RESPOND

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

Regulatory and other Barriers in the implementation of Response Options to reduce impacts from variable RES sources

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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 and DG in the European electricity system. Furthermore it develops and recommends policy and regulatory framework improvements that could effectively support the implementation of these market based response options in several member states. Other objectives are:

- Evaluate the impacts of an increasing penetration of RES and DG on the integral electricity system;
- Identify and analyse efficient response options of market participants that actively support an efficient integration of RES 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.
- Analyse, and assess improvements and changes of the policy and regulatory framework that facilitate the development and implementation of the recommended response options by market participants
- Formulate recommendations and a roadmap for implementing these improvements in five countries

Project partners:

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Executive summary

In order to counteract the negative impacts resulting from the increase of intermittent renewable energy sources (RES) and distributed generation (DG) on electricity systems (identified in deliverable D4 of the RESPOND project), a number of response options were defined, analysed and assessed in deliverable D5 of the same project. Subsequently, this document has been developed to detect actual and potential barriers that may hinder the implementation of the identified respond options. For this purpose, a detailed questionnaire was developed in order to expand and collect additional information for the five country case studies (Spain, UK, Denmark, Germany, and the Netherlands) regarding the national situation and the position of national regulators and parties on the different key barriers.

D5 market responses were aimed at reducing the (potential) increase of system costs resulting from generating more electricity with intermittent generation technologies now and in the future. The topics covered by this report (deliverable D6) concern the barriers that form a blockade to the implementation of D5 recommended options, measures, system changes, etc.

This report follows the structure of the aforementioned questionnaire and survey. Thus, we analyse and present the barriers in the context of their application in different segments or parts of the system, 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 main division of identified barriers is presented in the following in the following paragraphs.

Concerning **RES/CHP generation** the key issues are related to *pricing mechanisms* (of energy and ancillary services provided by this generation), the role of *support schemes* to achieve a diversification of the generation mix, and the improvement of the *technical capabilities* of this type of generation. Regarding **conventional generation** barriers are classified in those that have to do with the *incentives to provide reserves* (primary and secondary) *and balancing energy*, the *mechanisms to provide firmness in critical periods* and the *economic incentives to install new generation capacity*.

Concerning **demand options**, the main hurdles identified concern volatile market prices, metering and communication issues, heat or electricity storage, pricing rules and managing system security in the short term through, for example, the application of interruptible contracts, the access to ancillary services markets and the direct control of consumer equipment. Within **national markets** (including energy and ancillary services markets), the main issues that barriers refer to are market access (together with size limitations and aggregation of units) and prediction of energy production (together with responsibility of deviations and gate closures closer to real time).

The increase of interconnection capacity and the integration of national markets into regional ones are covered in the **regional markets** chapter. T**ransmission network** issues addressed include implementation of locationally and time differentiated

transmission charges, the construction of new transmission lines and the implementation of fair and efficient congestion management schemes. Finally, Regarding **distribution network** issues that are dealt with include: the design of time of use tariffs, the design of incentives for active network management to Distribution System Operators (DSOs), the integration of distributed generation in efficient network planning, and the provision of Ancillary Services by DG.
The following sections summarize the analysis of barriers carried out within the different segments.

RES and CHP Generation

Use of efficient pricing mechanism of energy and AASS

Sending efficient price signals to RES/DG generators should encourage them to behave efficiently, thus enhancing their value for the system. One first barrier to the implementation of efficient pricing mechanisms concerns the fact that charges to RES/CHP are not dependent on the location of these generators in some of the countries considered, namely Spain, the United Kingdom and the Netherlands. As a consequence of this, the geographical distribution of new generation shall not take into account the system needs. Besides, in Spain RES/CHP units that earn a Feed in Tariff are not allowed to provide ancillary services. This may cause a reduction in the flexibility of the system. Finally, in Spain and the Netherlands, generators are not paid their contribution to the primary load-frequency regulation service, which may erode the revenues expectation of RES/DG generation units to be installed.

Implementation of support schemes to achieve diversification of the mix

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 a balanced mix. One first barrier in this regard is related to the fact that, neither FITs applied in Spain and Germany, nor tradable green certificates implemented in the UK are dependent on the time of the day or the year when energy is produced by generators. Consequently, the production profile of these generators does not adapt to the level of load to be covered or the conditions in the system. Besides, support payments implemented in Spain, Denmark and Germany have not been efficiently designed, thus resulting in a evolution of installed DG/RES generation capacity that is not in accordance with predetermined objectives.

RES/CHP Technical capabilities

In general, there seem not to be major technical hurdles that prevent RES/CHP access to markets. This is owed to technical improvements in RES generation technology characteristics. Of course, participation in specific markets such as AS ones is still limited to those units that meet certain requirements (regarding, mainly, controllability).

Controllability of units can be improved through the combination of these technologies with storage ones. Non-controllable units can be required to provide some kind of frequency response such as primary frequency control. However, in the

Netherlands, Germany, and UK, small units connected to distribution networks are not obliged by network codes to provide power reserves. In Spain, the role of centralized control centres for the aggregation of RES/DG units has proved very relevant to facilitate the participation of units in reserve and balancing markets.

Conventional generation

Incentives to provide reserves and balancing energy

Main barriers to the provision of regulation reserves by conventional generation, which is necessary in order for the system to adapt to the variable output of intermittent RES generation, are of two types. 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, effectively discourages generators from providing these reserves, which may result, among other things, in less liquid AASS markets. Apart from this, as mentioned in the previous section about RES/DG, in some other countries like Spain and Germany generators do not receive any payment for the provision of the primary frequency regulation service.

Mechanisms to provide sufficient generation capacity in critical periods

Markets provide an incentive for generators to be available when the system needs them, since prices in these situations to be higher than normal. However, these incentives may not suffice in some cases to ensure that enough generation capacity is able to produce when needed. Therefore, availability payments may be necessary in these situations. Unfortunately, in some systems like the German, the UK and the Danish ones, no availability payments have been implemented. These payments may be necessary when market incentives for firm capacity provision are not successful.

Investment in new generation capacity

Again, 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 new capacity are not allowed. As a consequence of this, 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.

Demand

Use of variable market prices and efficient pricing rules

Applying efficient prices that are in accordance with the value of energy at each time is central to achieving demand responsiveness. However, in some countries like Spain, electricity price regulation is not efficient (a night tariff existed that encourage many consumers to shift all their energy consumption to the same period of the day).

A very high excise tax is applied in Denmark that causes energy prices to be very high no matter the operation profile and location of consumers. Finally, variations in wholesale prices and in the cost of AASS in all the considered countries are transferred to electricity tariffs as a common mark-up to the annual energy price. Therefore, prices do not change according to system conditions.

Deployment of metering and communication technology

Development and installation of this technology is necessary for consumers to be able to react to market prices and other economic signals. However, in all the considered countries but Spain the roll out of hourly meters has been very modest. Additionally, the functionality of these meters has not been agreed and standardization has not taken place, which makes very difficult developing communication protocols that can be implemented country wide. Lack of standardization is remarkably clear in the German and Dutch systems.

Use of heat or electricity storage

Heat and electricity storage may allow consumers to shift part of their load from high price hours to low price ones. Therefore, its implementation should be considered in every system. However, in the Spanish and German systems, the use of these storage systems at household level is very limited. In the UK, he use of district heating has very low popularity among the population, which hinders its implementation despite its potential for cost reduction and increasing system flexibility. Finally, in the Danish system, electric resistance heating systems, which could contribute to flexible demand, have been banned over the last years. However, these systems have been replaced by other more responsive technologies, like heat pumps.

Consumer acceptance of variable prices

In order for consumers to react to prices they must be willing to do so. Unfortunately, in every country consumers exhibit very low responsiveness to variable energy prices in the short term. The potential for cost reduction in the long term is very high (avoided costly investments). However, consumers are not able to anticipate this. Besides, most consumers show a remarkable risk aversive behaviour. Thus, instead of reacting to variable prices that they cannot control, they prefer signing constant price supply contracts (fixed tariffs).

Efficient management of system security in the short run

In order to be able to guarantee the system security, the System Operator needs the help of consumers, who should adapt their consumption pattern to the requirements of the system. An efficient way to do so is AASS. The Danish market does not have AASS markets, which is an important obstacle to achieving system security. However, they have implemented zonal energy prices that can result in an efficient management of congestion. Also in the Danish system, few industries have proved to be suitable for signing interruptible contracts, which is a powerful tool in the hands of TSOs to solve emergency situation where available power supply is below existing demand. Finally, in all countries, households lack the required technology and institutional/legal settings for signing interruptible contracts and participating in system services. This reduces significantly the responsiveness of a large fraction of total demand in a system.

National energy and ancillary services markets

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, i.e. 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 any 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. Also related to this, the curtailment of DG/RES to provide negative reserve is regarded as an option in Germany.

Regarding access to ancillary or system services (AS) markets, the main issue refers to the controllability of the 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.

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

In most countries (Spain, UK, Denmark and Netherlands) RES are 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 further RES deployment, since predicting the output of these generators than becomes the responsibility of the grid operators for whom it is much more difficult.

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 4 p.m in Spain) to 1 hour ahead of real time (UK, Denmark, Netherlands). The division of responsibilities between the TSO and the MO 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 employing a balancing market is preferred.

Regional markets

Increase of interconnection capacity

Two of the most important barriers in Spain and the UK that hinder the construction of interconnection capacity are the existing concerns about the impact of new transmission lines on the environment and the lack of fairness of the method employed to determine which countries should pay the cost of these lines. Note that cross-border lines typically produce benefits that are very much widespread in a region, while costs/disadvantages caused by them are not. This is also a barrier for building these lines in Spain, the UK and the Netherlands. Moreover, the complexity of the process aimed to obtain the permits required to build these lines is much higher than for national lines. Agents from Spain, the UK and Germany have identified this as very significant barrier. Apart from this, the lack of harmonization of national market rules is also limiting the power exchanges taking place between countries, which has been identified as a barrier in Denmark.

Integration of the operation of national markets

The most important barriers to the integration of the operation of national markets include the fact that, short term implicit energy and capacity auctions are not applied yet in Spain (SP-F border) and Germany, though these countries are interconnected to others through a meshed grid. Moreover, in all surveyed countries there is a lack of coordination of the allocation of cross border capacity that is carried out in the long term. Finally some parties in Germany, due to security reasons, argue that some degree of discrimination between local and regional transactions should exist when providing long term generation capacity reserves.

Transmission networks

Locationally and temporally differentiated network charges

A barrier to implement locationally differentiated and time varying tariffs, according to some parties in the Netherlands, is that locational marginal prices are too volatile, Besides, in the Netherlands and Germany these tariffs are also believed to be a source of unfair discrimination between agents in different parts of the grid, as well as between old and new generators. Other stakeholders in Spain are of the opinion that these tariffs may not affect investment decisions by agents due to the fact that payments resulting from support schemes to RES/CHP are so high in many systems that installing new RES generation will be profitable no matter which kind of generation it is or where it is installed. Finally, different stakeholders in the UK believe that implementing these charges makes regulation more difficult and therefore less attractive to policy makers.

Construction of new transmission lines

As for the construction of new lines, most stakeholders in all countries but the UK agree that concerns about their impact on the environment and health could represent a serious obstacle to these lines being built. Besides, parties in the UK have stated that the inefficiency in the allocation of the cost of these lines, the lack of efficiency of the use of transmission capacity that already is in operation, and doubts about the profitability of many of the transmission investment projects that are being considered now already result in a significant opposition to new lines.

Implementation of efficient congestion management schemes

Finally, talking about the application of congestion management schemes, applying zonal or nodal prices (the most efficient solution under ideal conditions) is against the regulation in place in some countries, like Spain or the Netherlands. Besides, most, if not all, parties agree that implementing such scheme would result in an increase in the degree of the market power held by power producers in importing areas. Finally, parties in Spain and the Netherlands have stated that computing several energy prices within their territories would make the market clearing process more complex, and the coordination with neighbouring markets would be more difficult. Others in the Netherlands say that using nodal or zonal prices would require also changing computer applications and allocating the congestion rents.

Distribution networks

Use of locationally and temporally differentiated charges

For the efficient integration of DG/RES in distribution networks the design of distribution charges, connection and use-of-system charges, paid by this type of generation is a relevant issue. Locationally and time varying distribution charges should be implemented. In those systems where locational distribution charges have not been implemented yet, main barriers identified by parties are legal (changing the tariff codes would be necessary in Netherlands). Additionally, allocating charges to generators in an efficient, cost-reflective, manner is also regarded as a challenge by authorities in Germany. For most parties consulted, volatility is not considered a problem when implementing this kind of charges. An exception to this rule is the Netherlands.

Implementation of ANM techniques

Active network management (ANM) is unanimously acknowledged as an effective measure to integrate variable distributed RES generation. In order to encourage DSOs to apply ANM, many countries have implemented efficiency incentives schemes that reward DSOs for reducing losses and increase service quality levels. However, the difficulty of computing an adequate level for these incentives, in the UK, and the fact that most systems are not taking into account the effect of DG-RES on losses and quality when computing the incentives, as explained by Dutch parties, is undermining their effectiveness. Finally, the incentives in place in some countries, like Spain, the Netherlands or Germany, to develop the technology required implementing these techniques are believed to be too weak.

Incentives for DSOs to consider DG in network planning

A potential benefit from DG RES is the cost reduction that can be achieved by integrating it in the process of planning the expansion of the grid. However, in those systems where incentive schemes for the efficient planning of the expansion of the grid by DSOs are applied, like in Spain and Netherlands, the reference remuneration level of the DSO and the efficiency factor ‘X’ are computed not taking into account the effect of DG. Other countries, like the UK and Germany, believe that implementing incentive schemes of this type is not necessary because incentives already in place for efficient system operation (losses and quality) are strong enough. Also, some parties in Spain and the Netherlands believe that existing huge DG-RES support payments encourage variable DG RES not to follow DSO's instructions, which renders the installation of variable DG RES as less beneficial, or even problematic, to operators. Related to the previous market response option, DSOs in the considered countries are not considering the possible future application of ANM when planning the expansion of their grids, which makes it more difficult for the system also to benefit from the presence of variable DG.

Provision of AASS by DG

DG of an intermittent nature may provide some system services that can be of help to the DSO. However, many of the existing generators do not comply with the technical requirements that must be met to provide these. Apart from this, the markets where variable DG could sell these services to the DSOs would probably not be liquid enough, since most of the potential generators that could provide a certain service would be owned by the same company. This has been identified as a barrier by parties in the UK and Germany. Even if competition could be established among potential providers of AS, generators may not find it profitable to offer them, since, according to parties in the UK, the Netherlands and Spain, the revenues resulting from the sale of their energy in the market may be much higher than those they would obtain by providing these services. Finally, parties in all countries have expressed their view that changing the network operation paradigm (from passive to active) is a very challenging and difficult to accomplish task that, nevertheless, needs to be carried out in order for DG to significantly contribute to the provision of some AASS.

This document shows that important barriers are present in every segment of the electricity system. Some of them appear in several countries, while others are only occurring in one or a few countries. In the report tables 6, 7, 9, 11, 12, 13 and 14 the main barriers per system segment, i.e. generation, demand, national markets, regional markets and transmission and distribution networks are summarized.

Contents

List of Figures

List of Tables

1 Introduction

The RESPOND project aims particularly at identifying efficient market response options that actively contribute to an 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 (UK, etc) for effectively support implementing these market response options. Other objectives are:

- Evaluate the impacts of an increasing penetration of RES and DG on the integral electricity system;
- Identify and analyse efficient response options of market participants that actively support an efficient integration of RES 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.
- Analyse, and assess improvements and changes of the policy and regulatory framework that facilitate the development and implementation of the recommended response options by market participants
- Formulate recommendations and a roadmap for implementing these improvements

RESPOND focuses the attention 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). In order to outline actual RES and DG development (with different penetrations of each technology) across Europe, five country blueprints (Spain, UK, Denmark, Germany, and Netherlands) have been selected as representative case studies within the project.

WP2 of RESPOND project (deliverable D4) has explored the development of the power system and role of RES and DG in the five countries Spain, UK, Denmark, Germany, and Netherlands with a time horizon up to 2020. In addition, WP2 has carried out a detailed impact analysis of increasing (intermittent) RES and DG penetration on the overall electricity system, comprising generation, transmission and distribution networks, trade and demand. The most important impacts relate to the variability and the unpredictability of generation from intermittent energy sources.

WP3 of the RESPOND project (deliverable D5) identified and classified a set of relevant technical and regulatory respond options in order to remove or mitigate the previously identified negative impacts of increasing DG/RES penetration on generation, demand, markets and transmission and distribution networks. A number of technical and organisational response options were defined, analysed and assessed. Important was the focus on unconventional response possibilities that arise in the dynamic electricity system including interaction between for example storage, demand response and market rules. The assessment included technical, economical and regulatory aspects. Response options (conventional as well as new options) were mutually compared on the basis of maturity of technology, economic efficiency, potential and interaction with other options. The electricity system in 2020 is the focus in the study of the options to address and mitigate the problems identified in D4. Therefore D5 focuses on the impacts that are most relevant in this time horizon. It should be noted that wind energy is the dominant contributor in this horizon.

This deliverable D6 is the result of WP4 of the RESPOND project and builds on the results form WP2 and WP3. WP4 aims at identifying barriers to the implementation of the response options that have been identified in WP3. These barriers must be assessed both from a regulatory and from a market perspective. The evaluation of these barriers, shall enable the definition of regulatory and policy recommendations for the different segments of the electricity business.

This chapter 1 has been organized as follows. Section 1.1 summarizes the impact assessment performed in WP2 of RESPOND project. The list of prioritized options of WP3 is presented in section 1.2. Finally, section 1.3 explains the further content and structure of this report.

1.1 Impact Assessment of Intermittent energy sources

Impacts of increasing (intermittent) RES and DG penetration in the overall electricity system are mainly due to two characteristics of intermittent generation – variability and unpredictability (or prediction error). Impacts (both positive and negative) due to variability and unpredictability were assessed in relation to generation, demand, transmission and distribution systems and markets & trade in D4.

Concerning generation, lack of correlation between the evolution of demand and that of intermittent generation will probably result in the ratio of the peak to low net demand (demand – Intermittent generation) being very high. This fact increases the number of times that conventional power plants will need to start-up or shut-down, and speeds up the ageing process of these generators, some may not even be able to operate in this system. Apart from this, there will probably be a significant number of hours when RES/CHP generation will replace conventional generation. Thus, the latter type of plants will have to operate partly loaded for a large number of hours, which will result in reduced market revenues for them. The need for more flexible units will increase in order to compensate for variations in the output of intermittent generators. On the other hand, renewable generation will not be able to provide firm generation capacity (these technologies usually have low capacity credits). Therefore, conventional generation or other system resources will be needed to meet the system needs when RES/CHP generation is not available.

The increase in the ratio of peak to low load, together with the possibility of intermittent generation exceeding the system demand may force the development of mechanisms to actively manage the level of load in the system. The system energy needs will have to be shifted, through different means, from the hour when it is scarce to those when there is an excess of it. Possible solutions in this regard are discussed in the following section. The correlation between the power output from certain intermittent generation technologies, like wind farms, and the need for electricity in the system may be increased if oil and gas heating systems are transformed into electricity consuming ones. According to the research work carried out within the RESPOND project, there may be a correlation between heat needs in the system and the existence of strong winds. Thus, the composition of electricity demand in the system may need to be altered.

Impact of RES generation integration on markets and trade are mainly associated with the effect that the existence of a large amount of this type of generation will have on spot market prices. In many systems like Germany, RES production has been given priority in the dispatch. Besides, RES has almost zero operational costs. Therefore, when this generation must participate in the market it tends to enter early in the merit order. In fact it results in intermittent generators being dispatched instead of conventional ones and market clearing prices decreasing. Fluctuations in the availability of the former produce price fluctuations. Hours with extremely low prices will be followed by other when prices will be extremely high although, on average, market prices will go down. Consequently, market revenues for existing conventional base load units will be reduced. This together with an increase in maintenance costs and a decrease in the useful life of these generators will be put much pressure on these generators, making it unattractive for them to keep the existing plants functioning or installing new ones of the same type. If RES generators participate in the market, prices earned by these generators may be especially low, since many of them will mainly be producing when prices are low due to expensive conventional units being replaced by RES/CHP ones. End consumer prices may be reduced as well if the cost of mechanisms to promote the installation of intermittent technologies is not paid through electricity tariffs.

Variability makes the output of non-controllable generators less predictable. System unbalances resulting from prediction errors will significantly increase as a result of the installation of large numbers of intermittent generators. Thus, the need for balancing services will largely increase as well. Primary, secondary and tertiary reserve will be provided by generators with regulating capacity. The amount and cost of balancing power will increase, which will represent an incentive for flexible generation to participate in the balancing market.

Unpredictability will make the output of intermittent generators less valuable for the system. Costs incurred by the system in order to solve the imbalances resulting from the prediction error corresponding to the estimation of the power production from intermittent generators will be large. Balancing costs that intermittent generators are responsible for should be internalized by these generators when bidding on the market. Thus, these generators should be made responsible for their balancing costs.

The geographical location of new RES and CHP generation may depend on a number of different factors: availability of primary energy (natural resources) that electricity is produced from, level of subsidies from RES/CHP support schemes that are in place in each area or country, etc. In any case, distribution of power plants corresponding to certain RES generation technologies, such as off-shore wind generation, may probably differ significantly from that of conventional generation and demand. As a consequence of this, significant transmission grid reinforcements may have to be carried out to connect this generation to the grid and transport the power output from these generators to other parts of the grid, where it is consumed. Additionally, high variability in the output of some intermittent generators (such as on-shore wind mills) may result in some transmission lines being used only to a small extend. This, in turn, means that building these lines will be less economical for the system than other network reinforcements. However, this will depend on the degree to which the production profile of these generators and that of other types of intermittent or conventional generators located in the same area are complementary.

The needs for network reinforcements to the distribution grid brought about by the installation of RES/DG generation at distribution level will depend on the amount of this generation built within each area in comparison to that of demand in the area. The correlation between the production profile of renewable and distributed generation and the consumption profile of demand in each area may also play a crucial role in this regard. For low to medium penetration levels of RES/DG generation, distribution grid investments, apart from connection facilities, are likely to decrease when compared to the present situation. On the other hand, in those areas where the amount of generation installed at distribution level is far larger than that of demand, investment needs may increase, especially if generation and demand profiles are not well correlated. New facilities would be needed to transport local power generation to other parts of the system. Increases in the network reinforcement needs would result in an increase in the level of distribution and transmission tariffs.

At the same time, the existence of large shares of intermittent generation within distribution grids may have non-negligible effects on the operation of these networks. Thus, power through some lines may flow in both directions, making the operation of distribution grids more difficult. It may be necessary to put distributed generation under the control of the DSO. This may change the strategy used to operate distribution grids from passive to active network management. Besides, other technical problems, such as those related to the increase in the voltage level of certain nodes may arise. These will have to be handled by the DSO using the resources at its hand, such as the participation of some generators and demand in the provision of ancillary services.

1.2 Analysis and prioritization of response options

Deliverable D5 of the RESPOND project has focused on the identification of those technical, market and regulatory response options that would help counteract the negative effects of variability and unpredictability on the functioning of the system caused by the integration of large shares of intermittent generation. A number of technical and organisational response options, originating from the different segments (generation, demand, trade and transmission and distribution networks) were defined, analysed and assessed. The assessment included ***technical***, ***economical*** and ***regulatory aspects***.

In identifying and analysing efficient market response options, the D6 report sought to look behind conventional options and also focused on innovative response possibilities and of comparing both types of options. Taking into account that since the electricity system in 2015 is the main focus of the study and wind energy is the dominant contributor in this horizon, the main options covered in the analysis were primarily related to increasing the penetration of wind resources.

Concerning ***generation***, a number of options were selected, aimed at increasing flexibility and adaptation of the generation mix on the one hand, and mixing assets to reduce aggregate generation variations and unpredictability on the other. These options are related both to conventional generation and RES/CHP. Main issues in implementing these options are related to subsidy schemes that promote the installation of RES/CHP and conventional generation capacity. Increasing flexibility may be achieved by allowing the participation of renewable and distributed generation in the provision of system services and encouraging the provision of these services by conventional generators.

Concerning ***demand***, the main objective of the options relate to the increase in demand flexibility by allowing end-users to adjust to price signals through changes in tariff structure, regulation and technologies that either store or add to electricity demand. Mechanisms should be implemented in order to encourage the participation of demand in the market. These may include the introduction of locationally and temporally differentiated end consumer energy prices that reflect the true market value of energy. Two fundamental issues must be addressed when implementing demand issues. First, there must be both metering and billing of end-users according to market prices reflecting the intermittency problems. Secondly there must be organisational capabilities and technological possibilities for adjusting electricity demand.

Concerning ***trade***, a number of ***storage*** options that facilitate the trading opportunities were proposed as relevant options. Storage could include hydro plants, local heat storage and heat pumps used in combination with CHP units. The organization of both regional and national markets including energy and ancillary services must be analysed. Among fundamental topics that might result in barriers to implementing options: market access, gate closure time, subsidy schemes, size limitations and management of deviations.

Concerning ***transmission networks***, different options corresponding to both operation and planning were identified. The main transmission options that TSO may use consist on increasing the interconnection capacity by investing in new lines, better management of existing lines, improving existing day-ahead and intra-day markets, developing control centres and developing improved intermittent generation output prediction tools, among others. Building interconnection capacity would allow power exchanges between areas or countries where there is an excess of energy produced from RES and other areas where power output by renewable and distributed generation is small. Several markets have only few years of experience, so there is a great potential for improving existing markets and co-operation or mergers between markets in neighbouring countries. Control centres that monitor intermittent energy sources in real time allow TSO guarantee system security maximizing the penetration of RES directly connected to the transmission grid. Continuous improvement of the wind power forecasting tools developed by system operator is needed in order to reduce the uncertainty of the wind production in the daily scheduling and the need of reserve capacity.

Concerning ***distribution networks***, options concerning to an active network management of DSO and to an increasing participation of demand were shown as most effective. Active network management options such as real-time network control, real time control of generation and demand or local system balancing and micro-grids were assessed. Demand response offers several advantages to network operators through lowering peak demand and postponement of investments. Demand response may be implemented by means of interruption contracts and real-time pricing or by the use of storage options. At distribution level, it is also of utmost importance that DSOs adopt new procedures for the planning of the expansion of the grid that take into account the existence of renewable and distributed generators. For this purpose, geographically and temporally differentiated distribution tariffs would encourage agents to make efficient decisions from the point of view of the system.

Response options (conventional as well as new options) were mutually compared and prioritized based on a set of criteria that included:

- ***Maturity***, availability and relevance of response option until/in 2015. It should be noted that the focus of the study is on the time frame from 2015-2020. Therefore, on the one hand the prioritized options must be mature in 2015 with regard to both the technical development and the required production facilities that will supply the market. On the second hand, for selecting options that are regulatory or organisationally related the appropriate regulation or market rules changes must be sufficiently simple to be implemented already from 2015
- Economic viability and impact on the electricity market.
- ***Potentials*** (to integrate large shares of intermittent generation, to eliminate several negative impacts, to contribute to improved performance of different segments of the electricity system). Potential is interpreted as the ability to mitigate the problems caused by intermittency and thereby increase the possible share of intermittent renewable energy sources within the EU. Therefore the potential criteria necessitates that the option is not only important in one country but in a number of countries that would constitute an important part of the EU renewable potential.
- Interaction with other response options.

According to these criteria, a list of prioritized options was assessed:

- Interconnection capacity
- Flexible demand (demand response)
- Dispersion of intermittent generation in EU countries (in different price zones) for example by coordinating subsidy schemes
- Cheap storage technologies (hydro, heat etc)
- Flexible generation mix
- Real time information on intermittent generation available to TSO
- Control systems including intermittent generation that enables TSO to maintain system security with lowest costs
- Active network management at the DSO level including flexible generation and demand response for distribution grid purposes

1.3 Report Structure and contents

This document has been developed to detect actual and potential barriers that may hinder the implementation of the respond options (with emphasis on the prioritized response options) identified in WP3 of the RESPOND project. For this purpose a detailed questionnaire was developed in order to expand and collect additional information for the five country case studies (Spain, UK, Denmark, Germany, and Netherlands) regarding the national situation and the position of national regulators on the different key barriers (related to market and regulatory issues). In addition, results obtained by related finished European projects such as DG-GRID and SOLID-DER have been also taken into account. The analysis of the results of the questionnaire, the related European projects, together with the information gathered in WP2 and WP3, should allow one to make policy and regulatory recommendations within WP5.

The topics covered by this report have been classified into barriers related to generation (including both conventional generation and RES/CHP generation), barriers related to demand, barriers related to markets, and barriers related to transmission and distributions networks.

Concerning ***RES and CHP generation***, the main issues are:

- Pricing mechanisms for energy and ancillary services
- Support schemes for RES and DG.
- Technical capabilities

Main identified issues related to ***conventional generation*** are:

- Incentives to provide reserves (primary, secondary, balancing)
- Mechanisms to provide firmness in critical periods
- Economic incentives to install new generation capacity

Failure to overcome the outlined barriers related to conventional and RES and CHP generation will hinder the implementation of prioritized options outlined in WP3 such as dispersion of intermittent generation in EU countries, cheap storage technologies, or achieving a flexible generation mix.

Concerning ***demand options***, the topics identified are:

- Metering and communication issues
- Pricing rules and incentives
- Technical possibilities

As indicated by WP3, in order to implement flexible demand and demand response as effective prioritized options, both metering and billing of end-users according to market prices on the one hand, and organisational capabilities and technological possibilities on the other, are essential to develop such strategies for overcoming variability and intermittency problems. Access to ancillary services markets could also provide additional incentives for demand to become flexible and controllable.

Concerning ***national energy*** (daily/intradaily) and ***ancillary service markets***, key issues are:

- Market access, which is related to size limitations and the possibility of aggregation of units
- Prediction of production, responsibility of deviations and gate closures closer to real-time

RES positive incentives (possibility of aggregation of units, gate closures closer to real-time, flexible access rules, incentives to improve the prediction of production) as well as negative limitations such as size limitations in access to markets or penalizations associated with the responsibility of deviations must be addressed adequately in order to facilitate the penetration and dispersion of intermittent generation in EU countries. Aggregation of units, prediction of production and gate closures closer to real-time will also enhance the availability of information of intermittent sources or TSO that can be used and implement in control centres for the planning and operation of the system including intermittent sources.

Concerning ***regional markets***, key issues are:

- Increase of interconnection capacity
- Integration of national into regional markets (spot markets, sharing of reserves)

The increase in transmission capacity could mitigate the variability impacts of intermittent generation if the two electricity systems are different, and also reduce the variation in prices. For an efficient use of the interconnection capacity, the harmonization of rules and procedures that better integrate the national markets into regional markets could also represent a non-negligible barrier in order to use the potentials of an increased grid.

For transmission and distribution networks, it is important to analyse:

- Time of use and locationally differentiated tariffs
- DSOs incentives for active network management
- DSOs incentives for efficient network planning taking into account DG
- DSOs incentives for improving quality of service integrating DG
- DG incentives to provide ancillary services to the DSO

These barriers concerning distribution networks have been widely investigated by other projects such as DG-GRID and IMPROGRESS.

For each topic, the developed questionnaire contained a set of questions addressed to find out:

- What is the current situation in the country and if this situation is in line with the recommendations that have been proposed at the EU level,
- Which barriers should be removed in order to increase the penetration of RES/DG and comply with EU recommendations,
- What specific proposals can be made in order to remove barriers and comply with EU recommendations.

Opinions of different stakeholders were consulted by the partners in order to fill the questionnaires that have been used in this report. In the following the list of the countries and partners of RESPOND in charge of filling up the questionnaire are listed:

- UK: Imperial College. Even though stakeholders were not directly consulted, publicly available documents from Ofgem and National Grid were used to fill up the questionnaire for UK
- Germany: ISET and DENA. Stakeholders consulted included Federal Network Agency (BNetzA), German Wind Association (BWE), Electrabel Germany AG, Evonik New Energies GmbH, German Association of Energy and Water Industry (BDEW)
- The Netherlands: ECN. Stakeholders consulted included TenneT (TSO) and distribution system operators Continuon and Essent
- Denmark: RISOE. Stakeholders consulted included Energinek.dk and DONG Energy
- Spain: Comillas University and REE. Opinions and views of stakeholders consulted included the Spanish TSO (Red Electrica de España), the National Spanish regulator (CNE) and generation and distribution companies (Iberdrola)

2 Generation

Various response options enabling RES/CHP deployment were selected in Deliverable D5. In terms of generation, these options are primarily aimed at increasing flexibility and adaptation of the current conventional generation mix on the one hand, and mixing assets to reduce RES aggregated generation variations and unpredictability on the other. The main issues regarding *generation aspects* identified in the surveyed countries are presented in this chapter, organized in terms of RES/CHP generation and conventional generation. In addition, the potential barriers to the implementation of the selected response options for efficient RES/CHP integration up to 2020 are synthesized, highlighted and discussed, and suitable actions to counteract the effects of such barriers are proposed.

2.1 RES/CHP Generation

RES/CHP generation shall take part in energy as well as ancillary services markets, since they will probably represent a significant fraction of the total amount of generation capacity in the system. Obstacles, amongst other, may be related to the remuneration perceived by RES/DG generators. This comprises the payments they receive according to the support schemes in place and the remuneration they obtain for the sale of energy and system services. Thus, for example, flexibility in the system can be increased by allowing the participation of renewable and distributed generation in the provision of system services, but the latter must be appropriately remunerated. One last barrier is related to the technical capabilities of RES/DG and whether these are compatible with the requirements made in order to get connected to the system.

2.1.1 Pricing mechanisms for energy and ancillary services

Energy markets

As RES/DG technologies may exhibit high initial costs, competitiveness of such systems, at least at relatively early development stage, must be ensured by adequate support mechanisms. In this respect, support for RES (and in some countries also CHP) has been introduced in *all* EU27 member states. The main support schemes adopted in the European countries can be classified in:

- Feed-in-tariffs (FITs) and premiums
- Quota obligations based on tradable green certificates (TGCs)
- Tax incentives
- Tendering systems

Feed-in tariffs and premiums are generation-based price-driven incentives. They are usually regulated by the government, paying to operators of eligible domestic renewable electricity plants for the electricity they feed into the grid. Feed-in tariffs take the form of a total price per unit of electricity paid to the producers whereas the premiums are paid to the producer on top of the electricity market price. An important difference between the feed-in tariff and the premium payment is that the latter introduces competition among producers in the electricity market. Thus, premiums are regarded as more efficient compared to feed in tariffs, which in turn can be improved by introducing a time-of-use structure. The cost for the grid operator is normally covered through the tariff structure.

Feed-in-tariffs and premiums may be designed in % of average market price for consumers, in case depending on the RES technology and voltage level. In alternative, such mechanisms could be related to external damages avoided or external benefits achieved. The duration of the support may be valid for the lifetime of the installation or only for a predefined number of years, and may be regressive or held constant with the years. The guaranteed duration of the support represents a key issue: a strong long term degree of certainty lowers the market risk faced by investors.

Quota obligations based on Tradable Green Certificates are generation-based quantity-driven instruments. The government defines targets for RES deployment and obliges any party of the electricity supply-chain (e.g. generator, wholesaler, or consumer) with their fulfilment. Once defined, a parallel market for renewable energy certificates is established and their price is set according to demand and supply conditions (forced by the obligation). Hence, for RES or CHP producers, financial support may arise from selling certificates in addition to the income from selling electricity on the power market.

Tax incentives are generation-based price-driven mechanisms that work through payment exemptions from the electricity taxes applied to all producers. This type of instrument thus differs from premium feed-in tariffs solely in terms of the cash flow for RES producers: it represents an avoided cost rather than additional income.

Tendering systems are quantity-driven mechanisms. The financial support can either be investment-focused or generation-based. In the first case, a fixed amount of capacity to be installed is announced and contracts are given following a predefined bidding process which offers winners a set of favourable investment conditions, including investment subsidies per installed kW. The generation-based tendering systems work in a similar way. However, instead of providing up-front support, they offer support in the size of the bid price per kWh for a guaranteed duration.

According to these classes of incentives, in general, RES/CHPs may have three typical options to sell their production, namely, receiving a *feed-in* tariff, receiving a (feed-in) *premium* over the market price, or participating in TGC trading. The incentives may differ by type of technology and primary fuel used, size, and age of the installation. Currently, no differentiation per voltage level or location is provided, albeit size discrimination can be implicitly doing this.

For instance, *Table 1* shows the FIT and premiums structure used in *Spain* in 2007 for the most common DG technologies. Only CHP and plants powered by means of biomass, biofuels or residues that chose the FIT alternative may opt for a ToU differentiation in peak hours and off-peak hours, with the year also divided in winter and summer days (on the basis of the date of time change).

Table 1 : Spanish FIT and premium structure for the year 2007.

<table>
<tr><th>Technology</th><th>Power Range</th><th>Start year</th><th>End Year</th><th>FIT</th><th>Premium</th><th>Cap</th><th>Floor</th></tr>
<tr><td rowspan="2">Windpower (on-shore)</td><td rowspan="2">No differentiation</td><td>0</td><td>20</td><td>7,32</td><td>2,93</td><td>8,49</td><td>7,13</td></tr>
<tr><td>20</td><td>Onwards</td><td>6,12</td><td>0</td><td></td><td></td></tr>
<tr><td rowspan="6">PV</td><td rowspan="2">P≤100 kW</td><td>0</td><td>25</td><td>44,04</td><td rowspan="8">N/A</td><td></td><td></td></tr>
<tr><td>25</td><td>Onwards</td><td>35,23</td><td></td><td></td></tr>
<tr><td rowspan="2">100 kW<P≤10 MW</td><td>0</td><td>25</td><td>41,75</td><td></td><td></td></tr>
<tr><td>25</td><td>Onwards</td><td>33,40</td><td></td><td></td></tr>
<tr><td rowspan="2">10<P≤50 MW</td><td>0</td><td>25</td><td>22,98</td><td></td><td></td></tr>
<tr><td>25</td><td>Onwards</td><td>18,38</td><td></td><td></td></tr>
<tr><td rowspan="5">CHP (Natural Gas)</td><td>P≤0,5</td><td colspan="2" rowspan="5">After 10 years, an age correction is applied that depends on the installed capacity</td><td>12,04</td><td></td><td></td></tr>
<tr><td>0,5<P≤1</td><td>9,88</td><td></td><td></td></tr>
<tr><td>1<P≤10</td><td>7,72</td><td>2,78</td><td></td><td></td></tr>
<tr><td>10<P≤25</td><td>7,31</td><td>2,21</td><td></td><td></td></tr>
<tr><td>25<P≤50</td><td>6,92</td><td>1,91</td><td></td><td></td></tr>
</table>

In the *UK*, most RES and CHP are not exposed to market prices differentiated by time (or location) because they are engaged in PPA (power purchase agreements) with larger market participants (typically energy suppliers) who pay a fixed rate for all energy produced regardless of time of output or location. Certain renewable technologies will receive Renewable Obligation Certificates (ROCs), that is, TGCs, traded on a separate ROC market. However, the ROCs are not applied according to time or location, but just to MWh output and to the generation technology. Similarly, certified “good quality” CHP schemes are exempted from the Climate Change Levy (CCL) – an additional charge on fossil fuelled generation sources, but again this is not related to either location or time output, and is only dependent on the CHP scheme meeting certain minimum standards in operating efficiency.

In the *Netherlands*, energy production is remunerated according to the time when it is produced, but not to location, except for two regions where temporarily congestion management will be applied in the future (planning: from 3rd quarter of 2009, in one region with the highest problems a simplified congestion management scheme as from October 2008).

Ancillary services markets

In addition to energy, ancillary services are essential for power systems to allow stable, secure and efficient operation. However, not all European countries have developed separate energy and ancillary services markets, and different pricing arrangements exist.

In general, without adequate support mechanisms in place, RES/CHP generators are not encouraged to provide the system with those services that are most valuable. This is mainly related to the fact that services are not priced according to the value they have from the system’s perspective. In particular, if the feed-in tariff, market premium or green certificate price offered on energy production is too high, generators are driven towards providing all their production on the energy production market and not to provide ancillary services.

For instance, in the *UK* an availability payment will be made for several type of AS, plus an additional payment if the service is called out. Depending on the system service, the payment will be related to location and time. RES/DG can provide some system services through an aggregator. Whether they are remunerated exactly by time of output and location will be dependent on the contractual agreement with the aggregator and the profit sharing arrangement.

In *Spain*, RES/DG units which choose to integrate their production through the spot market or contracts can participate in all the ancillary services markets if they are controllable. Their bids must be over 10MW, which can be obtained by aggregation. The ancillary services in which they can participate are congestion management, secondary reserve, and balancing market. However, RES/DG units under a constant feed-in tariff do not participate in ancillary services markets. Concerning voltage control, RES/DG receive incentives or penalties (in % of a fixed value of €/kWh) to keep their power factor (*cosφ*, ratio of active power to apparent power) between certain limits, depending on on-peak, off-peak and valley hour, and leading or lagging power factor, see figure 1 below.

Reactive Power Bonus

Type of	Power Factor	Bonus (%)		
		Peak	Inter	Off-Peak
Inductive	< 0,95	-4	-4	8
	< 0,96 y ≥ 0,95	-3	0	6
	< 0,97 y ≥ 0,96	-2	0	4
	< 0,98 y ≥ 0,97	-1	0	2
	< 1 y ≥ 0,98	0	2	0
	1	0	4	0
Capacitive	< 1 y ≥ 0,98	0	2	0
	< 0,98 y ≥ 0,97	2	0	-1
	< 0,97 y ≥ 0,96	4	0	-2
	< 0,96 y ≥ 0,95	6	0	-3
	< 0,95	8	-4	-4

Figure 1: Reactive power bonus for DG/RES generators in the Spanish market

There has been some complains by the system operator due this reactive support mechanism. In some buses there is sudden big voltage variation (up to 18 kV –which represents 0.05 pu in the 400 kV network-) due to the connection or disconnection of capacitor banks in order to receive the reactive bonus. This case highlights how significant is to develop right incentives or pricing mechanisms.

Another interesting case is related to the *Danish* experience, which witnesses a large number of small-scale CHP units with heat storage installed in the 1990s for medium and small-scale district heating systems. Originally, they faced a three-level feed-in tariff that encouraged electricity generation at peak load only. From 2005, the small-scale CHP generators are facing the wholesale market price with some add-on, so they will not generate electricity when wind generation is abundant and prices very low. In addition, a ban on electric boilers to supply district heating systems was *only* temporarily lifted, so that investment in electric boilers is in case discouraged. There are no similar restrictions for heat pumps, which will require a much longer utilisation time to be profitable.

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. However, the institutional setup is available in the form of the Nordic power exchange, Nord Pool.

In *Germany*, balancing power is tendered centrally for all four balancing zones in Germany. In these balancing zones there is no locational differentiation. If a balancing zone is short on balancing power and another one is long there should be an exchange. However, in the past this has not been the case and costs were higher than they could have been.

In the *Netherlands*, for regulating and reserve power, different prices are available for each PTU for regulating up and down. For relieving transmission constraints, prices vary also to location as producers at some locations are offered higher prices. In terms of voltage control and black start, each year the TSO asks all market parties to offer reactive power and/or black start services and then contracts the relevant generators.

2.1.2 Revision of RES/DG support schemes

In terms of efficient system (network) integration, which is the objective of this project, and with reference to the incentive mechanisms illustrated above, it can be generally stated that premiums on top of the market price are more efficient than constant FITs. In fact, generators receive the market price signal as a good indicator of the value for the system of the energy they are generating in each hour of the day. Likewise, suitable TGC market design can result in pushing towards energy provision when the system needs it most. Utilization of FIT schemes as opposed to the other mechanisms could thus result in impediment of further effective RES/CHP integration. Detailed discussions on these aspects are illustrated below, also considering alternative viewpoints.

Considering the *investor*'s point of view and the overall energy generated from RES/CHP, the performance of the support scheme can be benchmarked among different countries based on effectiveness and efficiency factors. *Effectiveness* means the ability to deliver an increase of the share of renewable electricity consumed, while *efficiency* represents a comparison of the total amount of support received and the generation cost. However, sometimes comparison in terms of effectiveness and efficiency may be difficult since several schemes may be in place for a limited number of years and the countries are continuously fine-tuning existing support measures. The experience has shown that investors in RES usually prefer a system that is stable for a large number of years. The credible continuation of policy and the abatement of administrative barriers are important to create a stable growth in renewable energy sources and bring about lower societal costs as a result of a lower risk premium (of investors).

When simply looking at the growth of renewable energy in recent years, we could then conclude that countries with strong feed-in tariff systems like *Germany* and *Spain* experienced enormous growth of RES capacity. Countries like the *UK*, with a quota obligation and a tendering system, experienced far less growth of renewable energy capacity. In fact, from the investor's point of view a feed-in tariff system provides more security than a green certificate system where the revenues per MWh are dependent on the demand for green certificates.

However, with respect to the generation-related definition of *efficiency* given above, a more comprehensive definition of efficiency should be put forward, taking into account additional costs for the overall system, such as balancing costs. Accordingly, the point of view of the investor should be regarded as only one of the possible, since overlooking the point of view of the network operator and of the society in general will hamper further efficient integration due to initial biased support mechanisms.

As a follow-up, effectiveness in terms of large RES/DG penetration or generation-based efficiency cannot be the only driver indices to formulate suitable incentive mechanisms. Indeed, the RESPOND project main focus is on *efficient integration* of renewables and DG in the electricity system when their production increases. Hence, rather than merely promoting the highest share of renewables in the system, suitable support mechanisms should aim at efficiently *integrating* RES/DG in the *system*, so that the *system*/*society* perspectives are to be regarded with prominent role.

Therefore, from the point of view of *network operators and balancing responsible parties*, it is crucial that support mechanisms take into account the actual system needs. Differentiated time-of-use tariffs/incentives and premiums on top of the market price, as mentioned earlier on, instead of fixed-feed-in tariffs, are capable to provide efficient market signal. Hence, the DG operator can know when power is mostly required and when not, and subsequently adjust (when possible) its power production so as to meet its economic requirements (by producing energy when prices are higher) and at the same time the network requirements (when generation is needed). Furthermore, support mechanisms should be combined with obligation to provide forecasts on the scheduled production in order to simplify the system burden in terms of ancillary needs. If these forecasts are not provided, or the deviation from the expected production is too high, adequate penalties should also be implemented. Alternatively, DG operators can be made balancing responsible for their own imbalance, giving them an incentive to provide reliable forecasts on scheduled production.

Similarly, quota obligation mechanisms could be quite effective in inducing competition among technologies and send market-based signals for the network sake. However, in order to ensure that all technologies can benefit of such kind of incentive, it is important that enough liquidity is available on the market, where not only low-cost options are realised. Hence, convenient performance of TGCs requires that targets for RES production or purchase are set high enough to ensure growth of capacity and fines for not meeting obligations are introduced and set high enough to provide an incentive to sell or purchase TGCs. In order to stabilize the TGC market, cost effective quota systems could include some financial/banking elements so as to limit the potential variations in certificate prices so feared by investors. At the same time, such limitations should still be able to allow the certificate price to increase, so as to guarantee certificate trade increase and thus enough market liquidity and RES investment on the long run.

From the point of view of the *whole power system* and *society*, RES/DG penetration could be increasingly expensive for the system, so that support schemes should be such that in the long run they do not hamper further deployment due to initially wrong incentives. In addition, wrong mechanisms might also lead to higher average market prices. Hence, again incentive mechanisms should be more market-oriented, avoid favouring certain technologies as opposed to other ones, and take into account the network needs.

It should be noted that all points of investors, networks, and society should be taken into account when analysing support systems. Hence, it is concluded that owing to the system point of view FITs should be rejected, while feed-in premiums and TGCs are both good candidates (with no specific choice between them) for support scheme implementation. Nowadays, both the feed-in tariff and premium schemes, as well as TGC schemes, are established in a number of European countries. Therefore, barriers and policy recommendations should be assessed for both systems.

2.1.3 Technical capabilities

RES/DG generation units built some years ago used to trip whenever a voltage dip or any other small system contingency occurred. This prevented the System Operator (SO) or Market Operator (MO) from relying on the power output of these units. Besides, most of these generators were not able to adjust their output according to the system needs, i.e. they were not capable of providing system reserves. All this together made it very difficult for RES generators to get connection to the grid, not to talk about the possibility of participating in markets. Today, most of these technical problems have been solved.

In the *Netherlands*, RES/CHP generation units are required to comply with certain technical requirements. These requirements depend on the voltage level at the connection point[1] and apply to all generators irrespective of the primary energy source (paragraphs 2.4. and 2.5. of the Network Code). Some of the technical requirements are stated below:

- 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);
- The electrical installation must be equipped with protection systems designed to meet certain specifications (e.g. under-voltage and over-voltage protection). For example, synchronous generators connected to low-voltage must be equipped with a device that disconnects the generator within 0.2 seconds when voltage level drops to 70% of the nominal level (section 2.4.2.4 of the Network Code). However, these specifications (which apply to all generators) do not seem to be restrictive for the development of RES/DG.
- The operation of the generator should not affect the state of the network and the connected parties (e.g. when the generator is synchronized with the network). The SO can instruct generators to increase/reduce their output or turn on/off their units in case of emergency. This measure applies to all

[1]Two voltage levels are defined by the Dutch Regulator for this reason; low-voltage, for voltage level of 1 kV and lower, and high-voltage, for voltage level higher than 1 kV.

generation units with an installed capacity of more than 5 MW and with available capacity at their disposal. No compensation is provided to the generators in this case.

The Network Code does not discriminate among 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 (par. 2.5.1.4 of the Network Code and 2.1.3 of the System Code)[1.] Therefore, these units are not obliged to meet the respective technical requirements about frequency response and reactive power provision.

In *Germany*, the grid codes defined the technical requirements that need to be met by RES/CHP connected to transmission. Main requirements are reactive power provision and fault ride through capability. There are already now in effect some technical rules of FGW (http://www.wind-fgw.de/) to be complied with, in addition to grid access rules produced by the TSO/DSO, for example E.ON Netz, for wind plants. This concerns, for instance, the reaction to frequency deviations in the grid, namely, obligatory grid disconnection to regulate the frequency.

Beginning in January 2009 the EEG has included a regulation for system services bonus. This law will be formulated in detail in a secondary legislation. It will include regulations for:

- behaviour of plants in failure situations
- voltage control and reactive power
- frequency control
- verification procedure
- behaviour in black start situations

The secondary legislation will also include: a) financial incentives to provide steady output, demand-driven, as well as improved grid and market integration of RES-E generation and b) qualification criteria to participate in balancing markets. However, 95% of RES-E is connected to the distribution system. Therefore, they do not necessarily have to comply with the grid codes and often do not do so.

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 following figure shows the threshold values for voltage dip duration and amount that wind generators have to ride through. No generator can disconnect from the network within the shadowed area during a single-phase, two-phase or three-phase short circuit.

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[1] It should be also noted that units with capacity smaller than 5 MW do not qualify for primary response anyway.

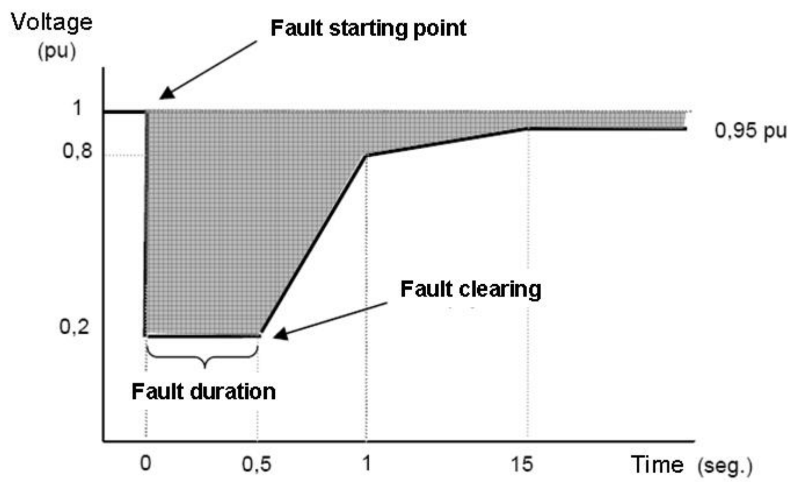

Figure 2: Requirements for voltage dip through ride in Spain

As long as the voltage is below 85% of the rated one, no consumption of active or reactive power is permitted at the connection point. During the fault and the recovery period, wind generators must be providing maximum current (never below nominal values). The reactive current component must be within the shadowed area of the following figure. By doing this, it is expected to keep an active power production as close to normal conditions as possible. Protections that trip the wind farm may have a response delay of 40 ms.

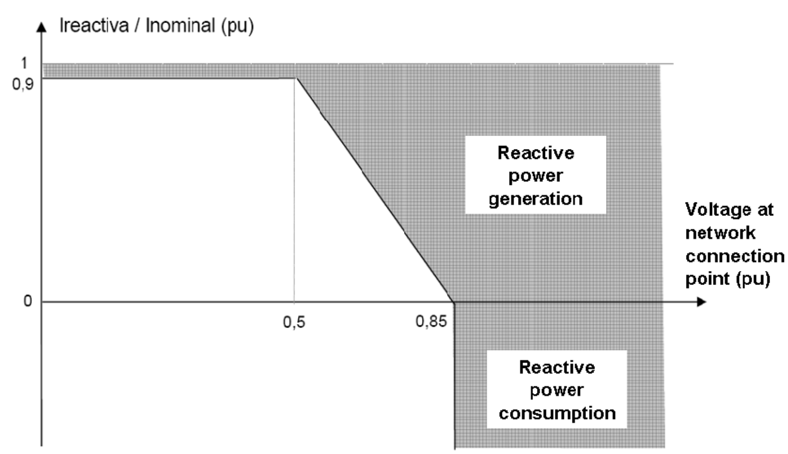

Figure 3: Reactive power component thresholds during fault and recovery period in Spain

Wind generators also have to contribute to primary frequency control. They must have the ability to reduce power output in case of over-frequency and raise it in case of under-frequency. In the latter situation, wind generators are only obliged to do so if wind speed is higher than the one corresponding to nominal capacity (maximum of 5% during 5 minutes).

Additionally, every unit or aggregation of units larger than 10MW must be connected to a control centre. Missing to fulfil any of these requirements would imply losing the rights to be remunerated under the conditions of the "Special Regime", i.e. losing the rights to perceive the RES/DG support mechanisms and other incentives. Finally, controllability is required to access AS markets.

Wind farms that were functioning after January 1st 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 January 1st 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 January 1st 2009.

In the *UK*, small RES (wind) is not required to comply with technical constraints and in most instances is required to trip off the system in the case of system faults. CHP units that are sufficiently large to require compliance (>100MW for a single unit) with the CUSC (Connection and use of system code) will need to meet the same technical constraints as conventional generation. However the number of RES/CHP systems that meet the requirements for mandatory sign-up to the CUSC is exceptionally small. Few RES/DG have anything to do with these requirements, and as yet there are no other regulations or special regimes that regulate the output of these generators.

2.2 Conventional generation

Achieving the level of flexibility that is required to integrate large shares of intermittent generation in power systems may only be possible if conventional generators have the ability and will to adapt their behaviour to the new system needs that will arise (or have already arisen) because of the installation of RES/DG power plants. The aggregated output of these generators will have to absorb a significant fraction of the *variable* and *unpredicted* changes in the output of other non-controllable generators both in the short and the long term. For this to happen, enough flexible conventional generation capacity will have to be in place in the system. This generation capacity will have to be available and producing when the system needs it to supply demand. Generators will have to quickly adapt their behaviour according to sudden unpredicted changes in net demand (demand – uncontrollable generation). In the following, we aim to identify market and regulatory barriers that may undermine the successful application of measures to achieve the aforementioned objectives.

2.2.1 Incentives to provide regulation reserves for conventional generation

Conventional generation can increase the flexibility of the power system through provision of primary, secondary and tertiary regulation reserves. Participation of these generators in the balancing service is compulsory in some cases (primary reserve), though the characteristics of the compulsory regulation service provided by generators may vary from one system to another (response speed, conditions for the response of generators to be triggered, etc). Participation in other balancing services is voluntary and, therefore, must be achieved through the use of economic incentives. Hence, unless the prices earned are attractive enough, generators will sell their energy in other markets.

The following section describes different mechanisms existing across a number of

European countries (Denmark, Germany, Netherlands, Spain, and UK).

As for the *Danish* system there is no particular mechanism for provision of regulating power and energy. The current system is based on legal vertical unbundling, with a matured organised market, balancing responsible parties, rules and regulations set by the TSO, and an – apparently well-designed – system of fees and tariffs. The success of this arrangement is a result of tradition, political agreements, a strong institutional organisation of the market, and abundant generation and transmission capacity.

The key mechanism for load-frequency regulation is the joint Nordic regulating power market, which covers East but not West Denmark. The key principle for this market is that the balance responsible parties submit bids for upward or downward regulation to the local system operator stating the offered quantity energy payment. The system operators send the regulating power bids to a 'coordinator' (Statnett in Norway), who compiles a joint list of all regulating power bids in the Nordic countries, sorted by price. If regulation of the frequency in the joint Nordic synchronic system is needed, the most advantageous regulating power bids on the joint list are activated taking grid congestions into consideration.

There is an expectation that the needs for load-frequency regulation services will increase in the foreseeable future along with the expectation of significant increase in wind installed capacity over the next decades. This may require new solutions – both technical and institutional – such as DC transmission lines between the UCTE and Nordel synchronised systems (planned or under construction) and more distributed CHP systems.

Participation in the balancing market through a tender is the customary procedure in place in *Germany* in order for the conventional generators to participate in the provision of primary, secondary and tertiary regulating power and energy. The participation of generators in these services is voluntary, and this has brought problems associated with the existing mechanisms. They have failed to achieve enough participation (liquidity) in those markets because the prices might be lower than anticipated and the prequalification criteria are very complex, only a small amount of capacity can qualify for these services. The needs for load-frequency regulation services in Germany are also expected to increase in the foreseeable future due to increased wind installed capacity.

Regarding the *Dutch* system, there is a secondary legislation in the form of grid and system codes (based on provisions in the Electricity Law 1998), which is aimed at promoting the participation of generators in balancing markets. Provision of primary reaction is compulsory for large generators (>60 MW). No financial compensation is provided. Furthermore, connected parties with contracted and provided capacity of more than 60 MW are obliged to offer all the available capacity that they can produce more or less and consume less to TenneT as Regulating and Reserve Power (RRP) by means of bids; other connected parties are allowed to do so (NMa/DTe, 2007a).[1] There is a bid ladder which contains bids of Regulating and Reserve Power with a dispatch time smaller than or equal to a Programme Time Unit (PTU), equal to 15

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[1] NMa/DTe, Grid code September 2007 version.

minutes.

For (small) CHP units with heat storage (in horticulture), the existing mechanisms which facilitate the Dutch generators to participate in the balancing market through aggregators are quite successful. This is due to the higher revenues of the balancing market compared to other markets which attracts CHP units to provide these services.

The increase of intermittent generation (onshore and offshore wind, CHP, PV) will increase the demand for regulation services. However, it seems that the current mechanism is still adequate to deal with these changes.

In *Spain*, contributing to the primary regulation service is mandatory (no remuneration considered). The required equipment must be installed at every generating unit. Generating units that don't comply may contract the service.

Secondary regulation has been established as a competitive market. The service is provided by several regulation zones (sets of generating units belonging to a generating company). The control is automatic and hierarchical: the SO sends signals to each company central dispatch, which in turn sends signals to its own units. The units participating in the service must react to the signals in 5 minutes. Up and down regulating capacity is not separated. The remuneration is comprised of a capacity payment (€/MW) for the total band provided (up and down), and an energy payment (€/MWh) corresponding to the price of the substitution regulation energy. The provision of this service is supervised, and a penalization of 150% of the capacity payment is applied if the units do not comply with the technical requirements of the service. The following table contains the mean annual prices obtained for the band and regulating energy in the secondary regulation market

Table 2 : Mean annual information for secondary regulation market in Spain in the last years

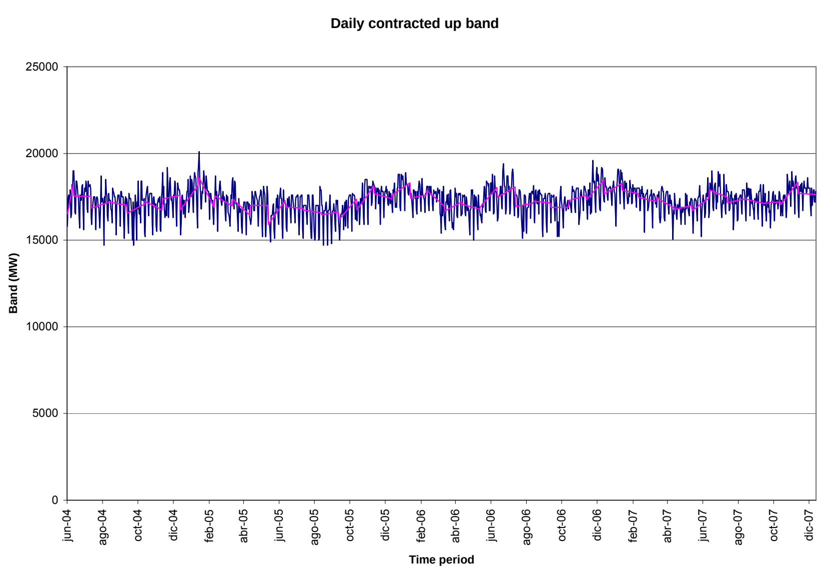
	SECONDARY RESERVE MARKET						
	CAPACITY TERM			ENERGY TERM			
	mean hourly band	Economic Volume	Mean price	Energy used	Economic Volume	Mean price up energy	Mean price down energy
year	MW	k€	€/MW	GWh	k€	cent/kWh	cent/kWh
2007	1240	208986	19.220	2137	68775	4.100	2.600
2006	1242	249996	25.041	2175	104758	5.700	4.000
2005	1217	326819	30.624	1985	105728	6.518	3.890
2004	1234	131403	12.143	2035	58027	3.599	2.013
2003	1205	168414	15.938	1967	50011	3.451	1.672
MEAN	1228	217124	20.593	2060	77460	4.674	2.835

Tertiary regulation in Spain is also established as a voluntary competitive market. This market is only cleared by the SO if secondary reserve is exhausted. Units that can be on before 15 minutes can participate in the tertiary regulation market. An energy payment (c€/kWh) is defined for this market. Usually, tertiary energy prices are very favourable compared to daily market prices. The following table contains the mean annual prices for the up and down energy prices in comparison to the mean annual daily market prices

Table 3 : Mean annual information for up and down regulation prices with respect to daily enery prices in Spain in the last years

	TERTIARY REGULATION				
year	Energy used GWh	Economic Volume k€	Mean price up energy cent/kWh	Mean price down energy cent/kWh	Mean price daily market c€/kWh
2007	4998	228875	6.900	2.200	3.935
2006	6587	403077	7.200	2.600	5.376
2005	5064	306680	8.543	2.840	5.573
2004	4699	161951	5.531	1.361	2.874
2003	4323	142055	5.689	1.077	3.026
MEAN	5134	248528	6.773	2.016	4.157

In those cases where provision of the regulation service is voluntary, the mechanisms that exist in Spain have been quite successful at encouraging generation capacity to participate in the service provision. This is due to high prices for providing secondary reserve and tertiary reserves. This encourages the participation of conventional generators in these markets.The hourly contracted secondary reserve has not varied in the last years in Spain, even though a high increase in wind generation capacity has been experienced (which should have increased the need for regulating capacity). One possible explanation of this fact consists of the improvement of the wind power production forecast that is taking place. Figure 4 shows the daily contracted up band and down band in the past years, indicating that the needs have not increased even though the increase in intermittent generation capacity such as wind.



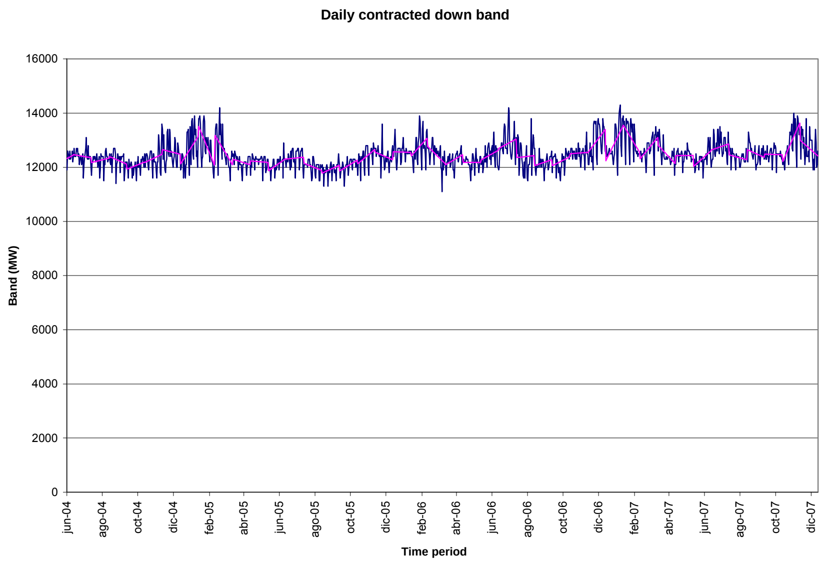


Figure 4: Daily contracted down and up band in Spain in the last years

The mean hourly up band is around 700 MW with a maximum of 900 MW, and the mean down band is around 500 MW, with values in the range [400-600 MW]. Figure 6 and Figure 7 show the mean hourly contracted up and down band.

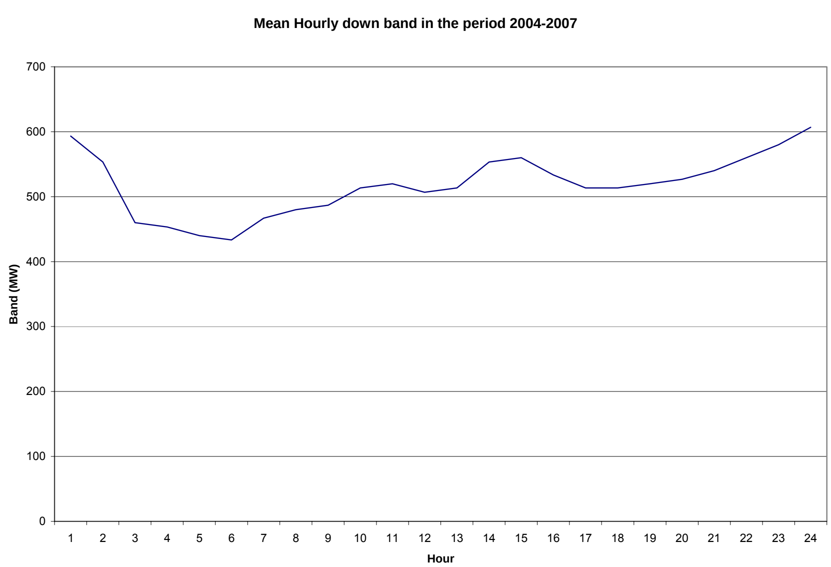


Figure 5: Mean hourly down band in Spain in the last years

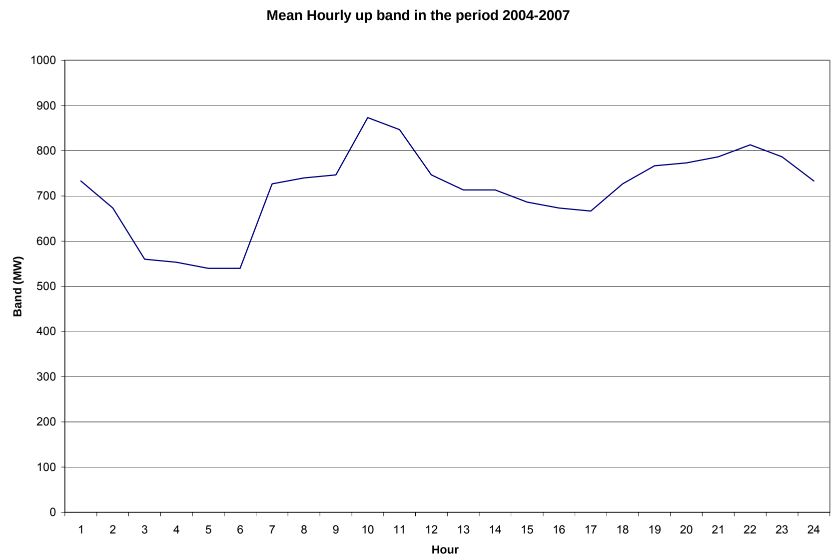


Figure 6: Mean hourly up band in Spain in the last years

Even though the band contracted in the Spanish secondary reserve market has not varied significantly, a mechanism of contracting supplementary reserve has been implemented in case the system operator decides that the hourly band contracted in the secondary reserve market is not enough to guarantee the load-frequency regulation.

In the *UK*, primary regulation is mandatory as part of the Connection and Use of System Code (CUSC) – the grid code that all eligible generators must comply with. Exempt generators are typically those under 100MW. Generators complying with the CUSC must have primary regulation services installed at every generating unit. There is no remuneration for this activity.

Tertiary and Secondary regulation in the UK are established as a voluntary competitive market. Services are tendered on an annual basis. Depending on the service provided, payment will be on the basis of a call-out charge (£/MWh) and in some instances will include a standing payment for availability (£/MW). The SO has developed a number of reserve products to allow a range of reserve service providers to participate in these markets.

Conditions for provision of secondary and tertiary services vary with the service. Some allow aggregated provision, others do not. Most have minimum response capacity allowable and time conditions for sustaining response; this varies according to the service. The SO sends signals to each company central dispatch and it sends signals to its own units. Figure 8 shows the reserve services timescales that exist in the UK.

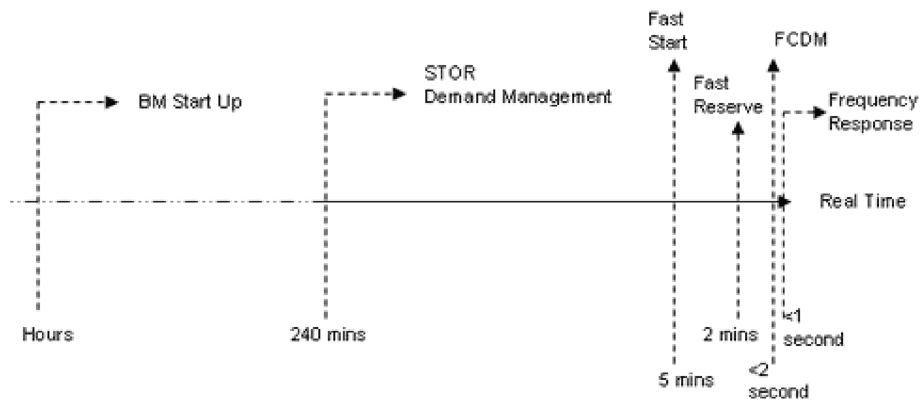


Figure 7: Reserve services timescales in the UK (Source: National Grid)

Fast Reserve is used in the UK to provide rapid and reliable delivery of active power through an increased output from generation or a reduction in consumption from demand sources, following receipt of an electronic despatch instruction from TSO. Providers of the Optional Service will receive an Enhanced Rate Availability Fee (£/h) payment for periods of time where they provide TO (following dispatch) with enhanced MW run-up and run-down rates. The Enhanced Rate Availability Fee is defined by the provider in the framework agreement. Providers of the Firm Service will receive an Availability Fee (£/h) for each hour in a Tendered Service Period where the service is available. TO will notify 'windows' during which it requires the service to be provided, for which a Window Initiation Payment will be made. During a window, Providers may also specify a Positional Fee (the cost of putting plant in a position where fast reserve may be provided). All fees for the Firm Service are submitted by the provider as part of the tender. An utilisation fee (£/MW/h) is payable for the energy delivered in both services (for Balancing Market Unit participants via a bid/offer acceptance). For the firm service this utilisation fee will be capped by the tender parameter submitted.

As an example, the following table contains the utilisation made of Fast Reserve in the UK in August 2007. Total reserve used was 12.3 GWh, which can be broken down into several price bands, see Table 4.

Table 4 : Fast Reserve Market Information (August 2007)

August	Price band (£/MWh range)	Volume (MWh)	Average Price (£/MWh)	Cost (£m)
	2000 to 99999	0	n/a	n/a
OFFERS	1000 to 2000	0	n/a	n/a
	300 to 1000	0	n/a	n/a
	0 to 300	10,426	119	1.24
Total		10.43GWh		£1.24m
	0 to 300	-1,641	12	-0.02
BIDS	-300 to 0	-191	-133	0.03
	-1000 to -300	-17	-440	0.01
	-2000 to -1000	0	n/a	n/a
	-99999 to -2000	0	n/a	n/a
Total		-1.85GWh		£0.01m
Total		12.27GWh		£1.25m

Source: National Grid

In those cases where provision of the regulation service is voluntary, the mechanisms that exist in the UK have been successful at encouraging generation capacity to participate in the service provision. Again, this is due to prices for secondary reserve and tertiary reserve which are high enough to encourage the participation of conventional generators in these markets

In the UK there is some concern that the need for reserve may increase with greater penetration of on and offshore wind generation. However, penetration to date has not been sufficient to indicate any serious changes. There are currently no additional mechanisms in place to facilitate an increase in demand for frequency regulation services.

2.2.2 Mechanisms for sufficient generation capacity in critical periods

Conventional generators must provide the system with the power it needs at times when demand is high and intermittent generators output is far from being able to supply it. Mechanisms to deal with this problem vary across EU-countries. Some systems have developed a system of payments and penalties so as to guarantee that capacity of the conventional generators is firm (capacity payments are an example of this). Other systems rely on market forces to encourage generators to be available when the system needs them. According to those backing this option, the prospect of earning high energy prices should lure conventional generators into selling their energy at times when demand is much larger than production by intermittent generators.

In *Germany*, the merit order system is the mechanism in place to balance the electricity production and demand, and there is no specific mechanism to guarantee enough generation is available at critical times. Hence, generators will always participate as long as their marginal costs are covered. However, due to the volatility in energy markets, if it is not expected that capital costs can be recovered, new capacity will not be built and older less efficient capacity will run, posing threaten to the overall system efficiency.

In the *Netherlands*, in order to ensure that there is adequate capacity and regulating capability to supply demand, the system operator contracts a certain amount of

Regulating and reserve power (275 MW) and emergency power (300 MW) on a yearly basis. Both are contracted *outside the market*, to prevent balancing power from competing with power in trade markets and therefore from not being available for securing supply during times of peak demand. Consequently, less supply is made available on trade markets and market prices will increase giving rise to investments in new generation capacity. The system has been able to cover all demand, no large-scale black-outs did occur during the last decades due to lack of generation capacity.

The necessity of contracting Regulating and reserve power and emergency power can be motivated by the possibility of two kinds of market failures. The first one is due to imperfect information: if the market does not take into account the effects of individual dispatch decisions on the system as a whole during times of peak demand, the market outcome might be not optimal. The second one is related to shortage of reserve capacity: reserve capacity has public good characteristics, as for technical and economic reasons it is not possible to curtail all customers individually from using it, even when they are not paying for the services delivered by that reserve capacity. This follows from the non-excludability nature of reserve capacity[1]. In many cases, free-riding of electricity consumers on reserve capacity may occur. For both reasons, institutional arrangements like the contracting of additional regulating, reserve, and emergency power are necessary.

In *Spain*, there is a mechanism of *availability payments*, or availability service, in place whereby the system operator is allowed to enter into bilateral contracts (no longer than one year) with peaking units. The generators commit themselves to be available when needed by the system, in return for earning the availability payments established in the contract. This mechanism has been successful in getting the commitment of generators to provide the amount of firm capacity required by the system.

In addition to the system of availability payments and the daily energy market, there are other mechanisms in the Spanish system aimed at committing generators to produce power whenever the system needs it. These are the tertiary energy, the deviations management, and the congestion management markets. Prices in these markets are attractive enough to encourage the participation of generators. The following table compares mean annual energy prices in the deviation management market to average market prices.

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[1] We here call a good non-excludable if it is either physically impossible or prohibitively expensive to prevent users from consuming it. Devices to curtail customers at a distance from consuming electricity are still quite costly to apply on households.

Table 5 : Mean annual information deviation management market and average market prices in Spain in the last years

	DEVIATIONS MANAGEMENT MARKET				
YEAR	Energy used GWh	Economic Volume k€	Mean price up energy cent/kWh	Mean price down energy cent/kWh	Mean price daily market c€/kWh
2007	2157	76189	5.200	2.500	3.935
2005	1350	81256	7.876	3.480	5.573
2004	1777	55758	4.517	1.888	2.874
2003	2018	52549	4.595	1.521	3.026
mean	1826	66438	5.547	2.347	4.157

In principle, base units have a natural incentive to be available when the system needs them, since energy prices at these times are much higher than average ones. However, peaking units are the ones setting the marginal price when the reserve margin is tightest or there is no margin at all. Therefore, market forces may not provide a strong enough incentive for them to be available. Thus, a system of payments corresponding to the firm capacity they offer has been put in place.

The *UK* operates an approach based on market forces to encourage generators to be available at times of peak demand. There are no capacity payments, and the SO does not contract directly with generators to ensure that there is sufficient capacity to meet peak demand. Generation and demand contract in the wholesale energy market and a system of imbalance payments/charges penalises participants that do not reconcile their contracted and metered positions.

The SO also publishes the “Winter Outlook” on an annual basis containing the latest information on demand and generation forecasts for the coming peak (winter) period. This market information is used by generation to make decisions regarding availability of plant and contracting with suppliers in the wholesale market to cover the peak periods. Whilst the SO does not have any explicit authority to maintain a generation capacity margin, this approach manages to maintain a margin of close to 20%. There are also reserve markets that the SO can call on to provide additional generation in times of system shortage.

Under the current arrangements and in a system dominated by conventional generation the existing capacity has sufficient incentive to be available at peak times as prices are highest during these periods. However, there is some uncertainty as to whether these arrangements will continue to be suitable in a system with high penetration of intermittent renewables. Under these conditions the generation capacity margin will increase significantly (as intermittent generation displaces energy but not the generation capacity of incumbent conventional plant). This is likely to result in reduced load factors of operation for conventional plant, particularly base-load – and will increase the requirement for peaking generation. Current indications of new generation coming on stream in the UK system over the next 7 years do not indicate any appreciation of this scenario as most new capacity is base-load. Although there are no explicit barriers that discourage participation when the system is stressed – in the longer term the lack of a capacity payment may mean that there are not sufficient signals for investment in appropriate generation capacity to support a system with high penetration of intermittent renewables.

Further analysis is needed as the UK system develops. Reconsideration of the decision to move to a market only system without capacity payment should be reviewed, and alternatives considered.

2.2.3 Economic incentives to install new generation capacity

Due to the integration of large shares of RES/CHP, revenues for conventional generators in the market might probably decrease. This is related to the fact that the amount of energy sales will decrease, since available RES/CHP come first in the merit order. Besides this, many conventional generators will have to operate far from their nominal functioning regime and they will have to cycle. Therefore, their operating costs will increase. As a consequence of this, investment in conventional generation may become less attractive.

In *Denmark*, as the market has operated so far with some overcapacity, there is no real experience of this issue. However, it has been an issue considered in several research projects under national and Nordic programmes. There is a school of thought that excessive market revenue in short periods will not be a reliable source for financing new investments. Some kind of extra payment may be necessary. This is currently the mechanism used for financing research in new technologies.

In *Germany*, there are no other incentives to power plant operators, besides market revenues, to install new generation capacity. However, alternatives such as capacity payments are considered to be further investigated, in the outlook of high amount of RES capacity installed and lesser runtime/revenues for new conventional capacities, although there is an expectation that market forces could solve these problems too. Nonetheless, as a matter of fact today much more new conventional capacity than is expected to be able to run economically is planned or is in the licensing procedure.

Similarly, in the *Netherlands* there are no direct incentives to encourage new capacity. The mechanism of contracting generation capacity outside the energy market as mentioned before, increases the prices for generation capacity (less supply available) and therefore gives an incentive to increase generation capacity or to import more electricity. The existence of harbours (makes transport of fuels for electricity generation cheaper, especially coal), enough cooling-water due to the sea and rivers, and many interconnections with neighbouring countries favours installation of more generation capacity.

An alternative scheme, such as extra payments apart from market revenues is deemed inappropriate since it will distort the playing field level with neighbouring countries, as The Netherlands did experience in the past. At the moment there is an investment boom in new generation capacity in the country, without extra payments.

In *Spain*, in order to secure a sufficient amount of generation capacity to cope with load increases, authorities have decided to implement a system of capacity payments, also called the investment service. If these capacity payments were not implemented, systems might be prone to go through periods of time when reserve margins have been completely eroded and, consequently, energy price spikes and load sheds would take place. Generators that are larger than 50 MW in size receive a capacity payment expressed in euros per installed megawatt and year during their first 10 years of operation. Installations need an administrative authorization issued by the General Direction for Energy Policy and Mines in order to benefit from this payment. The investment incentive depends on the system reserve margin, also called IC (the ratio of the installed firm generation capacity to the peak load), which is computed by the SO. If the reserve margin index falls below 1.1, or in order to accomplish security of supply objectives, the Spanish government may implement auctions aimed at setting the level of the investment incentive to be paid to generation companies in order for them to install new generation capacity.

The following figures shows the annual evolution of the peak demand compared to the total conventional generation capacity (excluding special regime) and the total generation capacity (including all special regime). The next one shows the ratio of the peak demand to the total and conventional generation capacity.

Implementing an investment incentive that depends on the level of the system reserve margin that exists when the investment takes place encourages agents to postpone investments in new generation capacity until the reserve margin is very tight, so as to earn the maximum capacity payment. These may be appropriate for values of the IC index that are above a certain level that is considered to be too high (1.3, 1.4). However, whenever the index gets below this level the investment incentive should be kept constant. Considering the possibility of organizing auctions in case the investment incentive has not been set at the right level is also sensible.

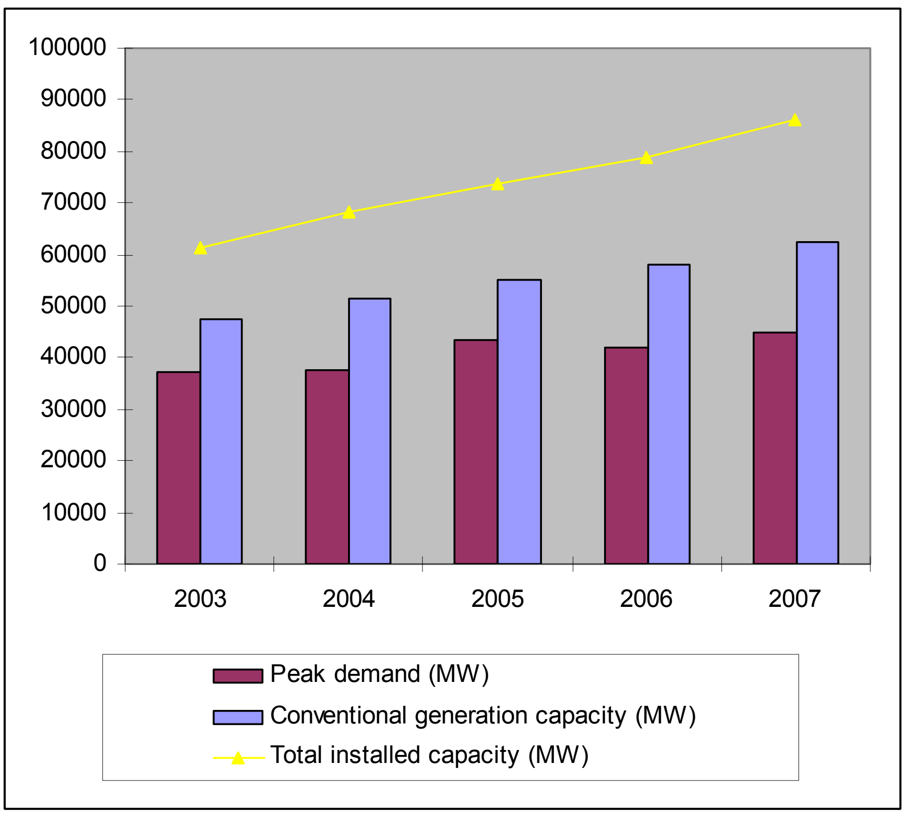

Figure 8: Evolution of peak demand and generation capacity in Spain in the last years

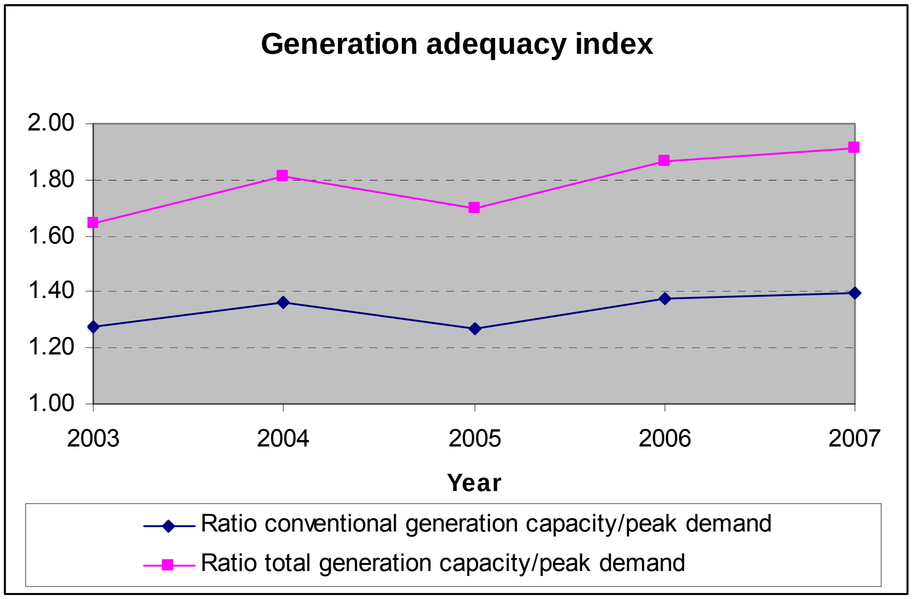

Figure 9: Evolution of the generation adequacy index in Spain in the last years

In the *UK*, there are no additional incentives apart from market revenues for the installation of new generation capacity. Historically the SO approach of publishing the winter outlook and the "Seven Year Statement" has been sufficient to ensure development of an appropriate generation background to support demand. Further incentives may be necessary to support a system with high penetration of renewables (with the problems outlined earlier) but further analysis is required to determine whether this should be some form of capacity payment external to the market. In any case, the UK is committed to a market based approach to system operation and investment, so investigation of whether the existing UK electricity market can provide appropriate signals for investment is essential.

2.2.4 Conclusions

RES/CHP: Pricing of energy and ancillary services

In terms of pricing mechanisms relevant to *energy provision*, in general premiums attached to market prices and TGCs are more efficient than FITs, as generators are pushed towards selling energy when it is more needed, providing suitable support to the overall grid performance. FIT coupled to ToU could be a solution to push generation to follow the grid requirements. In addition, location-based charges or incentives could help improve the overall network operation.

With respect to *ancillary services pricing*, RES/CHP systems do not in general receive incentives adherent to the real value of such services. In particular, market premiums much higher than AS prices would mean no DG participation in system services support. This highlights the need for integrated design of energy and ancillary services markets or pricing mechanisms. In addition, incentive/penalty mechanisms should be designed so as not to unbalance the "normal" grid operation. Similarly, as for instance pointed out by the Danish experience about CHP pricing system in the presence of increasing wind power, pricing mechanisms need to be updated quickly. In fact, in a fast changing scenario, excessive delays in providing adequate policy/regulation updates might cause distorted participants' behaviour and hurdle investments or market access for new high efficiency generation.

Controllability is a prerequisite to AS market participation. However, generators that in theory could be controllable such as CHP do not provide system services because they do not receive enough incentive for it. A mechanism based upon availability payments plus additional contribution in case the service is actually called out might help increasing the share of controllable RES/CHP providing AS.

RES/CHP: Support schemes

Most RES/DG generation technologies would not be profitable for the power plant developer without support. On the other hand, support schemes need to be fitted to the system requirements, so that TGC and feed-in premiums are to be preferred to FITs, otherwise further penetration of RES will be hampered.

Considering the diversification of the generation mix as one of the prioritized options analysed within the RESPOND project, in order to prevent that only low-cost options are realised within TGC mechanisms, gradually increasing targets should help move towards adoption of other DG options. Meanwhile, the higher initial-cost technologies might be supported by FIT-ToU or premium schemes, to help boost generation diversity and efficient system integration of further renewables. In addition, incentives should decrease with time, as typically production costs from technologies such as PV, wind, or even CHP, decrease with learning experience.

If energy prices/tariffs are too high and do not depend on system conditions (FIT-ToU or premiums), RES generators will not be encouraged to participate in ancillary services markets or any other market apart from the energy one, whereas this will be central to the correct operation of the power system.

It is also recommended that compulsory schedules of the expected production are provided to the SO, and that consistent deviations from these schedules are effectively penalized.

RES/CHP: Technical capabilities

In general, there seem not to be major *technical* hurdles to prevent RES/CHP access to markets, also owing to improvements in the capacity of riding through faults or voltage dips, for instance, which were main issues in the past. Whether or not non-controllable units have *obligation* for frequency response, reserve, and so on, depends on the regulation of the specific country, with most severe requirements applied to larger units, in case connected at a transmission level.

If the generation units cannot be controlled, they will be prevented from AS market participation. Technical availability of cheap enabling technologies such as heat storage or electric heaters/heat pumps can increase the deployment of RES/CHP in AS markets.

Conventional generation: Provision of regulation reserves

Provision of regulation reserve from conventional generators is a key issue not to hurdle the diffusion of RES/CHP technologies with their characteristics of (partial) variability and unpredictability.

When provision of primary, secondary and tertiary regulation services is voluntary, failure in achieving enough participation may occur if markets or equivalent mechanisms are not backed by adequate prices, and if too complex prequalification criteria are required. On the other hand, market mechanisms (above all for secondary and tertiary regulation), when correctly in place, appear to work very well, for both single large units and equivalent aggregated units. The main reason is the possibility to accrue high revenues on the balancing markets.

In most countries primary regulation is compulsory, at least for the larger systems, with no 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.

Forecasting techniques prove to be an enabling technology to increase the flexibility of the balancing system and allow more effective RES/CHP penetration and operation. A further point to highlight is that availability of interconnection with neighbour countries enables RES/CHP units to better handle their production, even in the presence of relatively bad forecasts.

Conventional generation: Provision of sufficient generation capacity

Luring conventional generators into guaranteeing the firmness needed by the system in the most critical times (demand high and intermittent generators output not able to supply it) is a delicate issue.

When market approaches are followed, due to high volatility in energy prices it might happen that capital costs are not recovered by generators. If this is the case, new capacity will not be built and older less efficient units will keep on running. On the other hand, if prices in the relevant markets are attractive enough, participation of generation to provide the needed firmness can be achieved. However, also the capacity type plays a key role. Indeed, capacity firmness should be guaranteed in terms of both base-load and flexible/peaking units, in order to guarantee enough flexibility.

Also, systems of imbalance payment/charges with respect to the positions contracted on the wholesale market, which applies in the UK, have been successfully put in place. However, this is enabled by a considerable amount of detailed information that is made available by the SO, so that generators can optimally planning their capacity utilization and contracts. However, further penetration of renewables will increase the requirements for peaking capacity with lower load factor, and the economic feasibility of such units based only on market forces might be at stakes.

In the case market forces were not sufficient to provide incentives to peaking units for firmness provision, system based upon capacity/availability payments or equivalent bilateral contracts between SO and generators prove to be quite effective. Utilization of such non-market tools seems also justified by possible market failures due to incomplete information for the SO dispatching and possibility of consumers to free-ride on reserve capacity.

Conventional generation: Investment in new generation capacity

Availability of and new investment in conventional generators in the presence of consistent penetration of RES/CHP might be endangered, as their overall revenues might decrease, and no additional capacity might be installed, although highly needed. Similarly, installation of base-load capacity rather than peaking plants might not be anyway sufficient to provide the degree of security and reliability needed by future systems.

Capacity payments outside the market aimed at providing system firmness implicitly push towards additional capacity. Indeed, on average such mechanisms increase the price for generation capacity and thus give incentive to new investment. However, 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.

In general, it is advised that further market studies are run to address the potential of only market forces (as it is envisaged for the UK) to push towards additional conventional generation investment in the case of large CHP/RES penetration.

The table below shows a summary of the main generation-related barriers to efficient RES/CHP integration emerged for the different countries surveyed. Columns indicate the classes of response options identified for efficient RES/CHP network integration, while rows indicate the relevant potential barriers to their implementation, as illustrated in the Chapter. However, most of these barriers can be overcome by 2020 by following the indications in this work and other current research activities at the European level. More specifically, only long-term and quasi-irreversible decisions taken now might represent a serious hurdle in the future, such as investments into non-suitable conventional generation capacity as it might be for Germany. Similarly, large deployment of long-term flat FIT support schemes (as in Germany or Spain) rather than (possibly ToU- and location-based) market premium or TGC incentives could lead to future system-related problems.

Table 6 : Generation-relevant barriers to efficient penetration of RES/CHP systems (per country)

	Pricing mechanisms for RES/CHP	Subsidy schemes for RES/CHP	Incentives schemes for conventional generation	General means to increase flexibility
No location-based charges/incentives for RES/CHP	SP, UK, NL			
No ancillary service participation for FIT-based RES/CHP units	SP			
No compensation for load/frequency support for RES/CHP	NL, SP			
No ToU-based FIT for RES/CHP		SP, D		
No ToU-based TGC for		UK		

RES/CHP			
Wrongly designed support mechanisms for RES/CHP	SP, DK, D		
Low market prices or complex criteria for regulation reserve participation from conventional generation		D	
No remuneration for primary regulation service from conventional generation (mandatory)		SP, UK	
No capacity payments as potential means to overcome market failures for firm capacity provision/investment (2020 perspective)		D, UK, DK	
Installation of expected non-economical conventional capacity		D	
Extra payments outside the market not allowed not to alter the playing field with neighbouring countries		NL	
Potentially wrong capacity investment incentives based on reserve margin		SP	
Market-oriented approach that could prevent outside-of-market conventional capacity drivers		UK	
Electric resistance heating banned			DK

3 Demand

Active demand may prove to be central to achieving the integration of a significant amount of renewable generation in the system. Despite the fact that technical capabilities of these generators have improved substantially since they were first installed, the overall flexibility of generation has decreased due to the existence of large shares of intermittent generation. Thus, in order for the system to adapt to changing conditions demand will have to take a more active role.

3.1 Market prices and demand response

Demand response imply getting demand to partly compensate for variations in supply, reducing demand when capacity is limited and marginal production costs high and increase demand when abundant capacity is available and marginal costs of production is low.

In order for demand to react to changes in system conditions, load facilities and communications infrastructure must be updated to allow:

the real time metering of demand;
exchange of information between consumers and the system operator (either at transmission or at distribution level);
the direct control of at least part of the consumption facilities by the market or system operator either via discretionary instructions or through a set of predetermined rules, and
improved access to wholesale markets and exposure of demand customers to real time electricity prices.

Apart from this, new demand technologies should be developed, probably in combination with heat or electricity storage ones, so that consumers can shift part of their load from those hours when energy is more valuable, and therefore expensive, to others where it is less.

In all the countries there are initiatives or research programs to study the possible impact of implementing advanced load control techniques.

3.1.1 Volatile market prices

Looking at the electricity market in general, over time demand and supply changes continually, introducing variations in the marginal cost of producing electricity. Taking the NordPool price region Western Denmark as a case, Figure 11, left, shows an average daily variation in demand and Figure 11, right, shows the variation in electricity production from wind power the second half of January 2007. Assuming a liberalized electricity market and perfect competition, the price of electricity equals the marginal production cost, and the variations in the demand and supply of electricity may be analysed in standard micro-economic supply- and demand-curve set-up. Figure 12, left, shows the effects on the price/production cost of changes in demand and Figure 12, right, shows the effect of changes in production capacity.

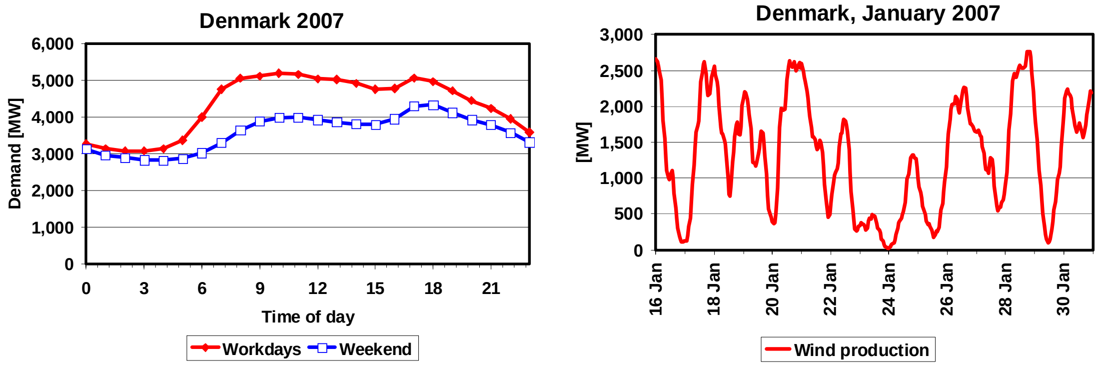

Figure 10: Average hourly consumption curve in Denmark, 2007, and the variation in wind power production the in second half of January 2007.

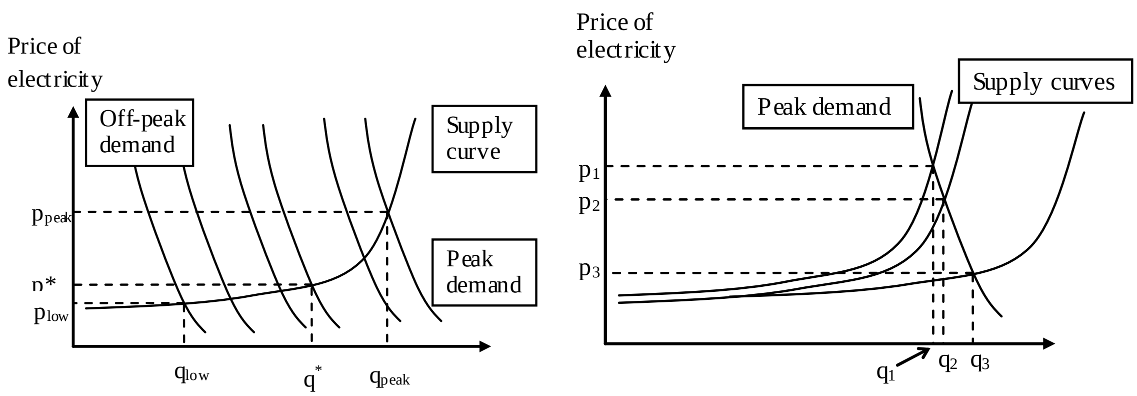

Figure 11 Effects of changes in the demand and supply of electricity.

Variations in demand change the position of the demand curve and imply a positive and systematic variation in the demand and the price/marginal cost of producing electricity, that is, a large demand implies a high marginal production cost and price. The supply curve changes position due to changes in available supply capacity, e.g. changes in the supply of wind power, and this generates an unsystematic negative correlation between the price and quantity consumed. That is, in periods with a large wind production the cost of producing the marginal kWh is low and so is the price. An increase in the amount of intermittent RES and DG production will increase the variation of the supply curve, increasing the variation in the electricity price/marginal cost of producing electricity.

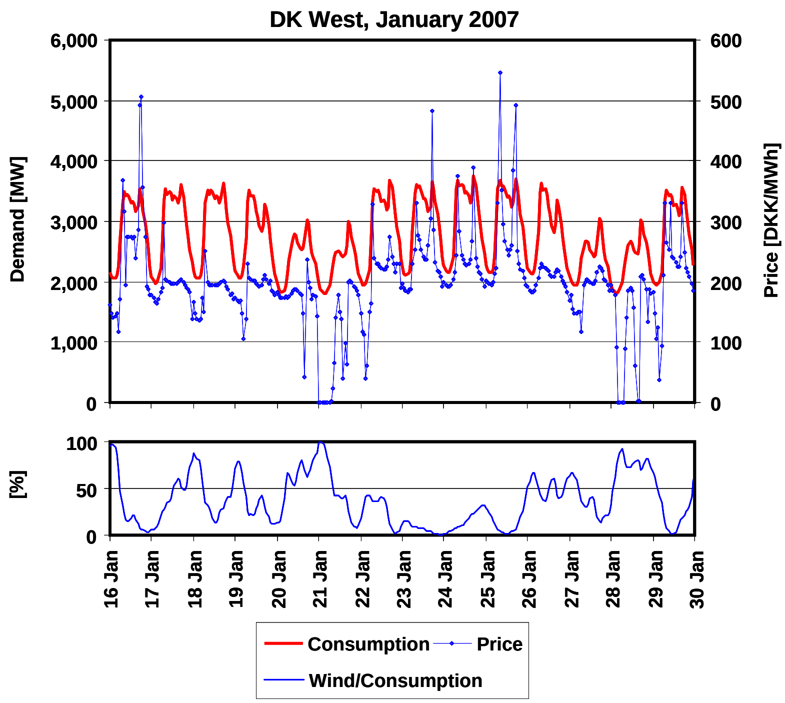

Figure 12: Hourly Nord Pool prices, consumption, and wind power production in West Denmark in the second half of January 2007.

Combining demand and supply changes and looking at an extreme period in West Denmark, Figure 13 shows the hourly variation in demand, wind production and prices at the day a head Nord Pool market the last two weeks of January 2007.

From this figure three important observations are:

- a systematic daily and weekly variation in the demand and price of electricity
- peak prices that are unsystematic in time and often related to limited wind power production
- low or even zero prices that are unsystematic in time and often related to a large production from wind power

Demand response imply getting demand to partly compensate for variations in supply, reducing demand when capacity is limited and marginal production costs high and increase demand when abundant capacity is available and marginal costs of production is low. Consequently, the variation in the price/marginal cost of producing electricity is reduced. Increasing demand response or flexibility of demand is one way to allow for more fluctuating/intermittent production in the system without the price/cost of production becoming very fluctuating. In a liberalised market an instrument for doing this is the price of electricity. However, the three “observations” reveal problems with different barriers requiring different technical solutions and different designs of incentives. Other dimensions of demand response are the response time needed and the type of customers targeted, e.g. response within minutes or day a head and large industrial customers or households. Again, this defines different barriers requiring different incentives and technical solutions. In this section, the main focus will be on demand response within the day a head market. However, a few issues related to shorter response times will be included.

Looking at the chain from the electricity market to customers, for customers to react to the cost of producing electricity three requirements are

- metering at the relevant level of time-intervals
- pricing/billing according to the varying costs of producing electricity or other incentives for changing consumption
- technical possibilities for customers to change consumption – includes automatic response on signals from the system operator.

For each of these requirements a number of barriers for demand response exist, which are addressed in the following

3.1.2 Interval metering and communication technology

Today many customers have quarterly or annual metering of their electricity consumption and therefore face an average price for their consumption. To have incentives for changing consumption pattern interval metering and a corresponding pricing is required. That is, a first barrier for increasing demand flexibility is the introduction of interval meters.

Current programmes for smart meters

The present status and plans for the introduction of interval meters differ considerably between countries.

In *Italy* around 30 million old electricity meters is being replaced by new interactive digital meters that record hourly consumption. In 2004 about half of the meters were replaced. Due to the large number of meters and the systematic replacement of old meters, the cost of new meters is reduced. In Italy a main argument for the replacement of meters is the automatic reading of meters and an increased security of correct metering.

In *Spain,* an implementation plan for the replacement of old meters with smart meters before December 2018 has been decided. For each DSO 30% of the meters should be replaced before December 2010, In 2012 additional 20% should be replaced and in 2015 further 20% should be replaced. Finally the remaining 30% should be replaced before December 2018, and demand response mechanisms should be fully operational by January 2014.

In *Denmark,* all customers with an annual consumption above 200,000 kWh had hourly metering of their consumption in 2004. In 2005 all customers with an annual consumption above 100,000 kWh had hourly metering. For small customers the situation is somewhat diffuse. Some of the DSOs have started replacing meters for private customers and have plans for all meters to be replaced, but other DSOs appear to wait. The Ministry encourage DSOs to introduce smart meters. However, it is the responsibility of DSOs to replace the meters, and the cost of metering should be reduced. The main purpose of interactive smart meters for DSOs is reduced costs for collecting information on consumption and that the new meters opens the possibility for billing actual monthly consumption instead of on account billing and a later adjustment. Also a faster accounting in relation to moving address is one of the advantages of the new meters. Hourly metering of consumption of small customers is at present not very common, the meters are able to record hourly consumption. However, the collection of data on hourly consumption requires additional it-resources. Whether advantages of hourly recording are able to pay for the additional investments and operational costs remain to be seen from present projects.

In the *Netherlands* connections with a transport capacity of 0.1 MW and network connections larger than 3*80 A (equivalent to some 500,000 kWh per year) are obliged to use smart meters. For small customers, a large scale roll-out of smart meters was scheduled for the period 2009-2015. However, this schedule has been suspended for fine-tuning of the functional requirements of the meters. For now, only demonstration projects involving smart meters are carried out.

In *Germany* the situation is quite different. The legislation on metering has been liberalized, implying that customers may choose to install smart meters. That is, there is not a general scheme for replacing existing meters, and smart meters will be installed mainly in relation to new installations or by customers that evaluate they may gain form hourly metering and prices. However, in six regions a demonstration project, called E-Energy, with smart meters showing the hourly electricity price has started giving customers incentives to change consumption according to costs of generation.

In the *UK* industrial and large consumers will typically have half hourly meters, and will be billed by their energy supplier accordingly. These meters are not explicitly “smart” but will be linked to an Energy Management System of some sort. The main obstacle to speedy adoption of this type of technology is the separation of meter ownership away from the network operator. Energy suppliers have responsibility for the metering system and mandating suppliers (operating in a liberalised competitive marketplace) to undertake wholesale replacement of all metering technologies against some kind of prescribed scheme is likely to be a long and complex process.

In general, the main barriers for smart metering are associated with the lack of experience in large scale deployment of these equipments. Moreover, some technological difficulties still exist regarding equipment and communication protocol standardization and solutions to manage such large volumes of information

Arguments and counterarguments for widespread use of smart meters

The status and plans in the different countries mirror a number of pros and cons of smart metering. In countries with a general roll-out of new meters, main arguments are automatic reading of meters, increased security of correct metering, billing of actual consumption and avoiding on account payments and faster accounting in relation to moving address. These advantages of new meters are related to billing of customers, and actually require monthly or quarterly readings, only. Finally, to prepare for future flexibility of demand requiring hourly readings is another major argument for replacing existing meters. However, this implies increased costs of data handling and quality control of measurements.

Looking at countries that hesitate to replace old meters, a number of barriers may be listed. The cost of replacing a meter is evaluated to between 100 and 200 Euro/meter (depending on the new meter and the scheme of replacement; a general roll-out is cheaper than a more diffuse replacement), and this may not be covered by potential savings. Other barriers implying that the replacement of meters may be postponed are that a number of standards and technical issues remain to be decided. What is required for the meter to be adequate, shall the meter just measure consumption, should it be measured hourly or within shorter time-intervals (15 minutes is required if customers are to be engaged in the regulating market), should it include the possibility of receiving a price-signal, should it include controlling individual appliances, or should the additional functionalities be handled by other technical solutions? That is, what is the present requirement, what is the future requirement, what should be included in the meter, and what is best solved by other technologies? What communication technology is preferred, power-line communication, sms-communication, optical fibre communication, or some other communication technology? Finally, software for communication and the handling of hourly readings exist, but experience with full scale implementation covering millions of customers is limited, and routines for updating and maintenance of software and meters are also limited. A completely different issue that may postpone a decision to replace old meters is who pays for the meters and who gains what from changing meters?

Summing up, the introduction of smart meters is one of the technologies that can be used for the demand to become flexible. In the future, technologies facilitating even small customers to become flexible are expected in the marked. However, replacing existing meters now is expensive, and in the future requirements to the functionality of meters may change. That is, replacing existing meters is a preparation for future developments, but at present future requirements are recognised partly, only. On the other hand, if everybody postponed the introduction of smart meters, experience with hourly metering systems, recognition of problems, future requirements and possibilities is postponed, too.

A supplement or alternative to smart meters would be electric appliances that can respond automatically to signals from the system operator.

3.1.3 Heat or electricity storages

Electricity and heat storages are key technologies to enable consumers to react on TOU pricing. Many countries have a long tradition for time-of-use pricing with low prices during night time. A key technology has been electric storage heating with ceramic heat storage, which was charged during the night and discharged during the day. Heat storages are often used by CHP generators to allow flexibility in electricity, , and thus benefit from variations in electricity market prices. Vehicles using electricity also have the potential for flexible electricity demand at the diurnal level. The basic technologies have existed for many years, but little market penetration has yet been experienced.

However, the use of heat or electricity storage devices is limited in consumption facilities in most of the five countries.

In *Denmark* and *Spain* there are no storages in consumption facilities. Electric storage heating has never been used in *Denmark*, and direct electricity resistance heating, which has some short-term flexibility, is limited. In addition electric heating is discouraged by programmes for conversion to other types of heating, preferably district heating, where available.

In *Germany* cold and heat storage do not play a major role, yet. Electricity storage is mainly investigated in form of pumped hydro storage, batteries for mobility and fuel cells. Also the possibility of adiabatic compressed air storage is investigated.

In the *Netherlands* agriculture and horticulture CHP units (1840 MW in 2006) are primarily used for heating of greenhouses and producing CO2 to enhance growth. These units usually dispose of heat storage and may be considered as consumption facilities. Besides, micro CHP units with Stirling motor will be installed in the future (developers expect 10.000 units are placed for field tests before the end of 2010). Typically units have a size of 1 kWe and 5 kWth. There are also some tests with micro CHP units with heat storage in boilers, which improves the possibilities of micro CHP for electricity production. The Smart Power Foundation is a Dutch network of companies and organisations involved in developing intelligent control, primarily of micro-cogeneration units, but also focussing at other sources of flexibility. ECN is working on a concept for an electronic market to integrate distributed generation and load control into energy and system services markets. Both SPF and ECN are in a stage of pilot projects.

In the *UK* some storage facilities are being explored as part of the IFI / RPZ programme of R&D. The historic Teles-witching programme made use of electric heat storage capabilities in UK homes. There are no current plans for widespread roll out of heat / electricity storage facilities. Although a recent government consultation on the treatment of heat did address this area, and a publication from a prominent UK campaigning organisation (Greenpeace[1]) highlighted the potential for CHP and heat network in the UK. The most important obstacle to electricity storage is clearly the cost of such devices. Heat storage although more feasible in terms of cost does not fare much better because of the limited interest in heat networks in the UK (traditionally community heating schemes reliant on CHP and heat networks have had very bad public approval rating).

3.1.4 Pricing rules and incentives.

Demand must receive information on the market value of energy and system services at all times and places in order to change according to system conditions. Therefore, energy and ancillary services prices should vary according to their value at each moment in time and in each part of the system.

Pricing rules

Having interval metering, for customers to react to the varying costs of producing electricity the price customers pay for their consumption has to reflect the varying costs. Aiming at different types of variation in the marginal costs of production a number of pricing rules have been developed.

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[1] The summary of the report is available at www.greenpeace.org.uk/files/pdfs/climate/industrialCHP_summary.pdf

Time-of-Use tariffs

Focusing at the systematic daily/weekly variation in costs (reflecting shifts in the demand curve) Time-Of-Use (TOU) tariffs is developed. According to TOU-tariffs the day/week is divided into pre-determined periods with different tariffs. Typically, three periods are defined, peak hours with a relative high price for electricity, a medium priced period and hours with low demand (night hours) and a low price. Knowing the price in advance, customers have an incentive to change behaviour and postpone consumption till periods with a lower price, thereby increasing demand in periods with low prices and decrease consumption in periods with high prices.

Barriers for shifting demand are mainly barriers for shifting behaviour, and that not all consumption may be shifted in time. For households, some of the consumption related to heating, hot water, washing, dish-washing may be shifted, but consumption related to lighting and many household appliances is difficult to postpone without significant loses of welfare. For companies and industrial customers, shifting demand in time may be very costly, but examples do exist e.g. cold stores may postpone some of their consumption to periods with low prices. An advantage of TOU tariffs is the low information costs related to the tariff, and in principle it may be applied to all customers.

In *Denmark* there is no tradition for TOU pricing for households. Billing for most customers is based on single annual readings of the meters by the customers themselves. Smart meters are being tested in some parts of the country, but mainly for other purposes that the introduction of TOU pricing.

In *Germany* some distributers offer a special night tariff.

In the *Netherlands* a simple peak/off-peak tariff is available mainly for households (peak periods are working days from 07 to 23 h.). Analysing the effect of TOU on shifts in demand, in general price-elasticities are reasonable high that is customers change their demand pattern.

In *Spain* TOU tariffs is used intensively and differentiated among customers according to their contracted capacity, i.e. the maximum active power consumption at a certain period. Very large customers with a contracted capacity of 20MW and over 5MW in all periods may choose a seven period tariff. Industrial customers have several possibilities depending of their size. For large industries a five period tariff is available, for small and medium sized companies two different three-period tariffs are available, and for small companies two additional two-period tariffs are available (between 15 kW and 50 kW of contracted capacity). Low voltage customers with a contracted capacity below or equal to 15 kW and households may choose a two period tariff.

Final consumers in Spain that do not buy their energy at the market, that is to say excluding large industrial consumers, pay regulated “integral” tariffs. These charges included Use-of-System costs, energy price and other services (market operation, stranded costs, RES support mechanisms…). These regulated prices are published periodically. Although due to political reasons of inflation control, during the last years these tariffs have been set below the real energy prices thus creating a tariff deficit.

However, at the beginning of 2009 regulated tariffs will disappear, except for low voltage consumers. For these consumers, a last resource supplier will be created.

Time-of-Use (ToU) tariffs exist in the *UK*, although mainly for large consumers. Because of the liberalised and competitive environment in the UK there are a variety of tariffs that industrial consumers in particular can sign up to, ranging from exposure to wholesale prices, to TOU differentiated products based on usage during peak periods. The most common tariff encourages large customers to avoid consumption during the "triad" period – which is the peak period during winter (typically between 17.30 and 19.30). In addition to this there are TOU meters linked to an old domestic tariff known as Economy 7[1], for customers with electric storage water heating. These customers were controlled through radio tele-switching. For the bulk of domestic customers there is no temporal differentiation. Those with tele-switch meters and on Economy 7 tariffs will have cheaper power during the night.

Final (domestic) consumers do not buy their energy in the wholesale market, but through energy suppliers operating in the retail market space. The final charge they pay is inclusive of use of system tariffs and network charges plus additional charges from the supplier (for metering and customer services etc). However energy supply is part of a liberalised competitive market, so these are not "regulated" prices. Customers are free to move to an alternative supplier that offers a more favourable tariff. Price comparison websites (and the industry watchdog) publish up to date information on all domestic pricing tariffs. Recently the Energy Supply industry has undergone investigation by the regulator, accused of artificially inflating prices and restricting the competitive market. If successful the regulator could force supply companies to surrender a proportion of these profits – the current situation is inconclusive.

A survey of empirical analyses of price-elasticities of short-tern varying electricity prices may be found in U.S. Department of Energy (2006)[2] Related to the integration of fluctuating electricity production, TOU tariffs facilitate additional production by shifting demand from normal peak to off-peak periods. However, the demand shifting does not reflect the un-systematic fluctuations/shifts in the production curve, and this limits the ability of TOU tariffs to integrate additional fluctuating production.

Reflecting some of the shifts in the production curve, examples where the TOU tariff is supplemented by a Critical Peak Price (CPP) exist. In France the Tempo tariff defines a day and night tariff that varies with three types of days; normal, expensive, and critical days where the price at critical days is about 10 times the normal day. The type of day is announced the day before. Another example is the GoodSent Select system used by Gulf Power in Florida. This tariff defines four levels where the most expensive hour is 6 times the low tariff and where the most expensive hour may

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[1] Economy 7 is a cheaper night time electricity tariff operating in the UK. The tariff operates typically from midnight and lasts for 7 hours, hence the name. During this period electricity costs less than the standard daytime rate, normally about a third of the cost. Appliances such as electric heaters and boilers are configured to operate and store heat during the cheaper period. Any electric appliance can make use of the cheaper electricity, such as washing machines and dishwashers

[2] "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them", http://eetd.lbl.gov/ea/EMS/reports/congress-1252d.pdf.

occur 1% of the year. This tariff is supplemented with a communication system that is able to disconnect certain appliances (e.g. air conditioners) when the price peaks.

Wholesale market prices

In a liberalized market expected demand and supply is normally cleared in a day-ahead market generating a production plan for the next day and forming day a head prices of electricity. These prices reflect expected systematic and un-systematic variations in demand and supply. Exposing customers to day-ahead prices gives an incentive to reduce demand when capacity is constrained and the price high and increase demand in periods with free capacity and a low price. In several countries (e.g. Denmark and Norway) at least large customers are offered a tariff reflecting the day a head market price. However, some reluctance to choose and react to hourly price variations is observed. Two major barriers for customers to react to hourly day a head prices are 1) costs of information and 2) costs of short term adjustments in consumption.

In addition, the day-ahead wholesale price does not fully reflect the variations of the costs for the system to deliver electricity to small customers.

Customer behaviour and welfare

Exposed to hourly prices, the customer has to obtain information about the development of prices. To react to the price a change in planed behaviour is required. For small residential customers costs of information may appear quite high relative to the potential saving. However, a number of technical solutions reducing information costs are available. For large industrial customers changing consumption pattern may have considerable consequences for production planning. Still, for some large customers some of their consumption may be moved in time without severe consequences.

Other barriers mentioned in the literature are volatility of bills and transformation of welfare between customers. Concerning volatility of bills, a flat rate is just an agreement on how the bill is settled. If the flat rate is calculated ex-post (the average price of electricity over the last period of consumption) on average for all customers, volatility of bills will be the same as under an hourly pricing. A flat rate agreed prior to delivery obviously reduces the uncertainty and volatility of the bill. However, this includes an insurance premium comparable to the difference between ex-post and ex-ante flat rates.

Concerning transfer of welfare between customers more than half of the customers may be worse off with an hourly pricing than with a flat rate (Borenstein 2007). This is a barrier for getting customers to choose an hourly pricing. However, the transfer of welfare between customers is actually what is wanted. Customers with a large demand when prices are high will pay more and vice versa. This gives customers with a high demand in periods with high prices an incentive to reduce consumption.

Another type of barriers is risk adverse behaviour at the company level – who gets blamed when prices and costs are high, and who is rewarded when prices are low and costs reduced. Often managers decide to do what they always have done or what competitors do.

That is, giving customers a free choice between an hourly and a flat rate may not be an optimal solution if it is evaluated that demand response in the day-ahead market is profitable in the long run or needed for the integration of additional intermittent production.

Customer preferences

For many customers major barriers for increasing demand response are a limited total gain from shifting demand and that, due to fixed price additives, variations in prices seen by the customers are dampened relative to the marginal costs of producing electricity.

Looking at Denmark, the average annual consumption by households is approximately 3600 kWh per household. With an average Nord Pool price around 0.035 EUR/kWh and the price variations seen at the Nord Pool market today, the maximum saving from shifting demand between hours is fairly low. In Norway and Sweden, where household demand is larger and the share of electricity used for heating is larger, potential savings from shifting demand is larger. Still, savings are quite limited and investments in metering and automatic control of consumption should be related to these savings.

Looking at what customers pay for electricity, in addition to the variable price at the market (for Danish customers the Nord Pool price) customers pay for subscription, transmission/distribution and taxes. In Denmark these additions to the market price vary between customer categories, and are (except for VAT) fixed payments per kWh. For households the fixed additives is approximately 80% of the electricity bill, for large companies the fixed additive is less than 50% of the bill. Fixed price additives dampen the relative price fluctuations that customers see. Therefore, an option for increasing the incentive for customer flexibility is to reduce the share of fixed additives; transmission/distribution payments may vary with loses in the grid, and taxes may be changed from fixed additives to a VAT type. However, increased volatility of bills also increases uncertainty in income to distributors and the government. Also, welfare changes between customer categories may be a barrier for shifting from fixed to VAT-type taxes/additives.

3.2 Managing system security

As the time of reaction gets very short, incentives based on a market price become inefficient and incentive based programs with predetermined actions or centrally controlled reactions become more effective. In incentive based programs a reservation payment or a discount on the price is agreed between the customer and the TSO, and the customer has to reduce demand from the grid when asked to do so by the TSO. In these programs focus is on security of supply and reaction times are from seconds up till 15 minutes where after fast reserves may be started. Incentive based programs are elaborated in many ways; direct load programs like mass market direct load control programs, curtailable load programs and interruptible programs and frequency controlled demand response programs. Mass market direct control programs targets residential and small commercial customers with equipment that may be turned off for a limited period of time. Examples are water heaters, electric heating, refrigerators, and swimming pool pumps. Switches and communication lines are installed and controlled directly by the party calling for load reductions. In most programs customers agree to a limited number of events per season and earn a credit or a payment for participating. In some cases also a payment per incident is given.

Looking at real-time pricing (or more precisely near real time pricing), customers are asked to react to market problems and high marginal production costs within an hour or 15 minutes. This requires that customers have a special flexibility, and very few customers are able to react with this short notice. In most cases these customers are characterised as being able to act as reserve capacity in the regulating power market; they may cut off demand for a shorter time-period when called upon. Examples are cold stores, greenhouses and customers with back-up capacity producing their own electricity when needed and therefore reducing the demand from the grid. Often, in addition to saving costs when prices are high, customers that are able to react within this short notice are given an additional payment for providing reserve capacity or regulating power market services.

3.2.1 Interruptibility of contracts

Curtailable load – and interruptible programs targets large commercial and industrial customers that are able to reduce their load with 100 to 1000 kW, and given a notification time the customers are asked to reduce consumption. Communication may include telephone, fax, and email or direct control. If the customer control the reduction, metering enabling the calculation of load reduction relative to baseline consumption is required.

Selective load shedding is the last measure any SO resorts to in order to avoid major safety problems in the operation of the system. Consumers with elastic demand may be willing to accept certain limitations to the supply service in exchange for discounts or other type of benefits. Signing interruptibility contracts may be useful to discriminate among consumers according to their demand elasticity and thus incrementing the social welfare of the system

In *Denmark*, only very few large consumers made use of this possibility of interruptibility contracts.. For small consumers the technology is available, but it is yet to be seen, how it should be implemented. It has been the topic for some studies and discussions a few years ago. A Danish example of interruptible contracts is the Flex demonstration project, where a brewery, a cold store, an ice skating ring, a supermarket, and a water supply plant plus a number of back-up generators have agreed to reduce demand from the grid when called upon by the TSO. In the management of the system the TSO uses these resources as regulating power.

In *Germany* industrial consumers have sometimes special interruptible contracts with generators in response for lower prices. The technology for interruptible contracts is being studied within a major three year demonstration programme on load management called E-Energy has started. In six model regions the load management will be investigated, mainly with the help of smart meters which will show energy prices and thus incentivise to follow consumption according to the generation.

In the *Netherlands* demand response is mainly applied by the industrial sector and horticulture sector (switching-off assimilation lighting). Large industrial interruptible demand participates in the market for reserve power. The TSO is currently contracting 300 MW of wholesale demand response reserves as so-called emergency reserves. The minimum desirable contract size for emergency power is 20-25 MW. Also aggregators/pools may provide emergency power, each pool participant should have at least 5 MW interruptible load available, and 100 MW as a maximum. Households and small businesses cannot participate in the emergency reserves due to lack of technological infrastructure (e.g. smart metering) and communication infrastructure to deal with the large amounts of data resulting from smart metering.

Suppliers of emergency power are remunerated according to the measured energy supplied. As a rule the remuneration is set on Imbalance settlement price for positive power + 10% (or minimum contract price) for each programme time unit (PTU) during the disconnection period (TenneT, 2008). Furthermore, business customers can sell interruptible demand to the supplier in exchange for a payment before interruption as well as a payment after real curtailment. As a supplier is part of a Program Responsible Party (PRP) in that way the imbalance of the PRP is reduced. Consequently, the TSO has to deal with less imbalance and system security is promoted (Deloitte, 2004).

In *Spain* currently, large consumers connected to high voltage networks with a contracted capacity of over 5 MW can sign interruptibility contracts. In exchange for a discount in their electricity bills, they commit to reduce their active power consumption in system emergency situations as a request from the System Operator or Distribution companies. From next 1st July 2008, when tariffs for large customers are disappearing, a new interruptibility service has been defined for large customers into the market. In this new service there is a new type of interruption with 0 min warning time and 1 hour interruption time. This makes a total of five types of interruptions possible depending on the interruption time and the warning time. In 2007, 211 large consumers consuming a total of 36,496 GWh in 2007, offered an estimated interruptible load of 2,800 MW in peak hours.

Consumers under an interruptibility contract receive a discount on their total annual electricity bill. This discount is proportional to the total load they are willing to reduce related to their real consumption. They may also receive a large penalty if the terms of the contract are not satisfied, which may be up to 120% of the discount already received. However, discounts are not geographically or time differentiated, and a market mechanisms to assign interruptibility contracts may be useful. As an example, last 19 November 2007, two interruption orders were sent to all customers in the Iberian Peninsula in two groups. The first order was sent from 17:40h to 20:40h to more less half the interruptible customers in the Peninsula and the second one from 19:00h to 22:00h was sent to the other half. A total estimated load of 2.400 MWh was interrupted during 19:00h and 20:40h.

The barriers to the development of DSM, the Spanish implementation plan for smart meters and related research initiatives have been previously described are section 4.1. The System Operator may not address directly to small customers so it is important to define the role of an agent having the commercial relation with small customers, such as an aggregator or a retailer.

In the *UK* large consumers connected to the transmission system can sign interruptibility contracts. They can also participate in the balancing mechanism (the real time system balancing market) with Bids (amount they will pay to increase demand) or Offers (amount they want to be paid to decrease demand). Any large demand customer that is a signatory to the Balancing and Settlement Code (BSC) can participate in the balancing mechanism in this way. Very few loads do this – most which can offer interruptible load services will opt for a bilateral contract with the SO.

Consumers will typically get an availability payment, and a call out fee if the load is interrupted. If consumers participate in the balancing mechanism they will be paid according to their offer in the market. For small customers this would require advanced metering infrastructure that is not currently available in the UK – see comments on the smart metering pilots in the UK and the lack of interaction of the network operators.

In general, the technology for interruptibility for small customers will be similar to demand response technologies in general. These are likely to become widely available in a few years from now. The main problem is not lack of availability of technology, but willingness of customers to accept interruptions. Furthermore there is a tendency to overrule interruptions in current experiments with interruptibility contracts for small users. Since the interruption of a service will actually affect comfort levels of customers, it is likely that those forms of demand response in which the service levels are not affected will be preferred by small customers (for example: shifts in the timing of the operation of an electric heater or airconditioner, while the room temperature remains within the temperature settings).

As smart meters and advanced demand response mechanisms are developed, new possibilities may arise for small consumers. Partial load shedding of domestic consumers would require that these technologies become fully developed and consumers have realized the benefits they can obtain from them. In the future, home automation networks together with smart meters would create an Advanced Metering Infrastructure. AMI is characterized by two-way communication between the equipment at the consumer's side and the SO. Needless to say, consumers have to perceive enough incentives in this regard, being these economical or environmental. An additional issue that must be addressed is the role of the retailer regarding these contracts.

Finally, in frequency controlled demand response programs, specific electric appliances are automatic disconnected for a shorter time during system contingencies and drops in the net-frequency. In Britain and Finland examples where industrial technologies are used as frequency controlled demand response include industrial ovens, pumping systems and metal works. Considering household appliances freezers, refrigerators and water heaters may without problems be disconnected for a shorter time. Frequency controlled disconnection has the advantage of giving a very quick response (within seconds) and may be used until other reserve capacity can be started. That is, frequency controlled disconnection is related to system contingencies and has a limited duration per incident. Increased intermittent production does not necessarily increase the need for frequency controlled demand response, but the need for demand response with a short time of notice may increase with capacity restrictions becoming tighter e.g. in periods when intermittent capacity is not producing.

3.2.2 Access to ancillary service markets

Electricity load may provide ancillary services, especially if it is combined with some form of energy storage. In fact, consumers in many countries must comply with certain requirements regarding, for example, their load factor, while they are remunerated for performing better than the required level. Using energy storage may help consumers provide regulation reserves while installing capacitors could allow them to contribute to voltage regulation.

In *Denmark* specific markets for ancillary services are not yet developed. However, most reserve balancing requirements may be solved by the regulating power market, which is a part of the integrated Nordic market, and the national balancing responsible parties.

In *Germany* industrial consumers, depending on their contract with the distributer, have to adapt their consumption profile. Also, they can have contracts for their reactive power consumption. Household consumers are not forced to comply with certain technical requirements regarding their consumption profile or their active to reactive load ratio.

In the *Netherlands* connected parties to the network (without generating units) shall satisfy specific requirements with regard to their active to reactive load ratio; specifically the power factor of a connected party shall vary between 0.85 (lagging) and 1.0 at any time (Paragraph 2.1.5. of the Network Code). Large consumers (with capacity of 60 MW or more) connected to the HV network are obliged to inform the TSO, through bids a day in advance, of their capacity to reduce their consumption (size of demand reduction and respective price). The bids (size and price) can be adjusted up to an hour before the PTU the adjustments concern (paragraph 5.1 of the Network Code). For consumers connected to the HV network and with capacity less than 60 MW, their involvement in the balancing market is voluntary. Upon voluntary participation, the same process shall be followed as for larger consumers.

The main obstacle in the realization of demand response services in the Netherlands presumably will be the lack of the required communication infrastructure between consumers and SO, the high amount of metering data and associated costs, and the high transaction costs of contracting small consumers for demand response services.

In *Spain* only large consumers connected to high voltage networks with a contracted capacity of over 15 MW are obliged to fulfil certain voltage requirements: for peak hours the should not consume more reactive power than 33% of the active power (keeping a power factor greater than 0.95 lagging), in valley hours they cannot produce reactive power into the high voltage network (leading power factor not allowed), and in plateau hours their power factor should be greater than 0.95 lagging while the leading power factor is not allowed. Small consumers are not allowed to participate, only generators belonging to a control area. For this reason, and the investment it requires, at the moment no consumer is participating in the secondary reserve market. Concerning the tertiary reserve market, it would be more plausible that the consumers participate in this service since for this service it is only necessary to modify consumption profile in 15 minutes time. However, only pumping units are allowed to participate in the market.

For consumers in the *UK*, there is no certain technical requirement to the consumption profile, ,but in terms of power factor, large customers should operate within 0.95 p.f lag to unity power factor. Reactive power charges will be levied if the operating power factor exceeds the limits. Small consumers are allowed to participate in the provision of secondary reserve. Typically they would participate through an aggregator. Several such commercial aggregation companied exist in the UK (e.g. flexitricity[1] and Gaz de France). The conditions that they must fulfil to participate are the same as for generators wishing to provide these services. There seems to be little interest from the part of medium to larger scale demand in offering these services (aside from those that are already offering high value interruptibility services). The SO has initiatited a number of schemes to try and make offering AS more attractive to demand with little success despite good engagement with demand customer through working groups. On the domestic customer side the lack of widespread half hourly metering or AMI (advanced metering infrastructure) makes this activity impossible at present.

In general, the main obstacle is the investment for the AGC control system that is required between the system operator and the consumer plants and processes. It would also imply technical challenges of the remotely controlled disconnection-reconnection devices. Thus, consumers can provide negative reserve to the ancillary service market. However, participation by consumers are not prepared from a technical point of view, lack of communication infrastructure.

3.2.3 Direct control of consumer equipment

As mentioned earlier consumers may not react on the information from smart meters or incentives from price signals depending time-of-use or wholesale market prices. In particular for small consumer technology for automatic control will be needed. However, the use of such equipment may not necessarily require smart meters or time-of-use price incentives.

Modern electric equipment for households is often equipped with a computer chip that directly and indirectly control electricity consumption using various algorithms. If there algorithms can be updated automatically by the electricity system operator (firmware update process) the equipment may add to demand flexibility. The relevant technologies are electric heating and cooling, water heating, cooking, washing machines, dish washers, and tumble dryers. Lighting is less suitable, while home computers in the form of laptops are equipped with batteries that will allow disconnection from the grid for 1-2 hours.

In the future, mass implementation of frequency controlled switches in household appliances, which may be turned off for shorter periods without significant losses for the customer, may increase the potential for short term demand response. However, the implementation of this technology in millions of small-scale appliances requires international standards for communication that must be used by producers of electric equipment as well as DSOs.

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[1] www.flexitricity.co.uk

The US Electric Power Research Institute (EPRI) is conducting a project "Enabling DR-Ready Appliances"[1] focusing on demand response (DR) for large end uses that contribute to peak demand. Other projects from EPRI, e.g. "Power Supplies for Consumer Electronics" are focusing on specific equipment, standards and software development.

A key issue is that experience suggests that customer reluctance to have unknown controls installed in their homes or businesses represents a barrier to more widespread participation in utility DR programs. However, these barriers would be overcome if major energy consuming appliances came ready to participate in DR programs out-of-the-box ("DR-ready").

Even with public acceptance of this control equipment a significant barrier for their use will be the limited operational experience by system operators in their communication with all types of customers, and the development of international standards for this type of communication will take time.

3.3 Conclusions

Metering and communication

Hourly meters are a precondition for exposing customers to the varying costs of producing electricity and new meters are being introduced in many countries. In most countries the main argument for changing meters is savings related to the billing of customers. Other arguments relate to future possibilities for automatic response and increasing demand flexibility. Still, communication standards and the functionality of meters is an issue, and handling of hourly metering for all customers is a challenge.

Pricing rules and incentives

For customers to react to the varying costs of producing electricity, prices have to reflect the variations. A number of pricing rules has been developed TOU, CPP, Day ahead market prices. Reflecting both systematic and un-systematic variations in the cost of production from a theoretical point of view day ahead prices are preferable. However, information cost of following hourly market prices is not negligible. Given hourly metering customers should be exposed to hourly market prices even if they do not react to the hourly variations. Customers with a high consumption in expensive hours will pay more than the average customer and therefore have an incentive for reducing consumption, mainly in expensive hours. That is, there will be a transfer between customers that from a theoretical point is preferable.

Calculations of short term gains from shifting consumption in time reveal that at present gains are quite limited. That is, in order to get customers to react on hourly prices, additional incentives are required. Market prices alone are not a sufficient incentive for customers to become flexible. An issue is fixed price-additives like grid-payments and fixed taxes that reduce the relative variation in the prices customers

[1] http://portfolio.epri.com/ProgramTab.aspx?sId=PDU&rId=117&pId=4246&pjId=4254.

pay. Getting these additives to follow system conditions will increase the incentive for customers to become flexible.

With a very short response time, prices become an inefficient instrument and incentive based programs like interruptible contracts and automatic or centrally controlled disconnections are being developed, but years of operational experience will be needed as well as development of industrial standards.

Table 7 summarises the main barrier that has been reported for the five countries.

Table 7 : Barriers reported by country studies concerning demand response

Barrier	Technology/ Investment	Legislation/ Regulation	Consumer behaviour/ Acceptance
Limited roll out of hourly meters	Denmark, Germany, Netherlands, UK		
Liberalised market for hourly meters with no standardisation		Germany	
Disputes about standardised metering functionalities without increasing costs too much			Netherlands
Electricity price regulation		Spain	
High excise tax per kWh for households		Denmark	
Limited response by consumers to price signals			All countries
Consumers are risk averse, and prefer a tariff known in advance		.	All countries
Variations in wholesale market price and costs of ancillary services as a mark-up to an annual calculated price per kWh		All countries	
Very limited heat and electricity storages in consumer facilities	Spain, Germany		
Electric heating replaced by district heating, natural gas or renewables		Denmark	
District heating has low public acceptance			UK
No specific market for ancillary services		Denmark	
Only few industries suitable for interruptible contracts	Denmark		
Lack of available technology for interuptibility contracts and participation in ancillary service markets for small	All countries		

consumers			

4 National markets

During the last years the generation and market parts of a high number of electrical power systems have evolved from a regulated business into national markets experiencing a number of policy changes in order to improve the economic efficiency of the electricity business. Due to the special features of the electricity product, competitive electricity markets are classified in energy markets and ancillary services markets. Energy markets include day-ahead markets and intraday markets. The most important ancillary services markets, defined as the markets that negotiate additional products necessary to guarantee system security, include balancing markets (which may include different time-scales such as the secondary reserve and the tertiary reserve) and voltage control. In order to increase the efficiency of the electricity business, a careful organization and design of the market must be proposed, guaranteeing a fair treatment to each of the agents participating.

This chapter analyses the main potential barriers found in order to encourage the investment and participation of generation (both conventional and RES) in national energy (daily/intraday) and ancillary service markets. Fair rules enabling market access and enough remuneration in fact provides the necessary incentive in order to achieve a flexible generation mix (including conventional generation, RES generation sources and storage options) and more dispersed intermittent generation that diminish variability and unpredictability of this type of generation sources.

Main potential barriers identified in designing energy and ancillary energy markets are:

- Market access, size limitations and aggregation of units.
- Responsibility of deviations, prediction of production and gate closures closer to real-time

It should be noted that market access issues related to the connection to networks were assessed in subsection 2.1.3. In this chapter market access is treated from the point of view of market design.

4.1 Market access, size limitations and aggregation of units

Currently, renewable and distributed generators are not allowed to sell their energy on some markets because they do not comply with minimum size requirements. Different mechanisms have been proposed and implemented to overcome this obstacle. Generation companies have created virtual power plants (VPPs) which comprise the power production from several (sometimes many) of these small RES and DG units. Aggregate production of RES and DG units is passed on to the market as if a single generation unit existed. Analogously, independent entities have been created to act as market aggregators. These entities sell the aggregate power production of several to many RES and DG units to the market. This power production is far more stable, and therefore far more predictable as well, than that of each individual unit when considered separately. However, designing an allocation procedure that allows one to compute the contribution of each of the generators within a virtual power plant to the provision of energy and certain ancillary services (such as the provision of regulation reserves) is not easy. This would require closely monitoring the dynamic performance of each of these generators. The allocation should be market based in order to maintain the economic efficiency of the system operation and facilitate competition among generators. Transparency of the process, which is central to the participation of RES/DG generators in markets, can be achieved by making relevant market information available to all parties.

Energy Markets

In general, RES/CHP generation is not *directly* prevented to access the energy market. Indeed, in most countries the Regulation has been updated in the last years to facilitate small generators to gain this access.

In *Spain*, no size limitations exist for RES producers to participate in the energy markets. However, actual technical requirements discussed in subsection (such as the inability of some of these generators to cope with small system disturbances and the obligation to install a control centre with direct communication with the network system operator for units above 10MW) must be taken into account.

In the *UK*, 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. Generators above 100 MW are registered as Balancing Mechanism Units. Those that do not sign the BSC will typically form a Power Purchase Agreement (PPA) with another larger entity already trading in the energy market. For small generation connected in distribution networks the PPA will be formed with an Energy Supplier. The Energy Supplier will net the total output from distributed generators from their demand requirements in a particular area. The generator will be paid feed-in tariffs. 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. Generators above 1 MW cannot sell their energy output at the energy markets directly. Concerning communication of RES to TSO/DSO, small scale generators are treated as negative loads and not centrally dispatched.

In the *Netherlands*, there are no size limits applied to the capacity of the units, but there are minimum trading volumes. DG is allowed to sell their energy through an independent aggregator or incumbent energy supplier. They receive benefits from reduced imbalance when they are part of a VPP compared to standalone functioning. This portfolio effect usually is shared between the aggregator and the client. An important barrier in the Dutch market, especially for small DG, is the substantial costs for trading on markets operated by APX (day-ahead and intraday markets) and ENDEX (forward and futures markets). The required AMR facilities have relatively high costs.

In *Denmark*, no size limitation has been reported. The transaction costs for small generators on the wholesale market could be too high, representing a barrier. In this way, virtual power plants are a priority area for the call for proposals for 2009 for the electricity research programme. Small generators can waive the annual participation fee they would otherwise have to pay on Nord Pool (15,000 EUR). Instead, they can opt for a higher variable fee per unit traded (0.13 EUR/MWh). This is of great help as in some other Member States, high market participation fees can be a hindrance to obtain market access for small generators (see e.g. http://www.npspot.com/trading/Trading-fees/).It should be noted that most wind and CHP capacity are owned by the major generators. Apart from transaction costs, no other significant barriers have been reported for Denmark.

In Germany, generators have to sell at least 100 kWh per hour in order to participate in energy markets. Technical constraints are imposed concerning ride through capability, but this does not prevent the participation of the generators in the energy markets.

Balancing markets

Access to ancillary or system services (AS/SS) markets is commonly restricted to those generators that comply with certain requirements. Their production must be *observable* and, in order for them to provide AS/SS, it also has to be *controllable*. Controllability is more a technical than a regulatory or policy problem. The regulating capacity of generators depends on their technical characteristics. Regarding the *observability* of RES/CHP, only the production of those generators that are large enough can be directly measured by the system or market operator.

Participating in the provision of some ancillary services is not possible for some types of renewable and distributed generators unless they are able to modify their active or reactive power output according to the system requirements. Thus, selling upward or downward regulation reserves is not possible for a generator if it cannot increase or decrease its output following instructions by the SO. Analogously, keeping the voltage level at a certain node within certain limits requires increasing or decreasing the reactive power output.

Presently, many renewable and distributed generators are not controllable and thus cannot participate in AS/SS markets. However, big efforts are being done by wind promoters to research the adaptation of wind farms to provide load following services and voltage control. Assuming that from a technical point of view wind generators will be mature in the near future, the participation of intermittent generators requires that present system operation practices are replaced by more modern ones. In fact, some prioritized options outlined by the RESPOND project (real time information on intermittent generation available to TSO/DSO, control systems including intermittent generation and active network management at the DSO level) are related to changing operational practices by system operators. Providing the DSO with the ability to monitor the behaviour of small individual generators could make many RES/DG generators useful for the provision of some AS/SS. Another option to enable RES/DG generators in general, and small ones in particular, to participate in AS/SS markets could be aggregating RES/DG units into larger ones. However, some AS/SS such as voltage control are of a local nature. Therefore, small RES/DG generators willing to provide these services would have to join others located within the same area, which may be difficult.

CHP or micro-CHP might be considered as “intermittent” when run under heat-following control strategy. However, as also discussed in the Demand chapter, CHP systems could be potentially used as *controllable* if enough incentives were available in order to provide grid services, so as to increase the system flexibility, which is one of the key options identified in the RESPOND project. In order to do so, suitable incentives or price signals should be designed, which would also require adequate communication infrastructure. In the case that communication costs were to be paid by the DG units, cheap communication structures should be available, above all for micro systems. In general, aggregation and control of several units from a centralized system at the distribution level would also help to select the most suitable units to provide grid support.

In *Spain*, RES/DG generators that may access the AS markets are those that sell their output at the energy market or through contracts, are controllable, and have a size of at least 10MW. The maximum wind energy output that the Spanish system can allow under safety conditions is calculated in real time at the TSO control centre for the “Special Regime” (CECRE). If the actual production is higher than this value any unit connected to it can be curtailed. A TSO can also curtail the production of any RES to solve grid congestions as a last resource. In the case of the DSO, the contracts signed with the owners of the units are taken in account to establish the priority to curtail production. Wind generators, as any conventional generator, are given 15% of the spot price in case of real time curtailment (they loose the premium for the curtailed energy). This must be regarded as a compensation for the generators, since if the curtailment takes place during the process of constraint’s solution after the daily market, no compensation is given. In order to participate in AS markets it is mandatory to be able to follow the orders of the system operator (*controllability*). Every generator contracted to provide ancillary services must be connected to a generation control centre which will be in communication with the TSO control centre. All costs derived from this must be paid by the RES/DG unit. There are penalizations associated with deviations with respect to the established programs and, in the case of wind power, for non-compliance with the requirements concerning voltage dips riding.

At the moment, intermittent energy sources are not able to participate in the Spanish secondary reserve market. Big efforts are being done by wind promoters to research and adapt wind farms so that they can provide load following services. Even though from a technical point of view it seems feasible in the near future, actual premiums over market price do not encourage wind farms to reserve part of their generation capacity to offer it as regulating capacity in the secondary reserve market.

Talking now about the UK, RES/DG systems that are smaller than 100MW are able to offer a few selected reserve/response services as part of an aggregated group (where the minimum group size is 3MW). Therefore, in order for small generators to take part in the AASS markets, they have to join into a large enough commercial (or virtual) unit. This can be achieved through an energy broker or managing the production of several units within a company from a control centre acting as the interface between these units and the market (for instance Gaz de France, Flexitricity, npower Cogen).

The System Operator in the British system can modify the scheduled output of RES/DG resulting from the 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 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 have bilateral connection agreement which allows DG to be curtailed for a relatively short period of time if it leads to significant saving 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.

In the *Netherlands*, only units larger than 5 MW and connected to the 1 kV voltage network or higher are permitted to provide ancillary services. Bids of positive or negative power to the regulating and reserve power market have a minimum size of 5 MW. VPPs in the Netherlands provide flexible horticulture CHP units access to the balancing market as well as possibilities for reducing imbalances after gate closure of the day-ahead market. Some RES/DG units may even provide emergency power through VPPs, on the precondition that exclusivity of power supply is guaranteed by providing the TSO insight to the contracts between the aggregator and the VPP. However, commercial aggregators are not yet available for electricity generation or demand sources that dispose of potential flexibility, such as residential heating through micro-CHP installations or heat pumps.

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 NordPool 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). These area prices are the starting point for the intraday market, Elbas. Any company controlling a portfolio of electricity generation or demand may become a participant on the Elbas and/or 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.

Wind power in Germany can be curtailed providing negative reserve, especially when grids are congested. From a technical point of view RES/DG can provide ancillary services, but some stakeholders argue that it is not sensible to curtail or let RES take part in balancing (except controllable units such as biomass) in order to reach the ambitious RES generation target. In order to improve the participation of RES generators in the operation and control of the system, better observability and remote controllability must be achieved.

Table 8 : Main country features concerning market access, size limitations and aggregation of units

Country	Market	Access, size limitations, aggregation of units
Spain	Energy Markets	-no size limitations -voltage dip through capability required and connection to a RES control centre of units > 10 MW -can be curtailed by TSO in real time losing 85% of market price and the premium
	Balancing markets	-Intermittent energy sources not able to

		participate.
UK	Energy Markets	-size limitations: generators < 1MW not able to participate -Generators above 100 MW are registered as Balancing Mechanism Units -Aggregation allowed -Curtailment by TSO
	Balancing market	-Generators greater than 100 MW registered as Balancing Mechanism units.
Netherlands	Energy Markets	- No size limits, but minimum trading volumes
	Balancing Markets	-only units larger than 5 MW and connected to the 1 kV voltage network or higher could provide ancillary services -Minimum bid size: 5MW -Implicit obligation for small units to provide balancing power/AS through an aggregator
Denmark	Energy Markets	- no size limitation
	Balancing Market	-No particular Ancillary Services market in Nordpool
Germany	Energy Markets	Minimum 100 kWh per hour in order to participate
	Balancing Market	Wind power can be curtailed, thus providing negative reserve

Table 9 : Barriers reported by country studies concerning market access, size limitations and aggregation of units

Barrier	Country
Possibility of being curtailed	Spain, UK
High Transaction Costs for trading in markets	Netherlands, Denmark
Commercial aggregators do net yet aggregate E production originating from micro-CHPs and heat pumps	All countries
Curtailing RES as negative reserve is a barrier to reach RES generation targets	Germany

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

In order for RES/DG generators to internalize the costs they make the system incur, these generators should be held responsible for the balancing costs they cause. Otherwise, they will not be operated efficiently, thus increasing the costs for the system of integrating large shares of DG/RES. What is more, if RES generators are not responsible for the deviations from their power output schedule, owners of these generators will not care about developing better prediction tools and providing the SO with a better estimation of their power output. However, making generators responsible for balancing costs may be a significant barrier since it decreases the profitability of investment projects to build these generators. A possible solution where RES/DG generators have to pay for these costs is to add a bonus to the subsidy they are paying these generators. This bonus is an amount equal to the balancing costs caused by an efficient generator of this type. In the end, a balance must be struck between the incentives for the efficient operation of RES/DG generators and those incentives aimed at promoting their installation.

Improving the accuracy of the prediction of the power output of intermittent generators is critical in order to reduce the balancing costs for the system of power imbalances caused by intermittent generators. According to some estimates by power companies and TSOs, no breakthrough in the development of prediction techniques is envisaged in the short to medium term future. However, the accuracy of the prediction of the aggregate production of these generators at system level may largely depend on the number of them that exists and their geographical distribution. If the production of a certain type of generators in each area is poorly correlated with that of generators of the same type in other areas of the system, and generators are evenly distributed across the system, their aggregate output is likely to be far less variable, and, thus, far more predictable, than the output of the generators located within each area. Apart from this, the lack of incentives for generation promoters to develop sophisticated prediction tools may be another important barrier to the improvement in the prediction of the output by these generators.

The accuracy of the prediction of the power production by the most important intermittent generation technologies (those that are not controllable) improves substantially with the proximity of this prediction to real time operation. Thus, regulation reserves would decrease notably if intermittent generators (and others) could balance their program in liquid markets that run until short time in advance of the real time. Gate closure times for day and intraday markets in the blueprint countries we are investigating range from 8 hours ahead of the operation in the Spanish market (last intraday market for each day closes at 4 p.m.) to 1 hour ahead of real time in the Danish and British markets. Forecast errors for time horizons below 7 hours are nowadays less than 8%.

DG/RES generators in Spain are responsible for the deviations they incur. Thus, they must pay imbalance costs that are proportional to their contribution to the total system deviation. This fact has encouraged them to develop better power output prediction tools. However, it should be noted that the support payments for RES/DG in Spain are far larger than the balancing costs they incur. Thus, being responsible for deviations does not represent a major barrier in the development of RES/DG.

In the Spanish system, every generator can adjust its production in the intraday market where there are six sessions, (one every four or five hours, approximately). If an imbalance between generation and demand still exists after intraday markets, the tertiary energy market and the deviation management market are used to re-establish the equilibrium.

According to the Spanish TSO experience, it could be feasible to join the intraday energy market sessions and the Spanish TSO deviation management mechanism in a single continuous balancing mechanism to bring continuous re-scheduling opportunities to program units. Maybe, the main barrier to carry out this is the current division of responsibilities between the Spanish pole of Iberian market, OMEL, which runs intraday energy markets, and the Spanish TSO, which s responsible for the deviation management process. This hypothetic future continuous balancing mechanism would have to be managed by the Spanish TSO since the TSO manages the operation of the network. Another barrier to further reducing the gate-closure time is the time required to carry out the security's studies and guarantee the technical viability of the scheduled production.

In Germany, RES/DG generators are not made responsible for the imbalances they cause in the system. On the contrary, grid operators are responsible for forecasting the production from intermittent energy sources connected to the grid they manage. Big research is being done in order to improve forecasting tools. In the German case, it is believed that making RES/DG responsible for the deviations they incur would create a barrier to the installation of RES/DG, which would have a negative impact on the amount of CO2 emissions.

Even though the reduction of the gate closure time would decrease the balancing cost, empirical analyses in Germany have shown that the utilization of the intraday market instead of the balancing market does not decrease the overall costs. Switching from minutes reserve to intraday markets becomes only economically efficient if the liquidity on the intraday market is increased. Thus, liquidity of intraday markets can represent a barrier to reducing imbalance problems.

Renewable and distributed generators are responsible for the imbalances they cause in the British system. Improving the accuracy of the existing prediction tools is necessary to reduce the amount of reserves required and the associated system balancing costs. In the balancing market, BMUs are especially encouraged to improve the accuracy of their output estimations so as to reduce the imbalance cost they need to pay. In addition, the gate closure time has been reduced from 3 hours to 1 hour ahead of real time.

Generators in Denmark are responsible for the deviations they incur. In addition, generators may contract the services of a Balance Responsible Party (BRP). A BRP can be balance responsible for production, consumption and/or trade. The balancing costs – as well as the market prices – are considered, when computing the subsidies to be earn by RES/DG. Thus, they do not represent a significant barrier to the entry of these generators in the market. The gate closure at Nord Pool is one hour ahead of delivery.

In the Netherlands, every generator or demand connected to the grid (including DG/RES) has program responsibility and consequently balancing responsibility. Deviations from the scheduled program are determined for each programme time unit (PTU, 15 minutes) and settled with the TSO on the balancing market. In practice, the program responsibility of most agents has been transferred to a small number of program responsible parties, which usually have large portfolios with a combination of generation and demand. This program responsible parties benefit from improvements in predictions of load and wind power production. Furthermore, program responsible parties are allowed to trade with other PRPs in order to reduce their imbalance. The gate closure time is 1 hour ahead of operation for the balancing responsible parties. The reduction of the gate closure time is not very realistic; limitations in start-up times and ramp rates in combination with the need to use regulating power for congestion management requires gate closure times that are long enough to conduct a load flow analysis and allow for rescheduling.

Table 10 : Main country features concerning responsibility of deviations, prediction of production and gate closures

	Responsibility for deviations	Prediction of production	Gate closures
Spain	- RES responsible for deviations, penalty in proportion to their contribution to the total deviation - support scheme is high enough to bear deviation costs	- Both TSO and RES make prediction of production	-Six intraday markets -Gate closure between 3 and 8 hours depending on intraday market -RES monitored in real time by TSO
Germany	-RES not responsible for deviations - making RES/DG responsible for the deviations they incur would pose a negative barrier	-net operators are responsible for the forecasting of intermittent energy sources	- Switching from minutes reserve to intraday markets only efficient if liquidity of intraday markets is assured.
UK	-RES responsible for deviations		1 hour
Denmark	- RES responsible for deviations	Generators may contract management of deviations with a Balance responsible party (BRP)	1 hour
Netherlands	- RES responsible for deviations	-program responsibility transferred to a small number of	1 hour

		program responsible parties	

Table 11 : Barriers reported by country studies concerning of responsibility of deviations, prediction of production and gate closures

Barrier	Country
RES responsibility for deviations	Germany
Time required for security studies	Spain, Netherlands
Liquidity of intradaily markets	Germany
Division of responsibilities between market operator and system operator	Spain

4.3 Conclusions

Market access, size limitations and aggregation of units

Regarding *access to energy markets*, although *direct* barriers seem actually not present in any of the surveyed countries, there are some key points that could be highlighted. In particular, high trading fees might in practice represent an obstacle to market access. Hence, a possible solution could be to reduce the direct trading fee or transform it into an equivalent one with different structure, more suitable to RES/CHP characteristics, as done in Denmark, for instance. Size could also be an issue for market access, as it is not practical to monitor several dispersed units at a distribution level. However, aggregation of units, which may be carried out through contracts with energy suppliers or trading agents, is an effective solution to overcome this problem, and is already taking place in several countries. The aggregation of units can also diminish the high transaction costs that is reported as an important barrier in Netherlands and Denmark. In fact, virtual power plants are a priority area for the call for proposals for 2009 for the electricity research programme in Denmark. In addition, the possibility of being curtailed by TSO for network security reasons can also prevent the participation of RES within markets.

Regarding *access to ancillary or system services markets*, the main issue found refers to controllability of the RES/CHP unit (or, in case, an equivalent aggregation of units, in order to overcome minimum-size threshold, as for the energy market). Controllability is a technical issue that is typically technology specific, and, in a way, also refers to the capability of riding through various fault situations. In this way, big efforts are being done by RES promoters to research the adaptation of units farms in the ability of load following services and voltage control. Assuming that from a technical point of view RES generators will be mature in the near future, the participation of intermittent generators require that system operation practices are replaced by more modern ones. Consequently, adequate remuneration schemes have to be designed in order to incentivise the participation of RES generators in ancillary or system services markets.

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

In most countries (Spain, UK, Denmark and Netherlands) RES are responsible for deviations, i.e. they must pay penalizations for the deviations incurred, which in fact constitute an incentive to develop better prediction tools. In this respect, aggregation of different RES generation units spread over a relatively large territory rather than clustered within smaller areas could help minimize the overall forecast deviations. Assigning balancing responsibility to RES has not been reported as a major investment barrier due to the fact that the support schemes compensate these costs. In addition, balancing responsibility can be transferred to program responsible parties (Denmark, Netherlands) that can reduce deviations by managing a large portfolio of generation and demand. Only in Germany, RES producers are not responsible for deviations. In this case, the prediction of production is transferred to the grid operators. This is considered as a barrier for RES deployment. Whether RES are made responsible for deviations or not, big efforts have been made in the improvement in the predictions: forecast errors for time horizons below 7 hours are nowadays less than 8%

Different energy markets are available to market players. Country analysis indicates that gate closure times within these markets range from a maximum of 8 hours ahead of real time (last intraday market for each day closes at 4 p.m in Spain) to 1 hour ahead of real time (UK, Denmark, Netherlands). Limitations due to start-up times and ramp rates, together with the time required to carry out the security's studies and guarantee the technical viability of the scheduled production, have been reported as the major barriers to further reducing gate closure times. Gate closure time in Spain could be closer to real time by implementing more intraday markets or even merging the intraday market with the deviation management market. However, the division of responsibilities between the market operator (which is responsible of intraday markets) and the system operator (which is responsible for the deviation management market) is regarded as a major obstacle to implement the latter measure. Even though intraday markets reduce gate closures times, in Germany the liquidity of these markets is considered a problem and employing a balancing market is preferred.

5 Regional markets

Regional markets like the Internal Electricity Market (IEM) of the EU are aimed at strengthening the level of integration among the different national markets in a region. Generators and consumers in a regional market should be free to contract their energy with any other counterpart within the region, no matter where it is located. Thus, RES/DG generators within a certain country should be able to sell their energy in other countries.

Given that primary energy sources are not evenly distributed across Europe, and taking into account the fact that distances between some European countries are large, the production of RES/DG generators in one country may probably not be highly correlated to that in some others. Thus, some countries in the region may export the excess of renewable energy that they have available to other countries where the amount of renewable energy produced is smaller. The same would apply to regulation reserves. Regional markets allow regulation reserves to be shared among countries in the region. Thus, the amount of regulation reserves needed is smaller.

5.1 Increase of interconnection capacity

Interconnection capacity is needed for the existence of renewable energy exchanges between countries. However, the construction of interconnection capacity has long been a pending task in the IEM. The move to reinforce the most important congestion corridors in the region has faced many obstacles. Thus, for example, 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.

Also related to this, 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 scheme whose results cannot be considered indisputable. They 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.

Stakeholders and institutions in most of the considered countries are of the opinion that increasing the interconnection capacity between countries, according to the guidelines provided by the Ten-E study, would result in an increase not only of the power exchanges between countries but also of the share of regulating reserves that would be provided regionally, i.e. the share of these reserves that would be provided by agents in other countries different from those where the reserves are needed. Only Denmark believes interconnection capacity between the Danish system and others is already more than enough to allow power exchanges to happen.

Main obstacles to the construction of regional reinforcements include environmental concerns and concerns about the fairness of the allocation to countries of the cost of these reinforcements (UK and SP). Other barrier, related to the previous one, is the fact that benefits yielded by regional lines are many times wide spread and some countries may oppose the construction of lines that cross their territory without them benefiting significantly from them (SP, UK and NL). The complexity of the permit process, where every country involved must accept the construction of the line is also regarded as a major obstacle (SP, UK and D). Finally, 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 (UK).

Most parties agree that, in order to overcome the aforementioned obstacles, providing executive powers to some sort of European wide body (regulatory agency), and promoting the coordination between TSOs (in order to identify those lines that are needed at regional level), will be necessary. Apart from this, some parties state that compensations among TSOs should be made compulsory, whether they are fixed, as advocated by some (DK), or determined on an annual basis, as advocated by others (NL). Another important factor may be the harmonization of market rules that would encourage agents to seek more power exchanges. Finally, using congestion rents to finance new network investments, instead of reducing transmission tariffs, may be an alternative as well.

5.2 Integration of national markets into regional ones

Benefits brought about by the integration of national markets into regional ones have been discussed extensively. Barriers to achieving this integration may be of two types. First, one can think of all those difficulties faced when aiming to achieve an integrated functioning of regional markets from an operational point of view. National market rules in different parts of the existing regional markets differ widely in many cases. Besides, harmonizing them is very difficult. Among other things, this is due to the fact that countries want to have some control over the energy dispatch within their systems rather than dealing with this issue at European level (and this is in accordance with the subsidiarity principle). It is clear that reaching an agreement at least on some basic rules, such as those concerning national markets gate closure times, is necessary.

Other obstacles are related to the lack of willingness by countries to promote power exchanges. In the view of many countries, national generation capacity should be devoted first to guarantee the supply of local load. Only the excess of generation over demand in each country could be exported to others. These countries may be worried that allowing limitless regional power exchanges could pose a threat to the supply of local load at times when excess capacity is tight.

The level of harmonization of market rules between the main European countries with significant RES generation and their neighbours varies widely from one case to another. Thus, in the long term, coordinated explicit auctions take place in most cases (SP, NL, UK). In the short term, coordination of gate closure time has been implemented in some cases (D), while, in most cases, some short of coordinated implicit auction has been implemented (SP-P, DK, NL). There are other cases where explicit auctions are held also in the short run (SP-F, UK).

Those systems whose level of integration with others is high have normally implemented implicit auctions, mainly Market Coupling, like NL, E-P or DK (also with

D). However, there are also cases, like that between UK and F, where implementing explicit auctions has been enough to allow significant power exchanges to take place.

From the answers by stakeholders and institutions, it seems clear that, in order to achieve a high level of integration between systems that are part of a meshed network, implementing some short of implicit auctions seems highly advisable (Market Coupling). Explicit auctions may allow the integration of two neighbouring systems if their connection is radial (like that between F and the UK). No single example of coordinated explicit auction scheme comprising several countries has been reported.

There is not a general perception that national security of supply concerns should result in a reduction of power exchanges between countries, since each country could benefit from the existing of generation resources in others. The integration of system services at regional level should benefit each of the different countries in the region. However, some entities have expressed their view that generation capacity in a country should not be reserved, in the long term, for the provision of regulating reserves to other countries. Only capacity available in the short term should be devoted to this (D).

5.3 Conclusions

Table 12 summarizes the main findings within this section. Columns correspond to the market response options that have been identified in this and previous sections, while rows correspond to the different barriers that may hinder the implementation of these response options. For each combination of a certain barrier and a certain option, the table provides the identity of the countries where the corresponding barrier is preventing the application of this response option.

Table 12 : Summary of the main barriers affecting the creation of regional markets

	Increase of interconnection capacity	**Integration of the operation of national markets**
Environmental concerns	*SP, UK*	
Lack of fairness of the inter-TSO payment scheme	*SP, UK*	
Widespread benefits yielded by cross-border lines	*SP, UK, NL*	
Complexity of the process aimed at obtaining permits	*SP, UK, D*	
Lack of harmonization of market rules	*DK*	
Short term implicit auctions not applied if needed		*SP-F, D*
Lack of multi-country coordination of long term cross-border capacity allocation		*SP, NL, UK, D, DK*
Integration perceived as a threat to security of supply		*D (reserves provided to other countries must not be provisioned in the long term)*

6 Networks

6.1 Transmission networks

The transmission activity is certainly affected by the installation of large shares of variable RES connected to the transmission grids and variable RES/DG to the distribution grids, since transmission power flows in the system depend on the balance between generation and demand in each part of the system. RES and RES/DG changes the geographical distribution of generation in the system, which, in turn, changes the balance between generation and demand within each area as well as power flows between areas.

Installing large shares of RES/DG generation may change the level of transmission network investments that are needed. Thus, appropriate measures should be taken for promoters to take into account the cost of these reinforcements. Considering the efficiency of required grid reinforcements is even more relevant due to the fact that transmission network planners are having great difficulties getting new lines built. Finally, the pattern of congestion in the grid is likely to change as a result of the installation of these generators. This may require the use of new efficient congestion management schemes.

6.1.1 Locationally differentiated and time varying tariffs

Promoters of RES and 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. 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. However, implementing locationally differentiated charges may be against the regulation in place in some countries, which may state that generators of each type in a system must pay the same level of charges no matter where they are located. What is more, changing from a system of charges that does not depend on the location of each agent to another one whereby generators pay according to their location requires designing a transition period and discriminating between old and new generators. This may pose a serious challenge to the adoption of this kind of tariffs.

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. Implementing such a tarification scheme may, again, face a series of obstacles, though it should be easier to implement than locationally differentiated tariffs.

RES generators (like any other generator) in most of the considered systems do not pay transmission use-of-system charges (TNUoS charges). Only generators in the Netherlands and some generators in the UK have to pay transmission TNUoS charges. Generators in the Netherlands only pay these charges for the amount of energy they withdraw from the grid. In the UK, generators connected to the transmission grid, or those connected to the distribution grid that are larger than 100MW, must pay TNUoS charges, though small generators connected to the transmission grid can get a discount. Regarding connection charges, DG/RES normally has to pay them but these are shallow in some cases (NL, UK) and deep in others (SP, D). Shallow connection charges may be regulated or depending on the type of generator i.e. voltage level (NL).

Transmission use-of-the-system charges paid by generators in most considered countries do not exhibit any form of temporal or locational differentiation (D, DK, NL, SP). In some cases, this is due to the fact that generators do not pay any charge for the use they make of the transmission grid (SP, DK). In others it is due to the fact that no locational/temporal differentiation has been introduced in transmission charges in general (NL, D). An exception to this general trend is the UK, where generators pay use-of-the-system charges that exhibit some form of locational (application of the LRIC methodology) and temporal (use of peak day pricing) differentiation. The latter charges are aimed at charging network users according to the cost they cause.

Regarding connection charges, one could say that those systems where these charges are not regulated but negotiated exhibit some sort of temporal/locational differentiation, since they are computed on a case by case basis according to the particular characteristics of the considered generator. These include all those systems where connection charges are deep (SP, D) and, in some specific cases, shallow charges (NL for those generators up to 150 kV).

All parties agree that transmission owners’ (TOs) attitude toward the connection of DG/RES does not depend on whether these generators pay the costs they cause but on whether these costs are approved by the regulator (acknowledged as regulated costs). In some countries (SP, NL), the TSO/TOs are forced to accept any connection requested as long as it is technically feasible. Furthermore, there are parties which believe that it is impossible to allocate grid costs on a cost causality basis and, therefore, that these should be socialized to network users (D, Electrabel).

Parties 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 (NL, UK). Others explain that, despite differences between charges may be large, prices and subsidies earned by RES are so big that investments in new RES capacity are unlikely to be influenced by transmission tariffs (SP). Some countries do not consider the possibility of introducing locational/temporal differentiation in tariffs.

The most important barriers to the implementation of locationally / time varying transmission tariffs that have been identified by parties in the considered countries include the following:

- Charges resulting from the application of these tariffs may turn out to be too volatile. Even differences in tariffs between nodes or points in time that are close could be significant (NL).

- 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 (NL, D). Discrimination between old and new generators is also seen as unfair in some cases (NL).
- 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 (SP).
- 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 policy makers view (UK).

6.1.2 Political and administrative barriers to grid reinforcement

As mentioned above, 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).

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 (NL, SP, D). In order to overcome them, many new lines have had to be buried, which significantly increases the cost and the technical complexity of the investment projects. This, in turn, becomes a major barrier to the construction of new lines (DK). Other concerns are related to the allocation of the cost of new network investments and the efficient utilization of existing assets (UK). Finally, the profitability of the investment projects in the current conditions is also under scrutiny.

In order to overcome opposition to the construction of lines, some believe that explaining better the benefits produced by these projects may be useful (D) but the majority of parties do not think so. Paying compensations to communities that are crossed by new lines for the environmental cost of these installations may be another option (SP). Giving national governments more competences related to the authorization process at the expense of regional/local governments may also be helpful (NL).

6.1.3 Efficient and fair 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.

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. Besides, some regulators have expressed their concerns about the possibility of local generation increasing the market power they hold if locationally differentiated prices are computed. Lastly, implementing an efficient congestion management scheme could result in an increase in the complexity of the process leading to the computation of the final program of power units, especially if some level of coordination between the energy dispatch in different countries or market areas is required.

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. The congestion management mechanism currently used in most systems is redispatch. Even Denmark is applying redispatch to solve specific grid congestion problems which do not occur systematically. The same holds for the Netherlands, which is applying a priority congestion management mechanism for new generators that want to be connected in congested areas (last generator connected is the first one that is constrained off if congestion arises), but is likely to implement a more advanced redispatch algorithm in the short term future.

Different variants of redispatch are applied in different countries. Thus, the redispatch algorithm applied in Spain does not result in an efficient energy dispatch in some situations. Generators in a congested region who must reduce their output are not chosen according to an efficiency index. In this case, the functioning of the redispatch algorithm could certainly be improved without having to introduce significant changes to the national regulation.

Most parties agree that introducing some market based method to solve congestion is highly advisable. Thus, authorities in the Dutch system are seriously considering the possibility of implementing a redispatch algorithm. However, no party or institution, but the Danish ones, sees the need to apply congestion management mechanisms that are more ambitious than redispatch. Reasons for regarding redispatch as a satisfactory option include the belief that grid congestion can be efficiently managed through the use of redispatch within their system (D), or the belief that applying some sort of nodal or zonal pricing would create significant problems, and would significantly increase the complexity of the congestion management process, while not delivering major efficiency increases (SP, UK, NL). Problems that are generally regarded as related to the implementation of nozal/zonal pricing are discussed in the following paragraphs.

Main barriers to the implementation of nodal/zonal pricing in the considered countries are the incompatibility with existing national regulation; the acknowledgement that significant market power problems may arise as a consequence of the application of locationally differentiated prices and the increase in complexity of the energy dispatch resulting from the use of this kind of solutions.

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. In contrast, other countries' market rules, like those in the UK and Denmark, allow for energy prices to be different, since locational price differences in energy bought by consumers in these countries are already taking place. The regulation in place is Germany states that, if significant internal congestion exists sometime, a market based, non-discriminatory congestion management method should be applied. However, grid congestion that exists nowadays is deemed to be efficiently dealt with by means of redispatch.

According to most of the consulted parties (DK, UK, NL, SP and some in D), 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 the parties in those systems where zonal pricing is already in place, like Denmark. 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.

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 others, like Dutch ones, splitting up the imbalance settlement according to price areas and changing computer systems represent non-negligible challenges. Finally, there are other systems, like the UK or Denmark, which think implementing these methods is perfectly possible, since, either they have already implemented them (DK), or they have already dealt with the problem of applying a different price to each consumer, although in a decentralized way (UK).

6.1.4 Conclusions

Table 13 summarizes the main findings within this section. Columns correspond to the market response options that have been identified in this and previous sections, while rows correspond to the different barriers that may hinder the implementation of these response options. For each combination of a certain barrier and a certain option, the table provides the identity of the countries where the corresponding barrier is preventing the application of this response option.

Table 13 : Summary of the main barriers related to the transmission of electricity

	Locationally differentiated and time varying tariffs	Grid reinforcements	Efficient and fair congestion management schemes
Volatility of charges	*NL*		
Source of unfair discrimination	*NL (also between old and new), D*		
Weakening of incentives from charges due to high level of FITs	*SP*		
Increase in the complexity of the regulation resulting from their application	*UK (less attractive for policy makers)*		
Environmental impact and effects on health		*NL, SP, D, DK (burying them is necessary)*	
Lack of efficiency of the allocation of the cost of new lines		*UK*	
Lack of efficiency of the use of existng transmission capacity		*UK*	
Disputed profitability of proposed projects		*UK*	
Measure contrary to national regulation			*SP (there must be a single L price), NL (significant changes would be needed)*
Increase in the exercise of MP resulting from their application			*SP, NL, UK, DK, D (some)*
Increase in the complexity of the market clearing process			*SP (coordination of the regional dispatch), NL (imbalance settlement and computer programs)*

6.2 Distribution networks

DG/RES generators of a intermittent nature should not be discriminated against when requesting access to the distribution grid. In order for this not to happen, DSOs should reap some of the benefits that the system obtains from the installation of DG. These benefits may be of different types: decrease in infrastructure investment needs, decrease in losses, increases in the quality of service brought about by these generators, etc. At the same time, DSOs remuneration should take into account the extra costs they incur because of the installation of these generators. Thus, distribution tariffs paid by generators should depend on their location and their output profile.

On the other hand, RES/DG promoters should be encouraged to install new generation at distribution level. Thus, they should profit from the benefits for the system caused by the generators they install. RES/DG should be allowed to sell ancillary services if they are capable of providing them. Additionally, their charges and revenues should depend on the incremental costs (either positive or negative) that they make the system incur.

6.2.1 Locationally differentiated and time varying tariffs

The SOLID-DER project has investigated the structure of distribution charges paid by DG/RES generators (both connection and UoS charges). These charges should be representative of the distribution grid costs that these generators make the system incur. In order for this to be true, charges to be paid by a generator may need to depend on the location and operation profile of this generator (time when it is expected to produce energy). However, some obstacles may lie in the way of the process of implementing locationally differentiated or time (profile) varying charges. For example, some studies have concluded that locationally dependent distribution charges may turn out to be too volatile. Other obstacles analogous to the ones hindering the application of locationally differentiated and time-profile varying transmission charges may apply as well (legislation/regulation and transition problems).

In most of the considered systems, DG only has to pay connection charges at distribution level. An exception to this is the UK, where these generators have to pay also use-of-the-system charges. These are being reviewed to allocate costs in a cost reflective manner.

Regarding connection charges, they are shallow in some cases (UK, NL for small generators, D) and deep in others (SP, NL for large generators). Deep connection charges are location and generation profile dependent since, theoretically, they represent the cost of the reinforcements that each new generator causes. Shallow connection charges may have some locational content as well. Thus, these charges can be made dependent on the distance to the grid of the generator to be connected to it (NL).

Therefore, distribution charges faced by DG in part of the considered countries exhibit some form of temporal or spatial differentiation. Deep connection charges, as those applied in Spain and Holland allow the DSO to charge generators according to the expected costs they will cause. These charges may have a significant locational content. Shallow connection charges (D, UK, NL small generators) can only have a small locational content, since they only concern a small fraction of total network costs. However, in some systems, differences exist among shallow connection charges paid by different generators. These differences may depend on several factors, like the distance from the generator to the grid. Use-of-the-system charges paid by distributed generators in some systems may be locationally and temporally differentiated. This is the case of the UK, where Long Run Incremental Charging (LRIC) is applied to compute the charges to be paid by those generators connected to the EHV network, while distribution use of the system charges paid by generators connected to the HV/MV/LV levels are computed according to a Distribution Reinforcement Model (DRM).

Revenues of DSOs do usually not depend on whether DG pays the costs it causes. Instead, they depend on the methodology applied to compute allowed revenues. These methodologies are normally based on the use of yardstick competition and the computation of a revenue cap. In some systems, the impact of the connection and operation of DG on DSOs' reasonable costs are considered (UK). In others, they are not explicitly taken into account (SP, D, NL).

Parties agree that deep connection charges, like those applied in SP or Holland for large generators, may drive investment decisions by DG promoters. Shallow charges are less likely to drive investment decisions, even when they have some locational content (as those in NL for smaller generators). When distribution use-of-the-system charges have locational/temporal differentiation (UK), parties agree they may affect investment decisions by agents.

In those systems where locational distribution charges have not been implemented yet, main barriers identified by parties are legal (changing the tariff codes would be necessary in NL). Additionaly, allocating charges to generators in an efficient, cost-reflective, manner is also regarded as a challenge by authorities in some countries (D). For most parties consulted, volatility is not considered a problem when implementing this kind of charges. An exception to this rule is the Netherlands.

6.2.2 DSOs incentives for active network management

Real time monitoring and control of DG/RES generation is far from achievable nowadays in most systems, since DSOs' management of the network is not active but passive. However, DG may contribute to reduce system losses and improve quality of service through the reduction of the net amount of energy to be transported by higher voltage networks and the provision of ancillary services. If DSOs could cash in on these benefits, they would probably promote the connection of DG/RES generation to their grids and would implement active network management techniques. These techniques would be aimed at taking advantage of the potential of DG/RES generators for operation cost reduction and service quality improvement. Active network management includes dynamically changing the grid configuration, real time monitoring of DG operation and communication with these generators so as to control them.

Barriers to the adoption of innovative management schemes may have to do with the lack of incentives for DSOs to change their operating practices or to technological challenges of the implementation of these schemes. We shall focus on barriers of the first type.

Active network management (ANM) has not been implemented yet in any of the considered systems. However, most parties acknowledge that applying ANM techniques would probably result in an improvement of both distribution losses and service quality levels.

In some countries (mainly UK, but also DK) research initiatives have been launched to develop active network management solutions. Besides this, research grants and tax cuts are being used in the UK to promote the development of the technology and operation processes required to implement ANM. The Netherlands is also considering employing this kind of incentives to trigger a change in the paradigm of operation of distribution networks.

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 incentives to reduce losses will be applied from 2009 on, and an incentive scheme to increase service quality is also planned. Mechanisms presently applied involve, in most cases, defining reference levels for losses and service quality and penalising (respectively rewarding) those DSOs whose losses and quality levels are worse (respectively better) than these reference levels (SP, UK, NL for service quality). In order to apply this type of schemes, it is necessary to define both the target or reference performance level and the size of the incentive provided to DSOs for improving their performance. Some of the entities consulted agree that the most difficult part of it is determining the incentive size (UK). Others (NL) point out that DSOs remuneration should take into account the effect that DG has on both losses and service quality, which is not common practice nowadays.

As explained above, agents consider that the most important obstacles to the implementation of incentive schemes are the difficulty of computing an adequate level for efficiency incentives (UK) as well as computing the impact of DG on losses and service quality (NL).

Besides, it is generally agreed (UK, NL, SP) that incentives schemes on their own are not enough to trigger a radical change in the operation of distribution grids. Therefore, other mechanisms should be used to complement efficiency incentives. These may be the launch of research projects aimed at developing technical and operational procedures for ANM where both public and private institutions participate (UK, DK, planned in NL). Other possibilities are research grants and tax cuts of the type currently used in the UK.

6.2.3 DSOs incentives for efficient network planning, incl. DG

Taking into account DG/RES when planning the expansion of the distribution grid may have a significant influence on the level of costs incurred. The SOLID-DER project favoured the adoption of revenue- or price cap remuneration schemes instead of cost of service ones, since the former can provide incentives to the DSO to develop the distribution grid that is optimally adapted to the system requirements. Provided such a mechanism is in place, DSOs should take advantage of the potential reductions in power flows caused by distributed generators thus not building certain lines that would be necessary if DG were not present in the system.

The SOLID-DER project has investigated the mechanisms in place in different systems to encourage efficient investment decisions by DSOs. Now, we shall focus on the barriers that hinder the implementation of efficient schemes to achieve this objective. These may include the difficulty to compute an efficient target level of investment costs to be incurred by the DSO, the difficulty to set the X efficiency factor to be deducted from CPI factor considered in this type of schemes or changing system conditions (regarding, for example, the penetration level of DG) that can justify a change in the target remuneration level of DSOs.

In order to encourage DSOs to carry out efficient network investments, an incentive scheme must be put in place. The determination of a ‘reasonable’ allowed CAPEX remuneration level for the DSO is acknowledged by some parties (NL, SP) as one of the main obstacles to achieve an efficient development of the grid. In some countries, the remuneration level is updated annually based on a formula, and is therefore completely decoupled from the actual level of costs (SP for quite a long time), while in others, some specific factors (connection density, penetration level of DG) affecting each DSO costs are not taken into account when computing its remuneration (NL). The penetration level of DG is a critical factor when computing an efficient level of CAPEX (NL, SP). To overcome these difficulties, some parties propose the utilization of network reference models separately for each distribution area (SP).

Determining the efficiency factor X in revenue cap schemes is also considered a challenge to be overcome in order to provide the right incentives. Normally, the same factor is used for every DSO, thus disregarding its particular situation (SP). In other cases, efficiency factors are adjusted from time to time so as not to allow DSOs' profits to increase much.

Some parties (UK, D) state that incentives for the efficiency in the operation of the system (losses, quality) should, on their own, result in efficient investments by DSOs aimed at improving the corresponding operation indexes.

Regarding the integration of DG in the process of planning the expansion of the grid, support schemes in some systems are believed to encourage DG to produce as much energy as it can regardless of the specific operation conditions that exist (SP, 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 lines.

Lastly, when planning the expansion of their grids, DSOs in the considered countries are not taking into account the likely future adoption of ANM techniques. Therefore, no coordination exists between network expansion planning in the present and the future adoption of active network management techniques.

6.2.4 Incentives for RES/DG to provide ancillary services to the DSO

Ancillary services provided by DG may be related to the operation of the system as a whole (namely the transmission grid) or to the operation of distribution grids. Thus, DG/RES generators may sell ancillary services to DSOs or be forced to comply with certain requirements. Both mechanisms may achieve the participation of these generators in keeping the system within safe margins. However, adopting the first one could lead to the provision of this service by those generators that can perform this task most efficiently.

Services that DG can provide the DSO will include voltage regulation and even black start capability under islanding operation, among others. Allowing DG/RES generators to participate in the corresponding ancillary services markets could represent an extra incentive for DG/RES promoters to install new DG.

Participation of generators in these markets would depend on the expected price levels in these ancillary services markets and how they compare to the expected revenues from selling their energy in the markets.

In some systems, distributed generators are required to comply with some minimum requirements regarding voltage regulation (SP, UK). In others they are not required to provide any help in this regard (NL). Requirements made to DG may involve the provision of a certain load factor (SP), or even the provision of voltage regulation, and may vary depending on the capacity and the voltage level of the considered generator (as it is the case in the UK). If DG provides services beyond the mandatory requirement, like providing voltage or power factor regulation when it is not compulsory, then it receives some extra payments. In some systems, these payments may be equal to the price resulting from the voltage regulation market (SP). The provision of other ancillary services (AASS) may be agreed through bilateral contracts, as in the Netherlands. None of the considered systems has implemented DSO AASS markets.

Conditions to be met by DG in order to be allowed to sell AASS are mainly technical, like controllability and fault ride through capability (NL). Not all the existing distributed generators in these countries comply with these requirements.

Finally, we shall discuss main obstacles to the creation of markets for DSO's AASS or the implementation of other kind of schemes that allow DG to sell this kind of services. Market liquidity (not enough potential providers/ all belong to the same company) is regarded by many parties as an important obstacle to the creation of AASS markets (UK, D). Lack of economic incentives for DG to sell AASS is also a major barrier to be overcome in order for DG to provide these services (NL, SP, UK). Finally, some state that due to the lack of controllability of these generators, as well as their inability to comply with other technical requirements, DG is not yet regarded by DSOs as a reliable option to provide AASS (NL).

6.2.5 Conclusions

Table 14 summarizes the main findings within this section. Columns correspond to the market response options that have been identified in this and previous sections, while rows correspond to the different barriers that may hinder the implementation of these response options. For each combination of a certain barrier and a certain option, the table provides the identity of the countries where the corresponding barrier is preventing the application of this response option.

Table 14 : Summary of the main barriers related to the distribution of electricity

	Locationally differentiated and time varying tariffs	DSOs incentives for active network management	DSOs incentives for efficient network planning taking into account DG	Provision of DSO ancillary services by DG
Measure contrary to national regulation	*NL*			
Difficulty of computing efficient distribution charges	*D*			
Volatility of charges	*NL*			
Difficulty of computing the level of operation efficiency incentives		*UK*		
Not considering the impact of DG on quality of service and losses		*NL*		
Incentives in place too weak		*NL, SP, D*		
Wrong refrence remuneration levels in revenue cap schemes			*SP (remuneration decoupled from costs), NL(specific situation of each DSO not considered)*	
Wrong level of the efficiency factor 'X' in RPI-X schemes			*SP (the same factor applied to every DSO)*	
Implementing incentive driven CAPEX remuneration schemes not necessary			*UK, D (incentives to improve operation are considered strong enough)*	
DG/RES support schemes encourage DG not to follow DSOs instructions			*SP, NL*	
DSOs not taking into account ANM when planning their grids			*SP, NL, D, DK, UK*	
Some RES/DG do not comply with technical requirements				*NL*
Lack of market liquidity of AASS markets (not enough independent providers)				*UK, D*
Lack of incentives for DG to provide DSO AASS				*UK, NL, SP*
DG not yet regarded by DSOs as a reliable source of AASS				*NL*

7 Final Conclusions and recommendations

In order to counteract the negative impacts resulting from the increase of intermittent RES and DG generation (identified in deliverable D4 of RESPOND project), a number of response options were defined, analysed and assessed in deliverable D5 of the same project. Subsequently, this document has been developed to detect actual and potential barriers that may hinder the implementation of the identified respond options. For this purpose a detailed questionnaire was developed in order to expand and collect additional information for the five country case studies (Spain, UK, Denmark, Germany, and Netherlands) regarding the national situation and the position of national regulators on the different key barriers.

In particularly in this report on the basis of the aforementioned questionnaire and survey, the barriers have been analysed and classified according to the segments or parts of the system, 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. Main conclusions on each segment and topic are presented below.

RES and CHP Generation

Pricing mechanisms and support schemes

Considering the diversification of the generation mix as one of the prioritized options identified, the performance of the different support schemes (FIT, premium over the market price or TGC trading) can be benchmarked among different countries based on effectiveness and efficiency factors. FITs are technology-specific and thus may be used to favour also less economically efficient options. Consequently, in general TGC systems are considered to be more economically efficient support instruments. However, in the case that TGC prices were not technology-specific, higher initial-cost technologies might be also supported by FIT-like schemes, ensuring more generation technology diversity at higher overall system costs. Meeting country targets seem easier under FIT than under TGC regimes but at a higher system costs.

In terms of efficient system integration, premiums attached to market prices or TGCs are in general more efficient than constant FITs, as generators are pushed towards selling energy when it is more needed, providing suitable support to the system. In addition, location-based charges/incentives could help improve the overall network operation (for instance by avoiding congestion) by boosting penetration of suitable technologies where they are most needed.

From the investors point of view a FIT system provides more security than a TGC system where the revenues per MWh are dependent on the demand for green certificates. However, effectiveness in terms of large RES/DG penetration cannot be the only driver to formulate suitable incentive mechanisms. The RESPOND project is focussed on efficient integration of RES/CHP when their production increases.

From the point of view of *network operators and balancing responsible parties*, it is crucial that support mechanisms take into account the actual system needs. Differentiated time-of-use tariffs/incentives and premiums on top of the market price, as mentioned earlier on, instead of fixed-feed-in tariffs, are capable to provide efficient market signals. Similarly, quota obligation (TGC) mechanisms could be quite effective in inducing competition among technologies and send market-based signals for the network sake. Furthermore, support mechanisms should be combined with obligation to provide forecasts on the scheduled production in order to simplify the system burden in terms of ancillary service needs.

From the point of view of the *whole power system* and *society*, RES/DG penetration could be increasingly expensive for the system, so that support schemes should be such that in the long run they do not hamper further deployment. In order to increase the system diversity/flexibility, incentives should decrease with time. In fact, owing to learning experience, typically production costs of RES technologies decrease with time.

Pricing mechanisms for Ancillary Services

Regarding pricing mechanisms for ancillary services (AS) provision, the main issue is relevant to the fact that RES/CHP systems, due to the design of the support scheme, do not receive incentives adherent to the real value of such services.

In particular, FIT or market premiums much higher than AS prices would mean no RES/CHP participation in AS related to the provision of reserves or balancing energy, and thus, less flexibility even when those systems were technically able to support it. Controllability is a prerequisite to AS market participation. However, generators that in theory could be controllable such as CHP do not provide AS due to lack of enough incentives. In the long run, this could prevent further RES/CHP installation due to their perceived incapability to provide AS, with additional need for conventional generation support. These aspects all together highlight the need for an integrated and updated design of energy and ancillary services markets and the review of the support mechanisms in place.

On the other hand, mechanisms such as availability payments or outside-the-market contracts between Transmission/Distribution System Operators (TSO/DSO) and RES/CHP for AS could help increase the share of controllable RES/CHP providing AS, as it this the case in UK.

Finally, as increasing RES generation variability will impose additional system burden in terms of balancing energy, compulsory schedules of the expected production should be provided to the SO, with penalizations in the case of deviations from these schedules. By not doing so, the system cost for AS might skyrocket with larger RES penetration, preventing effective integration of additional green generation.

RES/CHP Technical capabilities

In general, there seem not to be major technical hurdles to prevent RES/CHP access to markets, owing to technical improvements in RES generation technology characteristics. Of course, participation to specific markets such as for AS is still related to the technical potential (controllability) of the units. More specifically, if the generation units cannot be controlled, they will be prevented from AS market participation.

Controllability of units can be improved through the means illustrated in the “demand response” section, such as availability of cheap enabling technologies (e.g., heat storage or electric heaters/heat pumps). Also, non-controllable units can be required to be able to provide some kind of frequency response such as primary frequency control. However, in Netherlands, Germany, and UK, small units connected to distribution networks are not obliged by network codes to provide power reserves. In Spain, to facilitate the participation of units in reserve and balancing markets the role of centralized control centres for aggregation of such units have been demonstrated very relevant.

Conventional generation

Provision of reserves

Provision of regulation reserve from conventional generators is a key issue in order not to hurdle the diffusion of RES/CHP with variability and unpredictability characteristics. When provision of primary, secondary and tertiary regulation services is voluntary, failure in achieving enough participation may occur if markets or other mechanisms are not backed by adequate prices, and if too complex prequalification criteria are required. Hence, it is crucial to design and run an effective regulation reserve market, and to simplify participation schemes/requirements. On the other hand, market mechanisms (above all for secondary and tertiary regulation), work very well when correctly in place (e.g., UK, Spain, and the Netherlands), owing to the possibility to accrue high revenues on the balancing markets, thus ensuring enough market liquidity.

Again, aggregation represents an important resource for market participation. 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.

In the UK, Spain, and the Netherlands, primary regulation is compulsory, at least for the larger units, with no 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.

Interestingly, in Spain the hourly contracted secondary reserve has not varied substantially in the last years, in spite of a high increase in wind generation capacity, likely owing to improvement of wind forecast and the well functioning of this market. Hence, in general forecasting techniques prove to be an enabling technology to increase the flexibility of the system and allow more effective RES/CHP penetration and operation.

Availability of interconnection with neighbouring countries also enables the system to deal with higher penetration levels of RES/CHP units handling the variability in their production, even in the presence of relatively bad forecasts, owing to the possibility of exchanging energy through the interconnections.

Mechanisms to provide sufficient generation capacity in critical periods

Luring conventional generators into guaranteeing system firmness, ensuring their energy production, in the most critical times (demand high and intermittent generation not able to supply it) is a delicate issue.

Capacity firmness should be guaranteed in terms of both base-load and flexible/peaking units. Investment in only base-load technologies, for instance, might be insufficient to guarantee to the future system enough flexibility. The risk is that “wrong” units might be in operation, hurdling additional efficient RES and, at the same time, increasing the average market prices due to inefficient operation.

Under market approaches without any additional payments, such as in Germany and UK, due to higher price volatility, capital costs might not be recovered by generators. New capacity will then not be built and older less efficient units will keep on running. On the other hand, if prices are attractive enough, generation participation to provide adequate firmness can be achieved. Therefore the need for introducing capacity or availability payments is an open issue.

In Spain, availability payments for generators ensuring energy production at critical periods have been implemented. In Netherlands, the System Operator (SO) contracts on a yearly basis specific amounts of regulating and reserve power and emergency power to ensure the supply at critical periods.

Investment in new generation capacity

Further penetration of RES will increase the requirements for peaking capacity units, whose economic feasibility based only on market forces might be at stake. Indeed, their traded energy volume will decrease and their energy production cost will increase also due to off-design operation. In addition, on average the energy produced might be sold at lower average prices (cheaper RES will be dispatched first), even though they might set extremely high marginal prices in strategic peak hours. Uncertainty in market revenues might lead towards no additional capacity being installed. Therefore, if market forces are not sufficient to provide incentives to peaking units, system based upon capacity/availability payments or equivalent bilateral contracts between SO and generators prove to be quite effective. In particular, contracting balancing power outside the market prevents it from competing with power traded in the energy market. This kind of mechanisms appear a crucial resource in order to avoid reaching levels where the capacity margin is so thin as to generate price spikes and load-shedding intervention. Capacity payments outside the market aimed at providing system firmness implicitly also push towards additional capacity. Indeed, on average, such mechanisms increase the price for generation capacity and thus give incentive to new investment.

In some countries (e.g., Germany), installation of capacity not expected to be able to run economically might prevent RES penetration and increase prices. Likewise, installation of base-load rather than peaking capacity might not be sufficient to provide enough security and reliability in the future.

These issues might have to be dealt with at a regulatory level in order to prevent biased market outcomes that, besides damaging RES/CHP, would damage the consumers due to higher energy prices.

Demand

Metering and communication issues

Hourly meters are being installed in all five countries, although nowadays only Spain has a nation-wide programme. This is a precondition for exposing customers to hourly market prices. However, changing meters is costly and in most countries new meters are mainly argued by savings related to the billing of customers. What is relevant for the RESPOND project are the possibilities associated with new meters for automatic response and increasing demand flexibility, that would allow a more efficient integration of RES/CHP. Still communication standards and the functionality of meters are pending issues that should be solved for the successful penetration of this technology..

Pricing rules and incentives

For customers to react to the varying costs of producing electricity, prices have to reflect the variations. Reflecting systematic daily/weekly variations in costs, Time-Of-Use (TOU) tariffs have been introduced in many countries. Reflecting critical periods, Critical Peak Pricing (CPP) schemes have been introduced. The Tempo tariff in France is a combined TOU- and CPP-tariff. Day-ahead market prices would reflect both systematic and un-systematic variations in the cost of producing electricity. However, currently the wholesale market prices are reflected only in annual rates. From a theoretical point of view market prices are preferable and all customers should be exposed to these, however, information costs of following and reacting to hourly prices is not negligible.

Additionally, calculations of the gains seen by customers appear too small for shifting consumption in time. In addition, fixed price-additives e.g. grid-payment and taxes, reduce relative price variations and therefore reduces the incentive for reacting to market-prices. Getting these additives to follow system conditions, at least network charges, would give a better price signal and increase the incentive for customers to become flexible.

Introduction of automatic response technologies will increase demand response. Massive introduction of price and/or frequency controlled cut-off technologies in individual household appliances has a quite large potential for increasing demand response within households. Again the technological barrier here is related to the costs and availability of communication standards and the huge volume of information to be managed. Moreover, a key issue is that experience in the United States suggests that customer reluctance to have unknown controls installed in their homes or businesses represents a barrier to more widespread participation in utility demand response programs.

National energy and ancillary services markets

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. Aggregation of units is an effective solution to overcome size limitation, and is already taking place in several countries. The aggregation of units can also reduce transaction costs, which are reported as an important barrier in the Netherlands and Denmark. In fact, virtual power plants are a priority area in the call for proposals for 2009 in the electricity research programme in Denmark. The deployment of commercial aggregators can be further improved by including the possibility of aggregation of production originated from micro-CHPs and heat pumps. In addition, the possibility of being curtailed by the TSO for network security reasons can also prevent the participation of RES in markets.

Regarding *access to ancillary or system services (AS) markets*, the main issue refers to the controllability of the RES/CHP. Assuming that, from a technical point of view, some RES generators (wind) will be mature in the near future, their participation in AS requires that system operation practices are replaced by more modern ones, as well as the implementation of an adequate remuneration scheme that effectively encourage RES to participate in these markets.

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

In most countries (Spain, UK, Denmark and Netherlands) RES are 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. However, it has not been reported as a major barrier due to the fact that the support schemes compensate these costs. Only in Germany, RES producers are not made responsible for deviations (it is considered an important barrier for RES deployment). In this case, the prediction of production is transferred to the grid operators. Whether RES are made responsible for deviations or not, big efforts have been made in the improvement in the accuracy of the predictions: forecast errors for time horizons below 7 hours are nowadays less than 8% compared to figures over 15% in the past.

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 4 p.m in Spain) to 1 hour ahead of real time (UK, Denmark, Netherlands). Limitations due to start-up times and ramp rates, together with the time required to carry out the security's studies and guarantee the technical viability of the scheduled production, have been reported as the major barriers to further reducing gate closure times. Gate closure time in Spain could be closer to real time by implementing more intraday markets or even merging the intraday market with the deviation management market. However, the division of responsibilities between the market operator (which is responsible of intraday markets) and the system operator (which is responsible for the deviation management market) is regarded as a major obstacle to implement the later measure. Even though intraday markets reduce gate closures times, in Germany the liquidity of these markets is considered a problem and employing a balancing market is preferred.

Regional markets

Two main market responses have been identified in order to facilitate the creation of regional markets: increasing the interconnection capacity between national markets and increasing the coordination of the operation of these markets. The most important barriers that hinder the construction of interconnection capacity are the existing concerns about the impact of new transmission lines on the environment, and the lack of fairness of the method employed to determine which countries should pay the cost of these lines. Note that cross-border lines typically produce benefits that are very much widespread in a region, while costs/disadvantages are not. Moreover, the complexity of the process aimed to obtain the permits required to build these lines is much higher. Agents from several countries have identified these barriers as significant. Apart from this, the lack of harmonization of national market rules, which limits the power exchanges taking place between countries, has been identified as a barrier in Denmark.

The most important barriers to the integration of the operation of national markets include the fact that, short term implicit energy and capacity auctions are not applied yet in Spain and Germany, though these countries are interconnected through a meshed grid. Moreover, in all surveyed countries there is a lack of coordination of the allocation of cross border capacity that is carried out in the long term. Finally some parties in Germany, due to security reasons, argue that some degree of discrimination between local and regional transactions should exist when providing long term generation capacity reserves.

T&D networks

Transmission

The most important market responses related to transmission that would facilitate the integration of variable RES generation are the implementation of locationally and temporally differentiated transmission charges, the construction of new transmission lines allowing the transportation of the capacity produced by these units and the implementation of fair and efficient congestion management schemes. A barrier to implement locationally differentiated and time varying tariffs, according to some parties, is that locational marginal prices are too volatile,. Besides, they are also believed to be a source of unfair discrimination between agents in different parts of the grid, as well as between old and new generators. Other stakeholders are of the opinion that these tariffs may not affect investment decisions by agents due to the fact that payments resulting from support schemes to RES/CHP are so high in many systems that installing new RES generation will be profitable no matter which kind of generation it is or where it is installed. Finally, different stakeholders in the UK believe that implementing these charges makes regulation more difficult and therefore less attractive to policy makers.

As for the construction of new lines, most stakeholders agree that concerns about their impact on the environment and health could represent a serious obstacle to these lines being built. Besides, parties in the UK have stated that the inefficiency in the allocation of the cost of these lines, the lack of efficiency of the use of transmission capacity that already is in operation, and doubts about the profitability of many of the transmission investment projects that are being considered now already result in a significant opposition to new lines.

Finally, talking about the application of congestion management schemes, applying zonal or nodal prices (the most efficient solution under ideal conditions) is against the regulation in place in some countries, like Spain or the Netherlands. Besides, most, if not all, parties agree that implementing such scheme would result in an increase in the degree of the market power held by power producers in importing areas. Finally, parties in Spain and Holland have stated that computing several energy prices within their territories would make the market clearing process more complex, and the coordination with neighbouring markets would be more difficult. Others say that using nodal or zonal prices would require changing computer applications and allocating the congestion rents.

Distribution

For efficient integration of DG/RES in distribution networks the design of distribution charges, connection and use-of-system charges, paid by this type of generation is a relevant issue. Locationally and time varying distribution charges should be implemented. In those systems where locational distribution charges have not been implemented yet, main barriers identified by parties are legal (changing the tariff codes would be necessary in Netherlands). Additionally, allocating charges to generators in an efficient, cost-reflective, manner is also regarded as a challenge by authorities in Germany. For most parties consulted, volatility is not considered a problem when implementing this kind of charges. An exception to this rule is the Netherlands.

Active network management (ANM) is unanimously acknowledged as an effective measure to integrate variable distributed RES generation. In order to encourage DSOs to apply ANM, many countries have implemented efficiency incentives schemes that reward DSOs for reducing losses and increase service quality levels. However, the difficulty of computing an adequate level for these incentives and the fact that most systems are not taking into account the effect of DG-RES on losses and quality when computing the incentives is undermining their effectiveness. Finally, the incentives in place in some countries, like Spain, the Netherlands or Germany, to implement these techniques are believed to be too weak.

A potential benefit from DG RES is the cost reduction that can be achieved by integrating it in the process of planning the expansion of the grid. However, where incentive schemes for the efficient planning of the expansion of the grid by DSOs are applied, in Spain and Netherlands, the reference remuneration level of the DSO and the efficiency factor ‘X’ are computed not taking into account the effect of DG. Other countries, like UK and Germany, believe that implementing incentive schemes of this type is not necessary because incentives already in place for efficient system operation (losses and quality) are strong enough. Again, some parties believe that DG RES support schemes encourage variable DG RES not to follow DSO’s instructions, which renders the installation of variable DG RES as less beneficial, or even problematic, to operators. Related to the previous market response option, DSOs are not considering the possible future application of ANM when planning the expansion of their grids, which makes it more difficult for the system also to benefit from the presence of variable DG.

Variable type of DG may provide some system services that can be of help to the DSO. However, many of the existing generators do not comply with the technical requirements that must be met to provide these. Apart from this, the markets where variable DG could sell these services to the DSOs would probably not be liquid enough, since most of the potential generators that could provide a certain service would be owned by the same company. Even if competition could be established among potential providers of AS, generators may not find it profitable to offer them, since the revenues resulting from the sale of their energy in the market are much higher in many countries than those they would obtain by providing these services. Finally, as a consequence of all this, so far variable RES DG is not regarded by DSOs in most countries as a reliable source of AS.

Future research work

This document has shown that important barriers are present in every segment of the electricity system. Some of them appear in several countries, while others correspond to country specific barriers, see also tables 6, 7, 9, 11, 12, 13 and 14 with the main barriers in system segments generation, demand, national markets, regional markets and transmission and distribution networks, found in the analysis and the countries where the barriers are significant.

Based on the analysis and conclusions in this report in a next step in the RESPOND project the work will focus on formulating measures, regulatory changes etc necessary to implement the earlier as viable and efficient (report D5 of RESPOND) identified options to mitigate the system cost impacts by penetration of much more variable RES generation in the five EU countries. An efficient regulatory framework will be proposed and a roadmap for implementing these regulatory improvements step by step in effective and efficient manner.

8 References

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