Strategic Connections – Electricity Storage Connections

Guidance Note for DNOs

Tactical Solution 1:
Network access rights for new electricity storage customers

Tactical Solution 2:
Guidance on EREC P2/8 security of supply assessments for distribution networks with electricity storage

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1. Document introduction and scope

This guidance note sets out two common approaches relating to electricity storage:

1. The network access rights that DNOs should provide to new electricity storage customers when designing their connection to the distribution network. This applies to connection applications and applications to modify existing connections received on or after 30 September 2023, and where the connection that would be required to connect that electricity storage customer exceeds a size threshold. Section 4 explains the detail and how this is to be implemented.
2. How DNOs should treat electricity storage when undertaking EREC P2/8 security of supply assessments on or after 30 September 2023. Section 5 explains the detail and how to implement this, with worked examples in Appendices A and B.

The purpose of this document is to explain to DNOs how to implement these common approaches and to help ensure a consistent implementation across DNOs. These two common approaches were developed by an Energy Networks Association (ENA) industry working group[1] in which all DNOs were represented, and are supported by Ofgem[2].

Section 6 is a glossary, to aid understanding of the abbreviations and key terms used within this guidance note.

Whilst this guidance note is primarily intended for DNOs, it may be of interest to other industry stakeholders (such as the National Grid Electricity System Operator (NGESO), Transmission Owners, and electricity storage customers seeking a connection to the distribution network). Given this, and the desire for transparency in how DNOs plan and operate their networks, this document is freely available to any party.

2. Context for introducing these common approaches

The volume of connected and contracted electricity storage on the distribution network has grown significantly. By June 2023 the combined capacity of all contracted distribution electricity storage installations had grown to 53GW, with over half of this signed in the last regulatory year. To provide context to this volume, this is close to the total GB electricity peak demand (~60GW) and over seven times the highest forecast for distribution electricity storage at 2030 in the latest NGESO GB Future Energy Scenarios (FES). This volume continues to increase.

The outcome is that, in many areas, there is little spare network capacity for demand and generation growth or the societal decarbonisation that is essential to achieving legislated Net Zero targets – this volume of larger-scale electricity storage is adversely impacting GB customers.

The ENA's Strategic Connections Group (SCG) convened three workgroups to investigate solutions to this challenge. One of these, the Battery Storage Connections (BSC) workgroup, was tasked with reviewing the connection arrangements for electricity storage customers.

The BSC workgroup started by focussing on changes that could be implemented quickly by working within existing code and licence requirements. Based on this, four 'Tactical Solutions' were proposed to Ofgem on 12 May 2023[3]. These aim to manage electricity storage connections to help prevent the

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[1] The ENA's Battery Storage Connections (BSC) workgroup reports to the ENA's Strategic Connections Group (SCG).
[2] Ofgem's letter of support, dated 15 August 2023, is available at: https://www.ofgem.gov.uk/sites/default/files/2023-08/ENA%20SCG%20Electricity%20Storage%20Solutions%20-%20Ofgem%20Letter.pdf
[3] https://www.ofgem.gov.uk/sites/default/files/2023-08/ENA%20SCG%20Electricity%20Storage%20Solutions%20-%20ENA%20Letter%20and%20Supporting%20Information.pdf

situation deteriorating further and the triggering of unnecessary reinforcement. Ofgem provided a letter of support for Tactical Solutions 1, 2 and 3 on 15 August 2023 (see footnote 2).

Having gained Ofgem's support, these changes now need to be implemented. This guidance note covers the implementation of Tactical Solutions 1 and 2. These are:

- **Tactical Solution 1:** DNOs shall adopt a common interpretation of the network access rights that new electricity storage customers will receive under their Minimum Scheme. These are defined in Section 4.3.1. These network access rights are lower than those that some DNOs currently provide to electricity storage customers. This Tactical Solution reduces the risk of having to create additional network capacity that is likely to be very lightly utilised[4] and, combined with Tactical Solution 2, it enables better use of existing network capacity (meaning GB customers can connect more quickly and at lower cost). Overall network investment is expected to be more efficient. Electricity storage customers will still be able to choose a connection with lower network access rights, such as a Curtailable Connection as introduced by Access SCR.
- **Tactical Solution 2:** DNOs shall adopt a common approach to treating electricity storage when undertaking EREC P2/8 compliance assessments. This includes use of diversity factors and the demand side response (DSR) provision. These help to release some of the existing contracted but underutilised capacity for use by other customers and help DNOs to only build new capacity if it's needed – both these are in GB customers' interests.

The ENA recognises the capability of electricity storage to support customer supplies, provide energy security, and help facilitate the transition to Net Zero. The common approaches set out in this document are designed to help DNOs better reflect the operational profiles of electricity storage installations when planning and developing electricity storage connections and their distribution networks.

For more information on the context, the Tactical Solutions, and their justification, please refer to the ENA letter to Ofgem, dated 12 May 2023 (see footnote 3). A separate document covers the implementation of Tactical Solution 3.

3. Document governance

This guidance note does not supersede or override the requirements of any legislation, licence, or Core Industry Document. This guidance note is expected to be superseded by code change in due course; it will be withdrawn when appropriate. In addition:

- In relation to Tactical Solution 1: while this guidance note is not subject to code governance, Tactical Solution 1 has Ofgem's support. As such this guidance note is considered to be an "accepted industry standard" for the purpose of determining a Minimum Scheme in accordance with DCUSA Schedule 22 (CCCM) paragraph 1.1.
- In relation to Tactical Solution 2: while this guidance note is not subject to code governance, Tactical Solution 2 has Ofgem's support. As such this guidance note is considered to be an accepted explanatory note for the interpretation of EREC P2/8 and EREP 130/4.

[4] Analysis of electricity storage installations shows their average utilisation is just 4.6%, and ~80% of their contracted capacity sits idle for ~95% of the time.

4. Tactical Solution 1 – common network access rights for new electricity storage connections

This section explains the standard network access rights DNOs should apply to new electricity storage customers seeking a connection to their network.

4.1. Introduction to Tactical Solution 1

When a customer applies for a connection, the DNO must identify the Minimum Scheme to connect them to the network. The Minimum Scheme is defined in DCUSA[5], and is the is the default connection scheme provided in the absence of other requirements to connect the customer's required capacity.

The Minimum Scheme for a customer is dependent on the network access rights provided to the customer – the 'firmer' their network access rights, then the greater the security of supply, and so cost, of the network solution to connect the customer.

Despite this link to network access rights, and although a typical interpretation of the Minimum Scheme for an electricity storage connection means that the customer may be subject to some level of curtailment/interruption, neither DCUSA nor any subordinate documents set network access rights for such connections. Industry and Ofgem have traditionally used the terms 'firm' and 'non-firm' to describe network access rights. There is no single common definition as to what these terms mean. As a result of this and the desire to accommodate individual customer requirements, a range of interpretations and network access right arrangements have naturally arisen. In some cases, DNOs have reasonably based their interpretation on the EREC P2 planning standard. This has resulted in individual electricity storage customers being granted a very high level of 'firmness' that was originally developed and economically justified for groups of customers (e.g. whole towns), for whom the value of supply security is much greater than for electricity storage customers.

Continuing this approach risks providing inappropriately high network access rights to some electricity storage customers. This would adversely impact GB customers in four ways:

- Electricity storage customers will not get common treatment across DNOs.
- Higher levels of network access rights typically require greater levels of network investment, much of which is socialised across all customers (especially post-Access SCR) – i.e. customer bills will be higher.
- Delivering this increased network investment will divert valuable DNO and supply chain resource away from delivering the interventions customers need to enable Net Zero.
- Higher levels of network access rights are a barrier to higher network utilisation, as it reduces the DNO's ability to better share any underutilised network capacity reserved for electricity storage with other customers.

Continuing the current approach is not in customers' best interests. Therefore, under Tactical Solution 1, DNOs will adopt a common interpretation of the network access rights that new electricity storage customers will receive under Minimum Scheme. These are explained in Section 4.3.1.

Tactical Solution 1 means the network investment required to accommodate electricity storage installations is expected to be reduced. This in turn reduces the risk of having to create additional capacity which is very lightly utilised, and may enable electricity storage installations to connect more quickly. Tactical Solution 1, when combined with Tactical Solution 2, also enables better use of existing network capacity (meaning GB customers can decarbonise more quickly and at lower cost). In summary, customer-funded network investment is excepted to be more efficient.

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[5] Paragraph 1.1 of Schedule 22D of DCUSA V15.1, available at: https://www.dcusa.co.uk/dcusa-document/

4.2. Scope of application of Tactical Solution 1

This guidance note applies to all connection applications and applications to modify existing connections for premises where:

1. the application is received on or after 30 September 2023;
2. the primary purpose of the import capacity of the premises is wholly or mainly electricity storage; and
3. the customer is not:
    a. a domestic or non-domestic customer that is billed on an aggregated and non-site-specific basis or who is metered directly using a whole current meter[6]; or
    b. an Unmetered Supply customer.

This guidance note does not change the process by which a customer makes such an application. For applications within the scope of this guidance note, references to the firm and non-firm import/export requirements in Note 2 on page 16 of the ENA's *Connection of Power Generation Modules to DNOs Distribution Network in accordance with EREC G99* application form[7] are effectively superseded by the network access rights set out in this guidance document.

4.3. Implementation of Tactical Solution 1

4.3.1. Minimum Scheme network access rights

The Minimum Scheme shall be determined on the basis that the import to and export from the electricity storage customer's premises:

1. should not ordinarily be curtailed or interrupted when the relevant parts of the distribution network are intact; but
2. may be curtailed or interrupted when any of the relevant parts of distribution network are not intact (including but not limited to First Circuit Outages and Second Circuit Outages).

The electricity storage customer's connection offer and connection agreement shall include terms which explicitly permit unlimited, uncompensated curtailment/interruption when the relevant parts of the distribution network are not intact. These terms shall be included even if the distribution network has sufficient capacity to permit higher network access rights at the time of application. This is necessary to maintain the DNO's right to curtail/interrupt the import and/or export at any time in the future.

The DNO should use reasonable endeavours to minimise the amount of curtailment/interruption, even where it is permitted by the connection agreement.

4.3.2. Lower network access rights at customer request

These arrangements do not affect a customer's ability to request a connection with lower network access rights than those provided by Tactical Solution 1, either on an interim or enduring basis, or the customer's eligibility for a Curtailable Connection[8]. These may include curtailment/interruption when the distribution network is intact.

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[6] This means that Technical Solution 1 is not applicable for most domestic customers, or those small industrial and commercial customers with supplies of a similar size to domestic customers.
[7] Available from https://www.energynetworks.org/operating-the-networks/connecting-to-the-networks/connecting-generation-to-the-electricity-networks; commonly referred to as the Standard Application Form.
[8] As set out in DCUSA Schedule 2D.

5. Tactical Solution 2 – guidance on EREC P2/8 security of supply assessments for networks with electricity storage

This section explains the approach DNOs should take when undertaking EREC P2/8 compliance assessments for distribution networks with electricity storage:

- For controllable[9] electricity storage connections, see Section 5.2 and Appendix A.
- For non-controllable[10] electricity storage connections, see Section 5.3 and Appendix B.

The BSC workgroup has submitted an EREC P2 change modification proposal to the Distribution Code Review Panel (DCRP) to codify the treatment of electricity storage; this is explained in Section 5.4.

5.1. Introduction to Tactical Solution 2

EREC P2 is the distribution planning standard that determines the capacity and security of supply of the distribution network to secure demand[11] during planned and unplanned outage conditions[12]. DNOs are mandated to comply with EREC P2 as a licence obligation and by the Distribution Code. The current issue is EREC P2/8.

Core to EREC P2/8 is the concept of Group Demand, which is "the maximum demand of the group being assessed for EREC P2 compliance". Broadly speaking, the larger a Group Demand, then the greater the network security required by EREC P2/8 and so the greater the extent of the network assets and hence network investment needed to maintain compliance.

Given that this investment is recovered from consumers and given the need for DNOs to be efficient and economical, it's important that Group Demand is secured as cost effectively as possible by a combination of network assets and contracted security contribution from customers' assets. EREC P2/8 enables this in two ways:

1. It incorporates the contracted security contribution from demand side response (DSR) customers; this is any demand that would be disconnected during an outage. The effect is that this DSR demand does not need to be secured during an outage, and so does not generally trigger additional infrastructure/investment to secure it. The rationale is that demand covered by a DSR contract will be disconnected or managed during outage conditions, and therefore doesn't need to be secured by network assets.
2. It allows the use of diversity factors[13]. DNOs design their networks considering an appropriate level of diversity as it results in more efficient investment – networks are designed to secure the likely (diversified) Group Demand rather than the higher theoretical maximum Group Demand which is unlikely to occur. Designing the distribution network using diversity avoids unnecessary expenditure.

These two provisions enable DNOs to secure the underlying general customer demand of the network that will be present during an outage, rather than the theoretical maximum demand. These provisions therefore help avoid unnecessary investment and enable more efficient network planning; these are in

[9] By controllable, this means an electricity storage customer that has a commercial agreement and the technical ability to receive and respond to curtailment/interruption instructions.
[10] By non-controllable, this means any electricity storage customer that does not meet the definition of being controllable (footnote 9).
[11] EREC P2/8 only covers network demand (i.e. import) security of supply, it doesn't cover generation (i.e. export) security of supply.
[12] EREC P2 categorises these outage conditions as First Circuit Outage (FCO) and Second Circuit Outage (SCO).
[13] Diversity reflects that the total peak demand from a group of customers is less than the sum of the individual customer peak demands. This is because customers naturally use electricity at different times to each other, so their individual peak demands don't all occur at the same time.

customers' interests. This is especially relevant for electricity storage as analysis shows their average utilisation is just 4.6%, and ~80% of their contracted capacity sits idle for ~95% of the time, i.e. their demand at any point in time is likely to be much lower than their contracted capacity.

The application of the same network access rights for electricity storage customers as general demand and limited data about electricity storage operational behaviour have limited DNOs' application of these two provisions to electricity storage import to-date. However continuing this conservative approach means DNOs would have to reinforce the network more than if appropriate levels of diversity were to be assumed, and it limits how much of the existing underutilised network capacity allocated for electricity storage customers can be 'released' for the benefit of other customers – it is a barrier to higher network utilisation. This would increase the likelihood and duration of delays for new customers seeking to connect, and increase the network costs recovered through all customers' bills.

Tactical Solution 2 is for DNOs to apply the DSR provision (and cost benefit analysis (CBA) provision) and diversity factors when undertaking an EREC P2/8 compliance assessment on a network with electricity storage. The DSR provision shall be applied to controllable electricity storage (Section 5.2) and diversity factors shall be applied to non-controllable electricity storage (Section 5.3).

Tactical Solution 2 benefits customers generally as it enables better use of existing network capacity by other customers (meaning customers can decarbonise more quickly and at lower cost), and is expected to reduce the overall amount of new network investment required across GB to accommodate electricity storage installations (it reduces the risk of having to create additional capacity which is very lightly utilised).

5.2. How to treat controllable electricity storage import in EREC P2/8 assessments

When undertaking EREC P2/8 compliance assessments, DNOs should treat new and existing controllable electricity storage customers as having a Demand Side Response (DSR) scheme, to the extent permitted by the electricity storage customer's network access rights.[14] This approach covers a range of controllable customers including:

- New and existing electricity storage customers who have network access rights in line with Tactical Solution 1 (i.e. can be curtailed/interrupted in FCO and SCO conditions).
- New and existing electricity storage customers who have lower network access rights than those set out in Tactical Solution 1 (for example, can be curtailed/interrupted in intact, FCO, and SCO conditions).
- Existing electricity storage customers who have higher network access rights than those set out in Tactical Solution 1. For example, where a customer can't be curtailed/interrupted in intact or FCO conditions but can be curtailed/interrupted in SCO conditions, the DSR provision can only be applied when assessing EREC P2/8 compliance under SCO conditions.

In summary, this approach applies to all controllable electricity storage customers whose network access rights allow them to be curtailed/interrupted in FCO/SCO conditions. This approach considers the controllable element of such electricity storage import capacity as demand being supplied during outage conditions (i.e. it is deducted from the minimum demand that EREC P2/8 requires to be secured by network assets).

[14] i.e. an electricity storage customer whose network access rights mean their import capacity can be curtailed/interrupted in intact and/or FCO conditions can be treated as DSR in FCO and SCO conditions for the purpose of EREC P2 compliance; an electricity storage customer whose network access rights mean their import capacity can't be curtailed/interrupted in FCO conditions but can be curtailed/interrupted in SCO conditions can only be treated as DSR in SCO conditions for the purpose of EREC P2 compliance.

1. For example, considering electricity storage import with the network access rights described in Tactical Solution 1:
   i) Under network intact conditions, the electricity storage customer can expect to have unrestricted import capacity up to their agreed import capacity;
   ii) under **FCO** and **SCO** conditions, the electricity storage customer can expect to have their import capacity curtailed/interrupted.[15]
2. A control system is expected to be in place to curtail/interrupt the electricity storage import to maintain the network within the **FCO** (and where applicable **SCO**) capacity of the network.
3. EREP 130/4 Clause 5.1 applies whereby the electricity storage control system is considered to be a **DSR Scheme.**
4. The footnote to Table 1 of EREC P2/8 applies whereby activation of the **DSR Scheme** is equivalent to restoration of this demand.
5. In many cases, considering the operation of a **DSR Scheme** to be equivalent to demand being supplied will be sufficient to maintain compliance with EREC P2/8.
6. There are cases where the electricity storage import promotes a demand group to a higher Class of Supply and the increased requirements of Table 1 of EREC P2/8 may not be fully met by the associated DSR scheme. For these cases, EREP 130/4 Section 12 permits the use of Cost-Benefit Analysis (CBA) to justify divergence from the requirements of Table 1 of EREC P2/8, when to maintain compliance with Table 1 of EREC P2/8 would be uneconomical. Example 4 in Appendix A provides a CBA involving promotion from Class of Supply 'D' to 'E' demonstrating that network reinforcement to accommodate electricity storage import would not be economical.

One potential impact of using the DSR provision is that the import of an electricity storage customer is added to Group Demand. In some cases the addition of this import may move a Group Demand from one class of supply up to the next, or increase the restoration requirements within the same class of supply. The BSC workgroup considered each such potential 'tipping point' scenario – these are listed in Table 1, and Appendix A provides worked examples of the application of EREC P2/8 and EREP 130/4 for four off them (the others are outside the scope of this guidance document, for reasons explained in Table 1 below).

Tipping point within EREC P2/8	Outcome
Transition from Class of Supply A to B	While it is possible to apply Tactical Solution 2 to such situations, this guidance note does not provide a worked example for this scenario as it was considered to have limited application.
Transition from Class of Supply B to C	Restoration of **DSR** demand is expected to be sufficient to maintain compliance with EREC P2/8 – see Section 7.2.
Transition from Class of Supply C to D	Restoration of **DSR** demand is expected to be sufficient to maintain compliance with EREC P2/8 – see Section 7.3.
Movement within Class of Supply D to greater than 100MW	Restoration of **DSR** demand is expected to be sufficient to maintain compliance with EREC P2/8 – see Section 7.4.

[15] The customer could also expect to have their export capacity curtailed/interrupted during FCO and SCO conditions, but that is not relevant to this example as EREC P2/8 only concerns securing demand/import.

Transition from Class of Supply D to E	The increased requirements of Table 1 of EREC P2/8 may not be fully met by the restoration of **DSR** demand. A CBA in line with EREP 130/4 Section 12 can be used to demonstrate that reinforcement to accommodate storage import would not be economical and that compliance with EREC P2/8 is declared on that basis – see Sections 7.5 and 7.6.
Transition from Class of Supply E to F	Outside scope of this guidance – assessed in accordance with the relevant Transmission Owner's security standard.

Table 1: EREC P2/8 compliance worked examples in Appendix A

Table 1 shows a scenario where the inclusion of electricity storage import in the Group Demand causes the Group Demand to increase from class of supply D to E, which will require a CBA to demonstrate compliance with EREC P2/8. Section 7.6 in Appendix A provides a worked example and more information on how to undertake such a CBA. **However, whilst this CBA is an illustrative example, the principle in EREC P2/8 is that reinforcement to secure general demand customers is implicit within the economic analysis underpinning EREC P2/8. As such, reinforcement to accommodate fungible electricity storage demand alone would unlikely to ever be economical, particularly as the electricity storage import is likely to be curtailed/interrupted via the contracted DSR arrangements**. It is this general CBA principle that is recommended to be applied where the EREC P2/8 analysis identifies that network reinforcement is required to ensure compliance after an electricity storage installation is connected to the distribution network.

5.3. How to treat non-controllable electricity storage import in EREC P2/8 assessments

The approach in Section 5.2 should not be used for non-controllable electricity storage as there is no facility available to curtail/interrupt its import during network outage conditions. Instead, DNOs should use the diversity principles detailed in this section when undertaking EREC P2/8 assessments. These are based on historical utilisation data pooled by all DNOs.

EREC P2/8 allows DNOs to take demand diversity into account, and DNOs already apply diversity to other types of demand customer. This approach does not change the network access rights of electricity storage customers. It means DNOs don't have to build as much network capacity to accommodate electricity storage import to remain compliant with EREC P2/8. This is because the group demand takes account of diversity assumptions (based on historical electricity storage operational data) rather than allocating the full import capacity of the electricity storage connection.

Whilst the network may be compliant with EREC P2/8, this approach may increase the risk of network assets becoming overloaded if the historical diversity assumptions prove to be unreflective of current or future electricity storage operation. In applying this methodology, the DNO is encouraged to consider the network risk, operational consequences, and potential need for mitigating measures that might arise if the assumptions prove inappropriate.

Where non-controllable electricity storage is already connected and fully operational, the measured Group Demand will already reflect the historical operation of the electricity storage installation. If sufficient operational data has been collected, then it would be appropriate to supersede the generic diversity assumptions proposed below with individual installation-specific operational behaviour. Where the operation of an already connected electricity storage installation has demonstrated unpredictable operational behaviour or is reasonably expected to alter, or where insufficient data has been collected, the DNO may choose to continue to reflect the diversity assumptions proposed below.

5.3.1. How these diversity principles were developed

DNOs have collated historical import/export data for existing operational larger-scale electricity storage installations. This has enabled a more representative statistical assessment of the contribution that electricity storage installations make to Group Demand than would be possible for any individual DNO. The assessments considered the half-hourly historical import and export data from 19 electricity storage connections with a total installed capacity of 627MW along with the associated demand in the demand group for each half-hour.

This data was used to quantify the impact of electricity storage import on peak demand by considering the Group Demand both with and without the electricity storage to establish a relationship between the maximum import capacity of the electricity storage and any associated increase in Group Demand due to its operation. This analysis found that the contribution to Group Demand scales with the maximum import capacity of the electricity storage installation relative to Group Demand. This is because larger electricity storage installations have greater propensity to create new times of peak demand.

To avoid underestimating the likely import contribution at the time of peak demand, an approach was selected that is at least as stringent as the largest contribution for an electricity storage installation of that scale observed in the data assessed. This approach is more conservative than the calculation of security contributions from distributed generation (F-factors) under EREP 130/4. Further to this, a margin of error was built into the relationship to account for some of the uncertainty in the future operational behaviour of electricity storage installations.

5.3.2. The diversity principles to be used by DNOs

For the purposes of EREC P2/8 assessments, DNOs should use the following equation to calculate an expected diversity factor to be applied to <u>non-controllable</u> electricity storage to estimate how its import will diversify with the demand within the demand group:

$$DF_{ES} = min\left(0.75\frac{ES_{import}}{GD_{withoutES}} + 0.25\,,\ \ 1.0\right)$$

Where:

DF_{ES} = Diversity Factor to be applied to the aggregate Maximum Import Capacity of non-controllable electricity storage

Note, DF_{ES} is capped at 1.0 (full contribution) for scenarios where $ES_{import} > GD_{withoutES}$

ES_{import} = Aggregate Maximum Import Capacity of all non-controllable electricity storage in the demand group (MW)

$GD_{withoutES}$ = Group Demand excluding import/export flows from the non-controllable electricity storage (MW)

These assessments, including a worked example, are described in more detail in Appendix B.

5.4. Future work – EREC P2/8 change modification proposal

The approaches in Sections 5.2 and 5.3 are permitted by EREC P2/8 and EREP 130/4. Triggered by the work undertaken by the BSC workgroup, the DCRP are currently taking forward an EREC P2 modification to codify the treatment of electricity storage. It is expected that this proposed modification work will run through 2023 into 2024.

6. Glossary

Term	Description
Access SCR	Access and Forward Looking Charges Significant Code Review; a package of reforms changing how some distribution customers access and pay to connect to the distribution network.[16]
BSC workgroup	Battery Storage Connections workgroup; the ENA workgroup responsible for developing the two Tactical Solutions which are the subject of this document.
CBA	Cost benefit analysis
CCCM	Common Connection Charging Methodology (Schedule 22 of DCUSA); the methodology used to set charges for connection to distribution networks in GB.
Core Industry Document	Is defined in the standard conditions of the Electricity Distribution Licence as: "*means any and all of the following:* *(a) the Balancing and Settlement Code,* *(b) the Connection and Use of System Code,* *(c) the Distribution Code,* *(d) the Distribution Connection and Use of System Agreement,* *(e) the Grid Code,* *(f) (Not used),* *(g) the Revenue Protection Code,* *(h) the System Operator Transmission Owner Code,* *(i) the Retail Energy Code, and* *(i) any other document designated by the Authority for the purposes of this condition following consultation with the licensee.*"
Curtail / curtailment	Defined in DCUSA as: "*means any action taken by the Company to restrict the flow of electricity at the Connection Point, except where that restriction is caused by: (a) an Interruption to the Customer's supply; and/or (b) curtailment as a result of constraints on the transmission network.*"
DCUSA	Distribution Connection and Use of System Agreement; a multi-party contract covering the use of electricity distribution networks in GB.
DNO	Distribution Network Operator; a company that owns, operates, and maintains the GB electricity distribution network. There are 14 licensed DNOs in GB, and each is responsible for a regional distribution services area.
DSR	Demand Side Response; is defined in EREC P2/8 as: "*demand that is controlled in response to an instruction issued as part of an agreed demand side management arrangement with the* ***DNO*** *or other party*".
Electricity storage	Defined in DCUSA as: "*the conversion of electrical energy into a form of energy which can be stored, the storing of that energy, and the subsequent reconversion of that energy back into electrical energy.*"
ENA	Energy Networks Association; the industry trade association for electricity and gas network companies.

[16] More information available at: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-decision-and-direction

EREC P2/8	Engineering Recommendation P2 Issue 8, "Security of Supply"; the primary distribution planning standard that determines the capacity and security of supply of the distribution network to secure demand.
EREP 130/4	Engineering Report 130 Issue 4, "Guidance on the application of Engineering Recommendation P2, Security of Supply"; a guidance document which supports the implementation of EREC P2.
(NG)ESO	(National Grid) Electricity System Operator
FES	Future Energy Scenarios; forecast scenarios produced by NGESO showing how GB demand and generation metrics may change out to 2050.
FCO	First Circuit Outage; defined in EREC P2/8 as: "*a fault or a pre-arranged **Circuit** outage*".
GB	Great Britain
GW	Gigawatt; a unit of power.
Interruption	Defined in the RIIO-ED2 Regulatory Instructions and Guidance (RIGS) glossary as: "*The loss of supply of electricity to one or more customers due to an incident. This excludes voltage quality and frequency abnormalities, such as dips, spikes or harmonics.* *Where a customer (or customers) reports "low volts" then this should not be treated as a loss of supply, until the DNO confirms that the customer(s) is off supply. Equally, where a report of "reverse polarity" is received by the DNO, the customer(s) should be considered "on supply" until the DNO confirms that the customer(s) is off supply, or needs to be disconnected in order to carry out repairs to the DNO's network."* For the avoidance of doubt, this document's use of this term includes interruptions of any duration, for example both those shorter and longer than three minutes.
Minimum Scheme	As defined in paragraphs 1.1 to 1.7 of Schedule 22 of DCUSA.
MW	Megawatt; a unit of power.
Network access rights	Described in Ofgem's Access SCR Final Decision document as: "*Network access rights define the nature of users' access to the network and the capacity they can use. This includes how much they are able to import or export; when they can access the network and for how long; and whether their access is curtailable and what happens if it is. Network access requires a connection from the user's equipment to the wider network, and capacity availability on the wider network. For most users, the level and terms of their network access is defined via their connection agreement.*"
SCG	Strategic Connections Group; the main ENA workgroup/forum for network companies, DESNZ, and Ofgem to discuss connection issues pertaining to the GB electricity network.
SCO	Second Circuit Outage; defined in EREC P2/8 as: "*a fault following a pre-arranged **Circuit** outage*".
TO	Transmission Owner; a company that owns and maintains the GB electricity transmission network. There are 3 licensed onshore TOs in GB, and each is responsible for a regional transmission area.

7. Appendix A - Application of EREC P2/8 and EREP 130/4 to controllable electricity storage connections

This appendix provides worked examples to support Section 5.2. These worked examples show the approach DNOs should take when assessing networks containing controllable electricity storage against the minimum security of supply requirements set out in EREC P2/8.

It is intended that this appendix is read in conjunction with EREC P2/8 and EREP 130/4. The terminology and terms defined within EREC P2/8 and EREP 130/4 have been used in these examples and are **bolded**.

7.1. Summary of approach for controllable electricity storage and worked examples

When undertaking EREC P2/8 compliance assessments, DNOs should treat controllable electricity storage customers as having a Demand Side Response (**DSR**) scheme, to the extent permitted by the electricity storage customer's network access rights.[17] By controllable, we mean that the electricity storage installation has control arrangements so that it's import is curtailed/interrupted in relevant **FCO** and/or **SCO** conditions; in the context of EREC P2/8 this is equivalent to having a **Contracted DSR Scheme** with the **DNO** (as it forms part of the connection agreement).

One potential impact of using the DSR provision is that the import of an electricity storage customer is added to Group Demand. In some cases the inclusion of this electricity storage import may move a **Group Demand** from one class of supply up to the next, or increase the restoration requirements within the same class of supply – we call these 'tipping points'. This appendix provides worked examples (summarised in Table 2; detailed in Sections 7.2 to 7.5 of the application of EREC P2/8 and EREP 130/4 across the key tipping points within the minimum requirements of Table 1 of EREC P2/8 (replicated as Table *3* below). This appendix does not provide worked examples considering where a tipping point is not triggered as the minimum requirements under EREC P2/8 do not change significantly, however the process and the principles are the same: electricity storage import is treated as **DSR** as shown in the worked examples.

The key finding from the worked examples (summarised in Table 2) is that existing provisions within EREC P2/8 and EREP 130/4 are adequate to enable the implementation of Tactical Solution 2, i.e. the operation of controllable electricity storage can be accounted using the existing **DSR** provisions within EREC P2/8. This approach is generally sufficient to avoid triggering unnecessary reinforcements/investment for EREC P2/8 compliance purposes. A minority of cases are possible where the electricity storage import promotes a demand group to a higher Class of Supply, and the increased requirements of Table 1 of EREC P2/8 may not be fully met by the associated **DSR** scheme. One such scenario is where electricity storage means that a Class of Supply D demand group becomes a Class of Supply E demand group; in this instance a CBA may be required to justify this approach (see Section 7.6).

Tipping point within EREC P2/8	Outcome
Transition from Class of Supply A to B	While it is possible to apply Tactical Solution 2 to such situations, this guidance note does not provide a worked example for this scenario as it was considered to have limited application.

[17] i.e. an electricity storage customer whose network access rights mean their import capacity can be curtailed/interrupted in intact and/or **FCO** conditions can be treated as **DSR** in **FCO** and **SCO** conditions for the purpose of EREC P2 compliance; an electricity storage customer whose network access rights mean their import capacity can't be curtailed/interrupted in **FCO** conditions but can be curtailed/interrupted in **SCO** conditions can only be treated as **DSR** in **SCO** conditions for the purpose of EREC P2 compliance.

Transition from Class of Supply B to C	Restoration of **DSR** demand is expected to be sufficient to maintain compliance with EREC P2/8 – see Section 7.2.
Transition from Class of Supply C to D	Restoration of **DSR** demand is expected to be sufficient to maintain compliance with EREC P2/8 – see Section 7.3.
Movement within Class of Supply D to greater than 100MW	Restoration of **DSR** demand is expected to be sufficient to maintain compliance with EREC P2/8 – see Section 7.4.
Transition from Class of Supply D to E	The increased requirements of Table 1 of EREC P2/8 may not be fully met by the restoration of **DSR** demand. A CBA in line with EREP 130/4 Section 12 can be used to demonstrate that reinforcement to accommodate electricity storage import would not be economical and that compliance with EREC P2/8 is declared on that basis – see Sections 7.5 and 7.6.
Transition from Class of Supply E to F	Outside scope of this guidance – assessed in accordance with the relevant Transmission Owner's security standard.

Table 2: EREC P2/8 compliance worked examples in Appendix A

For convenience, Table 1 of EREC P2/8 is shown below as Table *3*.

		Minimum demand to be net after*	
Class of supply	**Range of Group Demand**	**First Circuit Outage**	**Second Circuit Outage**
A	Up to 1MW	In repair time: **Group Demand**	Nil
B	Over 1MW and up to 12MW	(a) Within 3 hours: **Group Demand** minus 1MW (b) In repair time: **Group Demand**	Nil
C	Over 12MW and up to 60MW	(a) Within 15 minutes: Smaller of (**Group Demand** minus 12MW); and 2/3 of **Group Demand** (b) Within 3 hours: **Group Demand**	Nil
D	Over 60MW and up to 300MW	(a) Immediately: **Group Demand** minus up to 20MW (automatically disconnected) (b) Within 3 hours: **Group Demand**	(c) Within 3 hours; For **Group Demands** greater than 100MW: Smaller of (**Group Demand** minus 100MW); and 1/3 **Group Demand** (d) Within time to restore arranged outage: **Group Demand**
E	Over 300MW and up to 1500MW	(a) Immediately: **Group Demand**	(b) Immediately: All consumers at 2/3 **Group Demand** (c) Within time to restore arranged outage: **Group Demand**

* for the purpose of complying with the requirement to supply the 'minimum demand to be met', activation of **DSR** is equivalent to restoration of demand.

Table 3: Extract from Table 1 of EREC P2/8

7.2. Example 1: Transition from Class of Supply B to C

This example illustrates the treatment of a demand group where the addition of an electricity storage (**ES**) connection causes the demand group to transition from Class of Supply B to Class of Supply C.

An **ES** is connecting to a network with an existing **Group Demand** of 10MW and hence currently falls within Class of Supply B. With the **ES** connected, the **Group Demand** increases to 15MW due to **ES** maximum import capacity of 5MW coincident with the demand peak. As can be seen from Table 1 of EREC P2/8 (see Table *3* above), this means that the demand group transitions to a Class of Supply C.

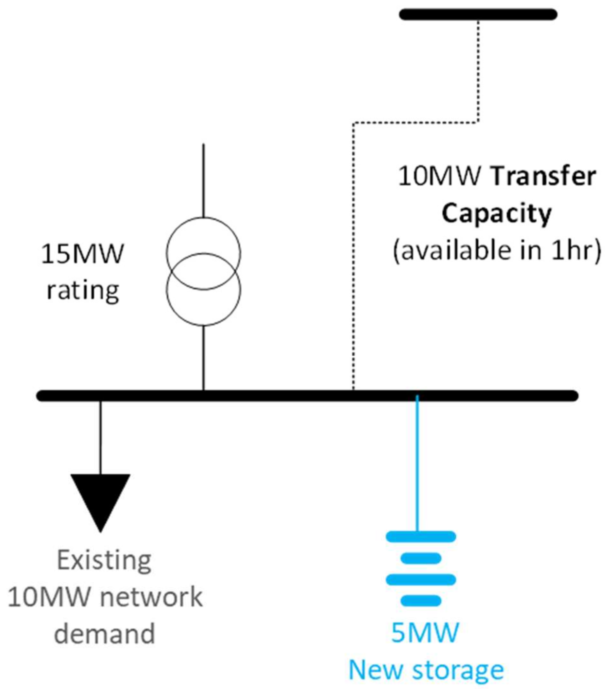


Figure 1: Example of a demand group transitioning from Class of Supply B to C

The following steps assess compliance with EREC P2/8.

a) Determine **Group Demand**

i. **Measured Demand** = 10MW existing network demand + 5MW of **ES** import (i.e. assumed to be importing at its maximum import capacity at the time of peak demand) = 15MW

ii. **Latent Demand**

Contracted DG/DSR Schemes/ES – none, i.e. the **ES** is not exporting at the time of the peak network demand hence there is no **Latent Demand**.

Non-Contracted DG/DSR Schemes/ES – none

iii. **Cold Load Pickup** = 0MW

iv. **Group Demand** = 15MW (Class C)

b) Determine Network Capacity

i. Intrinsic Network Capacity

FCO capacity = 0MW. From Table 1 of EREC P2/8 under a **FCO**, there is a requirement to secure 3MW within 15 mins and all demand within 3 h.

SCO capacity = 0MW. From Table 1 of EREC P2/8 under a **SCO**, there is no requirement to secure any demand.

The intrinsic network capacity of 0MW under an **FCO** is insufficient to meet the **Group Demand** restoration requirement.

ii. **Transfer Capacity** = 10MW available under a **FCO** within 1 hr.

Given that **Group Demand** (15MW) is greater than the summation of the intrinsic network capacity and **Transfer Capacity** (0MW + 10MW), it is now necessary to consider contribution to security from other means: **DG**/**DSR Schemes**/**ES**.

iii. Security contribution from **Contracted DSR Scheme** = 5MW, available immediately under a **FCO** (assuming the **ES** is curtailed/interrupted immediately to zero import in event of a **FCO**).

The total **System Security** contribution capacity, under **FCO** conditions:

- 10MW (**Transfer Capacity**) available within 1 hr + 5MW (**Contracted DSR**) available immediately, compared to a requirement of 3MW within 15 mins and all demand within 3 h; hence the network is compliant with Table 1 of EREC P2/8.

In summary, the level of demand restored via treatment of the **ES** as a **Contracted DSR Scheme** is sufficient to maintain compliance with the minimum requirements of Table 1 of EREC P2/8 under a **FCO**.

7.3. Example 2: Transition from Class of Supply C to D

This example illustrates the treatment of a demand group where the addition of an **ES** connection causes the demand group to transition from Class of Supply C to Class of Supply D, however the **Group Demand** remains less than 100MW.

An **ES** is connected to a network with an existing **Group Demand** of 45MW and hence currently falls within Class of Supply C. With the **ES** connected, the **Group Demand** increases to 85MW due to **ES** maximum import capacity of 40MW **ES** coincident with the demand peak. As can be seen from Table 1 of EREC P2/8, this means that the demand group transitions to a Class of Supply D.

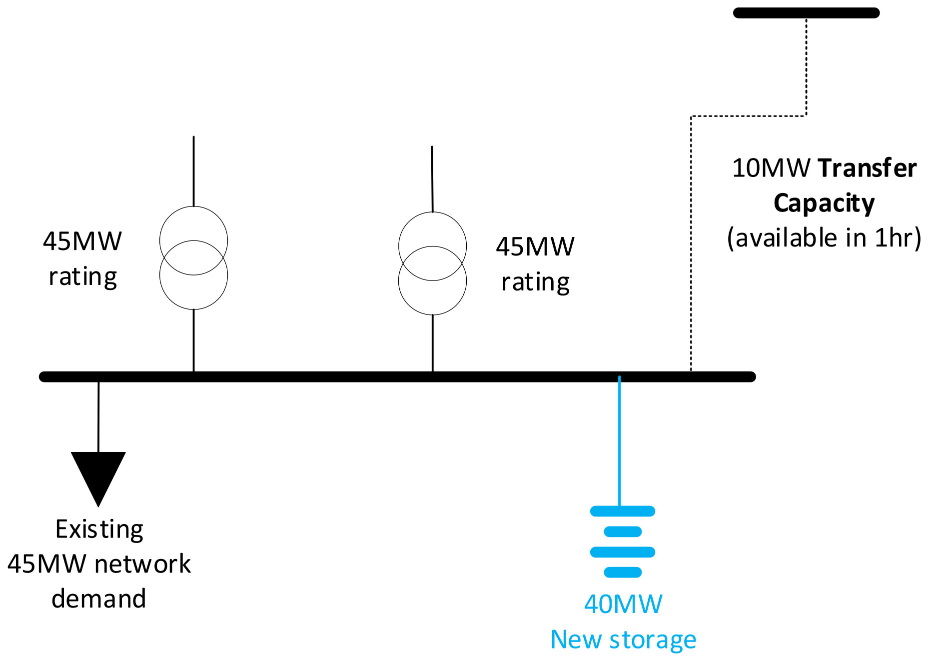


Figure 2: Example of a demand group transitioning from Class of Supply C to D

The following steps assess compliance with EREC P2/8.

a) Determine **Group Demand**

  i. **Measured Demand** = 45MW existing network demand + 40MW of **ES** import (i.e. assumed to be importing at its maximum import capacity at the time of peak demand) = 85MW

  ii. **Latent Demand**

  Contracted DG/DSR Schemes/ES – none, i.e. the **ES** is not exporting at the time of the peak network demand hence there is no **Latent Demand**.

  Non-Contracted DG/DSR Schemes/ES – none

  iii. **Cold Load Pickup** = 0MW

  iv. **Group Demand** = 85MW (Class D)

c) Determine Network Capacity

  i. Intrinsic Network Capacity

  FCO capacity = 45MW, available immediately. (From Table 1 of EREC P2/8 under a **FCO**, there is a requirement to secure **Group Demand** minus up to 20MW immediately).

  SCO capacity = 0MW (from Table 1 of EREC P2/8 under a **SCO**, for a **Group Demand** less than or equal to 100MW, there is a requirement to restore **Group Demand** within time to restore the outage).

  The intrinsic network capacity of 45MW under a **FCO** is insufficient to meet the 85MW of **Group Demand** i.e., there is a deficiency of 40MW.

  Under a **SCO**, the intrinsic network capacity will be available after restoration of the outage.

  ii. **Transfer Capacity** = 10MW available under a **FCO** or **SCO**.

Given that **Group Demand** (85MW) is greater than the summation of the intrinsic network capacity and **Transfer Capacity** (45MW + 10MW), it is now necessary to consider contribution to security from other means: **DG**/**DSR Schemes**/**ES**.

  iii. Security contribution from **Contracted DSR Scheme** = 40MW, available immediately under a **FCO** (assuming the **ES** is curtailed/interrupted immediately to zero import in event of a **FCO**).

The total **System Security** contribution capacity:

- Immediately available under a **FCO** = 85MW (45MW Intrinsic capacity + 40MW **Contracted DSR**). The EREC P2/8 requirement for this scenario is to secure 65MW (**Group Demand** – 20MW) hence the network is compliant with Table 1 of EREC P2/8.

- Available within 3 hours under **FCO** = 95MW (45MW Intrinsic capacity + 10MW **Transfer Capacity** + 40MW **Contracted DSR**). The EREC P2/8 requirement for this scenario is to secure 85MW (**Group Demand**) hence the network is compliant with Table 1 of EREC P2/8.

- Available within 3 hours under **SCO** = 50MW (10MW **Transfer Capacity** + 40MW **Contracted DSR**). The EREC P2/8 requirement for this scenario is to secure 0MW (**Group Demand** is <100MW) hence the network is compliant with Table 1 of EREC P2/8.

- under a **SCO** once the arranged outage has been restored = 95MW (45MW Intrinsic capacity + 10MW **Transfer Capacity** + 40MW **Contracted DSR**). The EREC P2/8 requirement for this scenario is to secure 85MW (**Group Demand**) hence the network is compliant with Table 1 of EREC P2/8.

In summary, the level of demand restored via treatment of the **ES** as a **Contracted DSR Scheme** is sufficient to maintain compliance with the minimum requirements of Table 1 of EREC P2/8 under both **FCO** and **SCO** conditions.

7.4. Example 3: Transition to 'more than 100MW' (within Class of Supply D)

This example illustrates the treatment of an existing Class of Supply D demand group where the addition of an **ES** connection increases the **Group Demand** to more than 100MW but the demand group remains Class of Supply D.

An **ES** is connected to a network with an existing **Group Demand** of 80MW and hence falls within Class of Supply D. With the **ES** connected, the **Group Demand** increases to 120MW due to **ES** maximum import capacity of 40MW **ES** coincident with the demand peak. This means that the demand group remains a Class of Supply D but the **Group Demand** increases to above 100MW.

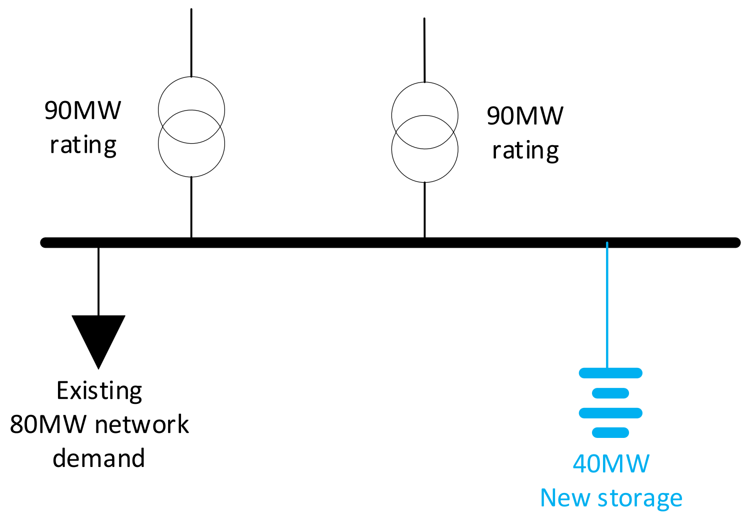


Figure 3: Example of a demand group changing from below 100MW to above 100MW

The following steps assess compliance with EREC P2/8.

a) Determine **Group Demand**

i. **Measured Demand** = 80MW existing network demand + 40MW of **ES** import (i.e. assumed to be importing at its maximum import capacity at the time of peak demand) = 120MW

ii. **Latent Demand**

Contracted DG/DSR Schemes/ES – the **ES** is not exporting at the time of the peak network demand hence there is no **Latent Demand**.

Non-Contracted DG/DSR Schemes/ES – none

iii. **Cold Load Pickup** = 0MW

iv. **Group Demand** = 120MW (Class D)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 90MW, available immediately. (From Table 1 of EREC P2/8 under a **FCO**, there is a requirement to secure **Group Demand** minus up to 20MW immediately).

SCO capacity = 0MW (From Table 1 of EREC P2/8 under a **SCO**, for a **Group Demand** of more than 100MW, there is a requirement to restore the smaller of: **Group Demand** minus 100MW; and 1/3 **Group Demand** within 3 hours).

The intrinsic network capacity of 90MW under a **FCO** is insufficient to meet the 120MW of **Group Demand** i.e., there is a deficiency of 30MW.

Under a **SCO**, the intrinsic network capacity of 0MW is insufficient to meet the 20MW immediate restoration requirement.

ii. **Transfer Capacity** = 0MW (Note: it is typical that **Transfer Capacity** would exist for a Class D group. For simplicity, this example has no **Transfer Capacity**).

Given that **Group Demand** is greater than the intrinsic network capacity, it is now necessary to consider contribution to security from other means: **DG**/**DSR Schemes**/**ES**.

iii. Security contribution from **Contracted DSR Scheme** = 40MW, available immediately under a **FCO** or **SCO** (assuming the **ES** is curtailed/interrupted immediately to zero import in the event of a **FCO** or a **SCO**).

The total **System Security** contribution capacity:

- Immediately available under a **FCO** = 130MW (90MW Intrinsic capacity + 40MW **Contracted DSR**). The EREC P2/8 requirement for this scenario is to secure 100MW (**Group Demand** – 20MW) hence the network is compliant with Table 1 of EREC P2/8.

- Available within 3 hours under **FCO** = 130MW (90MW Intrinsic capacity + 40MW **Contracted DSR**). The EREC P2/8 requirement for this scenario is to secure 120MW (**Group Demand**) hence the network is compliant with Table 1 of EREC P2/8.

- Available within 3 hours under **SCO** = 40MW (**Contracted DSR**). The EREC P2/8 requirement for this scenario is to secure 20MW (**Group Demand** of 120MW minus 100MW) hence the network is compliant with Table 1 of EREC P2/8.

- Under a **SCO** once the arranged outage has been restored = 130MW (90MW Intrinsic capacity + 40MW **Contracted DSR**). The EREC P2/8 requirement for this scenario is to secure 120MW (**Group Demand**) hence the network is compliant with Table 1 of EREC P2/8.

In summary, the level of demand restored via treatment of the **ES** as a **Contracted DSR Scheme** is sufficient to maintain compliance with the minimum requirements of Table 1 of EREC P2/8 under both **FCO** and **SCO** conditions.

7.5. Example 4: Transition from Class of Supply D to E

This example illustrates the treatment of a demand group where the addition of an **ES** connection causes the demand group to transition from Class of Supply D to Class of Supply E.

When considering this example it is important to remember that EREC P2/8 applies to **Circuit** outages and that busbar outages are considered on their merits and hence, in the example below, EREC P2/8 is only relevant to outages of the **Circuits** comprising the 240MW transformers if those **Circuits** are owned / operated by the **DNO**. In most cases such **Circuits** are part of the National Electricity Transmission System and as such the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) applies not EREC P2/8 or EREP 130/4. However, the example below illustrates the concern associated with larger demand groups and provides a general CBA principle which can be applied if EREC P2/8 analysis identifies that network reinforcement is required to ensure compliance.

An **ES** is connected to a network with an existing **Group Demand** of 220MW and hence falls within Class of Supply D. With the **ES** connected, the **Group Demand** increases to 370MW due to **ES** maximum import capacity of 150MW **ES** coincident with the demand peak. This increases the **Group Demand** to more than 300MW and hence the demand group transitions to a Class of Supply E.

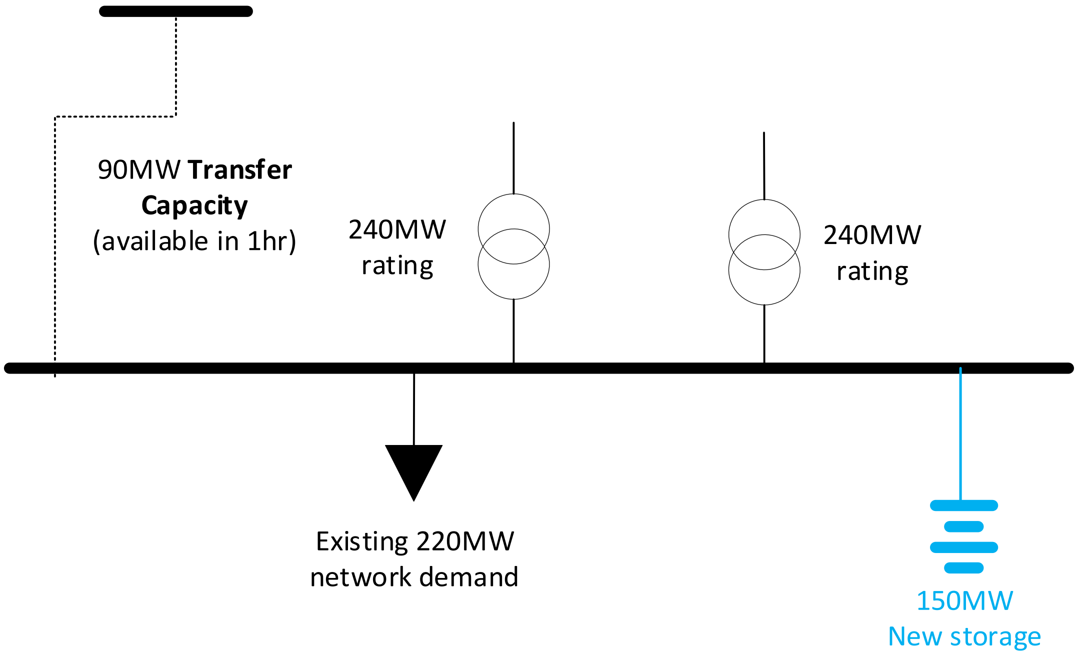


Figure 4: Example of a demand group transitioning from Class of Supply D to E

The following steps assess compliance with EREC P2/8.

a) Determine **Group Demand**

i. **Measured Demand** = 220MW existing network demand + 150MW of **ES** import (i.e. assumed to be importing at its maximum import capacity at the time of peak demand) = 370MW

ii. **Latent Demand**

Contracted DG/DSR Schemes/ES – none, i.e. the **ES** is not exporting at the time of the peak network demand hence there is no **Latent Demand**.

Non-Contracted DG/DSR Schemes/ES – none

iii. **Cold Load Pickup** = 0MW

iv. **Group Demand** = 370MW (Class E)

b) Determine Network Capacity

i. Intrinsic Network Capacity

FCO capacity = 240MW, available immediately. (From Table 1 of EREC P2/8 under a **FCO**, there is a requirement to secure **Group Demand** immediately).

Under a **FCO**, the intrinsic network capacity of 240MW is insufficient to meet the immediate restoration requirement i.e., there is a deficiency of 130MW.

SCO capacity = 0MW (From Table 1 of EREC P2/8 under a **SCO**, there is a requirement to restore 2/3 of **Group Demand** immediately).

Under a **SCO**, the intrinsic network capacity of 0MW is insufficient to meet the 247MW (2/3 of 370MW) immediate restoration requirement.

iv. **Transfer Capacity** = 90MW available after 1 hour under a **FCO** and **SCO.**

Given that **Group Demand** (370MW) is greater than the intrinsic network capacity and **Transfer Capacity** (240MW + 90MW = 330MW), it is now necessary to consider contribution to security from other means: **DG/DSR Schemes/ES**.

v. Security contribution from **Contracted DSR Scheme** = 150MW, available immediately under a **FCO** or **SCO** (assuming the **ES** is curtailed/interrupted immediately in the event of a **FCO** or a **SCO**).

The total **System Security** contribution capacity:

- Immediately available under a **FCO** = 390MW (240MW Intrinsic capacity + 150MW **Contracted DSR**). The EREC P2/8 requirement for this scenario is to secure 370MW (**Group Demand**) hence the network is compliant with Table 1 of EREC P2/8.
- Immediately available under a **SCO** = 150MW (0MW Intrinsic capacity + 150MW **Contracted DSR**). The EREC P2/8 requirement for this scenario is to secure 247MW (all customers at 2/3 **Group Demand**) hence the network is non-compliant with Table 1 of EREC P2/8. There is a **SCO** deficit of 97MW.
  Note: Prior to the **ES** connection with the **Group Demand** of 220MW, the network was compliant with the Class of Supply D requirements under Table 1 of EREC P2/8. Under this condition the **Transfer Capacity** is sufficient to restore 73MW within 3 hours (i.e. the smaller of Group Demand minus 100MW and 1/3 Group Demand). The 90MW of **Transfer Capacity** restored within 1 hour was sufficient to satisfy the Class of Supply D requirement.
- Under a **SCO** once the arranged outage has been restored the EREC P2/8 requirements and available capacity are as per the **FCO** condition.

In summary, this illustrates that the initial compliance assessment identifies the need for network reinforcement to cater for a **SCO** non-compliance driven by the transition of the demand group from Class of Supply D to E arising from the connection of the **ES**.

The following section considers the use of EREP 130/4 Section 12 CBA to justify divergence from the requirements in Table 1 of EREC P2/8 on an enduring basis.

7.6. EREP 130/4 CBA

EREP 130/4 Section 12 permits the use of a CBA to justify divergence from the requirements of Table 1 of EREC P2/8 under certain circumstances. This section provides a worked example and more information on how to undertake such a CBA.

This illustrative CBA example compares the capital cost of the reinforcement to the benefits arising from the reinforcement measured in terms of the Value of Lost Load (VoLL). This example compares the VoLL in the following two scenarios:

1. Connection of an ES as per Example 4 (Section 7.5) without any network reinforcement.

2. Connection of an ES as per Example 4 (Section 7.5) with an associated network reinforcement to satisfy the minimum **SCO** requirements in accordance with EREC P2/8.

In both scenarios this assessment calculated the Expected Energy Not Supplied (per annum) due to unplanned outages for the general customers supplied by the network. In both cases the **ES** installation is considered to have a **Contracted DSR Scheme**, so there is no benefit to the **ES** customer associated with the reinforcement.

7.6.1. Network Reinforcement Option

A network reinforcement option to provide additional security under **SCO** conditions has been considered. This includes the installation of a new OHL supplying a new 120MVA transformer, with an estimated cost of £25.1m and is shown in Figure 5.

The addition of a 120MW transformer means that the total System Security contribution capacity under a **SCO** becomes 120MW (intrinsic capacity under a **SCO**) + 150MW (**Contracted DSR**) = 270MW (immediately available), satisfying the **SCO** requirement of Example 4 (see Section 7.5).

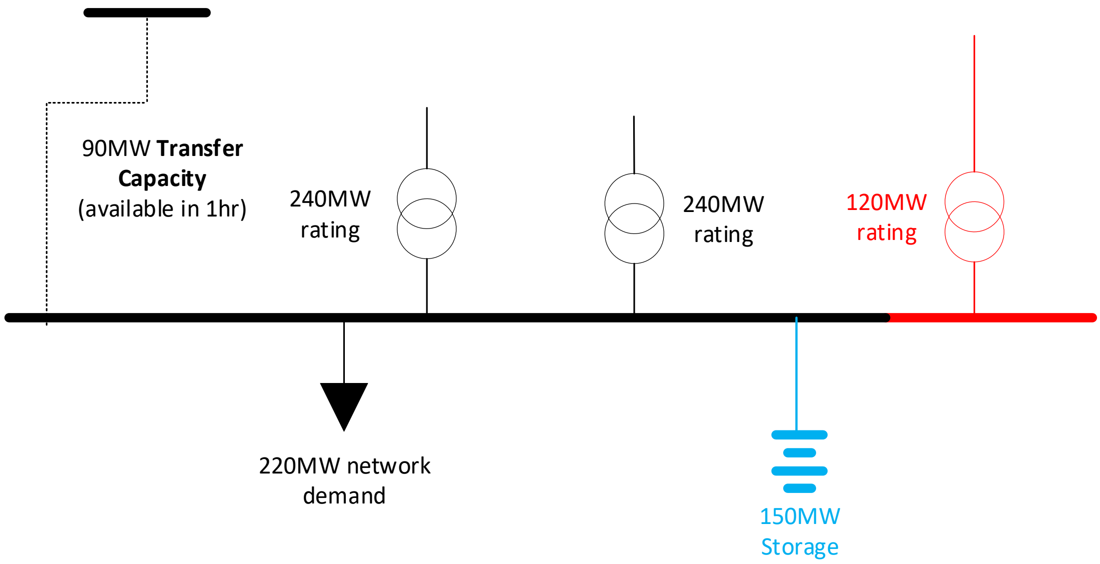


Figure 5: Reinforcement example for an ES connection

7.6.2. 'Expected Energy not Supplied' (EENS) due to an unplanned outage

The concept of expected energy not supplied (EENS) is a widely applied metric when assessing network outage risk and it represents the probabilistic calculation of energy that would not be supplied to a customer or a group of customers as a consequence of a network outage.

EENS = Peak demand (kW) x Restoration time (hr) x Fault rate (f/year/km) x feeder length (km) x Load probability (%), where:

- Peak demand – based on expected peak demand of customer(s);
- Restoration time – based on the time taken to restore supplies to customer(s) and/or repair the fault;
- Fault rate – the fault rate per km year for cables/overheads and the fault rate per year for transformers/switchgear;
- Circuit length – various lengths of circuit can be considered; and
- Load probability.

A load duration curve (LDC) is a static representation of a time-dependent load – see Figure 6. It depicts the duration for which the load will remain above certain values, i.e., % demand vs. % time.

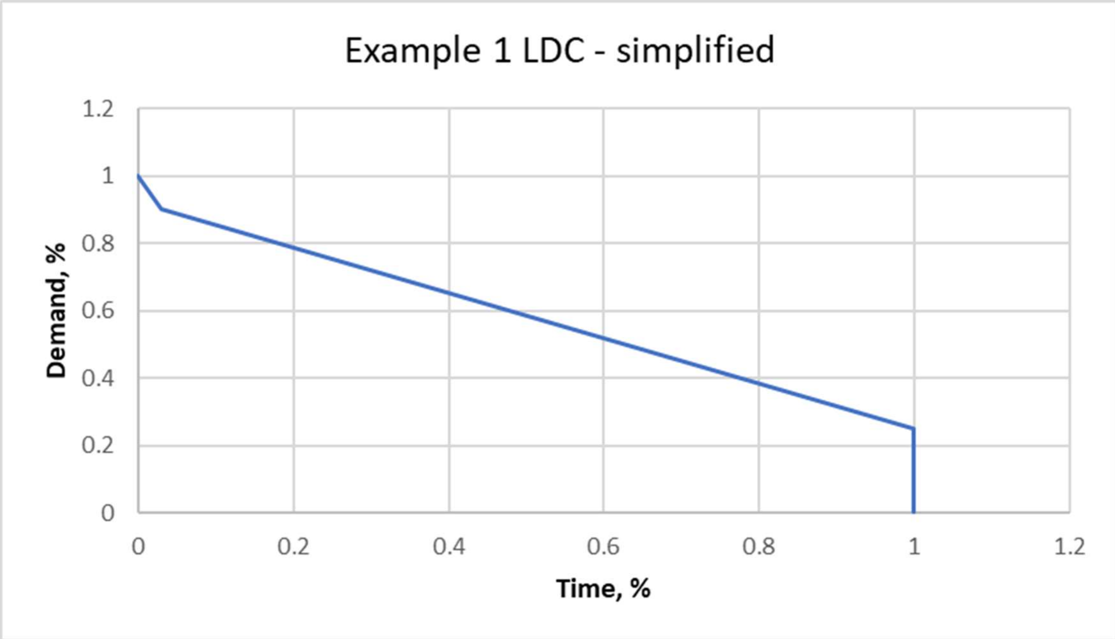


Figure 6: Simplified load duration curve of the demand group

When combined with a peak demand value (kW), the area under a LDC (kW, hrs) represents the total energy (kWh) supplied via the circuit for the period of time represented. The total energy can then be used to determine the average load over that period.

$$Area\ under\ LDC\ graph = kW \times hrs = energy\ supplied\ by\ circuit$$

$$Average\ load = \frac{energy\ supplied\ by\ circuit}{hrs}$$

Using the average load, a further parameter may be derived which provides a measure of the load probability – also referred to as the Load Factor.

$$Load\ Factor\ (pu) = \frac{Average\ load}{Peak\ load}$$

A **Circuit** with a high Load Factor is indicative of a **Circuit** which operates at a load level which is high for longer periods of time. It follows that plotting the simplified per unit (pu) version of the LDC, the area under the curve represents the Load Factor, i.e., the four plot points for the LDC are defined as follows:

$$Simplified\ LDC\ plot\ points = \frac{MW}{Peak\ MW}, \frac{Hrs}{Total\ Hrs}$$

Using the calculated EENS, the socioeconomic cost may be quantified using a Value of Lost Load (VoLL). The CBA assessment is focussed on the change in security of supply to evaluate the potential financial benefits for general demand customers in the case of a SCO. This may be done by comparing the EENS for general demand customers during a SCO with and without reinforcement.

The following parameters were used to calculate the EENS with and without reinforcement:

a) Without reinforcement, under a **SCO** the restoration of 220MW of customer demand would be restored as follows:

- 90MW in 1 hour; and

- 130MW in time to return the outaged plant to service (assumed to be 96 hours for transformer, 72 hours for switchgear, 12 hours for overhead line).

b) After reinforcement (as per Figure 4), under a **SCO** the restoration of 220MA of customer demand would be restored as follows:

- 120MW immediately;
- 90MW in 1 hour; and
- 10MW in time to return the outaged plant to service (assumed to be 96 hours for transformer, 72 hours for switchgear, 12 hours for overhead line).

c) Fault rates

To calculate the EENS the following fault rates have been assumed using historical fault data – see Table 4.

Asset	Fault rate (per unit, per km)
400/132kV transformer	1% per annum per transformer.
132kV busbars	0.48% per annum.
400/275kV OHL	0.04 double circuit permanent faults per 100km per annum.
NOTE: Fault rate for switchgear and busbars assumed to be negligible	

Table 4: Asset fault rates

As we are interested in a **SCO** event, this would occur in the following scenarios:

- Double transformer fault (probability of occurrence 0.01x0.01); or
- Double Overhead Line circuit fault (assuming overhead line is 25km in length); or
- Double Busbar fault i.e. both sections with fault (probability of occurrence 0.0048 x 0.0048).

d) Load probability

A typical load probability for domestic customers is 60%.

7.6.3. Value of Lost Load (with and without reinforcement)

This CBA considered a VoLL of £25,000/MWh.

Assuming the above restoration profile for a **SCO**, fault rates, and load probability, the EENS per annum for each scenario is calculated and thus the VoLL:

a) Without reinforcement: cost of EENS per annum = £265,217, based on 130MW restoration for

- Overhead line faults and 12 hour emergency restoration time
- Transformer faults and 96 hour emergency restoration time
- Switchgear faults and 72 hour emergency restoration time

b) After reinforcement: cost of EENS per annum = £31,149, based on 10MW restoration and the same fault and emergency restoration times as above

7.6.4. Conclusion

The benefit to general demand customers arising from the reinforcement is a reduction in EENS of £0.23m per annum. This compares to a capital cost of reinforcement of £25.1m. There are no benefits to the **ES** as in both scenarios (with and without reinforcement) the **ES** would be de-energised via the **Contracted DSR** arrangements.

A simple comparison of the above values indicates that the network assets would need to have a life expectancy of approximately 107 years to make reinforcement an economical option.

Whilst this CBA is an illustrative example, the principle in EREC P2/8 is that reinforcement to secure general demand customers is implicit within the economic analysis underpinning EREC P2/8. As such, reinforcement to accommodate fungible electricity storage demand alone would unlikely to be economical, particularly as the electricity storage import is likely to be curtailed/interrupted via the **Contracted DSR** arrangements. It is this general CBA principle that is recommended to be applied where the EREC P2/8 analysis identifies that network reinforcement is required to ensure compliance after an electricity storage installation is connected to the distribution network.

8. Appendix B – Calculation of EREC P2/8 diversity factors for non-controllable electricity storage

This appendix details the analysis underpinning the relationship proposed under Tactical Solution 2 to apply a level of diversity to total non-controllable electricity storage import capacity when undertaking EREC P2/8 security of supply assessments.

8.1. Methodology

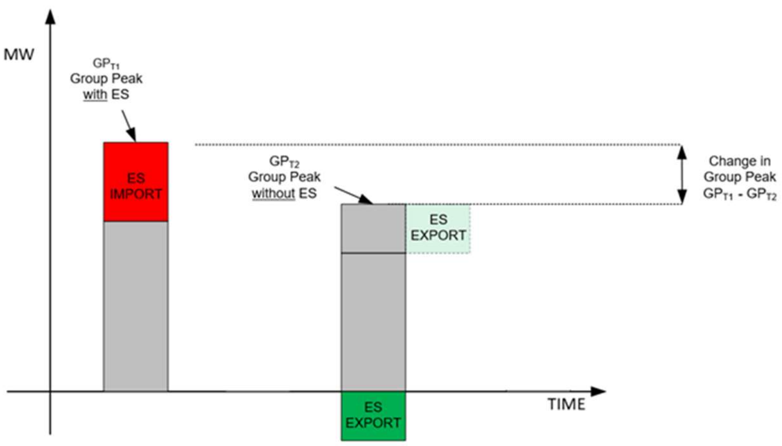
DNOs have collated historical import/export data associated with existing operational larger-scale electricity storage installations. This has enabled a more representative statistical assessment of the contribution that electricity storage installations make to Group Demand than would be possible for any individual DNO. The assessments considered the half-hourly historical import and export data from 19 electricity storage connections with a total installed capacity of 627MW along with the associated demand in the demand group for each half-hour.

This data was used to quantify the impact of electricity storage import on the peak demand of a demand group by considering the Group Demand both with and without the electricity storage to establish a relationship between the maximum import capacity of the electricity storage and any associated increase in Group Demand due to its operation.

To calculate the change in Group Demand due to the operational behaviour of the electricity storage, the peak demand of the demand group assuming that the electricity storage was not present was subtracted from the measured peak demand. Group Demand assuming the electricity storage was not present was established using the measured flows for the demand group with the power flows associated with the electricity storage subtracted (i.e. subtracting the electricity storage import and including the latent demand in the demand group masked by export from the electricity storage).

The ES Diversity Factor is this change in Group Demand due to the ES, divided by the registered maximum import capacity of the ES installation.

Analysis found that the contribution to Group Demand scales with the size of the electricity storage relative to Group Demand as larger electricity storage installations have greater propensity to create either an increase in the peak demand or to create a new peak demand at a different point in time. An ES Group Ratio was defined as the aggregate capacity of the ES in a demand group divided by the Group Demand without the ES (see Figure 7).



$$ES\ GROUP\ RATIO = \frac{ES\ CAPACITY}{GP_{T2}}$$

$$ES\ DIVERSITY = \frac{(GP_{T1} - GP_{T2})}{ES\ CAPACITY}$$

Figure 7: Calculation of the Diversity Factor for electricity storage (DF_{ES})

8.2. Factors affecting diversity

Table 5 shows the extent that different factors were considered when developing the proposed ES diversity principles.

Factor	Considered	Rationale
DNO ability to control the ES installation	Yes	If the DNO has limited or no ability to control the import to or export from the electricity storage, then diversity factors should be used when assessing EREC P2/8 compliance. It is important that the implications of the diversity factors being incorrect are considered as this may drive the need for mitigating measures to avoid unduly risking supplies to customers in the demand group. If the DNO has full control of the electricity storage then there is no need to consider diversity, and the principles of EREC P2/8 can be applied as per Section 5.2 and Appendix A.
Electricity storage import coincident with Group Demand	Yes	The diversity factors proposed have been established using historical import data from electricity storage installations in multiple DNOs and multiple groups.
Electricity storage import not coincident with Group Demand – but a new peak is created	Yes	The diversity factors proposed have been established using historical import data from electricity storage installations in multiple DNOs and multiple groups.
Size of electricity storage maximum import capacity in relation to Group Demand	Yes	The diversity factors proposed have been established using historical import data from electricity storage installations in multiple DNOs and multiple groups. Electricity storage installations with larger registered capacity have greater propensity to create new peaks in Group Demand and therefore greater impact.
Coincidence between import from multiple electricity storage installations in the same demand group (same & different operating mode)	Partially	Diversity between electricity storage installations with the same / different operating modes has not been explicitly considered. This would require more extensive usage data. Application of the diversity factors based on the aggregate registered capacity for all the non-controllable electricity storage installations connected within a demand group will conservatively consider coincident operation, i.e. as if these installations were a single electricity storage installation, or following the same operational/market signals.
Future electricity storage behaviour	Partially	There is a small allowance in the diversity calculation to account for some changes in future electricity storage behaviour. There may be significant uncertainties due to: limited historical data; service contract lengths and markets becoming more short-term; new installations tend to have increasing registered capacities and are importing/exporting for longer periods; size/economics of future markets.

		Diversity factors relating to operational modes may need to be developed. Given these future uncertainties in electricity storage operation, it is recommended that the proposed diversity principles be reviewed every 24 months to account additional operational data and changes in operational usage behaviours.
Hybrid sites	**No**	Limited operational data at distribution. **These are assumed to behave similarly to standalone operation.**

Table 5: Consideration of key factors affecting ES diversity

8.3. Summary results and relationship

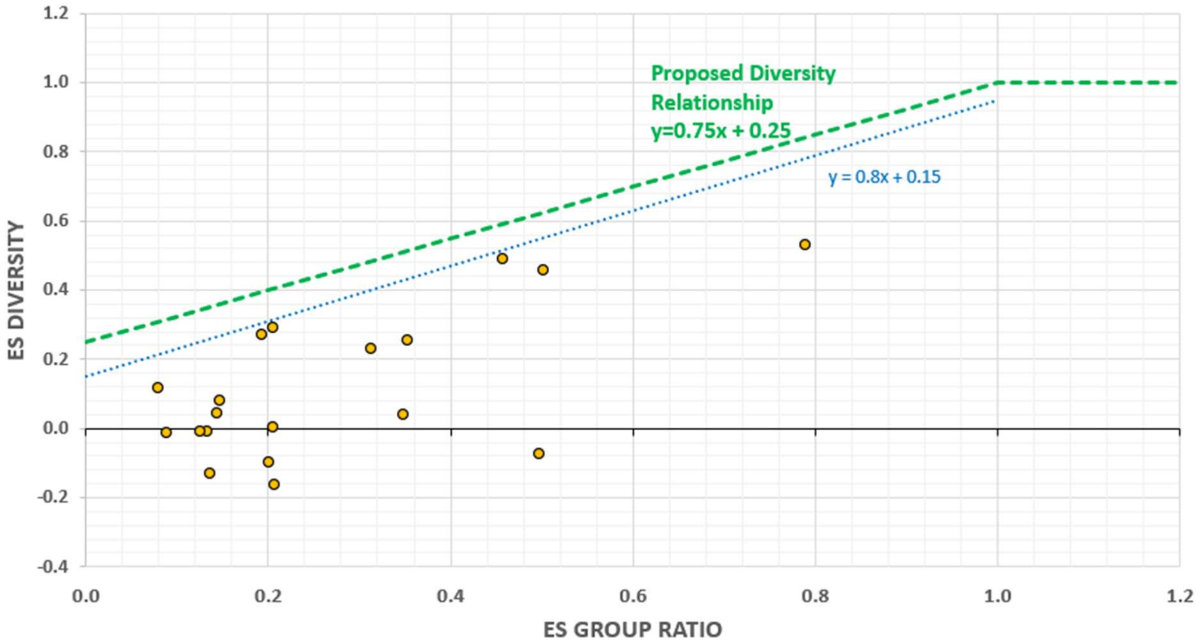


Figure 8: Summary of proposed diversity relationship compared with diversity from historical data

Key observations:

- Electricity storage installations with a higher registered capacity have greater propensity to create new peaks which can be seen by the trend of larger diversity factors for installations with a larger ES Group Ratio.
- To avoid underestimating the likely import contribution at the time of peak demand, an approach was selected that is at least as stringent as the largest contribution for an electricity storage installation of that scale observed in the data assessed. This approach is more conservative than, for example, the calculation of security contributions from distributed generation (F-factors) under EREP 130/4. A relationship at least as stringent as the largest increase in Group Demand observed across all 19 electricity storage installations can be described by blue dashed line.
- A small allowance has been included in the relationship described by the green dashed line. This is to account for the limited historical data used and future uncertainties in electricity storage operation. This increases the minimum diversity factor used for relatively small electricity storage installations from 15% to 25%. It also increases the minimum diversity factor used for large electricity storage installations from 95% to 100%.

- In 6 out of 19 instances, the measured Group Demand appeared to reduce due to export from the electricity storage installation, and would be expected to be accounted within an EREC P2/8 calculation as Latent Demand.

For the purposes of EREC P2/8 assessments, DNOs should use the following equation to calculate an expected diversity factor to be applied to non-controllable electricity storage to estimate how its import will diversify with the demand within the demand group. This is the equation for the dashed green line in Figure 8.

$$DF_{ES} = min\left(0.75\frac{ES_{import}}{GD_{withoutES}} + 0.25\,,\ \ 1.0\right)$$

Where:

DF_{ES} = Diversity Factor to be applied to the aggregate Maximum Import Capacity of non-controllable electricity storage

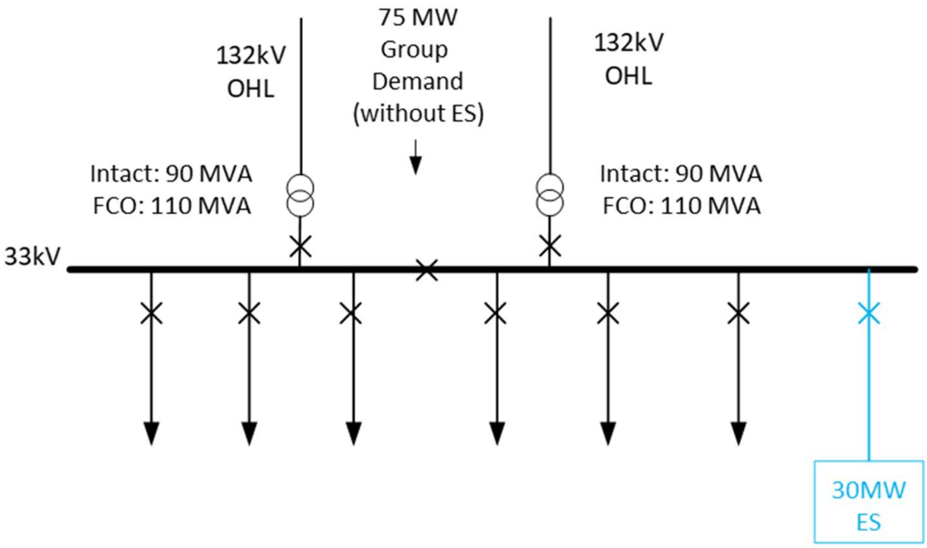
Note, DF_{ES} is capped at 1.0 (full contribution) for scenarios where ES_{import} > $GD_{withoutES}$

ES_{import} = Aggregate Maximum Import Capacity of all non-controllable electricity storage in the demand group (MW)

$GD_{withoutES}$ = Group Demand excluding import/export flows from the non-controllable electricity storage (MW)

8.4. Worked example

This example considers the amount of demand to be secured for a 30MW non-controllable ES connected within a network with Group Demand (excluding ES) of 75MW. The application of the Tactical Solution 2 diversity principles would lead to securing (0.55 x 30) = 16.5MW of the ES demand.



$$ES\ GROUP\ RATIO = \frac{30}{75} = 0.4$$

$$ES\ DIVERSITY = (0.4 \times 0.75) + 0.25 = 0.55$$

$$GROUP\ DEMAND = 75 + (0.55 \times 30) = \mathbf{91.5}\boldsymbol{MW}$$

8.5. Comparison with EREP 130/4 Annex G methodology

To avoid underestimating the import from electricity storage installations at the time of peak demand, a methodology was selected that is at least as stringent as the worst case.

The following provides a comparison with the method for calculation of security contributions from distributed generation (F-factors) in accordance with EREP 130/4.

In order to specify the contribution to System Security from distributed generation, Annex G of EREP 130/4 calculates a single F Factor using the average (more specifically the mean) minus 1 Standard Deviation. This means that there is a probability of 84.1% that the delivered distributed generation security contribution is the calculated value (i.e., F Factor x distributed generation DNC) or higher.

Taking a similar approach using the average increase in Group Demand plus 1 standard deviation was applied to the import and export data for a subset of electricity storage installations. This means that there is an 84.1% probability that the increase in Group Demand would this value or lower. The ES Diversity factors were found to all be within the range 12%-18%.

This method was discounted for two reasons, firstly the electricity storage utilisation did not follow a standard normal distribution curve, and secondly this method was significantly less conservative which risks increasing the likelihood of underestimating the Group Demand. These factors, coupled with limited historical data and uncertainties in future usage, meant that a method at least as stringent as the measured worst case was deemed appropriate until further utilisation data becomes available.

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