Integrating intermittent renewables sources into the EU electricity system by 2020: challenges and solutions

A EURELECTRIC TF Integration of Renewables paper

April 2010

The **Union of the Electricity Industry–EURELECTRIC** is the sector association representing the common interests of the electricity industry at pan-European level, plus its affiliates and associates on several other continents.

In line with its mission, EURELECTRIC seeks to contribute to the competitiveness of the electricity industry, to provide effective representation for the industry in public affairs, and to promote the role of electricity both in the advancement of society and in helping provide solutions to the challenges of sustainable development.

EURELECTRIC's formal opinions, policy positions and reports are formulated in Working Groups, composed of experts from the electricity industry, supervised by five Committees. This "structure of expertise" ensures that EURELECTRIC's published documents are based on high-quality input with up-to-date information.

For further information on EURELECTRIC activities, visit our website, which provides general information on the association and on policy issues relevant to the electricity industry; latest news of our activities; EURELECTRIC positions and statements; a publications catalogue listing EURELECTRIC reports; and information on our events and conferences.

EURELECTRIC pursues in all its activities the application of the following sustainable development values:

Economic Development

- Growth, added-value, efficiency

Environmental Leadership

- Commitment, innovation, pro-activeness

Social Responsibility

- Transparency, ethics, accountability

Dépôt légal: D/xxxx/xx.xxx/x

Integrating intermittent renewables sources into the EU electricity system by 2020: challenges and solutions

----

TF Integration of Renewables
Mr. Marcel CAILLIAU (BE), Chair
Mr. Kai ADAM (BE), Mr. José ARCELUZ OGANDO (ES), Mr. Hakon EGELAND (NO),Mr. Ricardo FERREIRA (PT), Mr. Håkan FEUK (SE),Ing. Federico FIGEL (IT), Mrs. Stine GRENAA JENSEN (DK), Mr. Jaakko KARAS (FI), Dr.. Cornelia KAWANN (CH), Mr. Cesar MARTINEZ VILLAR (ES), Mr. John MCMANUS (IE),Mrs. Simonetta NALETTO (IT), Mrs. Henrike OSTHUS (DE), Dr. Andreas POULLIKKAS (CY), Dr. Jan SUNDELL (SE), Mr. Ruud VROLIJK (NL), Mr. Bernhard WALTER (DE),Dipl.-Ing. Michael ZOGLAUER (AT)

Contact:
Marco FORESTI – mforesti@EURELECTRIC.org

TABLE OF CONTENTS

Executive Summary

Introduction

The EU's decision to have at least 20% of its energy supplied by renewable sources by 2020 means that European electricity markets will have to reach a renewables share of 30-35% of all generation sources, according to most estimates. The increased production of renewables will, to a large extent, be based on wind and solar power, which are by their nature intermittent, unpredictable and unevenly geographically distributed. The resultant increase in the amounts these types of RES will have significant and far-reaching effects on both the electricity market and on transmission and distribution grids.

EURELECTRIC fully supports the 2020 targets and has committed to initiatives to decarbonise the EU electricity sector by 2050. The aim of our association's work is not to question political targets, but to identify and propose efficient solutions to policy makers so as to assist them in meeting their agreed targets; this paper follows the same approach. As a general conclusion, this paper demonstrates how **market integration, a policy goal per se set by the EU, becomes even more urgent and indispensable to ensure a sustainable and secure power system** in the face of increasing levels of intermittent generation. Renewables targets and Security of Supply standards should not supersede the creation of a single EU market, but rather be part of the same strategy; we believe none of the three EU energy policy objectives can be reached without the other two.

Wholesale price dynamics

The marginal generation costs for wind (and solar) energy are very low. Depending on the amount of expected wind energy, there will be a different structure of marginal costs in the market and consequently a shift in the supply curve. Depending on the wind injection and the actual supply and demand curve of other market participants, prices will change much more from hour to hour compared to a case without wind injection. As a result, **spot price volatility will increase.**

With increasing injection of RES, we may also observe an increase in the frequency of situations where there is more supply than demand, even at wholesale prices equal to zero. This is due to the non-storability of electricity. To deal with this issue, some power exchanges have already introduced negative price boundaries (e.g. EPEX Spot and Nord Pool Spot). Our analysis concludes that negative prices indicate 2 major shortcomings: firstly that the necessary price signals to maintain an appropriate balance between supply and demand are missing; secondly that there is a lack of grid capacity for transporting the energy generated at low marginal cost to places where it is less efficient (or less profitable due to the different support schemes) to build similar RES plants. On the other hand, negative prices will increase price volatility, and will thus attract investments (for instance in flexibility, storability) that will in turn mitigate the volatile environment.

As a policy recommendation we believe that **common rules should be developed for neighbouring countries in order to avoid distortions related to negative prices**.

Balancing Markets

Traditionally, the amount of balancing energy, or reserve, provided by controllable thermal or hydro generation had to be sized to balance variations in demand or forced outages of the largest production unit. Large penetration of intermittent and in particular wind generation introduces additional requirements for balancing products and services: since wind generation has limited predictability, in order to cope with the forecast error, larger amounts of flexible sources are necessary.

The consequence for electricity systems with a high penetration of wind generation is a higher exposure to problems related to grid stability. Therefore, ancillary services markets should be developed so that customers and generators with flexible consumption or production can “offer” such flexibility to system operators and other market participants. EURELECTRIC considers it necessary to ensure **a level playing field for balancing responsibility** which applies to all producers, including wind generators, in order **to stimulate all market participants to carry out thorough and proper scheduling and forecasting and thus limit system costs**. Moreover, **integrated cross-border intraday markets with continuous trading are needed** to allow forecast updates to be incorporated into the market.

Impact on Generation Investments

Our analysis shows that only a small share of wind capacity can be considered as “firm”: every MW of wind capacity generally requires 1 MW of backup firm capacity to ensure 90% availability. This leads to an important conclusion: greater amounts of wind generation avoids fuel expenses but still requires investments to be made in backup capacity. The necessary backup capacity could be provided by new flexible generation plants or by prolonging the lifetime of existing ones. Moreover, a number of additional measures can help to compensate for more frequent imbalances between supply and demand, namely increasing interconnection capacity in order to “import” backup capacity from abroad, developing energy storage facilities (e.g. pump storage, district heating systems, electric vehicles, etc.), introducing “smart grids” and interruptible supply contracts or indeed any other Demand Side Management mechanism.
Higher RES penetration will result in a significantly reduced load factor for conventional generation, as the RES technologies will replace a growing section of the electricity supply curve. Therefore, the ability of existing back-up plants to recover their fixed costs may be weakened and may lead to earlier decommissioning decisions or discourage new investments.

EURELECTRIC believes that the market will find the equilibrium market price to stimulate the correct investments, provided that prices are allowed to change freely (without price caps/floors) and competition authorities accept the "price spikes" that will emerge. Nevertheless, **in some cases, the uncertainty faced by investors on the magnitude and frequency of "price spikes" may put the necessary back up generation capacity at risk**. If this occurs, market design rules may need to be reviewed. **Careful analysis is required to assess in which cases,** under which conditions and on what geographical scale **it may be advisable to introduce capacity remuneration models.**

Market integration as a solution for RES integration: the software

The development of a true internal market in electricity is one of the EU's main energy policy goals and an explicit objective of the Third Energy package. The large amount of planned additional intermittent generation sources will to a large extent challenge the process of market integration, making it more difficult, but at the same time even more necessary.

Based on existing scenarios, wind energy injection will be mainly concentrated in the north of Europe and Iberia, whereas the flexible generation is dispersed throughout Europe (with hydro reserves concentrated in the Nordic area and in the Alps). Should large deviations occur in day-ahead or intraday or balancing phase, all European flexible sources will be required to address such deviations. To achieve this, the following market integration tools - **market coupling, cross-border intraday and cross-border balancing - are indispensable to ensure and facilitate the contribution** (on a competitive basis) **of all available flexible sources throughout Europe**. In order to achieve this goal, EURELECTRIC has been proposing concrete solutions and possible roadmaps for a Pan-European electricity market for several years. More recently, EURELECTRIC has been cooperating with other stakeholders and policy makers to identify "target models" and implementation roadmaps for the different timeframes of congestion management: **day-ahead market price coupling, cross-border intraday allocation via continuous trading and integrated balancing markets based on TSO-TSO approach with common merit order**. We believe that these target models proposed in the process driven by the Florence Forum constitute the backbone for ensuring successful market integration.

Grid investments: the hardware

While market integration solutions only represent the "software" tools to achieve the ultimate goal of developing "a true internal market in electricity", this goal will not be reached if the necessary "hardware" is unavailable: urgent and extensive grid investments are also needed.
Grid investments are the key enabler to allow markets to cope with large volumes of intermittent RES. The introduction of high levels of RES will not only considerably affect both distribution and national transmission networks, but also transmission networks in adjacent and further away countries. Hence **the focus on investments should be shifted from a national to a regional and pan-European perspective**.

In this respect, we welcome the introduction of the ENTSO-E Ten Year Network Development Plan, as requested by the Third Package. However, taking into account that it takes at least 10 years to build a transmission line (within one country; a cross-border line would take even longer), any pan-European grid investment plans being drawn up now are already lagging behind. **There needs to be an increased sense of urgency, and strong determination to achieve the 2020 RES targets should be the main driver of any investment plan**.

With regard to regional grids (including off-shore grids), given that the benefits are shared among customers from different Member States, costs should therefore also be borne by several Member States, and the national regulators, together with ACER, must put in place rules that govern this. Setting up such governance is an urgent priority, as it may prove to be a much bigger hurdle in the future if it is not dealt with now.

Finally, the “revolutionary” change that energy markets are required to undergo to reach the RES targets also necessitates an associated revolutionary development in transmission technology. The process needs to be supported by the requisite R&D; therefore the necessary funds to support such R&D have to be established without delay.

1. Introduction

1.1 Scope and purpose of the paper

The electricity industry supports the EU's decision to have at least 20% of its energy supplied by Renewable sources by 2020. EURELECTRIC is fully committed to helping to ensure that this target is reached. In terms of electricity generation, it is generally expected that the share of renewables will be much higher than the agreed 20% target (reaching between 30-35% of all generation sources according to most estimates) and that the increased production of renewables will be to a large extent based on intermittent and unpredictable sources such as wind and solar power. Of all RES generation in 2020, wind and photo voltaic power are expected to represent almost 50% of the installed capacity (42% and 4% respectively)[1]. Compared to hydro and biomass generation[2] (estimated respectively at around 31% and 22% of total RES installed capacity in 2020) which are flexible and relatively controllable energy sources, wind and solar will be far more challenging to integrate in the system: it is therefore these two forms of renewable energy which will have the greatest influence in reshaping electricity markets and grids over the next decade. Figures from 2009 show that out of 26 GW of new power capacity invested in EU, wind generation was the leading source with 10,160 MW (39%), while photo voltaic accounted for 4,200 MW (16%), as the third source after gas[3]. For these reasons, this paper focuses on the integration of the afore-mentioned intermittent RES sources and in particular, on the integration of wind generation.

The resulting increased amounts of intermittent production will have significant and far-reaching effects on both the electricity market and on transmission and distribution grids: the purpose of this paper is to analyse these impacts and recommend appropriate solutions to policy makers. As was originally intended, increased amounts of renewables will lower the need for generation from fossil fuelled power plants; however, it will also dramatically affect the way that remaining conventional power plants are operated. Base load plants, including low carbon technology such as nuclear and fossil fuelled plants with CCS, may have to be operated intermittently if the European transmission system is not suitably adapted in time. Whilst it is envisaged that flexible conventional power plants will still be required well into the future, these will be operating fewer hours than similar plants in today's market and there will be greater requirements for ancillary services to balance the system and redispatch services to cope with transmission congestion. Considering all of these impacts, and the subsequent need to integrate larger market areas to minimise inefficiency, there is an urgent requirement to expand and reinforce the transmission system and integrate markets: this paper describes possible adverse consequences to markets, should the required investments not be made in time. Security of supply may also be affected in a number of different ways. Increased amounts of renewable energy generation will result in a reduction of fossil fuel imports and reduced profitability of conventional power plants. This in turn, can lead to insufficient investment and the failure to develop a secure system that delivers

---

[1] Elaboration based on appendix data of the European Commission, PRIMES model

2 Flexible and controllable RES, such as Hydro and Biomass, will have a role in smoothing the effects of both the intermittent and unpredictable RES.

[3] European Commission, DG Joint Research Centre, Institute for Energy, Renewable Energy Unit

low carbon emissions, particularly if electricity markets are not allowed to function efficiently as a result of, for example, inappropriate regulatory interventions. Also, it is expected that short term volatility will increase due to the very different merit curves determined by weather dependent RES, for instance the difference between those produced on a windy and sunny day and those on a cloudy day without wind.

Most importantly, this paper highlights how market integration, a policy goal per se set by EU, becomes even more urgent and indispensable to ensure a sustainable and secure power system in the face of increasing levels of intermittent generation. Renewables targets and Security of Supply standards should not supersede the creation of a single EU market, but rather be part of the same strategy; we believe none of the three EU energy policy objectives can be reached without the other two.

1.2 Some basic assumptions

As outlined above, this paper intends to investigate, on a rather qualitative basis, the impact of intermittent renewable energy sources on electricity markets and grids by the year 2020. The main outcome of our analysis is that the development and accommodation of renewable energy sources is only possible with the speedy introduction and effective implementation of market integration. In undertaking our analysis, we focused on the "systemic" effects and deliberately sought to avoid the use of detailed figures on the magnitude and location of these effects as much as possible. Where such figures are essential to support our thesis, we base our analysis on the best possible data-set currently available[4].

In order to focus on the key issues related to the integration of high levels of intermittent RES by 2020, we first set out a number of key assumptions which formed the basis of our work:

1. It's assumed that the **EU 2020 targets** for renewable energy should and will be met, and that consequently the share of RES for electricity generation will grow up to 30-35% of the total. EURELECTRIC fully supports the 2020 targets and has committed to initiatives to decarbonise the EU electricity sector by 2050[5]. The aim of our association's work is not to question political targets, but to identify and propose efficient solutions to policy makers so as to assist them in meeting their agreed targets; this paper follows the same approach. In this paper we also point out how some specific EU or national measures intended to support RES development could cause distortions or inefficiencies to the whole electricity system, including the integration of RES itself. However, the purpose of this paper is neither to question support for RES, nor the targets, but rather to propose policy choices that can maximise social welfare for both producers and consumers.

[4] At the time of writing a number of more quantitative publications exist in this field: European Commission reports, TSOs or Wind Association studies, consultants' reports, etc.

[5] See Declaration by European Electricity Sector Chief Executives on Electricity Markets, Supply Security and Climate Change & EURELECTRIC Brochure : Powerchoices - Pathways to Carbon-Neutral Electricity in Europe by 2050

2. On examining the required EU legislation necessary to promote RES development, an important feature that our analysis has to take as starting point is the so-called "**priority of dispatch**" included in the Renewables Directive 2001/77[6]. This requires that "Member States shall ensure that when dispatching electricity generating installations, transmission system operators shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria". As a consequence, other generation sources (nuclear, coal, gas, oil) have to be regulated downwards at certain times to keep the system in balance, but in addition to this, they also have to be available to offset the electricity demand in the event that intermittent renewables are not available as expected. While this provision may seem to have a limited impact on many of the current markets, this paper will discuss how the rapid development of RES capacity is increasingly impacting other types of generation and the longer term effects in 2020 and beyond, and possible solutions to accommodate RES integration.

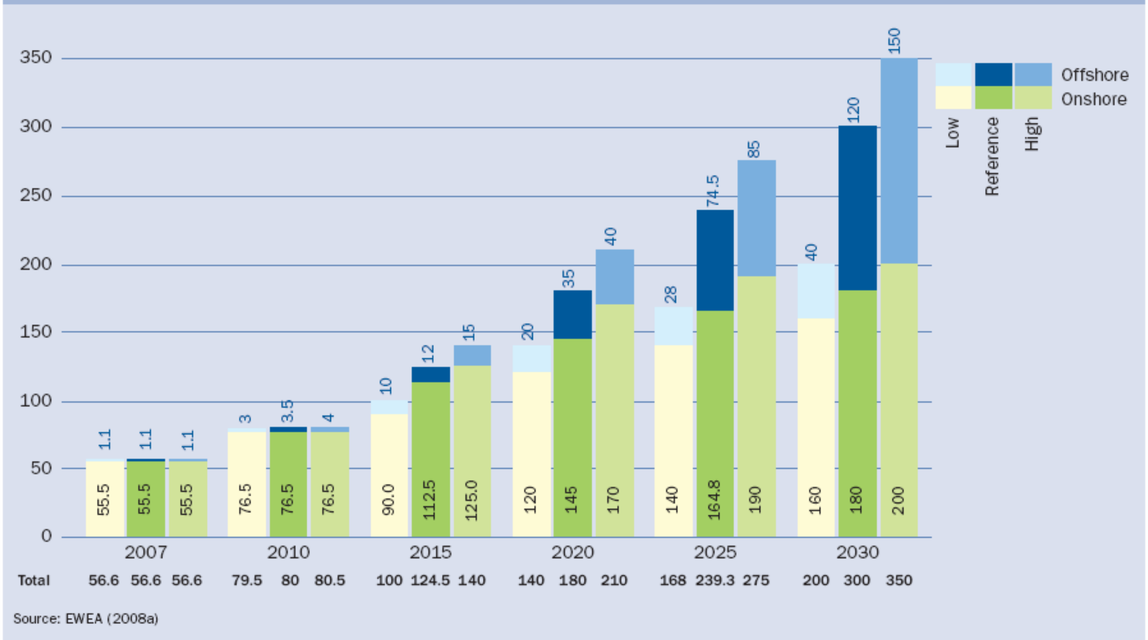
3. Apart from these political and legislative assumptions, one very important basis of our analysis is the forecasted **share of wind generation** in the system: how great will its impact be over the next 10 years? In terms of total capacity, as reported by EWEA[7], wind generation is expected to grow from the current (2008) 65GW to 140-210GW in 2020 (Picture 1). This indicates that in the next 10 years, the system will see new wind generation that is twice (or three times) the capacity already connected today. In relative terms the figures show that the share of wind generation capacity will grow from today's 8% to at least 16%[8]. Both in absolute and in relative terms, wind generation will increase 2 or 3 fold.

[6] Following the entry into force of the new Renewables Directive 2009/28, it is also a requirement that RES have guaranteed access to networks with priority dispatch, subject to secure network operation.

[7] "Integrating Wind - Developing Europe's power market for the large-scale integration of wind power", TradeWind / EWEA, February 2009.

[8] The data used by the EC "PRIMES" model, where wind generation capacity in 2020 is estimated at 155GW.

Figure S.19: EWEA's three wind power scenarios (in GW)

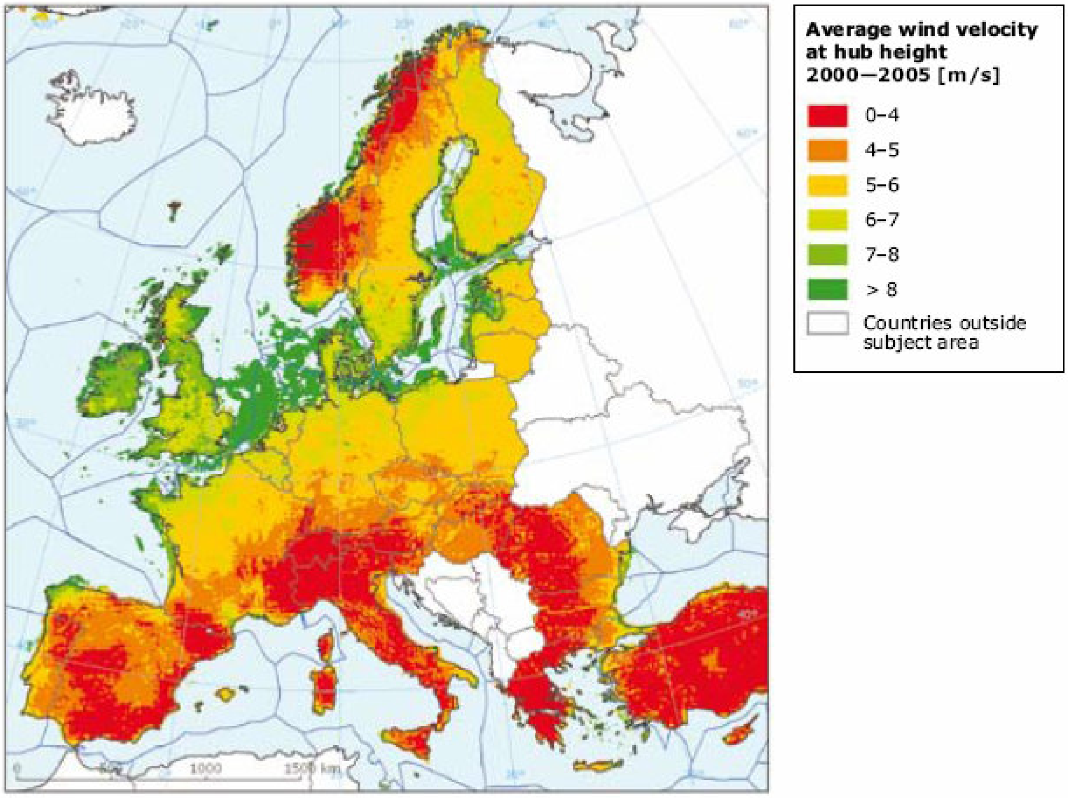


Source: EWEA (2008a)

Picture 1

4. Last but not least, generation from renewable energy sources like wind and solar has one particular feature to keep in mind: its **geographical concentration**. Within a Member State, locations suitable for wind or solar generation are generally unevenly spread out. If read in conjunction with assumption 3 above (installed wind capacity increases by 2 or 3 times), this means that certain country areas may not be heavily affected by future wind development, while others will experience radical impacts[9]. The graph[10] on the next page indicates where wind speed is adequate for further wind investment. As shown, the concentration of suitable wind sites for generation is located far from the off-take. While historically generation has mainly been built near to the load (by vertically integrated companies), this is no longer true, especially for off-shore wind farms. Increasing levels of wind generation will thus by definition exacerbate the loop-flows in the system due to the fact that injection happens increasingly far from the places of off-take. In their capacity calculation models, TSOs tend to take into account different scenarios for network security reasons: already nowadays the amount of interconnection capacities offered to the market is significantly lower than the previous NTC values.

[9] When looking at EU wide level, obviously, location of wind and solar generation will depend also on the different national allocation plans and on the difference between domestic support schemes.
[10] See 2009/28/EC of 23 April 2009 on the promotion of the use of energy from renewable sources, article 16 §2(c)



Source: EEA, 2008.

Picture 2

2. Wholesale market price dynamics

Wholesale power prices are determined by a range of fundamental factors including the supply of RES generation. At the same time, it is generally not possible to clearly distinguish the exact effects of these different price drivers on the resulting wholesale price. Of course, wholesale prices are only one part of the final customer price: this also includes factors such as government-induced costs (i.e. taxes, subsidies, levies) and grid-related costs. In this section we assess the possible dynamics of wholesale prices (level, volatility, particular effects, etc.) which may emerge following a large increase in intermittent generation in the system.

2.1 Short term price drivers

The main factors that may influence wholesale spot power prices include:

- Fuel prices (e.g. coal, gas) and fuel contracts flexibility
- CO2 prices
- Availability of the generation park: conventional as well as renewable generation, including in particular also balancing tools.
- Availability of wind and sunshine
- Where relevant: the level in the water reservoirs different in a wet/dry year.
- Availability of transmission capacity especially cross-border and the related allocation process (explicit auctions, market coupling, intraday model)
- Demand from hour to hour and long-term demand patterns: costs for guaranteed energy supply (8760 h/a) and costs of the related risks (e.g. financial crisis)
- Frequency of start-ups

All these factors not only influence the absolute level of spot prices but may also determine its range, i.e. the volatility. This is particularly true for wind energy which has probably the greatest influence on the short term price volatility.

2.2 Short term price volatility

The marginal generation costs for wind (and solar) energy are very low. Depending on the amount of expected wind energy, there will be a different structure of marginal costs in the market and consequently a shift in the supply curve (see picture number 4). Depending on the wind injection and the actual supply and demand curve of other market participants, prices will change much more from hour to hour compared to a case without wind injection. As a result, price volatility will increase.

In principle, higher price volatility creates more uncertainty for short-term operations. Whilst conventional plant operators can make reliable estimations about how long their plants will run in a regime without intermittent injection, this becomes much more difficult in situations where the merit order across the hours of the following day is less predictable. This will by definition lead to a less than optimal dispatch of their generation

units and some additional costs and risks (e.g. more start/stop costs) have to be taken into account, adding additional variations to the prices of the supply curve.
Some argue that the hourly variation of wind production is smaller when the wind output (in particular from off shore wind farms) is aggregated over more wind farms due to the portfolio effect. This is true as long as the market size is large enough to take up a considerable wind power portfolio. Furthermore, making use of the portfolio effect will require strong interconnections between markets in order to optimise the uptake of intermittent power sources like wind Only when the different wind farms are pooled, or interconnected with each other, or when it is possible to share the regional (smoothed) injection from the sum of the wind farms over all market places together (in a non-congested network), can it be expected that there will be a reduction in price volatility due to the intermittency of the wind.

Conclusion:
<u>Short-term price volatility will increase as a consequence of higher penetration of intermittent RES.</u>

2.3 Wholesale spot prices level: increase or decrease?

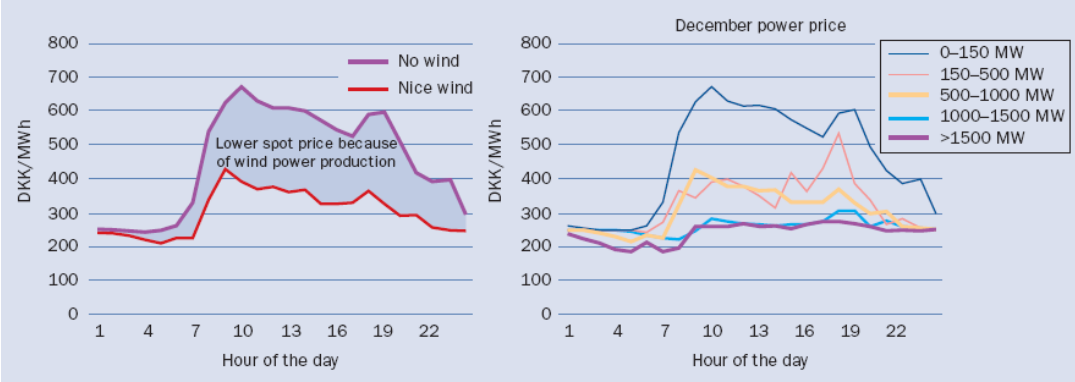
Any analysis, be it of historical data, or of simulations of future price evolutions, appears very difficult because of the number of interrelated effects which cannot be isolated; any conclusion needs to be treated very carefully. Furthermore, the dynamics of future generation investments will determine further effects on prices. Therefore, we believe that a quantitative analysis of the impact of renewable generation on the level of wholesale prices is by its very nature uncertain and in any case, outside the scope of an industry association paper. However, some static-qualitative analysis in the paper will show that there are reasons to expect both price decreases as well as price increases. With the increasing injection of renewable energy into the grid, electricity wholesale prices will become less dependent on fuel prices such as gas and coal. In turn, this may influence the power prices in both directions[11].

Price decreasing factors

1) Having a lot of energy injection with low marginal cost from mostly wind farms will certainly push the plants with higher marginal costs out of the market, leading to a lowering of the spot price. This has been observed in different markets by several analyses, amongst others by EWEA, as shown in Picture 3 below.

[11] It should be noted that end users' electricity expenditure (including prices, tariffs, taxes and levies) will depend on a number of factors: wholesale prices may have a lower impact than, for example, the mechanisms and the intensity of support schemes for RES development.

Figure S.13: The impact of wind power on the spot power price in the West Denmark power system in December 2005



Source: Risø DTU

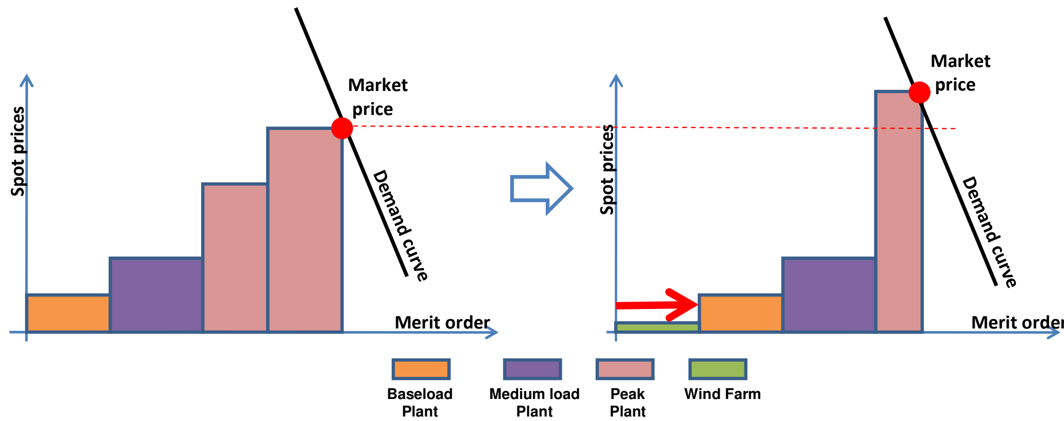
Picture 3

This picture shows a historical comparison between moments with and without wind. However, it is difficult to make a comparison between the hypothetical situation as it is “now” (with the intermittent sources connected to the grid) and another hypothetical situation where the wind farms did not exist at all (situation of the past) with a more stable programming possible for the conventional plants, whereby these conventional plants would have less start-ups and stops with higher efficiency working points.

2) The increased penetration of RES will have a direct impact on the consumption of other primary energy sources. For instance, 200 GW of wind generation with a load factor of 2500 hours, results in 500 TWh of electricity production that no longer needs fossil fuel, or approximately 1000 TWh of primary energy fuels (gas, coal, oil, etc) will not longer be required. Assuming that all other primary fuel demands (for heating, manufacturing, transport, etc.) remain globally stable into 2020, this would result in a reduction in demand for these fuels and thus, lead to a relative price decrease in these primary fuels.

Price increasing factors

1) Given the variability and intermittency of wind injection, when the wind is not available the injection has to be replaced by conventional power plants. However, this radically alters the running of these power plants, which will be required to start and operate for a shorter period of time. As a consequence, the start up costs have to be spread over fewer hours and the marginal bidding price of these plants will increase in order to cover these start-up costs over a shorter time period. This development is illustrated in picture 4 below: some of the plants are pushed out of the market, while the electricity generated by the remaining (gas) plants will be offered at higher marginal costs, giving rise to a higher equilibrium price.
This trend may be further accentuated if there is need to keep certain plants on line (must run plants) in order to have the required flexibility for upwards and downwards regulation (as further explained in the section on Balancing, Paragraph Chapter 3.2).

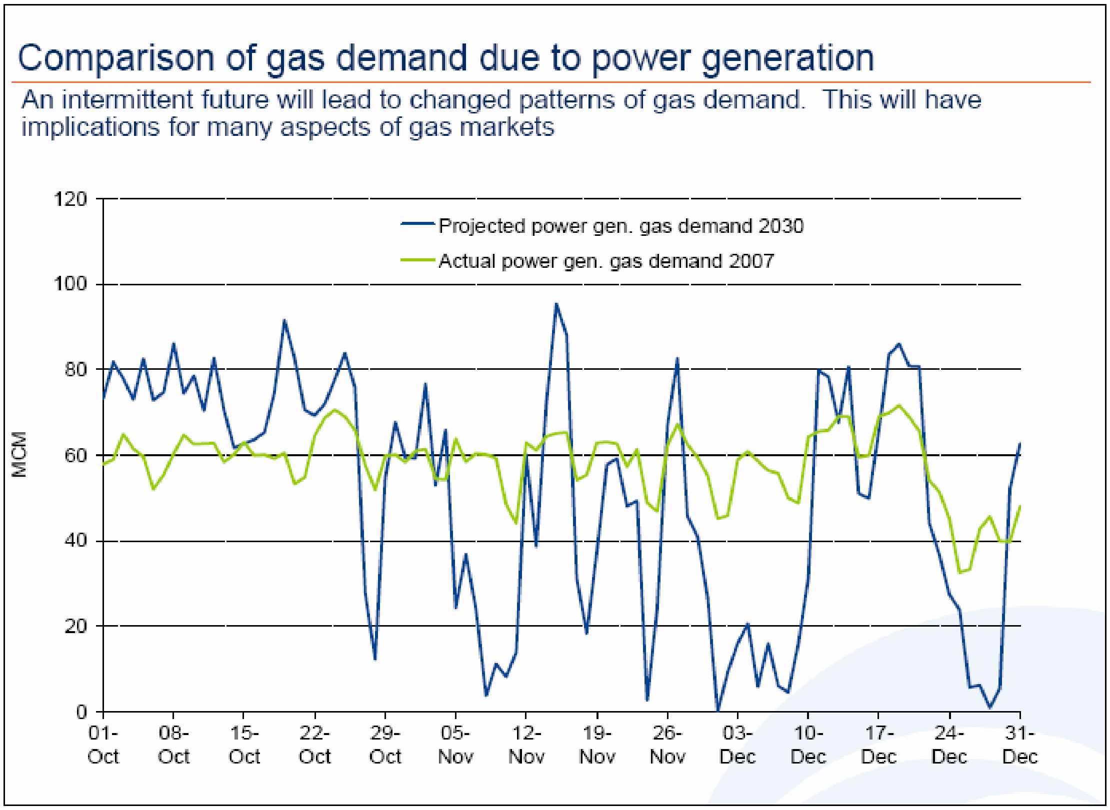


Picture 4

2) Although the second price decreasing factor mentioned above (lower demand for fossil fuels) might suggest the conclusion that "gas" will become cheaper, intermittent wind production will increase the level of variability of primary fuel demand for conventional gas plants that (amongst other flexible sources) provide the backup for wind farms. These plants will require additional gas flexibility via storage facilities, flexible production facilities, etc. An analysis carried out by Pöyry[12] shows the expected differences between the 2010 gas off-take and the simulated 2030 gas off-take. Picture 5 shows that the average gas off-take for power generation in the UK in 2030 will be lower[13] than nowadays, with the biggest expected impact being an increase in demand variability, which may eventually drive up fuel procurement costs and plants' operating costs. Lower (and more variable) use of primary fuels will in fact reduce the advantages of economies of scale for plant operation and for the fuel chain.

[12] "Impact of Intermittency: How wind variability could change the shape of the British and Irish Electricity Markets", Pöyry, July 2009.

[13] In absolute terms, this forecast may differ significantly from the future reality: to determine future gas demand for the UK market many other assumptions about the 2030 fuel mix need to be taken into account. However, the short term variability of demand can be taken as one of the most predictable impacts, due to the sharp increase in intermittent generation in the system.



Picture 5 (Source: Pöyry Energy Consulting)

2.4 Negative prices

With increasing injection of RES, we may also observe an increase in the frequency of situations where there is more supply than demand, even at a price of zero. This is due to the non-storability of electricity. To solve this issue, some power exchanges have already introduced negative price boundaries (e.g. EPEX Spot and Nord Pool Spot) [14].

For certain hours (mainly during weekends and especially during night hours) there will be a combination of the following factors:

- Very high injection of wind energy
- Low consumption

Based on the priority dispatch principle mandated by the Renewables Directive, TSOs are not allowed to curtail wind farms (with exceptions permissible only in the event of system security constraints). As a consequence of this situation, conventional plants will have to be regulated downwards. However, these plants cannot operate below a certain technical

[14] Even if negative prices do not "appear" in most of the wholesale electricity markets due to floors set at zero, the same oversupply situation occurs in all countries but it is dealt with differently, albeit still with a cost for society.

minimum output, thus the only way to reduce their production even further below this technical minimum would be to shut them down.

Conventional plants also have other constraints, such as a minimum down time, ramping rates for up and downwards regulation, and each start-up introduces additional costs. Regular starts and stops also increase maintenance and operation costs. In addition, most nuclear plants cannot be regulated downwards for a short period of time for safety reasons or because their ancillary circuits are not configured for regular start-up/stops. There are also other constraints in nuclear reactors which limit the ability for a fast start-up or require specific measures to stop them (like for instance the specific problems in the stretch-out phase).

As a result, there are situations where it makes more sense for such generators to keep their plants running by bidding in negative prices, because it is still cheaper to pay somebody to take the energy than to stop the plant and start it again shortly afterwards.

Another reason why oversupply occurs is the need to keep specific plants running for system stability, regulating power, etc. The additional power from such "must run" plants may result in oversupply to the market.

In the event of system security constraints, curtailment[15] of wind production is justified as it is already stated in the RES Directive. In the case of negative prices, however, it depends on the support schemes whether wind generation remains connected or not.

The occurrence of negative prices may result in the creation of a negative social welfare. From a macroeconomic point of view, it would be more efficient to curtail wind generation[16] at a certain level, rather than keeping wind farms on line, which can sometimes result in very extreme negative prices. From the demand point of view, we can imagine instances where additional load is introduced in order to benefit from such negative prices (including a shift of load), e.g. additional public lighting in service or where industrial customers start up additional equipment to benefit from these negative prices. For these reasons we believe that support schemes should be designed or adjusted so that wind generators have the incentive (safeguarding existing contracts and related expected profits) to disconnect or reduce their output when it's not economically efficient for society to keep them on line.

What measures might mitigate the problems associated with negative prices?

Support Schemes

Each country has its own targets for renewables and its own responsibility to achieve them. Support for renewables is necessary for achieving these objectives, and at the moment Member States are free to decide how to design national support schemes. Nevertheless, support schemes and market rules should go hand in hand so as to prevent distortions in the price formation or delays in market integration.

[15] The introduction of a compensation mechanism should be investigated also depending to the type of support scheme in place.

[16] The introduction of a compensation mechanism should be investigated also depending to the type of support scheme in place

On the other hand, having the appropriate support scheme in place could create incentives to find out the right balance between the creation of negative social welfare and the desired amount of investment in wind generation. Take, for instance the scenario that at least a part of wind generators' revenue depended on the real market price: on the one hand investors' slightly greater exposure to market risk may mean that investments are not made as quickly (and thereby potentially have an impact on the country's ability to reach its 2020 targets), but on the other hand, this would at least prevent wrong incentives as described above leading to energy being 'wasted'. It is Member States' responsibility to find the appropriate balance that ensures the 2020 targets can be achieved in the most economical way possible.

Differences in support schemes between Member States could also result in distortions, whereby wind generators do not necessarily invest in those locations where the renewable production is optimal, but rather in locations where they can maximise their profits. This would lead to a concentration of low marginal cost generation in certain Member States that would sooner or later be confronted with lack of grid capacity, increasing balancing cost and resulting negative prices. This scenario would then lead to additional investments in both grids and in balancing and back-up facilities being required. Clearly, it would make more sense to avoid such a scenario by ensuring that harmonised support schemes are applied in neighbouring markets, thus spreading out the concentration of wind generation over more markets.

The cases described above show that existing plants were not designed with the technical requirements to cope with a large amount of intermittent energy: market rules should be reviewed accordingly to adapt to this new context.

Market mechanisms

We are however confident that the market will put in place the appropriate mechanisms to efficiently cope with negative prices, should they become a more permanent feature of the energy system.

With the development and introduction of smart metering and smart grids, more and more customers will be able to "see" the negative spot prices and thereby receive the direct signals to enable them to respond and adapt their consumption behaviour accordingly, depending on the type of supply contract. For these reasons we affirm once again that end user regulated tariffs should be eliminated, since they do not allow correct signals for customers to react to market prices.

Negative prices will also stimulate investments in different "electrical energy storage" (or cogeneration with heat storage) facilities, which consume electricity when prices are low and deliver it back to the grid at times when prices are high, (pump storage is a good example). They will also stimulate investments in plants that provide greater flexibility, for instance lower "minimal technical plant output", lower start/stop costs, etc.

Market design

We also note that there are some additional administrative hurdles with regard to negative prices, since negative prices are already implemented in some markets, whilst they are not allowed in others (although they may be introduced in the future).

For instance, when markets are integrated in the day-ahead phase via market-coupling, there will be no convergence between the price from the negative price area and a neighbouring price area where negative prices are not allowed on the power exchange, despite the available cross-border capacity not being fully used. For these reasons, EURELECTRIC strongly recommends the development of common market rules that prevent the emergence of distortions when joining offers and interchanges of energy[17].

Transport capacity

This also brings us to a more structural solution to avoid negative prices: regions with abundant low price injection should be provided with sufficient grid capacity to "export" the low (and in particular negative) prices to other price areas. From a European market perspective, it can be argued that negative prices due to a higher proportion of RES generation would probably not occur if there were no grid constraints.

Conclusion:

- Negative prices indicate that the necessary price signals to keep an appropriate balance between supply and demand are missing.
- Negative prices also prove that there is a lack of grid capacity for transporting the energy generated at low marginal cost to places where it is less efficient (or less profitable due to the different support schemes) to build similar RES plants.
- Negative prices will increase price volatility, and will thus attract investments (for instance in flexibility, storability) that are beneficial in a more volatile environment.
- Common rules should be developed for neighbouring countries in order to avoid distortions related to negative prices.

2.5 Sharing the burden of the RES targets

The achievement of Member States' national overall targets set by the RES Directive for the share of energy from renewable sources in gross final consumption of energy in 2020, will entail an asymmetric contribution from the different sectors which contribute to the gross final consumption of energy. Technological constraints limit the capabilities of some sectors, even more so than the electricity sector, which contribute to the gross final consumption of energy (i.e. gas and oil), to meet this challenge.

[17] This view has been confirmed by a majority of CWE market participants in the recent survey where they were questioned about the need to harmonise the price boundaries between the different involved power exchanges.

Electricity is the key sector which will help to meet the target due to the possibility of using renewable energy sources in electricity generation. At the same time, it can be easily concluded that deployment and integration of RES in electricity entails a huge economic effort in terms of support incentives, operational costs, grid reinforcements and backup infrastructure.

So far, this burden is being assumed solely by the electricity sector and it is reflected in the final price consumers pay. In doing so, there is an incorrect economic signal sent to consumers since they might opt to switch to other less efficient sources of energy, which would only increase the need for renewable sources of energy in electricity so as to offset the increase in consumption of other types of final energy.

To avoid these undesired effects it is necessary to develop an effective system for sharing the cost burden of being compliant with the RES Directive targets amongst the different sectors contributing to the gross final consumption of energy.

3. Balancing markets

Traditionally, the amount of balancing energy, or reserve, provided by controllable thermal or hydro generation had to be sized to balance variations in demand or forced outages of the largest production unit. Therefore, the reserve was mainly required for upwards regulation. Large penetration of intermittent and in particular wind generation introduces additional requirements for balancing products and services.

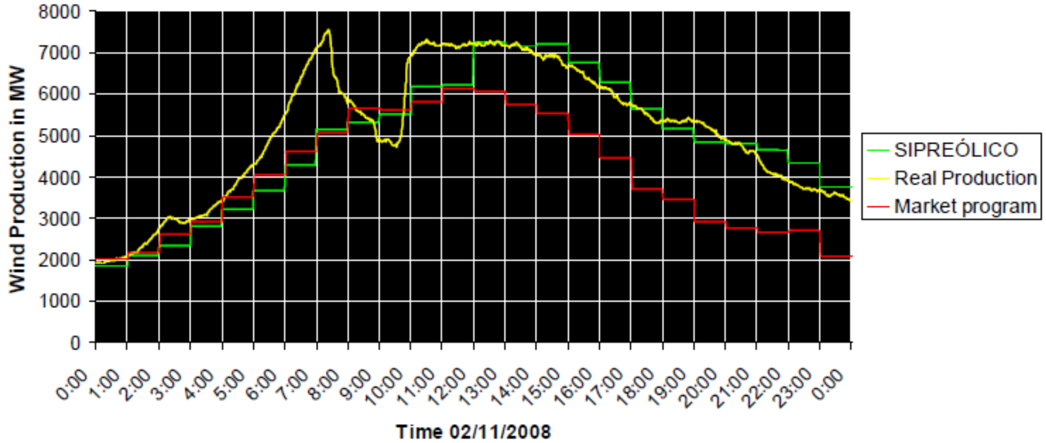
The reasons are twofold:

- Since wind generation has limited predictability, in order to cope with the forecast error, larger amounts of flexible sources are necessary.
    - This forecast error can be either negative, (less wind in real-time than forecasted, thus requiring upwards regulation) or positive (more wind in real-time than forecasted, thus requiring downwards regulation).
    - It should be noted that, in general, there is a portfolio effect which partially reduces the wind forecast error by considering the cumulative output from all wind farms as compared to the forecast error from an individual wind farm.
- The predictability of wind generation will improve over time, however, even with perfect forecasting, wind generation will remain intermittent, i.e. non-controllable, and very variable from one hour to another, and for this reason additional flexibility is required.

The consequence for electricity systems with a high penetration of wind generation is a higher exposure to problems related to the grid stability. The availability of an appropriate number of reserve power plants and their flexible dispatch becomes increasingly important to provide the necessary firmness and ancillary services to deal with these issues.

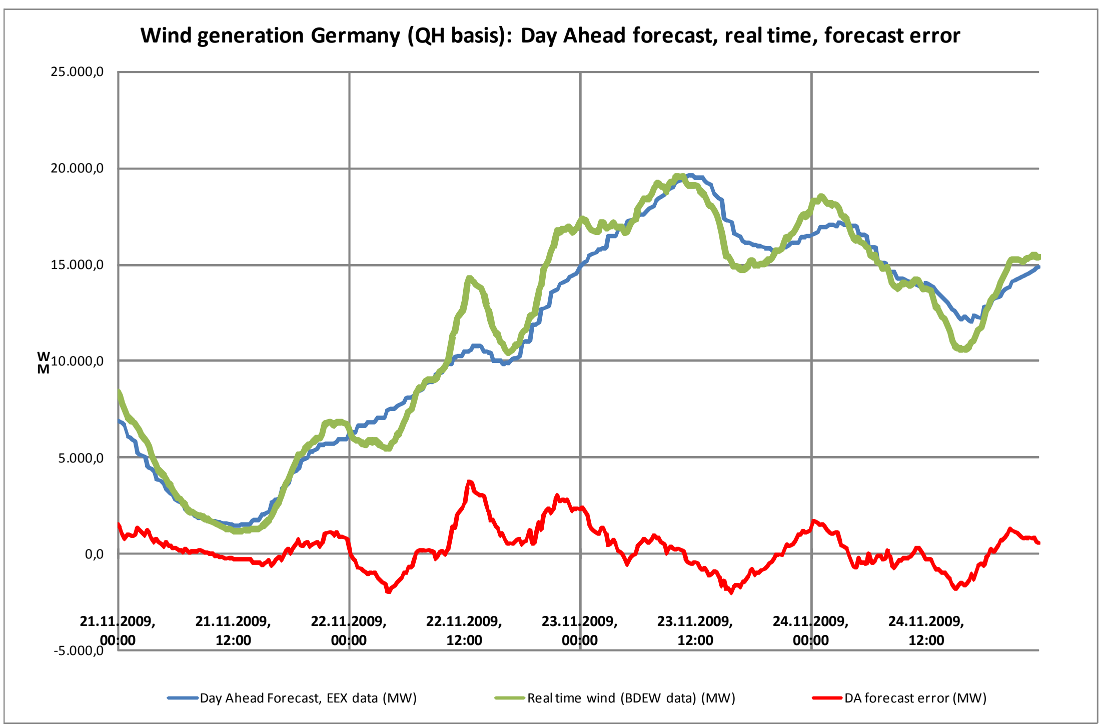
3.1 Some evidence and examples

The graph in Picture 6 (overleaf) shows an extreme case of wind forecast error in the Spanish electricity system. With one of the lowest demands of the year (on Sunday 2nd November 2008, 8h00, close to 20.000MW), wind prediction error hit 3.200MW. The system ran out of downwards reserves and it was necessary to decrease wind production to balance the system, from 7h22 to 9h30.



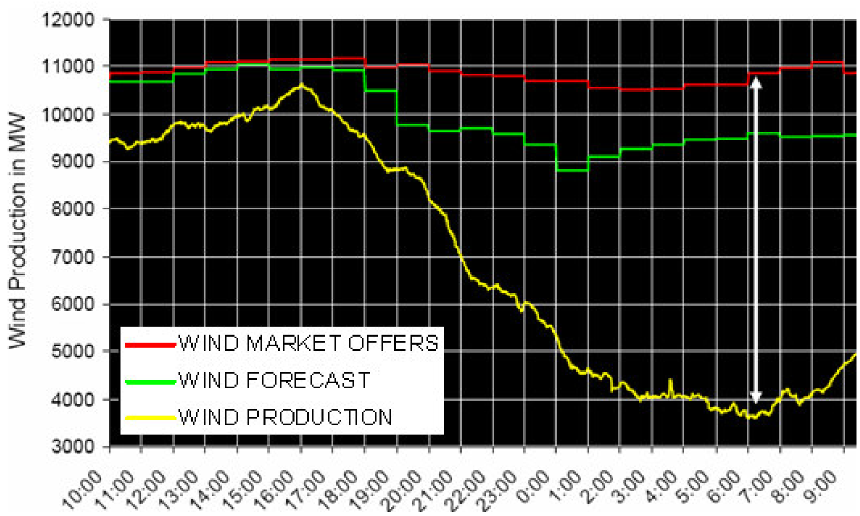
Picture 6

The lack of firmness of wind generation (i.e. the intermittency) and the lack of forecast precision (on day ahead) is reflected in the next chart related to the German situation. Between the 21st and the 23rd of November 2009, the wind injection increased from a few hundred MW up to about 20000 MW. During the same period, it can be observed that day-ahead forecast errors of between -2000 and +3750 MW occurred. It is also worth noting that on the 24th there was a high level of wind generation during off peak hours, which later decreased during peak hours of approximately 7000 MW.



Picture 7

There are also a small number of instances, where the difference between the real and forecasted wind production is as a result of wind generation being limited by the over-speed protection of wind turbines when the wind blows at high speeds. The graph in the Picture 8 shows one such instance where there was a difference of over 6.000 MW in Spain on the 23rd/24th of January 2009 between the wind generation forecast and actual production, as a result of the activation of the over-speed protection devices.



Picture 8

Clearly, in the future wind generators need to be subjected to similar levels of technical requirements as those of conventional plants in order to prevent risks to system security and to meet qualitative standards of supply (voltage, frequency, etc). This includes the mandatory installation in wind turbines of devices to support the resistance to voltage dips and prevent situations in which small (local) disturbances in the network could entail a large loss of wind generation.

3.2 Consequences

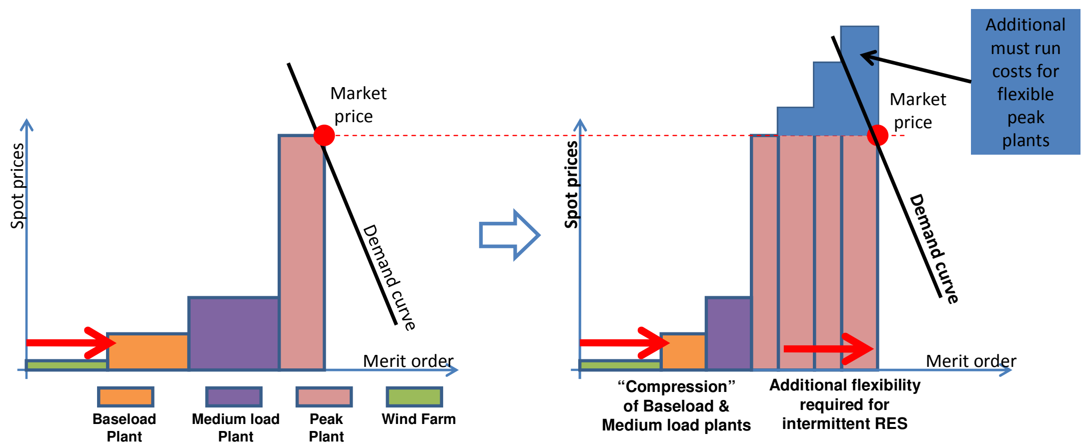
One important consequence is that the TSOs will need to procure higher amounts of reserve as compared to a similar sized system without intermittent (wind) generation. In their report, Frontier and Consentec indicate that based on experiences in Germany, Spain and Portugal about 0,25 to 0,3 GW of additional reserve is required per GW of additional wind capacity. Evidence from Germany shows that currently 7,5 GW upwards and 6 GW downwards reserve is contracted (compared to a total installed wind capacity of 25GW), while the largest conventional production unit is about 1,5 GW.

These additional requirements imply an increasing amount of mandatory dispatching of thermal units. It reduces the capability of generators to manage their portfolio (trading with these units is limited), and consequently reduces the offers on the commodity market.

On top of the measures outlined above, during periods of high wind injection, TSOs are also still obliged to keep negative regulation facilities. This means that at a moment where the spot market price is very low (or even negative), the system is obliged to be able to provide not only a positive regulation power, but also a negative regulation power. Therefore, conventional generators may be required to generate at lower, less efficient loads, to facilitate both upwards and downwards regulation.

As an example, consider a 400 MW CCGT plant with a minimum technical capacity of 200 MW, an efficiency of 50 % and a spot gas price of 25 €/MWh. In the event that this plant is obliged to produce 300 MW in order to be ready to produce 100 MW more (or 100 MW less) if needed, and the spot market price is 0 €/MWh, then this plant incurs a financial loss of 15000€/hour; this "must run" cost has to be paid by the TSO, in order to supply the required ancillary service. It should also be considered that there might be additional costs for the "option" of the gas supply.

As briefly mentioned in the previous section on wholesale price formation, the need to keep 'must-run' plants on line in order to have the required flexibility for upwards and downwards regulation determines not only a higher market price but a lower number of operating hours for "conventional" plants, including baseload and medium merit order plants, which are somehow "compressed" as shown in picture 9.



Picture 9

The need to keep flexible plants on line generates additional "must run" costs (highlighted in blue in picture 9) and possibly an oversupply if baseload and medium load plants are not sufficiently "compressible" (due to minimum generation output constraints). This oversupply may lead to negative prices as explained in paragraph 2.4.

Costs to reserve the band of secondary regulation and the additional spinning reserve for tertiary purposes are socialized in most markets through the system tariffs, which means that there is no price signal to the intermittent generators because of the higher flexibility requirements in the system.

In some markets, there is an overlap between ancillary services needed for system balancing and those needed for congestion management. Higher wind penetration might not only affect the costs for balancing the system (as indicated in the previous paragraph), but depending on the location of the wind generation, a higher congestion management cost via re-dispatching could also become necessary. EURELECTRIC recommends that a review of the procurement of all required ancillary services is undertaken in order to preserve an adequate cost allocation, otherwise costs of new requirements could be hidden in existing services.

3.3 Solutions: applying the same rules for all generators will improve efficiency

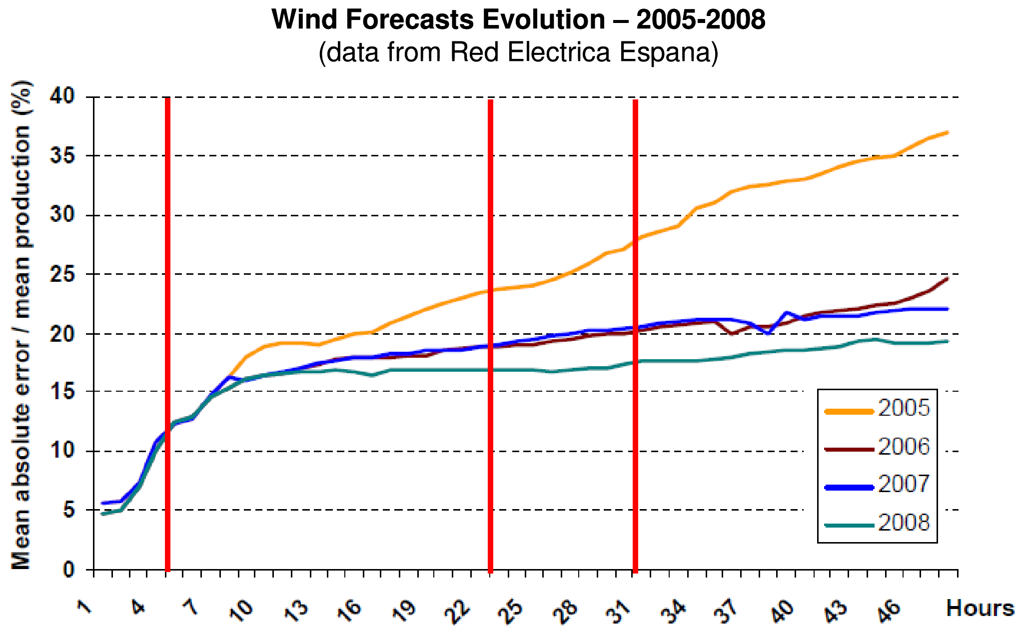
Spain's experience shows that making wind generators subject to the same balancing and scheduling obligations as conventional power plants does not jeopardize the development of this technology. On the contrary, this seems to be the best way to stimulate improvements in forecasting methods: as a result of it, system balancing requirements can be reduced and costs are fairly allocated.

From a social welfare point of view, the biggest issue is not the individual forecasts from different wind power generators, but the total wind power forecast (for which the TSO is generally responsible). That does not, however, remove the need to incentivise more accurate forecasting via individual, or pooled balancing responsibility.

A further requirement should be that once the lifespan of a subsidy for a certain wind farm has expired, the wind generator is required to compete on the market like any other producer, subject to the same obligations. It is therefore also in wind producers' interest to "get familiar" with forecasting and scheduling discipline as soon as possible.

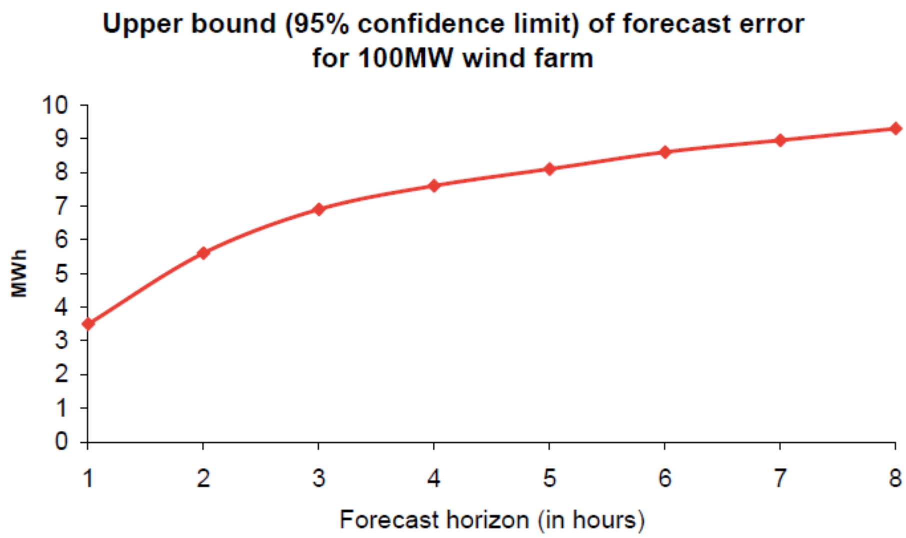
We believe that priority of dispatch and guaranteed network access for RES generation, set by the new RES Directive, should not exempt these generators from their scheduling and balancing obligations, otherwise full integration of wind generation in the market will never be achieved and wind generation will never be able to compete with other types of generation.

Errors in forecasting day-ahead wind generation have decreased in the last few years but they are still much higher than errors when the forecast is made few hours before real time. Figure 10 below gives an idea of the level of error in wind generation prediction when forecasts are made 48 hours in advance (from REE, Spanish TSO). The picture also shows the improvement of forecast techniques over the years.



Picture 10

The next graph[18] shows the 95% confidence limit of forecast error when the time horizon is in the range of 8 hours prior to the real time.



Source: ISET

Picture 11

[18] From a study of ISET, "Institute for Wind Energy and Energy System Technology", University of Kassel, Germany

Pictures 10 and 11 show how wind forecasting improves as we move closer to real time. In particular, during the last 3hrs before real time, forecasting errors decrease by about 50% (from 7 to 3,5 MWh for a 100MW wind farm). This tells us that introducing more flexibility via intraday trading with "gate closure" closer to the moment of physical delivery (i.e. 1 hour) can considerably improve portfolio optimization.

As a general principle, increasing trading possibilities via continuous intraday trading after the day-ahead session of the market allows the market to benefit from more up-to-date and accurate forecasts. As a consequence the number of ancillary services needed to balance the system would be fewer and social welfare higher. We believe that integrating cross-border intraday markets with continuous trading can contribute greatly to a more efficient integration of wind energy.

Conclusion:

<u>To deal with intermittency and wind forecast errors there is an increasing need for ancillary services. Ancillary services markets should be developed so that customers and generators with flexible consumption or production can "offer" such flexibility to system operators and other market participants.</u>

<u>There should be a level playing field for balancing responsibility which applies to all producers, including wind generators, in order to stimulate all market participants to carry out thorough and proper scheduling and forecasting and thus limit system costs.</u>

<u>Integrated cross-border intraday markets with continuous trading after the day-ahead market session are needed to allow forecast updates to be incorporated into the market. Consequently, the need for ancillary services would be less, and the costs passed onto the customers via network tariffs would be lower.</u>

4. Impact on new and existing Generation Investments

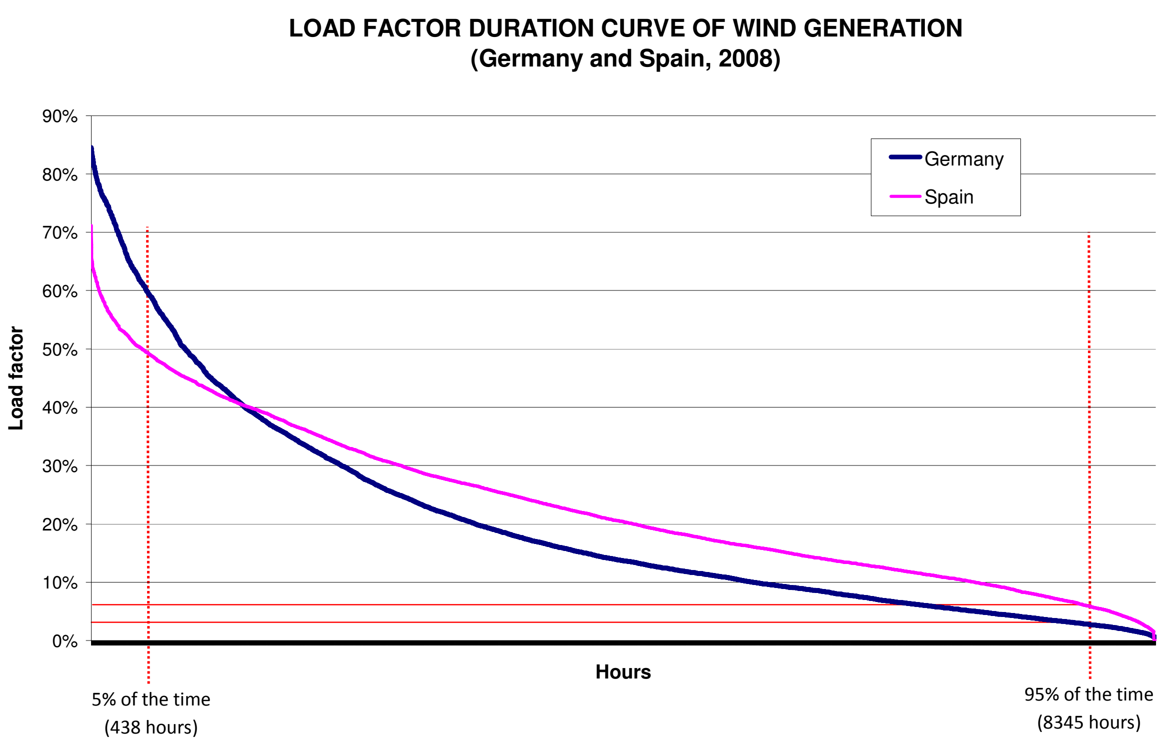
The purpose of this section is to identify the main impacts and system requirements that the introduction of high levels of RES might have on electricity generation activity and to point out some paths that will definitely contribute to security of supply and electric system efficiency.

4.1 System requirements for large share of intermittent generation

- **Need for investment in backup capacity due to the low "capacity credit" of wind generation**

  It is commonly accepted that wind is primarily an energy resource and not a capacity resource, with a key value in terms of offsetting fuel consumption and reducing emissions. To support this statement, the next figure shows the load factor duration curve for the Spanish and German electricity system during 2008. These are of course not representative for all markets, as they also depend on the actual yearly wind production; this illustration is only meant to give a general picture of this trend.

  On an hourly basis, the load factor (being the ratio of produced wind energy to installed wind capacity) is represented for both the German and Spanish systems (data from 2008). Installed capacity in Spain reached 16,4 GW and 23,46 GW in Germany in 2008.



Picture 12

The picture shows great similarities between both systems as far as the behaviour of the load factor of wind production is concerned, which allows some general conclusions to be drawn:

- On average, only 4% (2,5% in Spain, 5,5 in Germany) of the total wind installed capacity has a level of firmness of 95%, which is a similar level of availability to conventional power plants. So, wind's firm capacity contribution to the system is 4% of its total installed capacity.
- Around 55% of wind installed capacity (50% in Spain, 60% in Germany) has a level of firmness of less than 5%. In fact, the level of injection of wind generation never reaches a percentage higher than 77% (this limit is higher in Germany but lower in Spain), so 23% of wind installed capacity can be considered as fully unavailable.
- On average, the expected working rate of wind capacity has a 90% probability of oscillating between 4% and 55% with an average load factor of 22%.

In practical terms, every MW of wind capacity requires 1 MW of backup firm capacity to ensure 90% availability. This leads to an important conclusion: investments in wind generation avoid fuel expenses but do not decrease the need to invest in firm capacity, which is still required.

The backup capacity could be provided either via lifetime prolongation of existing plants[19], or by investment in new plants.

Still concerning the need for backup capacity that RES require, other instruments outside the scope of generation activity might be mentioned. For instance the development of interconnection capacity in order to "import" backup capacity from abroad, "smart grids"; storage facilities, and the ability to (remotely) interrupt supply to customers (domestic[20] or industrial) or any other DSM mechanism in general, can all be instrumental in balancing supply and demand.

To conclude, the analysis shows that only a small share of wind capacity can be considered as "firm", therefore a considerable amount of conventional capacity is needed as flexible back-up generation.

- **Lower load factor will affect existing plants and future investment decisions.**

As illustrated in the figure 9 baseload plants, "medium merit order" plants and also peak plants will be "compressed" due to the growing penetration of RES plants on the left side of the merit order. From this picture, it is clear that the targets set for RES penetration will result in a significantly reduced load factor for conventional

[19] Also the prolongation of existing plants might require substantial investments when plants are not compliant with the Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from Large Combustion Plants (LCPD).

[20] For instance, to switch off air conditioning appliances, with previous customer agreement, that might be remunerated for this possibility

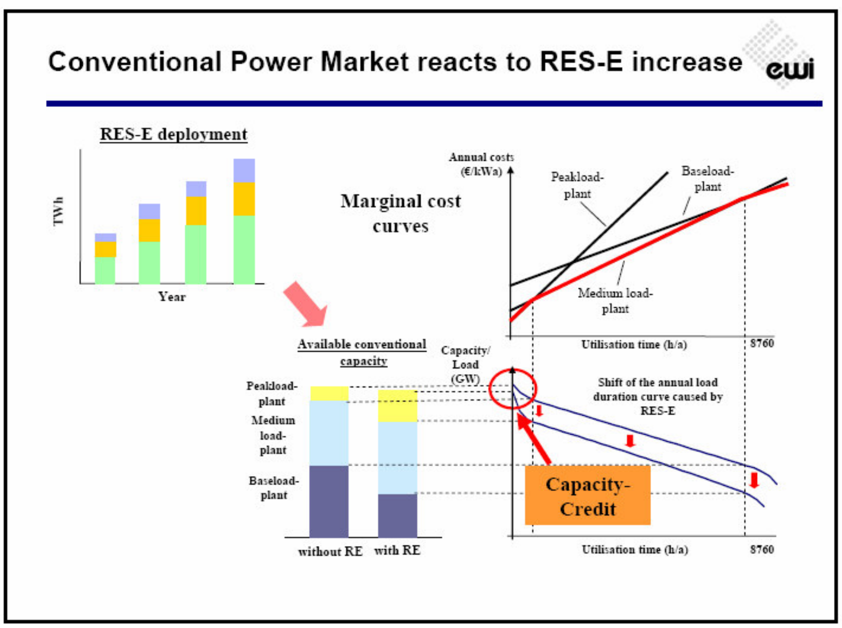
generation, as the RES technologies will replace a growing section of the electricity supply curve.

Therefore, the ability of existing conventional plants to recover their fixed costs may be weakened and may lead to earlier decommissioning decisions. Similarly, prospective investors in new conventional generation capacity will be facing increasing uncertainty, which, ceteris paribus, naturally weakens their appetite for investments in these conventional technologies.

EURELECTRIC believes that the market will work and will find the equilibrium market price, provided that prices are allowed to freely change, that policy maker intervention does not impact market equilibrium, and that competition authorities accept the "price spikes" that will emerge. Nevertheless, in some cases, the uncertainty faced by investors on the magnitude and frequency of "price spikes" may hinder the evolution of the conventional generation park. If this occurs, market design rules may need to be reviewed.

The figure 9 also illustrates that in order to keep the necessary flexibility (regulation up and down), it will be necessary to bring some specific (peak) plants in a 'must run' position, although they are "out of the money". The must run costs have to be covered by the system charges. We would like to stress that growing demand for flexibility and consequently increasing must run payments might "bring" the budget for these 'must run' plants in "balance" again. However, this will only be true for a small part of the generation park, and it does not solve the problem for the baseload plants and the medium merit order plants that will have fewer production hours in which they can generate margins to cover their fixed costs.

- **Adapting the generation mix towards greater flexibility**



.

Picture 13

The diagram in picture 13 prepared by Köln University outlines the evolution of the composition of the optimal portfolio mix with increasing levels of RES. The picture illustrates that some of the less flexible base-load conventional plants will be forced out of the markets, while others will be required to reduce or modulate their output in order to make room for more flexible generation.

This is in line with what is illustrated by the previous pictures 4 and 9: the expected increase in the number of both peak and mid-merit plants, needed in order to cope with the variability of intermittent sources, actually forces some baseload plants out, which results in a lower but steeper merit order curve. If this forecast proves to be accurate, more flexible plants (like hydro, pump storage, OCGT and CCGT) will be required[21].

The need for flexibility may be satisfied in many ways, most of them incorporating technological developments.

For instance, technological developments and investments may be made to allow for a quicker response (faster ramping speed) from conventional plants to provide support to the system, or to reduce the plants' minimum operating levels from the usual values. Other examples of increasing flexibility of the system relate to the development of variable speed pump turbines.

Other (technological) solutions to provide the needed flexibility to the system, but that fall out of the scope of the generation activity, can also be adopted and incentivised, as is the case of "smart domestic appliances" or other demand side management (DSM) instruments.

EURELECTRIC believes that the source of flexible support and balancing will vary between market regions and will depend on the form of the new load duration curve, the actual market prices) and the slope of annual cost curve of peaking plants. Moreover, the local opportunities (such as availability of hydro, pump storage) will be determining factors in the flexibility portfolio of the system.

- **Need for Storage**

With the introduction of large amounts of RES into the generation mix, storage should play two important roles: it will be a source of efficiency, as it allows renewable energy sources to be captured and stored for later use, thus not wasting resources which cannot otherwise be used; and it can also be a valuable instrument to provide the needed flexibility that was mentioned above.

Naturally, the increase in storage capacity (for instance, through pumping plants, gas storage, district heating systems, compressed air storage, or electric vehicles – "Vehicle-to-Grid" systems) will both depend on and affect the existing and prospective generation mix.

Therefore, in the presence of high levels of RES penetration, and given its intermittency, storage can be a valuable instrument that has to be taken into

[21] Whilst it may be technically possible to provide some of the required future flexibility through modifications to existing plants, investors will again be faced with the uncertainties already mentioned, which might prevent the investments from being made.

account by all agents within the electric sector value chain. Nevertheless, existing regulations may not allow the market to provide the right signals or the incentives needed for storage systems to develop adequately.

Market price differentials which might come with increased RES penetration are the primary market signal, indicating the need for storage. Therefore, caps (and floors) limiting price variations should be lifted.

Occurrence of negative prices in particular are a signal that additional storage is welcome, as storage actually then results in “consuming” additional electricity at negative prices, thus preventing more social welfare from being lost, or in other words, saving the electricity until its value has increased. This is particularly true if the storage reservoir can be filled up until there is a shortage in the system, giving the plant the opportunity to benefit from high peak prices.

The investment decision to build new or to expand existing pump storage plants does not only face cost recovery risk (like any other investment decision), but could also be further jeopardised by problems related to construction permits[22]. <u>EURELECTRIC urges Member States to create the appropriate licensing procedures for storage projects in order to avoid unduly additional delay in the investment decision process</u>.

4.2 Possible solutions to preserve security of supply and system efficiency

As illustrated in the previous paragraph, if back-up capacity is to be kept in the system, if existing plants are to be adapted to offer more flexibility or if new plants are to be built, and if sufficient flexibility is to be kept in the system (be it via more flexible plants, or via storage), investments will be necessary. However, with prices being more volatile and power load factors being lower, investment decisions become more and more uncertain.

Most European markets are nowadays “energy only” markets. Some of them are complemented by capacity reservations on behalf of the TSOs, others have capacity incentive schemes in place. In the following paragraphs we will briefly touch upon the two main models for market design (energy only markets and capacity markets), although this discussion will not analyse them in detail, nor pass an opinion on which of the two should be implemented.[23].

Under the energy-only market design, investors in new generation (especially peaking generation) must be able to fully anticipate and receive the actual level of scarcity rents over time if they are to correctly match the level of new investment with system requirements. But these scarcity conditions by their very nature are hard to predict, as they depend on the frequency and length of very short run of supply-demand imbalances caused by weather, intermittent generation, plant outages and other uncertain events.

[22] This is also valid for investment in new generation capacity.

[23] A more detailed analysis of a wide range of different possible models of market design can be found in the Brattle Group Paper “A Comparison of PJM’s RPM with Alternative Energy and Capacity Market Designs” – September 2009.

Policymakers are generally uneasy about allowing expectations of scarcity rents to be the sole driver for investment decisions which are also critical for system reliability and public economic welfare.

Price and bid caps have been introduced in some markets. These artificial limits often eliminate the scarcity pricing signals and rents, on which energy-only market design is based. OMEL in Spain, for example, has a cap of 180€/MWh. With such a cap in place, the long-term investment prospects of an "energy-only" model might be insufficient[24]. The price of ancillary services, in fact, will probably not be enough to offset lower operating hours of conventional plants.

According to a multi-client study undertaken by Pöyry Energy Consulting (Implications of Intermittency' - May 2009), energy markets that contain complementary mechanisms (e.g. capacity incentive systems) so as to mitigate uncertainty and price volatility, may prove to be an efficient way from the social welfare point of view, to incentivise the needed investment and promote security of supply.

1. In Energy only markets price spikes must be allowed to occur freely in magnitude and frequency

A quick analysis of the income of a peak plant that would have been dispatched at a price of 100€/MWh (being its marginal cost including the variable O&M costs) in the French market or the German market during 2008 or 2009 shows that such a plant would have generated the following revenues compared to Powernext or EEX prices:

Market	2008	2009
French market	23,414 € in 1.081 hours	13.547 € in 66 hours
German market	19.875 € in 892 hours	555 € in 45 hours

Roughly speaking, this would be an average of 15000 €/MW. Although a more detailed investment analysis is necessary, it is obvious that these 15000 €/MW do not cover the fixed costs of a peak plant[25]. The number of hours exceeding the 100 €/MWh threshold are also indicated in the table, and from this it can also be concluded that the running hours are very different. The upper price boundary in both markets is 3000€/MWh. In the example, the highest hourly peak was 3000€/MWh over 4 hours (French market, 2009), while all other hourly peaks were below 1000€/MWh. If the upper boundary had been 1000€/MWh instead of 3000€/MWh, the French 2009 average revenue would have been lowered (with 4*2000€/MWh) to 5547€.

From this example, it is clear that the current level of "spikes", if they persist for several years, would not create enough income from spot prices to trigger additional

[24] However, we should remind that the Spanish market design has been completed with a capacity mechanism that in its current methodology gives incentives to investment in new capacity depending on the reserve margin of the Spanish system.

[25] Depending on the type of plant (investment value, capital cost, depreciation period, etc.) the annuity covering the fixed costs varies somewhere between 50.000 and 100.000 €/MW, but other figures might be used in different circumstances.

investments in peak plants. Consequently, there would be a significant 'missing money' factor for investors unless the reduced income can be compensated for by expected revenues in the ancillary services market.

Our analysis in section 2.3 shows that more intermittent generation will probably lead to more frequent price "spikes". However, it is uncertain if they will be sufficient in number and in magnitude to cover the fixed costs of peak plants.

Roughly speaking, CCGT plants need a spark spread of about 10€/MWh to cover their fixed costs if they run 5000 hours per year. Intermittent renewables growth might reduce the number of running hours to about 2500 hours, or even less. This would mean that during the peak hours, about 10 €/MWh of additional market price has to be created in the market[26]; if not, such CCGT plants will not be built. It should, however, be noted that this figure only gives a very rough indication; each company will make more in depth analysis, taking into account their portfolio, the market where the plant is located, etc.

The acceptance of price peaks that could incentivise investments in peak capacity is very different around Europe. One example is the Swedish regulator, together with the TSO and energy agency, who declared that price peaks show that the market is functioning and gives incentives for (large) consumers to lower consumption and generators to invest in peak load capacity. By contrast, in other parts of Europe there is a very low acceptance of price peaks.

Conclusion:

Both examples demonstrate that investments in plants will only occur if investors expect market prices to reach appropriate levels with sufficient frequency, which might not happen considering the experience shown. It also supports the view that any cap (or floor for negative prices) should be avoided.

2. Capacity incentive systems as a possible fallback solution?

If sufficient revenues cannot be recovered in the energy market to support needed investment or to keep existing capacity operational, a fallback solution may be required. These mechanisms are generally based on the concept of a two-part price, with one set of revenues paying for energy on a €/MWh basis and another rewarding capacity needed on a €/MW-period basis. In theory, these mechanisms (depending on their design) allow the primary energy market to operate undisturbed, while recovering the 'missing money' needed to support new investments through capacity payments outside of the energy market (these may assume the form of competitive capacity mechanisms or auctions). These mechanisms should be designed in such a way that the payment amount is directly linked to the system's need for capacity or flexibility and valued by the market at the time of the investment.

[26] Governments, competition authorities and consumers will have to accept the need for the increased market spread. Only this way the conditions for the efficiency of energy-only market design will be met and its results attained, namely on what concerns the need for backup and flexible capacity.

Moreover, the existence of capacity payment mechanisms may also mitigate price spikes, which, as said, are usually a source of worry for governments and competition authorities.

An example is given by the study 'Implications of Intermittency', a multi-client study undertaken by Pöyry Energy Consulting, 1st May 2009[27]. This study looked at the effects of increasing levels of wind in both the United Kingdom ('energy only' market) and Ireland (System Marginal Pricing plus Capacity Payments).

As the Pöyry analysis shows, increasing levels of wind in the UK market will result in an increase in frequency and amplitude of price spikes, as conventional plants seek to cover their costs against a background of reduced load factors coupled with reduced system marginal prices. In contrast, the study found that there were far less price spikes in the Irish system as a result of the existence of the Capacity Payments and that the price spikes present, were essentially imported from the UK arising from the increased level of interconnection.

Different capacity incentive models might be considered.[28] Careful analysis is required to assess in which cases, under which conditions and at what geographical scale it may be advisable to introduce such models.

[27] A summary of this report is publicly available at:
http://www.ilexenergy.com/pages/Documents/Flyers/Other/GasIntermittency-Flyer_v1_2.pdf

[28] See for instance "The Brattle Group*" Paper mentioned earlier.*

5. Market integration as a solution for RES integration: the software

As can be concluded from the following extracts of the introduction to the third package[29], market integration, in particular stimulated via cross-border competition is one of its main goals, ultimately leading to price convergence.

> *(8) In order to secure competition and the supply of electricity at the most competitive price, Member States and national regulatory authorities <u>should facilitate cross-border access for new suppliers of electricity from different energy sources as well as for new providers of power generation</u>*
>
> *(59) The <u>development of a true internal market in electricity</u>, through a network connected across the Community, should be one of the main goals of this Directive and <u>regulatory issues on cross-border interconnections and regional markets should,</u> therefore, be one of the main tasks of the regulatory authorities, in close cooperation with the Agency where relevant.*
>
> *(60) Securing common rules for a true internal market and a broad supply of electricity accessible to all should also be one of the main goals of this Directive. To that end, <u>undistorted market prices would provide an incentive for cross-border interconnections and for investments in new power generation while leading, in the long term, to price convergence.</u>*

In order to fulfil this ultimate goal, EURELECTRIC, has been proposing concrete solutions and possible roadmaps for a Pan-European electricity market for several years[30]. More recently, EURELECTRIC has been cooperating with other stakeholders and policy makers to identify "target models" and implementation roadmaps for the different timeframes of congestion management: long-term rights combined with the use-it-or-sell-it mechanism, day-ahead allocation via a market price coupling algorithm, cross-border intraday allocation via continuous trading and integrated balancing markets based on TSO-TSO approach with common merit order. These different visions are also the main elements of the target models proposed in the process[31] driven by the Florence Forum. The proposed target models are actually the backbone for ensuring successful market integration.

However, these solutions only represent the "software" tools to achieve the ultimate goal of developing "a true internal market in electricity*"*. This goal will not be reached if certain "hardware" tools are not put in place: as the next chapter illustrates, urgent and appropriate grid investments are also needed.

---

[29] See Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC

[30] See for example EURELECTRIC Paper "Integrating Electricity Markets through Wholesale Markets: EURELECTRIC Road Map to a Pan-European Market", June 2005. See the EURELECTRIC Report "The Path from Regional Electricity Markets to a Pan-European Market: Building a Comprehensive EU Market Integration Strategy" – March 2010

[31] See MIDP (Market Integration Design Project) steered via the PCG (Project Coordination Group) under guidance of the Florence Forum. Initial findings presented in June 2009 and further work published on ERGEG website.

The whole market integration process briefly described above should be seen as a "business as usual" case. However, the huge amount of additional intermittent generation sources will to a large extent challenge the process of market integration, making it more difficult, but at the same time even more necessary. We believe that if the mentioned market integration tools (the software) are not put in place without any further delay, all EU key policy goals - the 2020 targets to tackle climate change, the internal integrated market for electricity and security of supply - will not be achieved.

5.1 Flexibility sources to compensate intermittency

One of the main consequences of the intermittency and difficulties in forecasting wind generation are problems with the stability of the system. This can only be ensured if the appropriate amount of flexible power plant capacity is available (see section on generation investments) and also, if it is still possible to bring the right number of flexible plants with market based mechanisms on line. There are indications that the required amount of generation flexibility is potentially available: on one hand there is already existing flexibility provided by hydro plants in the Nordic area and in central Europe (Austria, Switzerland), on the other hand, indications from the UCTE adequacy plan[32] confirm that sufficient CCGT plants are planned. However, in the event that the lines connecting hydro reserves to the rest of the European grid are overly congested or that the planned CCGT plants are not built in sufficient time/amount, then the whole electricity system may incur inefficiencies and higher costs for society.

Based on existing scenarios, wind energy injection will be mainly concentrated in the north of Europe and Iberia, whereas the flexible generation is dispersed throughout Europe. Should large deviations occur in day-ahead or intraday or balancing phase, all flexible sources will be required to address such deviations.

To achieve this, the following market integration tools - market coupling, cross-border intraday and cross-border balancing - are indispensable in ensuring and facilitating the contribution (on a competitive basis) of all available flexible sources throughout Europe.

Although in the day-ahead phase, wind forecasts might still be rather inaccurate, market coupling is the best tool to allocate cross-border capacity, at least compared to explicit auctions which by definition might not lead to the optimal outcome in the day-ahead phase. Continuous intraday trade organized via a central order-book for the whole of Europe will facilitate the necessary co-ordination of all flexible sources, in addition to the upwards and downwards management of these up to one hour before delivery (subject of available remaining cross-border capacity). And finally, TSO-TSO integrated balancing systems with a common merit-order will fine tune the position in the most efficient way.

For these reasons we urge decision makers to establish these important tools (or complete their implementation) where necessary.

[32] System Adequacy Forecast 2009 – 2020, UCTE – January 2009.

Conclusion: The market integration tools "day-ahead market coupling", "cross-border intraday" and "cross-border balancing" urgently need to be put in place on a harmonized basis throughout Europe in order co-ordinate and optimise the response from flexible sources to compensate for the effects of intermittent RES sources.

5.2 How to manage the system in the intermediate phase?

As already mentioned in the introduction, intermittent wind sources constitute a large part of the RES-E 35% target for 2020. They are mainly concentrated in the northern region of Europe, rather "far" away from the consumption location. Growing photovoltaic production might have similar consequences, but in general, this source is better distributed throughout Europe: there is a lower concentration degree. Grid investments will be necessary to accommodate the new energy fluxes through the grids, however, as experienced in the past, this type of investment will probably take longer to achieve, than the RES investments.

During the intervening transition period, which could last even beyond 2020, the transmission system will not be fit for the new generation situation. We will discuss our views about grid investments in the next section. In this section we would like to comment on how to cope with the lack of appropriate transport capacity during this transition period.

Due to the intermittency of wind injection, allocation of long term capacity will be more difficult for TSOs. Where part of the cross-border capacity is allocated with long term auctions, there is a risk for a reduction in the allocation of long-term capacity and with part of this volume might shifting toward the day-ahead market where there is more information on the likely wind supply. This will result in less market integration in the forward markets. The only way to mitigate this risk is by having the appropriate short-term tools in places, as argued in the previous section.

TSOs will also be confronted with potential overloads in the systems, requiring them to redispatch, whereby probably more expensive plants will have to be regulated upwards to the detriment of more efficient plants. Due to the geographical concentration of this wind injection, part of this redispatch might be no longer operated on a purely national basis, but also on an international level. In order to keep the existing price areas as they are, it will be necessary to develop smooth international redispatch rules and also the financial settlement rules associated with such interventions.

Conclusion:
It is necessary to develop appropriate international redispatch rules in order to cope with the possible transmission problems during the transition phase.

6. Grid investments: the hardware

6.1 Grid investments: the need of a regional approach

In former times grid investments were mainly driven by generation, load centres and network constraints. The Renewable Directive however has created a completely different situation: there is a clear commitment from the Member States to reach an ambitious target for renewable electricity production, and it is clear that this target cannot be met without an investment in wind energy. Wind maps are not secret data, and in the mean time, Member States have already appointed many locations where new wind farms can be built. We believe that TSOs are no longer in a position to wait until the wind farms are in the construction process before they start developing their plans or building the required grids, this being largely due to the fact that licensing for transmission is much more time consuming than for a wind farm.

There are important roles for the 3 key stakeholders:

- TSOs have to develop procedures to prioritize areas for reinforcements in order to facilitate the most urgent wind farms and launch the investment plans.
- Regulators should not refuse such investment proposals, even if they are in an early phase,
- Member States should be requested to facilitate procedures for permitting the new grids, because they are inherently linked to the ambitious goals they have set out.

The Third Package requires all transmission system operators to submit to the national regulatory authorities each year a 10-year network development plan based on existing and forecast supply and demand. This plan should indicate the main transmission infrastructure which needs to be built or upgraded over the next ten years. To identify investment gaps, especially in cross-border capacities, ENTSO-E will have to publish every two years a non-binding EU-wide 10-year network development plan, based on the national network development plans.

The national regulator may require a TSO to amend its 10-year network development plan if it is not in line with the EU-wide plan. Moreover, the Directive enables national regulators to take measures to ensure that the investments listed in the national network development plan are physically put in place. In order to make sure that TSOs really make the necessary and agreed investments, national regulators must provide incentives – especially for regional investments involving directly or indirectly two or more MS. A common incentive scheme for grid investments needs to be put in place. Therefore, ACER must not only put the right European framework for permitting new transmission lines in place as soon as possible but also give incentives for cross-border grid investments with national regulators facilitating ACER in this process

The main goal is to reduce the complexity of the authorization procedures for building both new internal and cross-border connections, in order to speed up grid investments. This incentive scheme should set rules for allowed attractive return on transmission investments for a longer time period to mitigate regulatory risks and for sharing costs among those who benefits from the investments.

Furthermore, the Third Liberalization Package gives no statement on how and or by whom the necessary investments on regional/pan-European scale should be remunerated, which is another important topic which needs to be solved in order to expedite cross-border investment.

In a recent report[33] EURELECTRIC recommends three main issues that need to be addressed in order to establish regional transmission investment incentives:

- Governance: Appropriate legislation at EU level should be developed to allow investments from a regional perspective. Member States should harmonise their regulatory framework to enhance market integration. Regulators should implement regional committees that decide on cross-border related issues. TSOs should plan cross-border related investments from a regional perspective.
- Socio-Economic Analysis: Regulators should develop a common model for evaluating regional socio economic benefits. Investment planning should be assessed and prioritised according to the result of this regional model. During this process, regulators should ensure transparency and appropriate involvement of market stakeholders through early and extensive consultations.
- Cost Sharing: Regulators should make sure that transmission investments with positive socio economic welfare are carried out and decide on distribution of costs between TSOs. This distribution should be based on the expected benefits from a regional perspective in a way that makes it attractive to invest. In practice, it could mean that a TSO from a neighbouring country, not involved in the construction of the transmission line, but benefiting from the increased socio-economic welfare due to increased cross-border capacities, could take part in financing the investment

Grid reinforcements are the key enabler to allow markets cope with large volumes of intermittent RES. The introduction of high levels of RES will not only heavily affect both distribution and national transmission networks, but also transmission networks in adjacent and further away countries. Hence the focus on investments should be shifted from a national to a regional and pan-European perspective, in order to accommodate large RES investments. This is further emphasized, by the fact that large scale transmission investments are also needed in order to facilitate the creation of the common European electricity market. However, when setting up projects to enhance the grids, the objectives and functionalities must be clearly defined.

Taking into account the fact that it takes practically at least 10 years to build a transmission line (within one country; a cross-border line would take even longer) such a pan European grid investment plan is already lagging behind. In 10 years – when the line would be ready if it has been started now – it is already 2020 and most RES has hopefully been already installed.

Conclusion

The 2020 targets will be jeopardized unless considerable grid investments are achieved.
The concentrated off-shore wind power expansion will require a regional grid planning process in order to cope with the new situation. Pro-active planning and investment are a

[33] EURELECTRIC Report on Regional Transmission Investment Incentives, October 2008

natural consequence of the chosen renewable ambitions, and should start without any delay.

6.2 Technical Framework

Several studies have proposed to create a meshed offshore grid that could link future offshore wind farms in the North Sea and the Baltic Sea and the onshore transmission grid. By creating a strong "outer loop" at sea some mainland network connections may be avoided. However, in the foreseeable future most off-shore wind farms will be connected to the nearest on-shore transmission network, since there are still no agreements to create this new off-shore grid infrastructure, to which all new wind farms could connect.

Also, most studies remain silent on what needs to be done with the mainland grid. In order to effectively integrate high amounts of offshore wind it is necessary to further upgrade the onshore network because offshore wind power causes significant congestion to the mainland grid. This is especially true for off-shore wind generation which are typically located considerably distances from the centres of demand. One possibility to alleviate this problem would be to connect these off-shore grids via a strong "super-grid" to the major inland load centres. The main goal should be to transport offshore energy to the area with the highest price and with a super-grid, it would be possible to transport this energy even further inland.

A good solution would be to implement an additional European super-grid that connects (off-shore) RES generation centres with load centres and also areas with high balancing sources. Increased investments will also make it possible to exchange balancing energy and further integrate markets as already indicated in the previous paragraph. This "green network" would also relieve the existing strained European transmission network by directly connecting RES generation and load centres and improving efficiency of RES development.

Conclusion: We have seen plenty of proposals for the creation of “North Sea Grid”, connecting and transporting the off-shore wind energy, but we are missing the complementary “mainland” grids enabling the transport from the off-shore and onshore wind farms to the centres of load.

Regarding the fact that the Commission is already thinking about developments until 2050 it might be worth to start thinking if it would not make sense to construct this separate "green network" connecting main RES and load centres with areas with balancing resources – especially in light of the introduction of all the additional new RES and the subsequent changes to the generation mix. However, this is of course a very strategic and political decision.

The management of a so called North Sea Grid will introduce new challenges to the relationships between TSOs and regulators. The ambitious UK target to connect 33 GW[34]

[34] On 10 December 2007, John Hutton, Secretary of State for Business Enterprise and Regulatory Reform (BERR), announced the commencement of a Strategic Environmental Assessment (SEA) to examine 25 GW

of offshore wind generation over the coming years, cannot be technically achieved without additional links to mainland Europe, to act as an off-take buffer in the event that wind injection occurs at a period of low demand in the UK. However, if such an event happens concurrently in both mainland Europe and in the UK (which is not unlikely as one cannot control the weather), new coordination structures need to be put in place between the different control rooms to ensure that the situation can be adequately managed.

The physical laws that govern the transmission of electricity are both well known and understood. It is common knowledge that AC grids cannot transport power over long distances without voltage problems. It is also well known that in a DC grid, cable faults cannot be interrupted on a selective basis. These aspects are perfectly understood and the technological choices made in the past can cope with these limitations.

However, the concentration of renewable generation at several hundreds (even thousands) kilometres from the centres of load is challenging these very well known features. It is easy to show nice diagrams on revolutionary interconnected DC grids that cross several times the North Sea, however, the technology is not yet there to operate such a grid securely. Building transmission lines from the shore to centres of load could be a real challenge if it is done in AC. New techniques would have to be developed to bridge such large distances.

<u>EURELECTRIC encourages all R&D that will contribute to the development of new technology and techniques needed to achieve the ambitious RES goal</u>. But at the same time, we are concerned by the lack of progress and the absence of emerging solutions.

R&D to develop grid technologies is not the only requirement for facilitating RES into the future. As indicated in a previous section, flexibility will be also a major requirement to integrate intermittent renewable in the grid. Flexibility could also be created via new technology e.g.

- Storage of wind energy in periods of high wind injection and low demand: in hydro reservoirs, (car) batteries, pump storage facilities, compressed air storages, etc.
- Off take could be encouraged in periods of high wind injection via price signals directly to the end consumers by using smart meters.

Conclusion

<u>The "revolutionary" change that </u>energy markets are required to <u>to reach the RES targets also requires an associated revolutionary development in transmission technology: they must go hand in hand. The process needs to be supported by the requisite R&D and the necessary funds to support such R&D have to be established without delay</u>

6.3 Economic Issues: Who will pay for the regional grid?

This question is particularly relevant for links through the North Sea (or elsewhere) where wind farms currently under construction are to be connected. One could also imagine that

---

of additional UK offshore wind energy generation capacity by 2020. This follows the 8 GW already planned for Rounds 1 and 2 of offshore windfarm projects around the UK.

in order to bypass a congested grid in a certain market, a transport line being built through a particular Member State, without having any (direct) connections in that Member State: Is such a transport line still to be paid via the tariffs in that Member State? Or more fundamentally, who will pay the "North Sea Grid" that is suggested in several proposals?

It will not longer be possible to have a one to one relation between renewable energy generated in a regionally operated grid and the destination of this energy. An example to illustrate this case is the Kriegers Flak, where in certain assumptions the off-shore wind energy could be transported to 3 markets (Sweden, Germany and Denmark). In certain proposals, the spare capacity of the cables could be used for third party access and shipment of energy from for instance Sweden to Germany. Wind energy injected halfway, would then never reach Sweden, but would be shipped directly to Germany. Subsidies are currently depending on the geographical location of the plants, but some national schemes, e.g. the German scheme also demands that the power is physically fed into the national electricity network in order to receive this support. This could make an otherwise rational solution like a connection which could be used for both wind power off-take and trade impossible. Similar situations could be imagined for a wind farm connected on a cable between UK and the Netherlands: although it might concern a "British" wind farm, how would the energy be remunerated if it were to be shipped directly to the Netherlands?

In EURELECTRIC's view, given that the benefits are shared between customers from different Member States, costs should therefore also be borne by several Member States, and the national regulators, together with ACER, must put in place rules that govern this. Setting up such governance is considered an urgent priority, as it may prove to be a much bigger hurdle if left to develop at a later stage in the future.

Conclusion

<u>Building and operating regional grids will require specific agreements to regulate the funding schemes and to establish the original ownership of the (renewable) energy injected in such grids.</u>

6.4 The role of distribution networks

Moving towards a low carbon electricity system will require radical changes on both the supply side (high penetration of mostly intermittent renewable generation resources at all voltages) and the demand side (energy efficiency, load shedding and the potential electrification of transport). As the network operator is the common link between these changing inputs/outputs there will need to be an evolutionary change in both network design and network operation from the largely passive (fit-and-forget) system of today to a more coordinated approach.

Generally, electricity networks have been designed to deliver energy via high voltage and low voltage systems, with a 'top down' direction of power flows. Distribution networks that were originally designed as "passive" networks to receive electricity from the transmission system will need to become more "active" as more embedded renewable generation - from domestic microgeneration to larger scale commercial units - connects. Increasing levels of distributed generation (DG) in distribution networks will initially displace local demand but in certain locations will ultimately result in 'export' onto the transmission system, this in turn will have implications for the requirements for transmission infrastructure.

DG will also pose operational and control challenges for traditionally designed and operated distribution network and so the Distribution System Operators (DSOs) will have to become much more involved in real time distribution system operation, making use of innovative solutions such as smart metering, voltage control, power flow management, dynamic circuit ratings and energy storage technologies. The key technical issues will be power flow management, voltage control and fault level management.

This change will need to be managed both by the transmission system operator and also by the DSOs. The move towards more active system management at distribution voltages will complement and support the transmission system operator (TSO). However, a prerequisite of meeting this challenge will be to ensure that two way communication between the DSOs and the TSO continues to be effective. Therefore, there is an increased need for cooperation between TSOs and DSOs.

This close coordination is especially relevant in two cases:

– Congestions in distribution network, which will become more frequent as RES penetration will further increase. These congestions become an issue since DSOs are generally not allowed to curtail generation to solve the constraint and TSOs have no control on this part of the network.

– Connection of RES plants to distribution network, since the short circuit power in each busbar is the main electrical characteristic to be considered and this depends most of the time on the voltage level (not on the ownership of the network).

eurelectric
ELECTRICITY FOR EUROPE

Union of the Electricity Industry - EURELECTRIC aisbl
Boulevard de l’Impératrice, 66 - bte 2
B - 1000 Brussels • Belgium
Tel: + 32 2 515 10 00 • Fax: + 32 2 515 10 10
VAT: BE 0462 679 112 • www.EURELECTRIC.org