Access and Forward-looking charges

Report 1: Current approach to the Design and Operation of the Electricity Transmission and Distribution Systems and User Characteristics

Access 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	

Distribution

Access SCR Delivery Group
Access SCR Challenge Group

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1 Executive summary

1.1 This is the first of two working reports, which together consider the Access Working Group's initial thoughts on options for access right definition and choice. This report attempts to answer a series of questions posed by Ofgem (the Acceptance Criteria) on how network companies currently design and operate the electricity networks. These questions are replicated in Annex 1.

1.2 The purpose of this first report is to provide an overview of the basis upon which the GB network operators currently design and operate their electricity networks. It highlights differences in approach, and planning standards utilised, between the distribution and transmission networks. In addition, the key factors and variables which affect the planning assumptions used by network operators are explored.

1.3 Also discussed are the assumptions made in the assessment of the impact of new connections, giving consideration to the application of diversity, dependent upon factors such as user type, user characteristics and voltage of connection.

1.4 Finally this report considers some of the drivers of network constraints and the application of flexible connection arrangements which have been adopted by network operators to respond to these drivers and secure cheaper and faster connections, and provide economic and efficient alternatives to reinforcement in many instances. Examples of these flexible arrangements include the Connect and Manage approach at transmission and active network management on the distribution system.

2 Introduction

Significant Code Review

2.1 This report will inform the Ofgem led Electricity Network Access and Forward-looking Charging Significant Code Review ('the Access SCR') and is the first of two reports produced by the Access SCR Delivery Group (see below).

2.2 Ofgem launched the Access SCR on 18 December 2018. The overarching objective of the Access 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 Access 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. These changes could create demand and generation 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 Following engagement with industry, Ofgem believes the current electricity network access arrangements and forward-looking charges will not efficiently facilitate these changes in our energy system. The Access SCR therefore identifies a number of key issues with the current arrangements and priority options for change. Consistent with this, the Access 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 (i.e. Distribution Use of System (DUoS) charges);
- a review of the distribution connection charging boundary; and
- a focused review of transmission network charges (i.e. Transmission Use of System (TNUoS) charges).

The Delivery Group

2.6 To deliver the Access 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 National Grid Electricity System Operator (NGESO), distribution and onshore transmission, network owners, the Energy Networks Association (ENA), relevant code administrators (e.g. DCUSA and CUSC), and a representative for IDNOs. 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 set up and tasked specific 'working groups' to consider and report on each of the aspects of the Access SCR listed above.

The Challenge Group

2.7 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 has informed the development of this report.

Scope and purpose

2.8 The sub-group was asked to establish how access rights and user characteristics are currently taken into account when planning the system. This report seeks to deliver this, providing an overview of how GB network operators currently design and operate their electricity networks, highlighting differences in approach and planning standards utilised.

2.9 With this information a better understanding of the value of improved access choice and definition can be attained, enabling development of access choice design options, and their analysis. The second report of the Access Working Group's takes forward this work, focusing on access choice design, improvements to cross-system access and the assessment of access choice and standardisation. The second report also introduces the key themes of **firmness**, i.e. the ongoing certainty of network capacity being available for a particular connection arrangement, and **access**, i.e. the extent to which users can import and/or export electricity and how these rights might be allocated.

Out of Scope

2.10 This report provides background information on how the network companies currently design and operate the electricity networks, seeking to set the context for Report 2, 'Option Variants of Access Choices', and the work of the other SCR working groups. The purpose of this report is not therefore to identify improvements to current practices/approaches, nor does it recommend options for change.

Dependencies with other documents

2.11 This report is one of a number produced by the Delivery Group. It should not be read in isolation as there are many areas across these reports that interrelate.

3 Current Planning and Security Standards and their application

What do planning and security standards prescribe currently?

3.1 The planning and security standards for the GB electricity networks define a number of physical capabilities and requirements, including:

- Thermal capability;
- Fault level capability;
- Voltage limits;
- Power quality, including harmonics distortion limits; and
- System stability and loss of power infeed.

The objective of these standards is to deliver safe, secure, reliable and economic supplies to customers.

Distribution Network Planning and Security Standards

3.2 The GB electricity distribution networks must be fit for purpose, reliable, safe and secure. Their design and operation must meet the requirements prescribed in the Electricity Safety, Quality and Continuity Regulations 2002 (ESQCR). The ESQCR regulate quality and supply continuity requirements as well as specifying safety standards. Compliance with ESQCR is a statutory requirement for distribution network operators (DNOs).

3.3 Licenced DNOs are also bound by licence conditions and the Distribution Code (D-Code). The Distribution Code covers the technical aspects relating to the connection and use of the electricity distribution licensees' distribution networks. The Distribution Code specifies procedures that govern the relationship between a distribution licensee and users of its distribution system for planning and operational purposes in normal and emergency circumstances. Annex 1 of the D-Code lists various design documents which are mandatory. Annex 2 of the D-Code includes other reference documents. A copy of the D-Code is available at: http://www.dcode.org.uk/annexes.html.

3.1 Licensed distribution network companies must also meet or exceed Engineering Recommendation P2 (EREC P2) (listed in D-Code Annex 1). This recommendation defines levels of network security for specific sizes of group demands. The requirements set out below from EREC P2 are also mirrored in the Security and Quality of Supply Standard (SQSS) which applies at transmission levels of the network (see Table 1). Guidance Note 1 of the D-Code explicitly states that EREC P2 does not apply to a single demand customer and for clarity this means firmness in respect of sole assets is an enhanced option available to the customer over and above standard design of service assets. EREC P2 is a demand focused security of supply standard which defines the minimum levels of network resilience required for a given amount of demand within an area of network (defined as group demand). In assessing group demand, EREC P2 takes account of the contribution made by generation local to that group.

3.2 Generation connections, as with all types of connection, must be designed to meet the same requirements for thermal capability, fault level capability, voltage limits, power quality, harmonic distortion limits and system stability. However, for generation, P2 does not specify additional levels of network resilience beyond an intact system, irrespective of the amount of generation with an area of network.

Table 1: Levels of network security for specific sizes of group demands (EREC P2)

Class of Supply	Group Demand Range	Minimum Demand to be Met After	
		First Circuit Outage (n-1)	**Second Circuit Outage (n-2)**
A	Up to 1MW	In repair time: Group Demand	Nil
B	Over 1MW and up to 12MW	(a) Within 3 hours: Group Demand minus 1MW (b) In repair time: Group Demand	Nil
C	Over 12MW and up to 60MW	(a) Within 15 minutes: Smaller of Group Demand minus 12MW and 2/3 Group Demand (b) Within 3 hours: Group Demand	Nil
D	Over 60MW and up to 300MW	(a) Within 60 seconds: Group Demand minus 20MW (automatically disconnected) (b) Within 3 hours: Group Demand	(c) Within 3 hours (for Group Demand greater than 100MW): Smaller of Group Demand minus 100MW and 1/3 Group Demand (d) Within time to restore arranged outage: Group Demand
E	Over 300MW and up to 1500MW	(a) Within 60 seconds: Group Demand	(b) Within 60 seconds: All customers at 2/3 Group Demand (c) Within time to restore arranged outage: Group Demand
F	Over 1500MW	In accordance with the relevant transmission company licence security	

3.3 Mechanisms exist for DNOs to derogate from full compliance with EREC P2 following an economic and risk-based assessment, where it is shown the risk of customer impact is very low and the cost of compliance is disproportionately high; this is typically only relevant where networks are occasionally operated at their margins and/or are in particularly sparse locations.

3.4 The EREC P2 criterion is being updated to version seven (P2/7). Along with the underpinning technical documentation (Engineering Report (EREP) 130) this update of EREC P2 will differentiate between contracted and non-contracted contributions from distributed generation, demand-side response and electricity storage.

3.5 The contribution from contracted sources will be based on the terms of the contract. Examples of contracted services include:

- exporting at time of peak;
- post-outage import curtailment; e.g. inter-tripping scheme, non-firm single customer connection, ANM scheme; and
- pre-outage import curtailment; e.g. constrained import at specific time of day, ANM scheme (‘dynamic’ DSR).

3.6 For non-contracted services the fortuitous security contribution from ‘export’ is based on the F-factor methodology.

3.7 Further to EREC P2/7 there is scope to further review security standards based on the analysis carried out by the DNVGL/Imperial College consortium (http://www.dcode.org.uk/assets/uploads/IC_Report_main_report_-_red.pdf). This may require further input to identify options for future demand security e.g. firm/essential vs flexible demands; requirements for future services including transport and heat and other. Additional planning guidance for distribution networks is available in ENA Engineering Recommendation (EREC) P5 [not referenced in D-Code] and G81 [In D-Code Annex 2].

Engineering Recommendation (ER) G99

3.8 There has been a recent growth in smaller sources of generation which have historically not been actively managed, although the network companies have been making progress to address this. This growth, along with the increasing share of intermittent generation and opportunities for storage have resulted in new challenges for the network companies in terms of the planning, operation and balancing of the distribution system.

3.9 To address these challenges, the ER G59 grid connection standard was replaced with ER G99 in April 2019 (http://www.energynetworks.org/assets/files/ENA_EREC_G99_Issue_1_Ammendment_3_(2018).pdf). This new engineering standard introduces new performance specifications to provide greater stability against grid faults, such as frequency, voltage and power factor, as well as optimising power quality.

3.10 As stated within G99, the DNOs have statutory and licence obligations to offer the most economic, technically feasible option for connecting generation to the distribution system (also known as 'minimum scheme' obligation). In addition, G99 lists the DNOs' main general design obligations as:

a) maintaining supplies to their customers within defined statutory voltage and frequency limits;

b) ensuring that the distribution networks at all voltage levels are adequately earthed;

c) complying with the "Security of Supply" criteria defined in EREC P2;

d) meeting improving standards of supply in terms of customer minutes lost (CMLs) and the number of customer interruptions (CIs); and

e) the facilitation of competition in the connection, generation and supply of electricity.

Transmission Network Planning and Security Standards

3.11 The Grid Code covers all material technical aspects relating to connections to, and the operation and use of, the national electricity transmission system.

3.12 The Security and Quality of Supply Standards (SQSS) set out criteria and the methodology for planning and operating the National Electricity Transmission System (NETS) with respect to the needs of both generation and demand connections. The SQSS establish a coordinated set of criteria and methodologies that transmission licensees use in planning and operating the NETS.

3.13 Both planning and operational criteria are set out in the SQSS and these determine the need for services provided to the relevant transmission licensees, e.g. reactive power as well as transmission equipment. The planning criteria set out the requirements for the transmission capacity (either investment or purchase of services) for the NETS. The planning criteria also require consideration to be given to the operation and maintenance of the NETS and so refer to the associated operational criteria where appropriate. The operational criteria are used in real time and in the development of plans for using the national electricity transmission system to permit satisfactory operation.

3.14 The SQSS contains both absolute Security Requirements which define the network capacity required to ensure there will always be enough capacity to meet peak consumer demands using the generation that is guaranteed to be available (i.e. not renewables that are dependent on the weather). Once the security requirements are met the Economic Standards are applied, these will only build capacity where that is a cheaper option than using operational measures to limit transmission flow to the capacity available. Typically, at transmission level, assets are not built to cope with unlikely scenarios, unless that scenario is required to guarantee security of supply.

3.15 Transmission Systems may be designed or operated to a lesser standard of security specified under SQSS for either generation or demand, this can be for;

a. Standing licence Condition C17 arrangement to derogate from SQSS in respect of Connect and Manage connection of generation, i.e. to enable user connection first and with transmission system compliance permitted to occur later;
b. A selective derogation requested from the Authority;
c. Design and operation to a lesser standard where the relevant users, demand or generation, agree (refer to SQSS para 2.16.2 for generation and para 3.13.2 for demand).

4 Diversity assumptions and network planning and operation

Diversity assumptions used at distribution and transmission

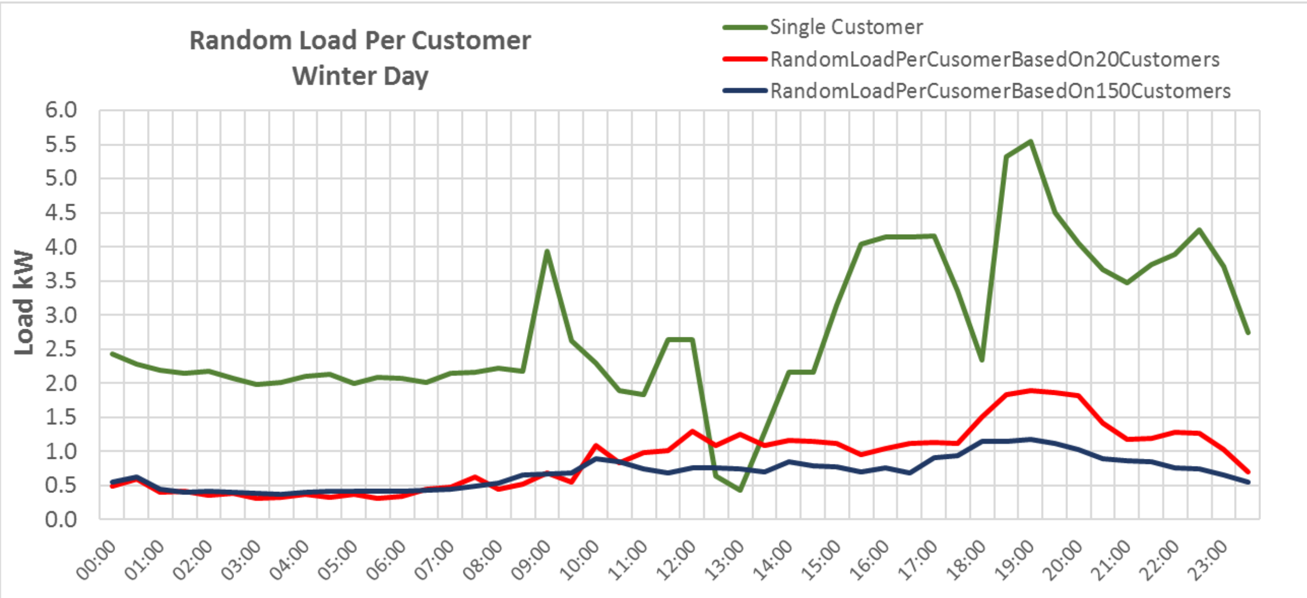
4.1 Diversity factor is defined as the ratio of the sum of the maximum demands of customers to the coincident maximum demand of the whole system. The maximum demands of individual customers do not occur simultaneously. Thus, there is a diversity in the occurrence of the load. Due to this diverse nature of the load, full load power supply to all the customers at the same time is not required.

4.2 Diversity is a function therefore of how different load patterns coincide over time or not. Where customers have continuous or highly deterministic energy patterns the level of diversity will be low. Whereas networks with customers who have irregular or 'peaky' load patterns will tend to have higher levels of diversity. In very broad-brush terms, diversity is greatest at the LV domestic level, where maximum import/export requirements are not defined, and energy flows are sporadic. However, even where maximum import/exports are defined, different operating patterns will lead to the simultaneous maximums being less that the total of each individual maximum.

Nature of domestic network usage

4.3 A network supplying many customers exhibits readily discernible patterns (in this case, the classic 'tea-time' peak). However, an individual customer's peak is not as defined and can occur at any time throughout the day. In other words, it's not just how much a domestic customer uses but when they use it that summates to the overall network capacity requirement.

Figure 1: Maximum load for 1, 20 and 150 customers based on 1000 Monte Carlo Simulations (from 245 customer profiles). Each line represents aggregated maximum load for 20 or 150 customers divided by number of customers to represent single customer load for reference[1].



[1] Source: http://www.thamesvalleyvision.co.uk/

LV (domestic) network design

4.4 Conventional distribution network design is typically based on variations of the formula: *Capacity required = 16 + (n x 1.8) kVA,* where n is the number of customers. The values of 16 and 1.8 will vary from region to region reflecting the nature of customers served, housing type and, importantly, heating type. Computer software is typically used by most DNOs and makes provision for different loads.

4.5 Given the ongoing and forecast uptake of low carbon technologies, the after diversity maximum demand (ADMD) values have been revised to reflect the electrification of heat and transport, to accommodate heat pump technology and domestic Electric Vehicle Supply Equipment (EVSE) and EV charging equipment. This is to ensure adequate supply capacity is provided at the time of construction and to avoid network security and supply issues arising from thermal, voltage and fault level constraints. As an example one network company uses the following ADMD values for non-electrically and electrically heated homes, respectively:

Table 2: Example ADMD values for non-electrically heated homes

Type of Heating	Type of House	Annual Consumption (kWh)	ADMD(kW)
Gas Hot Water and Central Heating and/or 3kW Immersion Heater	≥ 5 Bedroom Property	5000	2
	3 Bedroom Detached property or 4 Bedroom property	4250	1.5
	1 Bedroom / 2 Bedroom property or 3 Bedroom Non-Detached property	3500	1.0

Table 3: Example ADMD values for electrically heated homes

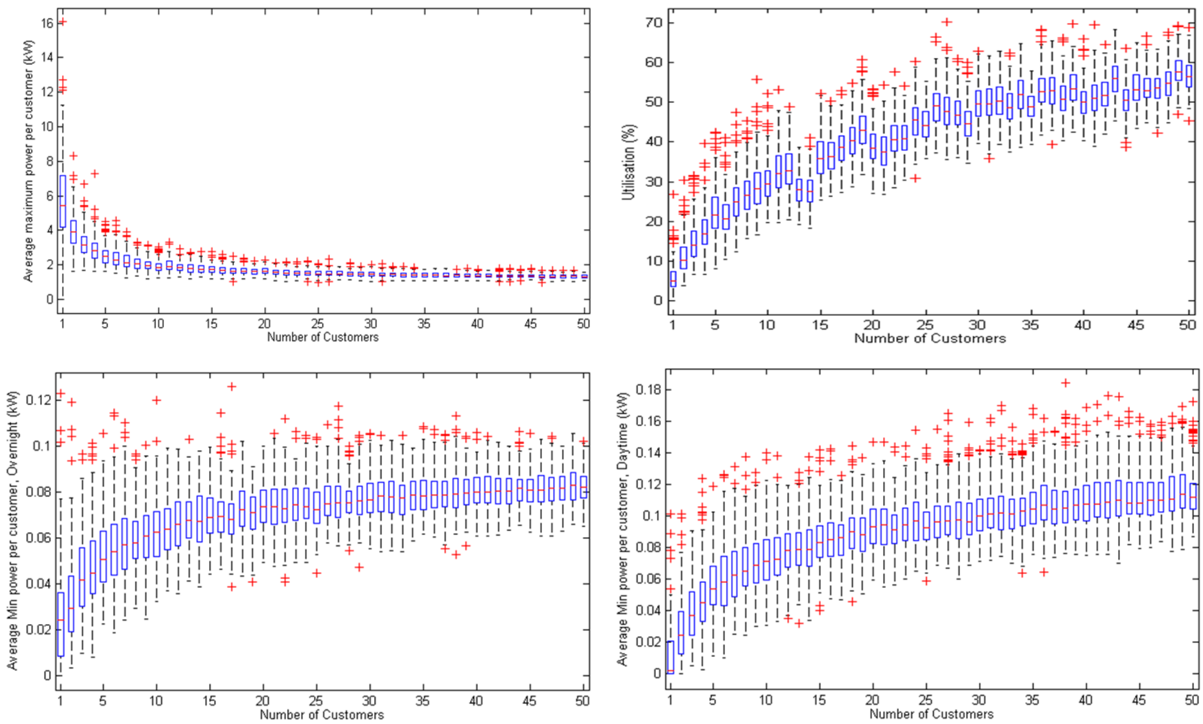
Type of Heating Scheme	H (kW)	ADMD (kW)
Water and Space Heating (Property EPC* Rating A-C)	Total heating load including water heating, storage and panel heaters	+ 0.5*H*
Storage radiators / panel heaters (Property EPC* Rating D-G)	Total heating load including water heating, storage and panel heaters	+0.6*H*
Electric Central Heating Boilers	Total value of installed storage space heating only	+ *H*
Heat Pump (air/ground source)	Total installed Heat Pump capacity	+ *H*
*EPC – Energy Performance Certificate; typically A-C for a new build property.		

4.6 The use of ADMD calculations are not typically extended by the network companies to include small-scale embedded generators, with the timing of peak demand rarely coinciding with that of, for example, high solar output.

4.7 The choice of fuse size does not impact network capacity planning assumptions. Network coordination and development is based on the nature of the electrical load connected. Fuses are sized to meet electrical protection requirements, i.e. sized to clear a short circuit fault given the prospective fault current at that point in the network and not to thermally limit the overall current taken by a service. In general terms, fuses are very poor at providing protection against overload, and may allow an overload condition to persist for several minutes or even hours, depending on the severity of overload.

4.8 The following four graphs further explore the cumulative effect of domestic customer usage. They have been generated by resampling many different combinations of actual energy usage to give the total capacity requirement for different counts of customers. This allows a statistical distribution to be developed (shown using box-plots with whiskers). The top two graphs focus on the peak demand requirement for a network. The bottom two graphs focus on the minimum demand which is always available to back-off generation.

Figure 2: Graphs showing cumulative effect of domestic customer usage



- **Top-left** - Shows peak capacity requirement divided by the number of customers served: i.e. for 1 customer we need to have a capacity of ~16kW, for 50 customers we need ~1.8kW per customer (90kW in total).
- **Top-right** - Graph illustrating the hypothetical utilisation of a network sized to exactly meet the demand requirement (where utilisation = volume of energy transferred divided by the maximum energy volume capability of network). Note: standard capacity options will mean the hypothetical utilisation is rarely achieved in practice i.e. for 1 customer utilisation could be near 0% but for 50 customers the utilisation could be as high as 70%. **Bottom-left** - Minimum demand requirement divided by the number of customers served i.e. for 1 customer the minimum capacity is 0 kW, for 50 customers the minimum capacity is around 0.06kW per customer (i.e. 3kW).

- **Bottom-right** - Day-time minimum demand requirement divided by the number of customers served: i.e. for 1 customer the minimum capacity is 0 kW, for 50 customers the minimum capacity is around 0.1kW per customer (i.e. 5kW). This implies 5kW of PV would be absorbed by a local network of 50 customers without any upstream power flow.

4.9 Whilst the behaviour of an individual customer could trigger reinforcement, the graphs illustrate that for, networks with multiple premises connected to them, it is more usual that reinforcement is driven by the behaviours of all customers and the cumulative impact that they have on system peak demand (locally, and in respect of higher network tiers, in aggregate with the behaviours of other customer groups). The effect is a statistical process which can be simplified to a first order polynomial. Therefore, in most cases, the behaviour of an individual customer's behaviour in isolation does not normally drive network reinforcement.

Extent to which changes on one part of the network affect other parts of the network

4.10 A new or changed connection is likely to change the power flows across the wider network. The extent to which these changes are relevant or impactful depends on the effects of scale and diversity.

4.11 The relatively small scale of a single domestic user means that changes to their usage will not even be visible at the primary substation that serves the town; whereas the scale of a large new housing development is very likely to have a noticeable effect on the local primary substation. The uptake of electric vehicles is predicted to have a substantial increase on demand, the impact of which will be dependent on when and where users charge their vehicles, and other social factors such as commuting distances.

4.12 The following table illustrates how individual user requirements require different network responses with respect to their individual location and the location of other users. Electric vehicle and increasing prevalence of embedded generation are likely to disrupt the methodology behind this table.

Table 4: Capacity planning considerations

	Capacity planning considerations			
Premises/ connection type	**for service cable / sole-user assets**	**for LV network**	**for HV network**	**for EHV network**
Domestic (LV)	Service cable/cut-out capability	ADMD (After Diversity Maximum Demand) of all connections	None – for single properties Quoted MD – for larger developments	None
Small non-domestic	Service cable/cut-out capability	ADMD (After Diversity Maximum Demand) of all connections	None – for single properties Quoted MD – for larger developments	None

Commercial/ industrial (Large LV)	Requested capacity	Requested Capacity + ADMD (if not on dedicated Tx)	Requested Capacity + HV Tx MD (if not on dedicated Tx)	None
Commercial/ industrial (HV)	Requested capacity	N/A	Requested Capacity + HV Group SMD	Subject to capacity requirement
Commercial/ industrial (EHV)	Requested capacity	N/A	N/A	Requested Capacity + EHV Group SMD

Transmission network design

4.13 Diversity is considered as part of each network study and it is dependent on the load characteristics of users connected to the network and the season. Typical analysis for a demand dominated network will consider the network extremes, winter maximum diverse load and summer minimum diverse load. For example, the winter maximum condition is set for full demand, minimum or no generation and the network assets set to winter ratings where applicable and is considered as a likely event. A similar approach might be applied in Summer where plant/line ratings will be reduced due to ambient temperature / solar gain. Maximum and minimum demands are updated yearly and are reflected in published Long-Term Development Statements.

4.14 At Transmission, for generation, assessments are made on local and wider areas of transmission networks in line with "Connect and Manage Guidance" (March 2013). For the wider areas, the security standard is first considered and then generation diversity is considered under a cost benefit analysis together with the annually updated Electricity Ten Year Statement Study Models. These factors are mainly based on the empirical data and operational experience. Under Connect and Manage, the Balancing Mechanism provides compensation to generation where restrictions on output are imposed by NGESO.

4.15 For the local areas models consider 100% of Transmission Entry Capacity (TEC), however as embedded generators mostly don't have TEC, the Statement of Works process will detail the volume of generation along with minimum demand figure for each GSP. These assumptions simulate the most onerous scenario with little diversity and work well for traditional Grid Supply Points (GSPs) where the group demand is much greater than the distributed generation. However, as the significant growth of distributed generation is affecting the transmission networks, it may be more appropriate to use local diversity factors provided sufficient control is available to ensure the network can always be operated safely particularly when the GSPs have comparable volume of distributed generation and group demand.

4.16 It is worth noting that a generator's output may change significantly from year to year and it is challenging to balance between the safety and the economy for Transmission Owners when considering the diversity factors in assessing new connections and planning. This is why it is important that there is visibility and control of small and medium sized generators (as defined by Grid Code).

4.17 For example, Scottish Hydro Electric Transmission (SHET) identifies the local and wider areas of transmission networks for the new generation connections, in line with "Connect and Manage Guidance" (March 2013). For the wider areas, SHET generally sets the fixed generation diversity scaling factors as shown in Table 5, used together with the annually updated Electricity Ten Year Statement Study Models. These factors are mainly based on the empirical data, operational experience in SHET network. The figures were last updated in 2016 and validated by 12 windfarms and 50 hydro schemes' measured data.

Table 5: Scaling factors for the SHET wider networks

Items	Diversity Scaling Factor
Demand	40% of Winter Peak Demand
Onshore Wind Generations	50% of Transmission Entry Capacity
Offshore Wind Generations	60% of Transmission Entry Capacity
Pumped Storage	50% of Transmission Entry Capacity
Other Generations (e.g. Hydro/Thermal)	40% of Transmission Entry Capacity

4.18 For the local areas, SHET used to apply 100% of Transmission Entry Capacity (TEC) for all the generations (including connected and new ones) and the minimum demand figure provided by the User, e.g. Scottish and Southern Energy Power Distribution (SHEPD). This assumption simulates the most onerous scenario with little diversity: the generations are exporting the theoretical maximum capacity whilst the demand is at the minimum level. This assumption works well for the traditional Grid Supply Points (GSPs) where the group demand is much greater than the distributed generations. However, the significant growth of distributed generations on SHET network calls for a more practical and economic assumption to take sufficient account of the local diversity factors particularly when the GSPs have comparable volume of distributed generations and group demand. SHET has been carrying out the new trials to reflect the diversity of distributed generations and demand at GSPs, which is based on the actual historical measurement data from the Network Management System for the net import/export power at GSPs.

5 Assessing Impact of new connections

5.1 This section describes how network companies assess the impact of new connections (generation and demand) and how these assumptions are applied in network planning, including when determining most efficient options, for example traditional reinforcement, flexible connection or flexibility services. It also considers where assessments are across network boundaries, transmission and distribution and embedded (IDNO) networks.

New connection options

5.2 Networks with new connections and/or general demand growth are designed to meet the requirements of the planning and security requirements described earlier in this report. Where a network is constrained the design options are to:

- reinforce to increase capacity in accordance with security of supply standards; or
- to flex within the existing requirements by either offering:
    - a flexible (non-firm) connection;
    - and/or contracting for flexibility services from other customers;
    - At transmission, constraints can be managed in real time through the balancing mechanism (BM) provided there is enough diversity in the area.

5.3 Network operators have a statutory duty to develop and maintain efficient, co-ordinated and economical systems. When offering new or augmented connections, network operators must base their offer to the customer on the least cost solution that will meet their needs and which will be compliant with relevant design standards technically acceptable design solutions (consistent with relevant design standards). If a customer requires a more secure design solution to meet their business case needs, they may be required to pay extra connection costs and/or ongoing use of system charges to meet these requirements.

5.4 In some circumstances flexible connection solutions can reduce the level of work that is required to provide a new or augmented connection whilst enabling the network to be managed within the network limitations necessary to maintain safe and reliable operation of the network within operational limits. In these circumstances the cost of providing and maintaining the connection could be lower. These flexible connections include a range of solutions including:

- Timed Capacity Connections;
- Export Limiting Devices;
- Local Management Schemes;
- Remote Inter-trip Schemes; and
- Active Network Management (Zones, Circuits and Local Schemes).

Determination of options and cross-boundary considerations

5.5 In England and Wales, the Transmission Impact Assessment (Appendix G) trial gives the DNO's a limit to how much generation can be connected, this allows distributed generation to be added to the networks without assessment of every connection. Once the DNO is close to meeting the limit, further assessment is undertaken to see if the limits can be changed. In Scotland the assessment of the impact of generation will include consideration by the network company of whether a reverse power flow is triggered at the T/D boundary and whether it can be reasonably expected that additional work is required on the transmission system as a result of its connection. In circumstances where either of these conditions are likely to occur a request for a Statement of Works will be submitted by the DNO to NGESO.

5.6 Individual network companies will each have their own investment decision making processes but in high level terms the approach will aim to make the most efficient network investments by assessing the trade-offs between network reinforcements (which typically have a long lifespan) and flexibility investments (which can scale and adjust from one year to the next). Engineering Recommendation P2/6 is undergoing review at present (to become P2/7) with the intention of allowing flexibility services as an alternative to conventional means of 'security of supply' in some circumstances.

5.7 In practical terms, there are geographical areas where the network status (either at T or D level) denotes that a flexible connection is the only connection practically available, for example where reinforcement costs are substantial enough to be prohibitive or cannot be undertaken within a reasonable time frame. Similarly, under a LIFO (Last In, First Off) arrangement there comes a point where the network does not have sufficient diversity to permit meaningful export capacity. A user's connection offer should reflect the access that they receive and therefore the costs of the connection.

Independent Network Operators (IDNOs) and Independent Connection Providers (ICPs)

5.8 Where an IDNO/ICP is involved in providing new connections to customers, typically the assessment of required capacity (for a given residential or industrial development) will be made by an ICP based upon information provided by the developer and in recognition of the design standards of the adopting network company. The ICP will generally make assumptions about the nature and type of load connected, in response to information provided by the developers.

5.9 The assumptions made by different ICPs may vary (for example in terms of allowances made for EV uptake), but in general an application will be made to the host DNO for a point of connection (POC), and (if available) a connection offer will be made for the requested capacity. The network company adopting the electrical assets will typically approve the design of the contestable asset works, other than in circumstances where the ICP has chosen to progress on the basis of self-assessment of contestable design. If capacity is not available, or several applications are received for connections to the same network, the host DNO will need to apportion the cost of associated reinforcement works, and/or will begin an 'interactivity process', the details of which are currently being explored by ENA Open Networks WS2.

5.10 In circumstances where an IDNO adopts the new network and operates it going forward, a bilateral connection agreement (BCA) with the host DNO will be put in place, defining the agreed power transfers (or maximum capacity) across the site boundary. In most cases there is no form of constraint, other than protection devices (typically fuses at LV, or protection relays at HV). As mentioned above, such control is very coarse, and unable to provide close limiting of load/generation.

5.11 LV services in particular are worthy of mention, as customers typically receive a 100A service (23kVA for single phase services). The cut-out fuse is not intended to load-limit and can allow significantly more current to flow (for prolonged timescales) before operating. This is often compared to some areas of mainland Europe where a customer is provided with a circuit breaker which will 'trip' immediately an agreed set-point is exceeded, providing a basic form of load limitation (and requiring manual reset by the customer).

Distribution Levels

5.12 System load data is critical to many business processes. Understanding, documenting, validating and tracking the demand on the network and the network components is critical to safe and efficient operation of the network and compliance with licence obligations.

5.13 An understanding of the historical performance is required as well as an understanding of the influencing factors which enable an estimate of future load to be made. The future demand estimation is therefore constructed from the following components:

1. Historical performance;
2. Basic background demand movements based on trends at a system wide level and high-level forecast change in background demand due to for example energy efficiency;
3. Impact of emerging and low carbon technologies (e.g. heat pumps, electric vehicles etc);
4. Local step changes arising from known developments (acquisition/disconnection etc). Where appropriate, this may include known or anticipated load step changes (at Primary Substation level and above) arising from future new connections or market intelligence via stakeholder engagement.

5.14 In order to assess the present and future demand on the network and at individual sites, a systematic approach is undertaken annually. For example, this assessment may consider the previous 12-month period (April-March) using the SCADA data along with metering data for all customers with an export MPAN. As well as the annual review of the network and prioritisation of the intervention plans, these annual assessments of maximum demand underpin wider business and stakeholder functions including the Week 24 data exchange to the Transmission System Operator.

5.15 At HV and above, a Normalised Maximum Demand (NMD) is calculated annually for each substation (or substation group). The NMD provides a baseline for the estimation of future demands. It may differ from observed maximum demand as it is: corrected for abnormal running; accounts for the presence of generation; and is compared against NMDs over recent years to identify anomalies and trends. Where generation is identifiable as connected but where there is limited or no access to data flows, the generic intermittency values outlined in EREC P2/6 are used.

5.16 When assessing the LV network, the design assumptions outlined in network companies' design policies are applied. These design assumptions (including the After Diversity Maximum Demand for different types of customers) have been built up over many years. These are periodically reviewed to account for changing customer behaviour, including for example more energy efficient domestic appliances or uptake of low carbon technologies such as electric vehicles. LCTs pose a challenge in that little or no historical information is available, and designers must work to 'best guess' principles until experience is gained.

5.17 Each year DNOs (not IDNOs) complete a review of their 132kV, EHV and HV network usage to produce a Long Term Development Statement (LTDS). The LTDS summarises seasonal capacity and power flow details for each Primary, BSP and GSP substation and interconnecting circuits. These values are then projected forward by considering historic trends and known changes (for example new connections). Through this annual iterative process, pre-connection assumptions are measured and refined post connection. Network companies do not directly forecast diversity per-se but instead forecast the resulting peak capacity requirements.

5.18 Where a customer has temporarily de-energised a site, for example on grounds of safety or where the customer wishes to carry out specific site works, the de-energisation is time bound and the assigned capacity continues to be included in making any network planning or investment decisions.

5.19 Whereas following a disconnection, the capacity is released and will be assumed unused in any network planning or investment decisions and the site will be required to apply again for any capacity needed at a future date. Studies may be required to assess network impacts on the HV and EHV networks following a disconnection. For example, reduced demand could cause local generation to overload the existing network if it was already near its limits.

5.20 A DNO dealing with a new connection request will typically assess capacity at a given point using historical data and applying a 'trend'. Often this approach does not consider whether a proportion of that capacity has previously been allocated to another customer / IDNO / ICP, yet remains unused and thus the DNO takes the risk that he/she re-allocates capacity that should be reserved. This is a business decision intended to provide design efficiencies and may mean that, in practice, available network capacity is allocated many times over.

5.21 The fact that a given 'design' ADMD does not appear in full, or might not be coincident with the peak demand on an upstream network, probably justifies the decision, but can be a risk if the load comes online over longer timescales than originally anticipated, for example a large development of several thousand houses may not see full load until 10 years after first becoming energised.

Transmission Levels

5.22 Scotland: Transmission diversity assumptions utilise fixed generation diversity scaling factors mainly based on the empirical data and operational experience in SHET network. The figures were last updated in 2016 and validated by 12 windfarms and 50 hydro schemes' measured data. Electricity Ten Year Statement Study Models are updated annually

5.23 Due to the lack of solid evidence/measured data reflecting the diversity for the contracted and new application generations, the 100% of TEC is still assumed at SHET. However SHET trials have shown that the present assumption generally underestimates the GSP's export capacity headroom.

5.24 The energy landscape is changing very quickly in GB due to the need to decarbonise the energy system. This creates uncertainty as to how the future energy system will develop because there are many different generation technologies that could help to achieve this. Which technologies are deployed will depend on several factors such as political support, economics, social acceptance and developments of the technologies themselves. To help reflect this uncertainty, National Grid ESO develop a range of scenarios to assess the future needs of the network against the different generation mixes as a single view is unlikely to be correct. These are produced in the Future Energy Scenarios (FES). The scenarios are developed with the intention of covering the credible range of uncertainty. This means, NGESO expect the future generation mix to be within the range of the scenarios, although the actual outcome may not align to any one specific scenario.

5.25 The diversity of the generation mix in FES is developed by a combination of internal modelling, market intelligence of projects being developed and stakeholder engagement. The diversity of the generation mix is informed by the scenario framework, which is used to determine which types of generation will be more prominent in each scenario. This ensures NGESO reflects the range of uncertainty across the scenarios. The FES also includes scenarios with different levels of distribution-connected generation. This was brought out explicitly in changes to the scenario framework in FES 2018, in which two scenarios had very high levels of distributed capacity (up to 65% by 2050). Full details of the future diversity of generation can be found in the data workbook published on the FES website[2]**Error! Bookmark not defined.**, with the future generation mix provided in tab ES1 of the FES Data Workbook.

[2] http://fes.nationalgrid.com/media/1366/2018-fes-charts-v2_as-published.xlsx

5.26 It is difficult to compare the difference between forecast and actual diversity in a reliable manner. This is because FES has only been produced since 2011 meaning that there is a limited period in which to make the comparison with actuals. In addition, both modelling and stakeholder engagement have improved significantly over the period, meaning that the current FES process is now very different. The implementation of Electricity Market Reform, including both the Capacity Market and Contracts for Difference, has provided greater certainty to power station owners and project developers, which is reflected in the scenarios. However, there are potential changes in policy, regulation and technology, which can lead to significant changes over a short period. One example is solar, which has increased significantly in recent years to over 12 GW today, yet FES 2014 assumed a range of around 4 – 6 GW. NGESO has now obtained access to better data sources and this is an area that it continues to develop.

5.27 Stakeholder engagement plays a key role in helping to validate and update the assumptions. In developing FES 2018, the NGESO engaged with over 650 stakeholders representing 430 organisations through a range of workshops, conferences, webinars and bilateral meetings. This helped to ensure it better understands the drivers that could impact the diversity of future generation to inform its modelling.

Diversity assumptions used in planning and assessing new transmission connection applications

5.28 In respect to assessing new connection applications and planning for the level of network reinforcement, the FES scenarios are used as reference to set up a range of shorter-term generation and demand scenarios for which analysis is undertaken. The principles laid out in the SQSS are used to study a range of conditions which ought reasonably to be foreseen to arise in the course of a year of operation.

5.29 More recently, a probabilistic approach has been taken to set generation output for planning purposes which inherently considers the diversity of generation by estimating actual outputs from generators in a given geographic area over a given time period. This is based on historical conditions, typical operating patterns of generators and probability density functions to create an onerous but credible scenario for planning studies. The data used in the probabilistic assessment described above comes where possible from actual data with each scenario being checked by an engineer to ensure it is sensible and credible.

How would better defined access options affect the level of diversity? How would this affect DNOs' network planning?

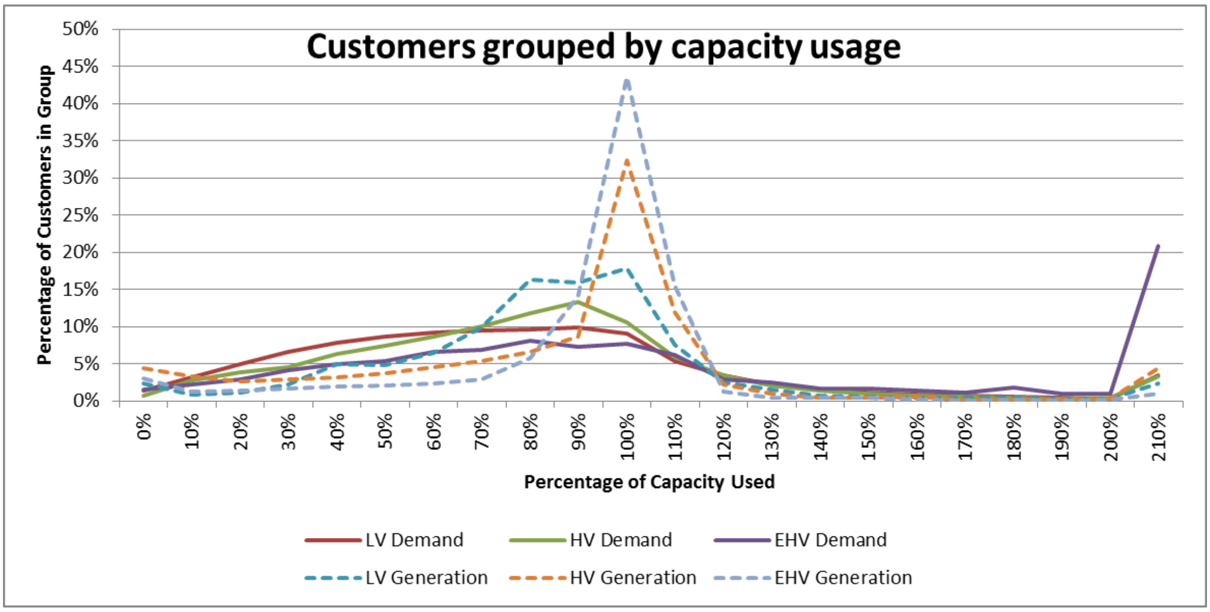
5.30 For an individual customer, diversity is inversely associated with utilisation. When utilisation of a customer's agreed maximum capacity increases to 100%, diversity ceases to be a relevant factor, or putting it another way, a high degree of diversity implies a low degree of utilisation. Better definition of access (e.g. time-of-day capacity limits) suggests that utilisation within the bounds of the definition would be higher – and hence diversity lower. Where networks serve more than one customer, analysis of diversity permits the network to be built with less spare capacity and hence connect more customers for the same level of peak utilisation. Diversity will be reduced where common behaviours are apparent – for example off peak heating or solar power export.

5.31 Table 6 and Figure 3 below show customers across all the DNOs grouped into 10% bands based on the proportion of maximum capacity which was used in the 12 months from October 2017, and split into HH LV demand, HV demand, EHV demand, HH LV generation, HV generation and EHV generation categories.

Table 6: Count of GB Customers by Percentage of Capacity Used

	0-50%		50-100%		100-150%		150%-200%		>200%	
	Number	*% of Group*	**Number**	*% of Group*	**Number**	*% of Group*	**Number**	*% of Group*	**Number**	*% of Group*
HH LV Demand	59,393	*32.8%*	85,544	*47.2%*	24,926	*13.7%*	5,237	*2.9%*	6,214	*3.4%*
HV Demand	6,184	*25.6%*	13,154	*54.5%*	3,381	*14.0%*	609	*2.5%*	807	*3.3%*
EHV Demand	364	*21.3%*	627	*36.6%*	255	*14.9%*	110	*6.4%*	356	*20.8%*
HH LV Generation	1,119	*16.4%*	4,534	*66.5%*	877	*12.9%*	128	*1.9%*	159	*2.3%*
HV Generation	610	*20.3%*	1,730	*57.7%*	481	*16.0%*	44	*1.5%*	133	*4.4%*
EHV Generation	149	*11.5%*	892	*68.8%*	235	*18.1%*	8	*0.6%*	13	*1.0%*

Figure 3: Percentage of capacity used by customer group



5.32 As the graph illustrates, most customers maintain utilisation within their allocated capacity, but that there is also a notable share of customers who exceed their agreed allocation by more than double. For generation customers, utilisation is strongly centred around 100%, whereas with demand customers, utilisation is more widely distributed up to 100%.

5.33 Depending on how 'Access' is further defined, it is likely that diversity assumptions will be reduced but may not be eliminated, with network companies continuing to need to assess the risk and mitigate for usage that is either outside an agreed allocation or significantly under it (for example where local demand is used to net-off local generation behind a constraint.

5.34 Likewise, network companies must still plan and account for common mode behaviours within customer energy patterns; for example off-peak heating is very prevalent in SSEN's SHEPD distribution service area where the Radio Teleswitch Service (RTS) is utilised to diversify space and water heating. If all customers' heating demands were coincident it would lead to significant capacity limitations. Similarly, little or no diversity is to be expected with EV charging (depending on the charger type/capacity) where the charge period may be several hours or more. Greater diversity is expected with faster charge rates.

Key factors and variables which affect the planning assumptions made by Network Operators for different types of network user:

	Relevance to Transmission and/or Distribution voltages?
Customer requirements - some customers (particularly small users) may be unable to define and keep within precise requirements. Without precise definition, DNOs necessarily apply diversity assessment in the provision of capacity (see paragraph 4.3 above).	**Distribution**
Changing requirements – particularly with small users and even HV users to come extent, changes to an initial requirement or operating pattern are not predictable and limited mechanisms exist for customers to make these changes known to a network operator.	**Distribution**
Common mode or correlated behaviours – which can include off-peak heating patterns, day-night generation production, air-conditioning loads, national or community events and production or process relationships (for example where a demand on one part of a customer's installation is tightly related to generation from, say CHP, at another part of their site)	**Distribution and Transmission (if at scale)**
Cyclic operating patterns – low utilisation patterns permit networks to operate at higher peak capacities through the application of cyclic duties. Higher utilisations reduce cooling periods and reduce overall peak ratings.	**Distribution**
Network monitoring – dependent on size of the connection and the 'requirement' for controllable access. Bespoke monitoring per connection could be costly or even prohibitive for small/domestic connections. In the absence of monitoring designs necessarily need to mitigate for higher degrees of variability.	**Distribution**
Network topology and design – some networks have inherent properties which can absorb more variability, whereas others may be constrained through to limited capacity and/or high utilisation.	**Distribution (and Transmission)**
Reserved Capacity - customers may have reserved capacity on the network, e.g. firm connections. Regardless of whether this is currently being utilised or not it must be taken account of.	**Transmission and Distribution**
Smart Technologies – e.g. controlled EV charging points, or flexibility services / demand side management are expected to become increasingly relevant, particularly if combined with future roll-out of smart meters.	**Distribution**
Weather events – some weather events can produce unexpected behaviour which needs to be considered; for example one DNO has noted that recent 'storm warnings' provoked a rash of EV charging and noticeable increase in demand prior to gales/storm event.	**Distribution (and Transmission)**

Constraint Management - There is a physical limit to the amount of power which can be transmitted through any piece of equipment on the network, when this limit is reached, it results in a constraint boundary. To remove the constraint boundary either the amount of power needs to be reduced or additional network reinforcement undertaken to increase the network's limit. Boundary capability is the maximum power transfer that can be achieved across the network while adhering to the SQSS requirements. The typical limitations of boundary capability are thermal circuit loading, voltage compliance or dynamic stability. To support development of wider network reinforcement options, NGESO perform an annual cost-benefit analysis on major constraint boundaries to compare the expected long-term constraint costs (i.e. paying generators to reduce their output) with the reinforcement investment cost – this cost benefit analysis is part of the Network Options Assessment (NOA)[3]. NOA recommends the most economic option to proceed with to meet the expected bulk power transfer requirements as outlined by the Electricity Ten Year Statement (ETYS)[4]. Also, NOA recommends what reinforcement options the (TOs) should start, continue, delay or stop (including Strategic Wider Works) to ensure they are completed at a time that will maximise consumer benefit. In addition, NOA indicates to the market the optimum level of interconnection to other European electricity grids – as well as any reinforcements required to facilitate those interconnections – to maximise European socio-economic welfare based on market-driven analysis.	**Transmission (and Distribution)**
Voltage Control - Reactive power services are how NGESO make sure voltage levels on the NETS remain within a given range, above or below nominal voltage levels. Instructions are issued to generators or other asset owners to either absorb or generate reactive power. Managing voltage levels comes from maintaining a balance between elements on the system, which either absorb reactive power (decreasing voltage) or generate reactive power (increasing voltage). Reactive power exports from distribution networks can exacerbate high voltage issues on the transmission network. Recorded data of reactive power flows at selected Grid Supply Points[5] indicate that there are more frequent instances where distribution networks are exporting reactive power onto the transmission network. The Energy Networks Association high volts working group acknowledged in their technical feasibility report in 2016[6] that the increased penetration of distributed generation was a contributing factor to the reactive power transfer from DNO's network to the NETS at the grid supply point. The growth of distributed generation has in many cases resulted in a reduction in active power demands seen at the transmission level. This causes flows on the transmission network to reduce which can cause lightly loaded circuits to generate reactive power which further exacerbates high voltage issues on the NETS.	**Transmission (and Distribution)**

[3] Network Options Assessment (NOA) - https://www.nationalgrideso.com/insights/network-options-assessment-noa
[4] Electricity Ten Year Statement (ETYS) - https://www.nationalgrideso.com/insights/electricity-ten-year-statement-etys
[5] A Grid Supply Point (GSP) is a point of connection from a DNO's network to the NETS.
[6] ENA High Volts Working Group Technical Feasibility Report - http://www.energynetworks.org/assets/files/news/publications/Reports/ENA%20HVWG%20Report%20Final.pdf

As illustrated in the Product Roadmap for Reactive Power[7] and the System Needs and Product Strategy (SNaPS) documents[8], there is a growing need for the absorption of reactive power which is a result of lower transmission demands, increased reactive power injections from distribution networks and changing demand patterns. Furthermore, with the more frequent displacement of large synchronous generators and less predictable power flows, the need for flexible reactive support will also increase. This trend is expected to continue for the foreseeable future which means that costs are likely to be incurred by NGESO to keep voltages within statutory limits. NGESO are developing new assessment and commercial procurement processes to enable them to evaluate and access a broader range of options for reactive power services which will deliver more value to consumers. More details can be found in the NGESO Product Roadmap for Reactive Power[9] and the Network Development Roadmap[10]. At distribution most connections are encouraged to keep within a power-factor of 0.95 (lead or lag). However there is provision to specify wider reactive power ranges or operating requirements to provide, says, voltage support if network topology requires this.	
Frequency Control - NGESO have a licence obligation to control NETS frequency at 50Hz (plus or minus 1%) by making sure there is sufficient generation and demand held in readiness to manage all credible circumstances that might result in frequency variations. The transition to renewable-based generation, including a large proportion of distributed generation, as well as increased interconnection to external power systems have led to a decline in system inertia due to their different characteristics compared to traditional thermal generation. A reduction in system inertia results in the NETS's frequency becoming more sensitive to distortions and increased rates of change[11] which has an impact on the level and speed of response required to maintain frequency within safe limits. This poses additional challenges when it comes to maintaining frequency within limits and so NGESO has needed to procure faster frequency control products via ancillary services to help mitigate the reducing system inertia. Renewable sources of energy such as wind and solar, being intermittent in nature, have contributed to an increase in volatility of power generation and a reduction in its predictability, resulting in more reserve and response products procured required to cater for swings in generation output and demand as well as uncertainties in generation/demand forecasting. Furthermore, as more electricity demand is being met by distributed generation, of which some are not currently required to provide frequency response, the liquidity in the number of options available to NGESO to	**Transmission**

[7] Reactive Power Roadmap - https://www.nationalgrideso.com/sites/eso/files/documents/National%20Grid%20SO%20Product%20Roadmap%20for%20Reactive%20Power.pdf

[8] System Needs and Product Strategy (SNaPS) - https://www.nationalgrideso.com/sites/eso/files/documents/8589940795-System%20Needs%20and%20Product%20Strategy%20-%20Final.pdf

[9] Product Roadmap for Reactive Power - https://www.nationalgrideso.com/sites/eso/files/documents/National%20Grid%20SO%20Product%20Roadmap%20for%20Reactive%20Power.pdf

[10] Network Development Roadmap - https://www.nationalgrideso.com/sites/eso/files/documents/Network%20Development%20Roadmap%20-%20Confirming%20the%20direction%20July%202018.pdf

[11] Also known as RoCoF (Rate of Change of Frequency).

control frequency is reduced. NGESO is working on redesigning the response and reserve markets to address these challenges whilst facilitating access for new participants to these markets**Error! Bookmark not defined.** as detailed in the Operability Strategy Report[12] and System Needs and Product Strategy[13]	
System Stability - Synchronous generators have an inherent stabilising effect which helps to reinstate the electricity system to a suitable operating condition following a disturbance, for example a system fault. In some cases, the transition to non-synchronous generators (e.g. solar and wind) can inadvertently cause the system to become less stable. The subject of stability is quite broad and covers a range of topics, these are explained further in the Operability Strategy Report 2018[12] and the suite of System Operability Framework documents[14]. As more work in this area is undertaken to monitor the situation and understand the challenge, as well as exploring innovative solutions, NGESO is likely to have to intervene at certain times to ensure the system remains stable. System stability can be a concern at distribution for particular combinations of network topology and spinning inertias.	**Transmission (and Distribution)**
Restoration - NGESO has the responsibility of ensuring that there are robust plans in place to restore power supplies to the GB system in the unlikely event of a partial or complete system shutdown. These plans rely on Black Start contracts to be established with suitable providers. The costs incurred by NGESO for the provision of Black Start services are described in the Black Start Allowed Revenue report[15]. The current restoration plans rely on conventional large synchronous generators. With the transition to a more renewable-based and decentralised generation mix, new approaches to restoration are being developed alongside investigations into the capability of different generation technologies to provide Black Start services. This responsibility extends to distribution companies for systems which are normally sperate from the GB grid (i.e. islands etc).	**Transmission (and Distribution)**
Balancing Costs - The quantity of embedded generation accessible and useable to NGESO for network management will influence the cost of managing the NETS. Currently the vast majority of distributed generation is not accessible or useable to NGESO and so cannot be used to support operation of the NETS. The Wider Access to the Balancing Mechanism Roadmap[16] shows NGESO's intent to allow these parties to provide services to NGESO. As a greater number of providers are able and willing to provide services to NGESO for network management, the increased competition should help minimise any upward cost pressure, however a lack of competitive pressure is likely to reduce this effect. The amount of competition may vary across the products NGESO look to procure due to some services requiring specific requirements which only a subset of	**Transmission**

[12] Operability Strategy Report - https://www.nationalgrideso.com/node/134161
[13] SNAPS - https://www.nationalgrideso.com/node/84261
[14] System Operability Framework (SOF) - https://www.nationalgrideso.com/insights/system-operability-framework-sof
[15] Black Start Allowed Revenue Report - https://www.nationalgrideso.com/balancing-services/system-security-services/black-start?market-information
[16] Wider Access to the Balancing Mechanism Roadmap - https://www.nationalgrid.com/sites/default/files/documents/Wider%20BM%20Access%20Roadmap_FINAL.pdf

generators will meet; for example, constraint management services can only be provided by generators located in a constrained area. The main system balancing cost witnessed by NGESO is constraint management with the majority of constraint costs attributed to the Scotland-England boundary. Actions have also been required to manage the south-east corner when interconnectors have been exporting, and a volume of management actions needed for system inertia during periods of high wind and solar output alongside low NETS demand. Historic costs associated with balancing the GB transmission system, including quantity of services procured and the value of these services are published on NGESO's website in the Monthly Balancing Services Statement (MBSS)[17] along with other BSUoS reports[18] with the costs broken down into different cost categories.	

Drivers of constraint and potential to managed through access options

5.35 A constrained network is defined as being a network with an asset or number of assets that are close to or exceeding their rated capability in terms of thermal capacity and/or fault level capability. Constraints can occur due to voltage and power quality (e.g. flicker) where a new connection on the network may cause the network to operate outside of voltage standards; LV +10% -6%, HV ±6% and EHV ±6%. Constraints can also be driven by other power quality factors such as Harmonics, flicker and dips. In most cases, at lower voltage levels, such constraints are not automatically applied and tend to be only in response to customer complaints or network events.

5.36 By better defining individual requirements and their broader community interaction, it may be possible to use more of the existing infrastructure, to the extent that a customer is able to define and keep within a stated requirement.

5.37 Triggers to constraints are driven by demand and generation connections, and also through reductions in demand and/or generation. Each connection type can cause different constraints in any given network, examples are as follows:

- Increased generation could cause thermal, power quality, voltage and fault level constraints.
- Increased demand could cause thermal, power quality and voltage constraints. However, for demands that are connecting large motor or variable speed drive they too could impact fault level.
- A decrease and/or disconnection of demand could trigger generation to be constrained due to thermal and voltage constraint.
- The conversion of existing demand or generation to a flexible arrangement in response to national markets could trigger thermal and voltage constraints, as a result of higher utilisation.

5.38 Access options may be aligned with the following network constraints with temporal definition of maximum and minimum export and import patterns:

- Thermal capability, and
- Voltage limits and dips.

[17] Monthly Balancing Services Statement (MBSS) - https://www.nationalgrideso.com/balancing-data/system-balancing-reports
[18] BSUoS reports - https://www.nationalgrideso.com/balancing-data/forecast-volumes-and-costs

5.39 Access options are unlikely to be aligned with the following network constraints as they are more of a function of network impedance and spinning inertia or non-linear responses rather than power transfer, though it is possible to envisage some form of a more binary access definition:

- Fault level capability, and
- Power quality/harmonics distortion limits.

5.40 Major constraint regions across Great Britain that the NGESO expects are;

- Increasing quantities of both transmission and distribution connected wind generation across the Scottish networks with limited capacity to transfer this power to England. There is potential for this north-to-south transfer to double in requirements within ten years.
- A potential growth of low carbon generation and interconnectors in the north of England, combined with the increase in Scottish generation mentioned above, will increase transfer requirements into the English Midlands from Northern England and Scotland.
- Potentially high growth in the generation coming from offshore wind on the east coast near East Anglia risks stressing this region of the network.
- The high volume of distributed generation connected along the south coast of England & Wales is challenging to manage for both the transmission and distribution networks whilst new interconnectors with Europe will place additional stress on the transmission network in the same areas.
- In the South West, the predicted growth in distributed generation can potentially become challenging to manage beyond 2020 especially at times of coincident windy and sunny days

5.41 A joint transmission and distribution network analysis conducted as part of the Regional Development Programme (RDP)[19] identified that:

- Many of the distributed generators which cause constraint issues on the distribution network will also cause similar constraint issues on the local transmission network, and
- There is a risk of fast voltage collapse and uncontrolled disconnection of distributed generation due to under-voltage protection for transmission circuit faults and outage combinations.

5.42 The RDP analysis also demonstrated that a "Whole System" solution of enabling visibility and control of distributed generation provides better value to the consumer and project developers in the management of constraints on the transmission network. The costs incurred will be the development of sophisticated systems to monitor and control the output of distributed generation and in the payment of compensation should these generators be constrained, similar to the arrangements already in place with transmission connected generators via the Balancing Mechanism.

How approaches differ for generation / demand and by size of user. [How planning and investment approaches account for the different access allocation processes - queue vs notification procedure]

5.43 The approach to network planning and investment is a function of the predictability of the customers' requirement. This can be considered in terms of:

- the customer's ability to define and manage within a specific pattern ie the more readily a requirement can be defined the more specific a network design can be. If the requirement is not well defined, then allowances and safety factors will be required.
- notice and/or acceptance of a new energy requirement ie in situations where energy requirements can change without notice or where the notice is post-event, then network

[19] Regional Development Plans (RDP) - https://www.nationalgrideso.com/insights/whole-electricity-system/regional-development-programmes

design will require more allowances and safety factors. Where specific acceptance and allocation process exist, the increased visibility allows far more specific network design.

5.44 Traditionally, you could expect small users to show a lower ability to define and manage an energy requirement and for the network company to have little notice of changed requirements; and for larger users to have well defined requirements which are understood well in advance. However, this is not necessarily the case – intermittent and or traded parties at higher voltages may have highly variable network requirements; and future deployments of demand-side management may result in highly predictable requirements for smaller users.

5.45 The 'size' of a customer might be an indicator of the required planning and investment approach - however it is clearer to refer to the customers' ability to define and give notice of their requirements.

How distribution users' (IDNO and DNO connected users) access to the transmission system currently defined?

5.46 Access to the transmission system for the vast majority of distribution connected users is not defined as is not provided for in current rules. The exception being large users (>100MW NGET, >30MW SPT, >10MW SHET & OFTOs) and any distribution connected users who opt to have a Bilateral Embedded Generator Agreement (BEGA) are contracted for Transmission Entry Capacity (TEC) which defines their access to the transmission system.

5.47 Distribution users, whether connected to DNO or IDNO networks, are either connected via the Electricity Act (Section 16) or through connection adoption via independent connection providers IPCs. Irrespective of the route to connection, once the user is connected to the distribution system the terms of use are contained in the National Terms of Connection (NTC), which for larger sites may be supplemented by additional site specific technical conditions. (http://www.connectionterms.org.uk/Schedule%202B%20National%20Terms%20of%20Connection%20v10-min.pdf).

5.48 The definition of 'Connect' in the NTC means the installation of the Connection Equipment in such a way that (subject to Energisation) electricity may be imported to, and/or exported from, the Customer's Installation over the Distribution System at the Connection Point.

5.49 For the connection of 'Relevant' embedded generation[20] (with potential of greater than £10k impact on the GB transmission system) a DNO is required to apply for a Statement of Works which provides for an assessment of the impact of generation on the transmission system. Whilst the Statement of Works process will identify whether transmission system works are required to facilitate a given connection, access rights to the transmission system for distribution users can only be obtained by distributed generation parties who enter into a BEGA with NGESO. For distribution connected demand users, no formal transmission access is defined.

5.50 From a demand perspective, the capability of the asset restricts access to the transmission system. There is no demand TEC at a transmission level therefore week 42 data from the DNOs is used to understand what is connected at a point in time and whether any reinforcement is needed.

[20] *National Grid ESO has been working with DNO's to develop an alternative to the Statement of Works Process. This currently exists as the 'Appendix G' process and is being developed as part of CMP192. Whilst not explicitly defining access, it does provide for where a DNO is able to permit the connection of generation at distribution.

6 Conclusion and Overview

6.1 This report has sought to provide explanation of the approaches taken by the GB network companies on the areas listed below and the foundations upon which they are based. An understanding of these key factors and how they impact the planning assumptions made by network operators is essential in taking forward the Access working group's second Report, which considers:

- the development of access choice design;
- consideration of improvements to cross-system access; and
- the assessment of access choice and standardisation,

Planning and Security Standards

6.2 The design and operation of the distribution system is prescribed in the Electricity Safety, Quality and Continuity Regulations 2002 (ESQCR). The Distribution Code lists various mandatory design documents, including Engineering Recommendation P2 (EREC P2).

6.3 The Security and Quality of Supply Standards (SQSS) set out the criteria and methodology for planning and operating the National Electricity Transmission System (NETS).

Diversity Assumptions

6.4 The application of diversity (through After Diversity Maximum Demand (ADMD)) is primarily applied by DNOs to connections of domestic LV customers. The application of ADMD is not typically extended to include small-scale generation.

6.5 At transmission, analysis for demand dominated networks is based upon network extremes, e.g. winter maximum diverse load and summer minimum diverse load. Generation assessments are made on local and wider areas of transmission networks in line with "Connect and Manage Guidance".

Assessment of impact of new connections

6.6 DNOs' investment decision making processes aim to make the most efficient network investments by assessing the trade-offs between network reinforcements and flexibility investments. The establishment of Engineering Recommendation P2/7 will consider the use of flexibility services as an alternative to conventional means of 'security of supply'.

6.7 NGESO produces Future Energy Scenarios (FES) which establishes a range of scenarios to assess the future needs of the network against different generation mixes. These FES scenarios are used as the basis of analysis to consider future transmission network reinforcement requirements. For the same reasons some DNOs have produced their own Distribution Future Electricity Scenarios (DFES).

Annex 1 – Product Description

Title	**Access arrangements**
Objective	To better understand how access rights and user characteristics are currently taken into account when planning the system, to understand the value of improved access choice and definition. To better understand the access choice design options, so that we can better analyse the value of these options. This includes considering the extent to which access choices are standardised and the extent to which they provide clarity about whole system access.
Acceptance criteria	**A publishable report on current arrangements to design the system and manage constraints.** • What do planning and security standards prescribe currently? This should also capture known future changes (e.g. P2/7 and other). • What are the diversity assumptions used at distribution and transmission? • How do network companies assess the impact of new connections and apply these assumptions in planning (e.g. need for reinforcement/flexibility), including across the T / D and DNO /IDNO boundary? This should cover both generation and demand. • How do network companies treat / assess flexibility, including current arrangements for visibility and coordination across the system (considering how this changes by voltage level)? • How are these assumptions validated and updated? Is there a difference between forecasts of diversity and network capacity requirements compared to actual figures? To capture behaviours and how treated – start with RFI information • What are the key factors / variables which affect the planning assumptions network operators make for different types of network user? • What are the drivers of constraint and which could be defined into access options / managed through access options? • How do these approaches differ for generation / demand and by size of user? How do planning and investment approaches account for the different access allocation processes - queue vs notification procedure? • How would better defined access options affect the level of diversity for both D & T? How would this affect network operators' network planning for different users? [consider as part of 2nd report?] • How is distribution users' (IDNO and DNO connected users) access to the transmission system currently defined? • How is transmission users' access to the distribution system (DNO and IDNO) currently defined? • How is distributor (DNO and IDNO) access to the transmission system currently defined? • How is IDNO access to the DNO's network currently defined? • How do approaches to planning or security standards and planning processes differ at distribution and transmission? • How does planning and capacity allocation work across the boundary? • How much design practice by DNOs / IDNOs is common? How much is left up to DNOs individual approaches? This should consider current utilisation by different users (default assumption and then identify departures). What are key areas of inconsistency / similarity? • By way of conclusion – qualitatively, how would better defined access options affect the level of diversity, considering the guiding principles set out on Ofgem's SCR launch document? How would this affect DNOs' network planning? What questions does this raise for the assessment of options?

High-level timescales (Secretariat to develop detailed project plan).	• 21 Jan - Launch sub-group • 25 Jan - Finalise sub-group members and product description • 13 Feb - Initial drafts of two draft deliverable documents • 26 Feb - Present two draft deliverable documents to Challenge Group • 01 Apr – Final draft of Report 1 and a draft of Report 2 shared with Delivery Group • Apr 19 - Final reports circulated to Ofgem
Dependencies - takes input from	Uses data from the information request.
Dependencies - provides input to	Informs the development of all the other access products.
Which DG members should be involved?	All network companies and NGESO.
Ofgem Lead	Amy/Stephen
Internal or external	External
Any comments on methodology used	The assessment should be against the guiding principles and should be in a format that we can update as we get further information.
Other comments	Initial thinking on design options: **Firmness** • How curtailment level is defined (e.g. a numerical cap (e.g. instances, kWh, frequency, duration) or a limit on cause of curtailment)? • What happens when curtailment level exceeded? (e.g. trigger for investment, payment to customer) • Whether firmness is based on a planning standard or not? And if so how (e.g. derogations as per SQSS, or alternatives embedded in the standard, changes to the nature of what the standard prescribes)? • Any associated conditions of access **Time profiled** • Granularity of time profiled access rights • What happens if access level is exceeded? • Any associated conditions of access **Shared access** • Any thresholds on the extent to which access can be shared (e.g. capacity, geographical region) • What access rights could be shared? • What happens if access level is exceeded? • The process for finding users to share access with • Any associated conditions of access **Access thresholds for small users** • Options for how thresholds could be set (e.g. capacity threshold, volume threshold, minimum number of instances above a threshold at peak) • Initial view on pros and cons, considering system impacts or conditions where they would apply

	Other basic parameters • how import / export rights are defined (e.g. separately / together, implicit / explicit, dependent on primary purpose?) • power factor • how implicitly / explicitly access is defined • interactions with access allocation processes – e.g. queue vs notification procedure. • other conditions **If time/resource allows, then the report would also cover options for short-term duration:** • Circumstance when short term access is made available (e.g. anytime or only short-term release of additional capacity) • What happens if access level is exceeded? • • Duration of access right (E.g. within year, a year, or several years)