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Engineering Report 130

Issue 3 2019

Guidance on the application of Engineering Recommendation P2, Security of Supply

ENA EREP 130 Issue 3 (2019) Draft v8 Issued

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Amendments since publication

Issue	Date	Amendment
Issue 3	January, 2019	Major revision of Issue 2 to: • Align EREP 130 with EREC P2/7 [N1] • Provide new guidance on assessing the contribution to security from Demand Side Response (DSR) Schemes and Electricity Storage (ES) • Update the F factors for assessing contribution to security from Distributed Generation (DG), using recent data from DG • Differentiate the contribution to security from DG, DSR Schemes and ES which is contracted with a Distribution Network Operator (DNO) and that which is not This issue has largely been re-structured to improve the flow of the guidance, based on a revised step-by-step flow diagram (see Figure 1). This issue includes the following principal technical changes. Introduction: Updated to reflect expansion of scope and inclusion of DSR Schemes and ES. Clause 1, Scope: Expanded to include DSR and ES. Clause 2, Normative references: Updated to reflect latest relevant references. Clause 3, Terms and definitions: All existing definitions amended to align with EREC P2/7 [N1]. New definitions added for: • Cold Load Pickup • Contracted • Demand Facility

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		• Demand Side Response Scheme • Electricity Storage • Non-Contracted • Regulatory Financial Performance Reporting Clause 4, Assessment process overview: Major amendment of guidance on process to reflect a new Figure 1, which replaces the previous process flow diagram (Issue 2 Figure 5.1). Clause 5, Determine the Group Demand and class of supply: Major amendment of guidance on assessing Group Demand. New guidance added to explain what a demand group is (new Figure 2 added). More detailed guidance included on assessing Latent Demand with supporting Annex A. Clarification of de-minimis test when assessing Latent Demand. A new Figure 3 replaces the previous (Issue 2 Figure 5.2), and new guidance on taking account of Cold Load Pickup. Clause 6, Determine capacity of network assets and assess compliance: Major amendment of guidance with the removal of the previous flow diagram (Issue 2 Figure 5.3) considered to be unnecessary. New guidance (Clause 6.2) added on determining the 'intrinsic network capacity'. New guidance (Clause 6.3) added on determining the Transfer Capacity. Clause 7, Contribution to System Security from Contacted DG, DSR Schemes, and ES: New guidance added on assessing the contribution from Contracted DG, DSR Schemes and ES, including the relevant considerations when developing such contracts. This Clause is supported by Annexes C and E. Clause 8, Contribution to System Security from Non-Contacted DG, DSR Schemes, and ES: This clause now replaces the previous guidance on assessing contribution from DG which has been subject to amendment and additions, i.e. guidance now focuses on Non-Contracted aspects and includes new considerations for DSR Schemes and ES. The guidance on de-minimis criteria for individual facilities/schemes has been clarified. The previous flow chart has been removed as it is no longer relevant (Issue 2 Figure 5.4). This clause is supported by Annexes B, D and E. Clause 9, Assessing compliance with Table 1: The main amendment to this clause includes new guidance (Clause 9.2) on conducting a high-level review of the options when the system capacity is insufficient to meet System Security requirements. Clause 10, Provision of system security: New clause providing guidance on planning remedial work to address a deficiency in system capacity. Clause 11, Cost Benefit Analysis (CBA): New clause providing guidance on undertaking a supplementary CBA when the options identified for remedial works are not considered viable. Annex A, Identification of Group Demand: The previous guidance on Group Demand (Issue 2, Clause 6.6) has been subject to amendment. New guidance has been added to assist in determination of Latent Demand. Guidance on establishing Latent Demand of DSR Schemes clarified and new guidance on establishing Latent Demand for ES added. Annex B, Capping DG/DSR Schemes/ES: Previous guidance on capping (Issue 2, Clause 6.3) has been removed as the concept of establishing the 'number of DG units equivalent to a first circuit outage' is no longer relevant, i.e. DG/DSR Schemes/ES are now considered on a 'per facility' basis. Hence, new guidance now added for capping, covering the capacities that are relevant. The guidance on

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		common mode failures has been subject to a minor amendment to account for active management network. Annex C, Technical check list: Minor amendment to check list for DG to align with changes throughout document. New check list items added for Non-Contracted DSR schemes and Non-Contracted ES. Annex D, Approaches for assessing the contribution from DG to System Security: The F factors for DG have been subject to a major amendment following analysis of DG data collated over the period 2013-2018. The F Factor values for both non-intermittent and intermittent DG apply to the facility, i.e. the consideration of the availability of DG units and the number of DG units for non-intermittent types is no longer applicable. Hence, the F factor values in Approach 1 have been replaced with new values. New table for intermittent persistence has been added to replace the previous tables & graphs in Approach 2. The types of DG have been updated to reflect the majority of DG connections on DNO networks. The previous methodology in Approach 2, which required knowledge of the availability of DG units and the number of units in a facility, has been deleted as it is now longer relevant. A new methodology for Approach 2 has been added for non-intermittent DG, which uses capacity factors. Annex E, Influencing factors for DG/DSR Schemes/ES Security Contribution: The previous guidance (Issue 2, Clause 6.2) on generation availabilities has been subject to major amendment. The explanation on establishing the availability of DG units has been deleted as it is no longer relevant. New guidance has been added for DSR Scheme considerations and ES considerations. Annex F, Examples: New examples have been added for Group Demand, Transfer Capacity, DG, DSR Schemes and ES. Annex G, Interpretation of Imperial College London Report [N8] findings: New Annex added to capture derivation of the F factor tables in Annex D from the Imperial College London report [N8]. Bibliography: The list of relevant informative references has updated.
Issue 2	December, 2014	Minor amendment to incorporate requirements for Demand Side Response (DSR). Document converted to the new ENA Engineering Report (EREP) template. This issue includes the following principal technical changes. Clause 3: New definition for DSR added. Footnote added for definition of Latent Demand. Clause 4.1: Added requirement to consider the contribution from DSR. Added explanation that DSR can be treated as either a reduction in Group Demand or an increase in System Capacity. Clause 6.10: New clause added for DSR. Clause 7.1: Added requirements for assessing the contribution from DSR. Annex A.4: Deleted reference to “ER G75/1”. Details of all other technical, general and editorial amendments are included in the associated Document Amendment Summary for this Issue (available on request from the Operations Directorate of ENA).

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Foreword

This Engineering Report (EREP) is published by the Energy Networks Association (ENA) and comes into effect from the date of publication. It has been prepared under the authority of the ENA Engineering Policy and Standards Manager and has been approved for publication by the GB Distribution Code Review Panel (DCRP). The approved abbreviated title of this engineering document is “EREP 130”.

This document replaces and supersedes EREP 130, Issue 2.

It is expected that readers of this EREP are conversant with the requirements in EREC P2/7 [N1].

Whilst implementing the guidance set out in this EREP, it is expected that compliance with all relevant industry standards is adhered to, including those Standards referenced in Annex 1 of the DCODE [N7]

Where the term “shall” or “must” is used in this document it means the requirement is mandatory. The term “should” is used to express a recommendation. The term “may” is used to express permission.

NOTE: Commentary, explanation and general informative material is presented in smaller type, and does not constitute a normative element.

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Introduction

The previous issue of this Engineering Report (EREP) focused on assessing the contribution to System Security provided by Distributed Generation (DG). However, the latest Issue of EREC P2 (Issue 7) [N1] recognises that demand may be secured using a combination of "network assets and non-network assets". Thus, the guidance in this EREP has been extended to provide guidance on assessing the security contribution from:

- network assets;
- DG, Demand Side Response (DSR) Schemes, and Electricity Storage (ES), that are contracted with a Distribution Network Operator (DNO) to provide a security service; and
- DG, DSR Schemes, and ES, that are not contracted with a DNO to provide a security service.

The experience that Distribution Network Operators (DNOs) now have assessing the security contribution from DG has provided an opportunity to refine and consolidate the guidance in this EREP.

1 Scope

This Engineering Report (EREP) provides guidance on how to assess whether an electricity distribution system meets the security requirements specified in EREC P2/7 [N1] by means of security contribution from network assets, Distributed Generation (DG), Demand Side Response (DSR) Schemes, or Electricity Storage (ES). In order to achieve this, there is a need to establish the Group Demand, as defined in EREC P2/7 [N1] and to assess the means of securing this demand in accordance with the requirement of EREC P2/7 [N1] Table 1. This EREP provides technical guidance on this assessment.

This EREP provides guidance on quantifying the security contribution where the DNO has a contract with a DG facility, DSR Scheme provider or ES facility. It also provides guidance on assessing the fortuitous security contribution from DG, DSR Scheme, ES where there is no contact in place with the DNO to provide security services.

This EREP also provides general guidance on contractual considerations which are relevant when a DNO is assessing the security contribution with a DG, DSR Scheme, ES to satisfy the requirements of EREC P2/7 [N1]. However, the details of any contractual and commercial considerations might take this outside the scope of this technical document.

This EREP also provides guidance on the use of cost benefit analysis (CBA) to establish the justification or otherwise, for providing additional security to meet the requirements of EREC P2/7 [N1] Table 1.

2 Normative references

The following referenced documents, in whole or part, are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

[N1] ENA Engineering Recommendation P2 Issue 7, *Security of Supply*

[N2] ENA Engineering Report 131, *Analysis Package for Assessing Generation Security Capability – Users' Guide*

[N3] Electricity Act 1989

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[N4] Utilities Act 2000

[N5] Energy Act 2005

[N6] Electricity (Northern Ireland) Order 1996

[N7] The Distribution Code for Great Britain (DCODE)

[N8] DG data analysis report by Imperial College London, 2019

3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

NOTE: Defined terms are capitalised where they are used in the main text of this report.

3.1
Capped
limited (contribution to System Security) during the assessment stage to ensure that the contribution to System Security from the DG, DSR Scheme, or ES does not exceed the contribution to System Security from a Circuit

NOTE: The term “Capping” should be interpreted as having the same meaning.

3.2
Circuit

part of an electricity supply system between two or more circuit breakers, switches and/or fuses inclusive

NOTE 1: Circuits may include transformers, reactors, cables and overhead lines. Busbars are not considered as Circuits and are to be considered on their merits.

[ENA EREC P2/7, Clause 3.1]

3.3
Circuit Capacity

appropriate continuous rating or cyclic rating or, where it can be satisfactorily determined, the appropriate emergency rating, taking into account the relevant environmental conditions and the expected demand profile, which should be used for all Circuit equipment and associated protection systems

NOTE: Circuit Capacity should be assessed in MVA.

[ENA EREC P2/7, Clause 3.2]

3.4
Cold Load Pickup
difference between the Measured Demand on a Circuit following re-energisation of that Circuit and the demand on that Circuit which the DNO would have reasonably expected had no de-energisation occurred

[ENA EREC P2/7, Clause 3.3]

3.5
Contracted
bilateral agreement between a DNO and party providing System Security from a DG facility, a DSR Scheme or an ES facility

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3.6
Declared Net Capability (DNC)
declared gross capability of a DG facility, measured in MW, less the normal total parasitic power consumption attributable to that plant

NOTE 1: Declared Net Capability (DNC) as used in this Engineering Report should not be confused with declared net capacity (DNC) as used in the Electricity Act [N3] and Statutory Instrument 2001 3270 [N4].

NOTE 2: For the purpose of this definition the term “parasitic power consumption” refers to the electrical demand of the auxiliary equipment, which is an integral part of the DG, essential to the DG’s operation. For the avoidance of doubt “parasitic power consumption” does not include demand supplied by the DG to an on-site customer.

NOTE 3: The DNC of a DG facility is taken as the aggregate nameplate capacity of all the units within the DG facility, less any parasitic load.

3.7
Demand Facility
facility connected to the distribution network which consumes electrical power

3.8
Demand Side Response (DSR)
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

[ENA EREC P2/7, Clause 3.4]

NOTE 1: The electrical power consumption of a Demand Facility can be modified using DSR.

3.9
Demand Side Response Scheme (DSR Scheme)
DSR arrangement which is being implemented at a Demand Facility

3.10
Distributed Generation (DG)
generating facility connected to the distribution network, where a generating facility is an installation comprising one or more generating units

[ENA EREC P2/7, Clause 3.5]

3.11
Distribution Network Operator (DNO)
person or legal entity named in Part 1 of the Distribution Licence and any permitted legal assigns or successors in title of the named party

[ENA EREC P2/7, Clause 3.6]

NOTE 1: A DNO might also be referred to as a Distributor.

NOTE 2: The definition of a DNO also applies to an Independent Distribution Network Operator (IDNO).

3.12
Electricity Storage (ES)
storage facility connected to the distribution network which, behaves as DG when exporting power to the distribution system and, behaves as a Demand Facility when consuming electrical power from the distribution system

NOTE 1: An example of an ES is a battery installation (treated as a Demand Facility when charging and DG when discharging).

NOTE 2: DG is differentiated from ES as it does not store energy.

NOTE 3: ES is a form of ‘other means’ as referred to in ENA EREC P2/7.

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3.13
First Circuit Outage (FCO)
fault or pre-arranged Circuit outage

[ENA EREC P2/7, Clause 3.7]

3.14
Generator
person who generates electricity under licence or exemption under the Electricity Act 1989 [N3] (as amended by the Utilities Act 2000 [N4] and the Energy Act 2004 [N5])

[ENA EREC P2/7, Clause 3.8]

NOTE: Electricity (Northern Ireland) Order 1996 [N6].

3.15
Group Demand
DNO's estimate of the maximum demand of the group being assessed for EREC P2/7 [N1] compliance with appropriate allowance for diversity

NOTE 1: When estimating the maximum demand of the group the DNO should, where necessary, take into consideration (but not be limited to) the following: the Latent Demand due to DG, the Latent Demand due to DSR, the Latent Demand due to ES, the effect of Suppliers time of use tariffs, the effect of Network Operator price signals, the effects of Cold Load Pickup and, data granularity implications (instantaneous peak vs. time averaged flow).

NOTE 2: The Group Demand at grid supply points must be consistent with the demand data submitted to a transmission company under the terms of the GB Grid Code [3].

[ENA EREC P2/7, Clause 3.9]

3.16
Intermittent Generation
generation facility where the energy source of the prime mover cannot be made available on demand

3.17
Latent Demand
demand that would appear as an increase in Measured Demand if the DG was not operating, the DSR was not implemented or other means (e.g. time of use tariff, export from electricity storage devices) of suppressing the Measured Demand within the network (for which the Group Demand is being assessed) was not operating

[ENA EREC P2/7, Clause 3.10]

NOTE 1: Latent Demand for an ES exists when there is export or restricted import, at the time of Measured Demand.

3.18
Measured Demand
summated demand measured at the normal (network) infeed points to the network for which Group Demand is being assessed

[ENA EREC P2/7, Clause 3.11]

3.19
Non-Contracted
absence of a bilateral agreement between a DNO and party providing System Security from a DG facility, a DSR Scheme or an ES facility

NOTE: Non-Contracted does not prohibit the existence of a contract outside of DNO involvement.

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3.20
Non-intermittent Generation
generation facility where the energy source for the prime mover can be made available on demand

3.21
Persistence (T_m)
the minimum time for which output from Intermittent Generation must be continuously available for it to be considered to contribute to System Security

3.22
Regulatory Financial Performance Reporting (RFPR)
documents and tables collected by Ofgem annually for the purposes of administering compliance and monitoring performance of DNOs in accordance with the regulatory framework

NOTE: Refer to Ofgem guidance on regulatory financial performance reporting.

3.23
Second Circuit Outage (SCO)
fault following a pre-arranged Circuit outage

NOTE: The recommended levels of security are not intended at all times to cater for a first fault outage followed by a second fault outage or for a simultaneous double fault outage. Nevertheless, in many instances, depending upon switching and/or loading/generating arrangements, they will do so.

[ENA EREC P2/7, Clause 3.13]

3.24
System Security
the capability of a system to maintain supply to a defined level of demand under defined outage conditions

[ENA EREC P2/7, Clause 3.16]

3.25
Transfer Capacity
capacity of an adjacent network which can be made available within the times stated in EREC P2/7 Table 1. Transfer Capacity will be limited by Circuit Capacity or other practical limitations on power flow

[ENA EREC P2/7, Clause 3.18]

4 Assessment process overview

When assessing whether a distribution system complies with the security requirements of EREC P2/7 [N1] DNOs should consider the contribution to System Security from:

a) network assets;

b) DG connected to its network;

c) DSR Schemes connected to its network; and

d) ES connected to its network.

NOTE: The contribution to System Security from DG, DSR Schemes and ES is variable dependant on whether the DNO has a contractual arrangement with the operator/provider of one of these non-network assets.

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The guidance in this EREC simplifies the presentation of Circuit ratings and security contribution from DG, DSR Schemes and ES, inferring a simple summation to assess aggregate capacities etc. However, in reality it will always be necessary to perform appropriately complex assessments, probably via modelling software, to ascertain that a Circuit is not unacceptably overloaded in the outage scenarios set out in EREC P2/7 [N1]. Note also Section 5.1 of EREC P2/7 [N1] where there is a specific requirement that equipment should not be overloaded to a point where it suffers unacceptable loss of life.

When seeking to assess whether a particular section of network is compliant with the security requirements in EREC P2/7 [N1] it is necessary to follow a procedure similar to that shown diagrammatically in Figure 1. This figure includes a number of stages and refers to clauses providing detailed guidance on each of these stages. For simplicity the security assessment process described in this EREP describes the general methodology which should be adapted by the DNO as appropriate.

For DNOs this exercise is a periodic one across the full network, supplemented by specific assessments at points on the network where the System Security needs to be reviewed as a result of changes in network design (including network reinforcement and new connections), DG or ES developments or implementation of DSR Schemes. Hence, ongoing compliance with EREC P2/7 [N1] should be achieved.

For substations serving a Group Demand over 12 MW the DNOs shall perform an annual security compliance review, normally aligned to the annual RFPR submission. In addition, for these substations, a security compliance review shall be performed where there are significant changes to network design, demand or generation.

In assessing the security contribution from DG, DSR Schemes and ES, the DNO will want to balance the effort required to obtain accurate data with the risks to loss of supplies from using inaccurate or uncertain data.

NOTE: An overview of the technical issues that may need to be considered are shown in the Technical Check List provided at Annex C to this report.

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Figure 1 – The assessment process

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5 Determine the Group Demand and class of supply

Considering a section of network, a DNO should identify the demand groups within its network where a security of supply assessment should be carried out. There will be numerous demand groups in a DNO network and lower voltage demand groups will combine to form larger demand groups, as illustrated in Figure 2.

The DNO should carry out a bespoke assessment of the Latent Demand based on the principles in this clause.

NOTE: 'Dashed' lines indicate a section of network and hence a demand group

Figure 2 – Typical demand groups (section of network) in a network

To identify the class of supply (see Table 1 in EREC P2/7 [N1]) for each demand group, the Group Demand first needs to be established – Figure 3 outlines the process and the need to determine the Measured Demand, any Latent Demand and the effects of Cold Load Pickup.

If there is DG, a DSR Scheme or ES connected to the network connected within the demand group, it will be necessary for the DNO to determine whether there is any Latent Demand (see Annex A) and, if so, if it should be added to the Measured Demand to establish the Group Demand. However, to avoid excessive and unproductive computation, there is a de-minimis test to determine the extent of Latent Demand assessment required.

- If the aggregate capacity of Non-Contracted; DG, DSR Schemes (where this can be readily established), and ES, is less than 5% of Measured Demand, then Group Demand should be taken as the same as Measured Demand.

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The de-minimis test shall exclude capacity from Contracted DG, DSR Schemes, and ES, as the DNO should account for Latent Demand associated with contracts (see Figure 2).

The DNO should establish the Latent Demand based on the principles outlined in this Clause and Annex A. With experience, further clarity may emerge which could be incorporated into later issues of this EREP.

Consider the scenario where the supply to Customer A has been interrupted due to a fault on circuit C2. In this case, where Customer A has agreed to a single circuit risk agreement, EREC P2/7 [N1] states that this customer's supply is considered to be restored when there is an outage on circuit C2. Customer A's demand is included in the Group Demand and used to establish the class of supply. However, where such a customer has a connection agreement with the DNO requiring only single circuit security, EREC P2/7 [N1] considers this to be a form of a DSR Scheme Contact between the customer and the DNO and that for the purpose of complying with the requirement to supply the 'minimum demand to be met', activation of this DSR Scheme is equivalent to restoration of demand.

The DNO should also consider whether the Group Demand should be increased to cater for the effects of Cold Load Pickup. Cold Load Pickup is only a concern when supplies to particular electrical loads are being restored following a period of interruption. The following are examples of loads which may exhibit Cold Load Pickup characteristics.

i. Electrical heating.
ii. Refrigeration.
iii. Air conditioning.
iv. Heat pump (HP), and
v. Electric vehicle (EV).

The magnitude of the Cold Load Pickup is dependent on a number of factors including the:

- duration of the outage;

  Typically, the longer the duration, the greater the Cold Load Pickup as the natural diversity is lost.

- time of day and year when the outage occurs;

  Outages in winter particularly, during the evening and overnight, would typically have a greater impact on the Cold Load Pickup resulting from electric heating. Outages in summer, particularly during the day, would typically have a greater impact on the Cold Load Pickup resulting from air conditioning load.

- nature of the load.

  Cold Load Pickup is likely to have an impact on the observed Measured Demand that reduces over a period of several hours. However, some demand such as EV chargers may impose a demand lasting only several seconds when supply is restored to a fully charged battery.

Historically the effects of Cold Load Pickup have not been explicitly taken into account in establishing the Group Demand and the effects have been accommodated within the short time rating of network assets. With increased use of cyclic and emergency ratings for Circuits, their capability to accommodate Cold Load Pickup may need to be established. The following criteria should be considered when evaluating the impact of Cold Load Pickup on the Group Demand.

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a) Cold Load Pickup should not be ignored if there is awareness that the network assets may not have sufficient short-time rating for a FCO or there is likelihood of the peak Measured Demand occurring during a Cold Load Pickup event; and

b) Cold Load Pickup may be ignored if the particular load is less than 10% of the total load for rural networks (where the majority of the network is overhead) and less than 30% for urban networks (where the majority of the network is underground)[2].

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[2] A report by Manchester University in 2016 [4] on the assessment of LV network capacity for electric vehicle (EV) and photovoltaic (PV) connection, found that the existing LV networks could host a certain percentage of these onerous loads prior to issues arising with capacity.

Figure 3 – Determine class of supply and Group Demand

6 Determine capacity of network assets and assess compliance

6.1 General

The next step is to identify the capacity of the existing network assets and establish if they are capable of securing the Group Demand identified in Clause 5, in accordance with the criteria specified in ER P2/7 Table 1 [N1].

NOTE: Voltage criteria and differing Circuit capacities and impedances may be limiting factors in determining the network capacity under FCO and SCO conditions. In such situations the use of network analysis software becomes essential to determine the network capacity.

For FCOs, the Circuit Capacity should normally be based on the cold weather ratings, but if the Group Demand is likely to occur outside the cold weather period the ratings for the appropriate ambient conditions should be used. Where the Group Demand does not decrease at the same rate as the Circuit Capacity (e.g. with rising temperature) special consideration is needed.

For SCO, in view of the proportions of Group Demand to be met in EREC P2/7 [N1] Table 1, the ratings appropriate to the appropriate ambient conditions of the period under consideration should be used, which may be other than winter conditions.

The term ‘class of supply’ is associated with a MW quantity in EREC P2/7 [N1], but Circuit Capacity should be considered in MVA with due regard for generating plant MW sent out and MVAr capability where appropriate.

6.2 Intrinsic network capacity

The intrinsic network capacity should be established by considering the Circuit Capacity of each Circuit supplying the demand group. The intrinsic network capacity is that which is available from the Circuits supplying the demand group under system intact and the depleted network conditions that need to be secured to the level set out in Table 1 of EREC P2/7[N1]: it is the capacity available within 60 s of the commencement of an outage.

NOTE: 60 s relates to an automatic switching facility that does not depend on communications, requires no local manual or remote initiation and which has been appropriately planned and designed considering the load on network assets and protection settings. A hot standby arrangement where an on-site transformer normally out-of-service is automatically switched in-to-service within 60 s of an outage occurring would be considered to be part of the intrinsic capacity.

For classes of supply B to E inclusive, the intrinsic network capacity should be determined under FCO conditions, i.e. with an outage of the most critical Circuit.

For classes of supply D and E, the intrinsic network capacity should also be determined under SCO conditions, i.e. with an outage of both the first and second most critical Circuits.

In the event that the intrinsic network capacity is insufficient to meet the requirements of EREC P2/7 [N1] it will be necessary for the DNO to establish the Transfer Capacity to meet any deficiency in System Security.

6.3 Transfer capacity

The Transfer Capacity should be established when the intrinsic network capacity is insufficient to comply with the requirements of EREC P2/7 [N1] Table 1.

Transfer Capacity relates to the capability of an adjacent network to supply demand of a given demand group during FCO and SCO conditions. Hence in addition to being affected by the Circuit Capacity of interconnection between the demand groups, Transfer Capacity is dependent on the capacity of an adjacent demand group(s) to the one being assessed.

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Transfer Capacity is generally utilised by network re-configuration via:

- Automatic switching of available network capacity via a local/remote network management system (typically within 15 mins) i.e. local/remote automation;
- Manual switching of available network capacity via a remote management system (typically within 15 mins) i.e. remote control; or
- Manual switching of available network capacity via local operation of equipment (typically within 3 hrs).

The following considerations are relevant when assessing the available Transfer Capacity.

a) Capacity of the Circuit used to implement the transfer and the time to implement

The Circuit Capacity of the Circuits used to transfer demand relevant to the time when the transfer is required and the demand profile that it would be exposed to.

b) Availability & reliability of the circuit used to implement the transfer

The co-ordination of planned outages is critical when considering the use of Transfer Capacity. Unless there is a high probability that a Circuit is available for demand transfer, it may be prudent to reduce the theoretical Transfer Capacity to reflect a Circuit's unavailability.

c) Gross and net demand (if any) on the Circuit used to implement the transfer

Unless a Circuit being considered is clean, i.e. there are no customers connected to it, it is necessary to establish the demand headroom available on the Circuit. Hence, before the Circuit is used to transfer demand, the gross demand (demand without DG/DSR Schemes/ES operating) and net demand (demand with DG/DSR Schemes/ES operating) should be established. This requires additional assessment in accordance with Clauses 5, 7 and 8.

In determining the capacity of a circuit to be used to implement demand transfer, the effects and response of any DG/DSR Schemes/ES must be considered once it is operating as a Transfer Circuit, e.g. fault level implications for connected DG or ES.

d) Impact of the demand transfer on the demand group to which the demand (or generation) is transferred

The DNO should consider whether the demand group 'receiving' the demand transfer will continue to operate within acceptable operating limit.

e) Whether interruptible demand on the adjacent network should be interrupted to create capacity for the transfer

Where relevant, the DNO should establish if it is acceptable to interrupt the supply to customers not affected by the FCO or SCO in order to create the capacity in the receiving demand group to implement the demand transfer.

f) Application of pre-outage transfer and post outage transfer

The DNO may consider it normal practice to re-configure the network in advance of a planned FCO. This may use the same Transfer Capacity as that applied following an unplanned outage.

g) Temporary network re-arrangement due to seasonal effects

The DNO may re-configure the network to an alternative 'normal' arrangement during seasonal events which may affect the Transfer Capacity of a demand group. In this case a security assessment should be considered for each seasonal network configuration.

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In the event that the intrinsic network Capacity and Transfer Capacity is insufficient to meet the requirements of Table 1 of EREC P2/7 [N1] it will be necessary for the DNO to assess the security contribution of DG, DSR Schemes and ES. With regards to item c) above, the DNO may have already initiated this assessment.

7 Contribution to System Security from Contracted DG, DSR Schemes, and ES

7.1 General

In considering the security contribution from means other than network assets, the DNO can initiate this by establishing whether the aggregate capacity of DG, DSR Schemes and ES connected to the network might be sufficient to meet any deficiency in System Security. If the aggregate is less than any deficiency, the actual DG/DSR Scheme/ES security contribution will definitely be inadequate to meet the requirements of EREC P2/7 [N1] Table 1 and it will be necessary for the DNO to consider remedial options (reinforcement, additional DSR arrangements etc). However, the contribution of the DG, DSR Schemes and ES might still be of value, in limiting the extent of remedial options.

In the event of the DNO needing to rely on DG, DSR Schemes and ES, during Circuit outages, the DNO needs to decide whether to rely on the fortuitous contribution associated with their normal commercial operation, or to enter into a commercial arrangement with the DG/DSR Scheme/ES operator/owner. This clause describes the aspects that should be considered when the DNO is entering into a contract arrangement, and Clause 8 describes the assessment of DG/DSR Schemes/ES which are not contracted with the DNO.

There will be DG/DSR Schemes/ES for which the DNO:

- cannot assess the output profiles, either from established or newly connecting DG/DSR Schemes/ES; or
- considers that the DG/DSR Schemes/ES does not exhibit predictable and steady output profiles; or
- requires enhanced System Security contribution beyond the normal observed profile, either to extend to 24 hrs operation, or to provide temporarily greater MW support.

In these cases where the DNO is seeking to rely on the security contribution, the DNO should consider entering into a contract with the DG/DSR Scheme/ES owner/operator. The contracted security contribution should be based on the capacity the DG/DSR Scheme/ES owner/operator is able to offer and provide acceptable reassurance that they will be able to provide the capacity when required by the DNO. The contract is likely to be such that the DG/DSR Scheme/ES operator/owner takes the risk of the facility being unable to provide an agreed capacity upon request.

The DNO should assess whether the costs, risks and benefits of procuring System Security contribution from DG/DSR Schemes/ES, through such a contract, is a more efficient and cost effective option overall compared to the additional System Security that would be provided by increasing the intrinsic capacity of the network or Transfer Capacity, for example by reinforcement.

Where the DNO has a contract with a DG, DSR Scheme or ES owner/operator which governs requests or operational instructions from the DNO, then the security contribution should be based on the terms of the bilateral agreement. The contract shall have considered dominance (Annex B) whereby the DNO is satisfied that any necessary capping has been accounted for within the contract.

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7.2 Determine the security contribution from Contracted DG

The issues that may need to be considered by a DNO when looking to enter into a contract with a DG facility owner/operator for the provision of a contribution to System Security are described below.

a) Number and capacity of generating units in the DG facility, i.e. DNC of the DG facility

b) DG action on receipt of DNO request/instruction for operation

   i. Response time, e.g. cold start/warm start/reconnection times required

   ii. Minimum export required

   iii. Minimum duration of required operation

c) Communication arrangement with DG facility, including the resilience of these arrangements

d) DG stability requirements and interface protection

   i. Agreed operating parameters and settings

   ii. Fault ride through capability required

   Evidence should be presented to demonstrate that the DG will ride through a range of credible network outages. Clause 8.3.1 provides guidance on assessing fault ride through for DG (which is relevant for both Contracted and Non-Contracted DG).

e) Availability/reliability requirements

f) Coordination of DNO and DG planned outages

g) The provision of information required to monitor the operation of the DG facility

The Contacted DG security contribution associated with the DG shall be based on the terms of the contract.

The security contribution associated with the contract shall incorporate any necessary capping of the DG security contribution to avoid dominance in accordance with EREC P2/7 [N1] Clause 5.2. Annex B of this EREP includes further guidance on capping.

7.3 Determine the security contribution from Contracted DSR Schemes

The issues that may need to be considered by a DNO when looking to enter into a contract with a Demand Facility owner/operator for the provision of a contribution to System Security via a DSR Scheme, are described below.

a) Maximum import capacity of Demand Facility;

b) Demand Facility action on receipt of DNO request/instruction;

- Response time
- Reduction in demand required expressed as either a maximum import or reduction of present demand (e.g. expressed a percentage of MW reduction)
- Maximum duration of required reduction (e.g. hours per day, maximum number of contiguous days)

c) Communication arrangement with Demand Facility;

d) Coordination of DNO and Demand Facility outages;

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e) The provision of information required to monitor the operation of the Demand Facility and the DSR.

For a Contracted DSR scheme, a contribution to security shall be applied when that import constraint is considered to be active and have an observed effect at the time period being assessed. The value of the security contribution from the active constraint shall be based on the observed performance under the terms of the contract, but cannot be greater than the Latent Demand.

The value of the security contribution from the active constraint shall be based on the terms of the contract.

When establishing the contribution value for the contract, it is expected that the DNO takes account of the following factors:

i. An increase in demand reduction magnitude increases the security contribution;
ii. An increase in demand reduction duration (generally but not necessarily) increases the security contribution;
iii. An increase in demand recovery period increases the security contribution;
iv. A reduction in energy recovery increases the security contribution;
v. A more uniform energy recovery increases the security contribution;
vi. A reduction in the ratio of DSR Scheme capacity : peak network demand, increases the security contribution; and
vii. A peakier load profile increases the security contribution.

The contract shall incorporate any necessary capping of the DSR Scheme security contribution to avoid dominance in accordance with EREC P2/7 [N1] Clause 5.2. Annex B of this EREP includes further guidance on capping.

7.4 Determine the security contribution from Contracted ES

Contracted ES is ES contracted to export at time of peak and/or ES contracted not to import at time of peak.

The issues that may need to be considered by a DNO when looking to enter into a contract with an ES facility owner/operator for the provision of a contribution to System Security are described below.

a) Maximum capacity of ES facility – for both export and import;
b) Agreed cycle of operation for ES facility;
   i. Hourly/daily sequence of operations, i.e. times of import and times of export
   ii. Duration of operating sequences (charge/discharge cycle time)
c) ES facility action on receipt of DNO request/instruction for operation;
   i. Response time, e.g. cold start/warm start/reconnection times required
   ii. Minimum export required
   iii. Minimum duration of export required

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iv. Reduction in demand required expressed as either a maximum import or reduction of present demand (e.g. expressed a percentage of MW reduction)

d) During ES export – stability requirements and interface protection;

i. Agreed operating parameters and settings

ii. Fault ride through capability required

Evidence should be presented to demonstrate that the facility will ride through a range of credible network outages. Clause 8.3.1 provides guidance on assessing fault ride through for generation (relevant for both Contracted and Non-Contracted).

e) Availability/reliability requirements for ES facility;

f) Coordination of DNO and ES planned outages.

The contribution to security from ES which is Contracted to export shall be based on the terms of that contract.

When establishing the contribution value for the contract, it is expected that the DNO takes account of the following factors.

i. An increase in ES capacity increases the security contribution;

ii. An increase in ES power increases the security contribution;

iii. A reduction in ES charge time increases the security contribution;

iv. An increase in ES efficiency increases the security contribution;

v. A reduction in the ratio of ES power: peak network demand, increases the security contribution;

vi. A peakier load profile increases the security contribution.

For ES which is Contracted to constrain its import (akin to a Contracted DSR scheme), a contribution to security shall be applied when that import constraint is considered to be active and have an observed effect at the time period being assessed. The value of the security contribution from the active constraint shall be based on the observed performance under the terms of the contract, but cannot be greater than the latent demand.

The contract shall incorporate any necessary capping of the ES security contribution to avoid dominance in accordance with EREC P2/7 [N1] Clause 5.2. Annex B of this EREP includes further guidance on capping.

8 Contribution to System Security from Non-Contracted DG, DSR Schemes, and ES

8.1 General

Where the DNO relies on the fortuitous security contribution of Non-Contracted DG/DSR Schemes/ES, it should be assessed in accordance with the guidance in this Clause. Where the DNO has a need for a definitive security contribution then the costs, risks and benefits of procuring this from a DG/DSR Scheme/ES owner/operator facility should be assessed (see Clause 7).

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If the aggregate capacity of Non-Contracted, DG, DSR Schemes which are known, and ES, is greater than any system capacity deficiency identified it will be necessary to carry out further analysis to calculate the security contribution from these sources.

NOTE: The aggregate capacity of Non-Contracted items will have been considered earlier in the assessment process, during calculation of Group Demand (see Clause 5).

The aggregate of Non-Contracted capacity may contain all or some of the items in a) - d).

a) Non-Contracted DG (the DNO should have notification records of all DG connected to its network);

b) Non-Contracted DSR Schemes which are known to the DNO (the DNO may have visibility of a DSR Scheme through information available from a third party);

c) Non-Contracted ES export (the DNO should have notification records of all ES facilities connected to its network);

d) Non-Contracted ES import constraints which are known to the DNO (the DNO may have visibility of an ES import constraint through information available from a third party).

8.2 De-minimis criteria

In addition to the de-minimis test in Clause 5, there is another de-minimis test for Non-Contracted DG/DSR Schemes/ES to establish whether the individual capacity is sufficiently small that it is considered inappropriate to assess its security contribution. It seems reasonable to base this de-minimis test on the Group Demand of the network to which the DG/DSR Scheme/ES is connected. It is recognised that establishing an appropriate de-minimis threshold is subjective, therefore a pragmatic approach needs to be taken. This report recommends that the de-minimis threshold should be set at 5% of Group Demand. Additionally, assessments of security contribution are not necessary for a facility below 100 kW in capacity, i.e. DNC of the DG, maximum reduction in demand associated the known DSR Scheme, capacity of the ES.

8.3 Determine the security contribution from Non-Contracted DG

The process for assessing the fortuitous contribution to System Security that can be provided by DG is described in the following sub-clauses. Where there is more than one DG facility in a network, a similar process is followed to establish the security contribution from each DG facility. The overall security contribution from DG within the demand group is taken to be the arithmetic sum of the contribution from each DG facility within that network.

When assessing the contribution to System Security from DG it is necessary to use one of the three approaches described in Annex D. Furthermore, the following influencing factors may be considered in further detail when assessing the DG contribution to security (see Annex E).

- Availability;
- Operating regime;
- Remote generation;
- Intermittency.

By using either generic DG information or bespoke operational data for a particular DG, it is possible to establish the F factors and hence the security contribution for each DG facility.

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This fortuitous contribution is based on the expected normal operational behaviour associated with a typical DG facility operating in the UK.

The assessment of Non-Contracted DG shall incorporate any necessary capping of the security contribution to avoid dominance in accordance with EREC P2/7 [N1] Clause 5.2. Annex B of this EREP includes further guidance on capping.

8.3.1 Assessing the ride through capability of the DG

In the context of utilising the contribution from a DG plant to ensure compliance with the requirements of Table 1 of EREC P2/7 [N1], it will be necessary for the DNO to be satisfied with how the DG facility will respond to events on the network. For example:

a) during a network fault that results in a FCO event, the DG will need to be either stable enough to remain connected during the fault and then continue to support the requisite level of demand during the period of the FCO, or until the demand can be transferred to an alternative network; or

b) if the DG disconnects as a result of the fault it will be necessary for the DG to reconnect and synchronise to the network to support the requisite level of demand either

   i. within the times allowable in Table 1 of EREC P2/7 [N1]; or

   ii. sufficiently rapidly to prevent any overloading of any remaining network assets supplying demand.

Unless the DNO has modelled the transient DG performance and has evidence to demonstrate that the DG will ride through a range of credible network outages it should be assumed that the DG will trip during a FCO or SCO unplanned outage. Similarly, the DNO should confirm the reconnection arrangements with the DG operator rather than assuming that a DG will automatically reconnect to the system once the network voltage and frequency has returned within normal pre-fault limits. The behaviour of a DG facility will be less certain during an unplanned outage than during a planned outage, e.g. for a demand group where supply continuity is required for a SCO, transient performance should be modelled under planned outage conditions.

8.4 Determine the security contribution from Non-Contracted DSR Schemes

DSR Schemes may be present on a network but not contracted with the DNO. In these cases, the assessment of DSR Scheme contribution to security would require either – DNO knowledge of the DSR Scheme or detailed research to determine existence of controlled demand reduction. The DNO is unlikely to have access to appropriate detailed data and this EREP recommends that Non-Contracted DSR Schemes should be assumed to have no contribution to security, unless the DNO is aware of site-specific details.

Where the DNO is aware of Non-Contracted DSR Schemes through liaison with third parties, the details should be acquired where possible. In this case the security contribution should be assessed based on the available information following the principles in Clause 7.4. The DNO should take a view of the confidence they have of this information.

Any assessment of Non-Contracted DSR Schemes shall incorporate necessary capping of the security contribution to avoid dominance in accordance with EREC P2/7 [N1] Clause 5.2. Annex B of this EREP includes further guidance on capping.

Since the demand reduction associated with a DSR Scheme is implemented in response to an instruction, it is distinct from other forms of demand reduction such as supplier time-of-use (TOU) tariffs. An ongoing research project by Scottish and Southern Electricity Networks suggests that there is insufficient evidence that financial incentives, e.g. TOU tariffs, are

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effective in changing consumer behaviour. Conversely, DNOs may acquire demand profiles of specific customers and details of specific types of tariff arrangements which demonstrate a change in consumer load patterns e.g. 'E7' off-peak heating time switched load, or wind spilling tariffs, where there is a recognizable and predictable link between the tariff and Group Demand. However, unless there is a strong link between tariffs/schemes and a reduction in demand, based on collated data, this EREP recommends that they should not be considered during assessment of network security, i.e. there is no Latent Demand and hence no contribution to security.

8.5 Determine the security contribution from Non-Contracted ES

The security contribution from Non-Contracted ES should be based on the recorded details for the facility – the DNO should have the import and export profile of ES facilities (for facilities >30 kW) connected to its network. The security contribution from Non-Contracted ES export should be subject to a site-specific study, i.e. ENA EREP 131 [N2] (see Annex D.5). The security contribution from Non-Contracted ES import should be subject to a site-specific study based on the principles in Clause 8.4.

The assessment of the security contribution from Non-Contracted ES shall incorporate any necessary capping of the security contribution to avoid dominance in accordance with EREC P2/7 [N1] Clause 5.2. Annex B of this EREP includes further guidance on capping.

The import from Non-Contracted ES should be assumed as being accounted in the normal demand profile, i.e. within the Measured Demand.

9 Assessing compliance with Table 1

9.1 General

Once the contribution to System Security from DG/DSR Schemes/ES has been determined, it is a simple matter of adding this value to the level of security contribution provided by the network assets. The network under consideration can be deemed compliant with the requirements of Table 1 of EREC P2/7 [N1] if the aggregate of the:

- Intrinsic network capacity;
- Transfer Capacity;
- Contracted DG/DSR Schemes/ES; and
- Non-Contracted DG/DSR Schemes/ES, is sufficient to meet the level of security required in Table 1.

It is critically important to note that this capability assessment needs to be done for each of the time periods specified in Table 1 of EREC P2/7 [N1]. For instance, in the case of Class C, the two time periods of concern are the demand that must be recovered in 15 mins and the demand that must be recovered in 3 hrs. Both periods must be assessed separately since the required demand, the number of Circuits and the security contribution from DG/DSR Schemes/ES could be different in each case. Compliance with EREC P2/7 [N1], is required for each time period.

If the demand to be met exceeds the system capacity (i.e. the capacity provided by the network assets plus the contribution from DG/DSR Schemes/ESF) under FCO conditions in any one time period, the system is declared as not complying with the requirements of Table 1 of EREC P2/7 [N1]. If the network under consideration is compliant under FCO conditions, then the process moves to checking for compliance under conditions of a SCO, noting that under EREC P2/7 [N1] the requirement to remain secure after a SCO only applies to Group Demands in excess of 100 MW.

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9.2 High-level review of options

In the event that the system capacity is insufficient to meet System Security requirements, as detailed in Table 1 of EREC P2/7 [N1], the DNO should undertake a review of the options to address the deficiency, such as:

- network reinforcement; and
- establishing contracts with DG, DSR Scheme, and ES owner/operator.

The review of the options should consider:

- budget costs associated with the network and non-network options;
- estimate of the longevity of the solution based on the demand growth scenarios; and
- the asset management strategy and network planning policy for the DNO.

Having understood the budget costs, coupled with the benefits of the options, the DNO should ascertain if compliance with Table 1 of EREC P2/7 [N1] is:

a) economically justifiable; and

b) aligns with the overall asset management strategy.

Should the high-level review of options indicate the compliance with Table 1 of EREC P2/7 [N1] is justifiable, then in-depth planning of the work should commence. Otherwise, the DNO shall prepare a supplementary cost benefit analysis (see Clause 11).

10 Provision of system security

In order to remain compliant with EREC P2/7 [N1], the DNO must ensure that there is or is planned to be sufficient System Security to meet the forecast Group Demand. Where a deficiency in System Security is identified, a detailed analysis of the options considered in Clause 9 should be undertaken. The detailed analysis should identify whether any network reinforcement or new contractual arrangements can be implemented in a timely manner, i.e. in advance of the demand group becoming non-compliant with the requirements of Table 1 of EREC P2/7 [N1]. Options considered should include:

a) Increasing the intrinsic network capacity (for example, network reinforcement, re-assessing the Circuit Capacity, assessing options for enhancing network voltage management);

b) Increasing the Transfer Capacity or the reducing the time for implementing Transfer Capacity (for example, network automation);

c) Implementing contractual arrangements for security services from DG/DSR Schemes/ES; and

d) Implementing a combination of a), b) and c)

In the case where network reinforcement or appropriate contractual arrangements cannot be completed in advance of the DNO network becoming non-compliant with Table 1 of EREC P2/7 [N1], the DNO shall request a technical derogation from Ofgem [5] for a specified period of time, i.e. timebound derogation.

11 Cost Benefit Analysis (CBA)

A supplementary CBA shall be prepared when the DNO's high-level review of remedial works indicates that the options are not economically justifiable and/or do not align with its asset management strategy.

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The CBA shall be based on the costs of achieving the minimum requirements set out in Table 1 of EREC P2/7 [N1] – It should primarily assess whether the cost of the reinforcement or implementing security service contracts to comply with the requirements in Table 1 are reasonable when compared with the improvements in the supply security that would be expected to be delivered.

The DNO's own CBA template or the latest CBA template available from Ofgem may be used. The CBA should primarily be based on the rate of return principle (discount rate), and should also consider:

a) Network losses and the economic value of those losses; and

b) The cost of supply interruptions to customers;

Expected Energy Not Supplied (EENS) is expressed in MWh over a specific time period (e.g. a year). Using the concept of EENS, it is possible to monetise the shortfall in system capacity where VoLL has also been calculated since the EENS can then be multiplied by VoLL. Hence, a change in EENS rising from remedial actions may be assessed based on:

- VoLL= £17,000 / MWh; different values of VoLL can be used where deemed appropriate by the DNO
- VoLL impact assessed for an appropriate period of time, relevant for the CBA

In the case where the supplementary CBA justifies providing additional system security to meet the requirements of EREC P2/7 Table 1, the DNO should progress plans for this, otherwise the CBA shall be used to demonstrate compliance with EREC P2/7 [N1].

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Annex A
(normative)

Identification of Group Demand

A.1 General

In order to ensure that there is sufficient System Security, it is necessary to identify the Group Demand to be secured. This requires that, as far as reasonably practicable Latent Demand within the network is identified and added to the recorded or Measured Demand, taking appropriate account of diversity and coincidence of demand and DG/DSR Scheme/ES profiles, to establish the Group Demand.

Latent Demand associated with generation, for example DG and ES export, is a straightforward concept which does not warrant detailed explanation.

DSR Schemes are considered as an increase in system capacity, hence the DNO will need to consider the extent to which the Measured Demand should be increased to reflect the demand that has been constrained by the DSR Scheme in order to establish the Group Demand that needs to be secured. Likewise, if an ES facility is Contracted not to import, then the Measured Demand will need to be increased by the constrained import, i.e. the Latent Demand for the ES not importing (akin to a DSR Scheme).

Equation 1 shall be applied when determining Latent Demand.

Latent Demand =

Contracted and Non-Contracted (where known) DG export at the time of Measured Demand

+

Amount by which the import at a Demand Facility is reduced by a Contracted or Non-Contracted (where known) DSR Scheme, which is active at the time of Measured Demand

+

Contracted or Non-Contracted (where known) ES export at the time of Measured Demand

+

Amount by which the import at an ES facility is reduced by a Contracted import constraint, which is an active at time of Measured Demand

Equation. 1

As implied in Equation 1, a DSR Scheme or ES import constraint contract, which is considered not to be active at the time of Measured Demand has no latency, i.e. Latent Demand = 0 MW. In deciding that the demand/import constraint was active for a particular facility, the DNO should consider the following options to determine the Latent Demand.

a) The terms of the Contract with the DNO

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The DNO has details of a contract and assumes that the maximum import capacity is required at the time of Measured Demand and is thus being constrained at or below a certain (as per a contract) value.

b) Measured import and observed unconstrained demand

The DNO has knowledge of and understands the demand profile for the particular facility to ascertain the actual demand which is being constrained at the time of Measured Demand.

Assessing the Latent Demand for an ES which is contracted to constrain import may become complicated if the ES is actually exporting at the time of Measure Demand. However, the ES may change operation in a very short time span, i.e. switch from export to import quickly, and the DNO should consider such scenarios. Example F.5.2 provides more guidance on such a scenario.

A.2 Contracted DG, DSR Scheme and ES

Where a DNO has a contract with a DG or ES facility to export, then the Latent Demand should be based on the terms of the contract, i.e. the export from the facility will be determined by the contract.

Where the DNO has a contract with a Demand Facility (DSR Scheme) or an import constraint contract with an ES Facility, then the Latent Demand may be determined using one of the options a) or b) in Annex A.1. The implications using the options is described below.

a) The terms of the Contract with the DNO

This method returns the maximum value of the Latent Demand as it is determined by the difference between the maximum import capacity (stipulated in the contract) and the constrained import capacity. The value may be an overestimate as the customer may not plan to take their maximum import capacity at the time of peak network demand.

b) Measured import and observed unconstrained demand

This method returns a ‘diversified’ value of Latent Demand, i.e. the customer may not necessarily wish to operate at maximum import capacity during the time when they are being constrained. This method is more difficult to apply as it requires an understanding and knowledge of what the import would have been had no import restriction been active, rather than assuming the customer would like their maximum import capacity. The DNO could determine the ‘diversified’ Latent Demand by assessing the customer’s import over a suitable period so that patterns in their import during periods when it is both constrained and unconstrained are established.

The example in F.4.4 indicates how the options a) and b) may be applied to a DSR Scheme and the example in F.5.2 indicates how the options may be applied to an ES with constrained import.

A.3 Non-Contracted DG, DSR Scheme and ES

For Non-Contracted DG/DSR Schemes/ES, the most rigorous assessment would require the impact of DG/DSR Schemes/ES known at each network node to be assessed for each half hour period, where the half hour timescale relates to the information typically available from DNO SCADA or the Elexon Settlements system. This analysis is potentially extensive, and in the case of Demand Facilities with on-site generation, DSR Schemes with third parties, or a site with an ES, obtaining the relevant data could be difficult.

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The key issue associated with establishing the Group Demand is striking a balance between the need to undertake significant analysis, with data that may not be readily available, and the risks associated with there being insufficient network assets and DG/DSR Schemes/ES to support the Group Demand. The risk arises because if, for example:

- the export from a DG is effectively being considered as negative demand, i.e. it carries a 100% security contribution, or;
- a reduction in demand at a Demand Facility in response to a third party DSR Scheme contract is effectively being considered as negative demand, i.e. it carries a 100% security contribution.

The magnitude of the risk relates to the aggregate capacity of Non-Contracted DG/DSR Schemes/ES in the network under consideration rather than the size of any individual DG/DSR Scheme/ES. It is recognised that establishing an appropriate approach is subjective, and that a pragmatic approach, needs to be taken. Hence, the 5% de-minimis test described in Clause 5 (the 5% figure is a practical limit and relates to the accuracy of typical DNO SCADA information).

The extent of the analysis is dependent upon a number of factors including:

- whether the generation is directly connected to the DNO network, as would typically be the case for landfill generation or a wind farm, or is embedded in a customer's installation with a significant amount of on-site demand, as would typically be the case for an industrial site with CHP generation plant;
- the coincidence of the maximum value of the Measured Demand and the maximum output from DG in the network for which Group Demand is being established.

Where the aggregate capacity of Non-Contracted DG/DSR Schemes/ES exceeds 5% of the Group Demand, but comprises large numbers of very small facilities, the capacity from these units need not be added to the Measured Demand, as there will probably be sufficient diversity for the overall network risk to be small. However, if the DNO considers the effect of such facilities to be material, the use of generic profiles for DG/DSR Schemes/ES would facilitate further assessment of the Latent Demand.

Having established appropriate details of any Non-Contracted DG/DSR Schemes/ES, the Latent Demand should be determined as described in Annex A.1, including options a) and b) for DSR Schemes and ES import constraints.

A.4 Establishing the Latent Demand from generation only sites, i.e. merchant DG

For a DG facility where there is no on-site demand, the contribution to Latent Demand is the export from the DG facility to the network. As indicated above, the most rigorous method is to summate the recorded half hourly output from all the DG (greater than 100 kW) for the network. These half hourly contributions are then added to the half hourly network demands measured at network entry points to establish the profile of demand from which the maximum demand, i.e. the Group Demand, can be found. However, where it is believed that there is good coincidence between the time of the maximum value of the Measured Demand and the maximum value of the contribution to Latent Demand from each DG facility, it will often be sufficiently accurate to estimate the Latent Demand by summating the export from the DG facility, at the time of the maximum Measured Demand.

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A.5 Establishing the Latent Demand from customers' demand sites with on-site generation

Where a demand site comprises DG with a capacity greater than 100 kW, wherever possible the actual site demand (i.e. the demand measured for the site plus the contribution to the Latent Demand associated with the on-site DG) should be established and the contribution to System Security from the DG should be assessed in accordance with EREC P2/7 [N1].

There are a number of options outlined below for treating demand sites with generation, which have differing requirements for the availability and quality of network and generation data. The purpose of describing these options is primarily to expand on some of the issues that need to be considered when assessing the contribution to Group Demand from such sites. Implementation of some of these methods may require an enhancement of existing data systems.

- Option 1. Obtain separate demand and generation data from the site operator in order to separately assess both the overall site demand and the security contribution from the on-site generation.
- Option 2. As Option 1, but where data from the site operator is not available and the DNO uses data from other sources, e.g. its own SCADA data and export information from the BSC Settlements system. The DNO would need to be comfortable that it had sufficiently accurate data to undertake the analysis before applying this option. The security contribution from the generation would be considered separately.
- Option 3. Estimate the contribution to Group Demand by ignoring any contribution to Latent Demand by the on-site generation and assume that only the ASC demand has to be met. It is important to recognise that the maximum site demand may be different from the ASC and any difference should be treated in the same way as for any other demand site that has a possible maximum demand different from its ASC. The security contribution from the generation would be considered separately.

  It is worth noting that where the customer has an ASC lower than the site maximum demand, they are effectively managing internally the risk of their generation not operating and in this case it may not be appropriate for the security contribution of the generation to be separately assessed.
- Net Option 1. The DNO could develop a model of the on-site generation in net terms based on the import/export data at the ownership boundary. Information may be obtained from the DNO SCADA system and/or the BSC Settlements system. In this case there would be no requirement to separately assess the security contribution from the generation.
- Net Option 2. The most general option is to explicitly allow the DNO to use its engineering judgement to determine the appropriate contribution to Latent Demand of the site to be used in an assessment of Group Demand. In this case there would be no requirement to separately assess the security contribution from the generation.

An approach based on Option 1 is the most robust and is the preferred approach where sufficient data is available and a high degree of accuracy is required. However as described above the application of a pragmatic option for disaggregating the demand and generation will often be sufficient.

A pragmatic approach for assessing the contribution to Latent Demand by on-site generation plant has been identified. This method is not completely rigorous but is generally thought to be appropriate where it is obvious by inspection that there is good coincidence between the

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maximum values of the Latent Demand and Measured Demand. This technique does cater for the following risks:

- basing the on-site demand on the import/export data at the ownership boundary – which could lead to an under engineered network; and
- ignoring the on-site generation and assuming that the ASC demand has to be met – which could lead to an over engineered network.

The technique for establishing Group Demand is therefore to take the lesser of the following two conditions.

- The expected generation output (G) at the time of the maximum Measured Demand, or
- The site ASC (A) minus the site import[3] (D) at the time of maximum Measured Demand. (i.e. A-D).

and add it to the maximum value of the Measured Demand.

i.e. Group Demand = maximum Measured Demand + min. [G, (A – D)]

The contribution to System Security of the DG should then be treated independently in accordance with Annex D.

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[3] Note that for a site that is exporting to the DNO's network, the import is simply a negative quantity.

Annex B
(informative)

Capping DG/DSR Schemes/ES

B.1 Dominance and capping

A principle of EREC P2/7 [N1] is that outage events relate to Circuits rather than loss of DG/DSR Scheme/ES contribution, i.e. no individual DG/DSR Scheme/ES should be dominant. The conditions that should be applied to test for dominance are as follows:

a) the security contribution of each of the following items shall be limited to the capacity of the largest Circuit:

   i. DNC of the largest contracted DG facility;
   ii. DNC of the largest Non-Contracted DG;
   iii. Aggregate DNC of multiple Non-Contracted DG facilities which are susceptible to common mode failure (see B.2);
   iv. Capacity of the largest contracted DSR Scheme provided by a Demand Facility;
   v. Aggregate capacity of contracted DSR Schemes which are susceptible to common mode failure (See B.2);
   vi. Capacity of the largest Non-Contracted DSR Scheme which the DNO is aware of, i.e. a known DSR Scheme;
   vii. Capacity of the largest contracted ES export
   viii. Aggregate capacity of multiple contracted ES facilities which export and are susceptible to common mode failure (see B.2);
   ix. Capacity of the largest ES which is contracted to restrict import;
   x. Capacity of the largest Non-Contracted ES import restriction which the DNO is aware of, i.e. a known ES import restriction.

b) the security contribution of the two largest DG/DSR Scheme/ES, as set out in items i) -x) shall be limited to the aggregate rating of the two largest Circuits.

If the first condition is not met (i.e. the DG/DSR Scheme/ES would otherwise dominate), then the capacity used to assess the security contribution must be Capped so that the DG/DSR Scheme/ES does not dominate and hence an outage of the largest Circuit can be taken to be the FCO. The process then continues with the calculation of the system capacity under this outage condition which is:

- the Circuit Capacity of the remaining Circuit(s); plus
- any Transfer Capacity; plus
- the appropriate DG/DSR Scheme/ES contribution determined in Clauses 7 and 8.

A similar Capping process is used to ensure that the SCO relates to the outage of the second largest Circuit.

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B.2 Common mode failures

Common mode failure of DG, DSR Schemes and ES can occur for a variety of reasons. EREC P2/7 [N1] requires that common mode failure of any active network management, protection, or control system associated with DG and DSR is considered. Other types of common mode failure are as follows.

- Fuel Source (DG) Failure of common fuel supply such as the gas supply to several landfill generating units on the same site; mains gas supply to CCGTs etc. should there be a gas network security problem, etc.
- Connection (DG, DSR Scheme, ES) It is possible that significant DG/DSR Scheme/ES contribution to Group Demand is connected via a single Circuit. It is necessary to check that loss of this Circuit would not trigger materiality considerations, although this is unlikely to happen in practice.
- Stability (DG, ES) Inability of certain types of DG/ES or types of protection to remain stable and/or ride through a system disturbance.

To avoid common mode failures of DG/DSR Scheme/ES degrading System Security beyond that expected in EREC P2/7 [N1] it is appropriate to cap DG/DSR Scheme/ES that is subject to common mode failure as provided in Annex B.1. Each type of DG/DSR Scheme/ES could be subject to common mode failure as provided in Annex B.1.

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Annex C
(informative)

Technical check list

C.1 Introduction

This Annex contains checklists for the various phases of the assessment process, as outlined in the main document. These checklists are intended as an aide-memoir for the network designer rather than being a definitive activity list.

C.2 Establish Group Demand

	Complete
Recorded maximum demand	
Latent Demand for contracted DG/DSR Scheme/ESF	
De-minimis test for Non-Contracted DG/DSR Scheme/ESF and hence any Latent Demand	

C.3 Establish network capability

	Complete
Circuit Capacity of individual Circuits appropriate to time of year	
Time of year of recorded maximum Group Demand	
Network Transfer Capacity	
Time within which Transfer Capacity is available	

C.4 Establish Contracted DG/DSR Scheme/ES security contribution

	Complete
Assess DG contracted security contribution	
Consider general DG issues in accordance with Annex C.6	
DSR Scheme contracted security contribution	
ES contracted security contribution	

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C.5 Establish Non-Contracted DG security contribution

	Complete
Assess non-contracted security contribution in accordance with Annex D	
Consider general DG issues in accordance with Annex C.6	

C.6 General DG considerations

	Complete
For each DG facility:	
C.6.1 General	
Capacity of DG	
Type of DG	
½ hourly output profile	
Merchant or process linked?	
C.6.2 Technical	
Interface protection • operating parameters and settings • ride through capability	
DG stability	
Status of the technology (proven/experimental)	
Evidence of good management procedures	
Proven performance track record, consistent capacity factor	
What are the cold start/warm start/reconnection times for generation?	
C.6.3 Fuel	
Contracted fuel supply	
Uninterruptible fuel supply (gas)	
Fuel stocks available	
C.6.4 Commercial	
Ability for DNO to request operation	
Contracted repair and maintenance	
Coordination of network and DG planned outages	
Expected lifespan of the DG plant	
C.6.5 Contract (where appropriate)	
Contracts in place	

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Ability to operate on demand	
Appropriate communications with Generator/DG plant to be in place	
C.6.6 Network & DG related issues	
Will generation under outage overload any remaining plant	
Does the generation need to run to a different loading pattern immediately - can the governor cope	
Can the AVR cope with the required PF under outage conditions etc.	
Will protection for remaining network still work/discriminate with generation	
Is the DG exposed to any common mode failure (e.g. gas supplies; drought)	
Will the DG cause voltage violations during outages	
Communication arrangements between DNO and Generator	

C.7 Non-Contracted DSR Schemes

	Complete
Where the DNO is aware of Non-Contracted DSR Schemes through liaison with third parties, the details should be acquired	
Where the DNO is aware of time-of-use tariffs and price signals which affect consumer demand, the details should be acquired	

C.8 Non-Contracted ES

	Complete
Where the DNO is aware of Non-Contracted ES through liaison with third parties, the details should be acquired	

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Annex D
(normative)

Approaches for assessing the contribution from Non-Contracted DG to System Security

D.1 General

This Annex describes three approaches for assessing the security contribution from Non-Contracted DG to System Security. Use of these approaches will form an integral part of the assessment process described in Clause 8.3.

Approach 1 provides the simplest method to assess the contribution. Approach 2 provides an additional assessment method for DG which is more specific than Approach 1; and Approach 3 is used where it is necessary to carry out bespoke analysis using site specific data.

D.2 Approach 1 – Generic approach

Approach 1 is a simple method based on the use of look-up tables and graphs. The look-up tables (Tables D.2, D.2.1 and D.2.2) are based on the analysis of export data of typical DG facilities by Imperial College London [N8]. The data represents:

a) export data at the point where the DG is connected to the DNO network;

NOTE: The data is based on DG technology type, i.e. the energy source associated with the DG facility. The number of separate generating units associated with a particular facility is not considered.

b) data sampled at 30 min intervals;

c) data collated over the period 2013-2018, inclusive.

It is valid to use Approach 1 in the following situations:

- where the DG type is one of those cited in Tables D.2.1 or D.2.2; or
- where a 'first pass' assessment is required to determine if a particular DG facility is likely to have sufficient capacity to provide a sufficient security contribution to satisfy a particular requirement.

Each DG facility should be assessed individually and the aggregate DG security contribution is the arithmetic sum of all the facility contributions. This summation gives a conservative assessment of the DG contribution.

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Table D.2

Distributed Generation Technology Type	Contribution (see NOTE 1 below)
DG as listed in Table D.2.1	F % of DNC
DG as listed in Table D.2.2	F % of DNC
NOTE 1: The contributions derived from this table apply from the point of time when the DG is connected or reconnected to the demand group following the commencement of an outage. This may be immediately if the DG does not trip, otherwise it will be from the point of time when the DG is reconnected.	

Table D.2.1 — F factors in % for Non-intermittent Generation

DG Technology Type (NOTE 2)	Period of assessment (NOTE 3)	
	Winter	Summer
Biomass	30%	25%
Landfill gas	28%	27%
Waste	35%	32%

NOTE 1: The F factors for Non-intermittent Generation are not affected by the number of units at an individual site. It is assumed that the energy source for the prime mover is available on demand so that persistence does not need to be considered.

NOTE 2: For DG technology types not listed in this table, it is preferable to seek site specific data to assess the contribution to System Security in accordance with EREP 131 [N2].

NOTE 3: Summer period refers to months May – August inclusive. Winter period refers to months November – February inclusive.

NOTE 4: The percentage values in this table are representative of the mean (M) minus 1 standard deviation (SD). Refer to commentary in Annex G for further explanation.

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Table D.2.2 — F factors in % for Intermittent Generation

DG Technology Type (NOTE 2 & 3)	Persistence, T_m (hours)										
	½	2	3	6	12	18	24	48	120	360	480
Onshore wind (Winter)	17%	15%	16%	14%	11%	9%	7%	4%	2%	1%	1%
Onshore wind (Summer)	13%	12%	11%	9%	8%	6%	4%	2%	0%	0%	0%
Offshore wind (Winter)	22%	21%	20%	19%	17%	15%	12%	7%	2%	1%	1%
Offshore wind (Summer)	16%	16%	15%	13%	11%	9%	7%	3%	0%	0%	0%
Hydro run-of-river (Winter)	19%	19%	18%	18%	17%	16%	15%	12%	5%	0%	0%
Hydro run-of-river (Summer)	7%	7%	7%	7%	6%	5%	4%	2%	1%	0%	0%
Hydro water reservoir (Winter)	12%	12%	10%	9%	7%	4%	3%	3%	2%	0%	0%
Hydro water reservoir (Summer)	5%	5%	4%	2%	1%	0%	0%	0%	0%	0%	0%
Solar (Winter)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Solar (Summer)	12%	11%	10%	9%	3%	2%	0%	0%	0%	0%	0%

NOTE 1: The F factors for Intermittent Generation are related directly to the period of continuous generation (i.e. Persistence).

NOTE 2: For DG technology types not listed in this table, it is preferable to seek site specific data to assess the contribution to System Security in accordance with EREP 131 [N2].

NOTE 3: Summer period refers to months May – August inclusive. Winter period refers to months November – February inclusive.

NOTE 4: The percentage values in this table are representative of the mean (M) minus 1 standard deviation (SD). Refer to commentary below Table D.2.1 for further explanation.

NOTE 5: Recommended values of T_m are shown in Table D.2.3.

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Table D.2.3 — Recommended values for T_m

P2/7 demand class	Switching (see NOTE 2 below)	Maintenance	Other outage (see NOTE 3 below)
A (FCO)	N/A	N/A	N/A
B (FCO)	15 mins / 3 hours	2 hours	24 hours
C (FCO)	15 mins / 3 hours	18 hours	15 days
D (FCO and SCO) (see NOTE 3 below)	60 s / 3 hours (see NOTE 4 below)	24 hours	90 days
E (FCO and SCO) (see NOTE 3 below)	60 s	24 hours	90 days

NOTE 1: The recommended values for Tm for the three system conditions may be applied at the time that an infeed is lost. For example, "Switching" values apply where the DG contribution is only required for the time necessary to reconfigure the system by switching operations.

NOTE 2: Switching values for T_m are only appropriate where sufficient Intrinsic network capacity and Transfer Capacity exist, as described in Clauses 6.2 and 6.3 respectively. 15 mins is only applicable for Class C supply as defined in Table 1 of EREC P2/7 [N1].

NOTE 3: Examples of "other outage" are an unplanned outage or an outage as part of a major project.

NOTE 4: SCO only applies for demands greater than 100 MW.

NOTE 5: FCO only applies where compliance is achieved by automatic demand disconnection of 20 MW or less.

D.3 Approach 2 – Using capability factors

This approach is applicable to Non-intermittent Generation and offers a more in-depth assessment of the security contribution in comparison Approach 1.

Approach 2 uses the concept of a 'capacity factor' which is defined as:

Capacity factor = (DG energy output for the assessment period) / (DG DNC x number of hours in the assessment period)

The capacity factors in Table D.3 are based on data collated by Imperial College London [N8] over the period 2013-2018, inclusive.

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Table D.3 — F factors in % for Non-intermittent Generation for varying capacity factors

Capacity factor range % (NOTE 1)	Period of assessment (NOTE 2)	
	Winter	**Summer**
Biomass (NOTE 3)		
80-max.	49%	46%
60-80	36%	35%
40-60	26%	29%
20-40	3%	6%
2-20	0%	0%
Landfill gas		
80-max.	67%	62%
60-80	56%	57%
40-60	47%	50%
20-40	23%	21%
2-20	8%	9%
Waste		
80-max.	67%	63%
60-80	57%	51%
40-60	43%	40%
20-40	23%	27%
2-20	2%	8%

NOTE 1: For DG technology types not listed in this table, it is preferable to seek site specific data to assess the contribution to System Security in accordance with EREP 131 [N2].

NOTE 2: Summer period refers to months May – August inclusive. Winter period refers to months November – February inclusive.

NOTE 3: The data analysis for biomass generators showed that capacity factors may vary more than 20% year to year, for more than 50% of the population. Hence, the F factors have been reduced accordingly to account for the variability. Refer to the report by Imperial College London [N8] for full details of the capacity factors.

NOTE 4: The percentage values in this table are representative of the mean (M) minus 1 standard deviation (SD). Refer to commentary below for further explanation.

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D.4 Approach 3 – Computer package approach

This approach uses a computerised model of the methodology which was used to create the tables used in Approaches 1 and 2. It offers the ability to accommodate a wide range of data and assumptions, and permits the underpinning conditions of the other approaches to be relaxed and modified. It is therefore appropriate for special studies and bespoke analyses.

Approach 3 may be used to assess the contribution to security associated with export from from Non-Contracted ES.

Approach 3 relies on the DNO obtaining a set of input data. This data could be provided by the Generator or from other sources, such as the DNOs own records. The exact details of the data required and how to use the analysis package are described in EREP 131 [N2]. The package is implemented in Microsoft Excel ® using the VBA environment and is available from the Energy Networks Association (ENA). The package calculates the security contributions from DG and can be used for assessing for compliance with EREC P2/7 [N1] in the same way as performed with either of the two previous approaches.

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Annex E
(informative)

Influencing factors for DG Contribution

E.1 DG availabilities

E.1.1 General

The considerations in this Annex are relevant to both Contracted and Non-Contracted DG.

The contribution to capacity, stipulated in a contract with the DG, may be informed by the considerations in this Annex.

The F factors in Tables D.2.1 and D.2.2 are based on data taken from DG which is considered typical or average. When undertaking a site specific assessment of DG contribution, the DNO may be aware of issues affecting the average expected reliability of the facility: technical, commercial and fuel availability considerations described below may be relevant. These considerations may also be relevant for new DG connecting to the network with no prior history.

Operation over the first year or two of a new DG facility could be used to confirm the appropriateness of using the F-factors in Tables D.2.1 and D.2.2.

E.1.2 Technical availability

Technical availability is constrained by planned or unplanned outages of the DG facility.

It can be observed that where the operator allows the DG facility to run continuously with full fuel being available, a good example being landfill gas, modern DG demonstrates generally very high technical availability.

E.1.3 Fuel source availability

Fuel source availability can be constrained by any restrictions in the primary energy source preventing the DG facility from achieving expected output over any time period. The impact of fuel source constraints is greatest where the DG facility has high technical and commercial availability but where fuel is limited or variable. Wind farms are an obvious example of this.

Landfill Gas is also a good example, where there may be high technical availability and continuous running to burn off the gas. However, the output may be limited by the absolute fuel availability with, say, a 1.5 MW unit having a continuous output constrained at 1 MW.

Some plant, such as CCGT installations, will have interruptible gas supplies, and where invoked, would reduce the fuel availability element of the overall availability.

E.1.4 Commercial availability

Commercial availability can be considered as being the result of the operator choosing, for financial reasons, to run their plant below full output or to take the plant off-line for any time period.

For example, the primary factor normally influencing the running of a CHP plant, and hence its commercial availability, will be the need to provide heat for a process on the same site. This may result in export to the system only being available when process demand falls, and

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in the plant being taken off-line for periods within a 24 hr cycle. In this case the implications associated with estimation of Group Demand must be taken into account.

Similarly, CCGT plant is observed to have high technical availability, typically above 90%, together with good fuel availability. However, when operated as a merchant DG facility with its main objective being to meet energy contracts, or provide energy balancing services, the availability of its full output is under the control of the operator and will be varied for purely commercial reasons.

E.2 Remote generation

When assessing the security contribution from a DG facility that is electrically remote from the point on the network where the contribution is being assessed (e.g. the infeed substation busbars), the key issue relates to the reliability of the network assets between the DG facility and the network point where a security contribution is required; this may affect the actual contribution from the DG facility. This effect need not be considered further unless there is particular reason to believe that the availability of the network assets is significantly less than that for a typical network.

Hence, if a DG facility is considered to be above the de-minimis level, then it should not be considered as being 'too remote' to provide a security contribution to a particular network and the security contribution should be assessed in accordance with the assessment procedures described in this report.

E.3 Intermittent Generation and selection of T_m

Table 1 of EREC P2/7 [N1] requires that some or all demand (depending on class of supply) should be restored within 15 mins or 3 hrs, or after the time to repair. Therefore, when looking to include a security contribution from DG facility a necessary part of the assessment process will be to ensure that the DG facility can contribute in the required restoration time and continue to contribute for the repair time or until demand transfers are effected. For example, following a forced FCO for a Group Demand in Class C, any contribution must be initially available in 15 min as required in Table 1 of EREC P2/7 [N1]), and fully available by 3 hrs. Once available, it is assumed that the DG needs to remain available for the duration of the forced outage, which for Class C is assumed to be 15 days, based on an emergency repair time for a 132 kV transformer, or until sufficient Transfer Capacity can be made available.

NOTE: The considerations in the paragraph above are also relevant for DSR Schemes and ES.

Different values of T_m might be appropriate depending on network configuration and worst case repair time. Indicative values for T_m are shown in Table D.2.3 in Annex D.

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Annex F
(informative)

Examples

F.1 Group Demand example

This example is intended to demonstrate the calculation of Group Demand.

Figure F.1 – Establishing Group Demand

a) Determine Group Demand

i. Measured Demand = 26 MW

ii. Latent Demand

Contracted DG/DSR Schemes/ES – none

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. Group Demand = 26 MW (Class C)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 30 MW, available immediately. (From Table 1 of EREC P2/7 [N1] under an FCO, there is a requirement to secure partial demand within 15 mins and all demand within 3 hrs, except Customer A who has agreement to a single circuit supply. The FCO capacity of 30 MW is sufficient to meet the Group Demand of 26 MW).

SCO capacity = 0 MW. (From Table 1 of EREC P2/7 [N1] under a SCO, there is no requirement to secure any demand).

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The intrinsic network capacity of 30 MW under an FCO is sufficient to meet the 26 MW of Group Demand. There is no requirement to consider Transfer Capacity or contribution from DG/DSR Schemes/ES.

Given that intrinsic network capacity is greater than Group Demand: the system is compliant with Table 1 of EREC P2/7 [N1], regardless of an outage on Circuit C1 or C2. Note that for an outage of Circuit C2 (3-ended circuit), the supply to Customer A is considered to be immediately restored following an outage of the Circuit C2: the agreed single circuit connection agreement is equivalent to a DSR arrangement which is activated during loss of the Circuit C2 (see EREC P2/7 [N1] Table 1 note on 'minimum demand to be met').

F.2 Transfer Capacity

This example is intended to demonstrate consideration of Transfer Capacity (see F.6.1 and F.7.2 for other examples).

Figure F.2 – Transfer Capacity example

a) Determine Group Demand

i. Measured Demand = 10 MW

ii. Latent Demand

Contracted DG/DSR Schemes/ES – none

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. Group Demand = 10 MW (Class B)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 0 MW (from Table 1 of EREC P2/7 [N1] under an FCO, Class B requires restoration for Group Demand minus 1 MW [9 MW] of

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demand within 3 hrs and restoration of the remaining demand within repair time

SCO capacity = 0 MW (from Table 1 of EREC P2/7 [N1] under a SCO, there is no requirement to secure any demand).

The intrinsic network capacity is insufficient to meet the requirements of EREC P2/7 [N1] and it is necessary to consider the Transfer Capacity.

ii. Transfer Capacity = 9 MW available within 1 hr under an FCO (and SCO)

In conclusion, the total System Security capacity under an FCO is 9 MW, available within 1 hr, which is sufficient for a Class B supply (the remaining 1 MW is restored in repair time). The distribution system is compliant with Table 1 of EREC P2/7 [N1]. For further development of this example, refer to F.5.1.

F.3 Contracted DG example

This example demonstrates how the System Security of, a distribution system containing DG which is contracted with the DNO, should be assessed.

An DG has a DNC of 8 MW and operates to an agreed contract with the DNO. The contract requires the DG to export 5 MW at an agreed time of the day.

Figure F.3 – Contracted DG example

a) Determine Group Demand

i. Measured Demand = 27 MW

ii. Latent Demand

Contracted DG/DSR Schemes/ES – 5 MW (export from contracted DG)

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. Group Demand = 32 MW (Class C)

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b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 30 MW, available immediately. (From Table 1 of EREC P2/7 [N1] under an FCO, there is a requirement to secure partial demand within 15 mins and all demand within 3 h).

SCO capacity = 0 MW. (From Table 1 of EREC P2/7 [N1] under a SCO, there is no requirement to secure any demand).

The intrinsic network capacity of 30 MW under an FCO is insufficient to meet the 32 MW of Group demand i.e. there is a deficiency of 2 MW.

ii. Transfer Capacity = 0 MW available under an FCO or SCO

Given that Group Demand is greater the intrinsic network capacity and no Transfer Capacity is available, there is a deficiency in System Security of 2 MW. Hence, it is now necessary to consider contribution to security from other means: DG/DSR Schemes/ES.

iii. Security contribution from contracted DG = 5 MW, available immediately (the DG contract stipulates the contribution and includes a requirement to remain connected under a fault forming the FCO. The DG is not designed to run in island mode and hence, there is no contribution under an SCO).

The total System Security capacity under an FCO is 35 MW, compared to a Group Demand of 32 MW. There is no requirement to secure demand under an SCO. The distribution system is compliant with Table 1 of EREC P2/7 [N1].

F.4 Contracted DSR Scheme

The following examples demonstrates how the System Security of, a distribution system containing a DSR Scheme which is contracted with the DNO, should be assessed.

F.4.1 Constrained import

Customer A consists of a 5 MW Demand facility, whose connection agreement with the DNO stipulates that their load (import) is constrained to 2 MW at the time of peak demand on the distribution system.

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Figure F.4.1 – Constrained import

a) Determine Group Demand

i. Measured Demand = 30 MW

ii. Latent Demand

Contracted DG/DSR Schemes/ES – 3 MW (The DNO is aware, from specific load information, that Customer A 'would like' 5 MW at the time of peak load. Since the DSR Scheme is active it is constraining Customer A import to 2 MW).

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. Group Demand = 33 MW (Class C)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 30 MW, available immediately. (From Table 1 of EREC P2/7 [N1] under an FCO, there is a requirement to secure partial demand within 15 mins and all demand within 3 hrs).

SCO capacity = 0 MW. (From Table 1 of EREC P2/7 [N1] under a SCO, there is no requirement to secure any demand).

The intrinsic network capacity of 30 MW under an FCO is insufficient to meet the 33 MW of Group demand i.e. there is a deficiency of 3 MW.

ii. Transfer Capacity = 0 MW available under an FCO or SCO

Given that Group Demand is greater than the intrinsic network capacity and no Transfer Capacity is available, there is a deficiency in System Security of 3 MW. Hence, it is now necessary to consider contribution to security from other means: DG/DSR Schemes/ES.

iii. Security contribution from contracted DSR Scheme = 3 MW, available immediately under an FCO.

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In conclusion, the total System Security capacity under an FCO is (30+3) MW, compared to a Group Demand of 33 MW. There is no requirement to secure demand under an SCO. The distribution system is compliant with Table 1 of EREC P2/7 [N1].

F.4.2 Intertripping arrangement

Customer A consists of a 5 MW Demand facility, whose connection agreement with the DNO stipulates that the supply is automatically tripped during an outage of either feeding Circuit. Hence, Customer A can import 5 MW whilst the system is intact but they would be disconnected in the event of an FCO.

Figure F.4.2 – Intertripping arrangement

a) Determine Group Demand

i. Measured Demand = 33 MW (this includes 5 MW load to Customer A)

ii. Latent Demand

Contracted DG/DSR Schemes/ES – none i.e. the intertripping arrangement is not actively managing Customer A's demand in an intact system and hence there is no Latent Demand.

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. Group Demand = 33 MW (Class C)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 30 MW, available immediately. (From Table 1 of EREC P2/7 [N1] under an FCO, there is a requirement to secure partial demand within 15 mins and all demand within 3 hrs).

SCO capacity = 0 MW. (From Table 1 of EREC P2/7 [N1] under a SCO, there is no requirement to secure any demand).

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The intrinsic network capacity of 30 MW under an FCO is insufficient to meet the 33 MW of Group demand i.e. there is a deficiency of 3 MW.

ii. Transfer Capacity = 0 MW available under an FCO or SCO

Given that Group Demand is greater than the intrinsic network capacity, and no Transfer Capacity is available, it is now necessary to consider contribution to security from other means: DG/DSR Schemes/ES.

iii. Security contribution from contracted DSR Scheme = 5 MW, available immediately under an FCO (Customer A tripped under an FCO).

The total System Security contribution capacity is 35 MW compared to a Group Demand of 33 MW; hence the system is compliant with Table 1 of EREC P2/7 [N1].

F.4.3 Active Network Management (ANM) system

Customer A consists of a 2 MW Demand Facility and Customer B consists of a 3 MW Demand Facility. The import by A and B are monitored and controlled by the same ANM system. The DNO's connection agreements with A and B stipulate that the load (import) is constrained to ensure the summated demand of both Customers (A+B) is not greater than 2 MW at the time of peak demand on the distribution system.

Figure F.3.3 depicts the power flows at the time of peak demand: it is assumed by the DNO that both Customers A and B wish to import their maximum demand (5 MW combined) but are constrained to 2 MW by the ANM i.e. the Latent Demand is assumed to be the maximum value of 3 MW. An alternative approach is for the DNO to assess the load profiles of Customer A and B and determine if both Customers actually require their maximum allowance at the time of peak i.e. diversified Latent Demand (see Annex A.1).

Figure F.4.3 – ANM system

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a) Determine Group Demand

i. Measured Demand = 30 MW

ii. Latent Demand

Contracted DG/DSR Schemes/ES – 3 MW i.e. the ANM system is actively managing Customer A and B's demand and constraining to 2 MW, from an assumed maximum of 5 MW.

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. Group Demand = 33 MW (Class C)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 30 MW, available immediately. (From Table 1 of EREC P2/7 [N1] under an FCO, there is a requirement to secure partial demand within 15 mins and all demand within 3 hrs).

SCO capacity = 0 MW. (From Table 1 of EREC P2/7 [N1] under a SCO, there is no requirement to secure any demand).

The intrinsic network capacity of 30 MW under an FCO is insufficient to meet the 33 MW of Group demand i.e. there is a deficiency of 3 MW.

ii. Transfer Capacity = 0 MW available under an FCO or SCO

Given that Group Demand is greater the intrinsic network capacity, and no Transfer Capacity is available, it is now necessary to consider contribution to security from other means: DG/DSR Schemes/ES.

iii. Security contribution from contracted DSR Scheme = 3 MW, available immediately under an FCO (Customer A and B constrained prior to an FCO event).

The total System Security contribution capacity is 33 MW compared to a Group Demand of 33 MW; hence the system is compliant with Table 1 of EREC P2/7 [N1].

F.4.4 Import constraint vs. operating regime

Two Demand Facilities (Customer A and B) each have a constraint imposed on their import via a contract with the DNO i.e. contracted DSR Scheme. The constraint applies at an agreed time of day.

The contracts have been in place for a number of years – the Demand Facilities are not necessarily operating as originally envisaged by the contracts.

The DNO is closely monitoring the import for each Customer, i.e. the DNO has an understanding of the operating regime at each Demand Facility. Hence, the DNO has sufficient information to undertake a detailed assessment of Latent Demand. The two customers are operating at the time of the Measured Demand as described in Table F.4.4.1.

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Table F.4.4.1 — Demand Facilities' operating regimes

Customer	Demand Facility operation
A	Importing 1.5 MW (DNO is aware that the Customer does not require any more import at the time of Measured Demand)
B	Importing 0 MW (DNO is aware that the Customer has changed its production and no longer runs plant at the time of Measured Demand)

The DNO has two options:

- Option 1: Treat the assessment of Latent Demand based on the measured data for Customers A and B. This assumes that the measured data is sufficiently reliable to reflect the operating regime of Customer A and B going forward; or
- Option 2: Treat the assessment of Latent Demand based on the contract it has with Customers A and B.

Figure F.4.4 — DSR Scheme contracts

Instead of examining a thorough step-by-step assessment for Option 1 and Option 2, as for other examples, a summary of the Group Demand calculation and the contribution to security is compared in Table F.4.4.2.

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Table F.4.4.2 — Summary comparison of Options 1 & 2

	Option 1	Option 2
Group Demand	28.5 + 0(A) + 0(B) = 28.5 MW	28.5 + 3.1(A) + 3.5(B) = 35.1 MW
Security Contribution	30 + 0 = 30 MW	30 + 2.6(A) + 2.5(B) = 35.1 MW
	Option 1 assessment allows the DNO to re-allocate the 1.5 MW of capacity which Customer A and B were originally expected to take when constrained. There are obviously risks to this approach as the Customers could change their operating regime. To address this risk, this may prompt the DNO to re-evaluate the contracts.	Option 2 assessment proves that the worst-case outcome works, i.e. the reason for the contracts.

F.5 Contracted ES

F.5.1 Export contract

An ES facility consists of 5 MW of installed battery storage and operates to an agreed contract with the DNO. The contract requires the ES facility to export 5 MW at an agreed time of the day.

Figure F.5.1 – ES export contract

a) Determine Group Demand

i. Measured Demand = 27 MW

ii. Latent Demand

Contracted DG/DSR Schemes/ES – 5 MW (export from ES).

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. Group Demand = 32 MW (Class C)

b) Determine Network Capacity

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i. Intrinsic network capacity

FCO capacity = 30 MW, available immediately. (From Table 1 of EREC P2/7 [N1] under an FCO, there is a requirement to secure partial demand within 15 mins and all demand within 3 hrs).

SCO capacity = 0 MW. (From Table 1 of EREC P2/7 [N1] under a SCO, there is no requirement to secure any demand).

The intrinsic network capacity of 30 MW under an FCO is insufficient to meet the 32 MW of Group demand i.e. there is a deficiency of 2 MW.

ii. Transfer Capacity = 0 MW available under an FCO or SCO

Given that Group Demand is greater the intrinsic network capacity and no Transfer Capacity is available, there is a deficiency in System Security of 2 MW. Hence, it is now necessary to consider contribution to security from other means: DG/DSR Schemes/ES.

iii. Security contribution from contracted ES = 5 MW, available immediately (the ES contract stipulates the contribution and includes a requirement to remain connected under a fault forming the FCO. The ES is not designed to run in island mode and hence, there is no contribution under an SCO).

The total System Security capacity under an FCO is 35 MW, compared to a Group Demand of 32 MW. There is no requirement to secure demand under an SCO. The distribution system is compliant with Table 1 of EREC P2/7 [N1].

F.5.2 Import contract vs. operating regime

Three ES facilities (Customer A, B and C) consist installed battery storage. The import by each ES is constrained, via contracts with the DNO, to 3 MW at an agreed time of day. The contracts with the DNO do not stipulate an export requirement.

The contracts have been in place for a number of years – the ES facilities are not necessarily operating as originally envisaged by the contracts.

The DNO is closely monitoring the export and import from each ES, i.e. the DNO has an understanding of the operating regime at each ES facility. Hence, the DNO has sufficient information to undertake a detailed assessment of Latent Demand. The three customers are operating at the time of the Measured Demand as described in Table F.5.2.1.

Table F.5.2.1 – ES operating regimes

Customer	ES operation
A	Importing 3 MW (DNO is aware that the ES would like to import 7 MW at the time of Measured Demand)
B	Importing 0 MW (DNO is aware that the ES has changed its operating regime and is no longer charging/discharging at the time of Measured Demand) NOTE 1
C	Exporting 2 MW (DNO is aware that the ES has changed operating regime from import to export at the time of Measured Demand)
NOTE 1: For an ES facility that is energised but not importing or exporting i.e. not charging/discharging, the DNO would expect a nominal current to be present.	

The DNO has two options:

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- Option 1: Treat the assessment of Latent Demand based on the measured data for Customers A, B and C. This assumes that the measured data is sufficiently reliable to reflect the operating regime of Customer A, B and C going forward; or
- Option 2: Treat the assessment of Latent Demand based on the contract it has with Customers A, B and C.

Figure F.5.2 – ES import only contract

Instead of examining a thorough step-by-step assessment for Option 1 and Option 2, as for other examples, a summary of the Group Demand calculation and the contribution to security is compared in Table F.5.2.2.

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Table F.5.2.2 — Summary comparison of Options 1 & 2

	Option 1	Option 2
Group Demand	28 + 4(A) + 0(B) + 2(C) = 34 MW	28 + 4(A) + 5(B) + 6(C) = 43 MW NOTE 1
Security Contribution	36 + 4 (A) = 40 MW NOTE 2	36 + 4(A) + 2(B) + 1(C) = 43 MW NOTE 2
	Option 1 assessment allows the DNO to re-allocate the 6 MW of capacity which Customer B and C were originally expected to take when constrained. There are obviously risks to this approach, as the Customers could change their operating regime. To address this risk This may prompt the DNO to re-evaluate the contracts.	Option 2 assessment proves that the worst-case outcome works, i.e. the reason for the contracts.
NOTE 1: The worst case for the ES at Customer C is 'changing' its normal operation at the time of Measured Demand from export to import within the DNO's network planning period. Hence, worst case Latent Demand is 6 MW. NOTE 2: The ES at Customer C is exporting 2 MW outside of a contract with the DNO. Hence, any security contribution would be based on an analysis using EREP 131, which would be lower than 2 MW. It is assumed to be 0 MW.		

F.6 Non-Contracted ES

F.6.1 New ES connection consideration

A DNO is considering a connection application for an ES facility which will consist of 3 MW of storage and requires to charge (import) full capacity at the time of distribution system peak demand. Prior to ES connection, the network is as shown in Figure F.2. The expected arrangement with the ES facility connected is shown in Figure F.6.1.

Figure F.6.1 – New ES connection consideration

a) Determine Group Demand

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i. Measured Demand = 13 MW (expected at time of maximum demand after ES connection)

ii. Latent Demand

Contracted DG/DSR Schemes/ES – none

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. Group Demand = 13 MW (Class C)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 0 MW. (From Table 1 of EREC P2/7 [N1] under an FCO, there is a requirement to secure 'the smaller of Group Demand - 12 MW or 2/3 Group Demand', i.e. 1 MW within 15 mins and all demand within 3 hrs).

SCO capacity = 0 MW. (From Table 1 of EREC P2/7 [N1] under a SCO, there is no requirement to secure any demand).

The intrinsic network capacity of 0 MW under an FCO is:

- insufficient to meet the 15 mins requirement to restore 1 MW, i.e. there is a deficiency of 1 MW.
- insufficient to meet the 3 hrs requirement to restore Group Demand (13 MW), i.e. there is a deficiency of 13 MW.

ii. Transfer Capacity = 9 MW available within 1 hr under an FCO

There is a deficiency in System Security of 1 MW within 15 mins and 4 MW [13-9] within 3 hrs. There is no available contribution from DG/DSR Schemes/ES – the ES is not contracted with the DNO to provide system security and the assessed security contribution assessed in accordance with EREP 131 is negligible. Hence, with the proposed ES connection, the distribution system is not compliant with Table 1 of EREC P2/7 [N1].

It should be noted that without the ES connection (as described in F.3), the Group Demand would be 10 MW (Class B): from Table 1 of EREC P2/7 [N1] under an FCO, Class B requires restoration for 9 MW of demand within 3 hrs and restoration of the remaining demand within repair time – this can be satisfied without the ES connection.

The next step is for the DNO to undertake a review of the options (see Clause 9.2) to address the deficiency, such as:

- network asset reinforcement; and
- establishing a contract with the ES facility

The most efficient solution is likely to be for the ES facility to be offered a connection with a constrained import to manage the customer related risk of not complying with the requirements of Table 1 of EREC P2/7 [N1].

However, a supplementary CBA (see Clause 11) may be required when the DNO's high-level review indicates that the options are not economically viable and/or align with the asset management strategy.

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F.6.2 Established ES facility

An ES facility consists of 5 MW of installed battery storage and operates outside of any contract with the DNO. Three scenarios are considered as depicted in Figure F.6.2.

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1) ES Importing 2MW

2) ES Importing 0MW

3) ES Exporting 2MW

Figure F.6.2 – Non-Contracted ES

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a) Determine Group Demand

i. Measured Demand

- Scenario 1 = 30 MW
- Scenario 2 = 28 MW
- Scenario 3 = 26 MW

ii. Latent Demand

Contracted DG/DSR Schemes/ES – Latent Demand associated with ES.

- Scenario 1: Latent Demand = 0 MW
- Scenario 2: Latent Demand = 0 MW
- Scenario 3: Latent Demand = 2 MW (ES export)

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. Group Demand

- Scenario 1: Group Demand = 30 MW (Class C)
- Scenario 2: Group Demand = 28 MW (Class C)
- Scenario 3: Group Demand = 28 MW (Class C)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 30 MW, available immediately. (From Table 1 of EREC P2/7 [N1] under an FCO, there is a requirement to secure partial demand within 15 mins and all demand within 3 hrs).

SCO capacity = 0 MW. (From Table 1 of EREC P2/7 [N1] under a SCO, there is no requirement to secure any demand).

Given that intrinsic network capacity is greater than or equal to the Group Demand for all scenarios, no consideration of the security contribution assessment from ES is necessary and the system is compliant with Table 1 of EREC P2/7 [N1]. However, for completeness, the contribution from ES for all scenarios is determined:

ii. Security contribution from Non-Contracted ES

- Scenario 1: There is no contribution to security from the ES.
- Scenario 2: There is no contribution to security from the ES, although previous profile data may indicate a likelihood of export.
- Scenario 3: The 2 MW export from the ES should be subject to an assessment using the methodology described in ENA EREP 131, i.e. contribution should be based on appropriate data analysis. Otherwise the contribution to security shall be assumed to be 0 MW.

F.7 Distribution system with multiple Non-Contracted DG

This example have been designed to demonstrate the assessment of security contribution from multiple Non-Contracted DG facilities, in accordance with this EREP.

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The distribution system used is illustrated in Figure F.7. The DNO knows that the system contains:

- an onshore wind farm having a DNC of 35 MW;
- a landfill gas DG installation having a DNC of 8 MW;
- a waste DG installation having a DNC of 1 MW;
- Fifty 1 kW microgeneration units at various locations in the demand group;
- an industrial site that has a biomass DG installation which operates 24 hrs per day at an output of 10 MW.

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Figure F.7 – Multiple Non-Contracted DG

There are two scenarios considered:

i. Scenario 1 (see F.7.1) – an assessment which ignores the new demand of 10 MW

ii. Scenario 2 (see F.7.2) – the assessment which includes the new demand of 10 MW

For simplicity the examples use Approach 1 of Annex D to determine the contributions from the sources of generation where relevant.

F.7.1 Scenario 1 – Assessment which ignores new network demand

a) Determine Group Demand

i. Measured Demand: 70 MW.

ii. Latent Demand

Contracted DG/DSR Schemes/ES – none

Non-Contracted DG/DSR Schemes/ES – Capacity of downstream generation: (35) + (1) + (8) + 10) = 54 MW.

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The sum of the downstream generation is > 5% of the Measured Demand, hence it is necessary to analyse the generation to establish the Latent Demand contribution to Group Demand.

Using the approach in Annex A, Equation 1.

- Onshore wind = 15 MW.
- Waste DG = 0 MW.
- Landfill gas DG = 6 MW.
- There are only a small number of microgeneration units with a low aggregate capacity, hence their impact on the Group Demand can be neglected.
- For the industrial site, there is sufficient information about the load and generation to apply the simple analysis in Annex A.2, i.e. the smaller of the expected generation output at a time of maximum Measured Demand (10 MW), and the ASC (7 MW) minus the import at the time of the maximum Measured Demand (5 MW), should be added to the Measured Demand, i.e. 2 MW, the smaller of (10) and (7 – 5).

iii. Cold Load Pickup = 0 MW

iv. Group Demand = 70 + 15 + 0 + 6 + 2 = 93 MW (Class D).

NOTE: The Group Demand is subtly different from the actual connected demand of 86 MW of existing load plus the 5 MW of net demand from the industrial site. This is because the Group Demand includes 2 MW of Latent Demand associated with the industrial site, i.e. demand that would appear if the generation at the industrial site was not running.

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 100 MW, available immediately. (From Table 1 of EREC P2/7 [N1] under a FCO, there is a requirement to secure all the demand immediately [assuming that there is no automatic disconnection][4]. The FCO capacity of 100 MW is sufficient to meet the 93 MW of demand.)

SCO capacity = 0 MW (From Table 1 of EREC P2/76 [N1] under a SCO, there is a requirement to secure all the demand within the time to restore the arranged outage)

ii. Transfer Capacity – not necessary to assess as intrinsic network capacity is sufficient to secure the Group Demand. For completeness,

10 MW available within 30 min under FCO or SCO conditions.

Given that intrinsic network capacity is greater than Group Demand, the system is compliant with Table 1 of EREC P2/7 [N1].

F.7.2 Scenario 2 – assessment which includes new network demand

In order to continue to demonstrate the application of EREC P2/7 [N1], this example develops Scenario 1 but with additional demand connected such that the Measured Demand increases by 10 MW.

[4] Strictly EREC P2/7 [N1] permits of the automatic disconnection of up to 20 MW of demand in this scenario. However, many DNO networks are not currently designed to automatically disconnect demand, and this example is based on the assumption that all demand should be supplied immediately.

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a) Determine the Group Demand

i. Measured Demand: (70 + 10) = 80 MW.

ii. Latent Demand

Contracted DG/DSR Schemes/ES – none

Non-Contracted DG/DSR Schemes/ES – Capacity of downstream generation: (35) + (1) + (8) + 10) = 54 MW.

The sum of the downstream generation is > 5% of the Measured Demand, hence it is necessary to analyse the generation to establish the Latent Demand contribution to Group Demand.

Using the approach in Annex A, Equation 1.

- Onshore wind = 15 MW.
- Waste DG = 0 MW.
- Landfill gas DG = 6 MW.
- There are only a small number of microgeneration units with a low aggregate capacity, hence their impact on the Group Demand can be neglected.
- For the industrial site, there is sufficient information about the load and generation to apply the simple analysis in Annex A.2, i.e. the smaller of the expected generation output at a time of maximum Measured Demand (10 MW), and the ASC (7 MW) minus the import at the time of the maximum Measured Demand (5 MW), should be added to the Measured Demand, i.e. 2 MW, the smaller of (10) and (7 – 5).

iii. Cold Load Pickup = 0 MW

iv. Group Demand = 80 + 15 + 0 + 6 + 2 = 103 MW (Class D).

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 100 MW, available immediately (From Table 1 of EREC P2/7 [N1] under a FCO, there is a requirement to secure all the demand immediately [assuming as before that there is no automatic disconnection]. Hence, there is a FCO deficiency of (103 - 100) = 3 MW.)

SCO capacity = 0 MW(From Table 1 of EREC P2/7 [N1] under a SCO, as the Group Demand exceeds 100 MW, there is a requirement to secure the smaller of; Group Demand minus 100 MW, and 1/3 of Group Demand, i.e. 3 MW within 3 hrs. As 10 MW Transfer Capacity is available within 30 min, there are sufficient network assets to meet the SCO requirements, there being an excess of 7 MW. There is a further requirement to secure all the demand within the time to restore the arranged outage.

ii. Transfer Capacity

Available immediately = 0 MW

Available within 30 minutes = 10 MW

As 10 MW Transfer Capacity is available within 30 min, there are sufficient network assets to meet the SCO requirements, there being an excess of 7 MW. However, there is a FCO deficiency of 3 MW (required immediately) and the network is non-compliant with EREC P2/7 [N1].

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It is now necessary to consider contribution to security from other means: DG/DSR Schemes/ES.

c) Security contribution capacity from DG/DSR Schemes/ES

iii. Security contribution from Non-Contracted DG

iv. The aggregate of the DNCs of the Non-Contracted DG in the network can be calculated. If this aggregate is less than the capacity deficit revealed in Step b) above, then there is no possibility that the DG capacity will make the network compliant. If the aggregate exceeds the deficit then further analysis is required.

v. The aggregate of all the Non-Contracted DG connected in the network = 35 + 1 + 8 + 10 = 54 MW. Hence there is the potential for the connected Non-Contracted DG to meet System Security deficiency, and the analysis therefore continues with step i.1:

- <u>Step i.1 – Check each DG source against the de-minimis criterion</u>

NOTE: See also Clause 8.2.

The microgeneration units are excluded from the compliance assessment as they are, even in aggregate, less than 100 kW.

The onshore wind farm (35 MW) is approximately 33% of the Group Demand, i.e. above the de-minimis criterion, and therefore the security contribution should be assessed.

The waste DG (1 MW) is less than 5% of the Group Demand (103 MW), i.e. below the de-minimis criterion, and is therefore not considered further.

The landfill DG (8 MW) is approximately 7% of the Group Demand, i.e. above the de-minimis criterion, and therefore the security contribution should be assessed.

The biomass DG (10 MW) is approximately 10% of the Group Demand, i.e. above the de-minimis criterion, and therefore the security contribution should be assessed.

- <u>Step i.2 – Fault ride-through capability</u>

NOTE: See also Clause 8.3.1.

The behaviour of each DG rated above the de-minimis limit, under the relevant outage conditions should be assessed. In this example, it is assumed that system studies have been carried out to demonstrate that the onshore wind farm and biomass facility remain connected under a fault forming the FCO condition and that the landfill DG will disconnect under fault conditions (e.g. owing to the sensitivity of its protection systems), and the DNO has agreed with the DG that they will automatically reconnect to the system within 30 min. DG contribution under SCO conditions can only be provided in practice in the event that the DG has been designed to run in island mode, or alternatively that there is sufficient interconnection to the rest of the total system to allow the DG to resynchronise.

- <u>Step i.3 – Establish security contributions</u>

NOTE: See also Clause 8 and Annex D.

At this point in the process the contribution from each DG facility can be established. In this example, Approach 1 (Table D.2.1 and Table D.2.2) in Annex D are used to establish the contributions from the DG. The time of year relevant for this example is winter.

Landfill DG

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– The F factor for the landfill gas DG = 22%.

– The security contribution from the landfill DG = ((22/100) x 8) = 1.7 MW.

Onshore wind farm DG

The security contribution from the wind farm is dependent upon the required value of T_m. In this example, the most onerous FCO relates to an outage of one of the two 100 MW network Circuits for a major reconstruction project.

– From Table D.2.3, the required value of T_m = 90 days.

– From Table D.2.2, the F factor for the wind farm = 0.

– From Table D.2, the security contribution from the onshore wind farm = (0/100 x 35) = 0 MW.

However, in this example the wind farm has the capability to provide continuity of supply under FCO conditions in the time period between the inception of the FCO and the time when the Transfer Capacity of the network can be utilised, in this case 30 min. A T_m value of 30 mins is used to assess this capability.

– From Table D.2.3, the required value of T_m = 30 mins.

– From Table D.2.2, the F factor for the onshore wind farm = 15%.

– From Table D.2, the security contribution from the onshore wind farm = ((15/100) x 35) = 5.2 MW.

Biomass DG

– The F factor for the Biomass DG = 32%.

– The security contribution from the biomass DG = ((32/100) x 10) = 3.2 MW.

- <u>Step i.4 – Checking for dominance</u>

NOTE: See also Clause 8.2.3 and Annex B.

By inspection, it can be seen that the contribution to System Security from each of the DG facilities is less than the capacity of one of the incoming Circuits, and hence the DG is not dominant and Capping is not required.

- <u>Step i.5 – Time durations</u>

NOTE: See also Clause 8.3.

Table F.6 summarises the security contribution from each DG facility and the time after the outage when the contribution is available. The security contribution after the SCO will depend upon the ability of the DG to synchronise with the depleted network conditions.

Table F.6 — Scenario 2 – DG contribution after a FCO

Distributed Generation	Security contribution (MW)	Time in which the DG is available post a FCO
Onshore wind farm (35 MW)	5.2	Immediately (but only for 30 mins)
Waste (1 MW)	0	N/A
Landfill (8 MW)	1.7	After 30 mins
Biomass (10 MW)	3.2	Immediately

- <u>Step i.6 – Checking for compliance with EREC P2/7 [N1] Table 1</u>

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NOTE: See also Clause 9.

The relevant network assets are the two transformers supplying the network, i.e. the capacity of each network infeed Circuit = 100 MW. The contribution to System Security from the generation established in Step i.3 is combined with the contribution from the network assets for both the FCO and SCO condition in each of the relevant time periods, i.e. immediately, within 3 hrs and within the time to restore the arranged outage.

FCO capacity (time period: inception of FCO to 30 mins)

From Table 1 of EREC P2/7 [N1] under FCO, there is a requirement to secure all the demand immediately (assuming that there is no automatic disconnection). Considering the security provided by network assets and DG facilities, there is a FCO capacity of (100 + 5.2 + 3.2) = 108.4 MW, i.e. a surplus of (108.4 - 103) = 5.4 MW.

FCO capacity (time period: 30 mins from inception of FCO to 3 hrs)

From Table 1 of EREC P2/7 [N1] under FCO, there is a requirement to secure all the demand immediately (assuming that there is no automatic disconnection). Considering the security provided by network assets and generation, there is a FCO capacity of (100 + 10 + 1.7 + 3.2) = 114.9 MW, i.e. a surplus of (114.9 - 103) = 11.9 MW. The change in capacity arises due to the fact that the onshore wind farm contribution has been replaced by the Transfer Capacity that is switched within 30 min of the inception of the fault and the resynchronisation of the landfill gas installation. The 10 MW Transfer Capacity can be sustained indefinitely, whilst the contribution provided from the wind farm will reduce with time.

The FCO capacity is the lower of these two figures, i.e. 108.4 MW.

SCO capacity (Time period: from inception of SCO to 30 mins)

SCO capacity immediately available = 3.2 MW (Biomass) plus 5.2 MW (onshore wind farm), although unless island mode operation is viable, this contribution can only be utilised if the transfer capability provides a Circuit to which the DG can be synchronised. Hence this capacity is zero in the event that no facility for island operation exists.

SCO capacity (Time period: 30 mins from inception of SCO to 3 hrs)

SCO capacity available within 30 min = 10 MW (Transfer Capacity) + 1.7 MW (Resynchronised landfill DG) + 3.2 MW (Biomass) = 14.9 MW, i.e. a surplus of (114.9 - 103) = 11.9 MW. This condition could persist for extended periods and hence it would be inappropriate to consider any contribution from the onshore wind farm as T_m could be in excess of 120 h. It is worth noting that the contribution to System Security from DG could only be realised if the generation could be synchronised to the system supplied from the Transfer Capacity Circuit. If this were not the case, the SCO capacity would be limited to the Transfer Capacity (10 MW).

In summary, by considering the contribution to System Security from the network assets alone, there is a FCO deficiency of 3 MW and a SCO surplus of 7 MW. Hence the network is non-compliant with ER P2/7 [N1].

Taking the contribution to System Security from Non-Contracted DG into account produces a FCO surplus of 5.4 MW. The increase in FCO capability arises due to the output from the onshore wind farm covering the period between the inception of the outage and the Transfer Capacity becoming available.

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The SCO surplus may increase to 11.9 MW due to the contribution from the reconnected landfill DG, the biomass DG and the Transfer Capacity, but may be limited to 7 MW provided by the Transfer Capacity. In either case, the system can be considered to be EREC P2/7 [N1] compliant.

The DNO would need to consider whether a contract was required with the Biomass DG (see Clause 7).

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Annex G
(normative)

Interpretation of Imperial College London Report [N8] findings

G.1 General

The Imperial College London report 'Review of EREP 130 F Factors' [N8] presents the full results of the analysis carried out by Imperial College London. These results have been used to produce the following tables in Annex D:

- Table D.2.1
- Table D.2.2
- Table D.3

The Imperial College London analysis calculates the Average, Minimum, Maximum and Standard Deviation of the F Factors of a large number of DC cases. In order to produce a single F Factor value for each technology type (for each season and capacity factor band where appropriate) in EREP 130 Annex D, the Average F Factor (more specifically the mean, M) minus 1 Standard Deviation (SD) is used. This means that there is a probability of 84.1% that the delivered DG security contribution is the calculated value (i.e. F Factor x DG DNC) or higher. This is considered to be a reasonable planning value to use.

The commentary below provides further explanation.

A normal population distribution about a mean value, M, is shown. The percentage of population within a standard deviation (SD) of the M follows the values shown, Hence, for 1SD below M, this represents 84.1% of the population

The following sections shows how the information from the Imperial College London report has been used to establish the values in EREP 130 Annex D.

References to Tables 5, 6, 9 and 10 in the following sections refer to tables in the Imperial College London report [N8].

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G.2 Derivation of F Factors in Table D.2.1 for non-intermittent renewable DG types

Technology Type	Winter						Summer					
	Number	Average	Min	Max	St Dev	Ave-1 St Dev	Number	Average	Min	Max	St Dev	Ave-1 St Dev
Biomass	76	52%	4%	86%	22%	30%	75	46%	4%	83%	21%	25%
CHP	13	29%	4%	60%	22%		14	25%	6%	55%	16%	
Fossil Gas	31	17%	2%	70%	20%		19	25%	2%	82%	29%	
Fossil Oil	8	33%	5%	56%	22%		6	44%	5%	83%	25%	
Gas	11	24%	3%	49%	19%		9	25%	7%	39%	13%	
Geothermal	2	4%	3%	4%	1%							
Marine - Tidal	3	16%	8%	29%	11%		2	15%	7%	23%	11%	
Mixed	27	38%	5%	79%	26%		26	42%	2%	81%	22%	
Other Generation	17	9%	2%	18%	6%		12	10%	4%	17%	5%	
Other, CHP	62	27%	2%	80%	24%		63	26%	3%	75%	23%	
Landfill Gas	74	51%	3%	83%	23%	28%	73	50%	4%	100%	23%	27%
Waste	71	54%	2%	82%	19%	35%	69	48%	5%	78%	16%	32%
NOTE 1: Replicated from Table 5. Seasonal statistical parameters of F Factors for non-intermittent DG in the Imperial College London Report [N8]												
NOTE 2: Data items in red font are used in EREP 130 Table D.2.1												
NOTE 3: Other technology types are considered to either insufficiently well-defined or too small sample size for inclusion in EREP 130												

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G.3 Derivation of F Factors in Table D.2.2 for intermittent renewable DG types

Technology Type	Season	Values	Persistence, h											
			0.5	2	3	6	12	18	24	48	120	360	480	Comments
Onshore wind	Winter	Average (%)	26	24	24	22	19	16	14	9	4	3	3	
		Min (%)	6	6	5	5	4	3	2	1	1	1	1	
		Max (%)	59	58	57	56	54	52	48	38	18	16	16	
		St Dev (%)	9	9	8	8	8	7	7	5	2	2	2	
		Ave - 1 St Dev	17	15	16	14	11	9	7	4	2	1	1	
	Summer	Average (%)	19	18	17	15	13	11	9	6	3	3	3	
		Min (%)	5	5	4	4	3	2	2	1	1	1	1	
		Max (%)	40	38	37	35	31	28	27	26	22	18	14	
		St Dev (%)	6	6	6	6	5	5	5	4	3	2	1	
		Ave - 1 St Dev	13	12	11	9	8	6	4	2	0	0	0	Values for T_m 360, 480 set to zero as F Factors can't increase
Offshore wind	Winter	Average (%)	32	31	30	29	26	23	20	13	6	4	4	
		Min (%)	6	5	5	4	4	3	2	1	1	1	1	
		Max (%)	51	49	48	46	43	40	37	26	19	19	18	
		St Dev (%)	10	10	10	10	9	8	8	6	4	3	3	
		Ave - 1 St Dev	22	21	20	19	17	15	12	7	2	1	1	
	Summer	Average (%)	24	23	22	20	17	15	13	8	4	3	3	
		Min (%)	3	2	2	2	1	1	1	1	1	1	1	
		Max (%)	35	34	33	31	30	30	29	28	25	20	12	
		St Dev (%)	8	7	7	7	6	6	6	5	4	3	2	
		Ave - 1 St Dev	16	16	15	13	11	9	7	3	0	0	0	Values for T_m 480 set to zero as F Factors can't increase

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(continued)

Technology Type	Season	Values	Persistence, h											
			0.5	2	3	6	12	18	24	48	120	360	480	Comments
Solar	Winter	Average (%)	6	6	5	4	2	2	2	2	2	2	2	
		Min (%)	3	3	3	2	1	1	1	1	1	1	1	
		Max (%)	13	12	12	10	5	5	5	4	4	4	4	
		St Dev (%)	2	2	2	1	1	1	1	1	0	0	0	
		Ave - 1 St Dev	0	0	0	0	0	0	0	0	0	0	0	Values set to zero as Solar can't contribute to security if demand peak is after dusk
	Summer	Average (%)	16	15	14	12	5	2	2	2	2	2	2	
		Min (%)	3	3	3	2	1	1	1	1	1	1	1	
		Max (%)	22	22	21	20	9	3	3	3	3	3	3	
		St Dev (%)	4	4	4	3	2	0	0	0	0	0	0	
		Ave - 1 St Dev	12	11	10	9	3	2	0	0	0	0	0	Values for T_m >18 set to zero as Solar can't contribute to security overnight

NOTE 1: Replicated from Table 9. F Factors for intermittent renewables DG types in the Imperial College London Report [N8]

NOTE 2: Data items in red font are used in EREP 130 Table D.2.2

NOTE 3: Where F Factors are adjusted from the (Ave - 1St Dev) formulae, justification is provided in the comments

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G.4 Derivation of F Factors in Table D.2.2 for intermittent hydro DG types

Technology Type	Season	Values	Persistence, h											
			0.5	2	3	6	12	18	24	48	120	360	480	Comments
Hydro run-of-river and poundage	Winter	Average (%)	36	36	35	35	34	33	31	28	21	10	9	
		Min (%)	6	6	6	6	6	5	5	4	2	1	1	
		Max (%)	74	74	74	74	74	74	73	73	69	56	52	
		St Dev (%)	17	17	17	17	17	17	16	16	16	13	12	
		Ave - 1 St Dev	19	19	18	18	17	16	15	12	5	0	0	
	Summer	Average (%)	17	17	16	16	15	14	13	11	8	3	3	
		Min (%)	3	3	2	1	1	1	1	1	1	1	1	
		Max (%)	41	41	41	41	41	41	40	39	33	12	8	
		St Dev (%)	10	10	9	9	9	9	9	9	7	3	2	
		Ave - 1 St Dev	7	7	7	7	6	5	4	2	1	0	0	
Hydro water reservoir	Winter	Average (%)	29	29	28	27	26	23	22	21	18	12	10	
		Min (%)	4	4	4	2	1	1	1	1	1	1	1	
		Max (%)	76	76	76	75	74	72	70	70	68	60	56	
		St Dev (%)	17	17	18	18	19	19	19	18	16	13	12	
		Ave - 1 St Dev	12	12	10	9	7	4	3	3	2	0	0	
	Summer	Average (%)	16	16	15	14	13	12	11	10	9	6	5	
		Min (%)	3	3	3	3	2	1	1	1	1	1	1	
		Max (%)	70	70	70	70	70	69	69	67	61	52	52	
		St Dev (%)	11	11	11	12	12	12	12	12	11	8	7	
		Ave - 1 St Dev	5	5	4	2	1	0	0	0	0	0	0	Values for Tm >18 set to zero as F Factors can't increase

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NOTE 1: Replicated from Table 10. F Factors for intermittent hydro DG types in the Imperial College London Report [N8]
NOTE 2: Data items in red font are used in EREP 130 Table D.2.2
NOTE 3: Where F Factors are adjusted from the (Ave - 1St Dev) formulae, justification is provided in the comments

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G.5 Derivation of F Factors in Table D.3 for non-intermittent renewable DG types

Capacity Factor	Winter						Summer					
	Number	Average	Min	Max	St Dev	Ave - 1St Dev	Number	Average	Min	Max	St Dev	Ave - 1St Dev
Biomass												
90%	22	76%	64%	86%	6%	49%	15	72%	61%	83%	7%	46%
70%	20	60%	42%	78%	11%	36%	18	58%	30%	77%	12%	35%
50%	11	45%	32%	57%	9%	26%	19	42%	30%	55%	7%	29%
30%	18	30%	23%	37%	4%	3%	12	32%	28%	36%	3%	6%
10%	5	7%	4%	14%	4%	0%	11	13%	4%	20%	7%	0%
Other, Landfill Gas												
90%	22	74%	50%	83%	7%	67%	21	72%	53%	100%	10%	62%
70%	14	65%	41%	75%	9%	56%	14	66%	43%	78%	9%	57%
50%	15	51%	43%	57%	4%	47%	13	54%	42%	58%	4%	50%
30%	12	29%	20%	36%	6%	23%	14	29%	11%	40%	8%	21%
10%	11	13%	3%	19%	5%	8%	11	13%	4%	19%	4%	9%
Waste												
90%	7	73%	64%	82%	6%	67%	4	71%	60%	78%	8%	63%
70%	39	64%	40%	75%	7%	57%	26	59%	44%	72%	8%	51%
50%	14	50%	37%	58%	7%	43%	26	45%	36%	54%	5%	40%
30%	5	26%	22%	28%	3%	23%	8	31%	22%	36%	4%	27%
10%	6	7%	2%	15%	5%	2%	5	14%	5%	20%	6%	8%

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NOTE 1: Replicated from Table 6. F Factors of non-intermittent generation for different capacity factors and seasons in the Imperial College London Report [N8]
NOTE 2: Data items in red font are used in EREP 130 Table D.3
NOTE 3: The data analysis for biomass generators showed that capacity factors may vary more than 20% year to year, for more than 50% of the population. To accommodate this to some extent the F factors have been reduced by applying that of the next lowest capacity factor value. For example rather than use a 70% F Factor (76-6) for a biomass plant with a 90% capacity factor, a 49% F Factor (60-11) is used

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