RESPOND
Renewable Electricity Supply interactions with conventional POwer generation, Networks and Demand

Recommendation of Policy and Regulatory options

- for facilitating large shares of intermittent RES into the power supply system -

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Project objectives

The RESPOND project aims at identifying efficient market response options that actively contribute to an efficient integration of (intermittent) RES-E and DG in the European electricity system and it recommends policy and regulation framework improvements that effectively support these market response options. Other objectives are:

- Evaluate the impacts of increasing penetration of intermittent type of RES&DG (i.e. wind, PV etc) in the electricity system;
- Identify and analyse efficient response options (from generation till demand) that actively can support an efficient integration of intermittent RES-E and DG in the electricity system;
- Identify barriers and failures in market competition and regulation that hinder the response options to be developed and implemented by market participants.
- Formulate regulatory and institutional improvements for absorbing large-scale contribution of variable RES-E&DG
- Develop Roadmaps for implementation of these regulatory & institutional system changes in five key EU countries

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Executive summary

Integration of a large share of intermittent RES&DG power generation, in particular wind, creates a number of problems for the electricity system in a country. These are mainly related to the unpredictability and variability of the power production. Reducing the impacts causes extra system costs for the system, if tackled in a traditional power system setting. But, if a number of technical rules and regulations are changed, market-based efficient integration of variable renewable energy technologies for electricity generation is possible. This report (D7) is analysing all measures and response options for changes in regulation and institutional setting per country. Furthermore, it formulates recommendations for improving the policy and regulatory framework in order to implement the response options, barriers for implementing them and the in five countries, required changes in regulatory, institutional and policy framework as identified in the earlier reports (D5 & D6).

Distributed and renewable generation

With larger penetration of intermittent type generation, in particular wind, also the impacts and, thus, the design of support schemes for promoting RES&DG becomes more important. Some of the DG/RES technologies – in particular CHP for larger heat distribution networks – are able to contribute significantly to handle intermittency, e.g. by adding heat storages, heat pumps, or electric boilers for down-regulation. Replacing feed-in tariffs with premiums on market prices is an important measure to expose DG/RES technologies to market prices which reflect the system wide supply and demand for electricity. Consequently, DG/RES will adjust their production schedules and produce only when it has added value for the electricity system and society as a whole. Commercial aggregators with a portfolio of small generating units will play a more and more important role on the market, e.g. in the form of ‘virtual power plants’. Also, the design of markets is important. Market splitting – following the principles from the Nordic electricity exchange, Nord Pool – into geographical areas with transmission constraints to neighbouring areas and large penetration of intermittent generation will create market prices that will encourage generators to contribute to system stability. Finally, technical requirements set up in the national grid codes such as fault-ride through capability should also be applied to small generators.

Conventional generation

In general, variable type of DG/RES will reduce the utilisation of existing and planned conventional units. This may create financial problems for owners (i.e. utility companies) and discourage their investment in new capacity. In addition, conventional generators will also have to face market incentives or legal obligations to supply balancing power and ancillary services, when needed by the electricity market. All and all, much of the extra system

requirements caused by variable DG/RES could lead to an extra burden for the conventional generators and their owners.

The main recommendation for increasing capacity firmness and investment in conventional generation will be that support schemes for maintaining existing conventional capacity should be considered in relation with existing support schemes for DG/RES. The location of new units is also an important factor. In particular, the existence of urban district heating grids or the potentials for the development of large urban grids from existing heating systems should be accounted for when tendering for new units and their site. Furthermore, one should note that some investment in new capacity intensive base-load systems (e.g., nuclear, carbon capture and storage – CCS) are highly depend on political decisions and strong support from the industry rather than market incentives.

In some situations the installation of base-load capacity rather than peaking plants might not be a sufficient guarantee to provide the flexibility that is needed in the future systems. Consequently, the required suitable capacity needs to be pushed through extra regulatory measures. Already now, market mechanisms in the form of annual, monthly or daily auctions may be used for reserve capacity, which may encourage contingency units or autoproducers with low utilisation time to contribute to peak load. In some cases, new capacity built for peak load may be needed.

Demand response

The functionality and a common standard for consumption meters should be decided upon as soon as possible. This to facilitate a timely development of a scheme for a general roll-out of meters, including an option to introduce simple meters, but to prepare these in advance for upgrades to so called “intelligent meters” that may receive signals and control the consumption of specific appliances. If intelligent meters should be an interesting option ,centrally controlled operation and updates of the software controling the functioning of the meter are necessary.

Customers should be charged the marginal cost of production and delivery of electricity to individual customers. Given hourly metering day-ahead prices in the market appear reasonable, giving the customer time to plan its consumption. If intelligent meters and price controlled cut-off units are installed, real time pricing and automatic response is an option. If congestion in the network implies local differences in supply/delivery costs than the consumer prices should also reflect these cost differences. Fixed price-additives should be reduced and as much as possible and changed into percent additives on the hourly prices. And this will increase the volatility of annual revenues and bills to be paid by customers.

Enabling technologies that increase demand flexibility fall in two categories: Control technologies and technologies that increase the share of flexible demand. In the medium term, technologies and communication standards should be developed for control technologies, while demonstration projects showing benefits and needed improvements can and should be carried out in the short term.

Concerning additional flexible demand, in the short term, heating and storage of heat is a relatively cheap option. In the medium and long term, other storage facilities and electrical vehicles (as demand load management tool) are promising technologies. Especially concerning the application of electric vehicles, the controllability of charging and possibly discharging of batteries is an important issue to solve first.

National Markets

The key instruments for integration of DG/RES are the electricity spot markets, which have been developed in several countries or regional groups of countries over the last two decades. These markets were not developed to support DG/RES, but as an instrument to introduce competition into the electricity supply industry, which should lead to less institutional and technological conservatism. There has been a dynamic development of the electricity markets in Europe. These markets have been able to accommodate the various new technologies. Further developments are being planned, often to facilitate the integration of distributed technologies and improve competition. Also the international integration of the markets is under development. However, in the short and medium term European harmonisation of rules may be premature or even counterproductive for the successful integration of European electricity markets. So far, the practical experience of the market participants is limited, and methods to analyse market results are yet to be developed.

The larger penetration of intermittent generation requires increasing the availability of balancing energy and the provision of reserve capacity, in order to guarantee the security and the reliability of the electricity system. Thus, the entrance of new flexible generation should be encouraged, as well as, an increase of the flexibility in the generation units that are already in operation, and also, of the demand. On the other hand, different options at European level are proposed to achieve possible reduction in local and total European needs for balancing such as the improvement of balancing coordinated actions among TSOs and the development of cross-border trading reserves.

Regional Markets

In order to achieve well functioning regional markets, new regional transmission lines would have to be built. To overcome the opposition of local people and authorities to the construction of these lines because of environmental reasons, which is a particular problem in the UK and Spain, could require – in the short to medium term – devoting congestion rents corresponding to other cross-border lines to their construction. Besides, benefits of the construction of these lines could be better explained. In the long term, some of these lines could be buried. An efficient inter-TSO payment scheme should be used to allocate the cost of interconnection lines, at least in the medium term. This would also allow authorities to overcome the opposition of those countries crossed by these lines that are not significantly benefitted by them, which represents a significant obstacle in Spain, the UK and the Netherlands. Side payments could also be paid to these countries, and in the long term, strong regional authorities could be left in charge of deciding over the construction of these lines. The creation of these authorities would speed up the process of obtaining permits for the construction of interconnectors (an issue in Spain, the UK and Denmark), together with the identification of a single entity within each country with jurisdiction over the approval of this type of lines, and applying efficient congestion management mechanism at regional level would render the construction of these lines more interesting to the region, which is for example demanded by parties in the UK.

In order to promote the coordination in the functioning of national markets within a region, coordinated implicit auctions are a useful instrument, possible to be implemented in the long term, to allocate regional short run transmission capacity. Consequently, complaints about the inefficiency of the methods and bureaucratic decision process presently heard in Spain, Germany and the Netherlands, might be effectively addressed. In the long term, an instrument as coordinated explicit auctions run by a central auctioneer should be used together with firm transmission rights. This seems to be a measure that needs to be implemented in all the countries considered in the study.

Transmission grid

Another solution for reducing a shortage of transmission capacity is applying locationally and temporally differentiated transmission charges, which stimulate a more efficient allocation of the cost of lines. Tariffs should be zonal and computed for each operation profile and technology in order not to become too volatile. Demonstration projects and marketing of this solution should be used to avoid the perception that these charges are discriminatory (an issue in Denmark, Germany and The Netherlands). To avoid support payments rendering transmission charges useless (issue in Spain and other countries), premiums instead of FITs should be pursued and the level of these premiums should be commensurated with the DG penetration level to be achieved. Most, if not all, these measures could be implemented in the medium term where shares of intermittent RES-E is expected to increase fast. Finally, generally in the medium term, existing methods to compute these tariffs should be replaced by simple ones used to compute charges in a limited number of zones and for a limited number of operation profiles.

Regarding the construction of new transmission lines, lines could be buried in densely populated areas, in order to reduce their possible impact on human health (perceived as a obstacle in the Netherlands, Spain and Germany). In order to do this, more efficient methods to bury lines could be developed and lines could be combined with other infrastructures (water, rail etc routes). Both measures will have an impact in the medium and long term. Besides, efficient cost allocation methods, based on beneficiaries theory, should be used to compute transmission charges in those countries where inefficiency problems are regarded a barrier (the UK). Transmission capacity in the UK should be allocated through more efficient coordinated market based methods, including efficient cost allocation methods. This instrument could be implemented in other countries in the medium term too. Finally, in order to ensure the profitability of network reinforcements in countries like the UK, the network expansion should be planned by a company, i.e. the TSO, with a public mandate to look after the satisfactory functioning of the system, using moderate cost reduction incentives. This instrument could be applied in other countries too and already in the medium term.

As for the necessary increase in the efficiency of congestion management methods, which has been considered an issue in Spain, Germany, the Netherlands and the UK, creating a central auctioneer in the region to allocate capacity on regional congested corridors would be the best alternative, though it would require making significant changes to regulation and might take some time to be implemented. Another possibility for addressing regional trade would be running an iterative market clearing process, which, nevertheless, would be (a too) complex process. As for internal congestion that occurs systematically, predetermined factors affecting the system price would allow one to compute the price in each area, similar to the market splitting method used by the Nordic power exchange Nord Pool.

Distribution grid

Introducing an instrument as “shallow connection charges with locational and temporal content” for addressing the issue of capacity bottlenecks seems necessary. However, this instrument is currently incompatible with national regulation in countries like Germany, the Netherlands and Spain. In order to solve this problem, major changes would have to be made to the electricity laws or locational signals would have to be sent through other means like DG/RES support payments. These could be applied in the short to medium term, depending on the shares of variable DG/RES. Another issue, in the Netherlands as well as other countries, is the volatility that these charges are believed to have. However, applying zonal tariffs that are only updated periodically could solve this objection.

Next step in improving the efficiency of DSO network planning and load management is providing incentives to DSOs for adopting the concept of “Active network management” (ANM). To overcome (in the Netherlands, UK, Germany and Denmark) the lack of reliable estimates of the individual impact of DG/RES connection and use of network (energy losses and quality of service), reference models to estimate the impacts can be used. DG may also have impacts on other system variables and performance indexes that all affect the DSOs' remuneration. Developing the enabling technologies to implement ANM is seen as a urgent necessity in Germany, the Netherlands, Spain and Denmark. This to deal with large scale connections of DG/RES to distribution grids. One could include these R&D costs in the regulated remuneration of DSO companies, so using higher rates of return than usual or/and pass-through of these costs to tariffs can solve that hurdle. Apart from this, the regulatory period before efficiency gains are included in tariffs (producing a reduction of these tariffs) could be extended. Measures to stimulate AMNs could be applied in the short term.

Finally, when trying to get DSOs to include DG (and its positive effects) in network planning, in Spain and the Netherlands, the authorities have again found it difficult to compute the revenues of DSOs when considering DG. Here again, reference network models could be used and the DSO should also keep part of the efficiency gains for themselves (at least in the first regulatory period). And in relation hereto to prevent RES support payments from interfering with the controllability of DG by DSOs (issue in Spain and the Netherlands) premiums instead of FITs should be applied. These premiums should also exhibit some kind of temporal differentiation. All measure to be applied in the short term.

Overall conclusion

The current liberalised electricity market has created an institutional structure of the electricity supply with an open and much more dynamic developments than in the previous organisation of the power industry. A new market environment with fewer traditional barriers but needing many other changes in the market competition and network regulation to secure also in the future a reliable and secure electricity supply to the customers in all EU countries. The spot and balancing markets are changed and adapted continuously in many countries to meet the new needs of the electricity system with increasing and large shares of intermittent type of RES generation and distributed technologies.

However, several system conditions mostly based on the past conventional generation and supply of electricity must be altered or changed to favour the integration of much more DG/RES. Generally, most of the measures proposed can be summarised and categorised as measures or regulation for:

- Increasing the flexibility of conventional generation, i.e. hydro power with reservoirs and gas fuelled plants.
- Constructing more transmission capacity.
- Enhance response capabilities by peak load units and heat distribution systems supplied by CHP.
- Establish commercial aggregators to develop 'virtual power plants'.

- Establish geographical price areas for spot and balancing markets to provide price signals for demand response and network congestion management.
- Regulation for proper pricing for incentivising demand response and Active Network Management by DSOs.

All measures proposed here are used in the next report to develop Regulatory Roadmaps for the countries considered in the RESPOND project. These can support authorities and institutions in the different countries to implement measures to facilitate absorbing larger shares of variable DG/RES technologies.

Acronyms and abbreviations

ANM	Active network management
APX	Amsterdam Power Exchange
AS	Ancillary services
BERR	Department for Business Enterprise & Regulatory Reform
BRP	Balance Responsible Party
BSC	Balancing and Settlement Code
CCL	Climate Change Levy
CECRE	Control Centres for Renewable Energies (Spain)
CHP	Conbined heat and power
DG	Distributed generation
DSO	Distribution system operator
DSM	Demand side management
DSR	Demand side response
EC	European Commission
EFET	European Federation of Electricity Traders
EEX	European Electricity Exchange
EU	European Union
FIT	Feed-in tariff
IEM	Integrated Energy Market
ICT	Information and communication technologies
IFI	Innovation funding incentive
ITC	inter-TSO Compensation
LRIC	Long Run Incremental Cost
MO	Market operator
MS	Member state (of the European Union)
nTPA	Negotiated third party access
Ofgem	Office of gas and electricity markets
PPA	Power purchase agreements
PV	Photo-voltaic
PRP	Programme responsible party
RES-E	Electricity generation from renewable energy sources
RO	Renewables Obligation
RPZ	Registered power zones
rTPA	Regulated third party access
SO	System operator
SP	Spain
ToU	Time of use
TPA	Third party access
TSO	Transmission system operator
UK	United Kingdom
UoS	Use of system
RPZ	Registered power zones
VPP	Virtual power plants

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1 Introduction

The RESPOND project aims at identifying efficient market response options that actively contribute to an economic efficient integration of (intermittent) Renewable Energy Sources (RES) and Distributed Generation (DG) in the European electricity system. Furthermore, the project develops and formulates recommendations for improving the policy and regulation framework in five EU countries (Denmark, Germany, The Netherlands, Spain and the UK, etc) for effectively support implementing these market response options. In brief the objectives are to:

- Evaluate the impacts of an increasing penetration of intermittent type of RES and DG generation and electricity supply on the system;
- Identify and analyse efficient response options of market participants that actively support an efficient integration of these variable RES and DG in the electricity system;
- Identify barriers and failures in market competition and regulation that hinder the necessary (system changes) response options to be developed and implemented by market participants.
- Analyse, and assess improvements and changes of the policy and regulatory framework per country that facilitate the development and implementation of the recommended response options by market participants
- Formulate recommendations and a roadmap per country for implementing these regulatory, system technical and institutional improvements

More precisely RESPOND project study focuses its attention on the current most important intermittent technologies, i.e. micro-CHP and photovoltaic (PV) (on low voltage networks in both urban and rural areas), off-shore wind generation (on extra high voltage networks) and on-shore wind generation (on medium and high voltage networks in rural areas).

So far the RESPOND project (deliverable D4) has reviewed and assessed the most important technical and economic (costs) impacts relate to the variability and the unpredictability of generation from intermittent energy sources (DG, RES, micro-CHP, PV) on the power systems from generation, via trade and balancing till consumption of electricity. Next the project (deliverable D5) has identified and classified a set of relevant technical and regulatory respond options to remove or reduce the previously identified negative system impacts of increasing DG/RES penetration, i.e. on generation, demand, markets and transmission and distribution networks. Important was also the part on unconventional response possibilities that arise in the dynamic electricity system including interaction between for example storage, demand response and market rules. The conditions and needs of the electricity system in five countries in 2020 are the focus in the study of these options.

Finally analysed and assessed were (deliverable D6) the actual and potential barriers that may hinder the market participants implementing the identified respond options. For this purpose, a detailed questionnaire was developed in order to expand and collect additional information for all the five countries, i.e. UK, Germany, Denmark Spain and the Netherlands. The barriers were placed in the context of the application of different options in different segments, i.e. generation (including both conventional generation and renewable and combined heat and power (RES/CHP) generation), demand of electricity, national and regional electricity markets, and finally transmission and distributions (T&D) networks.

The present report D7 builds on the previous project results and has to identify, analyse and assess and recommend per country the most effective regulatory, technical and institutional measures or instruments that policy makers, regulators and governments may use to support the expected increasing penetration of intermittent type of RES-E (included herein DG type of RES-E) in the electricity markets in most EU MS. The focus is on measures that facilitate and will incentivise market parties (stakeholders) to invest, or come up with changes in market rules and commercial arrangements or market conform solutions (response options) that reduce the system cost expected to occur if the share of intermittent DG & RES-E is supplying electricity in 2020 or before. This report also serves as a key input to the development of a “Policy and regulatory roadmaps in five countries” being the final RESPOND report.

The structure of the report D7 follows the same structure as used in the questionnaire (see D6). Starting with parts of questionnaire results from D6 and extending this with an elaborated analysis of regulation and current measure applied in the different five countries, UK, Germany, Spain, Denmark and the Netherlands result in D7. The chapters are per segment of the power system, from generation till demand, analysing all relevant options and measures/instruments to restructure the current power system in five countries in order to cope economic efficiently with large shares of intermittent DG/RES-E in the future.

Consequently this report’s main interest is the contribution of *RES-E/CHP technologies*, which are also eligible for support schemes on improving the system’s capability to cope with increasing variable DG/RES shares in supply. Generally we discuss the design of the RES-E/CHP technologies and their functioning in the electricity markets, as they have developed so far and the prospects for this in short (before 2020) or in the medium (around 2020) and longer term (beyond 2020). The current obstacles that have been identified in the countries can be mitigated by a range of solutions that combine measures for RES-E/CHP, conventional generation, demand response, market organisation and expansion and management of transmission and distribution networks as are the recommendations in this report. In *Chapter 2* recommendations for the RES-E/CHP technologies, which are eligible for various support schemes are presented. Both the design of the support schemes, the technical requirements to the technologies, and the design of the electricity markets may contribute to the further integration of RES-E/CHP.

Next, in *Chapter 3,* the measures are reviewed for conventional generators, who may still take most of the burden of balancing power and ancillary services. *Chapter 4* describes recommendations for demand respond, which can be controlled to a further extent thus also contributing, together with generation to the further integration of RES-E/CHP. *Chapter 5* is divided into two main parts. First part concerns an overview of the expected and required development of the main elements of the electricity markets, which are now generally found in most European countries particularly UK, Germany, Spain, Denmark and the Netherlands. Second part concerns recommended initiatives from national TSOs to facilitate further penetration of intermittent RES-E/CHP. Furthermore in *Chapter 6* the recommendations for regional markets both related to the development of physical international transmission lines and market organisation in the form of co-operation between the existing national and multinational electricity exchanges are formulated. *Chapter 7* focuses on the development and operation of national transmission grids, which are operated by the TSOs. This includes recommendations for transmission tariffs, measures for grid reinforcement and public acceptance of grid expansion, and management of grid congestion.

Chapter 8 focuses on the distribution networks, which are run by the DSOs. The recommendations relate to network charges, DSOs incentives for active network management, and DSOs incentive for taking into account DG in network planning and contribution to ancillary services by DG.

Finally, *Chapter 9* summarises the overall conclusions and recommendations of this report.

2 Distributed and renewable generation

RESPOND focuses in the analysis on the most important intermittent technologies, mainly micro-CHP and photovoltaic (PV) (on low voltage networks in both urban and rural areas.), off-shore wind generation (on extra high voltage networks) and on-shore wind generation (on medium and high voltage networks in rural areas).

Support schemes were and are important stimuli to encourage the penetration of these technologies in the here considered EU countries. The most important two of these schemes have been feed-in tariffs (FIT) and tradable green certificates (TGC). These have been successful in many European countries in terms of a significant penetration of some of these variable technologies, in particular that of wind turbines.

The most important impacts on the electricity system relate to the variability and the unpredictability of generation from these intermittent energy sources. However, some of the RES-E/CHP technologies are also able to contribute significantly to handle intermittency issues.

2.1 Price mechanisms and support schemes

Given that a significant fraction of revenues obtained by RES/DG comes from support payments, the amount of investment in each of the different RES technologies is clearly dependent on the levels of these payments. Therefore, efficiently designing support payments is a prerequisite for achieving an economic market based integration of variable DG/RES generation. RESPOND project identified as a barrier for large-scale implementation of these technologies that, neither FITs applied in Spain and Germany, nor tradable green certificates implemented in the UK do not include location or the time of the day or the year when energy is produced by generators related signals. Consequently, the production profile of these generators does not adapt to the level of load to be covered or the – at that moment prevailing – conditions in the system[1].

When DG/RES generators are contributing to reduce variability in markets, they need appropriate regulation, business models and commercial experience to operate in the markets profitably. In practice, this means aggregation of units either in the form of ‘Virtual power plants’, focusing on both electricity generation and sale on the spot market, and providing reserves and ancillary services for balancing and ancillary services markets. These functions are closely linked, so the same companies (brokers or commercial aggregators) already often operating on all markets, either with a portfolio of similar units, e.g. wind

[1] In Spain, most of the wind production is sold in the daily energy market, whose hourly prices are related to the level of load to be covered in the system.

turbines or complementary units of different technologies. These companies also play an important role in the development of spot and balancing markets, national grid codes, software for strategic bidding on power exchanges, etc.

RES/DG type of generators in some countries (e.g. Germany and Spain) are allowed to opt out of support schemes. In *Spain*, most of the wind production is sold in the daily energy market, whose hourly prices are related to the level of load to be covered in the system. In *Denmark* the production from older wind turbines, which are no longer eligible for FIT, is sold on the spot market by an aggregator, who is not BRP.

The *key recommendation* for support schemes are to take into account of system needs and to replace feed-in tariffs with premiums for DG/RES generators, and also to encourage these generators to take part in the whole range of spot and balancing markets (adapt regulation to that aim if necessary). The market premium that is required in addition to the market prices differs between countries and may be as low as € 13 per MWh for wind generators as in Denmark. This is a relatively small amount compared to the annual average electricity price around € 50 per MWh or few hours with extreme values above € 100 per MWh.

2.2 Technical capabilities for meeting system requirements

In general, there exist no major technical hurdles that prevent DG/RES access to daily energy markets. This is owed to technical improvements in RES generation technology characteristics. However, participation of DG/RES in specific markets such as Ancillary Services (AS) one, is still limited to those units that meet certain requirements (regarding, mainly, controllability). Controllability of RES/DG units may be improved through the use of storage devices and the aggregation of units. Non-controllable units are capable of providing some kind of frequency response such as primary frequency control. However, in the Netherlands, Germany, and UK, small units connected to distribution networks do not have to provide reserve power. In Spain, the role of centralized control centres for the aggregation of RES/DG units is deemed necessary to facilitate the participation of units in reserve and balancing markets. In Denmark, a large number of small and medium scale CHP units take part in the spot and balancing market.

The most prominent example of technical regulation that facilitates large-scale implementation of wind power is that of the grid codes for the five countries contain detailed but different requirements for *fault ride through capability and voltage dips* (also called voltage drops). These are different for units connected to different voltage levels (e.g. below and above 100 kV). For small thermal units the requirements vary with the capacity (e,g, in DK the limits are 11 kW and 1.5 MW).

The ability of modern wind turbines to regulate their production more easily than most thermal generators is an important contribution to the regulation capability that is needed for more penetration of intermittent generation.

As general *recommendation,* we say that large wind turbines/parks should be equipped with regulation capabilities and have the possibility to participate in the market for AS and balancing.

2.3 CHP generation with heat storages

The RESPOND project considers also the role combined heat and power (CHP), in particular micro-CHP for individual households with electric capacities of a few kW. By some experts, it seen as a technology of the future, but which also requires considerable amounts of research and development of candidate technologies such as Sterling motors or fuel cells. CHP in scales from some hundreds kW are mature technologies, i.e. gas motors, and gas and steam turbines, which are widely used in sectors horticulture, industry and district heating. But what is defined as small-scale and large-scale may vary significantly among countries. In some countries CHP units above 1 MW will be called large-scale. In countries with significant use of CHP for district heating, large-scale CHP are conventional units with extraction facilities for large interconnected urban district heating grids, while units at 100 MW and below designed for a particular industry or district heating grid are small-scale CHP, distributed or decentralized CHP. Small-scale CHP are normally back-pressure units that generate electricity and heat in a fixed proportion. However, since heat storage is a relatively cheap option, CHP might also contribute to a more flexible production of electricity and heat by CHP and thus could play a role in enhancing the power system's load flexibility in the future in countries having already those heating systems in place.

2.3.1 Micro CHP

CHP or micro-CHP might be considered as "intermittent" when run under heat-following control strategy. However, CHP systems could be potentially used as *controllable* if enough system incentives are available in order to provide such a grid services. This would increase the system flexibility, which is one of the key goals identified in the RESPOND project. In order to do so, suitable incentives or price signals should be designed and provided, which also require adequate and cheap communication infrastructure. In general, aggregation and control of several units by a centralized system at the distribution level would also help to select the most suitable units to provide grid support.

Micro CHP seems to have become recently a viable energy generation option in the UK. The industry forecasts that micro-CHP can realistically take up to a 30% share of the boiler replacement market until 2015, which would imply 5.6 million homes could have micro CHP installed by 2020. The electric capacities mentioned for micro CHP (1.1 and 3 kW) may represent different strategies for serving the annual heat demand in a normal household. Assuming a power-to heat ratio of 0.4, a small unit at 1.1kW electric will produce some 40 GJ heat in part load operation during 4000 equivalent full load hours. The same amount of heat can be produced assuming a power-to heat ratio of 1.1 for a larger unit at 3 kW in on-off operation using local heat storage.

Widespread use would enable micro-CHP to contribute as a response option, rather than require balancing from conventional generation. However this also would require that a significant share of these installations have an operational overcapacity that will allow some flexibility in their electricity production.

The only advantage of the micro-scale is that it does not require any enhanced infrastructure for heat distribution. The heat market for micro-CHP is enormous, and thus very attractive for industrial development. However, CHP technology has significant economies of scale, so expanding and interconnecting heat distribution systems to allow for larger scales of CHP units should be encourages or supported, when possible.

2.3.2 Integrated local solutions

Support schemes focusing on single DG/RES technologies may have a significant impact on that specific technology, i.e. wind. Other technologies require a more integrated approach that will involve both distributed generation, demand response, management of local grids, and operation on the spot (day-ahead and intraday) and balancing markets.

In *Germany*, the Federal Ministry of Economics and Technology has launched a programme “E-Energy: ICT-based Energy System of the Future” as part of the technology policy of the Federal Government. It stands for the comprehensive digital interconnection and computer-based control and monitoring of the entire energy supply system. It was decided that the electricity sector would be the first area addressed by the project, as the challenges with regard to real-time interaction and computer intelligence are particularly high due to electricity’s limited ability to be stored. For a model region Cuxhaven in northern Germany an intelligent energy management system is currently used to strike a balance between the supply and consumption of electricity that is generated locally. This includes load shifting for a cool house and trade on the electricity market place to respond to market prices and possible transmission network constraints in an area with a large capacity of wind turbines.

This example illustrates the important role of price signals for both generators and consumers. Price signals can encourage increases in system efficiency both in systems where transmission capacity is constrained and in those where it is not. *Recommended* are to develop methods such as in this example to let distributed generators and consumers face such price signals, in particular in areas where large amounts of wind power are connected to the transmission or distribution grid.

2.3.3 Market access for small-scale CHP generation with heat storages

In *Denmark* a large number of small-scale CHP units with heat storage had been installed in the 1990s for medium and small-scale district heating systems. Initially, they faced a three-level feed-in tariff that encouraged electricity generation at peak load only, but did not respond to the system needs caused by a significant capacity of wind power. To meet this last requirement CHP units above 10 MW were required to enter the market from 2005 and those above 5 MW from 2007. The process of market entry was prepared in collaboration between the TSO and six Balancing Responsible Parties (BRP), who are brokers or commercial aggregators, each leading a group of decentralized CHP plants.

Bids for up and down regulation must be made in steps of 10 MW. This limit is reasonable, because small units are aggregated by BRP. The broker/BRP submits hourly (or shorter) forecasts for production and consumption. They operate integrated on the spot market (Nord Pool) and the balancing market (TSO). The process also involved the development of software for the bidding process.

In conclusion, in all countries with a significant share of CHP there is a potential for flexible response, when the institutional setup is available to facilitate that. Establishing virtual power plants with commercial aggregators that operate on the spot market is strongly recommended to be introduced in the short term.

2.4 Market design for large-scale wind integration

Large shares of wind power have a significant impact on the system costs of producing electricity. In most of the European electricity exchanges price quotations on the day-ahead, intraday and balancing markets represent figures for nations with large variations in the penetration of wind power. Danish price areas within the Nord Pool exchange area are different. The generation from wind power in the price areas Eastern and Western Denmark cover on an annual basis 16 and 25 percent of the electricity consumption, respectively. Detailed market data are available from energinet.dk since 2000. From 2006 all price data are available in EUR/MWh.

An analysis of these data[1] show that most hours with little or no wind are consecutive, so storages with only few hours capacity will be of little help. Longer periods (e.g. 12 hours or

[1] Appendix A contains a detailed analysis of the market result for the Western Denmark price area for the years 2006, 2007 and 2008.

more) with little or no wind will occur roughly once a month. The longest period with low wind that was found during the three years was 76 hours in November 2007.

The analysis indicates that the balancing market is far more significant for dealing with the effects of intermittent generation than the intraday market. The balancing market seems not very important when the day-ahead area prices are high. On the other hand, there is a significant number of hours with ‘normal’ prices on the day-ahead market and up-regulation prices more than 100 €/MWh higher.

In the short term, negative prices on the spot market have been considered as the most important additional measure to address the challenge of the large amount of intermittent generation. Negative prices were introduced on the German EEX spot market from September 2008, and from October 2009 a negative price floor at -200 €/MWh will be introduced at Nord Pool and APX.

Negative prices will be an incentive for flexible generators to reduce their production – or consumers to use more – in few critical hours. Modern wind turbines are able to regulate their production more easily than most thermal generators.

There are areas in Germany and Spain that have a larger penetration of wind than Western Denmark, but so far these regions are not identified as price areas in the electricity markets.

2.5 Coping with variability and unpredictability by forecasting of RES-E/CHP generation

The RESPOND project assumes that the most important impacts of RES-E/CHP relate to the variability and the unpredictability of generation by intermittent sources. Therefore also forecasting of RES-E/CHP generation is an important topic to discuss.

Forecasting techniques are a promising tool to increase the flexibility of the balancing system and allow more effective planning of RES/CHP penetration and operation. In order to cope with DG/RES production variability, the capacity of interconnection with neighbouring countries should be increased. This would enable RES/CHP units to better handle their production domestically, even in the case of relatively badly forecasting from time to time the generated electricity.

Again, aggregation – or the development of more sophisticated ‘virtual power plants’ – represents an important resource for market participation, since variations in the production of the equivalent aggregate unit will be smoother than those of individual units. In this case, the SO should send signals to each company central dispatching centre with the required services, and this dispatching centre should in turn sends the directive signals to its own units.

Wind power will be able to respond to system requirement in the short-term – in particular for a few seconds or within an hour. The main barrier is several hours with little or no wind. The only means to meet this situation is reduced demand or other generators. Most of these situations will be addressed within the day-ahead spot market. In addition, the intraday market with gate closure shortly before real time may be an important tool for RES-E/CHP to reduce their production forecast errors, and thus reduce their exposure to imbalance costs, This is possible even when the intraday market may have a low liquidity. However, the practical experience with the intraday market is still limited in regions with a large share of wind power..

A situation with too much wind that stops a large number of wind turbines cannot be predicted very well with much certainty so far, but these situations are an exception. Also it is very unlikely that all turbines within one region stop at the same time. There will be time to activate other generators, and the TSO may increase the capacity for reserve capacity in daily auctions.

Regional price areas reflecting permanent imbalances among regions within the same country shall apply not only to the balancing and ancillary services markets run by the TSOs, but also to the intra-day and day-ahead markets in order to set the appropriate price signals to both generators and consumers. The demand response to these price signals is discussed in Chapter 4, and their role for congestion management in the transmission network (implicit auctions) is discussed in Chapters 6 and 7.

2.6 Recommendation on RES-E/CHP Generation

Policy and regulatory recommendations to enable large-scale integration of renewable and distributed generation include also many technical requirements – typically implemented in national grid codes – which should allow new generators to meet requirements of to participate in the market, changes in market rules facilitating the participation of RES/DG generators and the creation of commercial companies with a portfolio of generators and consumers, who should operate virtual power plants or act as balance responsible parties to meet the needs of the electricity system.

Short term implementation

If not already implemented the following recommendations shall be considered for RES-E/CHP generators in all countries.

- Harmonisation of requirement for fault ride through capability, ability to overtake voltage dips, and controllability for all larger wind turbines in national grid codes.

- Control centres for groups of wind turbines or contracts with commercial aggregators operation as Balancing Responsible Parties for all larger RES-E/CHP units
- Add heat storages, head pumps, or electric boilers for down-regulation to heat distribution networks supplied by CHP.
- Training of small RES-E/CHP generators for market participation and dissemination of standardised software for operation and bidding on spot and balancing markets

Medium-to-long-term implementation

- FIT to be replaced by premiums on market prices, in particular when penetration of intermittent generation has reached a certain level in areas with limited transmission capacity to larger electricity markets.
- Introduction of wholesale prices (as price signals for generators and consumers in regional price areas reflecting permanent imbalances among regions within the same country
- Enhance forecasting methods and tools – in particular concerning the geographical distribution of wind power.
- Expand and interconnect heat distribution networks to increase the flexibility of CHP units, heat storages etc.
- Support schemes for micro-CHP that encourage units with surplus capacity and heat storage, which allows on-off operation following electricity market prices.

Table 2.1. Recommendations for applying RES-E/CHP for reducing intermittency impacts

Market Response	Barrier	Recommendations		
		Short term	Medium term	Long term
Pricing mechanism	No location-based charges/incentives for RES/CHP (SP, UK, NL)	Introduction of regional price areas in spot and balance markets to reflect permanent imbalances among regions within the same country		
Pricing mechanism	No ancillary service participation for FIT-based RES/CHP units (SP)	Training of commercial aggregators.(BRP) and software development for participation in spot and balancing markets		
Pricing mechanism	No compensation for load/frequency support for RES/CHP (NL, SP)	Requirement in Grid Code for load/frequency support for larger RES-E/CHP		
Subsidy schemes	No ToU-based FIT for RES/CHP (SP, DE)		Premiums on market prices instead of FIT.	
Subsidy schemes	No ToU-based TGC for RES/CHP (UK)			
Regulation	Disconnection of wind turbines at grid faults	Harmonisation of Grid codes concerning voltage dips and fault ride through capability		
Regulation		Control centres for renewable energies		
Storage capacity	Lack of response options	Electric boilers for down regulation	Expansion of district heating grids and heat markets in industry	

3 Conventional generation

In general, RES-E/CHP will reduce the utilisation of existing and future conventional units. This may create discourages investment in new capacity by utilities and other power generation companies. On the other hand, conventional generators will also face market incentives or legal obligations to supply balancing power and ancillary services, when needed by the electricity market. So much of the extra system requirements caused by RES-E/CHP could end up as an extra “burden” for conventional generators.

While CHP of a micro or small scale is one of technologies that are considered as distributed electricity and therefore often eligible for various support schemes, CHP in medium and large scale is considered as conventional generation technology but might in some countries being capable of offering the power system response if needed by the system due to large-scale penetration of intermittent generation technologies.

Markets provide an incentive for generators to be available when the system needs them, since prices in these situations will be generally higher than normal. However, in some cases these price incentives may not be sufficient to ensure that enough generation capacity is able to produce when needed.

The barriers that were identified in the RESPOND project concern the expectation of too little revenue from the sale of electricity and the provision of balancing and ancillary services to support the necessary conventional generation capacity. In Germany and UK there do not exist such availability payments, though these payments may be necessary when market incentives for firm capacity provision are not successful. However, these barriers are not necessarily caused by penetration of intermittent generation. Some additional payment beyond the revenues generated by the market may be necessary anyway, or additional market features should be added.

3.1 Economic incentives to install new generation capacity or maintain the existing one

In the presence of a considerable penetration of (intermittent type of) RES/CHP, investment in conventional generators might be endangered, as their overall market revenues might decrease, while specific (short time span) need is increasing. This may be especially true in systems where no additional capacity payment is allowed. Revenues for conventional generators decrease as the amount of their energy sales will decrease, since available RES/CHP production come first in the merit order. In addition, many conventional generators will have to operate far from their nominal functioning regime and they will have to cycle. Thus, their operating costs will increase. Consequently, investment in conventional generation may become less attractive.

The fact that some markets have traditionally operated with some overcapacity, so far, did hide this growing lack of conventional generation for this services until now.

In the *UK*, in order for the system to meet capacity requirements, the SO approach is to publish the winter outlook and the "Seven Year Statement", which has been sufficient to ensure development of an appropriate generation background to support demand.

3.1.1 Investments beyond market incentives

Investment in new, capital intensive base-load capacity, which generally also dependent on political and socio-economic and long term other considerations and needs the support from the power industry, is to a lesser extend following short term market incentives. For example, note the new nuclear investments in Finland, France and Lithuania. Another example is the aim for expanding fossil fuel generation capacity with carbon capture and storage (CCS).

Additional mechanisms beyond market prices may be needed to achieve an efficient expansion of the generation capacity in the system. However, in many systems, like the UK or the Netherlands, extra payments outside the market to achieve the installation of new capacity are not allowed. As a consequence, periods of scarcity followed by other of excess capacity may occur. In the German system, and as a result of wrong incentive schemes, part of the conventional generation capacity installed is not thought to be well adapted to the role that this capacity may have to play in the future. Besides, capacity incentives in place in Spain have not been designed efficiently and capacity surges and scarcity may occur.

Capacity payments outside the market aimed at providing system firmness implicitly push towards additional capacity. Indeed, on average such mechanisms increase the price earned by generation in place and thus give incentive to new investment. Mechanisms such as in Spain, where the payments are a function of the system reserve margin, could push investors to postpone investment too far away, in order to earn the maximum possible capacity payments.

Implementation of such measures should be considered together with schemes for support of DG/RES and rules for competition among conventional and renewable technologies that address the targets of the European directives on CHP and renewable. The support schemes that are allowed in these directives are motivated by long-term environmental and security-of-supply issues.

3.1.2 Capacity inherited from the past

Most of the capacity that can react to price signals from the day-ahead market to meet the new requirements related to the existence of intermittent generation is neither new base load capacity nor peak load capacity, or capacity suitable to operate in part load far from their nominal functioning regime. The technical lifetime of power stations is several decades, which means that most of the existing capacity was build in the past to meet requirements that were different from those in focus today.

Few countries have the advantage of hydro power with abundant reservoir capacity, which is excellent to meet the requirements from intermittent generation within the framework of a modern electricity spot market.

During the period of liberalisation in the last two decades conventional generators have invested mainly in gas-fired capacity based on a shorter time horizon and higher discount rate than during the previous time of regional vertically integrated monopolies.

The remaining capacity inherited from the past is thermal units fuelled by coal, oil or gas, which are less efficient than similar units that are commissioned today or will be in the future. On an annual basis, they will operate on part load, often switching and far from their nominal functioning regime. This operation can be optimised using the price signals from the day-ahead, intraday and balancing markets.

There is a mix of such units in the five countries. Some technologies are capable of frequent starts and stops or running in part load; others must run constantly at best point with few starts and stops. However, for many units, if their actual operation is taking into account system needs this does not have to be much less efficient than the optimal operation of each type of units.

The traditional utility companies operate as commercial aggregators for most of these units, and excess revenue may be earned as a result of their market power. The history of electricity liberalisation during the recent two decades tells about introduction of competition to break monopolies and reduce market power.

3.2 Regulation and balancing reserves

Main barriers to the provision of regulation reserves by conventional generation, which is necessary in order for the system to adapt (for reducing unwanted load impacts) of the variable output of intermittent RES generation, are twofold. First, in some countries like Germany, reserve prices are quite low compared to energy prices and conditions to be fulfilled in order to be eligible for the provision of reserves are rather complex. This discourages generators from providing these reserves, which may result, among other things, in less “liquid AS markets” than necessary for proper trade. In some other countries like Spain and Germany generators do not receive any payment for the provision of the primary frequency regulation service.

Conventional generation will probably remain the largest supply technology in all European countries in next two decades, i.e. a major part of the balancing obligation will remain to be provided by conventional generation.

New capacity designated to respond to intermittent loads is not the only option for conventional generators to respond to intermittency. New conventional base-load capacity may be installed for many other reasons, and – as a side-effect – reduce the operation hours for less efficient existing capacity, which will be available for responding to intermittent generation.

However, regulation or financial support may be needed to avoid to early decommissioning of capacity that might still needed as balancing reserve

In *Denmark* there is large-scale CHP supply through large urban district heating grids. The large extraction-condensing units (250-500 MW) can shift between back-pressure (CHP) and condensing (electricity-only) modes. The volume of back-pressure mode follows the heat demand, while the operation in condensing mode is dependent of the electricity market as a complement to other generators. Of particular interest is their capability to increase the electricity output by some 15 % shifting from back-pressure to condensing mode. Most district heating systems are equipped with heat storages, which allow cut-off of heat supply for several hours.

In the *UK*, large capacity of CCGTs plants was established in the 1990s, after privatisation wave, leading to the so called “The Dash for Gas”. This capacity may be too expensive to operate in base-load in the future, but it will be valuable as capacity for response to intermittent generation and ancillary services in the UK.

In most countries, primary regulation is compulsory, at least for the larger systems, without compensation. If specific units are not able to provide the service, contracting the service from other units may be an interesting option helping overcome possible technical barriers.

This was identified as a barrier within the RESPOND project for the opportunity for RES-E/DG to sell this service to the TSO. However, it is unclear whether it should be recommended to change this practice. In the *UK* the requirement for providing primary reserves was expanded to all large generators – including wind parks – in order to apply equal rules for all generators.

The secondary and tertiary reserves are much more interesting for market operation. The design of auctions for reserves is a key measure in the hands of the TSO. These auctions may be for long-term contracts with particular generators, e.g. designated peak load units, or annual, monthly or daily auctions for reserves. The revenues from these auctions may be essential to support the capacity needed by the system. The fair design of these auctions is of particular interest for electricity regulators.

Installation of designated conventional peak-load electricity-only boilers seems the least attractive option for increased flexibility.

There is a range of possible future business opportunities for commercial aggregators, which may be offered by the market. Contingency units can be encouraged to take part in the market: However, there is no experience on their role in critical situations. Another opportunity is management of electric boilers, heat pump and heat storages for individual heating, currently supplied by natural gas or heating oil. Like district heating systems, individual heating with heat storages offer opportunities for the balancing and ancillary services market using electricity boilers – operating few hours per year – for down-regulation and heat pumps – with a high utilisation time – for up-regulation by reducing the electricity demand in critical hours.

3.3 Recommendations for increasing capacity firmness and investment in conventional generation

Short-term

- Support schemes for maintaining existing conventional capacity should be considered together with schemes for support of RES-E.

Short-term implementation – long-term impact

- Criteria for licensing or tendering for new conventional capacity shall focus on locational issues.
- In particular, the existence of urban district heating grids or the potentials for the development of large urban grids from existing heating systems should be accounted for.
- Implementation of rules for competition among conventional and renewable technologies that address the targets of the European directives on CHP and renewables could also be considered.
- Ancillary services markets should be created and they should be liquid enough. Revenues from well functioning AS markets should encourage existting conventional generation to keep in place operating and new conventional generation to be installed.

Short and medium term implementation

- Capacity payments outside the market for system firmness implicitly boost additional capacity should be considered carefully, taking into account that such mechanisms increase average prices for generation capacity and thus give incentive to new investment

Table 3.1. Main recommendations for using conventional generation options

<table>
<tr><th rowspan="2">Market Response</th><th rowspan="2">Barrier</th><th colspan="3">Recommendations</th></tr>
<tr><th>Short term</th><th>Medium term</th><th>Long term</th></tr>
<tr><td>Incentive schemes</td><td>Low market prices or complex criteria for regulation reserve participation from conventional generation (DE)</td><td rowspan="2">Requirement in the grid codes for participation in load/frequency control</td><td></td><td></td></tr>
<tr><td>Incentive schemes</td><td>No remuneration for primary regulation service from conventional generation (mandatory) (ES, UK)</td><td></td><td></td></tr>
<tr><td>Incentive schemes</td><td>No capacity payments as potential means to overcome market failures for firm capacity provision/investment (2020 perspective), (DE, UK, DK)</td><td>Support schemes for maintaining existing conventional capacity should be considered together with schemes for RES-E.</td><td></td><td></td></tr>
<tr><td>Incentive schemes</td><td>Potentially wrong capacity investment incentives based on reserve margin (ES)</td><td></td><td></td><td></td></tr>
<tr><td>Incentive schemes</td><td>Market-oriented approach that could prevent outside-of-market conventional capacity drivers (UK)</td><td></td><td></td><td></td></tr>
<tr><td>Tendering</td><td>Lack of response capacity</td><td rowspan="2">Implementation of rules for competition among conventional and renewable technologies that address the targets of the European directives</td><td colspan="2">Licensing or tendering for new conventional capacity focusing on the existence of urban district heating grids.</td></tr>
<tr><td>Regulation</td><td>Lack of response capacity</td><td colspan="2">Interconnection of existing urban district heating grids to markets for large-scale CHP.</td></tr>
</table>

4 Demand response

Other things being equal, increasing the share of intermittent production (mainly wind power) will increase the volatility of production, marginal cost of production, and prices. This is only occurring some times, while in most occasions prices generally will be rather low. Getting customers to perceive the varying prices in the market is one way to reduce the volatility and keep the system’s overall efficiency gains that may generally be obtained. However, for customers to react to market prices and their variations three conditions are to be met first: a) metering of consumption at relevant time-intervals, b) billing of consumption according to the marginal costs of production, and c) the ability of customers to change consumption in time to alleviate his higher cost of the consumer bill. Each of these three conditions poses a barrier to currently implementing these demand response by customers.

4.1 Metering and communication technology

Interval metering is a precondition for marked based demand response, and interval meters are being installed in all countries. However, the status on roll-out of meters is quite different in the case-study countries. In Spain a plan for a general roll-out is decided. In the Netherlands a general roll-out was planned, but is at present suspended. In Denmark and UK large customers have interval meters. A general roll-out for small customers has not been decided, but some companies have individual plans. In Germany customers may choose to install interval meters, but a general plan is not decided. Important conditions for an effective general roll-out of interval meters are a) the proper functionality of interval meters, b) communication standards, c) cost of meters and metering, and d) the ownership of meters and who profits from interval metering.

Concerning the *functionality* of meters, the discussion is related to how customers should be engaged in demand response and at what time-interval. Most interval meters presently being installed have hourly/half hourly metering, and are simple interval meters that just measure consumption each hour/half hour. Very smart meters may measure consumption continuously, receive signals and control the consumption of individual appliances. If the purpose of demand response is to get customers to reach to day-ahead prices in power markets, hourly meters are sufficient. If customers are to be engaged in ancillary services, automatic response is required. This may go via the meter, a price-signal or just via the frequency in the network. That is, a first decision is which problem demand response should address. Looking at intermittent production and wind power, the main problem is at the hour to hour level and metering each hour/half hour seems adequate. Still, to ease customer engagement, the meter may be a smart meter.

The definition of *communication standards* is related to the choice of meters and the functionality of these. At present, common communication standards have not been defined. One first issue is to define the functionality of meters and the development of a common communication standard.

Looking at the individual countries, interval meters presently introduced in Spain, Denmark and UK are mainly simple hourly/half hourly meters with automatic meter reading, but not equipped with automatic response options. In the Netherlands, the suspension of the general roll-out plan is due to a discussion of the functionality of the meters. In Germany installation of smart meters is liberalized and different meters may be chosen.

Concerning the *cost of meters* and metering a general roll-out gives the lowest cost per meter. However, from an economic point of view there is a discussion of how fast and how far out new meters should be introduced. The main arguments for the new meters presently being installed are savings related to automatic metering, security of metering, and billing of customers. For small customers, demand response is mainly an argument for the future and the additional costs of a smart meter may be argued with preparing for future options. Again, defining the future functionality of meters is a critical barrier.

A final barrier mentioned in the previous analyses is the *ownership of meters*. Typically DSOs install, pay and own meters, and have savings related to billing of customers. In a liberalised market, customers may change suppliers of electricity. The party in charge of metering should be distribution companies and not retailers. Thus, even if consumers change supplier, benefits from reduced metering cost will continue being received by the party that installed the meter and paid for it. Otherwise, counterincentives to the instllation of new meter would exist, as it has happened in the UK. If the retailing company installs and pays for the meter, legislation securing the installer of new meters an income or compensation when customers change supplier may be required. Alternatively, customers should pay for and own the meter.

Concluding, plans for a general roll-out of new meters should be encouraged for UK, Germany and Denmark. However, before actual roll-out of meters, firstly the functionality of meters should be decided on and precise communication standards should be developed.

4.2 Pricing rules

Given interval metering and a liberalised market, from a theoretical point of view customers should be charged prices in the market. Again, depending on meters, prices could be hourly prices in the day a head market or real-time prices. Looking at intermittent production day-ahead prices appear sufficient, but real-time prices and automatic control of specific appliances/consumption is an option for increasing security of supply and getting customers to participate in the market for ancillary services.

Looking at the present situation in the countries studied, for most customers wholesale prices are transferred to customers indirectly. Customers receive a fixed price covering all the price fluctuations, but do not see the hourly prices. In Denmark and UK large customers with hourly/half hourly metering may choose a tariff reflecting day-ahead prices. However, some reluctance to choose this rate is observed. In Spain Time-of-Use tariffs are used intensively and in the Netherlands a simple peak/off-peak tariff is available for the customers.

Time-of-Use tariffs give an incentive to shift demand in time, but it does not reflect the stochastic nature of intermittent production and price variations caused by this. To reflect price-variations introduced by intermittent production market prices are required. Barriers mentioned for introducing/accepting wholesale prices are a) information costs and costs of changing consumption, b) wealth transfers between customers, and c) short-term gains seen in the market are small and long-term gains not very transparent for the customer.

Information costs may be reduced by automatic control technologies but costs of changing consumption is difficult to change and will anyhow limit demand response.

Wealth transfers between different customers is a barrier for getting some customers to choose hourly wholesale market prices. Customers that have a large consumption in expensive hour will receive a larger bill. However, this is exactly what is called for. Even if customers do not react to hourly prices, customers that receive a larger bill have an incentive to reduce consumption, especially is expensive hours. That is, from an economic point of view, customers should not have the opportunity to choose anything but wholesale prices. From a political point of view, price differentiation for all customers per hour seems difficult to be accepted. However, the price on other goods e.g. gasoline changes all the time too.

The fact that short-term gains seen in the market are small and long-term gains not very transparent provides a low incentive to choose a “price per hour”. Besides, given an hourly price, the incentive for changing consumption is limited. Another reason for low short-term gains arethe limited variation in “hourly day a head prices” and partly by fixed additives to the wholesale price, e.g. fixed distribution charges and taxes per kWh. Increasing the share of intermittent production is expected to increase the price-variation. Fixed additives reduce the relative change in prices that customers pay, and this reduces incentives for changing consumption. Especially for Denmark the fixed tax-additive on household consumption is very large. Changing fixed additives to percent additives on the wholesale price is an option that increases incentives for changing consumption. The fraction of costs which does not depend on consumption should remain being charged as fixed prices. However, the fraction that is depending on the market outcome should depend on market prices. From a political point of view, this may be opposed due to volatility of annual revenues (average electricity prices vary but average consumption is relatively stable over years) and due to income-distribution policies. If electricity is evaluated a necessity good large taxes in years with high average prices may not be acceptable.

Concluding on prices, given interval meters, customers should be charged wholesale market prices and should not be given the opportunity to choose otherwise. For the integration of intermittent production day-ahead market prices appear sufficient, giving customers a reasonable time to react. Standards for informing customers about prices should be developed. To increase security of supply real-time pricing and automatic response by specific customers is an option for the long-term. Concerning price-additives, e.g. taxes these should be a type of percentage on the wholesale price. .

4.3 Enabling technologies

Today, only a limited number of enabling technologies that enable effectively demand response can – given the right incentives – be developed and used in the short run. Part of the consumption may be moved in time without very large costs, other parts are very costly to move. The share of movably consumption is difficult to assess, but in general consumption related to heating, cooling, and pumping may be moved a couple of hours without severe costs. In addition, storage technologies may be introduced and developed further.

Development of storage and enabling technologies is not necessarily driven by demand flexibility. In many cases, energy savings and comfort is the key issue but the same technologies will increase demand flexibility. Incentives for applying and encouraging the development of these technologies may be given nationally or at EU-level.

A first pre-requisite for developing and applying enabling technologies is that basic infrastructure and incentives are in place. That is, customers should be charged varying prices and information on price-variations should be easily obtainable. Next, new technologies have to prove their profitability for the customer and that they actually work. To achieve this, demonstration projects are needed. Finally, for some technologies, subsidy schemes, other economic incentives, or legislation may be needed. For, example, appliances may be equipped with control units cutting of the appliance if prices become very high or the frequency in the network drops. To implement this, standards, norms, and/or legislation that all new appliances should be equipped with a control unit may be needed. If a refrigerator is equipped with a frequency controlled cut-off both the negative benefit and the savings of a short cut-off is very limited for the customer, and therefore the incentive to choose a refrigerator with a control unit very limited. However, for the system, benefits are quite high.

To achieve this benefit, either customers have to receive a payment for accepting the control unit or legislation requiring all new refrigerators to have the control unit should be enforced.

To increase the share of movable electricity consumption, electric heating and storage of heat is a relatively cheap option and should be considered in every system. In the Spanish and German systems, the use of storage systems at household level is very limited and in UK district heating has a very low popularity.

In the medium and longer term another technology that may increase the share of electricity consumption that may be flexible in time is electric vehicles. In relation to this, it is important to decide whether charging of batteries may be controlled by prices or centrally by DSOs. In addition, when batteries are worn out for use in the vehicle, they may be used as stationary storage capacity and may be charged and de-charged according to system requirements.

4.4 Recommendations

All relevant initiatives to increase demand flexibility in the short-, medium-, and long-term are summarized in Table 4.1.

Currently, the potentials of smart metering are barely tested systematically. Therefore concrete implementation recommendations need accurately function and potential analysis and implementation of demonstration projects. RESPOND should suggest the expansion of field trials.

When this is done, a scheme for a general roll-out of meters should be developed. An option is to introduce simple meters, but to prepare these for upgrades to intelligent meters that may receive signals and control the consumption of specific appliances. For intelligent meters, an option to be considered is centrally controlled updates of the software that controls the functioning of the meter.

Concerning prices, customers should be charged the marginal cost of production and delivery of electricity to individual customers. Given hourly metering, day-ahead prices in the market appear reasonable, since they give the customer time to plan consumption. If intelligent meters and price controlled cut-off units are installed, real time pricing and automatic response is an option. If congestions in the network implies local differences in delivery costs and these differences are calculated prices should reflect these differences. That is, in the short-term where simple hourly meters are installed, sending customers day-ahead prices in the market is appropriate. In the medium- to long-term, where intelligent meters are installed, at least for some customers, real-time and local prices should be aimed for.

Finally, on prices, fixed price-additives should be reduced and as wide as possible changed to percent additives on the hourly prices. The fraction of costs which does not depend on consumption should remain being charged as fixed prices. However, the fraction that is depending on the market outcome should depend on market prices. However, this will increase the volatility of annual revenues and bills to be paid by customers.

Enabling technologies that increase demand flexibility fall into two categories: Control technologies and technologies that increase the share of flexible demand. Concerning control technologies, in the medium term technologies and communication standards should be developed. In the short term, demonstration projects showing benefits and needed improvements should be carried out. Concerning additional flexible demand, in the short term heating and storage of heat is a relatively cheap option. In the medium- and long-term, other storage facilities and electrical vehicles are promising technologies. Especially concerning electric vehicles, controllability of charging and possibly de-charging of batteries is an issue.

Table 4.1. Main measures for increasing demand flexibility

<table>
<tr><th rowspan="2">Market Response</th><th rowspan="2">Pre-condition</th><th colspan="3">Recommendations</th></tr>
<tr><th>short-term</th><th>medium-term</th><th>long-term</th></tr>
<tr><td rowspan="3">Metering</td><td>Functionality/Standardisation</td><td>Define a common standard for meters. New meters should be prepared for being smart</td><td></td><td></td></tr>
<tr><td>Roll-out of new meters</td><td>A general roll-out should be encouraged. To reduce costs of changing meters all customers in specific areas should change meters at the same time</td><td>All customers should have new meters</td><td></td></tr>
<tr><td>Ownership of meters</td><td>Owners of meters should benefit form savings on metering or be compensated if savings are gained by others</td><td></td><td></td></tr>
<tr><td></td><td></td><td colspan="3"></td></tr>
<tr><td rowspan="2">Pricing</td><td>Hourly prices</td><td>With hourly metering default pricing should be hourly prices</td><td colspan="2"></td></tr>
<tr><td>Price-additives</td><td>Price additives should be changed, to the extent possible, from fixed - to % additives</td><td colspan="2"></td></tr>
<tr><td></td><td></td><td colspan="3"></td></tr>
<tr><td rowspan="8">Implementation of enabling technologies</td><td>Control technologies:</td><td colspan="3"></td></tr>
<tr><td>Price signals</td><td colspan="2" rowspan="3">Control technologies should be developed and implemented by customers and suppliers</td><td rowspan="3"></td></tr>
<tr><td>Frequency signals</td></tr>
<tr><td>Centrally determined consumption</td></tr>
<tr><td>New consuming technologies:</td><td colspan="3"></td></tr>
<tr><td>Electrical vehicles</td><td colspan="3">Introduction of electric vehicles and securing that batteries are charged according to system needs</td></tr>
<tr><td>Heating</td><td colspan="2">Where economic increase the share of electricity based heating and storage of heat</td><td></td></tr>
<tr><td>Storage</td><td></td><td colspan="2">Develop storage facilities</td></tr>
</table>

5 National energy and ancillary services markets

5.1 Issues on electricity markets

The key instrument for integration of RES-E and micro-scale CHP are the electricity spot markets, which have been developed in several countries or regional groups of countries over the last two decades. These markets were not developed to support RES-E and CHP, but as an instrument to introduce competition into the electricity supply industry, which should lead to less institutional and technological conservatism.

5.1.1 Key elements of spot markets

Before the introduction of electricity spot markets, a small number of large generating units were scheduled by economic dispatch on the basis of short-term marginal costs of the available generating units in “merit order”, following the diurnal and seasonal variations in electricity demand, and taking into account network physical and security constraints. Load following and ancillary services were provided by hydro capacity or thermal units suitable for load variations on short notice including units running as spinning reserves. This task is dependent on short-term uncertainties in demand and events such as unscheduled outages of large units, rather than the level of the demand.

The introduction of spot markets has changed the method for economic dispatch, but hardly made any change to the overall way of approaching the load following (demand-generation balance) issue. In order to describe the new situation, next paragraphs provide the key elements in a day-ahead spot market using the terminology of the Power Pool of England and Wales after the privatisation of the electricity supply industry from 1990. All major generating units in England and Wales were required to participate in the market and bids on prices and volumes were linked to locations, which allowed the system operator to maintain the geographical balance between supply and demand.

The *demand curve* for each hour (or half-hour in the UK) within the next 12-36 hours is typically inelastic and is based on forecasts made by the system operator. The *supply curve* is made up of bids from the generators, each consisting of a price and a volume. After sorting the bids, the *system marginal price* represents the lowest price and the accumulated volume that will meet the demand. A *pool purchase price*, which consists of the system marginal price plus some *capacity payment* or *loss-of-load-probability, (LOLP) payment*, will then apply to all successful generators.

However, this procedure does not consider network constraints. Thus, the system operator needs to ‘constrain out’ generators in surplus areas with bids lower than the previously computed system marginal costs, and vice versa in areas with a deficit, where constrained on units will be scheduled despite having sent bids higher than the system marginal cost previously computed . In these cases the system operator shall compensate the difference between the bid price and system price and the costs of this arrangement will be added as *uplift* to the pool purchase price as a *pool selling price*.

An alternative to the design in England and Wales, and also in other countries, is that in the Nordic market. In contrast to the market in England and Wales, participation in the Nordic market, which started in the mid-1990s, was voluntary and bidders were legal entities each controlling a portfolio of different generating technologies. The Nordic market has now become the model for all electricity spot markets in Europe, both on the continent and in the UK. In addition to the day-ahead market, the power exchanges usually operate a forward market for contracts covering days, weeks, seasons or years, and intraday markets with gate closure time shortly before real time.

The geographical balance within the day-ahead market is established in the Nord Pool exchange either by geographical market splitting into areas with different prices, or counter trade by which the system operator within a price area buys up-regulation from generators in areas with deficit and down-regulation in surplus areas, with payments similar to the uplift mechanism as described above. Market splitting is used to manage transmission bottlenecks between the countries, while both methods can be used by the system operator within each country. The general recommendation by Nord Pool is that temporally imbalances should be met by counter trade, while permanent ones should be met by price areas. So far this recommendation has been practised in Norway only. By geography, Denmark is divided into two systems, East and West. However, market splitting into two price areas is now also considered within Western Denmark, when more wind capacity and further international connection will be installed in the coming years.

Differences between the demand and the contracted volumes in the day-ahead market are traded in an *intra-day market* with gate closure shortly before real time. This will reduce the differences between traded volumes and actual demands and deliveries. Also markets for ancillary services are being considered as a mechanism for providing generating capacity when and where it is needed.

Finally, differences between contracted and delivered volumes are settled by a mechanism that penalises deviations from contracted volumes.

This system was originally devised to manage predictable variations in demand as well as uncertainties concerning the real-time demands and unscheduled outages of generating units. Large volumes of intermittent generation will be additional sources of variations and uncertainty to be handled by the system.

The balancing and ancillary services mechanisms in the Nord Pool are based on contracts between the system operator and the owners of the generating capacity providing the services. These contracts are based on tender and auctions for capacities available for a longer or shorter period. With an increasing share of intermittent capacity and accumulated experience of the market participants, the length of the contracts becomes shorter. The most recent development has been the introduction of daily auctions for (up-regulation and down-regulation) reserve capacity in Denmark from April 2007 – in addition to the previous annual and monthly auctions. These auctions will gradually replace long-term contracts for reserves.

Different types of compensation are used for regulating power market. In Denmark, market suppliers get the price of their bid to the regulation market, In Norway, Sweden and Finland, where wind power is insignificant, all suppliers on the regulating market receive the marginal price for power regulation at the specific hour

The increase in wind power has made down-regulation quite important and profitable. This has lead to the introduction of negative prices on the day-ahead market – from September 2008 at the EEX in Germany and from October 2009 at Nord Pool.

During the last two decades there has been a dynamic development of the electricity markets in Europe. These markets have been able to accommodate the various new technologies. Further developments are being planned, often to facilitate the integration of distributed technologies and improve competition. Also the international integration of the markets is under development. However, in the short and medium term, European harmonisation of rules may be premature or even counterproductive. So far, the practical experience of the market participants is limited, and methods to analyse market results are yet to be developed.

The remainder of this section discusses other main aspects for the participation of DG/RES in energy and AS markets and measures that should be implemented to satisfactorily deal with them.

5.1.2 Market access, size limitations and aggregation of units

Existing barriers seem not to prevent the connection of RES/CHP and its participation in the energy market. However, there are some key aspects whose treatment could be modified. In particular, high trading fees might, in practice, represent an obstacle to market access. This is the case of the Netherlands and Denmark. Aggregation of units is an effective solution to overcome size limitation for entering the market and is already taking place in several countries. The aggregation of units can also reduce transaction costs. However, it is not possible for micro-CHP and heat pumps to integrate in commercial aggregators in most of the considered countries. In addition, the possibility of being curtailed by the TSO for network security reasons can also prevent the participation of RES in markets. This may be the case in Spain and the UK. However, curtailing RES in Spain is only considered an option when the remaining resources have been depleted and it is required to guarantee the security of the system. Also related to this, the curtailment of DG/RES to provide negative reserve is regarded as an option in Germany and Denmark.

Regarding access to ancillary or system services (AS) markets, the main issue refers to the controllability of RES/CHP. Assuming that, from a technical point of view, some RES generators (wind) will be controllable in the near future, their participation in AS requires that system operation practices are replaced by more modern (active) ones, as well as the implementation of an adequate remuneration scheme that effectively encourage RES to participate in these markets. In this regard, participation in AS market by RES/DG will only be profitable for them if RES/DG support payments are commensurate with the benefits that the RES/DG energy sold by these generators produces for the system. Thus, support payment systems where premiums over the market price exist, or even systems that establish a global quota for RES/DG (thus enabling competition among technologies) are preferable in this regard to Feed-in Tariffs.

Another option to be considered is whether rules for bidding in the market should be changed thus and the effect that changes in these rules could have both for intermittent and not intermittent generators. For example, is it possible that bids beyond the bidding period should be allowed for certain generators or is the bidding periods of e.g. 6 hours enough? The argument for the block bids is that the bidding price can be reduced if the start and stop costs can be divided on several hours with certainty instead of with just some probability. The next paragraph explains how block bids have been designed in the Nord Pool intraday market.

"Block bidding in the Elbas trading system. A block bid is an aggregated bid for several consecutive hours with a fixed bidding price and volume. A block bid must be accepted in its entirety; if accepted the contract covers all hours and the volume specified in the bid. A block bid can consist of all hours open for trading; hence a block bid can at the maximum be up to 32 hours long. The minimum length of a block bid is one hour. A block bid made for one hour differs from the ordinary hourly bid in the sense that the block bid is "all or none", whereas ordinary hourly bids also can be accepted partly".[1] .

5.1.3 Responsibility for production deviations, prediction of production and gate closures closer to real-time

In most countries (Spain, UK, Denmark and Netherlands) RES is responsible for deviations, i.e. they must pay penalizations for the production deviations incurred, which in fact constitutes an incentive to develop better prediction tools. Only in Germany RES producers are not held responsible for deviations. This may turn out to become an important barrier for

[1] Nord Pool:, Block bids manual.pdf, www.nordpool.com.

a much larger variable RES deployment, because then deviations caused by RES output prediction errors are larger and the TSO must provide larger reserves to offset these deviations. ..

Country analysis indicates that gate closure times within energy markets range from a maximum of 8 hours ahead of real time (last intraday market for each day closes at 17:45 in Spain) to 1 hour ahead of real time (UK, Denmark, Netherlands). The division of responsibilities between the TSO and the market operator in Spain, which does not allow merging markets, has been reported as the major barrier to further reducing gate closure times in this country. Even though implementing intraday markets result in gate closure times that are closer to real time, the liquidity of these markets is considered a problem in Germany and Denmark and employing a balancing market is preferred.

5.2 TSO balancing

This section proposes different regulatory initiatives in order to encourage an increasing entrance of renewable energy resources in the European electricity systems by means of an increase of the system's capability required to cope with the variation in the output of intermittent generation. This fact should respect TSO's perspective: to maximize renewable installed capacity and production in the system, but always warranting system security.

A safety operation of the system requires continuous adaptation of generation units output to cover demand evolution. In order to guarantee the fulfilment of this task at operational level, detailed long term planning and programming tasks are required to warrant system adequacy. The system operator will manage all available resources in real time operation, where generation and demand have to be fitted.

Increasing levels of not controllable generation (wind power, overall) produces higher balancing costs and it is necessary to encourage a higher participation in ancillary services provision, from both conventional and RES-P/CHP generation. Thus, entrance of flexible generation to the system should be encouraged. More often, TSO has to order conventional generation re-schedules and even start-up's and shut-down's actions. In this way, an adequate balancing pricing mechanism would yield several advantages.

Beside this, balancing costs will decrease if deviation from schedules will do so. Thus, it is very important in order to maximize renewable penetration in the system to improve forecast tools regarding both renewable injections (wind, solar, etc.) and demand evolution. Moreover, management of renewable units from control dispatches (with tele-measurements and tele-commands), and encouragement of their participation at intraday and balancing markets will improve the penetration capability of these units in the system.

Further system improvement can be provided by more flexible balancing tools or models that can guarantee the necessary reliability for electric systems if more and more intermittent generation penetrates.

Finally, adequate demand management schemes will provide further flexibility in order to maximize renewable entrance to the system.

Next, the main regulatory initiatives that should be implemented at European level, from the point of view of the management of system and ancillary services, are described.

5.2.1 Encouraging an increase in the flexibility of generation in the system

Higher levels of flexibility are required to integrate larger amounts of intermittent generation in power systems. The variable and unpredicted changes in the output of RES/DG power plants could be covered by conventional generators. Therefore encouraging entrance of necessary flexible conventional generation capacity is required. Some different market and regulatory mechanisms and incentives are analysed below to increase flexible part of the overall power generation in the system.

Economic incentives to increase the amount of flexible generation capacity available in the system

Provision of regulation reserve from conventional generators is a key instrument to allow increasing penetration of renewable intermittent generation with variability and unpredictability characteristics. Consequently economic incentives should be in place to secure a sufficient amount of conventional flexible generation capacity being available to cope with load and renewable supply variability.

Investment in conventional generation may become less attractive due to the integration of large shares of RES generation, as their energy sales and marginal energy prices could decrease, and wear could increase (due to more often start-up's and shut down's). Thus, additional economic incentives to install new generation capacity should be envisaged, besides energy incomes. If these investment payments were not implemented, systems might be prone to experience reserve margin shortages. This could have serious effects over system adequacy (long term) and security (short term) and, beside this, higher price volatility might take place. Thus, through this service there must be created enough long-term economic incentives to encourage flexible generation to connect to the system.

Regarding an EU comparison, while in the Spanish system there is nowadays such a long term incentive mechanism to install new conventional generation, in Denmark, Germany, and United Kingdom there is not currently such an explicit incentive mechanism.

Another mechanism to provide firmness in critical periods when demand is not supplied by intermittent generators output is capacity agreements between TSOs and conventional generation units for less than a year. Thus, an availability payment mechanism might be put in place, whereby the system operator is allowed to arrange availability bilateral contracts with flexible generation, as for example:

- Peaking capacity units such as gas turbines.
- Pump storage units: capability at the upper reservoir to be used in case of excess of renewable production in the system.

The generators commit themselves to be available when needed by the system, in return for earning the availability payments established in the contract. Through these contracts, there must be created enough economic incentive to encourage flexible generation availability when the system needs it.

This implies that besides energy markets, it is necessary to create parallel capacity markets with flexible generation in the system different time horizons (e.g. less and above a year). Next, different mechanisms in place at different EU countries to encourage conventional generators to produce energy whenever the system needs them to cover demand are described.

For instance, in the Netherlands the system operator contracts a certain amount of regulating reserve power and emergency power. These reserves are contracted outside the market, to prevent the possibility that contracted power is not available for securing supply during peak demand periods. In the case of the Spanish system, an availability service will be established in brief whereby the system operator will be allowed to enter into bilateral contracts with certain units. Service will be provided throughout 1year contracts. Finally, there is not a capacity service as such in Denmark, Germany and United Kingdom.

Minimum outputs below steady-state minimum output

High wind production (especially during valley hours) makes the system needs more flexibility from generators. This excess of wind might force TSOs to decrease conventional generation production in order to avoid spilling primary renewable resources. Indeed, sometimes conventional thermal units must be disconnected from the system in order to maintain a balance between generation and demand.

This fact might reduce power plants life span. Besides this, their operation's costs and wear increase. Thus, system security might be jeopardized, not only due to the mentioned conventional units wear, but also due to the fact that the fact that large amount of renewable is in place might cause a sudden trip of a great amount of renewable units in the system, if a fault occurs (nowadays a great percentage of old-technology renewable units connected to the system are not able to withstand voltage dips caused by faults in the system).

At TSO level, measures to enable more flexible conventional thermal units operation should be implemented, such as encouraging transient operation at lower minimum output levels during short periods of time. This fact should allow the system to better withstand high wind production during valley hours, avoiding disconnecting conventional thermal units from the system and increasing system security and adequacy since failure risk of these units needed to cover the demand at peak hours, is reduced, as well as, more reserve and balancing energy is available for the system's operation.

Summary of main recommendations

In order to establish via regulation in the system sufficient and effective economic incentives to promote the entrance of new flexible generation in the system and to obtain higher flexibility levels from already connected generation units both capacity and availability payments for generation could be implemented. Besides, units should increase their regulating capability (for example, reducing their minimum output level).

5.2.2 Demand response flexibility

Increasing flexibility of existing and new conventional generation units might not be enough to cope with large renewable intermittent generation increasing entrance in power systems.

Increasing demand response and flexibility may become a complementary and efficient way to allow a higher fluctuating/intermittent renewable production level in the system. The main advantages in this regard are the following:

- Demand response may counteract higher prices volatility caused by an increasing renewable supply level in the system, which brings benefits from the point of view of generation adequacy (lower financial risks due to price volatility).
- Demand response can provide more secure system operation at short term, and higher system adequacy in the long term.

Some different proposals are analysed in the following paragraphs in order to increase demand response flexibility.

Access to ancillary service markets for demand side providers

It should be encouraged a more active role of demand regarding ancillary services provision in several time horizons (annual, monthly, weekly and real time), throughout contracts between TSOs and providers.

Thus, demand side providers could commit themselves to reduce consumption when generation is scarce in the system and to increase it when a generation surplus occurs, in return for earning the payments established in the contract.

Next, different experiences in place in different EU countries that allow demand side to provide ancillary services are described. For instance, large consumers in The Netherlands connected to the high voltage grid have to inform the TSO of their capacity to reduce their consumption. Consumers connected to the high voltage network with contracted power equal to or above 60 MW are compelled to be involved in the balancing market.

In the case of the *UK* system, consumers are allowed to participate in the provision of frequency maintenance functions. They usually get involved in this through a commercial aggregation company. In the case of the Spanish tertiary reserve market, only pumping units are allowed to participate nowadays, as demand side providers. In the case of Germany, consumers are considered as reserve providers.

Demand response can increase by means of interruptibility contracts. Currently, large consumers connected to the transmission system can get this kind of agreement with Spanish and British TSO. Providers of this service get a discount in their electricity bills, in the Spanish case, and a call out fee if the load is interrupted in the British system. In Germany, only very few large consumers have interruptible contracts.

Encouraging storage devices in the system

As explained in the section of this document fro demand, electricity and heat storage devices are key technologies to enable TSOs to manage power system in a more efficient manner from both security and economy points of view.

An electric car is a kind of electricity storage. Electric cars connected to the network could bring higher flexibility levels in the system, acting as a storage mechanism in case of energy surplus in the system, and injecting energy when energy shortages occur. Different policies about the installation of electricity and heat storage devices have been developed in the EU countries.

In the case of the German system, electricity storage is mainly envisaged in the form of pumped hydro storage, batteries for mobility and fuel cells. Also the possibility of adiabatic compressed air storage is investigated. In The Netherlands, there are heating storage facilities linked to agriculture processes. In Spain, there is no specific plan to increase this kind of devices in the system, but it is under research the future integration of the electric car as an electricity storage device. In Denmark, the power company DONG has launched a project to build up an infrastructure for charging and shifting batteries for electric cars.

Control of customer equipment

Also commented in the section about demand, it is advisable that an increasing number of consumers become sensible to economic signals. Local equipments could control the level of demand based on energy prices. For this purpose, demand should receive continuous information about energy market prices in order to be able to adapt their consumption. This higher economic efficiency renders security improvements as well.

As the time reaction gets very short, automatic control response devices become more effective than incentives based on market price. Thus, control local equipments could be installed at certain consumers in order to let them to react to frequency/voltage drops in the system.

Beside this, additional control schemes can be developed to allow TSOs to order real-time customers load reduction/increase instructions, when system requires it. Next, different mechanisms in place in different EU countries to encourage the installation of smart meters in the system are described:

In the Spanish system every measurement's equipment for consumers below 15 kW of rated contracted peak demand must be substituted by smart meters before the end of 2018. In The Netherlands, connections equal or above 0.1 MW are obliged to install smart meters. Concerning small customers, only newly constructed houses are forced to install this kind of devices by law. In the UK there are plans for developing pilot projects to install smart meters.

Summary of main recommendations

Promoting a more active role of demand side in balancing services in the system. is paramount to its efficient functioning. In order to achieve this, demand should be allowed to access both energy and AS markets. More storage capacity should be installed on the demand side and the level of controllability of customer equipment should significantly increase..

5.2.3 Improvement and harmonization of balancing mechanisms at European level

National balancing mechanisms alone might not be a sufficient tool for a national TSO to manage the loads to guarantee reliability of supply at high variable RES/DG penetration shares. And additional instrument could be the coordination of balancing schemes between neighbouring TSOs in order to cope with this higher supply variability.

First ideas to encourage regional energy and balancing European markets

The following first set of ideas should be taken into account:

- To implement coordinated explicit interconnections capacity auctions and, complementary, implicit mechanisms (market splitting/ market coupling). Interconnection capacity should be filled sequentially through consecutive capacity auctions (yearly, monthly, etc., until day-ahead). Remaining Net Transfer Capacity (NTC) should be let, firstly, for intraday trading purposes and, secondly, for balancing purposes (EURELECTRIC, 2008)
- To harmonize at European level day-ahead market and intraday gate closure times.
- To coordinate intraday markets´ gate closure times with the creation of a continuous balancing mechanism (EURELECTRIC, 2008)

- Put intraday gate closures nearer to real time might decrease deviation costs of RES units as forecast would be more accurate. Nevertheless, it should be taken into account the security analysis time constraint (difficult to reduce from a realistic point of view).
- An adequate Ancillary services definition harmonization throughout Europe is envisaged as very advisable: definition of each service, time scales…
- Pricing mechanisms harmonization throughout Europe: for instance, in some systems Ancillary Services (AS) costs are recovered through end-consumer energy payments, while in other cases these are recovered through access tariffs (also known as use of system charges). Beside this, there are countries where access tariffs apply only to consumers, while in other countries access tariffs apply both to generators and loads. Capacity payments are another important factor to be harmonized throughout Europe.
- Furthermore, AS pricing mechanisms should be harmonized as well. For instance primary reserve is remunerated or not depending on the specific European system. Other example: there are systems where tertiary reserve receives double remuneration (capacity and usage), while in other systems only energy usage payment is applied for tertiary reserve providers.
- Negative prices on the day-ahead market can be a useful tool to encourage generators – including wind turbines to produce less electricity in few hours, when wind power is expected to exceed the demand and the capability of thermal generators to reduce their production economically. This was introduced on the German EEX market in 2008. From October 2009 a negative price floor at -200 €/MWh will be introduced by Nord Pool for Denmark.

Cross-border trading reserves

Implementing reserve trading mechanisms throughout interconnections have the additional benefit to increase the competition level at AS provision. Beside this, adequate reserve coordination between systems can produce benefits if one system is “long” and the adjacent system is “short”, regarding upward/downward reserve. Thus, it might be possible to reduce each TSO reserve requirement through a reserve sharing mechanism. This mechanism can be implemented either at TSO-TSO level, or at TSO – foreign provider level. The TSO-TSO approach is envisaged as the preferred solution (ERGEC, 2009)

The allocation of offers for balancing services to the neighbouring control areas should be possible only when it does not endanger the security of the local area. The development of a commercial arrangement to facilitate cross border service provision should, in no way, affect the ability of System Operators to perform inter-TSO Emergency arrangements.

One solution to this issue is the establishment of a balancing mechanism cross-border model, which has been implemented with success in some European countries, as in cross-border reserves market developed in the Nordel area.

Applying a cross-border balancing mechanism would produce a wider diversity of balancing reserves, and higher levels of efficiency and competitiveness (allowing foreign market players to participate in other countries' balancing markets) and, thus, a decrease of the total balancing costs. On the long run, full harmonisation of neighbour balancing markets could increase these beneficial effects. Main barrier to cross-border reserves trading is due to the lack of harmonization between the different national balancing markets services and procedures. Cross-border balancing trades may have to cope nowadays with a lack of harmonization in the following aspects:

- Differences regarding economic issues, as pricing methods or application or not of deviation penalties between balancing energy markets in different countries.
- Differences regarding technical prerequisites for the suppliers to provide balancing services (activation time, time to full activation).
- Gate closure times (different gate closures will lead to asymmetric market opportunities and different imbalance exposures at both sides of the border).
- Time interval for the submission of real-time energy bids in the real-time market.
- Pricing mechanism: marginal pricing versus pay as bid.

Creation of Balancing Responsible Parties and/or RES production aggregators

The creation of the so-called Balancing Responsible Parties (BRPs) seem a key issue for renewable integration in the system promoting a more active role from Balancing Responsible Parties closer to real time. Through these Balancing Responsible Parties, it would be allowed to aggregate generation (establishing the so called virtual power plants) and demand, in order to compensate for deviations. The Balancing Responsible Parties responsible would be in charge of keeping the balance by re-scheduling their generators output and demand entities consumption either at internal level of the Balancing Responsible Parties, or by participating in intraday processes or, closer to real-time, by participating in the continuous balancing market established.

Regarding RES production aggregators, in Germany, Netherlands, Spain and the United Kingdom, there is the possibility of aggregating RES production. Finally, it is important that the transition from aggregator's schedule level to physical unit's program level should respect security constraints in the system. For instance, in the Spanish case, the allocation of energy schedule's at physical units level is required to comply with the security studies carried out by the system operator.

RES-E balancing responsibility for deviations

It is quite important to establish adequate deviation pricing mechanisms in order to reach a good trade-off between:

- Adequate penalty to discourage deviations from schedule. It would promote better forecasting tools (wind, solar).

- Despite deviations penalties, there should remain an adequate incentive to participate in energy markets, by merging small production renewable units in Balancing Responsible Parties in order to compensate deviations.

Deviation pricing mechanisms should be harmonized at European level as well.

For instance, in the United Kingdom there are penalties associated with variations from contracted output in the wholesale markets – but these apply to all market participants. RES and DG would feel the impact of these penalties more severely because they are often intermittent in nature and thus more likely to deviate from their contracted position. Typically, intermittent RES and DG would contract with an energy supplier (as described earlier) to mitigate this risk. Regarding the German case, RES are currently not responsible for deviations, and this responsibility is assumed by the different German TSO´s. In Netherlands and in Spain, RES units are responsible for their imbalance like all other generators.

Finally, in Denmark, Netherlands, Spain and UK RES subsidies are attractive enough to compensate for RES deviation costs.

Summary of main recommendations

Harmonizing balancing services throughout Europe, and promoting balancing coordinated actions among TSOs is central to the integration of RES/DG.

5.2.4 Harmonizing at European level regulatory/technical requirements for renewable generation and promoting their future active role in AS provision

Nowadays, some European TSOs are rather reluctant towards high level of renewable generation units connecting to the system. Among other reasons, this is due to the lack of standardized technical requirements that would have to be imposed to all renewable units connected to the system, which are necessary to warrant system security. Beside these technical requirements, it should be promoted a future more active role of renewable units in AS provision, in order to avoid that all AS provision responsibility, on the generation side, remains in the hands of conventional generation.

Establishment of a set of harmonized requirements for RES-E units to AS

The following harmonized requirements should be implemented to allow RES to contribute to AS in all European countries:

- Increase the level of observability (tele-measurements). Every RES unit above a given size (in Spain ≥ 10 MW) must be observable (tele-measurements sent every 4 sec) from a control centre (24 hours duty).
- Withstand without disconnection pre-specified voltage and frequency dips.
- Contribute to voltage control tasks at Transmission level.

- Contribute to primary reserve obligations or to transfer its obligation (through a contract) to a third party.
- Be willing to obey real time instructions from TSO; for instance, real time generation reductions for security reasons.
- Requirements for RES to become AS providers:
- Minimum RES size (10 MW in the Spanish system)
- Capability to keep a given schedule
- Specific capabilities for each type of ancillary services such as to follow upward and downward generation ramps.
- RES units should participate in energy markets in order to make them responsible for their expected unbalances (if RES units remain under an integral tariff, this unbalance responsibility is assumed by TSOs).

Although these requirements might be seen as RES penetration barriers in the short term, they may maximize in the mid and long term the system capability to increase the amount of capacity installed of this type.

Next, certain technical requirements for RES units in Denmark, Germany, The Netherlands and Spain respective Grid Codes are described. In Denmark, the grid codes contain detailed requirements for fault ride through capability and voltage dips (in some GridCodes called voltage drops). These are different for wind turbines connected to different voltage levels below and above 100 kV. For small thermal units the requirements vary with the capacity. These limits are 11 kW and 1.5 MW. In Germany, main requirements are: reactive power provision and fault ride through capability. In the Netherlands, the power factor of units must be within limits (e.g. for generators in low-voltage networks, the power factor must be between 0.9 lagging and 0.9 leading).Besides, the electrical installation must be equipped with under-voltage and overvoltage protection.

In Spain, wind farms are mandated to be able to ride voltage dips of certain characteristics defined by the operational procedures of the SO. The threshold values for voltage dip duration and amount that wind generators have to ride are specified in the Grid Code, so no generator could disconnect from the network within a certain range during a short circuit (See D6, section 2.1.3). Wind generators also have to contribute to primary frequency control. They must have the ability to reduce power output if frequency is too high and raise it if frequency is too low. Additionally, every unit or aggregation of units larger than 10MW must be connected to a control centre. Finally, controllability of generation is required to access the AS markets in Spain.

Next, the curtailment capability of RES production by different TSOs is described:

- In Denmark there are annual, monthly and (since April 2007) daily auctions for reserve capacity). When activated, these reserves are paid at a market price for up-regulation or down-regulation. Market access by decentralized CHP generators was prepared in co-operation with several production BRPs and the TSO. Units above 5 MW must take part in the market. Down-regulation capacities include modern wind turbine and electric boilers for district heating systems.

- In Germany, the grid operator only gives an online signal to RES plant operator to shut down. They do not control the plants directly. A compensation for this curtailment is considered in the new RES remuneration framework.
- In the Netherlands, the TSO can instruct generators to increase/reduce their output or turn on/off their units in case of emergency and if previously taken measures did not have the desired result. This applies to all generation units with an installed capacity of more than 5 MW and with available capacity at their disposal. No compensation seems to be provided to any generator.
- In Spain, every unit above 10MW must be connected with a generation control centre. The network operator has no control over the remaining smaller groups. At the TSO control centre for RES units (CECRE), the maximum wind energy output that the system can allow under specific safety conditions is calculated in real time. If the actual production is higher than this value any unit connected to it can be curtailed. The TSO can also curtail the production of any RES-E to solve grid congestions as a last resource. Wind generators, as any conventional generator, are given 15% of the spot price in case of real time curtailment.
- In the United Kingdom, small scale generators are treated as negative loads and not centrally dispatched. Generators above 100 MW are registered as Balancing Mechanism Units. TSOs can modify their dispatch by buying the bids and offers they submitted to the BM market in order to maintain supply and demand balance and also the overall integrity of the system. TSO or DSO can curtail the production of any RES-E if system security is at risk. In the Balancing Mechanism Market, this is obtained by accepting the bids and offers submitted by BM units. This provides compensation if the RES is being curtailed. At distribution level, DSO and DG sign bilateral connection agreements which allow DG to be curtailed for a relatively short period of time if it leads to significant savings in the cost of upgrading the network to facilitate the connection. This also benefits the DG, since the connection cost / network charges will also be less.

Promoting the active contribution of renewable production units to the provision of ancillary services at TSO level

It should be encouraged a more active role of renewable production units in the provision of the following AS:

- Primary reserve
- Upward and downward reserves provision,
- Congestion management,
- Voltage support

For this purpose, adequate incentive mechanisms should be adopted at RES level (nowadays, RES incentives at European level are mainly applied for energy provision but not for AS provision).

Special consideration deserves primary reserve contribution as, currently, is mainly provided exclusively by conventional units. The objective of primary control is to maintain a balance between generation and demand within the synchronous area. Primary control aims at European synchronous area operational reliability and stabilises the system frequency at a stationary value after a disturbance or incident in a time-frame ≤ 30 seconds, but without capability to completely restore system frequency and power exchange to their reference values.

Considering primary control as one of the main services needed to guarantee the security of the electricity systems, the goal is that all generation units should provide it, if technologically possible. So far, this requirement might be seen in the short term as a RES penetration barrier, but in the long term, TSO's expected higher trust of the RES units performance, might allow for a higher RES penetration degree.

In order to encourage more fluctuating/intermittent production in the system, TSOs should allow transfers of reserve requirements between different generation units (when it is not technologically possible to provide it), by means of bilateral agreements. Thus, primary reserve requirement should be shared between all generation units connected to the system.

Next, requirements for the participation of RES/DG units in Ancillary Services markets in some European systems are described. In the Netherlands, only units larger than 5 MW and connected to the 1 kV voltage network or higher could provide ancillary services. Bids of positive or negative power to the regulating and reserve power market should have a minimum size of 5 MW. The Network Code does not discriminate between power generation units (conventional and RES/DG), apart from the section that refers to the provision of primary and balancing services. Specifically, generation units that cannot be regulated, or in other words, that are solely dependent on one or more uncontrollable energy sources, are exempted from the obligation of providing primary response and reserve power services. Therefore, these units are not obliged to meet the respective technical requirements about frequency response and reactive power provision. Units with capacity smaller than 5 MW do not qualify for primary response anyway.

In Spain, every RES/DG unit, with the exception of PV, have two options to sell their production: they can receive a feed-in tariff, or they can participate in enter the spot market or establish bilateral or long-term contracts, and receive a premium over the market price. PV only receives a feed-in tariff. The RES/DG generators that may access the AS markets are those that sell their output at the energy market or through bilateral contracts, are controllable, and have a size of at least 10 MW. This capacity can be reached through aggregation of smaller units. Regarding reactive power remuneration framework, every unit under the “Special Regime” (CHP and RES below 50 MW) is given an incentive to keep their power factor between certain regulated ranges.

In the United Kingdom, every generation unit with a capacity higher than 100 MW is obliged to take part in the provision of primary reserve. The secondary and tertiary reserve markets are voluntary. RES/DG units smaller than 100 MW are able to offer a few selected reserve and/or response services, as part of an aggregated group (where the minimum group size is 3 MW). In the energy markets, any generator which signs up to the Balancing and Settlement Code (BSC – essentially a code of conduct for use of the wholesale and balancing markets and a commitment to pay related charges) can participate in the energy markets directly. Generators under 100MW are not obliged to sign up to the BSC. Those that do not will typically form a Power Purchase Agreement (PPA) with another larger entity already trading in the energy market. For small generation connected to the distribution networks, the PPA will be combined with an Energy Supplier. The Energy Supplier will net the total output from distributed generators with their demand requirements in a particular area. The generator will be paid a fixed amount (£/MWh), independent of time of output. Typically, RES/DG units will choose to take a long term PPA with an Energy Supplier to hedge risk of imbalance in the wholesale markets. Aggregation for participation in AS/SS markets is only allowed for some selected reserve services.

In Germany up to 95% of RES-E are connected to the distribution system. The grid codes are binding for the connection to the transmission system, but not for the distribution system. Thus, RES-E generators do not necessarily have to comply with the grid codes and often do not do so.

As for whether RES/DG generation installed before the entry into force of these requirements are obliged or not to comply with them, the situation varies across countries. In Germany, the last amendment of the grid code is from 2004. Old RES/DG do not have to be retrofitted. In Spain, the obligation to be connected to a generation control centre or to be controllable in order to participate in AS markets is compulsory for every RES/DG unit regardless of its age. Wind farms that began to operate after 1 January 2008 are mandated to comply with the voltage dips riding requirements. Installations that started producing before this date must be adapted to do so before 1 January 2010 unless it is technically impossible for them to fulfil these requirements. In this case, they must communicate and justify this to the authorities before 1 January 2009.

Summary of main recommendations

Harmonizing, at European level, the technical requirements to be met by RES units and encouraging an active role of RES units in providing AS are two very important key elements of a new system that is able to cope with intermittent generation in each European country.

5.2.5 Other initiatives indirectly related to balancing mechanisms

Additional initiatives not directly related to balancing mechanisms, but that have been judged as important, as well as key elements for TSOs to admit and handle much higher levels of RES connected into the European system are:

- Increase of interconnection capacity with other TSOs (subject to environmental constraints): for this purpose it is possible to carry out interconnection rated voltage upgrades (for instance 220 kV interconnector's upgrade to 400 kV), usage of series capacitors, FACTS devices, etc.
- Monitoring in real time line temperature in order to take optimally advantage of all transmission capability.
- Considering RES contributions and use for handling intermittency impacts at both distribution and transmission planning levels

See below a summarizing, Table 5.1, providing an overview of necessary regulatory and technical changes and steps to facilitate the integration of RES/DG encouraging the adoption of and incentivises the above discussed system improvements.

Table 5.1. Summary of main recommended regulatory improvements on TSO balancing

<table>
<thead>
<tr><th rowspan="2">Regulatory initiative</th><th rowspan="2">Barrier</th><th colspan="3">Recommendations</th></tr>
<tr><th>Short term</th><th>Medium term</th><th>Long term</th></tr>
</thead>
<tbody>
<tr><td rowspan="3">Economic incentives to promote the entrance of new flexible generation in the system and to obtain higher flexibility levels from already connected generation units</td><td rowspan="3">Variable and unpredicted changes in the output of RES/DG power plants should be covered</td><td colspan="3">Encourage transient operation at lower minimum output levels during short periods of time</td></tr>
<tr><td colspan="3">Economic incentives (≤ 1 year): to encourage availability of generation units</td></tr>
<tr><td colspan="2"></td><td>Economic incentives (≥ 1 year): to encourage investment on flexible generation capacity</td></tr>
<tr><td colspan="2" rowspan="3">Promote a more active role of demand side in balancing services in the system</td><td colspan="3">Access to ancillary service markets for demand side providers</td></tr>
<tr><td rowspan="2"></td><td colspan="2">Encourage storages devices in the system</td></tr>
<tr><td colspan="2">Control of customer equipment</td></tr>
<tr><td rowspan="4">Harmonize balancing services throughout Europe, promoting balancing coordinated actions among TSOs.</td><td rowspan="4">Lack of harmonization at European level of balancing services</td><td colspan="3">Harmonize deviation pricing mechanisms (they should encourage forecast tools improvement)</td></tr>
<tr><td></td><td></td><td>Harmonize at European level day-ahead market and intraday gate closure times</td></tr>
<tr><td colspan="3">Implement explicit interconnection capacity auctions and reserve trading mechanisms throughout interconnections</td></tr>
<tr><td colspan="3">Creation of balancing perimeters and RES production aggregators</td></tr>
<tr><td rowspan="4">Harmonize at European level technical pre-requisites to be fulfilled by RES units</td><td rowspan="4">Lack of harmonization at European level of technical requirements for RES generation</td><td colspan="3">Withstand without disconnection a pre-specified voltage and frequency dips</td></tr>
<tr><td colspan="3">Increase the level of RES units observability from TSO´s (and RES integration in a control center)</td></tr>
<tr><td colspan="3">To be willing to obey real time instructions from TSO; for instance, real time generation reductions for security reasons.</td></tr>
<tr><td colspan="3">Controllability tests: capability to keep a given schedule</td></tr>
<tr><td rowspan="2">To encourage at European level an active role of RES units for providing AS</td><td rowspan="2">Lack of contribution of RES units for providing AS</td><td colspan="3">Contribute to voltage control tasks at Transmission level</td></tr>
<tr><td colspan="3">Contribute to load following tasks at Transmission level (primary, secondary and tertiary reserves), and congestion management</td></tr>
</tbody>
</table>

6 Regional markets

One big problem is that European and national targets are partly contradictory. Another one is that national solutions have to be developed for European targets. Instead, the development of European goals at European level (uniform solutions and joint implementation) should take place in cooperation with national regulatory authorities[1].

6.1 Increase in interconnection capacity

Building interconnection capacity between countries within the Integrated Energy Markets (IEM) of EU has been identified as a prerequisite in order for economic or reliability power exchanges to take place between these countries. However, several obstacles lie in the way of constructing additional cross-border capacity. Next, regulatory recommendations are provided that may prove to be useful in overcoming these barriers. Taking into account the average construction time of transmission lines, new interconnection capacity projected now could only be available in the medium to long term. According to D6 report of the RESPOND project, and other experts this measure would surely contribute to increase efficient cross-border power exchanges in all the EU countries.

6.1.1 Impact of new transmission lines on the environment

Social and political opposition to the construction of electricity transmission lines is ever growing stronger. Many consider these lines as damaging for the environment while not bringing any benefit to the areas it crosses. Environmental concerns are deemed to be an obstacle to the construction of new lines in the UK and Spain. Next, some recommendations are provided in order to overcome existing opposition related to the environmental effect of lines.

In order to make lines more environmentally friendly, many countries have already decided to bury new interconnection lines (as it is the case for the new cross-border lines between France and Spain). This may be effective in reducing social opposition to these lines. However, one must bear in mind that burying cross-border lines usually involves using DC instead of AC interconnectors. This, in turn, has major implications in the operation of power systems (for example, automatic primary regulation support by neighbouring systems in the presence of power unbalances within a certain one caused by a contingency would not be possible through these interconnectors). Besides, this option is significantly more expensive than building overhead interconnection lines. This alternative could be available in the long

[1] This issue is recently considered in the Third Liberalization Package of the European Commission, ec.europa.eu/energy/index_en.htm

term, since burying an interconnection line, either an existing or a new one, is a major infrastructure project. Burying interconnection lines will not be possible unless all the countries involved in the construction of the line agree on it. Therefore, this measure must be taken in a coordinated way. This measure could be implemented in any country and has in fact been implemented in large parts of some (like The Netherlands) for internal (distribution) lines.

Another option, involves providing some sort of economic compensation to countries where a line is going to be built that will not significantly benefit local agents. Different types of payments are possible: inter-TSO payments compensating for the cost of this lines are of course necessary (as explained in the next section) but, also, the implementation of a mechanism of side payments between countries, whereby those countries benefiting from the construction of a new line in a third one agree to pay the latter some extra compensations in order for it to accept the construction of the this line, would be possible. Their application should be studied and has been already proposed in (Coase, 1960). This recommendation could be implemented in the short term to medium term and could allow speeding the process of building new lines. Some countries could pay side compensations in order to get a line built while others not. Therefore, this measure is not intrinsically a coordinated one. However, the free riding problem may deter the former from paying compensations when others do not. Therefore, implementing a coordinated method to compute these compensations could be necessary in order for them to be applied. Paying these compensations may make sense in any country, since national laws are unlikely to prevent them.

Besides side compensations, congestion rents corresponding to cross-border lines could be used to finance the construction of new lines and pay compensations to countries where these lines will be built and are negatively affected by them. This option may also be difficult to apply in practice, since choosing the project to be financed with the rents from a different line could be a politically sensitive issue. This recommendation could be implemented in the medium to short term. This measure needs to be implemented in a coordinated way in all the countries of the region, since some coordination is needed in order to decide which lines should be built wit the money resulting from congestion rents. Compensations may have to be paid to those countries that are not benefitted by the construction of lines financed with regional congestion rents.

Better informing the public of the wide benefits brought about by lines that cross their territory would also be necessary, though this measure alone will not be sufficient, in general, to make those opposing the construction of beneficial regional lines change their mind. This option could also be implemented in the short to medium term. Information could be provided by countries on an uncoordinated basis. This measure could be implemented in any country.

6.1.2 Allocation of the cost of new investments to countries (TSOs) involved

The allocation of the cost of regional grid reinforcements may be a matter of concern for promoters of these projects and policymakers. The cost of transmission lines in general (and therefore that of congested corridors in particular) is allocated to member states in the IEM using an inter-TSO compensation (ITC) scheme whose results cannot be considered indisputable. Some countries argue that beneficiaries of a certain line are not necessarily the ones who end-up paying for it. This, of course, may cause them to oppose the construction of this line. This is believed to be a barrier today for the construction of new lines in the UK and Spain.

Therefore, implementing an ITC scheme that allocates the cost of regional lines proportionally to the benefit each country obtains from it would be a necessary tool and incentive for potential investors and users. As measuring economic benefits produced by lines is generally regarded as a very complex task, normally electrical usage is accepted as a proxy to these benefits. Then, an ITC method that is capable of computing the use that the agents within a country make of each regional line should be the used as the base to compute ITCs, see [Olmos et al., 2007] for a discussion on the subject. Given the difficulty to reach an agreement on the ITC method to use, this measure could only be implemented in the medium term (a year or two). This method must necessarily be implemented in all the countries at the same time, since the method to apply must be common to all the countries in the region.

6.1.3 Encouraging countries to allow the construction of those lines that benefit others

Benefits from the construction of cross-border lines are many times, much widespread. If the cost, and the environmental harm, born by a country where a line is to be built is higher than the benefit it gets from this line, this country will oppose its construction unless satisfactorily compensated. This is deemed to be a serious obstacle to the construction of new lines in Spain, the UK and the Netherlands.

Therefore, contributions to the cost of these lines should also be allocated based on the use of an ITC scheme. This could be implemented in the medium term and in a coordinated way. Besides, compensations should be paid to those countries that oppose the construction of lines. These compensations should be commensurate with the costs/environmental harm caused by the lines in this country. Otherwise, some countries could take advantage of the situation to extract large monopoly rents in order to allow the construction of lines in their territory. Therefore, strong regional regulatory bodies should exist with executive powers over regional issues. Again, this measure should probably also be implemented in a coordinated way. Compensations could be paid in any country. Funds for compensating countries could come from congestion rents corresponding to interconnection lines in the region. This measure could be implementable in the medium term, like the previous one. However, strong regional regulatory institutions are unlikely to be in place in the short term although the North-West European regional cooperation seems increasingly effective last year.

6.1.4 Complexity of the process aimed at obtaining construction permits

The complexity of the permit process, where every involved country must accept the construction of a regional transmission line is also regarded as a major obstacle in order to achieve the construction of these lines. This is a barrier to the construction of interconnection lines in Spain, the UK and Denmark. Similarly to what has been explained before, a regional regulatory authority, independent from national governments should have executive powers over the construction of regional lines when a conflict between several national states arises. Implementing such an institution would only be possible in the long term and should be the result of a regional agreement. If the line is built, countries negatively affected by it whose territory is going to be crossed by it should be appropriately compensated.

Besides this, authorities within each country in charge of authorising European scale transmission lines should be unique. Local governments should not be able to veto the construction of these lines when it has been approved by the corresponding national government. Again, changing national legislation in this regard could only be achievable in the medium to long term. Each country could separately determine the authority in charge of deciding over the construction of interconnection lines. This measure could be implemented in all countries.

6.1.5 Harmonization of national market rules

Lack of harmonization of market rules, which prevents agents from some countries from accessing other national markets, renders the construction of new cross-border lines among these countries less important. This barrier is explicitly acknowledged in the UK.

Mechanisms for the efficient allocation of interconnection capacity between countries should be put in place. These may include the harmonization of some minimum rules, though the operation of national markets could remain highly independent. National market rules to be harmonized should be those affecting the ability of external agents to acquire the transmission capacity required by them to trade their energy in a certain country (for example, national markets gate closure times). This recommendation could be implemented in the medium term (a couple of years) but, given the fact that the dispatch must be coordinated, it should be implemented in a coordinated way on all those interconnections whose capacity must be jointly allocated. See the next section for a more in depth discussion of this subject.

6.2 Coordination of the operation of regional markets

Unless the operation between neighbouring national power markets in a region is not coordinated to some extent by a regional Authority, i.e. a regional TSO, cross border power exchanges will not be able to take place. Even if we assume that some coordination between neighbouring TSO on a voluntary basis already takes place nowadays it is certainly not sufficient. A on legal grounds authority is needed otherwise disputes and uncertainty and high risks may prevent countries (TSOs) from fully exploiting the potential for efficient commercial exchanges at regional EU level. This must be regarded an issue of highest priority in EU countries today.

6.2.1 Efficient allocation of cross border capacity in the short term by implicit auctions

Implicit auctions are superior to explicit ones to allocate the interconnection capacity between countries in the short-term (day-ahead or intraday energy markets). However, the former generally require more coordination among national markets than explicit ones. Thus, many countries still do not apply short term implicit auctions on their borders with other IEM countries. Besides, even when implicit auctions are run on one border, the allocation of capacity in this auction is normally not coordinated with that in other borders, which is highly necessary in order to increase the efficiency of the final energy dispatch. The format of short term capacity auctions is thought to be a problem for the interconnection capacity between France and Spain and most borders of Germany and the Netherlands.

Coordinated implicit auctions are already being run in some sub-regions like NORDEL or the France-Belgium-the Netherlands one. These should be extended to other areas in Europe. In order to run efficient coordinated implicit auctions in meshed grids, like the one in the European central Plato, two options are possible: either a complex iterative process between the national dispatches in the different countries is implemented, or a single auctioneer is created and empowered with the ability to centrally allocate interconnection capacity in the region. We believe the latter option is superior to the previous one, and therefore, back the EFET proposal[1] to create a regional system operator that would undertake this and other functions. Both alternatives to amend the existing situation could only be implemented in the long term. Coordinated implicit auctions could be implemented in all countries if an iterative

[1] A practical step towards an internal electricity market: EFET proposal for a market in cross-border electricity transmission capacity rights. Press Release 34/07, 28th September 2007. European Federation of Electricity Traders.

process is run. If they are run by a central auctioneer, its implementation would be more difficult in those systems where there are strong national market institutions (like Spain or Germany).

6.2.2 Efficient allocation of cross border capacity in the longer term by coordinated multilateral explicit auctions

In the longer run, coordinated explicit auctions involving the different countries in the region are necessary. However, no single example of a coordinated explicit auction scheme involving several countries has been reported within the European market (all countries affected but the UK). This probably has to do with the fact that multi-country explicit auctions in the central plato in continental Europe would require a high level of centralization of the capacity allocation process. A central auctioneer should probably run these auctions. Several options are discussed in (Pérez-Arriaga et al, 2005) for the implementation of explicit auctions in the IEM. These type of auctions could only be implemented in the long run. Problems to implement these auctions in certain countries would be similar to those faced when implementing coordinated implicit auctions in the short run.

Besides this, firm transmission rights should be awarded to agents paying for firm transmission capacity and signing firm contracts. These transactions should have priority over any other kind of transaction and their enforcement should be made possible through the implementation of regional regulatory bodies like a regional energy regulator and the European Commission. Transmission rights of this type could start being issued in the medium term. Given that these rights would refer to interconnection capacity on several borders, the use of these rights should probably be launched in a coordinated way in the different countries in the region.

6.3 Summary of the recommendations

Table 6.1 summarises the main recommendations on the functioning of regional markets

Table 6.1. Summary of main recommendations for better functioning of regional markets

<table>
<tr><th>Market Response</th><th rowspan="2">Barrier</th><th colspan="3">Recommendations</th></tr>
<tr><th></th><th>Short term</th><th>Medium term</th><th>Long term</th></tr>
<tr><td rowspan="5">Increase Interconnection Capacity (D, SP, UK, NL)</td><td>Impact of new lines on the environment (UK, SP)</td><td colspan="2">Use of congestion rents to finance new lines (coordination necessary)
More public information on the benefits of lines</td><td>Bury new interconnection lines (coordination necessary)</td></tr>
<tr><td>Inefficient allocation of the cost of cross-border lines (UK, SP)</td><td></td><td>Use of an ITC scheme based on the identification of beneficiaries of lines (coordination necessary)</td><td></td></tr>
<tr><td>Benefits of lines wide-spread (SP, UK, NL)</td><td></td><td>Use of an efficient ITC scheme (coordination necessary)
Side compensations paid to countries</td><td>Creation of strong regional regulatory bodies (coordination necessary)</td></tr>
<tr><td rowspan="2">Complexity of the process aimed at obtaining permits (SP, UK, DK)</td><td rowspan="2"></td><td></td><td>Regional regulatory bodies that decide over new lines (coordination necessary)</td></tr>
<tr><td colspan="2">Centralization of decisions over the approval of interconnection projects within each country</td></tr>
<tr><td></td><td>Lack of harmonization of national market rules (UK)</td><td></td><td>Mechanisms for efficient allocation of interconnection capacity (coordination necessary)</td><td></td></tr>
<tr><td rowspan="2">Coordination of the operation of regional markets (UK, SP, NL, D, DK)</td><td>Inefficient allocation of capacity in the short term (inter-connection between France and Spain, D, NL)</td><td></td><td></td><td>Implementation of efficient coordinated implicit auctions: central auctioneer or iterative process (some level of coordination necessary)</td></tr>
<tr><td>Inefficient allocation of interconnection capacity in the long term (interconnection between Portugal and Spain, D, UK, NL, DK)</td><td></td><td>Firm transmission rights paid to agents signing firm supply contracts (coordination necessary)</td><td>Coordinated explicit auction scheme run by central auctioneer (coordination necessary)</td></tr>
</table>

7 Transmission networks

7.1 Locationally and temporally differentiated transmission charges

Promotors of RES and RES/DG generators should take into account the transmission grid costs that the system will incur as a result of their decision to install a new plant in a certain node. Grid locational signals are useful in any case (both for conventional and RES/DG generation). Their only objective is allowing promoters to see an additional cost component (the cost of building the grid) that was not being considered before. This, together with other signals should result in optimal global decisions by generation promoters. This cost may vary greatly from one point of the grid to another. Thus, transmission tariffs paid by generators or loads could exhibit some sort of locational differentiation. Otherwise, transmission costs may increase significantly as a result of the installation of this type of generators even if it is not necessary for them to do so at this place.

The cost of installing a new plant may clearly depend on the operation profile of this plant. Thus, if this plant produces power when local demand is maximum it may be able to reduce the amount of new import transmission capacity into the area to be built in the future. On the other hand, if its peak production takes place when local demand is minimum, additional transmission capacity may be needed to transport this power to other parts of the system. Hence, one can conclude that the level of the transmission tariff to be paid by a generator should depend on the production profile that the generator is deemed to have.

Parties in Europe tend to agree that, if transmission charges were differentiated by time and space, differences among charges paid in different nodes/areas and by different types of generators could be significant, thus affecting investment decisions by agents. However, there are other parties that think these charges would not represent and incentive strong enough to affect agents' decisions.

Implementing locationally and temporally differentiated transmission charges is attainable only in the medium term. Only generators in the UK pay Use of the system transmission charges that exhibit some sort of temporal and locational differentiation. Generators in Denmark, Spain and the Netherlands pay connection charges with locational and/or temporal differentiation. Therefore, this measure still needs to be implemented in the remaining cases.

At the national level the goal seems to optimize the grid load and the need to minimize grid expansion respectively. Due to different national conditions of production (solar, wind, hydro, etc) a reallocation may be expensive and inefficient. Therefore it is important to optimize the overall system (network cost, environmental impact, production conditions). For conventional power plants an allocation impact may be possible. In contrast, CHP and renewable power plants are hard to relocate due to their local dependencies.

7.1.1 Volatility of charges

Some parties have expressed the view that charges resulting from the application of temporally and locationally differentiated tariffs may turn out to be too volatile. Even differences in tariffs between nodes or points in time that are close could be significant. This has been pointed out in the Netherlands as a significant obstacle.

In order for the economic signals produced by transmission tariffs to be effective in driving decisions by agents, these should not be volatile. This could be achieved by implementing zonal tariffs, i.e. tariffs that are homogeneous over some zones of the system that are predetermined but can be periodically updated. Besides, tariffs should be computed for each operation profile in advance of the time frame that these tariffs refer to. Therefore, these tariffs would not depend on the actual use or benefit that agents get from the grid, but on the expected one. All this should result in these tariffs being fairly stable. Taking into account the opposition that the application of locationally differentiated tariffs will face, these measures could only be implemented in the medium term. Its application could take place separately in each country, though, if locational signals at regional level are to be given, then some coordination should exist. Computing zonal prices from nodal ones should be acceptable in any system.

7.1.2 Discrimination between agents

Applying different charges to different generators based on their type or operation profile and their location is seen by some as a source of unfair discrimination. Discrimination between old and new generators is also seen as unfair in some cases. This is pointed out as a major barrier in the Netherlands and Germany.

Despite this common belief, nothing can be deemed more reasonable and fair than making each agent (or group of agents, if zonal tariffs are applied) responsible for the cost (in this case, the network cost) that it makes the system incur. Otherwise, cross-subsidies would exist between agents that are efficient in terms of their situation in the grid and operation profile, and agents that are not. This should be deemed a cause of unfair discrimination. Comparable examples can be found in many other cases (price of households is not the same in different regions, why should the price of energy, or the level of network tariffs be the same?). Demonstration projects on the applicability and benefits of this type of initiatives should be launched. Heavy marketing of this type of policies could also help overcome political/social opposition. These measures could be implemented in the short term in any of the affected countries on separate basis. Additionally, in order for those who cannot afford large transmission charges not to be left without supply, special provisions (social transmission and energy charges) could apply to them. The latter measure could probably be implemented in the medium term. Again, social tariffs should be implementable in any system and systems could consider its application regardless of the situation in any other one.

7.1.3 Level of incentives for installation of new DG: comparison with transmission charges

According to others, the large size of the feed-in tariffs that are presently being applied to RES generation may discourage RES operators from taking into account grid locational signals when deciding on the location of their plants, since these plants would turn out to be very profitable no matter where they are installed. This is seen as a potential problem for system operation in Spain.

In order to overcome this problem, energy prices earned by RES producers should be commensurate with the benefit they bring about to the system. Thus, premiums, instead of FITs, are preferable. Premiums could be implemented in any country, though, in order not to distort competition, support mechanisms in different countries should be homogeneous. So some level of coordination is necessary. Second, the level of these tariffs should be adjusted so as to achieve the level of RES capacity required or, alternatively, a RES obligation scheme could be implemented where RES technologies could compete ones against the others. These measures could be implemented in the medium term. Finally, in this situation, locationally differentiated charges could probably make the difference between installing a RES plant in one part of the grid and installing it in another one, since expected differences in network charges between different points of a system, resulting from the application of an efficient tariff setting process, have proved to be comparable in size to other potential locational signals like the impact of operation decisions on losses.

7.1.4 Complexity of the network regulation

Finally, there is also the concern that implementing a system of nodal/zonal transmission tariffs may substantially increase the complexity of the system regulation and that of the monitoring of the system functioning, thus making it less attractive in policymakers view. This is perceived as a problem in the UK.

Using simple methods to compute transmission tariffs, like the so-called Average Participation one, presented in (Bialek, 1996; Kirschen, 1997), that are based on the application for simple rules, and whose results can be predicted within a certain error margin, should not be perceived as a significant increase in the complexity of the tariff setting process. Simple methods would be favoured by authorities in any country. Their application would not need to be coordinated. If tariffs were computed for a limited number of zones and technologies (operation profiles), the complexity of the process would be smaller. Applying these measures should be possible in the medium term. Reducing the number of tariff zones and technology profiles in their computation is deemed to be acceptable anywhere, since this would result in more predictable tariffs. This does not need to take place as a coordinated process.

7.2 Grid reinforcements

Installing new RES generators may require reinforcing the transmission grid. However, political and social opposition to the construction of new lines has been growing significantly. Besides, delays in the process to be followed to obtain the required permits may represent another important obstacle.

Significant socio-political opposition is faced nowadays by promoters of new transmission lines in most European countries. This has resulted in a significant delay in the construction of some lines. Average time for the construction of new lines ranges from 3 years (Spain, UK's best case) to 10 years (NL, D, UK's worst case). Building new grid lines is only possible in the long term. However, significant reinforcements to the grid are (and will be) necessary in all the considered countries.

Some general measures can be considered, like the use of side payments between regions so that the one where a line should be built is compensated for the cost (environmental and any other type) that it may bear due to the existence of this line.

7.2.1 Impact on health and the environment of new lines

Main concerns raised by local/regional governments and associations of consumers/network users about new transmission lines are environmental and those related to the effect of lines on health. This has proved to be a major barrier in the Netherlands, Spain and Germany. In order to overcome it, many new lines have had to be buried, which can only be accomplished in the long term. This certainly reduces the strength of the field caused by transmission lines around human beings. However, it also significantly increases the cost and the technical complexity of the investment projects, which may, in turn, become a major barrier to the construction of new lines. This measure has already been implemented in most countries like Denmark, The Netherlands or Spain, especially in urban areas. Coordination between countries would not be necessary in this case.

Research and development in order to develop more efficient processes to bury lines and, maybe, the sharing of transmission lines rights of way with lines used for other purposes (communications, other commodities, etc.) may contribute to reduce the cost of this type of projects. Developing more efficient ways to bury lines could only be possible in the long term. Sharing rights of way with other type of infrastructures can only be implemented in the long term as well. These two measures could be implementable in any system and this measure could be considered separately for each country.

7.2.2 Efficiency of the cost allocation of new lines

Other concerns are related to the allocation of the cost of new network investments, which is deemed not to be efficient in many systems. This is perceived a major barrier in the UK. Methods that seek the efficiency in the allocation of the cost of lines to their users should be implemented. Economics theory dictates that the cost of lines should be allocated to those who benefit from them in proportion to the benefit each obtains. Computing these benefits may be difficult but there are some cost allocation methods that offer a reasonable proxy to beneficiaries methods, see (Olmos et al., 2007). Implementing these methods would be possible in the medium term. Implementing efficient network charges could be difficult in those systems where transmission tariffs must be the same for all network users of the same type by law (Spain for consumers, The Netherlands). Methods applied in different countries could be different as long as they are all reasonable.

7.2.3 Efficiency of the use of transmission capacity within each system

Some parties are worried about the possibility that the already existing transmission capacity is not being allocated efficiently. This reduces the benefit that agents may extract from the construction of new lines. This happens to be a major problem in the UK. In order for this not to happen, coordinated market based methods, which allocate capacity to those agents that value it most, and therefore are willing to pay the highest congestion charges, should be implemented. Nodal or zonal prices are probably the best option in this regard, as the next section explains. Changing capacity allocation methods would be possible in the medium term in some countries like Germany if significant congestion arises. Its application could be more difficult in others like Spain due to social opposition. If significant congestion exists within a country, the allocation of local and interconnection capacity should take place jointly in a coordinated way with other countries.

7.2.4 Profitability of proposed reinforcements

Finally, the profitability of the investment projects in the current conditions is also under scrutiny. This may be a problem in the UK. In order for investments to be efficient, the expansion of the grid should be centrally planned by an institution looking after the interest of society (encouraged to do so through regulation). This institution could probably be an active TSO, like that existing in England and Wales, whose incentives are carefully designed. Authors in (Olmos, 2006) analyse the incentive scheme to be applied to TSOs. The planning process for the expansion of the grid could be changed in the medium term separately for each country.

7.3 Congestion management schemes

The installation of RES generation in far remote areas (for example wind farms both off-shore and on-shore) may produce congestion in the system. Apart from this, if the amount of new generation located within an area is significantly larger than demand and/or the pattern of power production by this generation is poorly correlated with that of demand in the area, additional congestion may arise because of the installation of DG. Under these circumstances, efficiently allocating the scarce transmission capacity may become even more urgent. Otherwise, welfare losses may occur. Most parties agree that introducing some market based method to solve congestion is highly advisable.

With the exception of Denmark (prices for the two separate areas that have been defined in this system are computed through implicit auctions that take place at regional level in the Nord Pool day-ahead market, as described above), no system within the ones analysed is applying nodal/zonal pricing to solve congestion within their systems. Therefore, the implementation of this type of methods should be investigated in the Netherlands, Spain, Germany and the UK. Changing congestion management methods is possible in the medium term.

7.3.1 Compatibility with national regulation

Congestion management schemes that provide efficient price signals may be incompatible with national regulation in place in some countries, which may require computing a single energy price for the whole system. The regulation in place in several countries does not allow different energy prices to be charged to consumers based on their location. This is the case of Spain, where prices earned by generators are allowed to be different, nevertheless, and that of the Netherlands, where the grid code and the system code would have to be significantly changed to apply nodal/zonal prices.

Similarly to what is stated for transmission charges, pricing the energy produced and consumed by agents according to the value it has for the system, which clearly depends on the location and time of production or consumption, is reasonable and would lead to significant gains in the efficiency of the energy dispatch (at least, assuming no significant market power exists). Otherwise, cross subsidies between more or less efficient generators and demands, based on their location and profile, will occur. Those consumers in an expensive importing area that cannot afford energy prices could be subsidised through social energy tariffs. This measure can be implemented in the medium term in any country in an uncoordinated way (consumers with social tariffs would not be competing against one other). If, despite this, implementing locational energy prices for load is not possible, at least its application for generators should be considered. This can be done in the medium term as well. Applying different energy prices to generators (zonal prices) would be possible in Spain, Germany or The Netherlands only if very significant congestion arises. The mechanism used to compute these charges should probably consider the existence of congestion on interconnections between countries.

7.3.2 Incentives from nodal/zonal prices to increase the exercise of Market Power

According to most of the consulted parties that have been consulted, market power exercise would be exacerbated if energy prices within congested areas were computed separately from those of the rest of the system. This is true even for parties in those systems where zonal pricing is already in place, like Denmark. Therefore**,** the effect of applying nodal/zonal prices on market power is perceived as a significant barrier in all considered countries. This is related to the fact that generators able to solve most of the existing grid congestion belong to one or very few companies, as a result of the decrease in the size of the relevant market when nodal/zonal pricing is applied.

Instead of applying nodal energy prices, zonal prices could be computed (see comments on their application made before). This would increase the size of areas whose prices are set independently from the rest of the system as a consequence of the existence of congestion, which should result in an increase in the number and size of competitors for any energy producer and, therefore, a reduction in market power. This measure can be implemented in the medium term.

Besides, different energy prices should only be computed to value systematic grid congestion that affects large parts of the system. This again, should result in larger price areas than in the case of local grid constraints. Therefore, the price of these areas should be more difficult to unilaterally modify. Again, modifying the scheme used to compute prices would be possible in the medium term in all countries but Denmark, where some changes to the zonal pricing scheme already used could be introduced in the short term (like the splitting of Western Denmark into two different price areas – Energinet.dk 2007). As mentioned before, the application of zonal prices should be coordinated among countries.

7.3.3 Complexity of the market clearing process

Last, but not least, the complexity of the process of computing zonal/nodal prices is also cited by some parties as an important difficulty to be overcome in the process of implementation of these methods. For some countries, like Spain, the process of coordination of the market dispatch at regional level would be much more difficult if several prices would have to be computed at national level. For some other systems, like the Dutch one, splitting up the imbalance settlement according to price areas and changing computer systems represent non-negligible challenges.

In order to reduce the complexity of the market clearing process, some centralized institution could be in charge of determining, according to aggregate energy/capacity bids by agents, what is the optimal use to be made of interconnection capacity. This option could probably only be implemented in the long term, since creating a central auctioneer is politically very challenging. This would be a coordinated response to this barrier. Fierce opposition to applying this coordinated dispatch could arise in many countries (all those countries considered but Denmark and maybe the UK).

The alternative to this, in meshed regions, would be implementing some sort of iterative process involving separately computed national dispatches whose complexity would certainly be significant. This could be implemented in the medium term, though significant implementation problems would arise. Less coordination would be needed and it would implementable in almost any country.

If congestion is persistent and predictable, predetermined nodal/zonal factors representing the difference in price between nodes or zones could be used to compute the constrained energy dispatched. These factors could vary depending on the time of the day, the week and the year and should probably be updated periodically. This, again, could be implemented in the medium term in England but its application in Spain, Germany or The Netherlands would be more difficult. Nodal factors' values should be conditioned by the expected allocation of capacity in interconnections.

7.4 Summary of the recommendations

Table 7.1 below summarises the main recommendations on the improvements of functioning of the transmission network in coping with variable RES/DG generation.

Table 7.1. Summary of main recommendations of the functioning of the transmission network for coping with high shares of variable RES/DG

Market Response	Barrier	Recommendations		
		Short term	**Medium term**	**Long term**
Locationally and temporally differentiated transmission charges (SP, D, DK, NL: UoS charges; UK: connection charges)	Volatility of charges (NL)		Implementing zonal transmission tariffs. (coordination advisable) Tariffs computed for each type of profile in advance of actual operation	
	Discrimination between agents (NL, D)	Demonstration projects for application of these tariffs Increase in the marketing of these charges	Implementation of social transmission charges	
	Level of DG/RES production incentives (SP)		Premiums instead of FITs (coordination necessary) Adjust level of tariffs/ RES obligation scheme (coordination necessary)	
	Complexity of the network regulation (UK)		Use of simple methods to compute tariffs Computing tariffs for a limited number of zones and operation profiles	
Building new grid reinforcements (UK, SP, D, DK, NL)	Impact of new lines on health and the environment (NL, SP, D)			Burying new lines Developing new more efficient methods to bury them Sharing rights of way with other types of infrastructure
	Lack of efficiency of the cost of new lines (UK)		Implementation of efficient cost allocation methods based on beneficiaries	
	Lack of efficiency of the use of transmission capacity within each country (UK)		Implementation of coordinated market based methods for allocation of transmission capacity	

			(coordination necessary)	
	Disputable profitability of proposed grid reinforcements (UK)		Development of the grid centrally planned by the TSO. Probably subject to moderate incentives	
Increase in the efficiency of congestion management methods (SP, D, NL, UK)	Lack of compatibility of proposed schemes with national regulation (SP, NL)	Implementation of social energy tariffs		
			Application of efficient differentiated prices only to generators (coordination necessary)	
	Incentives from nodal/zonal prices to exercise Market Power (SP, UK, DK, D, NL)		Application of zonal energy prices (coordination necessary)	
		Application of the recommended scheme only to systematic grid congestion in the main transmission system (coordination necessary)		
	Complexity of the resulting market clearing process (SP, NL)		Implementing an iterative process for the allocation of these capacity (at regional level) (some limited level of coordination necessary) Predetermined nodal/zonal factors for systematic predictable congestion (at national level) (some coordination necessary)	Alternatively, creating a central auctioneer to allocate interconnection capacity in a region (at regional level) (coordination necessary)

8 Distribution networks

Earlier in the RESPOND project, several barriers were identified regarding the integration of intermittent distributed and renewable energy generators in distribution networks (D6 report). In this section, we provide some policy and regulatory improvements to overcome some of these barriers or issues and to facilitating the efficient system integration of these variable RES/DG generation sources. For simplicity a similar analytical framework is followed as in report D6 of RESPOND.

Some of the main improvements and consequently recommendations in RESPOND can be find in outputs of previous other European projects, which were addressing the same topics, i.e. DG-GRID and SOLID-DER projects (Gómez et al., 2007 and Cossent et al., 2008).

8.1 Locationally differentiated and time varying network charges

The DG-GRID and SOLID-DER projects investigated the structure of distribution charges paid by DG/RES generators (both connection and use-of-system (UoS) charges) in EU-15 and EU new member states (MS), see (Cossent et al., 2009).

Connection charges are paid just once when a DG/RES or CHP generator requires network access to compensate for the costs of connection. On the other hand, UoS charges are periodically paid by network users (generally end consumers but also generators in some MS, such as in the UK and Denmark). A correct design of UoS charges and connection charges is a key issue to ensure fair and non-discriminatory network access. Therefore, this is one of the main requirements for an increase in the share of DG at European level.

In RESPOND D6 report the current situation about this issue in the RESPOND countries was reported. Connection charges are shallow in some cases (UK, Netherlands for small generators, Denmark, and Germany) and deep in others (Spain, and Netherlands for generators larger than 10 MW). Under deep connection charges, DG pays for all the cost of connection, including upstream network reinforcements. On the other hand, under shallow charges DG pays only the direct costs of connection. A trade-off exists between providing incentives for the optimal and cost-reflective sitting of new generation (deep connection charges) and facilitating entry for small-sized DG operators (shallow connection charges), for whom these charges may otherwise be a major barrier.

Regarding UoS charges paid by DG, only in Denmark and UK these charges are applied. These charges may be locationnally and time differentiated. This is the case of UK where

UoS distribution charges are computed according to a Distribution Reinforcement Model (DRM) (Ilex Energy Consulting, 2002).

The regulatory policy recommendation to efficiently integrate DG is to implement shallow connection charges in Spain and Netherlands together with UoS charges including differentiation per location (voltage level, rural/urban areas) and time of use (peak, fall and valley hours) in Germany, Spain, and Netherlands.

Connection charges should be averaged, regulated, and shallow, or at least shallowish, especially for small DG. The rest of the reinforcement costs can be socialized and recovered via UoS tariffs with location and time differentiation. Negotiation between DSOs and DG promoters ought to be avoided to prevent access conflicts. Discrimination can be caused either by the lack of unbundling between DSOs and DG ownership or by the fact that most DSOs regard DG as a source of problems rather than as an active element that can contribute to the operation of the network.

At the same time, UoS charges should be cost reflective, in order to better reflect the actual costs (and benefits) for the system caused by each agent. The cost causality criterion implies that UoS charges can be either positive or negative, since DG may achieve cost savings through losses reduction, investments deferral, voltage control, etc. For instance, a generator could be paid when producing at local peak demand time since losses will be decreased and voltage kept under margins. Otherwise, the DSO operating that area would receive some windfall profit for this whereas the generator causing the benefit would not perceive it. Properly designed distribution UoS tariffs must take into account the particular features of networks, such as the different voltage levels, areas of distribution, metering devices capabilities, planning criteria and quality of service requirements (Rodríguez Ortega et al., 2008). Nonetheless, their structure and computation methodologies should be adapted as DG reaches significant levels of penetration (Li et al., 2008; Sotkiewicz and Vignolo, 2007).

8.1.1 Compatibility with national regulation

As we have seen, only UK and Denmark are currently in line with this policy recommendation. In Netherlands, the main barrier for implementing locational UoS charges is legal because tariff codes should be changed. In Germany, allocating charges to generators in an efficient, cost-reflective, manner is also regarded as a challenge by authorities. The same kind of situation happens in Spain were generators no matter where they are connected, transmission or distribution, do not pay UoS network charges. A major change at the level of the Electricity Law would be required to modify the current situation. Implementing UoS charges for DG is not advisable unless conventional generators pay them too. Otherwise, instead of attaining the desired effects, they would represent a discriminatory measure against DG.

Another possibility to try to solve this situation is to look for the same effect through the already implemented support mechanisms for DG-RES and CHP. For instance, properly designed FITs or premiums (with location and time differentiation) can be used as a complement or a substitute to obtain the same results in countries where generators do not pay UoS network tariffs by law or regulation.

8.1.2 Achieving stable distribution charges

In the Netherlands, volatility of network price signals was reported as a barrier to implement UoS charges for DG. In general, practical applications of UoS charges are implemented through zonal distribution charges differentiated by voltage levels or network areas and in time zones as peak, flat, and valley hours. In this way, temporal and locational price volatility is partly avoided.

The aforementioned required changes related to the implementation of shallow connection charges and UoS charges with location and time differentiation in Netherlands, Spain, and Germany could be adopted in most of the countries in a short to medium term framework. It is clear that the new UoS tariffs must be consistent with the whole regulatory framework, including the support schemes for renewables, in each country.

8.2 DSOs' incentives for active network management

As it was stated in D6 RESPOND report, active network management (ANM) by Distribution System Operators (DSOs) includes real time monitoring of DG operation and communication with these generators so as to control them, changing the grid configuration in order to improve quality of service indicators and energy losses, and implementing advanced metering devices to facilitate the active demand response and the network management.

The current situation in most of the countries surveyed in the RESPOND project is that DSOs rely mainly on traditional passive network management practices. However, most of the countries are already applying some sort of incentive regulation associated to the reduction of losses and the increase in service quality. An exception to this is Germany, where incentive regulation will be applied from 2009 on. The regulatory discussion is nowadays focussed on whether incentive regulation would be enough to achieve the desirable transformation from passive to active management, or by the contrary, if new additional regulatory measures would be needed.

What it is clear is that, contrary to the current situation, DG observability and controllability should increase as "active network management" would be taken up by DSOs and thereby allow the system operator to take full advantage of the capabilities of DG to improve quality of service or defer new investments. This is illustrated in Figure 8.1 (from Djapic et al., 2007. c@ 2007 IEEE), where active management and coordinated centralized and decentralized control would allow overall system costs to decrease. As a consequence, future regulation should seek the promotion of network transformation to more active DSOs and be aimed at giving incentives for DG to participate in the provision of ancillary services and network support (see subsection 8.4).

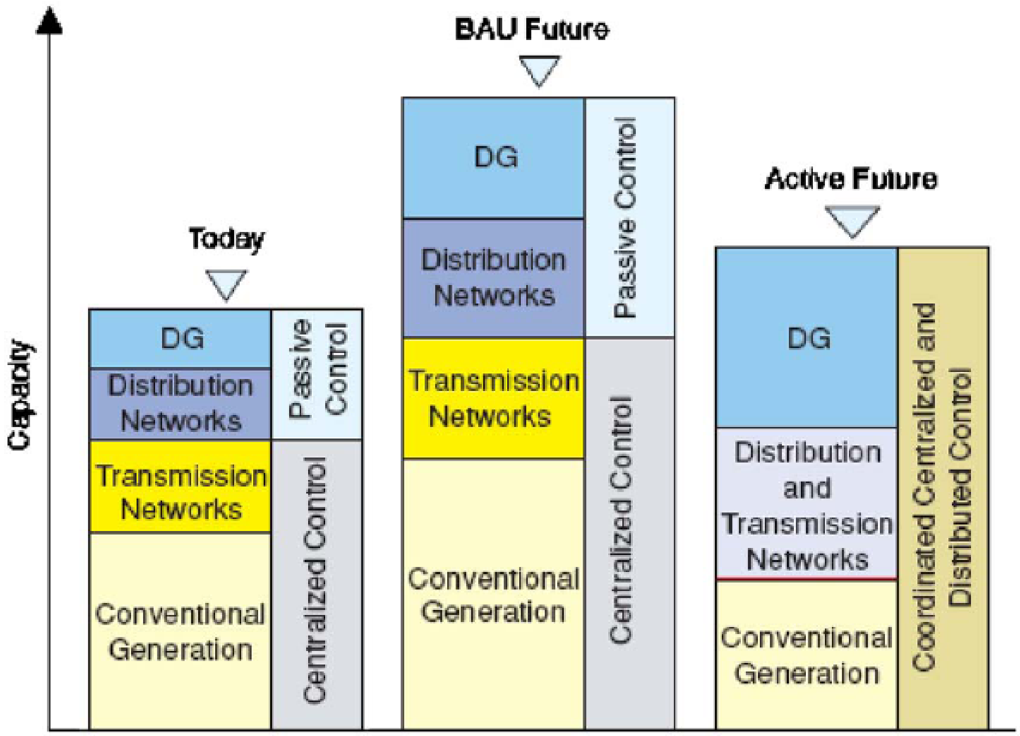

Figure 8.1 : Passive vs. active management of distribution networks.

Only in the UK and Denmark, some initiatives have been launched to develop active network management techniques related with the efficient integration of DG. For instance, in the UK, the Innovation Funding Incentive (IFI) permits DSOs to spend up to 0.5% of its revenues on eligible IFI projects related with any distribution system asset management aspect. Secondly, the Registered Power Zones (RPZ) mechanism focuses on the connection of DG to distribution systems by using innovative and more cost effective ways. If the regulator accepts a proposal as RPZ, the DSOs incentive to connect DG (in the UK the DSOs remuneration formula includes a term expressed as £ per kW of DG connected) is increased considerably for the first five years of operation.

The policy and regulatory recommendations in this regard are related with the implementation of specific incentives for DSOs to move in the right direction.

8.2.1 Assessment of DG impact on energy losses and quality of service targets

Current incentive schemes that promote improvement in quality of service levels and reduction of energy losses should be adapted to recognize the beneficial effect coming from contributions from the adequate control of DG. Here, the difficulty lies in computing the impact of DG on losses and quality of service as it has been reported by the Netherlands. However, the use of reference network models helping the regulator to assess targets for quality of service indicators and energy losses reference levels can be a very useful tool to perform this task. Reference network models are used by the Spanish regulator when calculating revenue caps and incentives for distribution companies (Gómez, 2007).

Additionally, in order to foster DG integration through innovation, specific performance indicators with associated economic incentives if DSOs reach specific targets, should be selected. For instance, the number of DG connections already integrated in the network in comparison with the total number of applications could be employed as a performance indicator.

Both types of recommendations can be implemented in all the countries D, DK, NL, SP and UK in a medium term framework.

8.2.2 Demonstration R&D projects and incentives for network transformation

Additional research and innovation programs should be implemented aimed at developing technical and operational procedures for ANM where both public and private institutions participate. There are some examples, as that already commented in the UK, Denmark, or that planned in the Netherlands, where they are also considering applying this kind of policies to trigger a change in the paradigm of operation of distribution networks. In Spain, there is a national program where demonstration projects are funded by the Ministry of Industry together with private companies. This line of research is also viewed as a European research priority line known as Smartgrids under the 7th Framework Programme.

From the point of view of the specific participation of DSOs in this kind of initiatives, or others in the same direction, R&D investment and costs can be included in the regulatory asset base as a separate item with higher rates of return or with a partial pass-through to tariffs that reduces the risk perceived by DSOs. In addition to this, the regulatory period to pass-through associated gains of efficiency derived from such innovations to customers, should be extended.

Both types of recommendations can be implemented in all the countries D, DK, NL, SP and UK in a short to medium term framework.

8.3 DSOs incentives for taking into account DG in network planning

DG-GRID and SOLID-DER (www.solid-der.org) projects investigated the way the connection and operation of DG can impact network design and future investments. The potential of DG to replace network investments is caused by the fact that DG is connected closer to end consumers or even on their side of the meter, thus reducing the net demand to be supplied through transmission and distribution grids. It is also important to acknowledge that some DG based on renewables, such as wind power, is not always connected close to loads. Article 14/7 of the EU Directive 2003/54/CE requires DSOs to consider DG, together with energy efficiency measures and demand response, as an alternative to network expansion. However, designing a regulatory mechanism to take into account this possibility is not an easy task.

In the RESPOND D6 report, the current situation about this issue has been described for the surveyed five countries. In most countries, but Germany, where a mechanism will be applied from 2009, an incentive regulation scheme to promote efficient investments by DSOs, as opposite to a cost of service regulation, has been put in place. Incentive regulation, theoretically, fosters DSOs' costs reduction while keeping quality of supply and security standards. Under this type of regulation, the determination of a "reasonable" allowed capital expenditure (CAPEX) to be paid to DSOs is a critical issue. This issue still becomes more complicated due to the effect of DG on investment requirements.

A novel approach has been introduced by OFGEM, the UK regulator, in the last price control review that allows Distribution Network Operators DNOs (it is the way DSOs are named in UK regulation) to choose between getting a lower CAPEX allowance but a higher expected return on investment (retaining more of the cost reduction if they can beat the target expenditure levels) or a higher CAPEX allowance combined with a lower expected return (OFGEM, 2004).

Table 8.1. Matrix for UK DSOs incentives related to CAPEX (allowed vs. actual)

DNO:PB Power Ratio Efficiency Incentive	100 40%	105 38%	110 35%	115 33%	120 30%	125 28%	130 25%	135 23%	140 20%
Additional income	2.5	2.1	1.6	1.1	0.6	-0.1	-0.8	-1.6	-2.4
as pre-tax rate of return	0.200%	0.168%	0.130%	0.090%	0.046%	-0.004%	-0.062%	-0.124%	-0.192%
Rewards & Penalties									
Allowed expenditure	105	106.25	107.5	108.75	110	111.25	112.5	113.75	115
Actual Exp									
70	16.5	15.7	14.8	13.7	12.6	11.3	9.9	8.3	6.6
80	12.5	11.9	11.3	10.5	9.6	8.5	7.4	6.0	4.6
90	8.5	8.2	7.8	7.2	6.6	5.8	4.9	3.8	2.6
100	4.5	4.4	4.3	4.0	3.6	3.0	2.4	1.5	0.6
105	2.5	2.6	2.5	2.3	2.1	1.7	1.1	0.4	-0.4
110	0.5	0.7	0.8	0.7	0.6	0.3	-0.1	-0.7	-1.4
115	-1.5	-1.2	-1.0	-0.9	-0.9	-1.1	-1.4	-1.8	-2.4
120	-3.5	-3.1	-2.7	-2.5	-2.4	-2.5	-2.6	-3.0	-3.4
125	-5.5	-4.9	-4.5	-4.2	-3.9	-3.8	-3.9	-4.1	-4.4
130	-7.5	-6.8	-6.2	-5.8	-5.4	-5.2	-5.1	-5.2	-5.4
135	-9.5	-8.7	-8.0	-7.4	-6.9	-6.6	-6.4	-6.3	-6.4
140	-11.5	-10.6	-9.7	-9.0	-8.4	-8.0	-7.6	-7.5	-7.4

According to Table 8.1, a Power Ratio Efficiency Incentive is assigned to each DSO, which is obtained based on the fraction of the CAPEX target selected by the company that is recommended by OFGEM´s consultant (PB Power). For instance, if the DSO investment target exceeds 120% of the consultant target (PB power ratio of 120 in the Figure), the allowed CAPEX is equal to 110% and the DSO would get a bonus of 0.6% in its income in case the actual CAPEX match the allowed CAPEX. If the DSO´s actual CAPEX are 70% of the target (due to improvements in efficiency) it would get a 12.6% increase of its income as a reward. By the contrary, if its actual CAPEX exceeds 140% of the target, then its income would be reduced by 8.4%. This approach is a way of introducing incentives for DSOs to achieve efficiency in network investments.

Despite this type of incentive regulation, in UK there is no evidence yet that DSOs are taking advantage of DG for reducing network investments. Moreover, additional measures related to engineering network design criteria have been implemented in order to realize the beneficial impact of DG. The Engineering Recommendation P2/6 (Energy Networks Association, 2006) acknowledges the contribution of DG to network security. This technical recommendation mandates DSOs to evaluate the contribution of the DG to the peak demand, depending on the technology and the number of DG units, when calculating network reinforcements. For instance, the required transformer installed capacity in a distribution substation could be reduced depending on the amount of DG connected in the distribution network supplied by that substation.

8.3.1 Determination of investment budgets and allowance for efficiency gains

In line with the schemes implemented in UK, our policy regulatory recommendation for providing incentives to DSOs for efficient investment taking into account DG integration and active network management is the following one. The regulator will allocate investment budgets for each individual DSO for the next regulatory period. This scheme leaves all system optimising decisions completely up to DSOs. At the end of the regulatory period, the DSO should inform the regulator on the network investment actually carried out. Efficiency gains that result in a reduction of investments investments, for instance, investment in active network management that integrates DG in order to postpone network reinforcements, will be recognized to the DSO as an allowed profit in that period. This scheme can be expensive in terms of regulatory control, as technical experts on behalf of the regulator should assess the efficiency of implemented actions. However it puts pressure on both, regulator and DSO, in order to take into account efficient integration of DG when allocating investment budgets.

This type of recommendations can be implemented in countries as SP and NL in the medium term due to the fact that they require important changes in the review control process that takes place in each regulatory period every four or five years. As it has been previously commented upon, regulatory tools that can be used for assessing investment efficiency are reference network models, like the one that is going to be used by the Spanish regulator.

8.3.2 Compatibility between support schemes and DG controllability

Another regulatory recommendation regarding the integration of DG in the process of planning the expansion of the grid, is to avoid support schemes that encourage DG to produce as much energy as it can regardless of the specific operation conditions that exist. That is the case of flat Feed-in Tariffs still in force in some countries, like in SP and NL. DG generators in these systems are unwilling to reduce their output when it is needed by the system. Thus, their output cannot be controlled in the benefit of the system so as to avoid the construction of certain new network installations. As it has been explained previously, it is preferable to apply FITs or premiums with temporal differentiation (peak, flat, and valley hours). This policy option can be implemented in the short-term because support schemes are frequently reviewed in most of the countries.

8.4 Provision of DSO ancillary services by DG

In the DG-GRID and SOLID-DER projects the role of DG in providing ancillary services to Transmission System Operators (TSOs) and to DSOs was highlighted as a relevant issue.

Electric power systems require generators to procure certain services in order to ensure their secure operation. These are known as ancillary services (AS), being the most relevant ones frequency response, power reserves, voltage and reactive control, and black start. Generators play a fundamental role in the provision of these services. Due to the fact that generation facilities have been traditionally connected to transmission networks, the Transmission System Operator was in charge of managing AS. However, the development of DG may bring similar possibilities at distribution level.

DG units are able to provide different AS and other network services that can lead to a more secure and efficient operation of the distribution network (Meyer, 2007; Van Thong et al., 2007). For instance, a more flexible operation of controllable DG according to network price signals can save investment or defer network reinforcements. In addition, DG can reduce the impact of network outages on customer supply interruptions if islanding operation is implemented in distribution network. Moreover, DG under local control or following system operation orders can provide voltage support or flow control when needed by the DSO. In order to implement in practice such possibilities it is required that DSOs introduce active network management in their distribution networks.

In the RESPOND D6 report, the current situation in the surveyed countries regarding AS provision by DG is described. Regarding voltage control and power factor regulation, some minimum requirements are mandatory in the UK and Spain. In Spain, some additional remuneration can be obtained by those generators that control its power factor depending on the time period (peak, flat, or valley hours). In the Netherlands, the provision of AS can be agreed on through bilateral contracts with the DSO or TSO with the condition that generators should meet some technical requirements, like controllability and fault ride through capability. DG may participate in the balancing market or provide reserves, mainly under aggregators. For instance, in Germany, Spain, and the Netherlands some Virtual Power Plants (VPPs) have been created to pool a number of small power plants in order to provide reserves or balancing energy, thus improving the participation of DG in these markets. For the time being, islanding is not allowed in most countries. In Denmark, only in pilot projects islanding operation is applied.

8.4.1 Arrangements between DSOs and DG to provide AS

The first policy recommendation is to establish an institutional framework that allows and encourages TSOs and DSOs to enter into commercial arrangements with DG promoters and aggregators in order to facilitate the provision of AS by these agents. However, in order for DG/RES to be able to effectively contribute to the provision of AS, these generators should have the technical capabilities that are required to provide them and be subject to strong enough incentives that encourage them to fulfil TS/DSO's requests. Different approaches can be implemented, for instance, bilateral contracts, regulated payments to the providers of the service, or finally active participation in those markets specifically created for trading this type of services, especially, markets for operational reserves and energy balancing.

Most of these policy alternatives can be implemented in the short to medium-term in most of the countries. When designing such kind of policies it is important to bear in mind some of the issues already identified in RESPOND D6 report as potential difficulties in their implementation. For instance, to ensure market liquidity (enough potential providers belonging to different companies) it is required to create specific AS markets. Lack of liquidity is not a problem in the balancing market, but can be an obstacle for the efficient functioning of secondary reserves market, as in UK and Denmark. On the other hand, in Spain the secondary reserve market is finely working since its creation in 1998.

8.4.2 Incentives for DG/RES to provide AS

Another relevant issue can be the lack of economic incentives for DG to sell AS when, due to support schemes in place, it already receives a higher remuneration for producing as much energy as possible with no required controllability, as it happens in Netherlands, Spain or UK. In this case as, it was recommended previously, one should avoid support schemes, such as fixed feed-in tariffs, providing temporal differentiation.

8.4.3 Incentives for implementing active networks

As it has been stated in the section devoted to Active Network Management, none of the previous recommendations would be technically feasible without changing the current paradigm of distribution networks by migrating to the more advanced concept of smart grids highly automated with much more possibilities for controllability and flexibility. It is clear that this deep transformation would require important technological and regulatory changes that would span for at least the next 15 to 20 years. Therefore, the full participation of DG providing all kind of AS keeping the security of the system is a long-term challenge that can be progressively achieved if the recommendations provided in this section are followed in the short and medium term.

8.5 Summary of the recommendations

In Table 8.2 the main recommendations for the improved functioning of the distribution network for coping with large shares of variable RES/DG are summarised.

Table 8.2. Summary of main recommendations improving tthe functioning of the distribution network for efficiently coping with variable RES/DG shares

Market Response	**Barrier**	**Recommendations**		
		Short term	**Medium term**	**Long term**
Shallow connection charges and locationally and temporally differentiated UoS charges (NL, D, SP)	Incompatibility with national regulation (NL, D, SP)	Introducing major changes in electricity laws Produce the same effect through the modification of DG/RES support payments		
	Volatility of charges (NL)		Application of zonal distribution charges updated periodically	
Use of DSO incentives for active network management (SP, NL, UK, D, DK)	Difficulty in computing the effect of DG on quality of service and losses (NL, UK, D, DK)		Use of reference network models to estimate the impact that DG will have on performance targets. Use of extra specific performance indexes, like the penetration of DG in the area	
	Lack of incentives to develop the required technology (D, NL,	R&D costs included in asset base with a higher rate of return		

<table>
<tr><td></td><td>SP, DK)</td><td>or with partial pass-through to tariffs to reduce risks

Extension of the regulatory period before passing through efficiency gains to tariffs</td><td></td><td></td></tr>
<tr><td rowspan="2">Incentives for DSOs to consider DG in network planning</td><td>Difficulty of determining allowed capex revenues considering DG and X factor (SP, NL)</td><td></td><td>Determination by the regulator of remuneration level in each period based on reference network models + DSO allowed to keep all revenues in that period from efficiency gains</td><td rowspan="2"></td></tr>
<tr><td>Incompatibility between support schemes and controllability of DG/RES (SP, NL)</td><td>Avoid support schemes that encourage DG to produce as much as possible (fixed FITs). Use FITs or premiums with temporal differentiation</td><td></td></tr>
<tr><td>Provision of DSO AS by DG</td><td>Lack of market liquidity of AS markets (UK, D)</td><td colspan="2">Allow flexibility in the participation of DG in AS: implement bilateral markets with the TSO/DSO; allow their participation in centralized markets, regulated payments, etc.</td><td></td></tr>
<tr><td></td><td>Lack of incentives for DG to provide these services (UK, NL, SP)</td><td colspan="2">Avoid support schemes that encourage DG to produce as much as possible (fixed FITs). Use FITs or premiums with temporal differentiation</td><td></td></tr>
<tr><td></td><td>Difficulty of changing the network operation paradigm (to ANM)</td><td></td><td colspan="2">Incentives for DSOs to implement ANM previously explained</td></tr>
</table>

9 Conclusion

9.1 Electricity liberalisation and technology choice

An important argument for the electricity liberalisation in the 1980s and 1990s was that the change in the institutional structure of the electricity supply industry would create an market dynamics that was necessary to overcome the “national monopolies and their high rents/profits” increase economic efficient of industry, i.e. by mitigating barriers for new generators and suppliers to enter the electricity market, which was seen by some as a barrier for more contributions of new and more environmental-friendly generation technologies. Spot and balancing markets are now found all over Europe, and these markets are developing continuously to meet the needs of the electricity system, including the newly upcoming intermittent and distributed power generation technologies.

Despite the liberalization process that has taken place in most systems, several barriers still lie in the way of implementing market responses aimed at favouring the integration of distributed and renewable technologies. This report has put forward some measures that should help overcome these barriers in those countries where the latter are perceived as real obstacles. Measures have been classified according to the barrier they are addressed at, the time horizon when they would become applicable, and whether their application should be coordinated in the different countries or not. The following paragraphs provide an overview of the main recommendations that have been identified and discussed in the main text.

9.2 Main recommendations

Increasing the flexibility of relevant conventional generation options: Hydro power with reservoirs and gas fired plants

Hydro power – in particular with reservoirs – is the generation technology that is best suited to respond to intermittent generation. Among the five countries Spain has a significant share of hydro power in most parts of the country. The generating capacity is large, but the amount of energy may be limited in dry periods. In Denmark and the Netherlands there is very little domestic hydro power, but Denmark has a long tradition for trade with countries with an abundance of hydro power. Besides this, the use of hydro reservoirs and required transmission lines may be enhanced by adding pumping facilities.

Power generation by gas fired plants is also very important when balancing scheduled/unscheduled variations of wind power and other intermittent technologies. Hydro resources tend not to be large enough to carry out this back up function in most systems. Contribution of gas plants to the back-up system capacity will increase in the future as a consequence of the fact that the hydro power potential is already fully exploited in most European countries.

Construction of additional transmission capacity

Transmission capacity in most EU systems has traditionally been relatively large. However, significant increases in transmission capacity may be needed to cope with the variability of wind power. Further interconnection capacity between Norway and Denmark, on the one hand, and Netherlands and Germany, on the other, is being built or is planned. Spain is also working to increase the interconnection capacity with its neighbours. Further expansion of the transmission capacity is recommended by the RESPOND project, and to existing reservoirs will enhance the capability to accommodate additional intermittent generation.

Use of heat distribution infrastructure and heat storages

Water-based heat distribution systems are necessary for the use of heat storages to be used in CHP units for flexible operation to respond to intermittent generation. These systems are widely different in size – from radiator systems in individual homes, heat supply in greenhouses or industries using heat or steam in different temperatures to district heating systems ranging from villages or blocks of flats to large interconnected urban district heating networks as in Berlin or Copenhagen.

Support schemes for micro CHP units mainly for individual homes are considered in the RESPOND project. There is a significant potential for this technology in the UK and the Netherlands, which may replace gas-fired heat-only boilers. It is recommended that units designed for on-off operation with heat storage should be encouraged as standard for mass production (e.g. 3 kW electric), rather than very small units (e.g. 1 kW) for continuous operation, which will follow the current heat requirement.

However, micro CHP is recommended only for the very small-scale heat distribution systems. If larger heat distribution systems are created, more flexibility will be added to respond to intermittent generation. So, the preferred recommendation is to establish larger heat distribution systems by interconnecting existing systems. This will allow the penetration of larger and more efficient CHP units, which can use fuels other than gas – in particular biomass. Larger heat distribution systems or district heating systems offer a range of options for flexibility that is needed by the electricity system, e.g. electric boilers for down-regulation, or electric heat pumps for heat base load, which may be cut off, when up-regulation of electricity is needed.

Response by peak load units

Installation of peak-load units, e.g. gas turbines to respond to the variability and unpredictability of intermittent generation is recommended only when the response from hydro power, CHP systems or larger gas fuelled units operating at intermediate load is insufficient.

Commercial aggregators

Aggregation of units is the key recommendation for operating an electric system with many small units. Commercial aggregators with a portfolio of similar units, e.g. wind turbines, or complementary units of different technologies should play a key role both in the basic energy supply and the provision of system services. Aggregators can also overcome size limitations on the day-ahead, intraday, balancing or ancillary services markets. Instruments and software such as 'virtual power plants' are being developed to be used by aggregators for control of their portfolio of different generation technologies and operation on the spot and balancing markets.

Geographical price areas for spot and balancing markets

In all countries there is a day-ahead market, which is the key instrument to generate price signals for generators with controllable technologies as well as consumers who are able to adjust their demand to price signals. These markets have been developed significantly in recent years. Cross-border market coupling was established early in the Nordic region and recently between the Netherlands, Belgium and France, leading to more efficient price setting and trade within a region. In most regions of Europe, existing price areas follow national boundaries. This is not efficient in large countries with a large penetration of wind power and bottlenecks in the transmission system. Splitting national markets into price areas that reflect these constraints have been practiced in the Nordic region for more than a decade. This leads to prices that reflect the expected amount of supply of wind power in each area, among other variables influencing the energy dispatch. In some hours zero prices have occurred, when wind production exceeds local demand, and even a negative price floor is being introduced in Germany and Denmark. To get the right price signals for generators and consumers, it is becoming increasingly important that the geographical price areas for the day-ahead market reflect the pattern of wind variations and transmission constraints.

Market splitting into price areas will also lead to more transparency concerning the need for new transmission capacity. Large and frequent price differences between neighbouring price areas clearly indicate the need for new transmission lines.

Pricing for encouraging Demand response and Active Network Management

With price signals in place that reflect the hourly variations in energy supply conditions in a geographical area, it is recommended that all customers face these prices, as soon as hourly metering is established. This is a necessary incentive for the consumers to adjust their demands according to system needs. This is also required to avoid cross subsidisation from customers with most consumption in cheap hours to consumers with most consumption in expensive hours.

In addition, it is recommended that the information from hourly meters is used by the DSOs for developing methods for active network management. is used by the DSOs when implementing methods for Active Network Management (ANM). The application of ANM techniques should have an impact both on the planning and operation stages of the management of distribution systems. Both demand and distributed generation should receive incentives to participate in ANM schemes.

Larger consumers are more able to respond on price signal and may even enter interuptibility contracts or take part in the day-ahead or intraday market. In particular, the cooling market can be further developed with centralised facilities for air-conditioning. When electrical vehicles are introduced it is recommended that charge and discharge of batteries are controlled centrally or by means of price signals.

In the final RESPOND report D8 all relevant measures and regulatory changes and improvement will be put in an time frame to secure a smooth and efficient transition of the power system in each of the five EU countries, each with different system conditions and needs for dealing with high intermittency RES/DG generation in the next decades.

Appendix A. Market results for Western Denmark 2006-2008

The generation from wind power in the price area Western Denmark covers about 25 percent of the electricity consumption on an annual basis. This is currently the largest share of wind power for any price area within an electricity spot market. Detailed market data are available from energinet.dk since 2000. From 2006 all price data are available in EUR/MWh. The maximum hourly demand in all the three years 2006, 2007 and 2008 was about 3.8 GW, and the maximum wind production was about 2.2 GW,

Strong interconnections between Western Denmark and other regions (up to 1.7 GW for import to Northern Germany with very similar conditions for wind power, and 1.7 GW transmission capacity to Norway and Sweden with little wind capacity and large hydro storage capability) will reduce the number of events with consecutive hours with high prices due to lack of generation from wind. Thus, the number of these hours was small in both 2006 and 2007 (see Table A.1). When spot prices were high, forecasts of generation from wind turbines were reasonable, and regulations after market closure were insignificant.

In Denmark, balancing is maintained within the framework of the joint Nordic regulating power market together with national balancing responsible parties, and rules and regulations set by the TSO.

In the Danish market, like in the rest of the *Nordic markets*, there is no particular Ancillary Services market. However, the price mechanism of day-ahead market divide the Nord Pool area into price areas, which reflects bottlenecks among the regions (Finland, Sweden, Norway divided into three or more regions, Denmark East and West, and the KONTEK link between Denmark and Germany). Any company controlling a portfolio of electricity generation or demand may become a participant on the Elspot market. The responsibility for the company's balance must be taken care of directly or indirectly through a balance agreement with the TSO, in the area in which trading takes place.

The variations in the hourly area price for Western Denmark are analysed in Table A.1 for the three years 2006, 2007 and 2008. The available infrastructure was nearly the same in all the three years, only the transmission capacity between Western Denmark and Germany has been increased. Table A.1 shows that the number of hours with extreme area prices, below 5 €/MWh or above 100 €/MWh, is quite small.

Table A.1. Prices in Nord Pool price area Western Denmark

	2006	2007	2008
Nord Pool System price, €/MWh	49.01	29.09	45.74
Area price €/MWh	45.81	34.82	58.33
EEX price, €/MWh	55.04	41.93	69.89
Area price >10 € lower than system price	1799	444	163
Hours below 5 €/MWh	80	185	63
Area price >10 € higher than system price	458	1691	4066
Hours above 100 €/MWh	11	105	293
Hours above 200 €/MWh	0	26	0
Hours above 400 €/MWh	0	5	0
2 or more consecutive hours above 100 €/MWh, events	2	25	34
3 or more consecutive hours above 100 €/MWh, events	1	16	21
6 or more consecutive hours above 100 €/MWh, events	0	2	9
Wind production above 100 % of consumption, hours	27	50	43
Wind production below 10 % of consumption, hours	381	371	352
Above 100 €/MWh and wind production below 10 % of consumption, hours	7	8	12
12 or more consecutive hours with wind production below 10 % of consumption, events	13	9	7
Highest number of consecutive hours with wind production below 10 % of consumption	40	76	25
Above 100 €/MWh and up-regulation more than 20 % higher. hours	1	5	22
Down-regulation negative price, hours	201	137	46
Up-regulation above 100 €/MWh, hours	68	204	585
Up-regulation above 200 €/MWh, hours	1	65	120
Elbas (intraday market): Price quotations, Elbas, hours (from April 2007)	0	1070	1834
Elbas: Difference more than 10 € to area price, hours	0	132	622
Southbound transit, hours	1722	4025	5098
Northbound transit, hours	3324	1091	538
Transit between Sweden and Norway, hours	2130	2678	2634
Export from DK-West to all neighbours, hours	1554	849	342
Import to DK-West from all neighbours, hours	29	116	171

The production from the same wind turbine capacity was 20 % higher in 2007 than in 2006 and in-between in 2008. 2006 was a dry year in Norway and Sweden, leading to import from Denmark, while 2007 and 2008 have been more wet years with export to Denmark and further to Germany. However, the much higher prices in 2008 are reflecting the much higher EUA (CO_2 allowances) prices in 2008 than the almost zero price level for 2007.

Figure A.1 shows the number of "extreme" hours in 2007. However, the criteria for extreme hours selected was quite modest.

Currently, low supply from wind is not critical for Western Denmark, but problems may occur in the future, if the existing thermal capacity will be reduced. Limited supply from wind (here defined as 10 % of consumption or less than half of the annual average) is found in about 4 % of all hours. However, most of those hours are consecutive, so short-term storages will be of little help. Longer periods (e.g. 12 hours or more) with little or now wind will occur roughly once a month. The longest period with low wind that was found during the three years was 76 hours in November 2007.

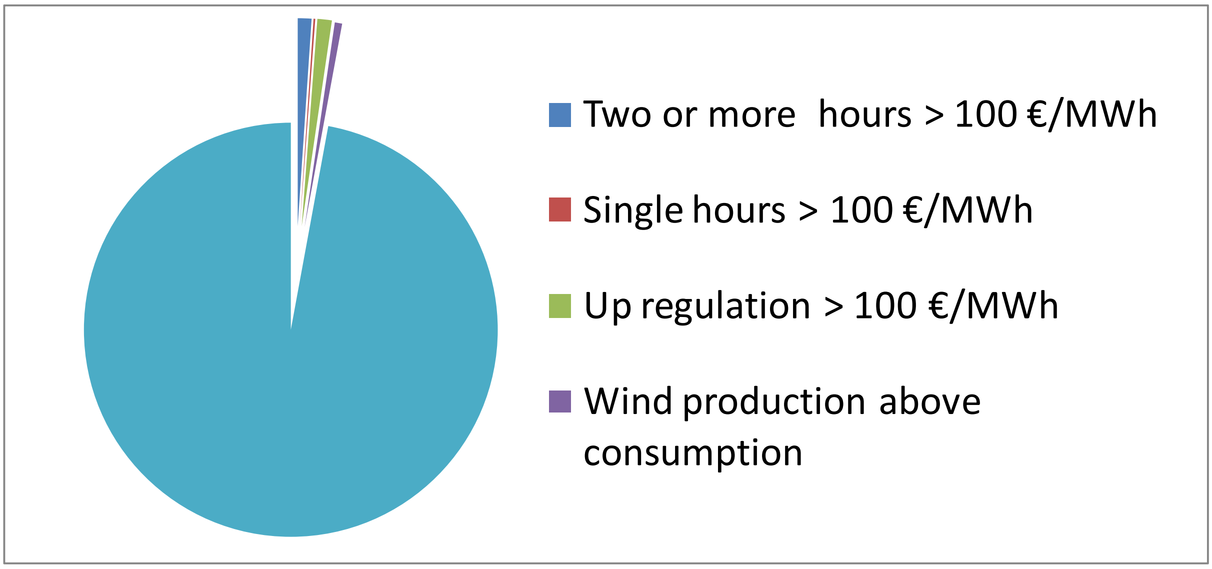

Figure A.1 Western Denmark. Extreme hours 2007

During the worst storm in recent years (Saturday 8 January 2005) some 2000 MW wind turbines in Western Denmark stopped due to wind speeds more than 25 m/s of mean wind. The TSO had to buy large amounts of regulation power. During the night the area spot and regulation prices had been zero, but prices were not abnormal during the outage of the wind capacity. Thus, the combined spot and balancing market was able to handle this particular event. However, by chance this was a Saturday with lower demand than weekdays.

The intraday market, Elbas, with continuous trade and closure time one hour before delivery was not introduced in Western Denmark until April 2007. It mainly works as a mechanism for fine tuning of the day-ahead prices. In 2008 there was price quotations for Western Denmark in about 20 % of the time. However, this market was designed to meet the requirements of large-electricity consuming industries, rather than the challenges of wind energy. It was originally introduced in Finland in 1996 (EL-EX) and shortly after merged with Nord Pool with trade also in Sweden and later Eastern Denmark and parts of Germany.

The balancing market is far more significant for handling of intermittent generation than the intraday market. The balancing market seems not very important when the day-ahead area prices are high. On the other hand, there is a significant number of hours with ‘normal’ prices on the day-ahead market and up-regulation prices more than 100 €/MWh higher.

Table A.1 also show that there are a number of hours with negative down-regulation prices, although the number of hours has been significantly reduced from 2006 to 2008. These negative prices are due to high start and stop costs of decentralized CHP generation in

Denmark. Also down regulation by using electricity in electric boilers in district heating systems may lead to negative prices.

The balancing market is used to handle imbalances within the price area of Western Denmark. This will not be sufficient, if the wind capacity is increased much further.

In the short term negative prices on the spot market are considered as the most important additional measure to address the challenge of the large amount of intermittent generation. Negative prices have already been introduced on the German EEX spot market, and from October 2009 a negative price floor at -200 €/MWh will be introduced by Nord Pool, which will be significant mainly for Denmark

In its System Plan 2007 the Danish TSO, Energinet.dk will explore most of the measures addressed in the RESPOND project to address the challenge from intermittent generation, such as "combining means, including steps to regulate wind turbine electricity generation, expand the transmission grid, use heat pumps, electric boilers, alternative connecting points and wind farm locations, demand response, electric cars, etc."

Western Denmark was 'born' as a price area within Nord Pool. However, in addition to the measures mentioned above, Energinet.dk in considering dividing Western Denmark into two price areas:

"In principle, the internal overload problems in the West Danish electricity transmission grid can be solved by introducing new bidding and price areas in Western Denmark. This will ensure that the exchange between the areas does not exceed the physical limitations of the system, as the trading capacity between the areas is defined on the basis of the potential for physical exchange. (...)

Unless the other means, as described above, are activated to such an extent that grid overload problems are eliminated, dividing Western Denmark into two price areas must be regarded as the only legitimate and realistic method for handling internal capacity restrictions".

This measure complies with the general recommendations for the Nord Pool exchange area that temporally imbalances should be met by counter trade, while permanent ones should be met by price areas. However, this recommendation has been practised in Norway only.

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