cost driver. Within some networks, the DNO has identified some relatively high loss equipment that justifies early replacement based on future savings in losses. While some of this expenditure is significant, it is not anticipated that there will be a continuing requirement for such expenditure in the long run, as the identified equipment will have been replaced.

[12] https://www.nationalgrideso.com/insights/system-operability-framework-sof
[13] Reactive Power Exchange Application Capability Transfer (REACT): http://www.smarternetworks.org/project/nia_nget0100
[14] http://fes.nationalgrid.com/fes-document/
[15] https://www.nationalgrideso.com/insights/network-options-assessment-noa
[16] Line loss factors on ELEXON website: www.elexonportal.co.uk/svallf

8.13 At lower voltages, losses can become significant, especially in cases where network capacity utilisation is high, such as may be the case where flexibility services are employed. At lower voltages DNOs have adopted the use of larger capacity cables at the time of installation to reduce the lifetime cost of losses. DNOs have also used higher efficiency transformers for many years.

8.14 The co-location of generation and demand has the potential to significantly reduce overall losses, if the generation matches the demand profile. The reduction in losses is currently credited to the generator (rather than the consumer) by giving the generator a line loss factor of less than unity. The most significant impact of co-location of generation and demand is the potential reduction in peak loading on the network supplying the area. However, this benefit is only realised if the generation offsets demand at times of peak demand. In such cases the need to reinforce can be avoided or deferred. DNOs are currently exploring commercial arrangements for demand side response services to reduce net peak demands, which will also reduce losses during peak periods.

Reactive power

8.15 Reactive power is both a by-product of and a requirement for the transmission and distribution of electrical power using AC systems. However, when there is a local imbalance in reactive power, the thermal loading on plant is increased and the local network voltage is impacted.

8.16 The reactive power requirements of the distribution networks are two-fold. The capacitive components of circuits (mainly associated with underground cables) produce a constant amount of reactive power irrespective of the loading on the network. The inductive components absorb reactive power and the requirements increase with the network demand. General demand customers have historically tended to have small reactive power requirements, increasing with demand. However, industrial and commercial processes can have large reactive power requirements and, without any power factor correction equipment, can increase the overall loading on the network.

8.17 At times of minimum demand, the DNOs will tend to be net producers of reactive power, with the excess being exported to the transmission network. However, at times of peak demand the networks may have a significant deficit of reactive power, with the shortfall being provided from the transmission network. While reactive power flows do not significantly increase network losses, they do utilise the thermal capacity of the network. The power factor for the network gives an indication of the useful proportion the network assets that is being utilised. For example, if a network is operating with a power factor of 0.95 then only 95% of the capacity being utilised is useful. The remaining 5% is being used to transfer reactive power around the network. If the network is operating at unity power factor, then all of the utilised capacity is being used effectively.

8.18 Within the distribution network it is normally more efficient to compensate for reactive power requirements locally. The standard national terms of connection require, unless otherwise agreed with the DNO, demand customers to always operate with a lagging power factor (importing VArs), as near to unity as is practicable and in any case no less than 0.95 lagging. Large industrial and commercial customers generally install power factor correction equipment to ensure their power factor remains within the required range, which helps to manage the flow of reactive power on the distribution network and has historically resulted in the DNO not needing to make significant investments to manage reactive power flows. Where customers do operate with a poor power factor the DNO is able to intervene, with the ultimate sanction of de-energisation, though such measures are rarely needed. However, smaller customers without reactive power metering, may not always operate near to unity power factor. Customers operating with a poor power factor will unnecessarily utilise additional network capacity, which may result in earlier reinforcement due to the overall loading on a particular asset. While there are no cited examples of reinforcement purely due to poor power factor, the reactive power requirements from all customers will have an impact on the overall loading of the network assets.

8.19 A reactive power, or power factor, charge may help to improve the overall utilisation of the network. However, for it to be effective, the charge would need to be set high enough to incentivise customers with a poor power factor to invest in local power factor correction equipment.

8.20 While it may be ideal to operate the network at unity power factor, reactive power also has an influence on the network voltage. Within the distribution networks this is not normally an issue, but the net reactive power flows will have an impact on the voltage on the transmission network. Hence, the ESO may seek to limit the reactive power flows at the transmission/distribution interface. On some parts of the distribution network, where it is proposed to connect a generator at the end of a long circuit, absorption of reactive power at the power generating facility may be used to enable a larger capacity generator to be installed, thus avoiding voltage rise issues. While this may lead to slightly less efficient network operation it can avoid significant reinforcement costs. The charging group will need to consider whether any reactive power charge would be applied to such customers, in which case there would be a balance between the cost of reinforcement and the expected lifetime cost of the reactive power charge.

8.21 Reactive power can be provided by directly connected users of the transmission networks under commercial arrangements, over and above the reactive capability mandated by the Grid Code. Where voltage issues exist and sufficient commercial products are not available, or they are less cost effective compared to asset solutions, then network assets may be required to ensure that the system can continue to operate within safe voltage limits. Reactive power tends to be a localised phenomenon. However, reactive power needs may arise from a combination of network characteristics and the behaviours of multiple users in an area.

8.22 While reactive power is actively traded with customers directly connected to the transmission networks, this is not generally the case for customers connected to the distribution networks. Most connection agreements do not permit distribution customers to trade reactive power (due to the historical requirements in the customer’s connection agreement and the current National Terms of Connection) even if it would be beneficial for the overall GB network. If reactive power trading is developed for distribution customers, then it will be necessary to determine whether such customers will be subjected to network charges for power factor/reactive power.

9 Energy technology, changing behaviour and load diversity

9.1 This section contains the subgroup's initial thinking around the impacts that emerging technologies and changing customer behaviour may have on the network, including the consequence of any reduction in load diversity. In particular, it highlights the challenges the network companies face and the strategies being established to address them.

Transmission

9.2 Energy technologies connected to the transmission network are changing in both generation and demand.

9.3 The changes in electricity supply are mainly driven by the trends of decarbonisation and decentralisation in the energy industry[17]. These changes will present ESO with operability challenges[18] to the future operation of the network in various aspects including

- Frequency control
- Voltage control
- Restoration
- Stability
- Thermal

9.4 Solutions are needed for ESO to economically maintain operability of the network against these challenges. Table 14 below, which is taken from SOF, illustrates the latest strategy from ESO to achieve such solutions efficiently through a combination of changes in codes and regulation, network assets and commercial and operational tools.

Table 14: ESO strategy setting out solutions for maintaining economic operability of the network

Topic	Codes and regulation	Network	Commercial and operational tools
Frequency control	• Implementation of pan-European response and reserve services • Wider access to the BM delivered through mods for Project TERRE		• New response services • New auction trial • Reserve review
Voltage control	• Removal of ERPS from the CUSC	• Trial comparison of network and commercial solutions in the NOA through pathfinder projects	• Request for information in South West and Mersey
Restoration	• Assisting in the development of a restoration standard • European code developments – Consultation on System Defence and System Restoration plans for GB	• Investigation of restoration approaches using generation in DNO networks • Review of restoration plans with TOs and DNOs	• Increasing transparency • Broadening participation in balancing services • Trialling alternative approaches for procurement

17 https://www.nationalgrideso.com/insights/future-energy-scenarios-fes
18 https://www.nationalgrideso.com/insights/system-operability-framework-sof

Stability	• Changes to generator protection settings in grid code and distribution code • New fault ride through requirements	• Investigation into including stability requirements in the NOA	• Operational RoCoF management • Regional vector shift relay changes
Thermal	• Wider access to the balancing mechanism	• Comparison of commercial and network solutions in the 2019 NOA	• Regional development programmes

9.5 On the demand side, EV charging and charging profile across the day and seasons can have impact on transmission networks. For SHET licensed area[19], such impact is likely to be predominately in built up areas such as Aberdeen, Dundee, Perth and Inverness. There is also likely to be significant local peak demand impact in these areas however peak impact may be flattened out by smart chargers. An innovation project led by ESO with research partners is near completion on future EV charging profile and impact on operation of the transmission system including the effect of EV behaviour within distribution networks which are discussed in below section.

Distribution

9.6 New technologies such as EVs, storage, and other Low Carbon Technology (LCT) that are able to automatically react to current market conditions, can result in a range of possible impacts on diversity, depending on how these technologies behave. This may be heavily related to the types of products they provide in the market and how the market rules work, including visibility of price signals. If these technologies operate in a coordinated fashion, the diversity could be high, leading to efficient system needs. Conversely, uncoordinated behaviour could drive national peak system needs which may drive inefficient network costs. However, localised issues could also occur if there is a cluster of customers responding to market conditions.

9.7 The ability of the DNO to manage centrally the times when customers can charge EVs, in order to offset the demand on the network, would be very different from where we are today, and new systems might be needed to facilitate the necessary arrangements. This may create extra costs which are different to existing ones. In the case of amass rollout of EVs and home batteries charging, problems could emerge with peak capacity as consumers take advantage of off-peak pricing.

9.8 The expectation is that additional loads from EVs and other LCTs will be mainly at off peak periods, but if price signals are not sufficiently strong, then customer behaviour may not create the diversity which is desired and demand at existing peak times could increase significantly. These signals will need to be passed on to customers in an effective manner. Unless houses have sufficient additional thermal storage then heat pumps will inevitably exacerbate the peak evening period due to the requirement by customers to heat their homes.

9.9 Currently most NHH customers do not have a defined capacity, so this is unlikely to have been considered so far in relation to how diversity works across the networks. The capacity of the service equipment for a domestic customer (typically 18kVA, but could be lower) is not an indicator of the capability of the low voltage network to which it is connected. In most cases, if all of the connected customers on a local network consumed 18kVA at the same time the network would be thermally overloaded and many customers would receive a voltage outside

[19] https://www.ssen-transmission.co.uk/media/2912/north-of-scotland-future-energy-scenarios-full-report.pdf

of the statutory limits. Any agreed capacity for a particular technology might need to be seasonal and/or time of day, otherwise customers will not be charged correctly for the costs they have created. While it is not currently known when peak demands could occur in the future, it would be prudent to incorporate the flexibility to have alternative peak periods in any new charging regime.

9.10 The emergence of a new service or technology has the potential to create a new peak demand period if there is a strong market incentive to provide a service at a particular time and there is a lack of diversity when the response is required. For example, if customers had access to real-time market pricing and the price dropped significantly due to high solar and wind generation output, localised demands might potentially exceed the local network capability.

9.11 The peak demand seen today (Mon to Fri around tea time) might not be the peak demand in the future. However, while networks are currently quite under-utilised at the off peak period, it is important that the charging of EVs is appropriately managed, and, for example, two million customers do not all charge at the same time. If they do, the networks will be stretched. Ideally such demand should be spread over a longer period of time. For example, if two million customers need to connect for two hours of charge, one million could start at midnight and the remainder at 2am.

9.12 DNOs operate using diversity and have various forecasts on how new technologies will impact on the networks.

9.13 Assuming that EVs have smart chargers, The FES scenario-based modelling suggests that potential overloads will mainly occur on the local LV networks where there will be less diversity. There is a risk that where multiple customers have the same demand or generation contract/incentive, then they will respond to the same signals and there will be a loss of diversity. This could be particularly true for frequency response services, potentially leading to voltage issues on the network and either the need to reinforce locally or to install local power management facilities on the low voltage network to create a more active distribution network with automated local control of consumer demand or generation.

9.14 Where localised control systems are implemented there will be a cost associated with the local control management scheme, which would be designed to avoid reinforcement costs. If the savings in reinforcement costs are to be passed on to customers, in return for local control of customer demand/generation at peak times, then it would be necessary to create a granular charging model that goes all the way to the local substation or end user, rather than the current charging models which are based on a DNO licence area. Alternatively, there could be a rebate for customers who provide flexibility regardless of where they are connected, which would negate the need for a highly granular charging model, but the localised benefit may be less significant due to the lack of targeting.

9.15 For larger customers participating in wide area active network management (ANM) schemes and other high voltage customer management schemes (typically not applicable to domestic and other smaller customers), there is an identifiable operating cost associated with the management scheme. These costs can be attributed to those customers who participate in the scheme, who have generally benefited from a cheaper initial connection cost by avoiding the potential reinforcement required to provide them with an unconstrained connection.

10 Conclusions and next steps

10.1 The report sets out at a high level initial conclusions regarding the link between cost categories and potential drivers:

- For TOs, 13.2% of cost categories are classified as primary and will need to be considered in further detail with an additional 73.7% of categories to be considered on a case-by-case basis. For the DNOs, 19.5% of costs are primary, while a further 77.4% of costs have been classified as secondary.
- The majority of the DNOs' load related reinforcement is driven by winter peak demand flows. However, there are also some that have been driven by summer generation, suggesting that it may be appropriate to introduce seasonality in charges. For the TOs, the majority of their reinforcement spend is due to multiple generation and demand connections.
- In addition to peak driven costs, the network companies have other significant cost categories, including asset replacement costs, which are locational, material and stable and operational IT costs.
- The subgroup concluded it will be appropriate to continue to apply some of the existing segmentation (e.g. voltage of connection) in the future. Although they identified other potential ways to segment customers (e.g. rural / urban), they noted that these are more subjective and careful consideration would be needed.
- The TOs identified that, in 2017/18, half of all GSPs in Scottish Power's distribution areas exported onto the transmission network. Examples of where this had happened in practice included new DG at the Dunoon 132kV substation requiring uprating of the shared circuit between Dunoon and the tee into the Sloy-Windyhill circuit.
- The TOs identified that there is a link between volume of customers and network costs, due to their relationship with network constraints and the need for boundary reinforcement. The DNOs identified some costs that are driven by customer numbers, including licence fees, which are shared on the number of MPANs held by each DNO.
- The DNOs identified that there are a small number of costs driven by customer numbers, including distribution of licence fees (allocation relates to MPANs) and call centre costs (relates to volume of calls). Further work may identify other operational costs that are linked to customer numbers.
- The subgroup did not identify any reinforcement costs that are driven by losses on their networks. However, the TOs identified that the ESO carries out activities to manage voltage issues caused by reactive power and the DNOs noted that customers are required to operate with a power factor that is no less than 0.95 lagging.

Next steps

10.2 This report contains initial evidence to support the work being undertaken by the Access and Locational Granularity subgroups and inform development of charge design options. However, there are several areas where additional work will be required to better understand issues, including:

- Further development of the TOs' classification of costs as primary, secondary or tertiary
- Whether costs vary by location within a network region and, if so, the customer groups that drive them

- The outcomes of trials and other work being undertaken by DNOs to identify the potential impact of EV and other emerging technologies and changes in customer consumption patterns on the networks
- Potential future changes in cost categories and drivers (e.g. Distribution System Operator costs) to help inform development of scenarios for modelling
- The wider whole of system costs associated with losses and reactive power
- Whether there are forward looking elements of asset replacement costs and operating costs, which are closely linked to reinforcement and other capital spend.

10.3 It is expected that this work will be carried out by one of the existing subgroups, although it has been identified that changes in membership may be required, due to the range of issues (e.g. network planners).

Annex 1 – Baseline Product Description

Product description on proposal to establish a Delivery Group sub-group focused on:

Network cost drivers

From	Ofgem
To	Delivery Group
cc	
Date	January 2019

Context and objectives

1. This advice is being sought in the context of Ofgem's Significant Code Review (SCR) into electricity network access rights and forward-looking charges, which was launched in December 2018.
2. This advice is a foundational piece of analysis that will be important in helping to shape the listing and analysis of charging and access rights options under the SCR. Given the foundational nature, it is important that the requested timeframes are achieved. Accordingly, we are keen to shape the scope of this task so it is manageable within the timeframes.
3. It is commonly understood that a goal of network charging and access reform is to make charges more "cost reflective". It is also commonly understood that building the network to manage constraints during times of peak congestion is a primary network cost driver and should be reflected in more "cost-reflective" charges.
4. What is less well understood is a) the extent to which peak cost drivers vary by time and location and b) what network cost drivers, other than managing peak congestion times, should be reflected in cost-reflective charges. This involves both the identification of those cost drivers and an assessment of the materiality of those cost drivers. This advice is being sought to drive this aspect of the SCR.
5. This advice is also being sought to inform the level of seasonality and locational pricing that would be desirable in more cost-reflective network charges to better manage times of peak congestion.
6. This request is focused on "network" cost drivers (cf. wider system cost drivers such as generation costs), unless otherwise stated. There are a couple of specific areas where consideration of wider system costs is also requested. The network costs should include all network costs arising from network conditions, design or user behaviour, regardless of who currently pays for them, as this is a regulatory decision.
7. While the SCR is Ofgem-led, the SCR will also involve significant industry input. A Delivery Group of network stakeholders has been established. We propose to establish a sub-group under the Delivery Group focused on network cost drivers to deliver this request. The sub-group would be comprised of a selection of network stakeholders and Bryan O'Neill from Ofgem's Engineering Hub. Scott Sandles and Patrick Cassels from Ofgem's access team will also be involved.
8. The objective of the work is to produce a report that details the hierarchy of network cost drivers for each customer type. This work will inform the analysis of charging and access rights options under the SCR. This work will be informed by Network Access and Charging SCR data request responses and it is envisaged that the subgroup will be required to review and agree the key cost drivers and required evidence base to justify their inclusion in the final report.
9. Once the key cost drivers have been identified the cost drivers will be ranked into a primary, secondary and tertiary group, where the ranking is based on the strength of the link between driver and cost. This initial ranking will be qualitative and should consider the extent to which each driver changes due to seasonal or locational factors.

10. Where possible this hierarchy should be underpinned by evidence as agreed in the workshop. It is expected that the evidence will be a mixture of data extracts, DNO process and procedures, third party standards i.e. (ENA Recommendations and Guidance) and data submitted to Ofgem (including existing RIIO submissions and annual data reporting requirements). Evidence will be referenced so far as reasonably practicable such that it is not included in the final deliverable.

11. Our expectation is that all supplied evidence shall be publicly available and/or non-confidential information (e.g. aggregated or cleansed to remove confidential information).

12. The above will be produced by the sub group and collated in a report. Where possible the report will include case studies to illustrate the roll of the cost driver in the derivation and allocation of costs and address the points listed in Section 4.

Deliverables and timeframes

13. Key deliverables and timeframes are set out in the following table.

Timeframe	**Deliverable**
1st Delivery Group meeting on **Monday, 21st January 2019**	Ofgem to discuss project with Delivery Group and seek feedback on the product description Sub-group established to take analysis forward – volunteers sought from among Delivery Group members
By **Friday, 25 January 2019**	Finalise list of sub-group members and product description and circulate offline via email to Delivery Group
Wednesday, 30 January 2019	Kick-off meeting of the subgroup and initial discussion of network businesses' response on info request
2nd Delivery Group meeting on **Wednesday, 13 February 2019**	Sub-group to present progress update to Delivery Group (can be verbal only)
1st Challenge Group meeting on **Tuesday, 26th February 2019**	Nominee from sub-group to present progress update to Challenge Group Challenge Group to provide feedback on scope of project
2nd Delivery Group meeting on **Wednesday, 6 March 2019**	Sub-group to present draft advice to Delivery Group for feedback (Draft advice should be Word document in report form)
2nd Challenge Group meeting in **March 2019 (Date TBC)**	Sub-group to present draft advice to Challenge Group for feedback (Draft advice should be Word document in report form)
By **end of March 2019**	Final report circulated to Ofgem, Delivery Group and Challenge Group offline **(Final advice should be in a report form capable of being published)**

14. The key deliverable of the sub-group is a publishable report

15. The analysis should draw on the data received through Ofgem's recent information request to network businesses, as appropriate

Engagement

16. Ofgem will act as the coordinator of the sub-group.

17. The role of the coordinator is to ensure work is allocated appropriately among sub-group members, to organise meetings of the sub-group, and to ensure deliverables and timeframes are met.

18. Primary Ofgem contacts for the sub-group are Beth Hanna and Scott Sandles.

Detail of request

Overarching request

19. We request the sub-group to:

    - Identify each of the key network cost drivers
    - Comment on how predictable/stable the links are between these drivers and network costs
    - Comment on the materiality of each network cost driver
    - Draw upon the data received from network businesses in response to Ofgem's recent information request, as well as other relevant data, where relevant

20. Below we set out specific areas we expect the advice to include at a minimum. This is not an exhaustive list, and the subgroup should use its judgement on whether additional topics should be considered. Where the subgroup identifies additional topics, these should be raised with Ofgem staff at an early stage in the analysis.

Evidence on peak driven costs, including locational and seasonal variations

21. The historical approach to investment in the network has been to assume that network costs are driven by peak demand levels on the network which are assumed to relate to peak flows and the requirement for additional network infrastructure:

    - What do the long term network development statements, business plans and other network planning activities suggest are the key cost drivers of network development? What is the link between network loading/flows and network costs?
    - Are these cost drivers expected to change in the future, and how could we develop a robust charging regime in the face of such change?

    Evidence of cost variation by location

    - How much reinforcement/replacement costs might vary in different areas of the networks
    - How much variation is there in the level of spare capacity across different areas/levels of the network
    - How much variation is there in the cause of costs in different areas – e.g. generation-led or demand-led

    Evidence of cost variation in timing of peaks

    - Within a particular season, how much do key peak events vary across different network areas and how they compare with overall system peak? Are there key characteristics of a network area that will lead it to have differently timed peaks? E.g. demand-dominated vs generation-dominated, rural vs urban?
    - Are peak conditions that are driving cost just present in a particular season? Or do different peak conditions drive costs in different ways/at different times across seasons? This should include consideration of differences in seasonal impacts across different locations within Great Britain

Evidence of cost variation by user segmentation

- Evidence on the extent of variation of impact of different categories/characteristics of user on networks (linked to questions within the access right PD on how planning approaches vary for different user types), considering types of generation and demand
- An initial view of whether this could support the definition of thresholds for more granular charging, and their pros and cons from a system perspective

Network costs which are driven by energy consumed or number of customers

22. For customers with smart meters and are half-hour settled (HHS), we are likely to consider charging designs such as time-of-use volumetric charges, agreed and actual capacity-based charges, critical peak pricing and similar charging designs for the purposes of designing charges that reflect times of peak congestion.

23. However, we also need to consider whether part of the charging design for HHS customers should be based on volumetric (non-TOU) charges or fixed charges. To inform these considerations we request the sub-group to identify:

    - Any there any network cost drivers which increase based on the total energy consumed of the customer—for which a flat rate volumetric charge may be appropriate
    - Are there any network cost drivers which increase or decrease based on the total energy consumed of the customer at an increasing or decreasing rate—for which an inclining block or declining block charge may be appropriate
    - Are there any other drivers of cost other than those identified above, which would be significant – e.g. based on customer behaviour type, or other network conditions?
    - Are there any network cost drivers which increase based on the number of customers—for which a fixed charge per customer may be appropriate

24. For each of the above, the subgroup should both identify the cost driver and provide a qualitative (or quantitative, if possible) assessment of the materiality of the cost driver. The materiality assessment should consider whether the materiality differs for between different types of users—e.g. between large or small users, generation or demand users, urban or rural users, etc.

Upstream vs downstream network costs

25. Conventionally, the network charging regimes have been ‘upstream-only’ i.e. charges are based on the costs of the network at and above the voltage level to which a user is connected. We request that the sub-group advise on:

    - Are there downstream network costs (i.e. below the voltage level to which a user is connected) which can be directly affected by the behaviour of upstream network users? If so, what are these costs?
    - Do these costs change in the case of a reverse power flow condition (when there is an export of power from lower voltages to higher voltages) or other network conditions? If so, how and what are these costs?

Losses and reactive power

26. Losses are an inevitable consequence of the transportation of electricity. Presently, the impact of losses (the requirement for more generation than demand) is accounted for in the designation of Line Loss Factor Classes (LLFCs) that affect how users are treated in balancing and settlement. We request that the subgroup advise on:

    - How do locational or temporal variations in network conditions, design or customer behaviour have a significant impact on network losses?
    - Is there merit to introducing the concept of network losses to the forward looking charge, and could doing so duplicate existing behavioural signals (e.g. LLFCs)? If so, how could these be adapted to better reflect drivers of network losses.

27. Reactive power is similarly an inevitable by-product in the production, transportation and consumption of AC electricity. Like active power, the transportation of reactive power can create additional network infrastructure requirements and may contribute to other costs, and it is therefore desirable that a local balance be maintained. This is presently managed through a combination of network assets investments, as well as technical reactive power obligations for network users that are supplemented by the actions of network operators. We request that the group advise on:

- What are the network cost drivers associated with investment in network infrastructure or operational costs for reactive power? What is the locational variation in these cost drivers?
- Would it be appropriate to consider reactive power as a component of the forward-looking charge? If so, what are the recommendations of the group for how to do so.

Impact of emerging technology and changing behaviour patterns on load diversity

28. Diversity of customer load is a core concept in the design of electricity systems. Emerging technologies that allow for more automated demand responses combined with poorly design cost reflective network charges), or without mitigating strategies (e.g. required technical operational standards) have the potential to reduce that load diversity.
29. For example, imagine that network charges were designed with off-peak pricing starting at X o'clock, and 2 million electrical vehicles and home batteries across Great Britain where programmed to automatically start charging at X o'clock. We request the subgroup advice on:
    - What challenges in managing the network and network costs might this create?
    - What challenges in managing the wider system and what wider system costs (e.g. generation investment or operational costs) might this create?
30. The types of emerging technologies (like EVs and heat pumps) which increase peak demand may also change current load profiles.
    - What impact could new intensive loads (like EVs and heat pumps) and changes in demand patterns, including provision of flexibility, have on diversity? What costs could this drive?
    - What impact might more tightly defined access limits have on diversity, and what impact could have on network costs?

Source of network cost information

31. It is important that the information on the cost of the network comes from an accurate and consistent source:
    - What are the sourcing options for information on the long run cost of the network? For example, could network costs be linked to RRP submissions, RIIO business plans, unit cost allowances?
    - How do these network costs vary according to location? For example, should the forward looking charges account for variations in the costs of network according to urban/rural areas, soft/hard ground conditions, or other locational factors?

Annex 2 – Transmission cost categories

The following table showing the costs types and whether they are material, locational, attributable, priority cost type, definition. This also includes a Function/ factors column where the group has determined the contributing factors of each cost.

		Material?	**Locational?**	**Attributable?**	**Primary/ Secondary/ Tertiary**	**Transmission Definition**
Load related	Connections within the price control	Y	Y	Y	Primary	Transmission connection assets - the assets specified in Appendix A to the Bilateral Connection Agreement.
	Reinforcement (Single user assets)	Y	Y	Y	Primary	Connection assets are defined as those assets solely required to connect an individual User to the Transmission system, which are not and would not normally be used by any other connected party (i.e. "Single User Assets"). Connection assets are defined as all those Single User Assets which: a) For Double Busbar type connections, are those Single User Assets connecting the User's assets and the first Transmission owned substation, up to and including the Double Busbar bay; b) For teed or mesh connections, are those Single User Assets from the User's assets up to, but not including the HV disconnector or the equivalent point of isolation; and c) For cable and overhead lines at a Transmission Voltage, are those Single User connection circuits connected at a Transmission Voltage equal to or less than 2km in length that are not potentially shareable.
	Reinforcement (Shared user assets)	Y	Y	Y	Primary	Shared assets at a banked connection arrangement will not normally be classed as connection assets except where both legs of the banking are Single User Assets under the same TO Connection Agreement. Other definitions of connection assets might apply.
	Fault level reinforcement	Y	Y	Y	Primary	Network development to relieve an existing network constraint or facilitate new load growth.

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Transmission Definition
Non-load capex (ex. non-op capex)	Diversions (ex. rail electrification)	Y	Y	N	Secondary	Diversions activity that is not fully recharged to any third party or agent, Diversions is a generic category that includes: • Conversion of wayleaves to easements, easements and injurious affection; • Diversions due to wayleave terminations, termination of a lease (s.25 Landlord & Tenant Act) or where a re-development clause exists within an existing easement or other consent documentation. • Diversion for Highways (funded as detailed in NRSWA).
	Diversions (rail electrification)	Y	Y	N	Secondary	same as above
	Asset replacement	Y	Y	N	Secondary	Asset replacement is an activity undertaken by a TO to remove an existing asset(s) and install a new asset.
	Refurbishment	Y	Y	N	Secondary	A one-off activity undertaken on an asset that is deemed to be close to end of life or is otherwise not fit for purpose that extends the life of that asset or restores its functionality.
	Operational IT and telecoms	Y	N	N	Secondary	IT and telecommunications systems and equipment which are used exclusively in the real time management of network assets, but which do not form part of those network assets.
	Blackstart	Y	Y	N	Secondary	• The series of actions necessary to restore electricity supplies to customers following a total or widespread partial shutdown of the GB Transmission System. • Black Start requires transmission substations to be re-energised and reconnected to each other in a controlled way to re-establish a fully interconnected system. • Black Start expenditure is associated with initiatives to improve the resilience of both the transmission network assets and the key telecommunications systems. Costs for this category exclude ESO costs which are factored into BSUoS. This category relates only to the TO's costs associated with meeting black start requirements.

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Transmission Definition
	BT21CN	N	N	N	Tertiary	The roll-out of BT's next generation communications network which replaces Public Switched Telephone Network (PSTN) with a Digital Internet Protocol (IP). Whilst effectively changing the communications protocol used on the existing network assets, it also accelerates the replacement of copper communications circuits with non-metallic optical fibre.
	Legal and safety	N	N	N	Tertiary	Investment or intervention where the primary driver is to meet safety requirements and to protect staff and the public.
	Flood mitigation	Y	N	N	Secondary	Current physical and non-physical measures of flood prevention in place on a site and/or potential improvements that reduce the risk of flooding.
	Physical security	Y	N	N	Secondary	Sites designated as critical national infrastructure by DECC. Includes all associated costs of complying with DECC requirements.
	Visual amenity	Y	Y	N	Secondary	
	Losses	N	N	N	Tertiary	A measure of the difference between units entering and units exiting the DNO network through different connection points.
	Environmental reporting	Y	N	N	Secondary	
Non-op capex	IT and telecoms (non-op)	N	N	N	Tertiary	Expenditure on new and replacement IT assets which are not system assets. These include Hardware and Infrastructure and Application Software Development.
	Property (non-op)	Y	N	N	Secondary	Expenditure on new and replacement property assets which are not system or operational assets, which includes: • Premises used by people (e.g. stores, depots and offices) which are not operational premises (e.g. substations) • Office equipment.
	Vehicles and transport (non-op)	Y	N	N	Secondary	Expenditure on new and replacement wheeled vehicles and generators which are not system assets but are utilised by the TO or any other Related Party for the purposes of providing services to the TO.
	Small tools and equipment	N	N	N	Tertiary	Small tools, equipment, plant and machinery which are used to work on, assist work on or test system assets.
SWW	Strategic Wider Works projects	Y	Y	Y	Primary	Projects valued over the TO specific SWW threshold which will be undertaken or continued into RIIO-T2.

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Transmission Definition
Network operating costs	Faults	Y	N	N	Secondary	Troublecall Occurrences classified under Interruptions reporting as Unplanned Incidents which require some form of action to restore an asset to Pre-Fault Availability.
	Severe weather 1 in 20	Y	N	N	Secondary	
	Tree cutting	Y	N	N	Secondary	The activity of physically felling or trimming vegetation from around network assets, which includes: • The felling or trimming of vegetation to meet ENATS 43-8 & ETR 132 requirements. • The inspection of vegetation cut for the sole purpose of ensuring the work has been undertaken in an appropriate manner. • Inspection of tree-affected spans where included as part of a tree cutting contract.
	Inspections	Y	Y	N	Secondary	The visual checking of the external condition of system assets including any associated civil constructions such as buildings, substation surrounds, support structures, cable tunnels and cable bridges.
	Repair and maintenance	Y	Y	N	Secondary	The activity relating to the invasive (“hands on") examination of, and the undertaking of any subsequent works to repair defects on, system assets. This includes minor repairs carried out at the same time as the maintenance visit and subsequent repair works undertaken to remedy defects identified by either inspection or maintenance.
	Substation electricity	Y	N	N	Secondary	

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Transmission Definition
Closely associated indirects (CAI)	Core CAI	Y	N	N	Secondary	This combines the following activities: • Network Design and Engineering • Network Policy • Project Management • Engineering Management and Clerical Support (EMCS) • System Mapping • Stores • Call Centre • Control Centre.
	Wayleaves	Y	N	N	Secondary	An activity included within CAI, incorporating the following sub-activities: • Wayleave Payments • Wayleaves and Easements/Servitudes: Admin Cost.
	Operational training (CAI)	Y	N	N	Secondary	It is the training of Operational Staff employed by TO or Related Party, or Agency Staff to support the direct activities on the network.
	Vehicles and transport (CAI)	Y	N	N	Secondary	The CAI activity associated with managing, operating and maintaining the commercial vehicle fleet and mobile plant utilised by the TO or any other Related Party for the purposes of providing services to the TO.
Business support costs	Core BS	Y	N	N	Secondary	
	IT and telecoms	Y	N	N	Secondary	Expenditure on operating and maintaining the operational and non-operational computer and telecommunications systems and applications.
	Property management	Y	N	N	Secondary	The costs of providing, managing and maintaining all non-operational premises (with the exception of operational training centres).
Other costs within price control	Network Innovation Allowance	Y	N	N	Secondary	Has the meaning given to it in Special Condition 3H (The Network Innovation Allowance) of the electricity transmission licence.
	Network Innovation Competition	Y	N	N	Secondary	Has the meaning given to it in Special Condition 3I (The Network Innovation Competition) of the ET licence.
Costs outside price control	Costs outside of price control	Y	N	N	Secondary	

Annex 3 – Distribution cost categories

The following table showing the costs types and whether they are material, locational, attributable, priority cost type, definition. This also includes a Function/ factors column where the group has determined the contributing factors of each cost.

		Material?	**Locational?**	**Attributable?**	**Primary/ Secondary/ Tertiary**	**Definition**	**Comments**	**Function/ Factors**
Load related	Connections within the price control	Y	Y	Y	Primary	Connection refers to the provision or upgrading of individual MPANs, points of connection for independent networks, ICPs or unmetered connections to end customers. All provisions of new MPANs/points of connection or upgrades of existing MPANs/points of connection must be referred to as connections within the annual reporting for connections.	Locational, values and MPANs could be identified by forecast connections	=function(new max demand at each Primary/ BSP/ GSP)
	Reinforcement (primary network)	Y	Y	Y	Primary	Network development to relieve an existing network constraint or facilitate new load growth.	Locational, values and MPANs could be identified by forecast works or long term development statement modelling at EHV level	=function(max demand at each Primary/ BSP/ GSP)
	Reinforcement (secondary network)	Y	Y	Y	Primary	Network development to relieve an existing network constraint or facilitate new load growth.	Locational, values and MPANs could be identified by forecast works or LTDS modelling at EHV level	=function(max demand at each Primary/ BSP/ GSP)

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Definition	Comments	Function/ Factors
	Fault level reinforcement	Y	Y	Y	Primary	Network development to relieve an existing network constraint or facilitate new load growth.	Locational, values and MPANs could be identified by forecast works or long term development statement modelling at EHV level	=function(max demand at each Primary/ BSP/ GSP)
	New transmission capacity charges	N	Y	Y	Tertiary	Transmission Connection Point Charges that are specifically related to a licensee requirement for new or reinforced TCPs that are energised after 1 April 2015.	Locational but covers all MPANs within the relevant GSP or GSPs	=function(max demand at GSP)
Non-load capex (ex. non-op capex)	Diversions (ex. rail electrification)	Y	Y	N	Secondary	Diversions activity that is not fully recharged to any third party or agent. Diversions is a generic category that includes: • Conversion of wayleaves to easements, easements and injurious affection; • Diversions due to wayleave terminations, termination of a lease (s.25 Landlord & Tenant Act) or where a re-development clause exists within an existing easement or other consent documentation. • Diversion for Highways (funded as detailed in NRSWA).	Has a locational element but these costs various all MPANs and therefore these costs are very difficult to separate and allocate to specific MPANs	=function(network size)

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Definition	Comments	Function/ Factors
	Diversions (rail electrification)	N	Y	N	Tertiary	See cell above.	Has a locational element but these costs various all MPANs and therefore these costs are very difficult to separate and allocate to specific MPANs	=function(network size)
	Asset replacement	Y	Y	Y	Primary	Asset replacement is an activity undertaken by a DNO to remove an existing asset(s) and install a new asset.	Locational, values and MPANs could be identified by forecast works. Asset replacement is partly dependent on usage although exact relationship is unknown.	=function(salinity, age, units, use, weather, network size)
	Refurbishment no SDI	Y	Y	N	Secondary	A one-off activity undertaken on an asset that is deemed to be close to end of life or is otherwise not fit for purpose that extends the life of that asset or restores its functionality.	Locational, values and MPANs could be identified by forecast works. Asset replacement is partly dependent on usage although exact relationship is unknown.	=function(salinity, age, units, use, weather, network size)

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Definition	Comments	Function/ Factors
	Refurbishment SDI	Y	Y	N	Secondary	A one-off activity undertaken on an asset that is deemed to be close to end of life or is otherwise not fit for purpose that extends the life of that asset or restores its functionality.	Locational, values and MPANs could be identified by forecast works. Asset replacement is partly dependent on usage although exact relationship is unknown.	=function(salinity, age, units, use, weather, network size)
	Civil works condition driven	Y	Y	N	Secondary	Civil engineering work associated with DNO network assets, including buildings and site works at substations.	Locational, values and MPANs could be identified by forecast works. Asset replacement is partly dependent on usage although exact relationship is unknown.	=function(salinity, age, units, use, weather, network size)
	Operational IT and telecoms	Y	N	N	Secondary	IT and telecommunications systems and equipment which are used exclusively in the real time management of network assets, but which do not form part of those network assets.	Non-locational and non-unit related but material	=function(network size, network propensity for real time management)

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Definition	Comments	Function/ Factors
	Blackstart	N	N	N	Tertiary	The series of actions necessary to restore electricity supplies to customers following a total or widespread partial shutdown of the GB Transmission System. Black Start requires distribution substations to be re-energised and reconnected to each other in a controlled way to re-establish a fully interconnected system.	Non-locational and non-unit related but material	=function(network size)
	BT21CN	N	N	N	Tertiary	The roll-out of BT's next generation communications network which replaces Public Switched Telephone Network (PSTN) with a Digital Internet Protocol (IP).	Non-locational and non-unit related but material	=function(network size)
	Legal and safety	Y	N	N	Secondary	Investment or intervention where the primary driver is to meet safety requirements and to protect staff and the public.	Not material and Non-locational and non-unit related but material	independent of network size
	QoS and north of Scotland resilience	Y	Y	N	Secondary	Costs where the primary purpose is to improve performance against the IIS targets or to improve the overall fault rate per km of the distribution network.	Locational, values and MPANs could be identified by forecast works. Asset replacement is partly dependent on usage although exact relationship is unknown.	=function(salinity, age, units, use, weather)

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Definition	Comments	Function/ Factors
	Flood mitigation	N	Y	N	Tertiary	Current physical and non-physical measures of flood prevention in place on a site and/or potential improvements that reduce the risk of flooding.	Locational, values and MPANs could be identified by forecast works.	=function(locational propensity to flood)
	Physical security	N	Y	N	Tertiary	Sites designated as critical national infrastructure by DECC. Includes all associated costs of complying with DECC requirements.	Locational but not material	=function(network size)
	Rising and lateral mains	Y	Y	Y	Primary	Individual DNO owned 3 phase cable or busbar, not laid in the ground, which runs within or attached to the outside of a multiple occupancy building for: • more than 3m vertically, or • more than 3m horizontally, and • to which a number of individual services are connected, usually via a distribution board.	Has a locational element but these costs are very difficult to allocate to specific MPANs although could be split through an urban/ rural function	=function(network size, urban/ rural ratio)
	Overhead line clearances	Y	Y	N	Secondary		Has a locational element but these costs are very difficult to allocate to specific MPANs although could be split through an urban/rural function	=function(network size, urban/ rural ratio)

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Definition	Comments	Function/ Factors
	Worst served customers	N	Y	N	Tertiary	There are two definitions that will apply during RIIO-ED1: • the DPCR5 definition that is used for the reporting of post WSC Scheme completion network performance for WSC Schemes carried out during DPCR5 • the ED1 definition that applies to reporting of WSC Schemes carried out during RIIO-ED1. DPCR5 definition is customers experiencing 15 or more higher voltage unplanned Interruptions over a three-year period, with a minimum of three higher voltage unplanned Interruptions in each year. RIIO-ED1 definition is Customers experiencing 12 or more higher voltage unplanned Interruptions over a three year period, with a minimum of three higher voltage unplanned Interruptions in each year.	Locational but not material	=function(network size, DNO performance)
	Visual amenity	N	Y	N	Tertiary	The mechanism for funding Visual Amenity Projects provided for in CRC 3J (Allowed expenditure on Visual Amenity Projects) of the electricity distribution licence.	Has a locational element but these costs are very difficult to allocate to specific MPANs although could be	=function(network size, urban/ rural ratio)

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Definition	Comments	Function/ Factors
							split through an urban/rural function	
	Losses	N	N	N	Tertiary	A measure of the difference between units entering and units exiting the DNO network through different connection points.	Non-locational and unit related but not material	=function(network size, units, demand, level of DG)
	Environmental reporting	N	N	N	Tertiary		Non-locational and non-unit related but material	=function(network size, urban/ rural ratio)
Non-op capex	IT and telecoms (non-op)	Y	N	N	Secondary	Expenditure on new and replacement IT assets which are not system assets. These include Hardware and Infrastructure and Application Software Development.	Non-locational and non-unit related but material	=function(network size)
	Property (non-op)	Y	N	N	Secondary	Expenditure on new and replacement property assets which are not system or operational assets. Includes: • Premises used by people (e.g. stores, depots and offices) which are not operational premises (e.g. substations) • Office equipment.	Non-locational and non-unit related but material	=function(network size)
	Vehicles and transport (non-op)	Y	N	N	Secondary	Expenditure on new and replacement wheeled vehicles and generators which are not system assets but are utilised by the DNO or any other Related Party for the purposes of providing services to the DNO.	Non-locational and non-unit related but material	=function(network size)
	Small tools and equipment	Y	N	N	Secondary	Small tools, equipment, plant and machinery which are used to work	Non-locational and non-unit related but material	=function(network size)

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Definition	Comments	Function/ Factors
						on, assist work on or test system assets.		
HVP	High value projects DPCR5	N	Y	N	Tertiary	HVP schemes specified and agreed with individual DNOs to be undertaken during DPCR5 and continued in RIIO-ED1.	Independent of charging factors	independent of network size
	High value projects RIIO-ED1	N	Y	N	Tertiary	Schemes specified and agreed with individual DNOs to be undertaken during RIIO-ED1 that were specified in the ED1 Final Determination or included during the price control period.	Independent of charging factors	independent of network size
Network operating costs	Faults	Y	Y	N	Secondary	Troublecall Occurrences classified under Interruptions reporting as Unplanned Incidents which require some form of action to restore an asset to Pre-Fault Availability.	Has a locational element but these costs are very difficult to allocate to specific MPANs	=function(network size, weather)
	Severe weather 1 in 20	N	N	N	Tertiary		Non-locational and non-unit related but material	=function(weather)
	ONIs	Y	N	N	Secondary	Any occurrence logged on the enquiry service operated by the licensee under Standard Condition 8 (Safety and Security of Supplies Enquiry Service (SSSES))which is not an incident and which is not as a result of being identified during the installation of, or attempted installation of, a Smart Meter.	Non-locational and non-unit related but material	=function(network size)

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Definition	Comments	Function/ Factors
	Tree cutting	Y	Y	N	Secondary	The activity of physically felling or trimming vegetation from around network assets.	Has a locational element but these costs are very difficult to allocate to specific MPANs	=function(network size, urban/ rural ratio, rate of tree growth in area)
	Inspections	Y	Y	N	Secondary	The visual checking of the external condition of system assets, including any associated civil constructions such as buildings, substation surrounds, support structures, cable tunnels and cable bridges.	Has a locational element but these costs are very difficult to allocate to specific MPANs	=function(network size)
	Repair and maintenance	Y	Y	N	Secondary	Category includes the activity relating to the invasive ("hands on") examination of, and the undertaking of any subsequent works to repair defects on system assets. This includes minor repairs carried out at the same time as the maintenance visit and subsequent repair works undertaken to remedy defects identified by either inspection or maintenance.	Has a locational element but these costs are very difficult to allocate to specific MPANs	=function(salinity, age, units, use, weather, network size)
	Dismantlement	N	N	N	Tertiary	The activity of de-energising, disconnecting and removing (where appropriate) network assets where the cost of dismantlement is not chargeable to a third party and no new assets are to be installed.	Has a locational element but these costs are very difficult to allocate to specific MPANs	=function(salinity, age, units, use, weather, network size)

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Definition	Comments	Function/ Factors
	Remote generation opex	N	Y	N	Tertiary	Fixed diesel generation stations that provide permanent emergency backup in remote locations including islands. Remote locations will generally only have a single electrical feed.	Locational but not material	=function(network size, urban/ rural)
	Substation electricity	Y	N	N	Secondary		Non-locational and non-unit related but material	=function(network size)
	Smart metering roll out	Y	N	N	Secondary		Non-locational and non-unit related but material	=function(network size)
Closely associated indirects	Core CAI	Y	N	N	Secondary	This combines the following activities: • Network Design and Engineering • Network Policy • Project Management • Engineering Management and Clerical Support (EMCS) • System Mapping • Stores • Call Centre • Control Centre.	Non-locational and non-unit related but material	=function(network size)
	Wayleaves	Y	N	N	Secondary	An activity included within Closely Associated Indirects, incorporating the following sub-activities: • Wayleave Payments • Wayleaves and • Easements/Servitudes: Admin Cost	Non-locational and non-unit related but material	=function(network size)

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Definition	Comments	Function/ Factors
	Operational training (CAI)	Y	N	N	Secondary	It is the training of Operational Staff employed by DNO or Related Party, or Agency Staff to support the direct activities on the network.	Non-locational and non-unit related but material	=function(network size)
	Vehicles and transport (CAI)	Y	N	N	Secondary	The Closely Associated Indirect activity associated with managing, operating and maintaining the commercial vehicle fleet and mobile plant utilised by the DNO or any other Related Party for the purposes of providing services to the DNO.	Non-locational and non-unit related but material	=function(network size)
Business support costs	Core BS	Y	N	N	Secondary		Non-locational and non-unit related but material	=function(network size)
	IT and telecoms	Y	N	N	Secondary	Expenditure on operating and maintaining the operational and non-operational computer and telecommunications systems and applications.	Non-locational and non-unit related but material	=function(network size)
	Property management	Y	N	N	Secondary	The costs of providing, managing and maintaining all non-operational premises (with the exception of operational training centres).	Non-locational and non-unit related but material	=function(network size)
Other costs within price control	Atypicals non sev weather	Y	N	N	Secondary	Those specific costs or events that are specified as Atypical under this definition, or where Ofgem provides an agreement for the costs to be reported as Atypicals in the RIGs, and they fall within Totex activities.	Independent of charging factors	independent of network size

		Material?	Locational?	Attributable?	Primary/ Secondary/ Tertiary	Definition	Comments	Function/ Factors
	Atypicals non sev weather (ex. from totex)	N	N	N	Tertiary	See cell above.	Independent of charging factors	independent of network size
	Network Innovation Allowance	N	N	N	Tertiary		Independent of charging factors	independent of network size
	Network Innovation Competition	N	N	N	Tertiary		Independent of charging factors	independent of network size
	IFI and Low Carbon Network Fund	N	N	N	Tertiary		Independent of charging factors	independent of network size
Costs outside price control	Costs outside price control	Y	N	N	Secondary		Independent of charging factors	independent of network size
NABC	Pass through	Y	Y	N	Secondary	Licence fees, transmission exit charges, business rates, smart metering costs etc.	Has a locational element but these costs cover all MPANs and therefore these costs are very difficult to separate and allocate to specific MPANs	=function(network size)
	Other non-activity based costs	Y	N	N	Secondary		Independent of charging factors	independent of network size

Annex 4 – Transmission Locational Regions

The following map illustrates the regions each TO used to determine whether a cost category had a locational driver. SHE Transmission has 2 regions - North and South of Boundary B2. SP Transmission also has 2 regions – North and South of B5 (up to B4 and B6). NGET has 3 regions – North of England (comprising the region North of Boundary B8, excluding North Wales and the West Midlands, up to B6), Wales and the West Midlands (comprising the whole of W ales and boundary B17) and the South and East of England region (comprising of everything south of B8 Excluding Wales).