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European Network of
Transmission System Operators
for Electricity

DEMAND CONNECTION CODE

CALL FOR STAKEHOLDER INPUT

5 APRIL 2012

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1 INTRODUCTION

1.1 BACKGROUND

Rapidly increasing Renewable Energy Sources (RES), implementation of Smart Grids, seeking effective competition and the efficient functioning of the internal electricity market while maintaining system security, are all driving significant changes to the electrical power system as we know it today. This will require a new framework to cope with these challenges and all participants of the energy market will face these changes.

In this context, ENTSO-E elaborates the "DSO and industrial load grid connection rules in electricity" including dedicated Requirements for Distribution Networks and Demand Facilities in line with EC's mandate [3]. This Network Code is referred to as the "Demand Connection Code" (NC DCC). The NC DCC will be based on ACER's Framework Guidelines on Electricity Grid Connections (FWGL) [1] and ERGEG's Initial Impact Assessment [2], both documents dealing with electricity grid connections for all users.

Other Network Codes that are being developed by ENTSO-E largely seek to harmonize existing procedures and requirements. The NC DCC by contrast will implement a completely new approach for some requirements at European level which can be seen in the preliminary scope [4]. Most countries already have a few connection requirements for demand users, but there has never before been a need for a common set of requirements across Europe.

The aim of this document is to define and discuss the challenges to be addressed by the NC DCC and put forward the main *new* topics for which solutions are sought. With this document ENTSO-E is outlining alternative approaches to address challenges which until now have not been widely covered in grid codes or standards. The purpose of this document is to initiate discussion on whether the solutions proposed in the NC DCC are the most efficient in preparation for the future. In some cases further information is required to finalise an initial view. Therefore, this "Call for Stakeholder Input" also asks stakeholders to provide ENTSO-E with information and/or release data[1].

1.2 CHALLENGES AHEAD: RES

1.2.1 CONTEXT

Security of the system cannot be ensured without considering the technical capabilities of all users. Historically large synchronous generation facilities have formed the backbone of providing technical capabilities. The energy system is changing rapidly especially with the massive integration of RES (wind generators, PV installations) in the European electricity network. Today RES, even at peak generation, usually provides less than 30 % of the power. In some countries (Ireland, Spain and Portugal) RES generation is already supplying up to 50 % of the load during some hours in the year. In 10-15 years' time it is expected that in the synchronous areas of Ireland and GB up to 100 % of the load may be supplied by RES alone. The EC goal is that by 2050 the electricity generation of the EU will be nearly 100 % CO_2 free, which implies that during many hours of the year RES has to supply 100 % of the load in some regions [5]. The case studies provided in Appendix 1 to 3 for some of the envisaged options for the NC DCC focus on the synchronous areas of GB and Ireland where contracted RES penetration and its implica-

[1] To respond to the questions posed, stakeholders are requested to use a response form which can be downloaded on the ENTSO-E website. Also further guidance on the DCC development process can be found there.

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tions is already ahead of the present situation in other European countries, but in line of what can be expected in other parts of Europe[2].

In terms of RES penetration it is common to discuss average RES figures, e.g. the EU target of 20% by 2020 is an average target for a year. In contrast, real-time RES production as a percentage of the total demand at any time is highly variable, typically up to 5 times larger than average production. The reality of this large ratio can be illustrated in Denmark, which has the highest penetration of wind in the EU. When Western Denmark (Jylland connected to Continental Europe) first exceeded 100% of demand from wind a few years ago the average wind penetration over the year was still “only” about 20%. Denmark currently copes with this challenge to a large extent through having in place a high capacity of links to other countries. The connection capacity of Denmark to Nordic countries and Germany exceeds 80% of its maximum demand and is still being extended further as Denmark continues to expand its RES capacity. This example shows the urgent need to develop the capabilities of the system further as more and more countries increase RES generation to comparable levels.

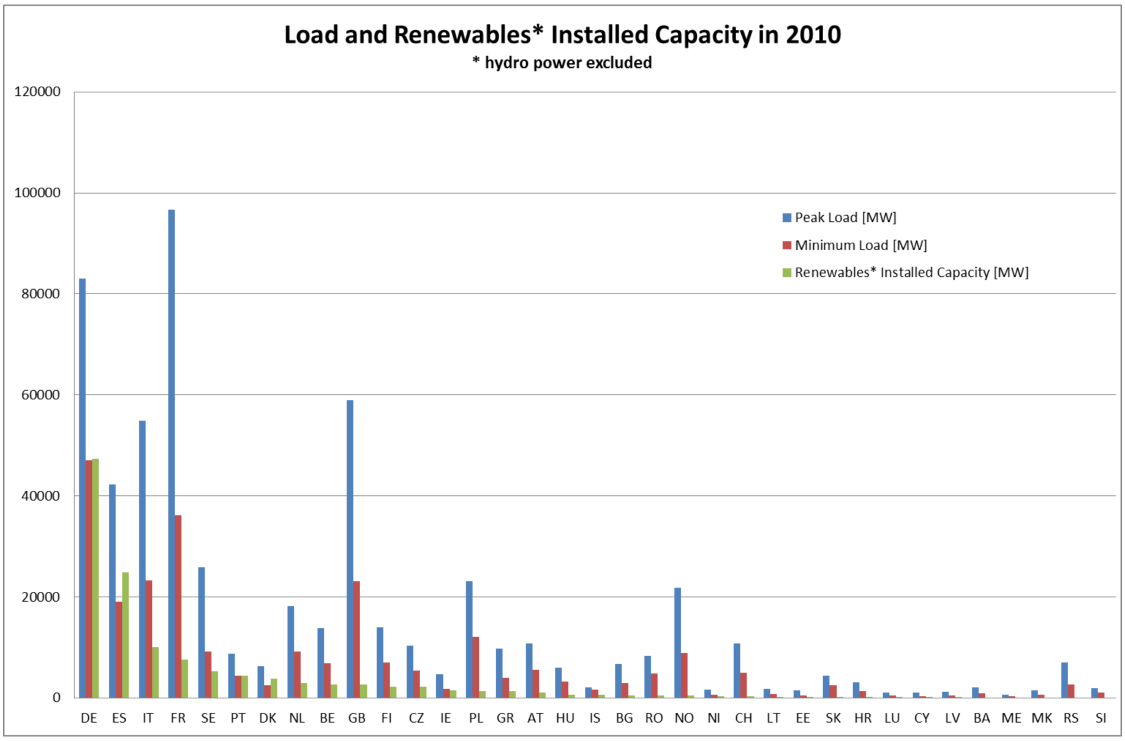

FIGURE 1 - PEAK LOAD VERSUS INSTALLED RES GENERATION IN 2010 [6]

Operating conditions with the highest real-time RES penetration (typically in windy / sunny conditions with moderate demand) present major system challenges, particularly where the high RES penetration extends to the total synchronous area. Studies in Ireland, the European synchronous area with the highest RES (wind dominated) penetration of non-synchronous generation plants (power electronics interface), indicate these challenges increase dramatically above 50% for the synchronous area. A range of system technical counter measures have to be planned to avoid a total block on RES development above about 10% average (50% highest). Alternatively, massive constraining off (wasting) of RES has to be accepted to maintain secure operation. These system technical capabilities are shared between Transmission (linking resources over longer distances), Generation and increasingly in the future also Demand. The Demand component can be developed to deliver an increasing contri-

[2] In this document the number of cases studies is kept limited. Additional cases from other regions are planned to be discussed further on the workshop of 18 April, as well as in the user group meeting of 19 April. More information on these events can be found on the ENTSO-E website.

bution during high RES generation in real-time to replace some of the system technical services normally provided by synchronous generators when these are connected, i.e. during normal or lower RES production.

In this context, the electrical power system will have to deal with the following challenges:

- RES generation predominately varies with weather conditions (sun, wind). The characteristic of variability and also uncertainty (difficult to forecast accurately) until close to real-time, introduces significant new challenges in system operation (power imbalances, lower levels of firm generation capacity, loss of services from displaced generation). This brings a challenge of maintaining stable operation of an electricity network with high penetration of RES. The main answer to this is to increase the controllability and the flexibility of all power system elements to deliver a power system which can react and cope better with the volatility of RES. [8].

- The increasing uncertainty arising from adding large generation forecasting errors (e.g. wind) to the familiar demand forecasting errors will require a greater volume of reserves to be available a few hours ahead of real-time. These reserves will have to be available even when synchronous generators, the traditional reserve providers, are displaced (disconnected from the system) by RES. See section 3.1 and Appendix 1.

- Renewable generating units are mainly non-synchronously connected. Consequently, the inertia of the system will be reduced when an increasing amount is connected to the grid. This will increase the frequency sensitivity of the power system to power imbalance and will need to be compensated by additional frequency regulating capabilities with fast acting frequency controls.

- High levels of embedded generation is impacting the effectiveness of existing power system defence plans, because they have been developed to consider pure load connected to the Distribution Networks. With the development of embedded generation, in the case of a major disturbance, it may not be possible to secure at least parts of the system, with the potential risk of a complete system breakdown. For these two aspects, see section 3.2 and Appendix 2.

- A significant proportion of RES is connected to the Distribution Network. As a consequence the DSOs have to increase their role in facilitating the connection and integration of RES while at the same time guaranteeing their customers a high level of power quality. Additionally, as embedded RES generation at times takes up a higher proportion of the total generation, it displaces central transmission connected generation. This creates a further challenge with regards to adequate reactive power resources to regulate the transmission system voltage. The role of the DSO networks and transmission connected demand in respect of consuming reactive power at times of high demand and generating reactive power at times of low demand therefore needs to be reviewed. See section 3.3 and Appendix 3.

The electricity power system, as designed today, will not be able to cope with the expected amount of RES generation without significant change. To achieve Europe’s renewable and carbon reduction ambitions a full review is required as to how different participants can contribute to providing support to cope with the challenges.

1.2.2 OPTIONS TO INCREASE RES PENETRATION IN THE SYSTEM

There are several options on how to deal with high RES penetration. The main options are described alongside their advantages and disadvantages in Table 2:

Option	Pros	Cons
synchronous conventional generators are required to provide the most significant system services	▪ No significant change from today	▪ Cost of constraining off RES and on synchronous generation when synchronous plant are not needed by the market ▪ CO_2 emissions because simultaneously RES generation is constrained off ▪ 100 % CO_2 free production can only be achieved with nuclear and CCS ▪ Risk of a lack of system services in the future if only this option is followed
RES generators to provide their share of the system services	▪ No additional CO_2 emissions for voltage support services	▪ In order to create headroom to provide the service, RES has to be constrained (and therefore wasted) with additional CO_2 emissions ▪ Embedded generation needs to be fully controlled (difficult with dispersed small units)
extensive building of storage systems	▪ Only limited CO_2 emissions (from less than 100% cycle efficiency) ▪ Supports RES integration	▪ New storage systems have to be built Europe wide ▪ Feasibility of building storage is not given in all areas ▪ High environmental impact to build large storage systems
Demand Facilities provide their share of system services	▪ No additional CO_2 emissions ▪ Supports RES integration ▪ Services have the potential to be provided at low cost and no or minimum consumer inconvenience ▪ Highly reliable as the risk is spread ▪ Consumers are enabled to participate in the electricity market, take action to reduce CO_2 and will pay less	▪ Public perception of possible inconvenience ▪ Public acceptance ▪ DSOs need to contribute more towards managing a system with high RES (e.g. voltage)

Table 2: Overview of options to increase RES integration

Table 2 seeks to consider the options to integrate RES based on the strength of their merits. The benefits from Demand Side Response (DSR) are clear. DSR has the potential not only to be relatively inexpensive, but also supports the EU goals to integrate RES and to empower customers to participate in the energy market. Customers can contribute as active players to reduce CO_2 emissions and their cost of electricity by accepting a modest level of flexibility.

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Questions:

1.1. What is your view of the high level analysis presented in Table 2?

1.2. What is your view of the conclusion that the "Benefits from demand side response (DSR) are clear and that DSR has the potential not only to be relatively inexpensive, but also supports the EU goals to integrate RES and to empower customers to participate in the energy market"?

1.3 DEVELOPMENTS AHEAD: SMART GRIDS

Smart Grids are a strategy/concept to increase system flexibility through smart and integrated system operations of flexible sources, loads and network components. In the Distribution Network, where a growing proportion of RES will be connected, the Smart Grid Initiatives are believed to be a key solution to the flexibility challenge, balancing at every moment in time the generation and consumption in the system.

There is a concern in the EC that there may be too many players and initiatives in the field of the Smart Grids, not always aligned. The EC Smart Grid Mandate (the Mandate) M/490 describes the situation as:

"The scope of the Smart Grids is large; thus the risk is that too many standardisation bodies work on this issue, providing inconsistent sets of technical specifications, causing non-interoperability of equipment and applications and that the priorities will not be precisely defined."

ENTSO-E seeks to address this concern in the following way:

- The main focus of the NC DCC is on cross-border issues, influencing operational security and the stability of the whole power system. Smarter services including DSR for the specific TSO purposes are within the scope of the NC DCC.

- The integration of RES with the help of Smart Grids in the DSO Distribution Network including use of DSR for DSO network management and the questions regarding market issues are not addressed by the NC DCC, nor are the time of use of demand (in aid of flattening the daily demand curve or matching it to production availability). These aspects, although relevant in the context of Smart Grids, are out of scope for the NC DCC.

The approach in the NC DCC will be to set out in requirements which facilitate the capabilities of DSR resources to contribute to a safe operation of the networks. The NC DCC requirements will therefore be an important building block allowing DSR services to be utilised effectively and efficiently in order to facilitate the introduction of RES in a Smart Grid environment. The NC DCC will maximise the DSR services potential and hence impact, providing capabilities for each cross border DSR service.

The progressive nature of both Smart Grid development and DSR services needs to be borne in mind when the requirements for the NC DCC are developed. As a result the requirements must be suited to both small percentage penetration of DSR and also to wide spread RES deployment throughout all voltage levels of the network. Being fit for purpose for interaction with a wide range of potential future generation portfolios is important.

1.4 GUIDING PRINCIPLES

The guiding principle of the NC DCC is to develop requirements for grid connection of Demand Facilities and Distribution Networks, including Closed Distribution Networks (CDN) and DSO networks, 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 now and in the future.

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Secure system operation is only possible by close cooperation between all users of both distribution and transmission networks and the Network Operators. In the context of system security the transmission and Distribution Networks and all their respective users need to be considered as one entity from a systems engineering approach. It is therefore of crucial importance that demand users are obliged going forward to meet the relevant technical requirements concerning system security as a prerequisite for network connection. Appropriate dynamic behaviour of all users and their protection and control facilities are necessary in normal operating conditions and in a range of disturbed operating conditions in order to preserve or to re-establish system security.

In this context existing national connection requirements as well as events from the past have been analysed. As stated above (see "1.2 Challenges ahead") a technical framework not taking both today's and tomorrow's challenges into account will limit the amount of RES integration possible, bear the inherent risk of jeopardising system security, and in some cases it may lead to (partial) black-outs. Consequently, the NC DCC will also take into account that future generation will be based on more volatile generation and that both generation and Demand Facilities providing DSR will be connected to all voltage levels. Therefore ENTSO-E will ensure that the NC DCC is compatible with the Network Code for "Requirements for Grid Connection applicable to all Generators"[3].

2 GENERAL APPROACH TO NC DCC

2.1 STRUCTURE

A major goal of all Network Codes is to enable secure system operation by equitable treatment of all users. In particular, the goal of the NC DCC is to ensure effective and efficient development of Demand Facilities and Distribution Network connections to meet upcoming needs to maintain secure system operation. The choice was made to develop a single network code for demand connection to ensure equitable treatment of all demand users by maintaining a consistent set of requirements for Demand Facilities and Distribution Network operators.

The main principles for drafting this code are based on ACER's FWGL and are given in the DCC preliminary scope document [4]. Topics that are new in comparison to present practices (for many or all countries) are discussed in Section 3 ("Requirements of NC DCC in light of future challenges").

2.2 LEVEL OF DETAIL

A choice has to be made on the level of technical detail of requirements in the NC DCC. The need for detailed requirements in the Distribution Networks can be challenged claiming that these are not relevant in a NC facing cross border issues and should be dealt with at national level. On the other hand, there may exist a need for harmonization of national practices and therefore the need for clearly defined requirements for industrial networks.

Bearing in mind the impact of Demand Facilities in contributing to operational security in the transmission and distribution systems, the NC DCC, which has its main focus on cross-border issues, must include requirements to local Demand Facilities which relate to wide area power system security. The aspects here of major importance are:

- In several of the past black outs of transmission networks (also cross-border), cascading effects of "local" problems have played an important role [7],[9],[10],[11]. Furthermore, it is clear that considering the amount of the local demand, its response (or lack of response) has played an important influence on the criticality of these issues.

[3] https://www.entsoe.eu/resources/network-codes/requirements-for-generators/

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- Aggregation effect of similar behavior of local Demand Facilities has an important impact on the power system security. Furthermore, this issue is becoming more and more stringent with the rise of intelligence in protection and control algorithms used in Demand Facilities.

However, recognising and respecting the specific characteristics of the networks by each single TSO or region, the impact of local demand on operational security will vary over Europe. Therefore the level of detail of the requirements varies and takes into consideration the principles of subsidiarity and proportionality. Consequently some requirements could have a rather prescriptive nature, when the effects on system security requires not only common methods and principles, but common parameters and settings as well. Other requirements could determine just the principles on an EU or synchronous area level and provide the necessary flexibility to be detailed at the most appropriate level (national or regional) in order to consider specific system conditions. Following the finalisation of NC DCC, the provisions in national codes or national regulation level will have to be adapted to fit the requirements of this network code.

ENTSO-E's initial view on this is the following.

- The necessary degree of detail is adjusted to the purpose of each requirement and is determined by the extent of the system-wide impact of each requirement. The relevant entity from the perspective of system security is predominantly the synchronous area and five of them are in the scope of NC DCC (Continental Europe, Nordic States, Great Britain, Ireland and Baltic States).
- The NC DCC focuses on significant users which are either Demand Facility or Distribution Networks (DSO or Closed Distribution Network Operator) connected to the transmission system.
- Furthermore, ENTSO-E proposes to facilitate all players to participate in the market place. To achieve this, all users must be allowed to be significant grid users in the context of DSR.

Question:

2.2.1. What is your view on ENTSO-E's interpretation of the level of detail required in the NC DCC?

3 REQUIREMENTS OF NC DCC IN LIGHT OF FUTURE CHALLENGES

The NC DCC as prescribed by ACER's FWGL shall cover a set of requirements for each type of significant grid user, defining the connection point and including the requirements related to the relevant system parameters that contribute to secure system operation. The vast majority of these connection requirements, where specified, were in the past addressed to grid users in dispersed and separate documents such as grid codes, connection agreements or contracts which were given to grid users before connection.

The NC DCC to be proposed is expected to put existing requirements in a single document, delivering a transparent, non-discriminatory and simplified approach.

Some new requirements are also proposed taking into account the future challenges and opportunities based on the evolution of the system, including RES development and Smart Grid implementation. DSR is already becoming a reality and therefore some new technical requirements are also needed to facilitate the capabilities of DSR resources to support transmission system security and to give many more demand Users access to markets for Ancillary services acquired by TSOs.

Other non-TSO instigated uses of DSR will remain outside the scope of this NC DCC. This includes expected application of DSR for DSO network management and DSR to influence the general demand profile for energy suppliers.

The new requirements identified by ENTSO-E cover the following:

- Demand Side Response delivering Reserve Services
- Demand Side Response delivering System Frequency Control
- Reactive power exchange capabilities
- Voltage withstand capabilities
- Frequency withstand capabilities

These topics are discussed individually in the following chapters. For three topics a more detailed analysis of the different technical alternatives is given in the Appendices. Stakeholders are asked to give their opinion on the questions stated in the following chapters. Where specific (cost) data is required, stakeholders are kindly requested to include the basis for the data or use publicly available data.

In addition to the topics above ENTSO-E would also like to ask stakeholders for an assessment of the following questions:

Questions:

3.1. Can equitable treatment be assured if the NC DCC includes only high-level requirements, with national legislative required to set specific requirements in each country? If so, how could equality in burden sharing be achieved in synchronous areas and across Europe?

3.2. In your opinion, is there any other new topic that should be included in the NC DCC?

3.1 DEMAND SIDE RESPONSE DELIVERING RESERVE SERVICES

Overall the consequence of RES development is a massive increase in the demand for reserves caused by greater forecasting uncertainty. This is combined with a reduced availability at time of high RES production of today's provision of these same services by synchronous generators. The detailed explanation and preliminary analysis is given in Appendix 1.

Demand which is capable of being deferred for extended periods, preferably up to 4 hours, can in principle be considered for such a service. The TSOs will need to know what level of reserve is available at any time and will wish to have an adequate cover (security), but not excessive cover (economics). Demand suitable to deliver these services exists from industry, from business premises and at household level. The potential for all these may be explored to give the least societal cost. The household level has not been used for those services so far and ENTSO-E proposes to explore this in view of the increasing need for this kind of service.

In many countries industrial and business demand already provide reserve capacity as an ancillary service. These services are expected to continue, and to be developed being encouraged through the market to expand in volume to meet the increasing demand, possibly with further market encouragement to widen the geographical base for the products.

The aim of the NC DCC is to set technical requirements necessary to provide DSR services. The way these services will be used is not in the scope of this NC.

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Questions based on the different available options put forth in section 7.1.1 in Appendix 1:

3.1.1. What is your view of the analysis presented on the challenge ahead associated with reduced availability of reserve services from synchronous generators at time of high RES production?
3.1.2. Is there any class of users that should be excluded from providing these reserve services?
3.1.3. What would be the technical and economical limits to the development of DSR for industrial customers, commercial premises and Closed Distribution Network operators?
3.1.4. In Appendix 1, options for the provision of mitigating the shortfall of reserves are given, are there any comparable alternative options other than the ones provided in Appendix 1?
3.1.5. What would be the typical cost to equip one appliance (e.g. a washing machine or a heat pump controller) under each of the 3 alternatives?
3.1.6. What form and level of incentive do you believe is required to encourage consumers not to switch the reserve off under option 1 and 2?
3.1.7. Considering the cost and consequences of the alternatives, do you support use of DSR for this purpose?
3.1.8. Which of the 3 DSR alternatives (1, 2 or 3) would be your preferred option to achieve the greatest societal benefit and for what reason?
3.1.9. If the services proposed here are provided, what further uses of these technical capabilities (see Appendix 1) would be most beneficial and why?

3.2 DEMAND SIDE RESPONSE DELIVERING SYSTEM FREQUENCY CONTROL

Overall the consequence of RES development is

- less capability to deal in a traditional way by means of Low Frequency Demand Disconnection (LFDD) with extreme frequency excursions due to a combination of deeply embedded generation and demand on the same circuits;
- a large reduction in the availability of economic frequency response

Questions based on the different options outlined in Appendix 2:

Regarding the DSR application related to temperature controlled demand to deliver a smarter, robust and a more user friendly LFDD-capability to avoid frequency collapse and hence contain the impact of rare events with large system frequency excursions:

3.2.1. Do you agree with the conclusion to apply this service universally using European Standards proposed as a result of the initial CBA based on Irish data?
3.2.2. ENTSO-E believes this service can be introduced for new appliances (and temperature controllers) without any detectable difference to the primary purpose of the service of the appliance. Can you share any specific knowledge or experience and associated data you may have on this topic?

Regarding the use of the temperature controlled demand beyond LFDD-capability for frequency response, following assumptions are taken:

- Primary performance of the temperature controlled function is not effected (operating within the same temperature tolerances);
- Conditions of near total absence of synchronous generators during windy / sunny conditions;
- Moderate demand for synchronous areas with extreme real-time RES penetration (initially expected in Ireland and GB)

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Three DSR alternatives have been identified (with a fourth alternative being 'do nothing'):

- Alternative 1: Voluntary service capability – mandatory usage
- Alternative 2: Voluntary service capability – voluntary use
- Alternative 3: Capability as standard, with mandatory delivery

3.2.3. If this further DSR for temperature controlled demand is introduced should this be arranged by each nation rather than at European level and if so should there be a requirement for **harmonising** within a synchronous area in order to provide burden sharing?

3.2.4. Are the **types of demand** suggested in Appendix 2 the most appropriate to provide this service giving continuous response to system frequency deviation away from the target frequency (50.0Hz)?

3.2.5. Please provide comments on the **specific data** used in the initial CBA presented.

3.2.6. The initial CBA indicates that alternative 1 may be able to provide the required services quicker than alternatives 2 and 3 (due to higher uptake). Do you have any comments about this **conclusion** and the underpinning **assumptions**, including
   - 20% uptake for voluntary service capability;
   - Increased unit cost for lower volume and supplying more than one option;
   - The costs identified.

3.3 REACTIVE POWER EXCHANGE CAPABILITIES

ENTSO-E has considered the consequences of greater contribution from RES in context of system voltage and availability of reactive power capability. With the highest level of RES penetration many synchronous generators are displaced, as they are not in merit and hence disconnected, at the times of high RES production. This removes a key source of reactive power. In many countries during such conditions the generation is concentrated away from the system centres to coastal areas (e.g. large wind) and also embedded (e.g. solar PV and smaller wind).

Moreover, the development of underground cables on the distribution (and even transmission) grid and the development of embedded generation in Distribution Networks have an increasing impact on the reactive power flows at the interface between transmission and distribution.

The above leaves the transmission systems with less reactive resources to

- be able to compensate the reactive demand of the DSO networks;
- cope with its own transmission related reactive demand.

Consequently, ENTSO-E believes that the voltage stability of the system should be supported by the TSOs and all stakeholders. Some requirements exist already in some countries, for generators and/or for customers and distribution system operators, but they need to be improved and to be harmonized across Europe in order to cope with the new challenges.

Cost Benefit Analysis carried out have shown that from a socio economic view point the total cost to meet the DSO system need for reactive power is lower if the reactive compensation is undertaken lower down in the system (closer to the demand) than if undertaken at the TSO EHV level.

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Questions on general reactive capability based on the Appendix 3:

3.3.1. General questions

a. Do you agree that increasing displacement of synchronous generation is a significant new challenge?
b. Do you agree that a review of existing requirements is needed, to take into account the new challenges mentioned above in Section 1.2 and 1.3?
c. Do you agree with the conclusion from the initial CBAs (Ireland & GB) that the societal benefits are greater for reactive management to occur closer to the reactive demand? In either case please provide the rational with supporting evidence where available on the aspects of the conclusion of the CBA that you agree or do not agree with.

3.3.2. Question specifically relevant for DSO connections

a. Do you agree that the development of cables and embedded generation introduce further challenges regarding reactive power control, including risk of high voltage during minimum demand?
b. Is it reasonable to ask DSOs to avoid adding to the problem of high voltage on the transmission system during minimum demand by avoiding injecting reactive power at these times?

3.3.3. What is your view on the most appropriate way forward, including but not limited to the following options:

- Do nothing. Leave the TSO to sort out reactive balancing. The CBA of the transmission located reactive capability option in the CBA is relevant here.
- General limit on power factor at transmission to distribution interface, e.g. better than 0.90 or 0.95, with the value set in each country by each TSO subject to public consultation and NRA decision or an equivalent process as provided by the applicable legal framework, such as the definition of a limit in MVAr.
- As in the previous point except the power factor limit set on a local (or zone basis) by the TSO following CBA & consultation / NRA decision.
- Total separation between distribution and transmission reactive flows (i.e. 0 MVAr at the interface).
- The DSO at network exit points treated in the same way as generation is treated in network entry points with the DSO expected to regulate voltage continuously. Should this be limited to slow time scales of minutes (e.g. achieved by means including transformer tapping) or extended to fast acting reactive power support for disturbed conditions?
- Establishment of full reactive markets (e.g. in zones) encompassing DSO contributions as exist in some countries with respect to generation today?

3.4 VOLTAGE WITHSTAND CAPABILITIES

Voltage stability is a key issue for system performance and security. A change of voltage in a certain point in a network results in a change of the power flow in an interconnected system around this point. The voltage may change due to loss of generation, loss of load, loss of transmission lines, or normal variations of connected demand. Recent experience has shown that most of the large-scale disturbances in the electricity transmission system in the recent years were caused by voltage instability (low voltage), particularly in Continental Europe.

High voltage situations are now increasing due to the development of underground cables in the distribution and the transmission grid, and due to the lack of generation support in specific areas. In these cases, any additional losses of demand due to narrow voltage withstand capabilities makes the situation worse.

Generator units used to contribute most to voltage stability. ENTSO-E is of the view that all kinds of network users into the future need to contribute to support voltage stability, taking into account their technical capabilities and their connection voltage level.

Also Distribution Networks, both DSOs and Closed Distribution Networks, provide a pathway for embedded generation and DSR to contribute to voltage stability and are essential to ensure that their capabilities can be utilised.

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In future, the increased volatility resulting from the intermittency of RES, coupled with a less controllable, wider and more dispersed generation portfolio increases the needs for stability and certainty in response from other elements in the network. Failure to do so is likely to increase the risk of indiscriminate loss of demand for all users in of system events resulting in. From this point of view, withstand capabilities in case of high voltage situations would be particularly valuable support for all demand users.

However, the focus of this NC DCC relates to cross border issues and therefore the NC only looks to place requirements on transmission connected demand users whose contribution is deemed significant enough in this context.

In all situations ENTSO-E recognises the right of the demand user to alter their demand for their own reasons and seeks only to increase the stability of demand by avoiding equipment limitations at the connection point of the Demand Facility.

Several options are possible to deal with this issue in the NC DCC:

i. Do nothing. Demand Units/ Demand Facilities/ Distribution Networks are not expected to be equipped with a defined voltage with stand capability. They can disconnect their facility due to changes in voltage. National grid codes will deal with local needs if necessary.
ii. Demand Facilities or Closed Distribution Networks are not expected to be equipped with a defined voltage with stand capability, unless offering DSR services. Demand Facilities or Closed Distribution Networks offering DSR services shall not disconnect in case of voltage deviations within prescribed ranges.
iii. Include voltage withstand capabilities in the NC DCC for Demand Units connected directly to a transmission-connected Demand Facility or Distribution Network, in order to avoid their disconnection in case of voltage deviations. Requirements shall be defined for all or part of transmission connected demand users.
iv. Include voltage withstand capabilities only at the transmission connection point, in order to avoid the disconnection of the Demand Facility or the Distribution Network, due to limitation of equipment at the transmission the connection point, permitting internal equipment, sensitive to voltage deviations, to be disconnected. Requirements shall be defined for all or part of transmission connected demand users.

To evaluate the need to implement voltage withstand capabilities in NC DCC we would like to ask the following questions:

Questions:

3.4.1. Do you agree with the analysis concerning the need of voltage withstand capabilities?
3.4.2. What are the technical limitations to voltage withstand capabilities in your Demand Units in option iii?
3.4.3. What are the technical limitations to voltage withstand capabilities in your Demand Facility or Distribution Network in option iv?
3.4.4. What would be the costs induced by such requirements in option ii, iii and iv?
3.4.5. Which alternative would you prefer? In case of option ii, iii or iv, shall the requirements be defined for all Demand Units/ Demand Facilities/ Distribution Networks or with specific voltage connection levels only?

3.5 FREQUENCY WITHSTAND CAPABILITIES

The operating frequency of the system is around 50 Hz. If there is an imbalance between generation and demand the frequency deviates from this target value. In this case a (predictable) reaction of demand returns the system to its target value and stable operation is ensured. In the future the generation is predicted to be based on more volatile energy sources and if demand trips during a frequency deviation this will bring a further dynamic element to the frequency control challenge.

As a consequence ENTSO-E evaluates if requirements to withstand frequency deviations should be required.

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Distribution networks (both DSOs and CDNs) provide a pathway for embedded generation and DSR to contribute to frequency response. Frequency withstand capabilities within prescribed ranges are therefore essential.

Two options are possible to deal with this issue in the NC DCC:

i. Frequency withstand capabilities are mandatory for Distribution Networks and all Demand Facilities.
ii. Frequency withstand capabilities are mandatory for Distribution Networks and for the Demand Facilities or Closed Distribution Networks, which offer DSR services.

To evaluate the costs to require frequency withstand capabilities in NC DCC ENTSO-E would like to ask the following:

Questions:

3.5.1. Do you agree that certainty is required in the performance of elements in the electrical power system to ensure stable frequency operation and to minimise the cost of procuring frequency response?
3.5.2. Which option (i or ii) would you prefer and for which reason?
3.5.3. Please provide cost information to establish frequency withstand capability over the full range from 47.5 Hz to 51.5 Hz for Distribution Networks and Demand Facilities and explain which typical apparatus are needed.
3.5.4. Please provide cost information to establish frequency withstand capability over a limited range from 49 Hz to 51 Hz for Distribution Networks and Demand Facilities and explain which typical apparatus are needed.
3.5.5. Which frequency-sensitive installations do you have in your Distribution Networks or Demand Facility?
3.5.6. Please provide cost information to reinforce frequency-sensitive installations with frequency withstand capability over the full range from 47.5 Hz to 51.5 Hz.
3.5.7. Please provide cost information to reinforce frequency-sensitive installations with frequency withstand capability over a limited range from 49 Hz to 51 Hz.

4 NEXT STEPS

The energy system is changing rapidly, especially with the massive integration of RES. This requires a new framework to cope with the challenges ahead. All participants of the energy market are faced with significant changes and the implementation of new processes and technologies. In line with the principles laid out in ACER's Framework Guidelines on Electricity Grid Connections, the Network Code for Requirements for Demand Connection (NC DCC) will have to break new ground to help to accomplish this task on a European level. In comparison to other network codes and standards that are to a large extent based on existing rules and procedures, the NC DCC will contain significant new requirements.

As a consequence, ENTSO-E conducts this “Call for Stakeholder Input” to collect opinions on the main new topics proposed, seeking to identify the most economic and efficient solutions to take forward.

The consultation on the questions stated in this document will be open for four weeks. ENTSO-E will use the answers received as guidance to further develop the NC DCC.

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6 ABREVIATIONS AND DEFINITIONS

6.1 ABREVIATIONS

CBA	Cost Benefit Analysis
CDN	Closed Distribution Network
DSR	Demand Side Response
DSR-SFC	Demand Side Response – System Frequency Control
LFDD	Low Frequency Demand Disconnection
LVDD	Low Voltage Demand Disconnection
NC DCC	Network Code – Demand Connection Code
RES	Renewable Energy Sources

6.2 DEFINITIONS IN THE CONTEXT OF THIS DOCUMENT

Closed Distribution Network - A system (network) which distributes electricity within a geographically confined industrial, commercial or shared services site and does not (without prejudice to a small number of households located within the area served by the system and with employment or similar associations with the owner of the system) supply household customers. This network will either have its operations or the production process of the users of the system integrated for specific or technical reasons or distribute electricity primarily to the owner or operator of the network or their related undertakings

Demand Facility - is a facility which consumes electrical energy and is connected at one or more Connection Points to a power network. For the purpose of avoidance of doubt a Distribution Network and/or Auxiliary Supplies of a Power Generating Facilities are not a Demand Facility

Demand Unit - a Demand Unit is an indivisible set of installations which can be actively controlled by a Demand Facility Operator to moderate its electrical energy demand. A storage device (excluding hydro pump-storage) operating in electricity consumption mode is considered to be a Demand Unit. If there is more than one unit consuming power within a Demand Facility, that cannot be operated independently from each other or can reasonably be considered in a combined way, then each of the combinations of these units shall be considered as one Demand Unit.

Distribution Network - is an electrical Network for the distribution of electrical power from and to third party[s] connected to it, a transmission or another distribution network, including Closed Distribution Networks.

Distribution System Operator - a Regulated Distribution Network Operator (electricity) of Distribution Network assets.

Transmission System Operator - means a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the Transmission Network in a given area and, where applicable, its interconnections with other Networks, and for ensuring the long-term ability of the Network to meet reasonable demands for the transmission of electricity.

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7 (APPENDIX 1) „DEMAND SIDE RESPONSE FOR RESERVES"

7.1 THE INCREASING NEED FOR RESERVE SERVICES ASSOCIATED WITH HIGH RES

Reserve capability is required by TSOs to deal with uncertainty ahead of real-time. Traditionally the dominant uncertainty has been demand and unscheduled position for generation (e.g. following a generation loss or unable to start / follow its required output).

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. TSOs define reserve ancillary services in this context and in real-time operation instruct at the lowest cost (subject to security standards being maintained). Generation part loaded from an energy market position (e.g. hydro, gas or coal) tends to be more economical than generation that needs starting up to provide the reserve service.

This CBA appendix does not cover headroom required for provision of frequency response. This is dealt with in Appendix 2.

Introduction of high levels of RES, particularly wind, but also solar PV and in the future wave energy, does significantly change the volume of reserves required. This is linked to the uncertainty in forecasting, e.g. wind (high uncertainty 4 hours before real-time, modest uncertainty 1 hour before real-time). As installed RES capacity increases year on year, so does the average level of uncertainty from the forecasting error. Secondly, for a given installed RES capacity, the forecast RES production varies hour by hour. At times of high RES production the forecasting uncertainty may be several times higher than when the average RES production.

As an example in the GB synchronous area the forecasting uncertainty associated with wind is expected to increase by 5 times from 2010 to 2025. The wind production level giving the highest uncertainty (wind forecasting error) in 2025 is expected to be 12 GW compared to 3 GW for average wind production. These forecasting uncertainties relate to National Grid's central scenario called Gone Green which is designed to meet the environmental targets (RES & $C0_2$) at the lowest cost to the end consumer. In this central scenario in 2025 RES production on its own is expected to exceed the total demand. This is based on scaled up production (to reflect future planned wind installations) using recorded hourly historic wind speed and demand data, which is available for the last 10 years.

It should be noted that there is a major difference between real-time RES penetration and average penetration. In Denmark, the country in the EU with the highest penetration of wind, Western Denmark (Jylland, connected to Continental Europe) exceeded 100% of demand from wind alone a few years ago, while the average wind penetration over the year for Denmark was still only 20%. Denmark managed this through very high interconnectivity having connection capacity to Nordic countries and Germany, exceeding 80% of its maximum demand.

During windy & or sunny times with high RES production synchronous plant is no longer "in merit" and is replaced by non-synchronous RES generation (e.g. wind & solar PV). Displacement of synchronous generation removes the most economic service for providing reserves, namely partly loaded synchronous plants. There can be intermediate conditions of moderate RES when more rather than less part loaded synchronous generation is available.

Overall the consequence of the RES development is a massive increase in the demand for reserves caused by the greater forecasting uncertainty. This is combined with a reduced availability at time of high RES production as currently reserve is most efficiently provided by synchronous generators.

7.1.1 WHAT ARE THE OPTIONS?

1.1. Do nothing, just leave it to the existing market players.
1.2. Open up markets to share reserve services beyond the existing control areas.
1.3. Open up for reserve service provision even between synchronous areas.
1.4. Define DSR reserve services, 3 alternatives considered.

The main focus of this CBA appendix is the provision of reserve services by DSR as identified DCC in the Preliminary Scope[4] under the heading "Demand management capability, balancing capability and provision of ancillary services". In this Appendix three different alternatives of the DSR option (1.4) will be compared to the do nothing option (1.1).

The other two options (1.2. and 1.3) are relevant (e.g. they already currently contribute greatly to managing Denmark's high penetration of wind), but are not covered in this CBA analysis, as they are outside the scope. However, options in 1.2 and 1.3 are expected to be covered in other NCs covering ancillary services. HVDC with regard to option 1.3 is likely to be technically acceptable and is expected to be part of the NC for HVDC Connections.

7.1.1.1 **HOW COULD DSR PROVIDE SUCH SERVICES?**

Demand which is capable of being deferred for extended periods, preferably up to 4 hours, can in principle be considered for such a service. The TSOs will need to know what level of reserve is available at any time and will wish to have an adequate cover (security), but not excessive cover (economics). Demand suitable to deliver these services exists from industry, business premises and at the house hold level. The potential for all these may be explored to give the least societal cost.

In many countries industrial and business demand already provide reserve capacity as an ancillary service. 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.

As explained in section 1, some countries with rapidly expanding RES have a challenging combination of rapidly increasing need for reserves combined with times when these services are no longer available from the largest traditional provider group, synchronous generators.

The types of demand with such potential flexibility not yet 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 ok, if adequately rewarded. There are also likely to be times for everyone when such a service is not acceptable, even if a generous reward is available. Examples of the latter include drying of some clothes which are to be used immediately or charging an EV for immediate use, when it has just run out of charge.

Please note that the DSR needs of DSOs' network constraint management and energy suppliers management of time of energy consumption by DSR, to flatten the demand curve are out of the scope of the NC DCC.

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7.1.1.2 WHAT ALTERNATIVES EXIST FOR BRINGING FORWARD / ENCOURAGING ADDITIONAL DSR RESERVE SERVICES?

- Alternative 1: Define optional service capability, leave delivery to market
- Alternative 2: Define standard service capability, leave delivery to market
- Alternative 3: Define standard service capability, with mandatory delivery

7.1.2 BASIC PRINCIPLE AND CAPABILITY TO GAIN ACCESS TO THE ANCILLARY SERVICES MARKET FOR RESERVE.

This can be achieved if the NC DCC defines qualities the TSOs need from the end consumer to enable the consumer to offer a service of interest to the TSO via some form of aggregation. The qualities in end user equipment can be specified at the European level and implemented through European Standards.

To achieve a complete working system, additional facilities would be required. This includes a consumer information service via the SMART meter, progressing the chain (e.g. via information hub / supplier or aggregator) eventually arriving to the TSO for contracting in larger blocks and with greater certainty. The TSO can with these facilities conduct the planning for adequate security at the lowest cost.

This NC DCC does not cover ancillary services trading or communication systems, nor does it cover the facilities to establish the chain triggering the actual use of the service (e.g. when wind is lower than forecast) or indeed cancelling of the trigger. This NC DCC is only focusing on the end users equipment meeting minimum functional standards to allow the end user to join the market when the two way information and trigger capability has been put in place.

7.1.3 ALTERNATIVE 1 – OPTIONAL SERVICE CAPABILITY, MARKET BASED DELIVERY

In this option the consumer faces a choice when purchasing equipment to have the capability to deliver a service or choose not to have this capability. To encourage the end user to buy equipment with the triggered delay / end of delay capability, the TSO may have to subsidise this option (possibly via the manufacturers). A key question is which consumer reimbursement per equipment would be needed to get a reasonable uptake.

If the end consumer chooses this capability, the washing / drying / charging of the EV would still operate normally most of the time. However, when the end user's aggregator is contracted with the TSO, on occasion the service will be triggered and the delay would take place. Under this service, the consumer would have an opportunity to disable the service when starting each use (e.g. a washing load) to have certainty of operation when the service is urgent. To encourage the end user to normally leave the service available, the user would be credited in some form via their own SMART meter from the aggregator selling the service to the TSO (e.g. either for availability or the actual trigger of the service).

The means of aggregating and the process of instructing the demand are out of scope of this NC. The mechanism for engaging this service is expected to be via an ancillary service. Its design and its use may involve various aggregators to deliver the overall volume and quality (i.e. certainty and timeliness) sought by the TSO. This could be envisaged to encompass two way simple communications between the appliance and the end user's SMART meter and similarly two way onwards communication to the aggregator and further on to the TSO.

7.1.4 ALTERNATIVE 2 – CAPABILITY AS STANDARD, MARKET BASED DELIVERY.

Similar to Alternative 1, except that the European Standards would be mandatory (i.e. all equipment purchased would have the capability). The consumer freedom to enable / disable the service would remain. The aggregator and hence indirectly the TSO would still know the volume of reserve available.

7.1.5 ALTERNATIVE 3 – CAPABILITY AS STANDARD, WITH MANDATORY DELIVERY

Similar to Alternative 2, except the end user has no facility to opt out ahead of a use, e.g. for washing sycles or a car charge.

7.1.6 DISCUSSION OF ALTERNATIVES

7.1.6.1 CONSEQUENCES OF THE DO NOTHING APPROACH FOR GB

For 2020

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 £450M in 2020/21. Risks include both inadequate provision (security) and high cost (with large wastage of RES energy).

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. This topic is covered in the CBA in appendix 2. 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 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.

7.1.6.2 CONSEQUENCES OF ENCOURAGING TRADING OF RESERVES – INCLUDING ACROSS HVDC

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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.

7.1.6.3 THE NEED FOR THE DSR ALTERNATIVE

It is likely that the option of wider sharing of reserves (as described in sections 2 and 8.2) is going to be challenging from a network capacity point of view between or within synchronous areas, possibly requiring significant investments to overcome bottlenecks.

The do nothing option is unlikely to deliver the required volume or indeed avoid large scale wasting of RES through constraining off. In a single country the RES constraining costs could run into several €100Ms per year, indicatively identified in section 8.4.10 as more than €500M per year in GB alone by 2025.

7.1.6.4 COMPARISON OF DSR ALTERNATIVES 1, 2 AND 3.

Alternative 1 Optional service capability and market based delivery

The take up at time of appliance purchase may be low as most consumers may not be able to envisage at that time the link to later energy cost reductions (lower bills), from providing valuable flexibility.

Alternative 2 Capability as standard and market based delivery

If the capability to defer/advance the demand is introduced as a European Standard for “wet appliances” and EV charging, the cost per unit is going to be the lowest due to high volume and fewest product variants. Indicatively, the cost may be around €5 per unit, in the main to recover development cost. The initial information from relevant manufacturers suggests however that may be too high, even indicating that there may be no additional cost per unit.

If there is no consumer choice when appliances are purchased one challenge is overcome, namely the practical difficulty to get all components to be able to deliver a DSR market system in place at the same time. The absence of consumer confidence at time of purchase without the total DSR market system is therefore not an issue.

This option would give the freedom to the consumer to override the capability on occasions when providing the service would be inconvenient. Therefore this option should be relatively uncontroversial; especially to those who may see this facility as an imposition on their personal freedom.

Capability for utilising this DSR between synchronous areas will rely on HVDC links. As the reserve ancillary service 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 re-

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serve availability when needed with the wider sharing and also potential for transmission bottlenecks inside countries even if HVDC links have capacity.

Alternative 3 - Capability as standard and mandatory delivery

This alternative would generate for the greatest ancillary service volume, availability, predictability and certainty. However, the imposition on customer choice would be unacceptable for many or even most of the consumers.

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8 (APPENDIX 2) „DEMAND SIDE RESPONSE FROM TEMPERATURE CONTROLLED DEMAND"

Application of Demand Side Response

from temperature controlled demand used for

smarter LFDD and frequency response under extreme RES penetration

8.1 THE INCREASING NEED FOR FREQUENCY RESPONSE SERVICES ASSOCIATED WITH HIGH RES CONDITIONS

Frequency control is required by TSOs to deal with perturbations in demand as well as modest changes in generation in real-time. It is also required to deal with major system frequency events, the most significant of which is either a big infeed loss (large generator or system interconnector trip) or a system split into two or more islands.

Frequency control measures deal with demand and generation balance in seconds and minutes. Traditionally the main source of frequency control under normal system state conditions has been part loaded generators, primarily synchronous generators. The need in a given synchronous area has been defined by the largest loss which the system is designed to cope with. This varies from Ireland 500MW to GB 1800MW to Continental Europe 3000MW. Relative to the size of the system the largest loss is most challenging in the smallest system e.g. loss in excess of 10% of total generation in Ireland compared with the largest system Continental Europe where the largest loss about 1%. This CBA appendix does not cover the headroom required for reserve services associated with forecasting uncertainty. This is dealt with in appendix 1.

In the context of normal system frequency regulation, introduction of high levels of RES (i.e. wind and solar PV) does in itself change the largest loss and therefore the need for frequency response capability. If there is still one large infeed on the system (e.g. a large generator), this challenge remains unchanged. However, it does decrease significantly the volume of part loaded synchronous generation ready to economically deliver frequency response. Type faults of RES due to equipment or protection could act as the largest loss.

The larger installations of RES are capable of delivering frequency response. They are particularly well suited to deal with high frequency events, as they can easily and economically deliver this service. RES support for low frequency response is much more taxing, as this requires RES to run with headroom, which means continuously spilling RES energy with consequential cost (compensation for Feed In Tariff (FIT) or equivalent RES financial support system) as well as environmental lost opportunity (CO_2 free generation wasted).

In the context of severe frequency events, introduction of large scale RES (e.g. moving beyond 50% at times of high RES and modest demand) introduces two major new challenges.

The first of these is due to the extensive component of RES delivered via power electronic converters which severely reduces system inertia (ability to slow down frequency change). Therefore during a large infeed loss the urgency to re-establish the generation/ demand balance becomes much greater. There is therefore a new need for very fast frequency response capability or ideally synthetic inertia replicating the beneficial slow down effect from the large mass of the shafts of synchronous generators.

The second challenge arises from the need for a means to cope with extreme events via defence plan measures, most notably Low Frequency Demand Disconnection (LFDD). This is currently achieved in stages by tripping Distribution System circuits. In the past this has been effective as these circuits tended to be pure demand. With the introduction of large volumes of small generation connected deep into the distribution system, LFDD measures to save the system from total frequency collapse is becoming less effective. In some extreme circumstances tripping a distribution circuit may even make the generation / demand imbalance worse because at times it is a net exporter, e.g. on a sunny day in an area of high solar PV installations.

During windy and/or sunny times with high RES production synchronous plant is no longer “in merit” and is replaced by asynchronous RES generation (e.g. wind & solar PV). Displacement of synchronous generation then also removes the most economic frequency response service, namely part loaded synchronous plant. There can be intermediate conditions of moderate RES when more rather than less part loaded synchronous generation is available.

Overall the consequence of the RES development is:

1. a large reduction in the availability of economic frequency response
2. reduced system inertia and hence need for faster response
3. less capability of dealing in a traditional way with extreme events

8.2 WHAT ARE THE ALTERNATIVES FOR PROVIDING FREQUENCY RESPONSE WITHIN THE SCOPE OF NC DCC USING DEMAND SIDE RESPONSE (DSR)?

8.2.1.1 COULD DSR PROVIDE SUCH SERVICES?

Demand which can be varied proportional to the deviation of frequency from its target value could provide this kind of service. Temperature controlled demand which has a target temperature with a small difference between the temperature it turns on and the temperature it turns off, is ideally suited to deliver such a service without inconvenience to the end user. The temperature remains within the normal tolerance band, although the exact switching on and switching off times are varied. In relation to the Figure 1 (see Section 8.3) of this Appendix settings with no deadband are possible.

8.2.1.2 WHAT KIND OF DSR SERVICES COULD DOMESTIC APPLIANCES PROVIDE?

Two types of services could be provided by domestic appliances in the context of DSR:

- application in case of extreme frequency event, as a SMARTer LFDD service;
- possibly for normal frequency management, related to high penetration

These two types have been explored further in the paragraphs below.

8.3 SMARTER LFDD APPLICATION FOR EXTREME FREQUENCY EVENTS – IRELAND CASE STUDY

8.3.1 OBJECTIVE

This section examines the benefits and costs associated with introducing DSR SFC across the Irish synchronous system. Results from Ireland are explained in detail and are shown as a test case for this type of service.

8.3.2 COST BENEFIT ANALYSIS ASSUMPTIONS

In order to develop a CBA a number of assumptions is required. These are outline below.

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.

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 scale of temperature controlled devices in Ireland were calculated in Table 1.

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 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 during these frequency deviations.

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	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

Settings for DSR SFC

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.

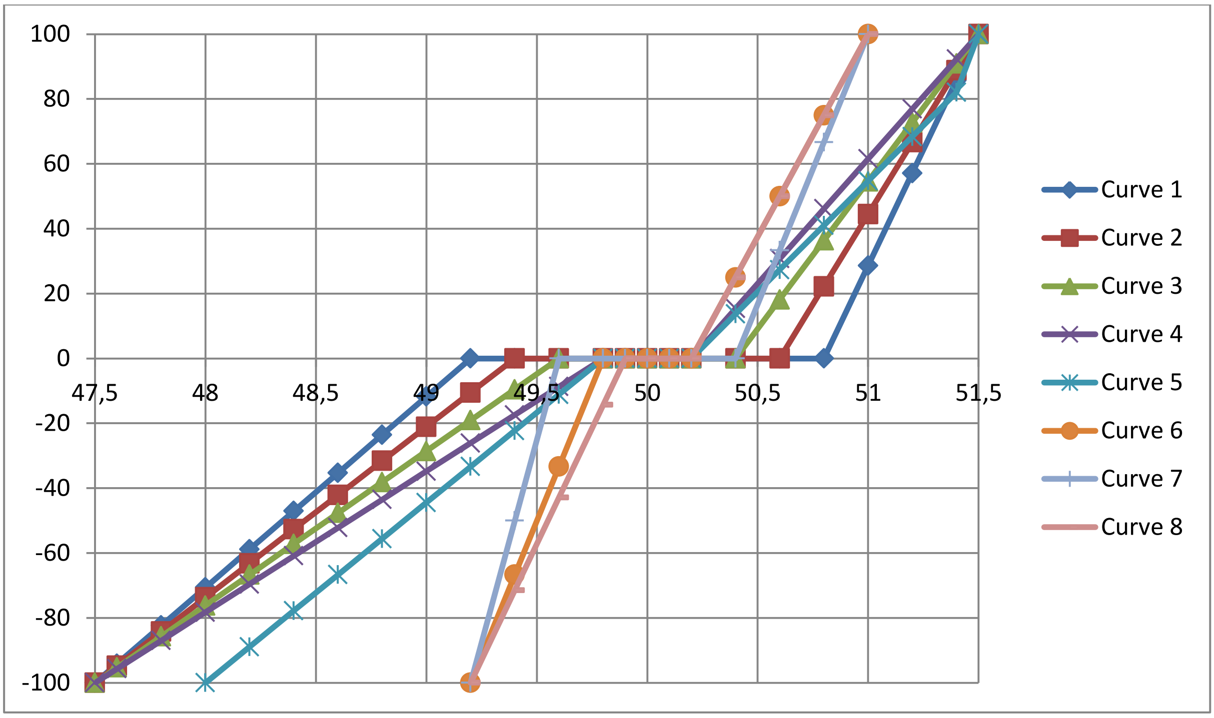

Figure 1 - Settings on DSR SFC temperature controlled devices

8.3.3 COST BENEFIT ANALYSIS COST SAVING CALCULATIONS

Three different cost benefit analysis calculations were performed to look at savings in energy costs, savings in capacity costs, Value of Lost Load (VOLL) for past large scale of demand losses or blackouts.

Savings in energy costs

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

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 on the system or increase its demand use.

The demand reduction can provide a net benefit in reducing the highest cost generation/other DSR. The benefit is based on the settings applied to the DSR SFC which dictate its use and the market price for generation/other DSR at the time that a frequency deviation occurs.

Therefore 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.

Given this net saving it is reasonable to consider whether DSR SFC could be sourced by market means, but as ultimately this service would be chargeable back to the same demand users at almost certainly a higher cost due to the administration of the billing and payment structure, it may not make practical sense.

The overhead of the payment structure would be variable given to the administration of assessing whom has changed their temperature controlled devices, when, their size, and life cycle. This would create a complex payment process. The most feasible system would be flat rate reduction or payment at source as part of the cost of purchase of the device.

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This saving would be directly chargeable back to the demand user with the additional cost of administration. 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 proportionately to the size of the demand user over the period of time it takes natural wastage to replace the existing temperature controlled devices.

Finally 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.

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	11 – 15 Interruptions
€6.97/MWh	16 – 20 Interruptions

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

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Current cost in €/MWh	Cost per annum[5] in 2020	Cost per annum[6] in 2030
8.2	€ 72,640,896.93	€ 93,403,919.03

Table 5 - Cost of equivalent DSR from STAR scheme

Rare historical 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.

Based on NRA reports [2], [3] the cost of this 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.

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.

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.

MWh Value of Lost Load[7]	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

[5]Based on 8760hrs on the total MW provided by DSR SFC as per Table 1.
[6]Based on 8760hrs on the total MW provided by DSR SFC as per Table 1.
[7] Taken from reference sources [2] and [3]

8.3.4 COST BENEFIT ANALYSIS CAPITAL COST OF DSR SFC

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 it is predicted 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), 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

8.3.5 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, not taking annuities into account.

MWh Value of Lost Load	MW available	Total benefit value of DSR[8]	€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

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

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Accounting for the increased uncertainty that arises from more intermittent energy it is envisaged that the challenges placed on TSOs will increase in the future. System operators working together will find continuing improvements which will deal with these changes. However, the future is unpredictable and based on past experience worldwide, future larger scale demand losses cannot be excluded. Therefore this CBA has been calculated both conservatively and 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 significant returns to the system user.

8.3.6 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.

8.4 NORMAL FREQUENCY MANAGEMENT RELATED TO EXTREME RES PENETRATION – GB CASE STUDY

The following case study shows the opportunities given by the use of temperature controlled devices in frequency management, not only in case of extreme frequency events but also in normal frequency management.

ENTSO-E would like to discuss this opportunity further.

8.4.1 WHAT ARE THE OPTIONS?

1. Do nothing and leave it to the existing market players.
2. Open up for frequency response provision sharing even between synchronous areas.
3. Define Demand Side Response frequency reserve services, 4 alternatives considered.

The main focus of this CBA appendix is the provision of reserve services by DSR as identified DCC in the Preliminary Scope[9] under the heading "Demand management capability, balancing capability and provision of ancillary services". In this Appendix four different alternatives of the DSR option (3) will be compared to the do nothing option (1).

The other option (2) is relevant, e.g. they already currently contribute greatly to managing Denmark's high penetration of wind, but are not covered in this CBA analysis, as they are outside the scope of the NC DCC. However, option 2 is expected to be covered in other NCs covering ancillary services. HVDC with regard to option 2 is likely to be technically acceptable and is expected to be part of the NC for HVDC Connections.

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[9] https://www.entsoe.eu/fileadmin/user_upload/_library/consultations/Network_Code_DCC/120222-Demand_Connection_Code_-_preliminary_scope.pdf

8.4.2 WHAT ARE THE ALTERNATIVES FOR PROVIDING RESERVES WITHIN THE SCOPE OF NC DCC USING DEMAND SIDE RESPONSE (DSR)?

8.4.2.1 HOW COULD DSR PROVIDE SUCH SERVICES?

Demand which is capable of being deferred for extended periods, preferably up to 4 hours, can in principle be considered for such a service. The TSOs will need to know what level of reserve is available at any time and will wish to have an adequate cover (security), but not excessive cover (economics). Demand suitable to deliver these services exists in industry, in business premises and at house hold level. The potential for all these may be explored to give the least societal cost.

In many countries industrial and business demand already provide reserve capacity as an ancillary service. These services are expected to continue, being encouraged through the market to expand in volume to meet the increasing demand, possibly with a further market encouragement of wider geographical base for the products.

As explained in section 1, some countries with rapidly expanding RES have a challenging combination of rapidly increasing need for reserves combined with times when these services are no longer available from the largest class of traditional provider, namely synchronous generators which are not available and maytake many hours to start (when cold).

The above situation combined with SMART meter technology opens up an opportunity for domestic access to this market. To make progress it is important initially to consider which types of demand may be capable of delivering a useful service and yet that will be acceptable to the consumer. This capability is closely linked to the ability to delay the demand at short notice for up to several hours

Experience exists already with such systems providing Ancillary services, although to date these are believed to be limited to the commercial sector.

8.4.2.2 **WHAT ALTERNATIVES EXIST FOR BRINGING FORWARD / ENCOURAGING ADDITIONAL DSR RESERVE SERVICES?**

- Alternative 1: Voluntary service capability – mandatory usage
- Alternative 2: Voluntary service capability – voluntary use
- Alternative 3: Capability as standard, with mandatory delivery
- Alternative 4: Do nothing

8.4.3 BASIC PRINCIPLE AND CAPABILITY TO GAIN ACCESS TO THE ANCILLARY SERVICES MARKET FOR FREQUENCY RESPONSE.

This can be achieved if the NC DCC defines which qualities the TSO need from the end consumer to enable the consumer to offer a frequency response service of interest to the TSO typically via some form of aggregation. The qualities in the end users' equipment can be specified at a European level, and implemented through European Standards.

8.4.4 ALTERNATIVE 1:VOLUNTARY SERVICE CAPABILITY– MANDATORY USAGE

In this option the consumer faces a choice when purchasing equipment to have the capability to deliver a service or choose not to have this capability. To encourage the end user to buy equipment with the frequency response capability, the TSO may have to subsidise this option (possibly via the manufacturers). A key question is how much per equipment would be needed to get a reasonable uptake. This analysis is based on £30 per appliance.

The service is defined through European Standards but the consumer has a choice to buy with our without the frequency response capability. Once the consumer has made a purchase and taken the subsidy there is no further freedom to enable / disable the service. The TSO would know the volume of frequency response available only from sales statistics. The uptake in this option is assumed to be 20%.

8.4.5 ALTERNATIVE 2: VOLUNTARY SERVICE CAPABILITY – VOLUNTARY USE

The service is defined through European Standards and the consumer has a choice to buy with our without the frequency response capability. In this option the consumer has the further freedom to enable / disable the service. For this option it is necessary to communicate via smart meter to the aggregator and hence indirectly the TSO to ensure that the volume of frequency response is known.

Additionally it is necessary to provide a further incentive to the consumer to leave the service in operation. This would also be managed through the smart meter. This is assumed to be £12 per year. However, because of the lower level of upfront commitment by the consumer, only £10 subsidy is offered at time of purchase. The uptake in this option is assumed to be 10%.

8.4.6 ALTERNATIVE 3: CAPABILITY AS STANDARD, WITH MANDATORY DELIVERY

A capability similar to Alternative 2 defined through European Standards. In this alternative there is no option the facility is standard. It is assumed that the cost would be £4 (€ 5). The uptake in this option is assumed to be 100% of the units bought.

8.4.7 ALTERNATIVE 4: DO NOTHING

The extreme case of RES (wind dominated) sometimes exceeding total demand is considered. Only a single cost is assumed, covering the cost of deloading wind. This is assumed at £100/MWh. It is assumed that the volume required is 2200MW to cover the 1800MW loss and that deloading is more effective (1.5 to 1) than for synchronous generation (2 to 1)[10]. For 10% of the year this would cost in the order of £290M, when ignoring costs for the rest of the 90% of the year when the wind is lower and also ignoring all other costs than the deloading of the RES. It is assumed that any nuclear generation running under these circumstances has been chosen to provide reserve to cover forecast uncertainty rather than provide frequency response.

8.4.8 PROPOSED PREFERRED DSR ALTERNATIVE

Alternative 1 is in the view of ENTSO-E the preferred alternative. It is considered to have significant societal benefits compared to do nothing. The volume of the service is unlikely to dominate this market, but could grow as the market grows.

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[10] National Grid's Frequency Response Technical Sub-Group Report version 1 November 15, 2011 Appendix B generation Scenarios, shows 2.2GW of primary response will be required in the 2020.

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8.4.9 GENERAL

Deferring or indeed advancing demand for substantial periods has the potential for various other TSO uses, including providing

- a smarter scheme than Low Frequency Demand Disconnection (LFDD) under extreme frequency imbalance;
- a smarter version of mitigation against rare voltage collapse (LVDD)
- local demand reduction to alleviate rare post fault transmission constraints into demand parts of the system;
- a smarter alternative to manually initiated demand reduction through voltage reduction in situations of inadequate generation capacity.

8.4.9.1 **LFDD**

Once the reserve demand capability has been established it can also be used as LFDD (extremely rare event, but high impact), contributing to overcome the new challenge from deeply embedded RES which may with existing arrangements result in tripping significant generation when using a conventional LFDD approach. This service should be added to all installations.

8.4.9.2 **LVDD**

Similarly the capability can also be used for another extremely rare event, but with high impact of sustained low transmission system voltage. This service should be applied where LVDD schemes are introduced.

8.4.9.3 TRANSMISSION SYSTEM POST FAULT CONSTRAINT RELIEF

It is possible to make better use of transmission capacity if means are in place to mitigate overloads when rare faults occur on the system, e.g. under N-1 security criteria a single fault affecting more than one circuit (e.g. a double circuit fault) may be alleviated in a generation export area by tripping appropriate generation should such a relatively rare fault occur. Therefore it is not necessary to restrict the pre fault loading of the export circuits as much with a capability similar to Alternative 1 defined through European Standards.

8.4.10 THE ANALYSIS

The analysis is detailed below.

The cost in £M / year per 100MW of frequency response for the 4 alternatives is calculated as:

- Alternative 1: 2.5
- Alternative 2: 22.5
- Alternative 3: 0.7
- Alternative 4: 13.2

Table A below illustrates calculating the cost for deloading wind at 10% of the time when wind exceeds demand in a year.

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	£/MWh	MW	10% in a Year (hrs)	Total £M
Cost to Deloading Wind (most expensive 10%, ignoring rest)	100	3300	876	**289**
	120	3300	876	347
	150	3300	876	434
	200	3300	876	578
Holding Cost on Wind for Response	**£/MW/h**	**MW**	**10% in a Year (hrs)**	**Total £M**
	0	3300	876	0
	5	3300	876	15
	10	3300	876	29
	15	3300	876	43
	20	3300	876	58
	25	3300	876	72
	30	3300	876	87
Taking minimum cost for deloading and ignoring holding cost for response , which is £290M + £0M				**£290M**

Table A: National Grid's Frequency Response Technical Sub-Group Report version 1 November 15, 2011 Appendix B generation Scenarios, shows 2.2GW of primary response will be required in the 2020, and the GB Grid Code recommends a factor of 2, but a factor 1.5 was used (2.2GW *1.5) which yields 3.3GW deloading head room.

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Temperature Control Potential for DSR	Total MW Potential for DSR	Total Net MW with load factor	Total Install/Replacement in MW per year
Domestic Fridge/Freezer	2000	400	40
Commercial Air Conditioning	2800	840	84
Domestic Heat Pumps	1400	700	70
Industrial Fridge/Freezer	2600	260	26
	8800	**2200**	**220**

Table B: Showing potential temperature controlled devices able to deliver DSR within 10 seconds. Note it is assumed that a 3.5kW heat pump is installed in 10% of off gas grid dwellings in 2020 which gives 1400MW capacity of domestic heat pumps. This equates to 400,000 dwellings (4M off gas grid UK homes). It should be noted that more heat pumps will be installed as the years progress, for example in 2030.

The potential Demand Side Response is governed by the duty cycle/load factor and the volume of new installed capacity each year, which is estimated as:

- 20% Domestic refrigeration yields 40MW / year
- 30% Commercial air conditioning yields 84MW / year
- 50% Heat Pumps yields 70MW / year
- 10% Industrial refrigeration yields 26MW / year

Alternatives		Year 0						Year 1						Year 5					
		Domestic F/F	Commercial Air Con	Domestic H/P	Industrial F/F	Generator	Total MW	Domestic F/F	Commercial Air Con	Domestic H/P	Industrial F/F	Generator	Total MW	Domestic F/F	Commercial Air Con	Domestic H/P	Industrial F/F	Generator	Total MW
1	**Voluntary / Mandatory 20% take-up**	0	0	0	0	2200	**2200**	8	16.8	14	5.2	2156	**2200**	40	84	70	26	1980	**2200**
2	**Voluntary / Voluntary 10% take-up**	0	0	0	0	2200	**2200**	4	8.4	7	2.6	2178	**2200**	20	42	35	13	2090	**2200**
3	**Mandatory + Mandatory**	0	0	0	0	2200	**2200**	40	84	70	26	1980	**2200**	200	420	350	130	1100	**2200**
4	**Do nothing constraint wind (nuclear for reserve)**	0	0	0	0	2200	**2200**	0	0	0	0	2200	**2200**	0	0	0	0	2200	**2200**

Table C: Showing the MW required to deliver DSR for each year.

Alternatives		C	R	Domestic F/F			Commercial Air Con			Domestic Heat Pumps			Industrial F/F		
		£/unit		Total Capital cost £M	Annualised Revenue	Annualised Cost @ DCF 0%	Total Capital cost £/M	Annualised Revenue	Annualised Cost @ DCF 0%	Total Capital cost £/M	Annualised Revenue	Annualised Cost @ DCF 0%	Total Capital cost £/M	Annualised Revenue	Annualised Cost @ DCF 0%
1	**Voluntary / Mandatory 20% take-up**	30	0	30	0	**3**	36	0	**3.6**	24	0	**2.4**	18	0	**1.8**
2	**Voluntary / Voluntary 10% take-up**	10	12	25	30	**32.5**	6	7.2	**7.8**	4	4.8	**5.2**	3	3.6	**3.9**
3	**Mandatory + Mandatory**	4	0	100	0	**10**	24	0	**2.4**	16	0	**1.6**	12	0	**1.2**
4	**Do nothing constraint wind (nuclear for reserve)**	0	0	0	290	**290**	0	290	**290**	0	290	**290**	0	290	**290**

Table D: illustrating the total capital cost to the manufacturer over ten years for the control temperature devices which depends on the alternative selected and annualised cost in millions for each category of temperature control device per year. Please note the £/unit is assumed for alternatives 2, 3 & 4, with reference to the explanation of the alternatives stated above.

Alternatives		Dom F/F		Com Air Con		Dom H/P		Indus F/F		Total	Total	Summary
		MW	Cost £M	MW	Cost £M	MW	Cost £M	MW	Cost £M	**MW**	**Cost £M**	**£M/100MW**
1	**Voluntary / Mandatory 20% take-up**	80	**3**	168	**3.6**	140	**2.4**	52	**1.8**	**440**	**10.8**	**2.5**
2	**Voluntary / Voluntary 10% take-up**	40	**32.5**	84	**7.8**	70	**5.2**	26	**3.9**	**220**	**49.4**	**22.5**
3	**Mandatory + Mandatory**	400	**10**	840	**2.4**	700	**1.6**	260	**1.2**	**2200**	**15.2**	**0.7**
4	**Do nothing constraint wind (nuclear for reserve)**	0	**0**	0	**0**	0	**0**	0	**0**	**2200**	**290**	**13.2**

Table E: The cost in £M / year per 100MW of frequency response for the 4 alternatives is calculated. Also illustrating, at the end of a ten year period (replacement/installed) the accumulated MW available and cost will defer for each alternative, each compared with the holding cost for wind for 10% of that year when wind exceeds demand.

9 (APPENDIX 3) „ EXPLANATION AND ANALYSIS ON DSO REACTIVE CAPABILITY”

ENTSO-E has analyzed the consequences of greater contribution from RES in context of system voltage and availability of reactive power capability. With the highest level of RES penetration many (and in some systems most / all) synchronous generators are displaced (not in merit and hence disconnected) at the times of high RES production (e.g. windy/sunny). This removes a key source of reactive power. In many countries during such conditions the generation (mainly from RES) is concentrated and geographically located away (e.g. wind in coastal or mountainous locations) from the system load centres and/or also embedded (e.g. solar PV and smaller wind).

Moreover, the development of underground cables on the distribution grid and even the transmission grid and the development of embedded generation in the Distribution Networks (including Closed Distribution Networks) have an increasing impact on the reactive power flows at the Transmission to Distribution network interface.

As a consequence this leaves the transmission systems with less reactive resources to:

- be able to compensate the reactive demand of the DSO networks;
- cope with its own transmission related reactive demand.

Consequently, ENTSO-E believes that the voltage stability of the system should be supported by the TSOs and all stakeholders. Some requirements exist already in some countries, for generators and/or for customers and distribution system operators, but they need to be improved and to be harmonized across Europe in order to cope with the new challenges.

Cost Benefit Analysis carried out have shown that from a socio economic view point the total cost to meet the DSO system need for reactive power is lower if the reactive compensation is undertaken lower down in the system (closer to the demand) than if undertaken at the TSO EHV level.

9.1 COST BENEFIT ANALYSIS ASSUMPTIONS

In order to develop a CBA a number of assumptions are required. These are outline below.

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 Irish Standard Transmission Charges & Timelines [1] available figures from the NRA, the Commission for Energy Regulation, the cost of a 220kV, 110kV, or 38kV switchgear and associated equipment to connect reactive support to the network is charged at:

Circuit breaker and associated equipment cost in €,000	Voltage
1050	220kV
730	110kV
54	38kV

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
Capacitor	15	€304,800
Capacitor	30	€364,800
Capacitor	45	€584,800
Capacitor	60	€662,800
Reactor	100	€399,000
Reactor	33	€131,667

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:

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Item	MVAr	220kV Cost	110kV Cost	38kV Cost
Capacitor	15	€1,355,800	€1,034,800	€358,800
Capacitor	30	€1,414,800	€1,094,800	€418,800
Capacitor	45	€1,634,800	€1,314,800	€638,800
Capacitor	60	€1,712,800	€1,392,800	€716,800
Reactor	100	€1,449,000	€1,129,000	€453,000
Reactor	33	€1,181,670	€861,670	€185,670

Table 3. Total equivalent cost for reactive compensation devices

Given the initial capital cost comparison of a 220, 110, and 38kV 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 Europe and impact on reactive power needs

A number of test cases were analyzed across Europe 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.

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. 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 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.

9.2 IRELAND CBA ON LV REACTIVE COMPENSATION

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 Binbane 110/38kV station at 38KV
2. 500MW @0.85PF demand connection at Flagford 220/110kV station at 110KV
3. 50MW @0.85PF demand connection at Finglas 110/38kV station at 38KV
4. 100MW @0.85PF demand connection at Ryebrook 110/38kV station at 38KV

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 complaint 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 in Binbane 110kV station		
Scheme	Assumption	Total cost in k Euros
110kV connected	Assume 30 + 22 MVAr capacitor blocks	2136
110kV centralised connected	Does not work	-
38kV connected	Assume 30 + 17 MVAr capacitor blocks	719
Test Case 2 – 500MW in Flagford 220kV station		
Scheme	Assumption	Total cost in kEuros
220kV Connected	Assume 6 * 60 + 20 MVAr capacitor blocks	9340
110kV Connected	Assume 6 * 60 + 20 MVAr capacitor blocks	9340
Test Case 3 – 50MW in Finglas 220/110kV station		
Scheme	Assumption	Total cost in kEuros
110kV Connected	Assume 33 MVAr reactor block	862
38kV Connected	Assume 35 MVAr reactor block	150

Test Case 4 – 100MW in Ryebrook 110kV station		
110kV Connected	Assume 30 MVAr capacitor block	1095
110kV Centralised at Finglas	Assume 30 MVAr capacitor block	1095
38kV Connected	Assume 30 MVAr capacitor block	419

Table 4. Results of test cases in Ireland

References

[1] CER 09077 Standard Transmission Charges & Timelines decision paper, May 2009

9.3 GB CBA ON LV REACTIVE COMPENSATION

Methodology and assumptions

For GB three 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, 500MW at 0.85PF, >500MW@0.85PF), and examine the needs for additional reactive power from either generation or reactive support.

The study considered two options, both from a Transmission point of view contribute similarly to the reactive balance and hence steady state voltage regulation:

1. Reactive support provided by the user at their connection point of 132kV.
2. Reactive support provided by the TSO at 275kV – optimum location determined by TSO performing study

The reactive compensation requirements have been determined against the standards specified within chapter 6 (Voltage Limits in Planning and Operating the Onshore Transmission System-table 6.1) of the NETS SQSS.

Results

Three demand sites were considered.

- Barking 132kV in London
- Bishops Wood 132kV in the Midlands
- Norton 132kV.

The reactive block requirements at the different voltage levels and for different demand injections are shown in table 1 below:

Substation	Up to 500MW@0.85		>500MW@0.85	
	HVreactive requirements(MVAr)	LV reactive requirements (MVAr)	HV reactive requirements (MVAr)	LV reactive requirements (MVAr)
Barking 132kV	None	None	2x150@275kV	3x60@132kV
Bishops Wood 132KV	None	None	2x150@275kV	2x60@132kV
Norton 132kV	None	None	1x150@275kV	1x60@132kV

TABLE 1

Simplified cost benefit analysis

Table 2 summarises the cost assumptions of the standard blocks of reactive compensation. It should be noted that only the cost of a standard AIS bay and standard MSC (no reactor requirement was found in the study).

Type	Reactive compensation block (MVAr)	Voltage level (kV)	Approximate Total scheme cost (£/m)
MSCs	45 #	132	1.4
	150	275	2.9

TABLE 2

The total cost of reactive compensation on the transmission network compared to that on the Distribution Network is shown in table 3 below.

Voltage level	Reactive requirement	Total Cost (£/m)
LV	8x45MVAr #	11.2
HV	5x150MVAr	14.5
Difference		3.3

TABLE 3

360 MVAr has been costed based on available information on 45MVAr units (8 rather than 6 @ 60MVAr.

Minimum demand

Currently there is no restriction on DNOs on the MVArs transferred to the transmission system. For cases of low demand this has contributed to creating overvoltage problems on the transmission network to the extent that transmission cables may need to be switched out and hence lowering security of supply (as has been the case during the summer of 2011).

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9.4 Conclusion Cost Benefit Analysis of Reactive Power requirements

Reactive power is most cost effectively provided beyond the transmission connection point of demand users.

Therefore the reactive power requirements should restrict the steady-state range of reactive power that may be imported and exported to a minimum, recognising that the ranges should permit the use of the capabilities of embedded generation and DSR.

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