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Engineering Report 130

Issue 3 2018

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

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First published, July, 2006; Amended, December 2014

Revised, 2018.

Amendments since publication

Issue	Date	Amendment
Issue 3	Month, 2018	Major revision of Issue 2 to: • EREP 130 is aligned 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 DG, using recent data from Distribution Generation • Differentiate the contribution to security from DG, DSR Schemes and ES which is contracted with a DNO and that which is not. This issue largely been re-structed 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

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Demand Facility
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-mininis 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, Sufficiency of the system capacity:
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, Plans for remedial work:
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 Latent Demand for ES added.
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		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 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 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 graphs for intermittent persistence have been added to replace the previous 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 requited knowledge of the availability of DG and the number of units on 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 DSR Schemes and ES. Bibliography: The list of relevant informative references has been 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.

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.

Introduction

The previous issue of this Engineering Report (EREP) focused on assessing the contribution to System Security as provided by Distributed Generation (DG). However, this latest revision 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 and;
- Distributed Generation (DG), Demand Side Response (DSR) Schemes, and Electricity Storage (ES), that are contracted with a Distribution Network Operator (DNO) to provide a security service
- DG, DSR Schemes, and ES, that are not contracted with a DNO to provide a security service

The continuing experience that Distribution Network Operators (DNOs) now have regarding security contribution from DG provides 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, and 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 in EREC P2/7 [N1] Table 1. This EREP provides technical guidance on these issues.

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 the assessment of the fortuitous security contribution from DG, DSR Schemes and ES where there is no contact in place with the DNO to provide security services.

This EREP also provides general guidance on contractual considerations that a DNO may need to consider when looking at security contribution from DG, DSR SQ ervices or ES to satisfy the requirements of EREC P2/7 [N1]. However, the detailed form that any contractual and commercial considerations might take is 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

[N4] Utilities Act 2000

[N5] Energy Act 2005

[N4] Electricity (Northern Ireland) Order 1992

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 DG, DSR Service, or ES does not exceed the contribution to System Security by 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]

NOTE 2: An electricity distribution system comprises network assets and non-network assets including DG, DSR Services and ES.

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, 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]

3.4

Contracted

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

3.5

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 [N2] and Statutory Instrument 2001 3270 [N3].

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 Generation is taken as the aggregate nameplate capacity of all the units within the DG facilitiy, less any parasitic load.

3.6

Demand Facility

facility connected to the distribution network, which consumes electrical power

3.6.4

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]

3.7

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 for the whole, or part of, a Demand Facility can be modified using DSR.

3.8

Demand Side Response Scheme (DSR Scheme)

DSR arrangement which is being implemented at a Demand Facility

3.8

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]

3.9

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).

3.10

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 Demand Facility when charging and DG when discharging).

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

NOTE 2: ES is a form of ‘other means’ as referred to in ENA EREC P2/7.

3.11

First Circuit Outage (FCO)

fault or pre-arranged Circuit outage

[ENA EREC P2/7, Clause 3.7]

3.12

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 [N4])

[ENA EREC P2/7, Clause 3.8]

NOTE: Electricity (Northern Ireland) Order 1992 [N4]

3.13

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 ESF, 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].

NOTE 3: Group Demand is the sum of the Latent Demand and the Measured Demand.

[ENA EREC P2/7, Clause 3.9]

3.14

Intermittent Generation

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

3.15

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 ESF exists when there is export or restricted import, during the time of Measured Demand.

3.16

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]

3.4

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 exclude the existence of agreements outside of DNO involvement.

3.17

Non-intermittent Generation

generation facility where the energy source for the prime mover can be made available on demand

3.18

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

3.19

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.

3.20

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]

3.21
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]

3.22
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) Distributed Generation (DG) connected to its network;

c) Demand Side Response (DSR) Scheme connected to its network, and;

d) Electricity Storage (ES) connected to its network.

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

The guidance in this EREC simplifies the presentation of Circuit ratings and security contribution from DG, DSR Services 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 outages 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 contained 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 EREC 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, DG or ES developments or operation of DSR Services. 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 Regulatory Financial Performance Reporting (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 and ESF, 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 will need to be considered are shown in the Technical Check List provided at Annex C to this report.

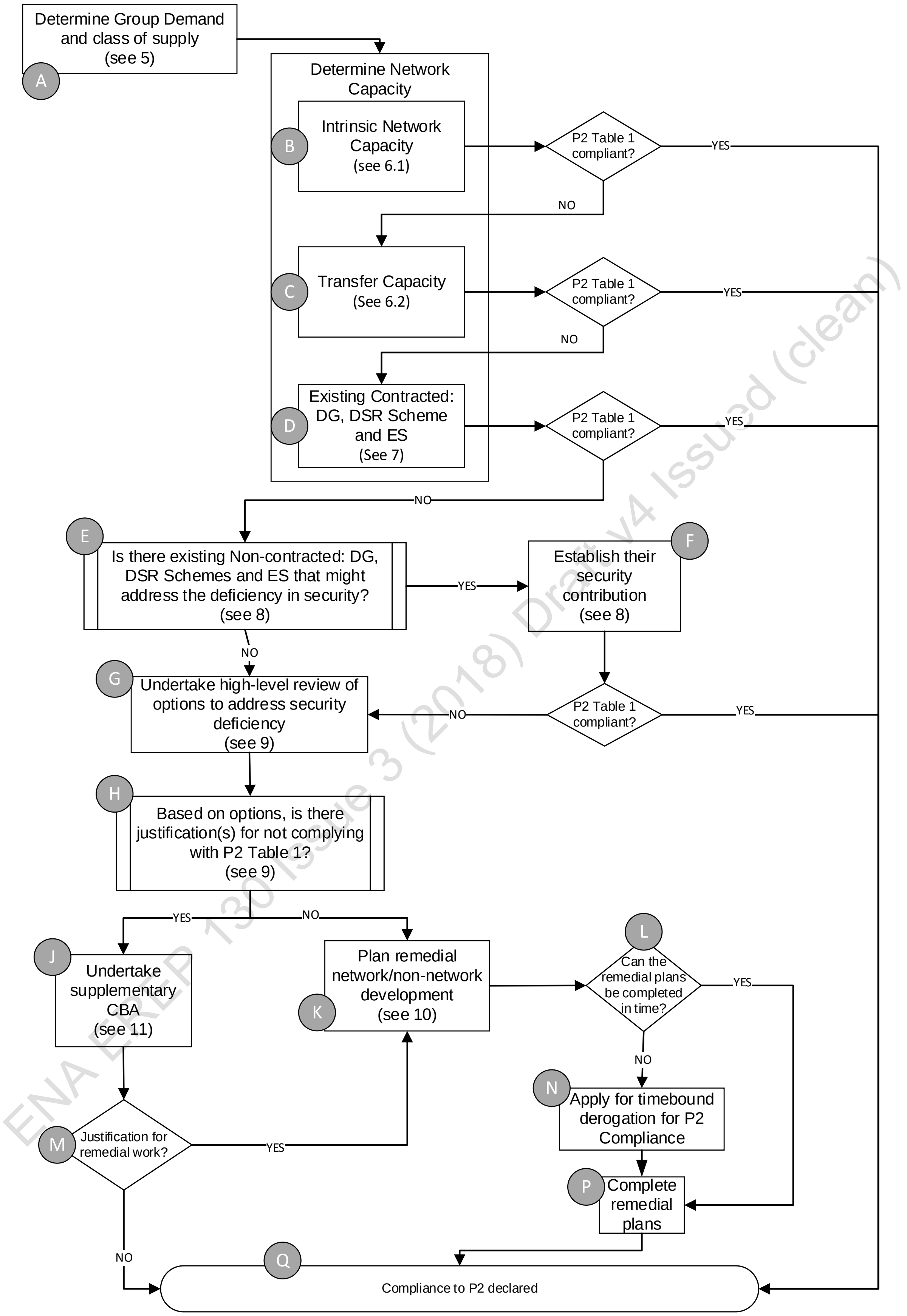
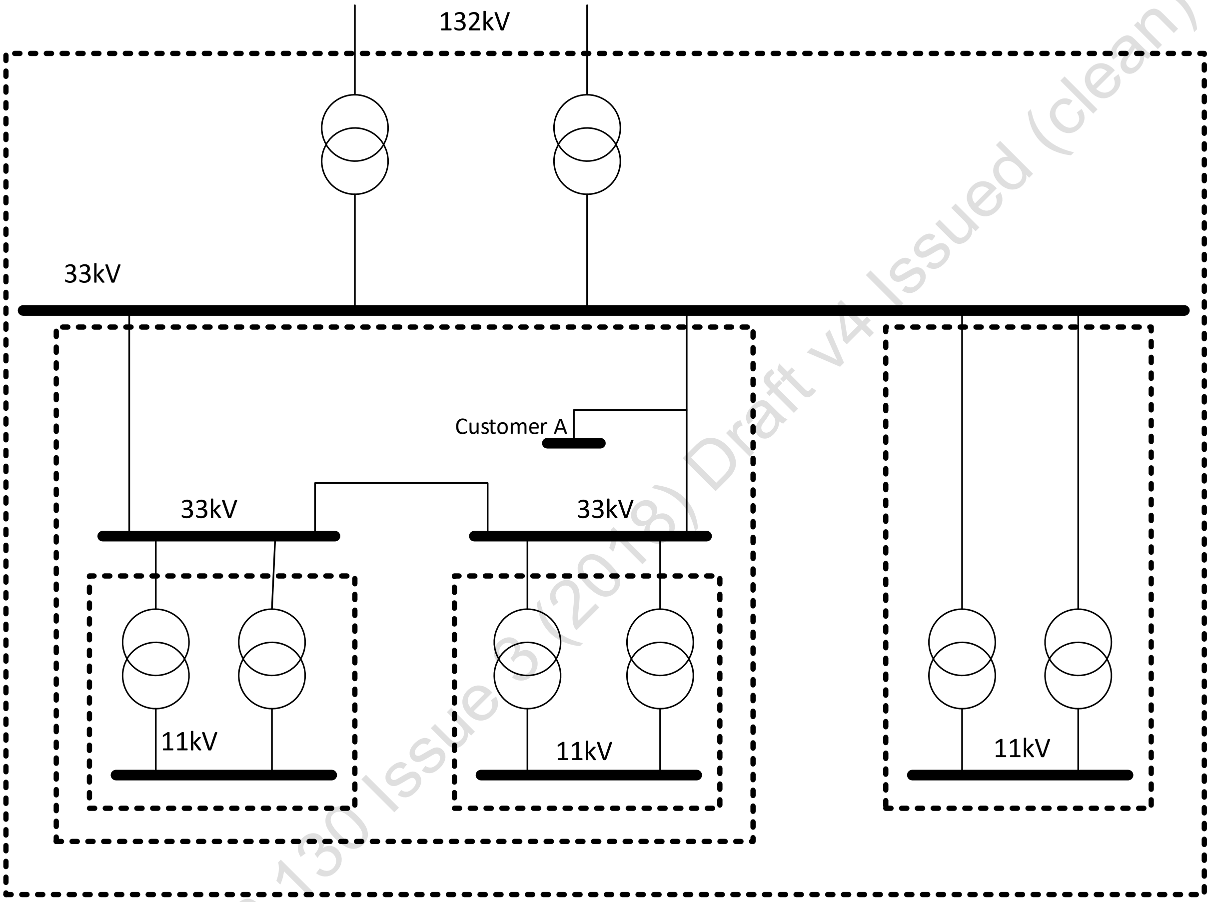


Figure 1 — The assessment process

NOTE: Detailed guidance on each stage of the process is given in the following clauses and figures; the relevant numbers are shown in brackets.

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.



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 sum of all the DG DNC, capacity of DSR Schemes, and capacity of ES is less than 5% of Measured Demand, then Group Demand should be taken as the same as Measure Demand.

The de-minimis test should exclude capacity from contracted DG, DSR Schemes, and ES, as the DNO is expected to have accounted to the Latent Demand associated with this contracts (see Figure 2).

Annex A provides detailed guidance on the assessment of Latent Demand.

For the case of customer A, who has agreed to a single circuit risk agreement, EREC P2/7 [N1] indicates this customer's supply is restored on activation of such an agreement when there is a Circuit outage. Hence, customer A may be excluded from the Group Demand calculation. For the case of customer A, their 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)

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 has 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 network assets, 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.

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

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

[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.

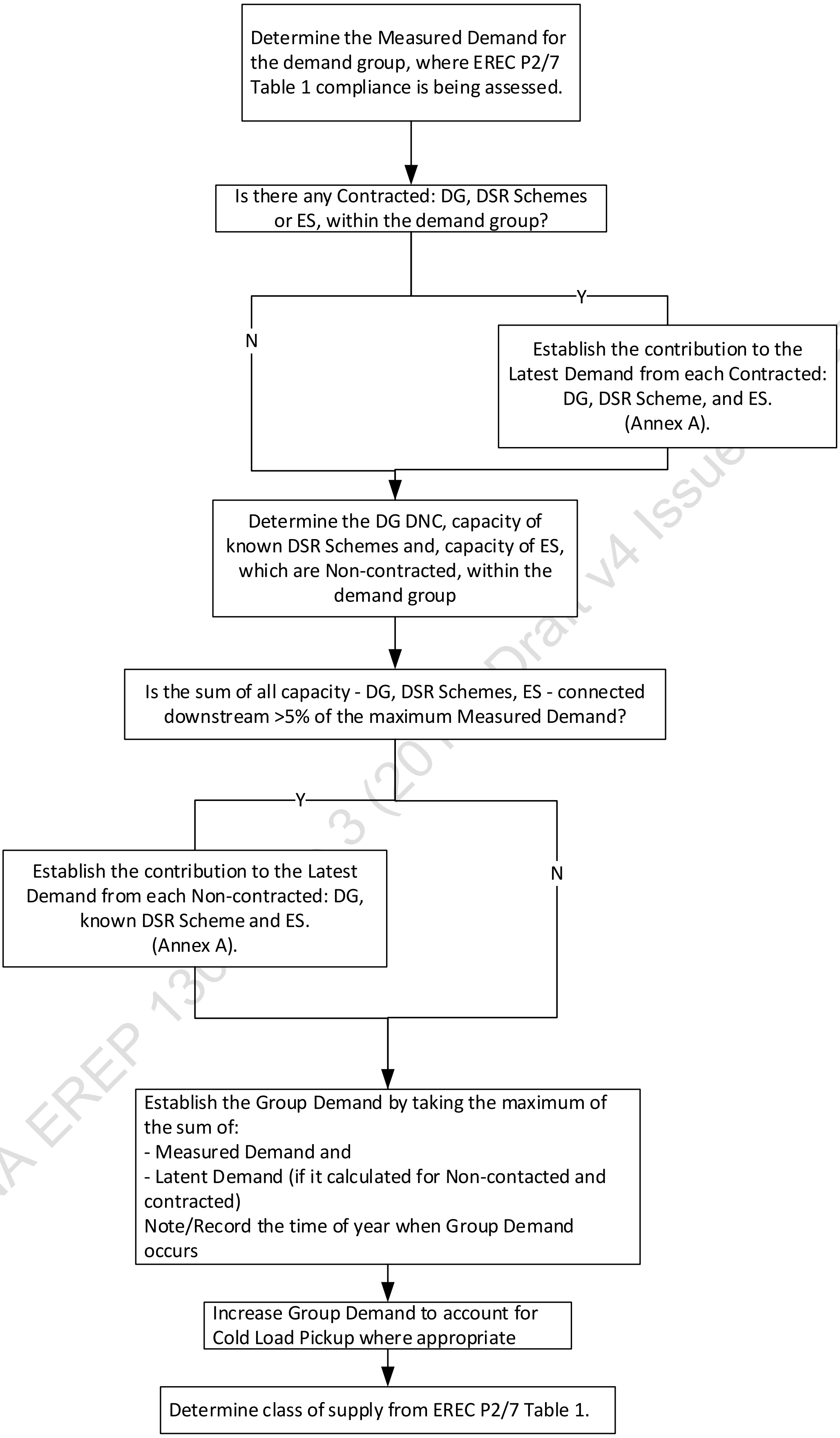


Figure 3 — Determine class of supply and Group Demand

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 First Circuit Outages, 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 are to 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 Second Circuit Outages, 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 rating 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 (no manual initiation required locally or remote) which has been appropriate planned and designed (load on network assets and protection settings considered).

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 be determined under FCO conditions and 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 also largely dependent on the adjacent demand group to the one being assessed.

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 minutes) i.e. local/remote automation
- Manual switching of available network capacity via a remote management system (typically within 15 minutes) i.e. remote control
- Manual switching of available network capacity via local operation of equipment (typically within 3 hours)

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 outrages is critical when considering the use of Transfer Capacity. Unless there is a very low probability that a Circuit is unavailable for demand transfer, it may be prudent to apply a fortuitous availability factor to the Transfer Capacity.

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

Unless a Circuit being considered is clear 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 Clause 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 affects

The DNO may re-configure the network to an alternative 'normal' arrangement during seasonal events. Hence, the Group Demand should be considered for each seasonal event to establish the worst-case situation for System Security.

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.

In considering the security contribution from means other than network assets, the DNO can initiate this by establishing has the potential it will be necessary for the DNO to identify the most efficient mechanism available to enhance System Security, this may mean assessing the contribution from DG. An assessment can be made to establish whether the aggregate of capacity of DG, DSR Schemes and ES connected to the network there is sufficient to meet any deficiency in System Security available from the network assets. 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 ESF might still be of value, in limiting the extent of remedial options

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

7.1 General

In the event of the DNO needing to rely on DG, DSR and ESF, during Circuit outages, the facility is unlikely to be asked to alter their operation to meet the DNO's requirements. Under these conditions, no service is being requested of the DG/DSR/ESF, and no contract for services is required. The DNO takes the risk of the facility being unavailable at the time of a depleted system. This is analogous to the uncontracted DNO risk of aggregated load being subject to variation above normal maximum demands.

There will be DG/DSR/ESF for which the DNO:

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

In these cases, and where the DNO elects to rely on a security contribution from the DG/DSR/ESF, the DNO should enter into a contract with the DG/DSR/ESF operator/owner to ensure that security services can be reliably provided when requested by the DNO. A security contribution will be based on the service that the DG/DSR/ESF is able to offer and guarantee. The contract is likely to be such that the DG/DSR/ESF takes the risk of the plant being unable to provide an agreed service upon request.

The DNO should assess whether the costs, risks and benefits of procuring additional System Security contribution from DG/DSR/ESF, through such a contract, is a more efficient and cost effective option overall compared to the additional System Security that would be provided by undertaking remedial work to network assets, for example reinforcement.

Where the DNO has a contract with a DG, DSR or ESF provider which governs requests or operational instructions from then 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.

7.2 DG

The contribution to security from DG which is not subject to a contract with the DNO should be treated as fortuitous in accordance with Clause 8. Where the DNO has a need for a definitive security contribution then the costs, risks and benefits of procuring this from a DG facility (existing or planned) should be assessed.

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

a) Number and capacity of DG facility i.e. DNC of DG

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

    i. Response time

    ii. Maximum export required from DG

    iii. Maximum duration of required operation

c) Communication arrangement with DG facility

d) DG stability requirements and Interface protection

    i. Agreed operating parameters and settings

    ii. Fault ride through capability required

    Agreed evidence to demonstrate that the DG will ride through a range of credible network outages.

e) Cold start/warm start/reconnection times required for DG

f) Availability/reliability requirements for DG facility

g) Coordination of DNO and DG planned outages

The DNC and the Latent Demand associated with the DG should be based on the terms of the contract.

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.

7.3 DSR Schemes

The contribution to security from a DSR Scheme which not subject to a contract with the DNO should be treated in accordance with Clause 8. Where the DNO has a need for a definitive security contribution then the costs, risks and benefits of procuring via a DSR Scheme provided by a Demand Facility (existing or planned) should be assessed.

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

a) Maximum and minimum import capacity of Demand facility

b) Demand facility action on receipt of DNO request/instruction

- Response time
- Reduction in demand required
- Maximum duration of required reduction (e.g. hours per day, maximum number of contiguous days

c) Communication arrangement with DG facility

d) Coordination of DNO and DG planned outages

The details of the contract for the DSR Scheme should define the quantities applied when assessing contribution to capacity and Latent Demand. Such quantities shall take account of the influencing factors described in Annex E.

The contract shall incorporate any necessary capping of the DSR security contribution to avoid dominance in accordance with EREC P2/7 [N1] Clause 5.2.

7.4 ES

The contribution to security from an ES which is not subject to a contract with the DNO should be treated in accordance with Clause 8. Where the DNO has a need for a definitive security contribution then the costs, risks and benefits of procuring this from an ESF facility (existing or planned) should be assessed.

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

a) Maximum and minimum export power of ES facility

b) Maximum and minimum import power of ES facility

c) 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

d) ESF action on receipt of DNO request/instruction for operation

    i. Response time

    ii. Maximum export required from ES

    iii. Maximum duration of export required

    iv. Maximum reduction in import for ES (where relevant)

    v. Maximum duration of export required (where relevant)

e) During ES export – stability requirements and Interface protection

    vi. Agreed operating parameters and settings

    vii. Fault ride through capability required

    Agreed evidence to demonstrate that the ESF will ride through a range of credible network outages.

f) Cold start/warm start/reconnection times required for ES

g) Availability/reliability requirements for ES facility

h) Coordination of DNO and ES planned outages

The details of the contract with the ES should define the quantities applied when assessing contribution to capacity and Latent Demand. Such quantities shall take account of the influencing factors described in Annex E.

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.

8 Contribution to System Security from non-contracted DG, DSR Schemes, and ES

8.1 General

Where the DNO relies on the security contribution of on-contracted DG/DSR Schemes/ES, it should be assessed in accordance with the guidance in this Clause.

If the aggregate of non-contracted, DG, DSR Schemes which are known, and ES, is greater than any deficiency it will be necessary to carry out further analysis to confirm the actual security contribution.

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

a) Non-contracted DG (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 (DNO should have notification records of all ES generation connected to its network)

d) Non-contracted ES import restrictions which are known to the DNO (the DNO may have visibility of an ES import restriction through information available from a third party)

The DNO may assess the import and export profiles from non-contracted DG, Demand Facilities with known DSR Schemes, and ES, and may conclude that the facility exhibits predictable and reliable import and/or export profiles. Even though the output may vary over short periods, the overall output profile may be considered to be sufficiently predictable and well understood. Additionally, the DNO may have acquired information on a DSR Scheme or ES operation on which may be corroborated by import and/or export profiles. In these cases, the DNO may determine a security contribution from the DG, DSR Scheme or ES.

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 DG facilities, DS Schemes, ES facilities rated below 100 kW in capacity (when testing if a DG meets this criterion, the DNC of the facility should be used).

8.3 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 facility, DSR Scheme, ES facility should be dominant. The DNO shall consider the capping requirements for single DG facilities, DSR Schemes, ES facilities, and groups – the guidance in Annex B should be referred to.

8.4 Determine the 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 and shown diagrammatically in Figure 4. Where there is more than one DG type or multiple DG facilities in a network, a similar process is followed to establish the security contribution from each DG subgroup. The overall security contribution from DG within the network 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 a DG plant or a group of DG plants it is necessary to use one of the three approaches described in Annex D. These approaches take account of the following influencing factors, which are described in further detail in 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 security contribution or F factors for each individual DG plant(s).

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

NOTE: An overview of the technical issues that will need to be considered is shown in the Technical Check List presented in Annex C to this report.

8.4.1 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 ER P2/6 [N1], it will be necessary for the DNO to be satisfied with how the DG plant will respond to both normal and credible abnormal 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 be capable of being re-connected to support the requisite level of demand either

    i. within the times allowable in Table 1 of ER 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 to normal post fault. The behaviour of a DG will be less certain during an unplanned outage than during a planned outage.

8.5 Determine the contribution from non-contracted DSR Schemes

DSR which may be present on a network but not contracted with the DNO. In these cases, the assessment of DSR contribution to security would require detailed research to determine the nature of the demand reduction. The DNO is unlikely to deploy the resources to acquire such data and this EREP postulates that the existence of uncontracted DSR is sufficiently low for it to be ignored during assessment of network security.

As DSR is initiated in response to an instruction, it is distinct from other forms of demand management such as time-of-use (ofgem) tariffs and price signals. An ongoing research project by Scottish and Southern Electricity Networks [5] suggests that there is insufficient evidence that financial incentives, e.g. TOU tariffs, are effective in changing consumer behaviour. Conversely, DNOs may acquire demand profiles and details of specific types of tariff arrangements which demonstrate a change in consumer load patterns e.g. time switching, ‘wind spilling’. Unless there is a strong link between demand management schemes and a reduction in demand, based on collated data, this EREP recommends that they should not be considered during assessment of network security.

Hence the security contribution from DSR should be based on the terms of a contract agreement between the DSR provider (which may be an aggregator) and the DNO (see Clause 7.3.

Uncontracted DSR should be assumed to have no affect on the Measured Demand i.e. Latent Demand is zero, unless the DNO is aware of site-specific details.

Where the DNO is aware of uncontracted DSR through liaison with third parties, the details should be acquired. The security contribution in this case should be subject to a site-specific study.

8.6 Determine the contribution from non-contracted ES

The security contribution from ES should be based on the terms of a contract agreement between the ES facility and the DNO (see Clause 7.4).

The export from non-contracted ES should be assumed to be zero at the time of Measured Demand, unless the DNO is aware of site-specific details for ES.

The import from uncontracted ESF should be assumed as being accounted in the normal demand profile i.e. within the Measured Demand.

Where the DNO is aware of non-contracted ES through liaison with third parties, the details should be acquired. The security contribution in this case should be subject to a site-specific study.

9 Sufficiency of the system capacity

9.1 General

Once the potential contribution to System Security from DG/DSR/ESF 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 DG/DSR/ESF contribution(s) and network contribution 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 min and the demand that must be recovered in 3 h. Both periods must be assessed separately since the required demand, the number of Circuits and the amount of DG/DSR/ESF 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/ESF) under FCO conditions in any one time period, the system is declared as not complying with 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.

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 asset reinforcement; and
- establishing contracts with DG/DSR/ESF providers

The review of the options should consider:

- Budget cost of implementation;
- estimate of timescales for implementation;
- 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 possible; 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 Plans for remedial work

For a given forecast maximum demand, the objective of remedial work is to address a deficiency in system capacity, identified by the DNO. A detailed analysis of the options considered in Clause 9 should be undertaken. The detailed analysis shall reveal whether the remedial work can be completed in a timely manner and should compare

a) Remedial work involving network asset reinforcement only

b) Remedial work involving arrangement of DG/DSR/ESF contracts only

c) Remedial work involving a combination of network asset reinforcement and DG/DSR/ESF contract arrangement

In the case where the remedial work will not be completed in advance of the DNO network system being non-compliant with Table 1 of EREC P2/7 [N1], the DNO shall request a technical derogation from Ofgem [6] for a specified period of time i.e. timebound derogation. The need to submit a timebound derogation may be omitted if the DNO can demonstrate that it has financially committed to the remedial work.

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 viable and/or align with the asset management strategy.

The CBA shall be based on the minimum requirements set out in Table 1 of EREC P2/7 [N1]. It should primarily assess the benefits of providing additional / fewer network assets i.e. main network assets and network assets to provide Transfer Capacity. It should consider the potential additional / reduced investment expenditure established from reinforcement estimates. It should also consider the benefits for establishing contracts with DG/DSR/ESF.

The DNO may apply their own CBA template, otherwise the latest CBA template available from Ofgem should be used. The CBA should primarily be based on the rate of return principle (discount rate), but should also consider:

a) Value of losses

b) Value of lost load (VoLL)

Expected energy not served (EENS) is expressed in MWh over a specific time period (e.g. a year). EENS thus makes it possible to monetise the shortfall in a system where VoLL has also been calculated since the amount of EENS can then be multiplied by VoLL. Hence, a change in EENS 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 lifetime of assets (20 years minimum)

Example: 3 MW Transfer Capacity, utilised for 6 hours once every 5 years

- EENS = 18 x 4 MWh in 20 years = 72 MWh

- 72 * 17000 = £1.2m break even

In the case where the supplementary CBA provides justification for remedial work, the DNO should progress plans for this, otherwise the CBA shall be submitted to Ofgem in support of a request for technical derogation from compliance with Table 1 of EREC P2/7 [N1].

Annex A
(normative)

Identification of Group Demand

A.1 General

In order to ensure that there are sufficient network assets and DG/DSR Schemes/ES to secure the customer demand, 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/ES profiles, to establish the Group Demand.

Equation 1 shall be applied when determining Latent Demand.

Latent Demand =	DG export at time of Measured Demand (contracted and uncontracted) + DSR not importing at time of Measured Demand (contracted and uncontracted when known) + ESF export at time of Measured Demand (contracted and uncontracted when known) + ESF not importing at time of Measured Demand (contracted)

Equation. 1

A.2 Contracted DG, DSR Scheme and ES

Where a DNO has a contract with a DG facility, provider of a DSR Scheme, or ES facility, then the Latent Demand will be based on the terms of the contract, as stipulated in Clause 7.

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 systems. 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.

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 considered to be negative demand, it is effectively being ascribed a 100% security contribution, or;
- a DSR Scheme action (reduction in demand) at a Demand Facility in response to a third party DSR Scheme contract is considered as negative demand, it is effectively being ascribed a 100% security contribution

The magnitude of the risk relates to the aggregate DG/DSR Schemes/ESF capacity in the network under consideration rather than the size of any individual DG/DSR Schemes/ESF. It is recognised that establishing an appropriate approach is subjective, and that a pragmatic approach, as described below, needs to be taken.

Where the aggregate DNC of the DG, capacity of DSR Scheme, and capacity of ES, in any given network exceeds 5% of the maximum value of the Measured Demand of the network, the DNO should make an assessment of the Latent Demand so that it can be added, making appropriate allowances for diversity and coincidence, to the Measured Demand to establish the Group Demand. 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 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/ESF would facilitate further assessment of the Latent Demand.

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

For DG where there is no on-site demand, the contribution to Latent Demand is the export from the DG 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 plant, it will often be sufficiently accurate to estimate the Latent Demand by summating the export from the DG, at the time of the maximum Measured Demand.

A.5 Establishing the Latent Demand from customer's 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 ER P2/6 [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 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.

A.6 Latent Demand for DSR Schemes

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 suppressed by the DSR Scheme in order to establish the gross demand that needs to be secured. In order to determine the effective security contribution from a DSR Scheme, an assessment is needed of the magnitude and longevity of the demand reduction which is likely to be delivered by the DSR Schemes in place at the time when the intervention would be needed to meet the security requirements of EREC P2/7 [N1].

A.7 Latent Demand for ES

If ES is importing during Measured Demand then the import of the ES will be included in the Measured Demand. If the ES is contracted not to import, then the Measured Demand will

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

need to be increased by the suppressed import i.e. the Latent Demand for the ES not importing (akin to a DSR Scheme).

If the ES is exporting then the Measured Demand will need to be increased by the export i.e. the Latent Demand for the exporting ES.

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

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 rating of the largest Circuit is greater than the security contribution of the:

  i. DNC of the largest DG

  ii. DNC of a multiple DG facilities which are susceptible to common mode failure (see B.2)

  iii. Capacity of the largest contracted DSR Scheme provided by a Demand Facility

  iv. Capacity of contracted DSR Schemes provided by a single aggregator

  v. 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 ES export

  viii. Capacity of multiple 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 rating of the two largest Circuits is greater than the security contribution of the two largest DG/DSR Schemes/ES capacities, as outlined in items i)-x).

If the first condition is not met (i.e. the DG/DSR/ESF 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 cyclic 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.

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 management network, protection, or control system associated with DG and DSR is considered. Other types of common mode failure are

- 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, ESF) It is possible that significant DG/DSR/ESF 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, ESF) Inability of certain types of DG/ESF or types of protection to remain stable and/or ride through a system disturbance.

To avoid common mode failures of DG/DSR Scheme/ESF 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 under the same arrangements as provided in Annex B.1. Each type of DG/DSR Scheme/ES that could be subject to common mode failure should be aggregated and this aggregate capacity tested for dominance and Capped accordingly.

Annex C
(informative)

Technical check list

C.1 Introduction

AUTHOR NOTE 1: This Annex could be removed as it duplicates most of the guidance in the document.

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/ESF	
De-minimis test for uncontracted DG/DSR/ESF and hence any Latent Demand	

C.3 Establish network capability

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

C.4 Establish contracted DG/DSR/ESF capability

	Complete
Contracts with DG	
DSR contracts	
ESF contracts	

C.5 Uncontracted DG

	Complete
For eachDG installation:	
A.4.1 General	
Capacity of DG	
Type of DG	
Operating period if less than 24 h	
½ hourly output profile	
Merchant or process linked?	
A.4.2 Technical	
Compliant with G59	
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	
What are cold start/warm start/reconnection times for generation?	
A.4.3 Fuel	
Contracted fuel supply	
Uninterruptible fuel supply (gas)	
Fuel stocks available	
A.4.4 Commercial	
Ability for DNO to request operation	
Contracted repair and maintenance	
Coordination of network and DG planned outages	
Expected lifespan of the DG plant	
A.4.5 Contract	
Contracts in place	
Ability to operate on demand	
Appropriate communications with Generator/DG plant to be in place	

A.4.6 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	
Will an island result (if so - longer checklist required)	
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.6 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 acquitted.	

C.7 Non-contracted ES

	Complete
Where the DNO is aware of non-contracted ES through liaison with third parties, the details should be acquired.	

Annex D
(normative)

Approaches for assessing the contribution from DG to System Security

D.1 General

This Annex describes three approaches for assessing the potential contribution from 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 non-intermittent 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 2, 2-1 and 2-2) and graphs (Figures D.1-D.5) are based on the analysis of actual export data on typical DG installations. The data represents the following characteristics:

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

NOTE: The data is based on DG type. The number of separate units associated with a particular facility is not considered.

b) Data sampled at 30 minute 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 2-1 or 2-2; or
- where a 'first pass' assessment is required to determine if a particular DG plant is likely to have sufficient capacity to satisfy a particular requirement.

Each DG type may be assessed individually and the aggregate DG capability is the arithmetic sum of all the type contributions plus any additional contribution from DG having an operational period less than 24 h, see Table 2. This summation gives a conservative assessment of the DG contribution.

Table 2

Type of Distributed Generation	Contribution (see NOTE 1 below)
Generation as listed in Tables 2-1	F % of DNC
Generation as listed in Tables 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 2-1 — F factors in % for Non-intermittent Generation

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.

Author Note 2: Values in table to be validated by ICL

Type of generation (NOTE 1)	Period of assessment (NOTE 2)	
	Winter	Summer
Biomass	32%	30%
Landfill gas	22%	20%
Waste	32%	24%

NOTE 1: For DG 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 [N].

NOTE 2: Summer period refers to months April – September inclusive. Winter period refers to months October – March inclusive. AUHTOR NOTE 3: ICL to confirm.

NOTE 3: The percentage values in this table are representative of the mean (M) minus 1 standard deviation (SD). Refer to commentary below for further explanation.

COMMENTARY ON: Standard deviation (SD)

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

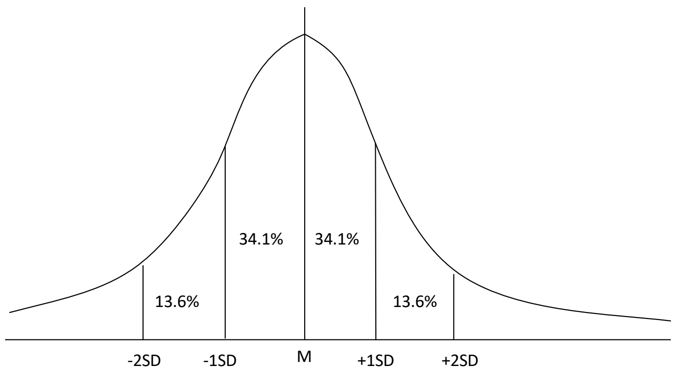


Table 2-2 — F factors in % for Intermittent Generation

The F factors for Intermittent Generation are related directly to the period of continuous generation (i.e. Persistence) and are not affected by the number of units at an individual site.

NOTE: Recommended values of T_m are shown in Table 2-4.

Author Note 4: Values in table to be validated by ICL.
Author Note 5: Further granularity in the values may be provided by inclusion of geographic regions (north, middle, south) – significant for wind and solar. Do reviewers consider this necessary?

Type of generation (NOTE 1 &2)	**Persistence, T_m (hours)**										
	½	**2**	**3**	**6**	**12**	**18**	**24**	**48**	**120**	**360**	**480**
Onshore wind (Winter)	15%	14%	13%	12%	10%	8%	6%	3%	1%	0%	0%
Onshore wind (Summer)	12%	11%	10%	8%	7%	5%	4%	2%	0%	1%	1%
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)	6%	6%	5%	5%	4%	4%	4%	1%	0%	0%	0%
Hydro water reservoir (Winter)	11%	11%	10%	8%	7%	4%	4%	3%	1%	0%	0%
Hydro water reservoir (Summer)	4%	4%	3%	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: For DG 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 [N].

NOTE 2: Summer period refers to months April – September inclusive. Winter period refers to months October – March inclusive. AUHTOR NOTE 6: ICL to confirm.

NOTE 3: The percentage values in this table are representative of the mean (M) minus 1 standard deviation (SD). Refer to commentary below Table 2.1 for further explanation.

Table 2-4 — Recommended values for T_m

This table provides recommended values for Tm for three system conditions that may apply 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.

P2/7 demand class	Switching (see NOTE 1 below)	Maintenance	Other outage (see NOTE 2 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: 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.

NOTE 2: Examples of “other outage” are an unplanned outage or an outage as part of a major project.

NOTE 3: SCO only applies for demands greater than 100 MW.

NOTE 4: FCO only applies where compliance is achieved by automatic demand disconnection of 20 MW or less.

Where consideration of a value of persistence other than that shown in Table 2-2 is required for Intermittent Generation, the appropriate DG contribution may be derived from Figures D.1 and D.2.

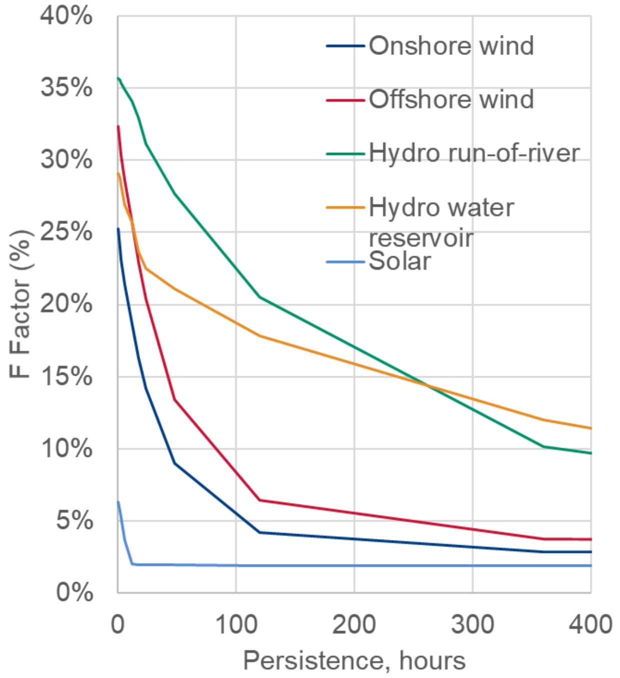


Figure D.1 — F Factors (%) as a function of Persistence T_m, for winter

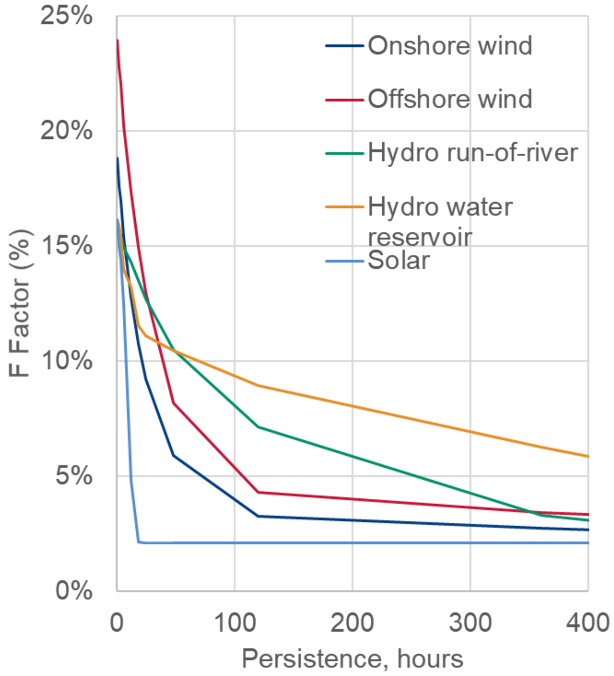


Figure D.2 — F Factors (%) as a function of Persistence T_m, for summer

D.3 Approach 2 – Using capability factors

AUTHOR NOTE 7: New Approach 2 is now based on capacity factors. This requires the DNO to determine the capacity factor for the DG being considered.

This approach is applicable to non-intermittent DG 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 output/DG capacity

The capacity factors in Table D.5 are based on data collated over the period 2013-2018, inclusive.

Table D-5 – F factors in % for Non-intermittent Generation for varying capacity factors

Capacity factor % (NOTE 1)	**Period of assessment (NOTE 2)**	
	Winter	**Summer**
Biomass (NOTE 3)		
90	49%	46%

70	36%	35%
50	26%	29%
30	2%	9%
10	0%	0%
Landfill gas		
90	67%	62%
70	56%	57%
50	47%	50%
30	23%	21%
10	6%	7%
Waste		
90	67%	63%
70	57%	51%
50	43%	40%
30	23%	27%
10	1%	8%

NOTE 1: For DG 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 [N].

NOTE 2: Summer period refers to months April – September inclusive. Winter period refers to months October – March inclusive. AUHTOR NOTE 8: ICL to confirm.

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.

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.

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 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 [N5]. 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 only and can be used for assessing for compliance with ER P2/6 [N1] in the same way as performed with either of the two previous approaches.

Annex E
(informative)

Influencing factors for DG/DSR Schemes/ES Security Contribution

E.1 Generation availabilities

E.1.1 General

The F factors in Tables 2-1 and 2-2 assume that there is no underlining availability issues associated with the DG

When undertaking a site specific assessment of DG contribution, or when the DNO is aware of an availability issue, the technical, commercial and fuel availability considerations described below should be accounted for. These considerations may also be relevant for DG plant connecting to the system with no history of overall availability.

If the plant type is well understood, technical availability may be judged. Fuel sources and commercial operation may be predictable. If these elements of overall availability cannot be assessed with some confidence, the DNO may choose a more conservative overall availability figure until some history can be developed, and/or seek to secure a desired availability through contract with the DG.

Operation over the first year or two could then be used to confirm the appropriateness of using the F-factors in Tables 2-1 and 2-2.

The overall average availability can be considered as the product of three specific elements: technical availability, fuel source availability and commercial availability. Each can be considered as 100% if fully available, providing a 100% overall availability and thus confirming application of the F-factors in Tables 2-1 and 2-2.

E.1.2 Technical availability

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

It can be separately observed where the operator allows the DG plant to run continuously with full fuel being available, a good example being landfill gas. Modern DG plant 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 plant from achieving expected output over any time period. The impact of fuel source constraints is greatest where the DG plant 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 in the plant being taken off-line for periods within a 24 h 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 plant 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 Generation operating regime at maximum demand

The operating régime of DG plant(s) at the time of Group Demand must be ascertained, e.g. whether it operates for 8 h or 12 h or whether it is continuously operated. Where the DG operates for at least 8 (or 12 h) the appropriate values for F in Table E-1 can be applied. In the case of restricted operating times, it is assumed that the increasing demand at the start-up time is the same as the decreasing demand at shut-down time. If this is not so, then the contribution may be less than the approach suggests. In the extreme, if the operating period does not span the peak demand at all, the contribution from such generation is zero.

If the operating times are restricted, the contributions in Table E.1 may be applied otherwise special studies will be required (refer to EREP 131 [N5]).

Table E.1 – DG contribution for plant with restricted operating

Restricted DG operation	Contribution
Plant operating for 8 hours	Smaller of value derived from relevant row above; or 11% of Group Demand
Plant operating for 12 hours	Smaller of value derived from relevant row above; or 12% of Group Demand
NOTE 3: The values assume that the operating period is such that operation spans the peak demand, and the demand at start-up is the same as the demand at shut-down, i.e. operation is symmetrically placed on the daily load curve. If these conditions do not apply, the contribution could be optimistic (e.g. at one extreme, the contribution would be zero if the operating period did not span the peak demand at all), in which case the generation ought to be treated as a special case and therefore subject to detailed studies to assess the expected level of contribution – See EREP 131 [N].	

E.3 Remote generation

When assessing the security contribution from DG that is electrically remote from the point on the network where the contribution is traditionally assessed (e.g. the infeed substation busbars), the key issue relates to the reliability of the network assets between the DG and the network point where a security contribution is required; this will affect the actual contribution from the DG. However, this effect has been taken account of in the probability analysis within the agreed methodology (see [N2]) and 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.

AUTHOR NOTE 9: The above statement may no longer be relevant. Reviewers to comment.

Hence, if a DG plant 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.4 Intermittent Generation and selection of T_m

EREC P2/7 [N1] requires that some or all demand (depending on class of supply) should be restored within 15 min or 3 h, or after the time to repair. Therefore when looking to include a security contribution from DG a necessary part of the assessment process will be to ensure that the DG 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 h. 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.

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 2-4 in Annex D.

E.5 DSR Scheme considerations

E.5.1 Network and DSR Scheme characteristics

The following should be considered when assessing the contribution from a contracted DSR Scheme

a) Load profile of the demand group

b) demand reduction magnitude of the DSR Scheme

c) DSR Scheme demand reduction period

d) energy recovery percentage of the Demand Facility providing the DSR Scheme

e) demand recovery period of the Demand Facility providing the DSR Scheme

f) demand recovery shape of the Demand Facility providing the DSR Scheme

g) number of demand facilities providing the DSR Scheme

h) reliability & availability of the DSR Scheme

E.5.2 Security contribution of DSR Scheme

The security contribution of the DSR Scheme (% of DSR Scheme capacity) increases as the:

a) demand reduction magnitude increases

b) demand reduction duration increases (generally but not necessarily)

c) demand recovery period increases

d) energy recovery reduces

e) energy recovery becomes more uniform

f) ratio of DSR Scheme capacity:peak network demand, reduces

g) load profile becomes peaky

E.6 ES considerations

E.6.1 Network and ES characteristics

The following should be considered when assessing the contribution from contracted ES

h) Load profile of the demand group

i) Peak of the demand group

j) Required peak demand reduction (magnitude and duration)

k) ES capacity (Wh)

l) ES charge and discharger time

m) ES efficiency

n) ES reliability & availability

E.6.2 Security contribution of ES

The security contribution of ES (% of ES capacity) increases as the:

o) ES capacity increases

p) ES power increases

q) ES charge time reduces

r) ES efficiency increases

s) Ratio of ES power:peak network demand, reduces

t) Load profile becomes peaky

Annex F
(informative)

Examples

F.1 Non-contracted DG

The examples in F.2, F.3 and F.4 have been designed to demonstrate the assessment of security contribution from non-contracted DG, in accordance with this EREP. The concepts captured in these examples include the following.

a) Establishing the system capacity.

b) Establishing the contribution to System Security from Intermittent and Non- intermittent DG.

c) Application of Approach 1 and 2.

d) Establishment of Group Demand where there are various types of DG, e.g. merchant DG plant and/or Biomass plant.

e) De-minimis issues.

f) Aggregation DG contributions to System Security.

g) DG response under outage conditions.

h) System capacity under FCO and SCO conditions.

The system used in the first two examples is illustrated in Figure F.1 and described below.

a) A network is supplied by two 100 MW transformers.

b) The existing Measured Demand is 70 MW.

c) The existing transfer capability available in 30 min is 10 MW.

d) New load is to be connected in the group which will increase the Measured Demand by 10 MW.

e) The network power factor is assumed to be unity and all ratings are expressed in MW.

f) The DNO knows that the network contains:

   i. a wind farm having a DNC of 35 MW;

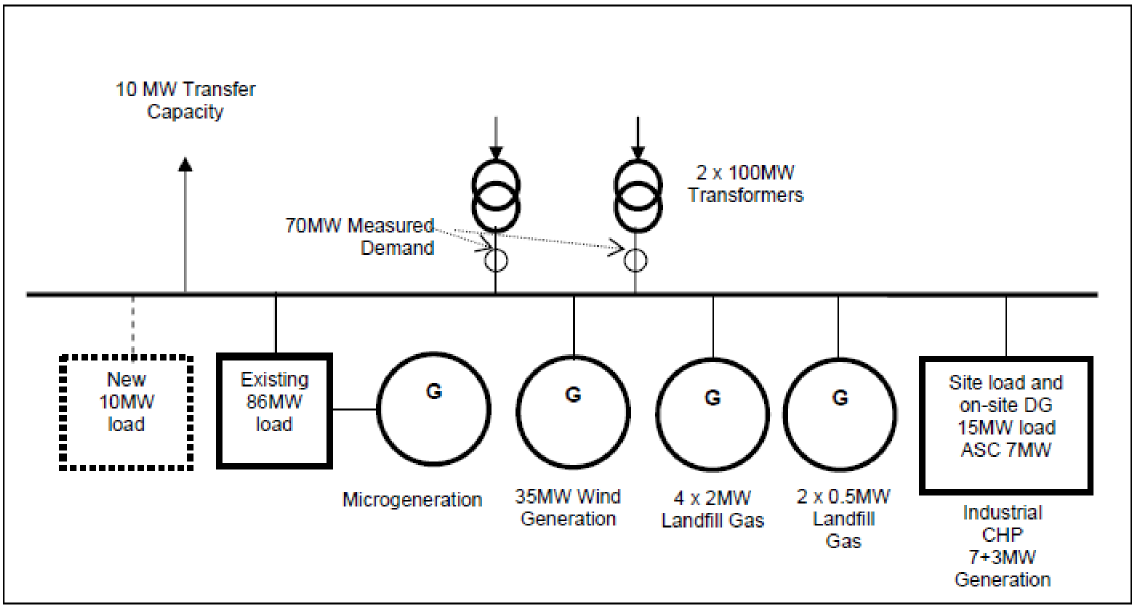
   ii. a landfill gas installation comprising 2 x 0.5 MW identical units;

   iii. landfill gas installation comprising 4 x 2 MW identical units;

   iv. fifty 1 kW microgeneration units at various locations;

   v. an industrial site that has a Biomass plant comprising a 7 MW gas turbine and a 3 MW steam turbine powered unit which operates 24 h per day. The site details are as follows.

- The actual site demand is 15 MW.
- The generation output at the time of the recorded maximum Measured Demand is 10 MW.
- The site import at the time of maximum Measured Demand is 5 MW.
- The Authorised Supply Capacity (i.e. the import limit of the site) is 7 MW.



AUHTOR NOTE 10: CHP to be changed to Biomass. Highlight that no contracted DG exists in example system.

Figure F.1 — Example system

The DNO has to assess whether the network is EREC P2/7 [N1] compliant once the new load is connected. Example 1 is used to assess the network compliance with the existing demand, Example 2 develops this example to analyse the EREC P2/7 [N1] compliance in the scenario that the demand increases by 10 MW.

It illustrates how the generation that is connected in the group can, under EREC P2/7 [N1], contribute to compliance.

The example is structured to follow the process set out in Clause 4 of this EREP. Each step of the process is cross-referenced to the appropriate sub-clause of the EREP. For simplicity it uses Approach 1 of Annex D to determine the contributions from the sources of generation where possible.

F.2 Non-contracted DG – Example 1

F.2.1 Step 1 – Determine the Group Demand and class of supply

NOTE 2: See also Clause 5.

a) Measured Demand: 70 MW.

b) Capacity of downstream generation: (35 + (2 x 0.5) + (4 x 2) + 10) = 54 MW.

c) 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.

d) Using the approach in Annex A.

i. The output from the wind farm at time of maximum Measured Demand = 15 MW.

ii. Measured Demand = 0 MW.

iii. The output from the larger landfill gas installation at time of maximum Measured Demand = 6 MW.

e) In this example there is sufficient information about the load and generation on the Biomass site 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).

f) There are only a small number of microgeneration units with a low aggregate capacity, hence their impact on the Group Demand can be neglected.

g) Therefore the Group Demand = 70 + 15 + 0 + 6 + 2 = 93 MW.

h) The network falls into class of supply D in EREC P2/7 Table 1 [N1].

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 Biomass site. This is because the Group Demand includes an allowance of 5 MW to cater for the latent effect of the Biomass generation plus the additional 2 MW that might need to be supplied at this site should it take up to its authorized capacity.

F.2.2 Step 2 – Establish the capacity of network assets

NOTE: See also Clause 6.

a) The relevant network assets are the two transformers supplying the network, i.e. the capacity of each network Circuit = 100 MW (i.e. intrinsic network capacity).

b) FCO capacity = 100 MW, available immediately (i.e. intrinsic network capacity).

c) SCO capacity = 0 MW immediately available & 10 MW available within 30 min (i.e. Transfer Capacity).

d) 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.

e) From Table 1 of EREC P2/7 [N1] under a SCO, there is a requirement to secure all the demand within the time to restore the arranged outage, i.e. capacity under SCO conditions is not required.

f) In conclusion, the network assets are sufficient to ensure that the network is compliant with ER P2/6 [N1], and no further analysis is required.

---

[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.

F.3 Non-contracted DG – Example 2 (additional network demand)

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

F.3.1 Step 1 – Determine the Group Demand and class of supply

NOTE: See also Clause 5.

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

b) Capacity of downstream generation: (35 + (2 x 0.5) + (4 x 2) + 10) = 54 MW.

c) 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.

d) Using the approach in Annex A.

   i. The output from the wind farm at time of maximum Measured Demand = 15 MW.

   ii. The output from the smaller landfill gas installation at time of maximum Measured Demand = 0 MW.

   iii. The output from the larger landfill gas installation at time of maximum Measured Demand = 6 MW.

e) In this example there is sufficient information about the load and generation on the Biomass site 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, and the ASC minus the import at the time of maximum Measured Demand, should be added to the maximum Measured Demand. In this case the smaller of (10) and (7 – 5), i.e. 2 MW.

f) There are only a small number of microgeneration units with a low aggregate capacity, hence their impact on the Group Demand can be neglected.

g) The gross network maximum demand (Group Demand): (80 + 15 + 0 + 6 + 2) = 103 MW.

h) The network falls into class of supply D in EREC P2/7 Table 1 [N1].

F.3.2 Step 2 – Establish the capacity of network assets

NOTE: See also Clause 6.

a) The relevant network assets are the two transformers supplying the network, i.e. the capacity of each network Circuit = 100 MW (i.e. intrinsic network capacity).

b) FCO capacity = 100 MW, available immediately (i.e. intrinsic network capacity).

c) SCO capacity = 0 MW, immediately available & 10 MW available within 30 min (i.e. Transfer Capacity).

d) 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).

Considering the security provided by network assets, there is a FCO deficiency of (103 - 100) = 3 MW.

e) 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 h. 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.

f) In summary, considering the network assets alone, there is a FCO deficiency of 3 MW (required immediately) and a SCO surplus of 7 MW and hence the network is non-compliant with EREC P2/7 [N1].

F.3.3 Step 3 – Assessing the potential security contribution from non-contracted DG

NOTE: See also Clause 8.

Step 2 indicates that the network assets alone are insufficient to ensure compliance with EREC P2/7 [N1] and hence further assessment is required. As there is no contracted DG, hence this next step assesses whether there is the potential for the connected non-contracted DG to meet the security deficiency.

The aggregate of the DNCs of the DG in the network can be calculated. If this aggregate is less than the capacity deficit revealed in Step 2 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.

In this example, the aggregate of all the DG connected in the network = 35 + (2 x 0.5) + (4 x 2) + 10 = 54 MW.

Hence there is the potential for the connected DG to meet System Security deficiency, and the analysis therefore continues to Step 4.

F.3.4 Step 4 – Assessing the contribution from DG

NOTE: See also Clause 8.3.

The following steps establish the security contribution from the DG in the network.

Step 4a – Check each DG source against the de-minimis criterion

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 first landfill gas installation (2 x 0.5 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 second landfill gas installation (4 x 2 MW) is approx. 7% of the Group Demand, i.e. above the de-minimis criterion, and therefore the security contribution should be assessed.

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

Step 4b – Fault ride-through capability

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 both the wind farm and Biomass generation will remain connected under a fault forming the FCO condition and that the larger landfill installation will disconnect under fault conditions (e.g. owing to the sensitivity of its protection systems), but has the capability to be reconnected 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.

Step 4c – Establish potential contributions

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, Table 2-1 and Table 2-2 in Annex D are used to establish the contributions from the DG installations

Larger Landfill gas installation

- The F factor for the landfill gas installation = 75%.
- The security contribution from the landfill gas installation = ((75/100) x 8) = 6 MW.

Wind farm

- 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 Annex D Table 2-4, the required value of T_m = 90 days.
- From Annex D Table 2-2, the F factor for the wind farm = 0.
- From Annex D Table 2, the security contribution from the 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 Annex D Table 2-4], the required value of T_m = 30 mins.
- From Annex D Table 2-2A, the F factor for the wind farm = 28.
- From Annex D Table 2, the security contribution from the wind farm = ((28/100) x 35) = 9.8 MW.

Step 4d – Checking for dominance

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 plants is less than the capacity of one of the incoming Circuits, and hence the DG is not dominant and Capping is not required.

Table 7 summarises the security contribution from each DG plant and the time after the FCO when the contribution is available. The contribution to System Security after the SCO will depend upon the ability of the DG to synchronise under the depleted network conditions.

Step 4e – Time durations

NOTE: See also Clause 8.3.

Table F.1 summarises the security contribution from each DG plant 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.1 — Example 2 – DG contribution after a FCO

Distributed Generation	Security contribution (MW)	Time in which the DG is available post a FCO
Wind farm (50 MW)	9.8	Immediately (but only for 30 mins)
Landfill gas installation (2 x 0.5 MW)	0	N/A
Landfill gas installation (4 x 2 MW)	6.0	After 30 mins
Biomass	6.9	Immediately

F.3.5 Step 5 – Checking for EREC P2/7 compliance with DG

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 4 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 h 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 generation, there is a FCO capacity of (100 + 9.8 + 6.9) = 116.7 MW, i.e. a surplus of (116.7 - 103) = 13.7 MW.

FCO capacity (Time period: 30 mins from inception of FCO to 3 hours)

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 + 6

+ 6.9) = 122.9 MW, i.e. a surplus of (122.9 - 103) = 19.9 MW. The change in capacity arises due to the fact that the wind farm contribution has been replaced by the transfer capability that is switched within 30 min of the inception of the fault and the resynchronisation of the larger 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. 116.7 MW.

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

SCO capacity immediately available = 6.9 MW (of Biomass) plus 9.8 MW (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 generation 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 hours)

SCO capacity available within 30 min = 10 (network Transfer Capacity) + 6 (Resynchronised landfill gas installation) + 6.9 (Biomass installation) = 22.9 MW. This condition could persist for extended periods and hence it would be inappropriate to consider any contribution from the 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 assets providing the network Transfer Capacity. 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 alone, there is a FCO deficiency of 3 MW and a SCO surplus of 7 MW. Hence the network is non-compliant with ER P2/6 [N1].

Taking the contribution to System Security from generation into account produces a FCO surplus of 10.7 MW. The increase in FCO capability arises due to the output from the wind farm covering the period between the inception of the outage and the Transfer Capacity becoming available.

The SCO surplus may increase to 19.9 MW due to the contribution from the reconnected landfill gas installation, the Biomass output 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 generation, based on the guidance in Clause 7.

F.4 Non-contracted DG – Example 3 Capping and common mode failure

AUHTOR NOTE 11: New example for capping required

F.5 Load only

F.5.1 Example 1

The system used in this example is as shown in Figure F.2.

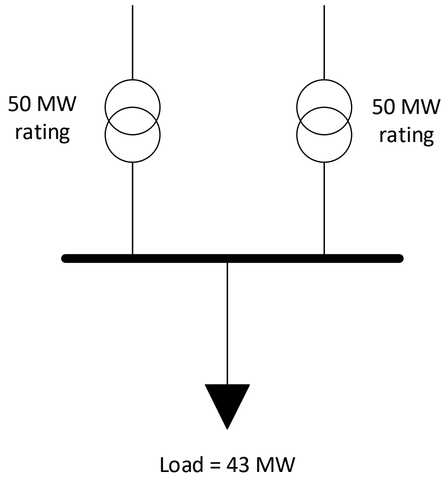


Figure F.2 – Load only, example 1

a) Measured Demand = 43 MW

a) Latent Demand

i. Contracted DG/DSR Schemes/ES – none

ii. Non-contracted DG/DSR Schemes/ES – none

Latent Demand = 0 MW

b) Group Demand = 43 MW (Class C)

c) Intrinsic network capacity

i. FCO capacity = 50 MW, available immediately

d) Transfer Capacity available is 0 MW.

i. SCO capacity = 0 MW immediately available

e) Given that Intrinsic network capacity is greater than Group Demand, no consideration required for DG/DSR Schemes/ES: the system is compliant with Table 1 of EREC P2/7 [N1].

F.5.2 Example 2

The system used in this example is as shown in Figure F.3.

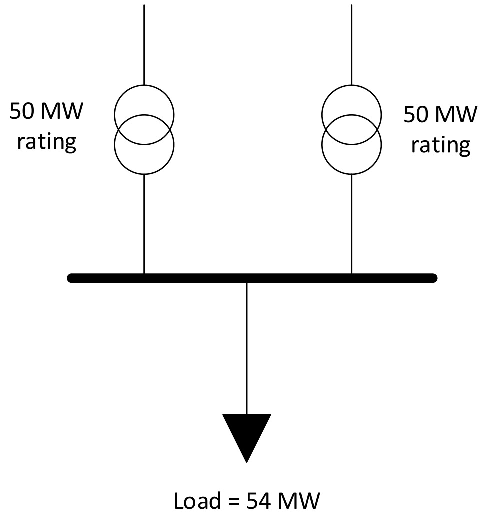


Figure F.3 – Load only, example 2

a) Measured Demand = 54 MW

b) Latent Demand

i. Contracted DG/DSR Schemes/ES – none

ii. Non-contracted DG/DSR Schemes/ES – none

Latent Demand = 0 MW

c) Group Demand = 54 MW (Class C)

d) Intrinsic network capacity

i. FCO capacity = 50 MW, available immediately

e) Transfer Capacity available is 0 MW.

i. SCO capacity = 0 MW immediately available

f) Given that Group Demand is greater the intrinsic network capacity, there is no Transfer Capacity and no security contribution from DG/DSR Schemes/ES: the system is not compliant with Table 1 of EREC P2/7 [N1].

F.6 DSR Scheme examples

F.6.1 Example 1

The system used in this example is as shown in Figure F.4.

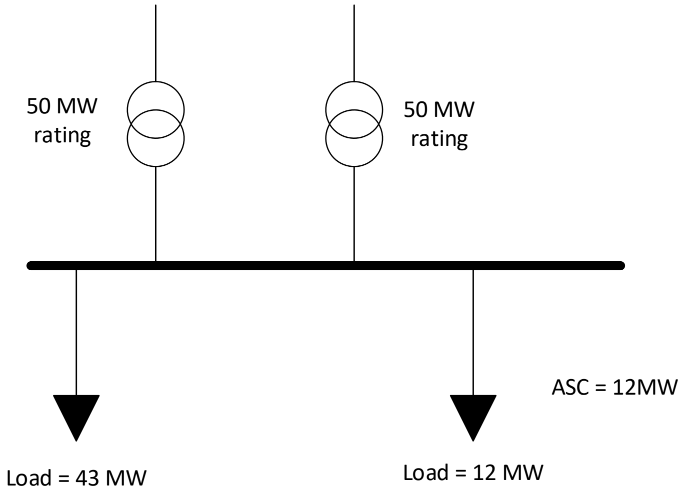


Figure F.4 – DSR Scheme, example 1

a) Measured Demand = 55 MW

b) Latent Demand

   i. Contracted DG/DSR Schemes/ES – none

   ii. Non-contracted DG/DSR Schemes/ES – none

   Latent Demand = 55 MW

c) Group Demand = 55 MW (Class C)

d) Intrinsic network capacity

   i. FCO capacity = 50 MW, available immediately

e) Transfer Capacity available is 0 MW.

   ii. SCO capacity = 0 MW immediately available

f) Given that Group Demand is greater the intrinsic network capacity, there is no Transfer Capacity, and no security contribution from DG/DSR Schemes/ES: the system is not compliant with Table 1 of EREC P2/7 [N1].

F.6.2 Example 2

The system used in this example is as shown in Figure F.5.

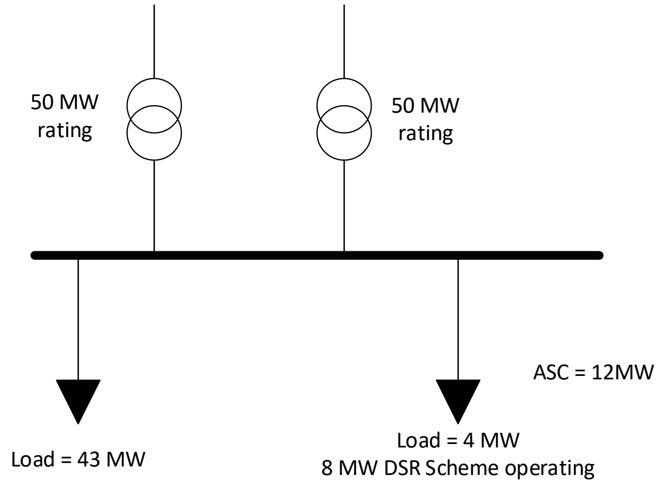


Figure F.5 – DSR Scheme, example 2

a) Measured Demand = 47 MW

b) Latent Demand

   i. DG/DSR Schemes/ES which is contracted – 8 MW from contracted DSR Scheme, available within 30 minutes.

   ii. Non-contracted DG/DSR Schemes/ES – none

   Sum of is DG/DSR Schemes/ES capacity is > 5% of the Measured Demand, hence it is necessary to take account of the capacity in the Latent Demand contribution to Group Demand.

   Latent Demand = 8 MW

c) Group Demand = 55 MW (Class C)

d) Intrinsic network capacity

   i. FCO capacity = 50 MW, available immediately

e) Transfer Capacity available is 0 MW.

   i. SCO capacity = 0 MW immediately available

f) Given that Group Demand is greater the intrinsic network capacity and no Transfer Capacity is available, there is a deficiency in System Security of 5 MW. Hence, it is now necessary to consider contribution to security from other means: DG/DSR Schemes/ES.

g) Security contribution from DSR Scheme

   The DSR Scheme is greater than 5% of the Group Demand i.e. satisfies the de-minimis criterion, and is therefore included in the security contribution calculation.

   Security contribution = 8 MW

h) The system is compliant with Table 1 of EREC P2/7 [N1].

F.7 ES examples

F.7.1 Example 1

The system used in this example is as shown in Figure F.6.

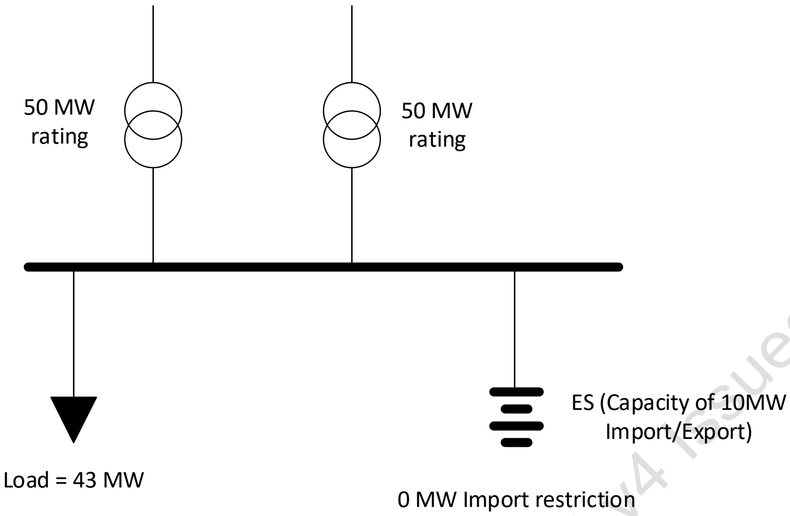


Figure F.6 – ES, example 2

a) Measured Demand = 43 MW

b) Latent Demand

   i. DG/DSR Schemes/ES which is contracted – 10 MW from contracted ES (import restriction).

   ii. Non-contracted DG/DSR Schemes/ES – none

   Sum of is DG/DSR Schemes/ES capacity is > 5% of the Measured Demand, hence it is necessary to take account of the capacity in the Latent Demand contribution to Group Demand.

   Latent Demand = 10 MW

c) Group Demand = 53 MW (Class C)

d) Intrinsic network capacity

   i. FCO capacity = 50 MW, available immediately

e) Transfer Capacity available is 0 MW.

   i. SCO capacity = 0 MW immediately available

f) Given that Group Demand is greater 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.

g) Security contribution from ES import restriction

The ES import restriction is greater than 5% of the Group Demand i.e. satisfies the de-minimis criterion, and is therefore included in the security contribution calculation.

Security contribution = 10 MW

h) The system is compliant with Table 1 of EREC P2/7 [N1].

F.7.2 Example 2

The system used in this example is as shown in Figure F.7.

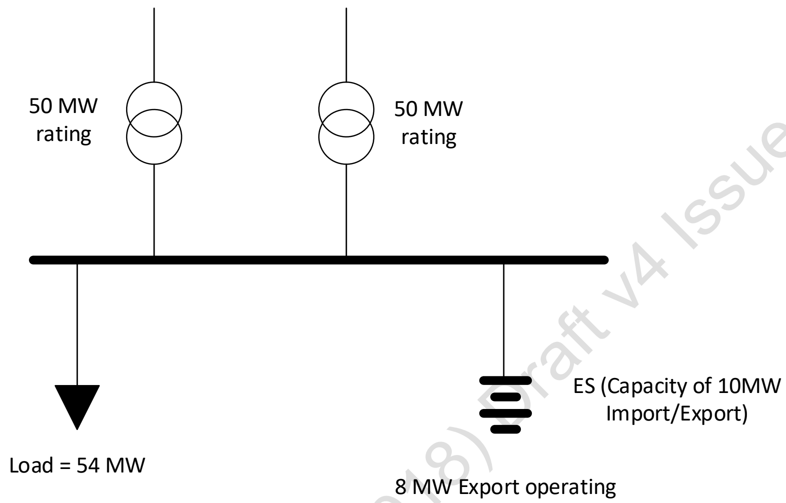


Figure F.7 – ES, example 2

a) Measured Demand = 46 MW

b) Latent Demand

i. DG/DSR Schemes/ES which is contracted – 8 MW export from contracted ES.

ii. Non-contracted DG/DSR Schemes/ES – none

Sum of is DG/DSR Schemes/ES capacity is > 5% of the Measured Demand, hence it is necessary to take account of the capacity in the Latent Demand contribution to Group Demand.

Latent Demand = 8 MW

c) Group Demand = 54 MW (Class C)

d) Intrinsic network capacity

i. FCO capacity = 50 MW, available immediately

e) Transfer Capacity available is 0 MW.

ii. SCO capacity = 0 MW immediately available

f) Given that Group Demand is greater the intrinsic network capacity and no Transfer Capacity is available, there is a deficiency in System Security of 4 MW. Hence, it is now necessary to consider contribution to security from other means: DG/DSR Schemes/ES.

g) Security contribution from ES export

The ES export is greater than 5% of the Group Demand i.e. satisfies the de-minimis criterion, and is therefore included in the security contribution calculation.

Security contribution = 8 MW

h) The system is compliant with Table 1 of EREC P2/7 [N1].

AUTHOR NOTE 12: Regarding the above example, the scenario may be different if the ES has been contracted to restrict import (10 MW restriction) and is exporting 8 MW outside of a contract. In this case the Group Demand could be considered:

- 46 + 8 = 54, OR
- 46 + 8 + 10 = 64

Reviewers to consider the most appropriate approach.

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For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

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