European Network of
Transmission System Operators
for Electricity

DEMAND CONNECTION CODE

FREQUENTLY ASKED QUESTIONS

27 JUNE 2012

Disclaimer: This document is not legally binding. It only aims at clarifying the content of the draft network code for demand connection. This document is not supplementing the final network code nor can be used as a substitute to it.

Foreword:

ENTSO-E has been instructed by Regulation (EC) N°714/2009 with the responsibility to draft network codes for providing and managing effective and transparent access to the transmission networks across borders, and to ensure coordinated and sufficiently forward-looking planning and sound technical evolution of the transmission system in the European Union, with due regards to the environment.

The elaboration process of the network codes is entirely a new legal tool which has not been experienced before. It should allow the European Commission to adopt a piece of legislation which will reflect the sound technical expertise and know-how of the European Transmission System Operators. ENTSO-E is in charge of drafting network codes upon request of the European Commission and in line with the framework guidelines specified by the Agency for the Cooperation of Energy Regulators (ACER). These network codes will then be submitted to ACER who will, if satisfied, recommend them to the European Commission for adoption via comitology. A more detailed description of the network Code development process is provided in response to FAQ 2.

ENTSO-E is committed to ensure thorough public consultation on its draft network codes before submission to ACER and is seeking for your expert views. Since the development process of the network codes is quite complex and has been a learning experience for all involved parties, ENTSO-E has therefore prepared this FAQ document to clarify the Demand Connection Code and explains the reasoning supporting the proposed requirements.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Frequently Asked Questions

As used in this paper, the capitalized words and terms shall have the meaning ascribed to them in the draft Demand Connection Code.

Answer to FAQ 1:

What are the "cross-border network issues and market integration issues"?

Regulation (EC) 714/2009 Article 8 (7) defines that "*the network codes shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States' right to establish national network codes which do not affect cross-border trade*".

The terms "cross-border network issues and market integration issues" are not defined by the Regulation. However, ENTSO-E's understanding of the terms has been derived from the targets of the EC 3rd legislative package for the internal electricity market:

- supporting the completion and functioning of the internal market in electricity and cross-border trade
- facilitating the targets for penetration of renewable generation
- maintaining security of supply

Based on these targets and in the context of the network codes for grid connection, the following interpretation of the terms "cross-border network issues and market integration issues" has been taken as a guiding principle:

The interconnected transmission system establishes the physical backbone of the internal electricity market. TSOs are responsible for maintaining, preserving and restoring security of the interconnected system with a high level of reliability and quality, which in this context is the essence of facilitating cross-border trading.

The technical capabilities of all the users play a critical part in system security. The Power Generating Modules have been a major contributor to system security for a long time, but the Demand Facilities and the Distribution Networks, and especially the DSOs take a part in system security as well. TSOs therefore need to establish a minimum set of performance requirements for Demand Facilities and Distribution Networks connected to their network. The performance requirements include robustness to face disturbances and to help to prevent any large disturbance and to facilitate restoration of the system after a collapse.

Secure system operation is only possible by close cooperation of all the users connected to the transmission network with the network operators in an appropriate way, because the system behavior especially in disturbed operating conditions largely depends on the response of Power Generating Modules in such situations, and also on the response of Demand Facilities and Distribution Networks. It is therefore of crucial importance that Demand Facilities and Distribution Networks are able to meet the requirements and to provide the technical capabilities with relevance to system security.

Moreover, harmonization of requirements and standards at a pan-European level (although not an objective in itself) is an important factor that contributes to supply-chain cost benefits and efficient markets for equipment, placing downwards pressure on the cost of the overall system.

To ensure system security within the interconnected transmission system and to provide an adequate security level, a common understanding of these requirements to all the users is essential. **All requirements that contribute to maintaining, preserving and restoring system security in order to facilitate proper functioning of the internal electricity market within and between synchronous areas and to achieving cost efficiencies through technical standardization shall be regarded as "cross-border network issues and market integration issues".**

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 2:

What is the relationship between the framework guidelines and network codes – what are the responsibilities of both and what is the process of network code development?

The relationship between framework guidelines and network codes as well as the process for the establishment of network codes are defined by Article 6 of Regulation (EC) 714/2009.

The Agency for the Cooperation of Energy Regulators (ACER), on request of the European Commission (EC), shall submit to EC, within a reasonable period of time not exceeding six months, a non-binding framework guideline. This framework guideline will set out clear and objective principles for the development of network codes, covering cross-border network issues and market integration issues relating to the following areas and taking into account, if appropriate, regional specificities:

- network security and reliability rules including rules for technical transmission reserve capacity for operational network security;
- network connection rules;
- third-party access rules;
- data exchange and settlement rules;
- interoperability rules;
- operational procedures in an emergency;
- capacity-allocation and congestion-management rules;
- rules for trading related to technical and operational provision of network access services and system balancing;
- transparency rules;
- balancing rules including network-related reserve power rules;
- rules regarding harmonized transmission tariff structures including locational signals and inter-transmission system operator compensation rules; and
- energy efficiency regarding electricity networks.

Each framework guideline shall facilitate non-discrimination, effective competition and the efficient functioning of the market.

Based on such a framework guideline the EC shall request ENTSO-E to submit a network code which is in line with the relevant framework guideline to ACER within a reasonable period of time not exceeding 12 months.

If ACER assesses that the network code is in line with the relevant framework guideline, ACER shall submit the network code to the EC. The EC will then initiate the comitology process to give the network codes binding legal effect. It is likely that the network codes through the comitology process will become European Union (EU) regulations making the provisions of the network codes applicable in all Member States immediately without further transposition into national legislation.

The main objective of the framework guidelines is to highlight **which** emerging questions/problems should be solved, leaving the approaches on **how** to solve them to the related network code(s). Figure 1 provides an overview on the complete process of framework guideline and network code development.

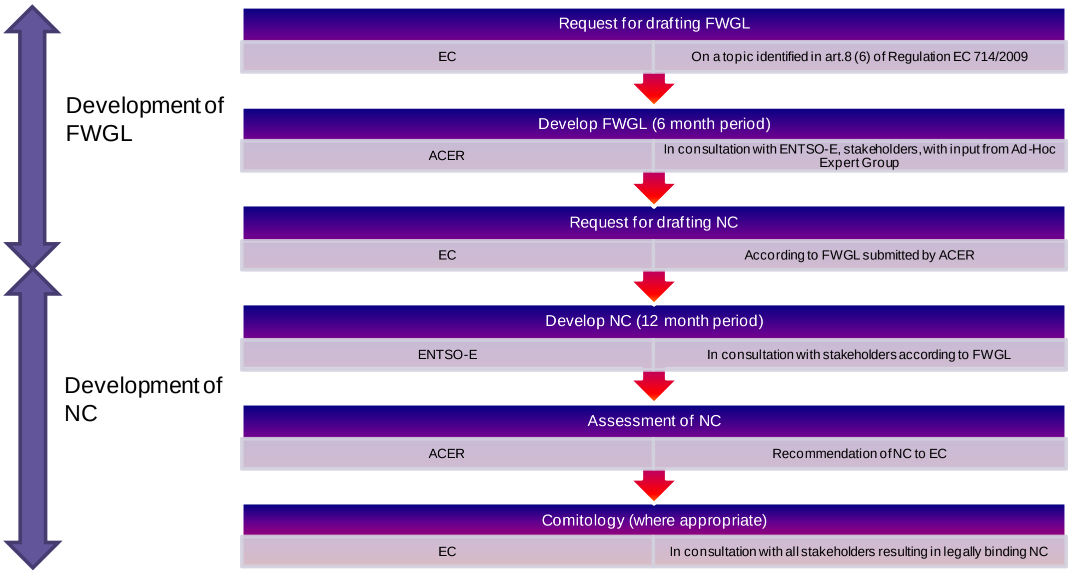

Figure 1: Framework guideline (FWGL) and network code (NC) development process

As reflected in the three year work program[1] which is regularly discussed by EC/ACER/ENTSO-E and consulted upon in the Florence Forum with all key stakeholders in the electricity sector, one or more network code(s) may correspond to a single framework guideline. The ACER framework guidelines on electricity grid connections[2] were published on 20 July 2011. In total, four codes are anticipated in the coming years: connection of generation, connection of demand, connection of HVDC circuits and connection procedures. The formal twelve month mandate for the network code on generation connection started in July 2011 and is scheduled to end June 2012. The mandate for the network code on HVDC connections is planned to commence in January 2013. For the fourth network code under these framework guidelines, regarding connection procedures, no starting date has been indicated so far.

In accordance with Article 10 of Regulation (EC) 714/2009, ENTSO-E shall conduct an extensive consultation process while preparing the network codes, at an early stage and in an open and transparent manner, involving all relevant market participants, and, in particular, the organisations representing all stakeholders. That consultation shall also involve national regulatory authorities and other national authorities, supply and generation undertakings, system users including customers, distribution system operators, including relevant industry associations, technical bodies and stakeholder platforms. It shall aim at identifying the views and proposals of all relevant parties during the decision-making process.

As the twelve month period after receiving the EC mandate letter within which the network code is to be developed, extensively consulted upon and internally approved by all ENTSO-E member TSOs, the initial scoping work on this network code already started in March 2011. In the period prior to receiving the EC mandate letter, ENTSO-E already worked through a set of five bilateral discussions with a DSO Technical Expert Group which started in July 2011. Additional bilateral meetings were held with IFIEC and CENELEC. This early scoping work resulted in the publication of a preliminary scope document[3] on 22 February 2012.

A first stage of public consultation was organised by ENTSOE, by publishing a “Call for Stakeholder Input “ document. This document explained the challenges ahead and the possible requirements to include in the DCC in order to contribute to face these challenges presented some element of cost-benefit analysis on possible

[1] http://ec.europa.eu/energy/gas_electricity/codes/codes_en.htm
[2] http://www.acer.europa.eu/portal/page/portal/ACER_HOME/Public_Docs/Acts%20of%20the%20Agency/Framework%20Guideline/Framework%20Guidelines%20On%20Electricity%20Grid%20Connections/110720_FGC_2011E001_FG_Elec_GrConn_FINAL.pdf
[3] https://www.entsoe.eu/fileadmin/user_upload/_library/consultations/Network_Code_DCC/120222-Demand_Connection_Code_-_preliminary_scope.pdf

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

requirements and ask the opinion of the stakeholders on the analysis and on the different solutions possible. This public consultation took place between 5 of April and 9th May 2012.

All output of the stakeholder interactions (bilateral meetings, workshops, user group meetings) during the formal development period of NC RfG can be accessed on the ENTSO-E website[4].

[4] https://www.entsoe.eu/resources/network-codes/demand-connection/

Answer to FAQ 3:

Does the network code apply in non-EU member states or in respect to cross-border issues between an EU member state and a non-EU member state?

It is foreseen that the Network Codes will be adopted via the comitology process in the format of an EU regulation.

Therefore, they will become binding vis-à-vis non EU-countries in accordance with the following principles.

1) For the non-EU countries which are parties to the EEA Agreement (the European Economic Area Agreement), the EEA Agreement provides for the inclusion of EU legislation that covers the four freedoms — the free movement of goods, services, persons and capital — throughout the 30 EEA States. The Agreement guarantees equal rights and obligations within the Internal Market for citizens and economic operators in the EEA.
   As a result of the EEA Agreement, EC law on the four freedoms is incorporated into the domestic law of the participating EFTA States. All new relevant Community legislation is also introduced through the EEA Agreement so that it applies throughout the EEA, ensuring a uniform application of laws relating to the internal market.
   As energy legislation covering the functioning of the internal market falls within the scope of the EEA-Agreement, the entire body of future Network Codes will almost certainly be EEA relevant, and hence be applicable and binding after decision by the EEA Committee and national implementation. The regular implementation procedures will apply.

2) As Switzerland is not a party to the EEA Agreement, the enforceability of the NC transformed into EU Regulation will need to be assessed in the context of the pending negotiations between Switzerland and the EU. However, Swiss law is also based on the principle of subsidiarity. Under this principle, self-regulating measures can be taken by the parties of the sector if they reach the conclusion that these rules should become common understanding of the sector. Based on the subsidiarity principle it is currently considered by the Swiss authorities to introduce under Swiss law, new rules compliant to relevant EU-regulations by the parties of the sector.

3) For the countries that are parties to the Energy Community Treaty, the Ministerial Council of the Energy Community decided on 6 October 2011 that the Contracting Parties shall implement the Third Package by January 2015, at the latest. Moreover, it decided "to start aligning the region's network codes with those of the European Union without delay". The Network Codes will be adopted by the Energy Community upon proposal of the European Commission. The relevant network codes shall be adopted by the Permanent High Level Group which shall seek the opinion of the Energy Community Regulatory Board before taking a decision.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 4:

How will ENTSO-E efficiently and transparently perform stakeholder consultation?

Over the next few years ENTSO-E will be required to develop and consult on a series of network codes covering most aspects of the electricity market, and the operation and the development of the electricity system. The active involvement of all stakeholders, expected to be reflected through their submission of comments during ENTSO-E public workshops as well as during the formal consultation, is considered to be crucial for the development of the network codes.

Each consultation will be composed of the following steps:

- preparation and announcement;
- stakeholders registration;
- comments gathering assessment and management including some statistical analysis; and
- Archiving.

Once the comments of stakeholders are assessed by ENTSO-E, they will be made publicly available, together with the corresponding answers/justifications. ENTSO-E will indicate how the comments received during the consultation have been taken into consideration and provide reasons where they have not been acted upon. All consultation material will remain publicly accessible for a period (envisaged to be at least one year) after the end of the consultation. Beyond this point, it will be archived by an ENTSO-E administrator so as to be available on request.

All ongoing, scheduled and finished consultations on draft network codes can be accessed at the ENTSO-E web consultation portal[5].

The reader is referred for further information to the ENTSO-E publication "Consultation process"[6] and the network code web sections[7].

[5] https://www.entsoe.eu/consultations/
[6] https://www.entsoe.eu/fileadmin/user_upload/_library/consultations/110628_Consultation_Process_Description.pdf
[7] https://www.entsoe.eu/resources/network-codes/

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 5:

What is the role of the subsidiarity and proportionality principle in the DCC?

One of the primary drivers for the network code is the set of requirements for Transmission Connected Distribution Networks and Demand Facilities across the EU as part of the fulfilment of the 3rd legislative package that contribute to maintaining, preserving and restoring system security in order to facilitate proper functioning of the internal electricity market within and between synchronous areas and to achieving cost efficiencies through technical standardization with a proper level of harmonization

However, complete harmonisation of all requirements for Transmission Connected Distribution Networks and Demand Facilities is not a pragmatic or cost effective solution due to the variance (due to historical, topographic and geographic effects) of network designs across Europe.

In these cases the principle of subsidiarity is applied, with the high level harmonisation of the requirement, generally in the form of a range specified in the code, and the more specific details and/or parameters specified at a more local level. In this manner, only the harmonisation of aspects of the requirements which can only be achieved at a European level in practice by means of a European legislation (derived from a network code) is included in the network code, whilst maintaining the necessary flexibility in the details to apply these requirements more efficiently at a more local level.

Following this principle, the requirements in the code also apply the subsidiarity principle with the individual requirements in the code being applied to their relevance at a European level. Aspects of this concept are discussed in detail in FAQ 6 and FAQ 18.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 6:

What is the appropriate level of detail of the network code? Is it too broad or too detailed?

The level of detail and the scope of the network code are in line with the scope defined by the corresponding framework guidelines provided by ACER which read as follow: “Furthermore, the network code(s) shall define the requirements on significant grid users in relation to the relevant system parameters contributing to secure system operation, including:

- Frequency and voltage parameters;
- Requirements for reactive power;
- Load-frequency control related issues;
- Short-circuit current;
- Requirements for protection devices and settings;

  ...
- Provision of ancillary services."

and "For DSOs that are defined as significant grid users, the network code(s) shall set out minimum standards and requirements for their equipment installed at the connection point between the transmission and distribution system networks.”

The requirements in the network code have a system wide impact; however the appropriate level of detail for each requirement has undergone a case-by-case consideration of its purpose, taking into account the extent of the system-wide impact as a guiding principle. The relevant entity from the perspective of system security is predominantly the synchronous area (Continental Europe, Nordic States, Great Britain, Ireland and Baltic States).

For the requirements with immediate relevance to system security on the level of a synchronous area, besides a common level of methods and principles, common parameters and settings (thresholds, limits) are necessary to achieve a sustainable set of common requirements, since one of the aims of the network code is to harmonise requirements for Demand Facilities throughout Europe to a reasonable extent to preserve system security in a non-discriminatory manner by applying the principle of equitable treatment. Other requirements of the network code are limited to the definition of common methods and principles and the details have to be provided by each TSO at national level (e. g. by explicit thresholds or parameter values). This allows consideration of specific regional system conditions (e. g. areas with different system strength, density of demand or concentration of Power Generating Modules). Therefore the level of detail of the requirements varies and the principles of subsidiarity and proportionality are applied.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 7:

Why do we need some requirements to apply even for domestic size of demand? Why are different categories of Demand Users introduced and what are the criteria for specifying the categories?

Meeting the EU energy policy targets regarding integration of renewable energy sources implies that the increased volatility of generation resulting from those sources will have to be taken into account and addressed in order to preserve system security. Also, demand users role in system security will become more significant: Demand Side Response is already becoming a reality and new technical requirements are needed to support system security.

New technical requirements concerning domestic level demand devices capabilities are expected to be mandatory but only to those devices designated following a transparent process. With the exception of Temperature Controlled Devices (devices which heat and cool, and therefore whose electrical usage is proportional to the temperature regulated) the offering of market services (and hence use of the device) from these technical capabilities into the market is expected to be voluntarily. Examples of Temperature Controlled Devices include but are not restricted to fridges, freezers, heat pumps and water heating.

Requirements for Temperature Controlled Devices are related to System Frequency Control which consist in an autonomous response to temperature targets of electrical devices in response to frequency fluctuations resulting in a reduction or increase in their electrical demand to diminish these fluctuations. Therefore, Temperature Controlled Devices **can be used as a minimum** as defence measures, to be activated only after other reserves have not allowed the system to return to a stable situation. This offers a valuable additional stage before LFDD stages are activated. DSR-SFC lowers the total load in the system without noticeable impact to any users and can prevent the first LFDD stage, in which a percentage of users will be completely disconnected from the system, from being activated. Moreover, Temperature Controlled Devices allow for natural response of demand to changes in frequency, reducing the scale of the step change in frequency which means that the generation units and the voluntary demand side response facilities contribution to frequency control could be diminished.

This mandatory DSR service for Temperature Controlled Devices, System Frequency Control, will not affect the primary function of the equipment (i.e. in a fridge to keep the contents within a safe temperature range) and will not be noticeable to consumers since only the timing of temperature response of the device is targeted.

Individually these devices are not of significance with regard to maintaining security of supply. However, when a very large number of them respond similarly to a common stimulus, such as frequency, which is shared within each of the five synchronous areas mentioned in FAQ 6, they quickly become a significant aid to security of supply with a benefit to the system envisaged to outweigh the cost of implementation based on CBA analysis.

Due to the potential scale of these devices in totality, DSR SFC is expected to be a major component in DSR with a significant impact in the security of the system in the years to come. The devices concerned shall be identified as significant by each Relevant TSO in co-ordination with all other ENTSO-E TSOs pursuant to Article 4(3) based on their inherent heat storage. This identification of Temperature Control Devices will be updated not more often than every 3 years. The capability to provide DSR-SFC will be mandatory for new devices built under new standards and its effect on system security will increase with the continuous natural wastage replacement of such devices in households over forthcoming years.

The requirements of this network code need to be forward looking. It will enter into force by means of European legislation, which means that it will be applicable for a rather long time and changes/amendments to them can only be implemented by running through extensive European legislative procedures. Therefore the anticipated mid-term and long-term developments of the power generating and demand portfolio need to be considered and anticipated, which are, amongst others, clearly driven by rapidly increasing decentralised generation and demand side response. Consequently it is undisputed, that capabilities to support the power transmission and distribution system security, which is currently provided from mainly bulk generation facilities, will in future be ensured by smaller Power Generating Modules and also by Demand Side Response.

In order to reflect these developments, the approach has been chosen to introduce, besides Temperature Controlled Devices, requirements for different categories of demand in the network code by following the principle of subsidiarity and proportionality. The criteria for specifying the requirements are the connection to the transmission network, the voltage level of grid connection, the existence or not of embedded generation and the existence of other voluntary offered Demand Side Response services.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 8:

Why is the option maintained to apply requirements retroactively?

As requested by the ACER Framework Guidelines the network code requirements will apply to Existing Demand Facilities and Existing Connected Distribution Networks if the relevant TSO has proposed a retroactive application and this proposal has been approved by the National Regulatory Authority (see FAQ 9).

A network code requirement shall apply to an Existing Demand Facilities and Existing Connected Distribution Networks only if it is demonstrated by a quantitative cost-benefit analysis that the costs to fulfil this requirement are lower than the benefits to the power system (see FAQ 11).

Currently the European power systems are changing rapidly: the internal market evolves, Demand Side Response and renewable generation increases, new transmission technologies, like FACTS (Flexible AC Transmission Systems), HVDC (High Voltage Direct Current) lines, etc. are introduced. In this situation there is a high uncertainty in anticipating the needs for power system security for the next 20 years. On the other hand, the requirements of this network code will be entered into force by means of European legislation, which means that they will be applicable for a rather long time and changes/amendments to them can only be implemented by running through lengthy European legislative procedures. Hence, it is essential to have the possibility to apply network code requirements retroactively to existing plants or distribution networks. Such application will be pursued in very particular and reasonable cases and, with all the necessary safeguards and respecting the provision of ACER's Framework Guidelines.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 9:

Does the network code apply to existing demand users or Distribution Networks? What is the situation of existing demand users or Distribution Networks after the entry into force of the network code? Do existing derogations still apply after its enforcement or will they cease?

In the context of the DCC, an Existing Demand Facility is a user which:

- is either physically connected to the Network, or
- under construction, or
- has a confirmation, provided in accordance with Article 3 (5) of the DCC by the Demand Facility Owner that a final and binding contract for the construction, assembly or purchase of the Main Plant,(i.e. motors, production plant, etc) of the Demand Facility exists 30 months after the day of the entry into force of this Network Code

In the context of the DCC, an Existing Connected Distribution Network is a Distribution Network:

- which is either physically connected to the Network, or
- for which the substation to connect it to the transmission network is under construction, or has a confirmation, provided in accordance with Article 3 (5) of the DCC by the Demand Facility Owner that a final and binding contract for the construction, assembly or purchase of the Main Plant,(i.e. motors, production plant, etc) of the Demand Facility exists 30months after the day of the entry into force of this Network Code

According to this definition, an Existing Connected Distribution Network which reinforces or expands its network without adaptations at a connection point to the transmission system, will remain an Existing Connected Distribution Network for which the applicability of this Network Code will follow the prescriptions of Art 3(3).

As requested by the ACER Framework Guidelines, the network code shall apply to New Users. It shall apply to existing demand users as well, if this has been proposed by the relevant TSO and this proposal has been approved by the National Regulatory Authority. Depending on the proposal by the relevant TSO (and the regulator's approval) there can be a variety in the application to Existing Demand Facilities and Existing Connected Distribution Networks:

- All Existing Demand Facilities and Existing Connected Distribution Networks shall meet all requirements
- All Existing Demand Facilities and Existing Connected Distribution Networks shall meet selected requirements
- Selected Demand Facilities and Existing Connected Distribution Networks shall meet all requirements
- Selected Demand Facilities and Existing Connected Distribution Networks shall meet selected requirements

Once retroactive application is approved and applies to certain existing users, they shall meet those requirements which are covered by the retroactive application, regardless whether it possesses a derogation from this requirement in the national code, which was issued on a national level *before* the network code entered in force. Although existing derogations are not suitable evidence of derogation from the network code in case of retroactive application, such documentation can however be useful background information when preparing the derogation application regarding the network code.

The user does have the possibility to pursue a derogation for specific requirements of the network code according to the procedure for derogation prescribed in the network code.

Existing users, which are not covered by the network code, shall continue to be bound by such technical requirements that apply to them pursuant to legislation in force in the respective Member States or contractual arrangements in force. Consequently, existing national/ local derogations may remain in force as well, provided that they refer to a requirement not covered by the European network code.

Although existing derogations are not suitable evidence of derogation from the network code in case of application to Existing Demand Facilities and Existing Connected Distribution Networks, such documentation can however provide useful background information when preparing the derogation application regarding the network code.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 10:

Does the network code deviate from existing requirements?

ENTSO-E have developed a network code with is a few deviation from existing requirements by taking and improving requirements from different existing national codes and regulations that have proven their efficiency on a respective issue and could be considered as best practice. Plus some new proposed requirements to further improve network flexibility and reliability relating to cross border issues.

One of the aims of the network code is to harmonise the requirements for Demand to a reasonable extent to preserve system security in a non-discriminatory manner. This network code cannot be in line with all existing requirements in each individual country by nature, because they do not currently provide the necessary level of harmonisation.

Therefore, harmonizing grid connection requirements provides the opportunity to improve system security by learning from experiences due to the diversities in Continental Europe (former UCTE), Nordic States (former NORDEL), United Kingdom and Baltic.

The draft network code was challenged against existing requirements by stakeholders during the informal consultations. The comments received enabled a further cross-check with existing standards and requirements. The stakeholder comments were assessed and have either lead to according amendments to the network code or the original position has been retained and justified.

Answer to FAQ 11:

How is cost-benefit analysis going to be applied to address the question of implementation of network codes for Existing Demand Facilities and Existing Connected Distribution Networks?

The ACER Framework Guidelines define that "*The applicability of the standards and requirements to pre-existing significant users shall be decided on a national basis by NRA, based on a proposal from the relevant TSO, after a public consultation. The TSO proposal shall be made on the basis of a sound and transparent quantitative cost-benefit analysis that shall demonstrate socio-economic benefit, in particular of retroactive application of the minimum standards and requirements*".

Before any Existing Demand Facility or Existing Connected Distribution Network is required to implement requirements of the network code, the relevant TSO will have undertaken a cost-benefit analysis, carried out a public consultation and the National Regulatory Authority (NRA) will have made the final decision based on information obtained from both the cost-benefit analysis and the consultation processes.

A cost-benefit analysis is an intensive process that requires resources from all market participants to collect the required data. To make best use of resources it is important to focus on cases of real merit. Therefore a filtering process is applied initially to identify these cases. This filtering consists of a high level analysis using a traffic light system. This method, applied by each TSO, evaluates if there is a reasonable prospect of justifying application to Existing Demand Facilities or Existing Connected Distribution Networks with respect to each requirement defined in the network code.

The marginal cost for implementing each part of the network code to Existing Demand Facilities or Existing Connected Distribution Networks is illustrated by the cost traffic lights. The socio-economic benefit of reducing the risk of large disconnection of consumers and associated balancing services costs through implementation to Existing Demand Facilities or Existing Connected Distribution Networks is evaluated by the benefit traffic lights.

- Costs
  Following engineering review, an outline decision is made about the required modification:
  - Insignificant modification: Green
  - Significant modification: Red

- Benefits
  Following engineering review, the reduction in demand loss and/or cost of balancing services is indicated:
  - No/low impact:: Red
  - Significant impact: Green

In respect of requirements for which this filtering process demonstrates that there is no prospect of justifying the application (e.g. "red" on costs & "red" on benefits) to the Existing Demand Facility or Existing Connected Distribution Network, then no further action will be taken. As a result, these requirements shall not be under the jurisdiction of this network code for Existing Demand Facilities or Existing Connected Distribution Networks. However, the Framework Guidelines allow for a review of this significance evaluation at a later date, but not within a period of less than 3 years. This ability to review later is intended to, on the one hand, allow the TSO to avoid excessive application to Existing Demand Facilities or Existing Connected Distribution Networks where this may prove unnecessary and, on the other hand, have a safety net for changes in circumstances.

If the filtering process demonstrates that there is a reasonable prospect of justifying the application of a requirement[s] to Existing Demand Facilities or Existing Connected Distribution Networks (e.g. benefit "green" and costs "green") then the TSO can proceed on to a more detailed assessment. For this task, the TSO will be assisted by the relevant owners (e.g. the Demand Facilities Owners and/ or the Distribution assets Owners) and /or the DSOs. Below is a high level summary of this:

- Cost-benefit analysis by the TSO for an item of the code on a national basis:
  - The relevant owners and/or the DSOs are required to co-operate by providing relevant data requested by the TSO within three months after receipt of the request, unless agreed otherwise.
  - The TSO completes the cost-benefit analysis and prepares a report. The cost-benefit analysis is based on methodologies described in the network code.
  - If the outcome of the cost-benefit analysis states that application to Existing Demand Facilities or Existing Connected Distribution Networks is not justified then there is no need for further action other than informing affected Stakeholders.

- Public Consultation:
  - If the outcome of the cost-benefit analysis states that the application is justified then the TSO undertakes public consultations, including amongst others, a proposal for a transition period for implementing the requirement.
  - If the outcome of the consultation demonstrates that at the end the application to Existing Demand Facilities or Existing Connected Distribution Networks is no more justified then there is no need for further action.
  - Following consultations resulting in "no further action" all affected parties and ENTSO-E are informed.

- NRA decision:
  - If the outcome of the consultation states that the application is still justified then the TSO sends the report including results of the consultation to the NRA.
  - The report shall include the following:
    - an operational notification procedure in order to prove the implementation of the requirements by the Demand Facility Owner or Distribution Asset Owner;
    - an appropriate transition period for implementing the requirements. The determination of the transition period shall take into account the obstacles for efficient undertaking of the equipment modification/refitting, but shall not exceed two years from the decision of the National Regulatory Authority on the applicability.
  - The NRA decides if the application to Existing Demand Facilities or Existing Connected Distribution Networks is justified based upon the report within 3 months.

- Implementation of application to Existing Demand Facilities or Existing Connected Distribution Networks:
  - If the NRA decides to go ahead, the Relevant Network Operator issues a LON (as per Article 29 of the Network Code).
  - The relevant owners and/or the DSOs carry out retrofit and demonstrate full compliance in respect of the specified issue to the satisfaction of the relevant Network Operator.
  - If the result of the retrofit is satisfactory as evaluated, then the Relevant Network Operator issues a FON (as per Article 28 of the Network Code) to the Demand Facility Operators and/or the Distribution Network Operators.

The TSO will provide information of the outcomes of the above processes to affected stakeholders in order to assist Demand Facilities and Distribution assets owners and their associates with the degree of certainty as the process allows. A summary of the national decisions on application of network code requirements to Existing Demand Facilities or Existing Connected Distribution Networks will also be shared with ENTSO-E, NRA and ACER.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 12:

Why does the network code not define certain requirements as paid-for ancillary services?

The ACER Framework Guidelines prescribe *"(...) Nothing in the network code(s) shall prevent commercial arrangements being used for the provision of ancillary services. (...)"*

The scope of this network code is to define the requirements for technical capabilities of Demand Facilities and Distribution Networks which are needed for secure operation of electricity transmission and distribution systems.

Requirements on Low Frequency Demand Disconnection and Low Voltage Demand Disconnection in this network code are linked to emergency procedures addressed in a TSO's defence plan and which are activated as a last measure to ensure secure system operation. Prior to this activation, other measures such as activation of reserves on a contractual or market-based mechanism have been taken. LFDD and LVDD are not considered ancillary services. It is when ancillary services do not suffice, that the defence plan is activated.

Requirements on reactive power capability at the connection point are set as design capabilities without prejudice on how eventual target points are set at the connection point.

The code lists a set of Demand Side Response services. Some device can be specified as requiring technical capabilities to be able to offer these services fitted as standard, notably on System Frequency Control. These services are either voluntarily provided by the end user or in the case of System Frequency Control specifically aimed at a use which has no noticeable impact to end users (see FAQ 23).

DSR SFC is envisaged as a minimum as a defence measure, to be activated only after other reserves have not allowed the system to return to a stable situation. This offers a valuable additional stage before LFDD stages are activated. DSR-SFC lowers the total load in the system without noticeable impact to any users and can prevent the first LFDD stage, in which a percentage of users will be completely disconnected from the system, from being activated.

The Demand Connection Code also lists some requirements for Demand Facilities volunteering to provide a specific set of Demand Side Response services. These requirements are only mandatory if the owner volunteers for these services. The code itself does not prescribe on which basis these services are activated or how they can be remunerated, nor does it exclude any possible implementation of these services on contractual basis or market based mechanisms.

It needs to be well distinguished between mandatory requirements of capabilities and the provision of ancillary services based on these capabilities. ENTSO-E agrees with stakeholders, that the provision of ancillary services is basically a market-related issue which needs to be appropriately remunerated. However, the introduction of remuneration provisions shall be subject to market-related network codes. Depending on the outcome of ACER's scoping exercise, this topic could be covered for example in the network code on balancing foreseen for 2013 according to the EC/ACER/ENTSO-E three-year work plan. These are to be in line with Directive 2009/72/EC which states that "*appropriate incentives should be provided to balance the in-put and off-take of electricity and not to endanger the system. Transmission system operators should facilitate participation of final customers and final customers' aggregators in reserve and balancing market"*

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

<u>Answer to FAQ 13:</u>

<u>Why does the network code not specify who pays for reinforcements of existing users to be compliant with the requirements? Who bears the costs for demonstrating compliance?</u>

Cost allocation of improvements is not covered specifically by the framework guidelines on electricity grid connection issued by ACER. The ACER Framework Guidelines state that *"The network code(s) shall always require the system operators to optimise between the highest overall efficiency and lowest total cost for all involved stakeholders. In that respect, NRAs shall ensure, that, whatever the cost-sharing scheme is, the cost split follows the principles of non-discrimination, maximum transparency and assignment to the real originator of the costs."*

Improvements of Existing Demand Facilities or Existing Transmission Connected Distribution Networks to achieve compliance with the network code based on TSO proposal can only be mandated after a cost-benefit analysis on a socio-economic level (see FAQ 11). Hence, costs of improvements for existing Demand Facilities or Transmission Connected Distribution Networks should be borne by the Demand Facility Owner or the Distribution Asset Owner.

Nevertheless, in case of replacement/improvements/modernisation of Existing Demand Facilities or Existing Transmission Connected Distribution Networks, it is required that the replaced/improved/modernised installations are compliant with the requirements of the network code, unless the Demand Facility Owner or the Distribution Asset Owner applies for a derogation from this obligation and this derogation is granted by the relevant Network Operator.

The responsibility on demonstrating compliance with the requirements established in the network code relies on the Demand Facility Owners or the Distribution Asset Owners. Consequently they shall bear their costs related to compliance tests and simulations. This should be done in alignment with the compliance principle set out in this network code and detailed further at a national level.

Answer to FAQ 14:

Why do TSOs impose requirements for connections to the distribution networks rather than the relevant DSO?

Secure system operation has only been possible in the past by close cooperation of Power Generating Facilities connected at all voltage levels with the Network Operators in an appropriate way.

This is so because system behaviour, especially in disturbed operating conditions, largely depends on the response of Power Generating Modules in such situations. For example, requirements for frequency stability are independent of the voltage level of the grid connection point of a Power Generating Module, because system frequency has global impact and the behaviour of Power Generating Modules at all voltage levels are affected equally by frequency.

The ongoing development and predicted continued trend of more demand facilities offering Demand Side Response (DSR), means that these demand facilities will also make up a material proportion in future years of the system wide potential dynamic response, notably in response to disturbed operating conditions. These devices are therefore the focus of the requirements in the DCC which relate to distribution connected demand users.

Demand Response, often referred to as Demand Side Response (DSR) is defined in this network code as follows: Demand offered for the purposes of but not restricted to providing Active or Reactive Power management, Voltage and frequency regulation and System Reserve. To be able to offer these services to the network, minimum standards and requirements shall be defined for Demand Users connected to the network.

Recent years have been characterized by rapid development of dispersed generation, in particular renewable (wind turbines and photovoltaic panels). Similar predictions for the location and scale of DSR can be envisaged not only from the political agenda of the EU as part of its Smart Grids Initiative, but from major industrial players development of the equipment to realize this goal and the installation program of smart metering as a pre-requisite to some of these services.

The changes in generation portfolio in all countries within Europe, has resulted in TSOs expressing the need to expand the requirements to a wider portfolio of devices than at present to ensure an appropriate level of system security. Notably the NC Requirements for Generators has requirements on Power Generating Modules connected to the distribution grid, that are comparable to those requirements, which Power Generating Modules connected to the transmission grid have historically had to fulfil.

For exactly the same reasons where traditional Power Generating Modules are diminished in favour of DSR the same need to replace these services into DSR devices occurs.

The DSOs are responsible for system security as well, but only the TSOs have the ability to assess and provide adequate control for an entire wide spread area. It is therefore only the TSO that can comprehensively assess which requirements are needed from a systems engineering perspective and what requirements should be met by DSR to maintain overall system security. It should be noted that some system security issues are dedicated exclusively to the TSOs, e.g. frequency control or system inertia.

The interaction and influence of dispersed generation and/or DSR connected to the distribution grid, due to their current and future scale, is much higher than in the past and new challenges will occur.

In addition, some DSR services offer to offset the impact of variability of many energy sources of RES but only if they offer a dependable and predictable response. Many of the requirements in the DCC ensure this and allow the DSR services to be used in a timely and effective fashion.

Generally fluctuations due to an unexpected loss of plant or equipment connected to the system create the need to utilise system reserve to return the system to acceptable limits. The main parameters which are actively managed with system reserve are system Frequency and Voltage.

In the context of this Network Code, System Reserve refers to active or reactive power reserves to actively manage the Network predominately to respond to Frequency and Voltage fluctuations.

Demand Side Response is distinguished by different System Reserve categories to provide response to Frequency and Voltage fluctuations, namely:

a) Demand Side Response Active Power Control (DSR APC),
b) Demand Side Response Reactive Power Control (DSR RPC),
c) Demand side Response Transmission Constraint Management (DSR TCM),
d) Demand Side Response System Frequency Control (DSR SFC)

Therefore, it is important that demand users connected to the distribution network meet requirements which are relevant to enable DSR. In addition, for some requirements, like those for frequency control, it is important that the performance of all demand users in a synchronous area are aligned when they experience the same incident (e. g. a frequency deviation). Therefore requirements for DSR need to be implemented in a coordinated way.

This need is supported by the ACER Framework Guidelines which states that: *"The network code(s) shall set out necessary minimum standards and requirements to be followed when connecting a consumption unit to the grid, to enable demand response and/or participation of consumption units in other grid services, on a contractually-agreed basis".*

The aforementioned increases in uncertainty in future network operation resulting from wider and disparate generating sources, longer bulk power trades across Europe, introduction of higher levels of DSR dynamic demand, results in a higher level, creates the need to increase certainty in reaction and hence harmonisation of all types of users capabilities, notably for distribution connected users in their frequency range capabilities.

It is evident that DSOs need to be strongly involved in these issues. Therefore, during both the informal and the formal period for developing the network code, several bilateral meetings with experts from the four largest European DSO Associations (Cedec, Eurelectric DSO, Geode and EDSO4SG) have been taking place and will continue to do so.

Answer to FAQ 15:

Why does the network code not provide for dispute resolutions?

The settlement of dispute provisions is commonly used for contractual types of relationships which are outside the scope of this network code.

Therefore, in case a dispute regarding the application of NC provision arises, it shall be referred to national courts - which are the ordinary courts in matters of European Union law - in accordance with national rules. Nevertheless, to ensure the effective and uniform application of European Union legislation, the national courts may, and sometimes must, refer to the Court of Justice and ask it to clarify a point concerning the interpretation of EU law (in the NC provisions).

The Court of Justice's reply takes a form of a judgment and the national court to which it is addressed is, in deciding the dispute before it, bound by the interpretation given and the Court's judgment likewise binds other national courts before which the same problem is raised. It is thus through references for preliminary rulings that any European citizen/ entity can seek clarification of the European Union rules which affect him.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 16:

Why do you not develop dedicated network codes for each type of Demand Facilities and Distribution Networks?

The requirements for grid connection of Demand Facilities and Distribution Networks have been developed from the perspective of maintaining, preserving and restoring the security of the interconnected electricity transmission and distribution systems with a high level of reliability and quality in order to facilitate the functioning of the EU-internal electricity market. Secure system operation is only possible by close cooperation of Power Generating Facilities of all types and Demand Facilities connected at all voltage levels with the Network Operators in an appropriate way (FAQ 1).

It is therefore of crucial importance that Power Generating Modules, distribution networks (including Closed Distribution Networks) and Demand Facilities are obliged to meet the requirements and to provide the technical capabilities with relevance to system security. To ensure system security within the interconnected transmission network and to provide an adequate security level a common understanding on these requirements to Distribution Networks and Demand Facilities, which are becoming increasingly more active, is essential.

From a system engineering perspective these capabilities cover:

- Frequency and voltage parameters;
- Requirements for reactive power;
- Short-circuit current;
- Demand disconnection for system defence and demand reconnection;
- Voluntary demand side response (Active Power Control, Reactive Power Control, Transmission Constraint Management and Very Fast Active Power Control);
- Provision and exchange of information for system management;
- Requirements for protection and control and
- Power quality requirements.

Major differences in the capability requirements for Demand Facilities and Distribution Networks result from the connection to the transmission network, the voltage level of grid connection, the existence or not of embedded generation and the existence of voluntary Demand Side Response.

Therefore, developing a single code for each type of Demand Facilities and Distribution Network, would have been highly inefficient in terms of keeping the network code as simple as possible. Keeping all these parts within a single network code aids the aim of the electricity market of equitable treatment for all users by maintaining a consistent set of requirements for all developers and owners of Demand Facilities and Distribution Networks.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 17:

Why does the network code not consider specific conditions which may apply to embedded Power Generating Facilities, in particular in industrial sites?

The network code does not exclude the consideration of such specific conditions. The approach taken is to assess the capability of the industrial facility to meet the network code requirements, with the embedded generation not present. This approach follows in the initial design, simulation or physical test of the requirements.

The final network code on "Requirement for Grid Connection applicable to all Generators" maintains a technology-neutral approach with regards to Power Generating Modules, but provides two general frameworks in which the specific use of the generator can result in specific agreements with the Relevant Network Operator on compliance to some requirements. Specifically these situations cover the right for islanding with critical loads to secure sensitive production processes, see NC RfG Art. 4(3)g, as well a possible exemption for industrial CHPs in which steam production is rigidly coupled to active power output, to some requirements on continuous active power controllability, see NC RfG Art. 4(3)h. For the avoidance of doubt, in all other cases compliance is required. It may be necessary to have a closer look at other conditions on a case-by-case basis founded on the principle of equitable treatment. Applying this principle, some cases may result in well justified derogations.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 18:

Do the requirements have to be considered as "minimum" or "maximum" requirements; what is the understanding of "minimum"/ "maximum" requirements?

"Minimum" relates to the request for defining the minimum set of requirements in the corresponding network code(s) which is necessary in order to achieve the objectives of the framework guidelines and consequently of Regulation (EC) 714/2009. The terms "minimum" (and "maximum" respectively) shall not be understood in the sense of defining minimum (or maximum) values for parameters, thresholds, ranges, etc.

The requirements established in the network code prevail over national provisions when implemented via European Regulation, and if compatible with the provisions in the European network code(s), national codes, standards and regulations which are more detailed or more stringent than the respective European network code(s) should retain their applicability. Nevertheless, additional measures remaining within the scope of the network code can, as a matter of principle, be taken at the national level provided that they do not contradict the provisions of the network code.

The following theoretical examples attempt to clarify this principle:

- Example 1: The network code determines the admissible operational voltage range for the 400 kV network to be limited by 380 kV (lower limit) and 420 kV (upper limit).
    - It is not admissible to define different limits on a national level.

- Example 2: The network code determines that the admissible operational voltage range for the 400 kV network shall be defined by the national TSOs with a minimum lower limit of 380 kV and a maximum upper limit of 420 kV.
    - It is not admissible to define ranges outside the minimum or maximum limit on a national level, but a range within these limits shall be defined by the national (relevant) TSO.

- Example 3: The network code does not determine an admissible operational voltage range for the 400 kV network.
    - It is admissible to define any kind of ranges on a national level, because it is not in conflict with the network code

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 19:

Why do you need the wide frequency ranges for operation and do not comply with the relevant IEC standard 60034 for rotating electrical machines?

The capability to maintain the connection of demand during deviations of the system frequency from its nominal value is important from the perspective of system security. Significant deviations occur in the case of major disturbance to the system, which considering splits of normally synchronously interconnected areas. The frequency movement is due to imbalances between generation and demand in each of the exporting and importing areas. A rise of frequency will occur in the case of demand deficit, while a surplus of demand will result in a drop of frequency. An example of such event was the islanding of Italy in September 2003, which eventually resulted in a total national black-out.

In general smaller systems will usually be exposed to higher frequency deviations than bigger ones. In the same way, peripheral systems which are part of very large systems, such as interconnected Continental Europe, but are weakly interconnected to the main system will be exposed to substantial frequency deviations in case of disturbances that cause the tripping of the interconnectors from the main interconnected system. Therefore, the capability to maintain the connection of demand under such frequency conditions is a prerequisite to keep the system “alive” in order to maintain security of supply and to restore system stability quickly.

The DCC does not request frequency withstand capabilities, but specifies operating ranges for which all demand facilities and transmission connected distribution network connection points should be designed, except for Demand Units providing DSR. This means that the unit should be able to safely withstand frequency deviations for the specified time durations or to safely disconnect automatically if needed within these ranges. These frequency ranges are those required from Generators by the NC Requirements for Generators.

Demand Facilities providing DSR, shall be capable of operating across the frequency ranges specified in the DCC, in order to be able to support the system in case of major disturbances. A reduced frequency range can be agreed between the Relevant Network Operator and the Demand Facility Owner to ensure the best use of the technical capabilities of a Demand Facility if needed to preserve or to restore system security.

During the informal discussions , with stakeholders, some stakeholders expressed their concerns on the wide frequency ranges expected by the draft claiming that they exceeded the provisions of the relevant IEC standard 60034 for rotating electrical machines, according to figure 1:

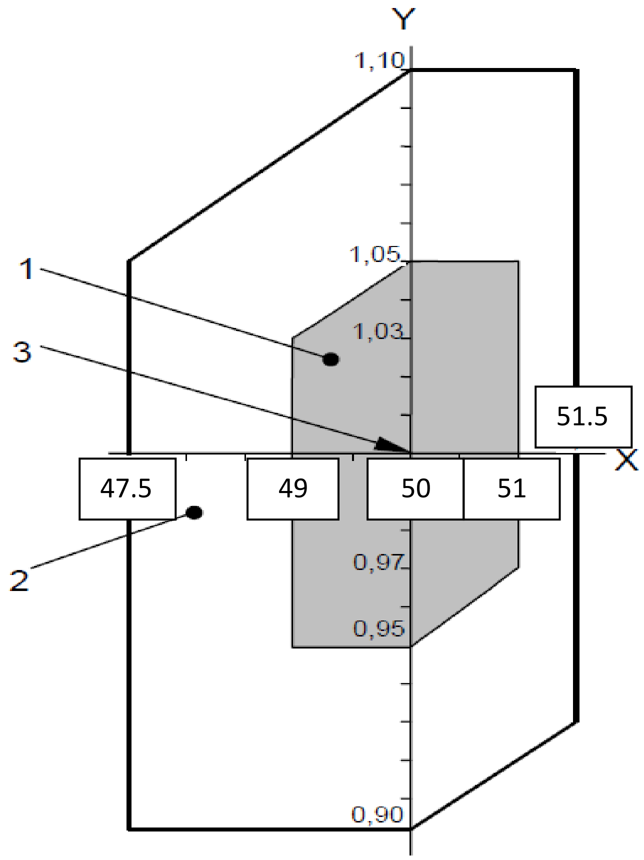

Figure 1: Frequency and voltage ranges for operation of rotating electrical machines (motors) according to IEC standard 60034, where the X axis is frequency and Y axis is voltage in pu.

The network code is in line with IEC-60034 in the sense that unlimited time operation is required within the range (49 - 51 Hz) as per area 1. In the case of time limited operation (area 2 in Fig.1), ENTSO-E acknowledges that to maintain the connection of demand cannot be generally required under these conditions, however situations in which the system frequency has been outside of the time-unlimited operation range have already occurred.

Therefore the need to meet the requirements in the code is restricted to Demand Facilities that voluntarily choose to provide DSR services into the market. The code also sets outs the requirement that all Demand Facilities and Distribution Networks should be designed to meet the expectation of the frequency ranges set out in Article 7 of the network code. This requirement means that either the facility or network should be technical capable of withstanding changes in system frequency within these ranges or otherwise appropriate remedial action should be taken, for example disconnection of equipment within inadequate capability.
Outside of the 49Hz to 51Hz range, system security and continuity of supply would be even more endangered if demand is disconnected unwontedly and consequently would not help to the system restoration. The need for predictability in the generation and demand balance cannot be understated in association with the need for reliance of DSR to work effectively if it is to be able to displace generation in the market. In this case, ENTSO-E considers that time period for operation within 48.5 - 49 Hz will be established by the relevant TSO on a local/national basis, since each system topology has different needs on operation frequency ranges for their demand. In the case of Continental Europe, and due to the existence of a large number of TSO's with different characteristics, the minimum time period for operation within the range 47.5 – 48.5 Hz, will be determined by each TSO.

ENTSO-E believes that a minimum operation period of 90 minutes is adequate for smaller synchronous areas in the ranges 47.5 – 48.5 Hz and 51.0 – 51.5 Hz, because situations where a frequency deviation to Area 2 of figure 1 may occur (even though countermeasures like low-frequency load shedding are implemented) in particular after severe disturbances which can be accompanied by a loss of communication and remote control infrastructure. Therefore a significant amount of time will be needed to prepare for system restoration under such conditions. In the future, it is expected that larger frequency excursions could take place following a disturbance due to the fact that large volume of renewable energy, non provider of system inertia, will be installed in the ENTSO-E synchronous areas.

As a conclusion, the frequency ranges defined in the requirements of network code reflect the need for maintaining/restoring system security.

Responses from the Stage 1 consultation 'Call for Stakeholder input' in this area would indicate that most equipment will be inherently suitable for these frequency ranges in both Demand Facilities and Distribution Networks, with notable exceptions in some critical and sensitive industrial processes.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 20:

Why do you need the wide voltage ranges for operation?

A change of voltage in a certain point in a network results in a change of the power flow in an interconnected system towards this point. The voltage may change due to loss of generation, loss of load, loss of transmission lines, or normal variations of connected demand.

If the voltage increases at a certain point in the network, electrical currents towards the point will decrease since demand depends on voltage and current. System losses will also decrease which will further increase system voltage. If the voltage increases over an acceptable value, the isolation of connected equipment is jeopardized.

If the voltage decreases at a certain point in the network, electrical currents towards the point will increase since demand depends on voltage and current. Reactive power losses will also increase, which will further decrease system voltage. This situation can result in loss of voltage stability and subsequently escalate to a large-scale disturbance (voltage collapse), if there is a lack of capacity to regulate voltage by static or synchronous equipment.

It is therefore of crucial importance for system security that all network users are capable of operating in a wide voltage range to be able to contribute to control voltage and to preserve voltage stability. Indeed, most of the large-scale disturbances to electricity transmission system in the recent years were caused by a loss of voltage stability.

From this point of view, voltage is indeed a “cross-border issue”, to be covered by the DCC.

Nevertheless, in case of a low voltage event, if a Demand User needs to disconnect from the connection point, the loss of load will potentially contribute to recover the voltage level, so no requirement is defined on extremely low voltage ranges in the DCC. However at less onerous low voltage ranges, the widespread loss of very large levels of demand may create a further undesirable instability in the network due to resulting fluctuations in generation/demand imbalance.

On the contrary, in case of a high voltage event, any additional loss of load will worsen the situation. Within a Demand Facility or a Distribution Network, some equipment are very sensitive to high voltage levels and need to be disconnected, but other equipment can support the same level and their loss is not necessary. Consequently, the DCC requires that the Connection Point of any Transmission Connected Distribution Network or Demand Facility at 110 kV or above shall be equipped to be capable of withstanding, without disconnecting from the network, a defined range of voltage within specified time periods, in order to avoid the loss of load due to limitations at the Connection Point.

The wide voltage ranges of the Demand Facilities and the Distribution Network Connections are important during ”normal” operation to contribute to the power system stability and also to support the system when local voltage problems or large disturbances occur.

All the DSR elements of a Demand facility with DSR are required to be capable of meeting the voltage ranges in Article 8 of the network code, as they are being utilised in the market to displace generation and therefore should be able to provide similar capabilities.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 21:

How should the combined effect of frequency and voltage ranges be interpreted?

For frequency the code specifies the expected operating ranges for which all Demand Facilities and Transmission Connected Distribution Network connection points should be designed. This means that the unit should be able to safely withstand frequency deviations for the specified time durations or to safely disconnect automatically if needed within these ranges. Demand facilities offering DSR services shall be able to withstand the frequency operating ranges in this code without disconnecting due to frequency.

For voltage the code specifies operating ranges which a demand facility connected at a voltage of 110kV or higher, as well as the equipment at a distribution network connection point shall be able to withstand without disconnection. The requirement appears to be more stringent for voltage than for frequency deviations since the voltage in the internal network of a grid user or in a distribution network can be regulated by mean of OLTC transformers. Frequency deviations would propagate throughout the system (with the exception of power electronic interfaces).

Each requirement applies on its own.

- Example for a Transmission Connected Demand Facility (≥110kV, but below 300kV) in Continental Europe: If 50.9 Hz (frequency limited time operation) and 1.09 pu (voltage limited time operation) occurs for 80 min, what will happen?
    - It is not allowed to disconnect on voltage in the first 60 minutes. If the voltage remains above 1.0875p.u. for longer than 60 minutes, it will be allowed to disconnect on voltage.
    - If due to a specific internal process, equipment characteristic, or any other reason this frequency cannot be withstood, the unit or a part of its internal system is allowed to disconnect for frequency at any time.

- Example for a Demand Facility offering DSR services: If 51.1 Hz (frequency limited time operation) and 1.09 pu (voltage limited time operation) occurs for 80 min, what will happen?
    - The first 30minutes the unit is not allowed to disconnect, neither for frequency, nor for voltage.
    - If the situation remains as such, the unit is allowed to disconnect for frequency after 30 minutes for frequency, even with voltage still within the 1.0875 – 1.1 pu range for less than 60 minutes.
    - If frequency comes back within the 49-51 Hz range in less than 30 minutes, but voltage remains within the 1.0875 – 1.1p.u. range, the unit is allowed to disconnect for voltage after 60 minutes.

Answer to FAQ 22:

Why do you limit the reactive power range of Demand Facilities and DSOs?

Different types of networks (e.g. distribution or transmission purpose), different network topologies (degree of network meshing) and characteristics (ratio of infeed and consumption) need different ranges of reactive power. The provision of reactive power at a certain point in the network strongly depends on the local needs which are described in the sentence before. For instance, highly meshed and/or heavily loaded networks need more lagging reactive power (production), whereas remote networks with modest power flows and low consumption need more leading reactive power (consumption) in order to keep the network voltage within the permitted range.

In general it is more cost effective to generate reactive power at the location where it is needed. In the future, more and more power is produced decentralized. The transport of reactive power causes higher losses on the lines and is possible only over limited distances. Therefore, for the benefit of the system and pursuing local reactive compensation, it is essential that Demand Facilities and Distribution Networks are capable to maintain their operation at their Connection Point within a pre-established and limited reactive range.

During the consultation on the "Call for Stakeholder Input", the stakeholders analyzed the Cost-benefit Analysis provided on the needs for reactive support. This CBA was based on an Irish, Italian and UK case studies showed the efficiency of meeting reactive power needs as close to the source of use as possible. The stakeholders mostly agreed on these CBAs. ENTSO-E for completeness has provided similar analysis for Sweden in Appendix 1, as a different topographic and geographic network design to ensure that the efficiency is consistent.

For each CBA, the same methodology has been used for the hypothesis and the calculation of costs and benefits.

Appendix 1 : Swedish study case

Cost of reactive power or equivalent reactive compensation devices

The cost of equipment to connect capacitors of a similar MVAr rating is highly dependent on the cost of the switchgear required to connect it to the network; the higher the connecting voltage the higher the cost.

Based on the current Swedish costs plant and associated equipment to connect reactive support to the network is charged at:

Circuit breaker and associated equipment cost in €,000	Voltage
950	400kV
730	135kV

Table 1. Cost of connection

A conservative assumption for the purpose of this analysis is a single cost for the cost of reactive support devices regardless of connecting voltage. In reality due to higher levels of insulation the cost of the devices would also vary in increasing costs at higher voltages.

For the purposes of this analysis the reactive support devices were limited to capacitors and reactors. The costs are shown in Table 2.

Item	MVAr	Cost
400kV Capacitor	44	€185,000
400kV Capacitor	50	€210,000
400kV Capacitor	90	€378,000
400kV Capacitor	150	€632,000
400kV Capacitor	425	€1,790,000
135kV Capacitor	50	€210,000
135kV Capacitor	105	€441,000
135kV Capacitor	150	€632,000
135kV Capacitor	405	€1,706,000
400kV Reactor	150	€1,895,000
400kV Reactor	300	€3,790,000
135kV Reactor	150	€1,895,000

Table 2. Cost of capacitors/reactor blocks

However given the insulation requirements for higher voltage equipment the use of a single price for capacitors/reactors regardless of connecting voltage is conservative.

Also the use of any other reactive compensation device (FACTS, SVC, etc) will have minimal impact to the CBA as the cost of the switchgear and associated equipment connecting the device to the network creates the difference in capital costs following this approach.

Using these assumptions the overall cost is:

Item	MVAr	Cost
400kV Capacitor	44	€1,135,000
400kV Capacitor	50	€1,610,000
400kV Capacitor	90	€1,328,000
400kV Capacitor	150	€1,582,000
400kV Capacitor	425	€4,640,000
135kV Capacitor	50	€940,000
135kV Capacitor	105	€1,171,000

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

135kV Capacitor	150	€1,362,000
135kV Capacitor	405	€3,896,000
400kV Reactor	150	€2,845,000
400kV Reactor	300	€5,690,000
135kV Reactor	150	€2,625,000

Table 3. Total equivalent cost for reactive compensation devices

Given the initial capital cost comparison of a 400, 135kV connected reactive support device with conservative assumptions it is clearly significantly lower in cost to connect the same scale of device to the lower voltage networks.

Examination of tests cases across Sweden and impact on reactive power needs

A number of test cases were performed across Sweden to examine whether the use of low voltage connected reactive compensation devices (although at a lower capital cost) would create the need for higher levels of reactive compensation and hence a higher capital cost to alternative transmission driven solutions to provide the necessary reactive power.

For any transmission related solution to be provided from reactive support devices then simple comparison of the capital costs and the need for technical adequacy can provide a number of findings.

In any situation where there is a need to provide reactive power across a transformer, then provision of reactive compensation at the low voltage side of the transformer is not only a lower capital cost but also reduces losses that occur passing power through the transformer itself. The maximum size of these reactive support devices in this situation will also be comparable due to voltage step changes, etc. Given that transformers are used in the supply of most demand users typically at the connection point then reactive compensation should be sited on the low voltage side of these transformers.

In the event that a single reactive compensation device on the users side of a connection point is not sufficient to meet the technical needs of a demand user (demand facility or distribution network) then a single reactive compensation device on the transmission side would also not be technical possible and therefore cannot be considered.

Also using a single reactive support device at the users side of their connection point (if technically acceptable) would normally be the lowest cost solution compared to multiple reactive support devices due to the duplication of switchgear requirements for connecting these devices. In situations where this assumption is incorrect the comparison of costs to use of a single reactive support device would provide a conservative cost benefit analysis.

Therefore as the cost of installing a single reactive support device on the demand user's equipment is a conservative comparison for cost benefit analysis it is the focus of these test cases in this CBA. The cost being at least comparable and generally more significant compared to a transmission network connected reactive support device at that same station, dependant on the presence of a transformer and which side of the connection point it is located.

Swedish Test Cases

Methodology and assumptions

Four locations were chosen for examination. The selection was based on location - a highly integrated point in the network with high levels of available high merit order generation (urban) and the inverse (rural location).

At each location the study examined the introduction of new load (50MW at 0.85PF, 100MW at 0.85PF, 500MW at 0.85PF), and examine the needs for additional reactive power from either generation or reactive support.

The study test cases selected were:

1. 50MW @0.85PF demand connection at Jönköping at 135KV
2. 150MW @0.85PF demand connection at Jönköping at 135KV
3. 500MW @0.85PF demand connection at Tenhult at 135KV
4. 500MW @1.00PF demand connection at Tenhult at 135KV

The results from these studies which provided viable network solutions are shown below in Table 4. Each of the test cases has been tested to be compliant with network planning standards.

Test Case 1 and 3 were examined looking at solutions at the connecting stations at 38kV and 110kV, and trying to centralise the reactive compensation requirements to provide widespread support.

The centralised solution is included to confirm whether the transmission solution can be optimised to be a solution for a wider area which might be cheaper than equivalent multiple 38kV reactive compensation devices. In each case this solution does not work as it is too remote from the location where the reactive power is needed.

Test Case 1 – 50MW at Jönköping		
Scheme	Assumption	Total cost in k Euros
400kV connected	44 MVAr capacitor block	1,135
135kV connected	50 MVAr capacitor block	940
Test Case 2 – 150MW at Jönköping		
Scheme	Assumption	Total cost in kEuros
400kV connected	90 MVAr capacitor block	1,328
135kV connected	105 MVAr capacitor block	1,171
Test Case 3 – 500MW at Tenhult		
Scheme	Assumption	Total cost in kEuros
400kV connected	425 MVAr capacitor block – assume 2 x 150Mvar + 125Mvar blocks	4.640

135kV connected	405 MVAr capacitor block – assume 2 x 150Mvar + 105Mvar blocks	3,896
Test Case 4 – 500MW at Tenhult		
400kV connected	150 MVAr reactor block	5,690
135kV connected	300 MVAr reactor block	2,625

Table 4. Results of test cases in Ireland

CONCLUSION COST BENEFIT ANALYSIS OF REACTIVE POWER REQUIREMENTS

The simulations shows clearly that reactive installations are more cost effective if they are done at voltages below grid voltage.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 23:

Why do you need DSR SFC and how will it be applied?

Demand Side Response System Frequency Control (DSR SFC) is a way of decreasing the demand of Temperature Controlled Devices, for example, fridges, freezers, heat pumps, immersion heaters, during periods of frequency deviations in the network.

During large disturbances in the network, for example caused by the loss of one or several generation units, a large shortage of power will occur. This will result in decrease of frequency and to prevent a total system collapse the automatic load shedding relays will disconnect a part of the load, causing a partial black-out of the system. This automatic activation of the Low Frequency Demand Disconnection (LFDD) is the last defence line to prevent a total black-out of the system.

DSR SFC may be used either only as a second last defence line before the Low Frequency Demand Disconnection (LFDD) will be activated automatically or with a wider setting range for providing automated frequency response to frequency fluctuations from nominal frequency. Depending on their point in the cycle of heating or cooling of Temperature Controlled Devices, the device can be switched off. The accumulated effect of switching a large number of Temperature Controlled Devices, will give a substantial reduction of load in the system.

In this way it should be able to prevent activating the LFDD and thus preventing large scale system black-outs, or with a wider setting provide necessary adjustments to the frequency/demand balance to restore the system to stable operation and restore system frequency back to nominal.

Due to the proportional nature of DSR SFC, it is expected this demand will respond before the normal wide spread arbitrary demand disconnection of users occurs. Dependant on the frequency range over which the demand will progressively respond will define whether some of this response will supplement other generation or DSR services. The setting of the frequency range will be determined at a synchronous system level, and provides the flexibility to compliment other market services to achieve a sustainable operational capability to respond to greater future uncertainty arising from greater RES integration and Pan European power transfers.

The DSR SFC makes use of the built in hysteresis of the Temperature Controlled Device. The hysteresis between the on and off temperature range of the device can be used to temporary delay the switch-on of the device or to temporary switch-off the device. The Temperature Controlled Devices on and off temperature range settings will not be exceeded by the DSR SFC when responding to frequency deviations from the nominal frequency. The DSR SFC will provide a response to deviations in Network frequency across a frequency range by corresponding changes to the Target Temperature in proportion of its maximum temperature range. The maximum change in Target Temperature will be at the widest when the system frequency is at the boundary of the system operating range defined by the Relevant TSO.

This functional requirement (DSR-SFC) shall be applicable to apply to all future installations of electricity demands which are intended to deliver a controlled temperature. The identification of which devices will be fitted with DSR SFC by default will be specified at the national level through public consultation and Nation Regulatory Authority Approval, but in co-ordination Europe wide between TSOs. The DSR-SFC functionality is expected to be implemented by inclusion in relevant European Standards for electrical heating and cooling equipment and associated control systems. The systems shall be designed to have no noticeable or negligible effect on the primary use of the facility. The priority of the temperature controlled devices shall at all times be to deliver the performance and comfort to a high quality level. This level shall be defined within the European Standards in accordance with the principle defined in this Network Code.

Answer to FAQ 24:

Why is very fast frequency response needed by some TSOs?

Lack of on-line conventional synchronous generation in the power system on some operational situations may substantially reduce system inertia inherently included in rotating synchronous machines. Therefore frequency variations can be faster and larger if sufficient fast active control is not provided.

In addition, on power systems with large transmission distances, a limiting factor for transfer capacity can be the voltage stability in contingencies by creating large power imbalance. If remedial actions to balance the system and reduce power flows between distant areas are delayed, the voltage sag along the transmission path can cause immediate voltage collapse.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 25:

Why is there a 0Mvar limit or a need for dynamic reactive power control to be applied to DSO Connections?

Overall system performance is improved, either technically or economically, if appropriate measures are taken concerning reactive power management for Transmission Connected Distribution Network at the Connection Point. Reactive power delivered where needed is more cost effective allowing also for reduction in losses, higher active power loading and less need for system reinforcements. Voltage stability is also recognised as an important basis for system security. Moreover, in the context of future development of RES generation and smart grids, demand facilities and distribution networks need to support the future power system.

If the Transmission Connected Distribution Networks has the capability at the connection point, based on proper network design, to maintain approximately 0Mvar exchange at nominal voltage for a load exchange of no higher than 25% of the Maximum Import Capacity, it is guaranteed that the reactive needs and compensation are allocated near their origin and where the overall solution is more cost effective. This is the reason why this requirement is placed at the Transmission Connected Distribution Networks.

Only where justified and in an adequate timeline may be required by the TSO from the Transmission Connected Distribution Networks the capability at the connection point to maintain an agreed reactive power exchange. The justification of the need for active power exchange is likely to be based around making best use of embedded capabilities on the Distribution network to support Transmission networks and adjacent Distribution networks therefore optimising overall costs.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 26:

What is the importance of LFDD/LVDD/OLTC and how do they interact?

Low Frequency Demand Disconnection (LFDD), Low Voltage Demand Disconnection (LFDD), and On Load Tap Changer (OLTC) blocking, are all emergency response actions utilised as part of a synchronous systems defence plan.

Both LFDD and LVDD utilise the disconnection of demand, generally as a last resort action, to restore the generation/demand balance in a network to avoid its collapse and wider spread demand and generation loss. Their principle difference is what parameter, frequency and voltage respectively, is measured and therefore acts a trigger for the resulting loss of demand.

Historic examination of past wide spread system events shows that both voltage and frequency driven collapse of the transmission network has occurred and should be protected against. ENTSO-E discusses these events and recognises the need for these responses in it Continental European Defence Plan [8].

This defence plan advises the use of OLTC blocking with LVDD and this is supported by past experience where LVDD has been fitted. OLTC blocking will inhibit the local tap changers to attempt to restore lower voltages to normal limits in wide spread voltage depressed conditions. Due to the weakened state of the network, the normal response of the tap changers will not restore the lower voltages, but inversely will worsen the situation with further depress the higher voltage networks instead. The code therefore links the required capability requirements of both LVDD and OLTC blocking.

[8] https://www.entsoe.eu/fileadmin/user_upload/_library/publications/entsoe/RG_SOC_CE/RG_CE_ENTSO-E_Defence_Plan_final_2011_public_110131.pdf

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 27:

Why is compliance testing and ON required in DCC?

Network Codes cover requirements which deal with cross-border and market integration issues. The potential impact of not complying to these specific requirements justify that adequate emphasis is put on operational notification and compliance testing in all grid connection codes.

The inclusion of compliance testing within the Code is in line with the minimum standards and requirements for connections defined by the corresponding framework guidelines provided by ACER which read as follows:

> *"The network code(s) shall define clear and transparent criteria and methods for compliance monitoring, including the requirements for compliance testing."*

With regards to the inclusion of ON in DCC, and without prejudice over a more detailed implementation in future codes (e.g. on connection procedures or grid access), it is the aim of DCC to provide the minimum harmonised provisions in line with the corresponding framework guidelines provided by ACER which read as follows:

> *"The network code(s) shall contain provisions committing TSOs and DSOs to publish and transparently communicate the detailed procedure for the initiation of new connection, including, inter alia, required documents, timing, methodologies, responsibilities, etc. This information shall also address the relevant grid access issues, which will be dealt with in more detail in the future Framework Guidelines for grid access."*

The procedures are also aligned with those in the Network Code for "Requirements for Grid Connection applicable to all Generators" where relevant in order to have an equitable treatment of all users. The eventual implementation at national level of procedures for both generators and demand users (notably EON/ION/FON) might not have the same extent in duration or detail and needs to be seen with respect to the relevant requirements in each code. These procedures are progressively more detailed in nature from the most deeply network connected embedded users to transmission network level.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Answer to FAQ 28:

Why is the Demand Connection Code not specifying the standards for Power Quality?

The term power quality is related to the degree of the distortion of the real grid voltage from the ideal sinusoidal wave. If the real grid voltage has the shape of an ideal sinusoidal wave, power quality is best. The more it differs, the worse power quality becomes. Bad power quality means a high degree of harmonics, flicker and voltage dips. These distortions can lead to malfunctioning of some grid users, but do not bear the risk of a wide-spread danger to system security. In contrast to other issues (e.g. voltage or frequency stability), the impact of power quality problems is limited to local customers.

ENTSO-E believes the application of Power Quality Standards are not a cross border subject although it may have a significant effect on the transmission fundamental frequency, voltage and currents and the design of the Demand Facility. Power Quality is more of a issue in the embedded network where discrete non linear loads cause the fundamental components to be distorted, but techniques are used to mitigate the harmonic (total harmonic distortion) effects, and the accumulated effect is less 'visible' on the transmission network.

Therefore, the impact of and the countermeasures against Power Quality problems, can be solved through local standards and moreover have to be considered as a local issue which is not covered by this Demand Connection Code.

However due to the need to include Power Quality standards in the design of a Demand Facility and hence its ability to meet all the requirements of this code requirements to meet locally specified standards are included.

Answer to FAQ 29:

How does the Network Code ensure the existing quality of supply?

The DCC covers a set of requirements for each type of significant grid user, related to the relevant system parameters that contribute to secure system operation (frequency and voltage, short-circuit current, reactive power, protection and control and demand disconnection for system defence and demand reconnection).

The vast majority of these connection requirements were in the past, for transmission and distribution systems in Europe, addressed in disperse and separate documents such as grid codes, connection agreements, contracts or even as references transmitted to grid users before connection. These requirements have contributed to ensure the existing quality of supply.

Some requirements have been added or improved in the DCC, such as voltage ranges or reactive power requirements, in order to improve the system performance, taking into account the development of embedded generation (see FAQ 20, 22 and 25).

Some others have been aligned throughout Europe to be more efficient to contribute to the system defence plan and restoration, like requirements on LFDD/LVDD and OLTC (see FAQ 26).

All these requirements have been defined regarding their potential effect on the existing power system and regarding the future changes expected (RES generation development, smart-grids, …) and their impact on system operation.

New requirements on Demand Side Response have been defined to use the Demand Users capabilities to modulate their load in order to support the security of supply (see FAQ 23 on DSR on temperature controlled devices). DSR development aims at reducing the risk of large load-shedding of customers.

From this point of view, the DCC will improve the quality of supply, by increasing the robustness of the power system and by reducing the risks of large loss of load, in the context of big changes expected in system operation, in line with the goals of the EC.

Nevertheless, the DCC alone would not be sufficient to ensure the quality of supply. The other network codes being developed by ENTSOE under ACER’s Framework Guidelines (Requirements for Generators, System Operation, Capacity Allocation and Congestion Management), will have a major contribution in the improvement of the quality of supply of all the network users.

Answer to FAQ 30:

Why information exchange is required and what are the appropriate equivalent models?

With regards to simulation models the demand facility is not required to model the entire network or provide updated simulation models for every instance when the DSO network structurally changes. It is also important to note that the simulation models requirements aim at obtaining the indispensable data necessary for the TSO to fulfil its responsibilities, for instance the appropriate technical parameters.

The DCC defines a set of requirements applicable to significant grid users hence, where appropriate, simulation models may be necessary to verify required capabilities and to use in all types of studies for continuous evaluation in system planning and operation. Traditionally these models were very simple and were often estimated by the TSO's.

New requirements such as Demand Side Response introduce a level of complexity concerning demand performance in the system that necessarily will require dynamic modelling besides steady state. In this situation the TSO, in order to be able to perform his functions and to guarantee system security, will need to perform different types of studies. In a responsible manner, the significant grid user shall have the responsibility to provide all data necessary for simulation.

In the future not only generators will play a role in the dynamic response of the system but also DSR. In addition, the move towards a more dynamic network with high levels of international interaction, variable energy generation or demand, and market based changes to demand usage and power production (inherent in a smart grid concept), requires more refined and accurate modelling to ensure fully functional markets and secure operation. In this environment more accurate modelling of non-dynamic aspects of a network, like network components (lines, transformers and cables) and the breakdown of demand users is invaluable in maximising system performance.

Answer to FAQ 31:

Can you provide additional CBAs on DSR-SFC to show that DSR-SFC is a technical and economical efficient solution to support system security?

During the consultation on the "Call for Stakeholder Input", the stakeholders analyzed the Cost-benefit Analysis provided on DSR-SFC. This CBA was based on an Irish study case and showed the efficiency of DSR-SFC to support system security. The stakeholders mostly agreed on this CBA, but ask ENTSO-E to provide a similar analysis based on cases in Continental Europe, to make sure that the efficiency wasn't limited to specific areas.

Consequently, ENTSOE elaborated 2 more study cases on DSR-SFC: one from Continental Europe and the other from Sweden.

Each of the three study cases shows the efficiency of this DSR services, in different uses chosen by the TSO's, to take into account the specificities of each area.

For each CBA, the same methodology has been used for the hypothesis and the calculation of costs and benefits. This FAQ presents the methodology of the CBA, the conclusions based on the 3 study cases, and then the 3 detailed CBA.

These common assumptions used in the CBA cover:

Number of temperature controlled devices

A number of European studies have investigated the demand breakdown based on the number of consumers and hence provide suitable research sources to derive the breakdown of temperature controlled devices, both in totality and location. Temperature Controlled Devices are for example, fridges, freezers, immersion heaters, heat pumps, etc.

Utilising the EC funded Synergy Potential of Smart Appliances [1] (D2.3 of WP 2) from the Smart-A project A report prepared as part of the EIE project 'Smart Domestic Appliances in Sustainable', the Demographic Yearbook edited by the United Nation [2], the UNECE Statistics for households [3], the scale of temperature controlled devices in CE, Ireland and Sweden in 2020 and 2030 were calculated.

Distribution of frequency deviations per annum in Europe

The statistical variation in system frequency has been used to analyse the possible settings for DSR-SFC and the benefits associated.

Evaluation of the costs:

Capital cost of DSR

Given that the majority of temperature controlled devices on the market today are electronic in nature and simplicity of the required DSR SFC control device in many cases R&D costs will make up the greatest proportion of the capital cost per unit to implement DSR SFC.

The report 'Synergy Potential of Smart Appliances' [1] sets out the perceived cost to circa €2-5 per device for the necessary frequency accuracy (equivalent to UK price in report).

Financial benefits to demand Users providing the service

Ultimately all energy costs are chargeable to the demand users of the network through a variety of cost recovery methods through the market.

To replicate a similar system for DSR SFC would create a complex payment process. However, number of alternative options could be employed; one possible feasible system would be a flat rate reduction or payment at source as part of the cost of purchase of the device, either during the first period of replacement of all the existing devices system wide or ongoing into the future.

Given that most of the devices are present in every home and most industry within the network ultimately the cost of implementing the move to mandatory DSR SFC would be socialised through annual network charges proportionately to the size of the demand user over the period of time it takes natural wastage to replace the existing temperature controlled devices.

Importantly, the net effect of DSR SFC is to move the time period that temperature controlled devices activate to balance for changes in frequency. As the operation time period is merely shifted the expected change in use of energy by the devices over the annum should be negligible.

Therefore, for the reasons given above the cost of paying demand users with temperature controlled devices for reductions in energy usage is not considered further in this CBA.

Evaluation of the benefits

Three different cost benefit analysis calculations were performed separately to look at the benefits in terms of

- Procurement of Frequency Containment Reserve (FCR)
- FCR Regulation Energy Cost,
- Value of Loss Load (VOLL) for past large scale of demand losses or blackouts.

Each synchronous area using this functionality differently, to take into account the national specificities and markets.

- **Procurement of Frequency Containment Reserve (FCR)**

As DSR SFC provides a source of dynamic demand it can act in a similar way to both a generator and demand unit by adjusting its demand usage to reduce the need for generation-based reserve.

The net cost of supplying such a service based on current payment rates can be used also to quantify the benefit of the DSR SFC, based on the assumptions made above.

It can be compared to the price of FCR, including voluntary demand shedding services, where they exist.

- **FCR Regulation Energy Cost,**

Utilising the historical dispersion in system frequency, the equivalent cost for the upward and downward energy provided for frequency containment action can be computed for the different assumed prices of DSR-SFR installation cost as well as for the different settings for DSR-SFC.

These regulation Energy Costs can be compared to the FCR regulation energy cost provided nowadays using Generation-based Load Frequency Control using the assumed price for FCR.

- **Value of Loss Load (VOLL) for past large scale of demand losses or blackouts (rare events).**

Given that the most conservative setting of DSR SFC will be to avoid the use of temperature controlled device in frequency regulation, an examination of past historic events and the potential net saving on a social economic basis will assess the major net benefit of DSR SFC.

Demand disconnection (non DSR) in low frequency events is the last operational response to retain system integrity. The social-economic cost of this event is measured in the Value of Lost Load (VOLL) demand and has a high cost.

DSR SFC can act as a wide spread response to these types of event making selective rather than arbitrary bulk demand disconnection. In this manner only non-essential demand (i.e. demand whose loss is negligible to the user) is disconnected, and hence the socio-economic cost of demand disconnection avoided.

Summary

The detailed CBAs are presented in the appendix of this FAQ.
For each of the three different cost benefit analysis calculations performed;

- Procurement of FCR reserve,
- FCR Regulation Energy Cost and
- Value Of Loss Load (VOLL) for past large scale of demand losses or blackouts,

The net annual savings are factors greater than the capital cost of implementing DSR SFC.
Therefore the sensitivity of the assumptions therefore made around the number of scale of users would also need to be out by similar amounts to affect the overall result and hence the tolerance for error is very large and can be excluded further.

Accounting for the increased uncertainty that arises from more intermittent energy it is envisaged that the challenges placed on TSOs will increase into the future. It can be expected that system operators working together will find continuing improvements which will counteract these changes.

However the future is unpredictable and future large scale demand losses should be assumed to continue. Therefore this CBA has been calculated both conservatively looking to the future, and confirms the rational for implementing DSR SFC to meet the objectives of the 3rd legislative package, providing security of supply, and integration of RES (for further information see the accompanying Network Code Demand Connection Codes , Explanatory Note).

The implementation of DSR SFC itself should help mitigate these uncertainties and, from the cost benefit analysis performed, looks to offer very significant returns to the demand user.

REFERENCES

[1] Synergy Potential of Smart Appliances[1] (D2.3 of WP 2) from the Smart-A project A report prepared as part of the EIE project ‘Smart Domestic Appliances in Sustainable’ 2008.
[2] Demographic Yearbook, Population Censuses' Datasets (1995 - Present), United Nations Statistics Division. Accessed on 27 May 2012.
[3] Private households by Household Type, Measurement, Country and Year, UNECE Statistical Division. Accessed on 2 October 2011.
[4] Self Conserving URban Environments (SECURE Project), Deliverable 5.6.1 of the SECURE FP7 Project, 2008.

Appendix 1 : Irish study case

Number of temperature controlled devices

Type	MW in 2020	% of peak load per annum	Number of units	2030	% of peak load per annum	Number of units	Units installed per annum Assume Yrs turnover
Fridge/Freezer	80	1.6%	2000000	103	2.0%	2571662	171444
Industrial Refrigeration	618	12.4%	51768	794	15.3%	66565	4438
Heat pump	210	4.2%	400000	270	5.2%	514332	34289
Immersions	104	2.1%	210000	133	2.6%	270025	18002
Total	1011	0	2661768	1300	0	3422584	228172

Table 1 - Number of temperature controlled devices in Ireland

Distribution of frequency deviations per annum in Europe and associated energy costs

Taking the statistical variation in system frequency over the last year the following profile in Table 2 has been identified. Table 2 also shows the typical market price cost per MWh at during these frequency deviations.

	System Frequency in Hz								
	49.2	*49.4*	*49.6*	*49.8*	*49.9*	*50*	*50.1*	*50.2*	*50.4*
Number of occurrences per annum	2	11	13	1500	2000	1708	2000	1513	13
Cost in € per MWh at time of occurrence	420	420	420	100	100	100	100	100	100

Table 2 - Statistical Frequency variation in Ireland

Setting on DSR SFC controller

The settings selected at a synchronous system level will impact on the use and hence benefit of the DSR SFC.

For the purposes of CBA the setting of the DSR SFC to avoid primary frequency regulation and operate beyond this part of the frequency spectrum present the worst case comparison. A positive CBA result using this assumption would justify any setting applied, as settings increasing the usage of the DSR SFC would also increase the CBA benefit significantly.

A range of settings were examined, reflecting varying strategies that could be employed, as presented in Figure 1. The X-axis gives the frequency ranges. The Y-axis indicates to which new reference point the temperature controller device is set, depending on the measured frequency, within an acceptable tolerance range. 100% indicates max allowed temperature increase for cooling (i.e. higher demand), -100% indicates max allowed temperature decrease for cooling (i.e. lower demand). For heating the situation is vice versa. A hysteresis in the controller would assure not all demand reacts at the same instance, resulting in a fast but smooth aggregated response. Curves 1-4 were rejected as these overlap Low Frequency Demand Disconnection (LFDD) and consequently cannot ensure that demand users essential load demand is not disconnected. Curve 5-8 were progressed with analysis of their prospective demand usage saving.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

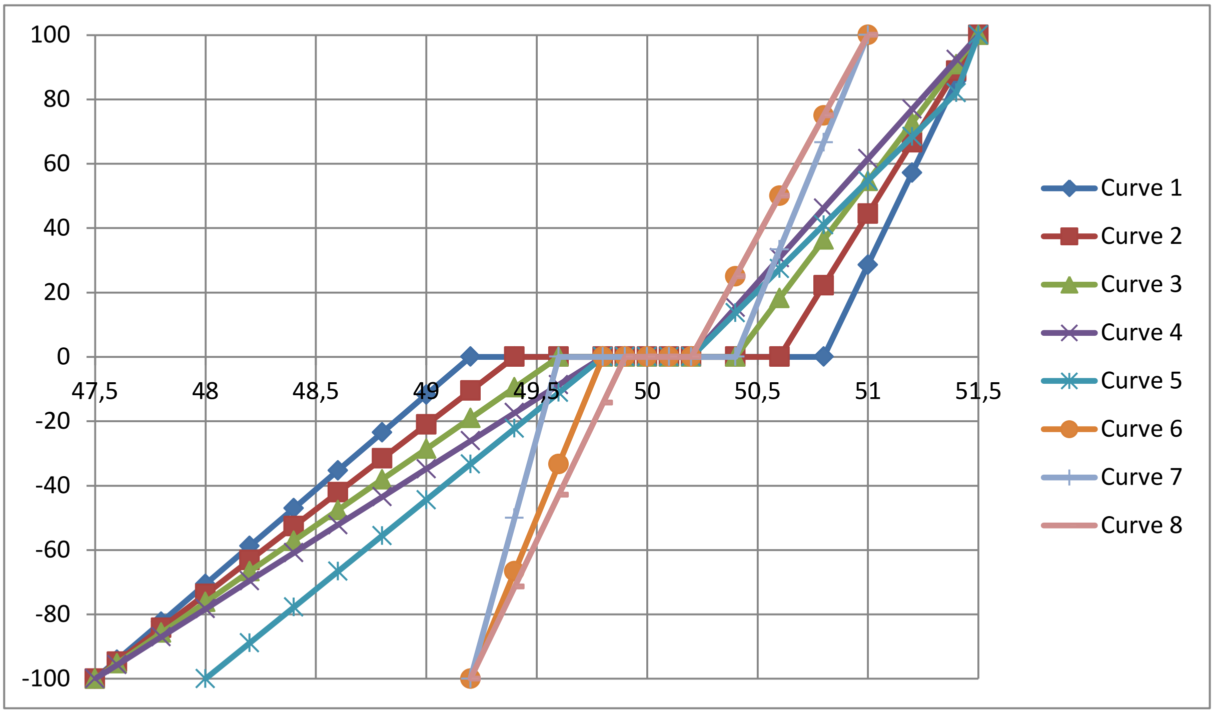

Figure 1- Settings on DSR SFC temperature controlled devices

Cost Benefit Analysis cost saving calculations

Three different cost benefit analysis calculations were performed to look at

- Procurement in FCR and savings in energy costs,
- savings in capacity costs,
- Value of Lost Load (VOLL) for past large scale of demand losses or blackouts.

Procurement of FCR and Savings in energy costs

Utilising the costs and frequency dispersion from a historic year in Table 2, and applying the settings for curves 5-8 in Figure 1, the savings in energy costs per MWh of demand disconnection are shown below in Table 3.

	Frequency in Hz									
	49.2	49.4	49.6	49.8	49.9	50	50.1	50.2	50.4	Total benefit in Euros per MWh
Curve 5	€ 50	€ 277	€ 327	€ 0	€ 0	€ 0	€ 0	€ 0	€ 192	**€ 847**
Curve 6	€ 453	€ 831	€ 982	€ 0	€ 0	€ 0	€ 0	€ 0	€ 351	**€ 2,617**
Curve 7	€ 453	€ 1,246	€ 0	€ 0	€ 0	€ 0	€ 0	€ 0	€ 0	**€ 1,700**
Curve 8	€ 453	€ 712	€ 842	€ 23,124	€ 0	€ 0	€ 0	€ 0	€ 351	**€ 25,482**

Table 3 - Illustration of savings per MWh of demand disconnection based on historic frequency dispersion

Equivalent capacity payment savings

Depending on the market within Europe any alternative to DSR SFC would expect to be given a €/MWh payment to be able to supply the market with its service. For the aforementioned reasons of increased administration costs these payments would not be expected to be paid to DSR SFC, but the net benefit can be factored into the Cost Benefit Analysis of DSR SFC.

However the net cost of supplying such a service based on current payment rates can be used to also quantify the benefit of the DSR SFC, compared to other equivalent sources which would require payment.

Currently the Short Term Active Response (STAR) scheme in Irelands rates are shown below in Table 4. Utilising this rate the equivalent cost of providing this service using STAR to DSR SFC is shown in Table 5.

Basic Payment for 20 interruptions per annum:	
€8.20/MWh	
Supplemental Rate Interruptions in excess of 20 per annum	
€1.74/MWh	1 – 5 Interruptions
€3.48/MWh	6 – 10 Interruptions
€5.23/MWh	1.1.1 11 – 15 Interruptions
1.1.2 €6.97/MWh	1.1.3 16 – 20 Interruptions

Table 4 - Statement of charges for STAR services (Rates up to Sept 2011)

Current cost in €/MWh	Cost per annum[9] in 2020	Cost per annum[10] in 2030
8.2	**€ 72,640,896.93**	**€ 93,403,919.03**

Table 5 - Cost of equivalent DSR from STAR scheme

Value of Lost Load (VOLL) for past large scale of demand losses or blackouts.

Based on NRA reports [2], [3] the cost of the loss of load demand can be as high as €25k/MWh, but is generally agreed to be in the region of 10.25-12.5k/MWh.

In Ireland in 2005, a demand disconnection of 639MW across the system occurred. Proportionally, this was one of the largest single events of demand disconnection in recent years.

Examining this event the cost and hence comparable saving DSR-SFC could have made to the demand disconnection lost is calculated. The savings against various estimates of VOLL are shown. The table also shows the reference 1300MW (see Table 1.) that could be available by 2030 and the corresponding net saving of an event which required the full DSR SFC to be utilised.

[9]Based on 8760hrs on the total MW provided by DSR SFC as per Table 1.
[10]Based on 8760hrs on the total MW provided by DSR SFC as per Table 1.

MWh Value of Lost Load[11]	MW available/Lost	Cost based
€ 10,270.00	1300	€ 13,354,191.01
€ 10,270.00	639	€ 6,562,530.00
€ 12,500.00	639	€ 7,987,500.00
€ 25,000.00	639	€ 15,975,000.00

Table 6- Social-economic cost of VOLL of big system event and use of full DSR SFC in Ireland

Cost Benefit Analysis capital cost of DSR SFC

The report 'Synergy Potential of Smart Appliances' [1] sets out the perceived cost to circa.€2-5 per device for the necessary frequency accuracy (equivalent to UK price in report), utilising these ranges the total costs are shown below:

Cost of unit in €	Cost per annum	Total cost over period
2	€ 456,000	€ 6,845,000
3	€ 685,000	€ 10,268,000
4	€ 913,000	€ 13,690,000
5	€ 1,141,000	€ 17,113,000

Table 7 - Total cost of DSR SFC in Ireland

Conclusion Cost Benefit Analysis of DSR SFC

The net annual savings of energy, capacity payment and rare historic events, are factors greater than the capital cost of implementing DSR SFC.

The assumptions therefore made around the number of scale of users would also need to be out by similar amounts to affect the overall result and hence the tolerance for error is very large and can be excluded further.

To demonstrate the impact of developing a market based delivery of DSR SFC and therefore excluding all other benefits and focusing on purely rare historical events, Table 8. shows the necessary frequency of occurrence of these events to break even for €2-5 per device capital cost.

[11] Taken from reference sources [2] and [3]

MWh Value of Lost Load	*MW available*	*Total benefit value of DSR*[12]	*€2 Euro Capital cost*	*€3 Euro Capital cost*	*€5 Euro Capital cost*
€ 10,270.00	**1300**	**€ 13,354,191.01**	**29 Years**	**19 Years**	**12 Years**
€ 10,270.00	**639**	**€ 6,562,530.00**	**14 Years**	**10 Years**	**6 Years**
€ 12,500.00	**639**	**€ 7,987,500.00**	**18 Years**	**12 Years**	**7 Years**
€ 25,000.00	**639**	**€ 15,975,000.00**	**35 Years**	**23 Years**	**14 Years**

Table 8 - Reoccurrence period of events for a break-even in the CBA for DSR-SFC

REFERENCES

[1] Synergy Potential of Smart Appliances[1] (D2.3 of WP 2) from the Smart-A project A report prepared as part of the EIE project 'Smart Domestic Appliances in Sustainable' 2008.
[2] 'The Value of Lost Load, the Market Price Cap and the Market Price floor', A Response and Decision Paper in SEM, Ireland, Sept 2007.
[3] ERSI Working Paper No. 357 'An Estimate of the Value of Lost Load for Ireland' by Eimear Leahy and Richard S.J. Tola, b c, Ireland, Oct 2010.

[12]Calculated by multiplying cost of VOLL and MW available in first two columns

Appendix 2 : Continental Europe Study case

Number of temperature controlled devices in Continental Europe (CE)

Utilising the EC funded Synergy Potential of Smart Appliances [1] (D2.3 of WP 2) from the Smart-A project A report prepared as part of the EIE project 'Smart Domestic Appliances in Sustainable', the Demographic Yearbook edited by the United Nation [2], the UNECE Statistics for households [3] the scale of temperature controlled devices in CE in 2020 and 2030 were calculated in Table 1.

Year	2020			2030		
Peak CE Demand (MW)	512149			582762		
Type of T°ctrld Devices	Average MW in 2020	% of peak load in 2020	Number of units in 2020	Average MW in 2030	% of peak load in 2030	Number of units in 2030
Fridge/Freezer	70258	13.7%	175092319	79945	13.7%	199233126
Industrial Refrigeration	72264	14.1%	5367329	82228	14.1%	6107348
Heat pump	23962	4.7%	406	27265	4.7%	463
Heating water load	39049	7.6%	0	44432	7.6%	0
Total	2.06E+05	40.1%	1.80E+08	2.34E+05	40.1%	2.05E+08

Table 1 - Number of temperature controlled devices in CE

Price of Frequency Containment Reserve (FCR) in CE

Taking into account the diversity of the approach for contracting frequency containment reserve in CE, it is assumed the following average price for reserve capacity.

- For action in the range 49.8Hz-50.2Hz: Primary Frequency Control Reserve (FCR) is assumed to be 30€/MW/h
- For action in the range 49Hz-49.8Hz: Voluntary load shedding of demand is assumed to be 1.5€/MW/h

Value of Loss Load in CE

Demand disconnection (non DSR) in case of low frequency events is the last operational response to retain system integrity. The social-economic cost of this event is measured by the Value of Lost Load (VoLL) and has a high cost. Based on Deliverable 5.6.1 of the R&D SECURE Project [4] and confirmed by other studies the cost of this loss of load demand can be as high as 20k€/MWh, but, in order to be conservative for this CBA a value of 8k€/MWh is chosen. As information a VOLL of 16k€/MWh and 20k€/MWh are also shown.

Distribution of frequency deviations per annum in Europe

The statistical variation in system frequency over the last 4 years can be summarized by the Figure 1.

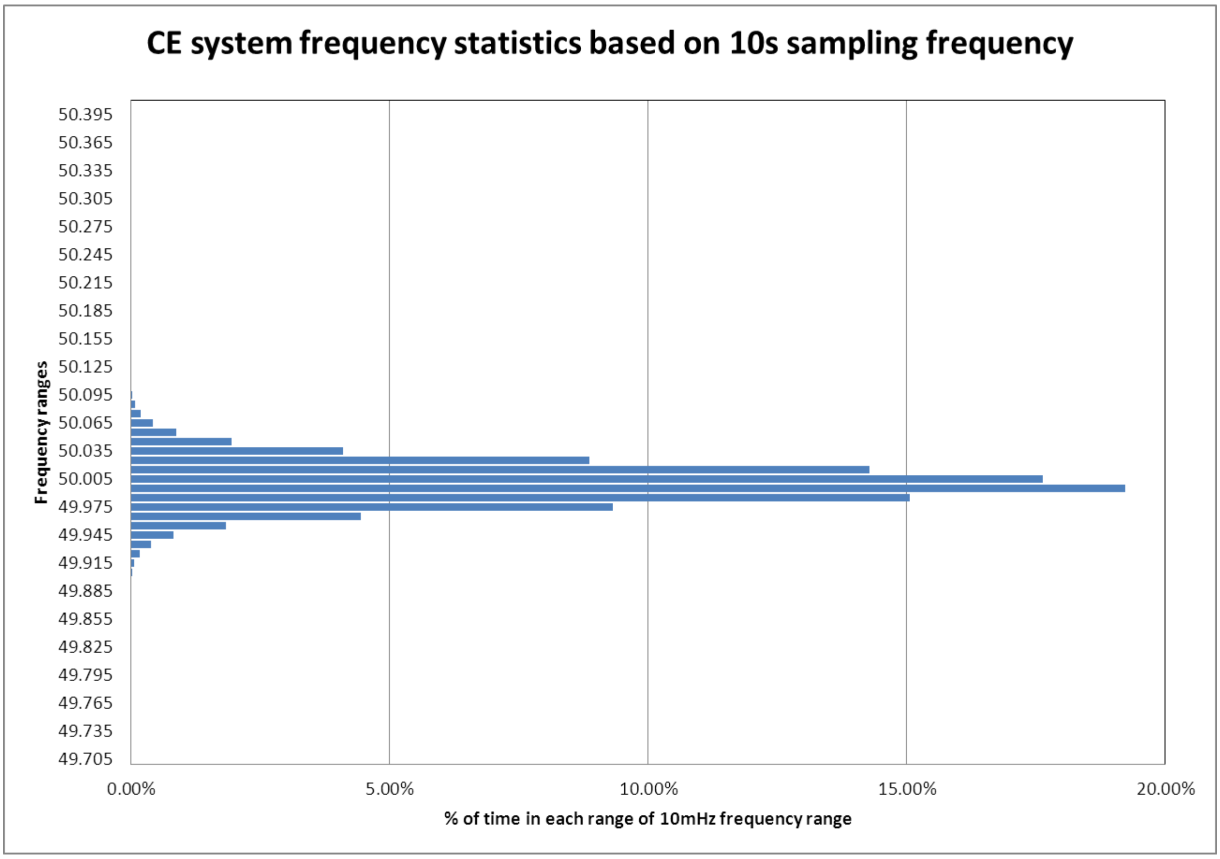

Figure 1- Statistical variation in system frequency over the 5 last years (May 07-May 12)

Setting on DSR SFC controller

For this CBA, different settings of the DSR SFC controllers were examined to reflect varying strategies that could be employed. It is clear that the selection of a strategy at a synchronous system level will impact the use and hence the benefit of the DSR SFC.

4 curves are therefore analysed for their prospective demand usage saving.

- Curve 1: Outside FCR & for under frequency deviation only
- Curve 2: Outside FCR
- Curve 3: Partially Outside FCR
- Curve 4: Completing/Replacing FCR (with 40mHz deadband)

The associated settings for each curve are shown in Figure 2.

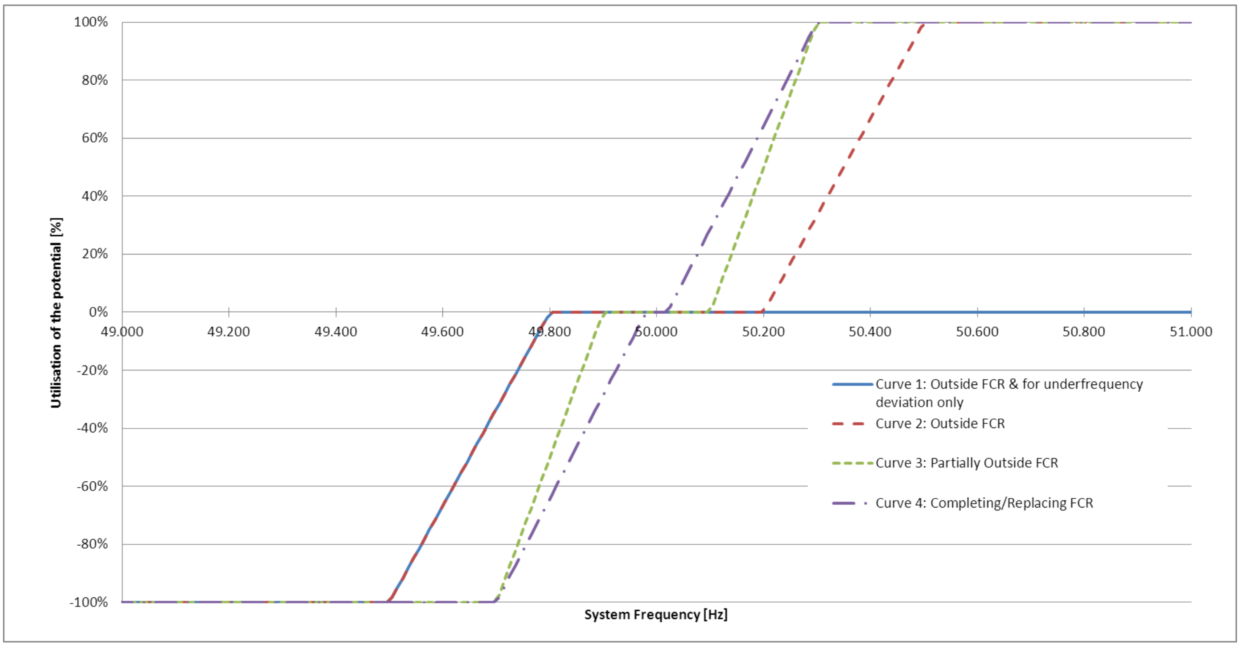

Figure 2 - Settings on DSR SFC temperature controlled devices

Cost Benefit Analysis capital cost of DSR SFC

The report 'Synergy Potential of Smart Appliances' [1] sets out the perceived cost to c.€2-5 per device for the necessary frequency accuracy (equivalent to UK price in report).

Cost Benefit Analysis cost saving calculations

Procurement of LFC reserves

If activated in the range 49.8Hz-50.2Hz, DSR-SFR can be used for completing/replacing generation-based FCR. Otherwise, it can be used for supplementing/replacing existing voluntary demand shedding services for FCR. Table 2 summarizes the impact for a variation of €2-5 per device capital cost to provide DSR-SFC.

DSR-SFC based LFC		Generation-based LFC in the range 49.8-50.2Hz	Volundary demand shedding services
Assumed cost for one device in €	Cost per MW per year in €	Cost per MW per year in €	Cost per MW per year in €
2.00	117.07	262800	13140
3.00	175.60		
5.00	292.67		

Table 2. Cost to cover annual LFC reserves

FCR Regulation Energy Cost

Utilising the historical dispersion in system frequency, the equivalent cost for the upward and downward energy provided for frequency containment action can be computed for the different assumed prices of DSR-SFC installation cost (€2-5 per device) as well as for the different settings presented in Figure 2.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

These regulation Energy Costs can be compared to the FCR Regulation Energy Cost provided currently using Generation-based LFC using the estimated price for FCR. Table 3 summarizes this comparison.

	Equivalent hours of full capacity usage /yr (h)	Average Regulation Energy Cost in €/MWh		
Assumed cost for one device in €		2.00 €	3.00 €	5.00 €
Setting on SFC				
Curve 1: Outside FCR & for underfrequency deviation only	0.032	3709.077	5563.616	9272.694
Curve 2: Outside FCR	0.039	3031.262	4546.893	7578.155
Curve 3: Partially Outside FCR	0.165	710.612	1065.918	1776.530
Curve 4: Completing/Replacing FCR (40mHz deadband)	47.771	2.451	3.676	6.127
Reference Primary Frequency Control (20mHz deadband)	216.614	1213.220		

Table 3. FCR Regulation Energy Cost in €/MWh

Furthermore, Table 3 also shows the number of equivalent hours per year of full capacity usage. This value clearly depends on the selected settings and gives an indication on how often could the devices be used.

Value Of Loss Load (VOLL) for past large scale of demand losses or blackouts

In the western part of CE in 2006, the first under frequency load shedding steps were activated. 17 GW of loads were shed in CE during this blackout. A similar amount of DSR-SFC could have avoid this bulk demand disconnection as, for each of the proposed settings of Figure 2, 100% of the temperature controlled devices would have been triggered during this event**.**

For sake of simplicity, it is assumed that the mean customer interruption during this event was 1h. This leads to Table 4 where the avoided costs at the assumed Value of Loss Load are provided. Furthermore, the frequency of such event than would justify the investment in DSR-SFC is also provided in Table 4.

	Cost of one blackout being saved			Equates to break even if this event occurs once every Yrs					
				Cost of unit in €					
	MWh Value of Lost Load	Required MW available	Cost in case of load shedding in €	2.00 €		3.00 €		5.00 €	
Event comparable to the 2006 CE	€ 8.000.00	17000	€ 136.000.000.00	68	Years	46	Years	27	Years
	€ 16.000.00	17000	€ 272.000.000.00	137	Years	91	Years	55	Years
	€ 20.000.00	17000	€ 340.000.000.00	171	Years	114	Years	68	Years

Table 4 - Social-economic cost of VOLL of big system event and use of full DSR SFC in CE

Conclusion Cost Benefit Analysis of DSR SFC

For each of the three different cost benefit analysis calculations performed above;

- Procurement of FCR reserve,
- FCR Regulation Energy Cost and
- Value Of Loss Load (VOLL) for past large scale of demand losses or blackouts,

the net annual savings are factors greater than the capital cost of implementing DSR SFC.

The assumptions therefore made around the number of scale of users would also need to be out by similar amounts to affect the overall result and hence the tolerance for error is very large and can be excluded further.

Accounting for the increased uncertainty that arises from more intermittent energy it is envisaged that the challenges placed on TSOs will increase into the future. It can be expected that system operators working together will find continuing improvements which will counteract these changes.

However the future is unpredictable and future large scale demand losses should be assumed to continue. Therefore this CBA has been calculated both conservatively looking to the future.

The implementation of DSR SFC itself should help mitigate these uncertainties and, from the cost benefit analysis performed, looks to offer very significant returns to the demand user.

REFERENCES

[1] Synergy Potential of Smart Appliances[1] (D2.3 of WP 2) from the Smart-A project A report prepared as part of the EIE project 'Smart Domestic Appliances in Sustainable' 2008.
[2] Demographic Yearbook, Population Censuses' Datasets (1995 - Present), United Nations Statistics Division. Accessed on 27 May 2012.
[3] Private households by Household Type, Measurement, Country and Year, UNECE Statistical Division. Accessed on 2 October 2011.
[4] SElf Conserving

Answer to FAQ 32:

Why is DSR-Reserve a technical and economical efficient solution to support system security?

Reserve capability is required by TSO's to deal with uncertainty ahead of real-time. Traditionally the dominant uncertainty has been demand and unscheduled position for generation. Reserves are typically required to be available from a time when an incident occurs until the time that generation can start up and produce replacement power, e.g. 4 hours for CCGTs. TSO's define reserve ancillary services in this context and in real-time operation instructs for reserve services at the lowest cost.

Introduction of high levels of RES, particularly wind, but also solar PV does significantly change the volume of reserves required. This is linked to the uncertainty in forecasting, e.g. wind hence demand which is capable of being deferred for extended periods, preferably up to 4 hours, can in principle be considered for such a service. Demand suitable to deliver these services exists from industry, commercial and at the domestic level. The potential for all these may be explored to give the least societal cost.

These services are expected to continue, and to expand in volume to meet the increasing demand, possibly with further market encouragement to widen the geographical base for the products.

The types of demand with such potential flexibility (Demand Side Response for Reserve) not yet fully engaged for this purpose includes "wet" white goods (e.g. washers, dishwashers and tumble dryers) and charging of electrical vehicles. In both cases this flexibility will only bring minor or even no inconvenience for most consumers. Therefore this may be an opportunity to develop new DSR services, if adequately rewarded.

During the consultation on the "Call for Stakeholder Input" the stakeholders analyzed the Cost-benefit Analysis provided on DSR for Reserve. This CBA was based on a GB study case and showed the potential future reserve cost to support system security if no other solution to provide reserves is developed to address the high RES penetration.

Stakeholders ask ENTSOE to provide further information to support this CBA. However, a further breakdown and amendments were made to the GB study case and a CBA was provided on the Swedish case. This additional information is detailed in the appendix below.

Summary:
The detailed CBAs are presented in the appendix of this FAQ for procurement of DSR for reserve.

The two key major challenges are to quantify the future reserve required and the cost associated with calling upon the reserve to secure security of supply. The assumptions made were based on best practice and were conservatively used, accounting for the increased in uncertainty that arises from more intermittent energy and challenges placed on TSO's & DSO's to balance generation and demand. It can be expected that system operators working together will find continuing improvements which will counteract these changes with the potential application DSR for reserves.

The implementation of DSR for reserve itself should help mitigate these uncertainties and challenges, and from the cost benefit analysis performed indicates that DSR for reserve capability implementation can be compensated by the financial savings gain when not using other sources such as interconnector, synchronous (reducing due to high penetration of RES) and wind, for reserve. In addition, DSR for reserve is also complimented from industrial and commercial temperature controlled devices, but not considered conservatively in these CBAs due the greater difficulty to quantify cost and assumptions.

ENTSO-E AISBL • Avenue Cortenbergh 100 • 1000 Brussels • Belgium • Tel +32 2 741 09 50 • Fax +32 2 741 09 51 • info@entsoe.eu • www.entsoe.eu

Appendix 1 : Swedish study case

In Sweden, the CBA is focused only on procurement of reserves. Nevertheless, DRS for reserve cannot be distinguished from DSR-SFC as the Swedish TSO buy the global reserves needed and only differentiate between activation frequencies.

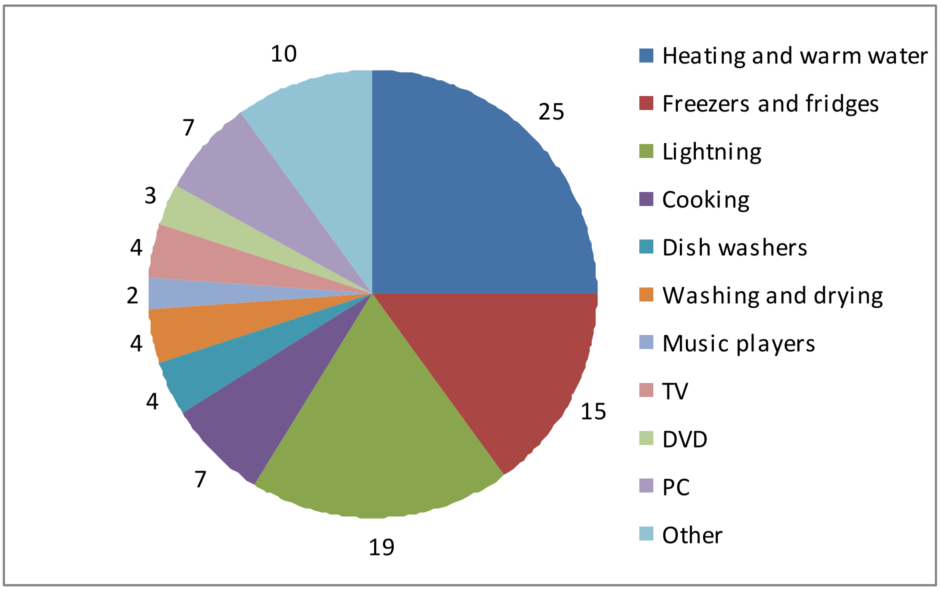

Chart 1 – Showing the percentage breakdown in 2010 for domestic appliances consumption which equates to approximately 73000 MWh.

Applying the above percentage breakdown for wet and temperature controlled appliances multiplied against the total energy Sweden consumes in 2010 yields the energy consumed for each category of devices.

Potential DSR Reserve sources	Penetration in 2010	Total energy in Sweden (MWh)	Days per annum used	Hours per days used	Average Demand in 2010 (MW)	Dispersion period hrs/day total use is spread over	Average dispersed demand (MW)	No. Of units
Washing machines & Dryers	4,566,800	3.00E+06	160	6	3,125	24	781	9,133,600
Dishwashers	3,495,000	3.00E+06	200	2.5	6,000	24	625	3,495,000
Fridge & Freezers	4,660,000	1.10E+07	365	24	1,256	24	1,256	9,320,000
Heating/cooling and warm water load	1,600,000	1.80E+07	365	24	2,055	24	2,055	6,400,000

Table 1 – Calculating the MW demand over a 24 hour day and the potential quantitative demand available to provide DSR for reserve and DSR for SFC.

Cost Benefit Analysis assumptions

1. DSR replaces all reserves from synchronous plant.
2. The cost for reserves is 71.4M Euros per annum.
3. The life cycle for the equipment is 15 years.
4. Interest rate for NPV calculation is 4%.

5. Breakdown of domestic households consumption based on 2010 data, 73000MWh (per annum).
6. Number of domestic households 4,660,000.

RESERVES	Amount (MW)
Frequency controlled normal operation reserve (49.9 - 50.1 Hz)	245
Frequency controlled disturbance (49.9 - 49.5 Hz)	440
Total	**685**

Table 2 – The available MW to support DSR for different activation frequencies.

Cost Benefit Analysis

Applying the assumptions previously stated the net present value indicates a break even over the 15 years if the cost for implementing the capability is 29 Euros per appliance. Assuming a spread over 15 years equating to €71.4m per annum means that the NPV cost over the 15 year period is €825.6m compared to a cost of €28.3m per annum to install DSR into appliances in Table 1.

This implies a return of approximately 29:1 in favour of implementing reserves through DSR.

Appendix 4 : GB study case

It is clear that significant uncertainty exists around the cost of reserve and thus it may be useful to consider how reserve costs may be affected by different drivers of the requirement mainly wind and interconnector variability.

For the purposes of this analysis, it has been assumed that margin costs rise in line with underlying power price. The cost of margin is set as a premium to the underlying power price, and the forecast power price is expected to be approximately double the 2010 base load electricity price in real terms, for example the effect of inflation.

Cost Analysis for Reserve

Consequences if no other reserve services are developed for GB.

In GB this strategy has initially identified that less than 50% of the reserve capacity needed for 2020 is available, without considering that most synchronous plants will be out of merit when the service need is greatest. The cost of this service is estimated to increase from around £100M in 2010/11 to the order of £565M (revised figure) in 2020/21, as per table 1. Risks include both inadequate provision (security) and high cost (with large wastage of RES energy).

Drivers	2010/11	2015/16	2020/21
Price			
Power Price £/MWh	41.82	66.96	84.08
Margin Price £/MWh	25	39	49
STOR Price £/MWh (utilisation only)	350	544	685

Volume			
SEL:MEL Ratio	0.6	0.6	0.6
No. of hours	4320	4320	4320
Basic Reserve			
Basic Reserve Requirement	2525	2525	2525
No. of hours	2160	2160	2160
Total Basic Reserve TWh	3.3	3.3	3.3
Total Cost £M	**81.8**	**127.2**	**160.0**
Reserve for Wind			
Wind capacity	3,802	11,872	26,771
Expected Average Wind Output*	641	3062	7531
Wind Load Factor	30%	30%	30%
Marginal Wind Effect	50%	39%	30%
Total Reserve for Wind TWh	0.83	3.09	5.86
Total Cost	**21**	**120**	**286**
Reserve for Response			
Largest Loss	1320	1800	1800
Response Delivery	0.55	0.55	0.55
No. of hours	2160	2160	2160
Total Reserve for Response Holding (TWh)	3.11	4.24	4.24
Total Cost £M	**0**	44	55
Reserve for Interconnector variance	0	500	500
Hourly Variation Across daytime peak (met through add. Regulating) TWh	0	1.296	1.296
Demand Peak Variation only (met through STOR) TWh	0	0.648	0.648
Hourly Variation Cost £M		50	63
Demand Peak Variation Cost £M		353	444
Total Cost + Interconnector (hourly variation)	**102.6**	**341.6**	**565.1**

Table 1 – Total operating reserve costs in the Gone Green Scenario. ***Reference: Operating the Electricity Transmission Network in 20220 – Update June 2011, Table 10, page 74.***

Central scenario in 2025 with 40GW of RES (mainly wind)

For 2025 and 2030 the above challenge is expected to increase significantly with particular difficulties with the central scenario expectation that variable RES alone (mainly wind) for an increasing number of hours in the year will exceed the total demand (100% penetration for the synchronous area of non-synchronous generation).

When the uncertainty is greatest (high wind volumes) the reserve requirement is expected to peak at 12 GW. For a limited number of hours in the year, something close to the following may be the toughest challenge; 30GW of RES production (75% of capacity) with 25 GW demand (25% above minimum demand). By 2025 GB may have capacity to export 10GW to the Continent / Nordic areas, with maybe 2 GW of import from Ireland during high wind conditions, giving 8 GW of net export. This would leave 3 GW for nuclear production likely to be second in merit after RES, maybe with 1 GW existing and 8GW new nuclear which can run at down to a minimum 25% output, i.e. 2 GW.

This scenario would potentially deliver 6GW of reserve from new nuclear, assuming it was all used for reserve covering forecasting uncertainty rather than used for primary frequency response. If no significant reserve was provided from either interconnectors or demand, this would leave another 4-6GW of reserve required from wind. Creating 6GW of headroom using wind for say 5% of the hours in the year (438hrs) would in relation to the current ROC prices push the cost of 6GW to €650M per year (@£100/MWh), while ignoring any cost for the other 95% of the time.

CONSEQUENCES OF ENCOURAGING TRADING OF RESERVES – INCLUDING ACROSS HVDC

Spare interconnector capacity at the end of energy trading (after intraday gate closure) could be used to provide reserve Ancillary Services (AS). This could additionally include reversal of the final trades. Capability for this between synchronous areas will rely on HVDC links. As the reserve AS is a relatively slow service there should not be any major technical challenges in terms of HVDC links, even for existing links. This is therefore a real option which may be explored in other NCs. Securing the reserve (e.g. 4 hours out) ahead of the gate closure time (e.g. 1 hour or in some countries even less ahead of real-time) will remain as a significant challenge for this option. Further challenges include lower certainty of reserve availability when needed with the wider sharing and also potential for transmission bottlenecks inside countries even if HVDC links have capacity.

REFERENCES

[1] Demand Connection Code Call for Stakeholder Input, 5 April 2012
[2} National Grid's: Operating the Electricity Transmission Networks in 2020 – Update June 2011