FRAZER-NASH CONSULTANCY

Electricity Engineering Standards Review

Technical Analysis of Topic Areas

Report prepared for BEIS

Final

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SYSTEMS AND ENGINEERING TECHNOLOGY

Authors

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During the project, Frazer-Nash and the Panel engaged a number of industry stakeholders. We would like to acknowledge all those who engaged and thank them for the input provided.

We are also grateful for the support provided by BEIS and Ofgem in delivering this work.

Please note

EXECUTIVE SUMMARY

The UK government has commissioned an independent panel of experts to conduct an Electricity Engineering Standards Review[1]. Frazer-Nash consultancy has provided technical support to the expert panel throughout the review.

This report summarises our analysis across six key topic areas related to the supply of electricity. These are:

- Voltage limits;
- Frequency, operability and stability;
- Reliability and security of supply;
- Resilience and black start;
- Network capacity for new developments and network reinforcements; and,
- Smart energy system interoperability.

We have mapped out relevant engineering standards for each topic area. We then identified opportunities for change and analysed evidence to establish benefits and risks. The analysis conducted was broad ranging and identified a number of opportunities for change within the electrical system which would create benefit. Key opportunities we have identified include:

- The reduction of voltage limits within ESQCR – this facilitates a range of benefits relating to energy efficiency, increased capacity for new load and increased connection of renewable generation;
- Redefining the Value of Lost Load to better reflect the value of electricity to consumers and of flexibility. The system requirement for supply availability (which is incentivised), security of supply (which is standardised) and resilience (the black start elements of which are soon to be standardised) will all flow from this;
- The development of a set of well-defined interoperability standards to enable system flexibility and consumer services. This should ensure coverage of all relevant system use cases to avoid emergent issues during implementation; and,
- Ensuring that long term views are taken for new developments and asset reinforcement; this is likely to drive the installation of larger components (e.g. conductors) to achieve through life cost benefits.

In many cases the industry has made efforts to capitalise on these opportunities, either through recent changes to standards, ongoing initiatives to change standards or through innovation projects. Other BEIS funded work is also ongoing which will facilitate the materialisation of these opportunities. However solutions must be adopted consistently and at scale to realise the potential benefits.

The conclusions from this technical report will inform the recommendations made by the independent panel of experts in support of the realisation of the benefits identified.

[1] https://www.gov.uk/government/publications/electrical-engineering-standards-independent-review

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1. INTRODUCTION

1.1 OBJECTIVES OF THE REVIEW

BEIS and Ofgem established an independent Panel to review electricity system standards. The purpose of The Panel was to assess how planning, operation and investment engineering standards should be updated, with a view to maintaining the high levels of security of supply currently provided to consumers at lower cost and achieving net zero greenhouse gas emissions by 2050 in Great Britain as whole. To realise this goal, BEIS selected Frazer-Nash to undertake research and project planning work to support the Panel.

The fundamental objectives of the Panel are to:

- Identify where current standards are locking in cost to Great Britain's consumers, or may be insufficiently flexible to facilitate the transition to a decarbonised electricity system; and,
- Make actionable recommendations to relieve these issues or constraints

These recommendations should seek to address:

- Technical changes which could be addressed in the short-term (i.e. within the current standards landscape); and,
- More fundamental changes to the engineering standards landscape and the process of engineering standards governance which will support the long-term needs of customers and facilitate the transition to a decarbonised electricity system.

The timing of this review is such that it is anticipated that network companies will accommodate relevant recommendations in their RIIO 2 business plans[2] (starting April 2021).

1.2 ROUTE TO DECARBONISATION

The decarbonisation of the GB energy system will have a wide ranging impact on the electricity system. A range of possible scenarios exist, with National Grid Electricity System Operator's (NGESO) Future Energy Scenarios (FES) providing different views on the future energy landscape and the demands on the electrical system. Reviewing the way the annual FES scenarios[3] have changed with respect to the uptake of low carbon technology such as electric vehicles (EV) helps reveal the scale of their potential impact on the network and the pace with which planning considerations have changed in a short space of time. For example, Figure 1 shows a large shift in the considered EV uptake between 2016 and 2019. Figure 2 also highlights the vastly different way these EVs could present themselves to the network as demand.

The 2020 FES (the full details of which had not been released when conducting the analysis below) highlights that *Steady progression* (that is slow incremental change) will not achieve net zero. Furthermore, the scenarios which do achieve net zero will necessitate high societal change. A Committee on Change (CCC) report highlighted that a fully decarbonised electrical system could be achieved by increasing the share of renewables and firm low-carbon power from around 50% today to around 95% in 2050 [1].

[2] Note this is more relevant for Distribution Network Operators (DNOs) given that RIIO T2 business plans have already been developed. The RIIO 2 period for DNOs starts in April 2023.
[3] Data on each of the annual FES scenario sets are available from the NGESO website.

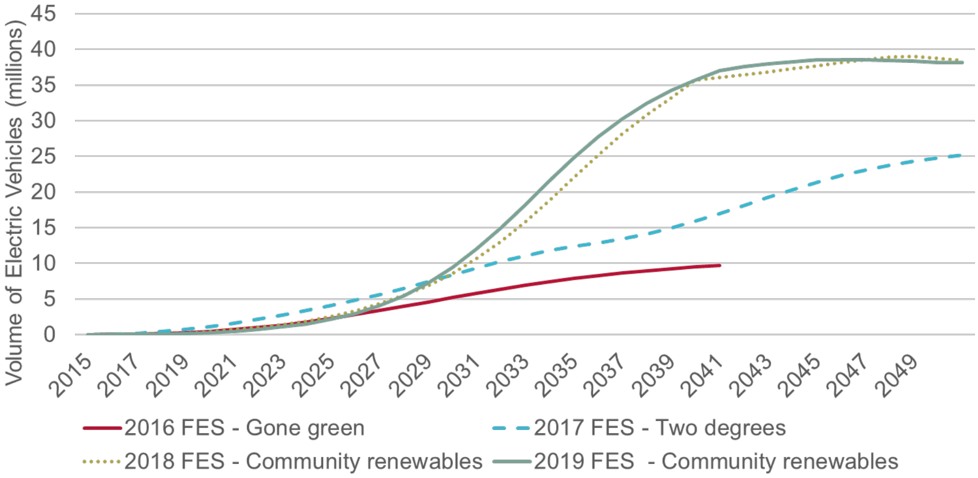

Figure 1: EV uptake within the FES Scenarios between 2016 and 2049 (focussing on high uptake scenarios)

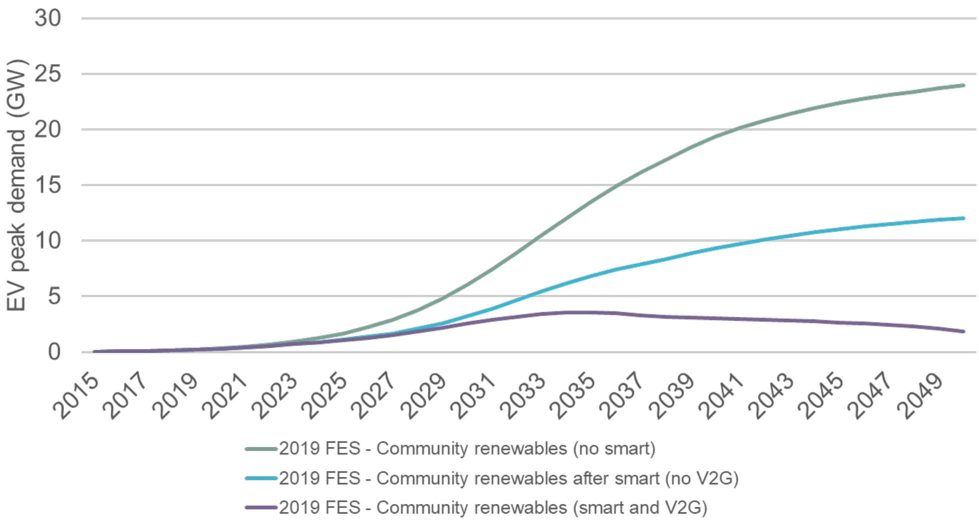

Figure 2: Peak EV power demand on the electrical system with and without smart charging and vehicle to grid capability

Significant legislation, market drivers and policy initiatives are already beginning to necessitate this change. Figure 3 presents an outline of significant policy decisions and market drivers against the anticipated price control periods for transmission and distribution companies.

Within Figure 3, the 2050 Net Zero legislation is the overarching goal. The various steps along the way will shape the needs of the electrical system. These include:

- The Scottish Government accelerating the net zero 2050 target to 2045;
- Cities across the UK targeting net zero by around 2030 (these include Bristol, Oxford, Glasgow and Edinburgh) and the implementation of low emission zones within many other cities;
- The UK government ban on the sale of new petrol and diesel cars in 2035;

- The Scottish government pledging to "phase out the need" for petrol and diesel cars by 2032;
- Market forces whereby battery electric vehicles may reach cost-parity with internal combustion engine (ICE) cars by 2025 (or earlier with incentives) [2], driving additional demand thereafter (1million by 2025 and 11 million by 2040 [3]);
- The proposed standards changes to new build houses which will see no more new homes connected to the gas grid by 2025 (with heat pumps a key replacement solution option) [4];
- The conclusions of a CCC report [1] stating that almost all replacement heating systems should be low carbon by 2035 (although not necessarily electrically powered); and,
- Investment in the offshore generation which could see around 30GW of wind connected to the transmission network by 2030 [5].

There are no doubt many other examples, and alternative projections, in addition to those highlighted above. One notably example is the increasing volume of energy storage and local generation which will be connected to the electrical system. Competing approaches, such as hydrogen power heat and transport, will also clearly have an influence in shaping this road map.

Figure 3 shows that many of these changes will be will be seen through the next two price control periods. This emphasises the need for swift action if changes are to be made to standards to facilitate an effect transition to net zero.

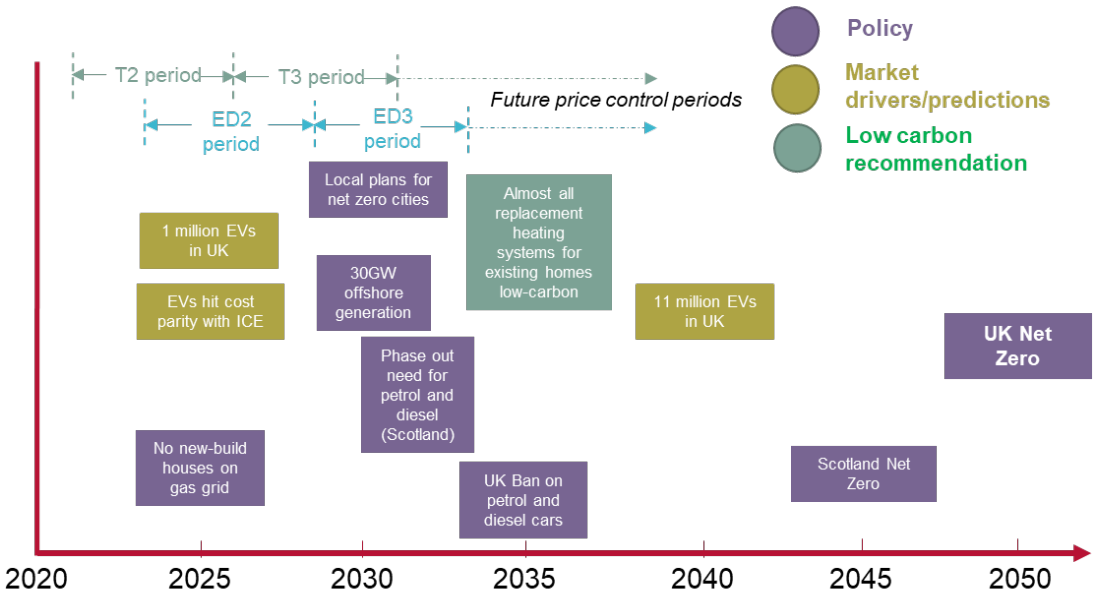

Figure 3: There are a range of external initiatives driving the needs of the future electricity system

1.3 TECHNICAL APPROACH

The role of Frazer-Nash within this project was to support an independent panel of experts reviewing the engineering standards governing the GB electricity system. This involved undertaking research activities and planning work to support the panel needs, as well as undertaking ongoing administrative support.

At the beginning of the project, the panel members downselected six key topic areas that formed the focus of technical investigations within the broader scope of the review. These topic areas were primarily identified on the basis that these were areas where:

- Changes to standards could bring about immediate benefit (e.g. increase value to consumers, decrease emissions and/or remove barriers to innovation); or,
- There were potential gaps in the standards landscape.

Whilst focussed on 'quick wins', the long term view for each topic area was also considered. Once the scope of each topic area was defined in detail, investigations sought to:

- Map out the range of relevant standards with a focus on engineering standards but also exploring international and product standards where appropriate;
- Determine the fundamental drivers for standards across each topic area;
- Identify options for changes to the current standards which were considered to be beneficial;
- For the identified options for change, conduct a thorough literature review of the evidence of implementation elsewhere or the benefits case. Relevant sources included Innovation projects from transmission and distribution network companies, research papers, previous standards review activities and international examples of implementation;
- Obtain and review evidence from government and industry about relevant ongoing activities; and,
- Conduct independent analysis activities where appropriate.

The scope of each topic area and the associated investigations were continuously refined throughout the project based on research findings and the direction of the panel. This allowed 'deep dives' to take place on the research areas of highest interest and the review was able to iterate towards a set of final recommendations evidenced by the review activity.

In addition to the research activities, Frazer-Nash worked with the panel and BEIS to organise and participate in a number of industry engagement events[4]. The events were used to assess stakeholder response and to identify missing viewpoints.

1.4 TOPIC AREAS

The six main topic areas investigated within this review are outlined below.

Table 1: Summary of topic areas investigated

Topic Area	Description and Areas of investigation
Voltage limits	This topic area was selected to evaluate the benefits and implications of extending the allowed voltage supply range to Low Voltage (LV) consumers.
Frequency, Operability and Stability	This topic area explores how the allowed frequency range and system Rate of Change of Frequency (ROCOF) plays on the driving cost into the electrical system and the mechanism to control these parameters.

[4] These were the IET Challenge Session (23rd January 2020), the Smart Systems Forum (7th February 2020) and the 2nd Industry Day 14th February 2020.

Reliability and security of supply	The focus of this topic area is on the current security of supply standards. This considered the means of assessing the economic efficiency of security of supply, system flexibility and the role of incentive schemes alongside the standards.
Resilience and black start	This topic area was identified in recognition that formalised standards for resilience had yet to be adopted. Areas for investigation therefore included performance based standards for recovery from significant outage events, emergent risks for the electrical system and the systems role in supporting critical infrastructure.
Future Installed Network Capacity	This topic area is related to the standards around how customer and network capacity is determined and the future needs. This included uptake of flexibility and time of use, asset sizing with respect to through life need and cost and the potential use of higher capacity and novel distribution solution options (3-phase and DC).
Smart energy system interoperability	This topic area is concerned with ensuring that future engineering standards enable flexibility, agility and inclusivity of new entrant participants.

Whilst the division into the different topic areas provides a convenient means of viewing the different way standards could be changed, the topic areas are often tightly linked. This will become apparent in the following sections. By way of example:

- The allowed voltage drop along a line can impact the peak capacity which it is allowed to carry;
- Changing the capacity of a line (through voltage limits or through changes to the current carrying capacity) will change the effective security of supply i.e. it enables an increased supply to a point in the network with similar reliability;
- Resilience and security of supply are intrinsically linked as will be discussed;
- Management of frequency is a key element of security and resilience;
- Equipment with magnetic circuits such as transformers and machines are rated on their voltage over frequency ratio – you cannot change one without considering the other;
- Interoperability of smart equipment will have a major impact of future system capacity (through load shifting), management of frequency (through frequency response) and by inference the security of supply.

Further details of these interrelationships will be highlighted throughout the report. Due to these relationships the potential benefits of changes to standards are related to one another. Therefore, whilst the benefits highlighted are valid for independent changes, the benefits do not always simply stack up and there will be a trade-off between changes made. These trade-offs have not been quantified as part of this work.

1.5 STRUCTURE OF REPORT

The report is structured as follows:

- Section 2 provides the general landscape of electrical system standards and stakeholders;
- Sections 3 to 8 detail the research activities for each topic area;

- Section 9 outlines preliminary conclusions and next steps; and,
- The Annexes provide supplementary information and supporting analysis.

Alongside this report, a separate report has been developed which presents the outputs of a deep dive review of electric vehicle smart charging standards [6]. This was conducted to support investigations within the smart energy system interoperability topic area. This report is included within Annex E.

1.6 ALIGNMENT WITH THE EXPERT PANEL REPORT

This technical report presents the evidence base which the Panel draw upon to develop their report. To ensure clear traceability of evidence information, the two reports were aligned in structure where possible with the sections in this report mapping to the Appendix C of the Panel report as shown in Table 2. Further references are made to sections of this report as appropriate.

Table 2: Direct mapping between the Frazer-Nash and Panel report

Frazer-Nash report section	Panel report section
Section 3 - Voltage Limits	Section C.5 - Voltage Limits
Section 4 - Frequency, Stability and Operability	Section C.6 – Frequency
Section 5 - Security Of Supply and Reliability	Section C.2 - Supply Security and Reliability
Section 6 - Resilience	Section C.3 - Resilience
Section 7 - Future Installed Network Capacity	Section C.4 - Capacity
Section 8 - Smart Energy System Interoperability	Section C.7[5] - Smart Energy System Interoperability

[5] Report reference [6] also supports this section.

2. OVERVIEW OF ENGINEERING STANDARDS LANDSCAPE

An initial activity undertaken within the project was to map out the engineering standards and codes which related to the topic areas of interest. These standards where then considered to form the core of the standards review activity. Table 3 provides a general overview of these standards including their purpose, a view on their 'level of prescriptiveness'[6] and the responsible parties. Beyond these however a range of international and product standards have been also been reviewed with a view to either understanding their potential impact on the core engineering standards (as was the case with product standards) or as examples of alternative practice for system design or operability.

Table 3 highlights that legislative regulation and regulatory schemes tend to be output based and the engineering standards are input based. Other British standards (e.g. BS EN 50160:2010 which will be discussed in section 3) also tend to be output based but with clear guidance in terms of required tests to demonstrate compliance.

[6] Referred to as Input standard (which direct the way planning or operation should be conducted) or Output standards (measures that reflect results).

Table 3: Overview of standards within scope

Main domain area	Applicable engineering standards, codes, regulations	Purpose/Function	Input or output based[6]	Responsible parties		
				Owner/ admin	Who complies	Checks compliance
Customer premises	The Electricity Safety, Quality and Continuity Regulations 2002	Set minimum requirements for quality of power supply	Output	HSE, BEIS, Parliament	DNOs	DNO, Customers
	The Electricity (Standards of Performance) Regulations 2015	Set minimum requirements for availability	Output	Parliament, Ofgem	DNOs	Ofgem
	Ofgem's Interruption Incentive Scheme (IIS)	Incentivises high availability of power supply to customers	Output	Ofgem	DNOs	Ofgem
Distribution network	Distribution code	Sets out the operating procedures and principles governing the relationship between operators and users	Input	ENA, DCRP Panel, Ofgem	DNOs, Generators, Suppliers, Demand customers, IDNOs	Ofgem
	Ofgem's Interruption Incentive Scheme (IIS)	As above				
	P2/7	Set to minimum design requirements for security of supply	Input – security	ENA, Ofgem	DNOs	Ofgem
	P0-PS-037 (EM7907)	Set minimum requirements for voltage supply and security of supply	Input – security Output – frequency and stability	SHEPD, Ofgem	DNOs	Ofgem
	EREC G98	Provide requirements for the connection of Power Generating	Input	ENA	Generators	Generators (self certify)

Main domain area	Applicable engineering standards, codes, regulations	Purpose/Function	Input or output based[6]	Responsible parties		
				Owner/ admin	Who complies	Checks compliance
		Facilities to the Distribution Networks (<3.68kW)				
	EREC G99 (update to Issue 5 in Nov 2019)	As above (>3.68kW)	Input	ENA	Generators	Generators, DNO
Transmission network	SQSS	Set minimum design and operational requirements for quality of power supply and security	Input – security Output – frequency and stability	NGESO Ofgem	ESO	Ofgem
	Grid Code	Sets out the operating procedures and principles governing the relationship between operators and users	Input	Ofgem	TO, Generators, Suppliers, Non-embedded customers	Ofgem
	Energy Not Supplied Incentive Scheme	Incentivises high availability of power supply	Output	Ofgem	TO	Ofgem
	Relevant Electrical Standards	Provide detailed technical specification for subsystems	Mixed (detailed technical specifications)	TO	Manufacturers	TO
	Network code on electricity emergency and restoration - Commission Regulation (EU) 2017/2196	Details planning requirements for system defence and system restoration	Input	EU	NGESO	Ofgem
Whole system	Electricity Supply Emergency Code	Outlines the process for ensuring fair distribution electricity rationing.	Input	BEIS	ESO, TO, DNO	BEIS

3. VOLTAGE LIMITS

There are a number of drivers for reconsidering the existing voltage limits on the electrical network. The expected increase in load from electric vehicles and heat pumps will increase voltage drop (and associated network reinforcement) on networks, the connection of distributed generation can cause overvoltage issues, and there is a range of evidence that voltage reduction and optimisation can improve the efficiency of load operation.

This topic area investigates the benefits and implications of extending the allowed voltage supply range, focusing on the final voltage supplied to LV consumers[7]. This includes changes to both the minimum and maximum supply voltages. This section discusses:

- The background and standards landscape for system voltage;
- The opportunities presented by changing voltage limits;
- The challenges and risks; and,
- Adoption and enforcement of voltage thresholds.

3.1 BACKGROUND AND STANDARDS LANDSCAPE

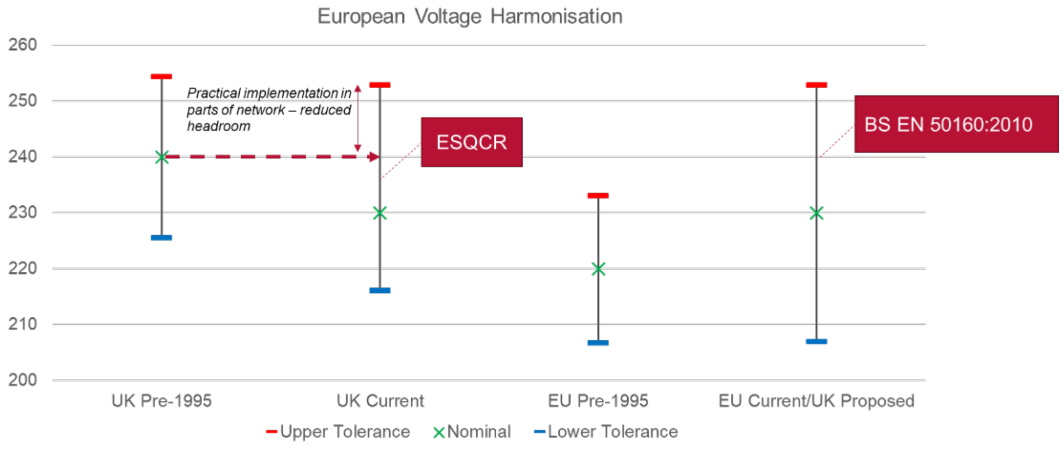

Figure 4: Overview of the historical and current voltage envelopes in the UK and Europe

Figure 4 illustrates the historical and current voltage envelopes in the UK and Europe. Key points from this figure are:

- Voltage harmonisation around the 230V nominal voltage level took place in 1995;
- The GB voltage limits are 230 V +10%/-6% as defined in the Electricity Safety, Quality and Continuity Regulations (ESQCR);
- The European voltage limits are 230 V +10%/-10%;
- British Standard EN50160:2010 defines the voltage envelope as 230 V +10%/-10%; and,
- The UK operates within the European/BS EN50160:2010 voltage envelope, but does not currently utilise the lower 4%.

In practice, the nominal operating voltage for distribution networks was not changed after harmonisation as it remained within the allowable voltage range.

[7] Noting that network changes to enable changes to LV voltage may occur at higher voltage levels.

The specific sections from the standards of interest are presented in the following subsections.

3.1.1 The Electrical Safety, Quality and Continuity Regulations 2002

The current UK allowed voltage limit of 230 V +10%/-6% is defined in ESQCR. It states:

- "27 (2),(3): ...voltage declared in respect of a low voltage supply shall be 230 volts between the phase and neutral conductors at the supply terminals… [with] … a variation not exceeding 10 per cent above or 6 per cent below the declared voltage at the declared frequency"

This is referenced within the Distribution Code (as known as D-Code) and various Engineering Recommendations and BS 7671 Wiring Regulations.

3.1.2 BS EN 50160:2010

BS EN 50160:2010 reflects the common European voltage envelope. It states:

"Under normal operating conditions excluding the periods with interruptions, supply voltage variations should not exceed ± 10 % of the nominal voltage Un".

This standard is referenced within "BS EN 60038:2011 – CENELEC Standard Voltages" which provides wider range of voltages in use across industry. It reflects the EN 50160:2010 limits for LV AC distribution.

3.2 OPPORTUNITIES FOR CHANGING VOLTAGE LIMITS

A number of potential benefits exist for reducing the voltage threshold. In the majority of cases, these have been investigated in the context of reducing the threshold to -10%. Research highlighting the opportunity to further reduce this is also noted.

The following subsections will outline the main areas where benefits could be achieved.

3.2.1 Releasing capacity and lowering total system reinforcement costs

The lower voltage limit determines the minimum voltage that should be supplied to a customer's premises. This must account for any voltage drop prior to the supply reaching the customers premises. The key variables are illustrated in Figure 5.

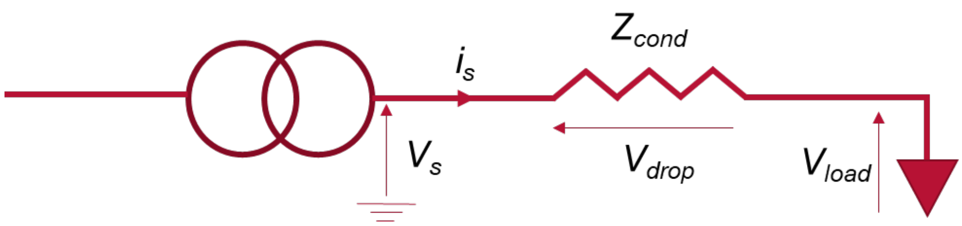

Figure 5: Simple representation of voltage drop along a conductor where an upstream transformer supplies power

Within the simple representation in Figure 5, V_{load} is

$$V_{load} = V_s - Z_{cond} \times i_s \qquad (1)$$

where V_s is this supply voltage from the transformer, Z_{cond} is the impedance of the conductor and i_s is the supply current.

If V_{load} is below the lower voltage limit during operation[8], then a voltage related intervention is required. Interventions include increasing V_s either permanently (although this can risk

[8] This is presented as a hard limit in ESQCR, unlike the probabilistic limit in BS EN 50160.

overvoltage issues for loads closer to the transformer) or via more active means or reinforcing the network to reduce the conductor impedance and hence voltage drop.

By reducing the lower limits on the voltage that can be supplied, a higher current (and hence load) can be supplied along the line before reaching this lower threshold. This effectively enables additional load to be accommodated on the network before a voltage related intervention is required. For example, if the voltage threshold was reduced by 4% to the -10% levels with BS EN50160:2010, this increases the peak allowed voltage drop[9] by 25%. Assuming constant resistance and current along the line, this would allow peak current to increase by 25%.

The key benefit of this effective uplift in capacity is ability to defer or avoid reinforcement as demand increases significant. Within [7] it was highlighted that several billion pounds worth of voltage related reinforcement would be required to manage increases in demand without changes to current operating practices (actual cost and volume is scenario dependent). These could be partially deferred through reduction in voltage limits, advanced voltage control or a combination of both. The value of advanced voltage control was assessed within [7] (in terms of reduced capital expenditure on the network) and this was said to be between £2.7bn and £4.9bn by 2030. Within [7] it was also noted that:

- "…for a proportion of circuit reinforcements, initially the voltage driven investments (in 2025) become thermally driven (in 2030), which cannot be mitigated by the advanced voltage control."

This highlights that whilst reinforcement may still be required, there is the opportunity to defer this.

Cost savings through changes to voltage management (albeit through voltage control technology rather than limit reduction) were also explored within ENWL's Smart Street project. This project found that for the whole of GB, there was a £518m benefit from deferred reinforcement out to 2060. A reduction in the voltage limit should be complementary to the approach taken in this project.

However one key point to highlight is that [8] indicates that undervoltage is not currently a widespread problem on LV networks[10] (typically less than 0.1% and often far lower). Therefore this would not necessarily provide a benefit in the short term, but would help support the expected substantial increases in loading.

Currently, overvoltage issues are more likely to trigger interventions. Reducing the lower threshold alone would not lower this reinforcement cost, but in conjunction with lowering the voltage set point these overvoltage issues could be reduced.

3.2.2 Lowering demand

Demand reduction could be achieved by reducing the supply voltage – something which is enabled through the reduction in voltage limit. Energy savings through voltage optimisation and reduction have been noted in various network-led projects. In addition, commercial voltage optimisation solutions have highlighted the energy saving benefits of lowering consumer voltages. These are outlined in the table below.

[9] The difference between the peak allowable voltage and the minimum allowable voltage. Within current regulations this is equal to 253 – 216.2 = 36.8V.
[10] However current arrangements rely on customers making voltage related complaints – issues may be more widespread than the reported figures.

Table 4: Summary of example case studies exploring the impact of voltage reduction on power and energy use

Case study	Power reduction	Energy reduction potential	Environmental benefit	Associated cost impact
ENWL, Smart Street innovation project [9]	Not quantified	Active voltage control solution: 5 – 8% Global setpoint change (passive solution): 1 – 4%.	Reduced emissions of 400 $MtCO_2e$ over the 2016 to 2060 period for GB	~£40 (up to £70) per annum per LV connected customer savings No cost comparison with the passive solution
SPEN, Flexible Networks programme [10]	Estimates 1% active power demand reduction per % voltage reduction.	Not quantified	Not quantified	Not quantified
WPD, Discussion paper on Adoption of EU Low Voltage Tolerances [11]	Not quantified	Estimated 1.5% energy reduction arising from a 2.5% voltage reduction 2201 GWh could be saved	Not quantified	Representing a saving of £11.95 per customer, or £315M pa total value.
Matt-E Voltage Optimisation [12]	Not quantified	Reducing the excess voltage by 18 V would typically provide 10% reduction in energy bills.	Not quantified	Using the same methodology as the Western Power Distribution figures would result in an actual 4.5% energy reduction at 240 V. This would benefit standard rate customers at £35.85, giving overall value to domestic customers of £945M p.a.

Case study		Power reduction	Energy reduction potential	Environmental benefit	Associated cost impact
PowerPerfector – iESCo Voltage Power Optimisation Technology [13]	Total from all installations	Not quantified	>3,295GWh	>1.8Mt C02e	>£275M saving in energy bills
	Whitehall Place Installation of 1 MVA PowerPerfector unit	Not quantified	11% energy savings	Not quantified	Around £19,000 p.a.
	NHS Royal London Hospital installation of six powerPerfector Plus units: [13]	Not quantified	10-11% energy savings	Not quantified	Around £86,500 p.a.
Single house trial [14]		Range from -2.8% to 25.3%	15.1% saving from reduction from 230 to 200V[11].	Not quantified	Not quantified

[11] Notably below both the limits in ESQCR and BS EN 50160:2010

It should be noted that in the case of commercial voltage optimisation solutions, sites are investigated, selected and solutions implemented on a site-by-site basis – energy savings associated with these installations are not necessarily representative or reproducible via a network wide reduction in voltage.

Furthermore, on their website iESCo suggest that "*The savings achieved from a transformer tap will be a fraction of those achieved through a powerPerfector. In addition, there will be no benefit to power quality or any protection of your electrical infrastructure. The savings and benefits of a powerPerfector installation will quickly outweigh a transformer tap*." This reflects the findings in the Smart Street project.

The SPEN Flexible Networks project did also note that any demand reduction will depend on the types of load present, and is therefore variable depending on the location on the network, time of day, time of year etc. Reference [14] provides a breakdown of the impact of the reduction in voltage for different appliance types. A sample of these are shown in Table 5. From the devices tested, around 65% of load types operated at reduced power consumption when a reduced voltage was applied. Whilst this is a limited study and did not reflect on any change to the performance of the load when operating with reduced voltage, it does help to illustrate the impacts of voltage reduction on load power usage.

Table 5: Sample of household loads and response due to reduction in supply voltage

Load type	Measured Power (W)		Power reduction %
	230V input	200V input	
Washing machine	400	348	13
Fridge	109	95	13
PC desktop	55	55	0
Air conditioning	800	635	20.6
Lighting	240	240	0
Induction hob	1012	1040	-2.8%

As highlighted within Table 5, certain load types will see no drop in power use. These are constant power loads which are typically power electronic interfaced loads and which draw more current to compensate for any voltage reduction (this will in turn increase the supply losses). This is important to note that as a significant portion of projected load growth will be constant power in nature – primarily electric vehicle charging and heat pumps (where variable speed variants are used). This will not negate the potential benefits of voltage reduction for other load types[12] however these will form a smaller proportion of total demand over time.

The reduction in demand will also clearly reduce loading levels on the network. This will have the effect of increasing capacity on the network and enabling more load to be connected. Within their Customer Load Active System Services (CLASS) project [15], ENWL helped to quantify these benefits. It is noted that:

- "*If the voltage is reduced by 5% Electricity North West could gain up to 250MW of network capacity, and defer the reinforcement of 28 primary substations with an*

[12] Assuming these do not become interfaced via power electronics, like for example lighting has through the use of LEDs.

> *associated cost of £15.9 million for up to three years. When applied at GB scale, it is possible to gain up to 3.1GW of network capacity (the equivalent of 135 new primary substations), and defer £78 million in reinforcement*".

It is worth noting that whilst lowering voltage will free up capacity by reducing demand, it will also reduce the amount of capacity released by lowering the minimum voltage limit (as discussed in section 3.2.1). This trade-off would need to be explored in order to maximise the capacity released related to voltage level.

3.2.3 Potential for increased generation headroom

The export of power from embedded generation results in an increase in network voltage, with an approximately linear relationship between the voltage rise and the amount of active power supplied by distributed generators [16]. Whilst this effect may be minimal for individual smaller generators, the cumulative effect of multiple generators can cause network voltage to increase towards the statutory limits. The impacts of this are:

- If the local network experiences overvoltage, power export may be constrained;
  - Figure 6 provides one particular illustration of the required response for an inverter extracted from Australian Standards;
- This restricts low carbon generation infeed, ultimately impacting customer bills and return on investment; and,
- As discussed above, the increased voltage can increase the power utilised by loads.

There is a theoretical risk of damage to consumer devices being supplied by these higher voltage levels (see section 3.3) however the existing overvoltage protection functionality of generation[13] should prevent this being realised in practice.

There are two ways in which additional headroom could be provided. First, increase the allowable operating voltage. Second, decrease the nominal operating voltage. Given the potential risks to loads from excessive voltages (expanded in later sections), this section will focus on the latter approach.

Dropping operating setpoints to lower in the range will allow the connection of more distributed generation. Lowering nominal setpoints is already an option, and there are multiple industry examples of this being carried out (including those highlighted in earlier sections) which have shown benefit [8]. However, reduction in the lower voltage limit would give greater flexibility throughout the varying load and generation profiles.

[13] These are specified within ENA Engineering Recommendations G98 and G99. Clearly these could be changed in future provided there was motivation to do so.

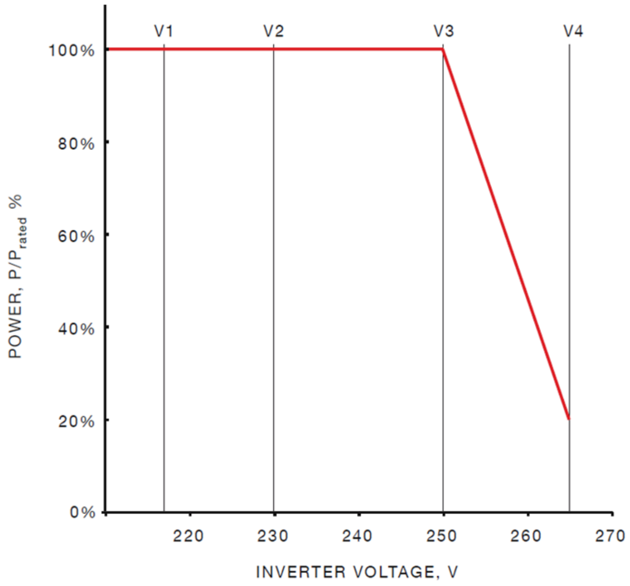

Figure 6: AS/NZS 4777.2: 2015 Figure 2(A) – Example Curve for a Volt-Watt Response Mode (Australia)

The effect of this on actual headroom will vary significantly with network conditions. Relevant parameters include:

- Supply voltage;
- Voltage at the receiving end (seen by the DG);
- The impedance of conductors from the main supply (a function of conductor size and distance);
- The load being supplied (and the timing of this load compared to peak DG output); and,
- Any other DG connected [16].

Within an example case study presented within [8] (based on the supply from an 800kVA transformer), the additional headroom created by reducing the minimum supply voltage to 207V was between 15 and 23%[14]. For the 23% headroom case, this represented an increase in maximum connected generation from 610kW to 750kW.

3.2.4 Related benefits

There are further benefits to voltage reduction which have not been fully explored within the sections above. These include:

- A reduction in network losses. The Smart Street project demonstrated a reduction of up to 15% in losses through advanced voltage control [9];
  - This is dependent on the associated power energy reduction being delivered [8]; and,
- Life extension for equipment resulting from operation closer to nominal voltage ranges.

[14] The range here is dependent on the assumed LV cable loop impedance.

3.3 CHALLENGES AND RISKS FOR CHANGING VOLTAGE LIMITS

Changes to the voltage limits and the associate shift in operating voltage does come with a number of risks and network costs. This section discusses these in two broad categories, the network risks and consumer risks.

3.3.1 Network Risks

Through previous analysis of this issue, the ENA highlighted a number of network related challenges and risks [8]. These are outlined below.

- A network which runs at higher voltage is more resilient. Operating Code 6 (OC6) voltage control demand response provides networks the flexibility to reduce load through voltage reduction. This flexibility will be reduced in areas where distribution voltages are lowered.
  - There is already some uncertainty about what demand reduction can be achieved. This was highlighted during Operation Juniper, which noted that demand reduction achieved from voltage reductions are likely to be lower than previously expected [10].
  - In their response to the ENA consultation on voltage reduction [17], National Grid Electricity Transmission (NGET) noted that as a worst case further voltage reduction could be counterproductive.
  - This has a knock on impact for the system operator and the need to procure additional reserve or frequency response to compensate for the reduction in effectiveness of OC6.
- There is a greater risk of nuisance undervoltage tripping.
  - Compared to the undervoltage protection settings in G59/G83 and G98/G99, there "is very limited risk that normal voltage fluctuations arising from changes in generation and demand will result in inadvertent tripping of embedded generation" if limits were reduced to -10% [8].
  - Problems with undervoltage tripping is possible during events such as transmission system faults or demand reduction through voltage reduction. The ENA note that "Customers at the very ends of LV feeders which are designed to operate at the lowest levels of voltage tolerance are most likely to see inadvertent tripping of generation" [8].
  - Resetting protection to counter these issues may require substantial effort as evidenced by the Accelerated Loss of Mains programme.
- Headroom benefits in terms of generation will only be realised where setpoints are reduced.
  - Within their report [8], the ENA note some of the operational challenges that reducing setpoints may pose. This is a manual task normally at primary substations where HV networks receive their supply.
  - Reference [8] also notes that in excess of 7000 substations across the distribution network would require investigation and in some cases upgrades/replacements would be necessary before the voltage could be reduced.
- Benefits on the distribution network could be offset by transmission system issues [17]. In particular, the reduction in demand will increase the voltage levels on the transmission system. The impacts of this include:

- Increased investment in reactive compensation NGET estimated that investment in the range of £1.5m to £5m per grid supply point (GSP) would be required. Applying this across the 492 GSPs in GB, the additional investment would be £738m to £2460m [17].
- The higher transmission voltage level reduces headroom for connected generation at that level and increases associated costs for Enabling Works for connection.
- There may be additional power factor control requirements placed on Small Power Stations.

These points highlight that there are a number of network considerations to decreasing system voltage and the whole system impact should be considered before adopting changes.

3.3.2 Consumer Risks

The key risk for lowering voltage limits is to appliances and their capability to continue operating.

Key evidence regarding the tolerance of equipment comes from research from Imperial College [18], [19]. The operating voltage of a range of equipment was assessed through experimentation. A summary of the output is shown within Figure 7.

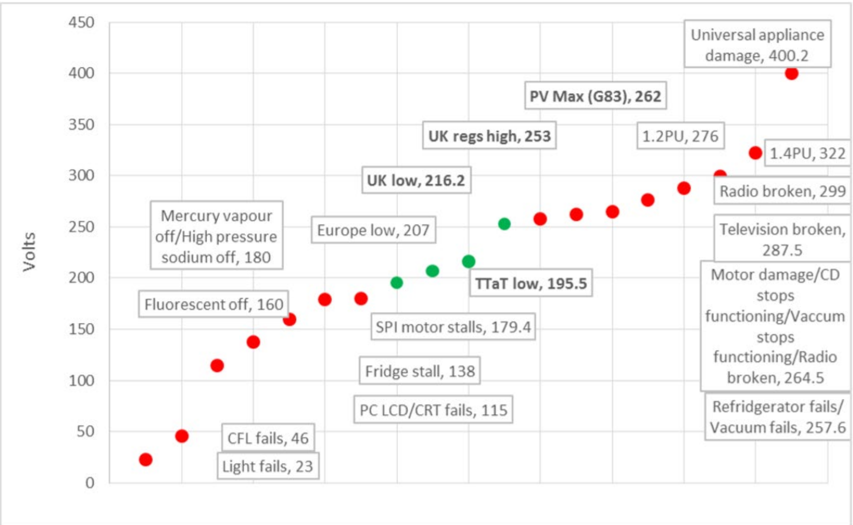

Figure 7: Practical effects of voltage levels on appliances behaviour (figure presented within [20], which summarised data originally presented in [18])

Figure 7 highlights that there is a relatively wide voltage envelope where appliances continue to operate. With regard to undervoltage, failure issues were only experienced at around 180V. The work highlighted that the vast majority of appliances would operate at -10%. Within this group, newer appliances should be compatible with the European Low Voltage Directive. As many will be designed to operate in the UK and the EU, there is a general assumption that this means they will operate within the proposed 230 V -10% range.

Whilst there was good coverage of load types, there are still uncertainties around the risk posed to older appliances – i.e. most appliances will work however there may be a limited number that do not. This issue was highlighted within [8]. One particular risk was related to older contactors predating 1988 which were designed for a 240V supply with an 85% to 110% tolerance. However it was stated that:

- "*BEAMA/GAMBICA set up a working group of interested companies to discuss… (impact of -10% on older appliances). Through more detailed discussion the working group was able to establish that there were no significant issues with a proposed change*."

Network innovation projects have not directly addressed the issue of impacts to consumer appliances. For example, WPD's *Voltage Reduction Analysis Results* [21] analysed the number of undervoltage events and how this may be impacted by voltage optimisation activities. However the work was network focussed, i.e. is the network providing the correct voltage level, rather than analysing the impact on appliance operation during those periods of undervoltage.

It is noted that a network led project[15] is ongoing to further investigate issues around safety and operability of lower voltage operation for loads. It is expected that the outputs of this project would help inform on a safe operating range.

Within their response to a consultation on the ENA report [8], AMDEA (a UK trade association) expressed concerns around the voltage drop within properties and the actual voltage seen by equipment [17]. This emphasised that considerations related to lower voltage operation should not end at the customer's point of connection.

With regard to the operation of loads at voltages higher than 253V, [20] notes that:

"Although many appliances do manage to continue to operate at higher voltages, there is a significant population of devices that will fail at only a few volts higher than 253V. F&M [18] *do not advise that voltage regulations are relaxed to increase the maximum voltage."*

This would suggest that there is significant risk in increasing maximum voltage. However again this refers to steady state operation and there may be opportunities to increase voltage transiently (e.g. the BS EN 50160:2010 approach to voltage compliance).

Furthermore, noting that overvoltage rather than undervoltage tends to be a bigger problem with the increase in DG, this actually highlights a more immediate risk to appliances.

3.3.2.1 EV chargers

In February 2020, an amendment to the IET Wiring Regulations [22] was published which relates to electric vehicle charging installations. Within this amendment, it is stated that a charge point should disconnect within 5 seconds if voltage is greater than 253Vrms (+10%) or less than 207Vrms (-10%). This would not pose restrictions on the reduction of voltage limits to the levels specified in BS EN 50160, however clearly issues would be caused for charge point operation beyond this level without changes to the wiring regulations and the charge point protection settings.

3.3.2.2 Quantification of consumer risk

It is noted that the previous research has primarily focussed on the ability to maintain operation. Whilst this failure of operation is unfortunate, generally it is not a dangerous failure mode[16]. There is still a lack of analysis around the safety risk from voltage reduction.

For example, the stall points for motors studied in the research from Imperial College were 138V (0.6pu) and 180V (0.78pu). Taking this forward, for example for a fridge motor, what is the likelihood that this stall condition leads to the motor drawing excessive current, overheating and

[15] This project was noted by the ENA over the course of the review.
[16] Exceptions to this include where the particular component fulfils a safety related function.

causing a fire risk[17]? Quantification of this risk should be a consideration before recommending substantial reduction in supply voltage.

3.4 INCENTIVE FOR VOLTAGE REDUCTION

Within [9], the subject of "*potential incentives and obligations on energy companies for increasing customers' energy efficiency to assist the UK's carbon targets*" through initiatives such as voltage reduction was discussed.

In regard to this it is worth noting that there are competing benefits from the reduction of voltage for the purposes of energy efficiency (i.e. reducing voltage and keeping it low) and enabling the connection of a greater volume of distributed generation (reducing voltage setpoints but allowing DG to increase the voltage at periods of increased output). This trade off will need to be understood to inform both implementation of voltage reduction and any related incentive scheme. The use of technology and data would also support the reporting and monitoring of such a scheme.

3.5 VOLTAGE LIMIT ADOPTION AND COMPLIANCE

Currently, domestic voltages are not routinely monitored by the networks, and issues are only investigated following customer reports of power quality issues. It is anticipated that this will change over time with the wide spread roll out of monitoring devices. These should provide greater visibility at the edges of the network and enable scalable solutions for reporting voltage compliance.

3.5.1 Technology for monitoring voltage compliance

SMETS2 smart meters will provide the ability to measure and monitor voltage in customer premises and this information may be used in the future by DNOs or third parties to monitor and potentially actively manage voltage performance. However currently there is no requirement from individual companies to include voltage in their in-home display and therefore customers may not have visibility of voltage issues. Secondary sub-station transformer monitoring is not currently widespread, but with the introduction of the distribution system operator and a move towards flexible networks it will be necessary for monitoring and control equipment to be installed at the secondary substation level. Such monitoring will at least provide visibility of voltage issues at transformer locations.

3.5.2 Testing methodology

Within BS EN 50160:2010, there is a defined testing methodology. This is:

Defined Test: "*Under normal operating conditions:*

− *during each period of one week 95 % of the 10 min mean rms. values of the supply voltage shall be within the range of Un ± 10 %; and*

− *all 10 min mean rms. values of the supply voltage shall be within the range of Un + 10 % / - 15 %.*"

This has been adopted within ENA EREC G101 - "Voltage Measurements for Assessment of Compliance with Statutory Voltage Limits" where assessment of compliance with statutory voltage limits is achieved through the following requirement:

[17] Fridges do typically have overload protection to prevent motor damage from high temperature operation [140]. However, associated relay components (e.g. PTC starter or overload relays) are one of the more common failure modes related to fridge fires [141], [139]. These components are in series with motor windings and would presumably be subject to additional heating from lower voltage/higher current operation.

- "95 per cent of the 10-min mean R.M.S. values of the Measured Voltage shall be within the appropriate Statutory Voltage Limits range."

This highlights that whilst ESQCR does notionally set hard limits for voltage, the measurement approach for assessing compliance does allow small excursions beyond this range. There is no mention of this potential conflict (hard limit versus probabilistic compliance test) within EREC G101.

With the greater availability of voltage data over time, it is envisaged that the compliance regime could be automated rather than necessitating DNO's to physically investigate issues.

3.6 FUTURE CONSIDERATIONS ON VOLTAGE LIMITS

As noted above, research from Imperial College London [18] indicated that the vast majority (above 98%) of domestic loads in the UK will operate with a minimum voltage of 0.85pu nominal voltage. Consumer and ICT equipment were noted to be far more tolerant to lower voltage operation than overvoltage. However, it is not clear whether this study examines a fully representative set of appliances.

The research indicated that the lower voltage level was considered to be applied at the consumer level, with network voltage anticipated to remain within the limits specified in BS EN 50160 (i.e. local voltage optimisation at the premises). While this supports reduction below -10% in terms of impact to consumer appliances, there has not been significant research conducted into the impact of this on the networks as a whole (i.e. how are the network risks highlighted above impacted?).

3.7 CONCLUSIONS

There is clear evidence that reduction and optimisation of voltage can:

- Reduce energy use as a whole, particularly at the consumer level;
- Enable load growth by effectively increasing the capacity of circuits without the need for reinforcement; and,
- Provide headroom to enable the connection of a greater volume of distributed generation.

Therefore changes to the way voltage is managed can ultimately reduce costs to consumers and greenhouse gas emissions (directly through energy savings and the integration of renewables and indirectly through providing capacity for low carbon demand).

The means through which these benefits could be achieved are through:

- Relaxation of voltage lower limit within ESQCR (e.g. in line with EU limits); and/or,
- Reduction in voltage operating setpoints, either actively or passively (which is facilitated by lowering of the voltage limit).

There is evidence of networks already acting on these benefits by reducing network distribution voltages within the current regulations and it is believed that a change to the standards would be complementary and supportive to these ongoing actions.

The evidence of energy efficiency and energy reduction benefit is strongest where voltage is actively managed, as shown by the ENWL Smart Street project and the commercial installations of voltage optimisation devices. However, this necessitates the installation of additional equipment to monitor and adjust voltage (e.g. on-load tap changers) with associated engineering and cost challenges for large scale roll out. Whilst a global reduction in voltage may not provide the same benefit levels in terms of energy efficiency, these may still be significant (up to 4%). This more passive solution could be employed more rapidly and would be enabled by widening the voltage levels set out in ESQCR.

With both demand and DG projected to increase significantly, the LV voltage profile will become far more variable throughout the day. The provision of additional headroom and footroom through changes to voltage limits will give networks greater flexibility to deal with associated issues. This includes reduction of voltage set points to manage overvoltage issues and the ‘do nothing’ option of allowing greater voltage drop on lines which enables voltage driven reinforcement to be deferred or avoided altogether.

There are clearly costs which would be incurred on the network to facilitate lower voltage operation, with implications for both network infrastructure and operations. These are significant and worth consideration alongside the benefits case.

There are still uncertainties around the safety impact of operating certain loads at lower voltage and it noted that there are ongoing projects within the industry aiming to address remaining risks.

Finally, it is envisaged that any voltage reduction activity would be phased in gradually around the country. This would enable the stakeholders to be informed and engaged in the changes and appropriate network reinforcements to be made which would ultimately mitigate the risk of changes.

4. FREQUENCY, STABILITY AND OPERABILITY

This topic area considers the role that the allowed frequency range in which the power system must be operated plays in driving electrical system costs.

This includes:

- Cost of frequency response service provisions;
- The management of distributed generation and their protection rules (e.g. Rate of Change of Frequency (ROCOF)); and
- Role of demand side response for frequency response.

The key questions considered through this section are:

- Can we change operating frequency?
- Can we change the maximum operational ROCOF (impacting both connected equipment and protection settings)?
- What is the role of inertia and system strength in the future system?

The topic areas Security of Supply and Resilience closely link to the management of system frequency. Distinguishing between the sections, here we are exploring the bounds within which frequency and ROCOF must be controlled. Issues related to system inertia will also be explored within this context. Security of Supply and Resilience consider the events during which frequency and system stability should be maintained.

4.1 FREQUENCY STANDARDS LANDSCAPE

Figure 8 presents a high level map of the key standards related to frequency and ROCOF. As shown, system frequency impacts (and is defined across) a number of different standards and some of these (e.g. G99) implement aspects of EU Commission regulations. The specific requirements and relationships of these standards are explored in the following sections.

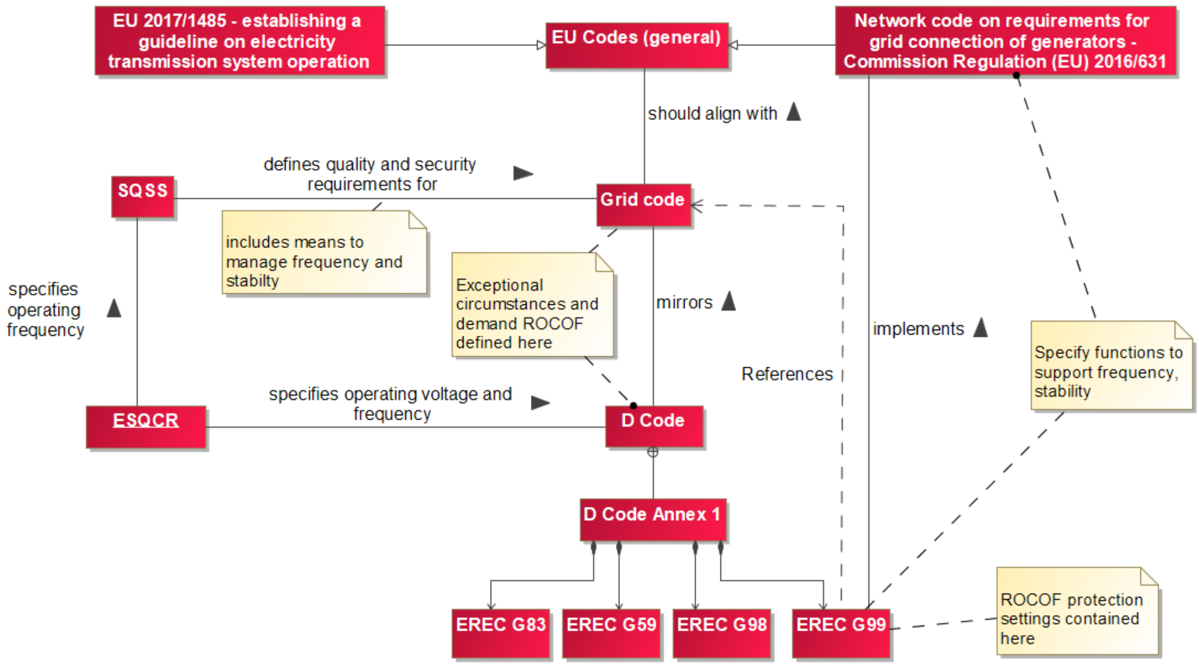

Figure 8: Map of relevant standards associated with frequency and ROCOF

4.2 FREQUENCY LIMITS

This section explores the current and future opportunities related to changing frequency standards. This section covers:

- Frequency requirements from the current standards; and,
- The current and future options for varying the frequency requirements.

For reference, Annex B.1 presents operational system data for system frequency and ROCOF for August 2019.

4.2.1 Frequency requirements

The requirements for system frequency are stated across multiple standards documents depending on the operating state of the system. The following sections highlight relevant details.

4.2.1.1 ESQCR

The ESQCR is the primary document that defines the system operating frequency. Within this standard:

Clause 27 states

- (2) “Unless otherwise agreed in writing between the distributor, the supplier and the consumer (and if necessary between the distributor and any other distributor likely to be affected) the frequency declared pursuant to paragraph (1) **shall be 50 hertz**….”
- (3) “For the purposes of this regulation, unless otherwise agreed in writing by those persons specified in paragraph (2), the permitted variations are— (a) **a variation not exceeding 1 per cent above or below the declared frequency**;…”

- (6) "Every distributor shall ensure that, **save in exceptional circumstances**, the characteristics of the supplies to consumer's installations connected to his network comply with the declarations made under paragraph (1)."

ESQCR therefore defines the statutory limits, the allowed variation in frequency (which appears as a hard limit), and that this can only be relaxed in exceptional circumstances. The legislation does not define what is considered to be 'exceptional circumstances'.

4.2.1.2 SQSS

The SQSS defines the "Unacceptable Frequency Conditions" which the operation of the transmission system is secured against. These conditions are:

"*i) the steady state frequency falls outside the*

- statutory limits of 49.5Hz to 50.5Hz; or

ii) a transient frequency deviation on the MITS persists outside the above statutory limits and does not recover to within 49.5Hz to 50.5Hz within 60 seconds."

Frequency should remain within condition (i) for the Normal Infeed Loss Risk[18], and condition (ii) for the Infrequent Infeed Loss Risk[19].

The SQSS therefore helps refine the ESQCR limits considering steady state and transient conditions. "Exceptional circumstances" are not explicitly explored in the SQSS.

4.2.1.3 Grid code and Distribution Code

The Grid Code defines the **Target Frequency** of the grid as:

"*That Frequency determined by NGET, in its reasonable opinion, as the desired operating Frequency of the Total System. This will normally be 50.00Hz plus or minus 0.05Hz, except in exceptional circumstances[20] as determined by NGET, in its reasonable opinion when this may be 49.90 or 50.10Hz. An example of exceptional circumstances may be difficulties caused in operating the System during disputes affecting fuel supplies.*"

The Grid Code[21] and DCode[22] provide further details of the allowable full frequency range in exceptional circumstances. It is noted that "*The System Frequency could rise to 52Hz or fall to 47Hz in exceptional circumstances*."

This flows down as a requirements for equipment (termed Plant and Apparatus) connected to the network. Table 5 outlines this requirement as stated in the Grid Code. Sustained operation outwith the range 47 - 52 Hz is not taken into account in the design of Plant and Apparatus.

[18] Until 31st March 2014, this is a loss of power infeed risk of 1000MW. From April 1st 2014, this is a loss of power infeed risk of 1320MW
[19] Until 31st March 2014, this is a loss of power infeed risk of 1320MW. From April 1st 2014, this is a loss of power infeed risk of 1800MW
[20] These are different exception circumstances and refer to longer term grid balancing challenges rather than the shorter term operational issues (e.g. adverse weather conditions) referred to elsewhere.
[21] See CC.6.1.3
[22] See DPC9.3.2

Table 6: Allowable frequency magnitude and durations for connected equipment[23]

Frequency Range	Requirement
51.5Hz - 52Hz	Operation for a period of at least 15 minutes is required each time the Frequency is above 51.5Hz
51Hz - 51.5Hz	Operation for a period of at least 90 minutes is required each time the Frequency is above 51Hz
49.0Hz - 51Hz	Continuous operation is required
47.5Hz - 49.0Hz	Operation for a period of at least 90 minutes is required each time the Frequency is below 49.0Hz
47Hz - 47.5Hz	Operation for a period of at least 20 seconds is required each time the Frequency is below 47.5Hz

4.2.2 Options for changing operating frequency

As a parameter largely seen by the whole system, there is limited scope for changing network frequency. Many elements of the system have been designed to operate around 50Hz and would either work less efficiently, or be damaged, by operating across a wider range[24]. Annex A.1 outlines the operational frequency range on key components.

Whilst it is recognised that cost is incurred in maintaining frequency short term and long term through various balancing products, we have not found any specific evidence of the benefits of widening the allowable frequency range.

However one key difference between GB and international standards relates to the way in which the limits are defined. Within ESQCR, the frequency limits are defined as hard limits (unless there are exceptional circumstances). However, as with voltage, BS EN 50160:2010 defines frequency limits probabilistically. BS EN 50160:2010 states:

"The nominal frequency of the supply voltage shall be 50 Hz. Under normal operating conditions the mean value of the fundamental frequency measured over 10 s shall be within a range of:

- *"**for systems with synchronous connection** to an interconnected system: 50 Hz ± 1 % (i.e. 49,5 Hz... 50,5 Hz) during 99.5 % of a year; 50 Hz + 4 % / - 6 % (i.e. 47 Hz... 52 Hz) during 100 % of the time;"*

The adoption of such a definition would serve the purpose of providing operational flexibility for transient frequency reductions and also provide a more definitive measure of the time in which the system is allowed to operate within the wider frequency band (i.e. a maximum of 0.5% of the year).

4.2.2.1 Future considerations on frequency limits

The section above considers the case today, considering a large interconnected system. In the medium to long term there is the possibility for more decentralized management for electrical energy supply. This may either be an alternative or complementary (or precursor for developing

[23] Details also contained within G99

[24] These issues are not insurmountable, and flexibility can be designed in where there is a benefit. For example certain aircraft work with variable frequency AC systems with an operating frequency range of 360-800Hz. This design enables large and unreliable gearing systems to be removed, however is at the cost of larger electrical components.

nations) to the traditional large interconnected and highly centralized system. The most popular concept is that of running microgrids[25]. An example microgrid architecture is illustrated in Figure 9. In this case, the assumptions around frequency management change.

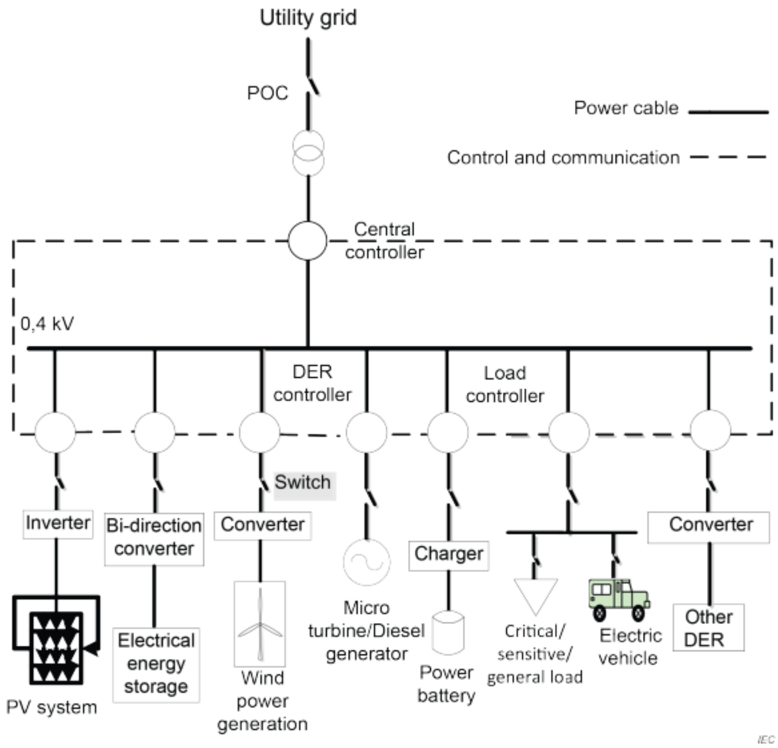

Figure 9: Example of a non-isolated microgrid (IEC 62898-2:2018 Part 2)

First, smaller electrical systems are sensitive to changes in generation and demand and so frequency can be more difficult to manage within tight limits. This therefore increases the benefits case for widening the frequency limits.

Second, the types of equipment connected to the microgrid may not have the same sensitivity to operating frequency (Annex A.1 highlighted that these were mainly larger synchronous machines, industrial plant and transformers). Therefore the same constraints on frequency would no longer bound the operational frequency range.

The potential for a wider frequency range for such systems is reflected in BS EN 50160:2010. It states:

“The nominal frequency of the supply voltage shall be 50 Hz. Under normal operating conditions the mean value of the fundamental frequency measured over 10 s shall be within a range of:

- ***“for systems with no synchronous connection** to an interconnected system (e.g. supply systems on certain islands): 50 Hz ± 2 % (i.e. 49 Hz... 51 Hz) during 95 % of a week; 50 Hz ± 15 % (i.e. 42,5 Hz... 57,5 Hz) during 100 % of the time*”

Adoption of such an approach would see the current frequency limits extended slightly under normal operating conditions and significantly under extreme circumstances. Such a change would impact a range of standards (DCode, G98/G99, ESQCR). It is envisaged that, if applying

[25] The IEC SC 8B Decentralized Electrical Energy Systems working group define a microgrid as a “*Group of interconnected loads and distributed energy resources with defined electrical boundaries that acts as a single controllable entity and is able to operate in both grid-connected and island mode*.”

to a microgrid, these standards would only apply when isolated. A non-isolated microgrid would need to comply with normal system standards.

BS EN 50160:2010 does not explicitly call out the option for a network to change state from *synchronous connection* to *no synchronous connection.* There are specific IEC standards which do cover this and define the technical specifications for microgrids. These are the IEC 62898 series of standards. Annex A.2 provides further details on the standards development activity around microgrids.

4.3 RATE OF CHANGE OF FREQUENCY LIMITS

This section explores the current and future opportunities related to changing ROCOF standards. This section covers:

- ROCOF requirements from the current standards; and,
- The current and future options for varying the ROCOF requirements.

4.3.1 ROCOF requirements

Requirements for the allowable ROCOF on the system are defined by two main characteristics:

- The tolerance of connected equipment (which may become damaged from exposure to rapidly changing system frequency); and,
- The role of ROCOF protection as a means of loss of mains protection.

Beyond this, there are also practical challenges with maintaining frequency within limits if system ROCOF beyond a certain level.

4.3.1.1 Equipment tolerance requirements

The ROCOF tolerance requirement for newly connected generation (that is >3.68kW) is contained within G99. G99 states:

- "*Power Generating Module shall be capable of staying connected to the Distribution Network and operate at rates of change of frequency up to 1 Hzs^{-1} as measured over a period of 500 ms unless disconnection was triggered by a rate of change of frequency type loss of mains protection or by the Power Generating Module's own protection system*".

The rating of 1 Hzs^{-1} was stated in the original issue of G99 and updated within G59 Issue 3 Amendment 7 to apply 1 Hzs^{-1} ROCOF setting retrospectively to all generation <50 MW.

On the demand side, DPC9.3.2.2 within the DCode specifies that "*Demand Units*[26] *must remain connected and operating normally for rates of change of frequency up to 1 Hzs^{-1} measured over 500 ms*".

It is assumed that normal passive loads are in no way sensitive to ROCOF and no evidence has been found to the contrary.

NGESO currently work to maintain ROCOF within 0.125 Hzs^{-1} and this is expected to increase[27] following the completion of the Accelerated Loss of Mains Change Programme (ALoMCP) [23]. These limits do not currently exist within the standards and only reflect current operational practice to ensure system stability.

[26] An appliance or a device whose Active Power Demand or Reactive Power production or consumption is being actively controlled by the Customer.
[27] During the review it was anecdotally noted that this could increase to around 0.3 Hzs^{-1}

4.3.1.2 Loss of Mains Protection requirements

Loss of Mains (LOM) refers to the system condition where the main supply to a section of the network is lost (e.g. due to a fault on the feeder). Figure 10 illustrates a typical islanded scenario. All generators that are connected to or are capable of being connected to the Distribution Network are required to implement Loss of Mains protection. There are a number of reasons for this. When a power island is formed it can create a number of operational and safety related problems. These include [24]:

- Voltage and frequency within the island cannot be controlled by the DNO or the System Operator.
- Auto reclosing following a loss of synchronism between the islanded network and the distribution network.
- Protection systems may not operate properly in an islanded system.
- The islanded network may become unearthed.
- Damage could be caused to equipment if the network goes outside design voltage and frequency limits.

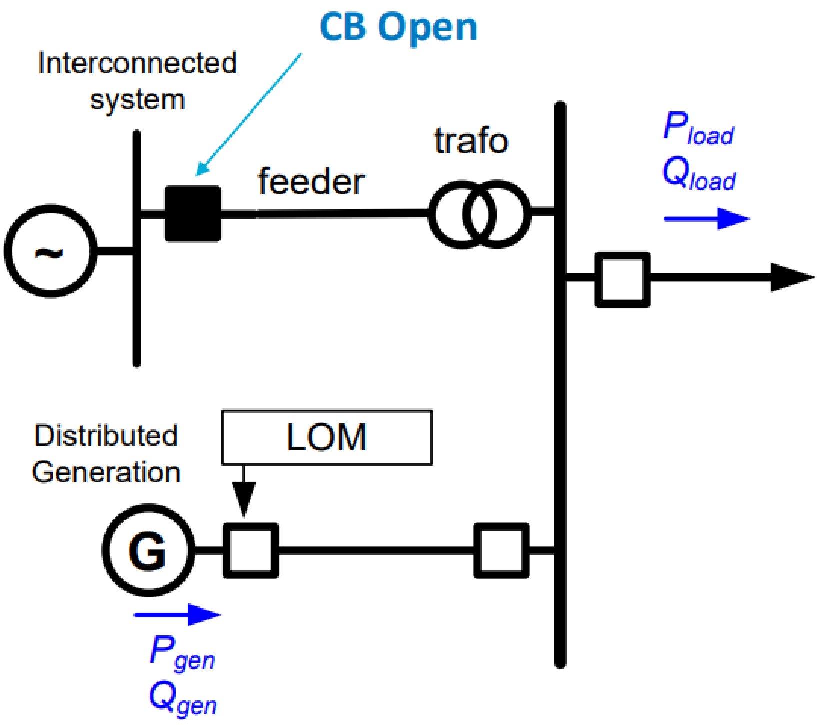

Figure 10: Typical islanded scenario [24]

There are three main forms of LOM protection:

- ROCOF – high ROCOF is indicative of a disturbance of the upstream supply system;
- Vector shift – detects sudden changes in the mains voltage angle caused by a change in output from the generating plant or changes to demand connected to the network.
- Intertripping – which works by monitoring circuit breakers that would normally trip in the event of a mains fault. Communication systems, such as pilot wires, fibre optic or microwave communications, are required to deliver Intertripping functionality

The need for LOM protection is primarily covered in Section 10.4 of G99. LOM protection is generally provided on Type A-C generators (those up to 50MW) via a ROCOF relay. G99 states voltage vector shift is no longer an acceptable form of protection for new generation.

The protection settings for the ROCOF relay is stated as 1 Hzs^{-1} (G99 Section 10.6.7, G59 section 10.5.7) and is being rolled out as part of the ALoMCP [23]. G59 states that the exceptions to this are:

- "Synchronous generation that was commissioned before 01/04/14 may, by agreement with the DNO, use a setting of less than 1 Hzs^{-1}, but not less than 0.5 Hzs^{-1}, with a definite time delay of 500 ms."

4.3.2 Options for changing ROCOF

Due to the changes in the generation mix and the associated reduction in system inertia (discussed more in section 4.4), it is becoming much more expensive to maintain the network within the current ROCOF limits. Management of system ROCOF incurs substantial constraint costs and therefore there is a strong cost incentive to relax ROCOF limits. Costs for 2018/2019 and 2019/2020 year to date are presented in Annex B.2. The costs shown are substantially above the forecast spend for the year, highlighting the scale of the problem.

However, it should be emphasised that the benefits of extending the ROCOF limits to 1Hzs^{-1} within the standards have yet to filter through to the network operation. This is being implemented through the ALoMCP [25] within a deadline of the 31 August 2022 to update their protection settings. Once this programme is complete, then it is expected that costs will come down. Within previous value calculations shown in Figure 11, it is noted that constraint costs will come down within 2-3 years (albeit these were calculated with constraint payments lower than are currently being paid). The ALoMCP roll out was estimated to cost between £31M - £96M [24], hence the period prior to NPV benefit.

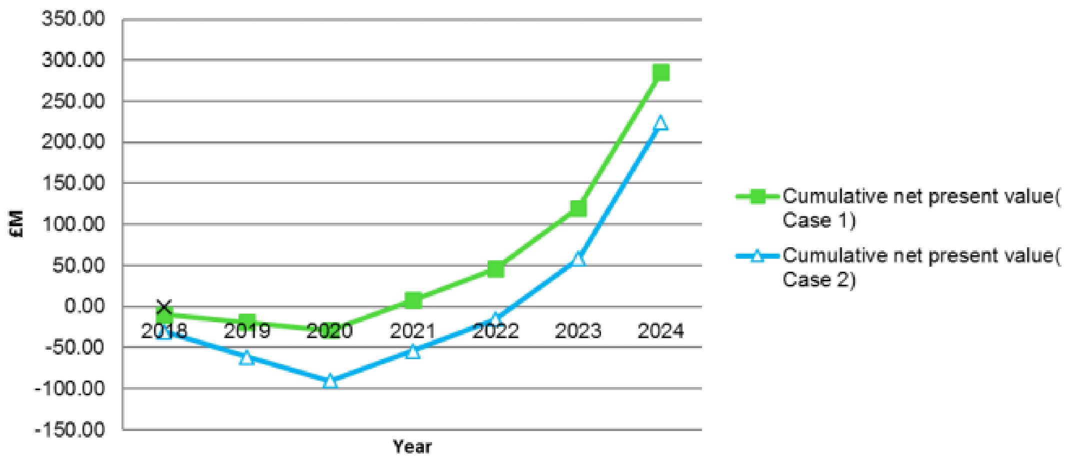

Figure 11: Net present value calculation from National Grid for the impact of implementing the Accelerated LOM change programme [24]

4.3.3 Future considerations on ROCOF

The position within GB is that 1 Hzs^{-1} remains the requirement until further notice. It remains to be seen whether there would be benefit in reducing this further in future from the perspective of constraint costs. Consideration would also have to be given to the investment costs of implementing any change.

There are two main risk areas with respect to a further reduction in the ROCOF setting:

1. The ability of connected equipment to withstand a high ROCOF; and,
2. The effectiveness of ROCOF as a means of Loss of Mains protection.

These are discussed further in the following subsections.

4.3.3.1 ROCOF withstand capability

Detailed work has been conducted into the ROCOF withstand capability of connected equipment by ENTSO-E [26]. The work highlights, as would be expected, that the ROCOF withstand of connected devices is highly variable. The paper notes that:

- Up to 4 Hzs^{-1} is possible for wind turbines;
- 2.5 Hzs^{-1} is a requirement for HVDC systems; and,
- 2 Hzs^{-1} a requirement for DC-connected power parks.

Whilst it is not stated in the paper, it is assumed that these are all for a 500ms measuring window. The key unknown is still around the capability of existing synchronous generation. Gas turbines in particular are noted as being susceptible to high ROCOF. This appears to be due to a Lean Blow Out failure mode.

The key message from the ENTSO-E work is that:

- "*Given the uncertainty on system characteristics and their future evolution, power generating modules need to be robust against changes to the system and shall provide RoCoF withstand capability which accounts for these varying system conditions*"

Therefore an increase of 'product' capability in tolerating a high ROCOF helps to future proof them in terms of operating within a low inertia system. Within the current GB standards, the withstand level and LOM settings are aligned. The ENTSO-E work suggests that there may be value in these diverging in future (as already appears to be the case with newer technology options). The future requirement for connected generation from the ENTSO-E is described in terms of both magnitude and duration for ROCOF. These are:

- ±2 Hzs^{-1} for moving average of 500ms window;
- ±1.5 Hzs^{-1} for moving average of 1000ms window; and,
- ±1.25 Hzs^{-1} for moving average of 2000ms window.

4.3.3.2 Impact on Loss of Mains protection

The long term role of ROCOF as a means of LOM protection is still unknown. The recent move to 1 Hzs^{-1} appears to largely resolve the containment issues and therefore may remain the solution for a number of years.

Any further increase of the settings may render it as an ineffective means of detecting LOM and increase the probability of issues such as unintended islanding. Work from the University of Strathclyde [27], analysing the change of ROCOF setting to 1 Hzs^{-1} at the consultation stage, highlighted that:

- *"ROCOF protection becomes very ineffective, especially with proposed setting option 4 (1 Hzs^{-1} with 500 ms delay).*
- *There is a significant difference (approximately two orders of magnitude) in the probability of undetected islanded operation between the existing recommended ROCOF settings (setting options 1 and 2) and the considered new setting options 3 and 4*"

However importantly:

- *"Risk related to accidental electrocution for proposed setting option 4 (in the region of 10^{-7}) lies in the broadly acceptable region according to the Health and Safety at Work Act 1974. Therefore, it can be viewed as acceptable according to the Act."*[28]

This highlights that at the 1 Hzs^{-1} setting ROCOF is already at the edge of its capabilities as a means of LOM protection. Referring to the level of 2 Hzs^{-1}, [28] notes "*ROCOF will cease to be an effective loss of mains protection".* Extension beyond this therefore does not appear to be an option in future and suggests new approaches to managing LOM may be required longer term.

As discussed within section 4.2.2, a decentralised energy system and the concept of operating microgrids would significantly disrupt current practice for managing LOM. Protection methods which enable effective and safe system islanding and ongoing operation with upstream system outages would underpin the operation of a more decentralised power system. Standards are still emerging for how these microgrids could be managed in future. Annex A.2 provides further details on the standards development activity around microgrids.

4.4 SYSTEM INERTIA

4.4.1 Challenges related to inertia

Inertia determines how quickly frequency will change when there is an imbalance between generation and demand. The relationship between system inertia and ROCOF is illustrated via the power system swing equation,

$$\frac{d_f}{dt} = \frac{dP \times f_0}{2 \times H_{sys}} \tag{2}$$

where d_f is the change in frequency over time, dt, dP is the change in active power, H is the system inertia and f_0 is the system frequency [29].

The NGESO Operability Strategy Report [30] highlights the key challenges related to inertia including:

- Reducing system inertia due to changing energy mix; and,
- ROCOF constraint is the dominant factor when managing system inertia.

National Grid (as it was then) stated that reductions in the largest credible loss (*dP* in (2)) is currently the most efficient solution. Reducing the largest credible loss would in turn reduce the system ROCOF in the event of that loss occurring. Additional inertia could be procured as an alternative, however the procurement of inertia is expensive. For example, adding 3 GW of synchronous generation to increase inertia will have approximately the same effect on ROCOF as reducing the largest loss by 100 MW [31]. This position may change over time and later sections discuss ongoing programmes to manage system inertia.

4.4.2 Role of inertia in the standards

There are no specific requirements to maintain a level of inertia within the current engineering standards. However Commission Regulation (EU) 2017/1485 Article 39 does create a requirement to consider establishing a minimum system inertia. Within Article 39 it is stated that:

"*3. In relation to the requirements on minimum inertia which are relevant for frequency stability at the synchronous area level:*

(a) all TSOs of that synchronous area shall conduct, not later than 2 years after entry into force of this Regulation, a common study per synchronous area to identify whether the minimum

[28] Risk of non-detection of LOM from ROCOF is mitigated through the operation of other protection methods (e.g. under frequency, under voltage)

required inertia needs to be established, taking into account the costs and benefits as well as potential alternatives. All TSOs shall notify their studies to their regulatory authorities. All TSOs shall conduct a periodic review and shall update those studies every 2 years;"

As part of this work, we have consulted NGESO to determine their position on the potential requirement to establish a minimum inertia standard. Their position is:

- "*NGESO is continually reviewing system stability and during the development and implementation of the System Operations Guidelines had determined that there was not a case to state minimum inertia benefits, in accordance with Article 39 of the Guidelines. NGESO has said that it will be using the two year review period within Article 39 to determine if such a requirement should be introduced into GB in the future in parallel with the development of stability requirements, products and services.*"

As highlighted within the System Operability Framework (SOF) and the Stability Pathfinder work, market based solutions are being sought to manage stability.

4.4.3 Requirement for the provision of inertia

An alternative means of providing inertia is to require connected sources to have this capability. This is inherent to synchronous generation but can also be provided by power converters through the supply of synthetic inertia. Internationally, requirements are being introduced within standards to provide this capability. For example, Hydro Québec enforce all wind turbines to provide synthetic inertia [32]. Other operators in Canada and Brazil are applying similar rules [33].

The inherent delay in the inertial response of synthetic inertia is one key uncertainty in the application of synthetic inertia [29]. If this cannot be employed within a very short timescale, i.e. within 500ms, then it will have a limited impact on system ROCOF over this period. It therefore may not tackle one of the key constraints on the system – the management of ROCOF and prevention of incorrect LOM protection operation. There is a strong business case if synthetic inertia can support management of ROCOF [34].

Related to this, NGESO are also in the process of introducing a non-mandatory technical specification titled:

- "GC0137: Minimum Specification Required for Provision of Virtual Synchronous Machine (VSM) Capability"

This will allow applicable parties (e.g. wind farms, HVDC interconnectors and solar parks) to offer an additional grid stability service.

It is noted that within the current governance structure, NGESO do have the capability to change standards (e.g. mandate requirements) in order to better manage system stability. However the governance process for making changes is relatively slow (proceed by consensus) and therefore this makes it difficult to respond to emergent issues in a timely way.

4.4.3.1 Stability pathfinder

Within the Stability Pathfinder project, NGESO are looking to establish alternative solutions and market arrangements to support the management of stability (includes inertia, dynamic voltage support and short circuit level contribution). Within this they are seeking a stability service across GB with zero MW output. The rationale provided for by NGESO for this service is:

- "*We require incremental stability capability beyond that which can be currently accessed through the market or the balancing mechanism. We currently access stability capability by calling on synchronous generators to run through the balancing mechanism. To make* *room for this generation and balance the system we take actions to turn down non-synchronous generation. This process is expensive, and through these pathfinder tenders we are exploring whether there are more economic solutions available which have less of an adverse impact on the wider system.*" [35]

Within Phase 1 of the project, tenders were sought for two known solutions to enable faster deployment. These are:

- Synchronous compensators; and,
- Synchronous generators running in a synchronous compensation mode.

Phase 2 of the pathfinder project has now launched with technical requirements defined in such a way as to facilitate the use of a wider range of technology types.

4.4.4 Understanding inertia on the system

As inertia decreases and the system becomes more sensitive to changes to system inertia, having an accurate understanding of what inertia the system has is increasingly important, on both the supply and demand side [36].

One area identified for standards in this area is to establish means to measure inertia in real time to help create a well-functioning market. Inertia monitoring is currently planned for testing by NGESO [30]. Two solution options are currently under test:

- A system developed by GE which is "*non-intrusive, continuously monitoring boundary activity and using machine learning to forecast the inertia up to 24 hours ahead"; and,*
- A system developed by Reactive Technologies solution which includes large ultracapacitors to inject power into the grid while measurement units directly measure the response.

The solution described by Reactive Technologies is described further within [37]. As well as supporting the inertia market, Reactive Technologies note that more accurate estimation of inertia has benefits including:

- Curtailment of renewables can be decreased (from 15% to 7%);
- Reserve procurement costs can be reduced (by between £30M-£100M); and,
- Grid resilience can be improved.

Central to the argument is that by better understanding the level of inertia on the system enables greater control over operability.

However it is recognised that these techniques are relatively immature. They will be built and tested during 2019/20. There is an aim for a real-time system to support operations, service procurement and network development by 2020/2021 [30].

4.5 SYSTEM STRENGTH AND FAULT LEVEL

System strength is another key parameter associated with the stability a power system. System strength relates to the size of the change in voltage following a fault or disturbance on the power system and how well the power system can return to normal operation following a disturbance or fault [38]. Short circuit level is a measure of power system strength.

As with system inertia, synchronous generation is a key source of short circuit current and by contrast non-synchronous inverter based generation (e.g. many renewable generation sources) provides limited reliable short circuit current [38] [39]. As the volume of synchronous generation declines, so does the system short circuit level with NGESO highlighting a national decline of up to 15% from 2019 levels by 2025 [39]. The Stability Pathfinder project, described in section 4.4.3.1, is in part designed to mitigate the decline in system short circuit level.

Low system strength can pose issues such as:

- Wider area under-damped voltage and power oscillations and voltage transients;
- Mal-operation or failure of network protection;
- Increased harmonic distortion;
- Instability of generation voltage control systems; and,
- Prolonged voltage recovery after a disturbance [38].

4.5.1 Standards and short circuit level

The avoidance of stability and other issues related to low system short circuit level are primarily managed through the SQSS with specific implementation guidance to system users provided via the Grid Code.

Within GB, there is no requirement to maintain a specific short circuit level although it was noted through this review that this has become the practice within Australia. In September 2017, the AEMC published a final rule to place an obligation on Transmission Network Service Providers to maintain minimum levels of system strength [40]. As part of the Fault Level Rule:

- *"Each region's System Strength Service Provider (SSSP) is required to maintain the minimum three phase fault levels at each fault level node in each region. AEMO is required to determine where the fault level nodes are in each region, plus the minimum three phase fault levels and fault level shortfalls at those fault level nodes. Fault level shortfalls are then to be addressed by the SSSPs providing system strength services*." [41]

This rule, and the associated methodology presented in [41], provides a benefit through the clear articulation of:

- The required minimum fault current level which must be maintained within (and how this is measured); and,
- The historical minimum fault current on each network (which were maintained for 99% of the year) and hence by extension the potential fault current shortfall.

Such an arrangement provides clarity on the extent of the regional issues present within Australia, the potential issues with the connection of further non-synchronous generation and provides a target for mitigations (e.g. the Stability Pathfinder project for the GB network).

Whilst the Grid Code does not stipulate a minimum fault current level, recent modifications have been made to require fault level data under both maximum and minimum demand conditions to be published (previously only maximum was published). This is now published as part of the Electricity Ten Year Statement and was included as part of the 2019 statement.

This will provide greater transparency on the regional short circuit level and the potential issues that different DNOs may face at their interface with the transmission network.

4.6 CONCLUSIONS

A key concern within this topic area were the high operational constraint costs associated with managing system ROCOF. It is noted that whilst these costs remain high at present (and continue to grow currently), the change in the ROCOF protection setting with G99/G59 and the implementation of this change through the ALoMCP should see these costs reduce substantially over the coming years.

Longer term there are questions around the suitability of ROCOF as an effective means of LOMs protection, particularly if the 1Hzs^{-1} setting was to be increased. This may necessitate changes to the way this protection function is specified and implemented.

The topic area also addressed management of system frequency. There is no significant drive to wider frequency tolerance at current however this may change over time if the electrical system becomes a less centralised system architecture.

Through the review it is noted that frequency requirements are stated across multiple documents and articulated in different ways: ESQCR presents a hard limit, SQSS defines Unacceptable Frequency Conditions, Grid Code defines the requirements across different time windows. A more consistent expression of frequency would be of benefit to system users.

Finally the topics of system inertia and short circuit level were discussed. Management of reducing system inertia is a key concern going forward for the network. However it is just one means (albeit an important one) to manage system frequency and ROCOF. Therefore from a standards perspective it appears more efficient to focus on the key outputs (frequency and ROCOF) rather than specify minimum levels of inertia to manage these outputs. Whilst declining short circuit level also continues to be a concern for system operation, no specific standards issues where noted. However it was observed that the practice within Australia of stating a clear minimum fault level requirement presented benefits and implementation of similar requirements in GB could support provision of system strength services.

5. SECURITY OF SUPPLY AND RELIABILITY

This topic area is focussed on the current security of supply standards, how these may constrain the utilisation of the network and how they may be adapted to meet the future needs of customers and the low carbon agenda. Areas of investigation include:

- Methods for valuing the reliability of supply;
- Enhanced utilisation of existing transmission or distribution assets through changes to deterministic reliability rules; and,
- The role of flexibility within the standards.

The capacity market arrangements and the electricity capacity reliability standard[29] were not reviewed in detail within this review. This topic is covered by a separate independent review activity [42].

5.1 THE VALUE OF A RELIABLE AND RESILIENT ELECTRICAL SYSTEM

5.1.1 Economic and societal costs of power outages

The UK's reliance on the electricity network has increased for many decades and this trend is likely to continue in future with the electrification of heat and transport systems. This reliance is forecast to continue increasing due to factors such as the anticipated electrification of transport and heating.

Power outages, particularly large-scale outages, have significant economic and societal implications. Due to the complex nature and size of the system, the potential economic impacts are extremely difficult to predict (and are closely tied to an individual's value of lost load (expanded on in the next section). However understanding the impact is fundamentally important to inform an economically rational response to outages (both in terms of defending against them and restoring from them). Table 6 presents a range of historical example costs for both single events and cumulative yearly impacts in the UK and internationally.

Various methodologies and tools are available to support the prediction of costs. One such tool is the Blackout Simulator [43][30]. Using this tool to simulate an example scenario of a 24-hour GB wide power outage provides an estimated economic damage of between £5.2 billion and £5.5 billion[31].

[29] The reliability standard is 3 hours of expected loss of load per capacity year as defined within Part 2 of The Electricity Capacity Regulations 2014.
[30] An online cost-simulation tool developed within a European Commission FP7 research project which uses the data from thousands of surveys and valuations in each of the EU-27 countries to estimate the overall costs of a supply interruption for a specified area, time and duration. Reference [47] provides a critique of the advantages and drawbacks of the tool; this report uses it purely for illustration.
[31] The results were taken for a blackout starting at midnight on the second Monday of each month in 2020. There is variance throughout the year based on customers' changing VOLL (which is considered to be lower in the summer months).

Table 7: Various examples of outage related economic costs

Event	Approx. number effected	Duration	Cost Estimate	Source
National cost of power interruptions in the US across the year	Varied[32]	Varied	$59 billion per year (2015-$)	[44]
			$30bn to $50bn per year	[45]
National cost of power interruptions related to severe weather in the US	Varied	Varied	$2bn to $3bn per year	[45]
Preventative Power Cuts in Northern and Central California	800,000	48 hours	$1bn to 2bn[33]	[46]
Canada / Northeast US, August 2003	50 million	Between one and four days' blackout	$4.5bn to $8.2bn	[47]
Italy/Switzerland 2003	56 million	Between 1.5 and 19 hours	€1.18bn	[47]
Somerset storms 2014	750,000 homes	90% restored within 24 hours,16,000 homes around 48 hrs, 500 homes around 120hrs (some homes where disconnected for weeks)	£431.6m	Event details from [47]. Cost calculated based on Ofgem CBA costs for CI and CML.[34]

Table 6 and the Blackout Simulator example simply serve as examples that customers and the economy are highly dependent on a reliable and resilient electrical system and economic damage can quickly escalate. This must be taken into account when considering economically efficient investment in the electrical system.

Beyond this there are other considerations including the longer-term effects macroeconomic impacts of electricity shortfalls, such as deterring investment [47], and the knock on effects on crime rates and critical services which depend on the electrical system [48].

5.1.2 Valuing a customer's reliability of electricity supply

Understanding the monetary value of the reliability of electricity supply is key to determining the appropriate investment to maintain this reliability to customers. The analysis of this value helps to highlight the competing tensions between reliability and affordability that customers face. Various terms are used to describe this value. These include:

[32] Majority of outage costs are borne by the commercial and industrial sectors
[33] This estimate was generated using the Interruption Cost Estimate Calculator, an American tool similar to the Blackout Simulator.
[34] CI (£s per interruption) is £15.44, CML (£s per minute lost) is £0.38.

- Value of Lost Load (VOLL) [49], [50], [51], [52], [47];
- Value of Customer Reliability (VCR) [53] [54];
- Customer Interruption Cost [50];
- Value of Service Reliability [55]; and,
- Electric service reliability worth [56].

There are also various metrics for these different terms including cost per interruption, cost per unit power and cost per unit energy[35]. VOLL, typically measured in cost per MWh, is the most widely used term and is used across GB to help guide network investment. As such, this report will use VOLL for ease of reference to represent this customer value.

There are a number of international practices for assessing VOLL. Points of variation include:

- How customer information is gathered (e.g. through surveys);
- The possible attributes of VOLL which are considered;
- How these attributes are combined to establish a monetary value for VOLL for different customer types; and,
- Ultimately how this value is used to inform network investment plans [52].

Naturally, this leads to variation in how different countries report VOLL and the relative differences for different customer types.

To help frame the key attributes which impact VOLL, [55] discusses the concept of a Customer Damage Function (CDF). The CDF represents the economic losses as a result of reliability and power-quality problems. The CDF is represented as:

$$Loss = function\langle \text{interruption attributes} | \text{customer characteristics} | \text{environmental attributes} \rangle$$

A range of attributes which influence VOLL are outlined in Table 8.

Table 8: Attributes influencing the impact of a power outage

Attribute type	Attribute
Interruption attributes	Interruption duration
	Season
	Time of day
	Day of the week during which the interruption occurs
Customer characteristics	Customer type
	Customer size
	Business hours
	Household family structure
	Presence of interruption-sensitive equipment
	Presence of back-up equipment

[35] As part of the OFGEM RIIO ED1 cost benefit template costs are provided for Customer Interruptions (£15.44 per interruption), and Customer Minutes Lost (£0.38 per minute lost)

Environmental attributes	Temperature
	Humidity
	Storm frequency
	External/climate conditions.

The value 'profile' (i.e. their relative importance and how they can change over time) of each of the technical factors outlined above will vary based on the type of customer. For example, values stated within [53] highlight for a domestic customer and small businesses the duration of an outage is a key and often dominant element for calculating value. The difference in monetised cost of a power outage can vary orders of magnitude between a short outage (up to 1 hour) compared to outages up to 24 hours [50] (i.e. there is a relatively low impact for short interruptions but rapidly increasing with duration).

Conversely, in some (but not all) cases, the value profile for large industrial customers can be relatively insensitive to outage duration. This can be due to typically high fixed costs caused by an outage (e.g. from the need to restart plant, such as a production line, following an outage which itself can take time). The impact can therefore be high initially and increase slowly with duration time [53].

5.1.2.1 Current methods and limitations

A VOLL of £16,000/MWh was established for RIIO ED1 by Ofgem and this figure is used to represent the economic measure of a supply interruption [57] (including setting the IIS incentive rates [58]). A VOLL of £17,000/MWh is now commonly used based on a 2013 study by London Economics [49]. This is a guide for determining suitable investment levels to deliver security of supply alongside standards and incentive schemes.

Key issues with the aggregation of a single value of VOLL are:

- It does not differentiate between different customer types or reflect the significant variation in financial and social impact of supply interruption for those customers.
- Important attributes such as outage duration or customer numbers are treated as having a linear increase in 'customer damage':
    - The impact of a community outage may be more than the multiple of individual VOLLs;
    - The impact of duration is widely analysed and can influence the headline VOLL figure (e.g. the methodology described in [54] uses the VOLL for different outage times within a weighted sum to calculate a singular VOLL value);
    - However, aggregating VOLL decouples solution options from the individual attributes. Again take outage time as an example: solution options that reduce either the frequency of outages or the duration of outages are not compared to their true value (i.e. it may be more cost effective to focus on solutions that reduce the duration of an outage when it does occur for residential customers as this is where the higher value lies).
- Fundamentally, it also does not account for the opportunities presented by a smart electrical system. These are discussed in the following section.

5.1.2.2 VOLL and flexibility

The approaches reviewed to date treat supply to a given customer as binary – either on or off. With the functionality provided by the smart control of demand this will increasingly not be the case and it will be possible to reduce total demand whilst continuing to supply essential loads[36].

To achieve this effectively requires an understanding of the temporal VOLL for different load types that an individual customer will connect to the network. For example, the VOLL for an EV charger, electric heater or a fridge will be negligible for momentary or short interruptions (although you would expect a sharp increase with duration based on when the battery requires to be charged, temperature in the home reduced or the risk of food spoiling increased). The utility provided by essential load (e.g. lighting, cooking, at home medical equipment) would represent a much higher £/MWh VOLL. Therefore whilst the overall VOLL for customers with a heat pump or EV may be higher (as [57] identities) this will be highly variable with outage duration (and potentially many other factors). None of the resources reviewed as part of this work reflect this load dependent view of VOLL.

The ability to differentiate between “essential” and “non-essential” demand, and the utility value of this load, will provide an opportunity for radically different management of network constraints. By switching off non-essential loads when a network is constrained, while keeping supply of essential loads, this new approach will:

- Enhance the utilisation of network assets; and,
- Ensure reliable supply to essential load.

Further work is required to understand how a regulatory incentive scheme could be aligned with such as design approach and how this would be monitored. Measures such as Customer Interruptions and Customer Minutes Lost take on a new meaning when considering interruptions or reduced supply to non-essential loads where the impact to consumers is low.

5.2 SECURITY OF SUPPLY STANDARDS LANDSCAPE

Figure 12 provides an overview of the key security of supply and availability standards and the relationships between them. The primary documents of interest for this topic area are the SQSS, Engineering Recommendation P2/7 and the Interruption Incentive Scheme. These will be discussed it the relevant sections below.

[36] This will in effect mean that a single customer will have multiple VOLLs at any one time depending on the load types that they use.

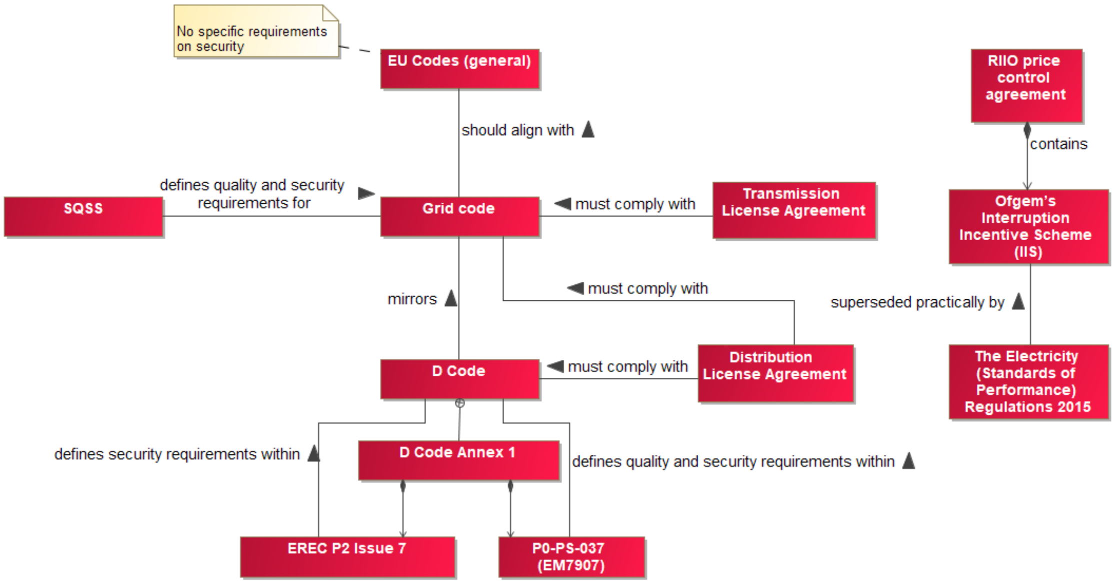

Figure 12: Map of relevant standards, agreements and regulations associated with security of supply and supply availability

5.3 SECURITY OF SUPPLY FROM THE DISTRIBUTION SYSTEM

Security of supply at the distribution level is driven by P2 and the IIS.

In cases where the connection of the whole of a group of demand[37] is lost, P2 sets a design standard for how quickly that group's demand, or part of it, should be restored. The network should be designed in order to enable restoration in that period of time. For some groups under some conditions, the restoration time is zero, i.e. the whole of a group of that size should not be disconnected at all for a single circuit fault outage or a single fault coincident with a planned outage. The effect of P2 is to set a minimum deterministic standard for the number of sources (traditionally circuit based) which must be connected to a given group demand and the capacity of those sources[38]. Different classes of supply are provided to different demand groups depending on the size of the group demand, within lower group demand classes nested within the larger groups. P2 was last updated in August 2019 (to issue 7). The latest update reflects the capacity provided by both circuits and non-circuit based solutions (e.g. demand side response, energy storage) when assessing security of supply. Engineering Report 130 is a guidance document which describes the acceptable means of compliance with P2.

The Interruption Incentive Scheme sets Customer Interruption (CI) and Customer Minutes Lost (CML) targets for DNOs and provides revenue incentives or penalties either side of that target. By setting performance targets for CIs and CMLs, the IIS incentivises high availability of supply to customers. Traditionally IIS targets are set based on historical performance and based on the asset base of the given DNO. This has also previously been considered to be a lagging indicator of network reliability [59].

[37] Group demand is defined within P2/7 as "*the DNO's estimate of the maximum demand of the group being assessed for EREC P2/7 compliance with appropriate allowance for diversity.*"
[38] The terms n-2, n-1, n-0 etc are used to describe the number of sources available to meet a given demand 'n'.

PO-PS-037 is the standard used by SHEPD. The current version aligns with P2 Issue 6 (P2/6) in terms of security. This also includes some additional considerations for outages related to rural networks.

In reviewing the standards related to distribution system security of supply, three key questions were considered:

1. Does P2 deliver value for money?
2. Do the current set of standards enable the value of system flexibility to be achieved?
3. Are deterministic standards required at all given the role the IIS?

The following sections outline investigations into these three questions.

5.3.1 P2 and value for money

The genesis of the question of whether P2 delivers value for money comes from a 2015 study conducted by Imperial College [40]. The work, reviewing P2/6 as it was then, highlighted that:

- "*the present security standards tend to be conservative, dealing with worst case scenarios. This implies that the present security standard would be cost effective only for "extreme" cases with high failure rates, long restore/repair times and low upgrade costs."*
- "*In most cases however, particularly at the medium voltage level, the existing networks (both feeders and substations) could accommodate demand growth in the short term, relaxing significantly the N-1 requirement.*"
- *For reliable networks, with low failure rates and low restore/repair times, the peak load could nearly be doubled without the need for network reinforcement (network could be operated with no redundancy, e.g. at N-0 security as relatively modest increase in interruption costs would not justify network reinforcement).*

Core to the argument above is that on a per substation (demand group) basis P2 is not economically efficient in a number of cases and the 'breakeven' VOLL which would justify certain reinforcement work is far in excess of the actual VOLL. This was particularly the case for circuits with high reliability. The conclusions therefore are that in many cases the standard could be relaxed (although not in all cases) and if the standard explicitly balanced the cost of network infrastructure with the security benefits delivered to electricity network customers[39] [60], then network costs would be reduced. The actual cost saving this provides varies with the scenario considered however the potential benefits of relaxing the N-1 security constraints at the GB level could reach up to £4bn to £7bn by 2030 in case of significant load growth at LV and HV level [40]. These cost savings are independent of any saving through deployment of load flexibility which was covered separately.

5.3.1.1 Why might the standards be overly conservative?

Fundamentally, the current distribution security of supply standards (P2/7) are based on probabilistic and cost-benefit analysis that has then been converted into a set of generic design rules. This is a strength in terms of simplicity and transparency of application, although the binary approach to risk (i.e. all risks are considered equal) can lead to a simplistic view of risk and non-optimal design for individual circumstances. As all supply routes will exhibit different

[39] This could follow the approach adopted by the electrical distributor in Victoria, Australia. Victoria is the only NEM jurisdiction that adopts a probabilistic approach to distribution network planning. This approach means that there are no mandatory security standards or reliability performance standards that the Victorian DNSPs must meet. Instead, the need for reliability-related investments is determined by applying a cost-benefit assessment". [138]

failure rates and different repair times, availability and security of supply will vary widely even where similar levels of asset redundancy is used.

5.3.1.2 DNO derogation from P2 compliance

The P2 standards are not applied at all times. As highlighted within [61]:

"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."

Therefore, options already exist for the DNOs to make risk and economic judgements regarding the provision of security of supply, which supports economically efficient design. Derogations from P2/6 were in place below the 60MW group demand level for a number of years [62] and P2/7 now provides the option for risk and economic studies (through the guidance within ETR 130) to be undertaken to justify any departure from the normal standard.

5.3.1.3 Increased cost of interruptions

Clearly, any reduction in security will reduce overall network reliability of supply and resilience against certain events. It was noted during the review that the work within [40] had focussed on assessing economically efficient investment on a per substation (demand group) basis. The potential issue is if individually economically sensible decisions were made it could incrementally increase the probability of failure across the whole network causing whole system problems. Resultant problems include the concurrent outage of multiple primary substations around the GB network and the associated outage costs and maintainability challenge for DNOs.

A key constraint within much of the analysis conducted to date is that it was based on a static value of VOLL (the costs savings from the ICL study were based on £17,000 MWhr although 'breakeven VOLL' and the impact of variable VOLL were explored). As outlined in section 5.1.2, aggregating and linearizing VOLL does not appropriately represent the customer type on a given feeder, the effects of larger scale or longer duration outages. Therefore further work, based around a more accurate determination of VOLL, is required to establish the true cost-benefit trade-off within the current standards.

5.3.2 Flexibility and security of supply

Smarter grid control will enable the provision of security through a more flexible and sophisticated system operation, rather than through asset redundancy only. This includes the use of demand side response, distributed generation and energy storage as means of providing capacity. Research from Imperial College calculates that the potential benefit of smart disconnections of non-essential loads could be between about £2bn and £3.4bn[40], which is achieved by avoiding reinforcement in distribution networks [40]. Work from The Association for Decentralised Energy estimates that if the UK deployed 4 GW of DSR (around half of what they estimate is currently available) through the Capacity Market then it would avoid the need for multiple new generators and provide a net saving of £2.3 billion by 2035 [63]. Looking at whole system costs, a separate Imperial College study indicated that approximately £10bn to £13bn of network CAPEX investment could be saved by 2050 by exploiting flexible technologies [64].

P2/7 (alongside the guidance document ETR 130) now recognises flexible operation can contribute to security of supply. Within P2/7 it states:

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[40] Not including cost of technology roll out.

- "For demand groups containing DG, DSR, or other means, the security contribution of the DG, DSR, or other means of providing network capability"

Within their P2 guidance documentation [65], UKPN note:

- "other DER can be considered as contributors to the security of supply and therefore used for EREC P2 compliance. These include, but not limited to; electricity storage, electric vehicles and flexibility services. In order to determine the effective security contribution from Demand Side Response (DSR), it is necessary to carry out an assessment of the magnitude and longevity of the demand reduction which is likely to be delivered by the DSR contracts in place at the time when the intervention would be needed to meet the security requirements of EREC P2".

This is now being used in practice to help prevent the need for system reinforcement (e.g. a demand side response scheme connected to the ENWL network [66]).

Importantly within P2/7, the security of supply in terms of capacity is unchanged. However as this capacity can now be composed of circuit and non-circuit based solutions, this provides the option for the circuit based capacity to no longer meet the peak demand (deferring or avoiding reinforcement) with flexible resources making up the difference to achieve the N-X design requirement.

However this will be more challenging for more distributed and 'non-contracted' capability. As stated in ETR 130:

- "Non-Contracted DSR Schemes should be assumed to have no contribution to security, unless the DNO is aware of site-specific details".

This highlights that for the above to be achieved in practice down to the customer level, there are key issues around:

- Visibility of this capability (i.e. does the DNO know how much demand reduction capability exists); and,
- Assurance of operation (can the DNO be sure the response will perform when needed and as expected).

Questions of uptake at the customer level are explored further in section 7, with section 8 highlighting issues around interoperability.

5.3.3 The role of P2 and the Interruption Incentive Scheme

It is the understanding of the Panel that is it the IIS rather than P2 that drives the bulk of the reliability of supply at the customer level[41]. This raises the question of whether P2 is required.

5.3.3.1 What does P2 do and why do we need it?

In cases where the connection of the whole of a group of demand is lost, P2 sets a standard for how quickly that group's demand, or part of it, should be restored[42]. The network should be designed in order to enable restoration in that period of time.

[41] Although it is noted that derogations were previously in place for P2 non-compliance under certain operating conditions and where demand was lower than 60MW [62].
[42] For some groups under some conditions, the restoration time is zero, i.e. the whole of a group of that size should not be disconnected at all for a single circuit fault outage or a single fault coincident with a planned outage.

This clarity of restoration time is not a feature of the ISS. This function of the standard is likely to provide important effects on outage duration (at least as a minimum standard for designers to work to and for consumers to understand) and would have to be replicated elsewhere.

5.3.3.2 Are we confident that IIS will deliver required outcomes?

Based on a review of CI and CML performance from the GB DNOs, CI and CML performance consistently remains high and they generally deliver to or better than targets. Table 2 highlights a sample of results from the 2016-17 RIIO ED1 report. Further results are published directly by the DNOs (e.g. [67]). Both reflect general target beating performance.

Table 9: Reliability status, 2016-17 [RIIO ED1 Annual Report 2016-2017]

	Customer Interruptions (CIs)[1]	Customer Minutes Lost (CMLs)[2]		Customer Interruptions (CIs)[1]	Customer Minutes Lost (CMLs)[2]
ENWL	32.90	33.71	LPN	17.22	19.78
NPgN	53.29	45.00	SPN	47.72	35.06
NPgY	48.54	38.01	EPN	49.37	39.20
WMID	58.96	31.97	SPD	42.89	29.33
EMID	44.13	21.96	SPMW	38.16	37.34
SWALES	41.64	25.73	SSEH	68.11	59.89
SWEST	52.45	39.70	SSES	47.82	43.30

1. CIs are the number of customer interruptions per 100 customers on the network.
2. CMLs are the average length of time customers are without power per interruption.

Figure 13 illustrates the historical CI and CML trend between 2001/2002 and 2017/2018. This highlights that both CIs and CMLs have approximately halved in this period. The particular significance of this is that P2 in terms of demand security has not changed over this period. This emphasises the effect that the IIS has had on end customer availability of supply.

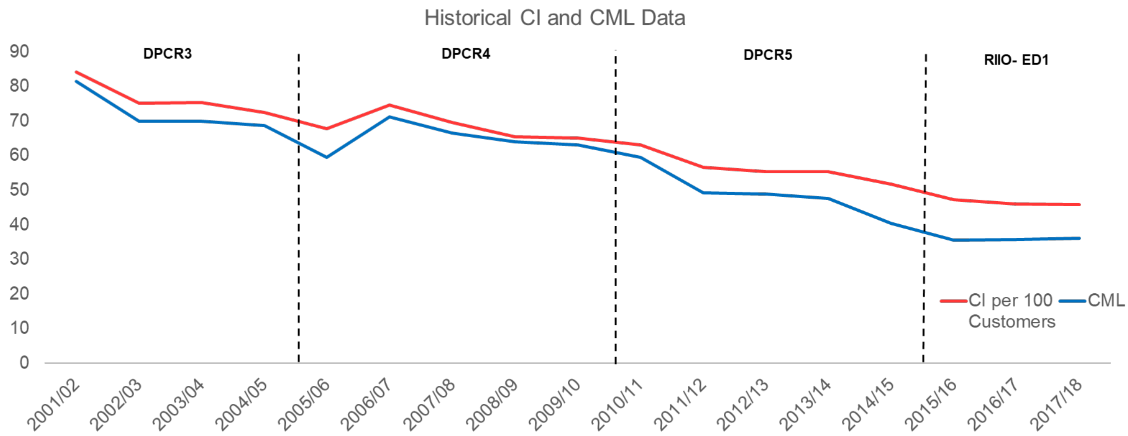

Figure 13: CIs and CMLs have continued to reduce since 2001/2002

In their design guidance [65] UKPN acknowledge that CI and CML targets may drive them to exceed the P2 design criteria[43] (although we do not have evidence to demonstrate how often this is done in practice). This implies the IIS is driving greater levels of security than P2.

[43] It was noted by the panel that this practice has been in existence for many years and the HV/LV network was already designed to a higher standard than P2/5 in 1978.

5.3.3.3 Should the IIS be changed?

Currently the CI and CML targets within the IIS act as a proxy for VOLL. This link could be adopted more explicitly within future incentive schemes [68].

This is explicitly part of the Australian Incentive Scheme. The rate used to calculate reliability incentive bonus/penalty is based on the "value of customer reliability" expressed as a value per unsupplied MWh. This is set at $97,500/MWh for central business district customers and half this value for all other customers, which have been derived through Willingness To Pay (WTP) studies [69], [70].

This provides some precedent for formally considering the value of reliability/lost load/unsupplied energy within the incentive scheme, albeit only considering two static values for business and other customers. Further work is required to define how this could be extended for the various parameters of VOLL discussed in section 5.1.2.

5.4 SECURITY OF SUPPLY FROM THE TRANSMISSION SYSTEM

Security of supply requirements for the transmission system are defined within the SQSS.

The SQSS is both a design and operational standard and focusses on the prevention, containment of and restoration from secured events[44] on the transmission system. As with P2, the minimum planning supply capacity and restoration requirement following secured events is based on group demand.

While not considered to be a significant driver for transmission security, National Grid do also monitor and report reliability of operation of the transmission system [71]. This is measured in Energy Not Supplied (ENS)[45]. NGET and the Scottish Transmission Operators (TOs) are incentivised to reduce ENS events through the Energy Not Supplied Incentive Scheme [71]. The target for NGET is 316 MWh per annum. NGET are penalised (up to £48m) for loss of supplies above this figure and earn money (up to £3.7m) for less than this. NGET is seeking to retain this incentive in the T2 regulatory period.

For context on performance, a benchmark of NGET's performance against international transmission utilities is presented in Figure 14. This highlights the high reliability of the NGET compared to international standards.

[44] "*A contingency which would be considered for the purposes of assessing system security and which must not result in the remaining national electricity transmission system being in breach of the security criteria. Secured events are individually specified throughout the text of this Standard. It is recognised that more* ***onerous unsecured events*** *may occur and additional operational measures within the requirements of the Grid Code may be utilised to maintain overall national electricity transmission system integrity.*"
[45] Volume of energy to customers (MWh) that is lost as a result of faults or failures on the network

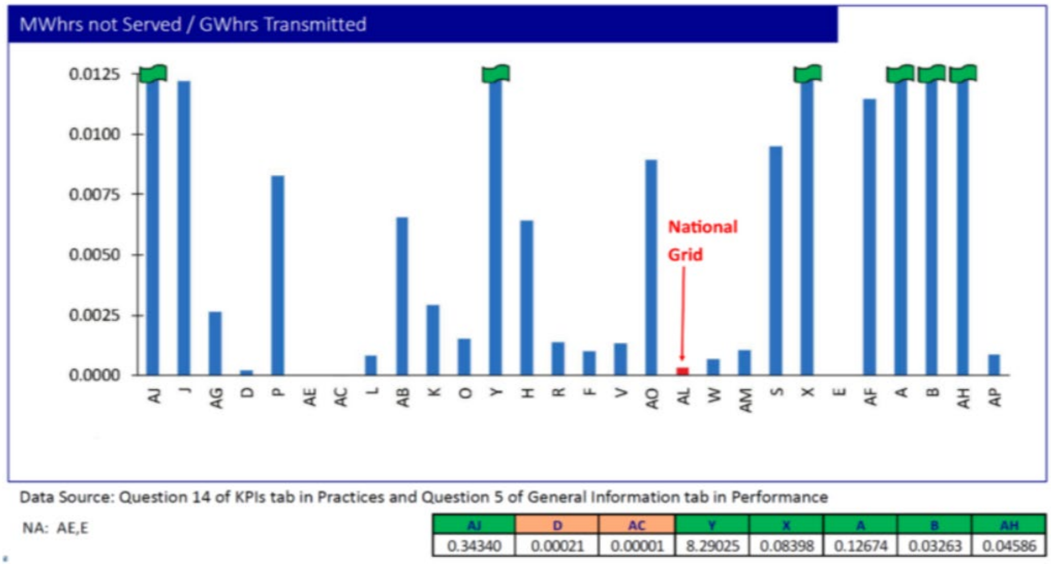

Figure 14: NGET's ENS performance against 27 other (anonymised) international transmission utilities for 2016/17. [71] (Original source: ITOMs Benchmarking report for 2017)

Compared to distribution system planning, transmission security of supply has received relatively little attention within the research literature with regard to more economically efficient design (perhaps due to the consequences of failures on this network). However, it is noted that flexibility in the generation connection rules through Connect and Manage has shown benefit by accelerating connection of renewable resources, albeit at with increased constraint costs [72].

Greater focus, if somewhat limited, has been given to operational approaches to maximise capacity, such as a 2011 study on the Scotland-England interconnector [73]. The study argues that fixed deterministic rules relating to the capacity can lead to economically inefficient network operation and excessive constraint costs on connected renewable generation. Relaxing operational security rules could, in theory, open up capacity on the network. This would be particularly effective in lower-risk operating environments (e.g. fair weather).

In reviewing the standards, this section has focussed on the question of operational flexibility and particularly that which supports better utilisation of transmission and renewable generation assets.

5.4.1 Operational flexibility and adaptive security

Within the SQSS, Section 2 relates to the “Generation Connection Criteria Applicable to the Onshore Transmission System”. This defines deterministic criteria that secures against Limits to Loss of Power Infeed Risk.

The criteria outlined can impose constraints on the transmission network – necessitating the reinforcement of the network (even if not justified through a cost-benefit analysis (CBA)) or increasing constraint costs. These constraints can be imposed for events with relatively low probability (e.g. busbar faults). The question therefore is, could alternative means of managing this risk be accommodated which would provide economic benefits?

One approach to achieving this is through ‘adaptive security’, a concept described in a Cigre C1.17 Working Group report titled “Planning to Manage Power Interruption Events” [48]. Adaptive security enables changes to operational security rules based on current operational risk[46]. The main benefit of such an approach is that the procurement of additional ancillary services or restrictions to the electricity market need only be implemented when operational risks are high (or relaxed when low depending on the rules are being adapted).

SQSS employs elements of adaptive security. Within the SQSS there is operational flexibility to increase security of supply in more adverse conditions: "5.6 *During periods of major system risk, NGESO may implement measures to mitigate the consequences of this risk*." This is similar to the above and allows system security to be increased in adverse conditions.

As an international comparison, the Australian transmission security standards are also adaptive [74]. These also appear to offer a more relaxed and dynamic view to transmission planning. These standards consider 'Credible and non-credible contingency events' (equivalent to 'secured' and 'unsecured events' in SQSS) which the network must be secured against (or not as the case may be). These are still deterministic standards, however noteworthy points are:

- Busbar faults are considered 'non-credible events' in the Australian standards, whereas they are secured against (i.e. credible) within the SQSS; and,
- There is a mechanism for re-classifying contingency events under certain conditions within the Australian standards (e.g. a busbar fault may normally be non-credible but during a storm it can be reclassified to credible for a time limited period).

On this basis there is a wider security envelope in the Australian standards than in SQSS and they are also more explicit about the conditions under which security requirements may change. Such an approach would provide some additional flexibility to better utilise assets within low risk operating conditions, whilst constraining operation when necessary.

Further work is required to quantify the scale of these benefits. Annex B.3 provides the transmission constraint costs for 2018/2019 and 2019/2020 year to date however it is not clear how much of this cost relates to the scenario described. Annex B.4 adds another dimension to this by breaking down constraint costs by fuel type, however this includes all constraints and not just those related to transmission. A more granular breakdown of the cost of securing against particular conditions would be required to better understand the cost/benefit of different operating strategies.

5.4.2 Challenges of adaptive security

Adaptive security does not come without risks and challenges [48]. If adopting a more flexible standard, e.g. the Australian approach of reclassifying faults, a key challenge is to ensure that additional security is available when required. If being adaptive in operational timescales, how should you account for planning timescales? For example, if the probabilistic approach to security has not brought forward the necessary investment then it may not be available in operational timescales.

Other challenges include understanding and visibility of risk. It may be difficult for a system operator to know with confidence what the probability of an adverse event is or, for example, the weather in a remote part of the transmission network.

5.5 CONCLUSIONS

The conclusions from this section are discussed below.

[46] This assumes probabilistic understanding of risk on the network.

5.5.1 The current use of VOLL

The current approach to considering VOLL as a single value (which may already be too low) appears to no longer be fit for purpose. The issues are:

- It does not differentiate between different customer types;
- The aggregation and linearization of attributes such as outage duration or customer numbers may disguise the magnitude of an outage or not appropriately value responses to an outage; and,
- It does not differentiate between load types whose response to outages can be very different.

Recognising the individual customers and loads have a different VOLL is complex to deal with, plan for and incentivise. However application of such means of monitoring VOLL will be critical to appropriately valuing a customer's reliability of supply (and the flexibility within that). A flexible approach to VOLL, and the concept of interruptible load, will require a restructuring of the current CI and CML based incentive scheme.

5.5.2 Distribution system security of supply

By their nature, deterministic standards can result non-optimal design by applying a 'one-size-fits-all' design approach. The counter to that however is the transparency of design rules (i.e. all DNOs following the rules rather than individuals interpreting outcome based measures differently) and the relative simplicity of their application, which reduces planning and design effort and cost.

The work from Imperial College showed that there are clearly cases where it would be inefficient and very costly to reinforce circuit based capacity following anticipated load growth. On a circuit by circuit reliability basis at least, reducing the demand security appears to be economically rational in many cases[47]. However, this will lead to an increased number of outages may have some undesirable wider system effects (such as the challenge in managing these outages).

It is acknowledged that a reduction in security of supply would be conceptually difficult to accept given the general trend for improving supply reliability. Therefore it is considered that the costly reinforcement cases are prime candidates for more flexible solutions which could maintain the same security of supply but with non-circuit based solutions. This is the approach allowed within P2/7.

Whilst the design rules to enable flexibility are in place, the infrastructure or lower level implementation standards are not. There are still key issues around volume and visibility of flexible capability and assurance of operation. Later sections of this report will explore questions of uptake at the customer level and interoperability.

5.5.3 Transmission system security of supply

For transmission systems, opportunities were noted around the use of adaptive security (e.g. the relaxation of n-X rules around operational redundancy during low risk events). There are international examples where the deployment of this approach provides additional operational flexibility than that afforded within the SQSS. In theory, this could make better use of transmission assets and reduce transmission connected generation constraints. However evidence of benefit of such an approach to the GB network is limited and further research is required into the risks and issues posed by such an approach to system security.

[47] It should be noted that there are already regional differences in reliability of supply so changes do not necessarily mean customers would be treated unfairly.

6. RESILIENCE

This topic area was identified in recognition that there is a range of external factors that could pose risks to the resilience of the electrical system and that formalised standards for resilience have yet to be adopted. Areas for investigation included:

- Performance based standards for recovery from significant outage events;
- Understanding electrical system role in supporting critical infrastructure now and in the future and the alignment between engineering standards and the wider national plan; and,
- Incorporation of security concerns (i.e. from physical and cyber-attacks).

6.1 DEFINING RESILIENCE

A range of definitions exist for resilience and its relationship to system reliability and security. For the purposes of the review the following definition was adopted:

- *"the ability to limit the extent, severity and duration of system degradation following an extreme event*"

Within this definition *extreme events* can be taken to mean different things. A Cigre working group paper [48] described the following possible interpretations:

1. *"A single event that is not secured against e.g. a single simultaneous fault outage of both sides of a double busbar (such as happened in Sweden in September 2003) or an event outside the area of a system operator's jurisdiction that has an impact on the SO's own area;*
2. *A combination of independent events that, together, are not secured against and which occur within such a short period of time (relative to an operator's ability to respond) that they are effectively simultaneous – an example of this is the loss of more than 1500MW of generation infeed within 2 minutes in GB in May 2008 (the biggest loss of infeed for a single event in GB is currently 1320MW and is the figure used to determine reserve requirements), or*
3. *A single, secured event that does not on its own lead to unacceptable consequences but sometimes can through a cascade of further outages so that it ends up as an 'extreme' event with unacceptable consequences.*"

These interpretations refer to the events themselves rather than the potential causes. Adverse weather such as storm and flooding will increase the probability and management of these events.

6.1.1 What this means for planning and operation

A complementary view on this is provided in a Cigre working group paper [48]. This helps to articulate the planning actions and measures through which resilience is managed. The stages or lines of defence referenced are:

- Prevention (helps to limit the **extent**);
- Containment (helps to limit the **severity**);
- Restoration (helps to limit the **duration**).

The stages and measures are illustrated below. This provides a useful framework to understand where certain system measures and standards sit within the overall system resilience.

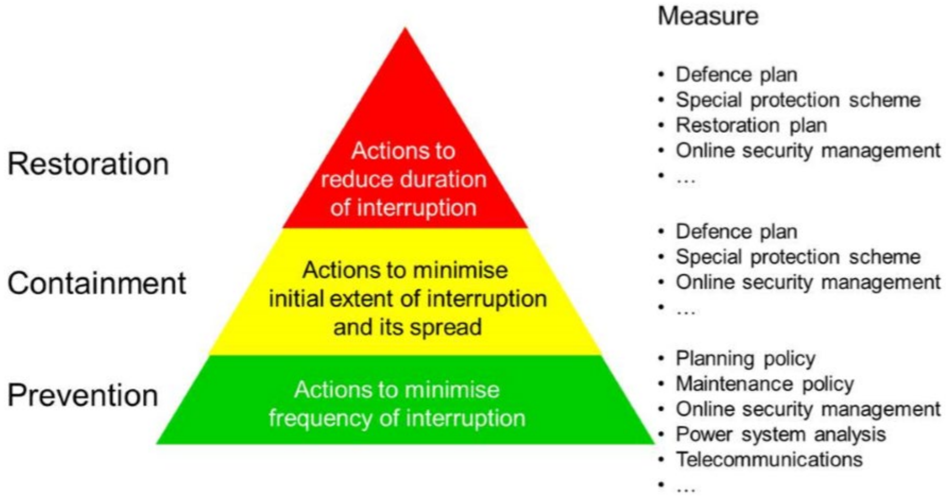

Figure 15: Management of major unreliability events

Noting that prevention is covered by security of supply (and also the means to manage frequency, stability and operability), this section will focus on the containment and restoration stages.

6.2 INCREASING RISKS FOR ELECTRICAL SYSTEM RESILIENCE

6.2.1 Climate change and the effects of extreme weather

Adverse weather conditions can significantly increase the probability of electrical outages and the risk of large-scale outages. The outages caused by storms during the winter of 2013/2014 are a prime example of the issues which can be faced. The effects of climate change are likely to make periods of adverse weather more severe and frequent with knock on consequences for the electrical system. According to a 2014 US study, some of these effects may already be seen based on the increased number of weather related outages experienced. Figure 16 illustrates the results of this study.

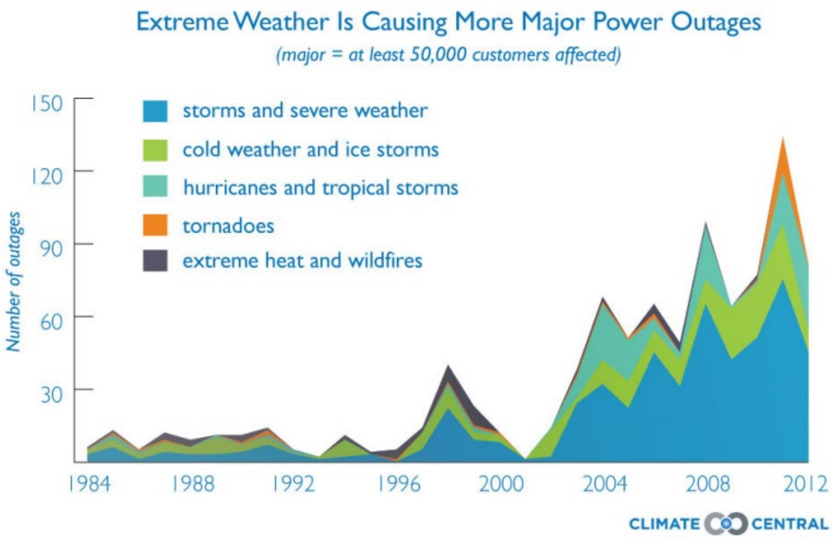

Figure 16: Plot of weather related power outages from the US

Adapting the electrical network to the effects of climate change was the topic of 2015 report by Northern Power Grid [75]. Key risks related to increases in temperature, precipitation, sea level and storm surges were discussed. The greatest climate threat to networks was assessed to be flooding with ENA ETR 138 (Resilience to Flooding of Grid and Primary Substations) developed to ensure this threat is tackled effectively. The report highlights that "*network operators will target the completion of agreed protection to grid and primary substations as follows:*

- *Transmission Sites: By the end of the Transmission Price Control Review finishing in 2022.*
- *Distribution Sites (Grid and Primary): By the end of the Distribution Price Control Review finishing in 2020.*"

The report [75] also identified a range of network product design standards which may need to reflect the effects of climate change in future.

6.2.2 Cybersecurity

The increasing digitalisation of the electrical system will create a number of cyber-risks which has implications for security of supply and network resilience. This review has recognised this issue, without cybersecurity being fully within scope of the review.

However is it acknowledged that there a range of published information on cybersecurity within the energy sectors and activities are ongoing between industry, government and standard development bodies to identify, control, and mitigate any risks. Work in this area includes:

- The Directive on security of network and information systems (NIS Directive) which is a piece of EU-Wide legislation adopted by the European Parliament on 6 July 2016 and was transposed into UK law in May 2018 [76]
  - The NIS Regulations impose new duties on Operators of Essential Services ('OES') and ensure compliance with defined minimum cybersecurity standards.
  - Existing standards include ISO/EIC 27001[48] and ISO/EIC 27019[49]
  - The thresholds to determine whether companies fall within the definition of OES are [77]:
    - For electricity generators, it is based on having a generating capacity greater or equal to 2GW (including cumulative capacity of multiple units);
    - For energy distribution and transmission network operators (gas and electricity), it is based on the potential to disrupt supply to greater than 250,000 consumers; and
    - For energy supply businesses it is based on the use of smart metering and the potential to disrupt supply to greater than 250,000 consumers.
- There is an ongoing project led by BEIS and the ENA to determine cyber-security risks related to distributed generation and draft a set of cyber security connection guidelines.

[48] Titled "Information technology— Security techniques — Information security management systems — Requirements"
[49] Titled "Information technology — Security techniques — Information security controls for the energy utility industry"

- European Network for Cyber Security (ENCS)[50] organisation publish a range of security requirements for smart meters, EV charging infrastructure and distribution and substation automation.
- Smart Grids Task Force Expert Group 2 on Cybersecurity publish recommendations for how to manage cybersecurity risks [78].
- The “Energy Delivery Systems – Cyber Security Procurement Guidance” issued jointly by BEIS and the ENA [79].

6.2.3 Dependence on a changing telecommunications sector

The ongoing operation of the electrical network is highly dependent on the telecommunications network. The various dependences are highlighted within a position paper from the ENA Strategic Telecommunications Group (STG) [80]. Within this paper it is highlighted that:

“*Without secure and reliable operational telecommunications, it would:*

- *be difficult to maintain the integrity, efficient operation and safety of the electricity network.*
- *be difficult to maintain supply to customers in fault situations.*
- *not be possible to monitor and control the flow of electricity.*
- *lead to significant delays in the restoration of supply to all customers, including vulnerable customers and communities.*”

Furthermore for it is noted that “*Efficient restoration of the electricity network in the event of a large-scale loss of supply (known as “Black Start”), is also dependent upon the availability of operational telecoms. Hence these communication systems need to be resilient to power outages and other system failures.*” With increased reliance on telecommunications within a smart grid (particularly at LV) these issues would only become more challenging.

Conversely, the telecoms industry is becoming more reliant on a secure consumer power supply.

The Ofcom CMR Report for 2019[51] shows the declining volume of calls from fixed lines year on year (down 17% in 2018) with the majority of calls going via the mobile network. Fixed Telephone services are also changing, with Openreach announcing that they will withdraw Wholesale Line Rental products that rely on the BT PTSN by 2025, switching the over 16 million telephone lines currently using the wholesale call products to IP based networks which support broadband based call services[52]. Virgin Media also intend to retire their PSTN, and currently anticipate completing their switch to IP in line within Openreach’s timescales[53].

Ofcom have released guidelines on requirements of VoIP, including the need for access to emergency service numbers in the event of a power outage. However, the 105 number to report an outage is not considered an emergency number, so is not included in the requirements[54] presenting customers with a problem for reporting outages.

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[50] https://encs.eu/
[51] https://www.ofcom.org.uk/research-and-data/multi-sector-research/cmr/interactive-data
[52] https://www.openreach.co.uk/orpg/home/products/wlrwithdrawal/wlrwithdrawal.do
[53] https://www.ofcom.org.uk/__data/assets/pdf_file/0032/137966/future-fixed-telephone-services.pdf
[54] https://www.ofcom.org.uk/__data/assets/pdf_file/0016/123118/guidance-emergency-access-power-cut.pdf (A1.19 & A1.20)

Government note on their Telecoms Resilience page[55] that in the event of a power cut, mobile networks would rely on battery backups, but that the installed batteries would only provide around an hour of mobile networks services before becoming "increasingly degraded".

Clearly this lack of resilience of the public telecommunication network would cause issues for the recovery from major outages. This continues to drive the need for private utility communication networks [80].

It is the understanding of the review team that there are plans to develop a telecommunications standard during 2020 which aims to address these types of resilience issues. The NIC funded Distributed ReStart project also has work planned to "*specify the requirements for information systems and telecommunications, recognising the need for resilience and the challenges of coordinating Black Start across many parties*" [81].

6.3 RESILIENCE STANDARDS LANDSCAPE

There is no specific system 'resilience' standard currently, however there are a number of aspects of the standards and plans which contribute towards overall system resilience:

- The SQSS define the bounds of secured events (and hence those considered to be extreme). The outage times related to group demand are not designed for extreme events.
- Commission Regulation (EU) 2017/2196 - Network code on electricity emergency and restoration[56], came into force on 18 December 2017. "Chapter III – Restoration Plan" of this code places requirements on UK network operators to make System Defence and System Restoration plans, and specifies what they must contain, to respond effectively to potentially disruptive events.
- Within the Grid Code, Operating Code 9 - Contingency Planning details the response to Total Shutdown or Partial Shutdown of the system. This focusses on the implementation of recovery procedures rather than specifying performance targets.
- The Distribution Code - Distribution Operating Code 9 - Contingency Planning. This section of the distribution code mirrors the structure within the Grid Code. The objectives of this operating code is "to enable co-ordination between all Users" (DOC9.2) in response to outage scenarios.
- The Electricity (Standards of Performance) Regulations 2015 (Part 2 Supply Restoration Standards of Performance for Electricity Distributors). This covers the response to power outages including severe weather.
- The National Emergency Plan: Downstream Gas and Electricity[57] and Electricity Supply Emergency Code (ESEC)[58] exist which describes arrangements between BEIS, industry, Ofgem and other parties for safe and effective management of emergencies. These plans include:

[55] https://www.gov.uk/guidance/telecoms-resilience
[56] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2017.312.01.0054.01.ENG
[57] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/577707/National_Emergency_Plan_for_Downstream_Gas_and_Electricity_2016.pdf
[58] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/698739/2018_03_29_Electricity_Supply_Emergency_Code__ESEC__2018_Revision_V1.0-.pdf

- The identification of Protected Sites (e.g. hospitals, railways, generation stations, nuclear sites, water and sewage systems etc) which do not have a backup supply which could be utilised in the event of an outage; and,
- “Variable Rota Disconnection Plan” for the supply of power to blocks of load.

- DPC7.4.8 Black Start Capability – covers the need for an Embedded Generator to notify the DNO if its Power Generating Module has a restart capability without connection to an external power supply

6.4 FAULT CONTAINMENT AND SYSTEM DEFENCE

6.4.1 System defence standards

Commission Regulation (EU) 2017/2196 - Network code on electricity emergency and restoration (NCER)[59], came into force on 18 December 2017. “Chapter III – Restoration Plan” of this code places requirements on UK network operators to make System Defence and System Restoration plans, and specifies what they must contain, to respond effectively to potentially disruptive events.

In response to this, NG ESO have developed a System Defence Plan (SDP) [82]. This plan provides a summary of how the requirements for System Defence specified in EU NCER will be satisfied in GB, referencing various aspects of current standards and identifying modifications that are required. The main areas covered are

- System protection schemes, including:
    - Automatic under frequency control;
    - Automatic low frequency demand disconnection;
    - Automatic over frequency control; and,
    - Schemes to avoid voltage collapse.
- System defence plan procedures; and,
- Assurance and compliance testing within the plan.

The following sections will touch on the standards related to three aspects of this plan and system defence generally: demand control, generation response and compliance.

6.4.2 Demand Control

6.4.2.1 Demand Side Response

Demand side response allows large industrial and commercial customers, small to medium enterprises and aggregators on behalf of small customers to vary their demand at peak times in order to save on their total energy cost. This is currently covered in Grid Code Operating Code 6 for Transmission customers and with a similar provision in the DCode for distribution customers. The level above which the DNO has to notify NGESO of its proposed or achieved use of Demand Control is 12 MW in England and Wales and 5 MW in Scotland at any DNO Connection Point. The effectiveness of demand response for system defence functions is dependent on the timescale in which the response is required.

[59] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2017.312.01.0054.01.ENG

6.4.2.2 Low Frequency Demand Disconnect (LFDD)

DNOs are obligated to install Low Frequency Demand Disconnect relays in order to be compliant with the Grid Code (Operating Code 6 – Demand Control).

During a fault outage, frequency response from generators will try to stabilise the grid frequency. If the frequency continues to drop below 48.8Hz, LFDD relays will disconnect customers in order to stabilise the grid frequency. The 200ms timescales for this to be performed necessitates a local autonomous response (i.e. not communication based). Different stages of LFDD will disconnect more customers if the frequency continues to fall. The number, location and size of the blocks and the associated low frequency settings will be as specified by the DNO. In principle, the use of a LFDD scheme is an effective means of system defence as illustrated in the four box model within Figure 17.

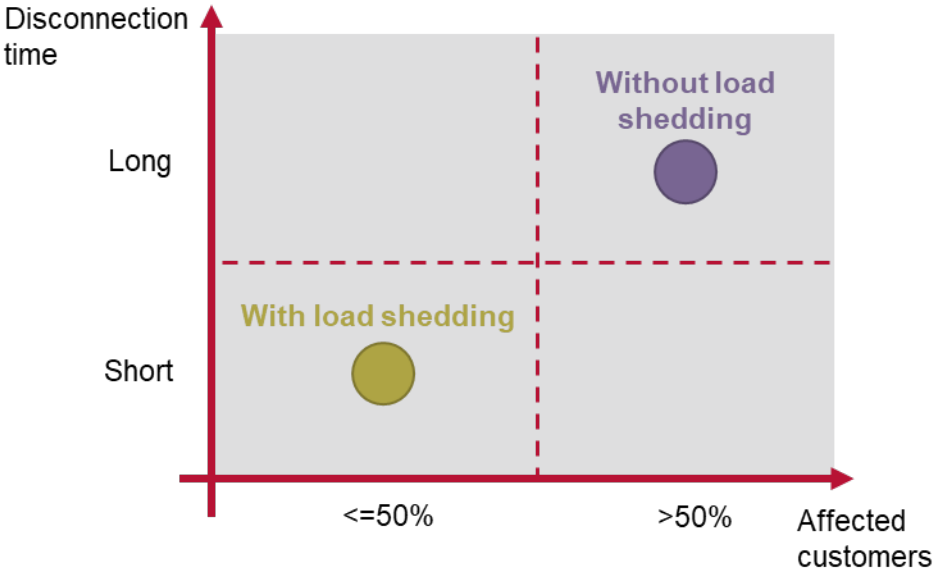

Figure 17: The usage of under-frequency load shedding schemes leads to benefits for all customers (figure adapted from [48])

Following the 9th August 2019 event, issues have been raised with the implementation of the LFDD scheme [83]. In particular this highlighted that critical loads may be disconnected within the early phases of this demand reduction scheme.

Within the DCode, DOC6.5.2 states that:

"The Demand subject to automatic low frequency disconnection shall be split into discrete blocks. The **number, location and size of the blocks** and the associated low frequency settings will be as **specified by the DNO**. The intention is that the distribution of the blocks will be such as to give a reasonably uniform application throughout the DNO's Distribution System, but may take into account any operational requirements and the **essential nature of certain Demand.**"

This highlights that the standard does have a descriptive provision to take account of the nature of loads, however this is not a specific requirement. The ESEC does provide more firm requirements to maintain supply to protected sites however this applies to rota-disconnection rather than LFDD events. As the 9th August 2019 event highlighted, the LFDD provision within the DCode was either not being applied or there was not clear visibility of what demand was within each of the schemes.

It is noted that, in relation to the discussion on valuing a customer's reliability of supply, metrics such as VOLL could come into play when designing the various LFDD tranches. Longer term this could consider a more flexible view of essential and non-essential load on a given part of network. This would increase the resolution at which demand is controlled (i.e. reducing the magnitude of load blocks) to minimise the number of customer disconnections.

6.4.2.3 Voltage reduction

As part of Operating Code 6 – Demand Control, demand reduction can also be achieved through voltage reduction. The extent of this reduction is discussed in section 3.3 as are the risks associated with any change to distribution voltages.

6.4.3 Requirements on generators to support system operation

DPC7.1.3 prescribes that generators connecting after 27 April 2019 must be compliant with Engineering Recommendation G99. G99 split out generators into different "Types" based on their connection voltage and registered capacity (see Table 4). These different generator types have varying amounts of requirements placed on them, with Type D being the most stringent.

Table 10: Generator types and associated ratings

Type	Connection Voltage (kV)	Registered Capacity
Type A	< 110	0.8 kW to < 1 MW
Type B	< 110	1 MW to < 10 MW
Type C	< 110	10 MW to < 50 MW
Type D	≥ 110	≥ 50 MW

Table 11: Generation response functions for system defence

Function	Description	Related standard
Frequency response	Frequency Response – Falling Frequency Frequency Response (LFSM-U) – Generators should have the ability to increase their power output in response to a falling frequency.	A function required to be performed by all generators based on G98/G99.
Fault Ride Through	Generators must remain connected and stable for a specific number of fault scenarios on the DNO network.	From G99: Type A – only required where specified by the DNO. Type B, C, D Generators – must ride through specified - Voltage against time curves.
Fast Fault Current Injection	Injection of reactive current from generators to support the Total System during a fault on the Transmission System.	From G99: Type B, C, D Generators – must ride through specified - Voltage against time curves. NGESO have reviewed alignment with Grid Code [84] at transmission level.

6.4.4 Compliance of generation

Increased certainty in a generator's performance under different network conditions supports system security in two ways [48]:

- Defining generator performance allows the system operator to more confidently predict the response of the power system to disturbances (provide that the prediction accurately reflects the generators performance); and,
- The generators then have a clear performance expectation which they can ensure they deliver.

G99 Annex's A, B and C contain the compliance requirements for Type A, B, C and D generators. Details are set also out in the Compliance Process section of the Grid Code. As part of the connection process, generators wanting to connect need to prove that they comply with the requirements. At transmission level, the ESO is responsible for assessing compliance provided by generators against the Grid Code requirements [85]. Compliance evidence at the distribution level is scaled based on the type of generator. A generator is required to notify the relevant party if it makes changes to its configuration[60] that may affect compliance and demonstrate compliance with the new configuration. Comparing G99 to its predecessor G59, there is a substantial increase in compliance evidence for newly connected generation.

Compliance with standards is a key part of system defence against potentially large scale events. This was again highlighted through the 9th August 2019 outage event, where non-compliance issues related to generator behaviour and under-frequency protection operation contributed to the scale of the event [83], resulting in penalties [86] being imposed on generators and a DNO. The challenges around designing an effective regime to encourage compliance is discussed further in [48].

6.4.5 Islanding

System islanding could be considered as a future means of system defence. There are international examples of this practice, for example the power systems in Romania and France. Details on the specific procedures used are described in [48]. Such an approach would lead to a number of standards changes. Some of these are discussed within section 4 (operation of microgrids). This is also related to the Distributed ReStart project discussed further in section 6.5.3.

6.5 SYSTEM RESTORATION

6.5.1 Restoration standards

There is no specific system restoration standard for significant outage events currently (although one is in development for Black Start scenarios as discussed in section 6.5.2); however there are a number of aspects of the standards and plans which contribute towards the overall system restoration. These are outlined below:

- The SQSS defines the bounds of secured events (and hence those considered to be extreme). The outage times related to group demand are not designed for extreme events.
- Commission Regulation (EU) 2017/2196 - Network code on electricity emergency and restoration[61], came into force on 18 December 2017. "Chapter III – Restoration Plan" of

[60] Both hardware and software. Control software for kit such as power electronics could significantly alter performance and be easily updated however this would rarely be visible to network operators.
[61] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2017.312.01.0054.01.ENG

this code places requirements on UK network operators to make System Defence and System Restoration plans, and specifies what they must contain, to respond effectively to potentially disruptive events.

- Within the Grid Code, Operating Code 9 - Contingency Planning details the response to Total Shutdown or Partial Shutdown of the system. This focusses on the implementation of recovery procedures rather than specifying performance targets.
- The Distribution Code - Distribution Operating Code 9 - Contingency Planning. This section of the distribution code mirrors the structure within the Grid Code. The objectives of this operating code is “to enable co-ordination between all Users” (DOC9.2) in response to outage scenarios.
- The Electricity (Standards of Performance) Regulations 2015 (Part 2 Supply Restoration Standards of Performance for Electricity Distributors). This covers the response to power outages including severe weather.
- The National Emergency Plan: Downstream Gas and Electricity[62] and Electricity Supply Emergency Code (ESEC)[63] exist which describes arrangements between BEIS, industry, Ofgem and other parties for safe and effective management of emergencies. These plans include:
  - The identification of Protected Sites (e.g. hospitals, railways, generation stations, nuclear sites, water and sewage systems etc).
  - “Variable Rota Disconnection Plan” for the supply of power to blocks of load.
- DPC7.4.8 Black Start Capability – covers the need for an Embedded Generator to notify the DNO if its Power Generating Module has a restart capability without connection to an external power supply.
- The National Risk Register. Risk H41 refers to a total failure of the electrical network This is currently stated as up to 7 days depending on the cause of the failure and associated network damage [87] [88]. Figure 18 provides an indicative worst-case profile for system restoration.

[62] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/577707/National_Emergency_Plan_for_Downstream_Gas_and_Electricity_2016.pdf
[63] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/698739/2018_03_29_Electricity_Supply_Emergency_Code__ESEC__2018_Revision_V1.0-.pdf

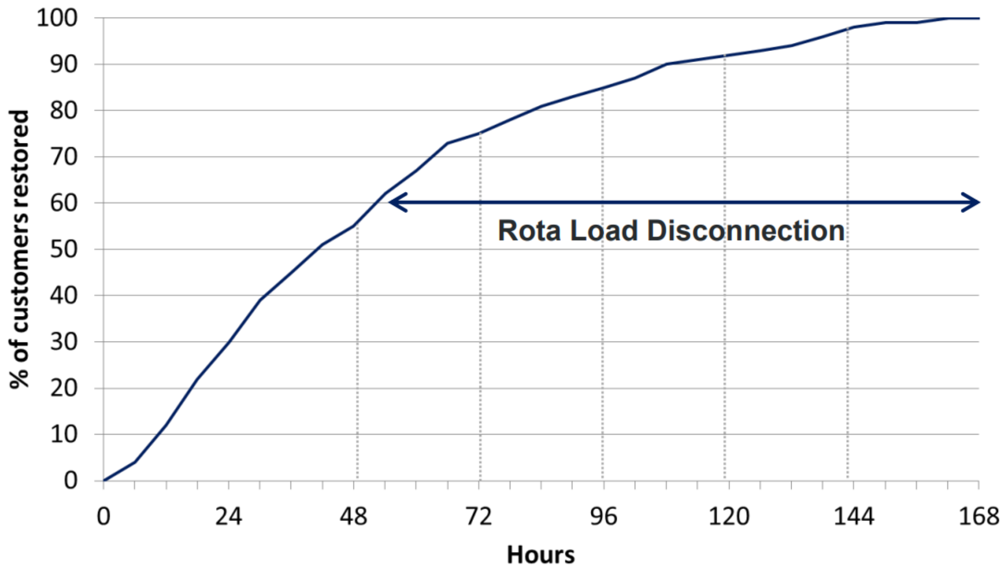

Figure 18: Indicative profile of black start restoration over time[64] [88]

6.5.2 GB restoration standard

A GB Restoration Standard, and associated implementation methods, are under development through the Black Start Task Group (BSTG), under the E3C. The standard will be outcome based and will specify required timescales for a restoration from a total shutdown for the country. The standard must first be agreed by the Secretary of State and then passed to Ofgem for implementation (e.g. through license agreements) [30]. The timescales specified will be underpinned by socio-economic analysis considering the impact of a Black Start event, its probability and the estimated service costs of providing this service.

This review recognised the development of such a standard as an important step for consumers. The benefits of this outcome-based standard for restoration include:

- Consumers have a basis on which to hold the industry to account, and make their own plans. This is particularly important for large industrial connections such as nuclear sites where supply outage time is a significant part of the nuclear site safety case.
- Society as a whole can express its priorities, giving clarity to developing and justifying the actions industry and regulators need to take
- Issues of regional and other inequality can be explored and decisions taken with transparency
- They provide the electrical industry with a specific target to work towards.
- The performance based approach may encourage innovation and efficiency incentives in the achievement of system goals.

The standard itself will not specify how the demand is met or what demand is met during the restoration period. It is anticipated the standard would be delivered in conjunction with other emergency plans (i.e. The National Emergency Plan and the ESEC). These would identify

[64] When developed, this aligned with a BEIS worst case scenario of a total power outage which occurs in the winter period, with little or no wind generation available. This will change based on the introduction of the standard described in section 6.5.2.

protected sites[65] and the Variable Rota Disconnection Plan. Demand control and reduction schemes may also be employed as stated within DOC9.1.4 (titled “Civil Emergencies”) to manage demand connection. The “National Risk Register[66]” should also capture the interdependencies on the electrical network with other critical demand.

The above highlights that rules and plans are in place to deal with the prioritisation of power supply to critical infrastructure. The publicly available information is relatively light in detail in terms of how this is achieved however it is appreciated that these plans may not be made public.

Through the review it was also noted that, in addition to protected sites, there may be the opportunity for future standards to reflect the cost and value of supply to other types of load. This could see larger numbers of customers reconnected following an outage, albeit at reduced power capacity. This would be enabled through more granular control of demand and better understanding of VOLL.

6.5.3 Distributed ReStart

The Distributed ReStart project is a three year NIC funded project being delivered in partnership between NGESO, SPEN and TNEI. The programme will develop and demonstrate new approaches to enabling Black Start services from Distributed Energy Resources (DER).

A standard review activity has been undertaken as part of the Distributed ReStart project [89], which focussed on potential barriers that current standards may impose. In general no insurmountable issues where uncovered. The key changes noted related to EREC G99. The review conclusion states:

- “*A number of potential issues were noted in the review of EREC G99. Several clauses relating to island operation, protection, frequency response and fault ride through may be subject to change, or derogations provided for a Black Start and restoration scenario.*”

These issues are similar to the issues around microgrid operation discussed in section 4.

6.6 MONITORING AND MEASURING SYSTEM HEALTH AND RESILIENCE

Within GB, system resilience is not measured or reported directly. This is in part due to ‘resilience’ being a function of many factors and therefore inherently difficult to measure at a whole system level. However a number of information sources do exist which begin to build up a picture of system resilience and these are described below.

NGESO carries out its own assessment of present, emerging and future risks and publish a number of forward looking reports. The annual Future Energy Scenarios report presents core scenarios reflecting different future energy generation and demand profiles which in turn informs on a range of electricity system requirements. This reporting structure is illustrated in Figure 19.

[65] The criteria for receiving Protected Site status is detailed in the ESEC.
[66] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/644968/UK_National_Risk_Register_2017.pdf

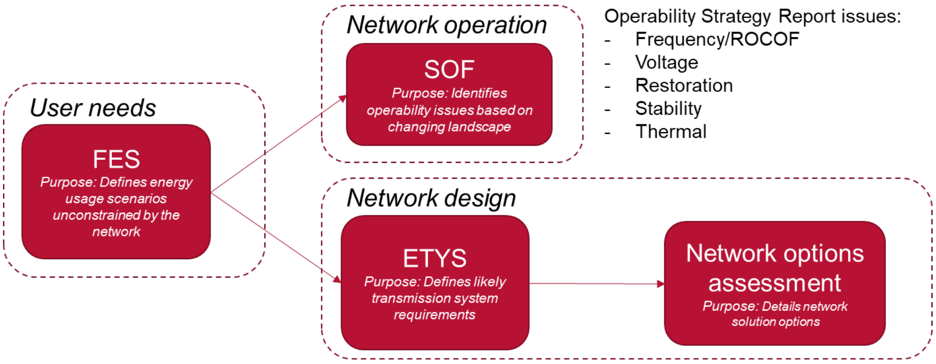

Figure 19: NGESO forward looking reporting structure

The System Operability Framework picks up on a number of issues related to system resilience. Its main report, the Operability Strategy Report, is structured to describe the key concerns and ongoing activities around the issues of: Frequency/ROCOF, Voltage, Restoration, Stability and Thermal. This report is updated twice a year to reflect changes throughout the year.

The strategy report is supported by a number of technical papers which are produced less regularly. These reports includes a summary of significant frequency or ROCOF events over the previous year. Whilst they cover topics relevant to the main strategy report they do not specifically map to the issues highlighted. The Operability Strategy Report and associated papers are generally discursive in nature rather than presenting formal measures of performance.

More formal reporting is provided through the networks' annual performance reports. The annual National Electricity Transmission System Performance Report [90] presents output performance measures performance (e.g. reliability, availability, security, quality of service) for the whole of the GB transmission network. Similar reports are available for distribution networks with Ofgem presenting a collated view of DNO performance through their annual report (as of 2020 the annual RIIO-ED1 Network Performance Summary) [91].

A significant volume of further data is also provided from networks to Ofgem to enable performance and network risks to be monitored (termed secondary outputs). Transmission Operators report secondary outputs through the Network Output Measures (NOMs) methodology [92]. The methodology is designed to assess:

- Network Asset Condition (via health index assessment), Network Risk (through a Replacement Priorities scale)
  - Various 'criticality' criteria feed into this including vital infrastructure and system security
  - Presented as a criticality-asset condition risk matrix
- Network Performance (reliability/availability)
- Network Capability (to meet demand under various conditions, boundary analysis)
- Network Replacement Outputs

DNOs present various information to Ofgem through their regulatory reporting packs. This includes:

- Failure and outage data and investment (which feeds into the annual performance report);

- Asset Health Index[67]; and,
- Load index for substations.

From the above, data on failures and outages provides a view of how the network is performing currently and health index and load index present a view of future risks on the network.

In some cases specific failures are reported with reference to existing standards or incentive schemes. Network reliability is reported with reference to the IIS as described in section 5.3.3. Other examples include the flooding risk of substations. ETR 138 defines the approach for defining the flooding risk of substations with this risk, and its mitigations, reported to Ofgem as part of the ‘Cost and Volumes reporting pack’ [93].

Similarly, ETR132 was formally started in January 2009, with a requirement to increase the resilience of the overhead line network to storms over a 25 year period through better tree management. Tree cutting costs and volumes (for compliance with ETR 132) reported in regulatory reporting packs with planned volumes included within company business plans.

The above highlights that there is a significant amount of information which must come together to assess system resilience, only some of which is publicly available.

The North American Electric Reliability Corporation (NERC) annual State of Reliability report [94] was noted by the Panel as an example of international good practice for collating disparate network information, analysing it and forming a forward and backward view of the risk of disruption to customers’ supplies.

The objective of the annual State of Reliability report is to provide an objective and concise information to policymakers and industry leaders on issues affecting the reliability and resilience of the North American Bulk Power System (BPS). It specifically:

- Identifies system performance trends and emerging reliability risks;
- Reports on the relative health of the interconnected system; and,
- Measures the success of mitigation activities deployed.

Contrasting with the current arrangements in GB the report provides a deeper exploration of the causes of system failures, the trends of these causes on the system and the severity of their failure. The report considers issues with individual asset types (e.g. assets which have contributed to outage) and significant events (e.g. poor weather, storms, fires) and system-wide trends and metrics. Within the report, key areas of focus include:

- **Event Analysis**: which details significant events (categorised by severity) that happened in the previous year, root causes and key lessons learned.
- **Reliability indicators**: which include Resource Adequacy, Transmission Performance and Unavailability, Generation Performance and Availability, System Protection and Disturbance Performance.
- **Severity Risk Index:** which is used to measure the relative severity ranking of daily conditions based on the impact on the BPS from load loss, loss of generation, and loss of transmission. This helps to identify the key conditions, or combination of conditions, which cause power system interruptions. (e.g. weather related events, loss of large generation).

[67] It will become a requirement to calculate Asset Heath Index based on the DNO Common Network Asset Indices Methodology (CNAIM) within the ED2 price control period.

- **Trends in Priority Reliability Issues:** which identifies specific issues of concern, trends performance against these issues, discusses ongoing/future risks across these issues and makes recommendations.

In most cases, the current performance of the network is contextualised with the historical performance and trends are established to understand the changing performance over time.

This characterisation of past and expected future performance of an entire power system provides clarity benefits and supports system-wide planning and decision making. Having a similar reporting process in GB would bring together some of the disparate reporting mechanisms and realise some of these benefits.

6.7 CONCLUSIONS

System resilience has a range of definitions. Within the context of this work, the main areas of focus were on the standards related to system defence against, and restoration from, extreme events.

Causes of extreme events are varied. It is however acknowledged that there are a number of growing threats to electrical system, for example more adverse weather conditions and cyberattacks. The greater dependence on the telecommunication network (and the more stringent requirements of the electrical system) are also noted. Various standards, plans or ongoing activities exist which aim to control and mitigate these areas of risk.

The events of the 9th August 2019 outage highlighted challenges relate to the execution of system defence measures (the measures themselves worked to defend the electrical system). The LFDD scheme is an example of this where critical loads were disconnected within the early phases of this demand reduction scheme. Current standards have provision to consider the “essential nature of certain Demand” however this was either not applied correctly or there was not clear visibility of what demand was within each of the schemes. Looking forward the visibility and understanding of VOLL within a given demand block could better inform and execute the LFDD scheme.

With regards to system restoration, a black start restoration standard is currently being finalised which will provide a performance standard for the recovery of system demand. The development of this standard is welcomed as it sets a clear expectation of the electrical system in the event of a significant outage.

7. FUTURE INSTALLED NETWORK CAPACITY

This section concerns the installed network capacity at the final connection point to the network and economically efficient methods of sizing electrical networks. This section specifically addresses issues related to:

- Future customer demand including demand flexibility;
- Standards related to specifying capacity needs now and in the future;
- Loss inclusive approaches to network design which may impact installed capacity; and,
- Alternative solutions to providing high capacity including 3 phase and DC supplies.

When discussing the issues above, there are inevitable overlaps with security of supply and these are highlighted where appropriate.

7.1 CAPACITY THAT CONSUMERS NEED, WANT AND SHOULD EXPECT

This section focuses on the future needs of the consumer from the perspective of an individual's connection to the network and their capacity requirements. This includes a review of the current literature available on the topic of the acceptability of interrupting consumer supply during peak loading times and at what level of minimum core access would be considered acceptable to consumers. The aim of this is to gauge consumer acceptance towards curtailment with a view to facilitating flexibility within the network.

7.1.1 Sources of increased capacity requirements

7.1.1.1 Demand

Significant increases in the use of low carbon heating and transport are key drivers for the forecast increase in system demand. Whilst there are various technology options for how these may be met (e.g. hydrogen boilers, hydrogen fuel cell cars, district heating etc), heat pumps and electric vehicles are projected to play a significant role. Example products and associated input power levels are detailed in Table 12. Alongside these power levels, the operational duration of these loads is a driving factor for increased peak demand on the system given this duration leads to greater coincidence of maximum demand between systems. The typical EV charging times shown in Table 13 help illustrate this. Similarly, Figure 20 illustrates the potentially high load factor of a heat pump in cold conditions. Over a large number of properties, these loads increase residential ADMD by around 2kW per EV charge point and 1.7kW per heat pump [95] (these will increase with the installation of larger loads).

Within GB the existing capacity limits of homes is limited by the incoming household fuse. This is typically rated between 60 - 100 Amps, which translates to around 13.8 to 23 kW of peak capacity. Given the individual household demand levels there does not appear to be a widespread need to revise these capacity limits (although they may be tested if multiple high power loads where connected in an uncontrolled fashion). The higher utilisation of this capacity will have network implications as discussed section 7.2.

Table 12: Example input power demand from domestic EVs and heat pumps

Load type	Typical range of input power
EV charger (Domestic) [96]	3.3 – 7.2kW[68]
EV charger (Commercial) [97]	11 - 22kW[69]
DC rapid charging	Typically 20 - 50kW (with higher power chargers becoming available)
Heat pump [98]	3-4kW[70]
Hybrid heat pump [99]	1-2kW (electricity demand only)

Table 13: Approx. EV charging times for a range of battery and charger sizes

Vehicle		Empty to full charging time for different charger size (hrs)				
Car model	**Battery size**	**3.3kW**	**7kW**	**11kW**	**22kW**	**50kW**
Nissan Leaf (2018)	40kWh	12.1	5.7	3.6	1.8	0.8
Tesla Model S (2019)	75kWh	22.7	10.7	6.8	3.4	1.5
Mitsubishi Outlander plugin hybrid (2018)	13.8kWh	4.2	2.0	1.3	0.6	0.3

[68] Typically single phase connection
[69] Typically three phase connection
[70] For commercial applications heat pumps can be scaled up to several hundred kilowatts [146].

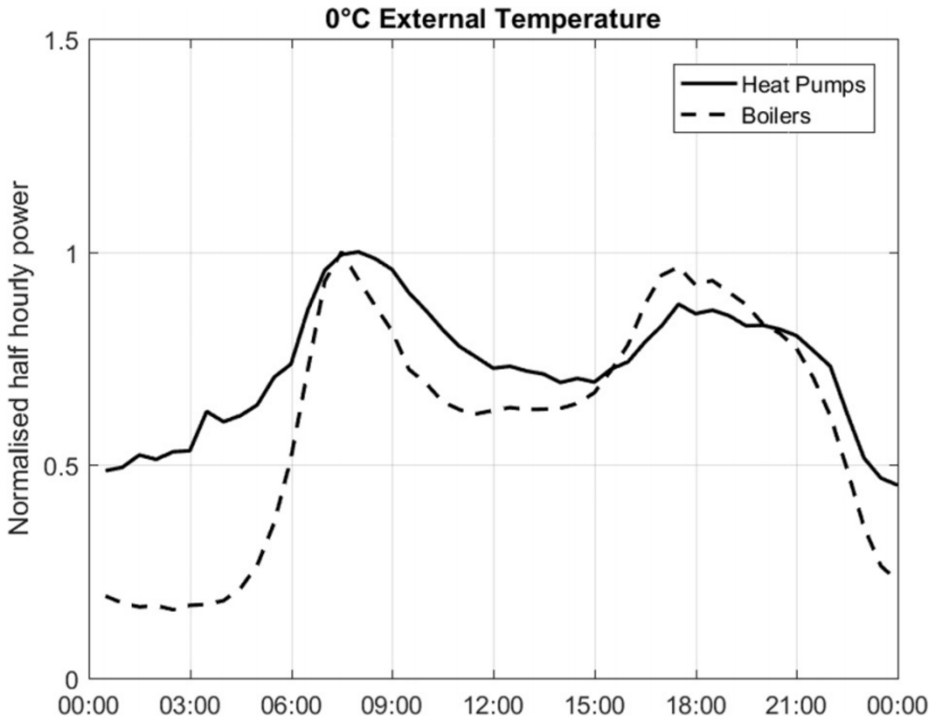

Figure 20: Comparison of heat pump and boiler daily load profiles at 0 °C external temperature [95]

7.1.1.2 Generation and storage

Solar photovoltaic (PV) systems are commonplace on new build properties and a range of domestic energy storage solutions are also emerging (including vehicle-to-grid (V2G)) which may provide an infeed to the grid. Increased energy efficiency and the ambition for new homes to achieve net zero emissions are key drivers for the installation and sizing of capacity for these technologies.

Within ESQCR, there is a regulation which states that any generation over 16A per phase has to apply to the DNO for connection in advance (now handled through the G99 application process). This translates to a power level of 3.68kW. Storage and V2G connections are treated as generation under the G99 process and also separately as a demand [100].

Throughout the course of this review it was noted that the 16A/3.68kW limit may form an artificial barrier to the connection of DG and storage. Whilst it may have been appropriate when ESQCR was written, technology has developed significantly since 2002 and there may be scope to relax this limit.

This issue has been recognised in part by the industry and a ‘fast track’ G99 application process has been developed to support the connection of generation and storage with a cumulative capacity of greater than 3.68kW provided that they meet certain other conditions [101]. Whilst this supports the customer connection and use of these devices, export is still limited to 3.68kW per phase (requiring the use of a G100 type approved device) [102].

There is also evidence of various generation and storage products being sized to this limit, highlighting that it is driving some market offerings. Examples include: integrated solar and inverter packages [103], standalone inverters for storage applications [104], and the Tesla Powerwall [105].

Further evidence is required to quantify the scale of this issue. However, the justification for the 3.68kW limit does appear worth revisiting, particularly if other areas of ESQCR (i.e. voltage and frequency) are to be revised.

7.1.2 Core capacity and consumer network access

Within their Significant Code Review, Ofgem are seeking to clarify "access rights and choices for small users" [106]. As part of this, they are considering the concept of minimum "core access". "Core access" can be defined as the amount of capacity that cannot readily be flexed and that provides for consumers' basic needs[71].

To understand what this means for consumers, Citizens Advice commissioned a report from CAG Consultants which considered:

- Is it possible to determine a, or a set of, common core electricity network capacity levels for domestic consumers and micro-businesses?
- What should the core level of access be set at?
- How could this be implemented (technical or commercial solutions)? What are the barriers/risks to consumers, suppliers and networks?

Through these questions, Citizens Advice sought to understand the power capacity needs for consumers now and in the future. In the context of engineering standards, these questions help to guide the installed capacity and understand the flexibility which could be planned into the system.

Key outcomes which we have derived from this work [107] are:

- Affluence rather than household type drives peak capacity; this may have an impact on how ADMD[72] or capacity levels are set as this tends to be done through property type (with variables based on load type etc);
- The peak capacity limits installed within continental households are commonly higher due to the widespread adoption of three-phase supplies;
- "*Load limiting by supply interruption is unavoidably contentious*" however there are various examples where this is implemented;
- The functionality for load interruption exists within smart meters however this does not provide load modulation functionality;
- The report points to a basic core capacity of around 2-3kW. This is based on defining core capacity as a half hourly "average";
- Electric heating, traditional or heat pump based, can double this to around 6kW; and
- An electric car could double this again, if consumers plug in on return from work. Smart charging should be able to avoid this, but peak capacity will still be high, around 6-7kW.

The report highlights that there are still a number of questions around what loads should be considered core. For example, electric heating and EV charging could potentially be considered core given the function that they provide. There is clearly some potential flexibility with these load types to achieve the required outcome over time (i.e. a warm home and a charged EV battery) however inevitably they will increase the peak demand of a given property.

[71] i.e. The proportion of the customers 13.8-23kW capacity limit that is considered firm.
[72] After Diversity Maximum Demand – as statistical estimation of the individual household demand that can be aggregated for planning purposes.

7.1.3 Demand for flexible load

The value of flexibility in terms of reduced network infrastructure is clear and previous sections have outline this value. However clearly these benefits will not be realised without uptake from customers[73]. This section briefly reviews the research on likely customer uptake in order to support the case for flexibility from the customer side. This is has primarily been studied from the perspective of time-of use (TOU) tariffs.

This was the topic of a 2018 paper from University College London which focused on the demand for TOU tariffs [108]. Within this paper, it is noted that: "*An underlying assumption of many of these studies, including government decarbonisation strategies[74], is that consumers will voluntarily sign up to a TOU tariff in the first place. However, the evidence on level of consumer demand for TOU tariffs is far less clear."* Key outputs of the analysis within the paper are:

- If enrolment in TOU tariffs is opt-in then uptake is likely to fall between 1% and 43%.
- If enrolment is opt-out then uptake could approach 100%.
- Real-time pricing tariffs appear less popular than static TOU rates.
- Different message framing for the positive benefits for TOU (i.e. not solely focussed on monetary benefits which are currently modest) may support greater uptake.

The paper highlights that there is still much to do to ensure consumers engage with tariffs such as TOU to enable system flexibility to be unlocked.

Related to this work, the idea of an opt-out scheme has been adopted by the EV Energy Taskforce [109]. Within their report, proposal 8 is to:

- ***"****Require private EV chargepoints to charge smartly by default[75], thus making smart charging participation an opt-out function by 2021."*

Such approaches will be important as even limited uptake, or wider spread uptake for a subset of load types (i.e. EVs), would provide significant flexibility to manage loads differently. Technically such approaches could be managed through solutions such as sub-metering.

A further key point to note is that technological solutions for implementing TOU solutions (e.g. a home energy management system) will clearly make a difference to both ease of implementation and value. Citizens Advice work highlights that automation and real time pricing could provide much more value [110] than static pricing. They state that:

- "*Most consumers cannot currently respond to the half hourly price changes. If automation controlling electric vehicles, heating and other appliances allowed this to happen, the value of time of use tariffs could increase to **£272 m a year."***

[73] The possible exception to this is during extreme events. Networks can already reduce demand under exceptional circumstances.
[74] For example the UK government Smart Systems and Flexibility Plan [143]
[75] This should soon be written into law as part of the within the Automated and Electric Vehicles Act 2018. Next steps following a consultation on EV smart charging is presented within [145].

7.2 PLANNED NETWORK SUPPLY CAPACITY FOR NETWORK REINFORCEMENTS AND NEW DEVELOPMENTS

7.2.1 General standards landscape

The provision of a specific capacity for demand is generally design practice rather than being quantified in a standard. P2 and ETR130 provide guidance on what to consider from a security of supply perspective. The Engineering Recommendation G81 titled "Framework for new low voltage housing development installations - Part 1 Design and planning" sets out a framework to determine "*minimum requirements for design and planning of new low voltage underground electricity networks and associated distribution substations for housing developments".* This includes guidance on equipment rating and the process for determining this rating. G81 is within Annex 2 of the DCode[76]. The general framework within G81 is referenced and reflected within the individual DNO's LV system design manuals and internal standards.

7.2.2 Planned capacity for new developments

G81 specifies that the "Host Distribution Licence Holder" determine specific design ADMDs for different classes of customer. The design process then uses this ADMD, for example in the following G81 instruction:

"*this voltage drop shall be calculated assuming that all customers are taking their design ADMD with allowance for unbalance and diversity*."

Host Distribution Licence Holder specific design ADMDs for different classes of customer are listed in Appendix B of G81.

Recent updates to DNO LV design manuals (e.g. [111]) do reflect the need to increase ADMD for new types of demand (e.g. EVs and Heat pumps). It is however the responsibility of the Applicant to identify where these loads exist.

7.2.3 Planning for low carbon technologies

There is no specific standard for managing the increased load associated with new types of demand, such EV supply equipment or heat pumps. However, it is noted that these are reflected in DNOs design manuals through the application of increased ADMD values[77]. For example, [111] increases ADMD by 1.5-2.5kW depending on the type of charge point installed.

It is noted that there is some difference between ETR130 and G81 (and the DNO specific LV planning manuals which flow from this) in relation to accommodating downstream sources and storage. For example, based on P2/7 and ETR 130 these sources may play a role in system security however when planning for specific capacity guidance is not provided within G81 (or the DNO design manuals reviewed) on whether ADMD should be revised down for embedded generation or storage. This is also an important consideration for system utilisation and losses as discussed in later sections.

7.2.4 Anticipatory reinforcement for future capacity requirements

Across both security of supply standards (for reinforcements) and new development capacity standards the focus is on existing or known demand. Given the potential for significant increases in demand in future and the long life span of network assets, there is clear economic benefit for planning for future demand, albeit there is some uncertainty about whether this demand will materialise. A large element of this is driven by the cost of undertaking a reinforcement work compared to the unit costs of the assets themselves. In analysis undertaken

[76] An electricity industry national standard that has a material effect on Users but does not implement any Distribution Code requirements and does not form part of the Distribution Code technical requirements.
[77] There remains some debate around what diversity, if any, should apply to EVs [144].

to support the Committee for Climate Change [1], it is highlighted that cable capacity accounts for just 8-10% of the whole upgrade costs and that over-sizing network infrastructure could avoid several billion pounds of network expenditure.

Through this review, there remains an open question on the role standards should play in driving economically efficient design practice in the case of uncertainty. A regulatory approach, where a cost-benefit-analysis (CBA) accommodates an option value for increased demand and allows for the probabilised costs of future reinforcement, may be a more appropriate route. Consideration of network losses is also significant when considering economically prudent installed capacity and this is discussed in the following section.

7.2.5 Planning for through life cost

Research has highlighted that significant through life net present value (NPV) benefits can be achieved through a loss-inclusive approach to network design. There are a range of strategies for reducing losses as discussed in [112]. One particular area of focus, which can lead to significantly different approaches to current practice, is oversizing conductors for loss reduction. A 2014 study conducted by Imperial College and Sohn Associates [113], [114] identified that the optimal design capacity for a LV cable was found to be 11-25% of its thermal rating, i.e. the capacity at least four times larger than the peak demand.

A 2018 study for UKPN [112] highlighted that, for a sample of distribution networks analysed, 36-47% of the total losses are in LV networks. For LV networks, the benefits of applying larger cables could include a reduction in losses of the order of 50-60%. The minimum cable sizes explored are 95mm^2, 185mm^2 and 300mm^2. Figure 21 illustrates a sample of the results related to losses against different cable sizes and Table 13 summarises the potential value to UKPN network areas.

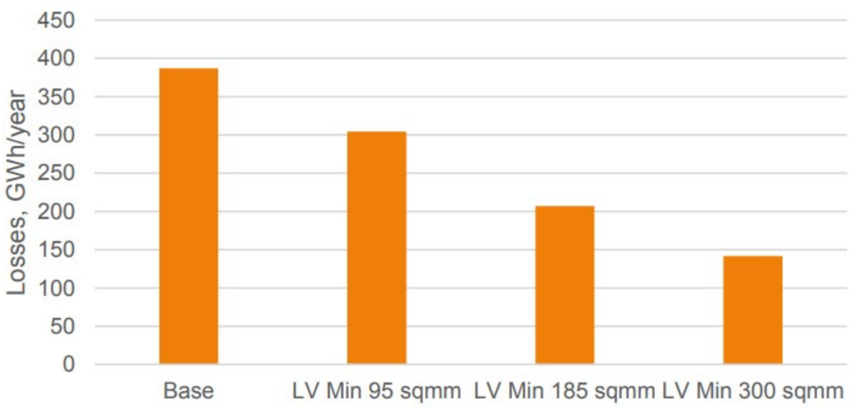

Figure 21: Losses on the representative SPN LV networks with different minimum conductor size policies [112]

Table 14: Capitalised value of the benefits of replacing all aluminium (Al) conductors with a cross sectional areas lower than 185mm² with Al 185 mm² for the UK Power Networks DNO group [112]

Individual DNO	Network section	Capitalised Value
London Power Networks	LV	£63-104m
	HV	£1.1-1.8m
Eastern Power Networks	LV	£114-188m
	HV	£24-39m
South Eastern Power Networks	LV	£87-144m
	HV	£15-25m

The quantitative work within [112] focusses on loss reduction and the economic payback this will provide. The benefit primarily sits with new developments or where reinforcements are triggered through other means. It is recognised that the payback is not sufficient for a 'retrofit' option (nor will it be achievable in practice). Key to the benefits case is that a large proportion of reinforcement cost is related to installation (e.g. digging cable trenches) as opposed to the cost of the increased size of cable. On this basis, Frazer-Nash conducted a short study to analyse the cost-benefit[78] of different conductor options. This study is presented within Annex C.1 and results align well with the findings of the ICL study.

Work has also been presented by ENWL, where a CBA comparing 185mm^2 conductors with 300mm^2 conductors for certain applications was presented [115]. In their analysis, the marginal price increase was £17.4k per km for LV cable (an increase of 19% of the overall installation cost) and £7.8k per km for HV cable (an increase of 8% of the overall installation cost). The outputs of the CBA similarly conferred benefits of the higher capacity solution on the basis of reduced losses.

The ENWL CBA and Frazer-Nash study in support of this review highlight that there are regulatory justifications for the installation of larger capacity conductors (even without the anticipatory capacity ratings discussed in section 7.2.4. With respect to standards, there is some guidance with respect to how to treat losses. Within G81 section 6.5, it is stated that:

- *"Systems must be developed to be efficient, co-ordinated and economical. The design shall **minimise lifetime costs**, including: initial capital costs, installation, operation and maintenance costs. An evaluation of system losses using loss £/kWh as used and stated by the Host DLH in Appendix B shall be carried out."*

Based on this, lifetime costs are firmly part of the existing guidance consideration. Losses are also part of the CBA consideration with ETR 130. Reference is made to the Ofgem CBA template upon which to make the economic assessment. No specific methods are prescribed which may lead to divergence in practice. It may be that further guidance (which is potentially enforceable) is required to ensure consistent understanding and assessment of lifetime costs.

One further point is that as loss-inclusive network design would lead to a situation where there will be a very significant "spare" capacity (in conductors at least), this could be used to enhance

[78] Using the OFGEM cost benefit analysis template

security / resilience of supply through smart control and load transfer. At the LV level this could be achieved through emerging technologies such as smart link boxes.

7.3 TYPES OF CONNECTIONS FOR FUTURE HOMES

7.3.1 3 Phase Supplies to Households

The use of 3 phase supplies is one potential solution to providing the increased capacity required to more effectively integrate low carbon generation and demand. Specific use cases include the connection of rapid EV chargers.

This was the subject of a position paper published by Renewable Energy Association (sponsored by WPD) titled "The feasibility, costs and benefits of three phase power supplies in new homes" published in August 2018 [116].

Within this paper it was concluded that "***Three phase connections should be introduced as standard*** *as this can be done for only a slightly higher cost to at present and will become even more pressing given Government commitments in The Road to Zero Strategy*." This proposal is for new build developments.

It was recognised that the high additional costs of retrofitting to existing homes is unlikely to make this economically viable as a general solution. The paper identified that where a three-phase supply was desirable to an existing home a pragmatic solution could be to use the first phase to power the existing household appliances, with the second and/or third phases connected directly to the EV chargepoint or a heat pump so these high power loads can benefit from the increased capacity.

For new developments, a key issue is that single phase options are still lower cost, and given the cost competition between developers there is a reluctance to adopt a higher cost solution[79].

Through this review, it was noted that limited other studies had been conducted to support (or otherwise) the conclusions of the REA report. In response to this observation, Frazer-Nash has conducted a survey of DNO charging statements (the results of which are presented in Annex C.2) revealing that the increase between single and three-phase connections ranged from 13% to 30%. Given the variance between these connections, it is difficult to draw definitive conclusions at this stage.

Given the drive for higher capacity solutions, the findings do not discount a three-phase connection being more cost effective through life and DNOs may wish to conduct further work to establish whether three phase connections should become more widespread in future. It is noted that there is wider spread adoption of three-phase connection within Europe [107].

7.3.2 DC distribution and supply within households

DC distribution has a number of potential benefits which conceptually make it an attractive means of power distribution. These include:

- It is possible to transmit more DC power through a cable of a given voltage rating than with AC. DC systems can deliver more power for a given transfer up to √2 times the power of an AC system for a given conductor size [117]. They are also are free from skin effect[80] and reactive voltage drop, further improving power transfer.

[79] If all developers were required to adopt 3 phase as standard it would level the playing field with respect to development costs amongst competing developers.
[80] Which could be relevant as we consider a substantial increase in cable sizes.

- Using DC distribution can reduce the number of required power conversion stages between source and load; This can deliver significant efficiency benefits for converter interfaced sources and loads[81];
- DC distribution better facilitates the paralleling of multiple non-synchronous sources. This can support better integration of DC sources (batteries) and synchronisation of intermittent renewable sources.

DC has applications across all voltage levels. It has been used for many years for point-to-point HVDC transmission with research ongoing around multi-terminal HVDC transmission networks (e.g. for offshore wind applications). There is ongoing interest at MVDC, for example the SPEN Angle DC project [118] assessing the conversion of existing AC distribution assets to DC. Across Europe there is a range of standardization activities going on for LVDC systems (including within buildings and homes) as described within [119]. However it is noted that:

- "*The most active industries in this regard have been telecom, data centres and transportation. The* ***electricity distribution companies*** *and the electrical contractors are* ***still rather passive****, at least from the standardization perspective*"

A research paper from the University of Strathclyde further reflects this view of standardization of LVDC [120]. It states that:

"*From this review, it has become clear that stand-alone DC applications have well-defined technical standards, but the technical specifications for more complex, integrated networks that will be found within the built environment and public distribution systems are still evolving*"

Areas highlighted for standardization include voltage levels, safety, earthing system design and protection. However in each case the technology is there to support adoption in the longer term.

Similarly a 2018 paper (based on experience in the USA) highlighted that whilst DC systems have proved safe and reliable, non-technical issues present key barriers. These include that industry professionals are unfamiliar with DC and the market for DC devices and components is currently small.

7.4 CONCLUSIONS

This topic area explored three main areas:

- Future customer demand including demand flexibility;
- The economically efficient capacity to install; and,
- Potential high capacity solutions.

Residential customer demand is being explored through the concept of core and interruptible capacity. Work to date has discussed core capacity requirements of anywhere between 2-7kW depending on the type of load used at a property. Customer response and uptake of flexible demand will be a key factors in managing a customer's (and the network's) peak capacity requirements without triggering contentious issues such as load limiting by supply interruption.

The capacity for customers to export to the network was also discussed within this section. Regulations within ESQCR state any generation over 16A per phase (~3.68kW) has to apply to the DNO for connection in advance. This limit was set in 2002 and given the advances in

[81] An EPRI 2006 study [142] shows a clear example of this for a commercial application, highlighting that for a data centre containing 1000 servers (that use DC power), $3.5 million could be saved annually on power supply costs based on the reduced conversion losses and associated cooling requirements when utilising DC distribution.

distributed generation technology since then, it may form an artificial barrier to the connection of larger systems. The justification for the 3.68kW limit appears worth revisiting, particularly if other areas of ESQCR (i.e. voltage and frequency) are to be revised.

On economically efficient design, there is a range of evidence to support the case of conductor oversizing for the purposes of both reducing losses (providing through life economic benefit) and hedging against future demand increase. More defined approaches (particularly around the consideration of load growth) would be beneficial to prevent divergent industry practices.

The section highlighted some of the opportunities around the use of 3 phase and DC supplies to homes. In both cases the findings of this work are inconclusive – i.e. there is not sufficient evidence to fully support the use of either. However the findings do not discount the idea that three-phase connections may provide benefit and be more cost effective through life and encourage DNOs to conduct further work in this area.

8. SMART ENERGY SYSTEM INTEROPERABILITY

Interoperability can be defined in an electrical power system context as:

"the seamless, end-to-end connectivity of hardware and software from the customers' appliances all the way through the distribution & transmission systems to the power source, enhancing the coordination of energy flows with real-time flows of information and analysis." [121]

From this definition, system and product interoperability and the data flows surrounding them will be key pillars in enabling system flexibility, as well as a range of other service options, down to the customer level. Figure 22 outlines the top level relationships between interoperability and other concepts discussed within this review such as flexibility solutions and customer uptake of such solutions. Figure 22 illustrates an iterative increase with respect to flexibility and likely customer uptake, with growth of flexibility placing more demand on the interoperable communication and data collection systems. Assurance that the systems will deliver the required functions are key to their incorporation into future engineering standards. The potential value of this capability is highlighted within section 5.

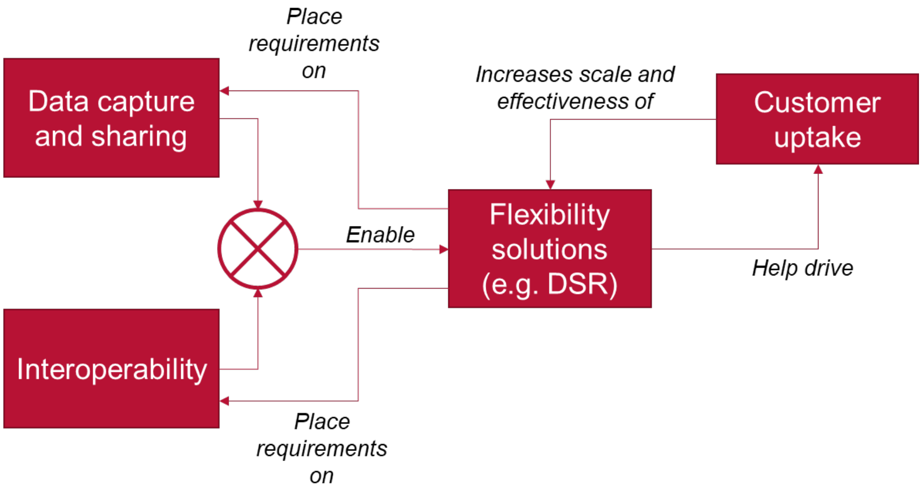

Figure 22: Interoperability alongside enhanced measurement and data capture is a key enable for system flexibility

The following sections explore two topic areas related to interoperability (with a focus on EV chargers) and electricity system data.

8.1 EV SMART CHARGER INTEROPERABILITY

In reviewing this topic area, key considerations were around the standards related to the interface between utility systems and micro and meso scale systems and aggregations of these systems. However the interoperability standards landscape is vast. The number of standards within this landscape make this topic complex to review – an issue which would also be experienced by developers and networks.

Reference [6] (a copy of which is included in Annex E) reports the outputs of a mapping activity conducted in support of this review and a summary of this report is presented within this section.

Due to the large volume of literature available, EV smart charging - modifying an EV's charge profile to maximise benefit to consumers and the power grid - was down-selected for further investigation. However, many of the results will be applicable to the use of Energy Smart Appliances. The following use cases were analysed to understand any interoperability barriers or risks:

1. Provision of short term frequency response (demand turn up and turn down)
2. Load shifting away from peak periods
3. DNO controlled demand turn down/turn off
4. Management of post-outage turn on and cold load pick up
5. EV manufacturer remotely running tools to monitor and extend battery life as part of the leasing deal

These 5 key use cases cut across the many topics discussed elsewhere in this report. The outputs of this mapping and use case analysis are summarized in the following sections.

8.1.1 The EV interoperability standards landscape

A large number of groups including the International Electrotechnical Commission (IEC), the Institute of Electrical and Electronics Engineers (IEEE) and ISO have developed interoperability standards. The Society of Automotive Engineers (SAE), the Internet Engineering Data Task Force (IEDTF), ZigBee Alliance and the Open Charge Alliance (OCA) have also undertaken more domain-specific development.

Figure 23 presents a summary of the standards and protocols that apply to EVs and energy smart appliances (ESAs).

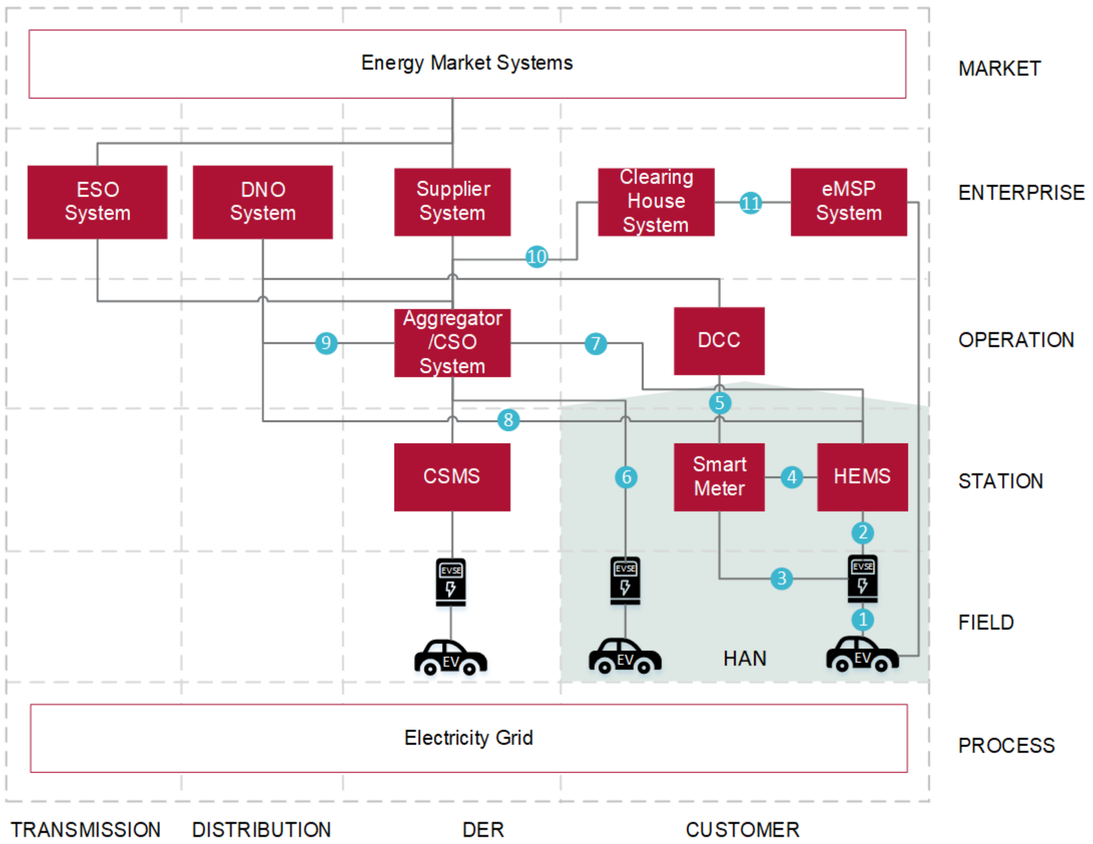

Figure 23: EV smart charging communications standards

Key standards and protocols for communications interfaces from Figure 23 are summarised in Table 15.

Table 15: EV communications interfaces - standards and protocols

Interface(s)	Standard(s)	Protocol(s)
1 EV:EVSE	IEEE 2030.1, IEC 15118, IEC 61851-23, IEC 61851-24	CAN bus (IEEE 2030.1), PLC (CCS) DNS, SDP, XML/EXI, TCP, UPD, TLS, IP, ND ICMP, DHCP (ISO 15118-2)
HAN 2 EVSE:HEMS 3 EVSE:Smart Meter 4 HEMS: Smart Meter	IEEE 2030.5, IEEE 802.3, IEEE 802.11, IEEE 802.15.4, ECHONET Lite	HTTP, XML/EXI, TLS, TCP, xMDNS, IP (IEEE 2030.5) IP (ECHONET Lite) WiFi, Ethernet, ZigBee, 6LoWPAN
5 Smart Meter:DCC	IEC 62056	DLMS/COSEM
6 EVSE:Aggregator 7 HEMS: Aggregator	IEC 63110, OCPP	XMPP, HTTP, SOAP
8 HEMS:DSO 9 Aggregator:DSO	IEC 62746-1-10, IEEE 2030.5	XMPP/HTTP, TLS (IEC 62746-1-10)
10 CSO:Clearing House 11 eMSP:Clearing House	IEC 63119	HTTP, SOAP/XML, JSON, TLS, TCP

As can be seen from the above diagram and table, there are a range of different possible communication architectures and associated standards for smart charging[82]. Additionally, Table 15 only shows standardised communications, and does not show the large range of proprietary protocols that may or may not comply with one or more of these standards.

8.1.2 Summary of findings on EV Smart Charging Use Cases

The findings of the analysis of EV smart charging use cases are shown in Table 16.

Table 16: Standardization issues related to EV smart charging use cases

Use case	Findings
Short term frequency response	Challenging to meet associated requirements regarding activation time, aggregation and operational metering posing key barriers. However early trials prove this service is possible with intelligent control and compatible communications.

[82] The above set is non exhaustive and more detail can be found in the associated report [6].

Load shifting	A more mature service, with open standards for communications emerging.
DNO/DSO dispatched demand turn down/turn off	There is current a lack of clarity in the criticality of services and priority in smart charging control.
Post-outage turn on and cold load pick up	There are examples of products offering a cold load pick feature but this is not current standard in GB.
Remote battery health management	Proprietary protocols are widespread

8.1.3 Conclusions

The conclusions of the review of the EV smart charging standards landscape are presented within this section. The full report on this review is presented within [6].

The report attempts to map the interoperability landscape for a representative set of EV smart charging use cases. The SGAM interoperability layers and OSI model for communications have been used to provide an abstract framework for description of the complex communications between EVs and the smart grid.

It was seen that international standards have emerged in the last decade to provide candidate protocols for communications from the charging assets up to the enterprise layer. The CHADeMO standard has emerged as the first V2G capable standard for EV to EVSE communications, with others likely to follow by mid-decade. At the higher level, open standards have provided the impetus for wider standardisation, notably OCPP and OpenADR. This has paved the way for other standards such as IEEE 2030.5, IEC 63110 and many others. Limited standardisation has occurred at the higher enterprise level of communications and in the specification of DSR services.

Many initiatives are ongoing internationally to fill the remaining interoperability gaps. The IEC TC 57 and 69 are notable participants in this process. Interoperability labs are also becoming popularised by government and industry in many countries to implement and test these new standards. In the UK, the BSI is developing two PAS to provide a framework for DSR services and classification of smart appliances to provide these services.

Despite this standardisation activity, the common usage of proprietary non-standardised protocols poses a significant barrier to widespread smart charging implementation. A number of smart charging use cases were investigated to understand these barriers and how they are being overcome.

The provision of short term frequency response services was seen to be a challenging use case, with associated requirements regarding activation time, aggregation and operational metering. Despite this, early trials prove this service is possible with autonomous control and compatible communications. The load shifting of demand is an example of a more mature service, with open standards for communications emerging. The direct dispatch of EVs by DNOs faces a lack of clarity in the criticality of services and priority in smart charging control. Cold load pickup is similarly lacking in the description of the service, inhibiting larger scale procurement. Finally, non-grid use cases face related challenges with proprietary protocols widespread.

The successful UK and international deployment of smart charging to meet the needs of the grid and consumers will significantly depend on the adoption of the growing volume of international and local communications standards. Recent trials provide reasons to be hopeful that this can be achieved, however all parties who oversee and participate in the smart grid have a role to play in this.

8.2 ELECTRICITY SYSTEM DATA

Electricity system data can come in many forms and have many uses. This section focusses on the engineering data which will enable the types of network investment savings discussed elsewhere within this report (e.g. a reduction in distribution network reinforcement and whole system costs including the need for new generation build)[83]. A short review was undertaken to identify:

- What type of data do we need, how will it be used and what technical solutions or standards will that drive?
- Are there ongoing programmes or activities which will address the data needs?

Within this section a representative set of use cases for electricity system data are described in order to identify relevant data needs and the technical solutions which will fulfil these needs. Conclusions are then drawn around the extent to which ongoing programmes of work within the sector will address these needs. Annex D presents a summary of the ongoing programmes of work within the sector considered relevant to the use cases of interest. It is noted that at the time of writing there are a number of ongoing programmes relating to the management of electricity system data and these are progressing at pace.

8.2.1 Electricity data use cases

Table 17 and Table 18 detail example use cases for which network monitoring will play a key role (both with and without open data sharing).

Analysis of such use cases can help identify requirements for monitoring location, parameter measured, data resolution and how data is shared

These use cases are divided into:

- Planning use cases: where high fidelity monitoring data can be used to support more efficient design of the electrical system, but can be based on historical data
- Operational use cases: where data of the necessary fidelity must be provided in real-time

[83] However it was recognised through this review that whilst there are clear benefits to network companies (e.g. for network planning and operation), data also has a high but difficult to quantify optionality value. Innovators may identify new ways to create value and a DNO's CBA may miss this value and hence undervalue data capture activities. Furthermore, data capture supports good planning decisions, but the cost of suboptimal decisions is difficult to quantify.

Table 17: Planning use cases for electricity system data

Use case name	Current practice	Outcome	Data requirements	Related asset
Secondary substation capacity management	Currently the majority of secondary substations are equipped with maximum data indicators. These only display the maximum demand since the previous reading and are read infrequently. From a planning perspective, these may lead to the unnecessary upgrading of transformers and associated feeders.	Monitoring of secondary substations can enable headroom to be understood and voltage compliance issues identified. The impact of DG can also be identified. This may enable deferred reinforcement of assets.	*Data provider*: DNO *Data user*: DNO/regulation *Data required (Type)*: Voltage and current, transformer temperature, weather, understanding of capacity limits Published data could just be headroom *Data Resolution*: Around 1 min	Secondary substations Could also including monitoring of feeders and other assets such as link boxes.
Managing network losses	Currently losses (how much is lost across the entire system) are calculated at a very gross level and then models and rules of thumb are used to attribute where those losses are occurring.	A more fine grained measurement, e.g. what energy is flowing into and out of each substation, would allow far better identification of where losses are occurring. This in turn would enable targeted network interventions and repairs to be undertaken to reduce losses	*Data provider*: DNO/TSO *Data user*: Parties investigating network performance *Data required (Type)*: Power flow across the network *Data Resolution*: 5 second resolution provides good accuracy (see: [114])	Substations across transmission and distribution
Regional / Local ROCOF	Currently whole system frequency is reported at a 1 sec resolution and ROCOF is only reported for significant events. Whilst frequency is largely systemic, ROCOF has much more local variation and will be proportional to regional inertia, system strength and potential size of a network event.	If ROCOF was published at a regional level, this would provide insight into the inertia and system strength in that area and support identification of suitable locations for new generation and storage.	*Data provider*: DNO *Data user*: Generators/storage providers *Data required (Type)*: Frequency or RoCoF at a regional level. *Data Resolution*: ROCOF protection settings are based on average ROCOF over 500ms.	Primarily transmission substations (although this could be rolled down to lower voltages to understand differences in ROCOF)

Table 18: Operational use cases for electricity system data

Use case name	Current practice	Outcome	Data requirements	Related asset
Real time management of substation/feeder capacity	Currently substation overloading (particularly secondary substations) is managed through its protection devices. Excessive current may trigger protection operation leading to downstream load disconnection. There may be local temperature alarms to alert the DNO of overloading leading to manual load disconnection to prevent asset damage.	Smart load (e.g. an EV/EV chargepoint) modulating its demand based on headroom available on the local feeder/substation. There is a requirement for the substation to be able to publish fine-grained, real-time load data in order for the downstream load to respond.	*Data provider*: DNO *Data user*: DNO/regulation *Data required (Type)*: Voltage and current, transformer temperature, weather, understanding of capacity limits. Published data could just be headroom. *Data Resolution*: 5 min	Secondary substations Could also including monitoring of feeders and other assets such as link boxes.
Voltage control and optimisation	There is currently limited visibility of operating voltage at LV. Operating at too high a voltage level can lead to wasted energy (through inefficient load operation) and distributed generation being constrained or disconnection.	Optimisation of voltage through visibility and control has the potential to reduce the energy used by customers and maximise the supply from DG. This is in part enabled through advanced monitoring coupled with appropriate voltage switching equipment (e.g. on-load tap changers)	*Data provider*: DNO/TSO *Data user*: Parties investigating network performance *Data required (Type)*: Transformer output voltage. Customer input voltage (can be provided via smart meters) *Data Resolution*: around 1 min	Secondary substations and associated voltage control equipment
Peer to peer energy or capacity trading	Peer to peer trading via the electrical distribution network is currently not implemented in GB outside of innovation projects.	Certain applications of peer-to-peer trading, particularly capacity trading, rely on the real time monitoring of network conditions. Openly published data would support analysis of where these applications could be implemented.	*Data provider*: DNO *Data user*: Peers - potentially via a neutral market facilitator *Data required (Type)*: Network capacity. *Data Resolution*: Variable depending on the nature of the trade.	Substations and feeders

8.2.2 Technical solutions

There are three main strands to technically enabling the use cases described. These are:

- **Data capture**: the requirements for increased monitoring infrastructure where it is not already in place.
- **Making data open - strategies and processes:** the requirements for third party access to monitoring and other relevant data. This should translate current plans for 'presumed open' data into reality.
- **Real-time data sharing - technology enablers:** the requirements for infrastructure to enable real-time data communication and the means of data sharing/streaming (e.g. hosting platforms).

Underpinning the more challenging use cases (e.g. real time management of substation/feeder capacity) is a long term move towards granular data on load flows, capacity, voltage, frequency from Tx down to LV being openly available and published in real-time. For data capture, network asset monitoring may include measurement of: voltage, current, temperature (i.e. of transformers) and weather information (ambient temperature, wind speed and direction, solar radiation). This will need to be coupled with high speed communication connections to facilitate data sharing.

8.2.3 Gap analysis

Table 19 presents a summary of the identified gaps between the ongoing development plans and initiatives and the delivery of the technical solutions outlined in the previous section. This table draws input from the ongoing activities presented in Annex D.

Table 19: Potential remaining gaps in development plans and initiatives

<table>
<tr><th colspan="2">Strand</th><th>Remaining gaps and barriers</th></tr>
<tr><td colspan="2">Monitoring and data capture</td><td>Networks have highlighted the intention to expand monitoring (particularly at LV). Additional information is required on deployment plans and scale. Ofgem have requested publication of Digitalisation Action Plans which should provide this information.

It is currently difficult for DNOs to fully quantify benefit to justify widespread investment. Tension exists between economically efficient network investment and enabling wider strategy (and novel sources of value).</td></tr>
<tr><td colspan="2">Making data open - strategies and processes</td><td>All networks have signed up to 'presumed open' but current plans around release monitoring data (both historical data and real time) is unclear. An ENA working group has been set up to develop progresses for data release. Digitalisation Action Plans may also provide potential route for this.</td></tr>
<tr><td rowspan="2">Real-time data sharing - technology enablers</td><td>Infrastructure for real-time data communication</td><td>Infrastructure for real-time data communication from substations (particularly at LV) may be lacking. Positive examples include the Northern Power Grid Smart Grid Enablers programme where investment in communication is being made.

The role of the smart meter network in delivering some smart grid use cases is unclear. Potential issues include data access, costs, granularity and latency particularly for data via the DCC.</td></tr>
<tr><td>Means of data sharing and streaming</td><td>Technology solutions needed to support widespread sharing of diverse data sources to private and public actors. Proposed options exist with ongoing development (however technical details limited currently). Need to determine a strategy for roll-out.</td></tr>
</table>

8.2.4 Conclusions and next steps

Currently the data collected on the electrical system is not sufficient to enable the full range of potential flexibility services, nor are there mechanisms in place (outside innovation projects at least) to effectively share this data to third parties or customers to enable. However, there is significant ongoing activity related to electricity system data. Whilst many projects are at an early stage, they are developing at pace. Key areas noted for further development are:

- The technical solutions for data sharing are immature;
- The deployment of monitoring and communication infrastructure needs to be scaled up;
- Networks have adopted ‘presumed open’ but have yet to communicate detailed plans for releasing data (work is ongoing here); and,
- There is uncertainty about what the smart meter network will deliver in terms of data to support load management and flexibility functions and it is likely additional monitoring is required to complement smart meter data for most of the use cases reviewed.

The adoption of standards for data capture, formatting and communication (many of which exist already) will support efforts to mature and scale up key use cases.

It was also recognised through this review that uncertainties around the cost-benefit of data sharing is a potential barrier to wider data capture and sharing. Whilst there are clear benefits to network companies (e.g. for more optimal network planning and operation), data also has a high but difficult to quantify optionality value. Innovators may identify new ways to create value and a DNO’s CBAs may miss this value and hence undervalue data capture activities. Furthermore, there will likely be economies of scale for greater data capture (as has been the experience with data in other sectors). Further work to understand the economic efficiency of rolling-out of monitoring and communication infrastructure by default would be would help to address this uncertainty and manage expectations for both network companies and other system users in future.

9. SUMMARY OF FINDINGS AND CONCLUSIONS

The analysis of the topic areas within this report identifies a number of opportunities for cost reduction and related benefit for consumers. The cumulative benefit of these changes has not been fully explored (partly due to the trade-off between certain changes) however these could easily add up to several billion pounds over the long term.

In many cases there have been recent changes to standards or there are ongoing initiatives which are seeking to capitalise on these opportunities. This report has highlight some key developments and it is recognised that there will be other good work ongoing which has not been discussed.

Detailed conclusions have been drawn at the end of each section topic area. Table 20 pulls the headline conclusions together alongside associated benefits and changes to the standards which would facilitate the technical opportunity. The evidence for the various benefits has been presented in detail within the previous sections and these sections present the sources, assumptions and potential issues in realising these benefits.

Table 20: Summary of technical opportunities, benefits and related changes to standards

Topic area	Opportunity	Benefit	Related changes to standards
Voltage limits	Accommodation of additional load	Capacity increase (up to 25% greater voltage drop) Deferred reinforcement of £518M. Possibly up to £4bn depending on load growth.	Relaxation of voltage lower limit within ESQCR (provides a direct impact).
	Headroom for additional DG	Additional 15 - 23% capacity for DG	Already achievable on some networks. Relaxation of voltage lower limit within ESQCR (provides flexibility for set point reduction)
	Energy reduction	Up to 8% energy reduction (4% for passive control) ~£40 per annum per LV customer Reduced network losses (up to 15%) Deferred reinforcement benefit £80M from 5% voltage reduction	
Frequency, Operability and Stability	Reduction in ROCOF constraint costs	Cumulative NPV of £305M by 2024	Already accommodated within G59/G99.
	Facilitate microgrid operation	Supports decentralised power system and future models for system resilience	A range of standard updates would be required. Particularly within G99 given the implications for LOM protection.
	Clearer expression of frequency requirements	Greater clarity for all network users.	No technical change but content of ESCQR, SQSS, Grid Code and DCode all impacted.
Security of supply and reliability	Redefine VOLL	Clearer reflection of supply value to customers. More effective implementation of flexibility.	Initially impacts ETR130 (where VOLL is currently).
	Reduce reinforcement cost	£4bn to £7bn by 2030 for significant load growth.[84]	Relaxation of the deterministic rules within P2/7.

[84] However this needs to be compared against whole system VOLL and system maintainability

Topic area	Opportunity	Benefit	Related changes to standards
	Incorporate flexible resources	Reduction of £2bn and £3.4bn of distribution network investment £10bn to £13bn of network CAPEX investment (inc. generation build and operating costs)	Design rules to enable flexibility are in place within P2/7. Further development of interoperability standards are required to exploit resource.
	Adaptive operational transmission security	Better utilise transmission assets and reduce constraints (but implications not fully explored)	SQSS (section 5. Operation of the Onshore Transmission System) would need to be adapted.
Resilience and black start	GB Black Start Restoration standard	Clarity over outage time during significant events.	New standard currently being finalised.
	Standards for emergent system risks (climate change, cybersecurity)	Ensure grid ongoing grid resilience.	Various standards and guidance developed with initiatives ongoing.
	Execution of system defence load shedding measures could be VOLL based	Ensure critical loads are not unnecessarily disconnected. Enable more customers to remain connected through disconnection of interruptible supplies.	Grid Code/DCode (Operating Code 6 – Demand Control) would be impacted.
Future Installed Network Capacity	Increase installed asset size for economically efficient design	Significant through life cost saving from oversizing conductors due to reduced losses. Also provide a hedge against future load growth uncertainty.	Covered within ETR130 and G81 to an outline level. Guidance on methodology could be more specific to ensure consistent practice.
	Increased the 16A/3.68kW limit for small scale generation and storage	Potential for increased DG connection without DNO management overhead.	Impact on ESQCR, the applicable power levels of G98/G99 and G100 (export limitation levels).

Topic area	Opportunity	Benefit	Related changes to standards
	Install 3 phase and DC to homes	Provide higher capacity and more efficient connection for high power[85].	3 phase could become standard for new developments. Greater standardization around DC required before widely implementable.
Smart energy system interoperability	Develop a set of well-defined interoperability standards	Underpins the delivery of system flexibility and services to consumers.	Standards being developed through the Energy Smart Appliances (ESA) Programme are a step towards this.
	Improved outage recovery through features such as cold load pickup management	Minimise network protection operation during load reconnection. Reduces need for investment in assets for infrequent loading conditions.	Opportunity to capture within forthcoming changes to the Automated and Electric Vehicles Act 2018. Impacts demand security assessment (ETR130).

[85] The economic efficiency of these design approaches has not been fully evidenced.

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11. GLOSSARY

Term	Definition
ADMD	After Diversity Maximum Demand
ALoMCP	Accelerated Loss of Mains Change Programme
BEIS	Department for Business, Energy & Industrial Strategy
BSTG	Black Start Task Group
CBA	cost-benefit analysis
CCC	Committee on Change
CDF	Customer Damage Function
CI	Customer Interruption
CLASS	Customer Load Active System Services
CML	Customer Minutes Lost
DER	Distributed Energy Resource
DG	Distributed Generation
DNO	Distribution Network Operator
DSR	Demand Side Response
ENA	Energy Networks Association
ENTSO-E	European Network of Transmission System Operators for Electricity
ENWL	Electricity North West Limited
EREC	Engineering Recommendations
ESEC	Electricity Supply Emergency Code
ESQCR	Electricity Safety, Quality and Continuity Regulations
ETR	Engineering Technical Report
ETYS	Electricity Ten Year Statement
EV	Electric Vehicles
FES	Future Energy Scenarios
GB	Great Britain
GSP	Grid Supply Point
HVDC	High Voltage Direct Current
ICT	Information and communications technology
LFDD	Low Frequency Demand Disconnect
LOM	Loss of Mains
LV	Low Voltage

LVDC	Low Voltage Direct Current
MWh	Megawatt Hour
NCER	Network code on electricity emergency and restoration
NERC	North American Electric Reliability Corporation
NGESO	National Grid Electricity System Operator
NGET	National Grid Electricity Transmission
NIC	Network Innovation Competition
OC	Operating Code
Ofgem	Office of Gas and Electricity Markets
RIIO	Revenue=Incentives+Innovation+Outputs
ROCOF	Rate of Change of Frequency
SDP	System Defence Plan
SHEPD	Scottish Hydro Electric Power Distribution
SOF	System Operability Framework
SPEN	SP Energy Networks
SQSS	Security and Quality of Supply Standard
SSSP	System Strength Service Provider
STG	Strategic Telecommunications Group
TO	Transmission Operators
TOU	Time-of Use
UKPN	UK Power Networks
VOLL	Value of Lost Load
WPD	Western Power Distribution
WTP	Willingness To Pay

ANNEX A - FREQUENCY STANDARDS AND MANAGEMENT

A.1 RESPONSE OF CONNECTED EQUIPMENT TO FREQUENCY

A.1.1 CHALLENGES OF LOWERING THE OPERATING FREQUENCY

A.1.1.1 Electrical machines with magnetic circuits (motors and transformers)

The tolerance of electrical machines to changes in frequency depends on the capacity of a machine's magnetic (iron) circuit. The excitation flux in the core of the motor or power transformers is directly proportional to the ratio of voltage to frequency (V/Hz) on the terminals of the equipment. At a certain ratio (dictated by the material and core dimensions), overexcitation of the core can occur and this can lead to machines overheating and ultimately failing.

Reference [122] highlights that "most international standards for power transformers specify a limit of maximum 5 % continuous overexcitation (overfluxing) at rated load current and maximum 10 % overfluxing at no load". They tend to operate close to these limits for efficiency reasons.

Standard IEC 60034-1 on Rotating electrical machines defines how voltage and frequency fluctuation impacts on temperature rise. As stated within [123], "*the standard divides the combinations into two zones, A and B. Zone A is the combination of voltage deviation of +/-5 % and frequency deviation of +/-2 %. Zone B is the combination of voltage deviation of +/-10 % and frequency deviation of +3/-5 %*." Motors are capable of supplying the rated torque in both zones A and B, but the temperature rise will be higher than at rated voltage and frequency. Motors can be run in zone B only for a short period. This is illustrated within Figure 24

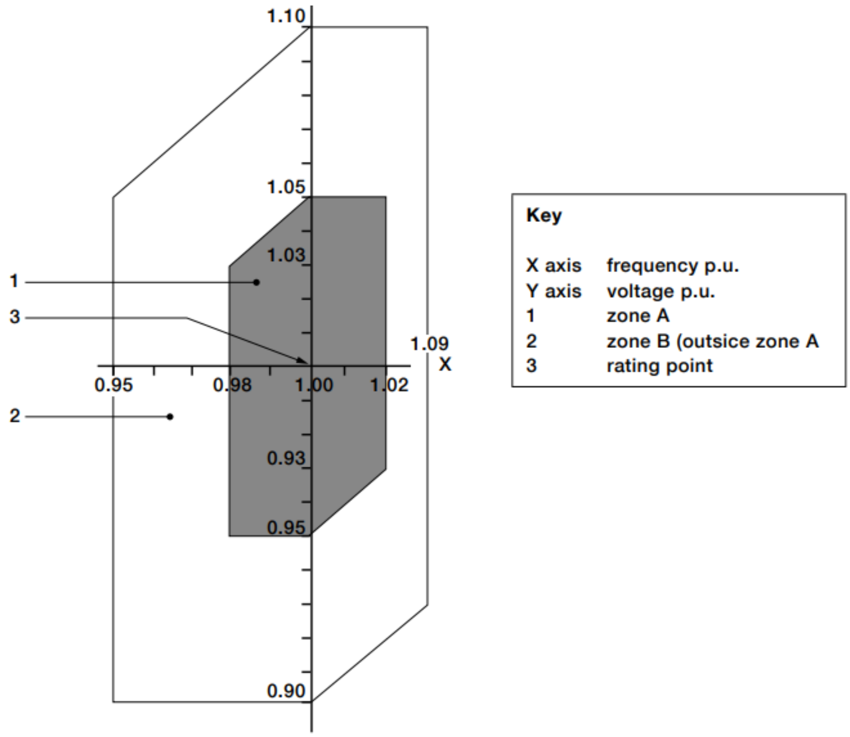

Figure 24: Voltage and frequency deviation in zones A and B (IEC 60034-1)

A.1.1.2 Steam Turbines

Reference [124] highlights that turbine blades are designed to operate in a narrow band of frequencies to avoid mechanical vibrations of blades at their natural frequencies and any deviation beyond this band could damage the turbine. Further references are provided which reference that a 50 Hz steam turbine may not be able to withstand frequency deviations greater than ±2.5 Hz.

A conservative estimate of the time-frequency limitations of a 60Hz steam turbine was presented in [125]. This highlighted that the turbine could run continuously at 59.4Hz (1% reduction) but would incur damage if run at 58.8Hz (2% reduction) for a cumulative period of 90 minutes and within for 10 minutes of operational time at 58.2Hz (3% reduction).

A.1.1.3 Industry applications

A stable frequency is required for some industry applications such as rolling mills, paper industries and processing lines that depend on the speed of motors. When the frequency drops, the process may be disturbed. This provides further practical challenges for widening operating frequency range [124].

A.1.2 INCREASING OPERATING FREQUENCY

Overfrequency is less of an issue for electrical machines as Flux density (V/Hz) decreases and ventilation and cooling is often improved. However similar challenges will exist in relation to turbine operation and industry applications. Increased frequency will also lead to increased power transmission and distribution losses due to the increased line and transformer impedance.

A.2 MICROGRIDS AND DECENTRALIZED ELECTRICAL ENERGY SYSTEM STANDARDS

Standards for the operation of microgrids have been developed by the IEC SC 8B standards group titled 'Decentralized Electrical Energy Systems'. The scope of this group is to develop standards to enable:

- "*the development of secure, reliable and cost-effective systems with decentralized management for electrical energy supply, alternative/complement/precursor to traditional large interconnected and highly centralized systems*." [86]

The IEC 62898 standards series is concerned with requirements for developing microgrid. The current standards within this series are:

- IEC 62898-1:2017 Part 1: Guidelines for microgrid projects planning and specification
- IEC 62898-2:2018 Part 2: Guidelines for operation.
- IEC 62898-3:2020 Part 3-1: Technical requirements – Protection and dynamic control. This has not been published yet but should be released in 2020.

A.2.1 FREQUENCY STANDARDS WITHIN MICROGRIDS

The set of standards is not prescriptive around frequency; the general requirements have been developed to apply internationally so the nominal frequency will be dependent on the country of interest. IEC62898-2:2018 Part 2 does however provide an examples of operation of a 50Hz system with relevant frequency limits. Figure 25 and Table 21 outline example frequency control parameters from the standard. Note that these are similar to those currently employed within GB.

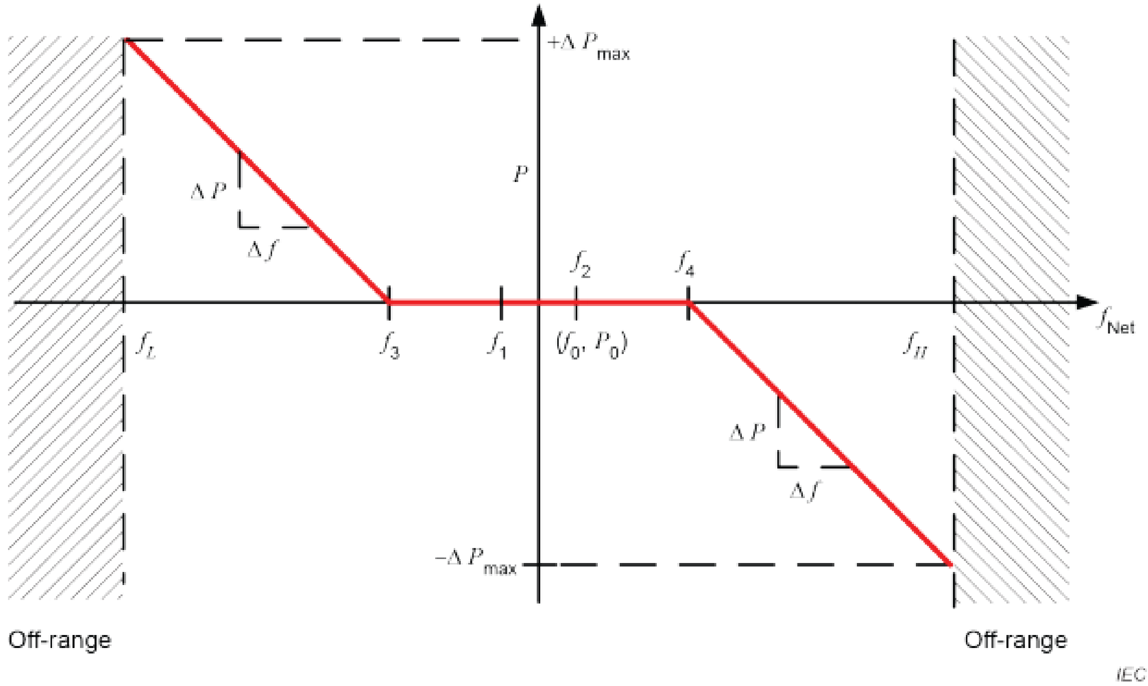

Figure 25: Power-frequency control in an isolated microgrid

[86] https://www.iec.ch/dyn/www/f?p=103:7:7332574360252::::FSP_ORG_ID,FSP_LANG_ID:20639,25

Table 21: Example of an isolated microgrid frequency response of a 50Hz system

Frequency parameter	Value (Hz)
f_0	50
f_1	49.95
f_2	50.05
f_3	49.5
f_4	50.5
f_L	47.0
f_H	53.0

A.2.2 COMMUNICATION WITHIN MICROGRIDS

Within many microgrid architectures coordination of control and protection is achieved via communication systems. IEC62898 proposes that these communication systems are built from existing communication standards used within the power industry. The standard states that IEC 61850-3, IEC 61850-4, IEC 61850-5 and IEC 61968-1 are recognized as the core standards for the smart grid and should be used for the microgrid applications.

ANNEX B - NATIONAL GRID ESO OPERATIONAL DATA

B.1 FREQUENCY AND ROCOF DATA

This section presents frequency and ROCOF data from August 2019. The frequency data shown within this section was extract from:

- https://www.nationalgrideso.com/balancing-services/frequency-response-services/historic-frequency-data

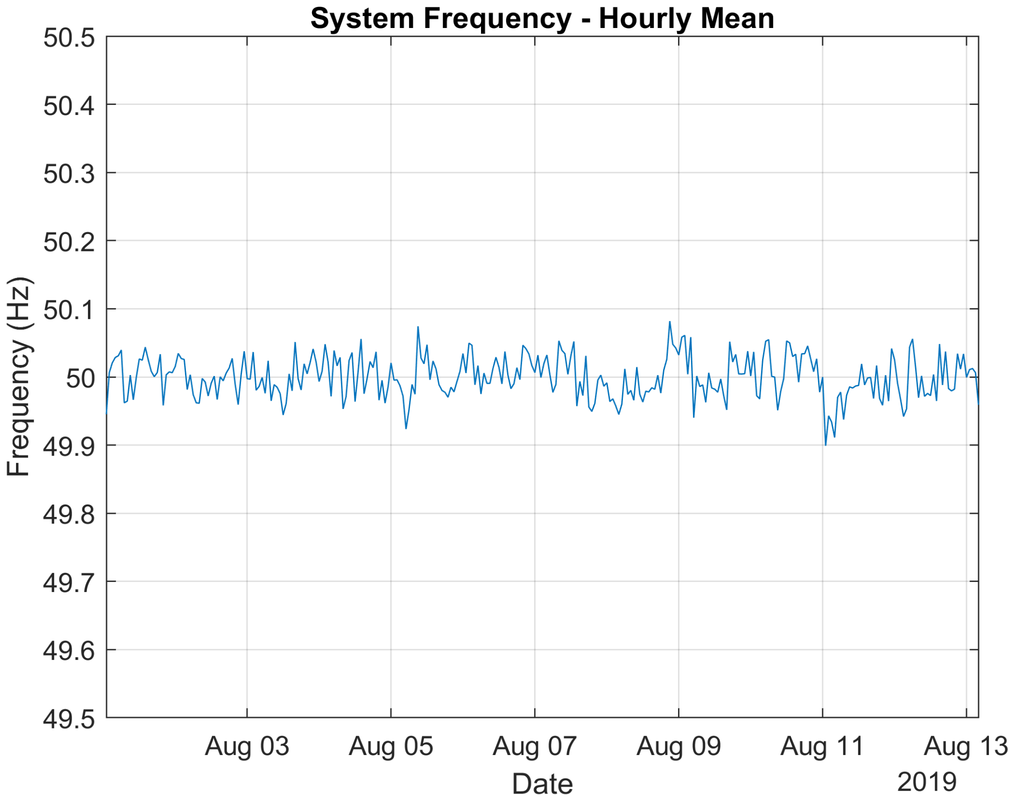

Figure 26: Hourly mean of the system frequency in August 2019 (calculated using 1 second resolution data)

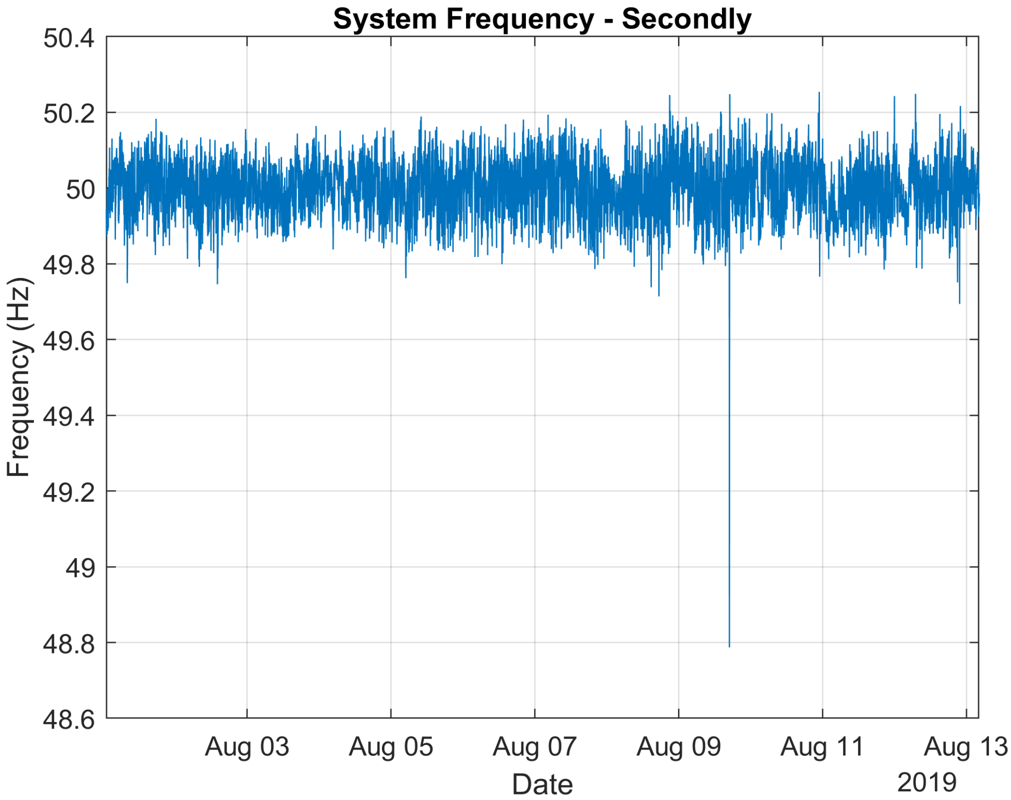

Figure 27: System frequency in August 2019 (plotted at 1 second resolution)

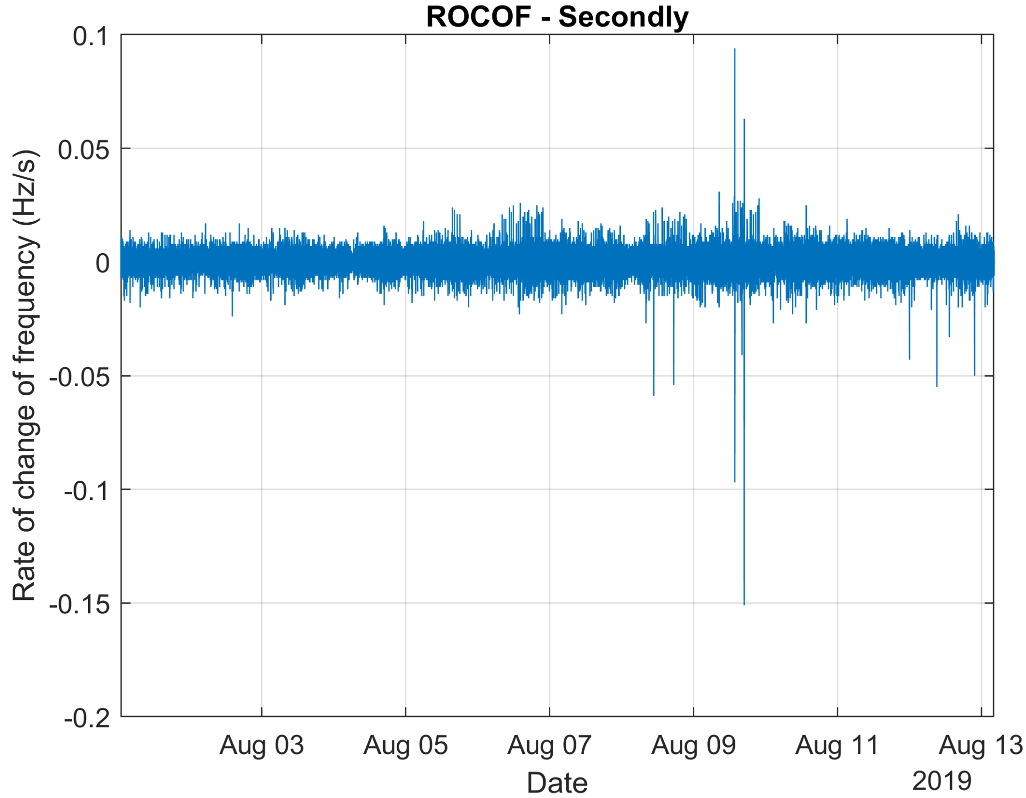

Figure 28: System rate of change of frequency in August 2019 (calculated using 1 second resolution data)

B.2 ROCOF CONSTRAINT COSTS

The data within this section was extracted from the following data sources:

- https://www.nationalgrideso.com/balancing-data/system-balancing-reports
- https://data.nationalgrideso.com/balancing/mbss

Data was not available for March 2020 and hence this has been predicted based on the average monthly cost throughout the 2019/2020 financial year.

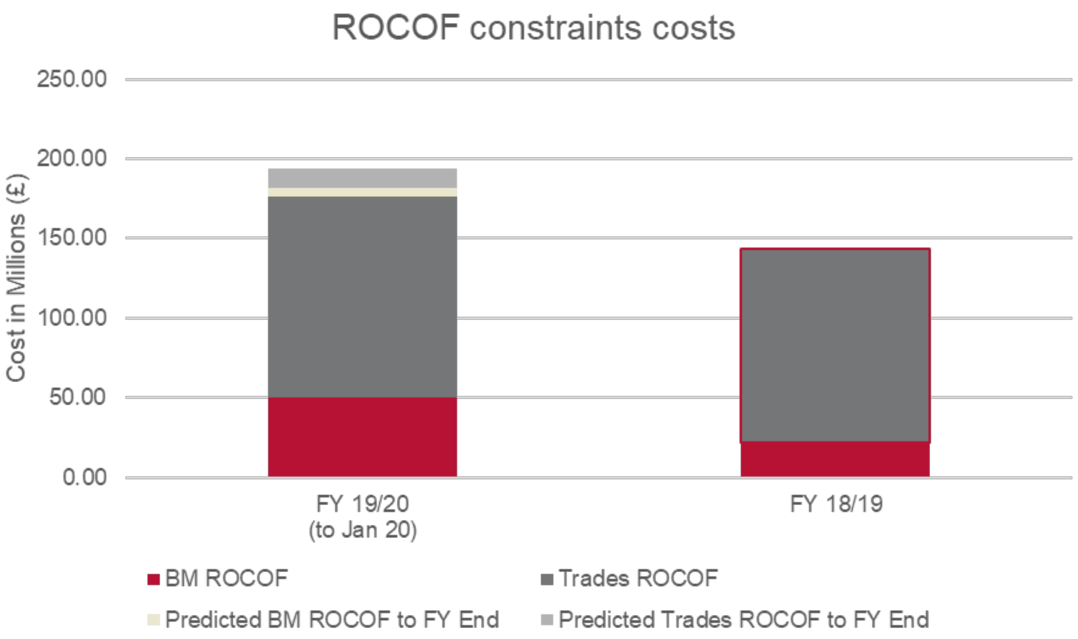

Figure 29: Reported ROCOF constraint costs in 2018/2019 and 2019/2020 financial years

B.3 TRANSMISSION CONSTRAINT COSTS

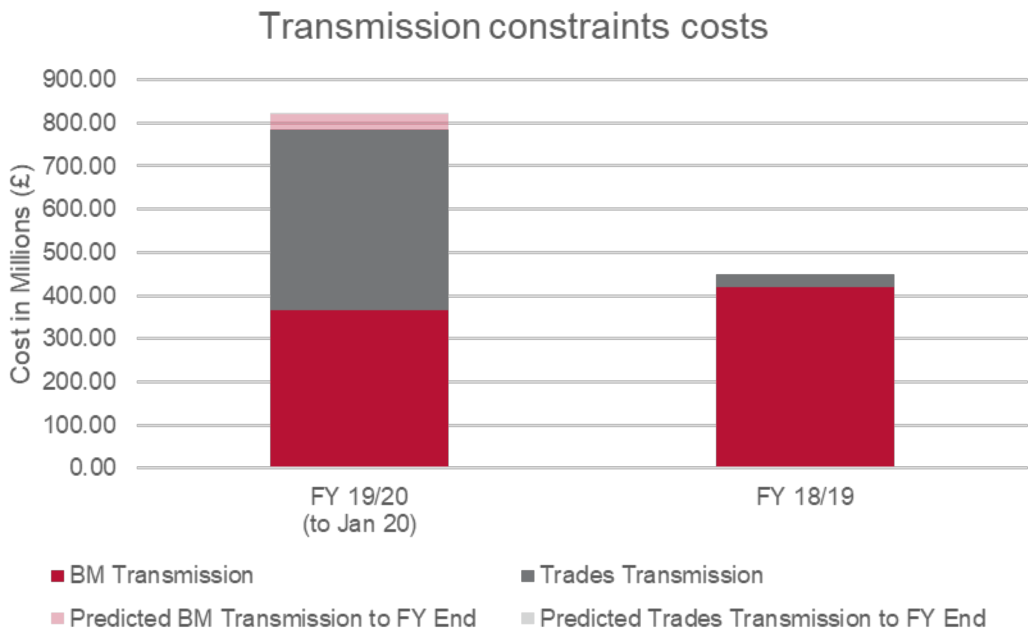

Figure 30: Reported transmission constraint costs in 2018/2019 and 2019/2020 financial years

B.4 CONSTRAINT ACTIONS BY FUEL TYPE

Breakdown of constraint costs by fuel type, for the year to date

Fuel Type	Payments to Manage Constraint	Payments to Rebalance System	Net Cost
COAL	3.62	10.32	13.94
GAS	48.83	229.41	278.25
INTERCONNECTOR	-21.00	3.48	-17.52
WIND	65.50	-0.01	65.48
OTHER	16.20	12.52	28.72
Total	113.15	255.71	368.86

Figure 31: Reported constraint costs by fuel type from November 2019

ANNEX C - CONDUCTOR RATING COST BENEFIT ANALYSIS

C.1 CONDUCTOR RATING COST BENEFIT ANALYSIS

C.1.1 INTRODUCTION

This annex seeks to investigate the impact of conductor sizing on through life cost. A cost-benefit analysis of different conductor size options for a relatively simple example network is carried out to perform this investigation.

The work has primarily been conducted to test the conclusions drawn from network wide studies conducted by Imperial College [114] [112][87], with a view to then determining the implications for engineering standards.

Other studies which are relevant to this work include:

- Work from the University of Bath [126], where, based on cost estimates from 2009, it was determined that the cost of long-term losses will overtake the cost of investment when the loading level exceeds 30-40%; and
- Recent network upgrade work from ENWL [115], which justifies the installation of a 300mm^2 conductor (as a opposed to a 185mm^2) on the basis reduced losses through life provide an economic benefit.

The structure of the report is as follows:

- Section 2 outlines the modelling work which has been undertaken;
- Section 3 presents results of the CBA for various scenarios; and
- Section 4 discusses the implications for the work for engineering standards.

C.1.2 MODEL SETUP AND ASSUMPTIONS

The modelling work has two key stages. These are:

- Calculation of losses; and
- A cost benefit analysis of conductor options.

The following sections describe the process for carrying out these modelling stages and assumptions made. All modelling has been conducted with Excel based tools.

C.1.3 CALCULATION OF POTENTIAL ENERGY LOSS

C.1.3.1 Network topology

Details of the electrical network used for this study are:

- It is a 3 phase supply with balanced supply on each phase;
- It supplies a group of 30 houses (this can also be scaled as described in following sections);
- The calculated load profile acts as a lumped load at the end of the 3 phase connection (i.e. no tapering of cables and full load carried).

C.1.3.2 Calculation of load profile

Key points related to the development of the load profile are:

[87] A key conclusion of this work was that the optimal design capacity for a LV cable was around 11-25% of its thermal rating.

- Energy demand for a group of 30 houses was calculated using the Loughborough University CREST Demand Model v2.2 [127]
- Two main scenarios were calculated: one including PV and one without PV[88].
  - When PV is included, it is assumed that 50% of houses have PV panels installed and gas central heating is used.
  - Without PV, electric water heating is assumed.
  - The model does not take into account electrical vehicle demand (this is not a standard feature).
- The model stochastically assigned the size of dwellings and their parameters drawn from a representative distribution.
- Daily profiles are created for summer and winter only and assumed to be representative of the year.

Annex C.1.7.2 illustrates the power demand profiles from the CREST demand tool.

C.1.3.3 Increased utilisation scenarios

In addition to the load profiles generated, scaling factors have been applied to increase the number of scenarios considered. These scaling factors have primarily been included to represent increased utilisation scenarios (e.g. an increased number of properties or a similar current flowing in a more heavily utilised part of the network). Scaling has been applied to load current to ensure I^2R losses are appropriately captured. These have only been applied to the high load case (electric water heating).

Note that no diversification has been applied to peak loading when scaling current (diversification becomes more likely as the effective number of customers increases). This however is naturally captured within the CREST demand tool for the base cases.

C.1.3.4 Calculation of energy losses

Key points related to the calculation of energy loss are:

- Losses are calculated on a per km basis;
- I^2R conductor losses are calculated each minute and then summed to represent a daily loss. These are then carried through for the lifetime of the conductor (meaning no change to demand);
- Power (and hence current flow) is assumed to be supplied at nominal voltage (400V/230V) and voltage drop has not been considered;
- Cable resistance data has been taken from SPEN design guidance [111] (see Table 28);
  - Conductor sizes considered are 35, 95, 185, 300mm^2 in line with the SPEN operational practice.

C.1.4 COST BENEFIT ANALYSIS

C.1.4.1 OFGEM template

The through life cost calculations have been performed using the OFGEM CBA template. The OFGEM template includes:

- Fixed cost of Losses of £48.42/MWh;

[88] These two variants provide representative high and low loading cases

- Traded carbon price[89], ranging from £7.30/tonne in 2016 to £304.66/tonne in 2060 (with a Electricity GHG conversion factor (tonnes per MWh) changing through time[90])[91];
- Capitalisation rates of 85%;
- Discount factors varying over time.

Full set of inputs can be viewed within the CBA spreadsheet used by ENWL [115] (see the 'fixed data' tab).

C.1.4.2 Implementation of the CBA

The calculations are performed following the published example by ENWL [115]. In summary:

- A conductor with a cross sectional area of 35mm^2 is the baseline solution upon which comparisons are made. Comparisons are made with conductors of 95, 185 and 300mm^2.
- The conductor cost used to establish the capital cost is the 'mid-point' cost shown in Table 27.
- Given the lack of clear data on installation costs for different conductor sizes, these have been excluded from the analysis.
  - This effectively assumes that installation costs is constant for all conductor sizes and compares the relative merits of installing different conductor sizes.
  - Note that this work is not seeking to justify total reinforcement costs (the Imperial College work found that loss reduction alone would not justify reinforcement).
- A volume of 1000km of cable is applied in the CBA template to achieve notable levels of investment and losses[92].
- Results are based on the calculated 45 year Net Present Value (note the lifetime of the conductor may be longer than this).

C.1.5 RESULTS

Tables 1 to 4 present the CBA results of the studies where loading is higher (i.e. electric water heating). Scaling is applied to the demand in these cases to consider the impact of higher peak current and utilisation on the most cost effective solution. Note that the 35mm^2 conductor is used as a baseline even though in some cases this would not be a viable solution (e.g. there are cases where cyclic rating is exceeded).

Table 5 presents the CBA for the low load case.

[89] Based on the 2012 values published here: https://www.gov.uk/government/collections/carbon-valuation--2
[90] Based on 2012 values published here: https://www.gov.uk/government/publications/2012-greenhouse-gas-conversion-factors-for-company-reporting
[91] Clearly, the results are sensitive to these parameters and they may change over time with a different generation mix and view of long-term carbon pricing.
[92] The CBA template is designed for high value projects rather than individual conductor replacements. Scaling is appropriate as the purpose of the CBA is to determine the cost effective solution for the given scenario rather than an actual cost saving.

Table 22: High load case 1 (determined directly from CREST Demand tool)

Cable Size (mm^2)	Estimated yearly loss/km (MWhr)	Peak current (A)	Percentage of cyclic rating[93]	Average utilisation[94]	45 year NPV against comparable solution (£m)
35	24.86	78.96	52.64%	23.36%	n/a
95	9.16	78.96	32.90%	14.60%	£17.94
185	**4.70**	**78.96**	**18.98%**	**8.44%**	**£18.60**
300	2.86	78.96	14.46%	6.43%	£17.32

Table 23: High load case 2 (Current multiplied by 2)

Cable Size (mm^2)	Estimated yearly loss/km (MWhr)	Peak current (A)	Percentage of cyclic rating	Average utilisation	45 year NPV against comparable solution (£m)
35	49.71	157.9	105.28%	46.73%	n/a
95	18.33	157.9	65.80%	29.20%	£38.42
185	9.39	157.9	37.96%	16.89%	£44.91
300	**5.73**	**157.9**	**28.92%**	**12.86%**	**£46.02**

Table 24: Demand case 3 (Current multiplied by 3)

Cable Size (mm^2)	Estimated yearly loss/km (MWhr)	Peak current (A)	Percentage of cyclic rating	Average utilisation	45 year NPV against comparable solution (£m)
35	74.57	236.9	157.92%	70.09%	n/a
95	27.49	236.9	98.70%	43.81%	£58.90
185	14.09	236.9	56.94%	25.33%	£71.22
300	**8.59**	**236.9**	**43.39%**	**19.29%**	**£78.46**

Table 25: High load case 4 (Current multiplied by 4)

Cable Size (mm2)	Estimated yearly loss/km (MWhr)	Peak current (A)	Percentage of cyclic rating	Average utilisation	45 year NPV against comparable solution (£m)
35	99.42	315.9	210.57%	93.45%	n/a
95	36.65	315.9	131.60%	58.41%	£79.39
185	18.79	315.9	75.92%	33.78%	£97.53
300	**11.45**	**315.9**	**57.85%**	**25.72%**	**£103.43**

93 Peak current divided by cyclic current rating (in percentage terms)
94 Average current divided by continuous conductor rating

Table 26: Low load case – includes 50% PV penetration and gas central heating

Cable Size (mm^2)	Estimated yearly loss/km (MWhr)	Peak current (A)	Percentage of cyclic rating	Average utilisation	45 year NPV against comparable solution (£m)
35	9.51	57.18	38.1%	13.4%	n/a
95	**3.51**	**57.18**	**23.8%**	**8.4%**	**£5.30**
185	1.80	57.18	13.8%	4.9%	£2.36
300	1.10	57.18	10.5%	3.7%	-£0.40

C.1.6 DISCUSSION

C.1.6.1 Discussion of Results

The results presented support the case that the consideration of lifetime losses will likely lead to larger conductor sizes presenting a more cost-effective solution. As expected, this effect is more pronounced as the utilisation of the conductor increases as the losses are proportional to utilisation. However even where utilisation is relatively low (see Table 5), an increased conductor size may be cost-effective across its lifetime.

Considering average utilisation, the most economic solutions range from between 8.4% and 25.7% for the cases considered.

Considering peak rating percentage, across our different scenarios the most economic solutions range from between from 19% to 57.9% (however note that the higher percentages may be due to larger conductor sizes not being considered). These are broadly in line (if at the higher end of the scale) with the conclusions of the work from Imperial College [114] (where conductors where most efficient at between 11-25% of thermal cable limits). Important points to note in comparing conclusions are:

- The way current demand has been scaled within this study is not fully representative of diversified demand (therefore the peak current may be lower);
- The load profile used has a relatively short period operating at peak current and therefore will not have a significant impact on losses through life;
- The capital cost of conductors used within this study was found to be higher than within the Imperial College study;
- It has been assumed that no reactive power is flowing in these cables.

C.1.7 SUPPORTING DATA

C.1.7.1 Cable cost and size data

Table 27: Example per km conductor cable costs

Cable Size (mm^2)	Commercially quoted conductor cost[95]	Calculated £ Amps.km	ICL assumed £ Amps.km[96]	ICL equv cable cost	Mid-point cost
35	£5,773.27	48.1	24.2	£2,904.00	£4,338.63
95	£9,130.00	47.6	24.2	£4,646.40	£6,888.20
185	£16,140.00	48.6	24.2	£8,034.40	£12,087.20
300	£21,000.00	48.2	24.2	£10,551.20	£15,775.60

[95] Quotes where provided by a commercial cable manufacturer for 95, 185 and 300mm^2 conductors. Costs for 35mm^2 were approximated from the average £ Amps.km. These are considered to provide conservative costs for the basis of this analysis.
[96] £ Amp.km figure provided via by ICL and applied to all conductor sizes.

Table 28: Conductor parameters and ratings

Cable Size (mm^2)	Cable resistance	Continuous Current rating	Cyclic current rating
35	0.868	120	150
95	0.32	192	240
185	0.164	332	416
300	0.1	436	546

C.1.7.2 Load profiles

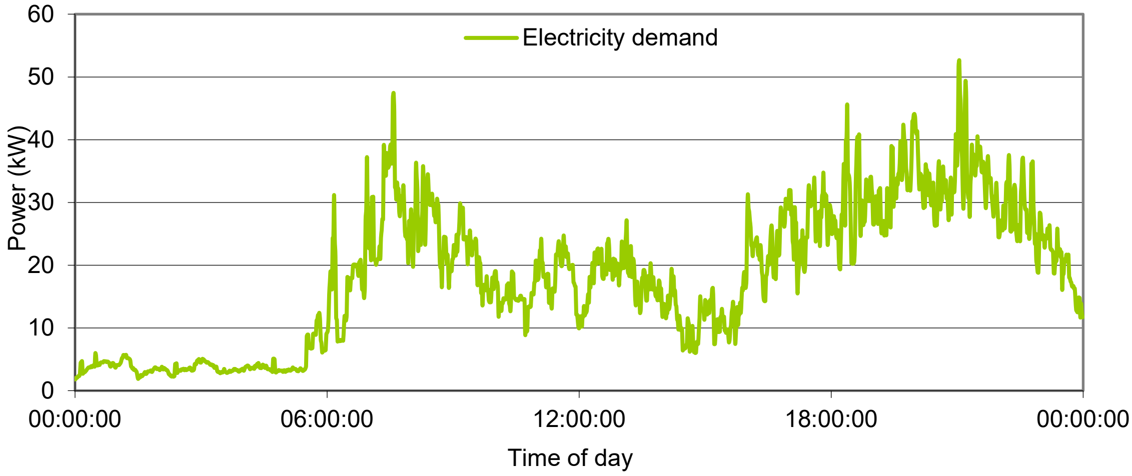

Figure 32: Generated demand profile for the high load configuration (summer)

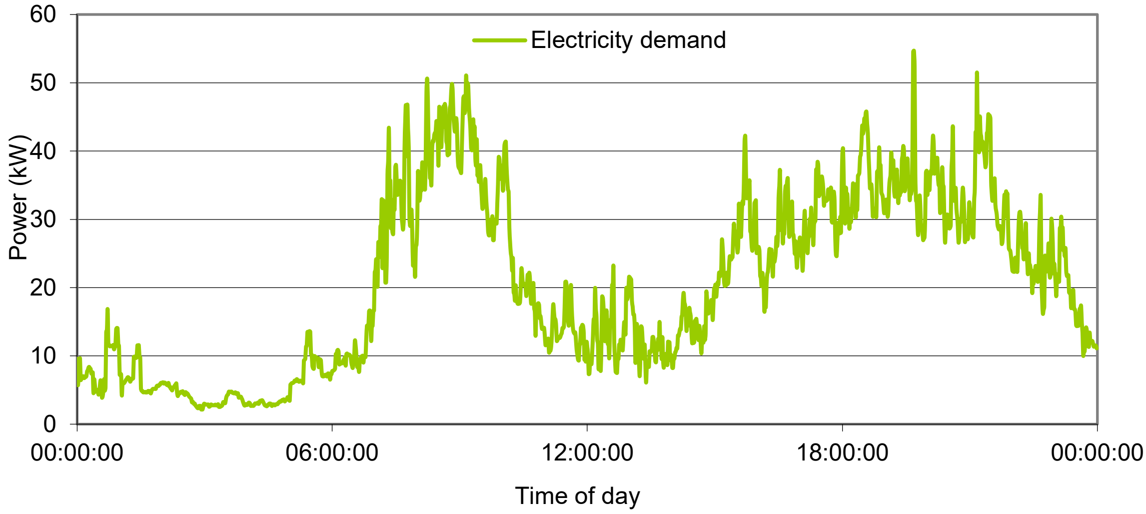

Figure 33: Generated demand profile for the high load configuration (winter)

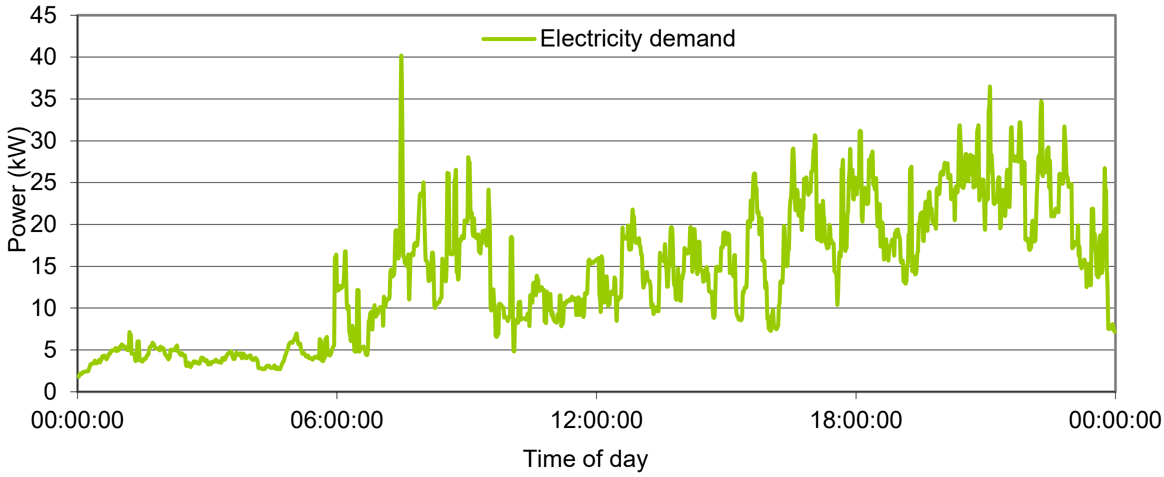

Figure 34: Generated demand profile for the low load configuration – with PV (summer)

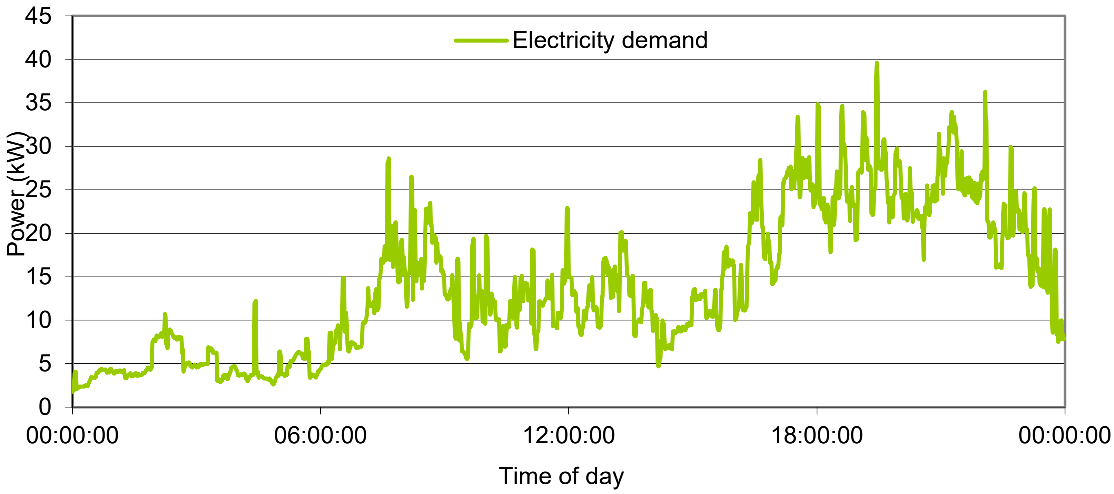

Figure 35: Generated demand profile for the low load configuration – with PV (winter)

C.2 COST OF 3 PHASE CONNECTIONS

Costs were compared for the different services offered by the DNOs that we considered to be most relevant. These are around the installation of service cable. Costs are extracted from the 'Construction' section of the Connections charging statements (section F) and have been presented as relative minimum costs for single phase and three phase installations to understand the percentage difference (where single phase is the base case). Maximum costs were discounted as it is assumed that the main costs of interest (e.g. cables and terminations) were likely to be driving the uplift from the minimum cost presented.

The costs have been derived from the charging statements of three DNOs with geographically different networks. These are:

- WPD East Midlands [128]
- UKPN LPD [129]
- SHEPD [130].

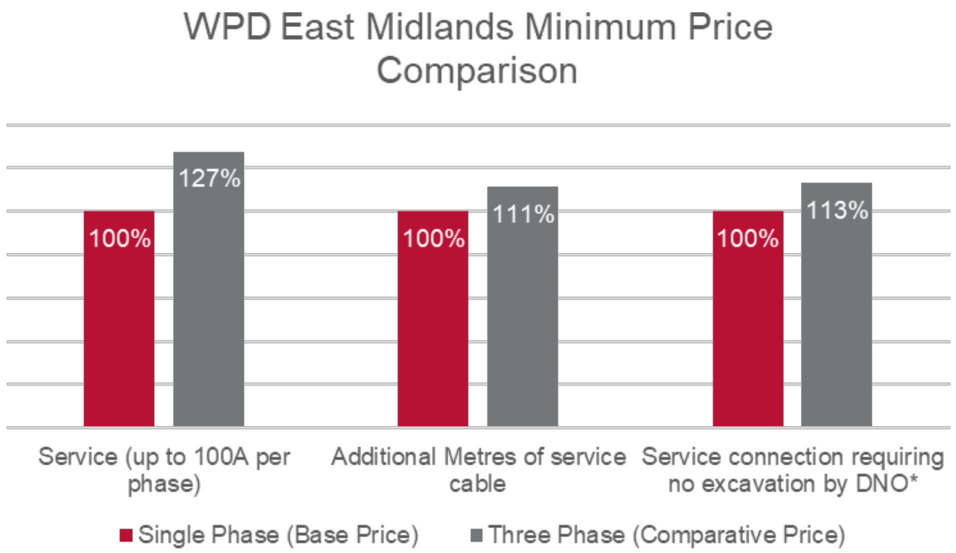

Figure 36: Relative comparison of single and three-phase connection price from WPD East Midlands

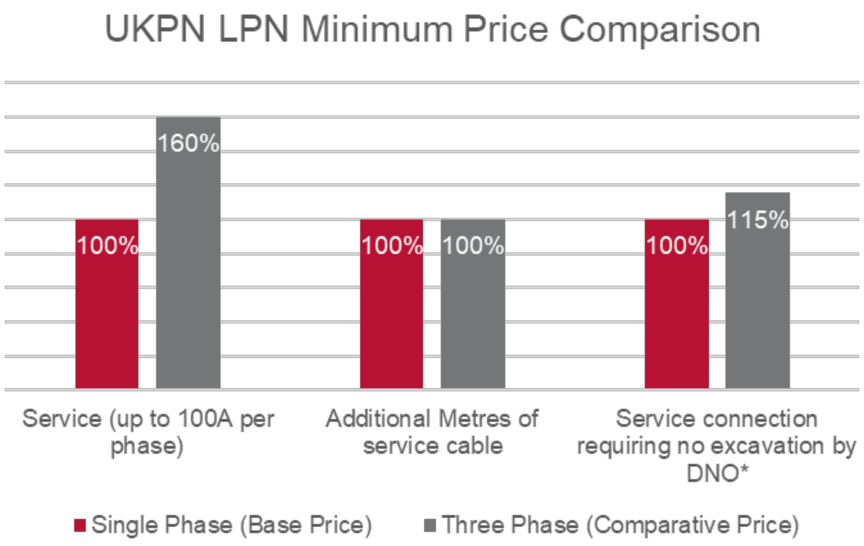

Figure 37: Relative comparison of single and three-phase connection price from UKPN LPD

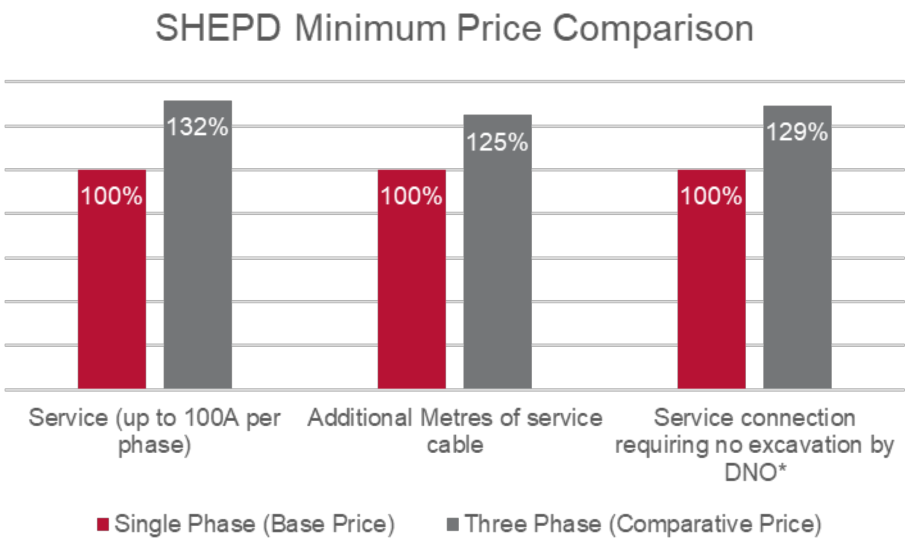

Figure 38: Relative comparison of single and three-phase connection price from WPD

ANNEX D - ELECTRICITY SYSTEM DATA INITIATIVES

D.1 INNOVATION PROJECTS

Initiative/ project	Scope	Related use case	Related technical enabler	Progress against technical objectives
SPEN FlexNet [131]	Previous innovation project which deployed monitoring across primary and secondary transformers and LV circuits. Primarily investigating monitoring technology and network operation use cases.	Real time management of substation/feeder capacity	Data capture Real-time data sharing - technology enablers	Provided understanding of monitoring tech, use cases and benefits. Elements of real time control but did not explore open data or third party integration.
ENWL Smart Street [9]	Recent innovation project focussing on voltage optimisation at an LV level (highlighting up to an 8% energy saving for customers). The technical solution was underpinned by voltage monitoring and the use of equipment such as on load tap changers and voltage support devices (e.g. capacitors).	Voltage control and optimisation	Data capture Real-time data sharing - technology enablers	Provided understanding of technology and benefits of voltage optimisation. Elements of real time control but did not explore open data.
OpenLV [132]	Project which has deployed LV monitoring solutions and made this open to third parties to allow real-time capacity management solutions to be deployed. This is a key example of what we are aiming for. Trials are complete within this project and results will be disseminated later this year.	Real time management of substation/feeder capacity	Data capture Making data open - strategies and processes Real-time data sharing - technology enablers	This is a small scale example exploring many of the features of the use cases and technical enablers. Full results yet to be shared publicly.
Flexr project (proposal stage) [133]	A Network Innovation Competition project proposal to develop a platform which would enable real-time data sharing across GB	Cuts across multiple	Making data open - strategies and processes Real-time data sharing - technology enablers	To be determined.
WPD Presumed Open Data (POD) project [134]	Ongoing NIA project reviewing all data held by WPD to ascertain the extent that it can be shared with third-parties. Includes use case identification and datasets with the highest value will be processed, standardised and published.	Cuts across multiple	Making data open - strategies and processes	To be determined.

D.2 OFGEM CONSULTATIONS

Initiative/ project	Scope	Related use case	Related technical enabler	Progress against technical objectives
Visibility of distributed generation connected to the GB distribution network	Currently open consultation. This is about visibility of DG and real-time exchange of data between DG and networks to manage grid stability and outages. This focusses on DG above 1MW only.	Not directly relevant to the outlined use cases.	Real-time data sharing - technology enablers	To be determined. May facilitate better data sharing between generators and networks.
Key enablers for DSO programme of work and the Long Term Development Statement	Consultation which ran early this year. The consultation covered a number of questions relevant to network monitoring, particularly the section on Network monitoring & visibility enablers.	Primarily “Real time management of substation/feeder capacity” Consultation responses also discussed “Peer to peer energy or capacity trading”	Data capture Real-time data sharing - technology enablers	Next steps have been published within reference [135] outlining the data expected to be published. Sets expectation for further monitoring at 11kV and LV as a DSO enabler but only where considered to be cost effective.

D.3 NETWORK ACTIVITIES

Initiative/ project	Scope	Related use case	Related technical enabler	Progress against technical objectives
DNO Digitalisation Strategies [136]	These lay out the ambitions of DNOs or TOs for the digitisation of their networks. Network monitoring (including LV monitoring) feature prominently across the DNO strategies. All DNOs have also adopted the ‘presumed open’ position for network data. Ofgem have asked for a "digitalisation strategy and action plan" to clarify our focus on a need for evidencing progress against these plans by 31 December 2020.	Cuts across multiple Emphasis on “Real time management of substation/feeder capacity”	Data capture Making data open - strategies and processes Real-time data sharing - technology enablers	Strategies touch on a number of key areas but plans currently not specific enough to assess
Northern Power Grid Smart Grid Enablers programme	As part of a the £83 million Smart Grid Enablers programme, installed high-bandwidth digital communications links to over 860 major substations and 7,200 secondary substations replacing old analogue links. They are also installing monitoring equipment for the first time in 1,300 secondary substations and obtaining data from 2,000 existing sites. This is a key example of networks investing in monitoring and importantly the communication infrastructure required to provide real-time information about their network.	Real time management of substation/feeder capacity Potentially an enabler for others.	Data capture Real-time data sharing - technology enablers	Current status not clear however this is an ED1 investment (so should be complete by 2023).
ENA data working group	DWG supporting the delivery of the Energy Data Taskforce Report recommendations, including working on Data Triage and demonstrators of the Digital Systems Map Includes a High Level Data Request Handling process for making data available.	Current scope is more directed at historical data.	Making data open - strategies and processes	To be determined. Should support all DNOs progress their ‘presumed open’ plans

D.4 WIDER INITIATIVES

Initiative/ project	Scope	Related use case	Related technical enabler	Progress against technical objectives
Energy Data Best Practice Guidance [137]	Guidance for identifying what data could be shared, how it could be structured and how it could be shared. If applied, may support sharing of monitoring data.	Cuts across multiple	Making data open - strategies and processes	Provides guidance which networks are beginning to adopt.
Modernising Energy Data Access projects: Icebreaker One and Siemens projects	Technology solutions needed to support widespread sharing of diverse data sources to private and public actors.	Cuts across multiple	Making data open - strategies and processes Real-time data sharing - technology enablers	To be determined (projects at an early stage)

ANNEX E - ELECTRIC VEHICLE SMART CHARGING

Mapping the Electric Vehicle Smart Charging Standards Landscape Error! Reference source not found.

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SYSTEMS AND ENGINEERING
TECHNOLOGY

Executive Summary

This report describes the current interoperability landscape for electric vehicle (EV) smart charging. There are a complex set of current standards relating to EV smart charging spanning physical connection, communications, security, safety and grid services. Adopted standards vary between countries, EV manufacturers, and commercial aggregators. A high level of standards development activity is ongoing at the international, UK and Distribution Network Operator (DNO) levels.

As EV smart charging transitions from the prototype to early commercialisation phase, large-scale trials of V2G are underway in the UK and internationally. Although proprietary standards are still prevalent, increasingly open standards for communications protocols are being adopted including the open charge point protocol (OCPP) and Open Automated Demand Response (OpenADR) standards. At the EV to EV supply equipment interface (EVSE), a relatively complete but evolving set of standards exist, including CHAdeMO in Japan and CCS in Europe and North America. At higher levels of communications, the standards landscape is less chartered, with IEEE 2030.5's smart energy profile (SEP) an example of the growing volume of applicable international standards. A large number of international, European and UK standards organisations are hard at work to fill some of the remaining gaps in communications standardisation and it is not yet clear which standards will be widely adopted.

Examining a representative set of smart charging use cases, barriers and opportunities for interoperability are comingled:

- For provision of short term frequency response services, interoperability barriers lead to challenges in meeting power accuracy requirements, in providing affordable operational metering and in achieving mandated activation times.
- In the case of load shifting of EV charging demand, large scale (1000s of EVs) trials in the UK and internationally suggest that interoperability is not a significant barrier to this use case. However even for this more mature service, communications protocols and applicable standards between EVSE and aggregators/eMSPs are proprietary and not often disclosed. Trial owners have encountered implementation challenges even with open standards such as OCPP and have reported issues with interoperability of different EVs, EVSE and aggregator platforms. Lower level communications protocols (Wifi/Zigbee) also caused connectivity issues for some customer participants.
- For provision of system-critical services such as DNO dispatched demand turn down for system events, there is a lack of standardisation for control rights and priorities. In the case of cold load pick up, the service itself is commercially available but has not been standardised such that it can be procured at scale.
- Finally, for provision of non-grid services such as extending battery life through OEM monitoring and control, no architecture or protocols are emerging as dominant.

Significant work remains to be done to ensure the interoperability landscape can accept the large expected uptake of EVs and maximise the benefits to society of increased volume of renewable generation, associated reduction in peaking plant investment and avoided network reinforcement costs.

Contents

E.1 INTRODUCTION

As part of the Electricity Engineering Standards Review, Frazer-Nash undertook a landscaping activity to map out the known interoperability standards, standards development initiatives/working groups and related projects. The aim of this review was to identify gaps and overlaps within this landscape with reference to a set of electrical system interoperability use cases.

This report summarises the mapping activity duly conducted. Due to the large volume of literature available, EV smart charging - modifying an EV's charge profile to maximise benefit to consumers and the power grid - was down-selected for further investigation. However, many of the results will be applicable to the use of Energy Smart Appliances including heat pumps. The following use cases were analysed to understand any interoperability barriers to implementation:

1. Provision of short term frequency response (demand turn up and turn down);
2. Load shifting away from peak periods;
3. DNO controlled demand turn down/turn off;
4. Management of post-outage turn on and cold load pick up; and,
5. EV manufacturer remotely running tools to monitor and extend battery life as part of the leasing deal.

Details of these use cases and associated discussion will be found in later sections.

E.1.1 WHAT IS INTEROPERABILITY?

Interoperability can be defined in an electrical power system context as:

"the seamless, end-to-end connectivity of hardware and software from the customers' appliances all the way through the distribution & transmission systems to the power source, enhancing the coordination of energy flows with real-time flows of information and analysis."[97]

There are a huge number of considerations to ensure smart grid interoperability as illustrated by the interoperability "layers" of the Smart Grid Architecture Model (SGAM) in Figure 39.

[97] GridWise Architecture Council, "Decision-Maker's Interoperability Checklist," V1.5, August 2010, p. 1, http://www.gridwiseac.org/pdfs/gwac_decisionmakerchecklist_v1_5.pdf.

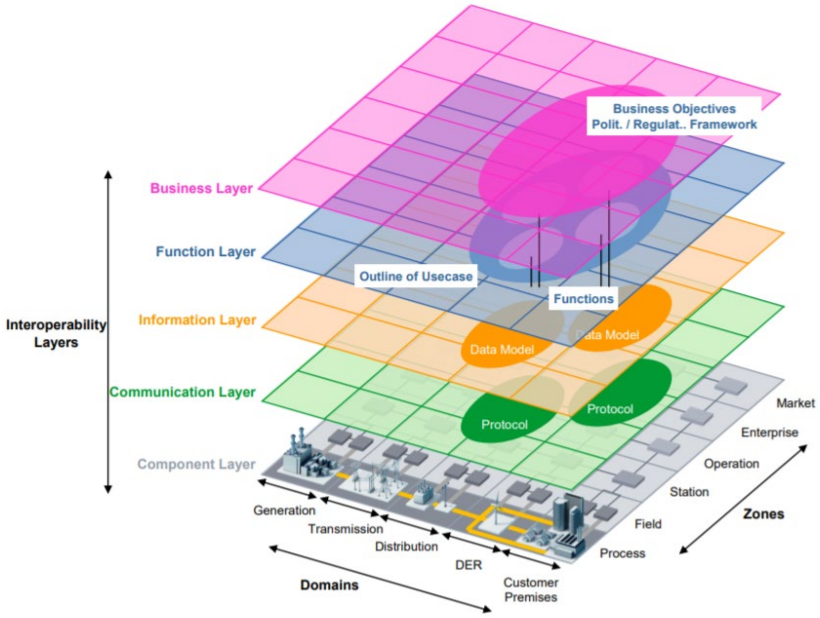

Figure 39: SGAM interoperability layers. Source: CEN-CENELEC-ETSI

Due to the technical focus of the Engineering Standards Review, the mapping herein will focus on the communications layer of the interoperability landscape to describe:

"protocols and mechanisms for the interoperable exchange of information between the use case actors."[98]

The following discussion also touches on other layers, particularly the information layer as part of cross-cutting issues affecting interoperability. The Open Systems Interconnection (OSI) model for communications as described in Annex E.5.1 is used throughout in order to identify the communications levels at which there are gaps or overlaps. While the EU's Smart Grid Coordination Group found that there are no gaps in standardisation of OSI layers 1-4[99], there are a wide range of different standards available and this in itself may cause interoperability issues if not carefully managed. Therefore, although the focus of this document is at a higher level (OSI session, presentation and application layers), it also discusses lower level standards and protocols.

E.1.2 REPORT STRUCTURE

This report will describe the current state of interoperability standards for smart charging through the following structured approach:

- **Section E.2:** maps the current interoperability standards landscape against the SGAM, exploring the current international standards applicable at all levels of communications;
- **Section E.3:** describes the ongoing efforts by international, European and UK standards organisations to enhance smart charging interoperability; and
- **Section E.4:** examines the interoperability gaps and barriers to effective delivery of grid and consumer services across a set of representative use cases and documents progress made to date.

[98] https://ec.europa.eu/energy/sites/ener/files/documents/xpert_group1_reference_architecture.pdf
[99] See section E.5.1 for more information

E.2 THE EV INTEROPERABILITY STANDARDS LANDSCAPE

A large number of groups including the International Electrotechnical Commission (IEC), the Institute of Electrical and Electronics Engineers (IEEE) and ISO have developed interoperability standards. The Society of Automotive Engineers (SAE), the Internet Engineering Data Task Force (IEDTF), ZigBee Alliance and the Open Charge Alliance (OCA) have also undertaken more domain-specific development.

Figure 40 presents a summary of the standards and protocols that apply to EVs and energy smart appliances (ESAs).

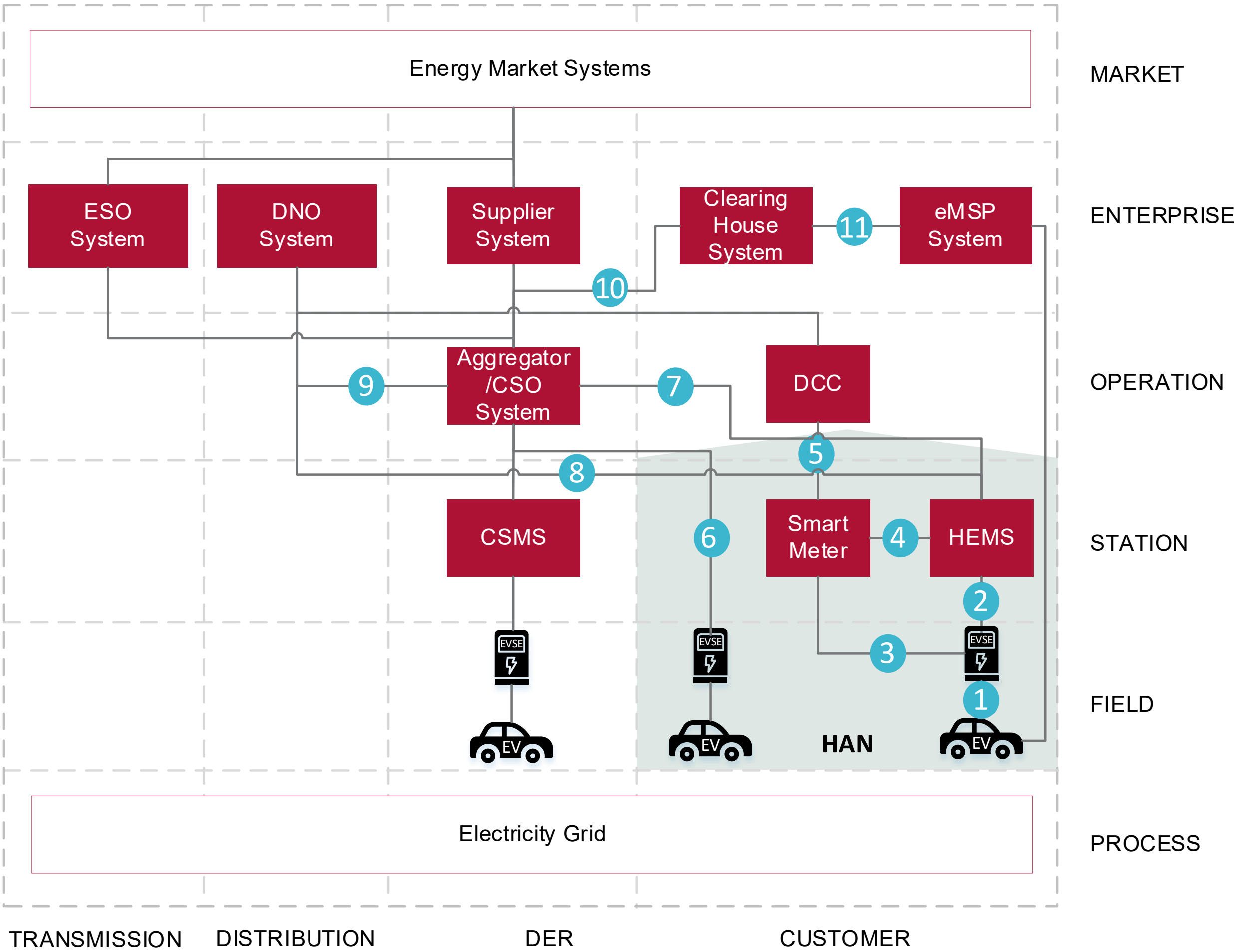

Figure 40: EV smart charging communications standards.

Key standards and protocols for communications interfaces from Figure 40 are summarised in Table 11-29.

Table 11-29: EV communications interfaces - standards and protocols

Interface(s)	Standard(s)	Protocol(s)
1 EV:EVSE	IEEE 2030.1, IEC 15118, IEC 61851-23, IEC 61851-24	CAN bus (IEEE 2030.1), PLC (CCS)

Interface(s)	Standard(s)	Protocol(s)
		DNS, SDP, XML/EXI, TCP, UPD, TLS, IP, ND ICMP, DHCP (ISO 15118-2)
HAN 2 EVSE:HEMS 3 EVSE:Smart Meter 4 HEMS: Smart Meter	IEEE 2030.5, IEEE 802.3, IEEE 802.11, IEEE 802.15.4, ECHONET Lite	HTTP, XML/EXI, TLS, TCP, xMDNS, IP (IEEE 2030.5) IP (ECHONET Lite) WiFi, Ethernet, ZigBee, 6LoWPAN
5 Smart Meter:DCC	IEC 62056	DLMS/COSEM
6 EVSE:Aggregator 7 HEMS: Aggregator	IEC 63110, OCPP	XMPP, HTTP, SOAP
8 HEMS:DSO 9 Aggregator:DSO	IEC 62746-1-10, IEEE 2030.5	XMPP/HTTP, TLS (IEC 62746-1-10)
10 CSO:Clearing House 11 eMSP:Clearing House	IEC 63119	HTTP, SOAP/XML, JSON, TLS, TCP

As can be seen from the above diagram and table, there are a range of different possible communication architectures and associated standards for smart charging[100]. Additionally, Table 11-29 only shows standardised communications, and does not show the large range of proprietary protocols that may or may not comply with one or more of these standards.

E.2.1 EV TO EVSE INTERFACE

The international standards that apply to the EV to EVSE interface are grouped into functional areas in Figure 41.

[100] The above set is non exhaustive. More detail can be found in the following sections

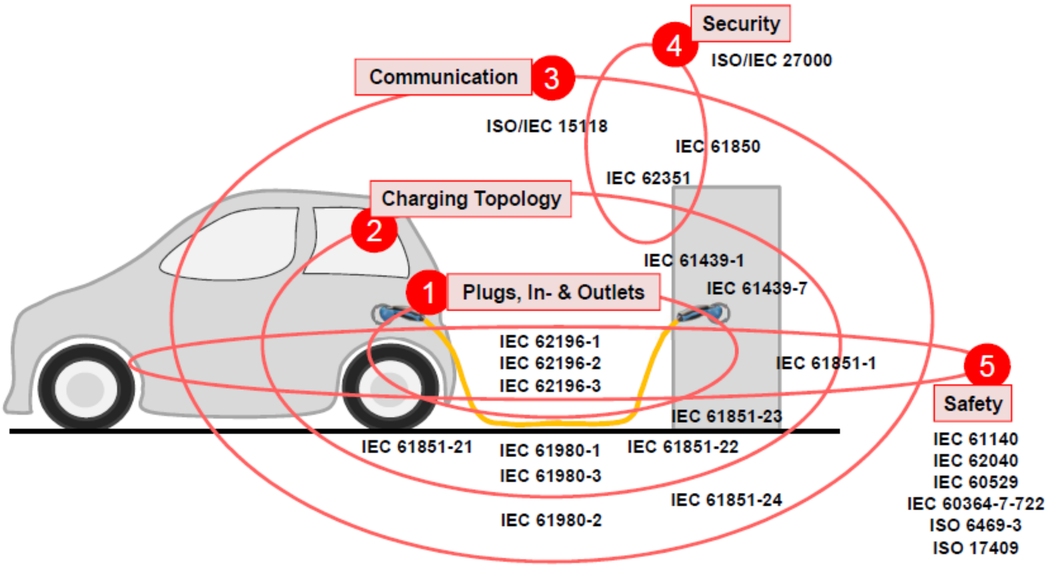

Figure 41: EV to EVSE interface standards. Source: EVS27[101]

Plugs and outlets are classified by the IEC 62196 series of standards. These can be further decomposed into 62196-1, which covers general information, and 62196-2 (AC) and 62196-3 (DC and AC/DC pin) which cover specific connector and inlet designs. The common commercial variants of IEC 62196 plug types are listed in Table 11-30.

Table 11-30: Chargepoint standards by plug/socket type

Common Name	International standard	Location(s)	Related standards
AC Fast Charging			
Yazaki/J1772	IEC 62196-2 (type 1)	US and Japan	SAE J1772
Mennekes	IEC 62196-2 (type 2)	Widespread, mandatory in the EU	VDE-AR-E 2623-2-2 (originating standard), 61851-1 (basic signalling)
Scame	IEC 62196-2 (type 3)	Used in France, Italy	61851-1 (basic signalling)
DC Fast Charging			
CHAdeMO	IEC 62196-3 (type AA)	Mostly used in Japan and by Japanese manufactured vehicles	IEC 61841-23 (System B), IEC 61851-24 Annex A (CAN communication), IEEE 2030.1 (CHAdeMO)
GB/T	IEC 62196-3 (type BB)	Mostly used in China	IEC 61851-24 Annex B (CAN communication), GB/T 20234.3

101 https://www.evs27.org/download.php?f=defpresentations/EVS27-4C-2840401.pdf

Common Name	International standard	Location(s)	Related standards
Combo1	IEC 62196-3 (type EE)	Mostly used in North America	SAE J1772, Combined Charge System (CCS) Type 1, IEC 61851-24 Annex C (PLC communication)
Combo2	IEC 62196-3 (type FF)	Widespread, mandatory in the EU	Combined Charge System (CCS) Type 2, IEC 61851-23 (System C), IEC 61851-24 Annex C (PLC communication)
Tesla Type 2	IEC 62196-2 (type 2)	Tesla chargepoints globally	Proprietary

EV charging standards are undergoing a period of evolution as described in Figure 42. China and Japan have stated an ambition to develop a unified standard, ChaoJi, that will enable rapid DC fast charging and vehicle-to-grid (V2G) capabilities. It is expected that this alignment will occur by 2021[102]. The CCS standard is not currently capable of V2G, however this is planned to change with vehicle-to-home (V2H) capabilities by 2020 and V2G by 2025[103].

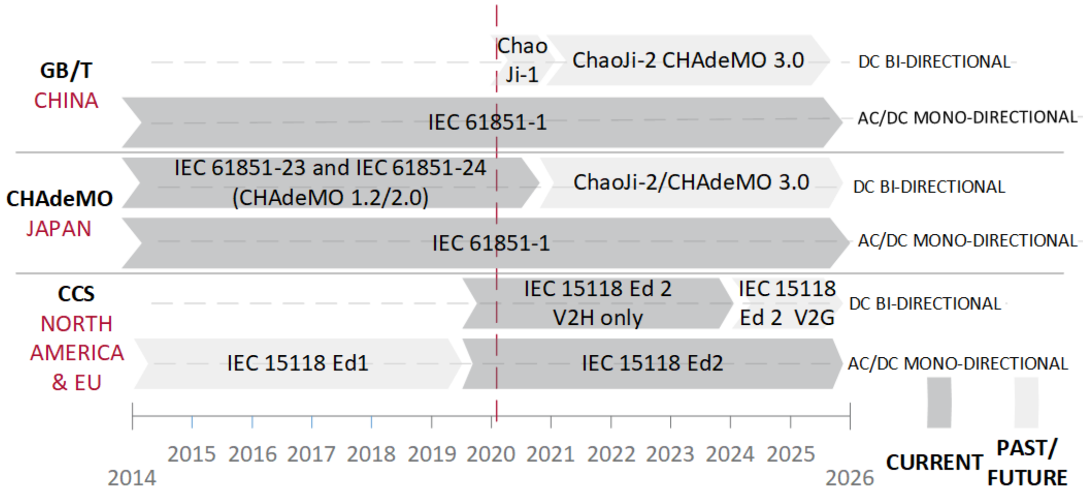

Figure 42: EV charging communications standard evolution

A few key standards series apply to EV communications with EVSE - these include IEC 61851, ISO 15118 and IEC 61850. The IEC 61851 series has a safety focus, of which the communications specific sections are IEC 61851-1 for AC charging and 61851-24 for DC charging. Additionally there is IEC 61980-2 which describes communications for wireless power transfer (WPT). The IEC 62351 series covers the security of communications.

IEC 15118 describes requirements for communications between the EV communication controller (EVCC) and charging point communication controller (CPCC) across the seven functional layers in Figure 52. ISO

102 https://www.chademo.com/chademo-to-jointly-develop-next-gen-ultra-fast-charging-standard-with-china/
103 https://www.charinev.org/news/news-detail-2018/news/the-five-levels-of-grid-integration-charin-ev-grid-integration-roadmap-published/

15118-2 is the existing section of the standard for mono-directional charging. An ongoing development is the introduction of IEC 15118-20 to include wireless and bi-directional charging, expected by the end of 2020[104]. ISO 15118-2 and ISO 15118-20 are not compatible[105]; the EVCC and CPCC must use the same version of these two standards.

The IEC 61850 series was initially developed for substation automation but has widened its remit to the wider power system. The relevant parts for EVs are IEC 61850-7-420 which describes an information model for distributed energy resources (DER) and IEC 61850-90-8 which shows how IEC 61850-7-420 can be used to model EVs and EVSE. This information model includes elements of IEC 62196, IEC 61851 and IEC 15118 described above and is intended to ensure consistent information exchange between grid operators, EVs and EV users. Figure 43 shows an example of the information modelled by the IEC 61850-90-8 standard, using the IEC-15118-2 as a representative example.

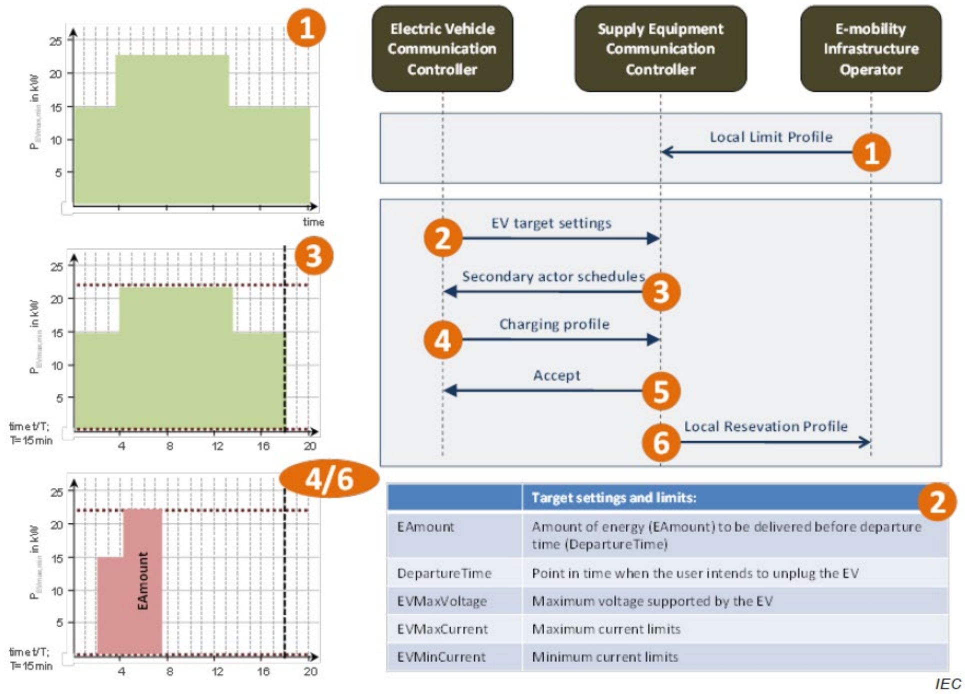

Figure 43: Example of charge schedule information exchange between an EV and EVSE according to IEC 61850-90-8 and IEC-15118-2

E.2.2 HOME AREA NETWORK

A large array of standards apply to device communications in a domestic setting, primarily related to the Home Area Network (HAN). The first group relate to protocols for local area networks that map to the physical (PHY) and data link layers (DLL) of the OSI model described in Annex E.5.1. This group covers wired and wireless communications protocols including IEEE 802.3 (Ethernet), IEEE 802.11 (WiFi) series and IEEE 802.15.4 (ZigBee, 6LoWPAN). A comparison of different wireless protocols is found in Figure 44, with protocol selection trade off characteristics including range, data rate, latency, and battery life.

[104] https://www.iec.ch/dyn/www/f?p=103:23:2701122434664::::FSP_ORG_ID,FSP_LANG_ID:1255,25
[105] See https://v2g-clarity.com/knowledgebase/what-is-iso-15118/

Feature	ZigBee/ IEEE 802.15.4	Bluetooth/ IEEE 802.15.1	Wi-Fi/ IEEE 802.11	RFID	I2C	SPI	HomePlug 1.0 (PLC)
Based data rate	250 kbps	1Mbps	11,000+kbps		100kbps-3.4 Mbps	20Mbpts	14Mbps
Frequency	2.45GHz	2.45GHz	2.45GHz	120kHz - 10 GHz	limited to either 100 KHz , 400 KHz or 3.4 MHz	Free (n MHz to 10n MHz) : where n is an integer from 1 to 9	5000kHz-1MHz
Range	10-100 m	10 m	1-100 m	10cm - 200m	few meters	100 m	1-3 km
Latency	30msec	18-21usec	0.3usec	25-300usec	Depends on the master clock	depends on the master clock	x
Nodes/Masters	65540	7	32		1024	2-3.	x
Battery life	years	days	hours	battery-less	low power requirement	low power requirement	low
Complexity	simple	complex	very complex	simple	simple hardware	simple hardware	simple
Security	128 bit	128 bit	WPA/WPA2	AES 128-bit	X	X	x

Figure 44: HAN Protocol comparison. Source: Renewable and Sustainable Energy Reviews[106]

Higher level standards that apply to the HAN are ECHONET Lite[107], which describes layer 5-7 of the OSI model for communications over IP, and IEEE 2030-5[108] provides details of the Smart Energy Profile (SEP) 2.0 - primarily an OSI Layer 5-7 protocol. A REST architecture is implemented using GET, HEAD, POST, PUT, and DELETE actions. SEP 2.0 mandates use of RESTful HTTP/1.1 as a “required baseline” for interoperable application data exchange. xmDNS - a multicast form of DNS that does not need a centralised DNS server - is used for device and service discovery. Because HTTP is used, compliance with IETF RFC 7230 requires “reliable transport” and hence TCP as transport protocol. Furthermore, authentication and encryption must be HTTP over TLS in compliance with IETF RFC 2818 and IETF RFC 5246. Finally, data encoding is provided by either XML and/or EXI. The information model is derived from IEC 61968 (Common Information Model) and IEC 61850.

In the UK, the SMETS 2 technical specification requires that smart meters must use SEP V1.2 - the previous version of the SEP protocol developed by the Zigbee Alliance - for all HAN communications including with EVSE. Additionally, the smart meter will communicate with the Data Communications Company (DCC) using Device Level Message Specification (DLMS) Companion Specification for Energy Metering (COSEM) tunnelled through SEP V1.2.

E.2.3 EVSE TO AGGREGATOR/CHARGING SERVICE OPERATOR

The initial focus for standardisation of smart charging was at the device level, relating to the protocols at the EV-EVSE interface described above. In recent developments, standard writing activity has shifted up a level to interfaces between the supply equipment and the party responsible for managing the asset, which in the UK may include aggregators and charging service operators. An aggregator is defined by EURELECTRIC as a party that aggregates load flexibility from users of LV and MV to provide services to the ESO and DSO. Standards relating to this interface include the forthcoming IEC 63110 which relates to management of EV charging station infrastructure. The first part of this standard is planned for publication in May 2021[109]. It is expected that XMPP will be used as the core communications protocol for messaging and encoding[110]. XMPP is an open standard which uses eXtensible Markup Language (XML) for data encoding (OSI layer 6).

106 https://www.sciencedirect.com/science/article/abs/pii/S1364032114007126
107 https://echonet.jp/about_en/
108 https://standards.ieee.org/standard/2030_5-2018.html
109 See TC 69 dashboard for updates at https://www.iec.ch/dyn/www/f?p=103:23:10725585252271::::FSP_ORG_ID,FSP_LANG_ID:1255,25
110 https://www.ncl.ac.uk/media/wwwnclacuk/cesi/files/20200115_Meet%20IEC%2063110_%20Paul%20Bertand%20SmartFuture-min.pdf

TLS will be used for encryption (OSI layer 4) and SASL for authentication of the application layer (OSI layer 7). Both IPv4 and IPv6 will be supported (OSI layer 3). IEC-63110 will provide support for chargers that comply with IEC-61851, ISO 15118-2/ISO 15118-20, and IEEE 2030.1 (CHAdeMO).

This standard will be informed by the OCPP, which was developed by the OCA, and hardware only that complies with OCPP will likely comply with IEC 63110. OCPP is an application protocol based on Simple Object Access Protocol (SOAP) over HTTP, which are OSI layers 6 and 7 respectively. OCPP 2.0 supports XML and Java Script Object Notation (JSON) data encoding (OSI layer 6).

In the UK, it is mandatory for charging points to comply with OCPP 1.6 and above (or an 'equivalent' standard) in order to participate in OLEV schemes such as the Electric Vehicle Homecharge Scheme (EVHS) and Workplace Charging Scheme (WCS)[111].

Additional interoperability considerations of IEC 63110 are that it uses the same protocol (XMPP) as the latest version of Open Automated Demand Response (OpenADR) (see section E.2.4) and IEC 61850-8-2 for exchange of data between virtual power plants (VPPs).

E.2.4 HEMS/AGGREGATOR TO DSO/TSO

OpenADR is an application protocol for exchanging messages between automated systems for the purpose of facilitating demand response including smart charging. The primary actors for message exchange are 'virtual end nodes' (VENs) that control resources and 'virtual top nodes' (VTNs) that manage VENs[112]. VENs can include houses or commercial and industrial (C&I) customers, while VTNs can include DSO or TSO. Suppliers/Aggregators can be both VENs and VTNs. OpenADR is currently at v2.0 and has been formalised as IEC 62746-1-10-2018.

E.2.5 OTHER COMMUNICATIONS

The remaining communications pathways relate primarily to Enterprise level communications (See Figure 23) for smart charging status, billing, and settlement. Actors include eMobility service providers (eMSPs), CSOs and clearing houses. An eMSP is defined as an entity that provides services to e-mobility customers outside of aggregators or charging station operators, including access to multiple charging stations. Due to the technical focus of the Engineering Standards Review, these are not discussed in detail here. However, one key standard that will influence interfaces with lower level communications is the IEC 63119 standard for EV charging roaming communications, of which part 1 was first released in 2019. This standard is limited to communications between different roaming endpoints and also between roaming endpoints and clearing houses. Communications protocols are not mandated, but recommended options include HTTP for service interfaces (OSI layer 7); SOAP/XML and JSON for message structure/encoding (OSI layer 6), TLS for communications security (OSI layer 5) and TCP for reliable transportation (OSI layer 4).

[111] https://www.gov.uk/government/publications/electric-vehicle-homecharge-scheme-minimum-technical-specification

[112] See for more information: https://www.ncl.ac.uk/media/wwwnclacuk/cesi/files/OpenDSR_%20Using%20OpenADR%20and%20OCPP%20together%20to%20enable%20smart%20EV%20charging-compressed.pdf

E.3 ONGOING DEVELOPMENTS IN EV INTEROPERABILITY STANDARDS

There is a huge amount of activity globally relating to standardisation of EV standards that impact interoperability. These initiatives are surveyed briefly in the following sub-sections, looking at international, UK and European standard development as well as the emergence of interoperability labs.

E.3.1 IEC TECHNICAL COMMITTEES

The IEC has a number of technical committees (TC) and working groups (WG) that are responsible for developing and updating standards. Two key TC relating to smart charging communications are:

- **TC 69**[113] for Electrical road vehicles and electric industrial trucks, with expertise on safety and protocols for electrical mobility; and
- **TC 57**[114] for power systems management and associated information exchange, with expertise on protocols for a distributed power system and smart grid.

  Joint WG11 (JWG11) is a joined Working Group between TC69 and TC 57, primarily related to development of the IEC 63110 standard described in section E.2.3. Other updates planned from TC 69 are:

- JWG 1 updates to the IEC 15118 series, with the IEC 15118-20 release to include wireless power transfer (WPT) and bi-directional charging planned for November 2020;
- WG 7 updates to IEC 61980 for WPT, May 2021;
- WG 10 updates to IEC 61851-3, mid-2020 to early 2021;
- Maintenance Team (MT) 5 updates to 61851-23 and 61851-24, February/March 2021; and
- WG 9 new issues of 63119-2, 63119-3, 63119-4, March 2023.

E.3.2 UK STANDARDS DEVELOPMENT

The UK government directed the British Standards Institute (BSI) in 2018 to investigate the interoperability landscape for energy smart appliances (ESA) including EVs. The Energy Smart Appliances (ESA) Programme is implementing the recommendations of the review including development of two Publically Available Specifications (PAS), one for classification of ESA devices (PAS 1878) and another to provide a framework for demand side response (DSR) services.

During the development of the DSR PAS the smart home communications architecture shown in Figure 45 has been proposed.

[113] TC 69 dashboard here: https://www.iec.ch/dyn/www/f?p=103:23:29588498699221::::FSP_ORG_ID,FSP_LANG_ID:1255,25
[114] TC 57 dashboard here: https://www.iec.ch/dyn/www/f?p=103:23:0::::FSP_ORG_ID:1273

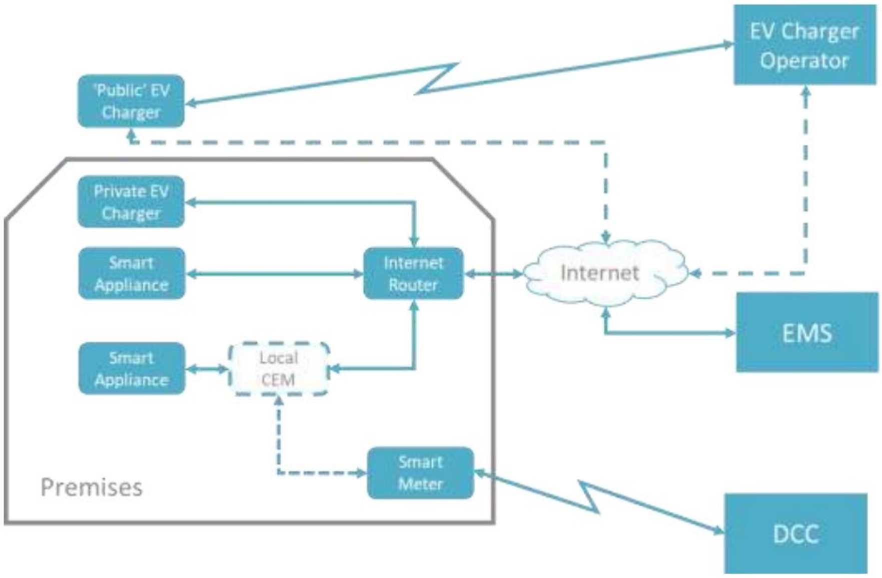

Figure 45: Smart home communications architecture proposed as part of BSI PAS development

The UK government expects to make compliance with these (or equivalent) standards mandatory under the upcoming *Electric Vehicle (Smart Charge Points) Regulations 2020*. Additionally, the UK government has proposed to establish a certification and assurance regime for the new standards to ensure interoperability is achieved.

E.3.3 EUROPEAN STANDARDISATION INITIATIVES

In March 2011, the European Commission and European Free Trade Association (EFTA) issued Mandate M/490 which requested the European Standards Organisations to develop a framework in order to support continuous enhancement and development of smart grid standards. The three European Standards Organisations comprise the European Committee for Standardisation (CEN), European Committee for Electrotechnical Standardisation (CENELEC) and the European Telecommunications Standards Institute (ETSI).

The CEN-CENELEC-ETSI Smart Grid Coordination Group (SG-CG) was formed in July 2011 in response to M/490. The SG-CG produce a series of reports including the SGAM reference architecture[115] and an Interoperability Tool[116] that summarises all standards related to interoperability, mapped to the SGAM interoperability layers and systems.

E.3.4 INTEROPERABILITY LABS

In recent years, a number of centres have been established globally that are devoted to EV interoperability with the smart grid[117]. These include:

[115] ftp://ftp.cencenelec.eu/EN/EuropeanStandardization/HotTopics/SmartGrids/Reference_Architecture_final.pdf
[116] ftp://ftp.cencenelec.eu/EN/EuropeanStandardization/HotTopics/SmartGrids/SGCG_Interoperability_IOPtool.xlsx
[117] See for a summary of EU and US centres: https://ec.europa.eu/jrc/sites/jrcsh/files/ES_InteropBroch_0713_v9%5B3%5D_0.pdf

- The U.S. Department of Energy's Electric Vehicle (EV) Smart Grid Interoperability Center at Argonne National Labs; and,
- The European Interoperability Centre for Electric Vehicles and Smart Grids located across two sites in Italy and the Netherlands.

The scope of research includes both hardware and communications protocols. The ongoing work of labs such as these will heavily inform the testing and implementation of standards.

E.4 EV SMART CHARGING USE CASES

There are a huge range of use cases for EV smart charging due to the ability of EVs to act as a form of mobile energy storage with both charge and discharge functionality. All of these different capabilities will require varying levels of interoperability between systems. The following sections attempt to understand the current landscape in standardisation of interoperability by examining an illustrative set of use cases. Examples from real world trials are used where possible to understand the challenges encountered in implementing connectivity between EVs and other actors or systems.

E.4.1 SHORT TERM FREQUENCY RESPONSE

This use case is defined in terms of the current short term frequency response products procured by National Grid Electricity System Operator. Using this definition, the most suitable products for EV smart charging are:

- Firm Frequency Response (FFR)[118] comprising both:
  - Dynamic FFR: provided continuously and further decomposed into
    - Primary: power raise within 2 seconds for 20 seconds duration.
    - Secondary: power raise within 30 seconds for 30 minutes duration
  - Static FFR: provided when a measured frequency deviation occurs, response within 30 seconds for 10 minutes duration.

For all of these services, the minimum response is currently 1MW. With a typical EV fast charger with V2G capability currently rated at 7-10kW, aggregation is required to provide FFR services. Furthermore, it is expected that it would be challenging to deliver these services under the current monthly and annual contractual arrangements. This is due to the daily patterns of EV movement - a community EV aggregator may be required to deliver a frequency response service during the day when few EVs are available. However, National Grid ESO has signalled a willingness to move towards real time procurement for short term frequency response services[119] and is currently trialling a weekly auction[120].

Early trials in Denmark suggest that generic provision of short term frequency response services using aggregated EV smart charging is possible[121]. Activation times for these services were found to be 4 seconds for local control and 7 seconds for remote control. These are compliant with Secondary but not Primary FFR. Furthermore, these trials noted that capabilities of the charger are limited to the standards available. It was found that the IEC 61851 standard did not allow sufficient control flexibility to deliver the service effectively nor specify detailed enough data communication for supporting measurement of the delivered service.

For both static and dynamic FFR, the standard deviation of active power error must be under 2.5%. The trials described above have shown that this kind of accuracy may be challenging to achieve and that there is a lack of standardised tests for EV and EVSE performance. This represents a key interoperability gap that will need to be filled to enable widespread FFR delivery by EV smart charging.

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[118] See for a useful explaination: https://www.nationalgrid.com/sites/default/files/documents/Firm%20Frequency%20Response%20%28FFR%29%20Interactive%20Guidance%20v1%200_0.pdf
[119]As part of the future frequency response services planned: https://www.nationalgrideso.com/document/157791/download
[120] A weekly auction trial is currently being conducted, see “Weekly Auction Trial” at https://www.nationalgrideso.com/balancing-services/frequency-response-services/firm-frequency-response-ffr?market-information
[121] https://www.ncl.ac.uk/media/wwwnclacuk/cesi/files/Webinar_PeterBA_2019-12-10-compressed.pdf

Another key challenge related to this use case is the requirement for suitable operational metering at the point of delivery for FFR provision. These requirements are found in section 3.14 of the FFR standard contract terms (SCT):

> *the Demand or Generation profile of the Contracted FFR Unit from time to time shall be ascertained by reference to a combination of second by second output data*[122]

Furthermore, devices providing dynamic FFR must be capable of operating in a frequency sensitive mode and communicating in real time via an automatic logging device (although this may only be required to be used at infrequent intervals). For the static FFR service only, the current solution required by National Grid ESO is a frequency relay that operates at a specified trigger frequency within an allowable tolerance. All of this equipment adds prohibitive levels of cost and complexity to the provision of this service using EV smart charging. For the frequency relay in particular, there may be statistical methods for estimating frequency measured at a neighbourhood rather than household level with acceptable levels of accuracy. Currently there are no standards that specify such methods or indeed other lower cost methods to deliver, measure and communicate operational performance to National Grid ESO.

Another condition of the dynamic FFR product is that full response is delivered within 2 seconds. For the reasons discussed above regarding latency, this may prove to be an interoperability barrier to providing this product. For potential future services such as the frequency response product currently being procured in Ireland with speed of response between 150ms to 300ms[123], this will prove to be an even greater impediment.

E.4.2 LOAD SHIFTING

The load shifting use case broadly covers shifting of demand over the day from peak times to lower demand periods. This use case will deliver system benefits including reduced curtailment of variable renewable generation technologies, reduced investment in peaking plants, and lower network reinforcement costs. The latter will be particularly critical at the LV level where the largest network impacts are likely to be felt. The benefits are likely to be delivered most easily in a domestic setting as this is where a large portion of vehicles are predicted to charge at peak times. Load shifting can be further broken into simple demand reduction through control of mono-directional (AC/DC) charging, and the emergence of V2G which can also discharge to the grid.

E.4.2.1 Mono-directional smart charging

Large scale trials of smart charging conducted in recent years both in the UK and internationally demonstrate that load shifting using smart charging is possible. However, interoperability continues to be a key barrier to widespread implementation of this use case across different EV models, EVSE products and aggregation platforms. Reviews of European trials completed to date show that many communications protocols used are proprietary and that there is no wide adoption of a single protocol[124]. One illustrative UK trial was the Electric Nation project led by WPD. Although led by a DNO, this trial employed two aggregator platforms - CrowdCharge and Greenflux - and exposed many generic interoperability challenges related to smart charging. OCPP was chosen as the communications protocol between the electric vehicle charging point and the back office provided CrowdCharge and Greenflux. However, it was noted that:

> *"The vast majority of UK based, and many European charge point manufacturers/suppliers contacted either had no smart charging capability or those that did, did not meet the OCPP 1.6*

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[122] https://www.nationalgrideso.com/document/154046/download
[123] P49 of http://www.eirgridgroup.com/site-files/library/EirGrid/Consultation-on-DS3-System-Services-Volume-Capped-Competitive-Procurement.pdf
[124] https://www.lowcvp.org.uk/assets/other/EVN-P-16-02+Smart+EV+Task+1+Charging+Options+Report+Issue+1.pdf

requirement, either because they were using an older version of OCPP or a proprietary communication protocol."

In addition to this difficulty, EVSE suppliers that did comply with the required OCPP version had different implementations - message syntax and so on - of the protocol to the back offices of CrowdCharge and Greenflux. This meant that changes would have been required on the aggregator side to convert EVSE communications from different chargers to a common format. Another problem was that one candidate charger used ECHONET Lite to receive control commands, requiring further modification of CrowdCharge's OCPP version. Due in part to these challenges, the aggregators nominated one smart charger model each for the final trials; the interoperability of different charger models with the flexibility aggregator platforms was inadequate.

Mandated standardised open protocols for end to end communications has been proposed as a solution to some of these challenges. For example, the California Energy Commission has provided a potential architecture using only existing available protocols for smart charging in Figure 46[125]. This uses standards described in the above sections of this report to provide use cases including utility (DNO/National Grid ESO in the UK) directed load control (see section E.4.3), energy management system communication within the home (see section E.2.2), and aggregator managed dispatch (this section).

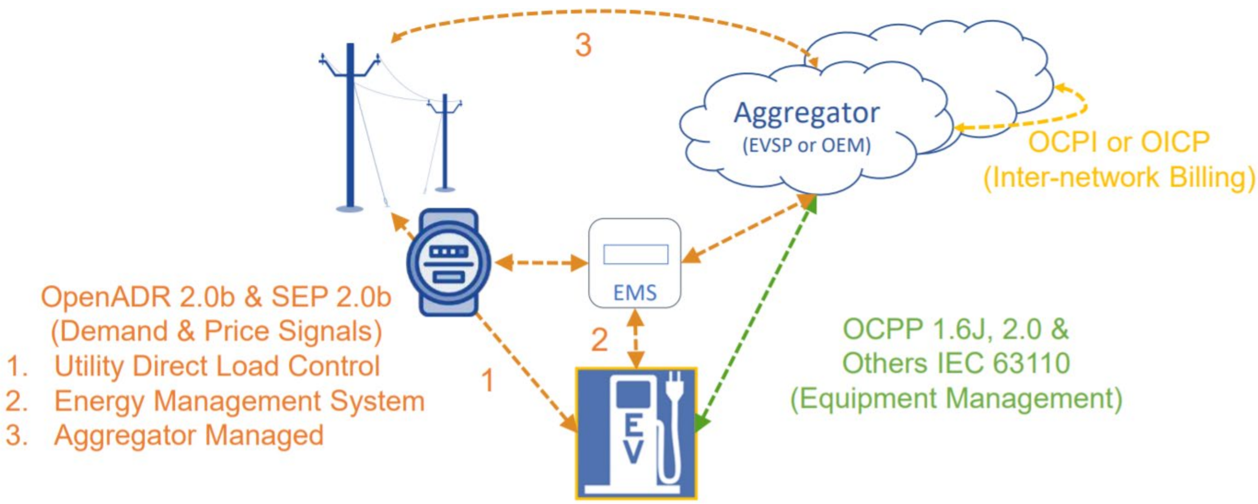

Figure 46: California Energy Commission Candidate Open Standards for Smart Charging

A solution compatible with this proposal has already been implemented as part of Southern California Edison's Charge Ready project[126]. This project aims to connect 1500 EVSE chargers using the communications architecture outlined in Figure 47, where EVSE communications vendors are equivalent to aggregators as defined in the present report. Users are provided with an incentive for load use between 11am and 3pm and for load reduction between 4pm and 9pm. Initial trials suggested load reductions of upwards of 15% were possible during the incentive period. While this is a US example, it demonstrates that

125 https://www.ncl.ac.uk/media/wwwnclacuk/cesi/files/Integrating%20PEVs%20with%20the%20CA%20Grid%20-%20CEC%20Noel%20Crisostomo%20Final-compressed.pdf

126 https://www.ncl.ac.uk/media/wwwnclacuk/cesi/files/Charge%20Ready%20DR%20Pilot%20Update%2020191002-compressed.pdf

open source protocols are capable of providing end-to-end communications between EVSE and suppliers via aggregators for load shifting use cases.

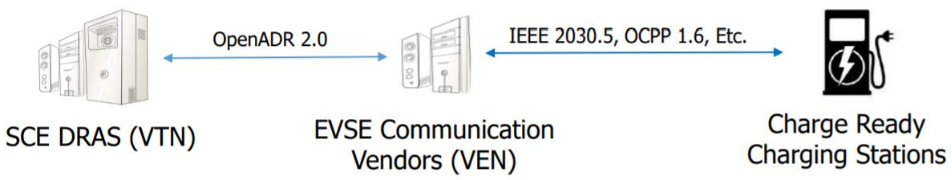

Figure 47: SCE Charge Ready communications architecture

Allego, an aggregator solutions provider based in the Netherlands, also uses OCPP for smart charging of its network of 15,000 connected charging sockets[127]. Grid operators can also inform Allego of any constraints on the grid using OSCP in Europe and OpenADR in the US. Finally OCPI 2.2, which has not yet been formally published, is used for EV user definition of charging profiles for each charging session.

As well as architectures that use the public internet, smart meters have also been proposed to enable load control of EV charging through the use of auxiliary load control switches. In the UK, this concept is being tested through two trials funded by BEIS due for completion in March 2021[128]. However, the vast majority of trials currently being conducted do not use this pathway and no standards exist that describe communications requirements.

E.4.2.2 V2G load shifting

V2G has received significant attention globally in recent years, with large progress made in the commercialisation of this service[129]. The UK government awarded £30m of funding for V2G innovation projects in 2018, including for demonstration projects involving over 2,700 V2G ready vehicles[130]. Currently CHAdeMO is the only EV to EVSE protocol suitable for V2G charging. Therefore, only commercially available vehicles with CHAdeMO compliant chargers can be used for large scale trials. All of the large scale UK trials reviewed will use Nissan LEAF, Nissan e-VN200, Mitsubishi iMieV or Mitsubishi Outlander PHEV vehicles[131]. The Sciurus project is being led by the supplier Ovo Energy and will deploy 1000 V2G units by March 2020.[132] The V2G units will be manufactured by Indra Renewable Technologies with Kaluza providing the design and operation of the platform. A typical V2G architecture is described in Figure 48.

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[127] https://www.ncl.ac.uk/media/wwwnclacuk/cesi/files/Allego%20webinar%20slides-compressed.pdf
[128] http://bidstats.uk/tenders/2019/W20/703070520
[129] See for a summary of current V2G trials: http://everoze.com/app/uploads/2019/02/UKPN001-S-01-J-V2G-global-review.pdf
[130] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/817107/electric-vehicle-smart-charging.pdf
[131] For a summary of these projects see https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/681321/Innovation_in_Vehicle-To-Grid__V2G__Systems_-_Real-World_Demonstrators_-_Competition_Results.pdf
[132] See for example , https://www.kaluza.com/case-studies/project-sciurus/, https://www.octopusev.com/powerloop, https://www.london.gov.uk/what-we-do/environment/energy/e-flex-vehicle-grid-trial

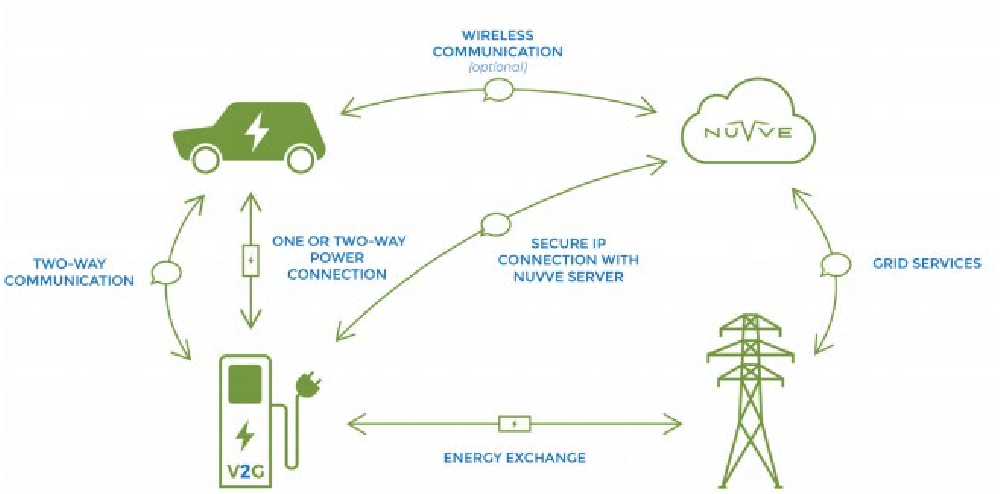

Figure 48 Typical EVSE-Aggregator connection. Source: Nuvve.com[133]

Due to the immaturity and complexity of the technology, V2G communications have evolved sporadically with many proprietary protocols specific to manufacturers or operators. This tendency may prove a significant interoperability barrier to plug-and-charge V2G functionality. To counter some of these trends Carbon Co-op, a UK-based energy services co-operative, are developing an open source V2G solution with a combination of OCPP with OpenADR as shown in Figure 49[134]. To develop this Carbon Co-op have partnered with Megni/Open Energy Monitor, the producer of the open hardware charger EmonEVSE. OCPP 1.6 is being used for EVSE communications and a HEMS will be used as the VEN to communicate to the back-end server. Demonstrator activity is expected to begin in April 2020 with full release of libraries and implementation details.

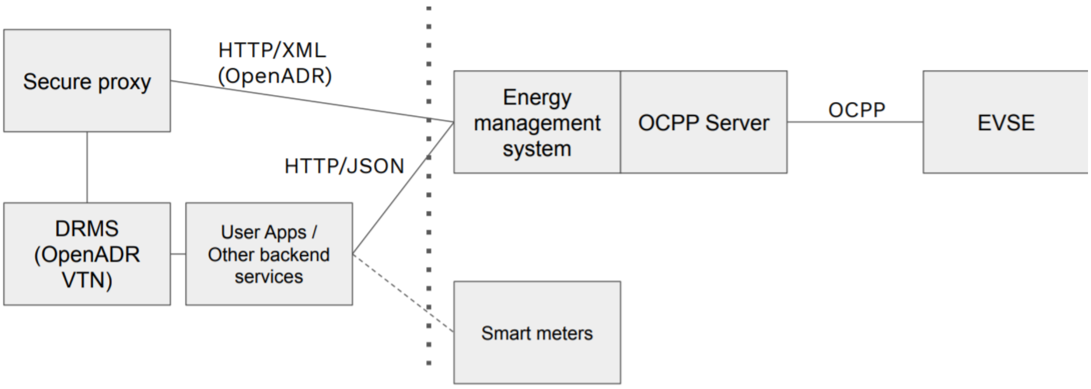

Figure 49: Carbon Co-op communications architecture

In terms of DNO connection standards, any V2G-capable vehicle is classified as both a generation and load[135]. As generation, compliance is required with ENA Engineering Recommendation (EREC) G99 (which replaced EREC G59 in April 2019). However, this document does not specify any standard protocols or architectures for communications interfaces and DNOs are currently investigating different approaches under active network management (ANM). Current protocols for communications between DNOs and Generators include simple current loop and DNP3. Additionally, the IEEE 1547 standard describes interoperability

133 https://nuvve.com/wp-content/uploads/2019/09/give-sell-sheet_v1.0.pdf
134 https://www.ncl.ac.uk/media/wwwnclacuk/cesi/files/OpenDSR_%20Using%20OpenADR%20and%20OCPP%20together%20to%20enable%20smart%20EV%20charging-compressed.pdf
135 https://www.energynetworks.org/electricity/engineering/energy-storage/vehicle-to-grid.html

requirements for distributed energy resources (DER) which may include V2G discharge. However, it does not cover the demand response aspects of smart charging.

As a demand load, installers of EV chargers have responsibility to notify DNOs of a connection under the following codes and regulations:

- Wiring Regulations BS7671 132.16 Additions and alterations
- Distribution Code DPC5.2.1
- IET Electric Vehicle Code of Practice v3 Section 11

E.4.3 DNO/DSO DISPATCHED DEMAND TURN DOWN/TURN OFF

This use case reflects a direct dispatch of smart charging by a distribution network operator (DNO) or distribution system operator (DSO), particularly for system critical cases such as load shedding.

In the UK, this use case will relate to the DNO as there are no organisations formally recognised as a DSO. However, the Energy Networks Association that represents the UK's DNOs and National Grid ESO is undertaking the Open Networks project that seeks to support the transition to DSO.

There have been limited trials of UK DNOs dispatching demand down or demand turn off of EVs. There is no standardised approach for this service such that it could be procured easily.

This use case also covers when a DNO can quickly interrupt non-essential loads in a household in response to adverse system conditions. This is as opposed to the DNO managing load switch off in much bigger chunks – i.e. at a street level or further upstream in the network. For DNO load interruption in critical scenarios, interoperability issues arise related to multiple actors - DNOs, EV users, aggregators, and OEMs to name a few - attempting to control the same infrastructure.

The first of these considerations is the latency associated with a control signal when DNO signals are sent via an aggregator platform or another party. Noting the latency issues discussed in section E.4.1, these additional delays may inhibit effective service delivery. Currently most communications standards at the levels between DNOs and EVSE (OpenADR, OCPP, SEP 2.0) are agnostic of the data link and physical layer protocols (Zigbee, WiFi, Ethernet) and hence do not describe network latency requirements, presenting a gap in standardisation to date. Additionally, there does not appear to be any definition within communications standards applicable to smart charging of the "criticality" of different control signals. This presents a challenge to determination of control priority in system-critical situations.

E.4.4 DISTRIBUTED RESTART AND COLD LOAD PICK UP

The distributed restart use case is still an emerging use case in the UK with a range of implementation challenges[136]. Therefore the following discussion primarily relates to cold load pickup.

The ENA Engineering Recommendation P2 Issue 7 defines cold load pickup as the:

- "difference between the Measured Demand on a Circuit following re-energisation of that Circuit and the demand on that Circuit which the DNO would have reasonably expected had no de-energisation occurred"

In the scenario where there is a prolonged outage, EVs represent a potentially significant cold load pickup demand. If uncontrolled, this could either lead to:

- Overloading of circuits and tripping of upstream protection; or,
- Significant overrating of circuits to manage these infrequent events[137].

[136] See joint TNO/DNO project: https://www.nationalgrideso.com/innovation/projects/distributed-restart
[137] P2/7 requires a DNO to plan for the effects of cold load pickup on their group demand

In this report, management of load pickup is consider to initially be an embedded function within EVSE (or the EV itself) due to the uncertainty about whether any communication infrastructure will be available following an outage. Therefore, this review is based on the standards related to the embedded functions within the EVSE/EV related to load reconnection (i.e. the chargers themselves rather than the communication with the charger).

First, it was noted that a number of EVSE products advertised the cold load pickup feature[138]. In one case this feature is described as:

> *"Time delayed and randomized (2-15 minutes) re-energizing of Charging Station following power outage. This feature protects electrical grid from overload from simultaneous re-energizing of chargers. Charging will automatically resume after the randomized delay."*

The functionality described would help support phased system load pickup. It is assumed that over the timescales described (i.e. 2-15 mins) the functionality described within other use cases could pick up the more granular control of load where further demand control is required.

An example of a UK charging point and associated standards is found in Annex E.5.1. The standard of key relevance to embedded control and functionality is EN61851-1. This standard describes a start-up sequence following a supply outage. However it does not appear to describe a cold load pick up sequence. Therefore it is unclear whether this use case is formally part of any EV charger standard. There are certainly industry developed methods for managing cold pick up[139].

There also appears to be recognition of this in the forthcoming *The Electric Vehicles (Smart Charge Points) Regulations 2020,* an extract of which is shown in Figure 50. Within the Government's consultation on Electric Vehicle Smart Charging[140], a maximum randomised delay of 10 minutes is proposed. The consultation also highlights the existing functionality within the SMETS 2 specification to allow "*for a configurable randomised offset of between 0 and 30 minutes for any change in price or switch state*". Whilst this is not discussed in the context of cold load pickup, there is the potential to extend this functionality to cover this use case. However this must ensure that any time setting is aligned with the needs and capabilities of the electrical system under adverse conditions (e.g. Is 10 mins enough? Should any chargers connect within the first minutes following reconnection?).

[138] However note that these products primarily appeared in the US market. https://rexel-cdn.com/Products/162A42BC-06BA-494D-9ADD-9937646F0306/162A42BC-06BA-494D-9ADD-9937646F0306.pdf, https://nesisolutions.com/uploads/EV-Charger-Delta-Electronics.pdf, https://media.distributordatasolutions.com/leviton/2017q2/1e4d9c10ff4d16e6c7fd5ec3f7a151866f4a2b63.pdf
[139] For example, see General Electric patent: https://patents.google.com/patent/US8600573B2/en
[140]https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/817107/electric-vehicle-smart-charging.pd

Operational requirements

9.—(1) A private charge point must be configured in a way which—

(a) ensures that when it responds to information received by it by adjusting the rate of electricity flowing through it, it operates with a random delay of up to [x] minutes; and

(b) permits the user of the charge point to override the random delay.

> "It is proposed that smart chargepoints will ordinarily be required to comply with British Standards Institution (BSI) standards, which are currently under development for smart chargepoints and smart appliances (see BSI Standards), before they can be installed."

Figure 50: Extract from draft regulations

E.4.5 REMOTE BATTERY HEALTH MANAGEMENT

This use case is different to the others explored above as it is not intended to provide grid services. Rather, its purpose is to maximise the usable life of the battery, potentially as part of a leasing agreement between the EV manufacturer and the EV lease holder. Despite the different end objective, many of the interoperability challenges described above are also present for this use case. A large number of proprietary protocols exist which may inhibit efficient co-operation of EVs between OEMs and other parties to both manage EV battery throughput and maximise grid value.

To address this difficulty, alternative architectures have been proposed such as that in Figure 51 in OEMs take ownership of the smart charging through a "white label" supplier which provide an intermediary platform or entity to mediate communications. Although this may go some way to alleviating interoperability issues, limited standards are available to describe this mode of operation. This may lead to challenges, particularly in communications between OEMs and aggregators, DSOs and energy suppliers. One potential option in this area is the IEEE 2030.5 (SEP 2.0) standard, however this has not seen significant uptake by OEMs to date.

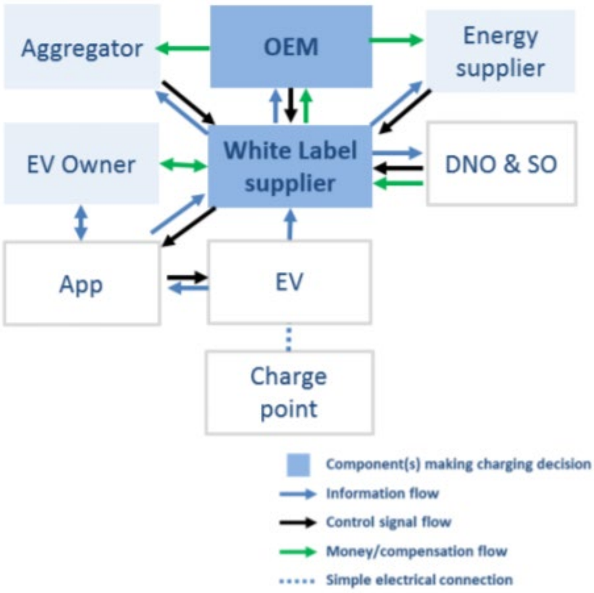

Figure 51: Alternative smart charging architectures, Source: V2GB

E.4.6 CONCLUSIONS

The preceding sections have attempted to map the interoperability landscape for a representative set of EV smart charging use cases. The SGAM interoperability layers and OSI model for communications have been used to provide an abstract framework for description of the complex communications between EVs and the smart grid.

It was seen that international standards have emerged in the last decade to provide candidate protocols for communications from the charging assets up to the enterprise layer. The CHADeMO standard has emerged as the first V2G capable standard for EV to EVSE communications, with others likely to follow by mid-decade. At the higher level, open standards have provided the impetus for wider standardisation, notably OCPP and OpenADR. This has paved the way for other standards such as IEEE 2030.5, IEC 63110 and many others. Limited standardisation has occurred at the higher enterprise level of communications and in the specification of DSR services.

Many initiatives are ongoing internationally to fill the remaining interoperability gaps. The IEC TC 57 and 69 are notable participants in this process. Interoperability labs are also becoming popularised by government and industry in many countries to implement and test these new standards. In the UK, the BSI is developing two PAS to provide a framework for DSR services and classification of smart appliances to provide these services.

Despite this standardisation activity, the common usage of proprietary non-standardised protocols poses a significant barrier to widespread smart charging implementation. A number of smart charging use cases were investigated to understand these barriers and how they are being overcome.

The provision of short term frequency response services was seen to be a challenging use case, with associated requirements regarding activation time, aggregation and operational metering. Despite this, early trials prove this service is possible with autonomous control and compatible communications. The load shifting of demand is an example of a more mature service, with open standards for communications emerging. The direct dispatch of EVs by DNOs faces a lack of clarity in the criticality of services and priority in smart charging control. Cold load pickup is similarly lacking in the description of the service, inhibiting larger scale procurement. Finally, non-grid use cases face related challenges with proprietary protocols widespread.

The successful UK and international deployment of smart charging to meet the needs of the grid and consumers will significantly depend on the adoption of the growing volume of international and local communications standards. Recent trials provide reasons to be hopeful that this can be achieved, however all parties who oversee and participate in the smart grid have a role to play in this.

E.5 ANNEX - SUPPORTING INFORMATION

E.5.1 OSI MODEL

Due to the pivotal role of communications, standardised or otherwise, in EV smart charging interoperability, a generic model for categorising communications is helpful. One such model is provided by the Object Systems Interconnection (OSI) model[141] developed by the International Organisation for Standardisation (ISO). There are seven OSI layers which each provide a different set of functionality as described in Table 11-31. The model spans from the application layer, which will directly interact with the same software application as the end user, to the physical layer which specifies the physical characteristics of the medium for communication transmission.

Table 11-31: OSI model layers

#	Layer name	Functions	Examples	TCP/IP Model
7	Application	Supports application and end user processes	HTTP, Modbus	4 Application
6	Presentation	Translates data from network to application format and vice versa	ASCII, SOAP, XML, JSON	
5	Session	Establishes, manages and terminates connections between applications	SCP, PAP	
4	Transport	Provides transparent transfer of data between end systems	TCP, UDP	3 Transport
3	Network	Routing, forwarding, addressing, internetworking, error handling, congestion control, packet sequencing	IP	2 Internet
2	Data Link	Encodes and decodes data into bits	WiFi (IEEE 802.11), Ethernet (IEEE 802.3), USB	1 Link
1	Physical	Provides the electrical or mechanical transmission medium		

Although there are many other communications reference models available, the OSI model is often referenced in ISO standards and is therefore useful to frame the discussions in the following sections. Other models such as the TCP/IP model[142] have less strict boundaries between layers due to development of the reference model after protocols were implemented, in contrast to the OSI model. A typical mapping between the OSI and TCP/IP layers is shown in Table 11-31

[141] See https://en.wikibooks.org/wiki/Network_Plus_Certification/Management/OSI_Model for more details
[142]For an overview of TCP/IP and a mapping to OSI see: https://docs.oracle.com/cd/E19683-01/806-4075/ipov-10/index.html

A layer can provide services to the layer above it and receive services from the layer below as shown in shown in Figure 52. Protocols refer to communications between the same layer in a different system instance.

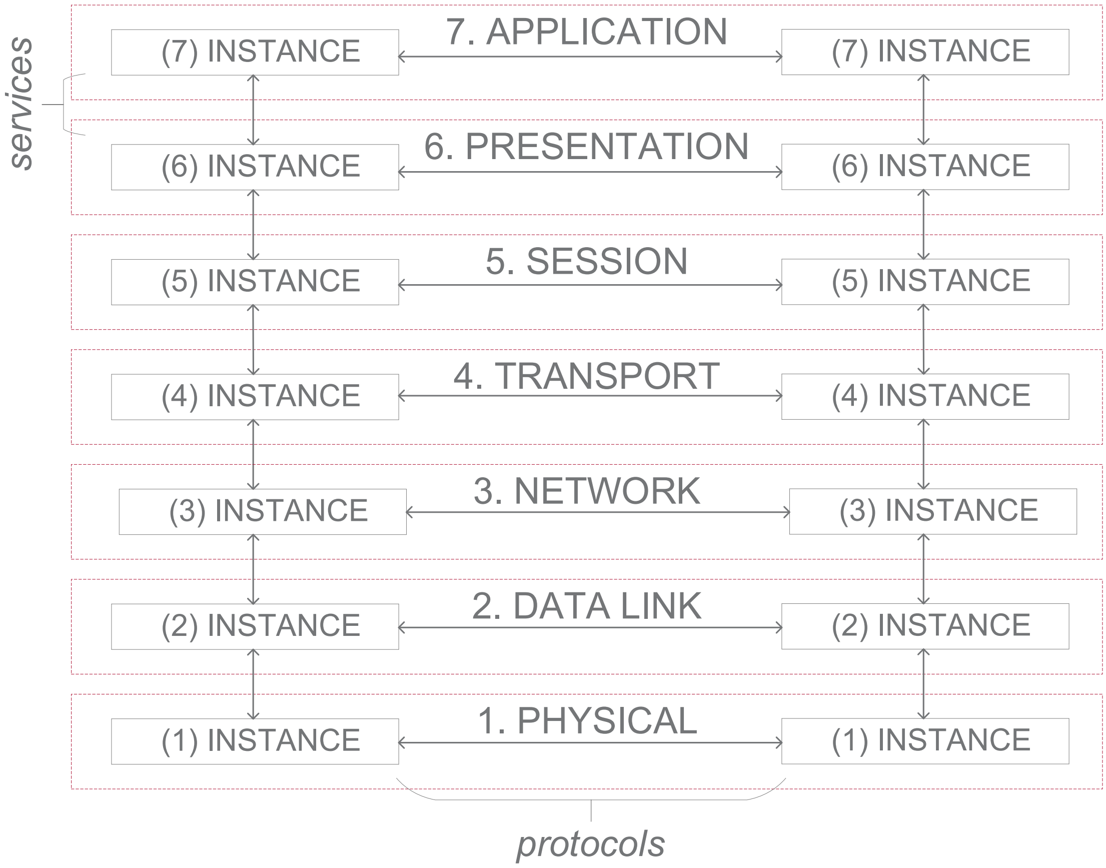

Figure 52: OSI model for communications

E.5.2 SAMPLE UK CHARGER

Table 11-32 details one example EV charger sold in the UK, standards complied with and the related international standards.

Table 11-32: Standards with which the pod point charger product[143] (sold in the UK) complies

Category	Standard	Standard type/scope	Relevant international comparison
Socket compliance	Type 2: IEC62196-2:2016 (with lock & lock status)	Plugs, socket-outlets, vehicle connectors and vehicle inlets (focus on physical design)	Overlap with SAE J1772
Standards compliance	LVD 2014/35/EU	The low voltage directive (LVD) (2014/35/EU)	n/a

143 https://d3h256n3bzippp.cloudfront.net/Solo-Charger-Commercial-Datasheet_191118_133213.pdf

	EMCD 2014/30/EU	Electromagnetic compatibility	n/a
	EN61851-1 and -22	Electric vehicle conductive charging system Part 1: General requirements Part 22: A.C. electric vehicle charging station	Overlap with SAE J1772 (specifically referred in Part 1)
	EN61000-3 and -2	Electromagnetic compatibility	n/a
	CE Certified	Health and safety marking	n/a
	BS7671: 2018	Wiring regulations	n/a

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