

Voltage Management in a Net Zero Electricity System Institution of Engineering and Technology Task and Finish Group Stage One Report

Executive Summary

The IET has formed a Voltage Management Task & Finish Group (TFG) to undertake a study for Ofgem addressing emerging concerns over the adequacy of grid voltage management. This interim report updates Ofgem on the progress of the study. It sets out the TFG's emerging analysis and signals the direction of its developing conclusions ahead of the final report.

Great Britain's electricity system is moving rapidly from one built around a few large synchronous generators to one in which a growing share of supply comes from distributed, weather-dependent, inverter-based resources, much of it connected to low voltage networks and beyond the meter. This transition is already placing the management of network voltage under strain. Evidence indicates that up to 5% of low voltage customers experience sustained voltages above the 253V statutory limit, that the trend is rising, and that nuisance tripping of solar PV inverters and EV chargers is now widely reported. At the same time, record low transmission demand, falling further as rooftop solar grows, is driving high system voltages and the prospect of reverse power flows not previously encountered.

The TFG's central concern is that, without a coordinated, whole-system approach to voltage management, some of the failings that contributed to the Iberian Peninsula event of April 2025 could in time find expression in the British system. Several factors make a comparable event less likely here, but the TFG's developing view is that the underlying risk is real and warrants a clear and timely response rather than reassurance.

The report finds that more active voltage management is both possible and necessary, that a substantial toolkit already exists or is in advanced trial, and that the principal gaps are in visibility of the grid edge, coordination across system levels, and governance keeping pace with technical change. The level of urgency is within usual industry timescales provided a prompt start is made, based on Clean Power 2030 projected levels of generation, energy storage and assumed EV deployment, but urgency will increase if deployment rates increase.

Significant uncertainties remain, set out in this report as knowledge gaps, and these will be a focus of the TFG's continuing work. The TFG's full analysis and recommendations will be presented in its final report to Ofgem; this interim report is intended to convey the direction of its emerging conclusions and the urgency it attaches to them.

Introduction

The IET has agreed to undertake a study for Ofgem regarding emerging concerns over the adequacy of grid voltage management. At the kick-off meeting with Ofgem on 19 Aug 2025, it was agreed that an IET Voltage Management Task & Finish Group (TFG) would be formed and work towards producing a position paper that would meet the following objectives.

- Define the scope of voltage management concerns.
- Explain the risks and opportunities.
- Explore the current policy context.
- Explore the extent to which the British 50Hz synchronous system might become exposed to a failure mode similar to that which led to the Iberian Peninsula event on 28 April 2025.
- Provide a roadmap of what is possible and realistic in the short and longer term.

This purpose of this interim report is to update Ofgem on the TFG's progress to date. The report summarises the TFG's analysis which suggests that a programme of enhanced active voltage management is now both possible and necessary in order to:

- Address current and emerging system operational issues;
- Reduce costs to customers directly through ensuring electrical appliances are operating within a supplied voltage range that enables efficient use of electrical energy;
- Increase grid hosting capacity for low carbon technologies (LCTs) in support of Clean Power 2030¹ and longer-term energy decarbonisation objectives in support of Net Zero;
- Improve overall grid efficiency in terms of effective voltage control, efficient asset utilisation, and economic management of system losses (hence indirectly reducing costs to customers).
- Increase overall system resilience to shocks arising from displacement of synchronous generation with weather-dependent inverter-based resources (primarily wind and solar generation).

¹ <https://www.gov.uk/government/publications/clean-power-2030-action-plan>

Scope of Voltage Management Concerns

A range of concerns arise from current and emerging issues that have implications for voltage management, from both an operational and economic perspective, but also from a wider system security perspective.

Voltages Above Statutory Limits

Evidence now suggests that up to 5% of LV-connected customers experience sustained voltages above the current statutory voltage limit (for single-phase supplies) of 253V (i.e. 230V + 10%). Moreover, the trend is rapidly increasing, sometimes leading to 'nuisance' tripping of solar PV inverters and EV chargers (i.e. over 20% of monitored EV chargers) the latter including as a result of Protective Earth & Neutral (PEN) protection operation. In recognition of this, the Energy Networks Association (ENA) has consulted on a proposal to reduce the lower statutory voltage limit for LV single-phase supplies from the current 230V-6% to a new lower limit of 230V-10%. This would allow DSOs² to reduce system voltage levels, so creating additional headroom to cater for the impact of solar PV generation whilst maintaining sufficient margin above the new lower statutory limit to help accommodate demand arising from EV charging and especially heat pumps. Ideally under normal operation conditions, the phase-neutral voltage at a customer's point of supply would be between 240V (low load) and 220V (high load). A voltage range of 220V to 240V would align with the voltage rating of most domestic single-phase appliances.

The ENA has also proposed to reduce system voltage levels by 1% for a period of one year, followed by a further 1% reduction for a further year. This would enable DSOs to gain experience of the impact on customers before implementing the statutory change (or further voltage reductions on a permanent basis). In practice there is evidence that the average supplied voltage might currently be closer to 243V. This is largely a consequence of ENA Technical Specification 35-1 for distribution transformers (originally designed for serving 415/240V LV systems) which stipulates a voltage ratio (for three-phase transformers) of 11,000/433V (equivalent to 250V phase-neutral). Hence a 2% system-wide LV voltage reduction could be expected to reduce the average delivered voltage to around 238V, still at the top end of the ideal range.

Appliance Efficiency

Notwithstanding the effects of statutory breaches in supplied voltage (ESQC³ Regulation 27(3)(b)) there is compelling evidence that higher than necessary voltage levels can lead to additional energy consumption by some (but not all) domestic appliances, hence leading directly to higher energy charges as well as system inefficiencies (for example higher network losses) that will also increase costs for customers. Since domestic appliances are generally

² Note: references to 'DSO' in this report are used where the function or responsibility lies specifically with the continually evolving DSO role within a DNO's organisation.

³ ESQC – Electricity Safety, Quality and Continuity Regulations 2002.

designed to operate most efficiently within a voltage range of 220V to 240V, there is considerable scope from this perspective for reducing the currently supplied average voltage of 243V by more than 2%.

Grid Code OC6 Compliance

In order to address these high voltage concerns, DNOs have in many cases adjusted primary substation transformer automatic voltage control (AVC) set points to reduce the target voltage from typically 11.1kV to 10.9kV at the substation 11kV busbars. In so doing it is not uncommon to find primary (33/11kV or equivalent⁴) transformers operating close to bottom tap under light load conditions. Not only does this leave little scope for further voltage reduction (including the above-mentioned ENA proposed 2% trial reduction over two years) it might also compromise DNOs' ability to meet the requirements of Grid Code OC6.5.3 which requires DNOs to effect, within 30 minutes, a voltage reduction at primary substations in up to two stages, each of between 2% and 4%, when instructed by NESO for demand reduction purposes (noting that primary transformer tap position steps are typically in the range of 1.25% - 1.43%).

High Transmission System Voltages

A reducing trend in power transfer from transmission to distribution, partly as a consequence of increasing levels of distributed energy resources (DERs) - combined with sustained levels of reactive power transfer (and even reverse reactive power transfer during light load periods partly as result of capacitive gain from distribution system cables) - has led to higher overnight transmission system voltages. However, with increasing levels of DERs such as solar PV farms and onshore wind (cable connections to which will further increase distribution system shunt capacitance) along with increased shunt reactance from transmission cables (including AC subsea cables) the challenge is set to increase with greater variances in both seasonal and intra-day reactive power transfer volumes. This will give rise to a need for increased reactive power support from DSOs. In that regard, as part of DSOs' responsibilities for voltage management, Ofgem's RIIO-ED3 Sector Specific Methodology Decision published on 21 May 2026⁵ proposes a requirement on DSOs to maintain power factor at the distribution-transmission interface within an envelope of 0.9 lag to 0.9 lead.

System Stability

From a wider system perspective, the Iberian Peninsula event in April 2025, and the expert panel's conclusions into the root causes, has given rise to a concern to better understand the potential vulnerability of the GB system to a similar event arising from system perturbations such as voltage and/or frequency excursions which might be more likely to arise as a consequence of the ongoing displacement of centrally dispatched synchronous generation by

⁴ Including variations such as 132/11kV, 22/6.6kV, etc.

⁵ <https://www.ofgem.gov.uk/sites/default/files/2026-05/ED3%20Sector%20specific%20methodology%20decision%20core%20document.pdf>

self-dispatching weather-dependent inverter-based resources (IBRs) such as wind and solar PV generation. Whilst system stability is dependent on both frequency and voltage management, this report focuses on the voltage related instability aspects of the Iberian Peninsula event (see Emerging Risks - System Resilience to Shocks).

Current Policy Context

Projected Growth in LCTs

The prospective expansion of solar PV (particularly rooftop solar PV) promoted by the UK Solar PV Roadmap⁶ complemented by the Government Warm Homes Plan⁷, the Local Power Plan⁸, and the Future Homes and Buildings Standards⁹, could lead to an installed solar PV capacity of between 45GW and 47GW by 2030, potentially rising to 85GW by 2035 if further barriers to rooftop solar PV are removed. In terms of further low carbon technologies (LCTs) impacting the electricity system, heat pumps, and to a lesser extent home EV charging¹⁰, have the potential to significantly increase peak demand, whilst vehicle-to-grid (V2G) chargers along with rooftop solar PV will raise the prospect of LV distribution networks exporting to higher voltage networks during high irradiance and/or low demand conditions.

To put this into context, on the bank holiday weekend of 24 May 2026, Britain's electricity system saw its lowest ever transmission demand, dropping to 12.62GW between 1pm and 1.30pm due to high solar generation and the bank holiday weekend reducing typical electricity demand. Given the target range of 45GW to 47GW for solar PV capacity by 2030 projected by the UK Solar Roadmap, this raises the prospect of future periods of negative (net) transmission demand with the potential for reverse power flows through various voltage levels of distribution systems, thereby further exacerbating the voltage management challenge.

The overall effect will be that, in the absence of increased attention to active voltage management, the voltage profile experienced (particularly but not exclusively) by LV networks will vary far more significantly than today, both in seasonal timescales - i.e. generally higher LV network voltages in summertime and lower voltages in winter; and in diurnal timescales – i.e. as a consequence of reduced network loading due to daytime solar generation, and increased winter evening peak-time network loading due to heat pump demand (assuming home EV charging occurs mainly overnight).

Clean Power 2030

The Clean Power 2030 Action Plan and longer-term electricity production decarbonisation policy goals are based on a programme of displacement of fossil fuelled generation (primarily

⁶ <https://www.gov.uk/government/publications/solar-roadmap>

⁷ <https://www.gov.uk/government/publications/warm-homes-plan>

⁸ <https://www.gov.uk/government/publications/local-power-plan>

⁹ <https://www.gov.uk/government/publications/the-future-homes-and-buildings-standards-building-circular-012026/the-future-homes-and-buildings-standards-building-circular-012026-letter>

¹⁰ The assumption being that the majority of home EV charging will occur overnight.

unabated natural gas-fuelled CCGTs and OCGTs) with increased capacity from nuclear, abated biomass, energy storage, interconnectors, and (especially) wind and solar PV generation, the latter encouraged by the UK Solar Roadmap and other policy initiatives cited above. Four consequences of these policies are that:

- Generation output at any given time will be increasingly dependent on weather conditions (and any grid constraints), hence requiring availability of dispatchable firm generation and/or energy storage capacity to cover prospective negative margins.
- System strength (short-circuit level and inertia) will be more variable with increasing reliance on sources of synthetic inertia¹¹ such as battery energy storage systems (BESS) connected through grid-forming (GFM) inverters. NESO is planning for a minimum inertia level of 102GVA.s which was approved by Ofgem on 28 May 2026¹² subject to a number of conditions, including a ten-week trial at 110GVA.s and securing an additional 200MW of Dynamic Containment.
- A more widely distributed source of onshore generation and energy storage (connected mainly to distribution networks and including ‘beyond the meter’ microgeneration - principally rooftop solar PV) will give rise to ‘visibility’ challenges (i.e. knowing the location and output of generation at any given time).
- Ramp rates associated with weather-dependent generation can be relatively high. Hence, at times when wind and solar generation is supplying the bulk of system demand, this can result in quickly varying levels of system infeed, requiring compensatory action (including through BESS) to maintain both frequency and voltage stability.

Strategic Spatial Energy Plan (SSEP)

As part of NESO’s obligation to produce an SSEP¹³ it will develop a range of six potential pathways, each of which will be compatible with not only Clean Power 2030 but also with the government’s overall energy policy and longer-term objectives regarding decarbonisation of energy production and demand. The plan will have a 25-year horizon with a 3-yearly review cycle. Although yet to be finalised and published (with the Secretary of State’s decision regarding pathway selection) it is evident that all pathways will involve a major expansion of renewables dominated by offshore and onshore wind and solar PV. Taking NESO’s System Adequacy Report¹⁴ purely as an indication, the pathways might include a combined installed capacity for offshore and onshore wind and solar PV of around 200GW by 2040, accounting for over half the total resource capacity of around 350-375GW, with nuclear, biomass, gas

¹¹ The term ‘synthetic inertia’ is commonly used to describe the capability of GFM inverters to rapidly inject active power into the system under a falling system frequency condition (albeit they confer no actual ‘inertia’).

¹² Approved by Ofgem in May 2026 following an independent review of NESO’s March 2025 Frequency Risk Management and Control Report, and NESO’s subsequent Supplementary Report:

<https://www.ofgem.gov.uk/sites/default/files/2026-05/FRCR-2025-Authority-Decision-May-2026.pdf>

¹³ <https://www.neso.energy/what-we-do/strategic-planning/strategic-spatial-energy-planning-ssep>

¹⁴ <https://www.neso.energy/data-portal/resource-adequacy-2030s>

(abated and unabated), hydrogen-to-power, interconnectors, energy storage, and demand flexibility making up the remaining capacity.

It follows that in order to ensure the system remains resilient to shocks and perturbations (including voltage oscillations) there will need to be a strong focus on both frequency and voltage management from a whole electricity system perspective.

Regulatory Policy - Obligations on DSOs

Ofgem's RIIO-ED3 21 May 2026 Sector Specific Methodology Decision¹⁵ introduces voltage management as a new responsibility of the DSO role in RIIO-ED3, including publishing a Voltage Management Strategy detailing how the responsibility would be implemented. DSOs responsibilities will include:

- Improving monitoring – understanding voltage headroom and legroom on primary networks (i.e. networks operating between Grid Supply Points (GSPs) and MV/LV distribution substations) and voltage issues at customer premises, using LV monitoring capability installed in RIIO-ED2 enhanced with smart meter data and data from third-party assets.
- Enhancing voltage management – improving ability to control voltage across both the primary networks and, where required, the secondary networks (the MV/LV distribution substations and associated LV networks) to ensure voltage remains within statutory limits and to eliminate interruptions of LCTs and curtailment of DERs where this is due to voltage issues.
- Reducing reactive power injection onto the transmission network with the aim of keeping power factor within an envelope of 0.9 lead to 0.9 lag at the distribution/transmission boundary.
- Providing Flexibility - for example using temporary voltage reduction to provide a flexibility service to NESO, for which DSOs will be rewarded through a newly introduced incentive.

Emerging Risks

LV Voltages Outside Statutory Limits

There is evidence that up to 5% of LV connected customers are, for sustained periods, being supplied at voltages above the statutory limit for single-phase LV supplies of 253V. In the absence of effective intervention, the number of customers, and both magnitude and duration of over-voltage events, can be expected to increase with increasing levels of installed solar PV capacity incentivised by the government's promotion of rooftop solar PV. Instances of 'nuisance tripping' of rooftop solar PV inverters and home EV chargers (the latter due to either

¹⁵ <https://www.ofgem.gov.uk/sites/default/files/2026-05/ED3%20Sector%20specific%20methodology%20decision%20core%20document.pdf>

high or low voltage) are already widely reported and will inevitably lead to loss of customer confidence in investing in LCTs. Steps to better manage LV system voltage are therefore now an immediate priority.

Lack of Voltage Event Ride-Through Capability

A further area requiring investigation and resolution is that there is evidence of rooftop solar PV inverters disconnecting at voltages well below the G98 specified over-voltage 'no trip' test thresholds (258.2V / 2.0s; 269.7V / 0.98s; and 277.7V / 0.48s). Tripping should not occur even at sustained voltages below 258.2V. Notwithstanding the inconvenience to customers, inadequate high voltage event ride-through capability also represents an increasing risk to overall system security.

System Resilience to Shocks

The ENTSO-E final report¹⁶ into the Iberian Peninsula event on 28 April 2025 identified a range of operational and, in particular, voltage management shortcomings. These include:

- Operational procedures with no explicit specification for dynamic voltage control and no effective financial penalties for non-compliance.
- Renewable Energy Source (RES) plants operating in fixed power factor control mode limiting reactive power absorption – hence unable to provide voltage support independently of active power export, and also no reactive power support available to compensate voltage fluctuations. Hence a rapid ramping down of active power export also contributed to a rapid increase in voltage.
- Generators (or connecting transformers or lines) disconnecting at a voltage level below the required voltage disconnection level, and before the time delay conditions were met, leading to a loss of reactive power absorption and resulting in a steep increase in voltage.
- Design of voltage control of local generation networks (behind the connection point) not aligned with system needs – including higher risk of disconnection under high voltage conditions due to voltage trip level and time delay settings below operational requirements.
- Process of manually switching-in of shunt reactors too slow to respond to rapidly increasing voltage.
- Rapid generation ramping coupled with relatively slow operation of transformer tap changers – hence response too slow to react to rapidly increasing voltage levels.

¹⁶ <https://www.entsoe.eu/news/2026/03/20/entso-e-publishes-expert-panel-final-report-on-28-april-2025-blackout-in-spain-and-portugal/>

- Inverter-based resource (IBR) instability combined with interaction with other IBR generators in the same area leading to forced oscillations posing a risk to the system of severe and rapid (within seconds) frequency and voltage fluctuations.
- Power System Stabilisers (PSS) not installed on all generators leading to inability to dampen oscillations, plus the action of some PSSs was insufficient to dampen the oscillations.
- An assumed high number of overvoltage trips of small PV units connected to the low-voltage DSO grids (based on manufacturer's specification data rather than direct observation). These units are assumed to have tripped during periods of high voltage ramping in the transmission network but also during and around periods of high voltages and voltage fluctuations (slow/fast changes, oscillations).
- Operating the Spanish system with a voltage range 380kV to 435kV, whilst generators were required to remain connected only up to 435kV or 440kV (depending on commissioning date) meant that the voltage margin was low or non-existent.
- Whilst active load shedding helped stabilise system frequency, some automated disconnections (including PHS plants) that were absorbing reactive power at the time of disconnection, intensified the overvoltage situation.
- The loss of active power export due to generators tripping on overvoltage exceeded the loss of demand from active load shedding, leading to frequency continuing to fall until the system collapsed and hence the blackout occurred.

The conclusion must be that without the necessary attention to an overall system voltage management strategy, there is a risk that some of these failings could begin to manifest themselves across the British 50Hz synchronous system, particularly as a result of the projected displacement of centrally dispatched synchronous generation with both transmission-connected and widely distributed weather-dependent IBRs in support of Clean Power 2030 and longer-term energy decarbonisation objectives.

Implications for Voltage Management

Given the increasing penetration levels for DERs and especially CERs (particularly rooftop solar PV), the system infeed loss risk will need to be fully understood, regularly re-evaluated, and quantified, to determine the operational planning margin requirement (OPMR) under all credible operational scenarios. Whilst a number of the Iberian Peninsula voltage management failings are less likely to apply in respect of the British system, for example due to it being an islanded synchronous system (no AC interconnection to other systems), as result of specific Grid Code obligations on generators, and because of NESO's range of available ancillary services (including those derived from its Voltage and Stability Pathfinder initiatives), this does not detract from the importance of addressing potential shortcomings in our current voltage management strategy that could ultimately lead to a widescale shutdown of the British electricity system.

Clean Power 2030

The Clean Power 2030 Action Plan has set stretching targets for deployment of solar PV generation (45-47GW), onshore wind generation (27-29GW), and battery energy storage (23-27GW). Depending on the degree to which their operational deployment is managed and coordinated, these technologies provide either potential challenges or opportunities for system voltage management, particularly at distribution system voltage levels. However, the potential prospect of sustained high oil and gas prices could conceivably drive even more rapid adoption of some LCTs, for example domestic solar PV and EVs, which could then exacerbate the voltage management challenge for LV networks. Moreover, should adoption be unevenly distributed across Britain (for example higher and more rapid take-up of LCTs in more affluent areas) then voltage management issues could become localised but more acute, requiring targeted interventions. Failure to deploy solutions with sufficient speed might then lead to politically unacceptable restrictions on the scale and rate of LCT adoption, and to customer disillusionment with the energy transition. In that regard, RESPs will have an important role in disaggregating SSEP national projections to reflect regional differentiators of LCT adoption.

Implications at LV System Level

The combined impact of high daytime levels of export from rooftop solar PV under light load conditions in spring or summertime (as demonstrated on the bank holiday weekend of 24 May 2026) and higher levels of network loading due to heat pump demand (and to a lesser extent home EV charging) during the winter evening peak period will require more sophisticated and granular methods for maintaining LV network voltages within operational and statutory limits. Even allowing for potential enhancements to primary network voltage control (which may already be compromised due to limited available primary transformer tapping range) this is likely to ultimately require voltage control capability further downstream than at primary substation level, including potentially AVC capability for distribution transformers (at least on a selective basis) and PQ control of solar PV and V2G EV chargers. The former has significant investment cost implications whilst the latter has technical, commercial coordination, and governance implications.

Wider System Level Implications

One of the more concerning aspects of the Iberian Peninsula event from a GB system perspective was the implicit widespread overvoltage tripping of small solar PV units connected to distribution systems, partly due to voltage trip levels and time delay settings below operational requirements. In that regard, the apparent propensity for rooftop solar PV inverters to trip at voltages below G98 specified 'no trip' test thresholds has highlighted the need for much greater visibility in terms of location of small solar PV units, a better understanding of their behaviour under system stress conditions, and a need for greater assurance over their voltage event ride-through capability.

Opportunities

Reducing the LV Lower Statutory Limit

The ENA has consulted on a proposal to change the LV voltage statutory limits for single-phase LV supplies from 230V+10% / -6% to 230V +/-10% giving a permitted voltage range of 253V to 207V. This wider bandwidth would allow DSOs greater scope for lowering overall system voltage to improve hosting capacity for LCTs, including heat pumps, EV chargers, and rooftop solar PV, whilst reducing (or possibly eliminating) instances of nuisance tripping of solar PV inverters and EV chargers due to high voltages. The proposal is supported by evidence of energy conservation arising from supplying customers closer to the 'ideal' range of 220V to 240V in line with most domestic appliance voltage ratings. Lowering LV system voltage to take full advantage of a lower statutory limit (if implemented) should be conditional on visibility of voltage levels delivered to customers and demonstrable voltage control capability. Moreover, given that instances of nuisance tripping have been recorded at voltages of around 207V (for example EV charger PEN protection) as well as at around 253V, it would be prudent to adopt operational limits of 230V +/-20V, i.e. an operational range of 210V to 250V.

DER/CER Integration

An immediate priority is to greatly improve visibility of DERs, and especially consumer energy resources (CERs), not only in terms of installed capacity and location (network connectivity) but also in terms of behaviour under system stress conditions. A further priority is to ensure ENA EREC G98/G99 alignment with regard to power factor range and both frequency and voltage event ride-through capability (including with regard to specified overvoltage and undervoltage trip settings). In the longer-term, the implementation of a PQ control regime for solar PV and V2G inverters, either through transmitted signals or preferably through autonomous operation and utilising the G98/G99 specified power factor range of 0.95 lag to 0.95 lead, has the potential to help control voltage at customers' supply terminals (i.e. operating at a leading power factor to absorb reactive power and contain voltage rise).

A further opportunity is for DSOs to procure reactive power services from DERs such as BESS and solar PV (including co-located solar PV and BESS). One advantage is that DSOs will have greater visibility than NESO of DERs and could even enter into contracts as part of agreeing connections to the distribution system. This could help DSOs meet their new regulatory obligation to keep reactive power within an envelope of 0.9 lead to 0.9 lag at the distribution/transmission boundary. On the other hand, there might be benefits in DERs providing reactive power services directly (and solely) to NESO to avoid possible dispatch conflicts, or potentially there could be a hybrid arrangement between NESO and DSOs governed by primacy rules.

D-STATCOMs

Whilst increasing levels of distribution-connected BESS provide an opportunity for voltage support through provision of reactive power services, their physical location and network connectivity is not determined by DSOs. Hence it is likely that DSOs will need to supplement

any contribution from BESS in order to meet their new regulatory obligation to keep reactive power within an envelope of 0.9 lead to 0.9 lag at the distribution/transmission boundary. One option is to install D-STATCOMS at strategic locations, for example at Grid (132/33kV or equivalent) substations. D-STATCOMS have the benefit that they are directly under the control of DSOs and so can provide a refined level of voltage support where and when it is needed.

Manual Adjustment of Distribution Transformer Winding Tap Positions

Although impractical as a dynamic voltage control methodology, it remains an option to reduce LV network voltages in exceptional cases where voltage levels are consistently high and anticipated to remain so despite upstream measures, and despite future additional network loading (e.g. due to heat pump demand). 3-phase distribution transformers to ENA Technical Specification 35-1 were originally designed for 415V 3-phase (240V single phase) LV networks and have a nominal voltage ratio of 11,000V/433V in order to allow for voltage drop on LV networks when fully loaded. Most are equipped with off-load tap position switches providing a typical tapping range of +/-5% in 2.5% steps (though a range of +7.5/-5% is now being specified by some DNOs for new transformers). Typically, transformer tap positions will be set at +2.5% for most substations, but with settings of +5% or +7.5% for substations close to the source primary substation, and nominal tap (0%) for remote substations (noting that the tap position relates to the HV winding of the transformer and hence a tap position of +2.5% means that the HV/LV winding ratio will be 2.5% higher than when on nominal tap).

As these are off-load tap position switches, it means that the transformer would have to be completely offloaded (or ideally de-energised) before operating the switch, which in turn would mean that a short interruption of supply would be required in most cases (even if one or more individual LV feeders can be backfed). Given there are several hundred thousand distribution transformers in service across Britain, this action would necessarily be undertaken on a very selective basis, where delivered LV voltage remains persistently high despite other voltage management interventions, and only as part of an overall distribution system voltage management strategy. It might in any case prove to be only a temporary solution.

Automatic Voltage Control (AVC) Compounding

AVC is installed at virtually all primary network substations. It involves the automatic switching of transformer tap positions to maintain transformer output voltage within a target range in response to changes in input voltage. Line drop compensation (LDC) is also applied in some primary (33/11kV or equivalent) substations to boost voltage under high load conditions in order to compensate for voltage drop along outgoing feeders. An adaptation might be possible whereby voltage is boosted under high load conditions but bucked under low load conditions. This could help alleviate high LV voltages in summertime when distributed solar PV generation output is high, and both MV and LV network (net) loading is relatively low. Care would be needed in cases where primary substations also serve summer-peaking areas such as CBDs, leisure centres, and data centre complexes with high levels of air cooling, since boosting voltage in response to the high summertime demand they impose could then exacerbate the high voltage situation for adjacent networks serving residential areas.

Monitoring and Smart Meter Data as an Input to Primary AVC Set Points

An approach being trialled by the NPg BEET project is to use LV monitoring and smart meter voltage data as an input to primary substation AVC set points. An algorithm is used to determine a primary transformer tap position that is optimised for the overall area served by the primary substation.

CLASS (Customer Load Active System Services)

SP ENW's CLASS project has demonstrated a number of applications including:

- Lowering primary substation tap positions to reduce demand (the observed impact was that a 1% voltage reduction resulted in a power demand reduction of between 1.3% and 1.48% depending on the customer mix (residential / industrial / commercial));
- switching out one of two (or more) paralleled primary substation transformers as a means of frequency response; and
- tap-staggering (operating tap changers out of step at primary substations) to absorb reactive power and help reduce high voltages.

There is potential to apply these techniques more widely across DNOs' distribution systems in support of the new regulatory obligations on DSOs in ED3, subject to there being sufficient scope to lower tap positions in circumstances where primary substation transformers are regularly operating close to bottom tap.

Enhanced Transmission System Monitoring and EMT Modelling Capability

The phenomenon of sub-synchronous voltage oscillations has been observed on a number of occasions on the GB transmission system. Although these have been of a temporary nature and/or have been successfully suppressed, it is relevant to note that the phenomenon was observed during the early stages of the Iberian Peninsula event, and lead to rapid (within seconds) frequency and voltage fluctuations. Two recommendations that emerged from the Iberian Peninsula final report are:

- TSOs should improve and expand the monitoring and detection framework by using existing phasor measurement units (PMUs) and oscillographs, or where required, installing additional PMUs, oscillographs, and power quality monitoring devices that are accessible to the TSO, particularly near interfaces with power plants, third party-owned HV network sections, DSOs, and HV connected customers.
- TSOs should implement automatic detection systems and effective early-warning tools to identify oscillations in a timely manner (including both inter-area and forced oscillations), locate their source in case of forced oscillation, and support prompt corrective actions, noting that automated corrective actions should be applied selectively.

The report does not comment on the extent to which IBR generators were connected through grid forming (GFM) or grid following (GFL) inverters - the latter being more prone to

interactions between their phase-locked loop control systems, with a higher risk of this leading to voltage and frequency oscillations. Although not stated as a recommendation in the report, this also suggests a need for enhanced electromagnetic transient (EMT) modelling capability to simulate conditions that might lead to voltage and/or frequency oscillations, particularly as grid in-feeds become increasingly dominated by IBRs. Moreover, given the increasing penetration of IBRs on distribution networks, the need for enhanced modelling capability also extends to these voltage levels.

Digitalisation and AI

A number of innovation projects are now exploring the potential for artificial intelligence and machine learning (AI/ML) to improve decision making across investment and operational planning timescales and in real-time applications. The scope for AI/ML in terms of electricity system planning, design and operation is extensive but in the context of this report, an opportunity also lies in its application to enhanced techniques for active management of system voltages. Access to an increasingly wide range of digitalised real-time or time-series data, including data from LV monitoring and smart meters, will enable better contingency planning and faster, and better, optimised actions for voltage control. That said, the current data and communications architecture for distribution systems does not provide the resolution necessary to identify transient behaviour. At transmission level, faster processing of data from monitors and PMUs to identify abnormalities (such as sub-synchronous voltage oscillations) and inform corrective actions will reduce the risk of suboptimal decisions, whilst ML will help refine decisions based on the observed impact of decisions over time. From a whole system perspective, the transition from a historically relatively concise population of centrally dispatched generation to a future much larger population of more widely distributed, largely self-dispatching, energy resources will require a more algorithmic-based approach to system control, increasingly facilitated through AI and ML.

Innovation / Innovation Rollout Mechanism (IRM) Funded Trials

A number of innovation or IRM funded trials have been or are being undertaken by DNOs to explore innovative opportunities for improved distribution system operational efficiency and voltage management. The following is a brief summary of some of these trials.

SPEN LV Engine - the objective of the project is to carry out a network trial of Smart Transformers to facilitate the connection of LCTs. This innovation is in line with the UK Government's CO₂ reduction targets which are driving the increase in electrification of both heat and transport.

UKPN NExT - the project involves the trialling of a new power-electronic device named the Network Exchanger (NEx). Fitted to secondary transformers, the NEx enables a higher level of control by independently managing how power flows on each phase of an LV system. This allows for more accurate voltage regulation, better load balancing across phases, and improved power factor.

NGED LV-ACT - a novel active power control transformer will be designed and, pending successful completion of a prototype, developed to assess its' ability to independently control active power flow in two feeders, either from the same substation (looped) or from adjacent substations (meshed). Load sharing will be facilitated, thereby removing constraints from one feeder by transferring load to another unconstrained feeder, while also controlling the voltage profiles along the feeders.

SPEN D-Suite - the project is an initiative aimed at enhancing the capacity and efficiency of low voltage distribution networks with the development of three power electronics devices: an LV Distributed STATCOM to manage voltage levels and improve power quality; a distributed soft open point to enhance network flexibility and reliability; and a distributed smart transformer to optimise energy distribution and efficiency.

NGED VRA - a program of voltage reduction was carried out across a selected trial area of South Wales which involved altering the AVC settings at 33/11kV transformers. These were shifted from a target of 11.4kV ($\pm 200V$) to 11.3kV ($\pm 165V$), enabling the impact of reduced voltages on energy consumption, maximum demand, and voltage profiles on real monitored networks to be quantified.

SP ENW Smart Street - the project involves a range of technologies, including ground mounted distribution transformers fitted with on load tap changers (OLTCs); smart vacuum circuit breakers and controllable switching devices; and both LV and MV shunt capacitors. Together these are able to reduce variations in delivered voltage under various loading conditions.

NPg BEET - the Boston Spa Energy Efficiency Trail applies a technology that harnesses data from local smart meters associated with a network served by a given primary substation to optimise network voltages for that network by adjusting transformer output voltage at the primary substation at 30-minute intervals.

UKPN / NPg Phase Switch System - the Phase Switch System (PSS) is an innovative smart-grid technology being trialled by NPg and UKPN which allows for the dynamic rebalancing of residential and commercial loads across the three phases of a low-voltage feeder, so improving phase load balance, reducing neutral current (and hence losses) and consequently improving voltage regulation across the three phases, thereby increasing hosting capacity.

SSEN Voltmetric - the objective of the project is to explore combining and analysing data from smart meters and LV monitors with information from the HV and EHV networks and Distribution Future Energy Scenarios (DFES) to produce an index of voltage and power quality health, and how this could be used to inform the deployment of voltage and power quality management techniques and policies to improve strategic network investment.

Each of the above innovations have the potential, if rolled out at scale, to improve the voltage management of LV networks, helping maintain voltage within statutory and operational limits, and increasing the overall efficiency of LV distribution. Further information about these projects can be obtained from DNOs' web-based innovation portfolios.

Implementation

A range of opportunities for improved system-wide voltage management have been described in this report. In terms of implementation and system-wide rollout, considerations include:

- Technology readiness level - particularly those arising from innovation funded projects where hardware or software has yet to reach commercial readiness (TRL 8 or 9).
- The need for new standards, or amendments to existing standards, to enable specifications for equipment to be drawn up.
- Sufficient commercial backing / risk appetite by the supply chain to commit funding to further development and production.
- The possible need for financial support to bring a product to market (e.g. venture capitalist funding).
- Supply chain constraints where production has commenced but demand might exceed initial production capacity.
- Implementation risk management - including conducting a measured trial period under close scrutiny to identify potential functional failures (infant mortality).
- High initial costs pending economies of scale from increasing future volume sales.
- Overall cost-benefit and risk analysis as part of assessing the business case.

What is Possible and Realistic in the Short and Longer Term

With the above considerations in mind, the table below summarises the applications outlined in this report, along with their potential impact and implementation period over short and longer-term timescales. The implementation periods shown are indicative, reflecting a realistic timescale over which a given application might be deployed at scale, but recognising that the continuous evolution of the power system will determine the extent to which some of these applications become an established part of the developing system architecture and asset base.

For each application the table provides an outline of the function, the enabling conditions and limitations, and the time-period over which the application might be expected to be implemented. In terms of the business case for implementation, this will require justification through CBA (and/or risk mitigation) studies. In terms of scale of implementation, this will be driven by need (or anticipated need) and hence will depend on a number of factors, including the chosen SSEP pathway, and both the rate and ultimate level of penetration of DERs, CERs and LCTs.

Note that the implementation period timescales indicated in the table below are intended to be indicative of the industry's current capability. However, it may be that the chosen SSEP Pathway, and RESP projections of LCT take-up, will require targeted acceleration of these timescales, at least across some areas of Great Britain. We recommend that Ofgem keeps this under ongoing review and stands ready to accelerate industry action in good time if necessary.

Application	Function	Enabling Conditions / Limitations	Implementation Period
Lowering MV system voltage	Adjusting primary substation AVC set point to lower output voltage and hence reduce MV and LV system voltage.	Sufficient primary substation transformer tapping range.	<5 years
AVC compounding (primary substations)	Adjusting transformer tap position according to substation loading to constrain voltage rise on MV and LV networks when solar PV output is high.	Sufficient primary substation transformer tapping range to accommodate voltage bucking.	<5 years
Lowering DTF tap position	Permanently lowering transformer tap position where LV network voltage is persistently high.	High resource implication – practically limited to LV networks experiencing unusually high voltage levels despite upstream interventions.	<5 years
Reducing LV lower statutory limit	Facilitating LV system voltage reduction by providing a wider statutory voltage bandwidth.	Results of ENA voltage reduction trial. Consensus for implementation following ENA consultation. SoS approval of ESQCR amendment (possible requirement for formal impact assessment).	<5 years
SIF / NIA / IRM funded projects	Dependent on individual project scope.	Development and rollout cost. Supply chain constraints.	5 - 10 years
CLASS (primary substations)	Lowering transformer tap position to reduce demand. Switching out one transformer for frequency response. Tap-staggering for reactive power absorption.	Sufficient primary substation transformer tapping range for voltage reduction or tap staggering.	<5 years
PQ control of solar PV & V2G inverters	Regulating inverter output power and power factor to constrain network voltage rise, particularly on LV networks.	Voltage event ride-through capability in line with G98/99 overvoltage trip settings and 'no-trip' thresholds. Implementation of PQ control regime (either through mandate or as a commercial ancillary service).	5 - 10 years
DSO procurement of reactive power from DERs	Enhanced network power factor and voltage control.	Coordination between NESO and DSOs in terms of procurement and dispatch to avoid conflicts - governed by primacy rules.	5 - 10 years
D-STATCOMs	Enhanced network power factor and voltage control.	Coordination between NESO and DSOs regarding location.	5 - 10 years

Application	Function	Enabling Conditions / Limitations	Implementation Period
Smart meter data to optimise AVC set points	Use of smart meter voltage measurements as an input to primary transformer AVC to optimise set points.	Sufficient primary substation transformer tapping range. Smart meter rollout level of completion and data polling capability.	5 - 10 years
Enhanced transmission system monitoring and EMT modelling	Earlier detection and correction of abnormalities (such as sub-synchronous voltage oscillations). Enhanced assessment of system instability risk conditions.	Sufficient granularity in terms of PMUs, oscillographs, and power quality monitoring devices. Sufficient data communications and processing capability (see also Digitalisation and AI).	<5 years but subject to continuous development informed by observed experience
Enhanced visibility of DERs and 'behind the meter' generation	Improved identification of location and capacity. Improved visibility of export patterns and behaviour under system stress events.	Access to data, including location and capacity. Access to real-time / time-series data including time-stamped event logs. Sufficient data communications and processing capability (see also Digitalisation and AI).	<5 years but subject to continuous development
Digitalisation and AI	Facilitating the transition to a less deterministic, more algorithmic-based, power system control methodology. Enhanced decision-making capability for operational contingency planning and real-time interventions.	Integrated communications infrastructure with sufficient resilience, capacity, bandwidth, and latency properties.	5 - 10 years

Knowledge Gaps Requiring Further Work

Several important knowledge gaps must be addressed before long term policy decisions can be made. As set out in this report, there is already strong evidence that more active approaches to voltage management can deliver material benefits, and that a range of technical solutions is available. However, further work is required to support coordinated, system wide implementation and future regulatory reform.

There remains limited understanding of the long-term implications of sustained operation at the lower end of the statutory voltage range. Whilst studies have highlighted the potential benefits of operating closer to nominal voltage, there is insufficient evidence on the cumulative impact on appliance performance and lifespan from operating below the rated voltage for the appliance (including the proposed lower statutory LV voltage limit), particularly for motor driven equipment. European standards indicate that appliances should be able to operate at these levels, but manufacturers have not yet provided formal endorsement for prolonged operation at a consistently lower range.

Whilst there is a known current lack of visibility within both NESO and across DSOs regarding network connectivity of DERs and CERs, **the need to address this knowledge gap will become increasingly critical to system stability and security as customer energy resources increase in scale and become more commoditised** (for example plug-in solar panels and home V2G chargers) potentially leading to an earlier than anticipated emergence of localised tipping points.

There is also **a lack of comprehensive assessment of the system wide implications of coordinated voltage adjustment across voltage levels.** In particular, the consequences of transformers reaching the limit of their tapping range are yet to be experienced. Where this occurs, adjustments may need to be made at higher voltage levels, but the impacts of such actions across both distribution and transmission systems have not yet been fully modelled. This requires detailed scenario analysis using whole system modelling approaches.

The coordination of real time or near real time control across large numbers of distributed assets presents a further area of uncertainty. **The methodologies required to coordinate assets at scale, whilst ensuring stable and predictable system behaviour, remain underdeveloped.** This includes the management of interactions between different control schemes and the avoidance of unintended system-wide effects.

Although there is strong evidence from trials and studies demonstrating the benefits of voltage optimisation, **a comprehensive cost-benefit assessment at a whole system level is still required.** Technologies such as low voltage monitoring, enhanced data integration, and advanced transformer capability can increase network capacity, improve resilience, and reduce peak demand. However, further work is needed to quantify the full value of these benefits, including avoided network reinforcement, operational savings, and the implications for cost recovery within the existing regulatory framework.

There is also a gap in the effective utilisation of data from grid edge technologies. Smart meters, electric vehicle chargers, and distributed generation assets already provide large volumes of voltage data and, in some cases, control capability. However, this information is currently neither sufficiently visible nor consistently integrated into network operation or planning processes. The challenge therefore lies partly in improving visibility, access, and standardisation of existing available data, and partly in the need for availability of more granular (including real-time and time-series) data to reveal operational behaviour, including under system stress conditions.

Customer engagement remains an area where further effort is required. Whilst there has been strong adoption of low carbon technologies, the willingness of customers to participate in flexibility arrangements specifically for voltage management purposes is not well understood, especially under weather-related system stress events when flexibility might be most valuable, but potentially less forthcoming. Further work is needed to assess customer preferences, appropriate incentives, and the potential impact on customer trust and experience. **There is a need to develop flexibility markets and/or provision of ancillary service opportunities that customers will engage with, maintain their commitment to, and feel adequately rewarded for participating in.**

Finally, although there is widespread operational experience of solar inverter disconnection and other voltage related impacts, **there is no comprehensive set of publicly available data quantifying the scale or frequency of these events** or the extent to which this is happening due to inverters tripping at voltages below ‘no trip’ test thresholds. This limits the ability to assess the impact on renewable generation, network performance, and customer outcomes, and therefore constrains robust policy development.

Governance and Technical Coordination

The governance arrangements that underpin the electricity system and the technical requirements of effective voltage management tend to be discussed in separate domains. **There is limited integration between the processes that define responsibilities, standards, and data exchange**, and those that determine how the network is planned and operated in practice. This separation is increasingly at odds with the needs of a more complex and decentralised system.

From a technical perspective, voltage management is inherently an operational and system control challenge, requiring detailed understanding of network behaviour, asset capability, and real time conditions. However, **the effectiveness of these technical solutions is dependent on governance frameworks that enable coordination across organisations, provide access to relevant data, and define clear roles and accountabilities.** At present, these enabling conditions are not consistently in place, limiting the ability to deploy technically viable solutions at scale.

This disconnect is particularly evident in the relationship between distribution and transmission level actors. NESO does not yet have sufficient visibility of conditions and actions

within distribution networks, despite their growing importance to overall system stability and performance. **The absence of structured mechanisms for information exchange and coordinated decision making creates a gap between system level oversight and local operational reality.**

Code governance, including both evolution of existing Grid and Distribution Codes and the development of new codes will be critical to coordination and integration, as will the development and governance of Engineering Recommendations and Technical Standards. **However, existing governance arrangements have neither the agility to adapt sufficiently quickly to the technical challenges presented by the rapidly evolving characteristics of the electricity system, nor the scope to ensure adoption and compliance.**

There are also challenges in aligning the different communities involved in governance and technical delivery. These groups operate with distinct priorities, expertise, and perspectives, which can lead to fragmentation in how problems are defined and addressed. While technical specialists focus on immediate and practical solutions, governance discussions often remain at a higher level, addressing broader questions of institutional design and regulatory structure. **Without effective integration, there is a risk that governance reforms will not reflect operational constraints, and that potential technical solutions will not be supported** by the frameworks required for implementation.

Addressing this issue will require a more coordinated approach in which governance and technical considerations are developed alongside one another. This includes strengthening data visibility across organisational boundaries, clarifying responsibilities for voltage management at different levels of the system, and establishing processes that enable structured engagement between policy, regulatory, and operational stakeholders. **A more integrated framework will be essential to ensure that voltage management can be delivered efficiently, consistently, and at the scale required to support the transition to a Net Zero electricity system.**