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Grid Investment and Support Schemes for Renewable Electricity Generation

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Abstract

The unbundling of formerly vertically integrated utilities in liberalized electricity markets led to a coordination problem between investments in the regulated electricity grid and investments into new power generation. At the same time investments into new generation capacities based on weather dependent renewable energy sources such as wind and solar energy are increasingly subsidized with different support schemes. Against this backdrop this article analyzes the locational choice of private wind power investors under different support schemes and the implications on grid investments. I find that investors do not choose system optimal locations in feed-in tariff schemes, feed-in premium schemes and subsidy systems with direct capacity payments. Consequently, inefficiencies arise if transmission investment follows wind power investment. A benevolent transmission operator can implement the first-best solution by anticipatory investment behavior, which is however only applicable under perfect regulation. Alternatively a location dependent network charge for wind power producers can directly influence investment decisions and internalize the grid integration costs of wind power generation.

Keywords: Renewable energy investment, transmission investment, coordination problem, external effects

JEL classification: D47, D62, L94, Q28, Q48

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1. Introduction

Transmission and distribution networks in the electricity industry are regarded as natural monopolies which require governmental regulation while the remaining parts of the value chain, namely generation, wholesale and retail can be organized competitively.[1] Based on this insight, a large number of electricity systems, for example in the United States or Europe, have been restructured over the last decades.[2] A central part of these restructuring efforts is unbundling, which describes the vertical separation of the monopolistic network from the potentially competitive parts of the system.[3]

In unbundled electricity systems, separate entities such as private generation investors and regulated transmission operators make investment decisions based on their individual agenda. Nevertheless, there exist strong interactions between these decisions which leads to a coordination problem. New power plants can for example increase network congestion and therefore force extensions which could be avoided by choosing a different location for the investment. This problem is intensified by the increasing importance of electricity generation from intermittent renewable energy sources such as wind and solar energy. Because of the weather dependency of these energy sources, the best locations for wind and solar power plants are typically distributed and located away from the load centres. Consequently, the integration of large amounts of generation capacity based on wind and solar energy into the electricity system requires substantial investments into the electricity grid.[4]

To foster investment into electricity generation from renewable energy sources, various countries have introduced support schemes such as feed-in tariff systems, feed-in premium systems or capacity subsidies.[5] A crucial difference between these subsidy systems is how producers of renewable electricity are exposed to market signals. Under feed-in tariffs renewable generators receive a fixed payment for every produced kilowatt hour of electrical energy independently of the market situation. Consequently, generators are entirely isolated from market signals. With capacity subsidies on the other hand, producers of renewable

[1] Natural monopolies exist when production with a single firm is less costly than production by several competing firms due to subadditive cost functions. See Joskow (2007) for a detailed discussion.

[2] See Joskow (1997) for a general discussion of electricity market liberalization for the US power sector. A similar analysis for European markets can be found in Jamasb and Pollitt (2005).

[3] Similar efforts have been undertaken in other network industries such as gas, telecommunication and rail, see for example Newbery (1997).

[4] The required grid investments in the European electricity system to reach the European CO_2 reduction and renewable energy targets are analyzed in Fürsch et al. (2013). The results indicate that optimal network extension requires transmission investments of more than 200 billion EUR until 2050.

[5] An overview of support policies for renewable electricity generation in OECD and non-OECD countries is provided in International Energy Agency (2015). The general question of the economic justification of renewable energy support instead of direct CO_2 pricing is not part this paper. The most common argument for renewable energy support policies are market failures due to learning spillovers. See for example Fischer and Newell (2008) or Gerlagh et al. (2009) for an analysis. An extensive review of literature on the rationale of support policies for renewable energies can be found in Fischer (2010).

energy are fully exposed to market signals because they generate revenue only due to electricity sales in the wholesale market. Feed-in premiums combine the described approaches by paying a fixed premium on top of the wholesale electricity price to renewable energy producers.

The exposure of electricity producers to wholesale prices and therefore also the choice of the support scheme for renewable energy has large implications for investment decisions. For example, the locational choice of investors for wind or solar power plants is affected by the subsidy system. When producers are isolated from market signals they base their investment decision solely on the the weather conditions at a specific location. If producers are exposed to market signals however, they have to take into account the correlation of the weather dependent electricity generation at the given location with market prices. For large investors, the influence of portfolio effects, which arise when they combine investments in locations with different weather conditions and generation patterns, has to be accounted for, too. Because of these interrelations the choice of the subsidy system also influences the need for grid extensions because different investment locations can lead to substantially different integration costs in transmission and distribution networks.[6] The described effect is especially pronounced for wind energy as different geographical locatinos can substantially differ in total wind power generation as well as their generation profiles over time.[7]

Against the described backdrop, this paper analyzes the influence of the subsidy scheme for renewable electricity generation on the locational choice of renewable energy investors and on grid investments. Building on that, inefficiencies in grid investments which arise due to deviations from the socially optimal allocation of renewable electricity generation capacities are of interest. Additionally, anticipatory behavior of the transmission operator and network charges for renewable energy producers are assessed as potential remedies for arising inefficiencies. To analyze these issues a highly stylized model with one demand node, two possible locations for renewable generation investment and lumpy transmission investment is developed. Electricity generation at the two locations is stochastic with different total expected generation and imperfectly correlated generation patterns. Renewable energy investments are subsidized by a feed-in tariff scheme, a feed-in premium system or direct capacity payments in order to reach an exogenous renewable target. The analysis is conducted for wind power, however the results apply for all intermittent and location dependent renewable energy sources.[8]

The analysis is mainly related to two literature streams. The first relevant literature stream examines

[6]See Swider et al. (2008) or Georgilakis (2008) for a discussion of technical problems of the integration of renewable electricity generation into power systems.

[7]See for example Elberg and Hagspiel (2015) for an empirical analysis of the of the market value of wind power at different locations in Germany.

[8]Other intermittent renewable energy sources are solar energy and marine energy.

the efficiency of different subsidy schemes for electricity generation from renewable energy sources. Hiroux and Saguan (2010) give an overview of the advantages and disadvantages of different support schemes with respect to the integration of large amounts of wind power into the European electricity system. They argue that support schemes should expose wind power producers to market signals in order to incentivize system optimal choice of wind sites and maintenance planning or to incorporate portfolio effects. Klessmann et al. (2008) on the other hand point out that market exposure increases risk for investors, which leads to a higher required level of financial support in order to stimulate investments. Andor and Voss (2016) find that an optimal support scheme for renewable electricity generation is a combination of capacity payments and generation-based subsidies paid on top of the market price, which internalize externalities arising from renewable energy based generation capacities and electricity generation. The impact of renewable energy subsidies on the spatial allocation of wind power investments is explicitly studied in Oliveira (2015) and Schmidt et al. (2013). Oliveira (2015) develops an analytical model to show that a feed-in premium system leads to investments, which are better aligned with the social optimum in comparison with a feed-in tariff system. Schmidt et al. (2013) analyze the spatial distribution of wind turbines under a feed-in premium and a feed-in tariff scheme based on an empirical model for Austria. They find that a feed-in premium system leads to substantially higher diversification of locations for wind power generation. Both papers do not consider capacity payments or the required grid extensions to integrate the wind power capacity into the electricity system.

The second relevant literature stream is focused on the coordination problem between transmission and generation investment in liberalized power markets. Sauma and Oren (2006) and Pozo et al. (2013) show that a proactive transmission planner can induce generation companies to invest in a more socially efficient manner by anticipating investments in generation capacity. Höffler and Wambach (2013) show that generation investment can lead to overinvestment or underinvestment in the electricity grid when private investors do not take the costs and benefits of network extensions into account. They also show that a capacity market can incentivize private investors to make socially efficient locational choices. The implications of renewable subsidies on the coordination problem are not part of the mentioned studies. The interactions of renewable portfolio standards and transmission planning are examined in Munoz et al. (2013). They show that ignoring the lumpy nature of transmission investment when planning the necessary grid extension for the integration of renewable energies can lead to significant inefficiencies in network investments. The effect of different support schemes is not part of the analysis.

In summary the contribution of the paper is to explicitly model interactions between the renewable support scheme and grid investments. The effects of reactive and anticipatory grid investments in unbundled electricity systems with renewable subsidies are analyzed. Therefore the paper intends to close the gap between the literature streams on renewable support schemes and the coordination problem between generation investment and grid investment in unbundled electricity systems.

The remainder of the paper is structured as follows. Section 2 introduces the model and analyzes the efficient allocation of renewable generation capacities as well as the investment problems for private renewable energy investors and grid investments. Section 3 introduces asymmetric grid investment costs, imperfect regulation of the transmission operator and network charges for renewable producers as model extensions. Section 4 gives a simple numerical example. Section 5 concludes.

2. The model

We consider a model with three nodes D, H and L, which are not connected initially. At node D electricity consumption is located with an inelastic demand of quantity d. Additionally, two conventional generation technologies are located at node D. A cheap base-load technology with marginal generation costs c_1 and limited generation capacity $\bar{q}$ as well as a peak-load technology with unlimited generation capacity but higher marginal generation costs $c_2 > c_1$. It is assumed that a political target to reach a generation capacity $K_T \leq d$ based on renewable energy sources is in place.[9] Additionally it is assumed that $\bar{q} \geq \frac{d}{2}$.[10] The renewable target can be reached by investments into wind generation capacity at nodes H and L. Investment costs for one unit of capacity are I^W.[11] Investments are subsidized either by a feed-in tariff system, a feed-in premium system or direct capacity payments. To connect the wind power plants at nodes H and L to the demand node D transmission lines have to be built. Investment into transmission requires investment costs I^L and is modeled as a binary decision. Hence, once an investment is made, the transmission capacity is unlimited, which represents the lumpy character of transmission investments.[12] The described model configuration is depicted in Figure 1. Figure 1(a) shows the nodes of the model as well as the potential network connections represented by dashed lines. Figure 1(b) shows the supply curve of

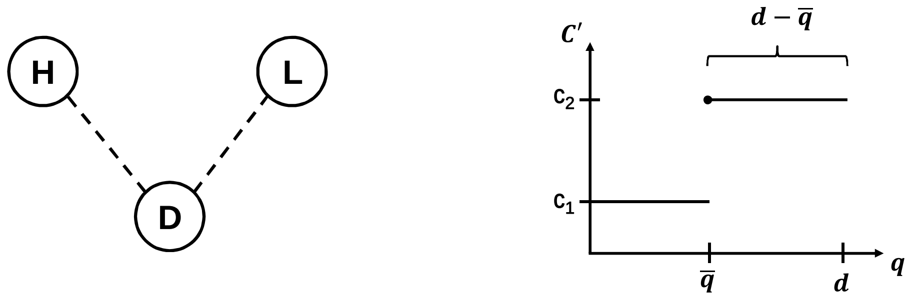
[9]In practice political renewable targets are defined in terms of capacity or electricity generation. However, even in countries with generation targets, for example Germany, the monitoring of target achievement is often undertaken based on installed capacity. See International Renewable Energy Agency (2015b) for a discussion.

[10]This assumption is made in order to focus the analysis on the question if and under which conditions the wind locations H and L are developed. Extending the analysis for $\bar{q} < \frac{d}{2}$ is straight forward but requires additional case distinction which do not provide substantial insights regarding the central questions of the study.

[11]The capacity factor is assumed to be one, which means that the full installed capacity is available for production if wind is present. In reality this factor is smaller than one and depends on the wind speed as well as the technical properties of the wind power plant.

[12]Lumpiness describes the fact that transmission capacity is increased in discrete steps as a result of strong economies of scale, see for example Joskow and Tirole (2005).

conventional generation with different marginal generation costs for the base-load and peak-load technology. The depicted quantity $(d - \bar{q})$ represents the amount of electricity that has to be generated with the costly peak-load technology if no wind power generation is present.



(a) Network configuration

(b) Supply curve of conventional generation

Figure 1: Basic model configuration

Wind generation at nodes H and L is stochastic with three possible states h, l and hl, which occur with probabilities ρ_h, ρ_l and ρ_{hl} $(\rho_h + \rho_l + \rho_{hl} = 1)$. In states h and l only wind power plants at node H respectively L produce electricity whereas in state hl wind power is produced at both nodes.[13] Additionally it is assumed that $\rho_h > \rho_l$ which means that the expected wind output is higher at node H.

The described configuration accounts for two important properties of wind power generation. The first property is a substantial variation of expected electricity generation between different wind locations. The second property is that wind power generation is imperfectly correlated between different locations as a result of the spatial variation in weather conditions. In the model the correlation between the locations H and L can be modified by the value of ρ_{hl}. If ρ_{hl} equals zero wind output is perfectly negative correlated between the two nodes. The higher ρ_{hl} the higher is the correlation between nodes and the lower is the probability that only one of the locations produces wind power.[14]

The dynamic setting of the model consists of three stages: Transmission investment, wind power investment and cost minimal dispatch. The dispatch takes place in the last stage of the model after the stochastic wind generation is realized. Investment decisions on the other hand are made with uncertain wind output.

[13] A fourth state in which none of the locations produce wind power is not included for reasons of simplification. Such a state could however be included without changing the results of the analysis.

[14] The described representation of stochastic wind power generation is similar to Ambec and Crampes (2012) and Milstein and Tishler (2015). Both papers analyze interactions between investments into dispatchable and intermittent sources of electricity generation. A disadvantage of this simple model of stochasticity is that the variance of wind generation can not be changed independently of the expected wind generation. Note that the model considers only one period of wind generation. However an extension with multiple periods, e.g. for every day in a year, can be realized by repetition, as done for example in Milstein and Tishler (2015).

To assess the effects of uncoordinated generation and grid investments as well as anticipatory and reactive behavior of the transmission operator (TSO), three different model configurations are considered:

(i) **Central planner**: The central planner jointly invests into grid and wind power capacities to minimize total expected system costs. This model setting represents a vertically integrated electricity system and is considered as a first-best benchmark.

(ii) **Reactive TSO**: Under reactive transmission investment revenue maximizing investment into wind power with feed-in tariff (FIT), feed-in premium (FIP) or capacity payments (CAP), happens in the first stage followed by transmission investment in the second stage. It is assumed that the TSO has to comply with the renewable target and is therefore obliged to connect all wind power investments from the first stage. Consequently, the TSO solely reacts to wind power investments from the first stage.

(iii) **Anticipatory TSO**: Under anticipatory transmission investment the transmission operator acts first and builds transmission lines to integrate wind power capacities according to the capacity target K_T. In the second stage, wind power investors build generation capacities given the network infrastructure from the first stage. As an additional steering instrument the TSO is able to limit transfer capacities of transmission lines. Hence, the TSO can actively influence wind power investments.

In all settings perfect information and risk neutral behavior of investors is assumed.[15] In the basic model, the TSO is assumed to behave benevolently as a result of perfect regulation. Imperfect regulation is discussed as a model extension in section 3. Figure 2 illustrates the dynamics of the model for all considered cases graphically.

The model is solved by backward induction. Therefore the dispatch problem, which is common for all described model settings, is solved first, followed by the renewable and transmission investment problems.

2.1. The dispatch problem

In the third stage of the model, the dispatch costs C_D are minimized based on investments in the prior stages and the realization of wind power generation. Consequently, conventional generation capacities at node D are used to meet the electricity demand that can not be covered by the wind power generation delivered to node D given the grid and wind power investments in the first and second stage. As a result,

[15] The long-term uncertainty of wind power production at a given location is low, while the short-term uncertainty, for example within one day, is high. Consequently, the assumption of risk neutrality in a model which evaluates revenue from wind power over the whole lifetime of the investment is uncritical.

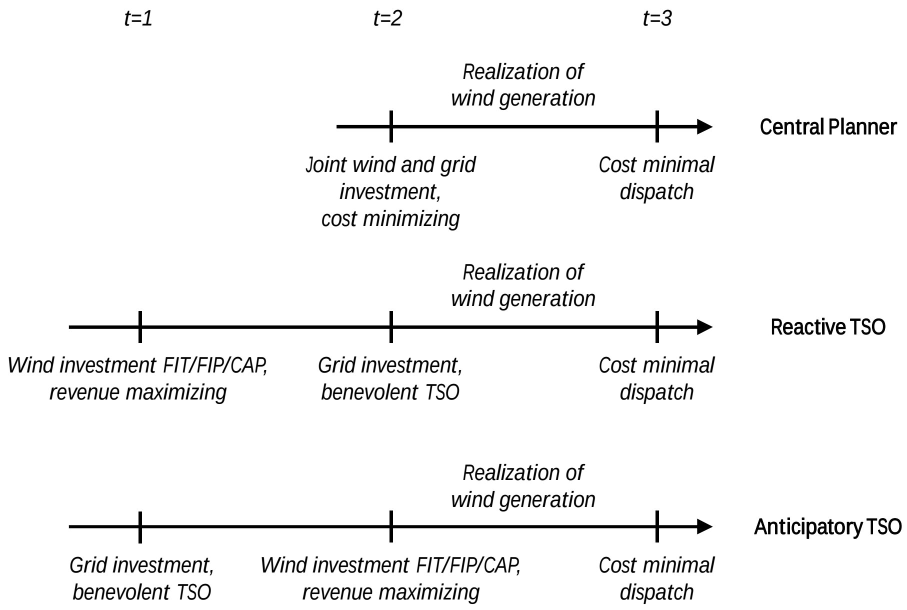


Figure 2: Dynamic model settings

renewable generation R is exogenous in the third stage and conventional generation q is dispatched according to the problem formulated in equations (1a) and (1b).[16]

$$\min_{q} C_D = \begin{cases} qc_1 & \text{if } q < \bar{q} \\ \bar{q}c_1 + (q - \bar{q})c_2 & \text{if } q \geq \bar{q} \end{cases} \tag{1a}$$

$$\text{s.t. } d = q + R \tag{1b}$$

The cost function (1a) represents the two available conventional generation technologies with marginal generation cost equal to c_1 as long as the conventional generation q is smaller than the maximum capacity $\bar{q}$ of the base-load technology. If conventional generation exceeds $\bar{q}$ the marginal generation costs c_2 of the peak-load technology incur. Equation (1b) is the balance constraint which ensures that electricity demand

[16]Curtailment of wind power generation is not considered

d is met. Setting the partial derivatives $\frac{\partial \mathcal{L}}{\partial q}$ and $\frac{\partial \mathcal{L}}{\partial \lambda}$ of the lagrangian $\mathcal{L} = C_D + \lambda(d - q - R)$ equal to zero yields the following expressions:

$$\lambda = \begin{cases} c_1 & \text{if } q < \bar{q} \\ c_2 & \text{if } q \geq \bar{q} \end{cases} \tag{2a}$$

$$q = d - R \tag{2b}$$

Equation (2a) expresses that the market price equals marginal generation costs. Equation (2b) states that conventional generation equals residual demand. These expressions are a stylized representation of the merit order effect as the market price for electricity drops from c_2 to c_1 if the wind generation delivered to demand node D is higher than $(d - \bar{q})$.[17]

When investment decisions are made, the realization of the stochastic wind output is unknown. Therefore the investment problems are based on the expected dispatch outcome which depends on the expected wind power generation $\mathbf{E}(R)$ delivered to node D:

$$\mathbf{E}(R) = \rho_h K_H + \rho_l K_L + \rho_{hl}(K_H + K_L) \tag{3a}$$

$$K_H = Cap_H L_H \tag{3b}$$

$$K_L = Cap_L L_L \tag{3c}$$

$\mathbf{E}(R)$ is a function of the installed wind power capacity at nodes H and L and the probability that these capacities will produce electricity. Additionally, a transmission line between the demand node and the wind site has to be in place in order to use the wind power production to meet electricity demand. This is expressed in equations (3b) and (3c) by the product of installed capacities Cap_H respectively Cap_L and the binary variables L_H and L_L which indicate if a connection between the wind locations and the demand node is in place.

Because of the piecewise linear form of the cost function of conventional power generation, several cases of connected wind power capacity have to be distinguished in order to determine the expected dispatch outcome. Decisive for the case distinction is if the conventional peak load technology is crowded out of the market because of the realized wind generation in each possible state. Based on this logic, five cases can

[17] See Würzburg et al. (2013) for a review of empirical studies which analyze the price depressing effect of renewable electricity generation for different European markets.

be distinguished as indicated in equation (4). The aggregated connected wind power capacity at both wind locations is represented by $K_A = K_H + K_L$.

$$\mathbf{E}(C_D) = \begin{cases} c_1(d - \rho_l K_L - \rho_h K_H - \rho_{hl} K_A) & \text{if } K_H,\, K_L > d - \bar{q} \\ c_1\big(\rho_l \bar{q} + \rho_h(d - K_H) + \rho_{hl}(d - K_A)\big) + c_2 \rho_l (d - \bar{q} - K_L) & \text{if } K_H > d - \bar{q},\, K_L \leq d - \bar{q} \\ c_1\big(\rho_h \bar{q} + \rho_l(d - K_L) + \rho_{hl}(d - K_A)\big) + c_2 \rho_h (d - \bar{q} - K_H) & \text{if } K_H \leq d - \bar{q},\, K_L > d - \bar{q} \\ c_1\big((\rho_h + \rho_l)\bar{q} + \rho_{hl}(d - K_A)\big) + c_2\big((\rho_h + \rho_l)(d - \bar{q}) - \rho_h K_H - \rho_l K_L\big) & \text{if } K_H,\, K_L \leq d - \bar{q},\, K_A > d - \bar{q} \\ c_1 \bar{q} + c_2(d - \bar{q} - \rho_l K_L - \rho_h K_H - \rho_{hl} K_A) & \text{if } K_H,\, K_L \leq d - \bar{q},\, K_A \leq d - \bar{q} \end{cases} \tag{4}$$

Analogously the expected market price $\mathbf{E}(\lambda)$ can be expressed by the marginal generation costs c_1 and c_2 weighted with the probability that each technology sets the market price in the five distinguished cases.

$$\mathbf{E}(\lambda) = \begin{cases} c_1 & \text{if } K_H,\, K_L > d - \bar{q} \\ c_1(1 - \rho_h) + c_2 \rho_h & \text{if } K_H > d - \bar{q},\, K_L \leq d - \bar{q} \\ c_1(1 - \rho_l) + c_2 \rho_l & \text{if } K_H \leq d - \bar{q},\, K_L > d - \bar{q} \\ c_1 \rho_{hl} + c_2(1 - \rho_{hl}) & \text{if } K_H,\, K_L \leq d - \bar{q},\, K_A > d - \bar{q} \\ c_2 & \text{if } K_H,\, K_L \leq d - \bar{q},\, K_A \leq d - \bar{q} \end{cases} \tag{5}$$

Equations (4) and (5) show that the expected dispatch costs as well as the expected electricity price decrease with increasing connected wind power capacity as a result of the merit order effect. Additionally the effect of imperfect correlation of wind generation between the locations is apparent because the conventional peak load technology is only displaced completely if the installed wind capacity at both locations exceeds $(d - \bar{q})$.

2.2. The central planner investment problem

The central planner jointly invests into wind power generation capacity and transmission lines in order to meet the wind power capacity target K_T. The objective of the central planner is to minimize total system costs which include expected dispatch costs and investment costs. With specific investment costs for wind power I^W and grid investment costs I^G this translates into the following minimization problem:

$$\min_{Cap_H, Cap_L, L_H, L_L} C_{Total} = \mathbf{E}(C_D) + I^W(Cap_H + Cap_L) + I^G(L_H + L_L) \tag{6a}$$

$$\text{s.t. } K_T = Cap_H L_H + Cap_L L_L \tag{6b}$$

$$L_L, L_H \in \{1, 0\} \tag{6c}$$

Because of the binary character of grid investments, problem (6) can be solved by analyzing optimal wind power investment and the corresponding system costs for all possible network configurations. Consequently, total investment costs with one wind location and both wind locations connected to the demand node D have to be compared. Based on this comparison the following proposition can be derived:

Proposition 1. *The central planner diversifies wind locations if the reduction of expected dispatch costs outweighs the required additional grid investment costs. Depending on the target for wind power capacity, two cases can be distinguished:*

(i) For $K_T \leq d - \bar{q}$ diversification is never optimal

(ii) For $K_T > d - \bar{q}$ diversification is optimal if $(c_2\rho_l - c_1\rho_h)\big(K_T - (d - \bar{q})\big) > I^G$

Proof. See Appendix A.

Proposition 1 points out that the central planner faces a trade off between reducing expected dispatch cost due to diversification of wind sites and the grid investment costs, which are required to connect the additional locations. For renewable targets below $(d-\bar{q})$ it is never optimal to develop both locations because there is no benefit of diversification as long as all the produced wind power at the better wind location H replaces costly conventional peak-load generation.

For renewable targets above $(d - \bar{q})$ the central planner always builds a capacity of $(d - \bar{q})$ at node H. The remaining quantity $K_T - (d - \bar{q})$ can either be also built at node H to replace base-load generation with probability $\rho_h + \rho_{hl}$ or alternatively at node L to replace peak-load generation with probability ρ_l and base-load generation with probability ρ_{hl}. Consequently, a prerequisite for developing the low wind location L is that the cost difference between peak-load and base-load generation outweighs the difference in expected wind output between nodes H and L. Formally this means that $c_1\rho_h < c_2\rho_l$ must hold. If this condition is true, the central planner chooses to build a capacity of $(d - \bar{q})$ at the better wind location H and the remaining $K_T - (d - \bar{q})$ at the low wind location L if the achievable reduction in expected dispatch costs outweighs the required investment costs for the additional transmission line to node L. For $K_T > d - \bar{q}$ the potential benefits of developing the second wind location increase with the renewable target. For $K_T = 2(d - \bar{q})$ the maximum potential benefit of diversification is reached, which means that the central planner never chooses to develop both wind locations if the condition $(c_2\rho_l - c_1\rho_h)(d - \bar{q}) > I^G$ is not satisfied.

The described result of proposition 1 is shown graphically in figure 3.[18] Expected dispatch costs when only node H is connected are depicted by the solid line. The reduction of expected dispatch cost for one

[18]The depiction in figure 3 assumes that $c_1\rho_h < c_2\rho_l$ is true.

additional unit of wind power capacity is $c_2(\rho_h + \rho_{hl})$ for $K_T \leq (d - \bar{q})$ and $c_1(\rho_h + \rho_{hl})$ for $K_T > (d - \bar{q})$. Expected dispatch costs with nodes H and L connected are depicted by the dashed line. For $K_T > (d - \bar{q})$ the reduction of expected dispatch costs is $c_2\rho_l + c_1\rho_{hl}$ for every additional unit of wind power generation. The difference between the solid and dashed lines corresponds to the reduction in dispatch costs due to diversification of wind locations. Developing the low wind location L is socially beneficial if this cost reduction exceeds the additional grid investment costs I^G.

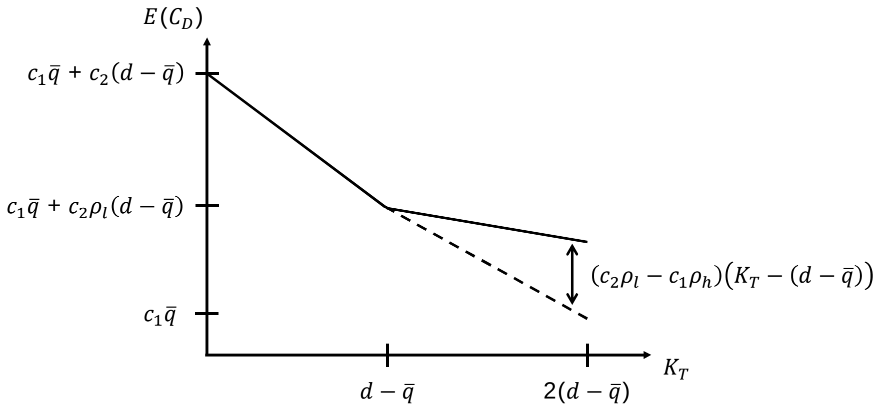


Figure 3: Expected dispatch costs in the central planner problem

An important result of proposition 1 is that the benefit of wind location diversification increases with ρ_l and c_2, while it decreases with ρ_h, c_1 and $\bar{q}$. Consequently, a lower quality difference between the high wind location H and the low wind location L as well as a steeper merit order of the conventional power plant fleet increases the benefit of developing both wind locations. A higher availability of cheap base load technology on the other hand decreases the achievable reduction in expected dispatch costs. Additionally, for a given probability ρ_h a higher correlation between the wind generation at both wind locations decreases the benefit of diversifying wind locations.

2.3. The renewable energy investment problem

In this section the investment problem for wind power producers in an unbundled electricity system is solved for a feed-in tariff scheme, a feed-in premium system and direct capacity payments. Based on these results the effects of reactive behavior of the transmission operator can be assessed. The central planner problem from the previous section serves as a first-best benchmark to identify inefficiencies.

2.3.1. Feed-in tariff

Under a feed-in tariff scheme, wind power investors receive a fixed payment for every produced kilowatt hour of electrical energy. Consequently, each revenue maximizing investor i faces the optimization problem expressed in equations (7a) and (7b). $\mathbf{E}(\pi_i)$ represents the expected revenue and FIT the fixed feed-in tariff.

$$\max_{Cap_{L,i},Cap_{H,i}} \mathbf{E}(\pi_i) = FIT * \mathbf{E}(R_i) - I^W(Cap_{L,i} + Cap_{H,i}) \tag{7a}$$

$$\text{s.t. } K_T = \sum_i Cap_{H,i} L_H + \sum_i Cap_{L,i} L_L \tag{7b}$$

FIT is assumed to be set by the regulator to a level which guarantees positive expected returns for all required investments to meet the capacity target K_T. Wind investors maximize the expected revenue by choosing wind capacities with the highest expected wind generation $\mathbf{E}(R_i)$ for a given FIT. Hence, investors never choose to build capacity at the low wind location L under a feed-in tariff scheme because the market value of the produced electricity is not internalized and $\rho_h > \rho_l$. This result is independent of the number of investors i because the lack of market signals prevents possible portfolio effects or incentives for strategic behavior.[19] As a result there is a tendency to underdiversification of wind locations compared to the first-best solution of the central planner because even if developing both locations is socially beneficial investors do not invest at node L. Consequently, inefficiencies can arise in an unbundled system with a feed-in tariff system if the transmission operator behaves reactively and builds the grid according to the decisions of renewable investors. The results are summarized in the following proposition:

Proposition 2a. *In a feed-in tariff system investors always prefer the location with the highest expected wind generation because the market value of electricity is not internalized. Therefore underdiversification of wind locations compared to the first-best solution is possible.*

Proof. See Appendix A.

2.3.2. Feed-in premium

In a feed-in premium system, renewable investors sell the produced electrical energy in the spot market and receive an additional fixed premium payment. Hence, investors have to take into account not only the expected wind generation but also the expected market price as well as the correlation between market price and wind generation. Equations (8a) and (8b) shows the resulting maximization problem for each renewable investor i. FIP represents the fixed premium payment.

$$\max_{Cap_{L,i},Cap_{H,i}} \mathbf{E}(\pi_i) = \mathbf{E}(\lambda) * \mathbf{E}(R_i) + \mathbf{Cov}(\lambda, R_i) + FIP * \mathbf{E}(R_i) - I^W(Cap_{L,i} + Cap_{H,i}) \tag{8a}$$

$$\text{s.t. } K_T = \sum_i Cap_{H,i} L_H + \sum_i Cap_{L,i} L_L \tag{8b}$$

[19] It is however not possible to determine the investment levels $Cap_{L,i}$ and $Cap_{H,i}$ of an individual investor because every distribution of the total wind capacity K_T over the investors is an equilibrium. See for example Hobbs and Pang (2007) for a detailed discussion of a similar example where the total supplied electricity is fixed due to a price cap.

Again it is assumed, that FIP is set to a level that guarantees the realization of the capacity target K_T with positive expected returns. In contrast to the feed-in tariff case, the number of investors i can change the allocation of wind power investments in a feed-in premium subsidy system. This is a result of the exposure to market signals which makes investors consider the effect of their investments on market prices and on the expected revenue of their aggregated investment portfolio. However, it is not possible to derive a unique solution for an oligopolistic market setting because every distribution of the optimal aggregated wind power capacity over the individual investors is an equilibrium.[20] Consequently, only the two extreme cases with one monopolistic investor or alternatively the competitive case with a very large number of investors which are able to enter the market are analyzed.[21] The main difference between these two cases is that the monopolistic investor has to take into account the aggregated revenue of total investments at all nodes, while investors do not consider these portfolio effects in the competitive setting.

For low renewable targets $K_T \leq d - \bar{q}$, the market price equals c_2 for all possible states h, l and hl. Consequently, investment is always more profitable at the location with the highest expected wind generation regardless of the number of investors. For investment levels above $(d - \bar{q})$ it is always preferable to install a capacity of at least $(d - \bar{q})$ at node H because of the higher expected wind output. Above that level an additional unit of wind power capacity at node H earns less revenue in the spot market because prices are depressed to c_1 if states h or hl are realized. However, investors can instead choose to invest at the second wind location, where they still earn the higher market price c_2 when state l is realized and c_1 in state hl. The additional premium payment is not affected by the market price and depends only on the expected wind power generation. As a result, the expected premium payment for one unit of wind power capacity is always lower at node L compared to node H. Consequently, in the competitive case, investors choose to develop the low wind location if the expected additional spot market revenue at node L outweighs the lower expected premium payments:

$$c_2 \rho_l - c_1 \rho_h > (\rho_h - \rho_l) FIP \tag{9}$$

In the monopolistic case the decision is more complex because all the installed wind power capacity at node H earns the lower market price c_1 in states h and hl if the single investor continues to invest at node H for renewable targets above $(d - \bar{q})$. By investing at the low wind location he can not only earn a higher spot market revenue for the marginal capacity but also prevent that earnings of the remaining assets at node H

[20] See also footnote 19.

[21] In practice, the market structure of wind power investment varies substantially between different countries. In Spain for example, investments are usually undertaken by large single entities such as power utilities or regional governments (see for example Schallenberg-Rodriguez and Haas (2012)), while in the German market a large number of investors compete for possible wind sites (see for example International Renewable Energy Agency (2015a)).

are depressed by the merit-order effect in state h. The resulting condition for developing the second location in the case of a monopolistic investor for renewable targets $K_T > (d - \bar{q})$ is formulated in equation (10):

$$c_2\rho_l - c_1\rho_h\frac{K_T}{K_T - (d - \bar{q})} + c_2\rho_h\frac{(d - \bar{q})}{K_T - (d - \bar{q})} > (\rho_h - \rho_l)FIP \tag{10}$$

By comparing the coefficients of equations (9) and (10) it can be seen that developing the low wind location is always more profitable in the monopolistic case compared to the competitive case as a result of the described portfolio effects. However, condition (10) converges to condition (9) as the renewable target increases.

Equations (9) and (10) show that in both cases the profitability of investing at the low wind location increases with the difference between c_2 and c_1. Hence, comparable to the central planner problem the steepness of the merit-order of the conventional power plant fleet is decisive for the profitability of diversification of wind locations. Additionally it can be seen that a higher feed-in premium decreases the profitability of investing at location L, because the share of revenue from the fixed premium payments in relation to the revenue generated from spot market sales increases. Consequently, diversifying wind locations becomes more attractive as the technological maturity of wind power plants increases and less premium payments are necessary to cover investment costs. An increase in the quality of the low wind location ρ_l increases the profitability of investments at node L because the expected spot market revenue at the low wind location increases and the difference in fixed premium payments compared to the high wind location decreases. Also, for a given probability ρ_h, a higher correlation between generation at the two wind locations decreases the profitability of diversifying wind locations.

For the monopolistic wind power investor the investment decision additionally depends on the level of the capacity target for wind power K_T and the difference between demand and base-load capacity $(d - \bar{q})$. This results from the impact of the merit order effect on the expected revenue of the total installed wind capacity. Especially for renewable targets slightly above $(d - \bar{q})$, the monopolistic investor always invests at the low wind location, because an additional unit of wind power capacity at node H would reduce the expected revenue of all his assets at the high wind location. Consequently, the left hand side of equation (10) goes to infinity as K_T approaches $(d - \bar{q})$.

The discussed results show that the grid investment costs which are required to connect the second wind location to node D are external costs for the wind power investor and are therefore not considered in the decision. Consequently, inefficiencies arise in a feed-in premium system if transmission investment follows wind power investors and the optimality conditions in proposition 1 are inconsistent with the behavior of wind power investors formulated in equations (9) and (10). Proposition 2b summarizes the results for wind power investments in a feed-in premium subsidy scheme.

Proposition 2b. *In a feed-in premium system investors develop both locations if the expected additional spot market revenue outweighs the lower premium payments. Depending on the number of players as well as the specific structure of wind power investment costs, grid investment costs and marginal conventional generation costs, over- or underdiversification of wind locations compared to the first-best solution is possible.*

Proof. See Appendix A.

2.3.3. Capacity payment

In a subsidy system with direct capacity payments, wind power investors generate revenue only in the spot market. Additionally they receive a fixed subsidy payment SUB for every unit of capacity they build, which is equivalent to a reduction of the investment costs. The resulting optimization problem is expressed in equation (11):

$$\max_{Cap_{L,i},Cap_{H,i}} \mathbf{E}(\pi_i) = \mathbf{E}(\lambda) * \mathbf{E}(R_i) + \mathbf{Cov}(\lambda, R_i) - (I^W - SUB)(Cap_{L,i} + Cap_{H,i}) \tag{11}$$

With capacity payments renewable investors maximize spot market revenue. For low renewable targets $K_T \leq d - \bar{q}$ the expected spot market revenue is higher at location H because of the higher expected wind generation. Once the installed capacity at the high wind location is equal to $d - \bar{q}$ and additional unit of wind capacity at node H generates expected spot market revenue of $c_1(\rho_h + \rho_{hl})$ because the conventional peak-load technology gets crowded out of the market in states h and hl. Investments at node L on the other hand generate expected spot market revenue of $c_2\rho_l + c_1\rho_{hl}$. Similar to the feed-in premium system, the solution depends on the number of players in the market. Again the two extreme cases of a very large number of investors and of a single monopolistic investor can be analyzed. In the competitive case, investors always choose to invest at node L if $c_2\rho_l > c_1\rho_h$. The monopolistic investor additionally takes into account portfolio effects due to the impact of his investments on market prices. The condition for investments at node L is formulated in equation (12):

$$c_2\rho_l - c_1\rho_h \frac{K_T}{K_T - (d - \bar{q})} + c_2\rho_h \frac{(d - \bar{q})}{K_T - (d - \bar{q})} > 0 \tag{12}$$

Again it is always more attractive to develop the low wind location for the monopolistic wind power investor in comparison to the competitive case. Compared to the feed-in premium system, the condition for developing the low wind location is less restrictive in the competitive as well as the monopolistic market setting. By comparing the results with the central planner solution it can additionally be derived that underdiversification of wind locations is not possible in a subsidy system with capacity payments.[22] Instead,

[22]See second part of proposition 1.

there is a tendency to overdiversification as the market value of wind energy is fully internalized while grid investment costs are external. Proposition 2c summarizes the findings.

Proposition 2c. *In a system with direct capacity payments investors prefer locations where the highest expected spot market revenue can be generated. Therefore investors tend to overdiversify wind locations compared to the first-best solution of the central planner. Underdiversification of wind locations is not possible.*

Proof. See Appendix A.

2.4. Anticipatory transmission investment

The results of the previous section show that in an unbundled electricity system inefficiencies can arise due to uncoordinated investment into wind power capacity and into the grid under all considered subsidy schemes. The possible inefficiencies are underdiversification of wind locations, which means that potential reductions in total system costs due to development of additional locations are not used, and overdiversification of wind locations, which means that wind power investments enforce inefficient grid extensions. This section analyzes if a proactive transmission operator can prevent these inefficiencies by anticipating decisions of wind power investors. It is assumed that the transmission operator is benevolent and minimizes total system costs. Additionally it is assumed that the transmission operator has perfect information and knows all relevant parameters of the electricity system. Consequently, the transmission operator decides whether to build transmission lines to nodes H and L based on the grid investment costs and the expected dispatch costs, which result from private wind power investments in different network configurations. To enable the transmission operator to prevent underdiversification of wind locations it is assumed that he is able to limit the transfer capacity of a transmission line once it is build. For reasons of simplification only the limitation of transfer capacity to the high wind location H is considered.[23] Based on these assumptions the optimization problem of the transmission operator is formulated in equations (13a) to (13c). $\overline{L_H}$ represents the limited transfer capacity to node H. $\mathbf{E}\big(C_D(\cdot,\ \overline{L_H})\big)$ expresses that the expected dispatch costs are now also influenced by the limited transfer capacity.[24]

$$\min_{L_H, L_L, \overline{L_H}} C_{Total} = \mathbf{E}\big(C_D(\cdot,\ \overline{L_H})\big) + I^W(Cap_H + Cap_L) + I^G(L_H + L_L) \tag{13a}$$

$$\text{s.t. } K_T = Cap_H L_H + Cap_L L_L \tag{13b}$$

$$L_L, L_H \in \{1, 0\} \tag{13c}$$

[23]Including the option to limit transfer capacity to node L into the problem would however not change the results

[24]The "$\cdot$" represents the remaining factors as discussed in section 2.1.

As discussed in the previous section two types of inefficiencies can arise depending on the subsidy scheme for renewable energy, namely underdiversification and overdiversification of wind locations. As the transmission operator has perfect information over the electricity system he can anticipate wind power investments and the resulting inefficiencies. If wind power investors develop too many wind locations, which is possible in a subsidy system with direct capacity payments or in a feed in premium system under the conditions explained in sections 2.3.2 and 2.3.3, the transmission operator can refuse to connect the low wind location L to the demand node D. This prevents overdiversification as investors have no incentive to invest at location L if they know that no transmission line will be built and they can not generate any revenue at node L. If wind power producers invest only at the high wind location H despite potential social benefits of developing both wind locations, the transmission operator can choose to build both transmission lines and force investors to move to location L by limiting transfer capacity to node H. This prevents underdiversification because additional investments above the capacity limit will not be able to generate positive expected returns. The optimal capacity limit is equal to $(d - \bar{q})$, which is the social optimal investment level at node H if diversification of wind locations is beneficial. Propsition 3 summarizes the results for the optimization problem of the transmission operator.

Proposition 3.

(i) If the subsidy scheme for wind power investment incentivizes overdiversification, the transmission operator chooses not to connect the inferior wind location L.

(ii) If the subsidy scheme for wind power investment incentivizes underdiversification, the transmission operator connects both locations and limits the transfer capacity to the superior wind location to $(d-\bar{q})$, which forces investors to develop both wind locations.

Proof. See Appendix A.

3. Model extensions

After the basic results and implications of the model have been discussed, this section introduces extensions that give additional insights on the coordination problem between subsidized renewable energy investments and grid investments in unbundled electricity systems.

3.1. Asymmetric grid investment costs

Throughout section 2 symmetric investment costs for grid investments are assumed, which means that investments costs for transmission lines to nodes H and node L are equal. In reality, the required costs to integrate different wind location into the electricity system can vary substantially based on factors such as the distance to load centers or effects on bottlenecks within the system.[25] Introducing asymmetric investment costs for grid extensions does not change the dispatch problem nor the investment problem of wind power producers. However, the first-best benchmark solution of the central planner and the transmission investment problem are different. The main difference to the solutions presented in section 2 is that connecting only node L is not dominated by connecting only node H.[26]

As a result, additional inefficiencies can occur when the transmission line to the high wind location H is more costly than the transmission line to the low wind location L. In this case it is preferable to connect only node L if the higher expected wind output at node H does not justify the additional grid investment costs. If wind power investors move first they will however prefer the better wind location H and therefore force the transmission operator to build the more costly transmission line. Analogous to section 2 a perfectly regulated and perfectly informed transmission operator can implement the first best solution by anticipating investment decisions of wind power producers and building the optimal network configuration proactively in a system with asymmetric grid investment costs. The mathematical formulation of the central planner problem with asymmetric grind investment costs is provided in Appendix B.

3.2. Imperfect regulation

The results in section 2 are based on the assumption of benevolent behavior of the transmission operator as a result of perfect regulation. In reality, transmission companies are not perfectly regulated and follow their own agenda inside the regulatory constraints. Depending on the regulatory system incentives to overinvest or underinvest compared to the socially optimal network configuration can emerge. Regulatory systems that incentivize overinvestment according to standard economic theory are cost-plus and rate-of-return regulation.[27] Under rate-of-return regulation the transmission operator is allowed to recover investment costs and to earn an additional rate of return which is set by the regulator. In the analyzed model a revenue maximizing transmission operator under rate of return regulation profits from building transmission lines to both wind locations. Hence, given the decision variables from section 2.4, the transmission operator can limit the transfer capacity to node H to a value below the renewable target K_T in order to force wind power investors to develop both locations in all considered subsidy systems.[28] Proactive behavior therefore enables the transmission operator to always build both transmission lines and earn the guaranteed revenue.

[25] See Swider et al. (2008).

[26] Note that a setting with two nodes where demand is located at one node and wind power investment is possible at both nodes can be modeled by setting grid investment costs for the connection to node H or node L to zero. The two node setting is therefore a special case of the three node model with asymmetric grid investment costs.

[27] See for example Averch and Johnson (1962).

[28] It is assumed that the transmission operator is not able to connect a location where no wind power capacity will be built in the second stage. Therefore he has to limit transfer capacity in order to steer investments.

An example for a regulatory system that incentivizes underinvestment is price-cap regulation with no adjustments of the cap based on the investment activity of the transmission operator.[29] In such a regulatory system the transmission operator would try to build as little transmission capacities as possible. Assuming that the transmission operator acts proactively and is obliged to enable the realization of the renewable target, it would be optimal to connect only one wind location. With symmetric grid investment costs, the transmission operator is indifferent between the locations. With asymmetric investment costs he connects only the location with lower grid investments.

The two examples show that imperfect regulation can lead to substantial inefficiencies in grid investment when the transmission operator invests proactively in an unbundled electricity system. A highly stylized mathematical representation of the discussed regulatory regimes in the analyzed model framework is provided in Appendix C.

3.3. G-component

One of the main results of section 2 is that wind power investors do not necessarily choose system optimal locations for their investments. Additionally it has been shown that proactive behavior of a benevolent transmission operator leads to the optimal system configuration, which is however only applicable under perfect regulation. An alternative approach to directly influence the investment behavior of wind power investors is a location dependent g-component. A g-component is a network charge which is set by the regulator and paid by power generators for the electrical energy they feed into the grid. This section analyzes if such a charge can be set to a level that reflects the impact of investments into new generation capacity on overall system costs, leading to an internalization of the external effects of private investments.

A g-component is not applicable in a feed-in-tariff system because the lack of market signals for investors does not incentivize diversification of locations. Therefore a g-component could only shift investments completely from the high wind location to the low wind location. In feed-in premium systems however, a g-component can alter the relationship between the revenue generated from spot market sales and fixed premium payments which determines the attractiveness to diversify locations for investors. Consequently, a g-component can adjust the investment problem of private investors, formulated in equations (9) and (10) in order to harmonize it with proposition 1.

Assuming that developing the low wind location is socially inefficient, the regulator can choose to charge a g-component at location L in order to deincentivize private investments. By introducing the g-component G_L

[29] For a detailed discussion of the effects of price-cap regulation on investment behavior see for example Laffont and Tirole (1993). Modern regulatory systems based on incentive and yardstick regulation can also be seen as a type of price-cap regulation where the price-cap is revised regularly based on industry benchmarks, see Joskow (2014). A comparison of rate-of-return and price-cap regulation can be found in Liston (1993).

into equation (9) and combining it with proposition 1, the following lower bound for G_L in the competitive market setting can be derived:

$$G_L \geq \frac{I^G}{\big(K_T - (d - \bar{q})\big)(\rho_l + \rho_{lh})} - \frac{(\rho_h - \rho_l) * FIP}{(\rho_l + \rho_{lh})} \tag{14}$$

The first term in equation 14 shows that the g-component introduces the grid investment costs as well as the renewable target K_T into the maximization problem of wind power investors. The minimum value of G_L increases with I^G and decreases with K_T because the social costs of developing the low wind location L are high if the connection is costly and if only small amounts of wind power capacity are built at node L, which still require the full lumpy grid investment. The second term in equation 14 results from the higher fixed premium payments at node H and reduces the lower bound for G_L. Analogously the lower bound for G_L in the monopolistic case can be determined by adjusting equation (10) and combining it with proposition 1:

$$G_L \geq \frac{I^G + (c_2 - c_1)\rho_h(d - \bar{q})}{\big(K_T - (d - \bar{q})\big)(\rho_l + \rho_{lh})} - \frac{(\rho_h - \rho_l) * FIP}{(\rho_l + \rho_{lh})} \tag{15}$$

Equation (15) shows that the lower bound for G_L is always higher in the monopolistic case compared to the competitive case due to the additional part in the first term. This results from the higher incentives to develop the second wind location for the monopolistic investor as a result of portfolio effects.[30]

A lower bound for G_H in order to incentivize investments at node L can be derived analogously, the results are provided in Appendix D. Similarly to the feed-in premium case, a g-component can be used to steer locational choices of private investors in a subsidy system with direct capacity payments. The resulting lower bound for G_L to prevent potential overdiversification can be obtained by setting FIP to zero in the solutions of the feed-in premium case. Underdiversification of wind locations is not possible in a system with direct capacity payments as shown in section 2.3.3.

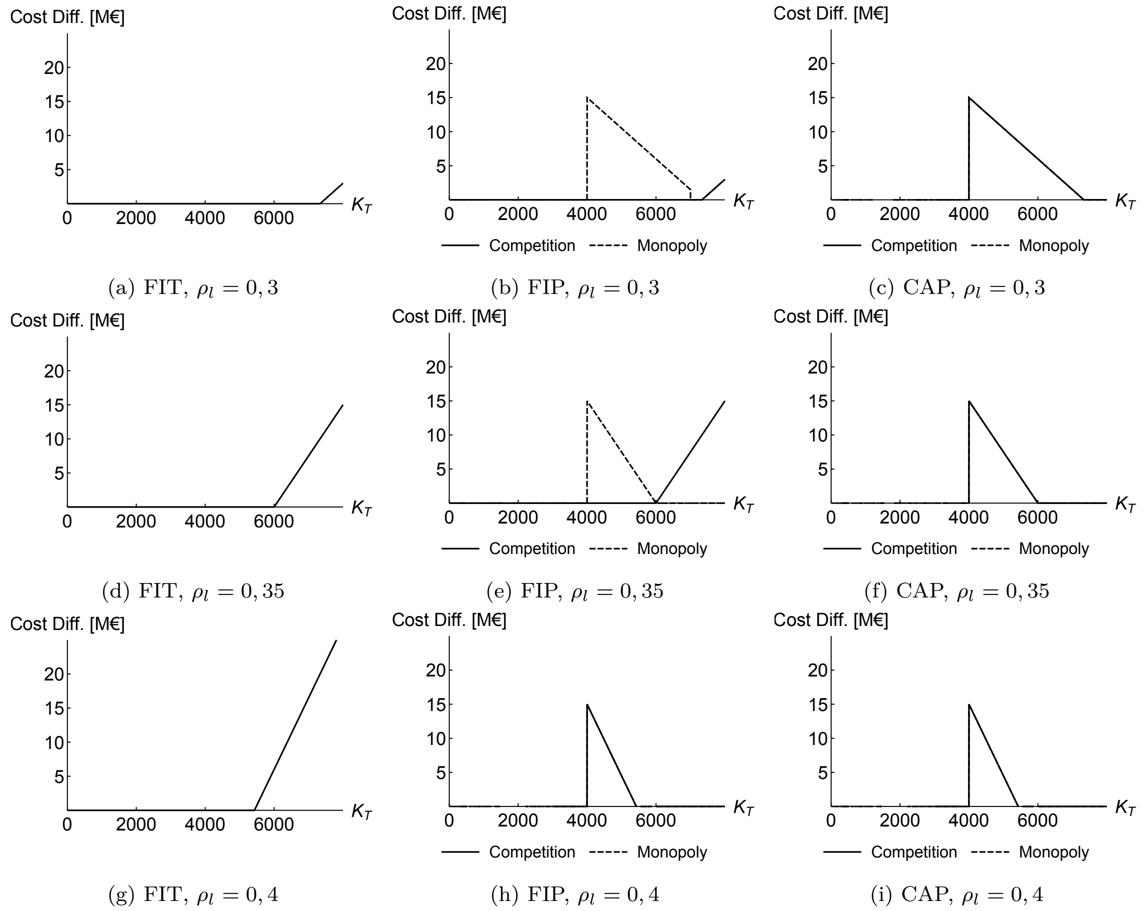
4. Numerical example

To illustrate the main implications of the analyzed model, this section gives a simple numerical example. The marginal generation costs of conventional power plants c_1 and c_2 are assumed to be 30 EUR/MWh and 60 EUR/MWh which corresponds roughly to the marginal costs of a coal-fired power plant and an open cycle gas turbine in Europe. The generation capacity of the coal-fired power plant $\bar{q}$ is assumed to be 6 GW and power demand d is set to 10 GW. The annualized investment costs for wind power capacity are assumed to be 80 EUR/(kW*a) and the annualized lump sum investment costs to connect the wind locations H and

[30] See section 2.3.2.

L to the demand node D are 15 million EUR/a. The probability for wind power production at the good wind location ρ_h is set to 0.45 while ρ_l is varied.

The results of the numerical example for different subsidy schemes and probabilities ρ_l are presented in figure 4. For the feed-in premium system and capacity payments figure 4 differentiates additionally between the competitive case with a large number of wind power investors and the monopolistic case with one single investor. Each graph depicts the difference between total system costs with private wind power investment and total system costs of the central planner solution as a function of the wind power capacity target K_T. Grid investments are assumed to follow wind power investments.



(a) FIT, $\rho_l = 0,3$ (b) FIP, $\rho_l = 0,3$ (c) CAP, $\rho_l = 0,3$

(d) FIT, $\rho_l = 0,35$ (e) FIP, $\rho_l = 0,35$ (f) CAP, $\rho_l = 0,35$

(g) FIT, $\rho_l = 0,4$ (h) FIP, $\rho_l = 0,4$ (i) CAP, $\rho_l = 0,4$

Figure 4: Inefficiencies in the numerical example for feed-in tariff (FIT), feed-in premium (FIP) and capacity payments (CAP)

In the first row, the probability ρ_l, which determines the quality of the low wind location is set to 0.3. In this setting the central planner invests at location L only for very high capacity targets above 7.33 GW. Accordingly no inefficiencies arise in the feed-in tariff system, which incentivizes investments only at the location with the highest expected wind generation, for targets below this value. The results for the feed-in premium in the competitive market setting are the same. In the monopolistic case however, the single investor chooses to develop the low wind location for renewable targets between 4 GW and 7 GW in order to protect his assets at node H from the merit-order effect. For targets above 7 GW, the monopolist does not diversify locations because the higher fixed premium payments outweigh the lower spot market revenue at node H. In the subsidy system with direct capacity payments, investors develop the low wind location in both the competitive and the monopolistic case because the revenue is only determined by spot market sales.

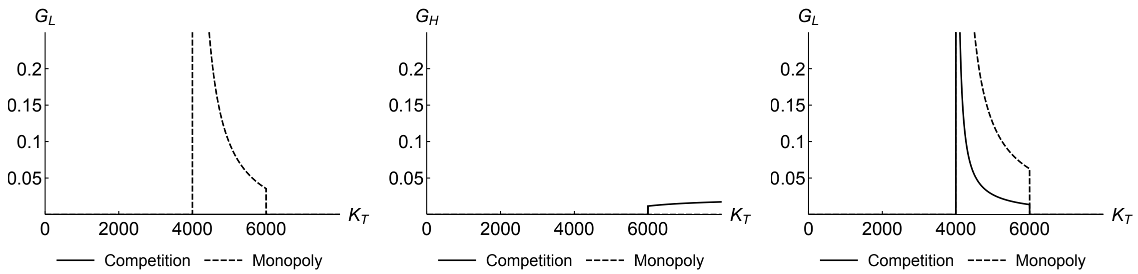
The second row in figure 4 depicts the cost differences between private investments and central planning for ρ_l equal to 0.35. The central planner develops the low wind location for renewable targets above 6 GW and the feed-in tariff system produces inefficiencies above this capacity level. Again investors develop the low wind location only in the monopolistic case and not in the competitive case with feed-in premiums. With capacity payments wind power producers invest at node L in both cases. It can be seen that the inefficiencies due to overdiversification of locations decrease faster with K_T as a result of the higher value of ρ_l.

In the third row of figure 4 the probability ρ_l for wind power production only at the low wind location is further increased to 0.4. The central planner invests at node L for capacity targets above 5.4 GW. With feed-in premiums as well as capacity payments investors develop the low wind location in the monopolistic and competitive case.

As discussed in section 3.3, the inefficiencies which arise due to uncoordinated investments into wind power capacity and the grid can be prevented in a feed-in premium subsidy scheme and a system with direct capacity payments by a location dependent g-component. The g-component internalizes the costs of overdiversification or underdiversifiation of wind locations into the investment decision of private investors. Figure 5 depicts the resulting lower bounds for the network charges in the numerical example for ρ_l equal to 0.35. It can be seen that G_L is always higher for a monopolistic renewable investor, who has stronger incentives to diversify wind locations due to portfolio effects. Also the lower bound for G_L is higher in subsidy systems with direct capacity payments compared to feed-in premium systems as the fixed premium payments dampen the benefit of developing both locations for investors as discussed in section 2.3.

5. Conclusion

This article analyzes interactions between the locational choice of private wind power investors in unbundled electricity systems under different subsidy schemes and the required grid investments to integrate the



(a) G_L, FIP, $\rho_l = 0,35$ (b) G_H, FIP, $\rho_l = 0,35$ (c) G_L, CAP, $\rho_l = 0,35$

Figure 5: G-component in the numerical example for feed-in premium (FIP) and capacity payments (CAP)

wind power capacity into the system. I find that private investors do not choose system optimal wind locations in feed-in tariff schemes, feed-in premium schemes and subsidy systems with direct capacity payments. In feed-in tariff schemes this results from the lack of internalization of the market value of the produced electricity into the investment decision. Under feed-in premium schemes and capacity subsidies the market value is internalized, but the system integration costs are not. Consequently, all three subsidy systems can result in inefficient system configurations if the transmission operator follows wind power investments.

The described inefficiencies can be prevented if a benevolent transmission operator anticipates investment decisions of private investors and steers investment in a system optimal way. However, benevolent behavior is only applicable under perfect regulation. In absence of perfect regulation, incentives to implement the system configuration that maximizes the revenue of the transmission operator inside the regulatory constraints arise. A possibility to directly influence investment decisions of private investors and to internalize the system integration costs are location dependent grid charges for power producers.

Based on the results of the analysis three policy recommendations can be derived. First, support schemes for renewable electricity generation should be designed with awareness for the consequences on the locational choice of investors. Second, inefficient steering of renewable investments by transmission companies as a result of imperfect regulation should be of concern. Third, policy makers should intend to design power systems which internalize not only the market value of electricity but also the location dependent integration costs for generation capacities into private investment decisions. In future work, the model could be extended with more complex representations of stochastic wind generation or risk averse behavior of investors. Another possibility for further research is an application of the model with real world power systems to quantify the inefficiencies of uncoordinated renewable energy and grid investments. Also an extension with multiple technologies or the introduction of incomplete information of the regulator and the transmission operator regarding the quality of potential wind locations are promising additions.

Appendix A. Proofs

Proof of proposition 1.

The problem can be solved by comparing the different network configurations. $L_L = 0$ enforces $L_H = 1$ and $Cap_H = K_T$. $L_H = 0$ enforces $L_L = 1$ and $Cap_L = K_T$. If $L_L = 1$ and $L_H = 1$, $Cap_H + Cap_L = K_T$ follows. $L_H = 0$ and $L_L = 0$ can be immediately ruled out because of $K_T > 0$.

For $K_T \leq (d - \bar{q})$, $\frac{\partial \mathbf{E}(C_D)}{\partial Cap_H} < \frac{\partial \mathbf{E}(C_D)}{\partial Cap_L}$ holds because of $\rho_h > \rho_l$. It follows that $L_L = 1$ and $Cap_L > 0$ is never optimal, which is equivalent to the first part of proposition 1.

For $K_T > (d - \bar{q})$ several cases have to be compared. Because $\mathbf{E}(C_D)$ is piecewise linear and strictly decreasing in K_H and K_L the optimal solution must be either $Cap_H = K_T$ and $Cap_L = 0$, $Cap_H = 0$ and $Cap_L = K_T$, $Cap_H = d - \bar{q}$ and $Cap_L = K_T - (d - \bar{q})$ or $Cap_H = K_T - (d - \bar{q})$ and $Cap_L = (d - \bar{q})$. Because of $\rho_h > \rho_l$ the solution $Cap_H = K_T$ and $Cap_L = 0$ dominates $Cap_H = 0$ and $Cap_L = K_T$ and $Cap_H = d - \bar{q}$ and $Cap_L = K_T - (d - \bar{q})$ dominates $Cap_H = K_T - (d - \bar{q})$ and $Cap_L = (d - \bar{q})$ for $K_T \leq 2(d - \bar{q})$. Plugging the remaining candidates for the cost minimum into equations 4 and 6a and comparing the results yields the second part of proposition 1 after some reformulation. □

Proof of proposition 2a.

Plugging equations 3a, 3b and 3c into equation 7a and taking the first derivative with respect to K_H and K_L yields $\frac{\partial \mathbf{E}(\pi_i)}{\partial K_H} > \frac{\partial \mathbf{E}(\pi_i)}{\partial K_L}$ because of $\rho_h > \rho_l$. $L_H = 1$ and $L_L = 1$ can be assumed for reactive behavior of the transmission operator as transmission lines are built according to wind power investment. □

Proof of proposition 2b.

Equation 8a can be reformulated as follows with $K_{A,i} = K_{H,i} + K_{L,i}$:

$$\mathbf{E}(\pi_i) = \begin{cases} (FIP + c_1)(\rho_h K_{H,i} + \rho_l K_{L,i} + \rho_{hl} K_{A,i}) - I^W K_{A,i} \\ \qquad \text{if } \sum_i K_{H,i} > d - \bar{q},\ \sum_i K_{L,i} > d - \bar{q} \\ (FIP + c_2)\rho_l K_{L,i} + (FIP + c_1)(\rho_h K_{H,i} + \rho_{hl} K_{A,i}) - I^W K_{A,i} \\ \qquad \text{if } \sum_i K_{H,i} > d - \bar{q},\ \sum_i K_{L,i} \leq d - \bar{q} \\ (FIP + c_2)\rho_h K_{H,i} + (FIP + c_1)(\rho_l K_{L,i} + \rho_{hl} K_{A,i}) - I^W K_{A,i} \\ \qquad \text{if } \sum_i K_{H,i} \leq d - \bar{q},\ \sum_i K_{L,i} > d - \bar{q} \\ (FIP + c_2)(\rho_h K_{H,i} + \rho_l K_{L,i}) + (FIP + c_1)\rho_{hl} K_{A,i} - I^W K_{A,i} \\ \qquad \text{if } \sum_i K_{H,i} \leq d - \bar{q},\ \sum_i K_{L,i} \leq d - \bar{q},\ \sum_i K_{A,i} > d - \bar{q} \\ (FIP + c_2)(\rho_h K_{H,i} + \rho_l K_{L,i} + \rho_{hl} K_{A,i}) - I^W K_{A,i} \\ \qquad \text{if } \sum_i K_{H,i} \leq d - \bar{q},\ \sum_i K_{L,i} \leq d - \bar{q},\ \sum_i K_{A,i} \leq d - \bar{q} \end{cases} \tag{A.1}$$

The partial derivatives with respect to $K_{H,i}$ and $K_{L,i}$ are:

$$\frac{\partial \mathbf{E}(\pi_i)}{\partial K_{H,i}} = \begin{cases} (FIP + c_1)(\rho_h + \rho_{hl}) - I^W & \text{if } \sum_i K_{H,i} > d - \bar{q} \\ (FIP + c_2)\rho_h + (FIP + c_1)\rho_{hl} - I^W & \text{if } \sum_i K_{H,i} \leq d - \bar{q},\ \sum_i K_{A,i} > d - \bar{q} \\ (FIP + c_2)(\rho_h + \rho_{hl}) - I^W & \text{if } \sum_i K_{H,i} \leq d - \bar{q},\ \sum_i K_{A,i} \leq d - \bar{q} \end{cases} \tag{A.2}$$

$$\frac{\partial \mathbf{E}(\pi_i)}{\partial K_{L,i}} = \begin{cases} (FIP + c_1)(\rho_l + \rho_{hl}) - I^W & \text{if } \sum_i K_{L,i} > d - \bar{q} \\ (FIP + c_2)\rho_l + (FIP + c_1)\rho_{hl} - I^W & \text{if } \sum_i K_{L,i} \leq d - \bar{q},\ \sum_i K_{A,i} > d - \bar{q} \\ (FIP + c_2)(\rho_l + \rho_{hl}) - I^W & \text{if } \sum_i K_{L,i} \leq d - \bar{q},\ \sum_i K_{A,i} \leq d - \bar{q} \end{cases} \tag{A.3}$$

In the competitive case, investors develop the locations in descending order of marginal revenue. For $K_T \leq (d - \bar{q})$, $\frac{\partial \mathbf{E}(\pi_i)}{\partial K_{H,i}} > \frac{\partial \mathbf{E}(\pi_i)}{\partial K_{L,i}}$ holds and $Cap_L > 0$ is never optimal. For $K_T > (d - \bar{q})$, comparing A.2 and A.3 yields equation 9.

In the monopolistic case several cases have to be compared. For $K_T \leq (d - \bar{q})$, $Cap_H = K_T$ is optimal because of $\frac{\partial \mathbf{E}(C_D)}{\partial K_H} > \frac{\partial \mathbf{E}(C_D)}{\partial K_L}$. $\mathbf{E}(\pi_i)$ is strictly increasing in K_H and K_L within each of the five distinguished cases in equation A.1. It follows that the optimal solution must be $Cap_H = K_T$ and $Cap_L = 0$, $Cap_H = 0$ and $Cap_L = K_T$, $Cap_H = d - \bar{q}$ and $Cap_L = K_T - (d - \bar{q})$ or $Cap_H = K_T - (d - \bar{q})$ and $Cap_L = (d - \bar{q})$.

Analogous to the central planner problem the solution $Cap_H = K_T$ and $Cap_L = 0$ dominates $Cap_H = 0$ and $Cap_L = K_T$ and $Cap_H = d - \bar{q}$ and $Cap_L = K_T - (d - \bar{q})$ dominates $Cap_H = K_T - (d - \bar{q})$ and $Cap_L = (d - \bar{q})$ for $K_T \leq 2(d - \bar{q})$ because of $\rho_h > \rho_l$. Plugging the remaining candidates into equation A.1 and comparing the results yields equation 10 after some reformulation. □

Proof of proposition 2c.

The capacity subsidy is equivalent to a reduction of the investment costs for wind power I^W. Consequently, the optimal solution can be derived analogously to proposition 2b with $FIP = 0$. □

Proof of proposition 3.

$L_H = 1$ and $L_L = 0$ implements $Cap_H = K_T$ and $Cap_L = 0$, the first part of proposition 3 follows.

If the transmission operator decides to limit transfer capacity $\overline{L_H}$ two cases can be distinguished. If $Cap_H \leq \overline{L_H}$ the decision problem for renewable investors is unchanged compared to propositions 2a, 2b and 2c. For $Cap_H > \overline{L_H}$, the marginal revenue $\frac{\partial \mathbf{E}(\pi_i)}{\partial Cap_{H,i}}$ equals $-I^W$, so $Cap_H \leq \overline{L_H}$ in the competitive case. In the monopolistic case, $Cap_{H,i}$ can be substituted by $\overline{L_H}$ in the definition of the five cases in equation A.1. Comparing this adjusted equation A.1 with $Cap_H = \overline{L_H}$ to $Cap_H > \overline{L_H}$ shows that $\mathbf{E}\big(\pi_i(Cap_H = \overline{L_H})\big) > \mathbf{E}\big(\pi_i(Cap_H > \overline{L_H})\big)$. Consequently the transmission operator chooses $L_H = 1$, $L_L = 1$ and $\overline{L_H} = (d - \bar{q})$ if it is optimal according to proposition 1. □

Appendix B. Asymmetric grid investment costs

Introducing asymmetric investment costs leads to the following expression for total system costs:

$$C_{Total} = \mathbf{E}(C_D) + I^W(Cap_H + Cap_L) + I_H^G * L_H + I_L^G * L_L \tag{B.1}$$

For $K_T \leq d - \bar{q}$ connecting both nodes H and L is dominated by connecting only node H because it is always preferable to build all wind power capacity at the better wind location H when both nodes are connected. Comparing the two possible outcomes for connecting one wind location leads to the condition in equation B.2 for developing the low wind location.

$$c_2(\rho_h - \rho_l)K_T > I_H^G - I_L^G \tag{B.2}$$

For renewable targets $K_T > d - \bar{q}$ all three possible network configurations have to be considered. Comparing the outcomes for the configurations with only one of the wind locations connected to the demand node D leads to equation B.3a. Equation B.3b gives the condition for lower system costs when both wind nodes are connected compared to only node H connected, equation B.3c gives the condition for lower system costs when both wind nodes are connected compared to only node L connected.

$$(\rho_h - \rho_l)\Big(c_1\big(K_T - (d - \bar{q})\big) + c_2(d - \bar{q})\Big) > I_H^G - I_L^G \tag{B.3a}$$

$$(c_2\rho_l - c_1\rho_h)\big(K_T - (d - \bar{q})\big) > I_L^G \tag{B.3b}$$

$$(c_2 - c_1)\rho_l\big(K_T - (d - \bar{q})\big) + c_2(\rho_h - \rho_l)(d - \bar{q}) > I_H^G \tag{B.3c}$$

Appendix C. Imperfect regulation

A highly stylized cost-plus regulation where all network investments enter the regulatory asset base with a guaranteed rate of return r can be expressed by problem C.1

$$\max_{L_H, L_L, \overline{L_H}} \pi_{TSO} = \big(I^G * (L_H + L_L)\big) * r \tag{C.1a}$$

$$\text{s.t. } K_T = Cap_H L_H + Cap_L L_L \tag{C.1b}$$

$$Cap_H + T_H > 0;\ Cap_L + T_L > 0 \tag{C.1c}$$

$$T_H L_H = 0;\ T_L L_L = 0 \tag{C.1d}$$

$$L_H, L_L, T_H, T_L \in \{1, 0\} \tag{C.1e}$$

Equivalently a highly stylized price-cap regulation with no adjustments based on investment activity can be expressed by problem C.2:

$$\max_{L_H, L_L, \overline{L_H}} \pi_{TSO} = \big(-I^G * (L_H + L_L)\big) \tag{C.2a}$$

$$\text{s.t. } K_T = Cap_H L_H + Cap_L L_L \tag{C.2b}$$

$$L_H, L_L \in \{1, 0\} \tag{C.2c}$$

Appendix D. Additional expressions for g-component

Introducing G_H into equation (9) and combining it with proposition 1 yields:

$$G_H \geq \frac{(\rho_h - \rho_l) * FIP}{(\rho_h + \rho_{lh})} - \frac{I^G}{\big(K_T - (d - \bar{q})\big)(\rho_h + \rho_{lh})} \tag{D.1}$$

in the monopolistic case, introducing G_H into equation (10) and combining it with proposition 1 yields:

$$G_H \geq \frac{(\rho_h - \rho_l) * FIP + \rho_h(c_2 - c_1)}{(\rho_h + \rho_{lh})} - \frac{I^G + (c_2 - c_1)\rho_h K_T}{\big(K_T - (d - \bar{q})\big)(\rho_h + \rho_{lh})} \tag{D.2}$$

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