# Report on the identified barriers and the proposed regulatory solutions for the three task-forces

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| Authors: | Camila Fernandes (Comillas- IIT)<br>Pablo Frías (Comillas- IIT)<br>Morten Stryg (DONG Energy)<br>Jan Hansen (DONG Energy) |
| WP Leader | Javier García González (Comillas- IIT) |

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## ACRONYMS

**ACE**: Area Control Error

**ACER**: Agency for the Cooperation of Energy Regulators

**BRP**: Balance Responsible Party

**CACM**: Capacity Allocation and Congestion Management

**CWE**: Central-Western Europe

**D**: day of operation

**D-1**: day before the day of operation

**DLR**: Dynamic Line Rating

**DSO**: Distribution System Operator

**ENTSO-E**: European Network of Transmission System Operators for Electricity

**EWEA**: European Wind Energy Association

**FACTS**: Flexible Alternating Current Transmission Systems

**FG**: Framework Guidelines

**H-1**: hour before the hour of operation

**HVDC**: High-Voltage Direct Current

**IT**: Information Technology

**NC**: Network Code

**NRA**: National Regulatory Authority

**NSCOGI**: North Seas Countries' Offshore Grid Initiative

**NTC**: Net Transfer Capacity

**PFC**: Power Flow Controller

**PMU**: Phasor Measurement Unit

**PST**: Phase Shifting Transformers

**RTTR**: Real-Time Thermal Rating

**SCADA**: Supervisory Control and Data Acquisition

**TF**: Task-Force

**TSO**: Transmission System Operator

**UCTE**: Union for the Coordination of the Transmission of Electricity

**VPP**: Virtual Power Plant

**VSC**: Voltage Source Converter

**WAMS**: Wide-Area Monitoring System

**WP**: Work-Package

## Executive summary

Despite the benefits of the innovative system management approaches and the novel technologies demonstrated in the TWENTIES, some regulatory barriers still prevent benefiting from the capabilities tested within the project. One important barrier preventing from benefiting from the capabilities proved in TF 1 and TF 2 concerns the current design of day-ahead, intraday and balancing services market designs, which rules were not defined to integrate high shares of intermittent renewable generation. In general, three market aspects should be improved in order to favor a higher penetration of renewable generation: liquidity, flexibility and integration with other power systems' markets. Apart from that, a major barrier to the development of offshore grids is related to the high investment need and cost allocation. To overcome this barrier the development of new tools, similar to the existing Inter-TSO compensation mechanisms will be required along with the development of joint support instruments and targeted EU funding. The adoption of grid technologies such as the ones tested in TF 3 include the establishment of economic (as well as environmental) criteria for assessing alternative solutions and the definition of standards for the use and control of these technologies. This latter is especially relevant when different TSO jurisdictions are affected, which will require the agreement among the involved TSOs. The main general regulatory recommendations for each task-force of the Twenties project are listed below.

1) Regulatory recommendations for TF 1

- Establishing market mechanisms for the procurement of system services and remuneration schemes based on cost-reflective prices;
- Defining markets for the procurement of balancing reserve capacity (where participants take the commitment of reserving capacity) and balancing energy (whereby the TSO balances the system based on the energy offers from reserve capacity providers and from other participants);
- Defining products that recognize the intrinsic characteristics of potential market participants such as renewable generators, load and storage units (shorter product lengths, gate-closure times closer to real-time, etc.);
- Imposing balancing responsibility on all market participants so that they are incentivized to adjust their schedules instead of increasing the demand for balancing services, which in turn increases system costs;
- Defining imbalance prices that reflect the costs imposed to the system by imbalanced market parties so that they receive the proper incentives to be balanced.

2) Regulatory recommendations for TF 2

- Definition of clear targets for offshore generation beyond 2020 (2030-2050) agreed between the EU and its member countries as the main driver for offshore infrastructure development;
- Incentivizing TSOs to invest in R&D and in new technologies. NRAs should grant appropriate incentives for investments in R&D and in new and untested technologies and recognize efficient costs of cross-border infrastructure and new transmission technologies investments as part of the TSOs Regulated Asset Base.

- Establishing a clear regulatory framework for offshore generation, including the harmonization of support schemes or the introduction of flexible mechanisms such as joint schemes to reduce the distortions coming from the national schemes;
- Creating mechanisms for the coordination of planning, development and operation of common offshore grid infrastructure, such as the creation regional initiatives or organizations (e.g. NCOGI[1] and Coreso[2]), the development of methodologies for coordinated transmission planning, ex-ante allocation of costs among infrastructure users;
- Developing a framework for grid infrastructure financing that acknowledges the particular financial needs of TSOs. In order to incentivize investors to finance complex projects, not only investment risks should be reduced but also attractive remuneration must be established;
- Harmonizing market designs and defining specific arrangements for offshore generation such as transmission capacity rights allocation, definition of bid areas and priority access in case of cross-border offshore assets, etc.;

3) Regulatory recommendations for TF 3:

- Incentivizing TSOs to invest in new and flexible grid technologies. National regulatory authorities (NRAs) should incentivize TSOs to invest in R&D by defining cost-reflective network tariffs. Also, efficient costs of new technologies must be acknowledged by NRAs in order to reduce TSOs investment-related risks;
- Developing methodologies for coordinated transmission planning and creation of regional organizations such as Coreso;
- Harmonizing grid codes (e.g. congestion management, priority access and renewable energy curtailment) for the operation of common infrastructure.

[1] North Seas Countries' Offshore Grid Initiative. See: https://www.entsoe.eu/about-entso-e/working-committees/system-development/the-north-seas-countries-offshore-grid-initiative-nscogi/

[2] Regional centre providing services of coordination of power flows' forecasting and operation in several countries in Western Europe. See: www.coreso.eu

## Introduction

The main objective of the TWENTIES EU Project is to remove barriers preventing a higher integration of onshore and offshore wind generation into the European power system by 2020. To achieve this objective, six large-scale demonstrations were developed by transmission system operators (TSOs) and generation companies, together with manufacturers and research centres, aiming at proving the benefits of several technologies and innovative system management approaches. These six demonstration projects were grouped into three task-forces, which addressed the following issues:

- Task-Force 1 (TF 1): what are the valuable contributions that intermittent generation and flexible load can bring to system services?
- Task-Force 2 (TF 2): what should the network operators implement to allow for off-shore wind development?
- Task-Force (TF 3): how to give more flexibility to the transmission grid?

Within the TWENTIES project, Work-Package 15 (WP15) goals are (i) to assess the local technical and/or economic impact of each demonstration project; (ii) to perform an analysis of the joint impact of all the demonstrations within each task-force; (iii) to identify the regulatory barriers preventing TWENTIES solutions' scaling-up, and to propose solutions to overcome those barriers. The impact assessment performed for the demos tested within TF 1 and TF 3 is described in detail in [1], while the impact assessment performed for the demos tested within TF 2 is presented in [2].

The objective of this report is to describe the main regulatory barriers preventing the adoption of each one of the TWENTIES solutions and to propose recommendations to overcome those barriers. For the purpose of this study, the different partners involved in the development and in the impact assessment of each TWENTIES demonstration project were consulted. Main barriers preventing the scaling-up of TWENTIES demonstrations were identified by: Demo 1: Iberdrola and Comillas-IIT; Demo 2: DONG Energy and Fraunhofer IWES; Demo 3: RTE and University of Strathclyde; Demo 4: Energinet.dk and DTU-Risø; Demo 5: ELIA and EDF; and DEMO 6: REE and Comillas-IIT. Based on the barriers identified by the different partners, regulatory recommendations are proposed for each demo. General recommendations at the task-force level are also proposed.

Apart from this introduction, this document is divided in four main chapters. The first three chapters perform an integrated analysis for each task-force comprising the main findings of each demonstration, the identified regulatory barriers and the proposed solutions, and a transversal analysis of the task-force for TF 1, TF 2 and TF 3, respectively. Finally, the main conclusions of this study are presented in Chapter 4.

# 1. TASK-FORCE 1

Task-force 1 includes Demo 1, led by Iberdrola (Spanish generation company), and Demo 2, led by DONG Energy (Danish generation company) and focuses on the participation of intermittent generation, such as wind power, flexible loads and distributed generation in system services' provision, in particular frequency and voltage control. The objectives of this chapter are to summarize the main conclusions of the impact assessment performed for each demo developed within TF 1 [1], to identify the main regulatory barriers preventing capturing the benefits provided by the demos and to propose recommendations to overcome the identified barriers.

## 1.1. Demo 1

The first demonstration project in Twenties (SYSERWIND) aimed at showing that wind power facilities in operation today can be upgraded to provide services like wide-area voltage control and secondary frequency regulation with limited changes in IT systems at the wind turbine and wind farm levels. The demonstration was carried out in 15 of Iberdrola's wind farms in the South of Spain arranged in three clusters with a total capacity of 481 MW: Arcos de la Frontera (111 MW), Tajo de la Encantada (122 MW) and Huéneja (248 MW). In order to meet the objective, new control regulators were developed and installed in the control centres and in the wind farms, making 240 wind turbines work in a coordinated way in order to control the voltage in a 350km 400 kV AC corridor. It was also necessary to develop a very short-term wind forecast algorithm due to the challenging requirements of providing secondary frequency regulation band with the necessary accuracy. Most importantly, these tools were fully integrated into the system operation and the transmission system operator's (TSO) tools.

### 1.1.1. Main findings

Despite the challenges faced in both parts of the demonstration, the project showed that voltage and frequency control can be successfully carried out by wind farms [3]. The hardware and software changes in the wind farms and control centres were kept to a minimum: the CAPEX for delivering these ancillary services is relatively low (around 100 - 150 k€ per 50 - 100 MW wind farm) and there is not a clear impact on the OPEX. The most significant cost for the implementation of active and reactive power control by wind farms is related with the installation of control centres for renewable generation, which allow the TSO to monitor and control those generators. In Spain, these control centres already exist and all renewable facilities larger than 10 MW must be connected to a control centre which in turn is connected to the TSO's control centre of renewable energies (Cecre). Furthermore, all renewable generators higher than 1 MW must send real-time information regarding their production to the Cecre. In this respect, it is worth mentioning that in power systems with significant shares of intermittent generation, control centres are essential to coordinate and guarantee the secure operation of the system, regardless if renewable generators participate in ancillary services provision.

According to the analysis performed in WP15 to assess the impact of voltage provision by wind farms in Spain wind penetration in that country is currently not limited due to voltage reasons in most cases. On the other hand, it was concluded that the importance of voltage control by wind farms is highly dependent on the network configuration. For instance, in less meshed grids wind penetration may be limited due to voltage reasons. In any case, as wind penetration grows voltage control by wind farms will become increasingly important. It is worth mentioning that voltage control by wind farms originates a slightly increment of active power losses in the wind farm grid, which can be reduced in case of developing an optimal voltage control strategy. The cost incurred by wind farms due to this slight increment of losses depends on the value of the regulated remuneration (i.e. support scheme), on the topology of the network and on the allocation of wind farms' losses.

In order to assess the economic impact of the provision of secondary reserve by wind generators in the Spanish power system, it was assumed that wind generators can participate in the Spanish secondary reserve market. The results of this analysis demonstrated that the provision of active power control by wind generators help to reduce the need for committing "extra" conventional generation in order to comply with reserve requirements. This avoids wind curtailment that would be required in case of scheduling extra conventional units for reserve requirements compliance, consequently reducing slightly system operation costs. In the Spanish case, it was observed that if pumped-storage hydro units are also allowed to provide active power control when consuming, the impact of the participation of wind generation on secondary frequency control is significantly reduced. Nevertheless, sensitivity analyses demonstrated that cost reductions are higher in systems with larger shares of wind power and/or lower flexible storage capacity, such as pumped-storage hydro units, where reserves constraints highly influence the resulting generation schedule.

Regarding these results, it is important to emphasize that the economic impact assessment focused on the participation of wind generators in the Spanish day-ahead secondary reserve market. The flexibility of intermittent generators one day in advance is highly limited due to production forecast errors. Nevertheless, as market gate-closures approaches real-time operation, the capability of wind generators to provide reserves can increase significantly, especially for the provision of downward regulation. In this sense, the study pointed out the need for market rules that favor this participation, such market gate-closure times closer from real-time operation in order to account for production forecast errors. Under the current market rules, it would not be economical for wind generators to provide secondary reserve in Spain. Under the Spanish market design, the provision of upward regulation by wind generators would only take place in situations of high wind production, when the TSO has to curtail renewable production in order to guarantee the generation-demand balance or enough online reserves. The provision of downward reserves would also be limited to those hours inasmuch as, according to the current market design, generators must provide both upward and downward reserve within the same hour, as it will be further explained in the following section.

### 1.1.2. Identified regulatory barriers and proposed recommendations

System services such as voltage and frequency control have always been part of the electricity sector, although their economic implications have become more tangible due to the unbundling and the liberalization of the energy sector. Nowadays, the significant penetration of intermittent generation is drawing increasing attention to the importance of these services, especially to the fact that European markets for ancillary services remain underdeveloped. For some services, compulsory provision without any remuneration remains the most common approach [4].

Due to this high penetration of intermittent generation and the increasing displacement of conventional units, several studies have emphasized the growing need for renewable generators to participate in system services provision, such as the ones presented in [5]-[7]. However, current market designs are generally not well-suited to the participation of renewable generation in ancillary services provision. Consequently, arrangements for the procurement of system services are the main barrier for the participation of wind generation in frequency and voltage control.

## Voltage control provision by wind farms

1) Current situation

The most common approach for the procurement of the voltage/reactive power control service is mandatory provision without any associated remuneration [8]. Nevertheless, generation technologies differ in their cost-effectiveness when delivering not only electricity but also ancillary services due to their different capabilities. If generators are not directly paid for voltage control services, they will include the costs they incur in the energy price, which is paid indirectly by end consumers. If all generation facilities incurred in the same costs to provide this type of services there would be no impact on the final customer. However, the costs incurred by the different service providers (mainly generators, and other reactive power compensating sources such as capacitor banks, shunt reactors, SVCs and STATCOM devices) are not the same. Hence, competitive mechanisms are needed in order to send efficient signals to service providers in order to guarantee system security while minimizing system operation costs [9].

In the case of wind generators, the enhanced features that they require in order to comply with voltage control service may involve higher investment costs when compared to conventional generators. Consequently, compulsory requirements for voltage control provision affect wind generators in particular. Mandatory procurement of voltage control service fails to acknowledge that wind generators can provide this service but in a different way than conventional power plants.

According to the current Spanish regulation for voltage control services, there is a minimum requirement for voltage control which is a mandatory and non-remunerated service. Apart from that, generators may offer an additional voltage control service, which would be remunerated by a regulated price established by the Spanish government. Although this regulation was established in 2001 (Operating Procedure P.O. 7.4), it is still not in force. Recently, a new operation procedure has been proposed by the Spanish TSO for the participation of renewable generators in voltage control provision. The proposed procedure defines the requirements that wind generators must comply with in terms of voltage control but is does not establish the remuneration scheme that would be applied to this service.

2) Recommendations for the provision of voltage control by wind farms

According to the results of the impact assessment performed for demo 1, wind penetration in Spain is currently not limited due to voltage reasons in most cases. In this sense, at least under current wind penetration levels in Spain, the benefits that could be obtained from the provision of voltage control by wind generators would not justify its implementation costs. Nevertheless, as mentioned in Section 1.1.1, the impact of the provision of voltage control by wind farms is highly dependent on the network configuration. In less meshed grids, this service may be essential to integrate wind generation. Furthermore, as wind generators displaces conventional generators, which are the units providing ancillary services to the system, the former will be increasingly required to provide these services.

In order to guarantee cost-effectiveness and maximize the procurement of flexibility that different technologies can offer, including wind generators, **it is recommended that a competitive mechanism is created for the procurement of reactive power, with a clear definition of the products to be procured and remuneration schemes allowing for cost recovery** [4], [9].

The proposed mechanism to procure reactive power is based on the regulatory framework for voltage control developed in [10] and takes into account the particular characteristics of this service:

i) Two products: installed reactive power capacity and use of this capacity to control voltages.
ii) Local service, i.e. possible service providers are limited to those units located in the area of the network where the voltage must be controlled.

As proposed in [10], it is recommended that a competitive mechanism is designed for the product with the highest cost, i.e. installed reactive power capacity. Different product lengths could be specified, varying from 3 months up to 2 years. Under this scheme, the TSO would identify the needs of reactive power under certain operating conditions (peak/valley hours) and the potential service providers. These potential providers would compete in the capacity market and, if selected, sign bilateral contracts with the TSO. The selected service providers would be committed to provide the service whenever the TSO requires it. Additionally to the capacity payment, a regulated compensation could be established for the actual use of the reactive power capacity.

## Frequency control provision by wind farms

1) Current situation

The provision of secondary reserves in Spain is a hierarchical system where there is a main operator, the Spanish TSO, and regulation areas, which correspond to the different generation companies and can be composed by one or more generating units. In real time operation, the Spanish TSO computes the Area Control Error (ACE) for the whole Spanish control area and distributes it among the different regulation areas proportionally to the assignment of reserve in the secondary reserve market to each one of these areas. Each regulation area is responsible for correcting its own ACE [11].

The Spanish TSO procures asymmetrical hourly upward and downward reserves through the secondary reserve market, which is held once a day for day ahead. The hourly requirements for secondary reserves are set by the TSO following UCTE (Union for the Coordination of Transmission of Electricity)[3] recommendations, which depends mainly on the level of forecasted load in each hour [12]. The typical requirements for secondary upward and downward reserves in Spain are 700 MW and 500 MW, respectively. These requirements have been historically kept constant despite the fact that Spain intermittent generation (especially wind) has increased significantly in the past years [13].

The ratio between upward and downward reserves assigned to each regulation area in the secondary reserve market must be equal to the ratio between upward and downward reserves required to the whole system. Agents allowed to participate in the secondary reserve market are controllable (i.e. non-intermittent) generation units. Generation units willing to provide

[3] The former UCTE corresponds to the ENTSO-E Regional Group Continental Europe.

secondary reserve must submit bids for upward and downward reserves (in MW) and their respective prices (in €/MW) to the market before 3:30 pm of the day before operation (D-1). All the cheapest bids that satisfy the total reserve margin required by the TSO are accepted. Those generators whose offers are accepted receive the clearing market price (payment for available capacity in €/MW), which is the same for upward and downward reserves. If the reserve capacity is effectively called by the system operator, the generation units providing the service receive (for upward reserve) or pay (for downward reserve) an energy price (in €/MWh). This value is established as the clearing price of the tertiary reserve market that would be held in case tertiary reserve was required to replace secondary reserve in use.

Every day, after the secondary reserve market is cleared, the system operator defines a minimum requirement for tertiary reserve, which is generally dimensioned by the rated power of the largest unit in the system plus 2% of the forecasted hourly load, and a component related to the wind forecasting error [14]. Generation units must bid their whole available tertiary reserve capacity to fulfill the previously indicated criteria before 11 pm of D-1. Tertiary reserve bids that are submitted to the market have a capacity component (in MW) and an associated energy price (in €/MWh). Only effectively used tertiary reserve energy is remunerated. If the total available reserve in the system does not meet the established requirement, the system operator will order the connection of more units to the grid until the requirement is fulfilled. Service providers can update their bids up to 25 minutes before real-time.

If wind generators are allowed to participate in the tertiary reserve market and place their bids in the last gate-closure for tertiary reserve (i.e. 25 minutes before the operating hour), there would be no significant barriers to the participation of those generators in tertiary reserve provision. On the other hand, the Spanish secondary reserve market design creates barriers to the participation of wind farms in secondary reserve provision which are mainly related to:

- *Intermittent generators (e.g. wind and solar) are not allowed to participate in reserve markets*.
- *Aggregation of units for technical requirements compliance and service provision*: aggregation of units for service provision is allowed only for units belonging to the same regulation area. When a new unit is included in a regulation area, its capability to deliver secondary regulation has to be tested. This test is carried out both at the unit and the regulation area levels.
- *Upward and downward reserves procurement*: in order to provide upward secondary reserve, primary renewable energy must be lost. This represents an important economic loss for wind generators since they do not get paid for the curtailed power. However, under current Spanish regulation upward reserves must be provided at the same time as downward reserves. This could limit or even prevent the provision of (downward) reserves by wind generators. In the best case scenario, under current regulation the provision of upward reserves by wind generators would only take place in situations of high wind generation, when the TSO would have to curtail wind production. This would limit the provision of downward reserves by wind generators to a specific amount which depends on the capacity offered for upward reserve provision.
- *Early gate-closure time*: wind generation forecast errors can be very significant for the lead time of the secondary reserve market.

2) Regulatory recommendations for the participation of wind farms in the Spanish reserve markets

According to the results of Demo 1, aggregated wind generators can provide both secondary and tertiary regulation. Furthermore, the economic impact assessment demonstrated that this participation can bring economic benefits to power systems' operation. Allowing wind generation to participate in reserve markets beneficiates not only power system operation (by providing the system with higher flexibility and, under some circumstances, cheaper balancing resources) but also wind generators (by reducing their deviations in relation to their schedules). Nevertheless, taking advantage of the flexibility that wind generators can bring to the system requires that current market designs are adapted. Since changing market designs can be a very complex task, some essential recommendations that do not require significant changes in the current market design are proposed:

i) **Wind generators should be allowed to participate in reserve markets**;
ii) Service provision capability should be tested at an aggregated level, i.e. units that individually could not comply with technical requirements but could contribute to service provision if aggregated with other **units should be allowed to present bids in portfolio**, independently from the generation company they belong to (i.e. regulation areas). In case the current design of regulation areas is kept, **a regulation area composed by as many wind generators as possible should be created**.
iii) **Upward and downward reserves are procured separately** as two independent products.

If the above described conditions are met, wind generators would have an incentive to provide, at least, downward reserve in the Spanish secondary reserve market, inasmuch as downward reserves are likely to be called when wind generation is high. Despite this, it important to take into account that wind generation flexibility can increase significantly the closer time gets from real-time operation. **In order to take advantage of the full flexibility that can be provided by wind generators, it is recommended that the Spanish secondary reserve market design is further adapted**. In this sense, two design alternatives are proposed: 1) splitting the secondary reserve market into a "capacity market" and an "energy market"; or 2) creating an intraday market for secondary reserve capacity. These proposals are described below.

1) Splitting the secondary reserve market into a "capacity market" and an "energy market":

The first design alternative is based on an existing secondary reserve market design (which, for instance, characterizes the Netherlands secondary reserve market [15]). The proposed "capacity market" would correspond to a day-ahead market for the procurement of secondary reserve capacity, taking into account the recommendations described in (i), (ii) and (iii). All agents (including wind generators) willing to provide reserve capacity could present bids for the capacity they are willing to offer (in MW) and the price they expect to receive for this capacity (in €/MW). The clearing price of this market would correspond to the market marginal price (i.e. price of the most expensive accepted offer). The units committed in this market would have an obligation to provide secondary regulation in real-time in case the TSO requires it, unless they are able to buy this capacity back from another service provider in the "energy market", which is described below.

The “energy market” would define the units which would be actually dispatched for secondary regulation in case the TSO requires it. This market could be designed as sequential intraday auctions with gate-closure times very close from real time (e.g. 1 hour or 45 minutes before real-time) or a continuous market where bids could be sent up to very close from real time (e.g. 1 hour or 45 minutes in advance). All the units accepted in the “capacity market” would have to bid, at least, the whole accepted capacity in this “energy market”. In order to avoid that units committed in the former bid a very high price in the latter, it could be required that units participating in the “capacity market” also present a bid for the maximum price they would be willing to receive for the actually used secondary energy. Other potential service providers that were not committed in the day-ahead “capacity market” could also participate in the energy market. If these potential providers are committed in the “energy market”, they would be entitled to receive the market marginal price (i.e. the price of the last accepted offer for a specific operating hour, in €/MW) if they are actually activated by the system operators. These providers would not receive the capacity payment since they did not participate in the day-ahead “capacity market”. Finally, it is recommended that negative prices are accepted in the “energy market”. This would reveal the need for higher flexibility during tight system situations in valley hours.

The general idea of this proposal is to guarantee that the TSO has enough secondary reserve capacity in case the system needs (through the “capacity market”) and that in real-time the cheapest resources are used to balance the system (energy market). An example of a situation in which both system operation and service providers would be beneficiated by this design would occur during valley hours with high wind generation and thermal generators are operating the their minimum capacity. In the current secondary reserve market design, conventional generators are the ones providing both upward and downward reserves to the system. In the above-described situation, wind generators would be the cheapest downward reserve resource in the system.

2) Creating an intraday market for secondary reserve capacity:

The second design alternative consists in introducing an intraday market for secondary reserve capacity with the same design as the intraday energy market. Under this design alternative, the TSO would procure secondary reserve capacity in the day-ahead secondary reserve market. The rules of this day-ahead market should take into account the recommendations proposed in (i), (ii) and (iii).

The Spanish intraday (energy) market is organized as six centralized auctions, with different gate-closure times and covering different energy scheduling horizons [16]. Here, it is proposed that a similar intraday market is created for secondary reserve capacity. Furthermore, it is proposed that both the intraday market for energy and for secondary reserve capacity comprise 24 daily sessions (auctions) with gate-closure times very close from real-time operation (e.g. 1 hour or 45 minutes in advance). This would facilitate not only a higher integration of wind generation and reduce their deviation costs but also a higher integration with other European intraday markets (continuous market design).

The purpose of this intraday market for secondary reserve is twofold:

a) generators committed in the day-ahead market could buy secondary reserve – for instance, in cases of unit outage, changes in wind forecast, changes in the unit schedule performed by the TSO due to transmission constraints, or to apply strategic modifications – and agents willing to enter this market could sell reserve;

b) If needed, the TSO could also buy additional secondary reserve in this market.

The two alternative designs for the Spanish secondary reserve market proposed here attempt to integrate as much as wind (and other intermittent) generation as possible and to provide the system operation with the maximum flexibility (all potential and cheapest balancing resources), while maintaining system security. Nevertheless, further studies which are not in the scope of this project are required to assess how these alternative designs would impact other market designs (e.g. imbalance settlement, balancing responsibility, etc) and require new market rules and/or tools.

Finally, regarding the tertiary reserve market, as it was previously mentioned, **if wind generators are allowed to participate in this market and to place bids at the last gate-closure for tertiary reserve (i.e. 25 minutes before real-time), there would be no significant barriers for the provision of tertiary reserves by wind generators.**

## 1.2. Demo 2

The goal of the second TWENTIES demonstration project (DERINT) was to show the potential of the Virtual Power Plants (VPP) technology to provide system services in Denmark. The VPP ("Power Hub") manages small power generators (such as small hydro power plants, industrial combined heat and power plants (CHP), and emergency generation sets) and power consuming units (such as pumps in waste water treatment, grow light in greenhouses, and cooling in cold storages). When units are used in an optimal way they are able to provide the services that are needed in the system. For example, water pumping can be stopped or started within a few seconds if the power system needs it.

Building a VPP consists of a range of tasks, which fall into three main groups: 1) Building the concept solution, including the IT solution; 2) Reaching an agreement with the unit owner and installing unit controls; 3) Running the daily operation, selling and producing services by optimizing the units. The VPP demonstration was set up in Denmark on fully commercial terms and integrated 47 units representing 15 different technologies. This means that on a daily basis the VPP delivers services to the Danish power system based on the controlled units. It also means that the VPP does not pay the unit owners more than it can earn in the markets with the same units.

### 1.2.1. Main findings

One of the conclusions from the project is that it is a challenging task to mobilize industrial units to participate in a virtual power plant. This task involves complex unit flexibility assessment and unit owner education in the complex issues of VPPs, power markets and future energy system [17]. Despite these challenges, the economic impact assessment performed for demonstration 2 showed that even when treated solely as a demand response unit, the VPP technologies have managed to decrease overall system costs and increase revenues. In the 2030 scenario, consisting of 400 MW cold storage and 300,000 electrical vehicles (2,800 MW), the benefit of the VPP was estimated in 27 M€/year in terms of cost savings in the day-ahead market. On top of that, the net balancing costs of the hour-ahead balancing performed by the Danish TSO is estimated to be reduced by 3.4 M€/year, so the total calculated savings amounts to approximately 30 M€/year.

Other important findings from the simulations performed in WP15 regards CO2 emissions and wind curtailment. It was observed that, depending on the system generation mix, the VPP may have adverse effects on CO2 emissions. For instance, if coal and lignite are dominant in base-load production and wind penetration is not too high, VPPs' participation in the market may increase CO2 emissions, which was the result of the 2020 scenario simulations. Nevertheless, in scenarios with high renewable penetration, such as the 2030 scenario, CO2 emissions are reduced (e.g. in 2030 the CO2 reduction due to the integration of VPPs was estimated in 280,000 ton/year). Finally, it was found that wind curtailment can be reduced due to the integration of VPPs. According to the simulations, reduction in wind curtailment could amount 18 GWh/year.

### 1.2.2. Identified regulatory barriers and proposed recommendations

1) Current situation

Currently, the design of reserve markets in Denmark is not fully adapted to the participation of VPPs. The main barriers preventing the participation of VPPs in reserves provision in Denmark have been report by DONG Energy. Some issues similar to the ones identified in the Spanish market (Section 1.1.2), such as market gate-closure times and joint provision of upward and downward reserve, also act as barriers to this participation. VPPs also face barriers related to the fact that, in general, the aggregation of production and consumption units for service provision is not allowed. Table 1 presents the main characteristics of the reserve markets in Western and Eastern Denmark [18].

**Table 1 – Characteristics of reserve markets in Denmark**

| **Western Denmark** | Purpose | Full activation time | **Market gate-closure** | **Product length** | **Product procured** | **Possible combined deliveries** |
|---|---|---|---|---|---|---|
| Primary reserve | Stabilize frequency | 30 sec automatic | 15:00 of D-1 | 4 hours | 2 products: up reserve down reserve | Production units or load units |
| Secondary reserve | Restore frequency and imbalances on the interconnections | 15 min automatic | Several days before the month of delivery | Monthly | Symmetrical up and down reserve | Production units & load units within the same BRP |
| Manual reserve | Restore system balance and automatic reserves | 15 min manual | 9:30 of D-1 | Hourly | 2 products: up reserve down reserve | Production units or load units |
| **Eastern Denmark** | Purpose | Full activation time | **Market gate-closure** | **Product length** | **Product procured** | **Possible combined deliveries** |
| Frequency-controlled normal operation reserve | Stabilize frequency | 150 sec automatic | Part of reserves: 15:00 of D-2; Rest: 19:00 of D-1 | Hourly | Symmetrical up and down reserve | Production units & load units within the same BRP |
| Frequency-controlled disturbance reserve | Stabilize frequency drops resulting from major outages | 50%: 5 sec; 50%: 25 sec automatic | Part of reserves: 15:00 of D-2; Rest: 19:00 of D-1 | Hourly | Upward reserve | Production units or load units |
| Manual reserve | Restore system balance and automatic reserves | 15 min manual | 9:30 of D-1 | Hourly | 2 products: up reserve down reserve | Production units or load units |

Apart from the reserves listed in Table 1, the Danish TSO also procures regulating power in the Nordic regulating power market [19]. Agents can participate in this market in one of two ways:

(i) by participating in the manual reserve market. In case a service provider is accepted in this market to provide manual reserve, this provider is committed to entering regulating power bids for a specified volume over a specified period of time. If this agent is effectively called to provide regulation in real-time, this player receives an availability payment (marginal price of the manual reserve market) plus the energy payment, which is given by the marginal price of the regulating power market (i.e. price of the most expensive activated bid);

(ii) by participating only in the regulating power market. In this case, if a service provider is called to provide regulation in real-time, he will receive only the marginal price of the regulating power market. Bids in the regulating power market can be adjusted up to 45 minutes before real-time and refer to the capacity potential providers are willing to offer for each hour (in MW) and the price for this capacity (in DKK/MWh) for upward and downward regulation, separately.

The main barriers for the participation of VPPs in balancing services markets in Denmark are described below:

- *Some units under the feed-in tariff mechanism cannot participate in reserves provision*: Hydro power plants and photovoltaic generators have the Danish TSO as their balance responsible party (BRP)[4] in order to receive the feed-in tariff. Since a commercial BRP is required for the provision of reserves, the participation of these units in reserve markets is not possible without leaving the feed-in tariff regime. It is worth mentioning that since 2003 onshore wind turbines owners have been allowed to choose a commercial BRP and participate in ancillary service markets while receiving feed-in tariff. In 2008 the regulation was extended to cover all wind turbines.
- *Long product length and early gate closure times that characterizes some reserve markets in Denmark*: as it can be observed in Table 1, primary and secondary reserve product lengths in Western Denmark may act as barrier to the participation of VPPs in those markets since the VPP may comprise, for instance, intermittent generation units, whose production forecast errors increases considerably with time. Furthermore, the secondary reserve market in Western Denmark is held a month in advance of service provision. Due to uncertainties related to some production and consumption units included in the VPP, this long lead-time would prevent the participation of the latter in that market.
- *Symmetric upward and downward reserves*: some reserve markets (secondary reserve in Western Denmark and frequency-controlled normal operation reserve market in Eastern Denmark) require that units (or aggregation of units) provide symmetric upward reserves and downward reserves (Table 1). Nevertheless, the bids for both

[4] Market participant or its chosen representative that is responsible (i.e. holds balance responsibility) for its imbalances (i.e. deviations between actual and programmed production, consumption or commercial trades).

upward and downward reserves will be determined by the minimum capacity to offer upward or downward reserve due to the symmetric bid requirement. Due to this, part of the flexibility of the VPP is not bid into the market (for instance, for wind generators is much easier to provide downward reserve than upward reserve, nevertheless, in that case, the provision of downward reserve would be limited by its capability for providing upward reserve).

- *Balance responsible party for the VPP*: In principle, electricity producers hold balance responsibility for the electricity produced at their own plants[5]. On the other hand, the BRP representing customers is the corresponding electricity supplier (i.e. the retailer responsible for buying electricity in the market and selling it to the end consumer). The fundamental problem is that, according to current market regulation in Denmark, only one BRP is allowed for each metering point. This leads to a barrier to VPPs since it may include load and production units with different BRPs.
- *Aggregation of production and consumption units for service provision*: until 2010 it was not allowed to aggregate production or consumption units into one bid for reserve provision. Recently, the Danish TSO has made some changes in regulation to allow the aggregation of production and/or load units for the provision of reserves. Table 1 summarizes the possible combined deliveries in the Danish reserve markets. In most of the markets, a delivery can combine several production units with different properties, which collectively can provide the required response within the required response time, or several consumption units with different properties, which collectively can provide the required response within the required response time. Nevertheless, production and consumption units cannot be combined within the same offer. In the case of the secondary reserve market in Western Denmark, production and consumption units can be combined within the same offer if (i) balance responsibility for all consumption and production units rests within the same BRP, and (ii) upward and downward reserves units are provided only by production or consumption units. Finally, frequency-controlled normal operation reserve can be provided by a combined delivery of production and consumption units as long as balance responsibility for these units rests within the same BRP.
- *Requirements for aggregated ancillary services*: aggregation systems are allowed in Denmark, but they must be approved by the TSO at the unit level (i.e. each single unit comprising the cluster must comply with technical requirements). There are no specific testing requirements for aggregation systems until now due to the novelty of the VPP concept. Current regulation for ancillary services' provision requires an individual test for each unit's minimum power, ramp rate, response time and response duration time. This constitutes a barrier to the participation of VPPs in ancillary services' provision since a VPP may contain individual units that do not comply with the technical requirements while the portfolio as a whole does.

2) <u>Regulatory recommendations for the participation of VPPs in balancing services markets in Denmark</u>

In order to facilitate the participation of VPPs in the Danish balancing services markets, the following recommendations are proposed:

[5] In case they do not want to hold balance responsibility themselves they are required to assign the responsibility to a BRP. For instance, small-scale producers usually assign balance responsibility to their retailer (i.e. the buyer of their production)

- **Renewable units under the feed-in tariff scheme should be allowed to switch to a commercial BRP so that they can participate in balancing services markets**. In this sense, it is recommended that, as long as renewable units are provided with proper means to ensure the balance of its production (i.e. liquid markets with gate-closure times close from real-time, i.e. from 1 hour to some minutes in advance, and a well-designed imbalance settlement), balance responsibility should be imposed to renewable units as well. The Spanish experience has proven that imposing balancing responsibility to these generators have fostered their participation in the day-ahead and intraday markets (including generators under the feed-in tariff scheme), have helped the improvement of forecasting tools [5], and, consequently, the reduction of intermittent generation deviation.
- Since forecasting errors of typical units comprising a VPP, such as intermittent renewable generators and load units, increase with time, short times between gate-closure and delivery are required to incentivize the participation of VPPs in balancing services provision. Short product lengths are also required for this participation since some units' production (or consumption) can vary significantly among hours, for instance. Therefore, **it is recommended that, at least, primary and secondary reserve product lengths in Western Denmark are shortened from hour and monthly blocks to one hour**. **It is also recommended that gate-closure times of primary and secondary reserve markets in Western Denmark are delayed**. One possible alternative is to procure part of the reserves at the current market time and procure the other part later, as it is done in Eastern Denmark (Table 1).
- **Independent bids for upward and downward regulation should be allowed** in the secondary reserve market of Western Denmark and in the frequency-controlled normal operation reserve market of Eastern Denmark **so that the full flexibility of VPPs can be bid into the market**.
- **The link between the BRP for consumption and the customer power supplier should be permanently removed**, which facilitates the definition of only one BRP for the VPP and allow the aggregation of more units. This requires the implementation in the Danish TSO Data Hub.
- **Combined deliveries (bids) with production and consumption units should be allowed in all markets**, as it is currently done in the frequency-controlled normal operation reserve market of Eastern Denmark. The removal of the barrier that the above recommendation refers to will allow the definition of one BRP for the VPP, which will facilitate the combined deliveries with production and consumption units. This requires that the Danish imbalance settlement is adapted to allow these combined deliveries.
- Clear requirements for aggregated systems comprising units that individually may not comply with technical requirements while the portfolio does must be established. In Figure 1, the left side shows an example of a unit that complies with technical requirements for the provision of ancillary services and the right side shows the aggregation of several units that individually do not comply with technical requirements but when combined they do.

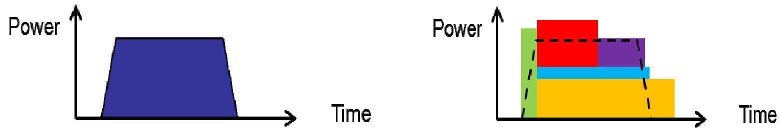


**Figure 1 – VPP's compliance with technical requirements**

In this respect, Dong Energy has proposed an approach for the approval of aggregated systems, which is described in the Appendix of this document.

Some of the proposed measures are currently being developed by Energinet.dk, such as the establishment of technical requirements for the provision of system services by aggregated systems. As well as proposed in Section 1.1.2 for the Spanish secondary reserve market, **balancing services products adapted to the characteristics of VPPs should be defined** also in the case of Denmark. A clear example of a market more adapted to the participation of VPPs is the Nordic regulating power market where, for instance, bids can be sent/updated very close from real-time (45 minutes before the delivery hour) and product length is shorter (1 hour) when compared to the primary reserve and secondary reserve markets in Western Denmark.

Finally, other recommendations proposed by DONG Energy refer to:

- Aggregated Online Measurement For Ancillary Services (partially solved barrier)

Currently the Danish TSO Energinet.dk gathers online measurements from all individual consumption units participating in ancillary services (normally > 5 MW). Energinet.dk wishes more information on participating unit types before reconsidering this requirement. An aggregated online measurement per 50-60 kV infeed point is under consideration. With a limited number of participating units, handling individual online measurements is manageable. Nevertheless, managing individual measurements for a large number of units (e.g. electric vehicles) will impose loads on both IT systems and back-office staff. As for production, all units are represented in Energinet.dk SCADA system, either with real measurements or with estimated ones (scaled values). According to Energinet.dk this system layout does not allow aggregated measurements. Therefore, individual measurements must also be sent for all units comprising the VPP.

**A proposed solution for online measurement of small consumption and production units is to allow VPP operators to send measurements to the TSO (and DSOs) via standardized interfaces**, for instance, the Inter-Control Center Communications Protocol IEC 60870-6. This proposal was validated by Energinet.dk.

- Metering responsible and metering operator

According to Danish legislation the local DSO is the metering responsible and has the responsibility and privilege to establish and operate online measurements of flexible consumption. However, the DSO can choose to allow others to be metering operators. Nevertheless, the final formal responsible for the measurement quality is the DSO. The process of setting up metering agreements with the DSO has so far proven to be very long and often only granted on an installation-to-installation basis.  In the context of the Twenties project, "Power Hub" has entered in a metering operator contract agreements with DONG Energy S&D

(and with SEAS-NVE (DSOs in Denmark). However, a case-to-case acceptance is required according to the contract[6].

Possible solutions for this barrier are:

- o Allowing DSOs to delegate online measurement responsibility to VPP operators. This is currently allowed in Denmark, but is subject to approval by the individual DSO;
- o Establishing common national processes and criteria for becoming operator of online measurements;
- o Allowing VPP operators to be pre-qualified as metering operators a national level.

### 1.3. Transversal analysis of Task-Force 1

The demonstrations developed within TF 1 proved that wind generators and VPPs are technically able to provide system services. If these capabilities are explored, important technical and economic benefits to power systems operation can be achieved. These benefits are related to the extra flexibility the referred units can provide to power systems in a context of increasing penetration of intermittent generation. Nevertheless, in order to fully deploy this extra flexibility, important barriers related to the current design of electricity markets must be overcome.

In general, each TSO is responsible for procuring balancing services in order to ensure real time balance between generation and demand in its control area. Therefore, TSOs, together with national regulation authorities (NRAs), should take the leading role in adapting balancing markets design for the integration of wind generators and VPPs. Nevertheless, taking into account the need to integrate European power systems and markets, especially due to the growing penetration of intermittent generation, the role of organizations such as ACER (Agency for the Cooperation of Energy Regulators) and ENTSO-E (European Network of Transmission System Operators for Electricity) becomes increasingly important for the definition of harmonized market rules for Europe.

*Main regulatory recommendations for TF 1*

- Establishing market mechanisms for the procurement of system services

In order to promote non-discrimination, competition, liquidity and to avoid entry barriers to new agents, market-based mechanisms should be used for the procurement of system services. This is especially true for services such as primary frequency control and voltage control, which are usually mandatory and non-remunerated services in many power systems. As the amount of power provided by intermittent renewable generation increases, the fraction of online thermal generation capacity offering these services will decrease, increasing the need for market mechanisms to ensure that alternative sources are incentivized to provide sufficient ancillary services. In this sense, service providers should be remunerated based on cost-reflective prices instead of regulated prices as much as possible. Regarding this remuneration, a common clearing price system (i.e. all suppliers receive the price of the most expensive accepted offer) is preferred rather than pay-as-bid price system (i.e. each supplier receives the price of its accepted offer) since in the former system providers have an incentive to bid their marginal cost [8].

[6] There are 90 DSOs in Denmark, which makes contract agreements with each VPP and DSO unrealistic.

- Defining markets for the procurement balancing reserve capacity and balancing energy

The balancing market should include separate markets for balancing reserves and balancing energy. The former refers to the market where the TSO buys in advance reserve capacity whereby service providers take the commitment of reserving the offered capacity from their portfolio (and non-compliance should be penalized). The latter refers to the market where the TSO balances the system based on the merit order of the bids received from the providers of reserve capacity and from other agents that did not commit reserve capacity but participate voluntarily in the balancing energy market [20].

- Allowing the adjustment of bids for balancing services closer to real-time operation

The possibility of adjusting bids for balancing services closer to real-time operation becomes increasingly important with the penetration of intermittent generation since it would contribute to reduce balancing costs. For instance, when an increasing wind feed-in leads to a reduction of conventional power generation. These power plants would be then able to provide upward reserve for the hours during which wind production is higher than the scheduled at a very low cost. Nevertheless, due to the absence of intraday markets for reserve capacity, this is likely to be provided by units with low day-ahead capacity costs and high variable costs, resulting in higher balancing costs [20].

- Defining products that incentivize the participation of all potential participants (e.g. renewable generators, loads and storage units)

The definition of system services' products should recognize the intrinsic characteristics of new potential market participants such as renewable generators, load and storage units in order to fully exploit their capabilities. These products should take into account, among others, the aggregations of small units, shorter product lengths, and gate-closure times closer to real-time [4].

- Increasing the liquidity of intraday markets

In most European day-ahead markets, market participants must submit their bids before 12:00. Within this lead-time[7] range (from 12 to 36 hours) intermittent generation can vary significantly. In this respect, reference [21] shows that the day-ahead wind generation prediction error in Germany is more than 20% of average wind production, but it can be reduced by considering shorter time scales. In this sense, a well-functioning intraday market is essential for intermittent generators to adjust their schedules according to better production forecasts, especially if they participate in balancing services markets. However, many European intraday markets are characterized by a lack of liquidity. According to the study performed in [22] for European power markets, the volume of trades in continuous intraday markets in relation to the volume of trades in the respective day-ahead market ranged between 0.5% in Denmark to 4.2% in Germany in 2009. The highest liquidity was observed in the Spanish intraday market (centralized in six discrete auctions), where the volume of intraday trading represented around 16% of the energy volume traded in the day-ahead market. According to the author, this higher liquidity is explained by the fact that auctions aggregate liquidity in one unique period, avoiding dispersion across single trades occurring over the whole trading period as it happens in continuous markets. Increased intraday market liquidity could be obtained by introducing centralized (sequential) auctions in certain points in time, as it is done in Spain.

[7] Lead time refers to the difference between the market gate-closure time and the delivery hour.

* Imposing balancing responsibility on all market participants

All market participants should be subject to balancing responsibility so that they are incentivized to minimize their schedule deviations through intraday markets instead of increasing the demand for balancing services, which in turn increases system costs. This is especially true for intermittent generation, which increase the demand for balancing services but is exempt from balancing responsibility in many countries [4]. Balancing responsibility provides an incentive for investments in forecast tools and for an active participation of renewable generators in electricity markets [5]. It is important to emphasize though that imposing balancing responsibility on renewable generators requires that they are given the means to ensure the balancing of its production such as the existence of well-designed intraday markets and well-established imbalance prices.

* Defining cost-reflective imbalance prices

Imbalance prices should reflect the (balancing) costs imposed to the system by imbalanced market parties so that the latter receive the proper incentives to be balanced. This is especially important in a context of high penetration of intermittent generation since its variability and limited predictability prevents these generators more than conventional ones from being perfectly balanced. Cost-reflective imbalance prices should reflect both energy and capacity payments, as proposed in [23] and [24]. Regarding energy payments, it is recommended that the imbalance price is settled at the marginal balancing cost the system incurs due to schedule deviations. Regarding the latter, since capacity payments are paid for all the scheduling period (and not only when it is activated, as it is the case of energy), its associated costs cannot be directly attributed to imbalanced parties. For this reason, it is recommended that an additive component is added to the energy imbalance price and allocated proportionally to the imbalance parties, as proposed in [24].

*Main ongoing measures/projects*

* ACER Framework Guidelines (FG) and ENTSO-E Network Code (NC) on Electricity Balancing

ACER Framework Guidelines[8] and ENTSO-E Network Codes[9] aim at providing harmonized rules that will define the European Target Model for electricity markets and focus mainly on cross-border exchanges. All network codes should be finished by 2014. Figure 2 presents the process for the development of these network codes.

ENTSO-E is currently developing the Network Code on Electricity Balancing and, according to the Framework Guidelines published by ACER [25], balancing services procurement should be market based and they should allow for:

(i) Aggregation of small units for service provision;
(ii) Participation of loads and renewable generators in the provision of balancing services;

[8] See: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Framework_Guidelines/Pages/default.aspx
[9] See: https://www.entsoe.eu/major-projects/network-code-development/

(iii) Service providers to place/update bids close to real-time as possible (at least up to H-1);
(iv) Provision of balancing energy without a having contract for the provision of reserves (at least for tertiary control);
(v) Renewable generators are responsible for their schedule deviation as any other conventional generator.

According to the schedule, ENTSO-E should submit the Network Code for Electricity Balancing in September 2013.

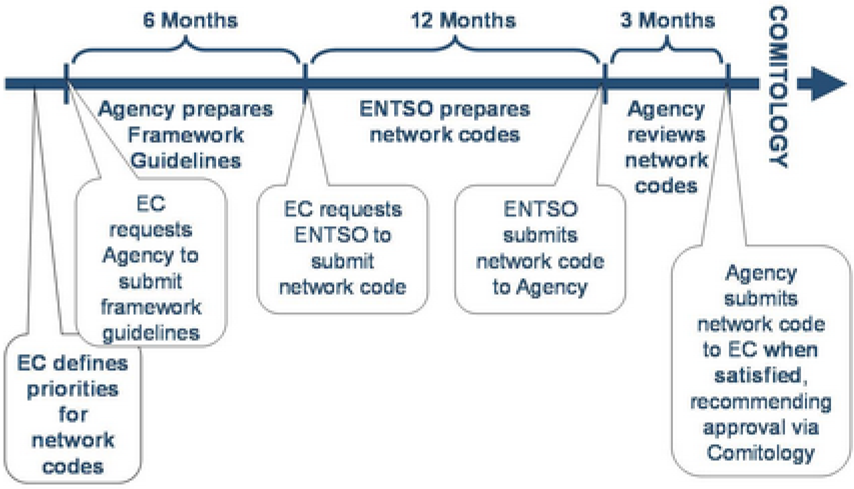


**Figure 2 – Process the development of European network codes (Source: www.acer.europa.eu)**

- European Wind Energy Association (EWEA) initiatives

EWEA is engaged in several projects and activities related to the design of electricity markets for the integration of wind energy. In [4], it recognizes that, although the EU Target Model an important step towards increased cross-border trading, and consequently, towards the completion of the Internal Energy Market in Europe, it does not effectively enable the optimal integration of wind generation in electricity markets.

- REserviceS EU Project[10]

The REserviceS project investigates the opportunities and costs of providing ancillary services from wind and PV systems by:

(i) Analyzing the needs for ancillary services (e.g. voltage and frequency support) in the European power system, with a growing share of variable renewables;
(ii) Identifying which ancillary services wind and PV can provide and which are of interest to system operators, today and in the future;
(iii) Analyzing factors influencing the provision of ancillary services by wind and PV;
(iv) Creating a European harmonized method to calculate the costs for ancillary services provided by wind and PV.

The final results of this project will be available in the beginning of 2014.

[10] See: www.reservices-project.eu

- eBADGE EU Project[11]

The overall objective of the eBADGE project is to propose an optimal pan-European Intelligent Balancing mechanism, piloted on the borders of Austria, Italy and Slovenia, that is also able to integrate Virtual Power Plant Systems that can assist in the management of the electricity Transmission and Distribution grids in an optimized, controlled and secure manner. The eBADGE project final results are expected to be delivered in September 2015.

Table 2 presents the main recommendations for TF 1 and identifies ongoing measures dealing with the respective barriers.

**Table 2 – Main recommendations for TF 1**

| | Ongoing measures | Further measures |
|---|---|---|
| Establishing market mechanisms for the procurement of system services | ACER FG on Electricity Balancing | ENTSO-E NC development |
| Allowing the adjustment of bids for balancing services closer to real-time operation | | Introducing sequential intraday auctions |
| Defining products that incentivizes the participation of all potential participants | ACER FG on Electricity Balancing, REserviceS project, eBADGE project | ENTSO-E NC development |
| Increasing the liquidity of intraday markets | | Introducing sequential intraday auctions |
| Imposing balancing responsibility on all market participants | ACER FG on Electricity Balancing | ENTSO-E NC development |
| Defining cost-reflective imbalance prices | | TSOs should charge actual deviation costs to unbalanced parties (capacity and energy) |

[11] See: www.ebadge-fp7.eu

# 2. TASK-FORCE 2

Task-force 2 includes Demo 3, led by RTE (French TSO), and Demo 4, led by Energinet.dk (Danish TSO), and focuses on the development and operation of offshore networks for the deployment of offshore generation. The objectives of this chapter are to summarize the main conclusions of the impact assessment performed for each demo developed within TF 2 [2], to identify the main regulatory barriers preventing capturing the benefits provided by the referred demos and to propose recommendations for the identified barriers.

## 2.1. Demo 3

The third TWENTIES demonstration project (DCGRID) addressed HVDC multi-terminal grids and their security constraints, which strongly impacts the resulting network topology and its interconnection with the AC grid. More specifically, the demonstration assesses the viability of two DC breaker solutions through large-scale demonstrations and proposes detailed specifications and technology standards for the future offshore grid industry. To tackle the complex task of designing, developing and operating new transnational grid facilities, Demo 3 analyses (based on the most suitable DC technology, Voltage Source Converter - VSC) were divided into three time scales [26], [27]:

1) Short-term (up to 2020) technical feasibility analysis: this analysis involved simulations to verify if a step-by-step offshore grid development starting from several radial connections, later extended to “H”, and then to a meshed five-terminal topology was feasible. The conclusion was that methods based on local voltage droop control are efficient in operating the DC/AC interconnected grids and enabling wind generation. Moreover, they accommodate a large range of failures in the electrical system without any need for high-speed telecommunications (so far such communication is required for DC fault detection only).
2) Medium-term (2020-2030) technical feasibility analysis: this analysis included (i) the development of a DC circuit breaker prototype by ALSTOM Grid; and (ii) the design and development of a low-scale real-time mock-up to illustrate the control and protection algorithms of a DC grid, as well as the interconnection of the physical DC grid to a simulated AC grid. Both demonstrations were successfully tested.
3) Long-term (2030 and beyond) economic analysis: this analysis compared several possible future network topologies in the North Sea area according to economic and reliability criteria. The study has shown that the assumptions and criteria used have a significant impact on the conclusions. Therefore, further studies must be performed further refined in order to obtain the optimal solution. The risk involved in developing and financing future offshore grids remains high [28].

### 2.1.1. Main findings

The economic impact assessment carried out for demo 3 suggested that new offshore network capacity would allow a higher deployment of offshore wind power potentials, which would contribute massively for a future sustainable European energy system. This new network capacity would not only allow local surpluses of wind power to be used elsewhere but it would also facilitate reserve power to be held remote from a particular area, minimizing the total need for holding reserves and reducing system operation costs. However, the development of offshore network capacity may also increase cheap generation with high carbon emissions in remote areas. In order to avoid this outcome, higher carbon prices would be required to reverse the generation dispatch merit-order, favoring lower CO2-emitting generation.

Regarding the design of the network, three cases have been modeled: a) connection of new offshore capacity solely to one shore with no new interconnection capacity between countries (radial connection); b) connection of new offshore capacity solely to one shore and new interconnection capacity in the northern seas (radial connection plus interconnectors); c) the development of a multi-terminal offshore grid. According to the study performed in [28], the cost-effectiveness of a meshed offshore network will depend on the cost of DC breakers, and on its potential to increase network reliability and to avoid onshore network strengthening.

### 2.1.2. Identified regulatory barriers and proposed recommendations

1) Current situation

The development of a meshed offshore grid faces significant regulatory and economic challenges. In [29] the North Seas Countries' Offshore Grid Initiative (NSCOGI)[12] has identified barriers that can significantly delay or prevent the development of offshore networks. Barriers to the development of offshore networks were also identified by the ISLES Project[13], which aimed at assessing the feasibility of creating an offshore interconnected transmission network and subsea electricity grid based on renewable energy sources off the coast of western Scotland and in the Irish Sea/North Channel area [30], and by EWEA [31]. The main regulatory barriers for the offshore grids are described below:

- *Lack of a clear agreed framework for offshore generation beyond 2020*: currently, there are no agreed targets for offshore generation beyond 2020 and no mid- to long-term perspective for grid development. The absence of this vision prevents investments in both offshore generation and grid infrastructure, especially taking into account to the high costs associated to these investments.
- *Responsibility for network planning and financing*: traditionally, national transmission network operators own and are responsible for planning and developing their grids. Only interconnection capacity between two countries (or control areas) has been part of bilaterally coordinated infrastructure development. Planning internal infrastructure or interconnection transmission capacity does not require any especial need for infrastructure planning and financing harmonization. Consequently, if offshore generation is connected to the shore through radial interconnectors, different national approaches will probably not act as a major barrier to the expansion of network capacity. Nevertheless, the development of a meshed offshore network requires at least a high-level coordination for planning and financing the common infrastructure.
- *Cost allocation*: the development of an offshore grid involves several stakeholders (TSOs, offshore generation promoters, national authorities, consumers of different countries, etc.) that do not necessarily benefit from this solution. This means that the distribution of cost and benefits is dispersed among different countries, with “winners” and “losers” which need to be compensated.

[12] NSCOGI is the body responsible for evaluating and facilitating the coordinated development of a possible offshore grid that maximizes the efficient and economic use of renewable sources. Webpage: https://www.entsoe.eu/about-entso-e/working-committees/system-development/the-north-seas-countries-offshore-grid-initiative-nscogi/

[13] http://www.islesproject.eu/

- *Network operation codes*: in general, codes for network operation are developed by each TSO for its control area. Among other things, these codes refer to congestion management procedures, priority access and curtailment of renewable generation under critical situations (such as low demand and high wind generation or when grid constraints are identified). In a context of a common offshore network, these aspects must be harmonized among the involved TSOs.
- *Regulatory framework for offshore generation:* support schemes (type and level) for renewable generation, as well as grid connection charges, may vary significantly among the different EU countries. Since a meshed offshore grid would allow for offshore generation to be transmitted to different countries, offshore generation investors would be exposed to different support schemes and charging regimes. This would originate uncertainties to potential investors and, consequently, affect investment decisions.
- *Electricity market designs*: market designs capacity allocation and congestion management (CACM) vary across EU countries. Furthermore, since offshore generation is subjected to large variations, cross-border balancing should be incentivized. Nevertheless, there are different approaches for the procurement and provision of balancing services, which would limit cross-border balancing services sharing.

Apart from those, important barriers for offshore interconnectors permitting also exist. These barriers are described in [32]. The referred study focuses on the potential conflicts with spatial planning, on environmental restrictions, and on other land and seabed constraints as imposed by public and private stakeholders.

2) Regulatory recommendations for the development of an offshore grid

The development of an offshore grid infrastructure will need strong supranational planning and coordination, apart from significant investments. In this sense**, the European Commission must play a major role in establishing a framework for the development of offshore generation and offshore grids**. In order to foster the development of an offshore grid, the following recommendations are proposed:

- Agreeing on a vision for offshore generation beyond 2020: The EU together with its member countries should agree on targets for 2030 and 2050 for the deployment of offshore generation potentials, which could be the main driver for the development of offshore grids.
- Developing methodologies for coordinated transmission planning and applying them to elaborate mid- to long-term development plan. A first initiative in that sense is the e-Highway2050[14] EU project, which aims at developing a top-down planning methodology to provide a first version of a modular and robust expansion plan for the Pan-European Transmission Network from 2020 to 2050.
- Establishing mechanisms for the cooperation of stakeholders involved in the national grid planning process. An example is the NSCOGI initiative, which gathers energy ministries, TSOs and regulators of its member countries[15]. A high level coordination

[14] See: www.e-highway2050.eu

[15] NSCOGI member countries are: Belgium, Denmark, France, Germany, Luxembourg, Norway, Sweden, UK, Ireland and the Netherlands.

between the involved parties is essential for the development of a common offshore grid.

- Developing common funding, such as the Connecting Europe Facility[16], which provides financial aid to the development of energy infrastructure among others, and creating financial instruments to facilitate access to long-term financing, such as the provision of debt facilities or the injection of equity into projects [33].
- Incentivizing TSOs to invest in R&D and in new technologies. NRAs should grant appropriate incentives for investments in R&D and in new and untested technologies and recognize efficient costs of cross-border investments as part of the TSOs Regulated Asset Base. In this sense, cost-reflective grid tariffs must be implemented.
- Allocating ex-ante cost and benefits of offshore transmission investments to the different affected stakeholders;
- Defining common grid codes for the operation of the offshore grid. An approach to operate a common grid is the establishment of organizations such as Coreso[17], which is a regional centre that provides services of coordination of power flows forecasting and operation involving several countries in Western Europe.
- Defining a common regulatory framework for offshore generation, which includes the harmonization of support schemes (or the development of joint support schemes to reduce distortions coming from the national schemes) and the harmonization of grid connection charges;
- Harmonizing European market designs for capacity allocation and congestion management. In this respect, ENTSO-E together with ACER are currently developing the Network Code for Capacity Allocation and Congestion Management, which will constitute the European target model for long-term, day-ahead and intraday cross-border capacity trading. Nevertheless, an integrated offshore grid will probably require special arrangements for cross-border capacity trading, especially taking into account that offshore generation will be connected to two or more countries.
- Developing a framework for cross-border balancing sharing to minimize the impact of a high deployment of offshore generation on reserve requirements costs. This will require the harmonization of (at least some) products and procurement methods for balancing services.

Finally, it is important to emphasize that although the economic case for the different possible offshore grid topologies (i.e. radial connections, radial connections plus interconnectors or a multi-terminal offshore grid) is still uncertain, **regulation needs to be proactive if a higher deployment of offshore generation is to be achieved** [34]. In this sense **the European Commission must play a leading role in establishing a clear regulatory framework for the development of offshore grids and the deployment offshore generation.**

## 2.2. Demo 4

The objective of the fourth TWENTIES demonstration project (STORM MANAGEMENT) was to demonstrate the shutdown of an offshore wind farm in Denmark under stormy conditions. Within the project a new controller was developed, the High Wind Ride Through control, so that individual offshore wind turbines stay in operation at higher wind speeds and shut down at very high wind speeds more gradually when compared to the situation with the old

[16] See: https://ec.europa.eu/digital-agenda/en/connecting-europe-facility
[17] See: www.coreso.eu

controller (High Wind Shut Down). The new controller was developed by Siemens and it was installed in 91 wind turbines located at the Danish wind farm Horns Rev II. The wind farm's shutdown is planned based on storms forecasts and the wind farm is ramped down sufficiently slow in such a way that power can be balanced by hydro generation available in Norway through the DC connection between this country and Denmark.

### 2.2.1. Main findings

Experience from stormy conditions in 2012 in western Denmark demonstrated that when offshore wind turbines are equipped with the new High Wind Ride Through controller it is possible to run these turbines for longer times during high wind speed periods [35]. This means that the total energy output from turbines equipped with the new controller during high wind speed periods is higher than the output from turbines equipped with the old controller algorithm, which would abruptly shut down the wind farm for wind speeds higher than 25 m/s. Measurements from Horns Rev II during stormy weather proved that the wind turbines equipped with the new controller could stay in operation in wind speeds of up to 32 m/s.

The new controller leads to less abrupt changes in production for the wind farm as a whole. Wind farms equipped with the new controller experience in extreme weather situations gradual reductions in production and the mechanical parts of the individual turbine is, in general, less exposed. Moreover, if wind speeds are high enough to decrease power production, the output drop occurs much more gradually compared to the case with the old system (the new controller increases the shutdown time from 3 minutes to 15 minutes). This presents an important advantage for balancing the electricity system. In WP15 it was shown that the new storm controller helps reducing reserve requirements to approximately 50% of the amount of reserves required compared to the situation when the control is not in place.

### 2.2.2. Identified regulatory barriers and proposed recommendations

1) Current situation

Demo 4 demonstrated that the High Wind Ride Through control can bring significant benefits for the power systems' stability and balancing. Since this controller presents a clear improvement in relation to the old controller, the main barrier that could prevent its adoption by TSOs is related to the inclusion of the functionality of the new High Wind Ride Through control in the grid codes.

2) Regulatory recommendations for the implementation of High Wind Ride Through controllers

The adoption of the new High Wind Ride Through controller tested in demo 4 does not face significant challenges. Taking into account the important benefits this new controller can bring in terms of integration of offshore generation, the main recommendations for the implementation of this new controller by TSOs are the following:

- **The functionality of the new controller should be included in the grid codes** for offshore generation. This will be essentially important if a meshed offshore grid is developed;
- **Incentives must be provided for TSOs to invest in R&D and in new technologies.** Efficient costs assumed by TSOs of investing in new technologies should be acknowledged by NRAs.

## 2.3. Transversal analysis of Task-Force 2

The demonstrations developed within TF 2 proved that a higher deployment of offshore generation can be achieved if those solutions are effectively implemented. As previously mentioned, although the economic case for developing offshore grids is not clear, regulation must be proactive if a higher deployment of offshore generation is to be achieved. In this sense, the European Commission should take the leading role, through ACER and ENTSO-E, in incentivizing the development of offshore generation and offshore grids.

*Main regulatory recommendations for TF 2*

- Definition of clear targets for offshore generation beyond 2020 as the main driver for offshore infrastructure development

Major offshore grid investments require that EU member countries continue to commit to offshore energy development beyond 2020 [31]. Therefore, targets for offshore generation from the mid- to the long-term (2030-2050) should be agreed between the EU and its member states. In this sense, a roadmap with timetable milestones should be developed by the EU in close consultation with member countries' stakeholders (i.e. energy ministries (government), NRAs and system operators).

- Establishing a clear regulatory framework for offshore generation

Establishing a common regulatory framework for offshore generation will be essential if this generation is connected to more than one country. In this sense, support schemes for offshore generation must be harmonized or at least flexible mechanisms should be created, such as joint support schemes to reduce the distortions coming from the national schemes [34].

- Creating mechanisms for the coordination of planning, development and operation of common offshore grid infrastructure

The creation of regional initiatives or organizations such as NCOGI and Coreso for the coordination of planning, development and operation should be encouraged by the EU and NRAs. This requires (i) the development of planning tools for coordinated transmission investments; (ii) the clear identification of technical and economic benefits of coordinated infrastructure development in respect to isolated (TSO level) grid development (development of methodologies for coordinated transmission planning); (iii) ex-ante identification of "winners" and "losers" and allocation of costs and benefits among them; (iv) acknowledgement from NRAs of efficient investments in cross-border infrastructure as part of the Regulated Asset Base of TSOs and provision of incentives for investments [36].

- Developing a framework for financing grid infrastructure

Creating a framework that acknowledges the particular financial needs of TSOs is essential for the development of offshore grids. This framework should go beyond the national regulatory framework and have a European component, which should not be limited to improving debt financing options or grants, but it should also incentivize equity financing. In order to incentivize investors to finance complex projects, not only investment risks should be reduced but also attractive remuneration must be established [33].

- Incentivizing TSOs to invest in R&D and in new technologies

NRAs should grant appropriate incentives for investments in R&D and in new and untested technologies and recognize efficient costs of cross-border infrastructure and new transmission technologies investments as part of the TSOs Regulated Asset Base.

- Harmonizing market designs and defining specific arrangements for offshore generation

Harmonized market rules are essential to facilitate cross-border trading. This harmonization is especially required if common grid infrastructure is developed. Furthermore, special arrangements for offshore generation should be developed. This refers to specification of the area(s) offshore generators connected to different countries are allowed to bid into, priority access in case of cross-border offshore assets, allocation of capacity rights to offshore generators so they can get access to the bidding zones. These arrangements are further discussed in [37]. Also, creating a framework for cross-border balancing services sharing is significantly important if high shares of offshore generation are deployed. Also, a clear framework for the participation of offshore generation and HVDC links in the provision of system services should be defined.

*Main ongoing measures/projects*

- Energy Infrastructure Package

In October 2011, the European Commission launched a comprehensive package to enhance Pan-European infrastructure development in the areas of transport, energy and information [38]. In respect to the energy sector, the package comprises:

(i) The Connecting Europe Facility, which provides financial aid to the energy sector of 9.1 billion €;
(ii) (i) The Connecting Europe Facility, which provides financial aid to the energy sector of 5.85 billion €
(iii) The identification of priority corridors that must be implemented in the coming decade, including corridors of the future Northern Seas offshore grid and electricity highways;
(iv) A proposal to introduce a binding overall time limit of three years for permit-granting processes to concentrate the permit-granting powers or coordination in one single authority;
(v) A proposal for a cost-benefit analysis to clearly demonstrate cross-border benefits and to provide the possibility to allocate costs following the benefits. In addition, it is proposed that NRAs provide regulatory incentives proportional to the risks incurred in these projects.

- North Seas Countries' Offshore Grid Initiative (NSCOGI)

NSCOGI gathers energy ministries, TSOs and regulators of Belgium, Denmark, France, Germany, Luxembourg, Norway, Sweden, UK, Ireland and the Netherlands to provides a framework for regional cooperation and to find common solutions to questions related to current and possible future grid infrastructure developments in the North Seas. The Working Groups' studies include the following topics: (i) grid configuration and integration, (ii) market and regulatory issues, and (iii) planning and authorization procedures. This initiative should be the main tool to implement the North Sea Offshore Grid.

- ACER Framework Guidelines and ENTSO-E Network Codes on Capacity Allocation and Congestion Management and on Electricity Balancing

The Framework Guidelines for capacity allocation and congestion management deal with the integration, coordination and harmonization of the congestion management regimes with the aim of facilitating electricity trade within the EU. Nevertheless, special arrangements for offshore grid infrastructure are not within the scope of these guidelines.

According to the ACER guidelines, the Network Code on Electricity Balancing must require the standardization of balancing services (both reserve and energy) products. In that sense, TSOs will be require to prepare a common proposal for standard balancing energy and balancing reserve products, including detailed specifications of their characteristics. The final Network Codes on CACM and on Electricity Balancing are expected to be finished by 2014.

- e-Highway2050 EU project

The e-Highway2050 EU project proposes the development and implementation of a top-down long-term transmission planning approach. The approach begins with the Pan-European Transmission Network as proposed by ENTSO-E in its Ten-Year Network development Plan 2012, which is assumed to be in line with the 2020 EU energy targets. A scenario-based methodology is followed taking into account all the relevant technical/technological, economic/financial and regulatory/socio-political dimensions needed to develop efficient and sustainable grid architecture options to meet future energy supply requirements. The modular long-term planning approach proposed in e-Highway2050 is broken down into five steps, presented in Figure X. The final results of the project are expected to be delivered by the end of 2015.

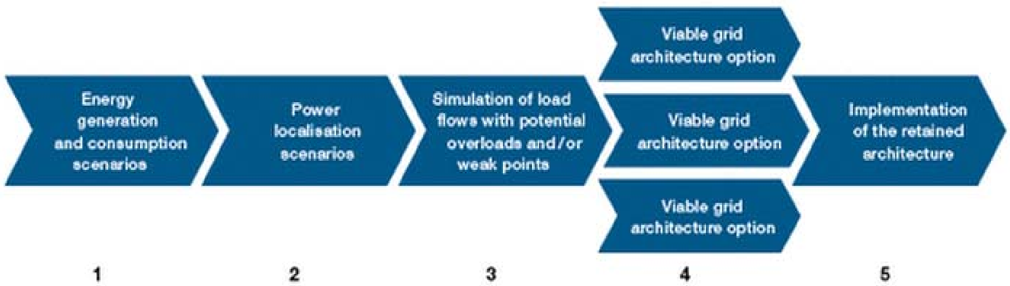


**Figure 3 – Long-term planning proposed in the e-Highway2050 project (Source: www.e-highway2050.eu)**

- EU Roadmap for moving to a low-carbon economy in 2050[18]

The EU 2050 Roadmap is a first step towards a common agreed vision for offshore and other renewable generation sources. This Roadmap looks beyond the 2020 objectives and sets out a cost-effective pathway for reducing emissions in 2050 by 80 to 95% compared to 1990 levels. This will require a massive deployment of renewable generation.

[18] See: http://ec.europa.eu/clima/policies/roadmap/index_en.htm

Table 3Table 3 presents the main recommendations for TF 2 and identifies ongoing measures dealing with the respective barriers.

**Table 3 – Main recommendations for TF 2**

| | Ongoing measures | Further measures |
|---|---|---|
| Definition of clear targets for offshore generation beyond 2020 as the main driver for offshore infrastructure development | EU Roadmap 2050 | Encourage EU member countries to actually agree on renewable targets for 2030 and 2050 |
| Establishing a clear regulatory framework for offshore generation | NSCOGI | |
| Creating mechanisms for the coordination of planning, development and operation of common offshore grid infrastructure | NSCOGI, Coreso, e-Highway 2050 project | |
| Developing a framework for financing grid infrastructure | Energy Infrastructure Package | Improving debt financing options and incentivize equity financing |
| Incentivizing TSOs to invest R&D and in new and flexible grid technologies. | | Acknowledgement of efficient investment costs by NRAs |
| Harmonizing market designs and defining specific arrangements for offshore generation | NSCOGI, ACER FG on CACM | Establishing specific arrangements for offshore generation |

# 3. TASK-FORCE 3

Task-force 3 includes Demo 5, led by ELIA (Belgium TSO), and Demo 6, led by REE (Spanish TSO), and focuses on the application of flexible transmission grid technologies, such as Flexible AC Transmission Systems (FACTS) and Dynamic Line Rating (DLR), to increase the flexibility of the transmission network. The objectives of this chapter are to summarize the main conclusions of the impact assessment performed for each demo developed within TF 3 [1], to identify the main regulatory barriers preventing capturing the benefits provided by the demos and to propose recommendations for the identified barriers.

## 3.1. Demo 5

The fifth TWENTIES demonstration project (NETFLEX) combined the use of Dynamic Line Rating (DLR) and Phase Shifting Transformers (PST) devices with a Wide-Area Monitoring System (WAMS) to extend the use of the existing grid, while maintaining system stability. This demonstration focused on the impact of these technologies on the increase of net transfer capacities (NTC) in the Central Western European (CWE) region. DLR devices such as Ampacimons (used in demo 5) can be installed quickly on overhead lines to provide accurate measurements of the capacity of the transmission system in real time. Power Flow Controlling devices (PFCs) such as PSTs and HVDC links provide the means for changing and re-distributing power flows locally. Phasor Measurement Units (PMU) and WAMS provide real time information about system dynamics.

### 3.1.1. Main findings

Demo 5 successfully developed a reliable DLR which forecasts one and two days ahead and delivers an average transmission capacity gain of 10% over the seasonal ratings (with 98% confidence). A smart controller to optimize the use of PFCs for re-directing flows to transmission lines with spare capacity, taking into account N-1 security criteria, was also developed in demo 5. By comparing wind deviations and the uncertainties on wind forecasts, system operators are able to estimate which part of the remaining transmission capacity margin can be allocated to the market and which part must be reserved for security purposes. Tests showed that the smart controller could enable the integration of approximately 7% more wind power into the existing system. Finally, the damping forecaster developed in the demo showed that the existing PFCs do not have a significant impact on the damping ratio [39].

Together Ampacimons, PFCs, PMUs, and the developed DLR-forecaster, smart controller and damping-forecaster allow a more accurate operational planning of transmission grids thanks to a more accurate monitoring of capacities and stability, and a tighter control over the power flows. The enhanced network flexibility tested in demo 5 demonstrated that more power can be transmitted with the existing grid. It is important to emphasize though it does not create permanent physical capacity as such. The enhanced flexibility allows network operators to close the gap between grid congestions and the effective commissioning of new network capacity, which takes between 5 to 10 years. Consequently, it allows a higher integration of variable generation with existing network assets.

The most significant economic benefit of the technologies tested in TF 3 is related to the relief of transmission congestions, which reduces the need to perform topological maneuvers and to redispatch out-of-merit generation, thus enabling a more efficient operation of the system. In WP15 the economic benefits of installing PFC and DLR devices were computed in terms of system costs savings due to higher NTCs in Belgium and in the CWE region. According to the results of this analysis the application of a smart-controller of PFC devices in the Belgium borders could reduce system operation costs by 50 M€ and by 250 M€ if fully deployed in the CWE region. The broad deployment of DLR devices in CWE region could reduce system operational costs by 125 M€.

### 3.1.2. Identified regulatory barriers and proposed recommendations

1) Current situation

Demo 5 demonstrated that the adequate coordination of smart transmission technologies (DLR, FACTS and WAMS) can bring more flexibility and economic benefits to the interconnected transmission system. Nevertheless, regulatory policies were in general not designed to foster grid modernization and current investment in R&D is still low. Deployment of new and flexible grid technologies is costly and, without incentives, TSOs are reluctant to invest in those technologies [40]. Furthermore, different regulatory frameworks for planning, developing and operating transmission grids may prevent effective collaboration across EU Member States. The main barriers for scaling-up the solutions tested in demo 5 are the following:

- *Lack of coordination across TSOs for the planning of transmission investments:* as mentioned in Section 2.1.2, generally each TSO is responsible for planning transmission infrastructure investments. Bilateral planning of interconnection capacity is common between TSOs. Nevertheless, multilateral planning coordination is needed when the planned infrastructure affects/influences power flows of various control areas.
- *Lack of harmonization among national network codes:* as mentioned in Section 2.1.2, in general codes for network operation (e.g. congestion management procedures and curtailment of renewable generation) are developed by each TSO for its control area. If a common infrastructure is developed, these codes must be harmonized or agreed among the involved TSOs.
- *Uncertainty related to investments in new/alternative transmission technologies:* building new transmission lines is the core business of TSOs. Usually, this activity is risk-free since the TSO know the costs and the impact on the network caused by new transmission lines and gets a regulated remuneration for that service. Nevertheless, investing new technologies with significant costs and whose benefits are not completely known still prevent TSOs from using technologies such as FACTS and DLR devices.

2) Regulatory recommendations for the implementation of flexible grid technologies in interconnected control areas

In order to foster investments in new and flexible grid technologies, **regulators must take a strong leadership role in supporting grid modernization by defining appropriate incentives for TSOs** to invest in R&D and innovation. Furthermore, **European regulatory frameworks for grid infrastructure development and operation must be harmonized** (or at least a high level coordination must be achieved).

- Developing methodologies for coordinated transmission planning and applying them to elaborate a development plan. Regional initiatives and organizations (such as Coreso) should be developed;

- Harmonization of grid codes (e.g. congestion management, priority access and renewable energy curtailment) for the operation of common infrastructure. As previously mentioned, organizations such as Coreso is a good approach for an efficient operation of integrated networks, especially when common assets are involved.
- Incentivizing TSOs to invest in new and flexible grid technologies. As previously described, the deployment of modern grid technologies is costly and, without clear incentives, TSOs are reluctant to invest in these technologies. In this sense, NRAs should incentivize TSOs to invest in R&D by defining cost-reflective network tariffs. Furthermore, efficient costs of new technologies must be acknowledged by NRAs in order to reduce TSOs investment-related risks.

## 3.2. Demo 6

The sixth TWENTIES demonstration project (FLEXGRID) tested the capability of a Flexible AC Transmission Systems (FACTS) device and a Real-Time Thermal Rating (RTTR) system to bring flexibility, enhance security and expand the capability of the network to evacuate more wind generation. This demonstration focused on the impact of these technologies on local constraints in the Spanish transmission network.

### 3.2.1. Main findings

Both the FACTS device and the RTTR system have been validated by simulations, lab tests and infield demonstrations. The application of these technologies provides extra capacity for the integration of renewables and increases operational security [41]. With the same level of security, these developments allow a more efficient management of the electrical grid by:

- Increasing the availability of infrastructure;
- Optimizing the management of the networks;
- Balancing the loads in the lines;
- Setting out immediate corrective actions.

Under WP15, the economic impact of demo 6 was assessed in terms of avoided redispatch costs and it was performed for five transmission lines representing four areas within the Spanish transmission network: Aragon (area where the devices were actually installed), North, Northeast, South and Center. The detailed technical analysis performed demonstrated that the impact of FACTS and DLR devices can vary greatly from one area to another. In general it was observed that in some areas these technologies can bring significant benefits in terms of redispatch cost savings, while in less congested areas the economic benefits are lower. In this respect, the areas where the highest economic benefits could be achieved do not always correspond to the most congested area. This can be explained by the fact that in some areas the capacity gain provided by the tested technologies is limited due to transmission constraints of nearby lines. For those areas, FACTS and DLR technologies can be a mid-term solution for transmission congestions (i.e. until the network is reinforced or new are built). In less congested areas, FACTS and DLR solutions could be an economic alternative to the reinforcement of the network, especially taking into account the long construction times required to build a new line and the strong public opposition which can delay significantly the realization of these projects.

### 3.2.2. Identified regulatory barriers and proposed recommendations

1) Current situation

Demo 6 has demonstrated that flexible transmission grid technologies such as FACTS and DLR devices can bring significant economic benefits in terms of operation costs savings to power systems. Furthermore these types of technologies are becoming increasingly important due to the growing need for transmission capacity expansion, which is motivated mainly by the high penetration of renewable generation. Added to that, building new transmission lines requires long construction times and faces strong public opposition, that may delay further or even jeopardize transmission investments.

Nevertheless, as explained in Section 3.1.2, installing technologies such as FACTS and DLR is not the common practice among TSOs. The deployment of these types of technologies is costly and benefits are still not integrated in TSO operation procedures. Consequently, TSOs are still reluctant to invest in these technologies.

2) Regulatory recommendations for the investment in flexible transmission grid technologies

Similarly to demo 5, in order to promote the investment in flexible transmission grid technologies, **NRAs must provide incentives to the TSOs to invest in R&D and innovation**. Furthermore, **efficient costs incurred due to the investment in new grid technologies must be recognized by regulators** so that the risks for the TSO are minimized.

## 3.3. Transversal analysis of Task-Force 3

Both demos developed within TF 3 have demonstrated that flexible transmission grid technologies can bring technical and economic benefits to the system and, in some cases, even delay building new transmission lines. As seen in this chapter, the main regulatory barriers to a large-scale implementation of these technologies are related to the lack of incentives provided to TSOs to invest in new technologies and to the lack of coordination among them to build and operate common infrastructure.

*Main regulatory recommendations for TF 3*

- Incentivizing TSOs to invest in R&D and in new and flexible grid technologies.

NRAs must incentivize TSOs to invest in R&D and acknowledge efficient costs of investments in new technologies. This requires the definition of cost-reflective network tariffs.

- Creating mechanisms for the coordination of planning, development and operation of common grid infrastructure

Regional initiatives or organizations such Coreso for the coordination of planning, development and operation should be encouraged by the EU and NRAs. As explained in Section 2.3, this requires (i) the clear identification of technical and economic benefits of coordinated infrastructure development in respect to isolated (TSO level) grid development; (ii) ex-ante identification of “winners” and “losers” and allocation of costs and benefits among them; (iii) acknowledgement from NRAs of efficient in investments in cross-border infrastructure as part of the Regulated Asset Base of TSOs.

*Main ongoing measures/projects*

- Coreso

Coreso is an independent company where engineers from several nationalities work together to check and improve electricity security of supply in Western Europe. Coreso carries out studies to analyses the security of the interconnected European transmission grids by simulating various scenarios, such as the sudden unavailability of an interconnecting line, and then formulate a plan of action required to ensure the continuing security of the transmission grid. These studies, together with proposed plans, are submitted to the TSOs' national control centres which assume operational responsibility for secure operation of their respective grids. Also, participates actively the CWE (Central Western Europe)[19] regional market coupling process by performing two-day-ahead forecasts for the CWE area.

- GridTech EU Project[20]

The objective of the GridTech Project is to conduct a fully integrated assessment of new grid technologies and their implementation into the European electricity system. The main objectives of the project are:

(i) The assessment of non-technical barriers to transmission expansion and to the integration of renewable electricity in European electricity markets;
(ii) The development of a robust cost-benefit analysis methodology for investments in new grid technologies;
(iii) The application of the cost-benefit methodology for investments in the transmission grid on national and European level;
(iv) The achievement of common understanding among key actors and target groups on best-practice criteria for the implementation of new technologies fostering large-scale renewable electricity and storage integration;
(v) Proposal of recommendations and action plans, taking into account the legal, regulatory, and market frameworks.

The final results of the project are expected to be delivered in the beginning of 2015.

Table 3Table 4 presents the main recommendations for TF 2 and identifies ongoing measures dealing with the respective barriers.

**Table 4 – Main recommendations for TF 3**

| | Ongoing measures | Further measures |
|---|---|---|
| Harmonizing market designs and defining specific arrangements for offshore generation | NSCOGI, ACER FG on CACM | Establishing specific arrangements for offshore generation |
| Incentivizing TSOs to invest R&D and in new and flexible grid technologies. | | Acknowledgement of efficient investment costs by NRAs |

[19] The CWE region comprises Belgium, France, Germany Luxembourg and the Netherlands.
[20] See: www.gridtech.eu

| | | |
|---|---|---|
| Creating mechanisms for the coordination of planning, development and operation of common grid infrastructure | Coreso, GridTech project | |

## 4. Conclusions

The six demonstration projects developed within the TWENTIES project proved that the proposed solutions can bring technical and/or economic benefits to power system and foster a higher and more efficient integration of renewable generation into the European power system. Nevertheless, important regulatory barriers still prevent TWENTIES proposed solutions to be adopted in large-scale. This report described in detail the main regulatory barriers related to the capabilities tested in each demonstration, proposed specific recommendations to overcome those barriers and identified main ongoing measure dealing with the different described issues.

The table presented below summarizes the main general regulatory recommendations proposed in this document.

| | Main TF, but also important for TF | Ongoing measures | Further measures |
|---|---|---|---|
| Establishing market mechanisms for the procurement of system services | **TF 1**, TF 2 | ACER FG on Electricity Balancing | ENTSO-E NC development |
| Allowing the adjustment of bids for balancing services closer to real-time operation | **TF 1**, TF 2 | | Introducing sequential intraday auctions |
| Defining products that incentivizes the participation of all potential participants | **TF 1**, TF 2 | ACER FG on Electricity Balancing, REserviceS project, eBADGE project | ENTSO-E NC development |
| Increasing the liquidity of intraday markets | **TF 1**, TF 2 | | Introducing sequential intraday auctions |
| Imposing balancing responsibility on all market participants | **TF 1**, TF 2 | ACER FG on Electricity Balancing | ENTSO-E NC development |
| Defining cost-reflective imbalance prices | **TF 1**, TF 2 | | TSOs should charge actual deviation costs to unbalanced parties (capacity and energy) |
| Definition of clear targets for offshore generation beyond 2020 as the main driver for offshore infrastructure development | **TF 2** | EU Roadmap 2050 | Encourage EU member countries to actually agree on renewable targets for 2030 and 2050 |
| Establishing a clear regulatory framework for offshore generation | **TF 2** | NSCOGI | |
| Creating mechanisms for the coordination of planning, development and operation of common offshore grid infrastructure | **TF 2** | NSCOGI, Coreso, e-Highway 2050 project | |
| Developing a framework grid infrastructure financing | **TF2**, TF 3 | Energy Infrastructure Package | Improving debt financing options and incentivize equity financing |
| Providing incentives for TSOs to invest R&D and in new and flexible grid technologies. | **TF 2, TF 3** | | Acknowledgement of efficient investment costs by NRAs |

| | | | |
|---|---|---|---|
| Harmonizing market designs and defining specific arrangements for offshore generation | **TF2**, TF 1 | NSCOGI, ACER FG on CACM | Establishing specific arrangements for offshore generation |
| Creating mechanisms for the coordination of planning, development and operation of common grid infrastructure | **TF 3** | Coreso, GridTech project | |

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## 6. Appendix: Practical approach for the approval of aggregated ancillary services

The approach proposed by DONG Energy for the approval of aggregated ancillary services is divided into (i) Verification and (ii) Proof:

(i) Verification:

The verification comprises 4 steps:

1. VPP Operator describes how aggregation rules ensure that:
    - Combined bids comply with market rules (e.g. production and consumption units are not mixed);
    - Offered capacity can always (or with some degree of certainty) be delivered.

| How does the VPP ensure: | VPP Operators desciption |
|---|---|
| **That offered volume can always be delivered** | *Unit Owners submit an ability forecast for each unit at least one day ahead.*<br>*It is assumed that the ability forecast is reliable. A reduction factor is considered for contributions from energy limited units*<br>*Power Hub's ability to manage insufficient deliveries from single units – e.g. due to energy limitations – are demonstrated under 'Proof'.* |
| **No bids across price areas or across Production and Consumption domain** | *When creating production and consumption units in Power Hub, they are always allocated to different 'Sites'. One Site can only submit bids to one Production BRP or one Consumption BRP and only for one price area.*<br>*In this way, bids are kept separately.* |
| **Combined bids comply with technical requirements on:** | |
| **1. Minimum Power** | … |
| **2. Response time** | … |
| **3. Linearity** | … |
| **4. Durability** | … |

**Figure 4 – Example of Step 1**

2. TSO sets up a test set where the simple sum of the non-compliant capacity is larger than the compliant aggregated capacity. This test set consists of:
    - A number of production and consumption units (at least 4 – 5 of each) with relevant technical data and forecasts;
    - Service requirements on power, response time, ramp rates and response duration;
    - The expected result (allowed aggregated capacity).

The test comprises a set of technical data and forecasts for the different units. A test set for primary reserve in Western Denmark based on production units could look like this:

| Unit | Type | Response 50 / 100% | Linearity 1) | Durability 2) (15' slots per hour) | 'Ability forecast' 3) | | | Comment |
|---|---|---|---|---|---|---|---|---|
| A | Production | 15 s / 30 s | Complies (analogue) | 1 | 250 / 0-250 MW (00:00-06:00) | 350 / 100-350 MW (06:00-12:00) | 200 / 200-200 MW (12:00-24:00) | Will not contribute due to too short durability |
| B | Production | 30 s / 60 s | Complies (analogue) | 2 | 0 / 0-0 MW (00:00-08:00) | 400 / 50-500 MW (08:00-18:00) | 100 / 50-500 MW (18:00-24:00) | Only half capacity due to half response time |
| C | Production | 15 s / 30 s | Complies (analogue) | 3 | 250 / 0-250 MW (00:00-06:00) | 200 / 100-400 MW (06:00-12:00) | 200 / 200-400 MW (12:00-24:00) | |
| D | Production | 30 s / 60 s | Complies (analogue) | 4 | 50 / 50-500 MW (00:00-08:00) | 400 / 50-500 MW (08:00-16:00) | 250 / 50-500 MW (16:00-24:00) | Only half capacity due to half response time |
| E | Consump-tion | 15 s / 30 s | Complies (analogue) | 1 | 250 / 0-250 MW (00:00-06:00) | 350 / 100-350 MW (06:00-12:00) | 200 / 200-200 MW (12:00-24:00) | Will not contribute due to too short durability |
| F | Consump-tion | 30 s / 60 s | Complies (analogue) | 2 | 0 / 0-0 MW (00:00-08.00) | 400 / 50-500 MW (08:00-18:00) | 100 / 50-500 MW (18.00-24.00) | Only half capacity due to half response time |
| G | Consump-tion | 15 s / 30 s | Complies (analogue) | 3 | 250 / 0-250 MW (00:00-06:00) | 200 / 100-400 MW (06:00-12:00) | 200 / 200-400 MW (12:00-24:00) | |
| H | Consump-tion | 30 s / 60 s | Complies (analogue) | 4 | 50 / 50-500 MW (00:00-08:00) | 400 / 50-500 MW (08:00-16:00) | 250 / 50-500 MW (16:00-24:00) | Only half capacity due to half response time |

**Figure 5 – Example of step 2**

3. Prior to commissioning, the TSO presents the VPP Operator with the test set(s) and:
    - The test set is entered in the VPP by the VPP operator;
    - The VPP operator extracts capacity bids for the desired period and service;
    - The TSO representative checks that aggregated capacity match the expected result;
    - The test is repeated for the remaining services.

In step 3, the VPP calculates the maximum available capacity per bid block:

| Type | Direction | Bid, block 1 00:00-04:00 | Bid, block 2 04:00-08:00 | Bid, block 3 08:00-12:00 | Bid, block 4 12:00-16:00 | Bid, block 5 16:00-20:00 | Bid, block 6 20:00-24:00 |
|---|---|---|---|---|---|---|---|
| Production | Up Reserve | 0 kW | 0 kW | 300 kW | 300 kW | 375 kW | 525 kW |
| | Down Reserve | 0 kW | 0 kW | 450 kW | 350 kW | 0 kW | 0 kW |
| Consumption | Up Reserve | 0 kW | 0 kW | 450 kW | 350 kW | 0 kW | 0 kW |
| | Down Reserve | 0 kW | 0 kW | 300 kW | 300 kW | 375 kW | 525 kW |

**Figure 6 – Step 3**

4. Evaluation of test:
    - If test is passed, the VPP is approved for (continued) use;
    - If the test fails, the test is repeated on the same day if possible. If not, a new test date is arranged within a short period.

The VPP should comply with the maximum permissible offered capacity (larger than 0.3 MW and one decimal only). These figures are compared by the TSO representative to the expected results shown in Figure 7 (permissible aggregated capacity):

| Type | Direction | Bid, block 1 00:00-04:00 | Bid, block 2 04:00-08:00 | Bid, block 3 08:00-12:00 | Bid, block 4 12:00-16:00 | Bid, block 5 16:00-20:00 | Bid, block 6 20:00-24:00 |
|---|---|---|---|---|---|---|---|
| Production | Up Reserve | 0 MW | 0 MW | 0.3 MW | 0.3 MW | 0.3 MW | 0.5 MW |
| | Down Reserve | 0 MW | 0 MW | 0.4 MW | 0.3 MW | 0 MW | 0 MW |
| Consumption | Up Reserve | 0 MW | 0 MW | 0.4 MW | 0.3 MW | 0 MW | 0 MW |
| | Down Reserve | 0 MW | 0 MW | 0.3 MW | 0.3 MW | 0.3 MW | 0.5 MW |

**Figure 7 – Permissible aggregated capacity**

This approach has been discussed with the Danish TSO, focusing on the following issues:

- Feasibility:
    - Is it feasible – and practical – from a TSO point of view?
    - How is the balance between “simplicity” and “reliability”?
    - How should new releases/modifications introduced in the VPP (e.g. new units) be tested?
        - Per request from VPP operator prior to release?
        - Periodic test (e.g. twice a year)?
        - Tests without prior notification (e.g. twice a year)?
        - Combinations, other?
- Is it applicable to other countries in Europe?

The conclusion is that it is feasible to approve combined deliveries for ancillary services. Nevertheless, binary and intermittent units with shorter response duration than a bid block (four hours in the case of primary reserve in Western Denmark) are still a challenge.

(ii) Proof:

When performing the proof of the VPP it is important to decide on 3 parameters:

1. The activated capacity [MW]: the proof can be performed with the entire offered capacity or just a share;
2. The activation degree [%]: this is determined by the frequency deviation (primary reserve) or activation signal (secondary and manual reserves). As opposed to 1., the activation degree can be used to test the linearity (ramp response) of the reserve;
3. The duration (minutes).

The project has proposed 4 different test methods to the Danish TSO: one full test and three partial tests. The approach and test methods have been discussed with the TSO and their comments are mentioned below:

A **full-capacity, full-activation, full-duration test** can be illustrated like this:

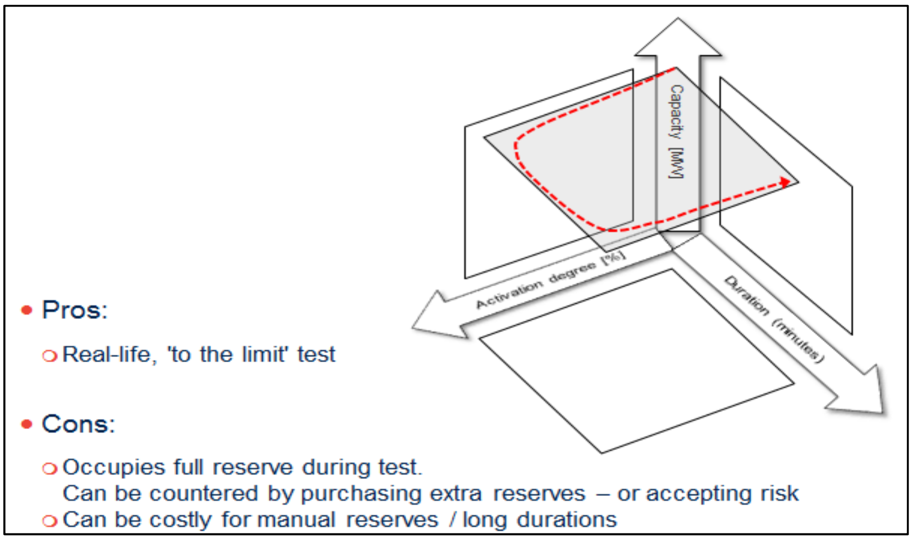
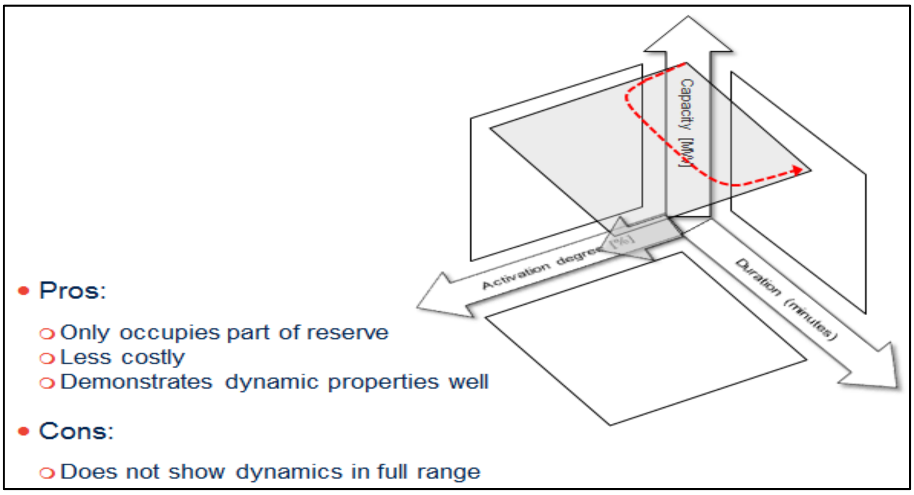



**Figure 8 – Full test**

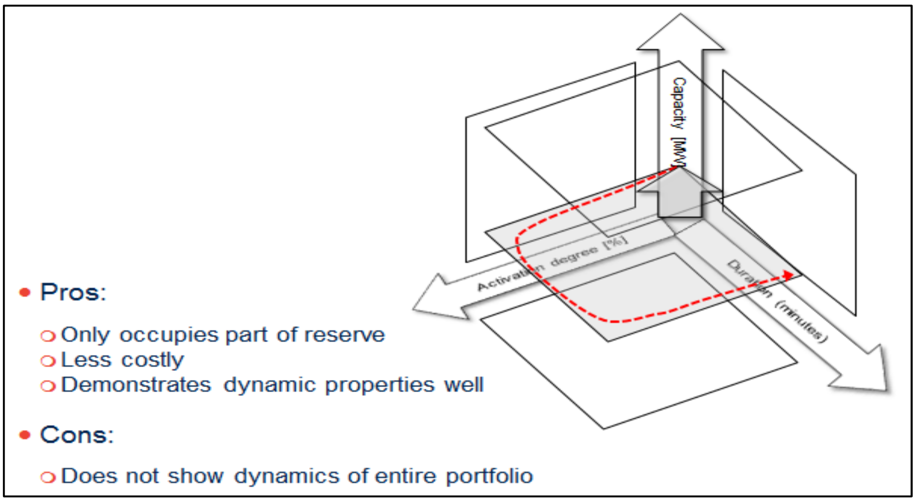
- In brief, Energinet.dk has accepted the proposal; the operationalization is pending;
- Energinet.dk prefers this test for manual reserves. Normal duration will be at least one hour. In order to mitigate the cost issue, the test may be carried out a day where the reserve has to be activated anyway;
- Although this is the ultimate proof of the full reserve, it would be more practical to perform a partial test for the reasons stated above. Also, for analogue reserves a full test cannot show the linearity of the reserve.

For this reason, three alternative partial tests were proposed (Figure 9):

a) **Full-capacity, *partial*-activation, full-duration test:** Energinet.dk does not regard this solution as satisfactory; among other issues it invites the VPP operator to be selective in which units should participate in the test.



b) ***Partial*-capacity, full-activation, full-duration test:** Energinet.dk does not regard this solution as satisfactory for the same reasons stated above.




c) **Full-capacity, full-activation, *partial*-duration test:** Energinet.dk finds this test suitable for primary and secondary reserves as a supplement to the evaluation of performance in normal operation and after major incidents.

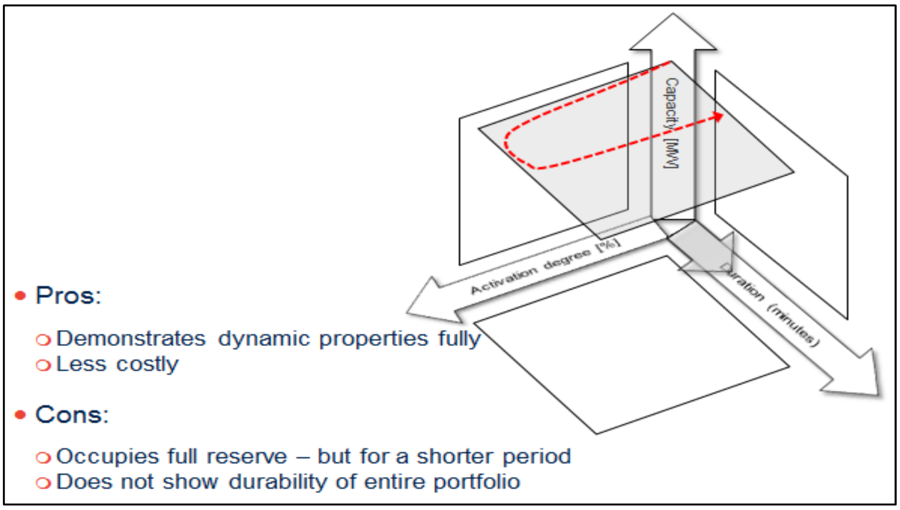



**Figure 9 – Proposed partial tests**

### Activation: Primary reserve

For the actual activation of the primary (frequency based) reserve, three different methods were proposed:

1. VPP broadcasts "fictitious" frequency measurement (e.g. 49.91 Hz ~ 50 % activation). Good test for amount and dynamics (provided synchronous broadcast);
2. VPP off-sets power frequency characteristic by a certain amount. Fair test of amount and dynamics; however, baseline is moving due to the natural frequency variations in the power system

3. VPP broadcasts “fictitious” frequency measurements to be applied by [t start; t stop] Good test of amount and dynamics, but complex.

Energinet.dk prefers that aggregated primary reserve are tested using method “2” since broadcasting a fictitious frequency implies a risk that the units do not return to using the actual power system frequency measurement after the test.

**Activation: Secondary reserve (LFC) in Western Denmark**

For the actual activation of the secondary reserve in Western Denmark, two different methods were proposed:

1. VPP calls for an absolute amount of reserve [MW]. Good test of amount and dynamics;
2. VPP off-sets actual secondary reserve by a certain amount [ΔMW]. Fair test of amount and dynamics; however, baseline is moving.

Energinet.dk prefers that aggregated secondary reserves are tested using method 1.

As for follow-up on the dynamic response, it was discussed whether the VPP should follow the same characteristic as the central power plants participating in secondary reserve provision. For now a simple static model is sufficient, even though the dynamic response of a VPP varies with the participating assets.

Energinet.dk requires that the settings of any controller in the VPP must be coordinated with the overall LFC controller settings. Such a controller has not yet been implemented in the VPP Power Hub. Energinet.dk may make an exemption from this requirement for pilot projects, e.g. the test phase of a future LFC in DK2.