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DISCUSSION PAPER

6

Elements of a Sustainable Design for Electricity Markets

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arrhenius Discussion Paper 6: Elements of a Sustainable Design for Electricity Markets
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1 Introduction

Electricity markets in Germany and Europe have changed substantially over the last thirteen years. The driving force behind this development was the EU directive on a common European energy market (EU-Directive 96/92/EC). It was followed by further directives, e.g. on the unbundling of electricity production and transport. At the same time, a number of measures on environmental and climate protection were introduced such as the EU emissions trading systems or the German feed-in tariff for electricity from renewable energy sources (the so called EEG = "Erneuerbare-Energien-Gesetz").

In the meantime, stakeholders have begun to realise, that liberalisation alone will not create a sustainable market with a high level of supply security. This is true not only, but especially if we aim for high shares of renewable energy. Accordingly, the market design should be adjusted. It has to pursue the following objectives simultaneously:

- The electricity demand of end consumers has to be met at any location in the grid at any time.
- The environmental and climate change targets have to be observed.
- The demand for electricity should be supplied at the lowest possible cost.

This article discusses some of the related problems and proposes concrete solutions. It will explicitly not cover all issues.

In the following chapters, we will describe the rules of the liberalised electricity market and we will demonstrate why they are not sufficient to meet the demands of an electricity system which is mainly based on renewable energy sources. Consecutively, we will list the specifications of such a system. In so doing we propose to concentrate on a cost efficient system, which focuses on the cost to consumers and not on the generating cost of individual technologies. Furthermore, we will comment on the role of electricity imports for security of supply. Finally, we will present an idea, how incentives to invest in new installations may be created in such a system, and how the debate might be carried forward.

2 Current functioning of electricity markets in Europe

As in other markets, prices for power are brought about by supply meeting demand. In the following sections, we focus on the supply side. Demand can be influenced in different ways. However, that is not the focus of this work. We will also not derive consumers' willingness to pay here.

2.1 Total average costs of electricity production and power prices

The total average electricity production costs of a power plant consist of a variable part, which is (typically) proportional to the quantity of electricity produced, and of a fixed part, which exists whether or not the plant is generating electricity. In order to simplify the analysis, it is assumed for the moment that there are only three cost factors for the production of electricity:

- capital costs,
- fuel costs, and
- environmental costs in the form of CO_2 emission allowances.

Capital costs are typically fixed costs. In contrast, fuel and CO_2 costs represent variable costs, which are proportionate to the amount of electricity produced. They depend on fuel prices, the efficiency of the power plant, the specific CO_2 emissions of the fuel used and on the price of CO_2 allowances. According to experience, other expenses such as fixed and variable operating and maintenance costs are small compared to the three aforementioned factors and are, thus, not considered for the basic analysis here (cf. Figure 1).

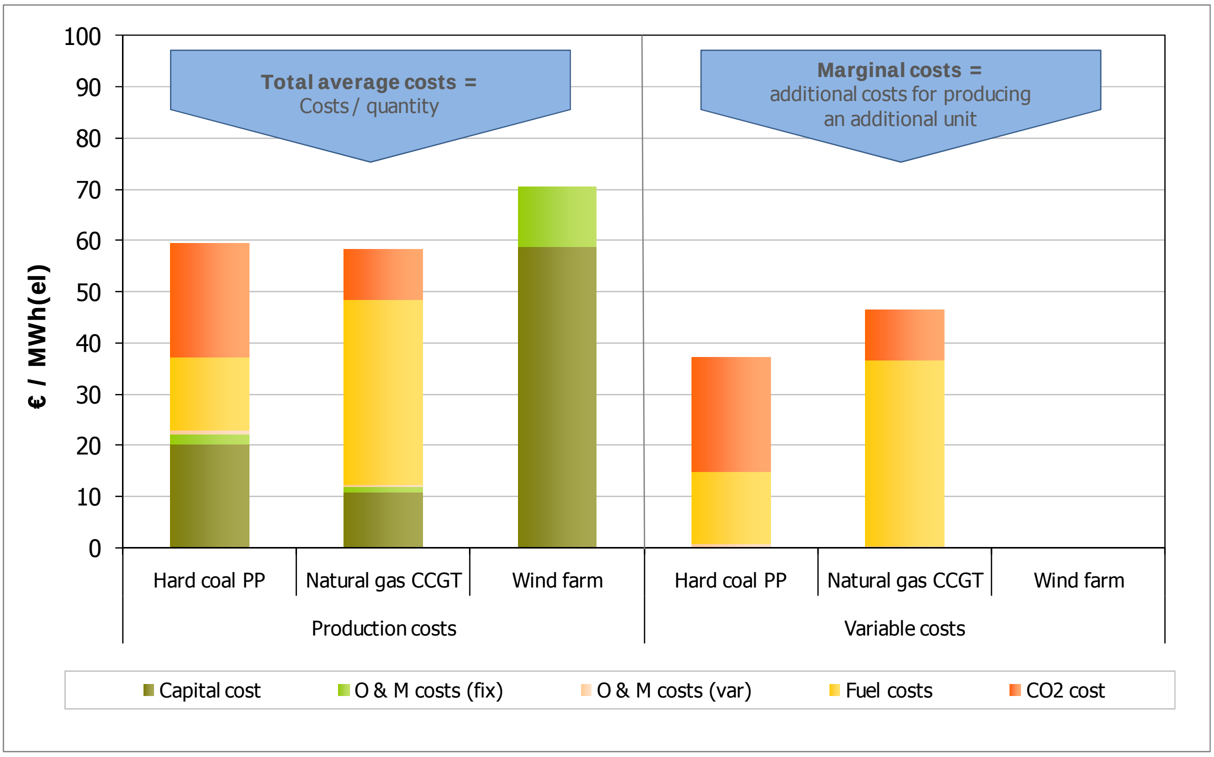

Figure 1: Electricity production costs of various power plants (schematic representation).

To be able to add the variable and fixed costs of the electricity production in euros per megawatt-hour (€/MWh), the fixed costs must be related to the amount of electricity generated. Therefore, the total investment sum for the power installation is distributed across the individual years of the targeted amortisation period using the annuity method. Dividing the so derived annual fixed costs of the investment by the corresponding electricity production, yields the specific capital costs of the power plant. They strongly depend on the amount of electricity that is produced.

The total average costs are of importance before an investment decision. Only if they are smaller than the expected average revenues, may the investor hope for profit. The revenues are determined by the power prices in the market and the amounts of electricity sold at these prices.

In contrast, <u>marginal costs</u> of electricity production are defined as the cost to produce an additional unit of electricity, e.g. a megawatt-hour. They are exclusively determined by variable costs, that is fuel and CO_2 costs. Since installations using renewable energy sources such as wind or solar do not have fuel or CO_2 costs, their variable costs are almost zero, at least within the simplified picture drawn here.

In the following, it is assumed that perfect competition prevails. This market form is also the objective of the European Commission in order *"... to make sure that companies compete with each other and, in order to sell their products, innovate and offer good prices to consumers."*[1] According to cost theory, producers offer goods at the marginal costs of production in such a competitive market. Capital costs are no longer relevant in this case.

Sorting all power plants according to their marginal cost of power production will result in an aggregated supply curve, the so-called "merit-order curve". The power price for each hour of the day is determined by the intersection of the aggregated supply curve and the total demand curve (cf. Figure 2).

Figure 2 shows the price finding mechanism for one individual hour. However, both, the merit-order as well as the demand curve undergo constant change on different time scales. Thus, calculations have to be carried out on an hourly basis rather than using annual averages for prices and quantities. The timing of the electricity production is important as electricity can only be stored on a small scale at high costs and must, thus, in general be utilised immediately.

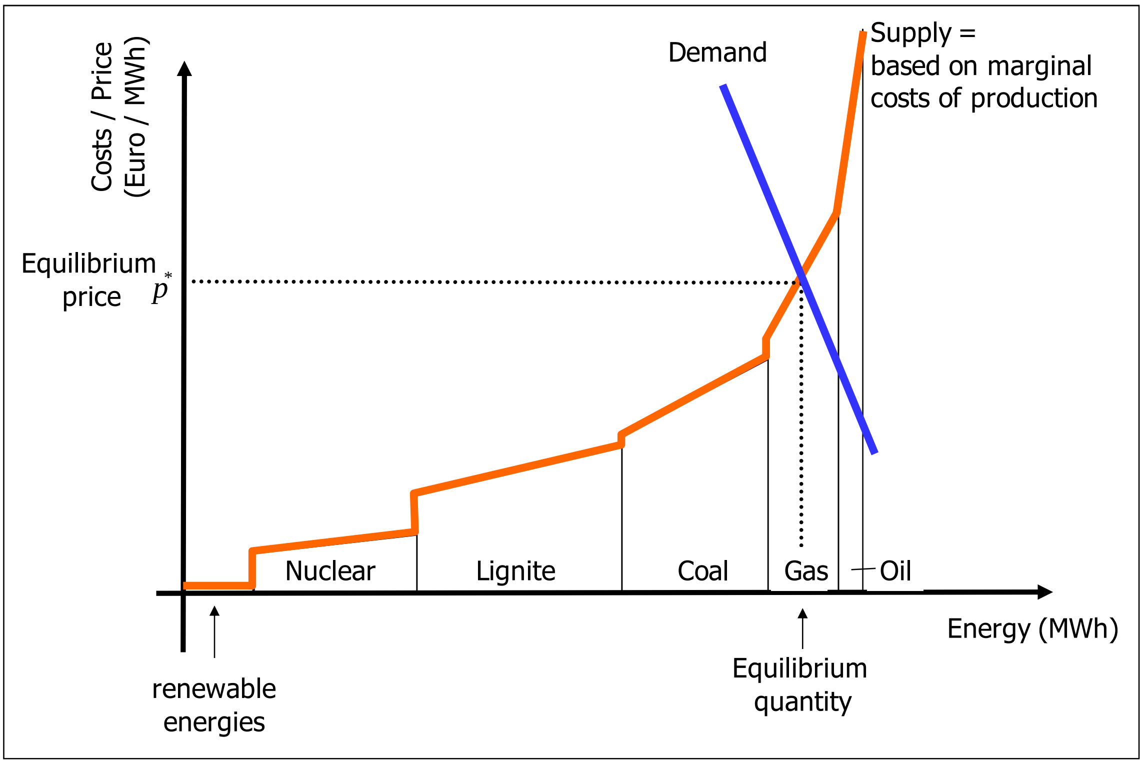

Figure 2: Pricing on the electricity exchange in one hour.

[1] Jonathan Todd, Commission competition spokesperson; transcript from an interview on BBC World, September 2007, Source: ec.europa.eu/competition/consumers/index_en.html. More information on EU competition policy is also available on this site.

2.2 Incentives for investments in new power plants

The pricing mechanism described above holds for existing power plants. The question now is, whether this mechanism is sufficient to generate incentives to invest in new power plants.

2.2.1 System inherent problems

Each installation, which earns a contract to supply electricity in a certain hour, will receive the product of the market price and the amount of electricity supplied as revenue. The sum of revenues over time has to cover the marginal costs and – in order to be economically viable in the long-term – the capital costs. Only when revenues exceed the sum of costs, may profits be earned. The difference between revenues and marginal costs is called contribution margin or variable gross margin.

A detailed analysis of contribution margins and capital costs under varying conditions such as fuel prices and CO_2 prices shows, that it is rather difficult for investors to cover their capital costs under the current conditions of the liberalised market. One reason for this observation is the fact that technical progress will only bring about small additional gains in power plant efficiency. Thus, variable costs of new plants are on a similar level as costs of older plants (Bode & Groscurth 2010). Consequently, the high capital costs in this sector cannot be regained and there are no incentives to invest. Attention was called to this problem several years ago (Weber 2002, BCG 2003). However, it has not attracted sufficient attention in the energy policy debate so far.

Market proponents argue that in times where demand exceeds supply, there will be so called scarcity prices, which may be above the highest marginal costs of a power plant in the system and which may therefore attract new investments (e.g. Joskow 2006, Ockenfels 2008). Whether this mechanism will suffice is an open question (cf. Weber 2002). Furthermore, it is not clear, whether this approach is the most cost-effective from the point of view of consumers and whether the lead time is sufficient to bring new capacities online before serious power shortages occur. Finally, it has to be taken into account that scarcity prices will only occur for a few hours per year in the beginning, such that incentives to invest will only increase slowly. In addition, scarcity prices will disappear as soon as new capacity comes on line, so that this newly built capacity will not benefit from these prices.

Thus, we may state that the liberalised electricity market in its current design does not create sufficient incentives to invest in new generating capacity, even without considering climate protection and renewable energy (Bode & Groscurth 2009). The uncertainty about long-term targets in climate protection and the instruments to pursue them aggravates this problem as does the extended use of renewable energy.

2.2.2 Renewable energy in the liberalised electricity market

Electricity production from renewable energy sources has continued to gain more and more importance in recent years. The foreseen addition of further capacity will bring the current market design to its limits.

As discussed in Sec. 2.1, power prices are based on marginal production costs in the current market design. It is a specialty of the most important renewable energy sources, i.e. wind and solar energy, that their marginal costs are almost zero. If we now see additional capacity exploiting these sources (e.g. triggered by a feed-in law), the supply curve is shifted to the right and the equilibrium price at the power exchange decreases (Figure 3).

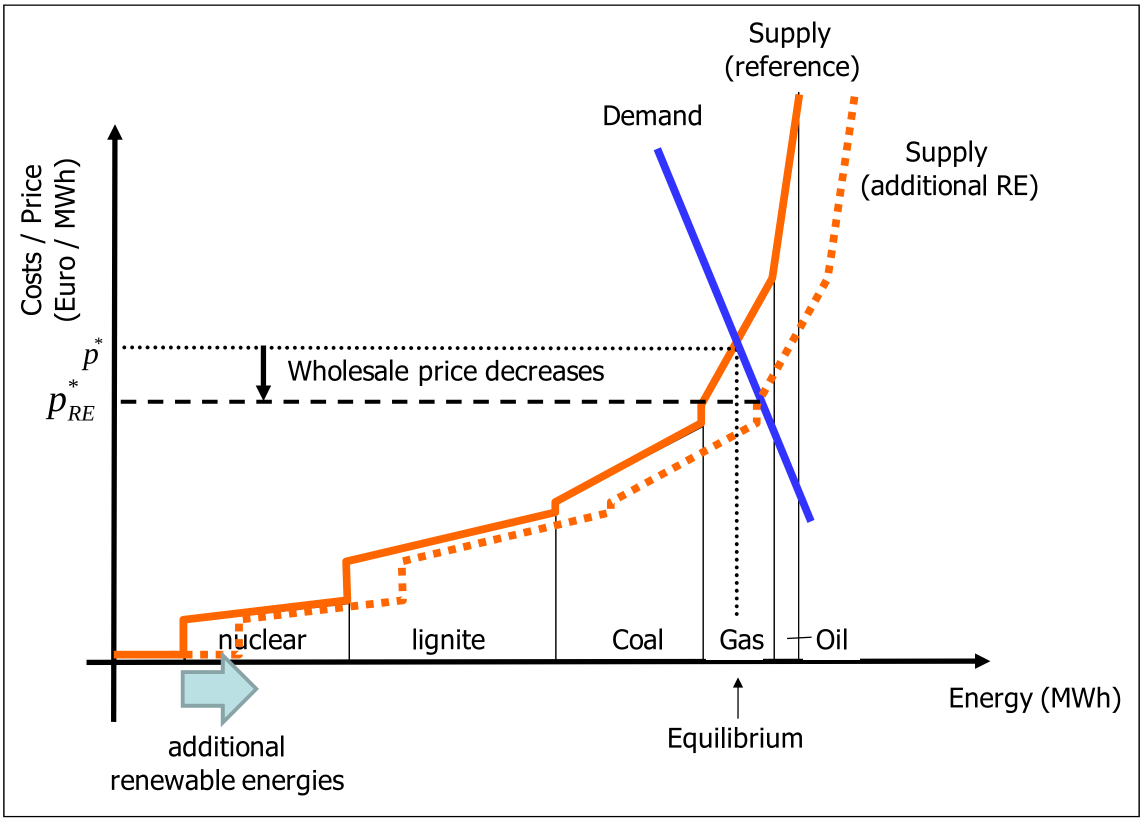

Figure 3: Effect of additional renewable energy capacities on equilibrium power prices.

It is essential to distinguish decreasing wholesale prices from retails prices paid by consumers. The latter may increase, nevertheless, as consumers have to pay for the higher production costs of electricity from renewable sources in one way or the other. In Germany, for example, this is put into practice via a levy put on top of the grid fee ("EEG-Umlage"). The net effect depends on the mix of renewable energy sources and their respective costs (Bode & Groscurth 2006) and may change over time.

Nevertheless, it is important to state that, with the continuing extension of electricity production from renewable sources,

- wholesale prices of electricity are systematically decreased whenever the intermittent renewable energies are available,
- that there will be a steadily increasing number of hours in which there is more electricity from renewable sources than actually asked for by consumers, and
- that in times where renewable source are not available, backup capacities in the form of conventional power plants and / or electricity storage are needed.

The three issues listed have a number of implications. The first issue leads to the conclusion that a continuous extension of renewable energy capacities needs sustained and sufficiently high incentives to invest. This is not the case for the current market design in combination with high shares of renewable energy (Bode & Groscurth 2009). Secondly, we have to consider suitable ways to utilise the surplus of electricity at certain times or which installations have to be shut down during those hours. The third point implies that new incentives have to be created to ensure that investors will build the necessary backup capacities.

3 Development of a target systems

After the Fukushima catastrophe some countries have intensified their plans to migrate their electricity systems towards very high shares of renewable energy sources. However, essential questions remain unresolved, especially when it comes to deciding how such a system might or should look like in the end. In the process so far, there is a lack of attention to the fact that it does not make sense to let all technologies grow unlimitedly. Rather sooner than later, technical limits to growth will be reached. We therefore pledge to start looking for a cost-efficient system. In so doing, we should no longer focus on the average generating cost of individual technologies, but on the total cost, which consumers have to pay in the end for the kilowatt-hour delivered to them. In this context, additional costs such as energy storage, transport or opportunity costs for not using existing capacities at times have to be taken into account.

Additionally, it is often demanded that electricity production should be as decentralised as possible. Pursuing such an objective may lead to a different, not necessarily cost-efficient mix of technologies. Nevertheless, society may decide to go into that direction. However, the consequences, such as potentially higher costs, should be made transparent in the debate.

3.1 Requirements for a cost-efficient system

In order to determine, how the electricity market has to be designed to successfully pursue the objectives listed above, we propose the following rather simple approach: The energy system should no longer be looked upon from the status quo, but from its final state, e.g. in the year 2050. If we aim at a share of 80% of the electricity being produced from renewable sources, such as foreseen in the latest energy concept of the German government, we can calculate the necessary amount of electricity which has to be produced each year. Considering a net electricity demand of 500 TWh per year for Germany, 80% correspond to 400 TWh of electricity from renewable sources. The calculation may of course be carried out similarly for other shares, which are sought at earlier or later points of time. However, one thing has to be clear: In this example, 400 TWh is the upper limit for renewable energy technologies altogether. Consequently, 400 TWh in total cannot mean building capacities for 400 TWh from wind energy, 400 TWh from photovoltaics (PV) and so on. Nevertheless, the current feed-in law does not foresee a steering mechanism addressing this issue so far. This is understandable from a historic point of view as the law started with renewable shares that could hardly be noticed in the statistics. Now, after 20 years of the exponential growth of wind, PV, and bio energies and a renewable energy share beyond 20%, it is time to start considering such a mechanism. Otherwise we are in danger of installing massive overcapacities at high and unnecessary costs. Consequently, when thinking from the end, capacity caps have to be an integral part of any good design of a feed-in tariff. At this point, it is an open issue, how long we will need a feed-in tariff in the first place. The answers to this question depend on a number of assumptions and diverge from "temporarily" (e.g. SRU 2011) to "forever" (e.g. Bode 2008).

Nevertheless, for both cases we can ask whether or not there is a cost-efficient system design, from which limits to capacities of certain technologies may be derived. Consequently, introducing the respective caps at an early stage of the development of renewable energy sources might be helpful if not compulsory from an economic point of view. Such a cost-efficient system would minimise the costs, which consumers would have to pay in the end for the electricity that they actually use. From the consumer's point of view, the costs of individual technologies are irrelevant.

Let us elaborate on this point with photovoltaics (PV) as an example. Even if this technology had the lowest average production costs of all renewable energy technologies, one could not base the energy system on PV alone. Obviously, PV will not produce during the night and will produce less in winter than in summer. Therefore, consumers will have to pay for backup in times of lower PV production, be it from conventional power plants, storages or other renewable energy technologies. Thereby, the average cost for the kilowatt-hour of electricity consumed is increased.

Furthermore, it has to be taken into account that the highest demand (= maximum load) in Germany occurs during the early evening hours in winter (Figure 4). Not only will there definitely be no power production from PV during these times, but it may happen, that there is also little wind. Thus, the complete maximum load of up to 80 GW would have to be covered by the backup capacities.

It should be noted at this point, that concepts such as "Smart energy", "Smart grids", "Smart metering" or "Demand side management" will allow for a substantial shift of loads. However, their potential is restricted to several hours, perhaps days. Shifting over weeks or even seasons seems hardly feasible with these approaches. Consequently, there are two remaining options for backup:

- importing electricity or
- producing electricity from domestic power plants with synthetic fuel, which is derived during times of surplus production from renewable sources.

For the functioning of the system described so far, it is also deemed necessary to adapt electricity grids to the new requirements.

Hour of a day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	64	64	62	58	54	55	55	53	56	57	58	58
2	62	62	60	53	50	50	51	49	52	53	55	55
3	60	60	58	51	48	48	49	47	50	51	54	54
4	60	60	57	49	46	47	48	46	48	50	[illegible]	54
5	60	60	58	50	46	47	47	46	48	50	[illegible]	55
6	60	61	59	51	48	47	48	46	49	51	[illegible]	56
7	64	65	63	53	50	49	50	49	53	55	65	60
8	70	71	67	57	56	55	56	56	61	62	71	67
9	73	74	71	62	62	62	62	62	66	68	73	70
10	74	75	73	65	66	66	66	66	69	71	74	71
11	75	77	74	67	68	67	68	67	71	72	76	72
12	77	78	76	69	69	69	69	69	72	73	77	74
13	76	77	75	71	71	71	71	71	74	74	76	73
14	75	76	74	70	70	69	70	70	72	73	75	72
15	74	74	73	68	69	68	68	68	71	71	74	70
16	73	73	72	66	67	66	67	67	69	70	74	71
17	74	72	70	65	66	65	66	65	68	69	76	73
18	78	75	70	64	64	64	65	64	67	68	80	77
19	79	79	74	64	64	64	65	64	67	69	80	77
20	77	78	75	64	65	64	65	64	68	73	77	74
21	73	74	72	64	64	63	64	64	69	74	73	71
22	71	72	70	65	62	61	61	62	70	70	70	68
23	71	71	70	64	62	60	60	61	65	66	68	67
24	68	67	66	62	60	59	60	58	61	62	62	62

PV produces here

Figure 4: Average daily load curves for different months (load in MW).

3.2 Import of electricity and security of supply[2]

To secure an uninterrupted supply of electricity at high shares of renewable energy, it is regularly demanded to extend interconnectors in the electricity grid within the EU and towards neighbouring regions. The idea behind this is to import electricity during times of low availability of intermittent sources in one country from other countries within or outside of the EU. One of the most far reaching projects in this respect is DESERTEC, which foresees to import electricity from solar-thermal power plants in Northern Africa into Germany and other EU countries. [3] However, one has to ask, whether this approach may actually contribute to security of supply and whether this is desirable in the first place. The decisive questions with this respect are:

- Will imports serve as a base load that is will there be a continuous stream of electricity? If so, then the backup problem remains for the residual demand on a lower level, but otherwise unchanged.
- Will imports only occur, when domestic production is not available? If so, which energy sources should be behind those imports in order to make sure, that import is possible at any time when it becomes necessary? If these sources are themselves based on intermittent renewable sources, there is a non-zero chance, that they may also not be available when needed.
- To what extent is Germany (or any other country) willing to make itself dependent on electricity imports? Should there be a minimum reserve with respect to capacity or to a timespan to be covered?

2 This chapter is a shorter version of work published earlier (Bode et al. 2011).

3 Cf. www.desertec.org/en/.

It should further be taken into account, that one of the most important technologies for Germany, wind energy, fluctuates not only during days and seasons, but also over years (cf. Figure 5). Likewise, backup has to be dimensioned to cover years with little average wind supply.

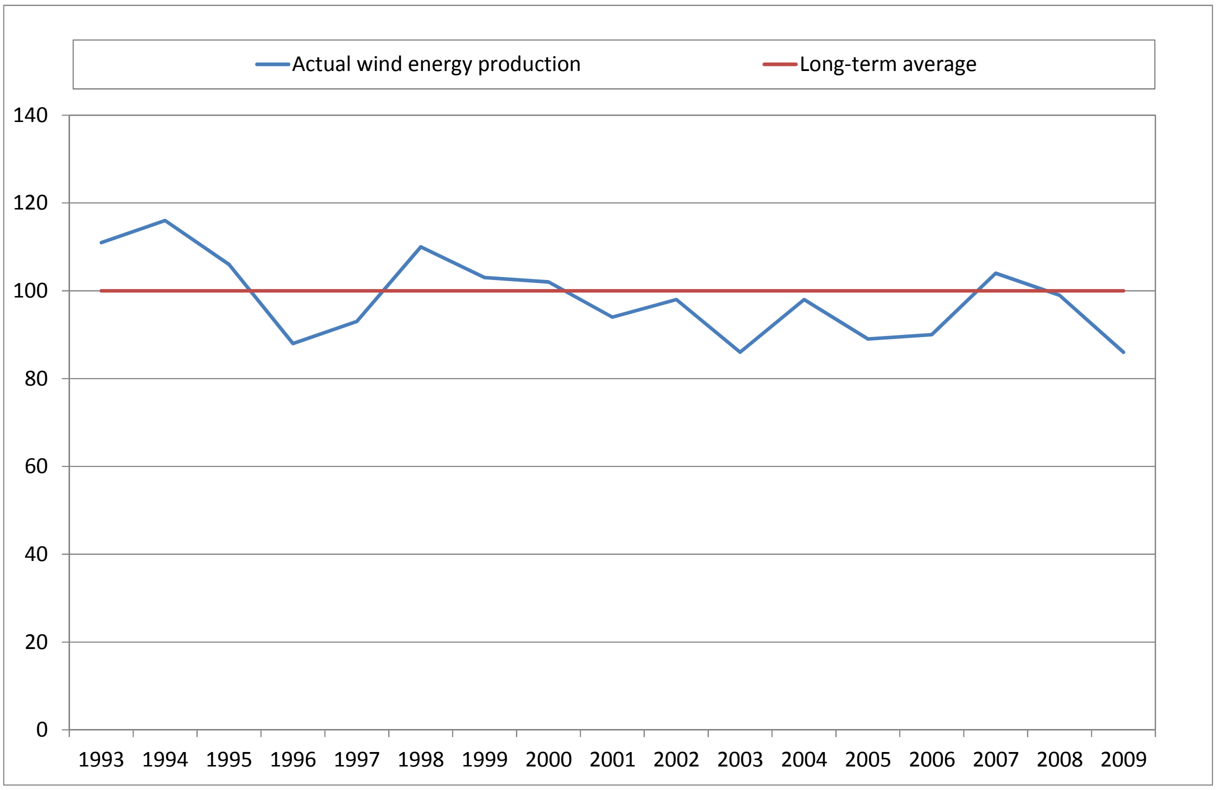

Figure 5: Wind energy supply 1993-2009 as a percentage of the long-term average (Bode et al. 2011, p. 30).

Another option to bring demand and supply together is energy storage. When discussing the feasibility of such a solution, it is important to not only focus on production capacities in MW or GW, but also on the energy volume stored in MWh or TWh. As back-of-the-envelope calculations can show, neither pumped hydro storage nor batteries of electric cars will suffice to deliver a secure backup for Germany.

During the redesign of the electricity supply in Germany and Europe, it has to be discussed, what level of self-supply will be desired. If a rather low share of imports or a rather large strategic reserve is found to be desirable, then the following questions have to be addressed:

- Which energy shall be stored?
- What capacity of conventional installations has to be installed?
- Should the backup capacity be used during standard conditions or only when shortages occur?
- What are the consequences for the targeted extension of the EU-wide electricity transport system?
- How should the reserve be financed?

3.3 Electricity generation from domestic storage and power plants

As discussed in Sec. 2.2, there are little or no incentives to invest in conventional power plants that could serve as efficient backup capacities. The same is true for long-term energy storage, as it would be needed for smoothing seasonal or multi-year fluctuations of the electricity supply from renewable sources.

Before discussing an innovative incentive scheme, we will provide a rough estimate of the requirements for storage and power generation capacities. Since the maximum load in Germany occurs in the early evening hours in winter (cf. Figure 4), there will be no contribution from PV at those times. In addition, longer periods of low wind velocities may occur simultaneously. It is rather futile to discuss at length, whether renewable energy sources may have a secured power contribution of 5% or 10% of the capacity installed. In a first order approximation, it suffices to assume that there has to be a backup for the full maximum load. Once we have installed three quarters of that capacity, we may make adjustments to this first and rough assumption. However, we are very far away from having this type of capacity installed, if we disregard nuclear and coal-fired power plants, which will no longer be part of the system in the mid-term due to the underlying objective.

When a certain share of renewable energy in the system is exceeded, it will no longer be possible to operate each and every new installation whenever the respective resource is available. There will rather be an increasing number of hours during which more electricity will be available than demanded. It is a matter of cost optimisation to decide, whether to start storing surplus electricity in one way or the other right away or to accept for the time being that some installations have to be shut down during those hours. The problem is aggravated as the build-up of renewable energy capacities continues. Whatever we decide for, in both cases the average cost of the kilowatt-hour of electricity provided will increase.

Rough calculations of the arrhenius Institute for a subsystem indicate that the build-up of wind energy is more cost-efficient than storage for up to a share of 80% of the electricity produced. Beyond that point, the share of renewable energy may hardly be increased without storage. A 100% supply from renewable sources is only feasible with energy storage, if we do not want to depend on imports.

3.4 UK experience

The current German government in its recent energy concept only concedes a "demand for further research" with respect to the issues discussed so far (Bundesregierung 2010). In the UK, the debate has already moved beyond this point. The British regulator for the gas and electricity markets Ofgem recognised the problems of security of supply and missing investment incentives as early as February 2010 in its consultation paper "Project Discovery: Options for delivering secure and sustainable energy supplies" (Ofgem 2010). In this paper, Ofgem identifies a number of possible solutions:

- minimum prices for CO_2 allowances,
- improved ability for the demand side to respond,
- enhanced possibilities for the demand side to react to price signals,
- enhanced obligations on suppliers and system operators,

- a centralised market for renewable energy,
- replacing renewables obligation with renewables tenders,
- tenders for all capacities,
- central buyer of energy, including capacity.

The demand for a centralised market for renewable energy and substituting tenders for renewables obligation are specialties of the UK system, which do not necessarily apply for other countries. In Germany, for example, there is already a single market for electricity from renewable sources.

The classification of the instruments suggested by Ofgem in Figure 6 shows the conflict between competition and economics on the one hand and security of supply on the other hand. This has been observed earlier (Newberry 2002), but has not found sufficient attention in the energy policy debate so far.

The "central buyer" suggested by Ofgem, probably the measure of last resort, would mean the end of a competitive spot market as we see it today. We think that some of the instruments suggested by Ofgem, such as a minimum CO_2 price, would provide only temporary solutions, but could buy some time. In addition all instruments will have to be scrutinised with respect to their legal feasibility (Figure 6).

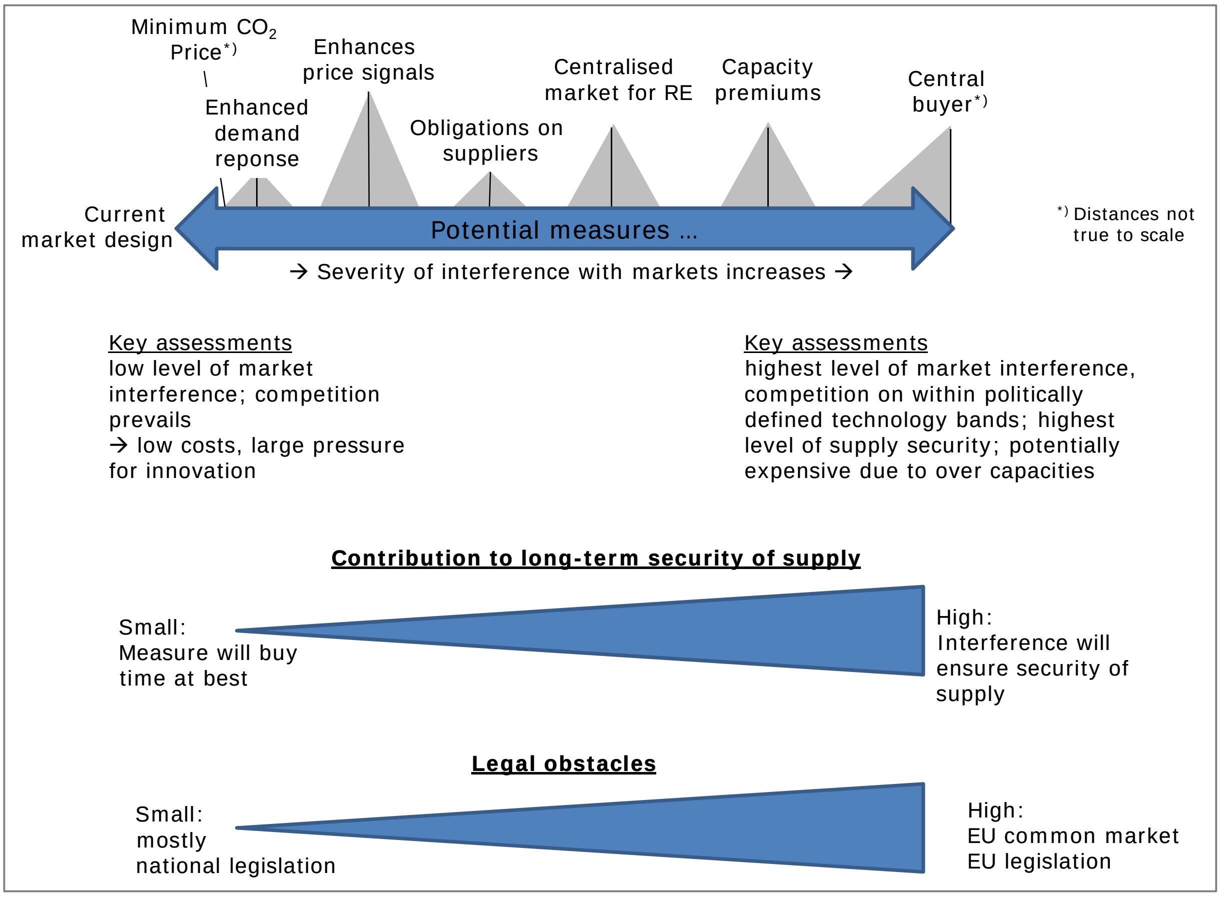

Figure 6: Possible market interventions according to Ofgem (2010), classification by the authors.

4 Investment incentives on the way towards a cost-efficient system with a high share of renewable energy

It has been demonstrated, that a high share of renewable energy in electricity production will not develop by itself in a liberalised market environment and that such a market does not provide incentives to invest in the necessary backup infrastructure.

Therefore, in the following we will put forward an idea for a redesign of the German feed-in tariff system (EEG) that is based on public tenders of electricity volumes. Hence, we call it **Volume-Market-Model**. Such tenders are a standard practice when it comes to placing public contracts. It may be compared to tenders for energy supply of public institutions or for the transport infrastructure. There is some experience with tenders for renewable energy outside Germany, which should be considered when such a system is designed.

In contrast to the EEG, the new approach distinguishes between technologies exploiting intermittent (e.g., wind energy or PV) and non-intermittent energy resources (such as bio energies). Furthermore, a tender phase and an operational phase are distinguished.

4.1 Technologies based on intermittent resources

4.1.1 Tender phase

A central institution yet to be named will place a tender for buying electricity from installations with a defined total capacity (in GW) and a given number of full-load hours over a fixed number of years. The maximum amount of electricity that will be remunerated under the contract may be calculated from these three characteristics.

The tender may distinguish between various technologies such as wind energy onshore, wind energy offshore, photovoltaics etc. The tender may also be differentiated with respect to the regional location of installations. The reason for this could be the optimal positioning of production capacities in an existing grid, which might serve to avoid expensive and tedious extensions of the grid infrastructure. The tender might further include requirements for system services. It could, for instance, become mandatory to install remote control which allows the system operator to influence the power production of the installation. In Germany, this is already the case for all larger installations. In addition, it could be required to install capacitances and inductances which contribute to providing reactive power on a local level.

Tenders should be placed continuously, e.g. once per quarter rather than annually, to prevent the market from fluctuating too strongly. Finally, they may contain provisions to support small and medium enterprises (SME).

All bids for the tender have to be placed with a specific amount demanded for the electricity delivered, i.e. in €/MWh or ct/kWh. Bids may address shares of the total capacity asked for. Contracts will be awarded in increasing order to those bidders, who have placed the lowest bids (in €/MWh) until the tender is fully placed. Each successful bidder will receive a contract for the delivery of an amount of electricity calculated as the product of

- the nominal capacity of the installation(s),
- the expected average full-load hours per year as given in the bid, and

- the initial contract length defined in the tender (in years).

Each contractor will receive the remuneration he has bid with.

In accepting the contract, the investor / operator will commit himself to build the awarded capacity and to deliver all the electricity produced by the respective installations to the agency in charge of the tender. He will not be allowed to sell part of the electricity directly.

4.1.2 Operational phase

When the capacity is built and commissioned, the operational phase begins. The respective installations will deliver electricity to the grid and will receive the contracted remuneration per kilowatt-hour delivered and taken. The remuneration may deviate from the expected average remuneration (= maximum remuneration divided by the contract length). This may have several reasons:

- Meteorological fluctuations influence the electricity production, e.g. in years of stronger or weaker wind.
- When the capacity is extended, the total production of electricity from renewable sources will meet a low demand in some hours. If the surplus cannot be exported or stored, some installations will have to cut their production.

If the maximum amount of electricity is delivered before the expected end of the contract, the contract will expire anyhow. This clause is important in order to determine the cost of the contract at its start and to avoid exaggerated remuneration. If, however, the maximum amount is not delivered during the contract period, the contract will be extended until that amount is reached.

Since the contract is based on the amount of electricity to be delivered and not on a fixed period of time, the operator will not suffer from a time shift in his delivery other than the interest on earlier payment. The latter might even be compensated. Furthermore, hardship clauses might be foreseen for smaller enterprises.

After the contract expires, the operator may sell the electricity produced himself. This is not a specialty of the Volume-Market-Model, but is the case under the EEG as well. The free marketing would begin somewhat earlier or later, if the duration of the tender contract is adapted.

Example 1 of the Volume-Market-Model for technologies based on intermittent resources

As the result of a tender, an annual electricity production of 50 MWh is expected over ten years, i.e. 500 MWh in sum. The actual production deviates from this figure. Cases a) and b) demonstrate the subsequent effects on the remuneration.

Case a) Shortening of the contract

Year	1	2	3	4	5	6	7	8	9	10	11	12	Sum
Expected volume for remuneration (MWh)	50	50	50	50	50	50	50	50	50	50	0	0	500
Actual volume produced (MWh)	50	50	*80*	70	50	50	50	50	50	50	50	50	
Actual volume remunerated (MWh)	50	50	80	70	50	50	50	50	50	0	0	0	500

The reason for the higher production in years 3 and 4 may be average wind velocities above average in those years.

Case b) Extension of the contract

Year	1	2	3	4	5	6	7	8	9	10	11	12	Sum
Expected volume for remuneration (MWh)	50	50	50	50	50	50	50	50	50	50	0	0	500
Actual volume produced (MWh)	50	50	*30*	50	50	50	50	50	50	50	50	50	
Actual volume remunerated (MWh)	50	50	30	50	50	50	50	50	50	50	*20*	0	500

The reason for the lower production in year 3 could be below average wind velocities in that year or forced outages demanded by the system operator.

Finally, it has to be discussed, who is responsible for the marketing of the electricity delivered and remunerated under the Volume-Market-Model. Imbalances in delivery will be smaller the more installations are taken together. Thus, ideally there should be a central institution taking the electricity from renewable sources and bringing it into the overall system, e.g. by selling it at the electricity exchange. This is the case in Germany today, where transport grid operators act as intermediaries. It is also recommended by the Brattle-Report, which was recently published in the UK (The Brattle Group 2010).

However, grid operators in Germany do not have incentives to provide the best possible prognosis for production from renewable sources and to stick to the logged-in schedules, since they may pass on any extra cost to the consumers via the EEG levy.

Thus, in order to keep system costs low, there should be incentives to keep schedules. This could, for example, be promoted by requiring all operators with a certain cumulated capacity to submit production schedules and to bear the cost of deviating from them.

A priority rule for electricity from intermittent sources is dispensable, since that electricity will bid at the exchange at a price of zero and will therefore normally be taken. Only if there is too much electricity in the market, will some installations have to cut production. This might be more rational than to bid at and accept negative prices, in which there is no advantage whatsoever for wind energy or PV. For the operators of these installations, cutting production would no longer be critical since their contracts will be prolonged accordingly.

4.2 Technologies based on non-intermittent sources

Technologies based on non-intermittent renewable resources such as bio energy, differ substantially from those using intermittent sources. In contrast to the current provision of the EEG in Germany, which provides incentives to produce as much electricity in each year as possible, in the future, incentives should be designed in such a way that

- they allow for building installations and keeping them ready to operate, but
- to actually operate those installations if and only if the residual load, i.e., that is the load minus production from intermittent sources, is larger than zero.

Thus, bio energy should not displace electricity production from wind energy and PV. The question of system services shall be put aside for the moment. Nevertheless, it has to be decided

- how cogeneration units should be treated and
- whether bio energy should be prioritised with respect to fossil fuel installations.

These two issues will not be addressed here.

The model proposed in the following is based on tenders for reserve energy. Since the possible periods for production are much longer for the installations under discussion here than they are in the reserve energy market, it is suggested to adapt the remuneration ex-post.

4.2.1 Tender phase

A central institution yet to be named will place a tender for capacity premiums for a defined total production capacity of installations based on non-intermittent renewable resources over a fixed number of years. The installations will sell the electricity produced on the market.

The tenders may distinguish between technologies, i.e. be restricted to solid biomass or biogas etc. For reasons of simplicity, we will speak of bio energy in the following. Tenders may also be differentiated with respect to regional location of installations. The reason for this could be the optimal positioning of production capacities in an existing grid, which might serve to avoid expensive and long-lasting extensions of the grid infrastructure. Tenders might further include requirements for system services. It could, for instance, become mandatory to install remote control which allows the system operator to influence the power production of the installation. In Germany, this is already the case for all larger installations. In addition, it could be required to install capacitances and inductances which contribute to providing reactive power on a local level.

Tenders should be placed continuously, e.g. once per quarter rather than annually, to prevent the market from fluctuating too strongly. They could contain provisions to support small and medium enterprises (SME).

All bids have to be placed with payments for the power provided, i.e. in €/MW. Bids may address shares of the total capacity asked for. Contracts will be awarded in increasing order to those bidders, who have placed the lowest bids (in €/MW) until the tender is fully placed.

Each successful bidder will receive, for every hour in which his installation is notified as ready-to-operate, the share x of the total premium promised in the contract. The share x is calculated as

*x = total capacity premium / (number of years * 8760 h/a)*

4.2.2 Operational phase

When the capacity is built and commissioned, the operational phase begins. Each operator will sell the electricity produced himself or via third parties (brokers) and will receive the respective revenues. The capacity premium will be paid on top for each hour, in which the installation is notified as ready-to-operate, independent of whether it will actually be operated or not. Capacity payments will end automatically, when the total premium awarded has been paid.

Under these conditions, the operator will bid at the electricity market with his marginal costs as described in Sec. 2.1. If the installation is "in the money", i.e. if it's marginal cost is smaller than the electricity price, it will earn revenues on the market, which are determined by the amount of electricity delivered times the market prices. It will earn margin contributions given by the revenues minus the marginal cost plus capacity premium.

If the installation is "out of the money", i.e. if it's marginal cost is larger than the electricity price, it will not receive revenues from the market. However, it will still receive the capacity premium as margin contribution.

One could argue, that the capacity premium should only be paid, if the installation is not operated. However, this would lead to the operator bidding at the electricity market with marginal costs plus capacity premium. He has to include losing the premium as opportunity cost in his cost calculations. The installation would then only be in the money, if the electricity price is higher than its marginal cost plus capacity premium. Consequently, the installation would be operated less frequently. The margin contributions earned during operating hours would be higher, but total contributions would be lower.

If the installation would happen to be the marginal power plant, the electricity price would rise by the capacity premium. Thus, consumers would not only have to pay the premium for installations directly supported, but for the total amount of electricity needed in that hour. This would generate additional margin contributions for all other installations, which is not intended.

To avoid exaggerated profits due to too high capacity premiums, margin contributions earned on the market could be subtracted from the premium, e.g. by shortening the contract period. This would create an incentive to operate the installation if possible, because the operator would receive margin contributions at an earlier point of time and could realize an advantage due to interest.

The model for technologies based on non-intermittent resources described here could be used to provide incentives for long-term storage capacities or conventional backup capacities as well.

4.3 Capacity premiums for storage

In its current design, the German feed-in law (EEG) allows for storing electricity from renewable sources, but provides little incentives to invest in storage technologies (Dietrich & Ahnsehl 2010 and 2010a). The reason for this is that losses during the storage cycle are not compensated and remuneration is only provided for the electricity production, but not for the storage infrastructure. Since storage will have a decisive role when further extending the share of renewable energy sources, this situation should be changed as soon as possible.

A capacity premium could serve as a suitable incentive. It has been explained for bio energy in Sec. 4.2, but is also applicable for storage technologies. However, there are some specialties, which should be taken into account. Storage for electrical energy consists of several components:

- a conversion unit, which transforms electrical energy, which cannot be stored in large quantities in practice, into another energy form suitable for storing,
- a storage for that energy form, and
- another conversion unit, which again produces electricity from the stored energy.

The most common and cost-efficient way to store large amounts of electric energy are pumped hydro power plants. They consist of electric pumps, which transport water from a lower to an upper basin and convert electric into potential energy. Turbines will then produce electricity by letting the water return from the upper basin to the lower level.

It is the role of energy storages (for renewable energy), to take energy in in times of high availability of intermittent sources and to provide it in times of low availability. This may occur on very different time scales, within a day, a week, a month or even between years. Depending on the time scale of storing and regaining the electricity, the different parts of the storage will be used to a very different extent.

Today, pumped hydro plants are typically loaded at night and will then provide electricity during the demand peak during day times. It is obvious, that their turbines cannot reach the same operational hours as pure hydro power plants. Consequently, from this reason alone electricity from pumped hydro plants is more expensive than from pure hydro plants, while the cost for the water pumps and the second storage basin are not even considered.

Nevertheless, due to a comparatively high number of operation hours and the leverage between pumping with cheap electricity and selling at high prices, pumped hydro power plants are economical under prevailing conditions. However, the potential for this kind of power plants is very limited due to natural conditions in most parts of Europe and due to the environmental problems related to their building.

In the beginning debate on the structure of a future electricity supply, which is mainly based on renewable energy, short-term storage is not the most pressing issue. Rather the unresolved problem is how to secure electricity supply, if renewable sources are not available or not available on the usual level over longer periods of time such as two or even four weeks. This may well be the case during misty, but calm conditions in winter. The storage capacities necessary to cover such periods would only operate over a few cycles per year or maybe even less than one cycle per year (cf. Bode & Dietrich 2011).

Figure 7 illustrates this dilemma. The investment cost is a fixed quantity. At a high number of cycles per year, the installation may earn substantial margin contributions, which may suffices to finance the investment. If, however, there are only a few cycles per year, the revenues from the electricity market will not be sufficient to carry the investment. Furthermore, potential revenues will decrease as the number of storages in the system increases.

Current feed-in tariffs such as the German EEG are not providing incentives to invest in such storages. Due to the potentially small number of cycles, it would be problematic to couple the remuneration to the electricity produced, because it would have to be very high. Thus, it would make more sense, to use the capacity mechanism described above to guarantee a steady stream of income to those who build such installations.

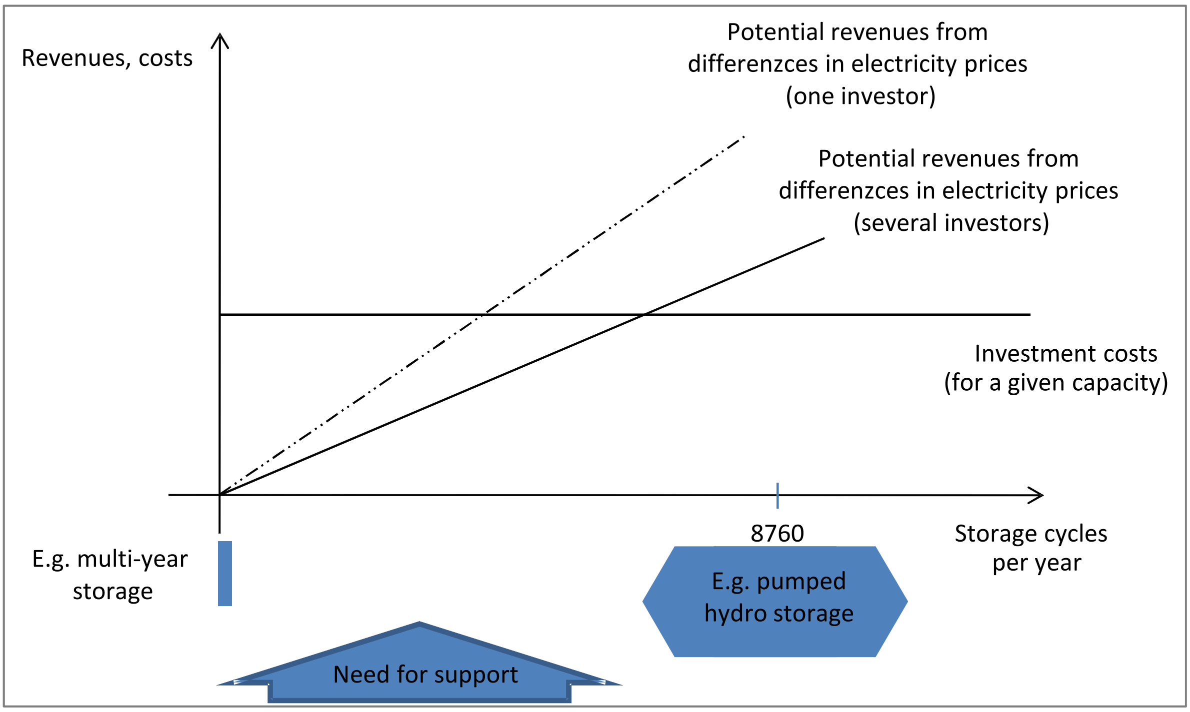

Figure 7: Incentives to invest in electricity storage with respect to the number of storing cycles per year from an investor's point of view (schematic representation).

4.4 Conclusions for the Volume-Market-Model

The Volume-Market-Model described in Sections 4.1 and 4.2 will create competition, which helps to reduce installation costs. The market instead of experts and lobbyists will determine the remuneration.

It will further provide enhanced influence on the location of installations in the grid and on the shares of different technologies. This will be of growing importance when extending the share of renewable energy in the system and aiming for 100% in the end.

It creates a simple mechanism to cut power production from intermittent sources, if more electricity is produced than is needed, without placing unbearable financial burdens on the respective operators. For production from non-intermittent sources, incentives are created to produce electricity, when it is actually needed.

At the same time, the fixed remuneration for electricity produced, proven as the single most successful element in renewable energy schemes, will remain untouched.

Potential disadvantages of the model may arise from a somewhat higher effort during project development, which might deter some developers, and from the tender procedure.

Before the new model is implemented, a number of questions have to be resolved:

- Who will determine which amounts from which technologies will be put for tender?
- Will requirements for system services by part of the tender and if so, how will they be taken into account when it comes to rewarding contracts?
- How should the new model be introduced? At a single point of time for all new capacities or stepwise, according to size of installations or according to technologies?
- In which phase of the project development should bids be placed? Will bids have to include a fixed location or may locations be determined after a contract has been won?
- What will happen if a project is not realized? How much time will developers have to build and commission the equipment?

5 General conclusions

Based on what has been said above, we propose a scheme for making the prevailing energy concepts more concrete.

Beforehand, it should be noted that the German target of producing 80% of the electricity from renewable source in 2050 is so far a statement of political will, but in no way legally binding. To provide stable conditions for investors, it would be helpful to make this objective a more binding one. A continued back and forth like with the phase-out of German nuclear power plants is not helpful for triggering investments into backup capacities needed in the mid- and long-term.

Assuming that the target is accepted politically and in society as a whole, there are the following tasks to be tackled:

1. Requirements have to be formulated for the technologies, which shall guarantee a large and growing share of renewable energy in electricity production up to 100% in the future. These requirements should become an integral part of any remuneration scheme as soon as possible.
2. It should be defined (with some band width), which technologies will contribute to the electricity production in 2050. Accordingly, remuneration schemes such as the EEG or potential successors should contain a volume component. Obviously, it will be difficult to determine today the energy mix 40 years from now. There will be too many new developments and insights on the road. Therefore, target bands for the individual technologies should be revised from time to time based on the actual development of costs, efficiencies etc.
3. It has to be determined, which capacities will be needed beside the 80% (or more) share of renewable energy in volume of electricity production, in order to secure power production at any point in time (production capacities, storage, grids etc.). In this environment

it has also to be discussed, what role fossil-fuel fired cogeneration should take and whether it should be given any priority status at all.

4. It has to be considered, whether a liberalised electricity market provides sufficient incentives to invest in the capacities defined above and which additional measures and instruments may be needed to ensure this.
5. It has to be defined, which actors with which mandate will continuously monitor the development and will make decisions an investments and incentives.
6. It has to be checked, whether the national way forward described here is in line with current EU law and policies.

Figure 8 shows these step in a chronological order and identifies loops.

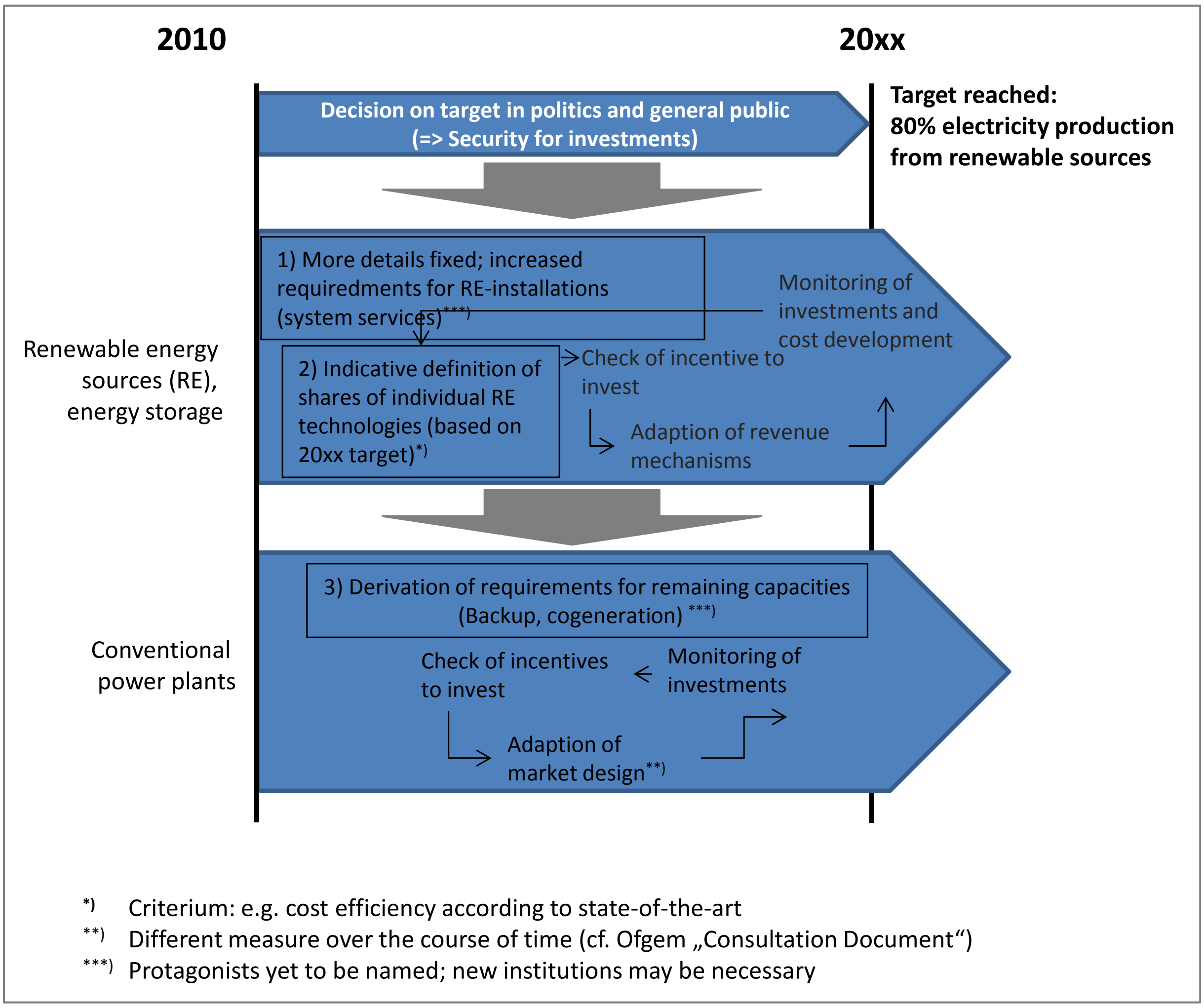

Figure 8: Potential scheme of actions on the way to reach renewable energy targets in the electricity sector.

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