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Power system and market integration of renewable electricity

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Summary. — This paper addresses problems of power generation markets that arise under high shares of intermittent generation. After discussing the economic fundamentals of wind and photovoltaic investments, the paper introduces the concept of the "Merit order effect of renewables". According to this concept electricity prices on wholesale power markets become smaller in periods during which large volumes of wind and photovoltaic generation is available and squeeze out relative expensive gas-fired power generation. The merit order effect of renewables has a couple of consequences. Among others it challenges the profitability of conventional power generation. If such generation capacities are still necessary, at least during a transitory period, a capacity mechanism may be put in place that generates an additional stream of income to the operators of conventional power generators. Another consequence of growing intermittent power generation is the need for concepts and technologies that deal with excess generation. Among these concepts are virtual and physical power storage capacities. In the last parts of the paper models are presented that are able to analyze these concepts from an economic point of view.

1. – Introduction

The last years have seen a strong increase in renewable-electricity generation in many countries. In particular capacities of onshore wind, offshore wind and solar generation are everywhere on the rise. The global potentials of these renewable technologies are large and sufficient to cover the total electricity demand if these technologies could be dispatched according to the schedule of electricity demand. Unfortunately this is not the case. During windy periods all wind generators would produce electricity at the same time. The electricity production of larger wind farms may exceed the regional electricity

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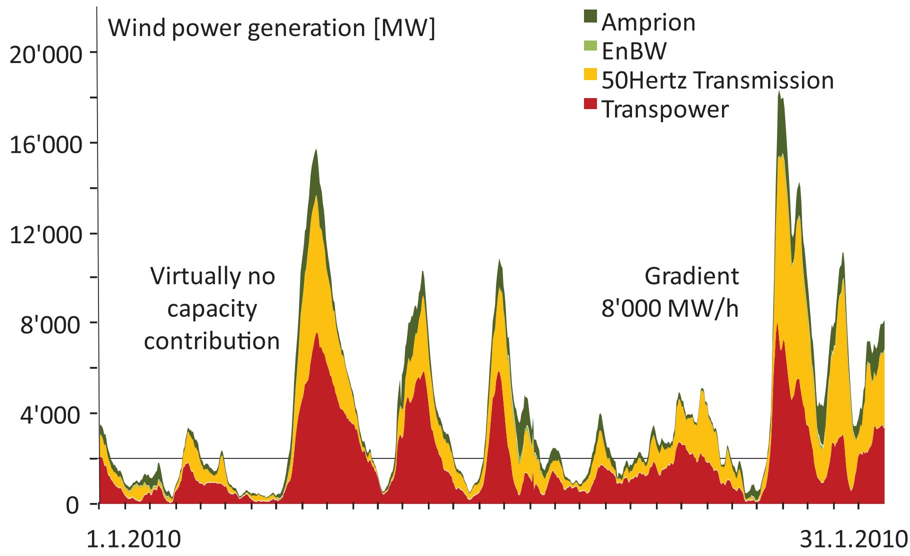

Fig. 1. – Volatility of wind power in Germany. Source: [1], p. 100.

demand. On the other hand during calm periods wind power generation may not be sufficient to cover the regional electricity demand.

An empirical example of the volatility of wind-based electricity generation is shown in fig. 1. It presents the feed-in of wind power into the grids of the four German regulation zones. The gradient of wind availability can be rather high. This requires conventional power generations to quickly increase or decrease generation. On the other hand even a strong increase of wind capacities will not prevent wind power generation deficits during calm periods of several days or weeks. The German wind power generation is still not sufficient to exceed national electricity demand, but with growing wind capacities the number of hours with excess generation will increase. This will increase the problems associated with the volatile nature of wind power generation.

In winter months solar capacities are hardly able to fill this gap. Daylight periods are short and solar insulation weak. But during the summer period solar energy, in particular photovoltaic, can contribute to the aggregated electricity demand, but with the same volatility problems as wind energy, for example excess generation in sunny hours around noon and no generation during the night.

From an engineering point of view, several concepts exist to solve the described intermittency problems:

– Curtailment of wind power generation if necessary.

– Providing dispatchable and flexible backup generation capacities such as geothermal or hydropower plants, biogas plants, and also certain fossil-fired power plants.

– Strengthening the transmission grid capacities over long distances in order to balance electricity supply and demand over larger geographical regions.

– Introducing demand side management with the intention to provide the balance between electricity demand and generation through flexible electricity customers.

– Large-scale storage capacities with pumped hydropower stations, batteries or electrolysis capacities which transform excess electricity into hydrogen or other chemical energy fuels. The stored energy can be used for power generation during deficit periods.

The engineering concepts, technologies additional costs of these options vary significantly. An important issue is that the costs per energy unit provided depend not only on the unit expenditures of the associated investment, but also on the number of hours per year during which the capacities are to be used. As example, the capital expenditures per unit of electricity delivered are ten times as large if the equipment is used during only 500 hours per year instead of 5000 hours per year. Section **2** looks at this aspect more in detail.

A follow up question is how the annual utilization period should be determined. If the dispatch of electricity technologies is determined by a central planner, the answer is trivial. More complex is the answer if the dispatch is based on the laws of market economics. In this case the annual utilization hours of each technology depend on its position in the so called merit order. The merit order concept explains both the annual utilization periods of individual technologies and the volatility of wholesale electricity prices. It is therefore quite central for understanding electricity economics and will be explained in sect. **3**

Based on the merit order concept, the remaining sections of this paper discuss market entry barriers of new technologies which may be needed for integrating volatile renewables into the electricity system. They also present ideas how to overcome these barriers.

2. – Economics of renewable-energy investment

Any economic analysis of investment decisions requires forecasting the cost and revenue streams over the expected lifetime of the planned investment. But only those economic variables have to be considered that are affected by the investment decision. If a company plans for an incremental expansion of capacity, the capital expenditures of the given installation as well as the management costs should be excluded, for example. However, the additional expected sales revenues per period generated by the investment are relevant. In the electric industry they depend on:

– the capacity Cap to be installed (measured in megawatt electricity generation),

– the capacity factor ν, specifying the expected percentage of annual full-load operation. As the year has $24 \cdot 365 = 8\,760$ hours, a capacity factor of $\nu = 20\%$ equals $0.2 \cdot 8\,760 = 1\,752$ full-load operation hours,

– the average expected price of electricity p_E (wholesale electricity price).

Given the power plant capacity Cap (in MW), the expected annual output Q and the corresponding annual revenues are:

$$Q = Cap \cdot \nu \cdot 8\,760 \text{ (in MWh)}, \tag{1}$$

$$p_E \cdot Q = p_E \cdot (Cap \cdot \nu \cdot 8\,760) \text{ (in Euro/MWh)}. \tag{2}$$

The financial counterparts of the annual revenues are the expected annual costs. They can be divided into variable costs and fixed costs. Variable costs C_{var} include costs for intermediate inputs such as fuels, emission rights, waste disposal, and to some extend wages (given flexible employment contracts). Variable costs per unit output $c_{var} = C_{var}/Q$ are obtained by dividing expected variable costs through the expected output Q.

The fixed costs are the annualized costs of the investment. A simplified analysis assumes the investment expenditure to take place in period t_0, leading to a negative cash-flow Inv_0 in this period. In the following years, the cash flows are $(p_{Et} - c_{var,t}) \cdot Q_t$. They should usually be positive in order to make the project economically viable. The time horizon is the end of economic project life T. A time series of annual cash flows can only be meaningfully evaluated if the individual cash flows are referenced to one period, for example $t = 0$. This is done by calculating the Net Present Value

$$NPV = -Inv_0 + \sum_{t=1}^{T} \frac{(p_{E,t} - c_{var,t}) \cdot Q_t}{(1+i)^t}. \tag{3}$$

In this formula, all future cash flows are discounted with the interest rate i. The term $(1+i)^{-t}$ is referred to as the discount factor. The economic evaluation of an investment project is positive if $NPV > 0$.

If the annual cash flows are to remain constant over the entire project life, eq. (3) can be rewritten to

$$NPV = -Inv_0 + (p_E - c_{var}) \cdot Q \cdot \sum_{t=1}^{T} \frac{1}{(1+i)^t}. \tag{4}$$

The sum on the right-hand side is the Present Value Factor of an Annuity

$$PVF_{i,T} = \sum_{t=1}^{T} \frac{1}{(1+i)^t} = \frac{1}{i} - \frac{1}{i \cdot (1+i)^T}. \tag{5}$$

In order to calculate the break even conditions, one has to set $NPV = 0$ in eq. (4). By solving for the electricity price p_E, one obtains is the break-even price that is required

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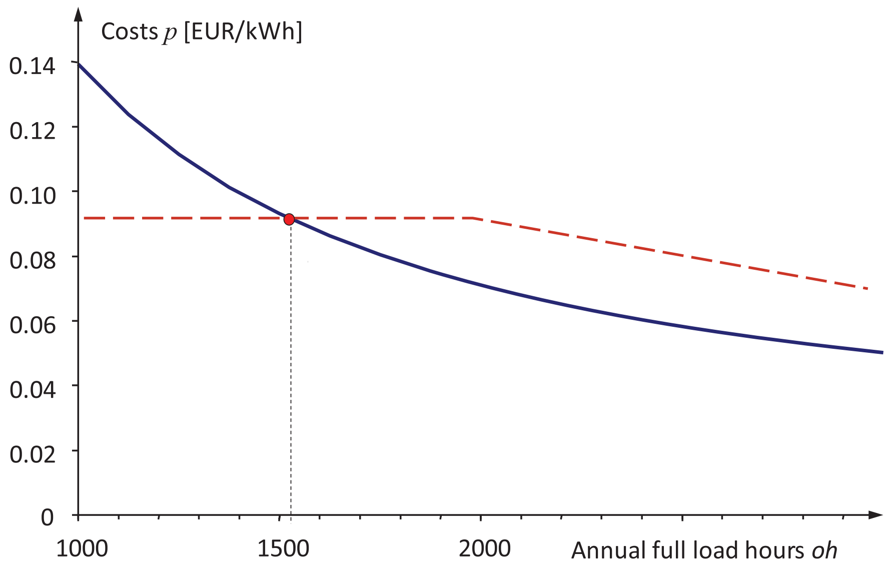

Fig. 2. – Example for the LCOE of wind power.

to cover the investment outlay Inv_0 and the unit variable cost c_{var}:

$$p_E = \frac{Inv_0}{Q \cdot PVF_{i,T}} + c_{var} = LCOE. \tag{6}$$

This is the levelized cost of electricity $LCOE$. Figure 2 presents the $LCOE$ of wind power as a function over the annual full-load operation hours (continuous line). The parameters assumed for this example are

$INV_0 = 975$, EUR/kW unit investment costs,

$c_{var} = 42$, EUR/kW unit operation costs (1–10 year),
58, EUR/kW unit operation costs (11–20 year),

$i = 5$ percent interest rate,

$T = 20$ years of economic use.

Figure 2 also shows the level of the German support for wind electricity (fixed feed-in premium, dotted line). Comparing this support with the $LCOE$, the conclusion is that wind turbines would allow an economic operation if they are installed at locations where the wind conditions would allow at least 1500 full load hours (break-even location). Investing at locations with better wind conditions would lead to significant profits, while wind installations at bad wind locations would be uneconomic. The example in fig. 2

presents a range of 0.05 to more than 0.14 Euro/MWh for the *LCOE* of wind power production.

The strong dependency of *LCOE* on the annual utilization hours is relevant for all types of electricity technologies: power generation plants, storage capacities, grid investments, combined heat and power installations etc. It is also relevant for demand side technologies such as electrolyzes, electrical heat pumps, etc. As a rule of thumb, capital intensive technologies([1]) require a large number of annual utilization hours, for example more than 5000 hours per year. If the market conditions do not allow such large numbers, the technologies are typically non-economic unless some form of state aid is granted. The emancipation from such political interventions requires efforts towards reducing the specific investment expenditures, in particular if annual utilization hours are physically limited.

3. – Merit order effect of renewable electricity

3˙1. *Power plant dispatch on day-ahead markets.* – This section explains the dispatch of electricity technologies according to market rules based on [2]. Starting point is the idea that on perfectly competitive markets each existing generation unit reaches its profit maximum if the dispatch is organized according to its marginal costs. This is shown by simple mathematics: It is assumed that the operator tries to maximize the periodic profit

$$\Pi(Q) = \bar{p}_E \cdot Q - C(Q) \tag{7}$$

(difference between the periodic revenues $\bar{p}_E \cdot Q$ and the periodic costs $C(Q)$). The optimal solution is ound by setting the derivative of the profit function with respect to the produced quantity Q equal to zero:

$$\frac{\mathrm{d}\Pi}{\mathrm{d}Q} = \frac{\mathrm{d}(p_E \cdot Q)}{\mathrm{d}Q} - \frac{\mathrm{d}C}{\mathrm{d}Q} = \bar{p}_E - \frac{\mathrm{d}C}{\mathrm{d}Q} = 0 \quad \rightarrow \quad \frac{\mathrm{d}C}{\mathrm{d}Q} = \bar{p}_E. \tag{8}$$

If the operator has no market power (or is not allowed to exercise market power), it does not influence the sales price p_E so that this price is exogenous: $p_E = \bar{p}_E$. The operator should adjust the individual production Q so that the marginal cost $\mathrm{d}C/\mathrm{d}Q$ —the additional expenditures associated with the generation of one additional electricity unit [MWh]— is equal to the fixed sales price $\bar{p}_E$([2]). If the marginal cost is smaller, the supply should be expanded, otherwise it should be reduced. Any sale at a price below the marginal costs is economically stupid.

Depending on the type of plant, marginal costs are the sum of several cost components:

- Additional costs for fuel needed to generate one unit of electricity. It depends, among others, on the fuel efficiency of the plant. It is worth to note that for

([1]) These are technologies with a large ratio "fixed cost/variable cost".
([2]) If the cost function $C(Q)$ is linear, the marginal cost is equal to the variable unit cost c_{var}.

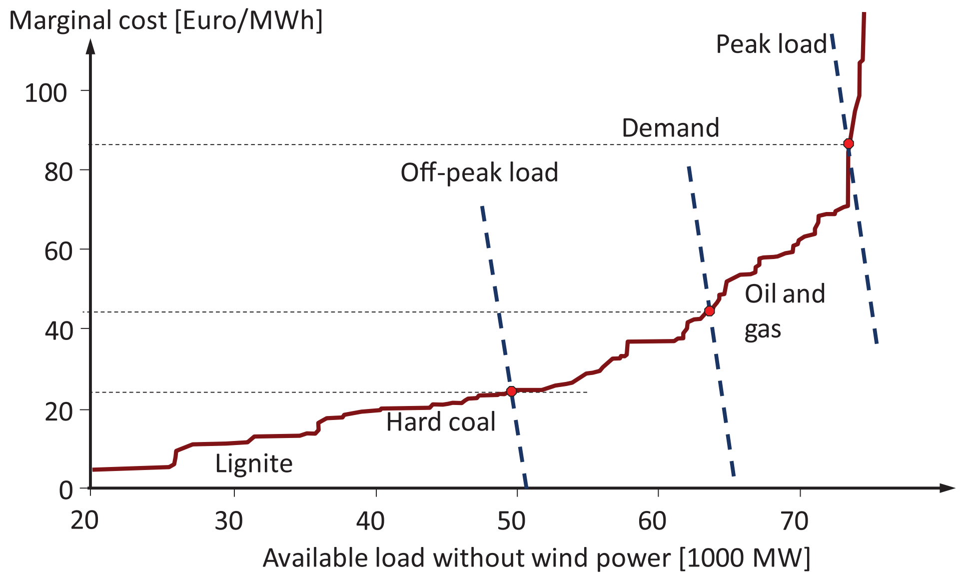

Fig. 3. – Merit order of German power plants.

wind and solar generators these costs do not exist so that their marginal costs are typically lower than the marginal costs of any conventional power plant.

– Additional costs for emission rights (if applicable). The corresponding contribution to the marginal cost depends on the tons of CO_2 emitted per MWh of electricity, multiplied by the CO_2 market price. Again, for wind and solar generators this cost component does not exist.

– If the output of thermal power plants falls below the optimal design level, efficiency losses occur and must be taken into consideration when calculating marginal costs.

– Fuel losses during start-up and shut-down periods.

– Accelerated wear of the equipment (boilers and pipes) due to thermal stress resulting from temperature change.

The investment costs and other costs such as personnel or administration expenditures are not affected by the generation decision and are therefore irrelevant for the evaluation of such decisions.

The aggregate electricity supply curve results from ordering the available electricity supply capacities of a country according their marginal costs. This is the merit order. Figure 3 shows a typical merit order for Germany (solid line). Compared to fossil fuel plants, wind and photovoltaic generators have rather low marginal costs and therefore stand at the beginning of the merit order. Nuclear and lignite power plants come next, whereby new lignite plants are before old plants due to their advanced fuel efficiency. Next in the merit order are hard coal plants, followed by Combined Cycle Gas Turbines (CCGT), open cycle gas turbines and older oil and gas plants with comparatively low fuel efficiencies.

Figure 3 also shows the electricity demand for three individual hours. The intersections with the aggregate supply curve (or the merit order curve) give the market clearing conditions for these hours, the produced electricity and the Market Clearing Price (MCP). The ask price of the last operator that is accepted —the last capacity that is dispatched— sets the MCP of the particular hour, while all other dispatched generators earn a contribution margin on top of their marginal costs which allows to cover (some of their) fixed costs. Due to the convex pattern of the merit order curve, hourly power prices for peak-load hours are higher and more volatile than hourly prices in off-peak periods.

The hourly MCP can be observed on so called day-ahead markets. The most liquid day-ahead market in continental Europe is organized by the European Power Exchange (EPEX). It is an auction market: All bids and asks for individual hours are aggregated into an hourly supply and a demand curve (see table II). After gate closure, the EPEX calculates the hourly MCP and informs market participants and the public about the trading results. Generators who have asked a price above the MCP are excluded from selling their generation on the day-ahead market. They have to curtail their generation accordingly as far as they cannot find a buyer for their generation on intraday markets. In this way, the number of annual operation hours is determined on free and competitive electricity markets.

According to fig. 3 more power capacity is dispatched in peak load periods than in off-peak periods. If suppliers offer electricity at their individual marginal costs (what they should do in order to maximize profits or minimize losses), the cheapest portfolio of capacities —in terms of marginal costs— is dispatched. Therefore capacities with low marginal costs achieve much more annual utilization hours than capacities with high marginal costs.

3˙2. *Impacts of renewables on the merit order*. – Having almost no marginal cost, wind and photovoltaic capacities stand at the beginning of the merit order. On free electricity markets they are dispatched whenever they are physically available, but their capacities may be curtailed if their generation —together with must-run capacities (for example Combined Heat and Power CHP)— exceeds the actual electricity demand.

The merit order curve moves horizontally according to the volatile availability of renewable electricity. If more wind and photovoltaic electricity is available, the merit order curve moves to the right. This has two implications:

- Given a certain quantitative demand, other generation capacities have to interrupt their power generation during periods with high availability of wind and photovoltaics. This refers to capacities with relative high marginal costs, which are actually gas-fired power stations, in particularly combined cycle gas turbines (CCGT). Coal-fired power stations are less concerned as their marginal costs are actually

TABLE I. – *Merit order effect estimates of wind and PV in Germany, 2006–2012.*

	2006	2007	2008	2009	2010	2011	2012
	Euros/MWh						
Sensfuß *et al.* (2008) [3]	−7.8						
Weigt (2009) [4]	−6.2	−10.4	−13.0				
vbw (2011) [5]					−8.0		
Sensfuß (2013) [6]		−5.8	−5.8	−6.0	−5.3	−8.7	−8.9
Speth, Stark (2012) [7]					−5.6	−5.6	
Cludius *et al.* (2013) [8]			−10.8	−7.8	−6.0	−7.7	−10.1

below those of relative climate friendly gas power plants([3]). With the growing share of renewables, coal-fired power stations will also have to interrupt generation during power surplus periods.

– Second, as wind and photovoltaic generation squeezes out relative expansive gas-fired power generation, the Market Clearing Price (MCP) on the day-ahead electricity market becomes smaller. This effect is called the "merit order effect of renewables" (see [3] and [6]). Due to the merit order effect of renewables, the wholesale electricity prices have fallen below marginal cost even of highly energy efficient CCGT. Such investments are no more economic today.

Several studies have quantified the merit order effect of renewables. An overview for Germany is presented in table I. Most of the studies cited here are based on a structural power market model based on a large databank of several hundred generation units. The hourly merit order function is calculated from the marginal costs of the capacities available in the respective hour. By comparing the merit order function with the hourly electricity demand, the Market Clearing Price (MCP) results. For estimate the merit order effect of renewables, two scenarios are compared: one using the historical renewable power generation and one without any renewable generation. Comparing the yearly average of day-ahead price between these two model runs gives an estimate for the merit order effect of renewables.

There are some challenges associated with structural market models: Usually the scenario calculated with the renewable power generation should reproduce the realized hourly day-ahead prices, but this is not automatically the case because real behavior of power plant operators may differ from the implicit assumption of cost optimal dispatch of generation capacities. In addition, some capacities are not available for day-ahead trading. Finally, public information about individual costs for fuels is not public. Therefore structural market models require some calibration before they are able to reproduce market results.

([3]) This is because gas prices are high compared to coal prices and because CO_2 prices are presently rather low.

Another approach for calculating the merit order effect of renewables is used in [8] and [5] and based on an econometric model (reduced form model). Starting point is a time series of hourly wholesale power prices (endogenous variable) which is assumed to be statistically correlated with exogenous variables such as fuel and CO_2 prices, hour-of-day effects, calendar effects (weekends, holidays, country wide vacations) wind and photovoltaic generation etc. The parameters describing the impact of the exogenous variables on the endogenous variable are calculated by an econometric estimation. Applying the model, two cases are simulated and compared, one with and one without wind and photovoltaic power generation. The second case results from simply setting the historic wind and photovoltaic generation to zero.

The merit order effect of renewables calculated with econometric approaches is in the range of results achieved by structural market models. Thus the quantification of the merit order effect turns out to be quite robust.

It can be assumed that the merit order effect of renewables has grown since 2012, because the renewable generation capacities in Germany are 20% larger in 2014 than in 2012. To check the consequences, [9] presents an updated econometric estimation of the merit order effect of wind and photovoltaics in Germany, based on the three year period between 2012 and 2014 (with the range of 26304 hours). According to this study, the merit order effect has reached 12 Euro/MWh in 2014. To put this result into perspective, it states that without electricity from wind and photovoltaics the day-ahead price 2014 in Germany would have been 44.80 Euro/MWh instead of 32.80 Euro/MWh. The downward price trend is continuing; in 2015 the average day-ahead price declined further to 31.60 Euro/MWh and has fallen below 25 Euro/MWh in the first half of 2016. Obviously this is a dramatic development for all those who produce and sell electricity on the wholesale market.

In the European single market restrictions to trade are prohibited. Therefore the German electricity price collapse spreads to neighboring countries. Power purchases from the attractive German wholesale market become attractive for foreign market participants. As a consequence, German net electricity exports have passed 8% of national generation. This puts a pressure on foreign wholesale prices are forces power generators in neighboring countries to curtail production([4]). In sum, the renewable capacity growth in Germany challenges not only the domestic electricity generation but also the generation in neighboring countries, in particular gas-fired power plants with their relative high marginal costs.

4. – Intermittency of renewables: Do we need capacity markets?

With the growing generation from renewable sources, conventional generators are exposed to twofold losses:

– reduced annual operation hours,

([4]) For example, the wholesale electricity price in Italy would be 2.5 Euro/MWh higher without the German merit order effect of renewables, according to our estimates.

– reduced revenues from electricity sales.

Thus the economic survival of conventional power generation is at risk, implying that existing plants are prematurely taken out of order and new investments into conventional generation are withdrawn. Different to conventional generators, state aid in favor of renewable generation makes investments into wind and photovoltaic still economical so that such investments are going on. But through the volatile nature of their generation, these capacities alone are not able to secure electricity demand.

Any generation system with rather high shares of wind and solar technologies needs some backup capacities, based on a combination of

– long-distance power transmission,

– large-scale electricity storage capacities,

– demand side management.

But all these options are costly and/or faced with other problems and bottlenecks. Therefore investments into dispatchable generation capacities are assumed to be inevitable.

Electric industry has much experience how to secure supply. As far as electricity cannot be stored, a reliable power system requires some excess and reserve generation capacities. The excess capacities are needed to cover unexpected loads, while reserve capacities are required to back-up scheduled and unscheduled generation outages and/or power demand spikes. In addition, some flexible generation capacity is required for supplying regulation power and other grid services, such as redispatch of generation in case of local bottlenecks in the transmission grid. As a consequence, reserve margins of about 10 percent of the maximum load are assumed to be necessary to secure electricity supply at any time (system adequacy).

But how this system adequacy can be reached? If the electric generation is dominated by one monopolistic utility, the solution is easy: The regulator requires the utility to guarantee the needed generation capacities according to a mandatory system adequacy level and allows the utility to recover the costs through electricity tariffs. But on competitive markets such an automatism is not feasible because supply security has the character of a public good: Each competitor is interested in avoiding the associated costs for securing electricity because this would allow him a competitive advantage on the power market.

Knowing this dilemma, the electricity market regulators have developed mechanisms in order towards securing electricity supply (based on the pioneering work of [10]):

– The (still) monopolistic Transmission System Operator (TSO) is requested to purchase capacities for supplying regulation power. The sellers of regulation power are determined by regularly pay-as-bid auctions and receive capacity payments if awarded. In return they must activate the awarded capacities at the disposal of the TSO.

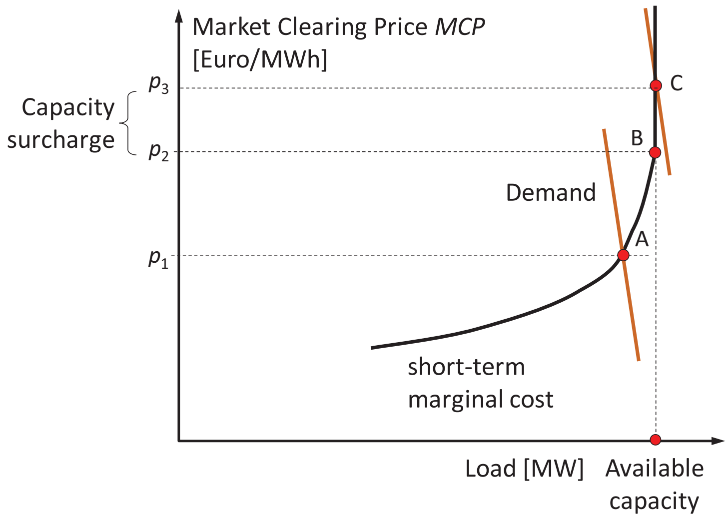

Fig. 4. – Electricity market under capacity shortage.

- In a liberalized market with retail competition each wholesale market participant (balancing group managers) has to purchase balancing power from the TSO to adjust for imbalances between supply and demand in its balancing group. If the imbalances are excessive, the regulator may impose fines and other sanctions. In extreme situations the TSO can even exclude balancing group managers from using the electric grid.

- In addition backup power markets exist where option contracts for compensating eventual plant outages are traded. The demand comes, among others, from the operators with small generation portfolios. Large generators can hedge the outage risks by own generation reserves.

Under the label "capacity market", a controversial discussion on additional instruments for securing electricity demand is presently underway (for example [11] and [12]). To explain this debate, fig. 4 is presented showing a simplified merit order function (similar to the concept explained in [13], p. 70f). Point A corresponds to a regular market situation in which the marginal cost of the last available power plant (*i.e.* excluding the reserve margin) sets the Market Clearing Price p_1. Because the day-ahead market is organized as a unified price auction, all power plants to the left of this last plant sell their electricity against the same price p_1 and thus earn (infra-marginal) rents on top of their marginal costs.

Point B corresponds to the last available capacity unit in the merit order with marginal cost p_2. In hours with regular market conditions the Market Clearing Price is below p_2 because available capacities are sufficient to cover the hourly demand. But in situations with high power demand and low wind and solar generation the aggregated available capacities may be insufficient. Point C in fig. 4 explains this case: There is no intersection between the demand and the merit order. But if the merit order curve is extended vertically above point B, an intersection in point C exists. The resulting MCP is $p_3 > p_2$ defining a positive price margin $p_3 - p_2$ which is called "capacity surcharge" or "capacity rent". The MCP exceeds the marginal cost of any generation capacity in the merit order. If such margins are observed, traditional competition theory would assume misuse of market power. But this is not the case. The price spike to p_3 is simply a market reaction to solve a capacity shortage problem and is necessary for balancing current discrepancies between (low) electricity supply and (high) electricity demand. If such situations are expected to occur frequently, the likelihood of premature closures of existing generation capacities declines and that of investments into new generation capacities increases, thereby solving the system adequacy problem.

There is some discussion among economists whether unpredictable occasional price spikes are sufficient for securing investments into power generation. From the investor's point of view such price spikes are basically price risks and need to be compensated by higher average wholesale prices. This can be seen as the disadvantage of markets solving the system adequacy problem.

But the market approach has other problems: Volatile and spiky wholesale power prices can be rather unpopular so that electricity customers may organize some political pressure in favor of lowering wholesale power prices. This pressure is typically orchestrated by the public reproach that generators manipulate market prices for obtaining excessive profits on behalf of their customers. If regulators follow these claims, they impose some explicit or implicit upper limit on wholesale power prices. In this case the wholesale power market cannot raise sufficient revenues for financing power plant investments. In the literature this is discussed as the "missing money problem" (see for example [14]).

The missing money problem may be solved by introducing capacity payments to certain power generators. If governments do not want to spend taxpayer's money, the capacity payments shall be raised from final electricity customers in form of capacity levies (similar to renewable-electricity levies). The selection of the plants may again be organized by auctions. In this case the regulator defines the auction frequency, the aggregated auction volumes and the conditions that successful plant operators must satisfy. Awarded power plants are taken out of the regular electricity dispatch and are scheduled by request of the regulator. This mechanism will increase the wholesale power prices during regular periods, but reduces the wholesale price in emergency situations, according to the criterion for releasing emergency capacities.

There is a "decentralized" alternative to a regulated auction based capacity market: Power generators and retailers are required to always keep their electricity schedules balanced. In order to stick to this rule, retailers may purchase an equivalent number of capacity guarantees issued by flexible generators or flexible demand. The same holds for power generators, in particular if they feed electricity from volatile sources into the grid. Flexible generators, electricity storage operators and final electricity customers with interruptible loads are typically on the supply side of capacity guarantees. The price for these guarantees shall be high in periods with tight capacities (weak renewable-electricity supply), but it can also be zero if sufficient capacity is available (strong renewable-electricity supply). The beauty of this "decentralized capacity market" is that its implementation can be left to the market. Innovations and competition will quite likely lead to cost-efficient solutions. The regulator can limit itself to enforce the balancing through sanctions on market participants that do not comply.

In addition to regulated and decentralized capacity markets a third concept may be used to solve system adequacy problem. It is based on the customer's choice to select the desired quality of electricity supply. Retailers may offer power supply contracts that give them the right to cut the supply during some hours per day, if capacities are short and prices high (usually during evening hours). Electricity customers can opt for a non-interruptible power supply but they have to pay a surcharge according to the individual cost associated with this service. The acceptance of interruptible supply contracts depends on the customer's value of lost load (VOLL; defined in [13], p.154ff, see also [15]) which varies according to time, power application, availability of own generation, electricity storage capacities etc. Such a concept would again initialize a variety of innovations so that the final result will be cost efficient compared to centrally planned capacity markets or mandatory investments into generation (or electricity storage) capacities.

5. – Using volatile excess electricity: "Sector coupling"

To conclude the former analysis, a manifold of possible approaches exists towards securing electricity supply in power systems with rather high shares of volatile generation capacities. The other side of the medal is that in such systems there will be many hours with excess generation.

Figure 5 presents such a constellation. The figure shows the cumulated electricity demand (negatively sloped bid curve) and supply (positively sloped ask curve) at the European Power Exchange EPEX for a Sunday afternoon in May 2016. In this hour the Market Clearing Price (MCP) was strongly negative, namely -130.09 Euro/MWh. This means that generators had to pay for selling electricity and buyers had earned money for purchasing electricity for this hour.

This constellation is characterized by low electricity demand and high electricity supply. But one has to ask why generators do not cut production, instead of paying for selling electricity. Several arguments can be brought forward for this behavior:

- (Renewable) Generators that would lose state aid in case of curtailing generation.
- Thermal power stations with technically limited generation flexibility.
- Must run capacities, for example generators that are obliged to provide regulation power.

For these reasons, wholesale power prices can become negative from time to time.

Even in periods when power prices are positive but close to zero, an economic incentive exists for final users to purchase more electricity. This additional demand would be helpful for integrating renewable electricity into electricity markets. If the additional electricity demand is used to replace fossil fuels in other energy sectors, it would also

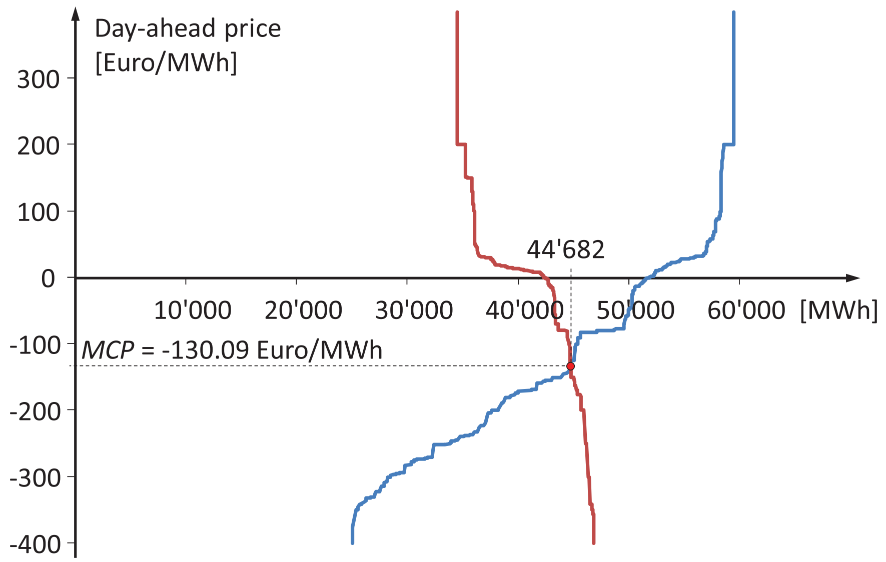

Fig. 5. – Bid and ask curves on the German day-ahead market for the hour 14–15 h on 8 May 2016.

contribute to the reduction of greenhouse gas emissions. The use of electricity in other sectors for this purpose is also known as "sector coupling" (see [16]).

Sector coupling examples are power-to-heat appliances in combination with hot water storage capacities. Heat production from electricity is usually regarded as energetically unattractive due to the associated exergy losses, but regarding the electricity system as a whole, the losses would be larger if the available renewably electricity would be curtailed due to insufficient power demand. In many cases relative minor investments are needed for developing power-to-heat capacities, because most central heating installations as well as some district heating systems are equipped with heat storage capacities. The number of hours with low or negative wholesale power prices will be small (at least for the time being), but regarding the low specific investments of power-to-heat systems, their economics should be attractive in principle even if their annual operation will not exceed 1000 hours per year([5]).

But for final electricity users power-to-heat systems are only economical if the resulting heat costs are below the final user prices of natural gas or heating oil which are in the range of 30–70 Euro/MWh. No problem would exist if the electricity price for final users is equivalent the wholesale electricity price: Power-to-heat makes only sense in periods with excess electricity from renewables, and just these periods are characterized by rather low and eventually negative wholesale prices.

([5]) See sect. **2**, in particular fig. 2, which highlights the basic mechanism between annual operation hours and levelized costs of energy. This mechanism applies not only for wind energy but also for power-to-heat systems and other electricity technologies.

Table II. – *Electricity price components in Germany in the year 2016.*

	Power purchase from the grid	Auto generation	Generation in „local context“
	Euro/MWh		
Grid fee	18.00 – 30.00		18.00 – 30.00
REN levy	63.54	22.24	0.00
Electricity tax	20.50	Legally unclear	
Concession fee	1.1 – 23.90		1.1 – 23.90
CHP levy	4.45		4.45
§ 19 StromNEV	3.78		3.78
Offshore levy	0.40		0.40
Total	86.77 – 121.57	22.24 – 42.74	23.73 – 83.03

Unfortunately the electricity prices for final users are by far higher than the electricity wholesale price. It includes costs of retailers (for marketing, purchasing, scheduling and metering), grid fees, renewable-electricity levies, electricity taxes. Table II presents an overview of the present situation in Germany. The situation in Germany is rather complex because of many special circumstances defined in the federal law. But as a general conclusion, the retail prices of natural gas are hardly met by retail electricity prices except in singular cases. This challenges the market introduction of power-to-heat systems.

Power-to-heat-systems may have only a chance if the price for electricity used for running these systems is sufficiently small. There are basically two approaches to get there:

– Define specific power-to-heat applications for which (most of the) grid fees, levies, fines and taxes have not to be paid. This approach is problematic because the regulator will hardly be neutral with respect to different concepts, technologies and investors. As a result, the success of power-to-heat does not depend on the specific competitiveness but on the specifications defined by the regulator.

– Shift the reference for grid fees, levies and perhaps taxes from energy (kWh purchased) to load (maximum electricity load in kW during a calendar year). As a consequence, the additional cost of electricity used for power-to-heat systems can become rather low, as far as the operation of these systems keeps the annual maximum load unaffected.

As a conclusion, it should be possible to modify the electricity tariff structure in such a way that power-to-heat systems may generally become economical for final users so that excess electricity from volatile renewable sources will be used on a large scale for substituting fossil fuels in the heat market.

Other sector coupling options are based on power-to-gas and power-to-liquid concepts. The core of such systems is the electrolysis of hydrogen. Subsequent processes may use this hydrogen to produce synthetic methane or methanol. There are two shortcomings here. One is that the energy losses of these processes are significant. The second is that the specific investment expenditures are relatively high, today at least 3000 Euro/kW installed capacity. Therefore the levelized costs become rather high if the operation of these systems is restricted to periods with excess electricity from renewable sources (see again table II). The operators have an economic interest to run these systems in base load, but this would be basically incompatible with the aim of integrating volatile renewable sources into the electricity market.

6. – Economics of electricity storage

A final sector coupling option is batteries. Due to the market growth for battery electric vehicles their costs are declining strongly. Therefore it appears likely that electricity will soon replace some fossil fuels in the transportation sector. But this process will not only be controlled by battery costs but also by the driving ranges of a fully charged battery vehicles and the achievable number of battery charging cycles (the economic lifetime of batteries in vehicles). The deeper discussion of these topics goes beyond the scope of this paper. This paper rather addresses the stationary utilization of batteries (and other electricity storage devices, for example hydropower pumped storage capacities) and explains some particularities concerning the economics of energy storage.

Independent of their physical and technical concept, the operation of electricity storage devices is characterized by creating additional demand for electricity in period of excess supply and additional supply in periods of electricity shortage. If dispatched in this way, storage technologies contribute to the market integration of volatile electricity generation.

The proper dispatch of storage capacities has to focus on the wholesale electricity prices: The charging of any electricity storage should happen in periods of low wholesale electricity prices, while the discharge should take place in periods of high prices([6]). Thereby storage capacities contribute to the stabilization of wholesale electricity prices. The revenues associated with this operation depend on the price spread between electricity for charging and electricity from discharging.

This price spread increase, among others, with the cumulated size of renewable-electricity capacities and shrinks with the mandatory introduction of capacity markets. The cumulated share of electricity storage capacities has also an impact. This is ex-

([6]) Insufficient grid capacities can also be a reason for curtailing renewable-electricity generation. A reliable concept for running electricity storage capacities is based on the elimination of such regional imbalances. Here the aim is so stabilize local distribution grids, independent of the current wholesale prices.

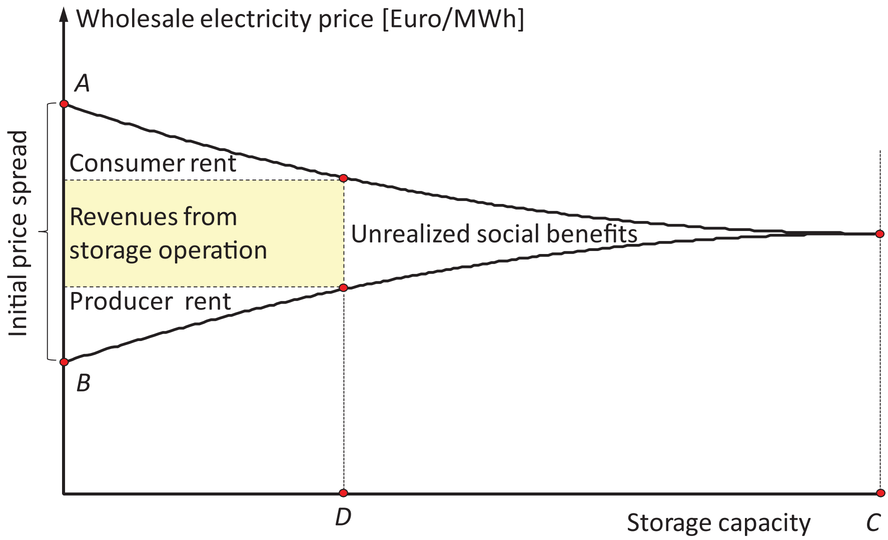

Fig. 6. – Cumulated storage capacity and power price spread (source: adapted from [1], p. 119).

plained in fig. 6. Without storage capacities the spread between the highest and the lowest hourly day-ahead price during a given period (24 hours of the day, for example) corresponds to the difference between the points A and B. The economic dispatch of electricity storage would reduce this spread, and there is a maximum storage capacity C which would imply the fully distinction of the price spread.

The revenues from an optimal operation of electricity storages correspond to the price spread which remains after the dispatch of the storage capacity, times the available storage capacity. Figure 6 presents an example. The rectangle corresponds to the cumulated storage revenues given the storage capacity D. The two triangles marked with "consumer rent" and "producer rent" indicate the social benefits associated with the reduced price spread resulting from the optimal operation of the storage capacities. The triangle to the right of the rectangle represents the unrealized social benefits due to the limited storage capacity.

Even if there would be no costs associated with investing and operating electricity storage capacities, the free market solution would not lead to the maximum storage capacity C because in this situation storage capacities would receive no revenues at all. Even if storage costs would be zero, the optimal storage capacity must be smaller than C. Of course storage costs exist and play a role. For the economic optimum it is crucial that the revenues exceed the investment and operation cost of the storage capacity. If this is not the case, no private storage investment is to be expected. For the social optimum the unrealized social benefits must be equal to the storage investment and operation cost. Thus a discrepancy between the private and the social optimum exists.

Another conclusion from fig. 6 is that the insider-outsider problem is highly virulent: Owners of electricity storage capacities have an interest to hinder newcomers to enter the market, even if the economic storage optimum is not yet reached, because each newcomer reduces the price spread and thus the revenues of the insiders. This problem is relevant, whenever a business concept is based on a price spread. It is particularly relevant for electricity storage capacities because even small additions to the aggregated capacities lead to a strong decline of an initial high price spread. For understanding this statement the reader may consult fig. 5 again. It shows a situation with a strongly negative Market Clearing Price. But this price would have be significantly higher if there would have been some more MWh electricity demand (red curve shifts to the right) or some MWh lesser electricity supply (blue curve shifts to the left).

7. – Outlook

Wind and photovoltaic generation technologies have moved from the innovation phase to the phase of market application and diffusion. If invested at favorable wind or solar locations, the levelized cost had fallen below the levelized cost of new gas and coal power stations. But for the comparative competitiveness of these renewable-electricity sources the levelized costs are not the only determinant. In electricity systems there must be a balance between generation and demand in all periods. Electricity potentials from wind and photovoltaics are principally abundant but electricity generation from these sources is by nature rather volatile. This poses additional challenges that must be solved before wind and photovoltaic can achieve larger shares in future power systems.

This paper does not address physical and engineering properties and features of technologies that can be used for integrating renewables into electricity markets. It rather presents ideas about how to assess their economics. Three cases are distinguished:

- Approaches to address situations with lacking electricity generation.
- Approaches addressing situations with excess electricity generation.
- Approaches to address both problems through electricity storages.

The paper concludes that no fundamental reasons exist why large market shares of renewables are not feasible, but additional system costs in one or another way are inevitable and the question arises how to cover these costs. This paper proposes some concepts, but without claiming to present a comprehensive assessment of all possible models and solutions which could come to one's mind. Regarding the dimension of the challenges and costs, the paper prefers solutions in which governments restrain from technology specific interventions but rather leave the selection of technologies to fair competition and market forces. Experience shows that this would lead to better and cost-efficient solutions. But governments have a role to play: They must create an appropriate environment for competition among technologies. According to the paper, here is the key deficit for integrating volatile generation into electricity markets which is needed in order to further increase the share of renewable electricity.

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