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Institutional Framework for the Development of Offshore Wind Power Projects

Key Aspects for Instrument Choice and Design from an Institutional Economic Perspective

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Institutional Framework for the Development of Offshore Wind Power Projects

Key Aspects for Instrument Choice and Design from an Institutional Economic Perspective

By
Albert Hoffrichter
Thorsten Beckers
Ralf Ott

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1. Introduction

National energy policy plans in Europe intend a large-scale expansion of offshore wind power (OWP) installations. The cost of future generation investments will highly depend on the institutional frameworks for the development of OWP projects.[1] The question as to which market design is most suitable for achieving the projected OWP expansion at low costs remains the topic of a controversial debate. This research paper aims at contributing to this debate by presenting a line of arguments based on institutional economic considerations on the fundamental mechanisms of providing electricity generation capacity.

Currently, EU member states apply very different approaches for the provision of OWP plants, which is reflected in a large variety of the institutional frameworks. Some countries with serious interests in OWP expansion apply targeted instruments which allocate comparatively moderate risks to OWP generators (i.e., investors and operators). A substantial share of contributors to public and scientific debates regard the application of such provision schemes as justified only for a transitional period. Part of the criticism dealt out merely aims at modifying currently applied mechanisms in order to confront generators with higher market risk. Other voices seek more drastic changes, considering the so-called "energy-only market" (EOM) to be the ultimate, supposedly superior target model for any kind of generation investment, including OWP. Especially the latter position is sometimes linked to a general bias towards "market-based" mechanisms, suggesting that the provision of goods should mainly be carried out by private market actors.[2] This view, however, neglects (New) Institutional economic findings which suggest that there is no one-fits-all solution regarding the framework for providing goods. Instead, the appropriate distribution of decisions and tasks (related to the good's provision) between market actors and the regulator (in the broad economic sense) highly depends on the specific circumstances. Therefore, considerations on the market design – which are largely linked to the allocation of tasks and decisions – should necessarily involve the characteristics of OWP investment.

One main goal of the economic analysis presented in this research paper is to lay solid foundations for a profound and objective debate on the institutional framework for the provision of OWP. In order to do this, we start by addressing electricity market design topics broadly, having a special focus on general advantages and disadvantages of

[1] This research paper was conceptualised by Albert Hoffrichter and Thorsten Beckers. Albert Hoffrichter, who primarily works as a research associate at Technische Universität Berlin – Workgroup for Infrastructure Policy (TU Berlin – WIP), was writing this research paper as a researcher at the Berlin-based Institute for Climate Protection, Energy and Mobility (IKEM). Thorsten Beckers is a researcher at TU Berlin – WIP and an honorary board member at IKEM. Ralf Ott supported the preparation of the research paper. He is a research associate at TU Berlin – WIP as well and was also working at IKEM at the time when the research paper was developed.

[2] Cf. for instance Toke (2007), „Trading schemes, risks, and costs: the cases of the European Union Emissions Trading Scheme and the Renewables Obligation".

assigning certain tasks to either market actors or the regulator. Afterwards, we move on to considerations specifically relating to OWP. The subject matter is kept abstract in the sense that we do not refer to any current situations in certain countries; instead, the analysis aims at providing a basis for practical applications. Our qualitative assessment of different institutional solutions is based on insights from economic theory in general and from New Institutional Economics in particular. We have a focus on remuneration and procurement schemes for offshore wind power plants, while excluding grid connection topics over large parts of the analysis (only certain aspects which are directly interrelated with the examined content are considered to a limited extent). Similarly, the topic of international cooperation (including, for instance, joint projects or the harmonisation of national institutional frameworks) is largely excluded from the scope of the analysis.[3]

The research paper is structured as follows:

- Section 2 starts with a definition of the set of objectives for our assessments and a brief introduction to some general institutional economic insights which are essential for the ensuing considerations. In a next step we discuss two conceptual models for the organisation of power generation investments, namely: (A) the above-mentioned EOM and (B) capacity remuneration mechanisms (CRM). As will be explained below, the CRM approach can be regarded as the underlying concept of targeted instruments for the provision of RES-E (electricity from renewable energy sources) plants. Our discussion involves taking a closer look at several design variations within this concept.
- Thereinafter, section 3 seeks to identify components of an appropriate regulatory framework for OWP investments. In order to achieve this, we determine the OWP characteristics which are most essential for adequate design choices and put them into context with the general findings obtained before.
- The final section 4 concludes the analysis with a summary of the main results.

[3] For an institutional economic analysis on international OWP cooperation in the form of joint projects cf. Hoffrichter / Beckers (2018), "International Cooperation on the Expansion of Offshore Wind Generation Capacity – Potential Benefits and Pitfalls of Joint Projects from an Institutional Economic Perspective", which presents another analysis developed within the framework of the Baltic InteGrid project.

2. Alternative institutional framework models for generation investment

2.1 Preliminary considerations

Assumed set of objectives for the analysis

When evaluating and comparing institutional frameworks from an economic perspective, it is necessary to define a set of objectives. Although energy policy decisions in practice can be based on a large variety of motives, three overarching objectives are usually assumed to play an important role, namely: security of supply, environmental protection and cost efficiency. These three criteria also form the set of objectives used in our analysis; however, we usually only discuss the cost efficiency aspect, as it appears to be the decisive factor for the problems examined.[4] Costs are regarded from a welfare perspective (which ignores the distribution of rents between producers and consumers) as well as from a consumer perspective; explicit differentiations between those two dimensions only appear when they are particularly relevant. As a relative measure, our cost efficiency objective does also comprise utility aspects. This means, when comparing alternatives we take expected differences with respect to value creation (including interrelated aspects such as a timely realisation of generation projects) into account.

Allocating decisions and tasks of a supply process

Designing the institutional framework for generation investment goes hand in hand with deciding upon the extent of centralised decision-making by the regulator on the one hand and decentralised decision-making by market actors − and thus the usage of elements of competition − on the other hand. Apart from certain fundamental framework regulations which are virtually indispensable for the provision of any goods, the reasonable allocation of decision-making responsibilities depends on various factors; weighing advantages and disadvantages is often not trivial. Making the right choices requires a deeper understanding of the relevant mechanisms and interdependencies, since neither competition nor regulatory planning can be considered as generally advantageous.[5] Instead, the specific characteristics of the decisions in question and the prevailing circumstances determine which alternative is preferable.[6]

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[4] We assume in this analysis that the expansion of OWP generally has a positive (net) effect on the environmental objective. Security of supply issues are included only implicitly at certain points of the analysis (especially in the context of site selection and plant layout/dimensioning).

[5] This proposition complies with findings of Friedrich August von Hayek, who classifies each economic activity as planning and states that "[c]ompetition (…) means decentralised planning by many separate persons" when discussing the allocation and transferability of knowledge in an economy. Cf. Hayek (1945), "The Use of Knowledge in Society".

[6] Cf. Ostrom / Schroeder / Wynne (1993), "Institutional Incentives and Sustainable Development − Infrastructure Policies in Perspective".

- Distribution of the relevant resources (including knowledge) among the actors
- Importance of the decision or task for society (often related to the importance of the provided good)
- Importance of strong incentives and possibilities to incentivise public actors
- Barriers to the coordination of market actors
    - Restricted rent sharing possibilities in the context of specific investments
    - Technological externalities
    - Public good attributes
    - Experience curve effects
    - Incomplete information on relevant supply and demand parameters
- Extent of uncertainty and hedging opportunities in the context of specific investments
- Economies of scope regarding the responsibilities for certain decisions and tasks

Although we do not consistently refer to the factors listed here throughout the analysis (i.e., some are mentioned below while others are not), each of them play a role for the underlying considerations.

Regarding the provision of power generation capacity, considerations on the organisational model should necessarily involve the core characteristics of electricity supply:

- First of all, electricity is a good of outstanding importance to modern societies and therefore achieving the main related objectives is vital. Although most tasks of the electricity supply process can, in principle, be delegated to private actors, the regulator remains ultimately responsible for the attainment of the aspired objectives.
- Investing in generation assets involves a large amount of decisions which are often interrelated, reaching from very general decisions such as choosing generation technologies and plant sites to detailed construction related decisions. While the question as to which exact decisions should be made by the regulator and which ones should be assigned to market actors is crucial to the functioning of the institutional framework, the answers (i.e., the most appropriate solutions) depend on the prevailing circumstances.[7]
- Building power plants always goes along with durable, capital-intensive and highly specific investments. This means that once resources are deployed in the course of

[7] Cf. for similar considerations Joskow (2010), “Market Imperfections versus Regulatory Imperfections”.

planning and implementing generation projects they can largely be considered as sunk costs.

Among the economic insights we apply, Oliver E. Williamson's New institutional economic analyses on the "make or buy" question can be deemed particularly useful for the examined content.[8] Williamson elaborates, how the respective suitability of alternative institutional mechanisms for coordinating transactions (in the original text: "markets" and "hierarchies") depends on the particular characteristics of a transaction. The problems examined by Williamson exhibit significant analogies to the choice between elements of competition and regulatory planning when designing an institutional framework for the provision of goods.

2.2 EOM versus CRM

2.2.1 Outline and assumptions

In this section we examine and compare the basic mechanisms of the EOM approach and the CRM approach (which we regard as the conceptual foundation of targeted RES-E instruments) with respect to the underlying objectives.

For our analysis, we assume a simplified set of actors in order to demonstrate interdependencies as clearly as possible: First of all, there is a regulator who decides upon the institutional framework and who is responsible for its implementation and application. Besides, the regulator (including associated public entities) may carry out certain tasks within the process of providing power plants itself. The other groups of actors are the final customers, the generators (comprising the roles of project developers, plant investors and plant operators) and the load serving entities (LSEs, i.e., retailers who supply final customers). We assume that members of these three groups act as private entities, whose decisions are guided by their respective particular interests.[9]

Concerning the organisation of electricity supply, we assume that final customers make contracts with LSEs on a liberal retail market and that changing suppliers is possible at relatively short notice. LSEs buy the volumes of electricity needed for customer supply on a liberal wholesale market from generators. There are no regulatory limitations to the duration of wholesale market contracts and their valuation is based on the marginal price principle (i.e., the highest successful bid for a certain product determines the price of equivalent transactions). We sometimes differentiate between two segments of the wholesale market: the forward market on which long-term contracts are traded, and the spot market which is used for short-term sales. There are no relevant differences between

[8] Cf. Williamson (1975), "Markets and Hierarchies: Analysis and Antitrust Implications – A Study in the Economics of Internal Organization".

[9] Regarding the regulator's actions we generally assume compliance with the underlying objectives. For practical applications it is however important to consider that public entities might sometimes pursue certain objectives on their own, potentially affecting their decisions.

the respective market designs, but these segments partly serve different purposes. We assume that operational decisions (and thus the dispatch of power plants) are usually based on spot market results in both examined models.[10] The forward market − as explained in detail below − plays an important role for investment decisions which are the focus of our analysis.

Last but not least, we consider several factors that influence future electricity sector developments to be unknown to all actors, resulting in significant environmental uncertainty. In light of long lifespans of plants which usually go along with long amortisation periods, this aspect is particularly important for the following considerations.

2.2.2 Model A: The Energy-only market (EOM)

2.2.2.1 Fundamentals of the EOM model

The core idea of the EOM approach is that the provision of generation capacity is primarily a result of the coordination between market actors. This means that investment decisions are decentralised and put into the hands of private supply and demand side actors. In accordance with the conception of the EOM approach, we assume effective competition on those markets (i.e., individual market actors cannot significantly influence market prices). In the examined basic EOM scheme all revenues for generators, and hence contribution margins for recovering investments, exclusively arise from sales of electricity volumes (see Fig. 1 for a simplified illustration of the examined EOM model).[11]

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[10] However, we discuss certain implications of the remuneration system for the incentives of OWP operators in section 3.

[11] It is possible that generators also receive revenues from short-term contracts on supplying ancillary services such as control reserve to the system. The corresponding streams of income are not further considered in our analysis, because their inclusion would increase complexity, while not changing the general assessment of the EOM model.

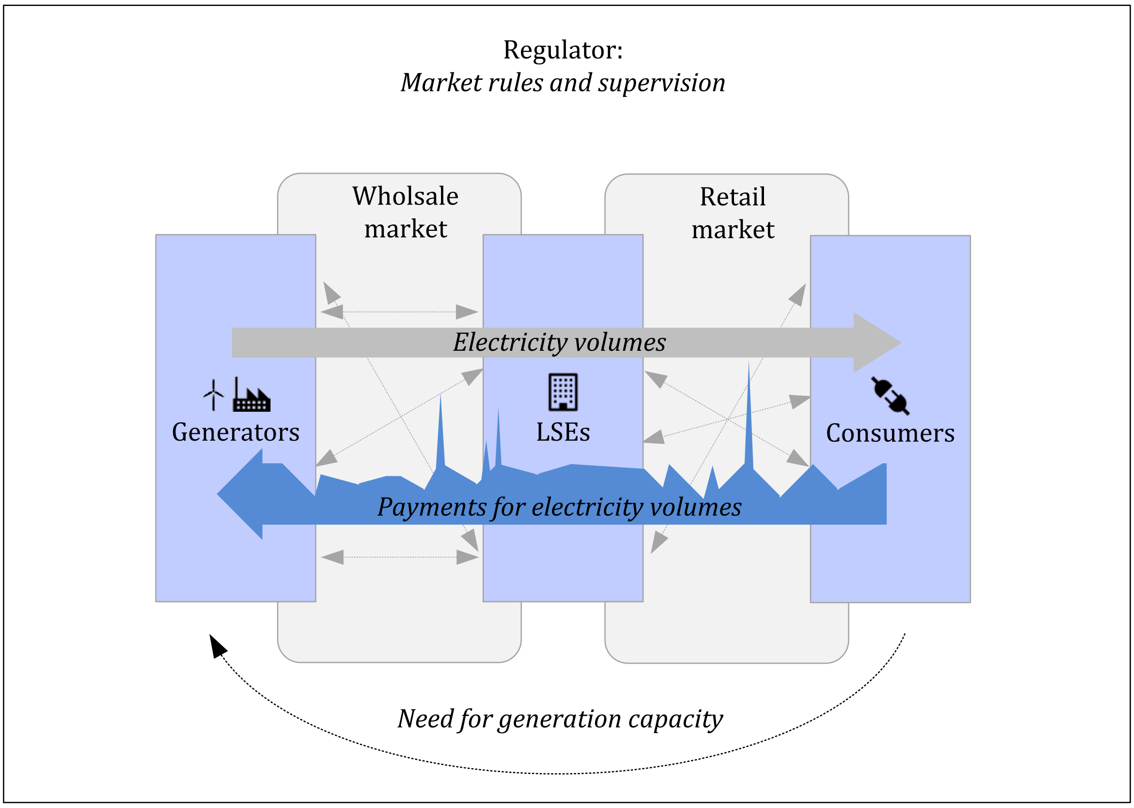

Figure 1: Basic EOM concept.[12]

2.2.2.2 Assessment of the EOM model's potential with respect to the underlying objectives

2.2.2.2.1 Efficiency regarding the cost of investments

In the examined EOM environment, it is fair to assume that generators are typically not able to sell large shares of a plant's lifetime production at the time of making the final investment decision. This assessment is largely based on the following interdependencies: Most final customers are incapable of adequately forecasting their individual electricity demands over a long period of time; thus they are usually not interested in committing to long-term delivery contracts with LSEs.[13] Individual LSEs, in turn, face uncertainties

[12] Own illustration. The lack of stable long-term relationships (vertical integrations) between generators, LSEs and consumers in the EOM concept is depicted by the small, dashed arrows in the two boxes "Wholesale market" and "Retail market". The unconventional form of the arrow labeled "Payments for electricity volumes" expresses the uncertainty of revenues for generation investors (for simplicity reasons the illustration does not take risk transformation services that LSEs possibly offer to consumers into account).

[13] Cf. Joskow (2006), "Competitive Electricity Markets and Investment in New Generating Capacity".

regarding the size of their future customer bases and the corresponding electricity needs. Consequently, LSEs procure large parts of required electricity volumes on a rather short-term basis (i.e., the lead times of forward contracts are significantly shorter than the lifetimes of plants).[14]

Against this background, future market sales and their predictability are of high importance for plant investments. The frequency of a plant's usage and prices obtained for sold electricity volumes majorly depend on the shape of the aggregated supply curve (merit order), which is changing over time. Along with a plant's own marginal costs of production, decisions of competitors regarding investments in new plants and further operation of existing ones mainly determine a plant's position in the merit order and the size of achievable contribution margins. Individual investors can usually predict the future behaviour of competitors only very roughly; essentially influencing it is usually not possible at all. Therefore, long-term forecasts are difficult and investors face a high uncertainty regarding the revenues a plant can generate over its lifetime.

Especially when further sources of uncertainty are taken into consideration, generation investment in a competitive EOM environment is confronted with high risks.[15] Private investors are typically risk-averse;[16] bearing risks they cannot control translates into higher costs of capital.[17] Hedging instruments for private investors might, in principle, be available on the market (including such that are offered by third parties who act as intermediaries for risk transformation). However, the risk premiums will often be high and render generation investments unattractive in many cases.[18] The high costs of capital might, firstly, constitute a problem with respect to prohibiting investments. Secondly, the costs of projects which are implemented nevertheless increase significantly. Given the high capital intensity of generation investments, the costs of capital represent a critical factor for the overall costs of electricity supply.[19] Increased costs of capital go along with potentially large welfare losses, which is of great importance for the evaluation of the EOM

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[14] The plausibility considerations which lead to this prediction of market behaviour are based on insights from economic theories. Although the underlying interdependencies are subject to the assumptions of the examined model environment, it is interesting to note that observations in real electricity markets which basically feature the described EOM design elements indicate a strong resemblance of LSE procurement behaviour (cf. for instance KEMA (2009), "Information Paper on Supplementary Market Mechanisms to Deliver Security and Reliability". More general examinations of procurement behaviour in existing literature on electricity markets such as in May / Jürgens / Neuhoff (2017), "Renewable Energy Policy: Risk Hedging Is Taking Center Stage" also correspond with our predictions.

[15] Cf. Stoft (2002), "Power System Economics: Designing Markets for Electricity"; Joskow (2006), "Competitive Electricity Markets and Investment in New Generating Capacity"; Cramton / Ockenfels (2012), "Economics and Design of Capacity Markets for the Power Sector".

[16] Cf. Arrow (1962), "Economic Welfare and the Allocation of Resources for Invention"; Arrow / Lind (1970), "Uncertainty and the Evaluation of Public Investment Decisions"; McAfee / McMillan (1988), "Incentives in Government Contracting".

[17] In this analysis the term cost of capital comprises all costs arising from capital being provided by the funding parties, including interest payments. Depreciation is explicitly not included.

[18] Cf. Joskow (2006), "Competitive Electricity Markets and Investment in New Generating Capacity". The fundamental underlying interdependencies are discussed in Arrow (1962), "Economic Welfare and the Allocation of Resources for Invention".

[19] For typical shares of investment and operation costs in the overall costs of providing power plants of different categories, cf. May / Neuhoff (2017), "Financing Power: Impacts of Energy Policies in Changing Regulatory Environments".

model.[20]

From the consumer perspective, the EOM design exhibits an additional flagrant deficiency: The remuneration scheme based on marginal electricity prices is not directly linked to the costs of providing plants. Risk-adequate rates of return in an EOM are usually already quite high (because generators bear high risks). If market prices are nevertheless sufficiently high and predictable to allow for new investments, there is no mechanism that steers returns to adequate levels. This means that profit contributions of generators may also exceed the required volumes by far, if the market structure leads to high inframarginal rents for generators, which results in excessive consumer payments.

Summing up, the great uncertainty for investors raises the costs of EOM investments substantially, which decreases welfare. If investments are still undertaken, there are no mechanisms to steer the rates of return to adequate levels. This high investment uncertainty can be regarded as one of the main, if not the primary source of problems of the EOM approach. In the following section we address further problems that arise from uncertainty, apart from the high costs of capital (but partly interrelated with them).

2.2.2.2.2 Efficiency regarding the provided overall capacity and generation technologies

The "missing money problem"

A large part of the existing literature on the EOM approach focusses on the so-called "missing money problem". However, it can be regarded as a rather particular phenomenon arising from the technical functionalities of the concept. The problem can be summed up as follows: As described above, the EOM design envisages the amortisation of plant investments based on market sales of electricity volumes, whose prices are determined by the corresponding market-clearing offers.[21] Assuming a static market situation with a specific fleet of plants with constant marginal costs, the plant with the highest marginal costs (the "top peaker") is never able to generate contribution margins. Furthermore, the achievable contribution margins for other plants might also be inherently insufficient to recover investments.[22]

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[20] Costs of capital reflect, among other things, the risk of bankruptcies including related transaction costs and the devaluation of specific investments (cf. for instance Harris / Raviv (1990), "Capital Structure and the Informational Role of Debt"; Leland (1994), "Corporate Debt Value, Bond Covenants, and Optimal Capital Structure"; Ang / Chua / McConnell (1982), "The Administrative Costs of Corporate Bankruptcy: A Note"). For this reason, costs of capital are directly relevant for welfare.

[21] This generally also applies to forward contracts which are evaluated based on observed and expected spot market results. Depending on the circumstances, forward prices might contain either discounts or premiums. This means that forward trading does not necessarily go along with additional contribution margins for generators, because there are no indications that demand side actors would be willing to consistently buy electricity forwards at prices beyond the highest spot market prices in an EOM environment. Cf. Joskow (2006), "Competitive Electricity Markets and Investment in New Generating Capacity".

[22] Cf. ibid. As described in section 2.2.1, the interdependencies discussed rely on the assumption of no exercise of market power (i.e., the generators' bids reflect their marginal costs). If, by contrast, generators would be able to exercise market

When the dynamics of electricity markets are taken into account, it is doubtful whether the missing money problem constitutes a relevant issue. First of all, marginal costs are usually not constant, but they depend on several variables such as fuel prices or the current operational statuses of plants. Therefore, the top peaker does not always have to be the same plant and it is entirely possible that each plant is able to generate sufficient inframarginal profits over time. Secondly, the plants with the highest marginal costs in a power system are often existing plants, because technological progress (which increases the efficiency of new plants) and the wear of plant components lead to relatively low efficiency levels. If these plants have already recovered their investments, they create inframarginal profits for other plants by setting high market prices, while not being dependent on large contribution margins themselves.[23]

These considerations lead to the conclusion that the missing money problem does not necessarily have to appear in an EOM environment. Apart from that, its presence or absence does not significantly affect the fundamental drawbacks of the EOM concept regarding cost efficiency.

Underinvestment and overinvestment

The EOM's market mechanisms do not consistently trigger investment decisions that comply with the cost objective. On the one hand, market prices do, in principle, provide relevant information on changes in relative scarcity over time. On the other hand, they do not – in contrast to the results of overly simplistic supply and demand models – automatically guide individual actors towards efficient decisions from a welfare perspective (let alone from a consumer perspective). This can mainly be attributed to the existence of transactions costs[24] which hamper the coordination of decentralised decision-makers.

First of all, transaction costs might lead to a different evaluation of investment projects from an investor perspective than from a social perspective. As described in section 2.2.2, a main feature of the basic EOM approach is that investment decisions are decentralised. In this context, the responsibility for resource adequacy is not explicitly assigned to a certain group of actors. Against this background, the high uncertainty regarding the recovery of investments potentially leads to an undersupply of generation capacity.[25] Due to the investors' higher costs of risk-bearing, generation projects might appear relatively unattractive to individual suppliers as compared to their value from the social perspective.

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power, they might be able to create sufficiently high margins for themselves (and for other peaker plants). However, such situations go along with typical monopoly or oligopoly problems, which we do not discuss in this research paper in more detail.

[23] In principle, contribution margins are only needed to recover the fixed operating costs. Taking the high specificity of generation investments into account (i.e., investment costs are mostly sunk) it could even be argued that this calculation applies, to a greater or lesser extent, to all existing plants.

[24] The term "transaction costs" describes the consumption of resources related to the determination, transfer and the enforcement of rights of disposal or further rights. Cf. Coase (1937), "The Nature of the Firm"; Coase (1960), "The Problem of Social Cost"; Williamson (1975), " Markets and Hierarchies: Analysis and Antitrust Implications ".

[25] Similar conclusions are drawn from the analysis of actual electricity markets whose design is based on the EOM approach in Joskow (2006), "Competitive Electricity Markets and Investment in New Generating Capacity".

Moreover, investors are often not able to appropriate the entire welfare increase induced by their investments. A typical example for this is the realisation of experience curve effects which are realised through the implementation of plant projects; the benefits are often widely spread over the economy.[26]

One way of preventing possible shortages is the complementation of the market design by a centrally procured capacity reserve (often referred to as "strategic reserve"). While such a measure appears to be effective with respect to preventing acute security of supply issues, its compatibility with the EOM's core ideas is questionable.[27] Moreover, adding a centrally procured reserve to the EOM does not alleviate the structural problems associated with high investment uncertainty; i.e., private market investments will still go along with excessive costs.[28]

In contrast to the scenarios described above, generators can also overvalue investment options. This can be the case, for instance, if their own (expected) producer rents rather result from an incorporation of other actors' rents than from welfare increases.[29] Even though effects that make investors undervalue investments and effects that lead to an overvaluation might be present at the same time, there are no indications that they tend to outweigh each other; it is rather likely that the prevalence of one or the other kind of effects leads to undersupply or (superfluous) redundancies, respectively.

Cyclic investment behaviour in EOMs is yet another problem that could lead to undesirable capacity situations. Generators base their investment decisions on available information such as market forecasts and the prices of forward contracts, which – provided that market mechanisms generally function properly – indicate upcoming capacity shortages or redundancies. At the same time, individual investment decisions often constitute business secrets. They can only be observed by competitors with a delay; i.e., when the development of a project has reached a certain stage. This usually implies

[26] These considerations – which are presented here in abbreviated form – correspond with findings from economic literature such as Kenneth J. Arrow's analyses on the "replacement effect"; cf. Arrow (1962), "Economic Welfare and the Allocation of Resources for Invention". Similar considerations can be found in Baumol / Willig (1981), "Fixed Costs, Sunk Costs, Entry Barriers, and Sustainability of Monopoly" and Dixit / Stiglitz (1977), "Monopolistic Competition and Optimum Product Diversity".

[27] Cf. Pérez-Arriga (2001), "Long-Term Reliability of Generation in Competitive Wholesale Markets: A Critical Review of Issues and Alternative Options"; Finon / Pignon (2008), "Electricity and Long-Term Capacity Adequacy: The Quest for Regulatory Mechanism Compatible with Electricity Market".

[28] In Hary / Rious / Saguan (2016), "The Electricity Generation Adequacy Problem: Assessing Dynamic Effects of Capacity Remuneration Mechanisms", a capacity reserve scheme and a (particular) CRM scheme are compared by means of a dynamic simulation model. The authors conclude from their analysis that the lack of influence of the capacity reserve instrument on investor decisions leads to additional costs, because old plants with high O&M costs remain in the system too long.

[29] As an example, a new plant could have slightly lower marginal costs than an existing one and thus, theoretically, replace its entire production, rendering the existing plant idle. Under such circumstances, the savings in variable costs, which reflect possible efficiency gains during operation, are rather low. Since generation investments, on the other hand, are virtually always of a considerable size, the overall welfare effect of such an investment can be expected to be clearly negative. Cf. in this context the analyses regarding the "business-stealing effect" in Mankiw / Whinston (1986), "Free Entry and Social Inefficiency".

that significant specific investments have already been made and the decision is virtually irreversible. The concealment of information impedes the coordination of investment decisions among generators. It can well be envisaged that too many generators would decide to invest at times of seemingly opportune conditions, while less favourable market forecasts would discourage nearly any investments. Such investment behaviour would result in periods with overcapacities and periods with shortfalls of the desired capacity margins.[30]

Overall, these considerations lead to the conclusion that, when taking transaction costs into account, it can by no means be assumed that investors are systematically incentivised to avoid undercapacities or overcapacities in the EOM model.[31]

Technological choices

For several reasons, investor choices regarding generation technologies and plant types can deviate in the EOM model considerably from desirable results. Market prices – as the main guideline for investor decisions – do not always comprise all costs and benefits that are relevant from a social point of view. Apart from the aforementioned experience curve effects, other factors such as externalities or public good characteristics of environmental protection or of security of supply play a role in this context.

A discrimination of RES-E technologies is particularly likely in an EOM environment. Against this background, there is a broad consensus in economic literature concerning the necessity of additional regulatory measures for achieving ambitious environmental targets; the debate on concrete policy implications is a lot more controversial. Regulators can generally choose from a wide range of instruments in order to promote the development of RES-E capacities. The generally available instruments differ considerably with respect to both the effects on the cost objective and their compatibility with the EOM approach. It can be argued that some instruments such as emission cap and trade schemes or renewables obligations (RO) have a fairly high compatibility with the EOM approach.[32] They create additional revenues for RES-E suppliers, while not significantly altering the EOM's mechanisms. Especially in the case of cap and trade schemes, investment choices remain in the hands of the generators. This aspect implies that such instruments usually also do not guarantee the development of RES-E plants. If other abatement options,

[30] Even though it can be argued that investors should, in principle, be able to anticipate such tendencies, the described problems are a common phenomenon in real electricity markets in which investment decisions are made by individual market actors. Cf. Ford (1999), "Cycles in Competitive Electricity Markets: A Simulation Study of the Western United States"; Ford (2002), "Boom and Bust in Power Plant Construction: Lessons from the California Electricity Crisis"; Hary / Rious / Saguan (2016), "The Electricity Generation Adequacy Problem".

[31] Cf. Cramton / Stoft (2006), "The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO's Resource Adequacy Problem".

[32] Cap and trade schemes typically establish a maximum level for the aggregate CO_2 emissions of several sectors over a certain period of time. Power generators – as well as polluters in other sectors – have to acquire (tradable) emission allowances according to the amounts of pollution caused by their plants. This increases the marginal costs of conventional plants and thus the market prices. Therefore, the relative attractiveness of RES-E investments increases. On the one hand, RES-E generators benefit from higher selling prices. On the other hand, they do not have to purchase any emission allowances for their own production.

including measures in other sectors, appear more profitable, investors will prefer them over the provision of RES-E investments. The RO instrument involves a regulatory decision on the minimum share of RES-E generation in electricity production. The decision as to which RES-E technologies are used is usually left up to generators.[33] Both of those approaches and similar "market-based" instruments are faced with several general issues which partly are related to high requirements regarding regulatory commitments. Apart from this, RES-E investment is still exposed to significant risk, because the revenues of investors remain dependent on market developments. This means that, despite a raise in average market prices, the risk premiums for RES-E investments, and thus the costs of capital, can be expected to stay comparatively high.[34]

The case of RES-E investments can be regarded as the most obvious example of investor decisions diverging from socially desirable technology choices. This problem is, however, not limited to RES-E plants. One important reason for this is that environmental uncertainty might affect different plant projects (regarding the generation technology and the cost structure) in a different way. The most efficient supplement to the electricity system might therefore not always be the most attractive option from an investor perspective.[35] Private generators typically prefer investment options (i.e., plant projects of certain generation technologies) for whose recovery the environmental uncertainty matters less over other options for which uncertainty plays a larger role. This means that investor decisions are not primarily guided by the question as to which type of plant represents the most sensible addition to the system from an overall perspective. Among various sources of uncertainty, limited information on competitor decisions potentially plays a particularly important role in this context.[36]

Coordination of generation investments and grid investments

So far, we have focused on the problems that arise from limitations to the coordination among actors on the electricity markets (i.e., among electricity generators and between

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[33] In the RO concept LSEs are required to acquire a certain amount of tradable "green certificates" which are created along with RES-E production.

[34] Cf. Toke (2007), "Renewable financial support systems and cost-effectiveness"; Toke (2007), „Trading schemes, risks, and costs"; Gawel et al. (2016), "The Rationales for Technology-Specific Renewable Energy Support: Conceptual Arguments and Their Relevance for Germany"; Gross et al. (2012), "On Picking Winners: The Need for Targeted Support for Renewable Energy"; Meunier (2013), "Risk Aversion and Technology Mix in an Electricity Market"; May / Neuhoff (2017), "Financing Power: Impacts of Energy Policies in Changing Regulatory Environments".

[35] Cf. Neuhoff / de Vries (2004), "Insufficient Incentives for Investment in Electricity Generations".

[36] To give an example, let us assume the power system is in need of several additional plants: Firstly, many additional peaker plants (which on the one hand go along with comparatively low investment volumes, while on the other hand operating only occasionally); secondly, few plants which are supposed to operate more constantly, while incurring higher investment costs (such plants are traditionally referred to as "baseload generation"). We further assume that there is a high uncertainty for all investors regarding the amount of peaker plant projects to be realised. While the revenues of "baseload plants" are not strongly affected by the number of peaker plants built, the operating hours of peaker plants, and thus achievable revenues, highly depend on parallel investment decisions in this segment by competitors. Under such circumstances, the majority of investors might tend to build "baseload plants", even though a system optimisation would suggest building predominantly peaker plants.

generators and demand side actors). Apart from that, a lack of coordination between generation planning and grid planning can constitute another important issue in the EOM model. With generation investment decisions decentralised, grid investment decisions have to be made under uncertainty regarding the spatial distribution of plants. Planning the grid exactly according to future needs is therefore not possible;[37] both grid overcapacity and excessive grid bottlenecks tend to increase the costs of electricity supply.[38] Additional regulatory action in order to align generation planning and grid planning potentially alleviates these problems. However, consistently implemented, such measures undermine the importance of generator decisions; the compatibility with the EOM approach must therefore be doubted.[39]

2.2.2.3 Design variations of the EOM model

It is essential to the EOM approach that any modifications to the basic concept do not substantially affect its core mechanisms. As mentioned at several points during our examination of the model, different potential problems render additional regulatory activity reasonable or even necessary. In some cases available measures appear fairly compatible with the EOM. In other cases the extent of regulatory activity interferes with the approach of decentralised investment decisions, which is at the very heart of the EOM concept. A substantially modified EOM concept hardly represents a reasonable target model: It is not possible to realise the main advantages envisaged (i.e., efficiency increases due to market-based decision-making processes), while the major problems of the approach (especially those related to the high investment uncertainty) are not cured by additional regulatory measures. In existing electricity systems with EOM-based market designs the implementation of such measures might still sometimes seem advisable in order to tackle urgent problems.

2.2.3 Model B: Capacity remuneration mechanisms (CRM)

2.2.3.1 Fundamentals of the CRM model (as the underlying concept of targeted RES-E instruments)

Definition: Use of the term "CRM" during the analysis

Most contributions to the scientific and public debates on CRMs refer to specific and often detailed institutional mechanisms for power plant investment and operation (sometimes similar terms such as "capacity markets" or "capacity instruments" are used in this context). They usually regard the CRM concept as either one comprehensive mechanism

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[37] Especially in the case of transmission grids, the time needed for planning, developing and constructing grid extensions can exceed the time needed for realising generation projects.

[38] Grid congestions are a common phenomenon in power systems and not per se a sign of inefficiency. Tolerating a certain amount of congestion is often deemed a viable way to avoid excessive grid expansion measures.

[39] Cf. Hoffrichter / Beckers (2018), "Cross-Border Coordination as a Prerequisite for Efficient Sector Coupling in Interconnected Power Systems – Institutional Economic Considerations on Allocating Decision-Making Competencies in the European Union".

for the provision of any kind of plants or as a mechanism to provide highly reliable capacity for backing up the intermittent infeed of RES-E plants (which are typically provided on the basis of separate RES-E schemes).

By contrast, our CRM discussion merely relates to the very fundamental ideas behind the concept. When using the term "CRM" in this analysis, we refer to a broad category of instruments for the provision of generation capacity which can either be applied individually or as part of a comprehensive mechanism. We consider instruments to be based on the CRM concept, if they feature the following general principles (for a simplified illustration of an exemplary CRM design, see Fig. 2):

- The regulator makes a – more or less detailed – decision as to which plants or types of plants are to be provided.
- This decision is implemented by (usually private) generators, who build and operate the plants according to certain specifications provided by the regulator (which can be regarded as part of the CRM design).
- In this context the generators – explicitly or rather implicitly – enter into contracts with the regulator whose durations typically correspond to the lifetimes of the plants.
- The successful execution of the tasks is remunerated according to the rules laid down in the regulatory framework. At least an essential share of the remuneration payments consists of relatively certain revenues that are not subject to great market risks.

There are various ways of selecting the actors who implement the regulatory decision and of determining the corresponding remuneration level; several approaches will be discussed in section 2.2.3.3.1.

Assumptions for the examination of the CRM model ("Model B")

Using the CRM definition described above, we explicitly include targeted RES-E instruments with the corresponding characteristics into our CRM discussion. While main parts of the argumentation below generally also apply to RES-E schemes that complement an EOM (which in this case does not represent a "pure" EOM approach anymore), throughout the following examination of "Model B" we assume an institutional framework in which all plants are provided on the basis of regulatory contracts. This means that we examine a CRM scheme consisting of several capacity instruments for different generation segments; the respective instrument designs are chosen by the regulator and can vary significantly between the segments.[40]

The CRM model is characterised by an active role of the regulator in the supply process. Some crucial decisions and tasks related to generation investment, which are left to "the

[40] A single overarching instrument with a uniform design is generally conceivable as well. But as we will show below (see section 2.2.3.3.2), there are good reasons for applying different targeted instruments for different generation segments.

market" in the EOM model, are centralised. As mentioned above, the regulator makes decisions as to which plants should be provided and implements capacity instruments which offer access to long-term contracts to the investors selected for building and operating the plants. As suggested by the name, the original idea of the CRM concept is to remunerate installed capacity. However, payments can equally be linked to volumes of electricity provided by generators or to other reference parameters without substantially altering the model's basic mechanisms.[41] Notwithstanding, we use the term "capacity payments" throughout the following passages.

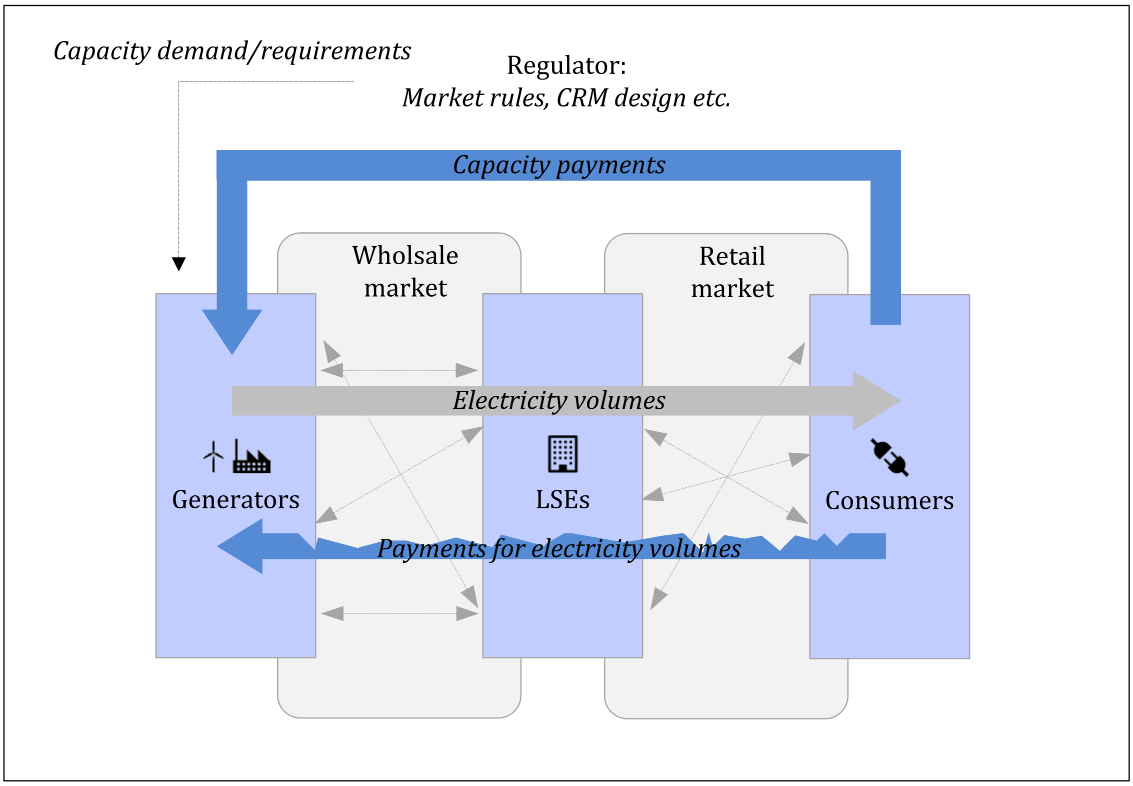

Figure 2: CRM concept (exemplary design).[42]

2.2.3.2 Assessment of the CRM model's potential with respect to the underlying objectives

The regulator chooses the admission criteria to capacity instruments and determines the capacity volumes to be procured. Hence, the regulator is directly in control of resource

[41] We will further elaborate on this aspect in section 3.4.1, when we discuss the design of targeted instruments for the provision of OWP.

[42] Own illustration. The simplistic CRM concept depicted here features direct flows of capacity payments from consumers to generators; it would generally also be possible to involve LSEs as intermediaries. The smaller size of the "Payments for electricity volumes" arrow as compared to Fig. 1 and the absence of large spikes imply that the applied CRM regime limits the amount of revenues that generators receive for electricity sales (we will discuss this topic in detail in section 2.2.3.2.1).

adequacy and can make sure that the attributes of plants comply with environmental objectives. Regarding the cost of electricity supply, the CRM approach generally offers large savings potentials in comparison to the EOM approach. Whether and to which extent these potentials can be realised depends on several factors, among which the degree of centralised knowledge always plays a crucial role.

2.2.3.2.1 Potential with respect to cost efficiency

The core idea of the CRM approach is that generators who implement the regulator's decisions receive predictable contribution margins for the amortisation of their investments. In contrast to the EOM model, the uncertainty about future market developments is not immediately linked to individual plant investments. Instead, large parts of the risk are spread over the entire group of consumers. If capacity payments cover large significant shares of investment volumes, amortisations are not highly reliant on market revenues. The costs of capital can therefore be kept at moderate levels, which is a key rationale behind the CRM approach. In light of the high capital intensity of plant investments, low costs of capital promise considerable savings in the overall costs of electricity supply. The costs incurred by consumers who carry market risks instead of generators do not outweigh the savings related to the lower cost of capital, because the costs of risk-bearing decrease: Given the minor importance of electricity market developments for the overall utility situations of most consumers and, in particular, the low probability of extensive devaluated specific investments in this context, the risks do not incur significant costs for consumers (both individually and in sum). For similar reasons, the regulator, representing the collective group of consumers, is often regarded to have a neutral attitude towards the risk of individual investments, which is related to the high number of public investment projects.[43]

Since the downside risk for investors is comparatively low in CRM schemes, there are arguments for curtailing upside risks as well. If generators receive market revenues in addition to capacity payments, it can be reasonable to limit the potential earnings from this second stream of income. Otherwise, in case of high market prices, producer rents might significantly exceed the risk adequate levels (at the expense of consumer rents). There are various ways of implementing effective limitations to market revenues. To give an example, when the concept of so-called "capacity options" is applied, generators who receive capacity payments can only take in market revenues up to a certain price level which is defined by the regulator. Whenever market prices exceed this level, generators have to repay the difference between achieved market earnings and the established maximum price to the regulator.[44] The proceeds can be used, for instance, to reduce

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[43] Cf. Arrow (1962), "Economic Welfare and the Allocation of Resources for Invention"; Arrow / Lind (1970), "Uncertainty and the Evaluation of Public Investment Decisions"; McAfee / McMillan (1988), "Incentives in Government Contracting".

[44] In order to further increase the incentive to have plants available for operation in times of scarcity (which typically go along with high market prices), generators could be obliged to make payments to the regulator irrespective of whether or not they actually sell electricity volumes, when market prices exceed the determined level.

consumer charges levied in order to finance the capacity payments.[45]

Another source of cost savings in the CRM model is the proper adaption of the institutional frameworks for different types of plant investments to their respective needs. In section 2.2.3.3.2 we will discuss this aspect and preconditions for harnessing the efficiency potential in detail.[46]

The design, application and adaptions of capacity instruments go along with transaction costs, primarily incurred by the regulator but also by generators and other actors who have to deal with the institutional framework. Although it seems inappropriate to assume that transaction costs in the CRM model are always higher than when an EOM approach is applied – which, as described above, also does not function without regulatory activity – they do represent a factor which has to be considered when assessing the practicability of the CRM model.

2.2.3.2.2 Centralised knowledge as a key factor for achieving desirable results

As the appropriate design of CRM instruments depends on the prevailing circumstances, finding the best solutions can be a complex task. Sufficient centralised knowledge is an essential precondition in this context. The regulator needs information on the benefits and costs of all relevant technical options as well as an advanced understanding of institutional mechanisms, which are available elements of the CRM. The higher the centralised knowledge, the better the regulator can adapt the framework to the respective characteristics of plants and to the prevailing market situations. It is important to consider the fact that part of the relevant technical knowledge is usually dispersed – i.e., held by the actors who develop generation projects – and thus has to be incorporated.[47] Setting up an efficient incentive system for decentralised action requires knowledge on costs and value creation as well as on the behaviour of generators and the functioning of regulatory mechanisms. Regarding the design of contracts with generators, the regulator should be aware of typical contractual problems, which are largely related to the general incompleteness of contracts.[48]

Although centralised knowledge is more obviously relevant in the CRM model, it also represents a necessity in the EOM model: Despite its initially passive role, the regulator has to be able to recognise potential problems and take effective countermeasures. This means that knowledge requirements are not necessarily lower in the EOM model than when a CRM based approach is applied.

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[45] The concept's name "capacity options" derives from the fact that the maximum price generators may receive for electricity sales resembles the strike price of a call option the regulator would have on the plants' production. Analogously, the capacity payments can be regarded as option premiums in this context.

[46] As mentioned above, in section 3 we will take a look at the distinctive characteristics of OWP and their implications for instrument design.

[47] We discuss this aspect in detail in section 2.2.3.3.2.

[48] Cf. for in-depth analyses on the implications of incomplete contracts Williamson (1985), " The Economic Institutions of Capitalism: Firms, Markets, Relational Contracting"; Alchian / Woodward (1988), "The Firm Is Dead; Long Live the Firm: A Review of Oliver E. Williamson's The Economic Institutions of Capitalism"; Tirole (1999), "Incomplete Contracts: Where Do We Stand?".

2.2.3.3 Design variations of the CRM model

This section deals with selected CRM design topics. In a first step, we will discuss variations of certain instrument design elements related to the procurement of the plants (section 2.2.3.3.1). This is followed by considerations on the reasonable level of detail and differentiation in the centrally established instructions for investors (section 2.2.3.3.2). In section 2.2.3.3.3 we discuss the usage of risk exposure in the incentive system for generators, before summing up the main aspects discussed in this part of the research paper in section 2.2.3.3.4. Different types of remuneration schemes (such as capacity payments, market premiums or feed-in tariffs) and their variations are not examined at this point of the analysis, but instead they are included in section 3 in which we discuss instruments for the provision of OWP capacity.

2.2.3.3.1 Mechanisms for the selection of projects and the determination of the remuneration levels

Capacity instruments are composed of various design elements and each of them potentially plays a decisive role for a scheme's functioning; both individually and, due to plenty of interdependencies, in combination with each other. The design elements may be found to belong to different categories: definition of the object and duration of regulatory contracts; contract design and provision of capital (including the incentive systems for suppliers, risk allocation and the temporal structure of remuneration payments); and the mechanism of the procurement process. While all of our considerations on CRM design presented in this research paper relate to one or more design elements, we do not discuss each category, let alone each element in detail. In this section, we focus on two components of the procurement process, namely: mechanisms for the selection of projects or suppliers, and approaches of determining the remuneration levels for generators. Besides, we touch upon the topic of quantity control (which can be regarded as the third integral part of procurement process design). For simplicity, we investigate two concepts for the procurement of plants which imply certain combinations of design elements: tender schemes and regulatory price offers.

The selection of projects and/or corresponding suppliers is a crucial part of any capacity instruments' procurement process. If the projects are predetermined by the regulator, the aim is to contract those actors who implement the projects most efficiently. If the selection process is designed in a way that different projects offered by the generators compete against each other, also the qualities of these projects have to be compared.

Tenders

The selection of offers via tender processes can be based on various factors. In case the offer price is chosen as the primary bidding parameter, the selection goes usually hand in hand with determining remuneration levels. Such a procedure aims at simultaneously picking the most efficient offers and limiting producer rents. Tenders may especially offer an advantage, if cost information (including efficiency potentials yet to be realised) is particularly asymmetrically distributed between the regulator and the generators; i.e., the regulator has problems to identify appropriate remuneration levels before receiving any price offers. Whether and under which circumstances this advantage can actually be realised is the topic of an ongoing debate in economic literature.[49] However, certain preconditions for a successful application of tenders can be identified.

Sufficient intensity of competition among generators is a necessary requirement for the limitation of consumer payments. Moreover, cost reductions usually presuppose certain minimum sizes of the generation projects. If, by contrast, investors of small-scale projects are obliged to participate in tenders, potential savings can easily be overcompensated by additional transaction costs related to the auction procedure.[50] Furthermore, the requirements of a tender might represent high or even insurmountable barriers to small players. The eligibility criteria for offers are of particular importance in this context. If participation in the tender requires substantial upfront investments, small investors can practically be excluded, as they usually have limited means of risk diversification.[51] Even if successful projects are entitled to remuneration payments before operation starts (i.e., start-up financing), the repayment ability largely relies on the acceptance of the investor's bid by the regulator. If the success of individual offers is uncertain − which is usually an implication of effective competition − there is a risk of stranded investments. This risk translates into high and possibly prohibitive costs of capital which means that small investors might find it difficult to raise funding in general. Small generation projects could therefore become comparatively inefficient or even not feasible at all.

Large investors with several parallel investment projects are more likely to be capable of bearing risks associated with a regulatory choice of contractors at an advanced stage of the development process. Still, also in such cases, the potential devaluation of specific investments can be expected to have significant cost impacts. Reducing the requirements concerning the development status of projects at the time of making a bid decreases the risk for investors. The downside is that weaker commitments to the investments come with an increased risk of projects being abandoned by investors in the case of unfavourable developments. This potentially endangers the achievement of capacity targets.[52] Because of this trade-off, the identification of suitable requirements is not a trivial task.

Many potential problems associated with a tender process can be significantly reduced with a proper design. However, design modifications might weaken the originally intended

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[49] Since it is difficult to clearly attribute observed price declines to the choice of the tender instrument, examinations of the results of practically applied RES-E tenders have also not yet delivered unambiguous answers. Cf. for instance Toke (2015), "Renewable Energy Auctions and Tenders: How Good Are They?"; Bayer / Schäuble / Ferrari (2018), "International Experiences with Tender Procedures for Renewable Energy – A Comparison of Current Developments in Brazil, France, Italy and South Africa".

[50] Cf. for further considerations on the transaction costs related to tender mechanisms del Río / Linares (2014), "Back to the Future? Rethinking Auctions for Renewable Electricity Support".

[51] The described interdependencies can largely be traced back to problems of specific investments under uncertainty, see section 2.1.

[52] In order to reduce this problem, generators can be obliged to pay a deposit which is withheld, if projects are not realised. Large deposits might however also represent an entry barrier to small investors.

mechanisms. Moreover, the most appropriate design depends on the prevailing circumstances and identifying the best solutions can be a complex task.

Regulatory price offer

If the regulator's knowledge on generation costs is sufficiently high, a regulatory price offer might sometimes be favourable. A price offer to generators means that all investors who fulfil certain criteria are entitled to contracts within the CRM. With the implementation of projects not depending on competitor decisions, the costs of capital are usually substantially lower. Other factors that affect the level of consumer payments are the degree of heterogeneity in the costs of generation projects and the extent to which such cost differences can be taken into account in the remuneration system. If the costs differ considerably between plant projects, a uniform price for all suppliers results in high producer rents for projects with particularly favourable conditions. As we will show in the following section, appropriate distinctions between offers lead to more adequate returns and hence better results from a consumer perspective; but certain preconditions must be met.

In contrast to other procurement mechanisms such as tenders, price offers do not automatically include a regulatory decision on quantities to be provided under the regime. If quantity control represents an important issue, additional provisions can be implemented; e.g., by establishing maximum amounts for new installations per period or by implementing an automatic decrease of the remuneration levels linked to realised expansion volumes.[53]

2.2.3.3.2 Level of detail and differentiation in the procurement and remuneration framework

As described above, centralised knowledge is a key element for making use of the potential the CRM approach offers. Just as in the EOM model, investment decisions by generators rest on their opportunities to enter into contracts. In the CRM model, however, the contractual terms and the requirements for investors are specified by the regulator (as opposed to decentralised coordination between market actors in the EOM). Investors in a CRM environment are typically offered concrete long-term remuneration models, while investment decisions in an EOM environment largely rely on assumptions about the possibilities of future market transactions. The better informed the regulator is, the better it can align the CRM's mechanisms and parameters with the attributes of investment projects and thus limit generation costs. Since the characteristics of plants vary considerably between different technological segments and even within these segments, the degree to which the regulator can assess relevant differences is of great importance. The abilities of plants to contribute to power supply highly depend on the chosen technology as well as on further design and construction decisions; the same applies to the costs. Similarly, the characteristics of the respective investment projects – i.e., how to typically structure and finance a project – differ.

[53] In the following section we discuss further aspects of steering the provided generation capacity to a desirable level.

Potential advantages of differentiation

A well-informed regulator is usually not at a disadvantage to market actors regarding general assessments of the expected benefits and costs of generation technologies. At the time of making investment decisions, generators often base their assessments on essentially the same available information and thus face the same uncertainties as a regulator. If the regulator has good reasons to assume that plants of a certain technology constitute efficient supplements to the electricity supply system, this information should be directly reflected in the institutional framework. This means that, under such circumstances, there is no point of creating broad competition between different generation technologies (which would ideally result in investors favouring exactly those technologies that have been identified as suitable beforehand). Instead, there should be a regulatory decision upon the development of generation capacity of the desired kind and corresponding capacity instruments for the implementation of this decision by generators.

Customising the design of both contracts and the procurement procedure to the characteristics of the respective generation technologies or the specific projects concerned can lead to significant cost savings.[54] By contrast, with a low level of differentiation it is virtually inevitable that the regulatory requirements match the characteristics of some technologies better than those of others. A part of the available options is therefore discriminated and the costs of projects which are developed despite facing handicaps increase.[55]

Technology-specific procurement appears particularly favourable, if technologies have comparatively high costs at a certain point in time, but promise large cost declines which can be realised through a continual deployment.[56] If rather immature technologies would have to compete against established ones, the realisation of experience curve effects might be impeded as investors do largely not include them into their individual calculations (the aspects mentioned above during the discussion on technological choices in an EOM environment apply analogously; see section 2.2.2.2.2).

Summing up the considerations presented in this section so far, there is nearly always a case for centralising at least basic decisions concerning the usage of plant technologies (and for making corresponding differentiations of applied capacity instruments). On the other hand, concerning the determination of the exact composition of the power plant fleet there are usually very good reasons to involve the market actors. The efficient generation mix depends on the actual costs of plant projects. One way to incorporate dispersed cost information is to oblige supply side actors to submit the relevant data to the regulator in advance. If this should, for any reasons, not represent a viable or sufficient solution, it is also possible to gather cost information during the procurement process. If the

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[54] Cf. Gawel et al. (2016), “The Rationales for Technology-Specific Renewable Energy Support”. Another potential advantage is, for instance, that an overcompensation of investors can be avoided, if the remuneration level is determined separately for each technology segment.

[55] In section 3.2, we will continue discussing this topic in a more concrete context (i.e., with respect to OWP capacity instruments).

[56] Cf. for instance Ondraczek / Komendantova / Patt (2013), “WACC the Dog: The Effect of Financing Costs on the Levelized Cost of Solar PV Power”.

procurement is, for instance, carried out via technology-specific tenders, elements such as maximum prices or price-elastic demand functions can be used to avoid the procurement of large quantities of technologies that turn out to be comparatively costly. In the case of particularly high cost uncertainty, there might sometimes also be arguments for making less detailed specifications in advance in order to allow for direct competition between different technological options.

General challenges regarding the instrument design

A possible downside of highly differentiated institutional frameworks is that the transaction costs related to designing, applying and adapting the capacity instruments tend to be comparatively high. Moreover, problems can be expected, if the central knowledge is insufficient for the chosen degree of differentiation. Overly precise requirements do not leave appropriate room for the integration of dispersed knowledge and possibly exclude efficient options that investors and operators would have chosen otherwise. It seems advisable that the regulator refrains from specific requirements (for instance with respect to the layout of plants), if the efficient solutions depend on circumstances of individual projects which are only known by generators.

However, the fact that generators possess part of the relevant information exclusively does not automatically render decentralised decision-making advantageous. The generators must also have incentives to apply their knowledge in a way which benefits the underlying objectives. As described above (when discussing the EOM model in section 2.2.2.2), problems of decentralised coordination potentially lead decision-makers to socially undesired actions. It might be possible to guide generator behaviour towards desirable decisions by setting targeted incentives. But – as we will demonstrate in the following section – setting up an appropriate incentive system can be a challenging task and the transaction costs of installing and applying incentive systems have to be taken into account.[57]

2.2.3.3.3 Using risk to incentivise generators

One essential question in the context of instrument and contract design is how risks can be used to incentivise generators. As shown above in the course of the EOM assessment, the mere exposure of generators to comprehensive market risks does by no means guarantee desirable investment decisions. Still less is such a risk allocation advisable with respect to the efficiency objective, since risks that generators cannot control well – let alone influence – lead to cost increases. In particular, this applies to decisions which go along with specific investments (see section 2.2.2.2.1).

Against this background, it is sometimes more reasonable to create incentives without exposing generators to risks. This can, for instance, be done by granting bonus payments that reward certain investment-related decisions which are considered preferable from a

[57] If the costs of collecting the required knowledge beforehand or the costs associated with suboptimal generator decisions are lower than the costs related to incentivisation, these alternatives seem preferable.

social perspective.[58] A main advantage of linking (additional) payments directly to the implementation of the investment measure is that there are no adverse effects on the costs of capital. Moreover, the incentives' effectiveness is not compromised by revenue uncertainty (as is the case if payments depend on market developments). Establishing risk-free incentive structures can be reasonable under the following circumstances:

- The regulator knows that certain solutions (e.g., certain plant layouts) significantly increase the value of a plant's contribution to electricity supply.
- The regulator has limited information on the solutions' costs.
- It is at least doubtful that implementing the solutions creates net benefits in each case (for instance, because the costs significantly depend on the specifics of each plant project which are hard to observe for the regulator).
- It can be expected that in many cases generators do not implement the solutions, although it would be desirable from a social perspective (a typical cause for this being limited possibilities of the generators to appropriate the corresponding welfare increases).
- The regulator can observe relatively easily whether investors have implemented the solutions or not.

When these conditions are met, risk-free incentives ideally make generators choose and implement the particular solutions (only) in cases in which the benefits exceed the costs.

By contrast, it can be preferable to expose investors to selected risks, if the circumstances diverge from the described setting in the following way:

- The regulator has limited means to assess the suitability of different available solutions.
- The costs of monitoring whether or not these solutions have been implemented by generators are comparatively high.

In such cases, using certain market risks can sometimes be the best option for incorporating dispersed knowledge and guiding investment decisions. A precondition is that the regulator is able to identify particular risks which, if borne by the generators, are likely to induce desirable actions. This assumes, firstly, a sufficiently reliable relationship between the corresponding variables. If, for instance, generator revenues are linked to market prices, the prices must adequately reflect the value of the plants' contributions to the system. Secondly, future market developments must be sufficiently predictable for generators to affect their investment decisions. If these conditions are fulfilled, bearing market risk ideally makes investors opt for solutions which increase both their net profits and social welfare.

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[58] Alternatively, the corresponding offers could be preferred in the selection process. Moreover, it is possible to combine the two alternatives. This would mean that opting for the desirable investment-related decision leads to both an advantage for generators with respect to their offer's score in the selection project and higher remuneration payments.

2.2.3.3.4 Summary

Aligning the institutional framework with the characteristics of different kinds of plant projects promises significant cost savings. However, more differentiation within the institutional framework is not per se preferable. Instead, the adequate degree of detail and differentiation depends on the prevailing circumstances. For one thing, the distribution of the relevant knowledge between the actors involved plays an important role in this context. Other relevant factors can be seen in the extent of coordination problems in markets and the feasibility of establishing adequate incentive systems. Since the initial situations can significantly vary between generation segments, it is sometimes reasonable to choose different procurement mechanisms. There are good reasons to establish clear and detailed specifications in areas in which the centralised knowledge is rather comprehensive; the design of CRM instruments should reflect all centralised knowledge. Conversely, if it is difficult to assess in advance which exact plants should be provided and if there are no persistent problems regarding decentralised coordination, the procurement framework should be more flexible and leave room for the incorporation of dispersed knowledge.

The two procurement approaches examined in this section − tendering procedures and regulatory price offers − both have potential advantages and disadvantages; none of the two alternatives dominates the other. Elements of competition are often useful for incorporating dispersed knowledge and thereby fostering efficiency. However, it is important to be aware of the fact that an ill-calibrated competitive framework might undermine the efficiency objective. Especially a design which provides an actual "level-playing-field" for substantially different plant categories (and thus substantially different investment projects) may hardly be achievable. It might prove extremely difficult to calibrate the requirements and mechanisms in a way that takes the different needs of different projects equally into account. Since certain compromises are inevitable, the resulting investment framework is likely to be suboptimal for any kind of plant projects.

Decisions a regulator makes despite lacking knowledge about the relevant interdependencies tend to lead to undesirable outcomes. Sometimes both centralised and decentralised decision-making processes are confronted with significant problems and must each be expected to result in suboptimal outcomes.[59] Therefore it is necessary to evaluate on a case-by-case basis whether investment-related decisions in a CRM-based scheme should be made by the regulator or left to generators, and, in the latter case, whether or not the incentives for generators should be based on risk exposure.

2.3 Interim results: A strong case for targeted provision schemes

Electricity is a good of outstanding importance to modern economies. There are usually

[59] Achieving theoretically optimal results is usually an idea far from reality in the context of providing electricity generation capacity. Regulators rather face the challenge to identify the institutional framework which leads to outcomes that diverge from ideal results as little as possible. Cf. for similar considerations Joskow (2008), "Market Imperfections versus Regulatory Imperfections".

societal goals with respect to the use of certain generation technologies. Against this background, it seems counterintuitive that the EOM approach envisages a provision of power plants which mainly rests on the decisions of market actors who bear considerable risks in this context. In the case of liberalised wholesale and retail markets with effective competition, decentralised hedging is typically possible only at substantial premiums, which results in high costs of capital. This aspect weighs particularly heavy, because generation investments are very capital-intensive, durable and highly specific.

The examination of the EOM model revealed several further problems which can be summarised as follows:

- Decentralised investment decisions in the basic EOM model can lead to either an excess of or a shortfall in target capacities; high uncertainty about future market developments makes shortfalls particularly likely. Additional regulatory measures can effectively address such problems. However, especially in the case of measures that prevent undersupply such as centrally procured capacity reserves, the compatibility with the fundamental ideas of the EOM approach is questionable.
- The investment decisions of market actors (with respect to generation technologies, plant layouts etc.) might significantly diverge from the most desirable choices from a system perspective. The reason for this is that investors – due to problems of coordination among market actors which are related to the existence of transaction costs – are often only confronted with parts of the total benefits and costs induced by their investments. Regulatory interventions into the market mechanisms can alleviate such problems. But consistent action often requires extensive central planning which drastically reduces the relevance of market mechanisms and thus undermines the rationale for applying the EOM concept.
- The EOM's market mechanisms do not steer generator revenues to appropriate levels. If market prices are sufficiently high to allow for generation investment despite the high level of uncertainty, the returns of some investors can be expected to drastically exceed risk-adequate levels. This implies excessive consumer payments.

The idea of the CRM concept seems consistent with the regulator's ultimate responsibility for electricity supply and with the existence of social preferences concerning the use of certain generation technologies. Generators who implement decisions by the regulator regarding the deployment of generation capacity receive comparatively predictable remuneration payments. Risk is used only specifically in order to incorporate dispersed knowledge and incentivise efficient decentralised decision-making. In this way, the costs of capital can be kept at moderate levels. If it can be assumed that certain generation technologies deliver valuable contributions to electricity supply, it appears recommendable to subdivide procurement segments accordingly and establish customised regulations. Targeted instruments based on the CRM concept (such as RES-E instruments with the corresponding features) offer a potential for significant cost savings in comparison to the EOM approach.

To which extent this potential can be realised depends on the prevailing circumstances. The regulator's knowledge about the electricity system and about the effects of its instrument design choices is a key factor in this context. Since usually part of the relevant information and know-how is originally possessed exclusively by supply side actors, it is essential to incorporate generator knowledge. This implies that certain decisions should be left to investors. The creation of a suitable incentive system is vital in this context, since broad discretion in decision-making for investors alone does not guarantee decisions that are favourable with respect to the objective of limiting the costs of electricity supply.

Last but not least, it is important to note that the presented findings are to be seen in the context discussed. It can by no means be deducted that in each real-life electricity system which relies on an EOM-based approach an immediate transition to a comprehensive CRM (for all generation technologies) would be preferable. In fact, the successful implementation of a CRM is subject to a wide range of factors. In some cases it might not be feasible to implement theoretically sensible reform models without substantial modifications during the legislative process that drastically change the effects with respect to the initially aspired goals. Besides, a certain degree of consistency and predictability in regulatory action is an elementary component of investment-friendly institutional frameworks. For this reason, care should be taken in order to avoid extensive devaluations of specific investments in the course of sudden paradigm shifts. Meanwhile, our analysis presents strong reasons for applying targeted instruments based on the CRM ideas at least in selected generation segments such as RES-E; this also holds true if these technologies would be competitive in an EOM-based system as well.[60]

Overall, the CRM approach can be considered as a suitable concept for the provision of power plants, whereas the EOM exhibits persistent functional shortcomings with respect to the assumed objectives.

[60] Against this background, the popular term “support instruments” might be a suitable expression for describing the promotion of the development of RES-E technologies, if their costs and benefits are not appropriately reflected in the pricing mechanisms of the currently applied (EOM-based) market design. On the other hand, the term is somehow misleading, because the reasons for applying targeted instruments for the provision of RES-E plants (especially cost efficiency effects) do not disappear when a technology has reached a high level of competitiveness.

3. Capacity instruments for the provision of OWP

Having highlighted the importance of adapting the design of capacity instruments to generation technologies, this section starts with an overview of the most essential characteristics of the OWP technology and OWP projects (section 3.1). Afterwards, we discuss rationales for using technology-specific capacity OWP instruments (section 3.2), before considering different options for the distribution of decisional responsibilities and risks between generators and the regulator (section 3.3). In section 3.4 we derive implications for the design of OWP instruments from the preceding considerations. Finally, section 3.5 sums up this part of the analysis.

3.1 OWP characteristics

In some respects, the core characteristics of OWP generation differ significantly from those of other generation technologies, including other intermittent RES-E plants. They can be summarised as follows:

- OWP typically offers relatively stable production patterns as compared to other intermittent RES-E technologies such as onshore wind power and photovoltaic (PV) systems.
- If densely populated countries approach ambitious RES-E targets, land use conflicts and negative externalities associated with onshore wind power and PV power stations will become increasingly relevant.[61] Located offshore, OWP plants can help limit the extent of such problems. However, there are other forms of spatial conflicts and negative externalities which have to be taken into account as well.
- Over the past few years, drastic OWP cost reductions have been realised. However, when using measures such as the levelised costs of electricity (LCOE) – which include investment and operational costs, albeit no externalities – the costs of producing one unit of electricity with OWP technology typically still appear high in comparison to the costs of onshore wind power and PV production at the most suitable locations. Since OWP is at a comparatively early stage of development, large experience curve effects can still be expected in the future.[62]

These attributes make OWP one of the main RES-E technologies with respect to its potential to contribute to carbon free electricity generation.[63] As concluded from our considerations in section 2, there are good arguments to apply targeted capacity

[61] Whereas potential land-use conflicts are particularly obvious in the case of ground-mounted PV stations, the scarcity regarding available space for other PV forms such as rooftop PV can be considerable as well.

[62] Cf. IRENA (2018), "Renewable Power Generation Costs in 2017"; Karltorp (2016), "Challenges in Mobilising Financial Resources for Renewable Energy – The Cases of Biomass Gasification and Offshore Wind Power".

[63] In practice, many regulators in Europe have decided to considerably expand OWP capacities within their national territories. While in some cases these decisions were backed by explicit OWP deployment targets, in other cases the decisions in favour of OWP expansion have remained rather vague.

instruments for the provision of generation capacity. Regarding the design of OWP instruments, several further characteristics of the technology have to be considered:

- OWP investments are durable, highly specific and – largely due to the lack of fuel costs – particularly capital intensive.[64]
- Typical OWP projects are very large with respect to both installed generation capacities and financial volumes; they often exceed the size of onshore wind and PV projects many times over. In connection with this characteristic, planning and development periods are typically also longer.
- Suitable plant sites are limited to certain areas at sea. These areas are usually public territory. Deciding upon their usage is hence a responsibility of the regulator (in the context of maritime spatial planning). This also means that regulatory decisions to build OWP plants at specific sites can usually be made without involving private property owners (while this is often necessary in the case of onshore wind power and PV projects). Nevertheless, several planning restrictions have to be considered (e.g., shipping activities, fishing areas, nature reserves and other protected areas, gas pipelines etc.).
- At present, new OWP plants can usually not rely on existing grid infrastructure which means that generation investments must be accompanied by grid extension measures. In contrast to onshore wind power and PV projects (which also require grid connections), individual OWP connections practically always involve voluminous transmission grid extensions; they go along with high costs as well as long planning and construction periods. The need of coordinating generation and grid investment decisions is therefore exceptionally high. This is all the more true when innovative connection concepts are taken into consideration. Replacing the concept of linking wind farm individually to the main grid via radial connections, innovative solutions potentially reduce costs; in addition, they might sometimes shorten the lead times of individual generation projects. Apart from the long-term vision of highly meshed offshore grids, shared grid infrastructures (such as converter platforms or main grid connection cables used by several wind farms) and "combined projects" represent two options which can also be implemented in the short-term. Such concepts require comprehensive regulatory planning under involvement of the concerned (regulated) grid operators and sometimes international coordination.[65]

Under consideration of these characteristics of OWP generation, we will discuss which design elements could be reasonable for OWP capacity instruments in the following

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[64] Cf. for instance Neuhoff / Ruester / Schwenen (2015), "Power Market Design beyond 2020: Time to Revisit Key Elements?".

[65] The term "combined projects" denotes grid extension measures which involve so-called "hybrid grid components" with the purpose of both interlinking power systems and connecting RES-E plants to the main grid. Cf. Orths et al. (2013), "Connecting the Dots: Regional Coordination for Offshore Wind and Grid Development"; NSCOGI (2014), "Cost Allocation for Hybrid Infrastructures"; Meeus (2014), "Offshore Grids for Renewables: Do We Need a Particular Regulatory Framework?"; Hoffrichter / Beckers (2018), "International Cooperation on the Expansion of Offshore Wind Generation Capacity".

sections.

3.2 Rationales for technology-specific capacity instruments

As was substantiated in section 2 with a broad range of arguments, the EOM is not a suitable target model for providing power plants of any kind in a cost-efficient way. Some of the described problems become particularly apparent in the case of OWP. The attributes of OWP include several important advantages and disadvantages which are usually not appropriately reflected in market prices and thus not adequately considered by decision-making actors. It is hard to imagine that all relevant externalities can be easily "internalised" through minor market interventions by the regulator (see section 2.2.2.3).[66]

The problem that the special characteristics of OWP might not be appropriately taken into account by generation investors appears similarly in the context of designing capacity instruments. Building on the considerations presented in section 2.2.3.3.2, especially technology-neutral concepts which decentralise generation technology choices seem problematic.[67] The design of such instruments would necessarily involve many compromises in order to establish direct competition for regulatory contracts between OWP projects and projects of other technologies (other intermittent RES-E technologies, other RES-E technologies or even technologies belonging to further categories). To give an example, let us imagine a capacity instrument which addresses both offshore wind farms and rooftop PV stations. It is virtually not possible that one uniform framework adequately considers the properties of both technologies, since they substantially differ in many respects. If, for instance, the lead time of procurement (i.e., the time between awarding contracts to generators and the start of operation) would be just long enough to allow for the development of rooftop PV projects, it would be too short to realise OWP projects. This leads to significant cost disadvantages for OWP projects which might effectively exclude them.[68] Longer lead times of procurement, in turn, would result in delayed realisations of PV projects, which undermine their advantage of comparatively short development periods. Technology-related differentiations of the rules might alleviate such problems. However, due to the large amount of relevant factors which would have to be differentiated and the difficulty of achieving a balanced set of parameters, the instrument design would eventually most likely still favour one technology over the other. This means that the creation of a competitive environment which results in improved technology choices seems, at best, highly ambitious. Establishing an actual "level-playing-field" can even be considered unrealistic in this context.

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[66] It is, for instance, questionable whether market prices always properly reflect the relative scarcity of production sites on land, because there can be considerable limitations to the amount of achievable lease payments due to various sectoral regulations (e.g., related to agriculture or building).

[67] Cf. also Gawel et al. (2016), "The Rationales for Technology-Specific Renewable Energy Support"; Gawel / Strunz / Lehmann (2014), "A Public Choice View on the Climate and Energy Policy Mix in the EU – How Do the Emissions Trading Scheme and Support for Renewable Energies Interact?"; Gross et al. (2012), "On Picking Winners: The Need for Targeted Support for Renewable Energy".

[68] Theoretically, OWP investors could also start developing projects sufficiently ahead of the regulatory selection. However, undertaking large investments under uncertainty about the project's realisation increases the costs.

For the reasons discussed, decentralising overarching OWP investment decisions is not likely to result in efficient outcomes. Instead, the following approach appears preferable, irrespective of the state of OWP expansion:

- The regulator makes a general decision whether or not to install new OWP plants, considering all relevant aspects on the basis of the information currently available.
- In case of a positive evaluation, technology-specific OWP instruments are implemented, offering long-term contracts to investors who are chosen for implementing the regulatory decisions.

Apart from the properties of OWP, the institutional framework should be adapted to further relevant circumstances such as the current distribution of knowledge and the prevailing market situation. Properly designed, targeted OWP capacity instruments provide appropriate investment conditions, allowing for the provision of OWP at comparatively low costs. In the following section 3.3, we will discuss which particular design elements could be suited for OWP instruments.

3.3 Allocation of decisions and risks between generators and the regulator

As explained in section 2, the process of providing generation capacity comprises many tasks and whether individual decisions should be assigned to generators or made a responsibility of the regulator has to be considered thoroughly. In the following section 3.3.1 we discuss different solutions for the distribution of OWP project development tasks between the regulator and generators. In this context we focus on certain decisions related to site selection and wind farm layout which can be regarded as particularly relevant for the overall costs of OWP. Afterwards, in section 3.3.2, we discuss which particular risks are likely to increase the efficiency of decentralised actions, when borne by generators.

3.3.1 Decision-making concerning the location and layout of offshore wind farms

Decisions on OWP project sites

Concerning the process of selecting OWP locations, we compare two opposite concepts: a largely decentralised approach where investors freely choose the sites for new wind farms and a centralised site selection (or site preselection) by the regulator.

When the decentralised approach is applied, the regulator is only involved in the site selection process as far as objectives from other sectors are concerned.[69] This means that investors carry out most of the tasks associated with the exploration of potential plant

[69] As mentioned in section 3.1, this applies for instance to potential interference with shipping and fishing activities, the preservation of nature reserves and other protected areas as well as to the construction and operation of gas pipelines.

sites and with other early project development steps.[70] If the regulator has established a certain trajectory for the expansion of OWP capacity – which, as we will demonstrate below, is often reasonable – wind farms at different locations compete against each other for realisation and remuneration under the capacity instrument scheme. Potential advantages of this approach include the following aspects:

- If the regulator lacks the competence for efficiently performing this task, decentralising site selections offers cost savings; it might even appear to be the only reasonable choice.
- When projects at different locations compete against each other, different technical concepts can be developed at the same time, ideally resulting in the identification of the most efficient solutions.

Disadvantages might especially arise from the following interdependencies:

- As some projects are eventually not selected by the regulator, there is a risk of extensive stranded investments (i.e., devaluation of upfront investments in the course of planning and development activities at sites not chosen in the end). These costs might often outweigh the aforementioned positive effects.
- Synergies of integrated generation and grid planning can hardly be realised. Planning and development of grid extensions (including offshore infrastructure and necessary hinterland grid extensions) have to be carried out either under uncertainty regarding the location of new wind farms or after the selection process, which might considerably delay the starting dates of operation.
- If the regulatory selection of wind farm projects does not include locational aspects, further synergies remain untapped: If wind farms far apart from each other are selected, the aggregate costs of their connections can be expected to be substantially higher than when a cluster of wind farms within one delimited area is connected to the main grid.[71] While it is theoretically possible to take locational aspects into account during the process of selecting OWP generation projects, designing a scoring system which adequately weighs generation related costs and grid related costs can be challenging. Moreover, such a procedure might require extensive regulatory planning, which would contradict the rationales for decentralising locational decisions in the first place.

The option opposite to completely decentralised locational decisions is that the regulator unilaterally determines the areas in which new offshore wind farms are going to be built. In this context, the regulator is responsible for the exploration, selection and development (or predevelopment) of areas for new OWP capacity. Nevertheless, it is generally possible to assign certain tasks of this process to private contractors who carry them out on behalf of the regulator. Once the locations have been determined, generators compete for the

[70] The decentralised site selection implies that also early project development tasks are carried out by generators: if tasks like the development of plant sites would be carried out by the regulator, there would hardly be any reasons for decentralising the selection of production sites.

[71] Cf. for instance Meeus (2014), "Offshore Grids for Renewables".

implementation of projects at the selected sites. This means that competition between generators is an essential aspect of this approach, but it starts at a later stage of project development in comparison to the decentralised concept. The centralised concept has the following potential upsides and downsides:

- In contrast to the decentralised approach, centralised planning of OWP locations allows for integrated optimisation, including both generation and grid costs.[72]
- Since development efforts can be concentrated on the sites which are assessed most suitable during the early exploration process, significantly lower devaluation of specific investments can be expected.
- A precondition for applying this approach is that the regulator is equipped with sufficient resources, including the relevant knowledge. Otherwise, there is a risk of inefficient choices. Firstly, the regulator might select generally inferior sites. Secondly, it is possible that the selection of locations excludes particularly efficient options with respect to wind farm layout and plant construction (we will elaborate on this subject towards the end of this section when discussing interdependencies between wind farm layout and locational decisions).

[72] Cf. ibid.

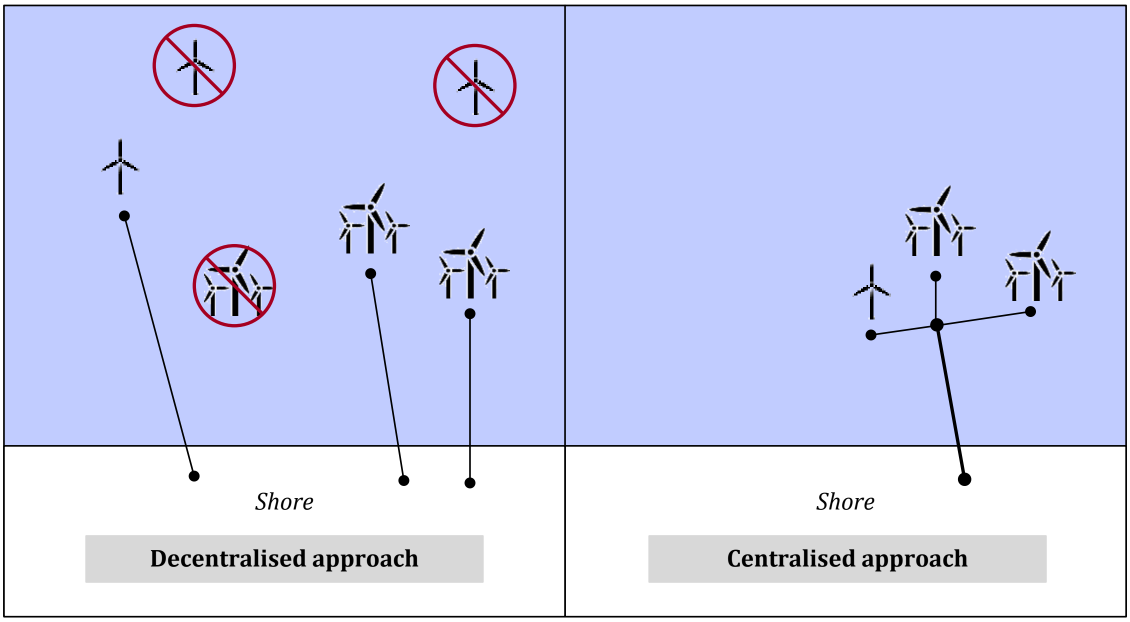

Figure 3: Possible outcomes of decentralised and centralised planning of OWP locations.[73]

Decisions related to plant design and wind farm layout

The current stage of global OWP expansion is characterised by a dynamic evolution of technical concepts. Against this background, it can be assumed that an essential part of the knowledge concerning efficient wind farm solutions is possessed by generators. Detailed regulatory specifications regarding such aspects as the use of certain types of wind turbines or the layout of wind farms might therefore be counterproductive. Instead, it seems reasonable that the corresponding decisions are largely left to generators. Competing against each other for the implementation of projects at the chosen sites, generators are encouraged to develop efficient technical concepts. The offer price helps the regulator identify efficient projects and suppliers. However, selecting projects only based on the offer price might impede major innovations, since investors are incentivised to choose the technical options which are currently available at the lowest costs. It could therefore be reasonable to create special segments for testing innovative concepts which are exempt from competition with regular offers.

Despite the reasons for largely assigning layout decisions to generators, establishing certain standards for generation projects can be conducive to the objective of reducing the overall cost of OWP generation. Standardisation with respect to the use of technical components or to the application of operational procedures might, for instance, be a

[73] Own illustration. The figure shows a scenario in which the centralised approach seems clearly advantageous for two reasons: Firstly, based on the selection of neighbouring production sites by the regulator, the wind farms are connected via one shared line to the main grid. Secondly, the decentralised approach leads to stranded investments in the form of abandoned wind farm projects which were ultimately not selected by the regulator (depicted by the struck through wind farm symbols).

precondition for connecting wind farms via common links to the main grid or to each other.[74] Since standardisation also has potential downsides such as lock-in effects which impede technological developments, the introduction of centrally established norms should be assessed on a case-by-case basis.

Interdependencies between locational and layout decisions

As mentioned above, the selection of production sites is interdependent with decisions on plant design and wind farm layout. The reason behind this relationship is that the suitability of technical concepts depends on factors such as wind yield, water depth and the structure of the seabed which often vary considerably between locations. While some maritime areas are particularly well-suited for certain kinds of technological concepts, different solutions might be advantageous in other areas. The selection of specific locations by the regulator is therefore likely to pre-empt some key decisions regarding plant design and wind farm layout. If the regulator does not adequately take all relevant aspects into account, the centralised site selection might exclude potentially preferable technical concepts which are not (economically) feasible at the chosen locations. Especially with respect the development of innovative concepts, it is important to acknowledge limitations to the regulator's capabilities and, accordingly, leave enough room for the incorporation of generator knowledge when making centralised decisions on the location of new wind farms.[75]

Summary and conclusion

Considering the attributes of OWP, centralising certain planning and development tasks seems advisable, while there are good reasons to leave many other decisions up to the generators who compete for the implementation of OWP projects.

In light of the discussed aspects, a centralised selection of locations for new OWP projects seems often preferable. Only in cases in which the regulator lacks the competences required for carrying out this task, or in which the transaction costs associated with centralised site selections are for some reasons excessively high, decentralized site selections might be advantageous. In comparison to other RES-E technologies, the transaction costs of active regulatory involvement in the selection and development of OWP production sites can be expected to be rather moderate, because the large size of OWP projects means that rather few production sites are needed. Moreover, offshore locations of plants imply that an extensive regulatory involvement in the planning process is indispensable. The reasonable degree of precision in centralised locational decisions largely depends on the regulator's knowledge. If the uncertainty regarding the evaluation of individual sites remains high after the regulatory exploration of generally suitable areas, the best option might be that the regulator only defines a preselection of several

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[74] Cf. Orths et al. (2013), "Connecting the Dots: Regional Coordination for Offshore Wind and Grid Development"; Hoffrichter / Beckers (2018), "International Cooperation on the Expansion of Offshore Wind Generation Capacity".

[75] If existing limitations to the centralised knowledge are not appropriately considered, regulators might, for instance, select sites which are mainly suited for conventional construction methods, while not seriously taking other locations into consideration where innovative OWP concepts could reach higher efficiency levels.

sites within a given area. The final choice of the sites at which projects are eventually developed (or developed first) could subsequently be based on the offers submitted by generators.

Regarding plant construction and wind farm layout it seems particularly important to allow for the integration of investor knowledge. It might often be preferable to limit the extent of regulatory specifications and entrust the bulk of decisions to generators. In this context it is essential to take interdependencies with centralised locational decisions into account.

3.3.2 Selection of risks for efficiency-enhancing incentive structures

As described when discussing the EOM model, there are many reasons why the evaluation of investment options can differ between the social perspective and the perspective of individual generators (see especially section 2.2.2.2.2). Establishing an appropriate incentive system for generators should be one of the main concerns of designing the institutional framework for OWP investments, because ill-conceived instrument designs might lead to undesirable investment decisions. Exposure to certain risks can be a reasonable component of the incentive system for investors. However, risk-based incentives have to be assessed carefully, because they tend to affect the costs of capital.[76] It is therefore essential to assess whether or not certain risks improve investor decisions without causing disproportionate increases in the costs of capital. Building on the general considerations presented in section 2.2.3.3.3, the following conclusions can be drawn with respect to the usage of certain risks:

- **Cost risks:** Directly confronted with the cost implications of their decisions, OWP generators are incentivised to use resources efficiently. This also includes the application of innovative methods which save costs. Another advantage is that the regulator must not be involved in detailed generator decisions, which makes extensive monitoring dispensable. In sum, there are usually very good reasons to expose OWP generators to cost risks.[77]
- **Production volume risk:** The exposure to production volume risks creates incentives for OWP investors to maximise their wind farms' quantitative contributions to electricity supply. Investors are encouraged to employ their resources (including knowledge) for identifying production sites and wind farm concepts which promise the most efficient use of the wind. Equipped with these decisional responsibilities, investors have a large influence on the achievable production volumes. The uncertainty about variable costs is of limited relevance,

[76] As described above, the costs of capital are particularly important for the overall cost of RES-E investments due to their high capital intensity. For a discussion of the same topic, but with respect to PV installations, cf. Ondraczek / Komendantova / Patt (2013), "WACC the Dog: The Effect of Financing Costs on the Levelized Cost of Solar PV Power".

[77] In the case of particularly innovative projects which go along with risks that the generators cannot control well there might be reasons to limit the generators' exposure to cost risk to a certain extent in order to avoid negative consequences on the costs of capital.

because the short-run marginal costs of available OWP production are constantly near zero.[78] However, some factors which cannot be controlled by generators also play important roles for the output possibilities; first and foremost the actual wind yield. On the other hand, the wind yield can be forecasted relatively well in comparison with other uncertainties (such as the long-term development of market prices). Therefore implied increases of the costs of capital can be expected to be rather moderate. If generators are held responsible for grid-related problems that inhibit the usage of the wind farm's output, the quantity risk might increase considerably. Such arrangements are only potentially reasonable, if generators have a large influence on the availability of the grid. Apart from its impact on investment-related decisions, quantity risk incentivises generators to minimise production interruptions during operation.[79] Overall, it seems appropriate to expose OWP generators to production volume risks, especially if major investment-related decisions are assigned to them.

- **Production value risk:** Although provided electricity volumes can function as a meaningful indicator for the contributions of a wind farm to electricity supply, the production value is a more precise measure. The value of produced electricity is not constant, but it changes with supply and demand. Investor choices regarding the production sites and design and layout concepts influence the generation patterns of wind farms and thus the achievable production values. Hence, it is generally desirable that generators consider the implications of related investment decisions. Some technical solutions which increase the production value also go along with higher LCOE (due to higher investment costs, higher O&M costs, or lower production volumes). Investors are only willing to opt for these solutions, if higher revenues outweigh the cost increases. One way of incentivising efficient investor decisions could be to link remuneration payments to wholesale market prices, because they are usually strongly correlated with the production value. Exposing investors to market price risk is only reasonable, if future market price structures are sufficiently well predictable for generators. Otherwise, bearing market price risk is likely to significantly affect the costs of capital, while the impact on investment-related decisions is questionable.[80] As far as operational decisions are concerned, OWP plants should always produce, when the marginal value of electricity is positive. When negative market prices occur, it might

[78] Whenever OWP plants are not available for production (for example due to a lack of wind) the marginal costs are virtually prohibitive. As explained in section 2.2.2.2.1, the marginal costs determine which plants are used to supply demand. In other generation segments varying fuel prices can substantially affect the achieved production quantities.

[79] In contrast to OWP and other RES-E technologies, the possible production volumes of power plants that use storable fuels usually depend less on locational and detailed design decisions. Besides, fluctuations in input prices might significantly affect the usage of plants. The arguments for fully exposing investors to production quantity risks are therefore generally weaker than in the case of OWP or other intermittent RES-E plants.

[80] The underlying interdependencies are explained in the course of the discussion of the EOM model in section 2.2.2.2.1. A further condition for the advantageousness of incentive structures based on market risk is that the regulator has limited knowledge on the cost and value implications of investment-related decisions (see section 2.2.3.3.3).

sometimes be necessary to curtail OWP production.[81] Since the marginal costs OWP are constant, generators have no informational advantage over the regulator.[82] Decisions to temporarily reduce the output of plants could therefore be centralised (i.e., for instance, made a responsibility of the system operator).[83] Regarding the planning of maintenance activities which interrupt operation, bearing production value risk theoretically incentivises generators to carry out this work during phases of low market prices. However, as such planning decisions have to take several other restrictions into account (such as the weather conditions or the availability of maintenance resources), the effectiveness of the incentive is questionable. In summary, exposing OWP generators to market risk in order to achieve more efficient investment decisions is only reasonable under specific circumstances; it must be doubted that operational decisions can be significantly improved.

- **Balancing risk:** If the task of selling electricity volumes is assigned to OWP generators, there are reasons for also exposing them to balancing risk. Being responsible for the accordance of actual production volumes with market sales, generators have incentives to develop accurate forecasts. However, it has not yet been demonstrated that direct marketing goes along with increased efficiency. Compared to centralised marketing of produced electricity from RES-E plants, a certain raise in transaction costs can be assumed.[84] It could further be considered an advantage that balancing risk triggers investments of OWP generators in flexible back-up capacity (in order to avoid imbalances and their financial consequences). But it is not evident why the task of providing back-up capacity should be carried out by OWP investors. The need for flexible capacity is determined by the aggregate installed capacity of intermittent RES-E plants in the electricity system. There are good reasons for providing flexible capacity via targeted instruments as well, instead of urging individual OWP generators to deliver capacity.

Whenever generators are not exposed to the risks mentioned above, these risks have to be borne by other actors. The corresponding cost implications (and potentially efficiency-enhancing incentives for these actors) have to be taken into account as well for an overall evaluation of risk allocation options. When market risks are borne by consumers, the cost effects are typically weak (as explained in section 2.2.3.2.1 in the course of the CRM model discussion). This option can therefore be regarded as a default solution for cases in which

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[81] With marginal costs near zero and no production-related emissions, intermittent RES-E plants should ideally be the last plants to be curtailed in the event of an electricity surplus. It seems imperative to make full use of all economically available flexibility options in order to keep the curtailment of intermittent RES-E production to a minimum.

[82] By contrast, generators who operate plants with significant and varying marginal costs (such as conventional plants, storage systems or biomass plants) usually have informational advantages over the regulator. Exposing generators to market risk can be a reasonable means to achieve efficient dispatch decisions in these generation segments.

[83] As we will explain in section 3.4.1, it is often reasonable that curtailments do not affect the remuneration payments generators receive.

[84] Due to the large sizes of offshore wind farms, cost increases can be expected to be rather small in comparison to other RES-E technologies with rather small-scale projects.

generators are not exposed to the corresponding risks.

Building on the presented considerations on the usage of risks, the following section 3.4 aims at identifying suitable design elements of OWP capacity instruments.

3.4 Implications for instrument design choices

In this section we discuss instrument design options with respect to two specific components of capacity instruments: the remuneration scheme (section 3.4.1) and the procurement mechanism (section 3.4.2).[85]

3.4.1 Remuneration scheme

Although the core idea of capacity instruments is to reward generators for providing plants (i.e., generation capacity) according to a regulatory decision, remuneration payments must not be calculated on the basis of the installed capacity (see section 2.2.3.1). Alternative reference units such as produced electricity volumes or production values might sometimes be more suitable for both incentivising efficient decisions of generators and measuring their performance.[86] In the following subsections we discuss popular RES-E instruments which are characterised by their respective remuneration schemes: feed-in tariffs (FIT), fixed market premiums (FMP) and sliding market premiums (SMP). Our aim is to examine whether they might be good fits for the provision of OWP capacity. Afterwards we address some overarching aspects.

Feed-in tariffs

The basic idea of the FIT scheme is that generators receive payments for each unit of electricity they provide to the system. The tariff levels are fixed in advance, ideally reflecting the LCOE including adequate returns on investment.[87] With remuneration payments depending on the electricity volumes provided, OWP generators bear quantity risk. They are not exposed to market risk, unless the regulator adopts additional rules which make remuneration payments subject to the usability of provided electricity volumes. This would mean that generators do not receive payments, if, for instance, market prices are negative. Especially if the basic version of the instrument is applied, which means that generators are not held (fully) responsible for possible curtailment needs,[88] the FIT scheme has a high potential with respect to the cost objective. Keeping the costs of capital at low levels and maintaining consumer payments stable even in the case of high market prices, the FIT scheme can be understood as a variation of the “capacity

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[85] As stated in section 2.2.3.1, the functioning of a capacity instrument and whether given policy objectives can be achieved ultimately depends on a large number of design elements, which we do not all discuss in this research paper.

[86] For simplicity, in this research paper we do not elaborate on further criteria to which payments can alternatively refer.

[87] We will discuss mechanisms for the determination of remuneration levels in the following section 3.4.2.

[88] As explained in section 3.3.2, curtailments due to grid-related issues should only be a reason for withholding remuneration payments to the extent that generators are responsible for them.

options” concept for RES-E plants (see section 2.2.3.2.1).[89]

Fixed feed-in premiums

In the FMP scheme, generators are usually responsible themselves for selling their electricity production on the market.[90] The essential difference to the EOM model is that generators receive premiums on top of their market earnings. Similar to the FIT concept, these payments are calculated on the basis of provided electricity volumes; the (fixed) level of the premiums is determined in advance (see Fig. 4 for an exemplary illustration of generator earnings in an FMP scheme).

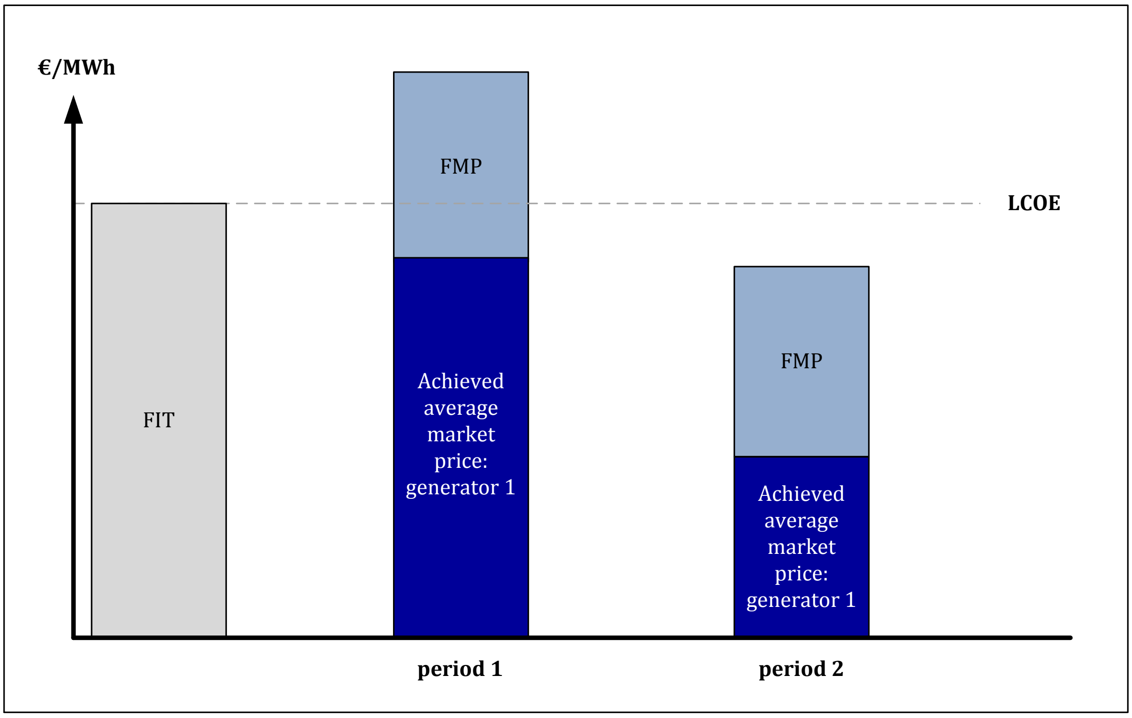

Figure 4: FMP scheme.[91]

OWP generators bear the full production value risk in addition to the production volume

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[89] An obvious modification of the original “capacity options” concept is that remuneration payments in FIT schemes refer to provided electricity volumes instead of provided capacity. Moreover, the call options of the regulator are subject to the availability of RES-E plants for production; otherwise RES-E generators would bear high market risks. Whereas determining the appropriate exercise price of the regulator’s option can be challenging in the case on generation technologies with significant and varying marginal costs, the obvious solution for “RES-E capacity options” (i.e., FIT schemes) is zero. This means that generators receive the capacity payment (i.e., the FIT), but no further market revenues for provided electricity volumes.

[90] By contrast, if a FIT scheme is applied, there are hardly any reasons for an engagement of the OWP generators in marketing activities, because generators do not bear market risk. If the production output is supposed to be allocated via markets, this task is usually taken care of by third actors on behalf of the regulator.

[91] Own illustration.

risk, because market price changes directly affect their revenues. Although the additional earnings in form of the premiums reduce the impact of the market risk on the cost of capital, significant increases still have to be expected (unless the premium level is so high that market revenues are irrelevant for amortisation which, however, implies excessive consumer payments). The revenues of generators are not necessarily capped, which means that high market prices would result in high producer rents at the expense of the consumers. A reduction of payments in such situations would be conceivable. But the premiums only justify fairly high price caps.[92] In general, the uncertainty of market returns justifies higher expected overall payments to investors. For this reason, the aggregate consumer payments in an FMP scheme are likely to significantly exceed FIT levels, if investors receive risk-adequate payments in both cases. As explained in section 3.3.2, the possibilities of OWP generators to align the production patterns of their wind farms with future market price structures are limited (partly because market forecasts are subject to high uncertainty). Therefore it can be doubted that the exposure to production value risk often leads to substantially higher generated production values which outweigh the cost increases.

Sliding feed-in premiums

The SMP approach can be understood as a hybrid of the FMP scheme and the FIT scheme. Similar to the FMP scheme, generators receive premiums on top of their market earnings. However, as suggested by the name, SMP levels vary over time. The idea behind the sliding feature of the premium is that the overall revenues for generators are supposed to approximately correspond to the FIT level which serves as a benchmark. For this reason, the regulator defines certain time intervals for which the SMP is calculated. At the end of each period the regulator determines the average market price achieved by all OWP plants and consequently the SMP level according to the difference between this price and the FIT level. If the weighted average of market prices achieved by a generator equals the industry average, its overall revenues exactly equal the amount of payments under a FIT scheme. If individually achieved market prices exceed the average or fall short of it in a certain period, the revenues diverge accordingly from the FIT level (see Fig. 5 for an exemplary illustration of generator earnings in an SMP scheme).

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[92] In comparison with the FIT approach, it seems less logical to withhold large parts of the upside risk when the investors bear the downside risk (i.e., their revenues decline when market prices decrease).

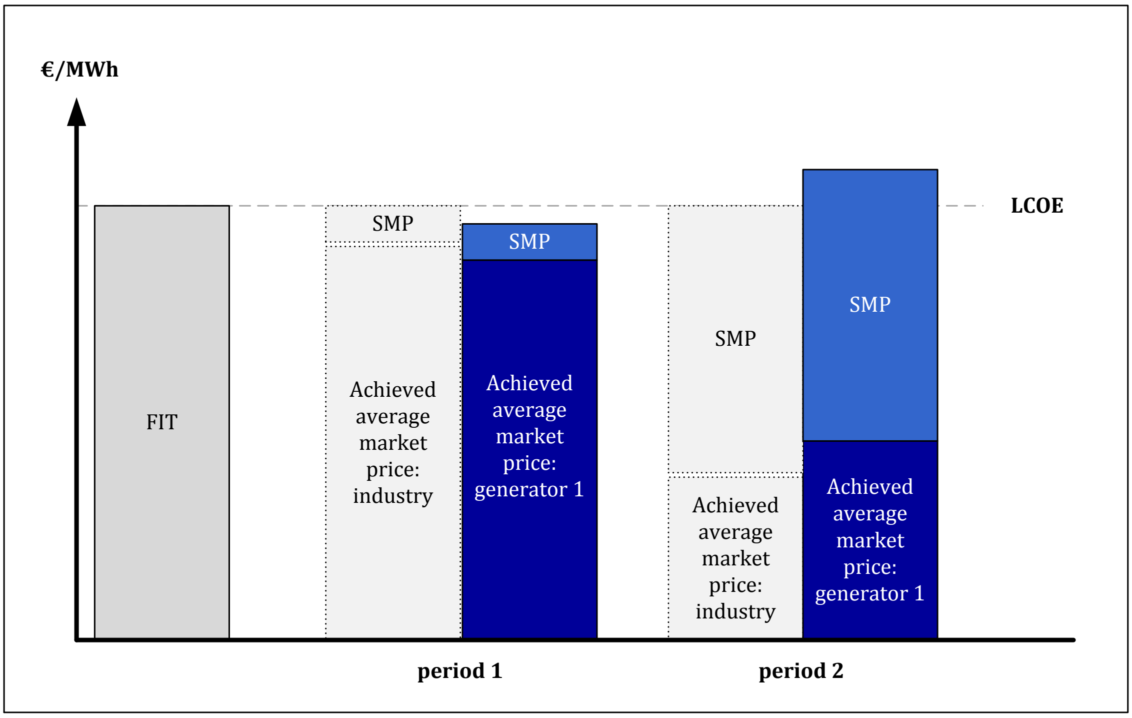

Figure 5: SMP scheme.[93]

This means that investors bear risk related to the correlation of their plants' availability for production with, first, the availability of other OWP plants and, second, market prices; generator revenues therefore depend on market developments. However, compared to the FMP approach, the cost implications of the risk can be expected to be small. While significant deviations from the FIT level in both directions might happen occasionally, they tend to balance out in the long-run. Nevertheless, it cannot be entirely ruled out that future changes in plant construction practices substantially change the average OWP production pattern. Therefore technical progress and investment decisions of competitors lead to certain revenue risks which potentially affect the costs of capital. However, if drastic changes of production patterns are unlikely, the difference between the FIT scheme and the SMP scheme can be expected to be comparatively small.[94] For the same reasons, the incentives for OWP generator to adapt investment-related decisions in order to raise the achievable production values are weak in SMP schemes.[95] In light of the

[93] Own illustration. The depiction assumes moderate deviations of the market prices achieved by the generator from the industry average.

[94] In May / Neuhoff (2017), "Financing Power: Impacts of Energy Policies in Changing Regulatory Environments", the authors even conclude from a survey on wind power financing costs in the European Union that sliding feed-in premium schemes currently do not increase the cost of capital as compared to FIT schemes at all.

[95] Existing quantitative studies also suggest that SMP, at least under currently prevalent conditions in the examined markets, have a rather negligible impact on RES-E investment decisions (compared to a FIT regime). Cf. for instance the analysis based on the examination of market prices regarding PV plant orientation in Germany in Zipp (2015), "Revenue Prospects of Photovoltaic in Germany – Influence Opportunities by Variation of the Plant Orientation" and the model-based

significantly reduced downside risk for investors, there are good reasons for establishing a cap to the possible market earnings of generators.[96]

Overarching aspects

The assessment of remuneration schemes for OWP instruments suggests that the FIT approach offers a high potential with respect to achieving the cost objective. The same can generally be said of the SMP approach, which is, one the one hand, conceptually different to the FIT approach, but, on the other, hand produces similar results. By contrast, the FMP concept appears to go along with considerable cost increases from both a welfare perspective and a consumer perspective. Similar outcomes can be expected when other instruments that expose OWP investors to high market risks are applied.[97]

Although this analysis focusses on the remuneration side of OWP investments, the interdependency with the financing side is worth mentioning. If generators implement the regulator's decision to build offshore wind farms on the basis of long-term contracts with targeted risk allocation, there are good reasons for a complementary involvement of the regulator in the provision of capital. Firstly, advantageous public financing conditions go along with direct cost reductions. Secondly, attracting further funding is easier and less costly when projects are financially backed by the regulator. Besides, public funding provides a solid foundation for project finance which might sometimes be favourable over corporate finance.[98]

As explained above, the risk-adequate returns for investors differ between the examined remuneration schemes. Apart from that, the expected overall revenues for investors primarily depend on the applied mechanism for the determination of remuneration levels, which we will discuss in the following section.

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considerations on the sliding premiums' influence on onshore wind power technology choices in May (2017), "The Impact of Wind Power Support Schemes on Technology Choices".

[96] This at least holds true, if there is a reasonable likelihood that market prices could permanently exceed the FIT level during the contract period.

[97] Amongst others, this includes "renewables obligations" as described in section 2.2.2.2.2. The presented assessment of remuneration schemes based on qualitative economic considerations is generally in line with the findings of empirical analyses which examine the impact of remuneration schemes on the costs of capital of RES-E projects in Europe. Cf. for instance Noothout et al. (2016), "The Impact of Risks in Renewable Energy Investments and the Role of Smart Policies"; Steinhilber et al. (2011), "RE-Shaping: Shaping an Effective and Efficient European Renewable Energy Market - D17 Report: Indicators Assessing the Performance of Renewable Energy Support Policies in 27 Member States". The same applies to the analysis based on both conceptual considerations and empirical observations which is presented in May / Jürgens / Neuhoff (2017), "Renewable Energy Policy: Risk Hedging Is Taking Center Stage".

[98] Cf. for a general and detailed discussion on the roles of private and public finance in the context of infrastructure projects developed by private actors on behalf of the regulator Beckers / Gehrt / Klatt (2010), "Rationales for the (Limited) Use of Private Finance in Public-Private Partnerships" . Apart from the classic motive of avoiding "contamination risk", project finance offers some further potential advantages such as uncomplicated financial involvement of several project partners; cf. Steffen (2018), "The Importance of Project Finance for Renewable Energy Projects". In light of the comparatively early state of expansion of OWP and the large sizes of individual projects, there are particularly good reasons to engage in joint ventures.

3.4.2 Procurement mechanism

In consideration of the special characteristics of OWP projects, tender mechanisms have certain advantages over regulatory price offers.[99] Reasons for this can be found in the large size of OWP projects, the importance of coordinated generation and grid planning and the comparatively early stage of OWP expansion (see section 3.1).[100] Provided that the level of competition between generators is sufficiently high, tenders generally offer a suitable framework for the procurement of OWP capacity. Since the large size of typical OWP projects (with respect to both installed capacities and financial volumes) usually predominantly attracts large investors, potential entry barriers for small generators seem to be less of a problem than in the case of small-scale RES-E projects.[101]

Moreover, regulatory price offers are hardly combinable with the approach of centralising the selection and predevelopment of OWP production sites (which was found generally recommendable in section 3.3.1, if certain preconditions are fulfilled). Competitive tenders, by contrast, are a well-suited mechanism for choosing generators who implement projects at the selected sites and for determining the corresponding remuneration levels. A tender design tailored to the prevailing circumstances represents a good basis for choosing the most efficient suppliers and projects, as well as for avoiding excessive producer rents.[102]

As mentioned above, it could be reasonable to create special segments for testing innovative technical concepts which are exempt from price competition with regular offers (see section 3.3.1).

To which extent synergies between grid connections of wind farms can be realised depends on the exact distribution of decisions and tasks between generators and the regulator. If OWP investors are made responsible for providing grid connections to offshore substations, offshore converter stations or even to onshore substations, the timeline of the procurement process plays an important role. The development of shared connection infrastructure is difficult for generators who plan to build neighbouring wind farms, if the contracts for implementing the corresponding projects are not awarded at the

[99] For a general comparison of these two approaches, see section 2.2.3.3.1.

[100] By contrast, in the case of onshore wind power and PV, it is – due to their different characteristics – highly questionable whether tenders lead to better results than regulatory price offers. On the one hand, there is empirical evidence for potential problems of regulatory price offers. To give an example, especially in the early years of applying the Renewables Energy Sources Act (EEG) in Germany, the regulator had difficulties in determining adequate FIT levels for onshore wind and PV generators which lead to excessive producer rents in some cases. This was largely related to limited centralised knowledge and to the exploitation of the information asymmetries by the renewables industry (i.e., successful rent-seeking activities; cf. for instance Gawel et al. (2016), "The Rationales for Technology-Specific Renewable Energy Support". On the other hand, such problems are likely to largely disappear with increasing centralised knowledge and experience. In accordance with these considerations, sound evidence has not yet been produced that RES-E tenders – in comparison to regulatory price offers – would perform better with respect to limiting producer rents.

[101] Cf. Kostka / Anzinger (2015), "Offshore Wind Power Expansion in Germany: Scale, Patterns and Causes of Time Delays and Cost Overruns".

[102] Apart from the aspects discussed in this analysis, the design of a tender mechanism comprises several further design elements which are potentially highly relevant for its functioning. Making the right design choices can be a complex task. In this analysis, we do not go further into the details of this matter.

same time. But even if this is the case, there is a substantial uncertainty regarding the success in the auction procedure which impedes early coordination. Another precondition for the realisation of synergies is that the regulatory framework leaves room for collaborative connection concepts. Overly restrictive regulations might force investors to refrain from joint actions and opt for separate grid connections instead. In light of these difficulties, it could be preferable in some cases that the regulator is largely responsible for planning grid connections. Especially if the centralised knowledge is not sufficiently profound to perform this task efficiently, it can be a reasonable alternative to contract well-qualified third actors who plan the grid infrastructure on behalf of the regulator.

Another relevant aspect – although not directly connected to the design of the procurement mechanism – is that longer-term calculability is particularly important to OWP supply side actors, because large project sizes lead to high step fixed costs at several stages of the supply chain. Tendering new capacity does not necessarily involve deployment targets for many years ahead, but it can be combined with such regulatory commitments. Reliable trajectories for OWP expansion can play an essential role for achieving further cost reductions. However, there are also reasons for maintaining a certain responsiveness to future cost developments.

3.5 Summary

The special characteristics of OWP have certain implications for the design of OWP capacity instruments. Using tendering procedures appears to be usually reasonable for the selection of generators and for the determination of payment levels. Regarding the remuneration scheme, there are good arguments for applying either the FIT approach or the SMP approach; the choice between these two alternatives largely depends on whether or not direct marketing is regarded as desirable.[103] In many cases, a regulatory selection and predevelopment of OWP production sites offers potential advantages over a site selection by competing generators. Concerning the development of concrete wind farm concepts for the selected production sites, there are good reasons for assigning this task to the bidders who participate in the tenders. Which design elements are ultimately most suitable for an actual OWP instrument in a given application scenario highly depends on the prevailing circumstances. The more profound the regulator's knowledge about the power market and instrument design, the more it can harness the cost efficiency potential of targeted OWP instruments.

[103] As stated in section 3.3.2, on the one hand, it has not yet been demonstrated that direct marketing goes along with increased efficiency. On the other hand – unlike in other RES-E segments – due to the large size of OWP projects the transaction costs which go along with direct marketing are of comparatively little relevance.

4. Conclusion

In light of the outstanding importance of electricity supply to society, the regulator is ultimately responsible for the achievement of related objectives. Therefore the regulator is necessarily, more or less actively, involved in the provision of generation capacity. There are very good reasons to assign certain tasks to generators, but maximising the amount of decisions which are delegated to “the market” should not be an aim of designing the institutional framework. Concerning OWP investments, the costs in EOM-based market environments are unnecessarily high and it is questionable whether a large-scale OWP deployment would take place. The reasons for this can be found in the great uncertainty about future developments and limited hedging possibilities. The economic analysis presented in this research paper delivers strong arguments for making general regulatory decisions upon the usage of the OWP technology and for the application of corresponding targeted instruments for the provision offshore wind farms. This explicitly also applies to situations in which OWP would be competitive in an EOM-based system as well. Although some general conclusions can be drawn from theory-based analyses, the appropriate design of actual OWP instruments largely depends by the prevailing circumstances; centralised knowledge is therefore a key to successful applications. In many cases, it can be reasonable to centralise the selection and predevelopment of production sites and subsequently put out contracts for building and operating offshore wind farms at these locations to competitive tender. In this way the amount of stranded investments can be limited and synergies with grid connection planning can be realised. By contrast, the development of concrete wind farm layouts and designs should usually be decentralised; i.e., largely made a responsibility of the competing generators. Considering the great significance of risk premiums for the cost objective and the doubtful effectiveness of market risk exposure, the FIT approach or the SMP approach appear to be generally suitable remuneration schemes. In order to select the most efficient projects and generators while avoiding excessive producer rents, the assessment of bids received in the tenders could be primarily based on the offer price. However, with respect to long-term efficiency it is very important that the regulator also actively enables the development and application of innovative OWP concepts. The general instrument design questions discussed in this research paper can be regarded as highly relevant for establishing an appropriate framework for OWP investments. Apart from these, various further aspects such as regulatory commitments to reliable trajectories for OWP expansion are arguably no less important for achieving a cost-efficient deployment of offshore wind farms.

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