Design and impact of
a harmonised policy for
renewable electricity in Europe

D5.1 Report

Review report on interactions between RES-E support instruments and electricity markets

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The beyond*2020* project *at a glance*

With Directive 2009/28/EC the European Parliament and Council have laid the grounds for the policy framework for renewable energies until 2020. **Aim of this project** is to **look more closely *beyond 2020*** by designing and evaluating feasible pathways of a harmonised European policy framework for supporting an enhanced exploitation of renewable electricity in particular, and RES in general. Strategic objectives are to contribute to the forming of a European vision of a joint future RES policy framework in the mid- to long-term and to provide guidance on improving policy design.

The work will comprise a detailed elaboration of feasible policy approaches for a harmonisation of RES support in Europe, involving five different policy paths - i.e. uniform quota, quota with technology banding, fixed feed-in tariff, feed-in premium, no further dedicated RES support besides the ETS. A thorough impact assessment will be undertaken to assess and contrast different instruments as well as corresponding design elements. This involves a quantitative model-based analysis of future RES deployment and corresponding cost and expenditures based on the Green-X model and a detailed qualitative analysis, focussing on strategic impacts as well as political practicability and guidelines for juridical implementation. Aspects of policy design will be assessed in a broader context by deriving prerequisites for and trade-offs with the future European electricity market. The overall assessment will focus on the period beyond 2020, however also a closer look on the transition phase before 2020 will be taken.

The final outcome will be a fine-tailored policy package, offering a concise representation of key outcomes, a detailed comparison of pros and cons of each policy pathway and roadmaps for practical implementation. The project will be embedded in an intense and interactive dissemination framework consisting of regional and topical workshops, stakeholder consultation and a final conference.

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This report

reviews the literature about the interactions between RES-E support instruments and electricity markets. In particular, the report focuses on the influence of RES-E technology characteristics on markets and grids, and on the market design features that influence RES-E deployment.

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Table of contents

Figures

Tables

1 Introduction

According to the Member States' Renewable Energy Action Plans, the share of renewable in electricity generation will reach 34% until 2020. The EU industry roadmap envisages even 42% (European Commission, 2012). Thus, by that point a considerable part of the market will be supplied by renewable sources, which makes it worth to carefully consider effects on markets and grids as a prerequisite to identify necessary and suitable changes in market design and grid regulations. Indeed, some countries such as Denmark, Germany or Spain have already reached large shares of renewables in their power systems.

The introduction of renewable electricity (RES-E) into electric power systems, grids and therefore electricity markets creates a number of impacts, from either the technical (operation and planning), economic and regulatory perspectives: first, when deployed in a significant amount, RES-E induces changes in the way generation systems and grids are operated; as a direct consequence, this penetration significantly changes the way wholesale markets function and conditions market outcomes (namely changing price dynamics) and finally, above of all this latter, the design of markets and grid regulation has an influence on the deployment of renewables, as well as the design of support mechanisms for RES-E affects the system operation and wholesale market outcomes.

While there is a growing and already significant amount of work analysing the impact of RES-E penetration on electric power system from both the technical and economic approaches, and has indeed been considered for policy design, the crossed implications of electric power systems and RES-E-related regulatory design (on the one hand impact of wholesale market and transmission and distribution rules on RES-E development and on the other of RES-E support mechanism design on power systems, markets and grids) has not been sufficiently studied yet.

There might be a number of reasons behind this need for sounder analysis on the regulatory side, but two can be specifically highlighted:

- Until recently, especially in the EU context, the priority has been to enhance the deployment of RES-E over the objective of optimizing the short- to medium-term efficiency of wholesale markets.
- At the same time, the regulatory design of electric power systems (regarding both wholesale markets and grids) has been conceived without taking into account the numerous impacts that a large penetration of RES-E have in them.

These facts have not been an issue while RES-E penetration has not been relevant. However, when the share of RES-E in the electricity mix becomes more significant, then the saliency of the impacts, and the need to address them, becomes larger (especially in the current context of economic crisis in a significant number of Member States).The impacts of RES-E on markets and grids can be multi-faceted: RE affect generation units' economic dispatch, transmission and distribution grids operation, market prices, balancing needs and procedures, investment requirements, etc. Moreover, as previously mentioned, the existence and degree of these impacts will depend on the way RES-E is promoted. Different policies will induce different types of renewables, with different characteristics (such as flexibility, dispatchability, marginal cost, etc.), and this will result in different impacts on markets and grids: e.g. policies promoting fixed quotas of the different RES-E technologies will not induce the same results in markets and grids than a more volatile tradable green certificates open to any RES-E, since the planning of the rest of the generation system (the expansion of the conventional generation mix) will be affected by the uncertain future configuration of the RES-E generation side. Also, a harmonized EU policy might result in a different geographical location of RES-E plants than the one that should be expected in the current scenario, with the ensuing consequences on grids and regional markets.

These impacts in turn may need to be addressed through changes in market design and grid regulation, which need to be different depending on the RES-E policy pathway and hence on the type of RES-E technologies promoted.

The objective of this report is to review existing studies of these interactions between RES-E and electricity markets, grid policies and regulatory designs, in order to inform future work within this work package, the assessment of the impacts of different RES-E policy pathways. Thus the analysis is split in two steps.

First, section 2 develops a first approach to the impact that RES-E policy pathways can have on electric power systems. To facilitate this assessment, it is first required to decompose the policy pathways into the elements behind them, since it is these elements, and the corresponding effect on the type and characteristics of technologies they promote, which really impact markets and grids. We discuss therefore the correspondence between design elements, technology characteristics, and markets and grids impacts.

Then, the second part of the analysis is developed in sections 3 to 5, in which we look at the changes required in market design and grid regulation in order to make compatible larger shares of RES-E with an efficient operation of power systems.

- Section 3 introduces in a first step the effects of RES-E on grids and markets that have already been identified in the literature, presenting the major open issues that have been identified along with the major electricity generation system functions, and to classify them in a logical fashion to facilitate an orderly discussion.
- Then, section 4 reviews wholesale market regulatory design in the presence of significant amounts of RES-E. We analyze different market designs that already exist or are planned for in Europe.
- Section 5 reflects on the challenges that grid regulation (both at the transmission and distribution level) has necessarily to face when the penetration of RES-E is large.

Finally Chapter 6 summarizes and concludes.

2 From policy pathways to influences on grids and markets

All electricity generation technologies influence the electricity markets. However, as mentioned earlier, this influence depends not only on the type of technology, but also on its characteristics (which vary even within technologies, e.g. solar PV can be promoted in rooftops or in large PV plants). And in turn, the type and characteristics of the RES-E technologies promoted will depend upon the design elements of the policy pathways chosen.

This Chapter assesses the correspondence between RES-E policy pathways, their design elements, the type and characteristics of technologies promoted, and the resulting impacts on markets and grids. This decomposition will then allow to identify and attribute correctly the responsibility of the impacts, in order to change in the right way the electricity markets and grid regulation.

The analysis presented here is rather abstract, particularly in the first and last stages: in the first one we do not start from precise RES-E promotion instruments such as feed-in tariffs or tradable green certificates, since we believe that the instruments in themselves say very little about the impacts that they may cause. It is rather the way the detailed implementation of these instruments is designed, or even the context in which they are developed, which can be attributed the impacts.

Second, we will not talk about specific technologies such as wind or solar PV. Again, we have preferred to decompose them into different characteristics (such as marginal cost, variability or dispatchability), which in turn result in different impacts. We do however analyse in Annex I RES-E technologies and their characteristics.

This section has three parts: first we look at the correspondence between policy pathways and design elements; then at the relationship between policy design elements and technology characteristics; and finally, at the influence of technology characteristics on markets and grids.

2.1 From policy pathways to design elements

2.1.1 The policy pathways and design elements studied in the beyond*2020* project

Support instruments for RES-E are characterised by three main parameters – the type of support instrument chosen, the degree of harmonisation and the specific design elements. All of these have an indirect influence on grids and markets through their impact on the technology mix and geographical location but also a direct influence for example by setting rules for the participation of renewables in the market. The impact of support policies on the electricity mix will be modelled in work package 4 of the beyond*2020* project and results will be used to identify and quantify effects on markets and grids.

As shown in Figure 1, EU Member States currently use a variety of policies to support electricity generation from renewable sources. The most important instruments are the following ones: feed-in tariffs (FIT), feed-in premiums (FIP) and tradable green certificates (TGC) or quota systems (Batlle et al., 2011). All of them (plus tendering) have been incorporated into the analysis and the policy pathways proposed in the project, as shown in the first Beyond 2020 Report “Pathways for a harmonised RES-E support scheme in the EU” (Del Rio et al., 2012).

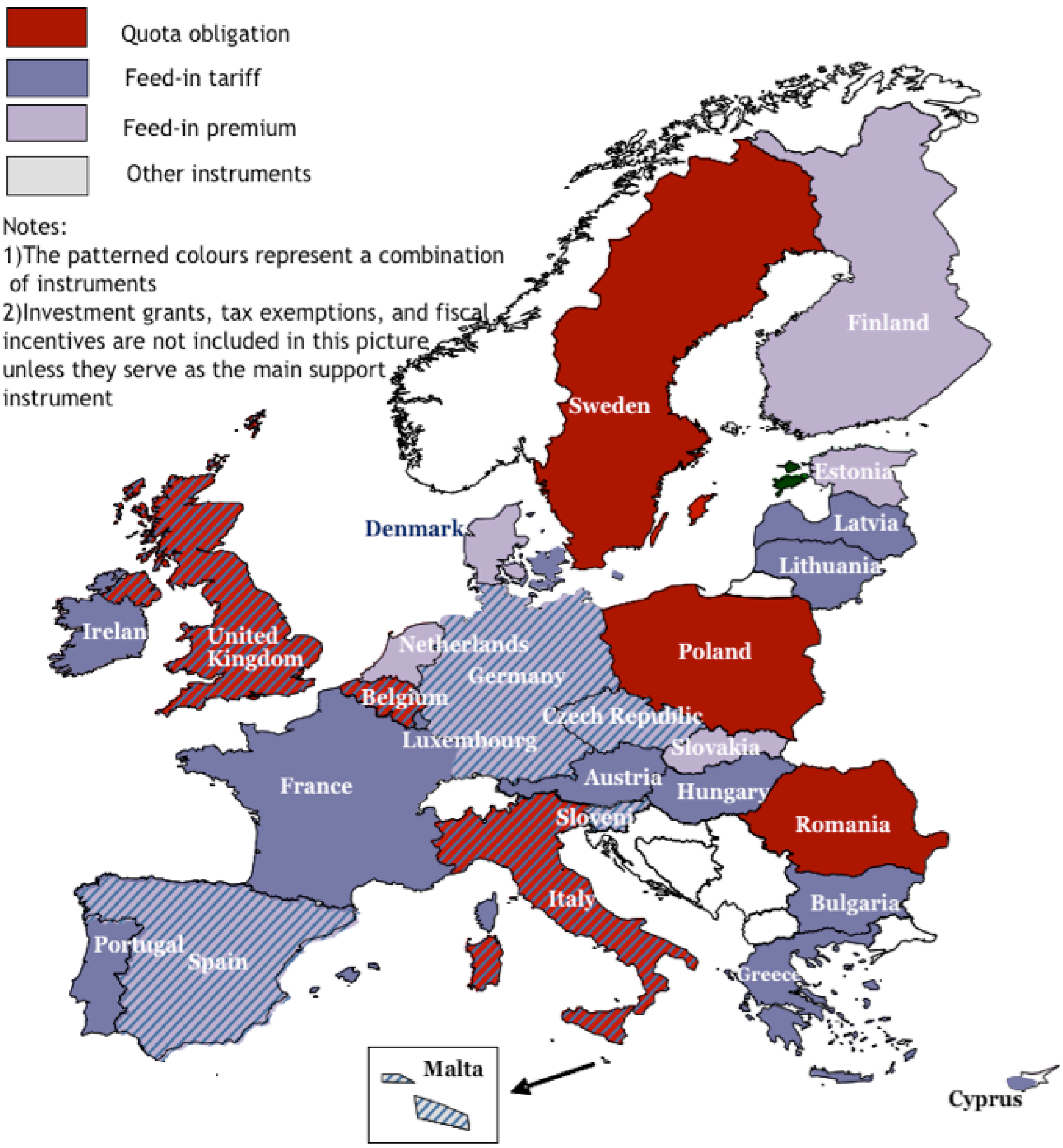

Figure 1 Renewable energy support instruments in EU Member States

However, support instruments as such do not determine completely the impact of RES-E on markets and grids. In fact, apparently different schemes can become absolutely equal in some respects: a TGC system with long-term contracts resembles very much a tender. A FIP with long-term contracts in the electricity market resembles a FIT. A FIP with no guarantee of selling RES electricity resembles a TGC. Therefore, we consider it more interesting to decompose support instruments into their characteristics and design elements, since this will allow us to better trace the final impact of RES-E development on markets and grids. Figure 2 gives a schematic overview on how we will determine the influence of several policy pathways on markets and grids.

In this section, the direct influences are explored in more detail. The chosen types of support instruments and design elements correspond basically to the ones identified during the inception phase of the beyond2020 project, compare (Del Rio et al., 2012). Table 1 provides a comprehensive illustration of selected pathways and the corresponding design elements.

Based on those design elements we proceed to derive an extended set of design elements which have a direct effect on either the investment decision, or on the operation of certain RES-E technologies. This set comprises most of the design elements from Table 1 and moreover includes general policy design characteristics that can be subdivided into framework conditions and more general elements that are applicable to several design elements from that table.

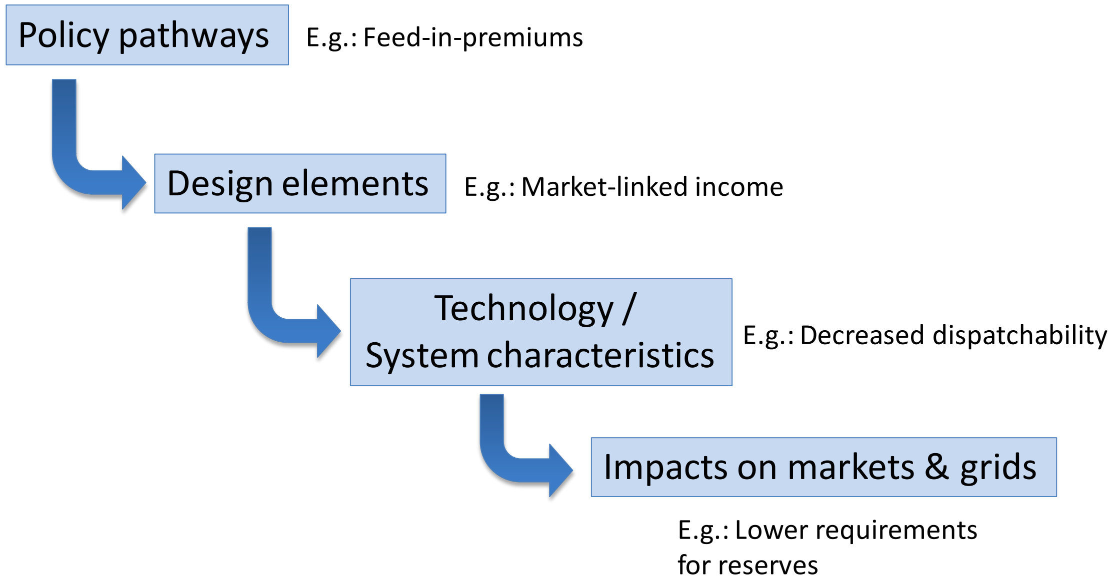

Figure 2 Decomposition of policy pathways into impacts on markets and grids

Table 1 Overview on selected policy pathways and assigned design elements (Del Rio et al., 2012).

<table>
<tr><th>FIT</th><th>FIP</th><th>TEN</th><th>QUO banding</th><th>QUO</th><th>ETS</th></tr>
<tr><td>Fixed (Feed-in) tariff</td><td>Feed-in premium</td><td>Tendering for large-scale RES</td><td>Quota with banded TGC</td><td>Quota with TGC</td><td>no dedicated support for RES</td></tr>
<tr><td colspan="6">Common design elements</td></tr>
<tr><td colspan="5">Duration of support</td><td rowspan="4">No elements applicable</td></tr>
<tr><td colspan="5">Plant size limits</td></tr>
<tr><td colspan="5">Financial burden falling either on consumers or taxpayers</td></tr>
<tr><td colspan="5">Technologies eligible for support (all vs. only new plants)</td></tr>
<tr><td colspan="6">Instrument-specific design elements</td></tr>
<tr><td colspan="4">Flow of support*</td><td></td><td rowspan="10">No elements applicable</td></tr>
<tr><td colspan="2">Cost-containment mechanisms</td><td>Timing of tendering rounds</td><td colspan="2">Minmum TGC prices</td></tr>
<tr><td colspan="2">Support adjustments**</td><td>Recycling of proceeds</td><td colspan="2">Guaranteed headroom</td></tr>
<tr><td>Demand orientation</td><td>Cap / Floor</td><td>Deposit/ guarantee/penalty</td><td colspan="2">Distribution of proceeds from penalty</td></tr>
<tr><td colspan="2">Technology-specific support level</td><td rowspan="3">Organisation of tender</td><td rowspan="3">Credit multipliers / Carve-outs</td><td rowspan="3"></td></tr>
<tr><td colspan="2">Size-specific support level</td></tr>
<tr><td colspan="2">Location-specific support level</td></tr>
<tr><td>Purchase obligation</td><td colspan="2" rowspan="2"></td><td colspan="2">Banking / Borrowing</td></tr>
<tr><td>Forecast obligation</td><td colspan="2"></td></tr>
</table>

* Constant or decreasing support levels over time for one explicit plant

** Includes approach (Periodic revisions; Degression; Cap-based adjustments) and frequency of adjustments

The policy pathway ETS does not consider any dedicated RES support and, consequently, includes no design elements in an explicit manner. However, it has strong implications on the development of RES technologies and on electricity markets. Thus, it is therefore considered as "design element" in (the broader context) within this report. Moreover, the degree of harmonisation may also influence markets and grids to a significant extent due to differing preferences for the location of RES investments. Besides also the level where different design elements are set (i.e. at EU or Member State level) appears important.

A detailed description of the extended list of design elements and support characteristics is given in the following section.

2.1.2 Extended list of design elements and support characteristics

The design elements identified, which can be included in the different support instruments, and which also result in different characteristics of the RES-E technologies promoted, are described below (and in further detail in Del Río et al, 2012). For each element we provide a short overview of the implications that may result on markets and grids (although this will be developed further in the corresponding section).

However, it should be mentioned that some of them do not appear explicitly as such in our first report: this report presented design elements and also policy pathways. Here we have further decomposed policy pathways (such as the choice of FITs or TGCs) into design elements relevant for this work package, because we consider that it facilitates the analysis of these pathways, and also helps to understand the similarities and differences between policy pathways. For example, as mentioned before, a TGC with a requirement for long-term contracts happens to be equivalent to a decentralized tender. Therefore, the difference is not between e.g. FIPs and FITs in abstract, but between their practical implementation, which is materialized in design elements.

2.1.2.1 Design elements common to all pathways

Technologies eligible for support (all vs. only new plants)

Typically, newly implemented RES-E support systems only apply to new installations since existing plants have generally already benefited from another support system. Frequently, for example with the aim to increase market liquidity in a certificate trading regime provisions are defined that allow for the transition from the old to the new support scheme. The need to include existing plants in a new system may also arise in order to incentivise repowering of already installed RES-E installations or to imply additional requirements of any kind (for example new quality of service standards or participation in balancing markets) to an existing RES installation.

In particular repowering of existing plants might lead to a reduction of the need for additional grid infrastructure: the grid is already there, there are no needs for new lines than in the case of new plants. It can be expected that in general the inclusion of existing plants in a new support scheme would result in an increase of the related support expenditures. Otherwise one could hardly assume that plant operators are willing to switch from an old to a new system. Moreover, as a direct market impact it is also feasible that existing plants are influenced in their generation pattern via the new support scheme and, thus, changes in price volatility or balancing demand could result.

Flow of support (greater support in the first years vs. constant support over time)

Especially for dispatchable plants, a decrease of support in later years means that production is maximized in the first years of the plants lifetime. This might influence the need for balancing, the merit order effect, electricity wholesale price volatility and total generation costs.

Note that generally this design element only belongs to systems where support levels are defined ex-ante. Thus, a quota scheme based on TGCs would not fall under this classification for example.

Duration of support

In general, both the duration and the level of support deserve key attention for a possible RES investor. Both together determine the attractiveness of a support scheme implemented. Longer support periods are sometimes used for example to weigh out lower support levels. If the duration of support is short, plants enter the free market after a shorter period. This might represent an important obstacle for fuel-dependent RES technologies such as biomass or biogas where revenues from the selling of electricity on the wholesale market may be too low or too risky to incentivise operation sufficiently.

Cost burden of RES-E support (consumers or tax payers)

Financing by electricity consumers leads to higher retail prices which may lead to a reduction of electricity demand in the mid- to long-term. However, overall cost levels remain unaffected. In general, financing by consumers is usually perceived by investors as less risky: taxpayers finance through budgets that must be negotiated annually, whereas the laws by which the cost is set upon consumers typically last longer.

2.1.2.2 Instrument-specific design elements

Demand orientation

In case a FIT is implemented and the level of support is coupled to the actual electricity demand RES-E generators are incentivised to adapt their generation according to demand patterns. On the one hand, this increases the efficiency of the market and reduces the need for balancing energy. On the other hand this measure mainly affects RES-E generators which are actually capable to control their output without wasting fuel (thus this design element does have only a limited influence on variable RES-E generators) and leads to higher administrative costs of the support scheme.

Technology-specific support

Some support instruments allow for the eligibility of particular technologies and, moreover, distinguish the height of support offered, whereas others (e.g. TGC without banding) do not distinguish between technologies. In the latter case the technology mix promoted is less diverse and has lower costs in the short term. Dynamic learning processes for potentially lower costs for some technologies in the future are however not supported.

Size-specific support

If small-size applications receive special support this has the following effects on grids and markets: market power might be reduced as smaller and more diverse owners enter the market. Overall generation costs increase as smaller applications are often more expensive. As smaller installations are often connected at a lower voltage level, distribution grid enforcement becomes more important, the effect of decentralized generation on the need for transmission grid extensions is not clear at the current point in time.

Location-specific support

If higher support is given at locations with less optimal resource endowment (as happens in some countries with stepped tariffs for wind), renewable power plants are more evenly distributed over the region. This might lead to a reduced need for grid infrastructure. However, the use of sites with fewer resources increases overall generation costs. As explained above, the geographical distribution of renewable power plants is one of the crucial elements for deriving the impact on grids and (to a lesser extent, if we talk about the European context) markets.

Minimum / maximum support prices (Cap/floor/penalty)

This type of instrument helps flatten out support levels in the case when they are tied to wholesale market prices (as in FIPs or TGCs). It also mitigates the potential market power implications previously mentioned.

Cost-containment mechanisms

Caps on total costs can lead to stop-and-go investment cycles. This could result in high scarcity prices and price volatility but this effect depends on the predictability of developments. This measures increase also the risk perception of investors, who cannot fully predict when and how the price can be reduced (and therefore, they face the risk to need to stop the ongoing project if the expected rate of return at the beginning is no longer guaranteed). Furthermore caps on total costs might also influence the technology mix. On the other hand, cost-containment increases the political acceptability and sometimes the credibility of the system.

Purchase obligation

The purchase obligation minimizes investment risks especially in those cases in which the remuneration is not linked to market prices (if this is the case, the risk hedge is less significant since at the time the purchase obligation activates, the wholesale market price is often nil o negative). If there is no purchase obligation, the probability of negative prices might however be reduced as overproduction is decreased.

Forecast obligation

This design element can lead to a lower balancing demand and less problems with intra-day adjustments. On the other hand, it will probably increase the cost of RES-E producers.

Support adjustments

The more frequent the adjustment of support levels, the lower will typically be the cost of the support system (assuming constant improvements in technology). This does not necessarily imply a large risk for investors, as long as adjustments are not fully retroactive, and as long as planning horizons are short enough to know about the level of support for a specific project before starting with its planning or construction.

Distribution of proceeds from penalties/deposit

This feature only corresponds to quotas or tenders. The way penalties for non-compliance may be (re) distributed will have an impact both on the cost of the system and on the distribution of its volatility.

2.1.2.3 *Conditions of regulatory and support framework*

Cooperation with third countries

Cooperation systems (which are, after all, trade arrangements) typically result in lower costs for the same RES-E target. On the other hand, it may imply more grid requirements (if a physical trade of electricity is required).

Eligibility of plants in other countries

Very much related to the last point, although within the EU: if countries allow RES-E from other countries to benefit from their support systems, this will typically result in lower costs (although maybe not significantly). However, it may have strong implications on the acceptability of the RES-E policy within the participating countries, and may also require additional grid investments (in the host or exporting country).

Distribution of grid connection costs

The way grid connection costs (deep, shallow, or super-shallow) are shared will influence very much RES-E deployment, as shown in the relevant section.

Degree of harmonisation

The degree of harmonisation of the support scheme within Europe may have significant impact on the location of stimulated RES investments. Moreover, consequences can be expected to arise on costs, markets or grids.

2.1.2.4 General support characteristics

Exposure to market risk (support tied to market prices)

When the support is tied to market prices, RES-E producers receive market signals and, to the extent they are able to do it (the dispatchability of some of the RES-E is limited, so the effectiveness of the signal can be very low), may act accordingly, thus making more efficient the operation of the market (including the reduction of the need for balancing). Conversely, this can increase the risk perceived by RES-E producers and thus overall costs as administrative costs. Also, as discussed by Batlle et al. (2011), this factor can also have an impact on the market structure, since it might increase the market power of dominant players.

Support based only on ETS

This is not a design element, but rather a policy option in itself: Investments in RES-E would be incentivised through their lack of carbon emissions (and therefore by not being required to pay carbon emission allowances). However, since this feature is what characterizes essentially this system, we chose to present it here as a "design element" to facilitate the discussion of results and impacts as well as the corresponding analysis.

Table 2 List of policy design elements influencing markets and grids

Common design elements					
Techologies eligible for support (all vs. only new plants)					
Flow of support (constant or decreasing)					
Duration of support					
Cost burden (taxpayers, consumers)					
	Concerned pathways				
Instrument specific design elements	FIT	FIP	QUO	QUO(b)	TEN
Demand orientation	x				
Technology specific support	x	x		x	x
Size-specific support	x	x		x	x
Location-specific support	x	x		x	x
Minimum/maximum support prices (cap/floor/penalty)		x	x	x	
Cost-containment mechanisms	x	x			
Purchase obligation	x				x*
Forecast obligation	x				x*
Support adjustments	x	x			
Distribution of proceeds from penalties/deposit			x	x	x*
Regulatory / support framework					
Cooperation with third countries					
Eligibility of plants in other countries					
Distribution of grid connection costs					
Degree of harmonisation					
General support characteristics					
Exposure to market risk (support tied to hourly market prices)					
Support based only on ETS					

* Depends on the actual organisation of the tender

2.2 The relationship between policy design elements and technology characteristics

We now move on to describe the relationship between policy design elements and technology characteristics. This is an intermediate step required before we reach the final outcomes (the influences on markets and grids).

Our goal here is to preliminary assess the impact that different design elements may have on the characteristics of the technologies being promoted by the corresponding support scheme. These characteristics will then result in different outcomes for markets and grids.

2.2.1 Technology-specific characteristics and interactions

The technology-specific characteristics we have identified, and which will determine the final outcomes on grids and markets, are described below. We put together both characteristics of technologies and of combination of technologies (such as e.g. diversity of the RES-E mix): both drive the impact of RES-E support systems on electricity markets and grids.

2.2.1.1 Technology characteristics

Costs of technologies (levelized cost)

Costs of electricity generation per unit of electricity and their development over time. Total system generation costs need to be covered by the electricity consumers. Technologies with higher generation costs therefore increase electricity retail prices.

Cost structure

Spot market prices are based on marginal costs that correspond to short-term operational costs. Hence, the structure of the cost of RES-E technologies (higher or lower capital or variable costs, for example) will determine the impact on marginal prices in electricity markets.

Cost volatility

The volatility of the cost of the electricity produced by a certain technology is also an important driver of outcomes for markets and grids. Some support schemes may result in more volatile costs, increasing risks, decreasing political acceptability, or creating complications in the distribution of costs.

Firm power/ Availability

Degree to which plants contribute to system adequacy and full load hours. This can be measured in terms of capacity credit, or in any other measure of firm power. If plants are not available, they cannot contribute to system adequacy and additional backup capacities need to be contracted. Name-plate installed capacity overall must increase in order to guarantee the same degree of system adequacy; grid optimisation might become more difficult as generation according to name-plate capacity is reached seldom.

Variability

Some RES-E technologies are more variable or intermittent in their production than others. Wind, run-of-the-river hydro and solar are essentially variable, whereas biomass is less variable. Variability depends on the timeframe considered: for example, some technologies are variable in the short term, but more stable on an annual level.

Predictability

Degree to which production from the generation unit can be adequately forecasted for specific timeframes. This will affect balancing needs, and also grid operation.

Dispatchability

Possibility of regulating or actively influencing the output of a power plant. Traditionally, electricity generation reacts flexibly to changes in demand. Dispatchability of variable renewables is restricted by weather conditions, although it can be mitigated with storage.

2.2.1.2 System characteristics

Geographical concentration

Some renewable resources are more geographically concentrated than others: often wind or biomass are more concentrated than solar. However, as previously stated, the final geographical distribution or concentration of RES-E will depend not only on the availability of the resource, but also heavily on the support scheme and the chosen design elements. For example, site-specific support schemes may result in less concentration than others, since the availability of the resource is compensated by the level of support.

Diversity

Diversity in technologies may influence long-term electricity costs, but also the acceptability of the policy, administrative costs, etc.

Grid location

By this we refer to the location of a power plant regarding load centres and existing grids, including decentralised or centralised power generation. If locations of power plants change, grids need to be adapted to the new situation. Locational signals (e.g. nodal prices or discriminatory transmission charges) from grid regulation, or included in the different support systems may result in more optimally located plants than others.

Retail prices

Finally, retail prices may change differently than costs. For example, if support is financed by taxpayers, electricity consumers will see little change in their costs. If electricity markets are liberalised changes in prices may be amplified compared to cost-of-service systems.

2.2.2 Correspondence between design elements and technology characteristics

In the following table we relate the design elements presented before with the technology characteristics outlined above. The goal here is to show the expected impacts of the different design elements on the technology and system characteristics described above.

This is only an approximation that will be refined during the modelling phase of the project, but that has been informed by our review of the literature. For example, we would expect that a support system with a price discovery mechanism would result in lower costs than one in which the level of support is set by the regulator. Or, when the support is tied to hourly market prices, then this typically results in less variable technologies being incentivised. Given that it is only an approximation, we are using only qualitative information (++ when we expect a large positive impact, - when we expect a negative impact).

Table 3 Correspondence between policy design elements and technology characteristics

	Technology and system characteristics										
Design elements	Cost	Cost structure	Cost volatility	Firm power	Variability	Predictability	Dispatchability	Geographical concentration	Diversity	Grid location	Retail prices
Eligibility of plants	-										
Constant support levels	-										
Duration of support	-										
Cost burden (taxpayers, consumers)											
Demand orientation	+		-		-	+	+		-		
Tech-specific support					+				+		
Size-specific support											
Location-specific support	-							+		+	
Minimum/maximum support prices	-		-								
Cost-containment mechanisms	-		-								
Purchase obligation	-										
Forecast obligation	+				-	+	+				
Frequency of adjustment of support levels	-										-
Tenderings promoting bigger projects	-	-						+	-	+	
Distribution of proceeds from penalty											
Cooperation with third countries	-				-			-	+		
Eligibility of plants in other countries											
Distribution of grid connection costs										-	
Degree of harmonisation	-							+			
Support tied to hourly market prices (as in FIPs)	+	-	-		-		+	-	+		
Exposure to market risk	++	-			-		+	+	-		
Support based only on ETS	-				-		+	+	-		

2.3 Influence of technology characteristics on markets and grids

Finally, from the characteristics of the technologies promoted, we need to make the last step to the influence on markets and grids.

The following chapters will address the theory and empirical evidence behind the influence of certain technology characteristics and non-technology-specific outcomes on electricity markets and grids. However, here we introduce on a qualitative basis the major aspects to be considered.

This assessment will however need to be informed by the modelling exercise in WP4, in which the result of different policy pathways on the technology mix and on markets and grids will be evaluated.

2.3.1 Major influences on electricity markets and grids

The major influences considered (notwithstanding other influences that may arise in the development of the project) are:

Overall cost

By this we mean the change in the cost of the supply of electricity. This change in principle should be transferred to consumers, although this may not be the case in some markets.

Price/Merit order effect

The introduction of RES-E in an electricity market may alter the order in which power plants are dispatched, and, this may also change wholesale market prices in liberalized systems.

Price volatility

A large penetration of variable RES-E may increase the volatility of prices in the market. Although volatile prices can be hedged, increased volatility usually creates additional costs or problems in markets.

System adequacy

Adequacy refers to the ability of a system to provide electricity in a most efficient way. When prices change, the long-term investment signals sent by markets may be altered, sometimes resulting in these signals not being efficient. In addition, RES-E may change firm power, thus altering the adequacy of the system.

Market power

A large introduction of RES-E may also change the conditions in which market power arises, and also in the way it may be exercised by firms.

Balancing needs

Being generally variable energy resources (VER), RES-E will typically increase the need for balancing in power system (or for intraday trading), that is, the need to correct mismatches between supply and demand.

Balancing cost

The cost of balancing the system may also change with the introduction of RES-E, not only because of a change in the balancing needs but also by a change in the price of the balancing services.

Cross-border trade

Different support systems for RES-E may result in a different geographical location of RES-E plants, which will in turn affect cross-border trade. This may be especially relevant for offshore wind.

Grid losses / Change in the need for grid investments

Since RES-E has to be installed where the renewable resource lies (with some variation depending on the support system), grids may need to be reinforced or extended to allow for this RES electricity to be transported closer to the load.

On the other hand, when renewables are installed as distributed generation, RES-E may reduce the need for grid reinforcements by reducing congestion.

Cost of grid investments

The reinforcements or extensions of the grid required by RES-E will imply an additional cost on the system. However, the issue is not only the cost, but how it is allocated between the agents.

2.3.2 Correspondence between technology characteristics and influences on markets and grids

As done before, in the following table we relate the characteristics identified in section 2.2.2 with the major influences on electricity markets and grids. For example, when the technologies promoted feature a cost structure with low variable costs, there will be impacts on the overall cost (which may be lower for liberalised markets), for the merit order and electricity prices (which may be lower), for system adequacy (which may worsen due to the lower prices), and also for the possibility of market power (higher when inframarginal technologies enter the market).

Again, this is just an approximation based on the literature review and therefore is expressed in qualitative terms (+ for positive impacts, - for negative impacts). A more precise assessment will be carried out in the modelling phase of the project.

Table 4 Correspondence between technology characteristics and final impacts on markets and grids

	Impacts								
Outcomes	**Overall cost**	**Price/Merit order effect**	**System adequacy**	**Market power**	**Balancing needs**	**Balancing cost**	**Cross-border trade**	**Needs for grid extension**	**Cost of grid investments**
Levelized costs	More high cost technologies in the mix lead to higher overall system costs								
Cost structure	Changes in cost structure might coincide with overall cost increases if high cost technologies are involved	An increased share of rene-wables with low variable costs leads to lower wholesale mar-ket prices	An increased share of variabel renewables can lead to lower system adequacy due to more volatile prices	Market power can increase when scarcity prices play a more important roel ion the system					
Cost volatility	+								
Firm power	-		-		-	-	-	-	-
Variability	+	-	-		+	+	+	+	+
Predictability	Higher predicta-bility leads to higher overall system costs	more predictable means that agents can adjust their bids	Higher predica-tability means that system adequacy is easier to reach		Lower predi-catbility increa-ses the need for balancing or intra-day tra-ding-	Cosnequently balancign costs may increase	Less predicatable generation increases the need for cross-border trade	In order to facilitate cross-border trade, the grid needs to be extended	Accordingly, costs for grid extension increa-se
Dispatchability	Lower dispa-tchability (all else equal) leads to higher system costs.	less need for startup costs which can be passed on to prices	Higher dispa-tchability increa-ses system adequacy		Higher dispa-tchability de-creases the need for balancing and increases the potential for balancing-	Therfore, balan-cing costs de-crease	Higher dispa-tchability makes crodss-border trade less impor-tant	Dispatchable plant do not require signifi-cant grid exten-sions	The costs for grid investments are low when new plants are dispa-tchable and not geographically bound.-
Geographical concentration	- (usually)				+	+	+		
Diversity	+ (usually)								

	Impacts								
Outcomes	**Overall cost**	**Price/Merit order effect**	**System adequacy**	**Market power**	**Balancing needs**	**Balancing cost**	**Cross-border trade**	**Needs for grid extension**	**Cost of grid investments**
Grid Location	-	less congestion, less negative prices	+		-	-		-	-
Retail prices									

3 Impacts of RES-E on electric power systems

This Chapter introduces in a first step effects of VER on grids and markets that have already been identified in the literature. These issues have been examined from different perspectives and there is rapidly growing amount of literature on this topic. The objective of this section is to present the major open issues that have been identified along with the major electricity generation system functions, and to classify them in a logical fashion to facilitate an orderly discussion. However, some preliminary new ideas (or at least some new perspectives on well-known topics) will be introduced.

Due to the fact that not all renewable technologies contribute to these effects in the same way, the Annex of this report analyses the characteristics of the most important renewable technologies and shows their respective contribution to each effect. The last section summarizes our findings.

3.1 General discussion of influences

The effects of the penetration of renewable generation will affect market decisions made at all timescales and across geographic regions, since a variable and only partly predictable source of power generation, with zero variable costs, will be brought about to a power system that has to balance generation and varying demand at all times. At high levels of penetration, the characteristics of the bulk power system can be significantly altered. These changes need to be considered and accommodated into the current planning and operation processes, which were not designed to incorporate large volumes of VER generation. Multiple new issues must be addressed, ranging from increasing power system flexibility by a better utilization of transmission capacity with neighbouring areas, to demand side management and optimal use of storage (e.g. pumping hydro or thermal), changes in market rules to schedule the plants closer to real time or many other aspects related to the generation unit commitment. For instance, the future mix of generation technologies will have to accommodate the strong presence of intermittent generation and be able to cope with more cycling, fewer hours of operation and different patterns of electricity prices[1]. This and many other key factors are largely discussed later in this report.

In general, several effects of an increasing renewable penetration on markets and grids have already been identified. Roughly speaking, the policy and regulatory intervention to favour the deployment of RES-E has a number of expected effects in the functioning of wholesale electricity markets:

- From the very long to long term, the expected outcome is a maximization of the energy systems sustainability, and thus, a minimization of the energy supply costs in the future. The implementation of RES-E support mechanisms is already leading and expected to lead to a significant increase on the learning curve of a number of RES-E technologies[2]. As stated, from the electricity supply costs perspective, in the very long term, RES-E are expected to turn into a huge improvement of efficiency.

[1] Storage, at scale, represents the most straightforward way to deal with these issues. However, storage at the low cost and large scale needed will take some time. In the interim, if a large deployment of VER happen to take place –which will likely be at the decadal scale– other sources of flexibility will be needed.

[2] Indeed this has been for instance the case of wind generation, whose costs have been reduced dramatically in the last two decades, to such extent that currently they are close to turn wind production into a technology which does not need any support to enter into power system. See for instance the auction prices that resulted from the auctions held in Brazil (Batlle & Barroso, 2011).

- From the long to the medium term, the strong presence of VER will imply a re-adaptation of the generation technology mix. In the medium term, the load factors of the currently installed conventional generating units will decrease and in the long term, in principle, if regulatory incentives are properly designed, a higher proportion of less capital-intensive alternatives (generating units and demand response solutions) is expected to be installed. Due to the wide variability of RES-E, in most of the electric power systems[3], the need for the so-called back-up capacity will be larger than the one related to other sources. From the total cost of energy supply side, RES-E imply a lower reduction of capacity needs than other generation alternatives, but at the same time, in principle this capacity will have lower investment costs.

- From the medium to short term, on the one hand, VER entail a zero- or low-cost energy contribution. On the other hand, particularly in mainly thermal systems, due to the fact that the VER production is less correlated with the demand needs, VER imply a very significant change in the scheduling regime of the rest of the generating facilities in the system. This issue will have a key impact not only in the short-term operation of electricity systems, complicating significantly the unit commitment problem, for thermal plants will have to cycle intensively; it will also condition significantly capacity expansion, since not only low capital investment units will be needed, but also flexible ones, characterized by less relevant operation constraints, minimizing the cost of cycled scheduling. Again, from the operation cost perspective, in these shorter terms (e.g. from one week to one day ahead real time), the impact of VER is bidirectional, meaning a price decrease due to a reduction of variable operation costs (i.e. fuel costs) and a price increase due to thermal units constraints, since the related costs will have to be internalized in shorter time periods, and thus their weight in the cost per MWh produced can be significantly larger.

- From the short to the very short term, the unpredictability of VER generation in the short term leads to a larger need of provision of reserves. Although there has been a positive evolution in the forecast error in the last years, -e.g. in the Spanish system, beyond five hours ahead, this error is still around 15% (Imaz, 2011)-, the larger the amount of VER installed in the system, the larger the costs related to reserves contracting.

In the sections that follow this general introduction on the influences of RES-E on electric power markets, the discussion is particularized on the so-called VER. Next, just to support this general approach that opens this section, we first very briefly introduce the main technical characteristics of the two main VER, wind and solar PV, the ones expected to be deployed in a larger extent in the near future. More details about these technologies, and also about hydro and biomass, can be found in the Annex. Then, as an introduction to the detailed discussion on technology basis, we will divide this first general review according to the different time spans previously outlined, starting from the short term (ancillary services needs), discussing then the impact on unit commitment costs and spot market prices and closing with the expected influence on generation investment and thus on system adequacy.

3.2 Variability characteristics of wind and solar generation

Wind and solar generation are both intermittent. Intermittency comprises two separate elements: non-controllable variability[4] and partial unpredictability. Non-controllable variability implies a likelihood that an individual plant could be unavailable when needed that is significantly higher than in conventional plants. Note that the output of a plant could conceptually exhibit much variability,

[3] This is not for instance the case in those systems in which storage capacity is abundant, as it is the case of the mostly hydro-based ones, e.g. the Brazilian power system.

[4] Although in the vast majority of cases it is still not taking place, VER curtailment, negative balancing and ramp rates control is technically possible. In any case these actions are just unidirectional, as VER output can only be reduced.

while being 100% predictable. Although the output of any actual power plant is variable and unpredictable to a certain point, wind and solar generation have these characteristics in a degree that justifies the qualification of “intermittent”.

Wind generation is variable over time, due to the fluctuations of wind speed[5]. Although figures are very much system-dependent, some illustrative statistics can be found in EURELECTRIC (2010): for instance, on average, only 4% (2.5% in Spain, 5.5% in Germany) of the total wind installed capacity has a probability of 95% of being present at all times, which is a similar level of availability expected in conventional power plants.

Especially the deviation of actual wind generation from day-ahead forecasts becomes increasingly important at higher penetration rates (Weber, 2010; Obersteiner & von Bremen, 2009). The variability of wind generation also decreases with spatial aggregation. Wind energy output over larger geographic areas has less variability than the output of a single wind power plant.

Although forecast techniques are significantly improving over the years, predicting wind’s output is much more difficult than predicting the output of conventional generators or load. Generally, only very near-term wind predictions are highly accurate (Xie et al., 2011). In particular, the error for 1- to 2-hour ahead single plant forecasts can be about 5-7%; for day-ahead forecasts, the error increases up to 20% (Milligan et al., 2009).

Solar power is characterized by a diurnal and seasonal pattern, where peak output usually occurs in the middle of the day and in the summer, so it is quite well correlated with the hours of high demand of many electric power systems. On the other hand, due to the lack of thermal or mechanical inertia in PV systems, and the impact of clouds, rapid changes have been observed in the output of PV plants[6]. Spatial diversity, as with wind, can mitigate some of this variability by significantly reducing the magnitude of extreme changes in aggregated PV output.

Compared to wind energy, PV solar output is generally more predictable due to low forecast errors on clear days, and the ability to use satellite data to monitor the direction and speed of approaching clouds.

3.3 Requirements for operating reserves and other ancillary services

3.3.1 Increased need and costs for balancing or intraday adjustments

Following Milligan et al. (2010), operating reserves are defined as the real power capability that can be given or taken in the operating timeframe to assist in generation and load balance, and frequency control. There is also need for reactive power reserve, but it will not be discussed here. The types of operating reserves can be differentiated by: a) the type of event they respond to, such as contingencies, like the sudden loss of a generator or a line, or longer timescale events such as net load ramps and forecast errors that develop over a longer time span; b) the timescale of the response; c) the type of required response, such as readiness to start quickly a plant or fast response to instantaneous frequency deviations; d) the direction (upward or downward) of the response. See also Milligan et al. (2010) for a thorough international review of definition and use of reserves.

[5] For example, at the end of 2010 the installed capacity of wind in the Spanish system amounted to 20 GW, with a wind production record of 14962 MW on November 9th, 14:46, meaning at that time 54.2% of total production. Conversely, an annual minimum of 250 MW was recorded just three months before, on August 17th, 7:11.

[6] Although the ramping characteristics are fast for PV plants, the time it takes for a passing cloud to shade an entire PV system depends on factors such as the PV system size, cloud speed, and cloud height, among others. Therefore, for large PV systems with a rated capacity of 100 MW, the time it takes to shade the entire system will be on the order of minutes, not seconds (Mills et al., 2009).

A critical issue in power system operation with a large volume of intermittent production is the amount of operating reserves that will be needed to keep the power system functioning securely and efficiently. The practical implications are: a) more expensive operation, as a number of plants have to be maintained in a state of readiness and kept from being used normally to generate electricity, regardless of the regulatory framework; b) a long-term impact on the generation mix, as appropriate investments have to be done to have these plants installed and ready when the level of penetration of intermittent generation makes these quick response plants necessary. A comprehensive review of the new requirements that intermittent generation may impose on power systems can be found in Holttinen et al. (2011).

While for lower shares of wind energy, balancing required for demand deviations is still the decisive factor, Consentec (2008a) find that extended balancing becomes necessary if the share of variable renewables exceeds 30% of electricity production (Milborrow, 2011; Weber, 2010). Another problem for balancing VER is that fewer power plants are available to provide the full spectrum of current balancing services. The reduced number of possible participants in the market especially for positive balancing services can reduce liquidity and increase prices in these markets. Thus, additional balancing services may be associated with significant costs (Erdmann, 2008; von Roon, 2011b).In Germany, liquidity in the intraday market has already improved but is not yet sufficient for the integration of large amounts of wind energy (Borggrefe & Neuhoff, 2011; Weber, 2010). In Spain, the need for balancing services remained constant despite a high penetration of wind in an isolated system due to the liquidity of the intra-day markets. Liquidity is reached there by the operation of six centralized intraday auctions (Borggrefe & Neuhoff, 2011).

A review of the numerous studies that have been made on the subject of the impact of intermittent generation on the need for additional reserves appears to lead to the following findings, which have to be adapted to the diverse characteristics of each individual power system:

- The observations and analysis of actual wind plant operating data have shown that, unless in those few cases in which extreme weather conditions arrive, wind does not change its output fast enough to be considered as a contingency event. Therefore the largest contingency to be considered in the determination of reserves is not affected by wind penetration. Also, both the uncertainty and the variability of wind generation may affect the required amount of regulating (secondary) reserves, but not significantly in most cases. Fast response reserves–frequency response and regulating reserves–should be ready to respond to quick fluctuations in solar or wind production. Since power systems already need these kinds of reserves to cope with load fluctuations and unexpected emergencies, the practical relevance on production levels or costs of the presence of VER on the demand for these reserves is not deemed to be of much relevance.

More important is the impact of errors in the prediction of the output of wind and solar on the day-ahead schedule of plants, since this requires having ready a significant capacity of flexible generating plants with relatively short start-up times and/or fast ramping capabilities, such as OCGT and CCGTs plants, to provide load following and supplemental (tertiary) reserves. Therefore, improvements in wind plant output forecasting offer a significant opportunity to reduce the cost and risk associated with this uncertainty (Lew et al., 2011), minimizing the need for more balancing and intra-day trading (Weber, 2010; Nievel, 2011). However, most authors do not consider higher quality wind forecasts as sufficient to solve the problem (Weber, 2010; Borggrefe & Neuhoff, 2011). Improvements in prediction require better models and more observational data. The benefits of wind output aggregation at power system control level and the need for large investments in observational networks favour centralization of the wind forecasting activities. The involvement of demand response can potentially reduce costs.

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 and may increase market prices.

As pointed out in Holttinen H. et al. (2011), an 'increase in reserve requirements' does not necessarily mean a need for new investments, as countries already with much wind power have learned from experience. Note that most wind-caused reserves are needed when wind output is highest and, therefore, the conventional power plants must have more spare capacity to provide reserves. Critical issues appear to be the capability to follow steep long ramps if the wind forecast errors are large enough that the slow units cannot follow, although this matter could be mitigated by regulating wind plants (the so-called pitching).

3.3.2 Availability of other ancillary services

Power systems must be able to maintain their integrity while responding to different kinds of contingencies that take place in very short time scales: short circuits in lines, sudden loss of load or generation, or special system conditions that gradually become unstable. Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact (Kundur et al., 2004).

There are several forms of instability that a power system may undergo. Transient stability refers to the capacity of the generators to maintain the synchronism in the presence of transmission line faults. Spontaneous low frequency oscillations must be damped quickly. Frequency excursions due to abrupt imbalances between generation and demand should be contained and the frequency brought swiftly to its nominal value. Voltages have to be maintained within safe boundaries at all times. The allowed response time to these contingencies typically ranges from some milliseconds to a few seconds or even minutes, therefore with some overlap with the activity of fast operation reserves. The most crucial factors for the stability of a power system are its mechanical inertia (provided by the rotating masses of all the turbines and the electricity generators) and its capability to damp any perturbation (Rouco et al., 2008).

The physical characteristics of wind and solar PV plants are substantially different from those of thermal plants–including concentrated solar power units–which consist of a boiler producing high-pressure steam that drives a turbine rotating in the same shaft with a synchronous generator. The ability to regulate frequency and arrest any sudden rise and decline of system frequency is primarily provided through the speed droop governors in conventional generators.

In principle, the inertial response of wind turbines and solar PV plants to the overall power system is almost negligible. Therefore, in systems with a high penetration ratio of wind farms, the effective inertia of the system may be reduced and the system response to large disturbances could be significantly affected. This situation is more likely to happen for system conditions with a strong wind output and light demand. In particular, small standalone or weakly interconnected systems, as for example the Irish or the Hawaiian power systems, are more vulnerable to contingencies like the sudden loss of generation (Xie et al., 2011).

An additional consideration is that long transmission lines are required by power plants that are located far from the main load centers–typically hydro, nuclear and, more recently, large wind or solar plants. The synchronizing power capability of these lines is significantly reduced when they are heavily loaded (Gautam et al., 2009).

Power management and frequency control

Many modern wind turbines are capable of pitch control, which allows their output to be modified in real-time by adjusting the pitch of the turbine blades. This capability can be used to limit ramp rates and/or power output of a wind generator and it can also contribute to power system frequency control. A similar effect can be realized by shutting down some of the turbines in a wind farm. Unlike a typical thermal power plant whose output ramps downward rather slowly, wind plants can react quickly to a dispatch instruction taking seconds, rather than minutes. Operators need to understand this characteristic when requesting reductions of output. Examples of implementation of these techniques to provide frequency control can be found in Martínez de Alegría et al. (2004) or Gautam et al. (2009).

Detailed simulations of a large penetration of wind generators equipped with doubly fed induction generators in the New York (assuming 10% wind) and WECC (assuming 20% wind) regions, have shown that wind plants can actually contribute to system stability by providing low voltage ride through capability and dynamic VAR support to reduce voltage excursions and dampen swings (GE ENERGY, 2005). From the WECC system frequency response study, results have shown benefits provided by special wind plant controls specifically contributing to system frequency performance during the first 10 seconds of a grid event by providing some form of inertia. These cases show that wind generation does not necessarily result in degraded frequency performance (Miller et al., 2010).

Large PV solar plants can potentially change output by +/- 70% in a time frame of two to ten minutes, many times per day. Therefore, these plants should consider incorporating the ability to manage ramp rates and/or curtail power output. The use of inverters in solar PV plants makes them able to provide real-time control of voltage, supporting both real and reactive power output. Due to their energy storage capability, the electrical output ramps of a solar thermal plant can be less severe and more predictable than solar PV and wind power plants.

Concentrating solar thermal plants that use steam turbines typically make use of a “working fluid” such as water or oil; molten salt may be used for energy storage. The mass of working fluid in concentrating solar thermal plants results in these types of plants having stored energy and thermal inertia. Due to their energy storage capability, the electrical output ramps of a solar thermal plant can be less severe and more predictable than solar PV and wind power plants.

Voltage control

Most wind generators that were deployed more than a few years ago were equipped with minimum voltage protections that can trip the unit, with the purpose of protecting both the machine and the power system. As noted by Rouco et al. (2006), a large amount of wind power generation can be tripped if the voltage dip affects a large fraction of the power system with much installed wind capacity, leading to a potential system collapse. Depending on the technology being used, the dynamic response of wind power generators to voltage dips may be different. A sudden significant loss of wind production may also occur when wind velocity in a region happens to exceed the safety specifications of the plants, which then have to shut down immediately.

Voltage control can also be implemented in wind power plants, which, as well as PV plants, can control reactive power. As variable resources, such as wind power facilities, constitute a larger proportion of the total generation on a system, these resources may provide voltage regulation and reactive power control capabilities comparable to that of conventional generation. Further, wind plants may provide dynamic and static reactive power support, as well as voltage control in order to contribute to power system reliability. The most demanding requisite for wind farms, especially those equipped with doubly fed induction generators (DFIG) is the fault ride through capability. The effect of such a voltage dip in the wind turbine is different for different wind turbine system technologies. Voltage ride-through can be achieved with all modern wind turbine generators, mainly through modifications of the turbine generator controls. Older types of wind turbine-generators at weak short-circuit nodes in the transmission system must be disconnected from the grid unless additional protection systems are provided, or there may be a need for additional transmission equipment.

Grid codes and VER as ancillary services providers

All these factors, plus the knowledge that large levels of penetration of wind and also solar PV are anticipated to take place in many countries, lead to two major conclusions. First, the operation of power systems with a strong presence of VER has to be profoundly reconsidered and grid codes have to be adapted to this new situation (Tsili et al., 2008). Second, wind and solar PV plants can no longer be regarded as passive units, shutting down when system faults occur and with local control of regulation. In this new context, they must behave as much as possible as ordinary power plants, which are able to provide reactive power, remain connected during system faults and increase the amount of control effort required to stabilize system frequency (Xie, et al., 2011). These features are considered essential for the future integration of high wind penetration in electric power systems.

The good news is that wind generation is technically able to actively participate in maintaining system reliability along with conventional generation. It is now possible to design wind generators with a full range of performance capability that is comparable, and in some cases superior, to that in conventional synchronous generators. This includes voltage and VAR control and regulation, voltage ride-through, power curtailment and ramping, primary frequency regulation and inertial response.

3.4 Changes in electricity wholesale prices

Experience and modelling show that increasing shares of renewable electricity lead to changes in the level and volatility of energy wholesale prices.

3.4.1 Merit Order Effect

First of all, electricity wholesale market prices at times of high renewable generation and thus average electricity wholesale prices are reduced due to the Merit Order Effect (Bode & Groscurth, 2006; Morthorst and Awerbuch 2009; Haas, 2011; Traber et al, 2011; Sensfuss et al, 2007): wind and solar generation directly reduce the overall supply costs, since a zero variable cost energy contribution replaces expensive fossil-fuel electricity production.

Figure 3 shows a stylized merit order curve (the example is taken from the German market). The right curve includes more must-run renewables plants. The resulting new price is lower than the original price as plants with higher marginal costs (in this case gas-fired plants) are driven out of the market.

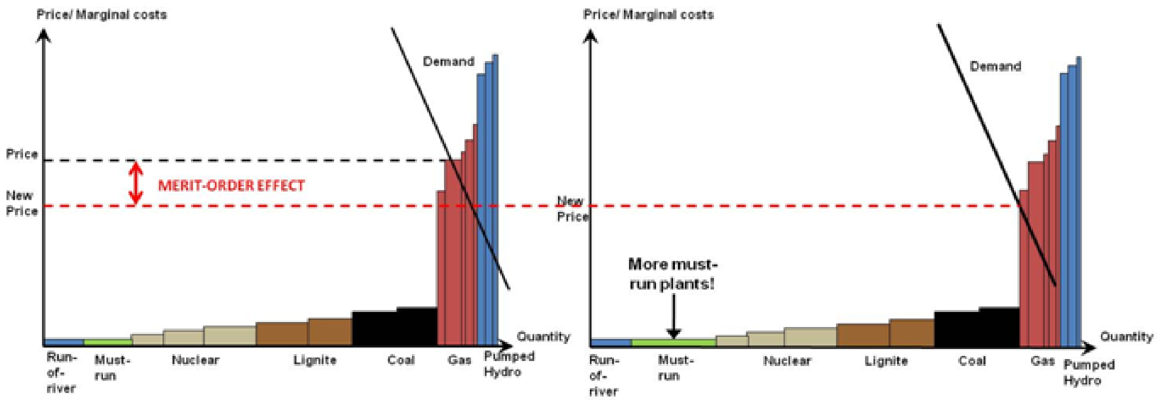

Figure 3. Merit order effect

It has been traditionally argued that especially high wind and solar generation reduce the electricity price in the wholesale market at least in the short term (Felder, 2011; Wissen & Nicolosi, 2007; 2008; Nielsen et al, 2011). The merit order effect has been quantified by several authors (Pöyry &

EWEA, 2010; Green, 2010; Labandeira et al, 2009). Sensfuss et al (2007), as an example, estimate that renewables have reduced the electricity price by 7.83 Euro/MWh in 2006. Schüppel et al (2011) find that price effects are bigger in times of high demand as the merit order curve is steeper at the margin.

However, the calculation and quantities are debated. Pérez-Arriaga & Batlle (2012) note that while this effect is undoubtedly significant from a cost perspective, in a wholesale generation market the price reduction may be less important. This happens when the addition of wind does not change the technology that sets the marginal price in most of the hours of the year. This is often the case in Europe with systems with a large component of combined cycle gas turbines (CCGT). To date, the newly installed CCGT plants worldwide are quite standard, with similar heat rates and also fuel costs within each power system. Most of the drop in electricity prices that has been observed in some of these electricity markets, as in Spain, might be better explained due to the reduction of the CCGT load factors, and the activation of the inflexible take-or-pay clauses included in the natural gas supply contracts[7].

In the longer term, as argued in the next section, new investments have to be considered – if less base load plants and mid merit plants are part of the electricity mix, peaking plants with higher marginal costs are used more frequently. According to some authors this might lead to an increase of the average wholesale price (Erdmann, 2008; Wissen & Nicolosi 2007; 2008; Green, 2011).

3.4.2 Increasing cycling and price peakiness

The second impact is due to the lack of correlation of wind production with demand. Wind output alters the shape of the net load to be satisfied with conventional thermal generation, therefore changing the traditional way to schedule the thermal portfolio. Peaks of thermal production no longer occur when demand is highest. In addition, VER production may result in such a low value of net demand (mostly at night in the case of wind, and during the day in the case of solar PV) that will force a large number of thermal units to shut down only to have to start up a few hours later.

The term "cycling" refers to the changing operating modes of thermal plants that occur in response to varying dispatch requirements: on/off operation, low-load cycling operations and load following. Lefton et al. (1996) put forward a good qualitative summary of the impacts of fossil power plant cycling operation: significant increase in equivalent forced outage rate (EFOR), additional capital and maintenance expenditures and increase fatigue-related and creep-related wear and tear. These translates into a significant cost increase caused by operation, maintenance, and capital spending, replacement energy and capacity cost due to changed EFOR, cost of heat rate change due to low load and variable load operation, cost of start-up auxiliary power, fuel, and chemicals, cost of unit life shortening and general engineering and management cost (including planning and dispatch).

Since the increasing penetration of wind and solar is unavoidably going to lead to a significant increase of these cycling-related costs, any sound economic analysis needs to properly take these expenses into consideration, particularly due to the fact that the actual and expected costs of cycling fossil units that were originally designed for base-load operation is greater than most utilities had estimated.

The extent to which the combination of a large penetration of VER, the resulting increased cycling needs and the impact of technical operation constraints of conventional generating units may affect the economic dispatch of the power system and the electricity market outcomes in the future is an active research topic at the present moment. There is a growing number of modeling analyses that

[7] For example, if a CCGT unit expected to produce 6000 hours per year and signed a contract with a pay penalty of 25% of the price for the first 5000 hours, but it happens later to expect an actual production of only 3000 hours per year (due to the large penetration of wind, or demand reduction because of the economic crisis or simply flawed investment planning) its opportunity cost (i.e. its rational bid in the market) is reduced by 25%.

deal with the impact this new scheduling regime will have in the short to medium term, as for example Denny (2007), Delarue et al. (2007), Goransson and Johnsson (2009) and Troy et al. (2010).

Batlle et al. (2012) review the sources of costs that are expected to suffer changes as the penetration of VER (and thus thermal cycling operation) grows. Significant costs are incurred when shutting down and starting up a thermal generation plant. A considerable amount of fuel is needed to raise the boiler to its minimum operating temperature prior to producing electricity. Moreover, the heating and cooling processes intensify the wear of plant equipment that shortens the maintenance cycles. Cycling, and starting-up in particular, accelerates component failure, resulting in an increase in failure rates, longer maintenance and inspection periods and higher consumption of spares and replacement components. The results are higher operating and maintenance costs and lower plant availability.

These costs can be conceptually framed within three main factors, namely:

- Fuel start-up costs (fuel needed to heat the boiler);
- Energy production costs as a function of the incremental heat rate curve (that is, a curve taking into account the efficiency-loss costs due to suboptimal operation regime[8]);
- O&M costs (reflected in a Long-Term Service Agreement), which strongly depend on the operating regime.

As thoroughly analyzed by Batlle et al. (2012), the impact of the increase in the number of starts on the maintenance of the generating units turns to be a crucial factor in the power system operation when a significant amount of renewable generation is installed. As a summary, the previous components of the total cost are expected to change when a large amount of wind and particularly solar enters in the system. The fuel start-up cost can increase or decrease due to the fact that the number of starts will increase at the same time that the cost of each start will decrease. As mentioned, this is because the number of hours between two consecutive starts is lower in the presence of wind and/or solar. The energy production cost is expected to rise as a result of the increase in the number of hours producing below the maximum output. In most cases (as a result of the abovementioned effects), the larger the number of starts, the larger the additional operation and maintenance cost each start causes. Starts are responsible for shortening the maintenance period and therefore the annualized value of the maintenance costs. Therefore, the O&M cost increases in the presence of wind and/or solar due to the reduction of the time between two consecutive maintenances caused by the higher number of starts. The cost increment due to this last effect can be two or three times larger than the fuel start-up cost, which has traditionally been the only start-related cost one that had any impact on the operation costs of conventional thermal plants.

The impact of these effects on price is to steepen peaks. In off-peak periods, when expensive minimum load thermal operation that would not normally be dispatched comes into play by lowering prices below production costs, it takes the place of less expensive generation, prompting a rearrangement of the merit order. The ultimate result is that the marginal price is set by units with lower generating costs. Prices tend to decline. During peaks these units need to recover their start-up, shutdown and minimum load costs, raising the price of power.

Pöyry (2009) and Green (2011) show using a modelling approach for the UK, that price volatility in the short term increases substantially with higher shares of variable generation. Both negative prices and high scarcity prices occurred frequently in their simulation. Studies for the German market also predict more volatile and less predictable prices for the EPEX day-ahead market (Nicolosi & Fürsch, 2009). However, for 2010 and 2011, peak prices have almost disappeared from the German

[8] Given the cost involved in stopping and re-starting plants, one alternative is to keep them running at the minimum possible output. Production costs (fuel consumption) are higher (per unit generated) at minimum load operation than at full capacity. Plant efficiency is lower, further increasing the extra production costs attributable to this factor.

spot market and price volatility was reduced as the market has become more competitive but also that the increased share of solar power is pushing down prices at peak times (LBD, 2011).

3.4.3 Negative or zero electricity wholesale prices

Electricity generation from VER is less flexible in following electricity demand. This is especially true for variable and weather-dependent renewables such as wind, solar PV, river hydro and to a lesser extent concentrated solar power. Depending on the chosen support policy, also dispatchable technologies such as biomass, biogas and reservoir hydro are incentivised to generate without considering price and demand developments. As a consequence, at times of low demand, oversupply of electricity can lead to very low or even negative electricity wholesale prices.

The variability of a high share of generation in a completely renewable system leads to changed load profiles for non-variable plants (Pöyry, 2011; Nicolosi, 2010; Obersteiner & von Bremen, 2009; MacCormack et al, 2010). Currently, this can be observed in the phenomenon of negative or zero prices already occurred in those PX in which the VER presence is more significant (see Figure below).

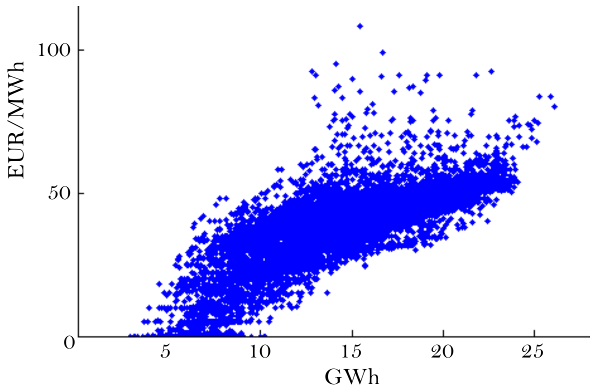

Figure 4. Prices in the Spanish market in 2010

As described by Pérez-Arriaga & Batlle (2012), the presence of VER in power systems has frequently motivated the creation of ad hoc market rules to deal with the new patterns of behaviour that have been encountered. A prominent case is the so-called "priority of dispatch" rule included in the EU legislation –the Renewables Directive 2001/776– to promote the development of renewables. This requires that "Member States shall ensure that when dispatching electricity generating installations, 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". The practical effect of this rule is that production with renewables can only be limited because of security reasons. Therefore, whenever the market price equals zero or a negative value, even if the optimal solution of the unit commitment algorithm indicates that the most economic option is to curtail wind rather than to stop some conventional thermal plant for a short period of time, renewable production will be scheduled and receive the feed-in tariff or premium, if this is the case.

Several reasons have been given to support this drastic rule. In the first place, the rule helps meet the committed renewable production targets, as well as any carbon reduction targets, by minimizing curtailments of renewable production. The rule may also incentivize a more flexible operation –to avoid being driven out of the market– of conventional plants that, otherwise, might not try to make an effort to accommodate increasing volumes of intermittent generation. In addition, it also helps to reduce financial risks for investors and therefore may reduce support costs.

The down side of this rule is that it may be the cause of inefficient dispatches of generation, as it may constrain what otherwise would be the optimal unit commitment, whether based on generators operating costs or bids. Note that conventional generators may be willing to bid negative prices to avoid being shut down. This is normal rational economic behaviour of the agents in a competitive market and should not be interfered with. Wind or solar generation would be also willing to bid a negative price to retain the income from any financial support scheme that is linked to production, although this might not be considered acceptable.

As an example, negative bids are allowed in the German electricity wholesale markets since 2008 and negative prices have already been observed. These price developments are sometimes seen as useful for the market as a signal to restructure the generation fleet but they increase costs for renewables support (Nicolosi, 2010). While negative prices are mostly associated with an oversupply of wind energy, there are several additional structural reasons. First, in the German system grid operators sell all renewable electricity in the electricity wholesale market regardless of the price. Second, many plants on the system are not very flexible. Thus, they only stop generation as a reaction to negative prices if these are expected for a longer period as otherwise costs for ramping the plant up and down as well as the opportunity costs of minimum standstill times are more expensive than a short period of negative prices. The last issue is that plants have to produce at a certain level to be technically able to offer balancing services when called upon (Andor et al, 2010; Brandstätt et al, 2011).

3.4.4 Market power

Market power is one of the most important challenges in the present electricity system in many European countries. It can incur high costs for society as market prices are artificially increased. Due to the special characteristics of electricity, the power sector is particularly prone to market power (de Hauteclocque & Perez, 2011). In addition, price volatility in a system with high shares of renewable generation is accentuated with a high degree of market concentration (Green, 2010). Apart from wholesale market prices, market power can also increase costs for re-dispatch and balancing (Neuhoff, 2011).

The value of renewable electricity in the wholesale market is lower than that for electricity generated from other sources (Bushnell, 2010). According to Twomey & Neuhoff (2010) this is the case especially for wind which already contributes considerably to overall electricity production and is not correlated with the demand profile. These authors state that in a system with market power, average prices for wind can be even lower (Twomey & Neuhoff, 2010). Green (2011) however states that in the UK market wind generators that have a high output in winter get almost the same average prices as conventional generators.

Batlle et al. (2011) discuss that when remuneration of RES-E installations is tied to short-term energy market prices, as it is the case in the feed-in premiums regime, RES-E receive market signals that may lead to more efficient operations, but, conversely, this approach also creates incentives for incumbent generators to increase their market power by assembling a generation portfolio that includes both RES-E infra-marginal capacity and conventional units.

3.5 Generation adequacy: Changes in the future mix

A number of noteworthy papers have discussed how RES-E can change the optimal capacity mix in the long term. For example, Lamont (2008) and Nicolosi and Fürsch (2009) include the consideration of RES-E in the standard screening curves approach to illustrate how increasing VER leads in the long-run to a lower share of base-load technologies and a lower average utilization of the generating capacities. Bushnell (2010) and Green & Vasilakos (2011) assess the long-term impact of the introduction of large amounts of wind on electricity prices and capacity expansion (in the US and Great Britain respectively), extracting similar conclusions on the basis of stylized equilibrium models.

However, there is still a significant lack of tools and literature dealing with the implications of detailed short-term operation costs on the long-term capacity expansion problem, which may no longer be negligible when the amount of VER becomes significant. One attempt in this respect is the one developed in Traber and Kemfert (2011), where a simplified representation of start-up costs is included in a long-term analysis focused on evaluating the need for regulatory technology-oriented incentives.

3.5.1 Flexibility

In this new context, a key factor that minimizes the cost increase of the economic dispatch is the flexibility capability of the thermal plants. The cost impact of a large introduction of VER will therefore be inversely proportional to the amount of existing flexible generation: the larger the inflexible capacity (older coal units and nuclear, typically), the larger the operation costs; and the larger the flexible capability (including storage facilities and demand response services) the lower these costs.

The role of those technologies that until now have been considered inflexible (older coal and nuclear, typically) will have to diminish radically. In the future they will probably exhibit more flexibility if the incentives exist to make proper investments in refurbishing the plants and changing the maintenance contracts.

A power system can respond with flexibility to the variability and uncertainty of VER with more resources than new investments in flexible power plants. To start with, as indicated in the previous section, a very important source of flexibility is the spare capacity of already existing flexible power plants. For instance, the New England Wind Integration Study (NEWIS) has revealed that the ISO-NE system presently has adequate resources to accommodate up to 24% of annual energy penetration of wind generation by 2020, see GE Energy et al. (2010).

Demand response holds a huge potential that still has to be demonstrated; see FERC (2011). This includes applications that have been used for a long time, such as interruptibility contracts with large industrial consumers, as well as others that still are in its infancy, like tapping the response of smart domestic appliances or of large aggregates of medium size consumers, as the company ENERNOC has already achieved.

Capacity credits

While there is agreement regarding the fact of the lower availability of weather-dependent renewables, there is a heavy discussion regarding the capacity credit of these technologies. The capacity credit is the percentage at which capacity of a power plant can be taken for granted and thus can be used to calculate system adequacy and operational margins. The exact value of assumed capacity credits therefore determines the need for storage or back-up plants for VER.

From a reliability perspective, according to NERC (2009), the system planner has to maintain some percentage reserve margin of capacity above its demand requirements to maintain reliability following unexpected system conditions. Reserve margins are determined by calculating the firm capacity of supply resources; this requires that some fraction of the rated capacity be discounted to reflect the potential unavailability of the resource at times when the system is in high-risk of not being able to meet all the demand.

If a large portion of the total supply resource portfolio is comprised of VER, the reliability evaluation becomes more complex. However, this does not fundamentally change existing resource adequacy planning processes in that the process must still be driven by a reliability-based set of metrics. The analytical processes used by resource planners range from relatively simple calculations of planning reserve margins to rigorous reliability simulations that calculate probabilistic measures of loss of some demand.

The capacity contribution of conventional generating units to reserve margins is mostly based on the unit performance rating, forced outage rate, fuel availability and maintenance schedules. However, the capacity contribution of VER is not straightforward, as it will depend on their variability and uncertainty, as well as on the correlation of their output with electricity demand. It has been noted in NERC (2009) that current approaches based on the "Effective Load Carrying Capability (ELCC)" or "Capacity Factor" (CF) may need to adapt to properly include VER, see also IEA (2011). Thus, for ELCC, the weather-driven correlation between VER and demand is critical, where a large amount of time-synchronized hourly RES-E generation and demand data is required in order to estimate its capacity contribution. For CF calculations, the definition of high-risk reliability periods has been identified as key for calculating the capacity value of wind. Approximations should be avoided and more detailed approaches, such as ELCC with abundant historical data should be employed.

For a conventional, dispatchable plant, capacity credits of 95% are typically assumed. For VER, capacity credits are undoubtedly lower although the importance of this factor is very dependent on specific system characteristics, such as interconnection or hydro storage capacity. Exact estimations vary however widely, especially in the case of wind energy and will therefore be further discussed in the following sections.

Capacity credits of some renewable technologies namely solar PV and wind are relatively low. Thus more installed capacity or other measures such as increased storage or demand side management are necessary to keep the same level of security of supply (Gross et al., 2006). The need for additional capacities can be at least partially mitigated by an increase in demand side management and the introduction of smart grid technologies (Wilson, 2010).

In several studies it has been noted that the capacity value of wind decreases as the penetration of wind increases, indicating that its incremental contribution to reliability decreases (NERC, 2009) (ESB National Grid, 2004). The contribution can be up to 40% of installed wind power capacity in situations with low penetration and high capacity factor at peak load times, and down to 5% under higher penetration, or if regional wind power output profiles correlate negatively with the system load profile. The smoothing effect due to geographical distribution of wind power has a positive impact on the wind capacity value at high penetration, subject to having enough capacity in the grid (Parsons & Ela, 2008). It remains to be well understood the logic behind this result, which is probably the effect of a "common cause of failure": a quasi-simultaneous absence of the wind resource throughout the entire system. The larger the presence of wind in a system, the stronger this negative impact is on the system reliability performance.

Note also that a sudden loss of all RES-E power on a system simultaneously, e.g. due to a loss of wind is not a credible event. It might happen because of automatic disconnection in case of excessive wind velocity, but this can be mitigated by adequate control measures. A sudden loss of large amounts of wind power, due to voltage dips in the grid, can also be prevented by requiring fault-ride-through from the turbines.

The worst credible scenario for VER under a reliability viewpoint consists of an extended period of time –maybe as long as a few days– with very low output, during a high demand season. It is very important to characterize the probability of occurrence and the depth and duration of these events, since the power system has to be ready to cope with them.

The lower predictability of renewable generation when compared to conventional power plants can also reduce system reliability. As explained above, the need for balancing and intraday adjustments as well as the need for ancillary services might increase.

3.5.2 Cost recovery and investment incentives for non-variable plants

In power systems under competitive market conditions generation capacity expansion is left to the decentralized decisions of private investors, who will evaluate the convenience of building plants in a particular power system depending on the expected price levels and operating conditions during the lifetime of the potential facility, among other considerations. There is an ongoing discussion whether energy-only markets are suited to allow for high enough scarcity prices in periods of low excess capacity to provide sufficient investment incentives even in a conventional system (Joskow, 2006; Batlle & Rodilla, 2010). Furthermore, so far no nuclear or renewables plants have been built relying on the market alone. For example in the UK; most investment after privatisation went into combined cycle gas turbines (CCGT) with comparatively low capital and high operational costs and the operator of nuclear plants went bankrupt in a market with a low share of renewables due to low gas prices (Clough et al, 2011). The changes in the electricity wholesale market described above (lower average and more volatile prices as well as changing load profiles) lead to even harder conditions for cost recovery and investment incentives. The uncertainty regarding the adequate technology mix, the penetration of renewables, and the economics of such a mix under the anticipated future prices and operating conditions raise concerns about attracting sufficient investment in these flexible plants under a competitive market regime.

Several studies for a diversity of power systems –see for instance MIT (2010), DOE EERE (2008), GE Energy (2010), Charles River Associates (2010), Poyry Energy (2009)– have analyzed, in detail, plausible future scenarios with a large presence of wind and solar generation, and shown that, if the market mechanisms would properly work, this also should lead to an increased presence of flexible mid-range generation capacity with high cycling capability and low capital cost. The function of some of these plants –typically open cycle gas turbines, OCGT– is almost exclusively to provide reserve capacity margins. Other plants are subject to heavy cycling regimes with relatively low capacity factors (e.g., 2000 to 3000 hours per year), typically combined cycle gas turbines, CCGT. These results are obtained under the assumption of centralized planning. Ideally the same mix should also be the outcome of a competitive electricity market.

However, a number of recent studies conclude that capacity mechanisms are necessary to provide sufficient investment incentives (WWF, 2012; EWI, 2012; RAP, 2012).

3.5.3 Grid infrastructure, market and re-dispatch

Often, the best renewable energy potentials are not located near centres of electricity demand. In Germany for example, wind parks are so far mostly built in Northern Germany while the highest demand for electricity occurs in the South of the country (Moser, 2009; DENA, 2010). Wind potentials in the UK are best in Scotland and other Northern areas as well. On a European scale, solar potentials are best in Southern countries while wind potentials are highest in the North.

Therefore, depending on the technology mix and geographical distribution of renewables resulting from the selected policy path, current existing infrastructure might become insufficient for providing secure electricity supply.

This is the case both within but also between Member States. In Germany, regular grid congestion along the North-South corridors can already be observed and is expected to further increase (Neuhoff, 2011; E.ON, 2011b; Moser, 2009; Wawer, 2007b; Inderst & Wambach, 2007). The same is true for other European countries.

Grid congestion also leads to a higher need for re-dispatch. For example the German electricity market treats the national grid infrastructure like a copper plate i.e. plants are dispatched regardless of their location respective to demand without considering the possibility of grid congestion. So far, this is no problem as the grid is designed to incorporate maximum power flows from plants. Grid congestion does not occur frequently and re-dispatch costs are therefore still low (Schmitz &

Weber, 2011; Boot & van Bree, 2010). The necessity for re-dispatch and thus the costs for integrating renewable electricity are however rising.

3.5.4 Ownership structure and market power

Power plants based on renewable energy have a more diverse ownership structure including farmers, communities and households. This is probably even true if current efforts of incumbents to invest in big renewable generation units are taken into account. The new actors can possibly reduce market concentration and thus possibilities for exerting market power (Ackermann, 2007).

4 Electricity market regulation for large shares of RES-E

Wind and solar power have only recently reached significant levels of penetration in some countries, but they are expected to grow much during the next few decades, and contribute substantially to meeting future electricity demand.

As mentioned before, wind, photovoltaic (PV) solar, run-off-river hydro and concentrated solar power (CSP) with no storage (referred to as Variable Energy Resources, or simply VER) have non-controllable variability, partial unpredictability and locational dependency.

One of the major present concerns in this respect is how these VER may affect the efficiency and remuneration of the different market agents in short-term (day-ahead and adjustment) electricity markets. As has been already discussed from different perspectives, see for instance Baldick et al (2005) and Litvinov (2009), the particular characteristics of the short-term electricity auction design, which includes the auction objective, the bidding formats and the pricing rules, may affect in general market results.

In this section, we discuss how the efficiency and results in each of the different short-term market designs may be affected by a high penetration of VER. We argue that a strong presence of intermittent renewable generation may exacerbate the different impacts of the alternative design options.

4.1 Day-ahead market design for high shares of RES-E

Short-term operation in the vast majority of the market-oriented electric power systems is critically conditioned (in some cases fully determined) by the results of a centralized auction algorithm managed by either an Independent System Operator (the common approach in the US) or an organized spot market, i.e. a Power Exchange (the widespread solution implemented in the EU). These algorithms do not just determine the daily system unit commitment, but also settle the remuneration for the generating units scheduled. The fact is that market outcomes differ depending on the particular design characteristics of these algorithms.

It is still not far from being clear to what extent these market results can be affected, and which are the key factors that need to be taken into account to evaluate this impact in the different electric power systems. Next, we focus on assessing the performance of the different short-term auction and pricing designs when a large amount of VER enters the system, in an attempt to shed some light to the discussion on which short-term auctions and pricing designs might be optimal in this upcoming context.

First, on the basis of Rodilla et al. (2012), the main and most common designs implemented in practice in organized day-ahead markets (DAMs) worldwide are classified and reviewed. Three main design elements of these DAMs are highlighted. Then we argue how there are three design elements that largely condition the potential market results when significant amount of VER is in place.

4.1.1 Alternative design elements of day-ahead auctions

Electricity wholesale markets are composed of all the commercial transactions of buying and selling of energy and also other related to the supply of electricity (the so-called operating reserves), which are essential for this to occur in adequate conditions of security and quality. These transactions are organized around a sequence of successive markets where supply and demand trade the abovementioned products related to the supply of electricity in different periods.

Roughly speaking, in organized short-term electricity markets the day-ahead market (sometimes half hourly, some others even every five minutes) prices are, in principle, determined by matching generators offers and consumers bids. However, this can be achieved in a number of different ways.

Short-term electricity auctions can be classified around three major criteria:

- Whether they use complex bidding or simple bidding;
- Whether the pricing rule is discriminatory or non-discriminatory;
- Whether single, zonal or nodal prices are computed.

A number of other aspects could also be distinguished (Baíllo et al., 2006): the trading intervals used (hourly, half hourly or even every five minutes), if portfolio bidding is allowed or not (i.e. if no link is required between bids and units or on the contrary each bid must refer to a particular unit), if is there a limited number of bids for each portfolio or unit per time interval, if price caps are implemented, etc. However, next we will focus on discussing the three ones previously highlighted as most relevant plus one more, if negatives prices are allowed and to what extent[9].

4.1.1.1 Complex versus simple auction

Since electricity is a very complex commodity, and its production is subject both to inter-temporal constraints and to the existence of a number of non-convex costs, the format of the generators offers can range from the so-called simple one (a series of quantity-price pairs per time interval) to a grayscale of more complex alternatives, in which inter-temporal constraints and/or multidimensional cost structures can be declared. We build our brief review of the main alternatives around the two extremes (complex and simple auctions), and then we introduce the hybrid alternatives implemented to amend these latter simple designs.

Complex auctions

In a complex auction generation agents submit offers, representing the parameters and costs which define best their generating units' characteristics (fuel cost, start-up cost, ramp up limit, etc.). With all these data, the market operator clears the market using an optimization-based algorithm which maximizes the net social benefit. This optimization algorithm shares most of the characteristics of the traditional unit commitment, but with the only difference that the data considered are market agents bids instead of costs. Usually, market prices are obtained as a by-product of the complex optimization-based algorithm.

Simple auctions

The downside of the complex-auction approach is the associated complexity of market clearing process. This factor has been the key argument held by (mainly) generators to move towards a much simpler auction, where the efficiency of the economic dispatch that results from the market clearing is sacrificed in favor of the transparency of the price computation process.

In the so-called simple auction scheme, the format of the offers does not explicitly reflect the generation cost structure (e.g. an offer component for the start-up cost) or imply any inter-temporal constraint. Instead, market agents submit simple offers/bids, which exclusively consist of price-quantity pairs representing the willingness to sell/buy the underlying product (one MWh in a certain time period of the day, e.g. an hour). Matching the market and obtaining the volume of electricity that is traded in each time period of the day is straightforward when offers and bids are simple: generation's offers are sorted in order of increasing prices and the demand's bids are sorted in order of descending prices.

[9] The discussion that follows is based on Rodilla et al. (2012).

Fully simple offers/bids do not imply any inter-temporal constraint. This means that for instance the offers of one thermal generating unit in the day-ahead market could be accepted in the third, fifth and seventh periods, leading to a resulting unit schedule which could be highly uneconomical or simply infeasible from the technical perspective. As we later further discuss, the main drawback of this approach is that it entails that to some extent generators have to anticipate (based on conjectures) the dispatch so as they properly internalize all cost in the hourly price component.

Hybrid or semi-complex auctions

In principle, the previous inconvenience could be partially fixed either by means of subsequent secondary trading (in the so-called intraday markets, in the EU context, or in the real-time market, e.g. in the US, see below) or closer to real time later in the balancing mechanisms/markets managed in most cases by the System Operator. However, in an attempt to combine the advantages of the complex and the simple auction design, EU PXs have opted for implementing hybrid alternatives, allowing linking semi-complex conditions to their offers.

The common idea behind the design of these semi-complex designs is simply to introduce as few complex constraints as possible in the auction, so as to not to complicate the matching process in excess while at the same time removing the huge risk at which agents are exposed in the simple auction context. Obviously, there is a whole continuum, between the extreme of including all potential constraints and the extreme of including none of them. The larger the number of constraints allowed, the closer the offers can represent the cost functions of the generating units.

In practice, this trade-off has been achieved either by introducing some of the most relevant (most difficult to be internalized) constraints, as it is the case with the ramp-up constraint (used in the Iberian day-ahead market) or by allowing some heuristic-based inter-temporal constraints in the offers format, in most cases not necessarily representing actual constraints or cost components, but rather a mixed effect of many of them.

Some of the complex conditions and offers used in semi-complex auctions are for example user-defined block bids (implemented, among others in the Nordpool, EPEX Germany and EPEX France), meaning that a market agent can offer/bid a price/quantity pair for a set of consecutive hours (three as a minimum), flexible hourly bids (Nordpool & EPEX France), i.e. price/quantity pairs with no pre-defined hourly period assignment or the so-called minimum income condition implemented in OMIE, enabling a generating unit to include a minimum income condition expressed as a fix (expressed in euros) and variable term (in euros per MWh) associated to the whole set of hourly bids corresponding to one particular unit.

4.1.1.2 Pricing rules: discriminatory versus non-discriminatory payments

The computation of market prices as well as the related determination of the generating units' remuneration is a quite controversial and still open issue in the context of complex auctions. We can classify these approaches in two large groups:

- non-linear pricing rules (also known as discriminatory pricing schemes), according to which, on top of the hourly prices, some additional side-payments are provided on a differentiated per unit basis;
- linear (or non-discriminatory) pricing rules, according to which the same hourly price is used to remunerate all the hourly production and no side-payments exist.

As it can be straightforwardly observed, the key factor that differentiates these two rules is that they yield different payments for consumers and correspondingly different income for generating units.

Non-linear pricing

In the context of complex auctions, non-linear (or discriminatory) pricing is undoubtedly the most extended pricing rule (especially in the US markets). This mechanism translates into each generator having a remuneration consisting of:

- first, a set of (non-discriminatory) prices which serve to remunerate all production in each time period,
- and then, some additional discriminatory side-payments (in practice computed as a lump-sum daily payment) which are calculated on a per unit basis.

As a consequence of the method used to compute marginal prices, these prices do not include the effect of non-convex costs (as it is the case with start-up or no-load costs). This is the reason why additional payments are considered on a per unit basis so as to ensure (if necessary) that every unit fully recovers its operating costs.

Linear pricing

Although the non-linear pricing approach is the most extended alternative in the context of complex auctions, linear pricing is also a possibility. Linear pricing in this type of auctions entails computing non-discriminatory hourly prices in such a way that all generating units fully recover their operation costs (thus avoiding the need for discriminatory side-payments of any kind), so in each time period (e.g. hour) every MWh produced is remunerated with the same hourly price.

Finally it is important to remark that we have just focused on the complex auction context. The reason is that the linear versus the non-linear pricing discussion has been less relevant in the context of simple auction. This is mainly because the question on whether or not the single price should internalize the effect of non-convex costs (such as the start up cost or the no-load cost) makes no sense in the simple auction scheme. In the simple auction context generators have to internalize all types of costs in their price-quantity pairs offers. Once submitted, there is no way for the market operator to make distinction on which part of the price corresponds to convex and which part of the price corresponds to non-convex costs.

4.1.1.3 Prices and transmission constraints: nodal, zonal and single pricing

A number of regulatory options are open to deal with the allocation of limited transmission capacity for transactions among players under normal market conditions[10]. One way to differentiate the main categories of options is to gather them in two main groups: those pricing algorithms that involve a detailed representation of the transmission network, and those other which consider a simplified one.

Nodal pricing

Nodal pricing applies security constrained economic dispatch to derive a bus by bus Locational Marginal Prices (LMP), the prices paid for the energy consumed or generated at a given transmission node.

Combining the definitions of LMPs provided y PJM Interconnection and ISO-NE in their websites, we have that LMPs reflects the value of energy at a specific location at the time that it is delivered. If the lowest-priced electricity can reach all locations, prices are the same across the entire grid. When there is transmission congestion (heavy use of the transmission system in an area), energy cannot flow freely to certain locations. In that case, more expensive and advantageously located electricity is ordered to meet that demand. As a result, the LMP is higher in those locations.

Nodal energy pricing provides an accurate description of the technical and economic effects of the grid on the cost of electricity. They implicitly include the effect of grid losses and transmission con-

[10] This initial description benefits from Rivier et al. (2012).

gestion, internalising both effects in a single value (monetary unit per kWh) that varies at each system node.

Zonal pricing

Zonal pricing consists of using a single market price except where significant grid constraints arise frequently between a limited number of sufficiently well-defined zones of the power system. Once the most frequent points of congestion are identified, the grid nodes affected by internodal congestion are grouped into areas or zones. As defined by Baldick et al. (2005), in this context "a zone is a set of nodes in geographical/electrical proximity whose prices are similar and are positively correlated over time. This pricing mechanism distinguishes energy prices by zone in lieu of by nodes, and the same price prevails at all nodes within a given zone.

A widespread alternative which can be considered as a particular case of zonal pricing is the so-called single pricing model, i.e. transmission congestion is fully ignored when the electricity market is cleared. This alternative is implemented in those markets where supposedly no systematic or structural congestion occur.

Thus, the market is first cleared in the day-ahead PX considering the simplified representation of the network (e.g. taking into consideration predefined theoretical interconnection capacities between the zones or directly ignoring transmission congestion in the case of single pricing).

In the (supposedly) few cases in which grid constraints are detected, the System Operator re-dispatches the system, determining which players must withdraw from the system and which are to be included. Energy removed to solve the network constraint may be paid at the respective agent's bid price (if a specific bid related to the constraint solving mechanism is in place), at the opportunity price (energy market price less the price of the agent's bid), or not at all. When additional energy is requested, it is normally paid at the respective agent's bid price.

4.1.1.4 Negative prices

As it is well-known, electricity market clearing may sometimes result in negative prices. When this is the case, generation pays demand (and/or pumping) to consume electricity. But, why would generation be willing to pay for producing? There are two main reasons for this to happen:

- For some of the generating technologies (mainly thermal, such as nuclear or coal), it is very costly or even technically impossible to reduce their output (or stop producing) for short periods of time in which the demand level is not sufficiently high so as to accommodate all the output associated to these units. When there is at least one unit facing this very costly dispatch, it makes economical sense that prices go down to negative values, as they are supposed to reflect the opportunity cost (what the energy is worth)[11].

  From this point of view related to thermal operation, there is no discussion about the fact that negative prices are a reasonable and efficient expected market result (however, as we discuss a few lines below, pricing rules do not always allow this result to arise). Generally speaking, nega-

[11] By the way of illustration, let us consider a CCGT unit being scheduled from 0 to 5 a.m. and then from 6 a.m. to 17 p.m. That is, the unit would start-up to produce for five hours, then it would shut down and be offline for one hour, and then would have to start-up again to produce for twelve hours. Since the start-up cost is higher than the cost of producing at the minimum load output during one hour, this same unit would reduce production costs if it would rather be kept online at this minimum load output during the interval that goes from 15 to 16 p.m. In this case, it is easy to derive that this CCGT would be willing to pay for producing during this hourly interval, but, how much? The answer is as much as the total costs it could save by producing in that hour. When a unit facing this situation is marginal in the hours she would be willing to pay for producing, the market price should ideally go to negative values.

tive prices due to operation constraints are more likely to appear as a consequence of this costly or infeasible thermal operation regime, when the next characteristics meet in an electricity system:

- Thermal-dominated generation mix.
- System with large amounts of inflexible generation. This is for example the case when there is high nuclear penetration or when some type of generation enjoys priority or obligation of dispatch (this latter is the case with RES in most of the EU electricity systems, as later discussed).
- Low valley demand (minus inflexible generation) values when compared to peak and shoulder load (minus inflexible generation) values.
- Very low (or inexistent) demand elasticity and low pumping storage capability

But this is not the only driver behind negative prices. There is also another one (and possibly the main) driver which is close-related to some type of regulatory technology-oriented support mechanisms that we next describe.

• A number of subsidized technologies (mainly VER), are entitled to receive production tax credits, premiums, etc. on their electricity sold. This means that some generators are willing to sell their output for as low as the minus value of the incentive they receive to produce power. Wind generators are a clear example of this latter type of generator. If one of these subsidized generators happens to be marginal, prices will go to negative values.

Pricing rules may limit negative prices

It is noteworthy that some pricing rules do not allow whichever negative price to appear. This can be a direct consequence of explicit market intervention or rather a consequence of the details of the methodology used to compute prices. We next briefly describe these two different cases.

First, some systems have explicitly introduced a price floor that limits the potential negative value the price may reach. For instance, this price floor has been set to minus 100€/MWh in Ireland or to zero (thus, not allowing negative prices) in the MIBEL (Spain and Portugal) electricity market.

Second, a more subtle type of limitation can be implicitly embedded in the methodology used to compute prices. For instance, we have just seen how in some systems prices are computed as the dual variables (shadow prices) associated to the generation-demand balance constraint of the linear optimization problem that results when the commitment decisions have been fixed. But note that if the commitment decisions are fixed, the role start-ups costs may have in the actual value of the energy in one particular hour is lost. Thus, such methodology would never allow a price to reflect the opportunity cost of a unit that is being forced to shut down to then start up after for example just one hour. In other words, from the first of the two drivers highlighted above does not lead to negative prices in the non-linear (or discriminatory) scheme[12].

[12] In some complex auction designs agents are allowed to submit a negative value for their energy costs component ($/MWh). In some other markets, on top of the previous characteristic, it is also allowed the energy cost component to vary along the periods (hours) of the next day. In this latter case, it is somehow possible that some negative prices due to these thermal constraints would arise for generators are able to express the opportunity cost a start up may induce. However, note that this deviates from the previously mentioned objective of the complex bidding alternative, as a way to induce generators to declare the parameters actually defining their production cost structure.

4.1.2 Auction and pricing design for high shares of RES-E

Under normal circumstances, the particular design of the short-term market (format of the bids, market clearing algorithm and pricing and remuneration rule) conditions the market results. As discussed by Rodilla & Batlle (2012), a significant penetration of VER may exacerbate the outcomes of the different design elements just introduced. Next the arguments of these authors are developed.

4.1.2.1 Efficiency of the economic dispatch resulting from simple and complex auctions in the presence of VER

In the simple auction scheme, agents have to calculate the quantity-price pairs in such a way that all expected costs (including non-convex costs, such as the ones related to starts) are properly internalized. This way, for instance, a peaking unit expecting to have to start to produce electricity the next day in four hours (e.g. for the evening peak, from 6 p.m. to 10 p.m.) and then shut down, would have to impute all operation-related costs in those hours. Note that, since generators do not know in advance the resulting dispatch (e.g. the hours in which the unit will be finally committed), it is evident that this internalization is subject to risk (e.g. the market clearing results might imply that unit should be committed just two hours), and thus, may lead to inefficiencies in the resulting dispatch (the income in these two hours might not be enough for the unit to fully recover its operating costs).

On the contrary, complex auctions enable generators to better align their offers with their actual generating units' cost structure. This scheme allows agents to better express their willingness to buy and sell electricity, since it allows them to declare all parameters defining generation technical constraints (e.g. ramp-up and down limits, etc.) and generation costs (heat rate efficiency rate, hot start cost, cold start cost, wear-and-tear-derived costs, etc.). By providing all these detailed data, the generating unit is most likely scheduled in the most efficient way. In this context, the generator does not need to anticipate ex-ante which the resulting dispatch will be, since this intricate issue can be left in the hands of the optimization algorithm.

As previously stated, in the case of the day-ahead markets of EU Power Exchanges, in which simple bids were originally considered, this problem has been tackled in two sequential (ex-ante and ex-post) and complementary ways: semi-complex conditions aim at reducing the risk of market agents associated to the simple bid decision-making process, and secondary markets provide market agents with additional opportunities to reschedule their positions[13]. Thus, these two tools can be used to first avoid and then (if necessary) correct a non-profitable scheduling that has previously resulted in the day-ahead market.

Nevertheless, in practice these two alternatives are still far from solving the efficiency loss problem linked to simple bidding. First, secondary markets in theory would allow market agents to first solve the potential infeasibilities that might result from the day-ahead market clearing, and at the same time to gradually adjust their schedules to changing conditions. But on the one hand, transaction costs, although not significant, cannot be considered as negligible: being able to properly trade in these markets implies additional costs for market agents. And more importantly, due to the traditionally oligopolistic structure of a good number of electricity markets, these secondary markets have proven not to be always liquid enough, increasing the costs for particularly generators owning small generation portfolios, and thus affecting to their competitiveness[14].

[13] Intraday sessions as for instance the ones implemented in the Iberian or French cases or balancing markets as the ones also implemented in France or Elbas in Nordpool.

[14] See for instance Batlle et al. (2007). Although the situation apparently has improved after the implementation of intraday markets, observed balancing spreads have occasionally been rather significant.

Second, semi-complex conditions certainly are a valuable tool for market agents to mitigate their risk to face an uneconomical (or even technically infeasible) schedule resulting from the market clearing. But by no means they guarantee that efficiency of the schedule resulting from the market clearing is maximized. Most of the simple bids linked to semi-complex conditions explicitly or implicitly expose generators to the necessity of anticipating under uncertainty their expected dispatch. This is for instance evident in the case of block bidding, where generators have to decide the hourly interval in which they are willing to offer their energy (e.g. from 10 a.m. to 15 a.m.). Then, on the basis of this expected dispatch, it is possible to add a "kill-the-offer" condition if a minimum income is not perceived. In the example of the block bid, this is expressed usually through an average price.

Simple and semi-complex-conditioned offers allow for a significantly less flexibility than the complex bidding alternative. Note that the kill-the-offer condition allows avoiding the risk of losses for the generating agent, but does not avoid the risk of not being scheduled in the most efficient way from the standpoint of the overall system economic dispatch optimization[15]. For instance, an offer killed by the semi-complex condition may have been scheduled in some other intervals in such a way that both the system and the agent would have been better off.

VER and the efficiency of the auction design

A large penetration of VER directly increases the need for flexibility and thus for balancing resources. This has been the case in those markets in which the deployment of VER has been particularly significant, as for instance the German or Spanish cases, to name two particularly relevant examples. But, at least for the moment, since storage technologies and demand response tools are not yet sufficiently developed, this increasing need has not been accompanied by an equivalent addition of flexible technologies able to cope with it with the same level of efficiency. Thus liquidity is lower, and therefore the cost of adjusting the generation programs resulting for the market clearing are larger.

In the case of complex auctions, the presence of wind does not impact in a relevant way the generators strategies. Obviously, the associated uncertainty will introduce a risk component in the determination of the net social benefit, but this should not affect to generators' offers, since again, the algorithm is the responsible of finding the optimal schedule.

In the case of simple auctions, ideally, under perfect information, the offers of all the market agents would also lead to the most efficient economic dispatch, the one corresponding to the equilibrium under perfect competition conditions. But in this case, a significant amount of wind in the system entails an additional source of uncertainty on the expected day-ahead market scenarios on which the bids building process of each market agent is based. The consequence is therefore that the disparity of these market agents' estimations grows, and thus the errors are more likely and the market result further deviates from the optimum.

As argued by Vázquez et al. (2012), there is empirical evidence about the fact that VER significantly complicates the bidding task of market agents in simple and semi-complex day-ahead markets: bidders make an increasing use of semi-complex constraints as the amount of installed VER grows, as well as also these constraints activate the kill-the-offer condition accordingly. This kill-the-offer condition can allow some generators hedging from an incorrect assessment of the future market conditions when building the bids, but it will obviously will be too restrictive for some others whose production could probably have been scheduled in a different pattern than the one implicitly included in the semi-complex offer. When the amount of offers killed by the algorithm becomes large, the efficiency of the market results can be put into question.

[15] Ideally (in a competitive market) this solution is also supposed to represent the equilibrium, i.e. the desired schedule from the agent's point of view in the absence of market power.

Take for instance the case of the Spanish system, where the deployment of wind and solar technologies has been more than remarkable[16]. Since the start of the market in Spain back in 1998, market agents operating in OMIE, the Iberian day-ahead market, can link their hourly quantity-price pairs to semi-complex constraints. The market clearing algorithm then searches for a solution that respects the constraints, so result is that a number of bids are killed. This is clearly illustrated in the figure below, in which for a particular hour back in 2010, the market matching, including the supply function before considering the quantity-price simple offers and the finally considered offer curve, resulting from the activation of the semi-complex conditions (in thick trace) are shown.

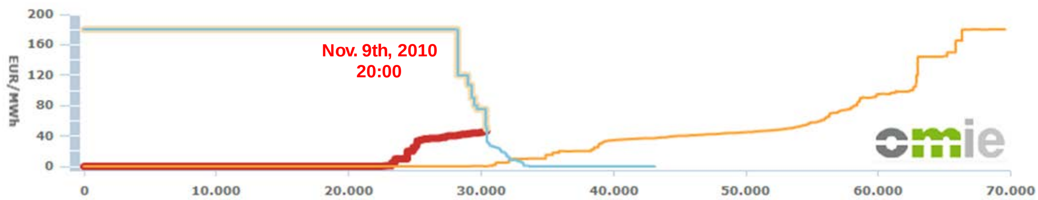

Figure 5 Renewable Market price settlement in OMIE

The effect that VER have had on the relevance of these semi-complex conditions is clearly illustrated in the figure below, taken from Vázquez et al. (2012). The withdrawn energy in the day-ahead market stemming from the activation of the minimum income condition in the peak hours is depicted along with the evolution of daily wind production from 2002 to 2010.

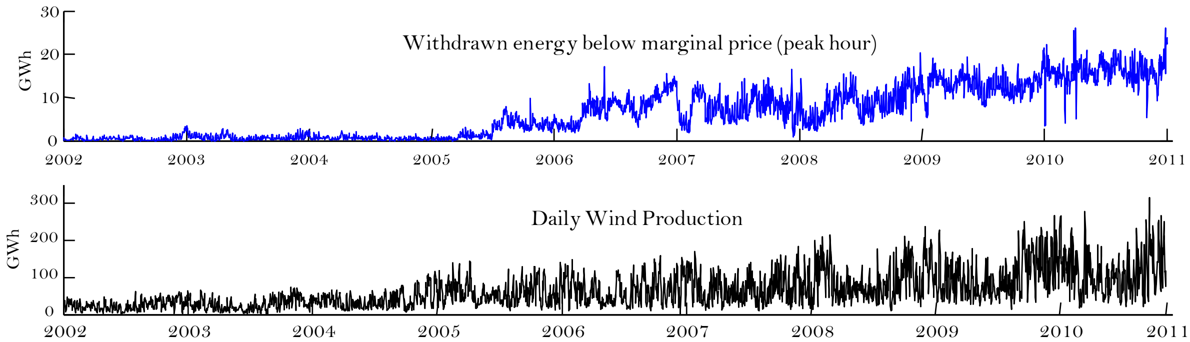

Figure 6 Energy withdrawn as a consequence of the activation of the complex conditions

As the installed capacity of VER (namely wind, but also a significant amount of solar PV, around 4 GW as for the end of 2010) has grown, the amount of energy discarded in the final market clearing due to the activation of semi-complex constraints has increased accordingly[17].

In the same line, Borggrefe & Neuhoff (2011) argue market design needs to allow generators to adjust their energy production and provision of balancing services in a joint bid, so that they can contribute to an efficient system operation.

4.1.2.2 Non-discriminatory versus discriminatory pricing in a context with high penetration of VER

Veiga et al. (2012) show how the pricing rules implemented (either uniform prices or the shadow prices resulting from the unit commitment plus additional side-payments) may amplify or reduce

[16] As of the beginning of 2012, the installed capacity of wind was close to 21 GW, plus 4 GW of solar PV and 1.2 GW of solar thermal, while the recorded peak demand in 2011 was 44 GW.

[17] It is important to note that this increase cannot be attributed to a demand growth, since in the Spanish case electric power demand has experienced a very significant decrease from 2008 (281 TWh) to 2011 (261 TWh), a drop of around 7.5% in three years.

the resulting change on short term price dynamics due to the presence of VER. To do so, the authors base their discussion on a simulation analysis using a detailed unit commitment model, able to capture the impact of cycling in the short-term price formation.

The two pricing contexts selected are respectively a simplified version of the pricing rules in force in the US ISOs short-term markets (as e.g. PJM or ISO-NE) and a simplified version of the pricing rules in force in the SEMO short-term market in Ireland. While in the first ones a uniform price not including non-convex cost is used in addition to some discriminatory side-payments to ensure operation cost recovery, in the latter just uniform prices including the effect of the non-convex costs serve to remunerate all generation.

The authors show how in the particular context of a system with large penetration of VER, non-convex costs are expected to increase and argue that, due to the increased impact of the non-convex costs of conventional thermal plants, the growing deployment of VER exacerbates these differences, which can have a relevant effect on the long-term capacity expansion of the system. It can be observed that the income in the linear pricing context increases when a significant amount of solar is added into the system due to the increase of the costs related to the larger need to start the plants and therefore to increase the O&M costs.

The authors illustrate how the income for a baseload plant is significantly different depending on the pricing rule implemented, what naturally would lead to a different generation mix in the future. The income in the discriminatory context is equal without and with a large penetration of VER as the calculated prices do not include the non-convex costs such as no-load or start-up costs of the marginal units and the marginal generator is a ccgt plant in both scenarios. Conversely, in the linear scheme, these start-up costs are perceived by all units.

One of the main conclusions extracted by Veiga et al. (2012) is thus that the role of short-term market prices as optimal long-term signals is to give incentives to bring in the most efficient investments (from the net social benefit standpoint). In order to give these optimal signals, prices need to reflect what the energy is worth, and this necessarily calls for internalizing all related-costs in the market price. Thus, in order to send proper sound long-term market signals, market prices should internalize the non-convex-cost-related component of the actual value of electricity.

4.1.2.3 Wind and efficiency of zonal pricing

Nodal prices implicitly include the effect of grid losses and transmission congestion, internalizing both effects in a single value (monetary unit per kWh) that varies at each system node. They are, therefore, perfectly efficient signals for economic decisions concerning the short-term operation of generation and demand, since they correctly convey the economic impact of losses and constraints at all producer and consumer locations. Gilbert et al. (2004) showed that implicit auctions maximise the use of transmission capacity.

In densely meshed transmission grids with no systematic or structural congestion, nodal pricing is often regarded to be an unnecessary sophistication and a limited number of zonal energy prices are preferred across the entire network. In these cases, under the assumption that grid costs have a relatively small impact on the market, grid effects are disregarded for reasons of transparency and simplicity. This approach is aimed at enhancing market standardization, increasing market liquidity.

But, as discussed for instance in Baldick et al. (2005), "when the transmission congestion within zones does not prove to be minimal, (...), then the allocation of zonal redispatch costs can quickly become large and inefficient". Next we briefly discuss how in most real cases, an increasing penetration of wind aggravates the inefficiency of zonal pricing.

Borggrefe & Neuhoff (2011) also argue that nodal pricing provides appropriate price signals for the economic design, encouraging the effective use of transmission capacity while improving interfaces between balancing and intraday markets.

When discussing the importance of implementing nodal pricing in the presence of large amounts of VER generation, two different cases can be tear apart:

- In some cases, particularly in the case of wind, the best sites to develop VER are concentrated in specific areas of the transmission system, sometimes far from demand[18]. As discussed for example in MIT (2011), the planning process in most restructured electric power systems is significantly more difficult than within vertically integrated utilities because decisions about the generation expansion are the result of market forces modified by the regulator's support for renewables and other policies, rather than centralized planning. When generator build times are shorter than those for transmission, planners are forced to either anticipate new generation and build potentially unnecessary infrastructure or wait for firm generation plans before starting the process and thereby potentially discourage new generation investment. The evidence is that, since transmission planning on the vast majority of cases takes much longer to plan, get approvals, and build a high-voltage transmission line than a wind farm or solar generating facility, currently transmission reinforcements are finally developed significantly later than what in principle it would be desirable.

  At least in the medium run, transmission will be increasingly constrained around these areas with good VER resources, so zonal pricing will lead to higher inefficiencies if the number of areas is not strongly increased to render zonal pricing closer to nodal pricing[19].

- In other cases, VER are irregularly dispersed in different areas of the system, often presenting different generation patterns. VER modify the patterns of power flows and prices so that the use of zonal pricing becomes increasingly inefficient.

4.1.2.4 Negative market prices in the presence of a large VER penetration level

We have seen that negative market prices may arise driven by two major factors: on the one hand, very costly thermal dispatches which could be avoided (lowered) in case demand consumption was higher in certain periods, and on the other hand, because of the existence of RES-E support mechanism that provides the installations with an out-of-the-market remuneration on a per MWh produced basis.

With these two major drivers in mind, we now qualitatively analyze the effect VER (mainly wind) may have on the appearance of negative market prices. But first, it is important to remark that this assessment cannot be performed without paying attention to the particular regulatory mechanisms supporting VER technologies. In this respect, two different factors of RES-E support schemes may affect to different extents the negative price dynamics:

- First, those mechanisms in which a "priority of dispatch" rule applies.

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[18] Just to mention three different examples of onshore wind, take for instance the case of Texas, where most of the wind farms are located in the West, Germany, in the North, and Rumania, in the southeastern region of the country, close to the Black sea. Obviously offshore wind aggravates this phenomenon.

[19] Although this is the most common situation, it has not been always the case. For instance, take the Spanish example: first, there are no significant differences among the wind mill load factors all around the country, and second, the FIT for wind resulted in more than 40,000 MW applications of interested capacity when the government target was only 2,000 MW per year installation (recently a renewable moratorium was announced). Instead of implementing auctions, which in principle it would have appeared as the best alternative, the System Operator, alleging transmission network stability and efficiency, allocated the permits in a disperse way all around the country, so no significant bottlenecks have yet appeared due to wind.

- Second, those in which they receive an out-of-the-market premium or production tax credit (PTC) based on their actual output.

The first support scheme has a direct bearing on the potential appearance of very costly thermal dispatches. We saw that the larger the amount of inflexible generation, the more acute this issue may become. The so-called “priority of dispatch” rule included in the EU legislation –the Renewables Directive 2001/776– to promote the development of renewables establishes that “Member States shall ensure that when dispatching electricity generating installations, 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”. The practical effect of this rule is that production with renewables can only be limited because of security reasons, so strictly speaking it would be fair to rename the rule as “obligation of dispatch”, since for instance wind generators are not stopped even in those cases in which negative prices are well below the quantity of the feed-in tariff or the premium. In this context, these VER are nothing but an inflexible production which may push thermal units to more costly dispatches, that, as pointed out previously, may lead generators to be willing to pay for producing in certain periods (and this willingness may be quite large in some cases)[20].

The second factor is that a production-based incentive makes generators to be willing to sell their output for as low as the negative value of the incentive they receive to produce energy. This can also have a significant distortion effect that is larger the higher the incentive is. However, note that as long as VER production is committed in the market in this context, the price will necessarily be equal or above the offer VER submits to the market operator. Thus, unlike the previous case, when no obligation of dispatch applies, the distortion effect is limited, and prices cannot be below the negative price incentive as a direct consequence of VER production.

This latter argument leads us to an evident but also relevant conclusion. Negative prices are just a transitory consequence of the impact of the just discussed factors, but they will gradually disappear. PTCs apply to first 10 years of operation, and feed-in tariffs or feed-in premiums for as much as 20 years. Once this period is over, the VER installations will start to be fully exposed to market prices, and therefore they should be expected to produce only if it is economically efficient from the point of view of the whole system. Also, according to the observed learning curves of RES-E, specially wind but also solar PV, it should (hopefully) be expected that the time in which these technologies are fully competitive without needing any extra remuneration is close[21]. When any of these two or both situations occur, prices will then be naturally capped at a floor of zero (or close to zero). If a price ever falls below this value, it is either because there is no wind production at all (which is unlikely), or equivalently, because all wind energy production is being spilled for purely market-based economical reasons (probably as unlikely as the previous assumption).

[20] Several reasons have been given to support this drastic rule. In the first place, the rule helps meet the committed renewable production targets, as well as any carbon reduction targets, by minimizing curtailments of renewable production. The rule may also incentivize a more flexible operation –to avoid being driven out of the market– of conventional plants that, otherwise, might not try to make an effort to accommodate increasing volumes of intermittent generation.

[21] In the Brazilian case, wind power has been winning generation auctions for ~110 BRL/MWh (~61 US$/MWh), full energy price.

4.2 RES and adjustment markets

4.2.1 The need for flexibility in system operation

As discussed previously in section 3.3, both the variability and uncertainty of VER ask for more flexibility of the generation portfolio and in the operation of the power system, including the design and utilization of transmission and distribution networks.

System operators need to have generation, demand resources, or any other form of flexibility in the power system ready to respond whenever ramping and dispatchable capabilities are needed; for example, during morning demand pickup or evening demand drop-off time periods (NERC, 2009).

The power system needs more flexibility to handle the short-term effects of increasing levels of wind. The amount of flexibility will depend on how much wind power capacity is currently installed, and also on how much flexibility already exists in the considered bulk power system (Parsons & Ela, 2008). Even with perfect forecasting, wind generation will remain variable, for instance from one hour to the next, and for this reason additional flexibility is required.

There are several dimensions in achieving flexibility: a) better use of the flexibility that the existing system has or may have, for instance by changing market rules or by integrating current small balancing areas into larger ones; b) adding new flexible plants to the existing portfolio; c) utilizing flexibility contributions of the intermittent units.

There are different flexibility capabilities that are needed from all the power plants in a system with a strong presence of intermittent generation, corresponding to the different functions in power system operation, and ranging from fast response to frequency disturbances to the capability of shutting down and starting up again frequently. These capabilities include: a) ramping of the variable generation (modern wind plants can limit up- and down-ramps), 2) regulating and contingency reserves, 3) reactive power reserves, 4) quick start capability, 5) low minimum generating levels and 6) the ability to frequently cycle the resources' output. Additional sources of system flexibility include the operation of structured markets, shorter scheduling intervals, demand-side management, reservoir hydro systems, gas storage and energy storage. System planners and electricity market regulators must ensure that suitable system flexibility is included in future bulk power system designs, as this system flexibility is needed to deal with intermittency on all time scales. It therefore can be said that, as penetration of intermittent resources increase, system planners need to ensure that the added capacity has adequate flexibility to meet the total new flexibility requirements of the system. This is a new design requirement for future systems, and it can be met with local generation, interconnections with other systems or demand resources.

The contribution of most power plants to the flexibility of the operation of a power system is–up to a certain point–a function of the existing economic incentives. Technical minima, ramping capabilities, start-up times and hydro reservoir management can be modified given the adequate economic conditions. It is a regulatory challenge to define these conditions and a technical challenge to respond to them. See, for instance, the debate on the regulating capabilities of nuclear generation units in Pouret et al. (2009).

Demand response is another potential source of flexibility; see NERC (2009). Demand responsiveness by means of time-variant retail electricity rates, such as real-time pricing (RTP) or interruptible load agreements, could potentially reduce wind integration and forecast error costs. Through a price signal in the form of RTP, consumer demand could be made to follow the supply of wind generation, where if wind generation is high, for example, electricity demand will increase as a result of low electricity prices. Conversely, if wind generation is low, electricity demand will decrease as a result of high electricity prices (Sioshansi, 2010). Actual deployment of demand response schemes and an evaluation of its potential in the US can be found in FERC (2011).

4.2.2 Additional requirements of operating reserves

This issue has already been addressed in section 3.5.1 so we will not elaborate it further. It seems that careful attention must be given to the relationship between flexibility and reserves. It has to be realized that the need for flexibility is not the same as the need for reserves, which is smaller since a part of the variation of the net load–i.e. the original load minus intermittent generation output–can be forecasted. As it has been shown before, reserves mainly depend on forecast errors and the overall flexibility in scheduling deals also with the changes in output level for several hours and a day ahead; see Holttinen et al. (2011). These points out the open question of how to precisely define the flexibility requirements of a power system and how to incentivize the investment in the right kind of power plants and the provision of flexibility services.

4.2.3 Coordination of balancing areas

Large volumes of intermittent generation would be integrated much more easily in existing power systems if some institutional and organization problems could be properly addressed. One of them is the integration and coordination of balancing areas: the extension of the areas that are responsible for offsetting the variability and uncertainty of wind and solar production will smooth out the impacts and pool existing resources more efficiently and reliably.

As described in NERC (2009), ancillary services are a vital part of balancing supply and demand and maintaining bulk power system reliability. Since each balancing area must compensate for the variability of its own demand and generation, larger balancing areas with sufficient transmission proportionally require relatively less system balancing through operation reserves than smaller balancing areas[22]; see, for instance, Parsons et al. (2008).

With sufficient bulk power transmission, larger balancing areas or wide-area arrangements can offer reliability and economic benefits when integrating large amounts of variable generation. In addition, they can lead to increased diversity of variable generation resources and provide greater access to other generation resources, increasing the power systems ability to accommodate larger amounts of intermittent generation without the addition of new sources of system flexibility, and benefitting competition, removing entry barriers for new and small generation and retailing companies. In this line, Borggrefe & Neuhoff (2011) argue that coupling national balancing markets will then again increase market efficiency and reduce potentials to exercise market power.

4.2.4 Reduced scheduling intervals

Arrangements for the provision of the different kinds of ancillary services (and in particular operating reserves) widely depend on the individual power systems. In some cases the commitments for energy and some operating reserves are made at the day-ahead time range (e.g. the US power markets), while in others balancing energy transactions are scheduled one or two hours before real time (as it is the case in many EU power markets). More frequent and shorter scheduling intervals for energy transactions may assist in the large-scale integration of intermittent generation. If the scheduling intervals are reduced (for example, providing intraday markets to adjust previous positions in day-ahead markets and closer to real time balancing markets), this will help to reduce the forecast errors of wind or solar power that affect operating reserves.

Given the strong level of presence of wind or solar generation in some power systems, there should be a level playing field for balancing responsibility, which applies to all producers, including wind

[22] For instance, in the US, New York, New England, and Texas are each tightly integrated and have one balancing authority each, while Arkansas and Arizona each have eight and Florida has eleven (MIT, 2011).

and solar generators (although perhaps with some less stringent requirements) in order to stimulate all market participants to carry out thorough and proper scheduling and forecasting and thus limit system costs.

In summary, the virtuous combination of adequate available transmission capacity, larger balancing areas and frequent scheduling (within and between areas) may significantly reduce the variability impact of generation and demand, increase predictability and therefore reduce the need for additional flexible resources in power systems with large penetration of intermittent renewable generation. Consequently, the need for ancillary services would be less, and the costs of running the power system would be lower. As an example that this can be accomplished, mandatory Framework Guidelines has been recently adopted in the European Union with some of the necessary components: A pan-European intra-day platform to enable market participants to trade energy as close to real-time as possible to rebalance their positions, with the participation of the system operators to facilitate an efficient and reliable use of the transmission network capacity in a coordinated way, see ACER (2011). A similar approach is proposed in NERC (2009).

5 Interactions between RES-E and grid regulation

There are two significant lines of interaction between RES-E and grids. In one direction, the deployment of RES-E has an important influence on the way the grid is to be built and regulated. On the other hand, grid regulations (particularly regarding cost allocation rules) have a large influence on RES-E deployment. Since, at least concerning the first aspect, there are significant overlaps with the design of the electricity market, we will address this topic in more detail in section 5.

5.1 Challenges of RES-E for grid infrastructure

Often, the best renewable energy potentials are not located near centres of electricity demand. In Germany for example, wind parks are so far mostly built in Northern Germany while the highest demand for electricity occurs in the South of the country (Moser, 2009; DENA, 2010). Wind potentials in the UK are best in Scotland and other Northern areas as well. On a European scale, solar potentials are best in Southern countries while wind potentials are highest in the North.

Therefore, depending on the technology mix and geographical distribution of renewables resulting from the selected policy pathway, current existing infrastructure might become insufficient for providing secure electricity supply.

This is the case both within but also between Member States. In Germany, regular grid congestion along the North-South corridors can already be observed and is expected to further increase (Neuhoff, 2011; E.ON, 2011b; Moser, 2009; Wawer, 2007b; Inderst & Wambach, 2007). The same is true for other European countries.

As previously introduced, the fact that often the best renewable energy potentials are not located near centres of electricity demand implies that RES-E may increase the need for new interconnectors, both at the national and European level. There is however not much literature on how to allocate the costs of these interconnections, although some recommendations on how to address the issue at the EU level for the connection of offshore wind farms have already been put forward by Meeus et al (2012), in which three guiding principles are proposed to minimize the total investment cost of transmission and generation: the planning principle, the competition principle, and the beneficiaries pay principle. The authors also argue for the benefits of combined solutions (mixed farm to shore and shore to shore investments).

Another challenge arises due to the increasing congestion of the grids (in turn due mostly to the difficulty of building new lines). In this context, variable energy sources can add complexity to the operation of the grid, and modify the context in which decisions are made over nodal or zonal prices. As mentioned before, this is discussed in more detail in section 5.1.2.3. Let us summarize this by saying that nodal prices would improve significantly the operation of the grid, and would also make fuller use of the existing network in Europe, as shown by Neuhoff et al (2011).

5.2 Challenges for RES-E of grid regulation[23]

The distribution and transmission networks will have to adapt to the new situation so that the revolution towards a sustainable low-carbon energy model can take place.

[23] The discussion developed in this section can be found in the work develop by Pérez-Arriaga et al. (2012), researchers from Comillas University.

Transmission and distribution networks have to be separately considered, since their functions and the challenges they will have to face are so different.

5.2.1 Transmission policy

The increasingly new role of transmission networks will include reaching to those places where the best large renewable resources are located, enlarging the footprint of VER – therefore increasing their economic value and their contribution to the reliability of the power system –, and permitting the integration of otherwise quasi independent electricity markets.

There are some unrelenting transmission policy issues, which will become more acute under the new conditions. If very large amounts of power have to be transported from distant places (off-shore wind production from the North Sea, solar power from Northern Africa to Europe, large wind resources from the sparsely populated Mid-West in the USA) and very broad market integration is an objective, then just reinforcements of the existing high voltage grid (400 and 220 kV in Europe) may not be sufficient and some sort of overlay or supergrid will have to be built, perhaps using higher voltage levels and direct current (DC) technology.

Policy and institutional framework

- How to reconcile wide interconnection interests (EU or USA in scope, for instance) with national or local interests?
- How will these decisions be made, both *by whom* (some planning authority with such a wide reach) and *how* (a method that can cope with a problem of such a huge dimensionality and uncertainty)?

Novel technologies

Another open issue is the best use of existing or novel technologies to minimize the environmental impacts and to make maximum use of the existing or future transmission capacity: gas insulated cables, superconductors, low sag conductors, phase measurements, wide area monitoring, flexible alternating current transmission systems (FACTS), etc.

Cross-border interconnections

Transmission networks and flows will crisscross interconnected power systems, where some agents, companies, states or entire countries will benefit clearly from these flows while others will not obtain much benefit from the lines sited in their territories.

- Should the cost of these lines be socialized or should these costs rather be allocated to the beneficiaries of the transmission facilities?
- How can the benefits and beneficiaries be identified in an objective way?
- How to make whole and minimize the hostility of those who do not benefit from the installation of transmission facilities in their vicinity?
- How to address the coordination of the operation of large interconnected power systems?

Transmission planning

Given the large uncertainty and the diversity of interests that exist in the expansion of the transmission network:

- Should all decisions be left to a central planner under a regulated monopoly scheme or other business models with more participation of stakeholders are also possible?

5.2.2 Distribution policy

Integration of renewable generators is together with many other relevant ones (e.g. higher efficiency in energy consumption in homes and commercial buildings or deployment of future plug-in electric vehicles) is a driver demanding a profound transformation on the way electricity distribution grids are designed and operated. This transformation needs to result in an enhanced distribution grid, more sophisticated and complex than the actual.

Present distribution electricity grids have been designed to carry electricity from the meshed transmission grid, where most of the generation resources were connected, to final electricity consumers. Distribution grids are characterized by one-direction flows from sources to loads, radial structure, simple operation rules and acceptable reliability of supply. Planning and operation of distribution grids are based on "fit and forget" practices. Distribution grids are presently planned to supply the future peak demand with ample design margins. And they are operated in a passive mode, meaning that once the distribution grid facilities have been installed, for the most part, medium – several kilovolts – and low voltage grids are not monitored or controlled in real time. Customer meters are used for energy settlement and commercial services, but not for network operation. Automatic control systems almost do not exist and grid operators are mainly focussed on ensuring continuity of supply and reconnecting affected customers in case of grid failures or maintenance works.

However, much of the expected volume of electricity production with renewables will be connected in distribution networks, either in low voltage (small wind, roof-top solar panels), or in medium and high voltage distribution. This will force distribution utilities to change the customary procedures for design and operation and, in most cases, to incur in additional costs. Distribution is treated as a regulated monopoly worldwide, although it has been always difficult to determine the adequate level of remuneration and the proper incentives to promote reduction in losses and an optimal level of quality of service. This will become much more challenging with significant amounts of distributed generation, signaling the need for advanced network models and an in-depth revision of the remuneration procedures, as OFGEM is presently doing in the UK, see (OFGEM, 2010). There is the need, again, of an in-depth revision of the regulation of the distribution activity. In this case to assign roles to distributors, retailers and energy service companies on who is doing what in metering, aggregation of consumers, relationship with the distribution system operator, interaction with the end-consumers and control of their appliances, as well as improving the models of remuneration while taking into account quality of supply.

Smart grids

Both in the technical literature and in the non-specialized media the term "smart grid" is frequently used suggesting a radical departure from the present transmission and distribution networks. Smart grid is a loosely defined concept, which includes a diversity of technologies and innovations. The European Union Smart Grids Platform[24] defines smart grids as "electricity networks that can intelligently integrate the actions of all the users connected to them – generators, consumers, and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies". The USA Energy Independence Security Act of 2007 provides a very comprehensive definition.

The transition from the present electricity grids to transmission and distribution networks with enhanced capabilities requires very significant volumes of investment in new facilities as well as in innovation efforts. Most of them are mainly related to the implementation of much more complex and sophisticated information, communication, and control systems. In addition, investment in grid infrastructure will be also needed to replace old assets, to increase network redundancy and to

[24] See http://www.smartgrids.eu/

connect new generation sites and demand users. Finally, operational and maintenance costs should be re-evaluated taking into account the new structure and functionalities provided by smart grids.

Existing electricity grids are already smart. But they need to become much smarter to cope with the new realities of a much more complex, decentralized and interactive power sector, in its way to facilitate an efficient, reliable and carbon-free electric supply. It will be a long, evolutionary process that will use and expand existing network capabilities and add new ones. The design and implementation of adequate regulation at both distribution and transmission levels will be essential in guiding the financial resources and technical capabilities of the private firms towards this common objective.

Grid charges

As argued by Cossent et al (2009), a correct design of grid regulation, in particular use-of-system charges and connection charges for distribution systems are key elements for the large-scale deployment of RES-E in a fair and non-discriminatory way. Other important topic is the use of nodal or zonal pricing, discussed in section 5.

Only a few countries employ use-of-system charges for RES-E, although this would clearly be a good option for regulating correctly the way they are deployed and operated. All use connection charges.

Most countries in Europe use shallow connection charges (by which the RES-E plant only pays for the direct cost of connection), and only some (Spain and the Netherlands) use deep connection charges, by which plants must pay all the cost of connection, including upstream grid reinforcements. The choice between these two options has to strike a balance between providing incentives for deployment, particularly for small-sized operators, and incentivising an optimal and cost-reflective siting of new generation.

Another important issue is whether the DSO is the one determining the total cost of connection. If connection charges are not published ex-ante, this may create disadvantages for RES-E developers in the negotiations with DSOs. Under the current system, DSOs do not have clear incentives for the integration of RES-E, except for low-penetration situations and for low concentration of RES-E plants. Higher penetrations typically result in negative impacts for DSO benefits, mostly due to the need for network investments, which may not be adequately paid for. DSOs are therefore reluctant to facilitate connections.

A way to balance all these considerations would be to promote regulations in which connection charges for RES-E are averaged, regulated, and shallow. And then to socialize the rest of the reinforcement costs, recovering them through use-of-system tariffs. Cossent et al (2009) also recommend to implement incentive-based regulation for DSOs in order to strengthen the incentives for an efficient integration of RES-E.

6 Conclusions

The objective of this report has been to review existing studies of the interactions between RES-E and electricity markets and grids policies and regulatory designs, in order to inform future work within this work package, the assessment of the impacts of different RES-E policy pathways.

Since in some cases the amount of work that can be found in the literature is rather scarce (specially on how regulatory design of RES-E and wholesale markets and grids regulation affects both the RES-E deployment and the overall power system efficiency), we have delved into the development of a sound and novel discussion of these issues.

First, we have approached the discussion about the specific impact that these RES-E policy pathways can have on electric power systems functioning and efficiency. And the core of the work developed has been centred in proposing a methodology that instead of taking the different RES-E subsidization instruments as starting point of the assessment, first proposes a decomposition of the policy pathways into the elements that conform them. We have developed also a first analysis on the specific influence that each one of this design alternatives can have.

Then, we have addressed the first approach to the discussion on the changes required in market design and grid regulation in order to make compatible larger shares of RES-E with an efficient operation of power systems.

In order to provide the adequate background for this analysis, we have reviewed intensively the literature dealing with the study of the operational and economic impacts of intermittent generation, showing the multiple challenges that most power systems will have to face in the future. There is overwhelming evidence that system operation practices and power sector regulation will have to adopt innovative approaches.

Next, we have set the basis of the work to be faced in the next step of the work package, testing the different regulatory design alternatives for wholesale markets and grids in the presence of large amounts of RES-E

The actual development indicates that renewable generation especially wind and solar power have an increasing impact on system operation and grid regulation already today. Therefore the right steps has to be implemented now to avoid an inefficient and less reliable power system when the contribution of wind and solar will increase further in the future. The identification of the right steps is expected to be the major outcome of the work package at the end of the project.

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A) ANNEX I: Description of RES-E technologies

As was explained before, the impacts of RES-E on markets and grids depends on the policy instruments chosen, but also on the characteristics of the technologies being promoted. So far, most assessments do not look into the technology mix when assessing the influence of renewable on markets and grids. This section tries to fill the gap by analyzing the characteristics of each technology and deducing the corresponding influences. It complements the information already provided in the main body of the document.

7.1 Wind

Wind energy in 2011 made up 6.3% of total EU electricity generation with an installed capacity of 93,957 MW (EWEA, 2011). Wind penetration in some countries is much higher – e.g. in Denmark 25.9%, in Spain 15.9% and in Portugal 15.6%. For example in Spain, in April 2012, 61% of demand was covered by generation from wind power. Wind power heavily influences the development in electricity markets already (EWEA, 2012). In the following, the characteristics of wind energy (onshore and offshore) and its influence on markets and grids are described based on existing literature.

7.1.1 Characteristics of the technology

Cost structure and total generation costs

Electricity generation from wind involves high capital costs and very low operational costs. In the case of offshore wind, costs are more expensive in general and also costs of operation are considerably higher than for onshore wind due to more difficult logistics and increased wear and tear of materials in rough offshore conditions.

Overnight investment costs for onshore costs are currently between 1100 and 1800 €/kW whereof 70-85% are for the turbine, operational costs lie between 35 and 50 €/kW. This corresponds to levelised costs of electricity generation between 40 and 120 €/MWh (IEA, 20120a; IEA, 2010b; Mott-McDonald, 2010; Nitschel et al, 2010). As an example, for the UK this means that wind onshore is cost-competitive compared to almost all conventional power generation technologies apart from CCGT plants. Costs differ however over countries.

Offshore wind is more expensive than onshore wind. Furthermore, expectations for cost reductions of offshore wind have not proven real. As shown in Figure 7, costs have even increased over the last years. There are a number of reasons for this development including the scarcity of turbine developers and increasing steal prices. Nevertheless, offshore wind will most probably remain more costly than onshore wind due to the more complex and difficult installation, operation and maintenance in seawaters.

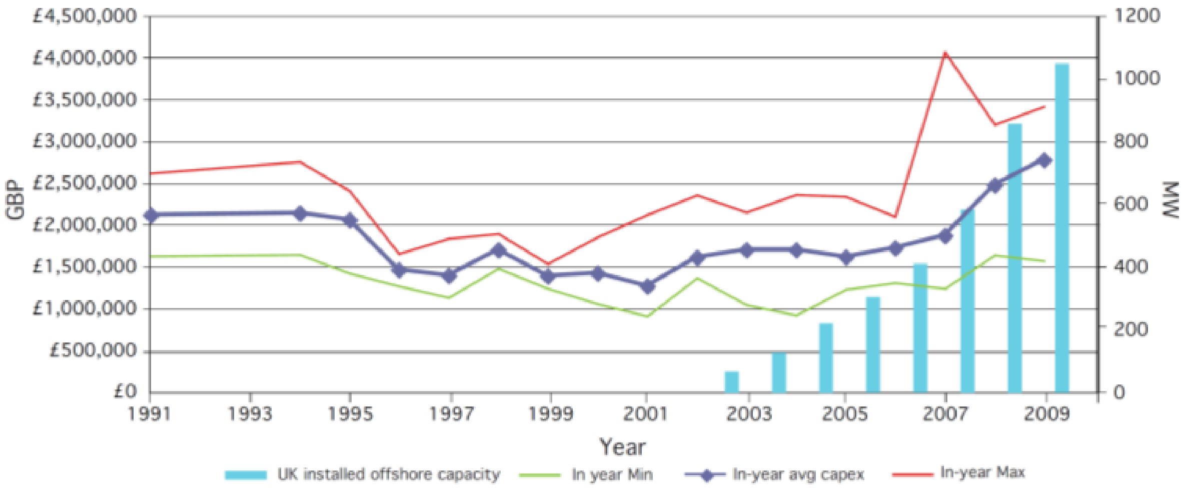


Figure 7 Average actual wind offshore CAPEX per MW for UK installations (UKERC, 2010)

The calculation of levelised costs depends however on the quality of the resource at a certain location – locations with less favourable wind conditions have higher costs per unit of electricity produced as capital costs are distributed on fewer units. Furthermore, assumptions regarding the plant's life time, financing conditions etc. play are major role in estimating total generation costs. Estimated generation costs are nevertheless the basis for calculating feed-in tariffs in most European countries.

Dispatchability, flexibility and predictability

Generation from wind energy is weather dependent and dispatchibility is therefore restricted to reducing electricity output when the wind regime would allow for higher generation. Despite the fact that such curtailment means wasting almost cost-free energy, it can be useful to avoid negative prices or provide negative balancing services.

In the restricted way described above, wind plants with corresponding technological equipment can be regulated very fast and are thus flexible. However, not in all countries wind plants are equipped to react to changes in demand. In Germany, this fact currently leads to a lower effect of he newly introduced market premium than expected.

The lack of predictability of electricity generation from wind is often stated as a major challenge. However, wind forecasts have improved substantially over time. In order to make use of improving forecast quality closer to real time (shown in Figure 8 for Germany), the integration of wind energy increases the need for a liquid intra-day or balancing market.

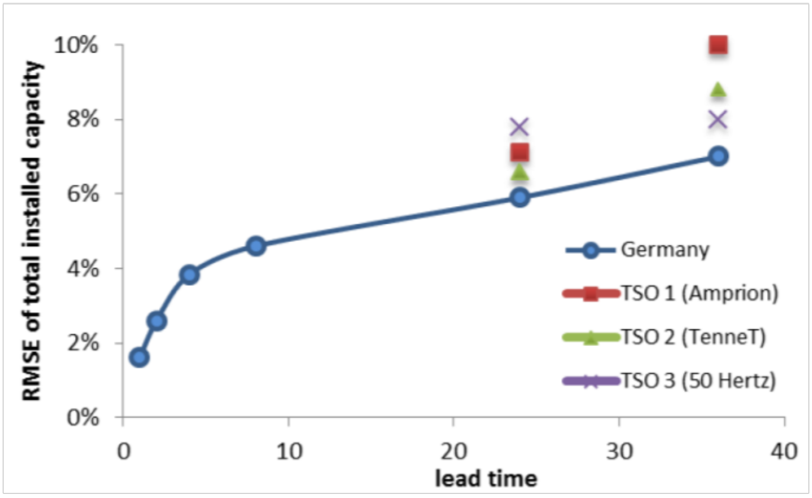


Figure 8 Improvement of wind forecast accuracy closer to real time *for Germany and three transmission zones (Borggrefe & Neuhoff, 2011)*

A wider geographical distribution in a strong grid reduces this effect as generation from a wider area is much less volatile than from a single wind park as shown in Figure 9 for US states. However, one must to keep in mind that this effect increases with distance – Danish wind generation is for example closely correlated to German wind generation but the smoothing effect between Irish and Danish wind farms is considerable.

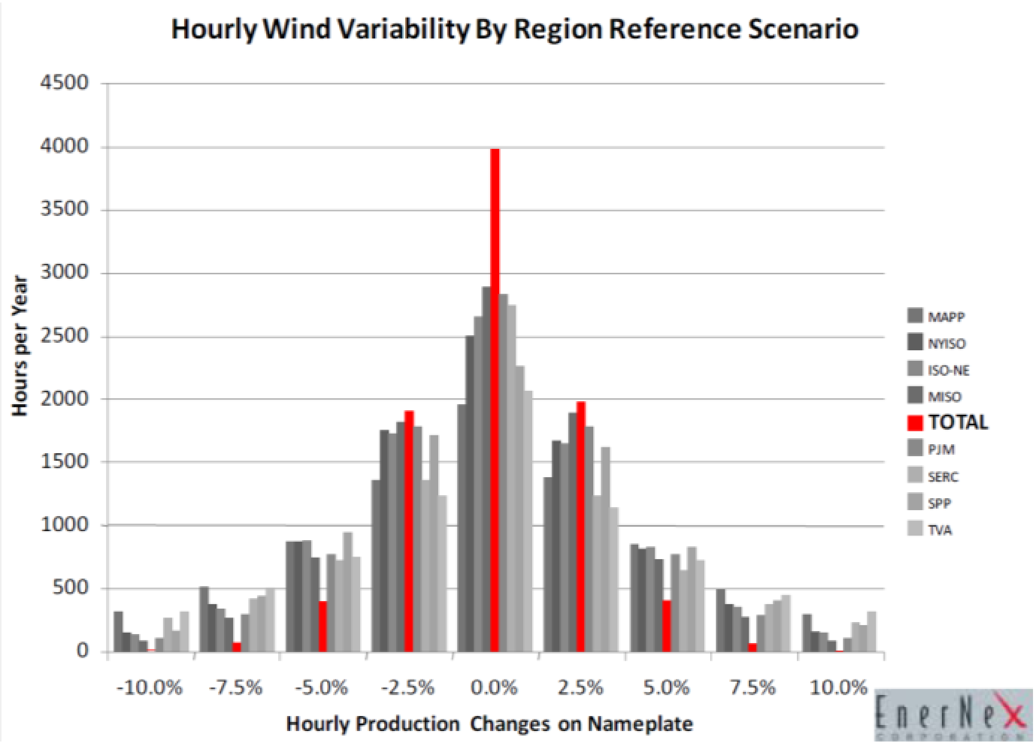
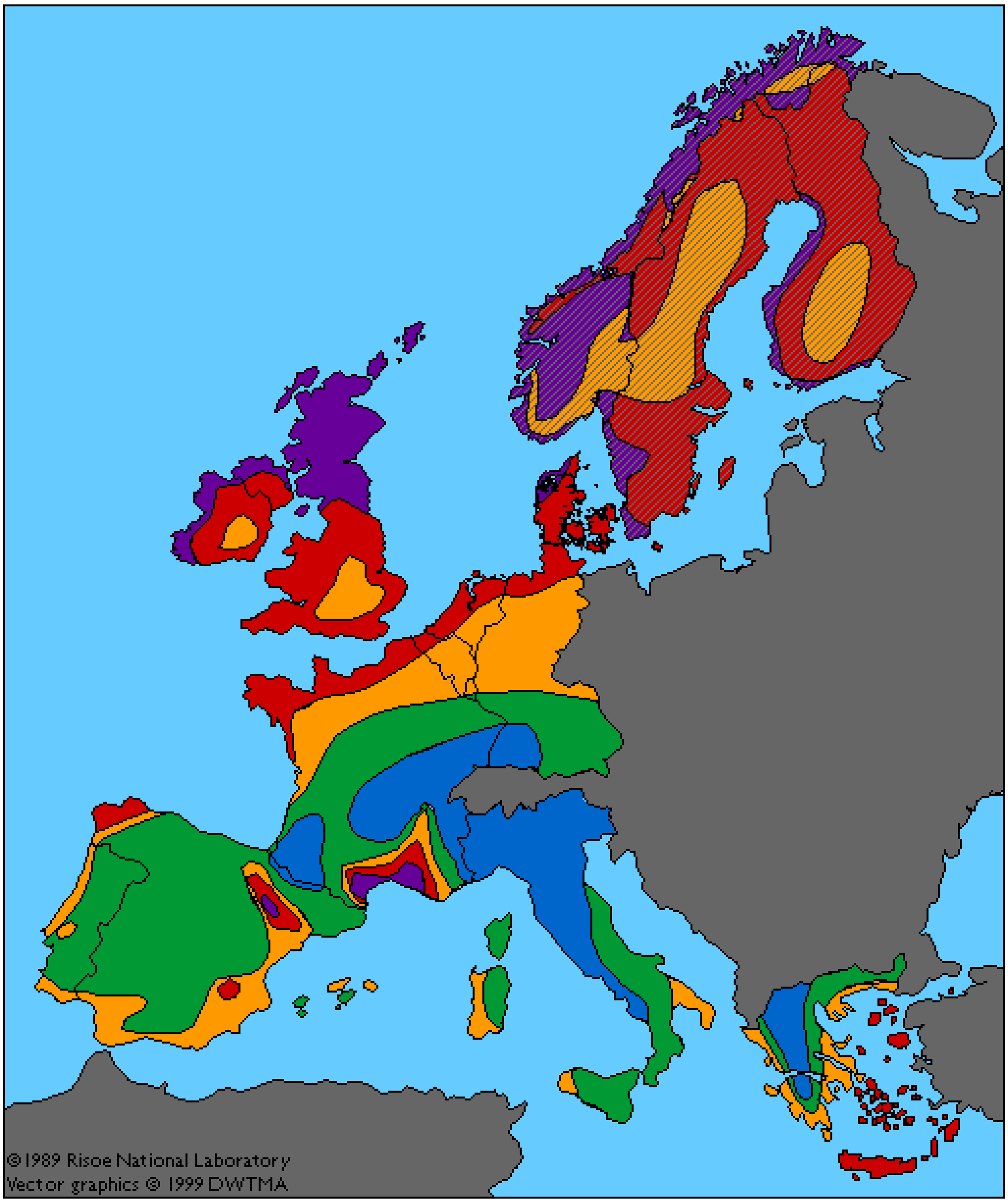


Figure 9 Reduction of wind variability over larger geographical area (Ellis et al., 2011)

Location

Figure 10 shows a map of wind energy potential in Europe. Wind generation is cheapest (given the same investment conditions) in areas with a good resource level. Locations best suited for developing onshore wind in terms of resource endowment are thus in Northern Europe (especially Scotland, Ireland and Norway) as well as in the French Mediterranean region. However, most of these locations are located far away from load centers and thus costs to develop grid infrastructure and other related costs need to be considered when actually locating the wind parks. In principle, onshore wind generation is applicable almost everywhere so that the location of wind power plants mainly depends on the chosen support instrument and the exact level of support.



Wind resources at 50 meters above ground level for five different topographic conditions: 1) Sheltered terrain, 2) Open plain, 3) At a coast, 4) Open sea and 5) Hills and ridges.

	m/s	W/m²	m/s	W/m²	m/s	W/m²	m/s	W/m²	m/s	W/m²
	>6.0	>250	>7.5	>500	>8.5	>700	>9.0	>800	>11.5	>1800
	5.0-6.0	150-250	6.5-7.5	300-500	7.0-8.5	400-700	8.0-9.0	600-800	10.0-11.5	1200-1800
	4.5-5.0	100-150	5.5-6.5	200-300	6.0-7.0	250-400	7.0-8.0	400-600	8.5-10.0	700-1200
	3.5-4.5	50-100	4.5-5.5	100-200	5.0-6.0	150-250	5.5-7.0	200-400	7.0-8.5	400-700
	<3.5	<50	<4.5	<100	<5.0	<150	<5.5	<200	<7.0	<400
			>7.5							
			5.5-7.5							
			<5.5							

Figure 10 Onshore Wind Potential in Europe (European Wind Atlas 2011)

Offshore wind parks in Europe most parks are currently all situated in the North Sea with installed capacities in ten countries as listed in Table 5. There is also potential for developing offshore wind in the Mediterranean. This potential has however not yet been developed. In general, offshore wind generation tends to be placed far away from centers of demand.

Table 5 Installed capacity wind offshore 2011 in Europe (EWEA, 2012)

Country	UK	DK	NL	DE	BE	SE	FI	IE	NO	PT	Total
No. of farms	18	13	4	6	2	5	2	1	1	1	**53**
No. of turbines	636	401	128	52	61	75	9	7	1	1	**1,371**
Capacity installed (MW)	2,093.7	857.3	246.8	200.3	195	163.7	26.3	25.2	2.3	2	**3,812.6**

Voltage Level

Figure 11 shows typical grid connection levels of renewable energy technologies. Onshore wind parks are usually connected at medium to high voltage levels depending on their size. Large onshore wind parks and offshore parks are connected at transmission grid level. The voltage level of the connection is important to determine necessary reinforcement and extensions of the grid infrastructure.

In the past, distribution grids at lower voltage levels were mainly used to distribute electricity generated by centralized power plants to the electricity consumers. Thus, the generation of electricity at these grid levels might require additional investment but at least special evaluation and observation.

While in the case of onshore wind, the connection at lower grid levels and/or at locations far from load centers might require grid enforcement; offshore wind requires additional grid connections (AC or DC) to their point of production of the shores.

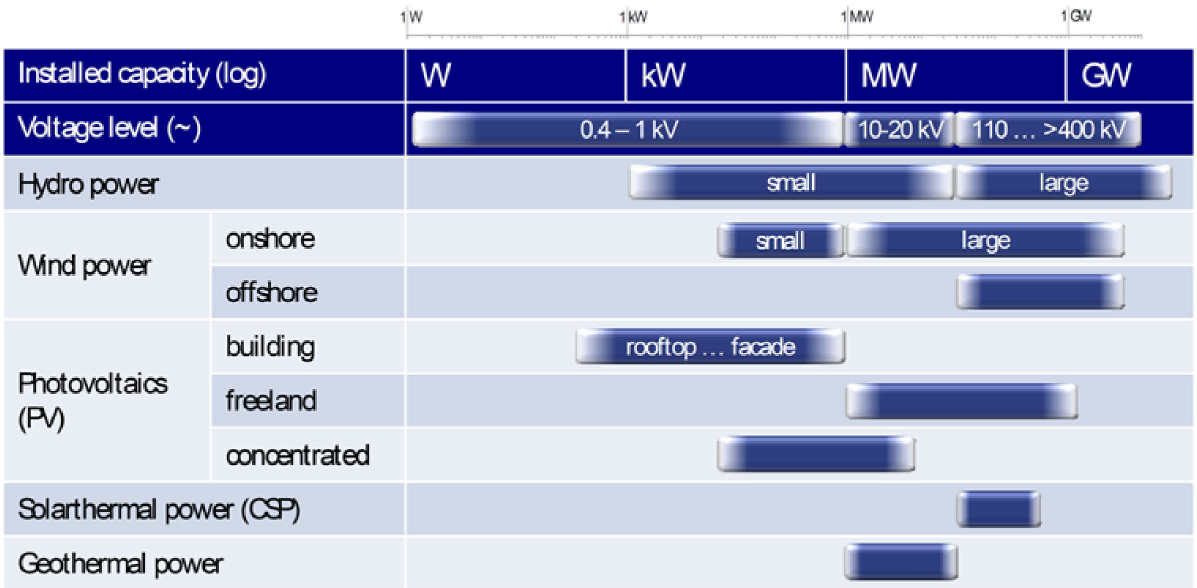


Figure 11 Bandwidths of installed capacities of renewable power sources (logarithmic scale) and grid connection levels, differentiated by renewable energy technology (Altmann et al., 2012)

Generation Profile

Electricity generation from wind parks is typically not very well correlated to electricity demand. Wind generation is quite variable. Output differs between months (see Figure 12), over the day, between days (see Figure 13) and from year to year.

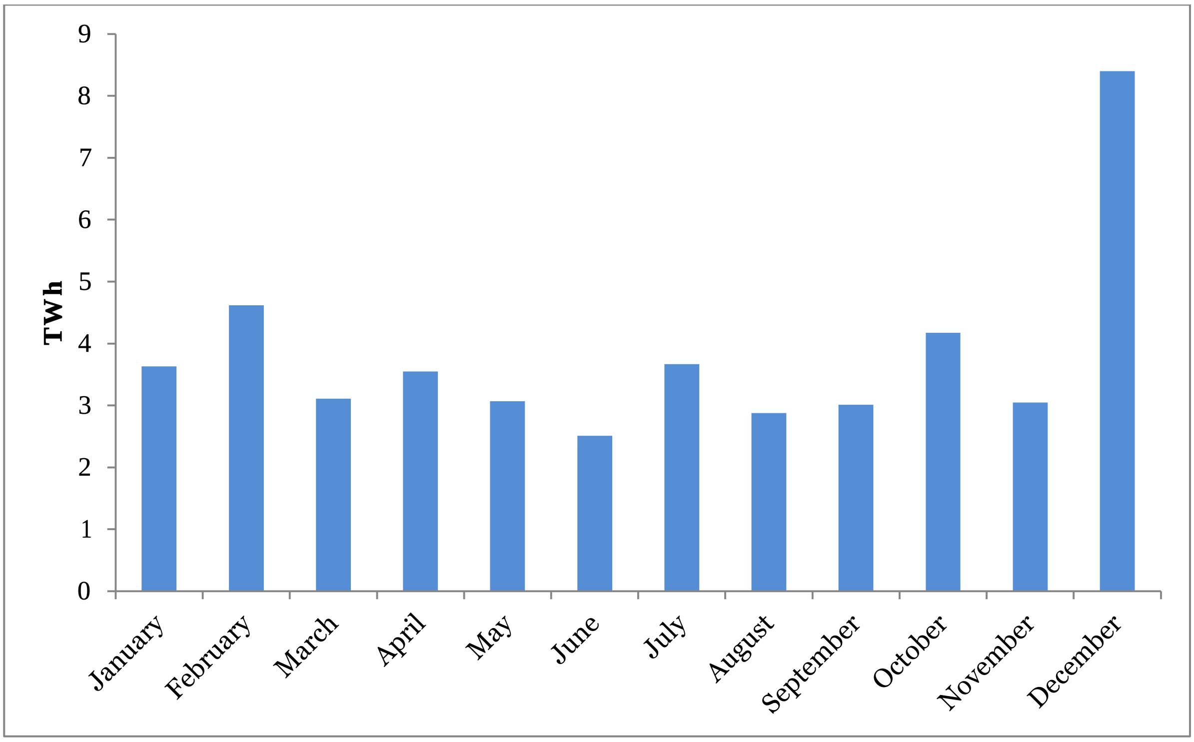


Figure 12 Monthly electricity generation from wind power in Germany 2011

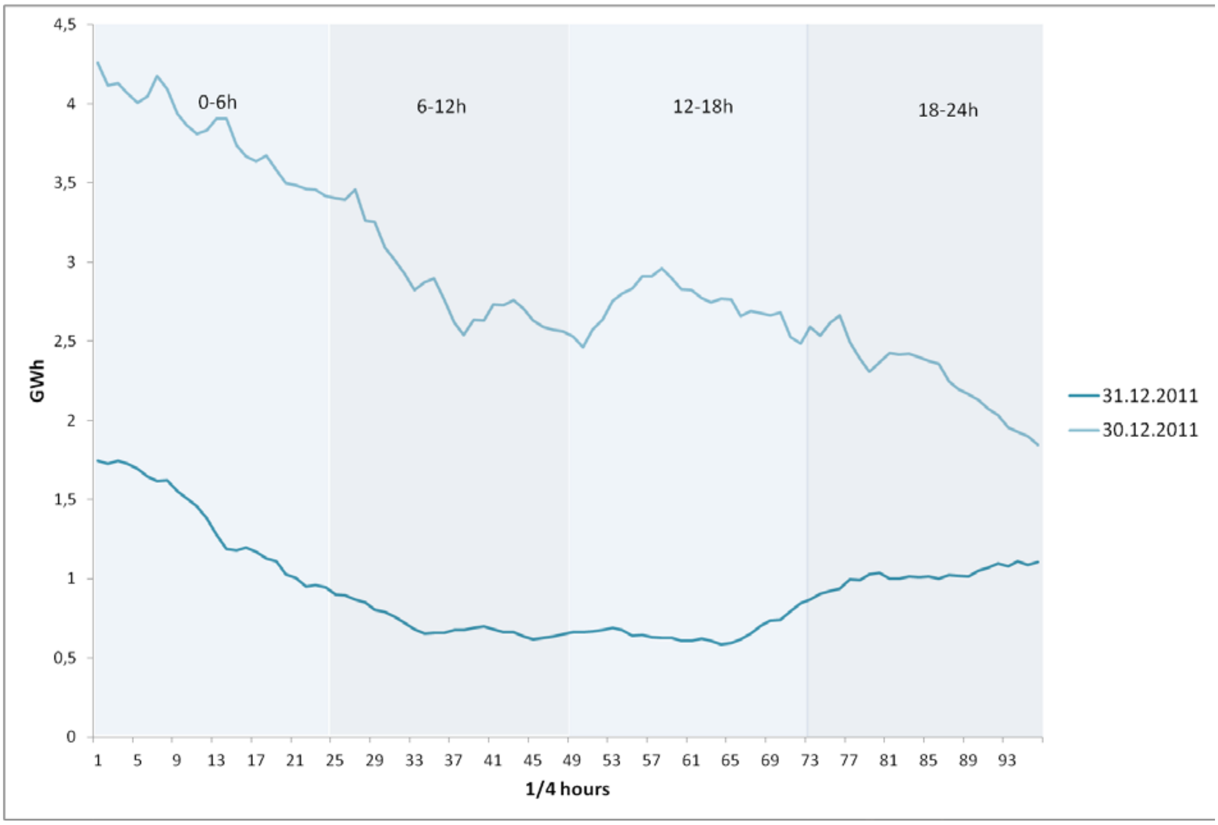


Figure 13 Wind generation in Germany for two consecutive days in 2011 (data for 15-minute blocks)

On a European scale, wind generation is typically highest in winter which corresponds to a period of high electricity demand (notonlywindenergy, 2012). However, generation is also often high during the night, when demand for electricity is rather low.

Wind offshore generation is generally more stable and predictable due to a more stable wind regime and a resulting higher number of full load hours. However, more complicated maintenance activities might diminish this advantage.

Availability (capacity credit)

At the locations with the best resources in Europe, wind generation can reach up to 3000 full load hours per year. At sea, a number of 3500 to 4500 full load hours is calculated (Danish Energy Authority, 2005). This corresponds to an availability of up to 34% for onshore and 51% for offshore wind. At other locations, the number of full load hours can be much lower.

The capacity credit indicates which part of the installed capacity of a power plant can be relied on in times of peak demand and thus can replace other firm capacities (this can be storage, demand response, generation or interconnection). There is a wealth of literature regarding the capacity credit of wind plants. Figure 14 shows a comparison of estimated capacity credits for different countries and periods. While the values differ substantially from 5% to 40%, there is agreement on the factors influencing the capacity credit of wind: Higher wind penetration, locations with a volatile wind regime or locations with low resources decrease the capacity credit, while geographical dispersion and location with stable wind regimes increase the capacity credit. The capacity credit can best be estimated via modeling a power system based on weather, production and demand data with a high degree of spatial and time resolution.

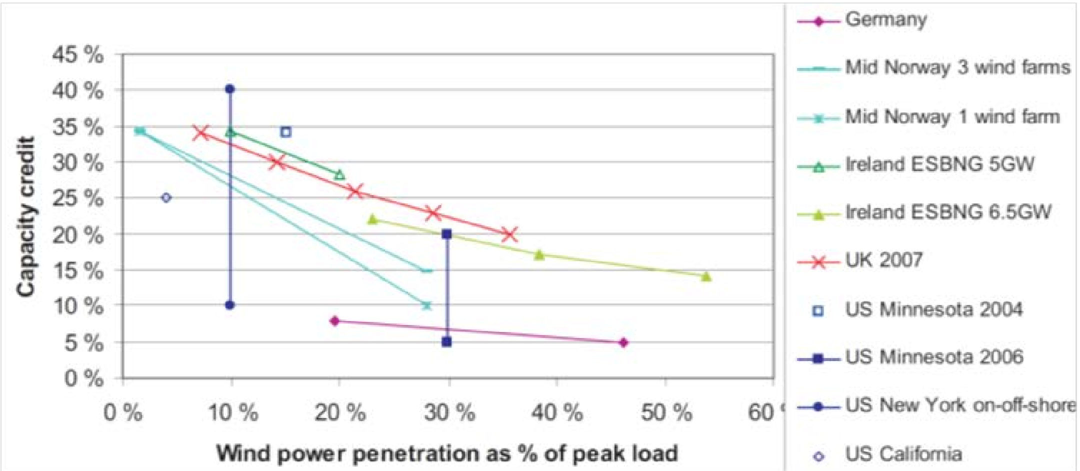


Figure 14 Capacity credits of wind power (Ensslin et al., 2008)

Ownership structure

An increasing share of wind power, especially smaller wind parks, can lead to a more diverse ownership structure through the involvement of cooperatives, individuals, communes etc. However, if the development is primarily big onshore or offshore wind parks established players like the big utilities play a bigger role. The type of support scheme can influence the ownership structure. Depending on the risk involved in investment in renewables, smaller or bigger actors will become active.

Currently, a number of bigger wind parks and especially offshore wind parks are owned and operated by big utilities and in some countries commune enterprises that also own and operate conventional power plants. A considerable number of plants are however managed by ‘new’ actors in the sector such as communities or private landlords. For example, in Germany the number of cooperatives in the energy sector investing in wind parks and other renewables is rapidly increasing (KNi, 2012).

Ability to deliver ancillary services

It is often argues that wind plants require additional balancing due to their relatively unpredictable output.

However, wind parks can also provide frequency and voltage control. Special control software is required for delivering frequency control. Pitch control is necessary for providing voltage control. For wind plant, the delivery of negative frequency control is quite suitable as this kind of ancillary service is often needed in times of high generation from wind.

Positive frequency control requires that the wind plant is not run at full output and thus implies relatively high opportunity cots as no fuel costs can be saved a in the case of conventional plants running in part load. Furthermore, in most countries the balancing mechanism does not allow for wind parks to participate in frequency control services due to their unsecured availability.

7.2 Solar PV

With high growth rates of installed capacity in Europe as shown in Figure 15, solar PV starts to play a more important role in some European electricity systems. In Germany for example, PV generation contributed 3.8% of total electricity generation in 2011. On sunny days, it even contributes up to 20% (Fraunhofer ISE, 2012). Solar PV's contribution in Italy was 3% in 2011 after extremely high growth rates of newly installed capacity (Stagnaro, 2012). Thus, a thorough analysis of the characteristics of this technology and its influence on markets and grids appears important.

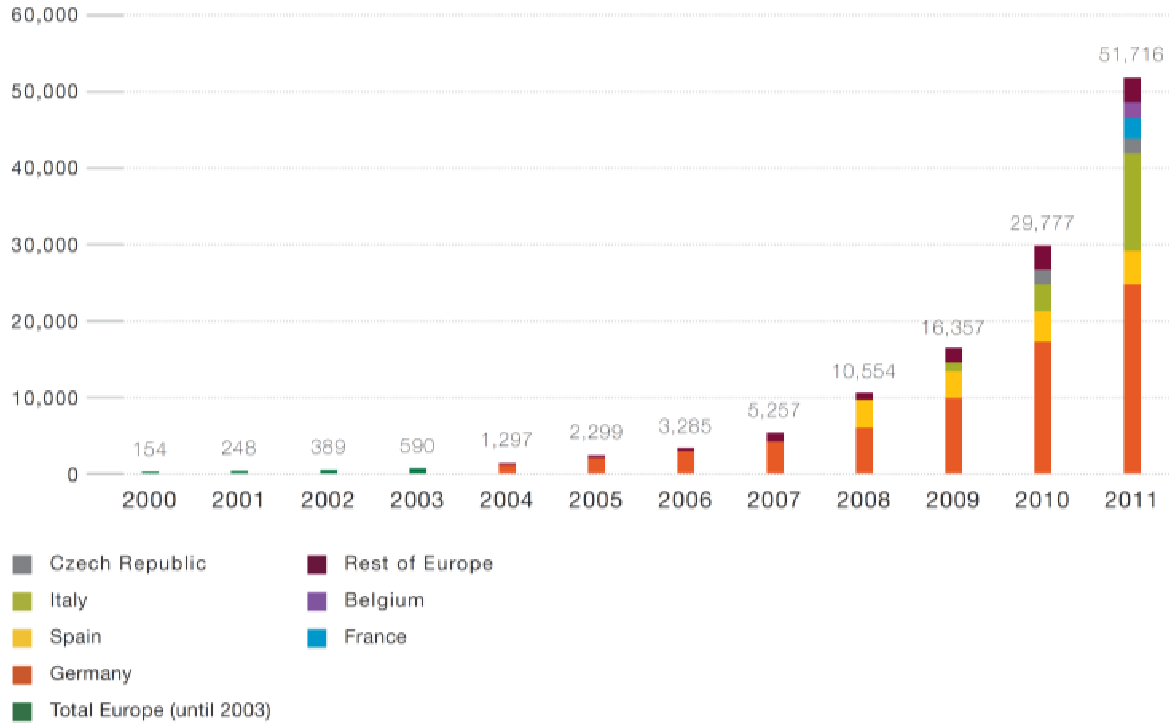


Figure 15 Development of cumulative installed photovoltaics capacity 2000 – 2011 in MW (EPIA, 2012)

7.2.1 Characteristics of the technology

Cost structure and total generation costs

As for wind, investment costs make up the most prominent part of the costs of electricity generation from PV. Operation and maintenance costs are extremely low.

Module costs are responsible for about 50% of total investment costs for a PV installation. Prices have decreased considerably over the last years: In Germany, the price per kW installed capacity for a rooftop installation of 100 kW_p was 2.19 Euro in the third quarter of 2011 – compared to 5 Euro in 2006. Prices for smaller rooftop installations remain higher at around 3 Euro/ kW of installed capacity (Fraunhofer ISE, 2012).

Despite these impressive piece developments, levelized costs of electricity generation from PV are still comparatively high – for Germany, levelized costs of around 0.24 Euro/kWh are reported, for Italy costs are lower at around 0.18 Euro/kWh due to the better solar resources in the country (Fraunhofer ISE, 2012; Stagnaro, 2012). According to other sources, levelized costs vary widely across countries and locations between 0.15 and 0.40 Euro/kWh (EPIA, 2011; IEA, 2010a; MottMacDonald, 2010; Nitschel et al., 2010).

Even if levelised costs are still high compared to other generation technologies, PV starts to reach grid parity i.e. its levelised costs are equal or lower than retail electricity prices. This makes investment in PV installations financially interesting for households even without subsidies in cases where the rate of own consumption is high.

Dispatchability, flexibility and predictability

PV is also a weather-dependent form of electricity generation. Electricity production seldom reaches the maximum installed capacity due to weather conditions but also due to mostly higher temperatures of the cell in operation when compared to test conditions. In Germany a regulation allowing for a feed-in of only up to 70% of maximum installed capacity was introduced in 2012 to avoid unnecessary grid extensions. The output of plants that want to feed-in more than the 70% can be curtailed in times of system stress.

Downward regulation of electricity output or curtailment is possible for PV plants and can be realized very quickly if the right electronic control mechanisms are in place. Tracking systems (mostly used for ground-mounted PV) allow for a more precise regulation including upward regulation if the plant is kept in part load (compared to the maximum possible generation at a specific point in time). However, regulation always leads to losses of otherwise almost costless electricity.

Output from PV plants is generally more predictable than output from wind plants as generation is restricted to hours with sunlight and follows a distinct seasonal pattern according to the strength of solar radiation. Good national whether forecasts improve the predictability of PV production. In Germany for example, due to the wide distribution of PV across the country local changes in cloud cover do not change the generation pattern too much (Fraunhofer ISE, 2012). The situation might be different in Italy where PV is still concentrated in the Southern part of the country (Stagnaro,2012).

Location

Figure 16 shows the distribution of solar resources across Europe. As can be seen, resources are unevenly distributed across countries. Unsurprisingly, the best conditions for solar PV can be found in the Southern part of Europe. This also corresponds to the number of full load hours that can be reached at each location which is shown in the map in Figure 20.

However, electricity generation from PV is possible across Europe – the difference is that a higher installed capacity is necessary in areas with lower resources to produce the same amount of electricity generation which increased overall generation costs. On the other hand, distributed and decentralized generation might reduce the need for extensive transmission grid extensions and attract higher local investment rates.

So far (as shown in Figure 15) Germany is the country with the highest installed capacity of PV in Europe despite its comparatively low resource level. Resources in Italy, the country with the second highest installed capacity, resources are much better. Interestingly however, feed-in tariffs to support PV are currently higher in Italy than they are in Germany.

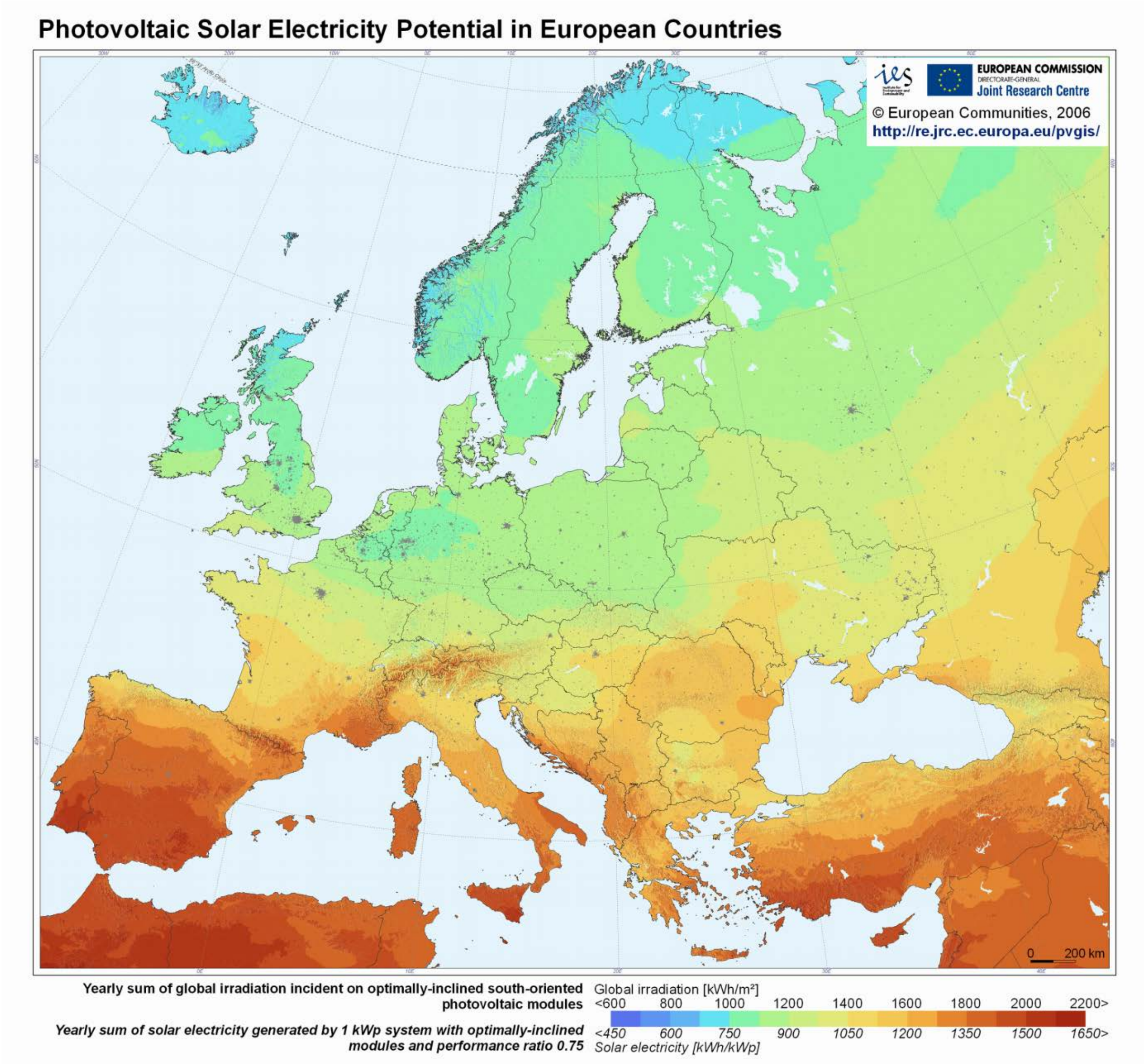


Figure 16 Photovoltaic solar electricity potential in European countries (European Communities, 2006)

Voltage level

PV plants are mainly small plants and are therefore mostly connected at the distribution gird level. In Germans 90% of installed capacity is connected to the rural low voltage grid, the remainder is connected to the medium voltage grid (see Figure 17). A high concentration of PV plants in a low voltage grid can sometimes lead to overproduction in this grid. In this case, electricity needs to be fed back into the medium voltage grid. If the PV plant density is high in one grid, transformers might need to be upgraded to realize this.

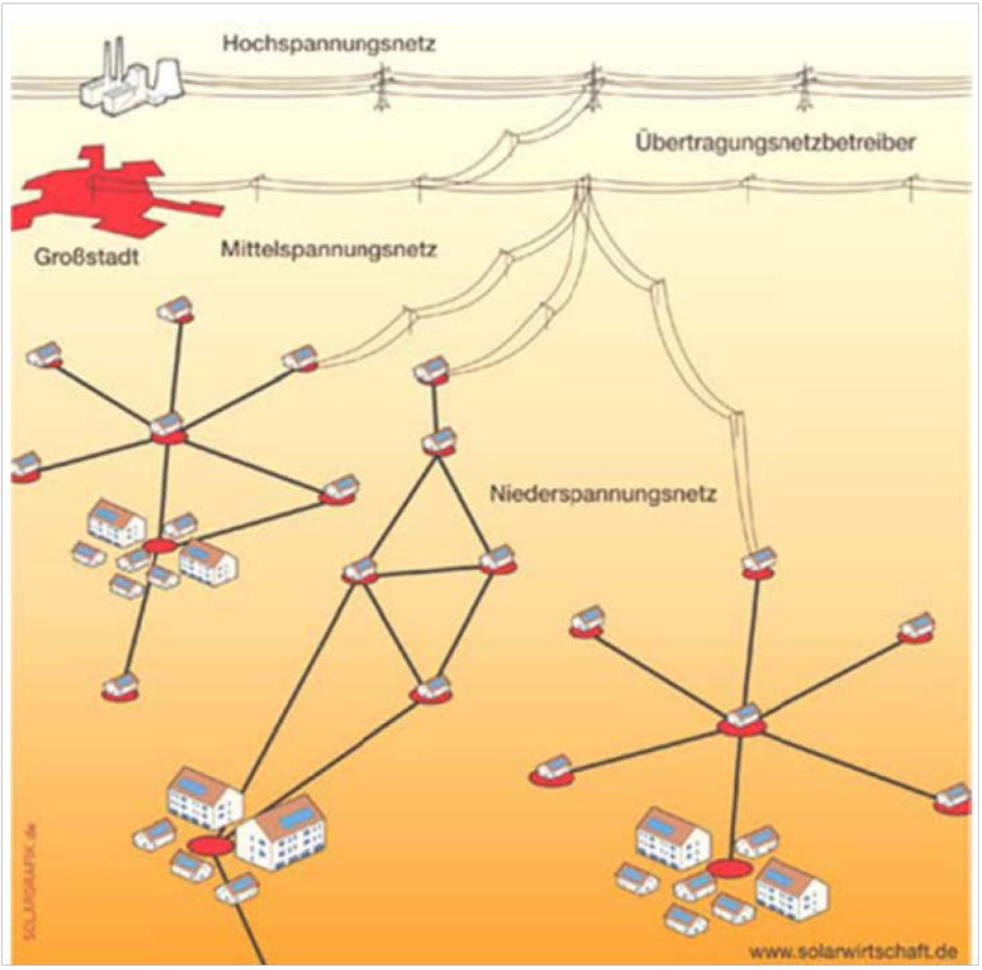


Figure 17 PV generation in rural low voltage grids in Germany (Fraunhofer ISE, 2012)

Generation profile

As mentioned above, the generation profile of solar PV is much more regular than that of wind with clear daily and seasonal patterns.

Figure 18 shows PV generation in Germany for each month of 2011. Figure 19 shows the daily generation for two randomly chosen subsequent summer days and two winter days. Nevertheless, considerable differences can also be observed between different summer months depending on the weather pattern in the distinct year. Also between consecutive days, the timing and amount of PV generation can diverged substantially.

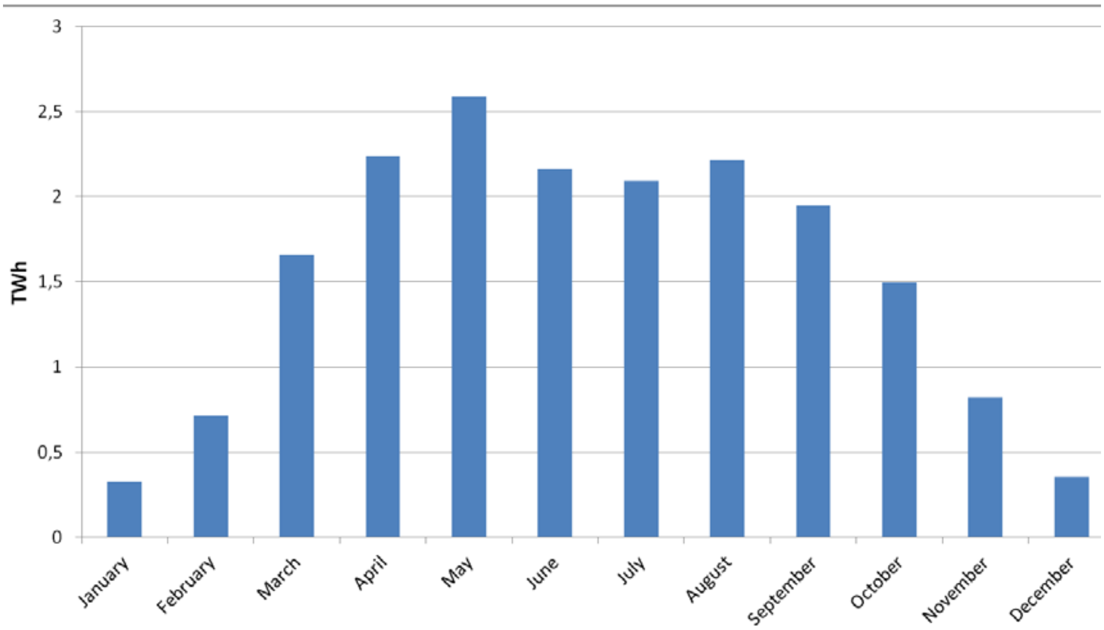


Figure 18 Monthly electricity generation from solar PV in Germany 2011

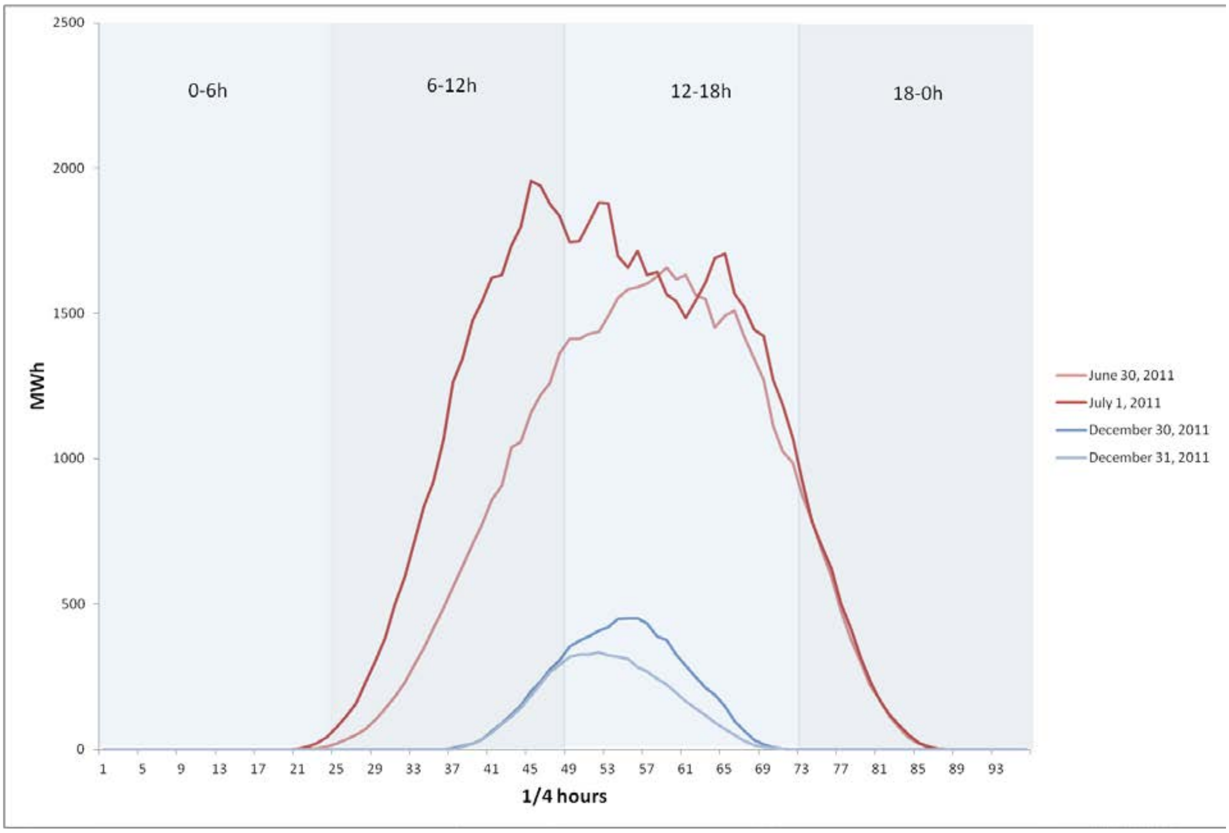


Figure 19 Electricity generation from solar PV in Germany for two consecutive summer days and two consecutive winter days of 2011

Availability (Capacity credit)

As for wind, the number of full load hours and as a consequence the availability of plants is higher in countries with better resource endowment. For example, the IEA uses numbers for availability of PV plants between 10% for Denmark and the British Isles and 20% for Spain (IEA, 2011).

The determination of the capacity credit for solar PV is quite straightforward – it is 0% as there is no solar PV generation during nighttimes and thus PV does not deliver any share of firm capacity. However, in some countries, PV output is quite closely correlated to the fluctuations of electricity demand over the day. PV reaches its highest generation level around noon when many countries (at least in the Southern part of Europe, but also in Germany) reach their maximum demand level.

Despite its comparatively low availability and capacity credit, PV therefore contributes substantially to meeting electricity demand.

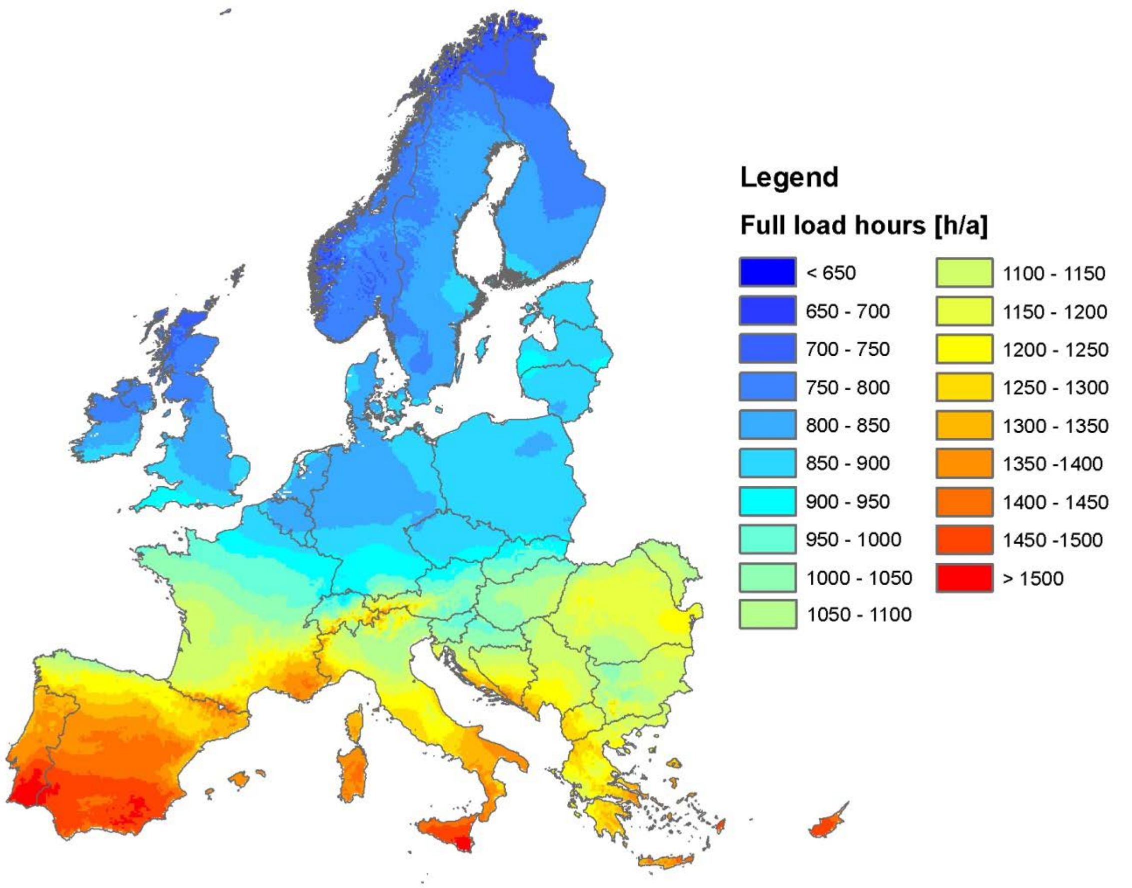


Figure 20 Annual full load hours of optimally inclined PV modules (Held, 2010)

Ownership structure

So far, at least in Germany, the ownership structure of PV plants is very diverse as shown in Figure 21. The big utilities hold only a very small share of 0.2% of installed capacity. The majority of PV installations are owned by households (39.3%) and farmers (21.2%).

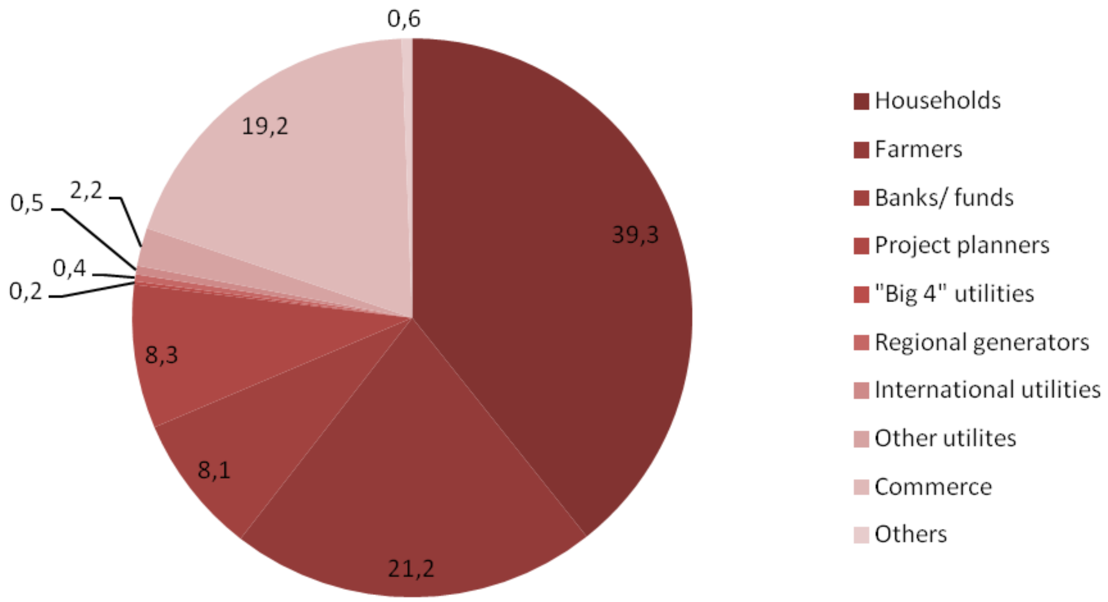


Figure 21 Ownership shares (%) of installed PV capacity as of 2010 (Fraunhofer ISE, 2012)

Ability to deliver ancillary services

PV plants can deliver reactive power at an additional investment cost of around 2% of total investment costs. The availability of frequency ride through capabilities comes at an extra cost of 1% of total investment costs (Consentec & IAEW, 2011).

7.3 Biomass and biogas

Biomass electricity generation is mainly based on the combustion of solid biomass, biogas and biodegradable fraction of municipal solid waste AEBIOM (2011). Over the last decades, electricity from biomass became the second driver for the growth of the renewable sector in the EU besides wind energy. Especially the solid biomass and biogas sectors contribute significantly to this development with a share of more than 80 per cent (64.8 TWh) of the additional biomass generation since 1999.

7.3.1 General description of the technology

Power generation from biomass takes place via co-firing in fossil fired power plants, direct combustion of biomass in conventional power generation plants and as cogeneration or combined heat and power (CHP) generation[25].[26]. The main driver behind cogeneration is the fact that the overall efficiency of generation can be significantly increased by making use of the waste heat which is a by-product of electricity generation. Heat delivered from CHP plants is used for process or space-heating purposes throughout all sectors of economic activity including the residential sector. Thus, given the same amount of final energy demand the need for primary energy can be reduced. This makes even more sense in the case biomass is used as primary fuel due to its high costs. Recently, efforts in applied research to further develop the idea of cogeneration to tri-generation[27] and com-

[25] IEA report „Biomass for power generation and CHP“

[26] COGEN Europe (http://www.cogeneurope.eu)

[27] Ahrenfeld (2012)

bined cooling, heating and power[28] (CCHP) have made progress and offer promising opportunities to the energy-efficient and flexible operation of future energy systems.
Figure 22 gives and overview on the share of biomass fuels and biomass-fired CHP plants in the EU. It can be seen that on average the main fuel used is solid biomass, followed by biogas and MSW. About 50% of biomass electricity is generated in electricity-only, the remainder in CHP plants. The share of fuels in different countries directly correlates to the availability of resources. In the Nordic countries as well as in Austria, Bulgaria, Hungary and Poland there is a high share of solid biomass due to their huge forest resources and the fact that there exists a strong forestry industry generating large amounts of waste biomass that can be used as fuel in cogeneration plants, for co-firing in plants that use other fuels as primary fuel. The non-availability of solid biomass and the lack of side products from industry lead to higher shares of other types of biomass feedstock in other countries. Country-specific particularities like agricultural traditions – e.g. cultivation of maize in Germany – lead to a higher attractiveness of biogas production. However?, the composition of fuels and the implementation of cogeneration units in a country is also a result of structural conditions regarding the distribution and size of the demand for heat and electricity. For example, while plants fired with solid biomass are usually of bigger size, biogas units tend to be small to medium sized. As a result, the distribution of fuels and plant configurations reflects to some part the historic structure of centralised versus decentralised supply of energy within the different countries.

Biomass resources can take a variety of forms and shapes and is processed in many ways which leads to a number of possible utilisation paths. Figure 23 shows exemplarily the main process steps of heat and electricity supply from biomass feedstock. The different biomass resources originate basically from the forestry, agricultural, or industry sector and from different sources of waste, respectively. These resources are collected, stored and transported and are then converted via thermo-chemical, physical-chemical and biochemical methods into the three major fractions solid, liquid and gaseous fuels. Solid biomass consists of agricultural residues, wood wastes as well as residues from forestry, or wood and paper industries, municipal solid waste (MSW), dedicated energy crops and reclaimed wood. Gaseous biomass comprises landfill gas, manure biogas and wastewater treatment biogas.

[28] Wang (2006)

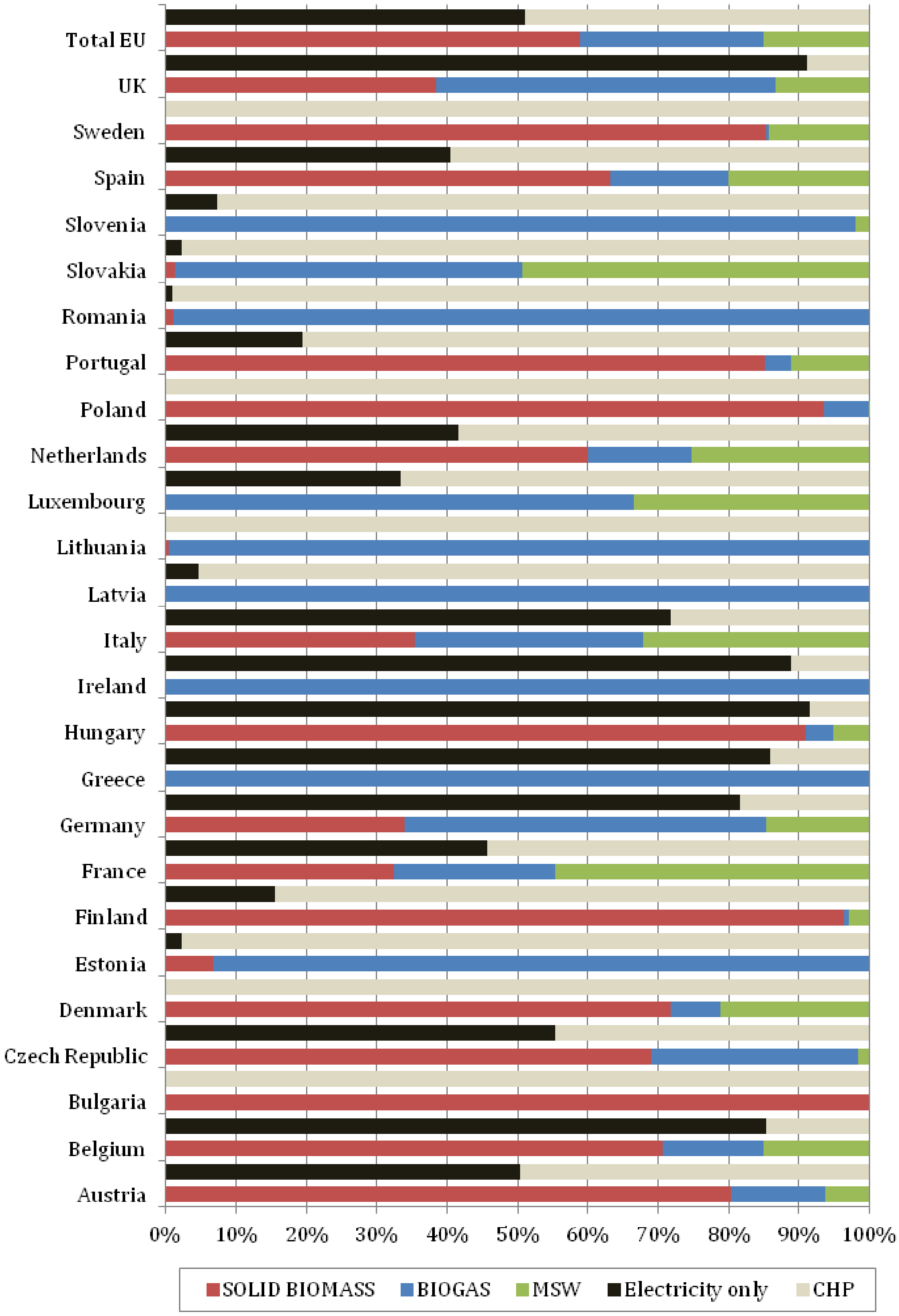


Figure 22 Biomass fuel and biomass-fired CHP share in the EU in 2011 (source: Observ'ER 2011)

Furthermore, the gasification of solid biomass is of increasing interest due to its options. Liquid biofuels are mostly used in the transport sector, but also to fire reciprocating internal combustion engines.

The economic and ecological footprint of certain utilisations paths is fairly different, which raises the need for close investigation of suitable supply chain designs for a given location. Of special interest regarding the interaction of biomass electricity generation with electricity markets is the generation technology in use since it determines the technical characteristics of the power output. Consequently, the most common generation technologies that are suitable to be operated with biomass fuels are addressed within this report. Those technologies are listed in Figure 23 in the red marked process step which represents the stage of combustion. A rough classification of technologies can be made in several ways, based on input fuels, technical maturity, market shares or capacity ranges[29]. The gross capacity being installed consists of so-called conventional prime mover technologies, namely steam turbines, reciprocating internal combustion engines (e.g. diesel and spark ignition engines) and combustion turbines. A second set of promising technologies are micro-turbines, Stirling engines, ORC processes and fuel cells which are especially suitable to be fired with biomass, mainly in gaseous form. Compared to direct combustion, the major advantage of biomass gasification is that the extracted gasses can be used in various power plant configurations.

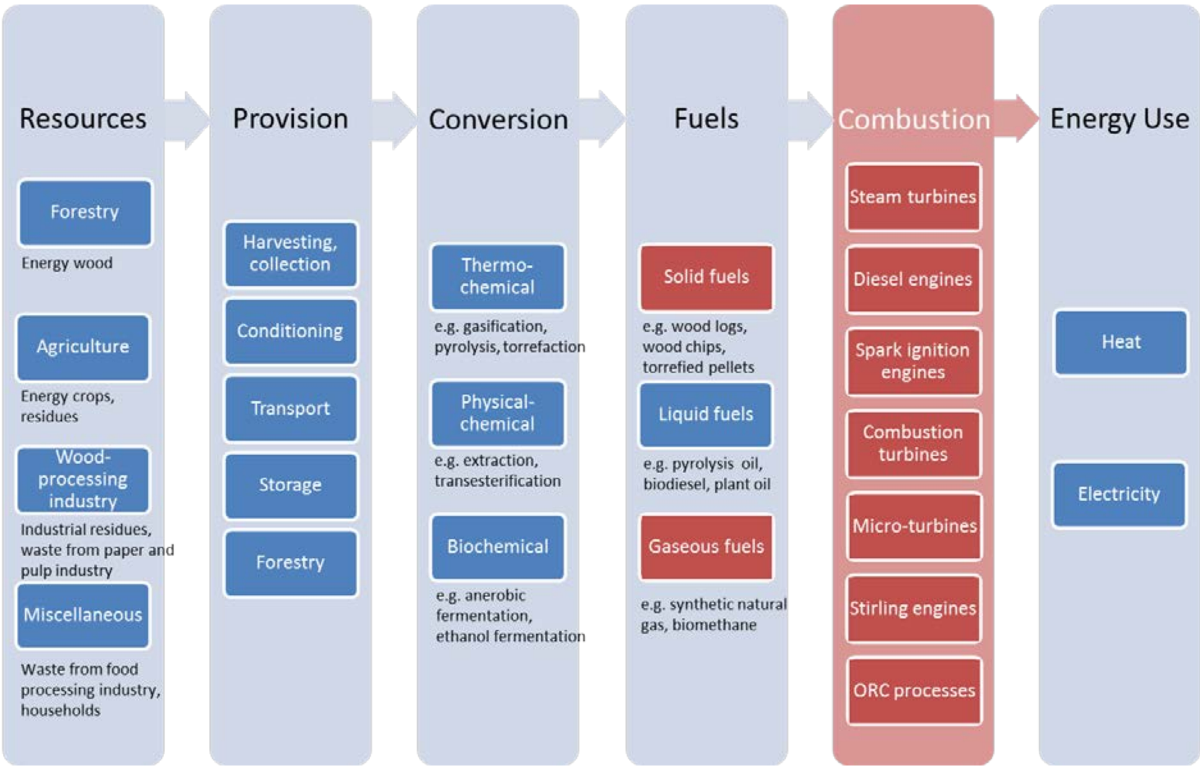


Figure 23 Illustration of the variety of bioenergy utilisation paths. Source: own illustration, adapted from Kaltschmitt et al. (2009)

Table 6 summarise typical parameter value ranges of already realised projects. The parameters are grouped in general, technical, economical as well as environmental classes and represent the relevant characteristics of generation technologies suitable to be fired with biomass fuels. In the following a short characterisation of the technologies will be given based to Wang (2006).

Steam turbines are a mature technology and thus are very reliable and have a long life time given the condition of proper operating and maintenance. With a suitable boiler they can be run on any kind of fuel. Some drawbacks comprise their poor electrical and part-load efficiency as well as a slow start-up time. As a result, steam turbines are more suitable for centralised applications rather than for future application in decentralised power systems. However, new concepts aggregate a set of small-sized turbines in a way that the overall system can be operated with fractional power output and therefore overcome poor part-load behaviour of large-size turbines. Steam turbines are either designed as *backpressure turbines* or as *steam extraction condensing turbines.* Beside others, the major difference is that turbines with steam extraction decouple the power from the heat out-

[29] Wang (2006)

put by respecting a design-specific transfer function. Figure 24 illustrates an example for a simplified transfer function that can be used for modelling those two design options.

Table 6 General parameters of selected electricity generation technologies. Sources: Wu (2006), Vambuka (2007), Obernberger (2003)

Technology / Parameter	Capacity range	Fuel used	Reliability	Life cycle	Availability
Unit	[kW/MW]	[-]	[-]	[yr]	[%]
Steam turbines	50kW - 500MW	Any	Good	25 - 35	90 - 95
Diesel engines	5kW - 20MW	Gas, propane, distillate oils, biogas	Good	20	95
Spark ignition engines	3kW - 6MW	Gas, propane, liquid fuels, biogas	High	20	95
Combustion turbines	250kW - 50MW	Gas, propane, distillate oils, biogas	n.a.	20	96 - 98
Micro-turbines	15kW - 300kW	Gas, propane, distillate oils, biogas	Good	10	98
Stirling engines	1kW - 1.5MW	Any (gas, alcohol, butane, biogas)	Average	10	80
ORC process	100kW - 1.5MW	Fuels with low combustion temperature (e.g. biomass)	High	n.a.	90 - 98
Fuel cells	5kW - 2MW	Hydrogen and fuels containing hydrocarbons	n.a.	10 - 20	90 - 95

Table 7 Technical parameters of selected electricity generation technologies. Sources: Wu (2006), Vambuka (2007), Obernberger (2003)

Technology / Parameter	Overall efficiency	Electrical efficiency	Part load performance	Power to heat ratio	Output heat temperature
Unit	[%]	[%]	[%]	[1]	[°C]
Steam turbines	60 - 80	7 - 20	9.5	0.1 - 0.5	Up to 540
Diesel engines	65 - 90	35 - 45	Good	0.8 - 2.4	a
Spark ignition engines	70 - 92	25 - 43	Good	0.5 - 0.7	a
Combustion turbines	65 - 87	25 - 42	Fair	0.2 - 0.8	Up to 540
Micro-turbines	60 - 85	15 - 30	Fair	1.2 - 1.7	200-350 (b)
Stirling engines	65 - 85	~40	Good	1.2 - 1.7	60-200
ORC process	70 - 95	10 - 18	16.5 - 18	0.16 - 0.2	n.a.
Fuel cells	85 - 90	37 - 60	Good	0.8 - 1.1	260-370

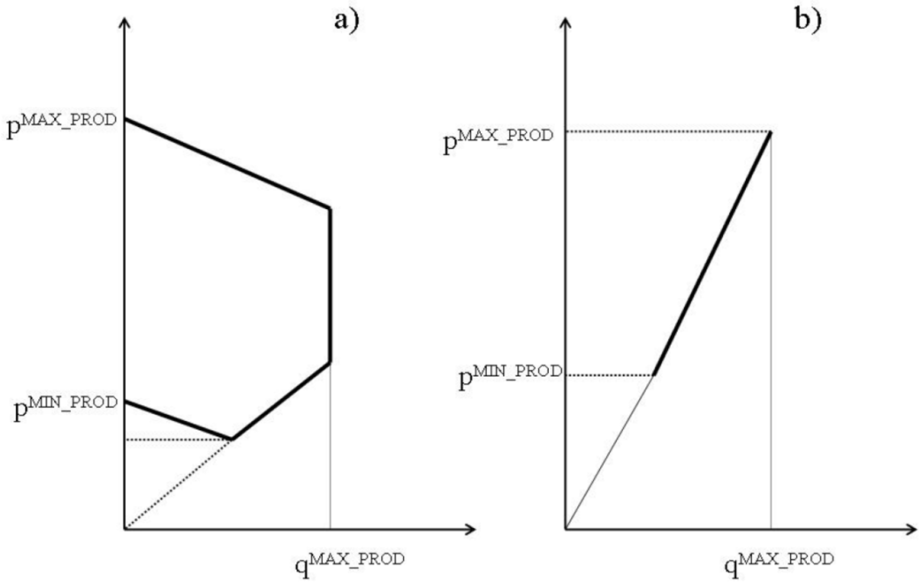


Figure 24 Simplified PQ-chart (P… Power / Q… Heat) for a) extraction-condensing turbines and b) back-pressure turbines (Source: Meibom (2007))

Diesel engines and spark ignition engines fall under the category *reciprocating internal combustion engines*. Diesel engines are run with diesel, but can also use other petroleum products, such as heavy fuel oil or biodiesel. Spark ignition engines are mainly operated with natural gas, as an alternative they can be fuelled by bio- or landfill gas. The technology is widely used in applications below 1MW and characterised through a fast start-up capability, good operating reliability and high efficiency at partial load operation. The major drawbacks of the technology comprise their relatively high operating noise, high operation and maintenance costs due to a large number of moving parts and a high degree of emissions.

Table 8 Economical and environmental parameters of selected electricity generation technologies. Sources: Wu (2006), Vambuka (2007), Obernberger (2003)

Technology / Parameter	Average investment costs	O&M costs	CO2 emissions	NOx emissions	Noise
Unit	[$/kW]	[$/MWh]	[kg/MWh]	[kg/MWh]	[-]
Steam turbines	1000 - 2000	0.004	c	c	Loud
Diesel engines	340 - 1000	0.0075 - 0.015	650	10	Loud
Spark ignition engines	800 - 1600	0.0075 - 0.015	500 - 620	0.2 - 1.0	Loud
Combustion turbines	450 - 950	0.0045 - 0.0105	580 - 680	0.3 - 0.5	Loud
Micro-turbines	900 - 1500	0.01 - 0.02	720	0.1	Fair
Stirling engines	1300 - 2000	n.a.	672 (d)	0.23 (d)	Fair
ORC process	380	0.001	very low [20]	very low [20]	n.a.
Fuel cells	2500 - 3500	0.007 - 0.05	430 - 490	0.005 - 0.01	Quiet

Combustion turbines are frequently used in larger-scale cogeneration units due to their high reliability and large range of power. Smaller-sized turbines below 1MW have so far been uneconomical because the electrical efficiency of such turbines decreases with its size. Due to their high output temperature combustion turbines are often combined with steam turbines to so called combined-cycle gas turbines (CCGT). Combustion turbines require premium fuels, e.g. natural gas, but can be operated with biogas as well. Compared to steam turbines they are easier to install, are less area intensive and have lower capital costs. In comparison to reciprocating engines the maintenance and operations costs are lower, but so is their electrical efficiency. The efficiency of combustion turbines is also sensitive to the location and time in terms of ambient temperature and altitude.

Micro-turbines are the extension of combustion turbine technology to small scale applications. They require natural gas, diesel, gasoline or other similar high-energy fuels as input. Research on biogas is ongoing. The main field of application is distributed energy systems, whereas the turbines are operated not only by power producers, but in future applications also by consumers, including industrial, institutional, commercial and residential users of electricity. Beside the electricity generated also the heat can be utilised to produce low-pressure steam or hot water. A striking characteristic of this technology is its flexibility to combine small-scale individual units to large systems of multiple units. Further the noise is lower compared to engines of comparable size and due to lower combustion temperatures the NOx emissions are lower. The main drawbacks are the high first costs and a relatively low electrical efficiency which is highly sensitive to changes in ambient conditions as well.

Stirling engines are still at the stage of development and up to now only a few research and demonstration projects are in operation. In comparison to internal combustion engines this technology is based on external combustion. Consequently, any kind of fuel, e.g. gasoline, alcohol, natural gas, butane, biomass) can be used to generate the necessary heat which then drives the thermodynamic process. Because of its concept Stirling engines produce low noise and have low air emissions. Since it is a premature technology the investment costs are still high and no statistical data on reliability are available.

ORC processes are based on a similar process than that one of steam turbines, with the difference that the working fluid is not water, but an organic working medium (e.g. iso-pentane, iso-octane, toluene or silicone oil). The working fluids of ORC processes vaporise at lower temperatures than water and as a result the process can be fired with lower input temperatures, which is especially beneficial for the use of biomass as input fuel. The ORC technology is still under development and shows therefore increased investment costs in comparison to other comparable technologies. However, the environmental indicators of the technology are low and demonstration projects have already shown promising results.

Fuel cells comprise a number of different technologies which have in common that they are static and consist of no moving parts and are therefore quiet during operation. The main focus of application lies in the transport sector, but also the power generation sectors seems to be a promising field of application for that technology. In general, fuel cells show high electrical efficiencies and good part-load behaviour as well. Since the technologies are still under development there is not much experience with the use of biomass fuels in combination with fuel cells. Basically, phosphoric acid fuel cells (PAFC), molten carbonate fuel cells (MCFC) and solid oxide fuel cells (SOFC) could be considered to be operated with some sort of biomass fuels.

7.3.2 Current state and potentials in the EU

To get an overview on the current state and the estimated future potential of biomass power generation within the EU the following graphs provide a comprehensive summary of available data from different sources.

Figure 25 gives an overview on the current share of total CHP generation on the gross electricity consumption and the corresponding share of biomass fired CHP units. It can be seen that the countries fall into two groups. The one group of countries currently generate approximately one third up to half of their total power generation with CHP units. The other group lie in the range below 20 per-cents and are distributed more steadily. The share of biomass units corresponds to the already mentioned country-specific availability of biomass and the existence of biomass processing industries. For this reason, it can be seen that especially the Nordic countries, e.g. Sweden and Finland, but also Austria and Portugal occupy a distinguished position within Europe.

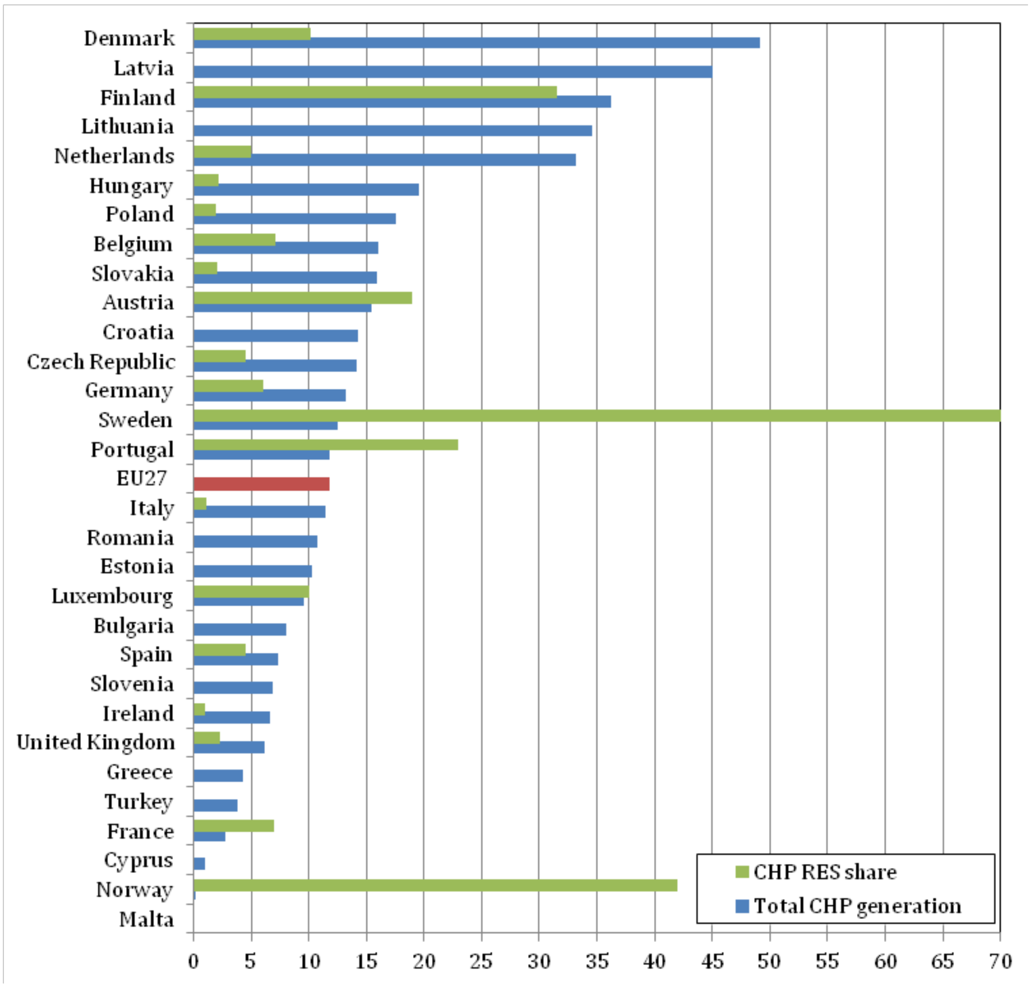


Figure 25 Combined heat and power generation, 2010 (in % of gross electricity generation). Source: own illustration based on Eurostat and IEA (2010)

In terms of currently installed and planned CHP capacity, the EU has carried out an extensive survey within the CODE project[30]. Within this study the Member States were asked to provide information on their existing stock of CHP units and their estimations on the economic potential of cogeneration in 2020. Figure 26 summarises the results of the consultation. It can be seen that Germany leads by far with regard to existing capacity. It is followed by Denmark, Netherland and Poland which do have installed approximately 10GW of capacity. Germany also reported the highest estimated potential till 2020. Whereas Denmark and Netherlands do not see any additional potential, especially the United Kingdom, Poland and Italy estimate that a doubling of its CHP capacities would be still economically viable. By contrast, Figure 27 and Figure 28 summarise projections and modelling results of EURELECTRIC and PRIMES scenarios, respectively.

[30] http://www.code-project.eu

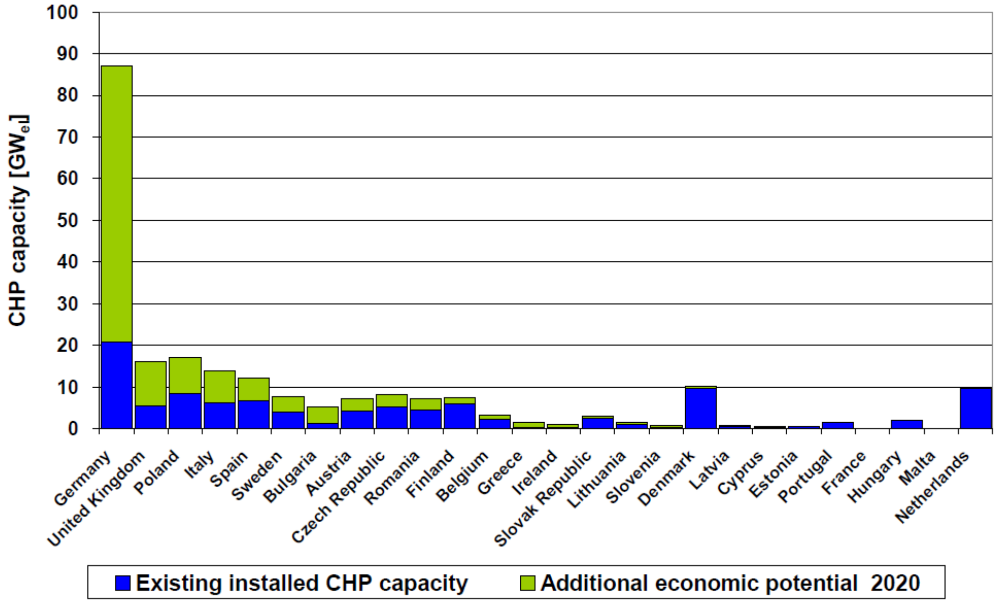


Figure 26 Existing installed cogeneration capacity in the EU and reported additional economic potential in 2020. Source: CODE (2011)

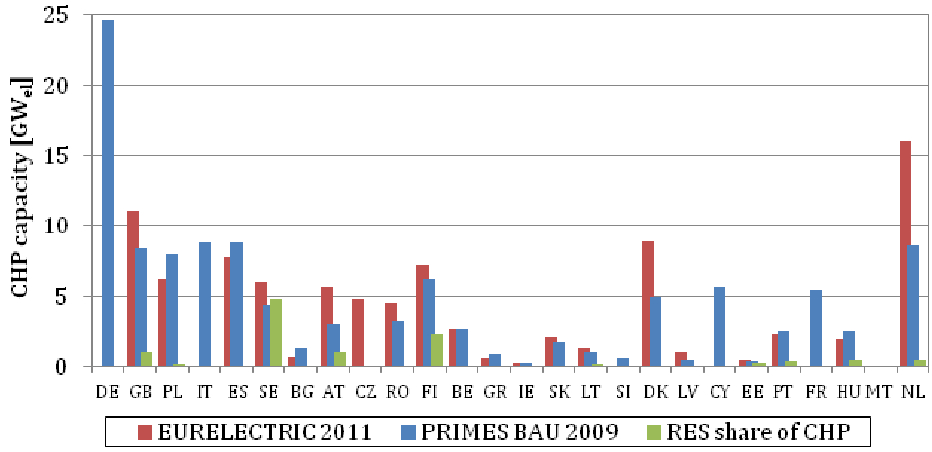


Figure 27 Forecasted installed CHP capacity and corresponding RES CHP-share of the EU in 2020 according to EURELECTRIC (2011) and PRIMES BAU (2009).

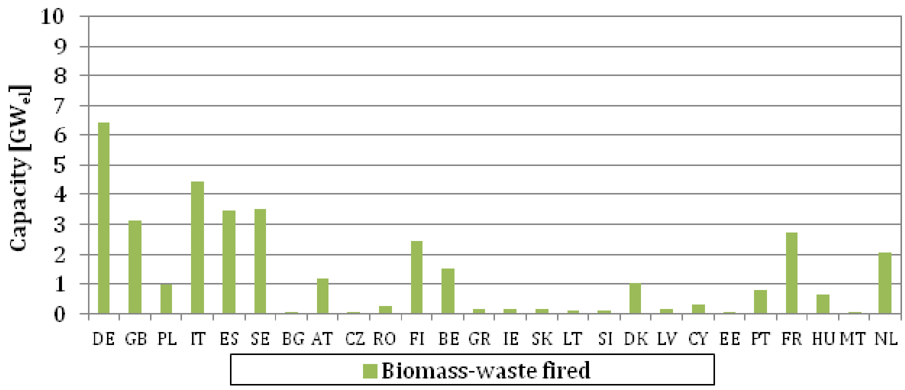


Figure 28 Electricity generation from biomass-waste in 2020 according to PRIMES BAU (2009).

Beside the case of Denmark, where only half the capacity than currently installed as reported by the country itself is assumed to be there in 2020, the PRIMES scenario fairly precisely reflects the current situation as modelling result for 2020. Under the assumption that PRIMES use the same input data as reported by the CODE project, this implicitly means that no significant growth in CHP capacities are estimated by PRIMES in its BAU scenario till 2020. However, the EURELECTRIC forecasts indicate a stronger growth in Denmark, Netherland and Austria than PRIMES, whereas the forecasts for the other countries more or less lie in a similar range[31]. The RES-share of CHP capacities in Figure 27 – based on EURELECTRIC forecasts – indicates that only a few large-size biomass-fired plants are expected in Europe till 2020, primarily in Sweden and Finland. However, it is basically possible to switch the input fuel from fossil to biomass fuels in most plant configurations. Thus, according to the availability and future cost development of biomass resources the available potential for cogeneration could be basically utilized by biomass as well.

Figure 28 depicts the power generation from biomass-waste in the EU countries in 2020 according to the PRIMES BAU scenario. It can be seen that a significant amount of power is being estimated to come from biomass residues from various industry sectors and urban areas.

7.3.3 Characteristics of the technology

Cost structure and total generation costs

The levelized power generation cost of biomass CHP plants range from 68.94 €/MWh$_{el}$ (50 MW$_{el}$ Biomass integrated gasification combined cycle (BIGCC)) to 311.14 €/MWh$_{el}$ (wood chip boiler with 35 kW$_{el}$ Stirling engine) under the assumption that all generated heat can be sold for 20 €/MWh$_{th}$ throughout the year[32]. When assuming that the generated heat is only utilised 3000 hours per year and is not profitably deployed elsewhere the rest of the year, the costs are in the range of 84.14 to 320.67 €/MWh$_{el}$ for the same technologies. Corresponding costs for biomass power plants without cogeneration are higher because the additional profit from selling heat usually offsets the additional costs incurred by the necessary upgrade requirements of the plant.

The costs of comparable conventional technologies range from 41.41 (hard coal-fired condensing power plant) to 78.18 €/MWh$_{el}$ (natural gas CCGT with CHP) when again assuming a heat utilisation of 3000 hours a year. Thus, biomass based technologies are still considerably more expensive than conventional technologies.

Figure 29 provides an overview on the share of fixed and variable cost categories of total costs for different biomass-fired CHP plants. In contrast, the corresponding shares for two conventional reference power plants are also shown at the bottom of the figure.

The share of variable costs (fuel plus O&M costs) compared to fixed costs (capital costs) is a decisive factor to determine the optimal (i.e. least-cost) unit-commitment of various power plants throughout a year[33]. In competitive markets every supplier is forced to offer its generation capacity at marginal costs to the market. In a first approximation the marginal costs may be considered to be equal to fuel and O&M costs. A certain generation unit is dispatched when the market price is greater than or equal to the marginal costs of the unit, unless technical restrictions prevent an operation at this point in time. In order to ensure economical operation the cumulative marginal return resulting from the difference between marginal costs and market prices needs to cover the fixed costs of the

[31] Due to the fact that EURELECTRIC did not provide data for every country a comprehensive one-to-one comparison is not possible.

[32] Kalt (2012)

[33] A common practice to determine the least-cost dispatch of dispatchable power generation portfolios is the construction of *Screening-curves*.

unit. Consequently, power plants with a high share of fixed costs on total costs need to be dispatched most of the time throughout the year to cover their fixed costs. In contrast, units with a high share of variable costs require fewer operating hours per year to cover their costs. The corresponding generation units are called *base-load* and *peak-load* units[34].

The reference units in Figure 29 represent a typical base-load unit (CPP) and a typical peak-load unit (CCGT). It can be seen, that beside plant oil CHP plants the share of capital costs are in the range or even higher than the share of the base-load reference plant. This is critical because due to the increasing share of variable (i.e. non-dispatchable) renewables in common electricity markets the operating hours of dispatchable power plants will be systematically reduced.

[34] In this connection, it is often made a further differentiation into *medium-load* units as well.

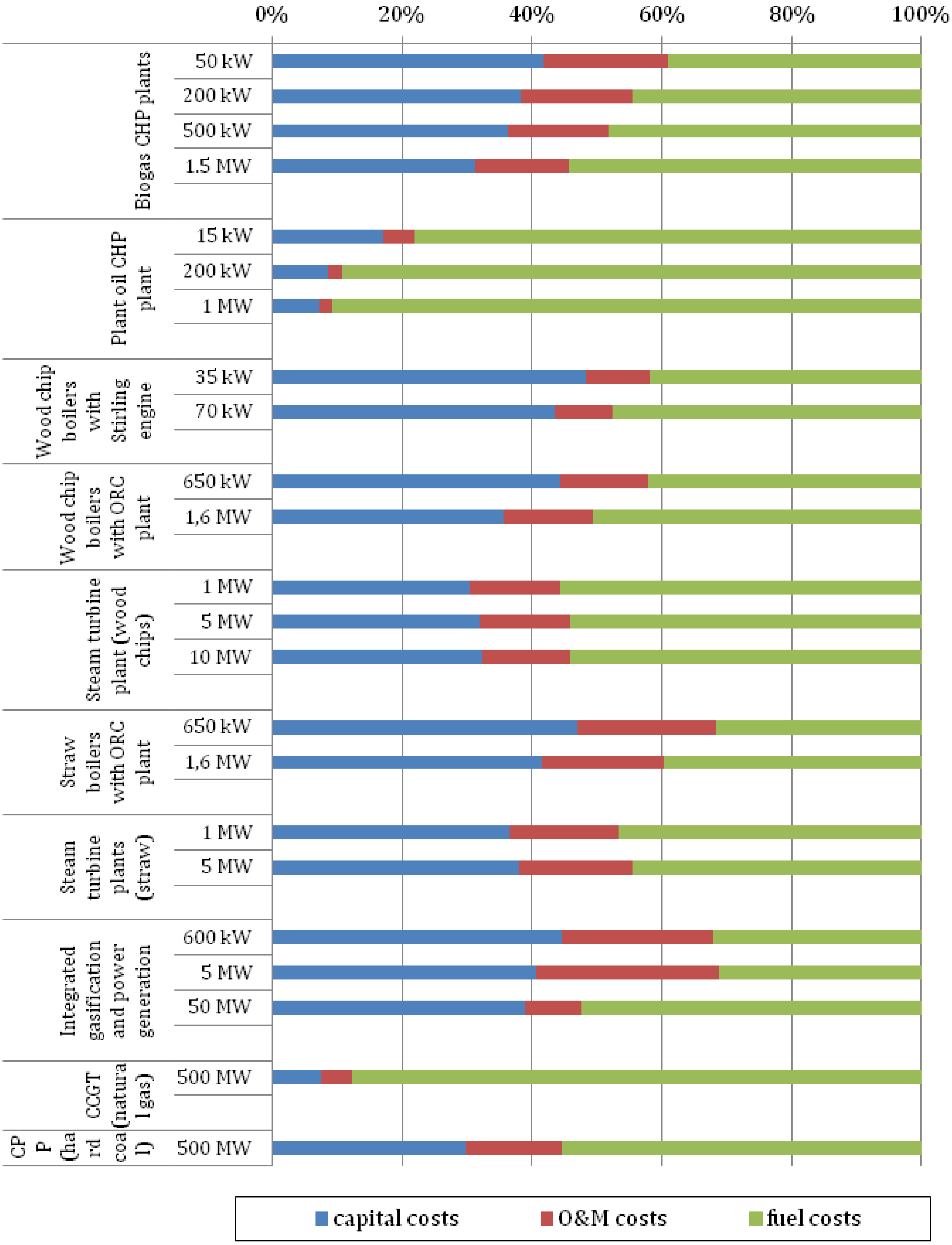


Figure 29 Share of different cost categories of biomass-fired CHP plants on total costs. Kalt (2012)

Dispatchability, flexibility and predictability

Electricity-only biomass generation units are fully dispatchable and their power output flexibility is primarily determined by the technology used (see Table 7). Small-sized turbines and engines can typically start-up within a few minutes[35]. Currently, research is ongoing to accelerate the start-up and flexibility of larger power plants. For example, the start-up of large combined cycle units can be reduced by 60% when using a heat recovery system to preheat the steam turbine during start-up[36].

Combined heat and power (CHP) generation units have to be differentiated according to their mode of operation. Basically, they can be operated in a *heat-driven* mode and an *electricity-driven* mode. When operated in heat-driven mode, they are obliged to supply a certain amount of heat to their customers. In most designs the heat output is via a heat-to-power ratio directly coupled to their electricity output, which means that the heat demand determines the electricity output at every point in time. Due to the fact that biomass-fired CHP units are often receiving a feed-in-tariff per MWh electricity, the plants are equipped with peak-load boilers and are designed to operate in base-load operation. There are a few measures to decouple the heat- from the electricity-production and enable CHP units to act more price-oriented in electricity markets, while still maintaining their obligation to deliver a certain amount of heat. For example, there are different possibilities to modulate the power-to-heat ratio of CHP units. Especially, the variation of the extracted steam mass flow in extraction condensing steam turbines is one promising measure. Furthermore, existing power plants can be retrofitted via installing a thermal storage to store excess heat in times of high electricity prices and low heat demand and vice versa, respectively.

Figure 30 illustrates exemplarily the modelling result of an application of a thermal storage in connection with a CHP backpressure steam turbine for one week in September. The power generation follows the price signals in the spot market, whereas the thermal storage balances the heat output.

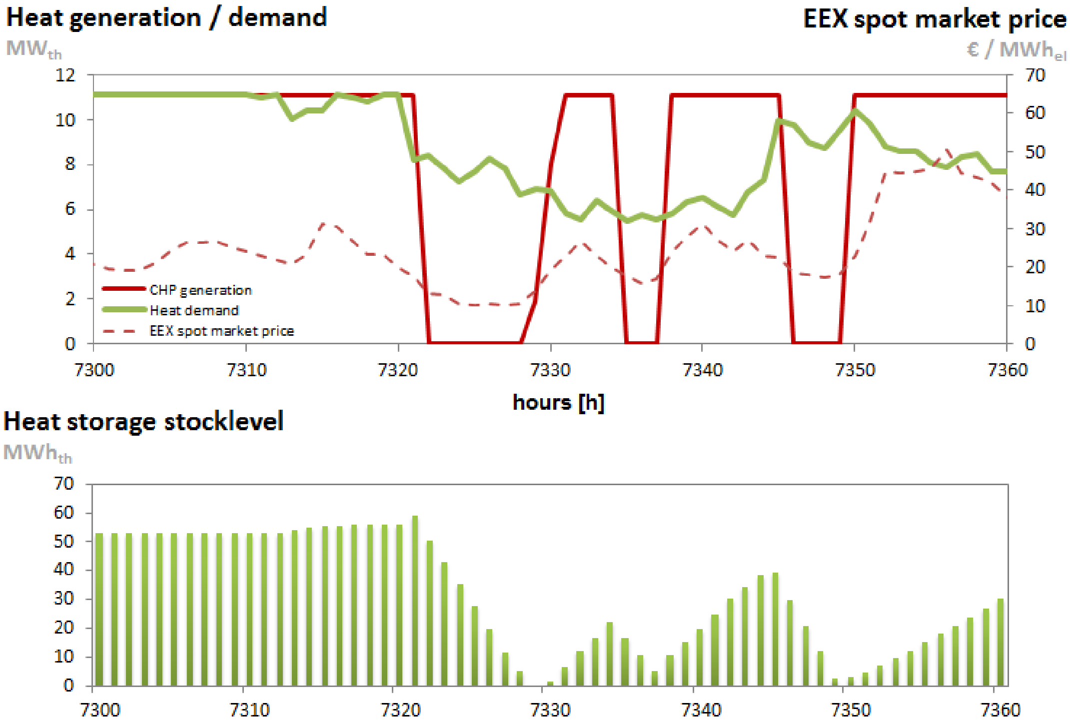


Figure 30 Heat generation in heat-driven mode (green) versus generation in electricity-driven mode with heat storage (red) and corresponding heat storage stock level. (Source: Ortner (2012))

[35] Gerhardt (2009)

[36] Henkel (2008)

Voltage Level

Basically, the voltage level at which a certain generation unit is connected depends on the generation capacity of the unit. As depicted in Table 6, the capacity of common biomass units can range from a few kW up to several MWs. Manufacturers supply power generation units in multiple voltage sizes. Due to technical reasons, the generator voltage is inversely proportional to the size of the generator. This implies that large-size power plants are equipped with generators of high voltage output to avoid high generator costs. This is reasonable since low-voltage grids are distribution grids and the power produced from small biomass? generators is consumed locally most of the time. This so called *decentralised* or *distributed* generation has to deal with some further issues with regard to system stability. Due to the fact that their power output does have an influence on the voltage level, they have to respect additional restrictions in their operation. Grid management techniques to handle increased decentralized generation are currently subject to intense research.

Availability

Current experience in the operation of biomass-fired power plants shows that there are still process steps and design elements that have to be improved and thus the availability is lower than for conventional technologies[37]. One of the main issues to be tackled is to ensure a constant quality of biomass resources over several deliveries. For example, changing amounts of water as well as unwanted ingredients in the input fuel often cause unplanned outages or problems during plant start-up. Additionally, due to the less clean combustion of biomass maintenance must be more frequent. Basically, if such premature problems can be overcome biomass power plants are able to reach the same availability as conventional plants with the same technology.

Ability to deliver ancillary services

Historically, almost exclusively the transmission system operators (TSOs) accounted for the provision and management of ancillary services. These comprise frequency control, voltage control, congestion management, improvement of voltage quality, network restoration, optimisation of grid losses and the capability to provide fault-ride-through. In future, with a higher share of decentralised generation, also distribution system operators (DSOs) will have to increase their efforts to maintain system stability. Distribution generation, especially from several renewable sources, do have a great technical potential to provide ancillary services as well. Table 9 gives an overview on the technical suitability of CCHP units to deliver those services.

Table 9 Technical potential of CCHP units to provide ancillary services according to their grid coupling technology (source: Braun (2006))

	Grid Coupling Technology	Thermal-driven	Electricity-driven
Frequency control		No	++
Voltage Control,	Inv	+	++
Congestion Management,	SG	+	++
Optimisation of Grid Losses	AG	No	-
Improvement of Voltage Quality	Inv	++	++
	SG	No	No
	AG	No	No
Black Start	Inv	No	++
	SG	No	+
	AG	No	No

[37] Obernberger (2005)

Islanded Operation	Inv	No	++
	SG	No	++
	AG	No	No
Fault-Ride-Through	Inv	++	++
	SG	-	-
	AG	--	--

The type of grid coupling technology used is crucial to the delivery of ancillary services for all technologies, because it determines the degrees of freedom to adjust reactive power, frequency and voltage output. Inverter (INV) offers the highest degree of freedom and can adjust all parameters independently and offer all types of services. Asynchronous generators (AG) do offer the worst capability due to the fact that they easily risk to loose synchronism with the grid and can provide reactive power only with additional external equipment. However, when asynchronous generators are designed as double-fed asynchronous generators (DFAG) they have a restricted capability to provide reactive power as well. Synchronous generators (SG) can adjust their reactive power and output voltage and thus can participate in voltage control, congestion management and optimisation of grid losses, but have also fewer capabilities to offer fault-ride-through.

In the case of the generation technology itself CCHP units have to be differentiated according to their mode of operation, namely if they are thermal-driven or electricity-driven. If they are program-responsible for the delivery of a certain demand of heat, they nearly have no possibility to actively offer ancillary services in the electricity market. However, if they are electricity driven they have a great potential to participate in all the relevant services to maintain the operation of the system.

7.4 Hydro

Hydro electricity still contributes the highest share (69%) among renewable technologies to European electricity supply. In 2009, hydro power contributed 16% to total European electricity generation (EU 27 plus Croatia, Iceland, Norway, Switzerland and Turkey)(Eurelectric, 2011). In some European countries the contribution of hydro power is substantially higher i.e. in Norway (~95%), Austria (>60%),Latvia (~50%) or Portugal (~18%).

In order to describe the hydro power technology and derive implications for electricity markets and grids, it is necessary to distinguish between three main technology types:

Run-off-river power plants are operated by using the velocity of the water flowing in a river. No storage or reservoir forms part of a typical run-off-river plant. Therefore, the generation profile of these plants is highly dependent on weather and seasonal patterns.

Reservoir plants include a reservoir to store the water before using it for electricity production. The reservoirs are usually fed by both precipitation and a river inflow. Ti a certain degree, reservoir hydro plans can be used to balance electricity output according to demand and supply fluctuations. However, their total production also depends on water availability according to seasonal and weather patterns.

Pumped storage power plants have an important role in storing electricity generated from other sources. These plants include an upper and lower reservoir and a pump that can move water from the lower reservoir back up to the upper reservoir. Thus, the potential energy stored in the water can be used to produce electricity more than once. Pumped storage power plants reach a roundtrip efficiency of up to 80% which is very high compared to other forms of electricity storage like hydrogen or methane. Precipitation and river-inflows into the upper reservoir can increase the plants' electricity output.

Several countries plan to increase their installed capacity with a special focus on pumped storage capacity. Norway, often considered as Europe's hydro battery due to its large installed capacity of reservoir hydro has so far only one functional pumped hydro plant. Hydro power plants can reach efficiencies higher than 90%, for pumped hydro plants the roundtrip efficiency is almost 80%:

7.4.1 Characteristics of the technology

Cost structure and total generation costs

As for wind and solar energy, investment costs are the most important cost component of hydro plants. A study of Austrian hydro plants shows investment costs of 760 to 7100€/kW. The high variation is due to the fact that investment costs for hydro plants are highly dependent on the location. Costs increase at locations with lower height differences and lower installed capacities. 70% of investment costs are construction costs, 20 to 30% are costs for mechanical parts (turbine, generator etc.) and 5 to 10% for electro technical components. The remainder are costs for planning, permits etc. In addition, costs of ecological compensation can some up to about ten to 20% of investment costs. Yearly operational costs make typically make up around 2% of investment costs. Based on an interest rate of 4.5% p.a., a lifetime of 70 years for the building part and of 40 years for the mechanical part, electricity generation costs for hydro plants are rather low at between 0.02 und 0.083 €/kWh. Generation costs decrease with higher height differentials and bigger installed capacities. However, assumed full load hours, interest rates and life times have a high influence on calculated levelized costs of electricity production as is the case for all technologies but especially for those with high initial investment (Strom aus Wasserkraft, nn,ny). A Spanish case study for a small hydro power plant (Alonso & Tristan, 2011) shows levelized generation costs within the Austrian range of 5.1 €c/kWh. Eurelectric (2011) shows figures from a meta study by the International Panel on Climate Change between 2 and 15 €c/kWh with a median at around 5€c/kWh. The European Small Hydro Association (ESHA, 2012) finds similar figures for small hydro plants of 2 to 14.5 €c/kWh. Thus, hydro offers a relatively cheap source of renewable electricity. There is however no expectation of considerably sinking generation costs for the future as hydro electricity is considered a mature technology.

Dispatchability, flexibility and predictability

The three different kinds of hydro power plants have considerably different degrees of dispatchability. Electricity generation from run-off-river plants depends exclusively on precipitation and seasonal patterns like melt water etc. The plant's output can only be regulated downwards. Reservoir hydro plants are very dispatchable in contrast as electricity can be generated whenever water is available in the reservoir and the reservoir is used as energy storage. However, as shown by electricity shortages in highly hydro-dependent Brazil in dry years or by the variable yearly Norwegian electricity output (Ehlers, 2011), also electricity generation from reservoir hydro is ultimately dependent on water availability and precipitation regimes. The case for pumped hydro plants is different. As water can be pumped back into the upper reservoir and reused for generation, their dispatchability is not dependent on weather patterns. Pumped hydro plants must however be considered more as a storage option then a renewable generation technology.

Figure 31 shows the monthly electricity output of the different plant technologies for Germany in 2011. It can be seen that all technologies show seasonal variations. Interestingly, in the case of run-off-river plants, electricity generation was highest in Jul and August which does not at all correspond to the yearly demand profile. Figure 32 shows total output from hydro plants in Germany over three years. It becomes apparent that output tends to be higher in summer months. However, yearly variations of this generation pattern are considerable. Groiß & Boxleitner (2011) analyze electricity output from hydro plants between 1994 and 2006. Their analysis reveals considerable variation of output between years but also between regions – in every year observes some regions produce above their long term trend others below. Variations in total production are reduced considerably over a larger geographical area.

In general, hydro plants (especially reservoir hydro and pumped hydro plants) can react very quickly and flexibly to changes in electricity demand. The plant can start from zero to full output in a few minutes. This makes reservoir and pumped hydro plants an attractive technology for integrating renewables. In the case of Denmark and Norway, wind and water already seem to be used as complementary sources (although Green & Vasilakos (2009) find that Danish exports are correlated to tits conventional generation and thus currently Danish coal complements hydro and hydro does not complement wind yet). It can also not be taken for granted that hydro plant operators fulfil a role as back up plants for wind power as (in the case of reservoir and pumped storage plants), plant operators have to consider opportunity costs of electricity generation. As every litre of water can only be used once for generating (without back-pumping) plant operators need to consider electricity price fluctuations when optimizing their output (Ehlers, 2011).

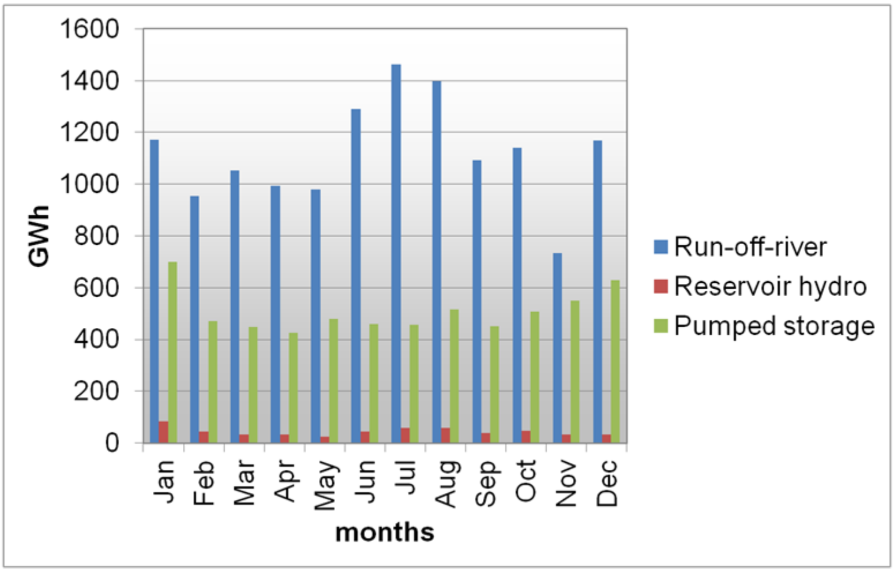


Figure 31 Electricity generation from hydro plants in Germany 2011 (Destatis, 2012)

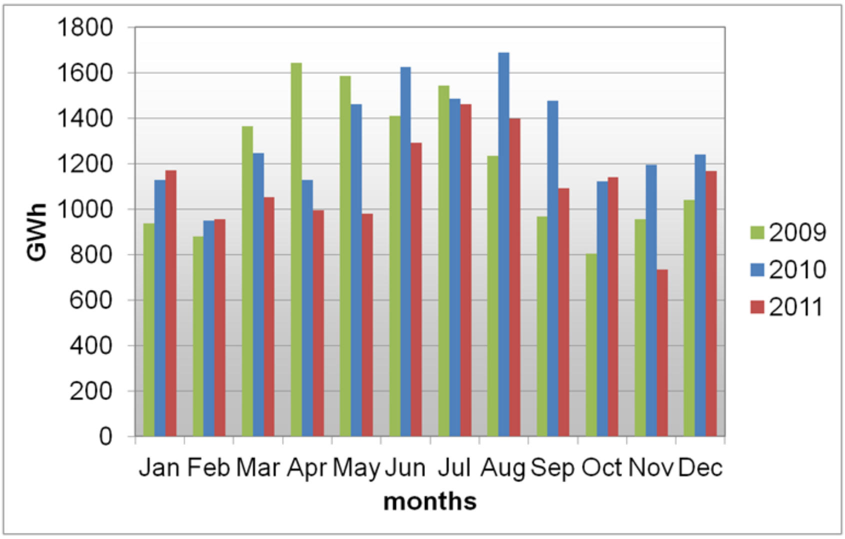


Figure 32 Monthly electricity generation from run-off-river plants in Germany 2009 – 2011 (Destatis, 2012)

Location

Figure 33 gives an overview of the current geographical distribution of electricity generation from hydro power across European countries.

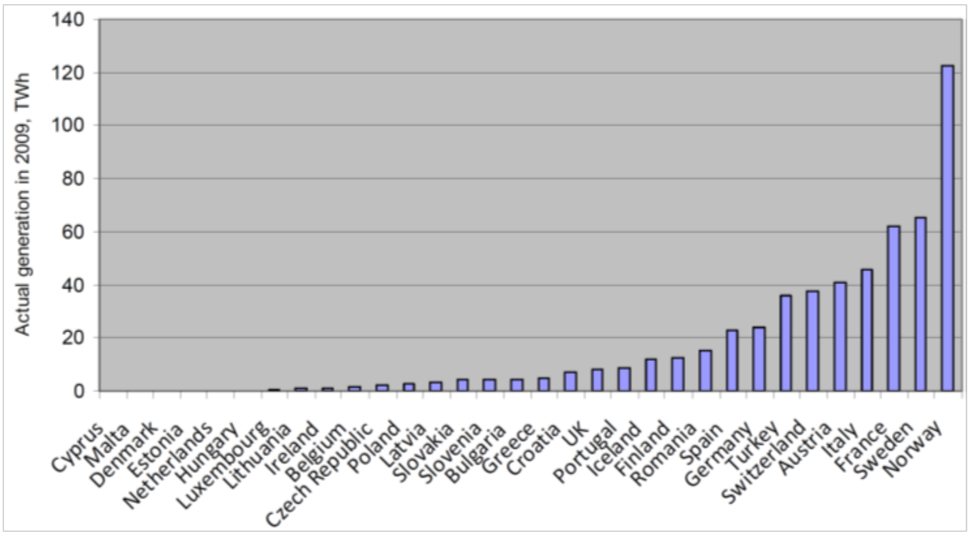


Figure 33 Electricity generation from hydro power (TWh) (Eurelectric, 2011)

The highest generation from hydro power can be found in Northern Europe (Norway and Sweden) and in the Alpine region (France, Italy, Austria, Switzerland and Germany). These regions are often considered as batteries for Europe that could balance fluctuating electricity generation from variable renewable sources if pumped hydro facilities are installed. So far however the installation of pumped storage plants has not been profitable in Sweden and Norway due to the abundant installations of reservoir hydro. Figure 34 gives an overview of currently installed pumped storage plants.

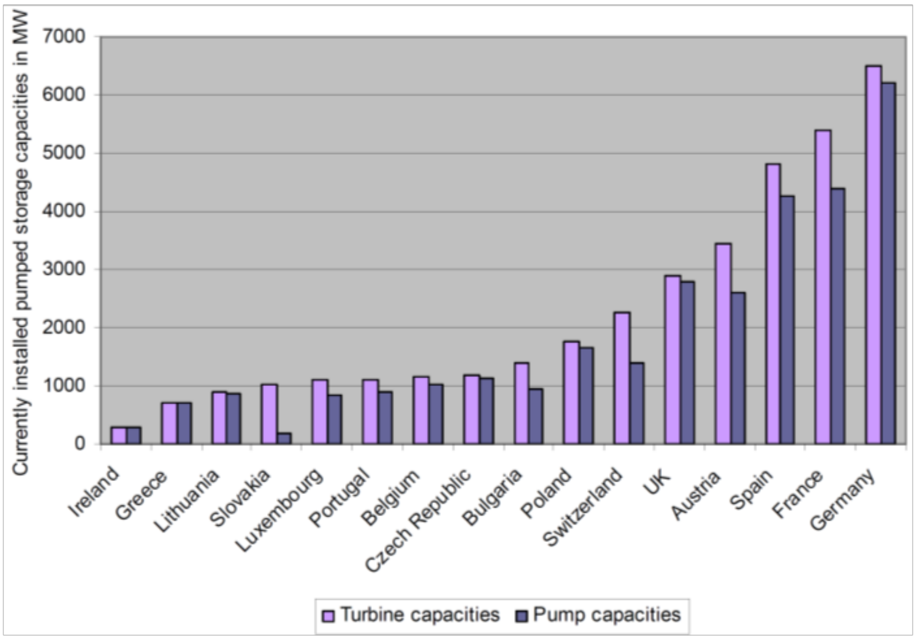


Figure 34 Installed pumped storage capacities (MW) (Eurelectric, 2011)

According to RWE Innogy (2009) only 64% of the overall economically viable European hydro potential is currently used. The potential in the EU-15 is already covered at 72% but unused potential still adds up to 165 TWh/year. In South-Eastern Europe the potential is considerable as well due to the fact that in this region only 41% of economically viable potential are taped so far – the remaining economically viable potential amounts to 145 TWh/year (Deutsche Bank Research, 2010). According to Eurelectric (2011) the remaining technically feasible potentials in the EU-27 amount to 276 TWh/year. If Albania, Bosnia-Herzegovina, Moldova, Former Yugoslav Republic of Macedonia, Montenegro, Serbia, Ukraine, Croatia, Iceland, Norway, Switzerland and Turkey are considered as well the remaining technically feasible potential is 650 TWh/year. However, as can be seen in Figure 35, a big part of this potential comes from Turkey which is not considered in the RWE Innogy estimates. Nevertheless, it can be concluded that there is still important potential for hydropower development in Europe despite the already high degree of usage.

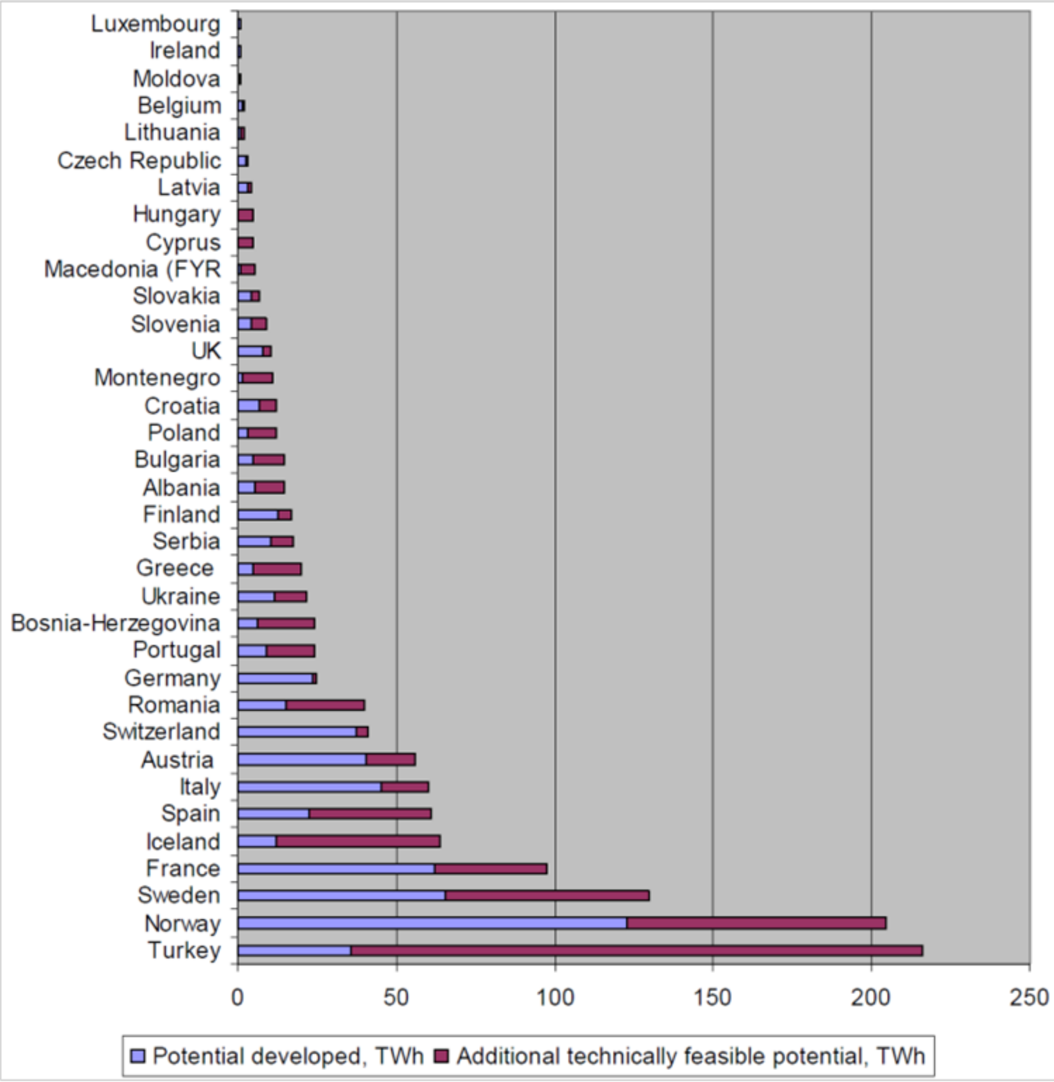


Figure 35 Developed and remaining technically feasible hydro power potential (TWh) (Eurelectric, 2011)

Eurelectric (2011) also collected data regarding planned pumped storage capacities in Europe. The outcome of their enquiry is shown in Figure 36. If all planned projects were realized pumed storage capacities would rise to 30 GW. In addition, the Norwegian potential which was estimated at 10 to 20 GW could be realised (Eurelectric, 2011). Eurelectric (2011) states that more plant specific data would be necessary to assess the possible contribution of pumped storage plants to integrating variable renewables.

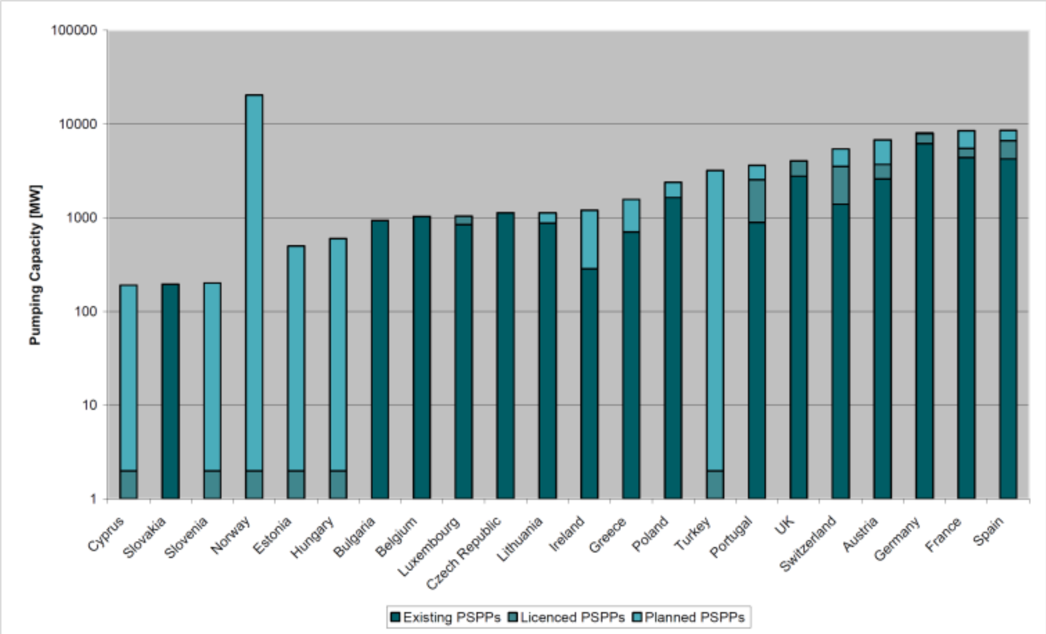


Figure 36 Existing, licensed and planned pumped storage power plants in Europe (MW) (Eurelectric, 2011)

Voltage level

Hydro plants exist in a variety of sizes and are thus connected to different grid levels. Bigger hydro plants including pumped hydro facilities are connected to the transmission grid. Depending on their location in the grid especially reservoir hydro and pumped storage plants can alleviate grid congestion. Many European countries currently support the installation of small hydro power stations (<10 MW) to tap remaining hydro potentials. These plants are typically run-off-river plants and are connected to the distribution grid.

Availability (Capacity credit)

The small hydro power plants considered in the Austrian study mentioned above (Strom aus Wasserkraft) reach between 4100 and 5000 full load hours per year, the big hydro power plants between 2500 (pumped storage) and 5900 full load hours. DENA (2008) assumes 1000 full load hours per year for a pumped storage plant. A case study of a small hydro power plant in Spain reveals an average of 3135 full load hours per year for this plant (Alonso & Tristan, 2011). Kaldellis at all (2005) use capacity factors of around 45% for Greek small hydro power plants.

Thus, for hydro power plants, a higher availability than for most wind plants can be assumed with capacity credits observed of between 36% and 67%. Full load hours for pumped storage plants are typically lower. However, this is not due to availability issues but due to economically and financially optimized behaviour.

Ownership Structure

Big hydro power plants are traditionally owned by big utilities but also (depending on the country) by local utilities.

Ability to deliver ancillary services

Run-off river plants have only little or no storage capacity. Thus, they can only provide very short term storage possibilities and can therefore only provide frequency and voltage control in short timescales (Eurelectric, 2011).

Reservoir power plants are often used as peaking plants and for load following. Depending on the reservoir size, they provide long term large scale energy storage. In addition with their fast response time of around 5 minutes they lend themselves to delivering a broad range of ancillary services including frequency and voltage control as well as black start capabilities and reactive power (Eurelectric, 2011). Pumped storage power plants can provide the full range of services as well (Eurelectric, 2011).

7.5 Overview and summary

In this Annex, the main renewable technologies were presented with their characteristics and their main impacts on electricity markets and grids. The results of the analysis are summarized in Table 10 and Table 11 respectively.

Table 10 show (as explained in the previous sections) that there are substantial differences between the main renewable technologies for electricity generation in terms of the characteristics determining their influence on markets and grids. While PV, wind and run-of-river hydro plants are usually considered under the same heading as weather-dependent variable renewables they differ in terms of their total cost levels, ability to deliver ancillary services, predictability, generation profile, availability and ownership profiles. What they have in common is their cost structure with high capital and low operational costs and their restricted ability to deliver ancillary services. In the case of hydro one always has to keep in mind the differences between run-of-river, reservoir and pumped storage plants. Biomass and biogas are dispatchable technologies and thus seen as different from the variable renewables. Biomass plants have more similarities to conventional plants in terms of their cost structure, predictability, flexibility etc. However, there are also some similarities – e.g. costs of biomass electricity generation are almost similar to costs of PV and the ownership structure is much more diverse than is the case for conventional plants as well.

Table 10 Overview of technological characteristics of main renewable electricity generation technologies

Characteristics	Wind	Solar PV	Biomass/biogas	Hydro
Cost structure	High capital costs, low operational costs (higher for offshore wind)	High capital costs, very low operational costs	Capital costs around 30 to 46% of total costs depending on technology; fuel costs 30-55%	Relatively high capital costs, low operational costs; opportunity costs for reservoir and pumped storage plants
Total generation costs	Levelized costs: Onshore wind: 4-12 €c/kWh Further cost reductions expected	Levelized costs: 15-40 €c/kWh Further considerable cost reductions expected	Levelized costs: 7-31 €c/kWh	Levelized costs: 2-15 €c/kWh No substantial cost reductions expected
Dispatchability and flexibility	Restricted; fast curtailment and reduction of ramp rates possible for plants with adequate features	Restricted; fast curtailment and reduction of ramp rates possible for plants with adequate features	Comparable to conventional power plants; restricted by heat load (for heat-following CHP plants), availability of raw materials (biogas) and plant architecture	Run-of-river plants with restricted dispatchability; reservoir hydro (restricted by water availability) and especially pumped hydro dispatchable; very fast reaction times

Predictabil-ity	Forecast quality im-proving, especially close to real time	Easier to predict than wind	Dispatchable plant thus good forecast quality	Good day-ahead forecast quality
Location	Offshore; resources unevenly distributed across Europe; in prin-ciple possible every-where (higher costs at bad locations)	Resources best in Southern Europe but generation is feasible everywhere; mostly decentralised gener-ation	CHP plants: close to heat load; otherwise: proximity to raw material preferable	Best resources in Alpine region, Northern Europe, Pyrenees; possible along rivers
Voltage level	Low to high voltage grid depending on size of wind park; offshore wind at high voltage	Mostly rural low volt-age grid; bigger plants connected to higher level grids	Low to high voltage grid depending on plant size	Big plants connected to high voltage grid
Generation profile	Fluctuating, in Europe typically higher pro-duction in winter than in summer months	Regular seasonal and diurnal pattern	According to heat demand for heat-driven CHP plants; flexible generation for other plants (if not under FIT re-gimes)	Seasonal pattern for run-of-river plants; considerable fluctua-tions between years
Availability (Capacity credit)	5 to 35% depending on location and penetra-tion level	10% (Northern Eu-rope) to 20% (Spain)	Slightly lower than for conventional plants; expected to increase	36 to 67% depending on location and plant design
Ownership structure	Diversified: utilities, cooperatives, private landlords, communes	Highly diversified: households, farmers, communes, utilities	Utilities/local com-munities/farmers and industry	Big plants mostly owned by big and communal utilities
Ability to deliver voltage and frequency control	Possible at slightly higher costs	Possible at slightly higher costs	Possible with some additional investment (e.g. gas storage for biogas plants, heat storage for CHP plants)	Reservoir and pumped storage plants can deliver the full range of ancillary services

The observed differences between technologies also have an impact on the interactions with grids and markets shown in Table 11. PV is the technology with the highest impact on electricity price levels due to its low marginal costs in combination with the good correlation to electricity demand. Wind power also reduces average wholesale prices. But, as wind output is often high at times of low demand the effect is less pronounces given the same amount of electricity generated over the year. In the case of hydro power, at least reservoir ad pumped storage plants include opportunity costs into their marginal costs and thus are not ready to generate at very low prices which reduced their impact for price reduction. Biomass and biogas plants usually have higher than or comparable mar-ginal costs to conventional plants and can thus stabilize the market price (if they are not under a FIT regime).

Volatility of market prices increased especially due to the variable nature of wind generation; PV at current penetration levels rather reduces price volatility due to its limiting impact on peak prices. Hydro power output varies considerably between years and thus decreased investment security for dispatchable power plants whose full load hours will fluctuate accordingly. Biomass and biogas but also reservoir hydro plants can have a stabilizing effect here due to their dispatchability and flexi-bility. Negative wholesale prices can occur due to high wind output in low demand times (without curtailment) but also CHP plants contribute to this effect.

The highest need for intraday trading and balancing is induced by high wind penetrations due to its increasing forecast quality close to real time. Solar PV also increases the need for intraday trading. This is less the case for hydro power as day-ahead forecast quality is good even for run-of-river plants and reservoir and pumped storage hydro can provide additional balancing and intra-day flexibility.

Total generation costs are increased by using high cost technologies such as offshore wind, PV and certain biomass and biogas technologies. However, cost reductions due to deployment can be expected for these technologies. Costs for hydro are low but will probably not decrease any further as the technology is considered mature and many sites are already taken.

Wind and solar increase the need for ancillary services and can only offer these to a limited extent. Biomass and biogas can be used just as conventional plants for providing ancillary services. Reservoir and pumped hydro plants can deliver the full range of services, but not run-of-river plants. Consequently additional measures are necessary to provide system adequacy with high penetrations of wind, solar and run-of-river plants but not for biomass/biogas or reservoir and pumped storage hydro.

All technologies require additional grid infrastructure; and all but hydro (apart from small hydro) contribute to reducing market power in the electricity sector.

Table 11 Overview of impacts on grids and markets of main renewable electricity generation technologies

	Wind	Solar PV	Biomass/ biogas	Hydro
Merit Order Effect	++	+++	-	+
Volatility of whole-sale prices	++	+	-	+
Negative wholesale prices	+	+	+	+
Increased need for balancing and in-tra-day trading	++	++	-	o
Total generation costs	o	++	++	-
Need for ancillary services	+	+	--	o
System adequacy	-	-	++	o
Additional need for grid infrastructure	+	+	+	+
Increase of market power	-	--	--	o

The analysis in this Chapter shows that there are considerable differences in terms of characteristics but also in terms of implications for grids and markets between the different renewable technologies. Therefore, the detailed investigation of impacts of policy pathways on grids and markets during the remainder of the Beyond 2020 project will be based on the projected technology mix and geographical location.