Report D5.1, August 2016

Cash flow analysis of past RES auctions

AURES

Short about the project

Auctions for Renewable Energy Support: Effective use and efficient implementation options (AURES)

This project helps assessing the applicability of different auction types to renewable support under different market conditions. It also explores which auction types and design specifications suit particular requirements and policy targets in European countries. By establishing best practices and a knowledge sharing network, we contribute to informed policy decision-making and to the success of auction implementations across Europe.

Target-oriented analysis: Through analysis of empirical experiences, experiments and simulation, we will create a flexible policy support tool that supports policy makers in deciding on the applicability of auction types and certain design specifications for their specific situation.

Capacity building activities: We undertake specific implementation cases to derive best practices and trigger knowledge sharing amongst Member States. We strive to create a strong network with workshops, webinars, bilateral meetings, newsletters, a website that will serve as capacity building platform for both policy makers and market participants (including project developers, auctioneers,etc.). Wherever required, we can set up specific bilateral and multilateral meetings on specific auction issues and facilitate cooperation and knowledge sharing. Additionally, we offer sparring on specific implementation options, drawing from insights gained during the first phases of the project (empirical analysis of previous auctions in Europe and the world), conceptual and theoretical analysis on the applicability of specific designs in certain market conditions and for certain policy goals issues and facilitate cooperation and knowledge sharing. Additionally, we offer sparring on specific implementation options, drawing from insights gained during the first phases of the project (empirical analysis of previous auctions in Europe and the world), conceptual and theoretical analysis on the applicability of specific designs in certain market conditions and for certain policy goals.

Project consortium: eight renowned public institutions and private firms from five European countries and combines some of the leading energy policy experts in Europe, with an impressive track record of successful research and coordination projects.

In this report we analyse three past auction cases by simulating single investment appraisals with the discounted cash flow model which was developed in the course of task 5.1 of the AURES project. The undertaken analysis aims to quantify the effects of chosen design parameters of the respective auction on the required support level of the simulated project and therewith the effect on the (non-strategic) bid price. The three example auctions and the respective simulated investment technologies are taken from the AURES work packages 4 and 7:

- Solar PV auction in Germany (WP4)

- Onshore wind power in Spain (WP7)

- Offshore wind power in Denmark (WP4)

The DCF model and this report contribute to the first of three tasks in work package 5 of the AURES project:

T5.1   Cash flow-type model to analyse changes in private investment incentives

T5.2   Game theoretic modelling of renewable energy auctions

T5.3   Prospective renewable energy system modelling

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1 Introduction

A discounted cash flow (DCF) model for the simulation of single investment appraisals of auction participants was developed as part of the work package AURES WP5 – model-based analysis: learning from simulation. In this report we use the model to answer some of the project's research questions, such as the influence of both auction design parameters (e.g. penalty levels) and project specific parameters (e.g. project lifetime or internal discount rate) on the expected bid prices. Generally, we want to link the project specific costs to the observed bid prices on a quantitative basis given a certain auction design. For interested users, the model is freely available on the AURES website together with a detailed user manual.

1.1 Motivation

In this report we use the DCF model, which is published on the AURES homepage, to analyse single investment appraisals for past auction examples. Three past auction cases from implementations in Europe, two of those with remarkable outcomes, are simulated in order to evaluate the support level outcomes of these auctions from an economic perspective. Using the model we analyse the economic impacts of the respective auction designs and market conditions on simulated project cash flows and quantify possible impacts on the bid prices that have been observed in the respective auction case. Furthermore, we aim to assess if bid prices in the investigated cases seem to be on the whole based on actual project costs or rather on aspects related to strategic behaviour.

1.2 Scope

In the first section, the applied DCF model is briefly described. For a more detailed description of the model please refer to the user manual that can be found on the AURES website.

The subsequent sections present the results of the simulations conducted for the following three past auction cases. Section 2 addresses several rounds of the pilot solar PV auctions in Germany, conducted between April 2015 and August 2016 (Tiedemann, 2015). We simulate a non-strategic bid price range based on a range of possible project costs and compare this to the observed bid price ranges. Furthermore, we identify the most sensitive parameters by conducting sensitivity and threshold analysis for several input parameters. Finally, we conduct a 'what-if' analysis, investigating the effect that a different timing of penalty payments would have had on the resulting bid prices.

Section 3 addresses the onshore wind power auction in Spain conducted in January 2016. This auction has already been described and evaluated in AURES WP7 (del Río, 2016). Here, we add a quantitative element to the analysis by investigating a range of likely project costs of single investment projects to simulate cost-based bid price ranges. The outcome of the DCF model is then compared to the observed auction result. In light of the very low support level result, we focus on the question what a realistic cost-based support level might have been. We then conduct sensitivity analysis for the discount rate. Finally, we conduct a 'what-if' analysis regarding the impact that a switch from the investment-based to a production-based remuneration would have had on the resulting bid prices.

Section 4 addresses the auction of the Anholt offshore windfarm in Denmark conducted in 2010. The case has already been described and evaluated in AURES WP4 (Kitzing & Wendring, 2015). Again, we here add a quantitative element to the analysis by simulating likely cost-based bid price ranges. In light of the rather high support level result, we focus on the question what aspects of the auction design might have contributed to the high outcome. Here, we pay special attention to the influence of penalty levels and the probability of project delay.

Section 5 summarises the main conclusions and describes some limitations of the applied DCF model. We also propose some questions to be addressed in an agent-based modelling approach, which is part of the subsequent tasks of work package 5.

1.3   DCF model

In the course of task 5.1 of the AURES project, we have developed a discounted cash flow (DCF) model that can simulate cost-based bid prices and thus support levels required for single investment projects participating in an auction. The simulation is based on particular market conditions and assuming country- and technology-specific project characteristics. The model is capable of simulating different auction designs, and can handle rather different implementation options, as demonstrated in this report. The main output of the model simulation is a non-strategic bid price, meaning that the bid price outcomes from this model are mainly cost-based and cannot capture any profound strategic considerations for which game theoretic modelling would be necessary.

The model thus aims at developing an understanding for realistic support levels, yet, it is not intended to predict the actors' actual bid prices based on strategic behaviour simulations. This issue will be addressed in the subsequent task 5.2 where an agent-based simulation focusing on game theoretic modelling is applied.

The output generated with the DCF model always represents a single investment project. As the name indicates, the model uses a discounted cash flow approach. Starting from the year of evaluation (the year when the auction takes place), the free cash flows are calculated as given in the example in Table 1 for each year of the project lifetime. However, not all components occur in every year. E.g. the free cash flow of year zero (the year of contracting) includes only the capital expenditures (CAPEX).

Table 1: Calculation of the annual free cash flows

Revenues from power market
+ Revenues from support
Total revenues
-    OPEX
-    Balancing expenditures
EBITDA
-    CAPEX
-    Payable tax
Free cash flow

All free cash flows are then discounted using the assumed internal discount rate of the project (see below).

The evaluation method applied is the net present value (NPV), which is the present value of the anticipated free cash flows generated by the project. The NPV is calculated in the following manner (Crundwell, 2008):

$$NPV = \sum_{t=0}^{n} \frac{CF_t}{(1+r)^t}$$

where CF_t is the free cash flow in year t, n is the project lifetime and r is the project specific internal discount rate. Here, the applied discount rate is the user defined weighted average cost of capital (WACC). It can be expressed with the following formula (Brealey & Myers, 1981):

$$WACC = \frac{E}{V}k_e + \frac{D}{V}k_d(1-r_t)$$

where E is the invested equity and D is the invested debt. V is the sum of D and E, thus the total capital investment (CAPEX). k_e and k_d are the cost of equity and the cost of debt respectively.

The evaluation date is year 0, i.e. the year of contracting the project.

1.4   Components of the free cash flow calculation

The model includes no economies of scale effects for the simulated technologies. Therefore, all single components of the annual free cash flows are calculated per kW of installed capacity. Furthermore, the terminal value is assumed to be zero, i.e. the installation has no remaining value at the end of the project lifetime. The model uses nominal values for all components.

1.4.1   Revenues from power market

The revenues from power market ($R_{m,t}$) for each operational year t are calculated as:

$$R_{m,t} = q \cdot \pi_t \cdot I_t$$

where q is the annual power production, π_t is the achieved power price of year t and I_t is the inflation index. The inflation index for year t is calculated as:

$$I_t = I_{t-1} \cdot (1+i)$$

with i being the inflation rate. The inflation index of the evaluation year (year 0) is set to 1.

1.4.2   Revenues from support

The revenues from support payments ($R_{s,t}$) occur in each year during the support period, starting with the first year of operation. Depending on the chosen remuneration type the revenues are calculated differently.

In case of <u>sliding premium</u> remuneration:

$$R_{s,t}^{sliding} = q \cdot (s - \pi_t \cdot I_t)$$

where s is the support level and q is the annual power production, π_t is the achieved power price and I_t is the inflation index of year t.

In case of <u>fixed premium</u> remuneration:

$$R_{s,t}^{fixed} = q \cdot s$$

where s is the support level and q is the annual power production.

1.4.3 CAPEX

The CAPEX is the total capital investment for the project. For the model it is assumed that the total CAPEX occurs in year 0.

1.4.4 OPEX

The costs for operation and maintenance occur yearly during the operating time of the project. It is assumed that they are constant in real terms, i.e. the respective user input is multiplied with the inflation index to result in the nominal value. Thus, the annual OPEX are calculated as:

$$OPEX_t = m \cdot q \cdot I_t$$

where m are the user defined annual OPEX per kW power production, q is the annual power production and I_t is the inflation index of year t. The balancing expenditures are not included here.

1.4.5 Balancing expenditures

The balancing expenditures (BEX) are the expenditures associated with trades on the balancing market to compensate for errors in the power production forecast. For each year of the operating time they are calculated as:

$$BEX_t = l \cdot R_{m,t}$$

where l is the user defined share of balancing expenditures and $R_{m,t}$ are the revenues from power market in year t.

1.4.6 Depreciation

The model assumes linear depreciation, i.e. the total CAPEX is divided by the user defined depreciation time to result in the annual, nominal depreciation. The depreciation occurs during the depreciation period counting from the first year of operation. It is subtracted from the earnings before interests, taxes, depreciation and amortisation (EBITDA) to result in the earnings before interests and taxes (EBIT).

1.4.7 Payable tax

The payable tax (T) is calculated for each year of the operating time. It is calculated as:

$$T_t = x \cdot EBIT_t$$

where x is the corporate tax rate defined by the model user.

1.4.8 Free Cash Flow

The free cash flow is calculated for each year of the project lifetime as:

$$CF_t = EBITDA_t - T_t$$

with T_t being the payable tax in year t.

1.5 Placement factor

In addition to the purely cost-based bid price ranges (or, rather cashflow-based bid price ranges), we also let the model select a specific bid price within this range, depending on different factors selected by the user related to market conditions (e.g. if strong competition is expected in the auction) and market position of the bidder (e.g. if they have a strong interest in winning). The placement factor (f) is calculated as the product of the individual placement factors corresponding to the chosen states of the parameters under "Market Conditions" and "Market Position". The factors are pre-defined in the worksheet "Placement Factors" in the applied DCF model. The factor decides where in the resulting range of possible bid prices the selected bid is placed.

The selected non-strategic bid price (B) is thus calculated as:

$$B = b_{max} + f \cdot (b_{high} - b_{min})$$

where b_{max} is the maximum non-strategic bid price within the non-strategic bid price range and b_{min} is the minimum non-strategic bid price within the non-strategic bid price range.

2 Case 1 – Solar PV in Germany

Germany conducts technology-specific pilot auctions for ground-mounted PV plants. In total, there will be nine rounds with three auction rounds conducted in 2015, 2016 and 2017 respectively, following a fixed schedule.

In the following, an example investment project participating in the German auction is simulated using the DCF model.

2.1 Auction scheme

Some main aspects of the German auction scheme are described below based on Tiedemann (2015).

The auctions are organised as capacity based multiple-item auctions. The total amount of auctioned capacity varies from round to round between 100 and 200 MW. The remuneration type is a sliding premium paid for 20 years. Bidders need to specify the size of their projects and the level of strike price for the sliding premium. A ceiling price applies in each auction round, which equals the current support level for roof-mounted PV plants pursuant to sections 51 §2 no. 3 and 31 §1 to 5 in BMWI (2014) at the time of the auction.

In auction rounds one, four and five, projects were awarded on a pay-as bid basis, while a uniform-pricing approach (pay-as-cleared) was applied in the second and third round. A price-only criterion was used in all cases.

Penalties apply for both delay and non-compliance. In case an awarded project is not commissioned within 18 month after contracting, the awarded strike price for the sliding premium is reduced by 0.3 cent/kWh as a penalty for delay. If the project is not commissioned within 24 month after contracting, a non-compliance penalty has to be paid. The non-compliance penalty amount depends on the size of the project and the planning status at the time the bid was submitted. If only a preliminary planning approval was available at bidding time a bid bond amounting to 50 €/kWp had to be provided, while it is reduced to 25 €/kWp if the planning approval was final. Usually, the bid bonds are being repaid to the project owners at time of commissioning. In case the project is non-compliant, the bid bonds are retained.

2.2 Market conditions

Germany has a liberalised electricity market with substantial over-capacity and a well-functioning support system for renewable electricity production. In 2015, the PV market faced a crisis with very few additional installations (Tiedemann, 2015). A possible reason for that was the reduction of the administratively set support level in 2012, which reduced the annual new installations of ground-mounted solar PV plants from about 3 GW in 2012 to around 1 GW in 2016 and less than 500 MW in 2014 and 2015 (Kelm et al. 2014).

The abrupt decline in new investments has possibly caused many readily developed projects being set 'on the shelf' waiting for better support conditions to return, thus increasing the overall pipeline of PV projects in Germany. In this light, all conducted auction rounds until today showed a high level of competition with substantial over-subscription. The first round showed the highest over-subscription with 4.7 times more offered capacity than total

capacity auctioned, while the lowest over-subscription with 2.5 was observed in the fifth round (Bundesnetzagentur, 2016a, 2016d).

Regarding bidder structure, the majority of bids stemmed from middle sized investors with the legal form GmbH or GmbH and Co.KG (Bundesnetzagentur, 2016a).

For the first two rounds, bidding statistics were compiled showing how many projects, which were not awarded in the first round, participated again in the second round. The result showed that 200 MW of the total offered capacity of 558.4 MW in the second auction round were repeated bids. Thus, about 360 MW of new projects participated in the second round leading to new competition. However, the analysis also showed that the majority (about 56%) of successful bids in the second auction round were projects which were not successful in the first auction round (Bundesnetzagentur, 2016a). Based on those statistics, it seems that bidders may have lowered their bid price for the same project in the second auction round compared to the first round, even though there were only four months in between.

2.3   Observed bid prices

Table 2 shows the results of the five auction rounds for utility scale solar PV plants in Germany. Available data for round one was based on winning bids only, while for round two, three, four and five it was based on all participating valid bids. A uniform pricing rule applied in round two and three (i.e. the highest successful bid determined the support level for all projects) while a pay-as bid pricing rule applied in rounds one, four and five. This can explain the lower minimum bids (lowest bids received) in rounds two and three compared to the other rounds.

Table 2: results of the auctions for utility scale solar PV plants in Germany
(Bundesnetzagentur, 2015a, 2015b, 2015c, 2016c, 2016d)

	Round 1	Round 2	Round 3	Round 4	Round 5
Support	20 years sliding premium				
Date	apr-15	aug-15	dec-15	apr-16	aug-16
Max bid [ct./kWh]		10.98	10.98	10.98	10.98
Min bid [ct./kWh]	8.48	1.00	0.09	6.94	6.80
Weighted average all bids [ct./kWh]		8.65	8.08	7.97	7.84
Weighted average winning bids [ct./kWh]	9.17	7.82	7.55	7.41	7.23
Highest successful bid [ct./kWh]	9.43	**8.49**	**8.00**	7.68	

2.4   Implementation in DCF model

The only major difference in the design between the auction rounds is the pricing rule. However, the (strategic) implications of this auction design feature cannot be modelled in a single-investor, cost-based DCF model. Thus, one model implementation can be seen as a simulation that in principle could be valid for all rounds.

2.4.1 Project characteristics

Table 3 shows the assumed project characteristics as implemented in the DCF model.

Table 3: project characteristics for the German solar PV auction simulation

Technology	Solar PV
Location	DE
Operating Time [years]	25
Lead Time [years]	1
Delay Probability [%]	5
Length of Delay [years]	1
Non-compliance probability [%]	5
Depreciation time [years]	20

Recent studies assume a system lifetime of 25 years for projects built before 2025 (Mayer & Philipps, 2015). A short installation period of 1 year is assumed for solar PV installations.

Linear depreciation over 20 years is the general rule for utility scale solar PV installations in Germany (Bundesministerium der Finanzen, 2000; Bundesministerium der Justiz und für Verbraucherschutz, 2016). For smaller companies, there is the possibility of special depreciation of 20% within the first 4 years of operation given certain limits of the respective operating figures of the company (Bundesministerium der Justiz und für Verbraucherschutz, 2016).

The probabilities for non-compliance and delay are initially assumed to be 5%.

The capacity factor is estimated using energy yield data bases for solar PV installations in Germany for the years 2005 to 2015 (Solarenergie-Förderverein Deutschland e.V., 2016). The data show an increasing capacity factor with the location from North to South and from West to East. The average capacity factor over all data in Germany leads to a capacity factor of 10.86%. Using the P75 production data leads to an average factor of 10.62%. The highest average capacity factor was measured in South East Bavaria with 11.60%.

The achieved power price includes the correlation of the solar PV production profile with the hourly profile of spot market prices in Germany. A market value factor (MVF) can be defined in this way. The achieved power price is then the average power price multiplied with the MVF.

The MVF in Germany is estimated based on market value data from netztransparenz.de (2016) in the years 2014 and 2015. The resulting factor is 0.99.

We assume that the CAPEX is composed of the costs for the modules, the inverter and the balance of system (BOS). Mayer & Philipps (2015) give a detailed cost analysis for the total system cost. The medium cost assumptions for the single components are shown in Figure 1:
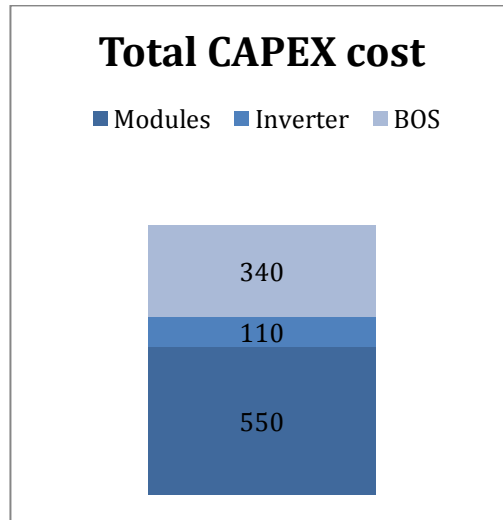
Figure 1: Estimation of total capital cost of utility scale solar PV installations by component in €/kWp, real 2015

The study suggests a range of the total system costs between 935 and 1055 €/kWp.

The yearly OPEX is estimated to range from 6.3 €/kWp to 22.4 €/kWp based on NREL (2016).

In case that a PV plant will receive support payments after winning in the auction, the owner is exposed to all costs related to balancing power. Generally, it is not straightforward to estimate the balancing costs of a single power generator. For solar PV there is less data available regarding the balancing costs than there is for wind power. Recent studies point out costs of 0.5 – 1 €/MWh (Fürstenwerth, Pescia, & Litz, 2015), 1.5 – 2.6 €/MWh (Hirth, Ueckerdt, & Edenhofer, 2015) and 1.9 – 3 €/MWh (Hirth, 2015). The average day-ahead power price in Germany in 2015 is assumed to be 35 €/MWh. This leads to a share of balancing expenditures between 1.4% and 8.6% of the revenues from power market. For the model implementation a rather conservative assumption of 6% is chosen.

Table 4 sums up the assumptions under the different scenarios as implemented in the DCF model.

Table 4: Assumed project characteristics for the German solar PV auction simulation

Assumption	Low	Medium	High	Source
Capacity Factor	10.62%	10.86%	11.6%	Solarenergie-Förderverein Deutschland e.V. (2016)
Achieved Price [€/MWh]	53.4	57.4	61.2	energinet.dk (2015),netztransparenz.de (2016)
CAPEX [€/kWp]	935	1000	1055	Mayer & Philipps (2015)
OPEX [€/kWp*a]	6.3	14.3	22.4	NREL (2016)
Balancing Expenditures		6%		Hirth et al. (2015)
Corporate Tax Rate		29.70%		KPMG (2015)
Inflation Rate		1.90%		Bundesministerium der Finanzen (2015)
WACC		4.00%		Noothout, Jager, Rooijen, & Angelopoulos (2016)

2.4.2   Support characteristics

The support characteristics are implemented as shown in Table 5.

Table 5: Support characteristics for the German solar PV auction simulation

Remuneration type	Sliding premium
Duration of support [years]	20
Prequalification cost/Sunk cost [€/kWp]	35
Penalty for delay	Reduced support level of 0.3 ct./kWh
Penalty for non-compliance	One-off payment of 50 €/kWp

The sunk cost of 35 €/kWp are estimated by using the cost share of planning and development work on the total CAPEX according to Mayer & Philipps (2015). Those costs are assumed to be borne completely by the bidder since the locations are not pre-defined and all preliminary planning has to be conducted by the investor. The cost for placing a bid are 715€ and are not refunded in case of not being awarded (Bundesnetzagentur, 2016b). However, these costs are negligible compared to the planning and development costs.

2.4.3   Market conditions and market position

The states chosen for the different market conditions and the market position of the simulated investment appraisal are shown in Table 6.

Table 6: States for market conditions and market position for the simulation of an example project participating in the German solar PV auction

Condition	Chosen State	Main reason
Level of Competition	High	High over-subscription in all rounds
Sunk Cost	High	Mainly medium sized companies
Secondary Benefits	Low	No specified sites, high level of competition in the market
Market Position	Weak	Mostly medium sized specialised companies
Ambition to Win	Low	Repeated auctions with fixed schedule

In the German PV auctions, the participating bidders were made aware of the high over-subscription: the volume of submitted bids, the range of submitted bid prices and the structure of participants was published after each auction round. This causes a strong signal generation throughout the repeated auction process (Haufe & Ehrhart, 2016). Of course, this only applied after the first auction round.

Assuming that the total planning costs of 35 €/kWp are sunk cost in case of not winning in an auction round, the sunk cost are deemed high for medium sized project developers. They would amount to 175,000 € for the average bid size of 5 MW (Bundesnetzagentur, 2016c).

The secondary benefits are deemed to be low in the simulated auction, mainly because there are no pre-defined sites which could offer a specific benefit to some investors. Moreover, the market shows a high level of competition and it can be doubted that winning a project in one auction round could increase the market share of one single company significantly.

The market position is set to weak since the bidder structure showed that most bids are submitted by companies of similar size with most of them being technology specialised. This does maybe not apply for the bids from larger companies with legal forms AG or SE, however, those bids represented only a minority of the submitted offers. In this light, it is assumed that all bidders are experienced and have a well-developed supply chain which enables them to lower their investment costs. However, there is no advantage for a single bidder, since this experience is assumed for the majority of participants.

The ambition to win is set to low, since the auction is conducted repeatedly with a fixed schedule and known auction volumes. As it was shown in the statistics of the first two auction rounds, there is a high share of projects participating in the subsequent round when not being awarded a contract. Therefore, the ambition to win in exactly one simulated auction round is not deemed to be high.

2.5 Comparison of the results

Figure 2 shows the resulting non-strategic bid price range for the simulated project taking part in the German solar PV auction. The bid prices range from 8.05 ct/kWh to 12.68 ct/kWh. The non-strategic bid price that the model proposes based on the chosen market conditions (see previous section) is 8.40 ct/kWh. Assuming low competition in the auction, the resulting bid price would be 9.21 ct/kWh, which is very close to the average price seen in the first auction round. This could be an indication that the bidders expected less competition in this round, since no information on the over-subscription was available at this time.
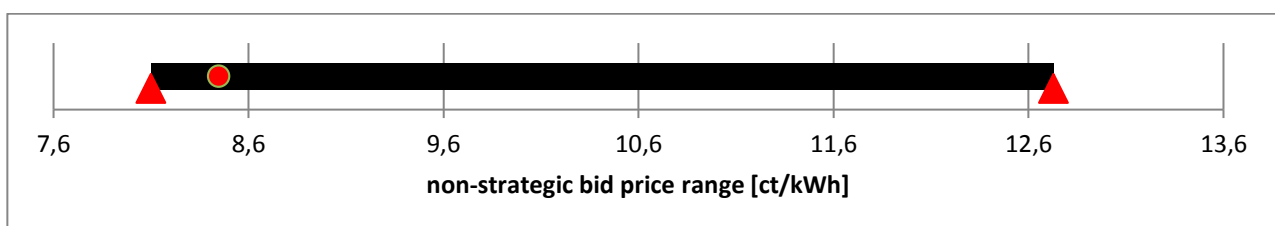

Figure 2: Non-strategic bid price range for German solar PV auction

The simulation results in a final bid price that is close to the observed bid prices in Table 2. The result is in between the observed average bid price of the second and third bidding round. The average of the fourth and fifth bidding rounds are lower than the simulated bid price range, which could be due to strategic bids or to 'better', i.e. more cost-effective, projects than assumed in the simulation. Some of the assumptions are thus further scrutinised with sensitivity analysis in the next section.

Generally it can be stated that the resulting bid price range is rather large and seems to overestimate the observed bid prices more than underestimating them. This could be an indication that the assumptions for the capacity factor

and the achieved price are too low in the "high" scenario while at the same time the pessimistic assumptions for the CAPEX and OPEX are too high.

2.6 Sensitivity analysis

Figure 3 shows the change in the resulting bid price when increasing the assumption of five parameters by 1% of their respective medium case assumption. It shows that the CAPEX, the operating time and the WACC assumption have the most significant impact on the resulting bid price. Therefore, the impact of those parameters is analysed in more detail in the following subsections.
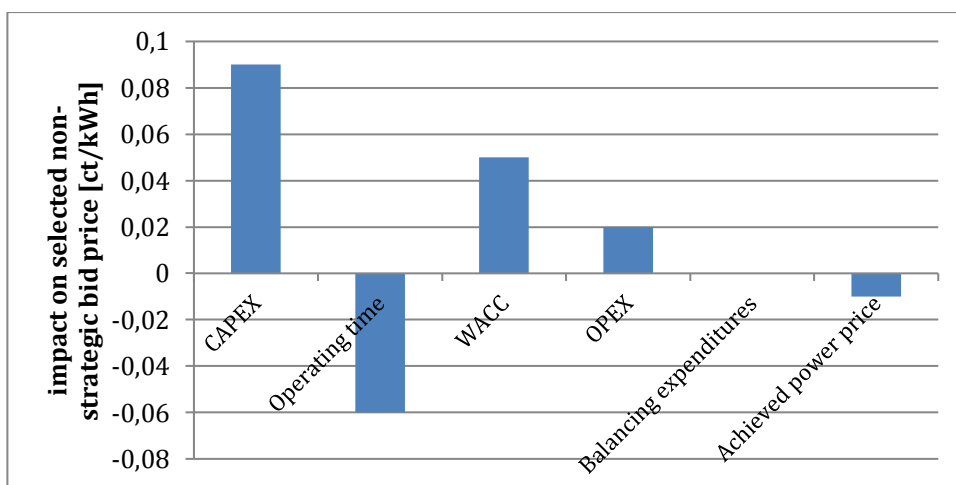

Figure 3: Impact of different assumptions on the modelled non-strategic bid price. The implemented changes are 1% of the medium case assumption.

2.6.1 Operating time and discount rate

Figure 4 shows the results for the non-strategic bid price when increasing the project operating time under different internal discount rates (WACC). The findings for the discount rate range from 3.5% to 4.5% and are mainly based on onshore wind power projects (Noothout et al., 2016). For solar PV projects, a lower discount rate than for onshore wind projects can be expected, assuming that the production from solar PV is more stable and predictable compared to the production from onshore wind power and assuming that the risk for damage is lower.

When all other assumptions are kept constant, an increase in the operating time of one year leads to a decreased non-strategic bid price of approximately 0.23 ct/kWh in case of a WACC of 4% and of 0.25 ct/kWh in case of a WACC of 3.5%. When assuming a WACC of 4% and an operating time of 30 years as suggested by Mayer & Philipps (2015) for installations after 2025, the resulting bid price would be 7.26 ct/kWh. An assumed operating time of 27 years would lead to a simulated bid price of 7.94 ct/kWh which is very close to the average of the observed bid prices in the fourth auction round of 7.97 ct/kWh.

In case of a lower WACC of 3.5%, even the lowest observed bid price in the fourth auction round of 6.94 ct/kWh could be simulated when an operating time between 28 and 29 years is assumed.
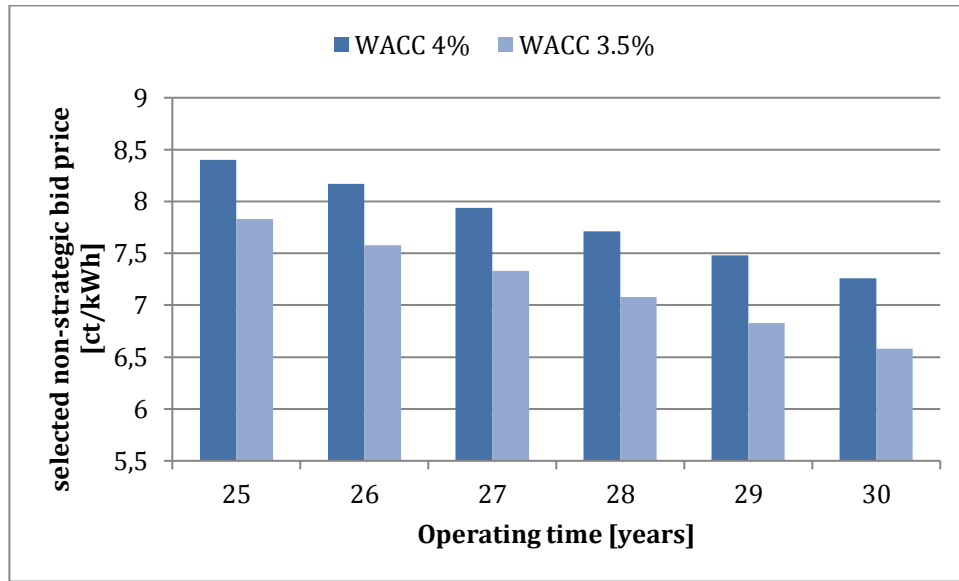
Figure 4: Non-strategic bid prices for German solar PV auction depending on operating time with two different internal discount rates

2.6.2   CAPEX and OPEX

Figure 5 shows the results when varying the assumptions for OPEX and CAPEX by 5% and 10% of the base value respectively. It can be seen that the influence of the same relative change in CAPEX is higher than the one for a change in OPEX. A decrease of the assumed CAPEX by 10% would lead to a simulated bid price of 7.53 ct/kWh while a 10% decrease in OPEX would result in a bid price of 8.16 ct/kWh. Recent studies expect a decrease in both CAPEX and OPEX of up to 50% until 2050 (Mayer & Philipps, 2015).

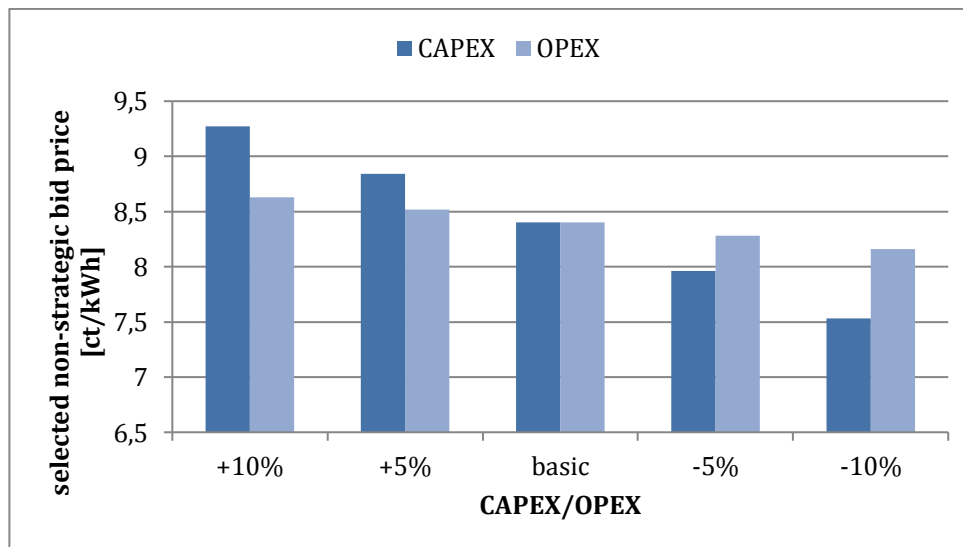*Figure 5: Non-strategic bid prices for German solar PV auction depending on assumed OPEX and CAPEX*

2.6.3 Timing of penalty payment

The timing of the penalty payment for non-compliance was simulated by moving the time of penalty payment forward: We changed the year in which the penalty is paid from year three (as in the basic simulation) to year zero, i.e. the year of contracting. In the basic simulation the penalty is due when the penalty case applies, i.e. the project is not commissioned within the first two years after contracting. In the amended simulation the penalty has to be deposited as a financial guarantee and is then repaid in case that the penalty case does not apply and the project is commissioned on time. Both cases are simulated with different delay probabilities and different WACC. The results are shown in Figure 6.

The results show that the timing has no significant influence on the overall profitability of the projects and thus on the non-strategic bid price. In case of a delay probability of 5%, the non-strategic bid price does not differ if the timing of the penalty payment is changed. This is the case both with a 4% and 6% assumed WACC. When the delay probability is increased to 10%, the bid prices increase by 0.01 ct/kWh in both WACC cases when the penalty has to be paid in year 0. In case of a delay probability of 15% the bid price increases by 0.01 ct/kWh with a project WACC of 4% and by 0.02 ct/kWh with a project WACC of 6%.
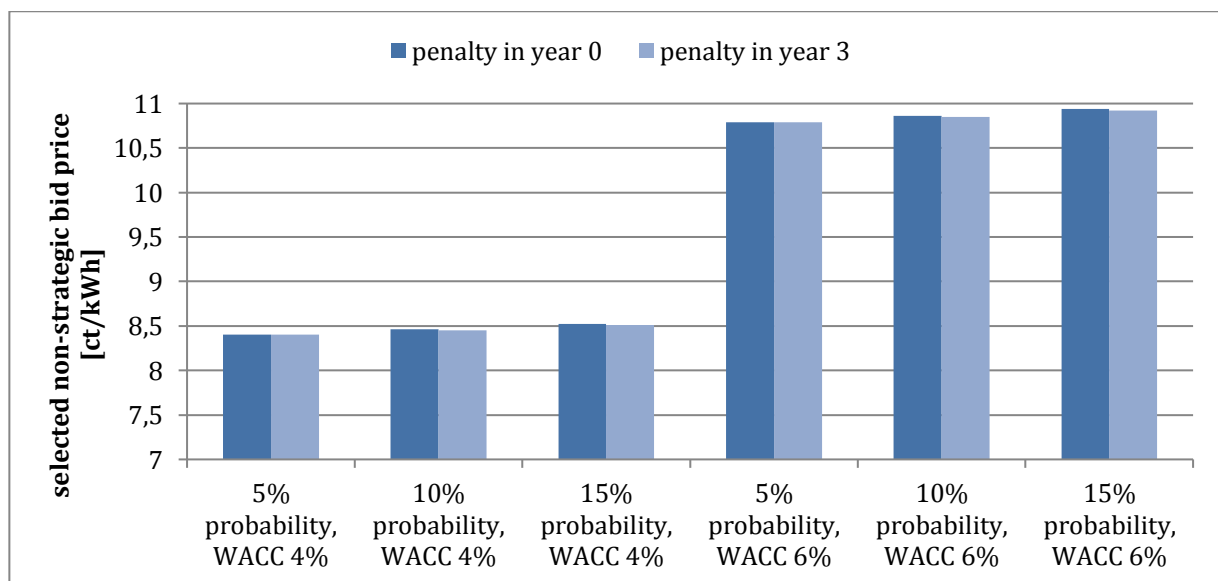
Figure 6: Impact of timing of the penalty for non-compliance

2.6.4 Impact of WACC and CAPEX on bid price decrease

As mentioned above the average bid price level and also the resulting support level in the German solar PV auction decreased from round to round. Furthermore, a detailed analysis of the first two bidding rounds showed that many projects that were not successful in the first round were successfully participating in the second round (see Section 2.2). In the following, we investigate which changes in WACC and CAPEX assumption would be necessary to justify the decrease in bid price necessary for the same project to be successful in the subsequent auction round.

For doing this, we assume that the projects not winning in a round were close to the marginal project and thus offered a bid close to the highest successful bid, but slightly above (marginal losing project). The same project then lowered the bid price in the subsequent round and offered a price close to the highest successful bid but slightly below (marginal winning project). The highest successful bids of rounds one, two, three and four are shown in Table 2. Based on this we derive that a marginal project must be able to decrease the bid price by 0.94 ct/kWh from round one to round two, by 0.49 ct/kWh from round two to round three and by 0.14 ct/kWh from round three to round four.

Figure 7 shows the results for a threshold analysis for WACC and CAPEX of the simulated project in order to lower the bid price by the respective amount. For a better comparison the values are normalised using a basic value of 4% for WACC and 1000 €/kWp for CAPEX. The required decrease in WACC from round one to round two would be 0.78% pts. This corresponds to a decrease in cost of equity by 3.92% pts using the formula given in Section 1.3 and assuming a debt-equity ratio of 80/20 and cost of debt of 3.9% pts. The required decrease from round three to round four of 0.12% pts could be achieved by a decrease in the cost of equity by 0.62%. Such a decrease seems to be realistic when taking into account the indicated ranges of cost of equity for investments in onshore wind power in Germany found by Noothout et al. (2016) where a range of +/- 2% pts is indicated by interviewees. In contrast, a decrease of 3.92% pts that would have been necessary between round one and round two seems not to be realistic. Hence, the decrease in bid prices between rounds one and two cannot be fully explained by reduced return expectations of owners within realistic ranges.

A decrease of CAPEX by nearly 10% from the basic value would be necessary to enable a cost-based bid price decrease from round one to round two. This results in a CAPEX assumption out of the range described by Mayer & Philipps (2015). The assumed CAPEX values vary by +/- 6% around the medium assumption. Similar to the WACC, this means that the decrease in bid prices between rounds one and two cannot be fully explained by a CAPEX reduction within realistic ranges, while the decrease from round two to three and round three to four may be based on realistic reductions in CAPEX.
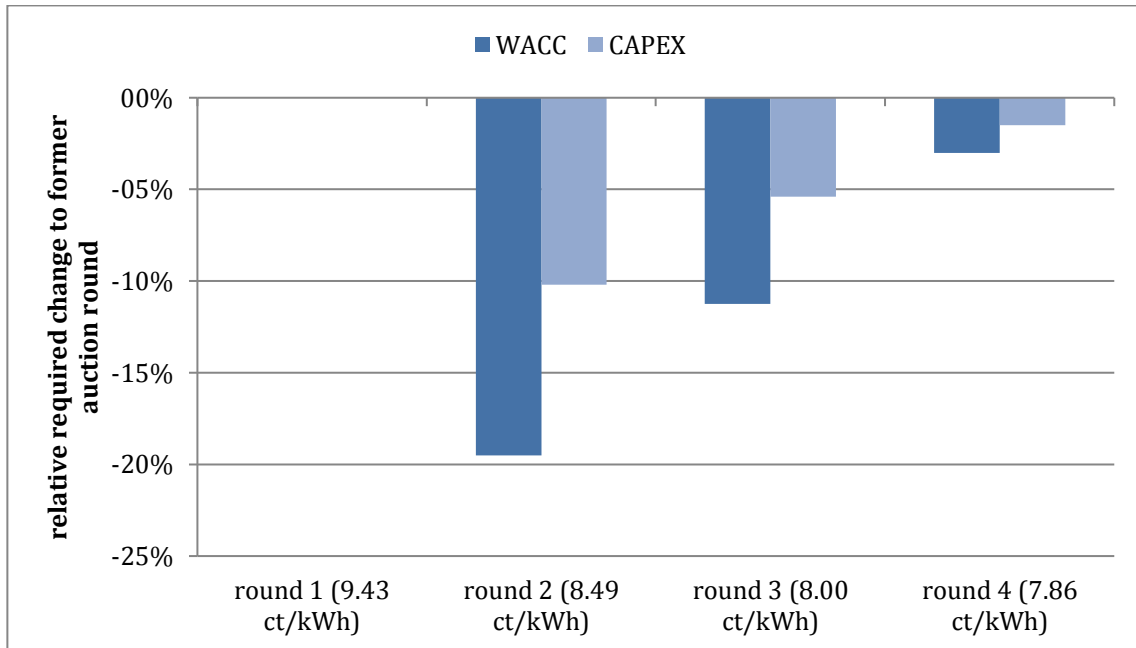
Figure 7: Changes in WACC and CAPEX required to moving a marginal project from losing to winning in the subsequent auction round. Base value WACC 4%, base value CAPEX 1000 €/kWp. Bid price in brackets shows the highest successful bid of the round.

This analysis shows that the single values for the required changes from round one to round two do not seem to be realistic. Even if both effects could have worked in parallel, it seems that the bid placements in the German PV auctions contained a strategic element – either a strategic add-on in the first round or a strategic underbidding in the second round.

In contrast, the required changes to becoming a marginal winning project in round four from being a marginal losing project in round three seem to be in a realistic range. Investors could have improved their supply contracts for realising the project with lower CAPEX or lowered their return expectation on the invested capital.

3 Case 2 – Onshore wind power in Spain

Spain conducted an auction to allocate support for biomass and onshore wind power in January 2016. The remuneration is different to many other auction schemes applied in Europe since it is paid as an investment grant.

The auction resulted in a remuneration level of zero, i.e. no support payments for the awarded projects. In the following, an example investment project for onshore wind power is implemented in the DCF model and a bid-price for the Spanish auction is simulated in order to quantify an economically reasonable bid price level. Moreover, the case shows how the model can be used to simulate investment-based support schemes.

3.1 Auction scheme

In the following, the main features of the Spanish auction scheme are described. Further details of the design and the outcome can be found in del Río (2016).

The auction was organised as a capacity-based, multiple-item auction for 200 MW of biomass plants and 500 MW of onshore wind power. The remuneration was an investment-based support. Bidders had to specify the amount of installed capacity they want to offer and a discount on the investment cost for a reference plant. In this way, a discount of 0% corresponds to the highest support (receiving the complete investment cost as for the reference power plant) and a discount of 100% corresponds to no support at all. The basic investment cost for a reference onshore wind power plant was set to 1200 €/kW.

Projects were awarded on a uniform pricing basis using a price-only criterion. However, the support agreement is not project specific, i.e. it can be used for any project location all over Spain.

A penalty for non-compliance of 20€/kW applies after a grace period of 48 month from contracting.

Concerning the market conditions, it is important to mention that a moratorium came into force in 2012 cutting all renewable energy support for newly installed projects. The auction was the first measure which re-introduced any kind of support for renewable energy since then.

3.2 Observed bid prices

The auction resulted in a discount on the investment cost of 100% for all projects, i.e. in no support at all. Reasons for this outcome were mainly identified to be of strategic nature: Especially the market conditions, with no support for renewable energy projects after the moratorium from 2012, was deemed to create an obsession to win in the auction with investors trying to receive some remuneration for projects being in the pipeline (del Río, 2016). This situation, combined with a uniform pricing approach, could have led to speculative bids in the hope that other bidders will set a higher support level.

It was also mentioned that there could have existed an ambition to push competitors out of the market, a phenomenon which is described as crowding-out in Haufe & Ehrhart (2016).

3.3 Implementation in the DCF model

3.3.1 Project characteristics

Table 7 shows the project characteristics as implemented in the DCF model.

Table 7: Project characteristics for the Spanish onshore wind auction simulation

Technology	Onshore wind
Location	ES
Operating Time [years]	20
Lead Time [years]	3
Delay Probability [%]	5
Length of Delay [years]	2
Non-compliance probability [%]	5
Depreciation time [years]	20

The capacity factor of onshore wind power in Spain is estimated to be between 22% and 31% (Boccard, 2009). Since the auctioned support was not location specific, a project capacity factor on the higher end of 29% is assumed when the locations with very good wind conditions are chosen. Since the cash flow model can only deal with production based remuneration types, we have modelled the support as a fixed premium paid for one year. Thus, it has to be converted into an investment-based support by multiplying it with the annual power production. For this reason only one capacity factor is implemented for the scenarios low, medium and high in order to make the conversion to the investment-based support comparable.

The wholesale electricity price in Spain was about 20%-25% above the prices in Germany over the period of 2013 – 2015 (European Commission, 2016). For the market price assumption this trend is assumed to continue and the German power price projection from energinet.dk (2015) is therefore increased by 20%. The market value factor for wind power in Spain is assumed to be 0.9.

The CAPEX and OPEX are estimated as in the implemented default values in the DCF model based on European averages.

The balancing expenditures seen by wind power generators are estimated to be between 2-3 €/MWh on average (EWEA, 2015a). Relating this to the average power price in the Spanish power market in 2014 and 2015 of around 45 €/MWh (European Commission, 2016), this corresponds to a share between 4% - 7% of the revenues from power market. For the simulation a medium value of 5.5% is chosen.

Table 8 shows the assumptions under the different scenarios as implemented in the DCF model.

Table 8: Assumed project characteristics for the Spanish onshore wind auction simulation

Assumption	Low	Medium	High	Source
Capacity Factor	29.0%	29.0%	29.0%	Boccard (2009)
Achieved Price [€/MWh]	57.7	62.0	66.1	energinet.dk (2015),European Commission (2016)
CAPEX [€/kW]	1150	1200	1250	Bourgeois (2013)
OPEX [€/kW*a]	36	39	42	Valpy & English (2014)
Balancing Expenditures		5.50%		EWEA (2015a), European Commission (2016)
Corporate Tax Rate		28.00%		tradingeconomics (2016c)
Inflation Rate		2.40%		tradingeconomics (2016b)
WACC		10.00%		Noothout, Jager, Rooijen, & Angelopoulos (2016)

3.3.2 Support characteristics

Table 9 shows the support characteristics as implemented in the DCF model.

Table 9: Support characteristics for the Spanish onshore wind auction simulation

Remuneration type	Fixed premium
Duration of support [years]	1
Prequalification Cost/Sunk Cost [€/kW]	0
Penalty for delay	No penalties
Penalty for non-compliance	One-off payment of 20 €/kW

The investment-based support in the Spanish auction is modelled as a one year fixed premium. In this way, the support is paid on top of the market price in the first year of operation, i.e. in the fourth year after contracting in the basic expectation case. In the Spanish auction, only successful bidders have to pay 0.17 €/kW to cover the administrative costs. Since many projects which participated in the auction were ready developed projects which were in the pipeline after the moratorium in 2012 (del Río, 2016), it is assumed that the sunk cost in the auction were very low and are therefore modelled to be zero.

The penalty for non-compliance applies in the fifth year after contracting.

3.3.3 Market conditions and market position

The chosen states for the different market conditions and the market position of the simulated investment appraisal are shown in Table 10.

Table 10: States for market conditions and market position for the Spanish onshore wind auction simulation

Condition	Chosen State	Main reason
Level of Competition	High	Many projects in the pipeline
Sunk Cost	Low	Administrative costs charged only for successful bidders
Secondary Benefits	Medium	Possibly ambitions for crowding-out
Market Position	Weak	Many developers in the market
Ambition to Win	High	Absence of a schedule for regular auctions

Del Río (2016) points out that there was a large pipeline of already developed projects when the auction was conducted. Therefore, it was obvious for most of the participants that the competition in the auction will be very high, also taking into account the moderate totally auctioned amount of 400 MW for onshore wind power and the absence of a schedule for regular auctions. The lack of a clear periodicity also caused a situation where project developers were desperate to receive some remuneration for their projects (del Río, 2016).

Regarding the secondary benefits it was mentioned that there were possibly ambitions to push competitors out of the market. Furthermore, the support rights are fully transferable, which also creates secondary benefits of trading the support rights on a secondary market.

3.4 Simulated bid-price

Figure 8 shows the resulting non-strategic bid price range. The lowest bid price is at 36.64 ct/kWh and the highest bid price is at 51.00 ct/kWh. The bid prices for a one year fixed premium can be converted into bid prices for an investment-based support by multiplying them with the annual production of 2540.4 kWh. Doing this results in a range of 930.8 €/kW to 1295.6 €/kW. Expressed as a bid price for the Spanish auction this would mean a range of discount on the initial investment of the reference plant between 22.4% and 0%.

The bid price that the model proposes based on the chosen market conditions (see Section 1) is with 36.85 ct/kWh very close to the lower end of the bid price range expressing the assumed market conditions. The placement factor is 0.02. Expressed as a bid price for an investment-based support, this corresponds to 936.1 €/kW or a discount on the initial investment of 22.0%.
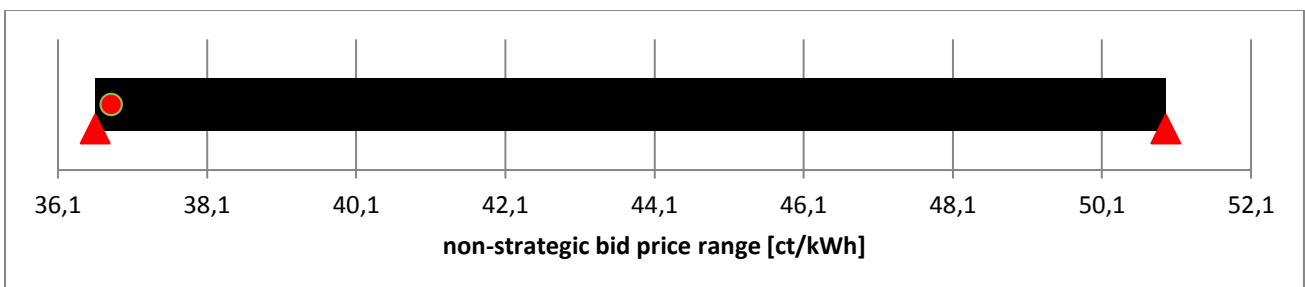

Figure 8: Non-strategic bid price range for Spanish onshore wind auction simulation

Comparing the simulation results with the observed outcome of a discount of 100% on the initial investment, it seems obvious that those offers were far from expressing real project costs.

3.4.1 Sensitivity to the WACC

As mentioned by Noothout et al. (2016) the main risk factor for investments in renewable energy in Spain are sudden changes of the support policy framework. An increased risk can increase the cost of capital and in this way significantly affect the simulated bid price. A main change in the support policy of Spain occurred in 2012 where all support for newly installed renewable energy projects was abolished as mentioned above.

When assuming that many of the projects were already planned at this time and were only postponed until the auction, the financing parameters could have been fixed from the time the project was initially planned. Therefore, some of the projects could have been calculated with a lower WACC than the assumed 10%.

Figure 9 shows the impact of a decreased WACC of the projects. It can be seen that the discount rate has a significant impact on the resulting bid price level. Assuming a WACC of 8% could already lead to a bid price of 54.5% on the initial investment, assuming the same market conditions.

A threshold analysis for a support level of zero and the implemented investment results in a WACC of 4.77%. This discount rate makes the project profitable in the medium scenario without any support. Noothout et al. (2016) indicate a WACC between 3.5% and 4.5% for onshore wind power investments in Germany. However, these values do not seem realistic for Spain. The threshold analysis results in a WACC of 5.61% assuming the most optimistic parameters for the achieved price, the CAPEX and OPEX (see also Figure 9).
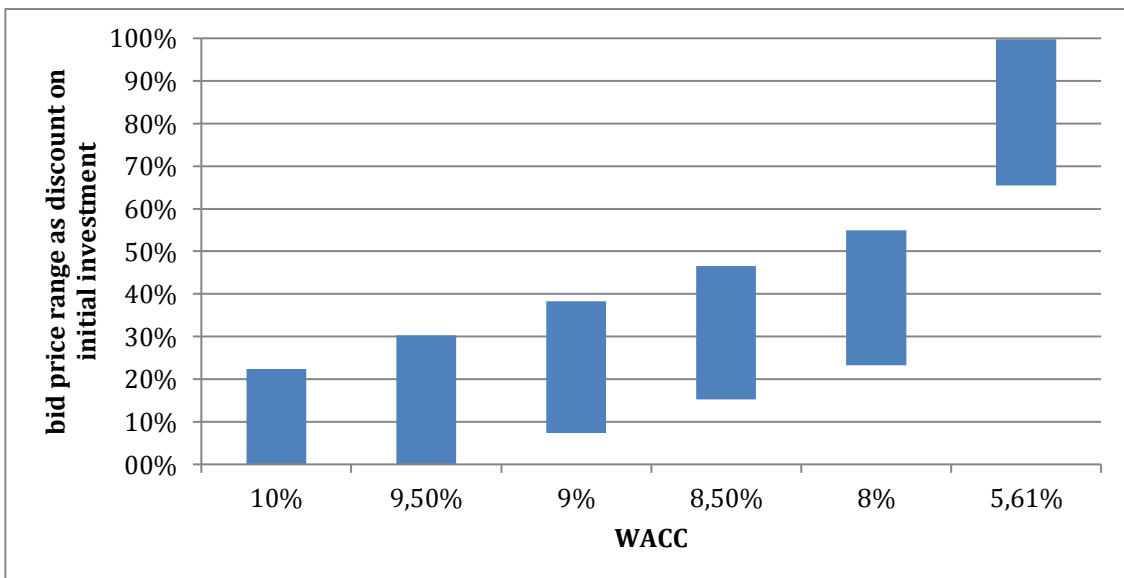

Figure 9: Impact of the discount rate (WACC) on the bid price range on in the Spanish onshore wind auction

3.5 Discussion of auction design

The main factors which make the auction in Spain different to other RES auctions conducted in the EU are the investment-based remuneration and the absence of a regular schedule for consecutive allocation rounds (del Río, 2016). The impact of those two parameters is analysed in the following.

3.5.1 Influence of the remuneration type on the sensitivity to the WACC

The remuneration type of an investment-based support means that the support is paid in only one year at the beginning of the operating time as an investment grant. During the remaining lifetime, the only income can be generated on the power market. In contrast, sliding premium support is more equally distributed over the whole lifetime of the project.

This difference has a significant impact on the sensitivity of the bid price to the discount rate. Figure 10 shows the dependency of the non-strategic bid price when simulating the onshore wind power investment with an investment grant paid in year four and with a sliding premium paid for 15 years. The results show clearly that the bid price is much more sensitive to the WACC assumption when the investment-based support is chosen. Mind, that the support levels are not directly comparable to each other due to their different type. The figure only illustrates the sensitivity of the respective bid prices under the different schemes.
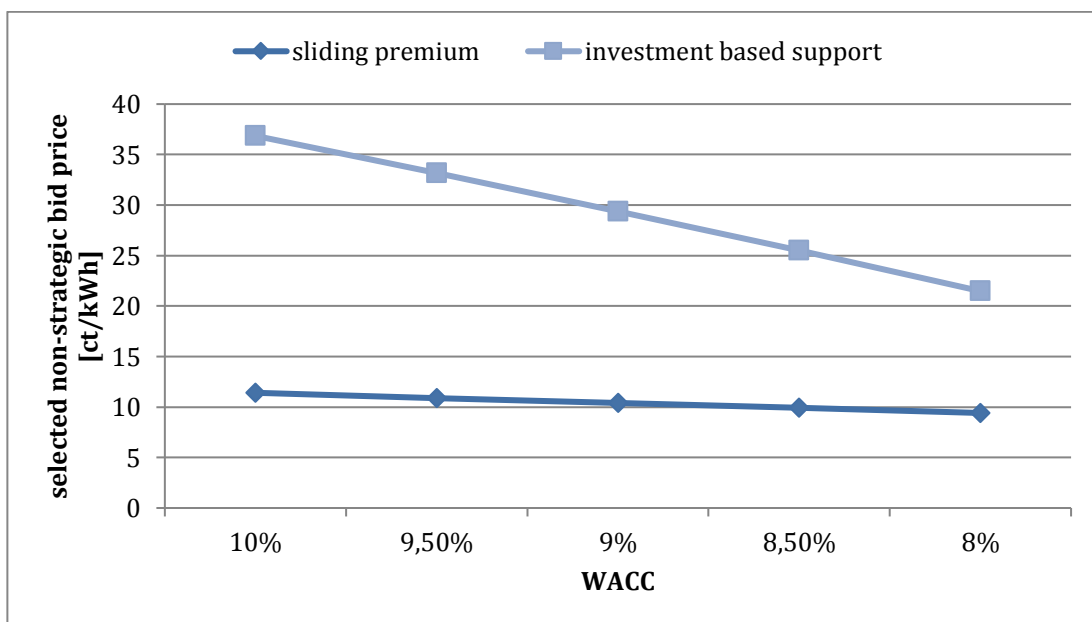
Figure 10: Non-strategic bid prices for an onshore wind power project depending on the WACC under different remuneration types

Especially in Spain, the discount rate is a crucial parameter due to recent changes in support policy and uncertainty concerning the regulative framework. In this light, the investment based remuneration can lead to very large differences in the bid prices induced by differences in the financing structure of different investors. When choosing sliding premium remuneration instead, the bid prices of those projects would be closer together. This could have a positive impact on the perceived fairness of competition (when using a price-only award criterion).

3.5.2 Influence of a missing regular schedule

Having a regular schedule of auctions would mainly affect the level of competition and the ambition to win in each auction round. We can only simulate that rather crudely based on the market conditions and placement factors implemented in the DCF model. Both parameters would be reduced. This would directly influence the placement factor and therewith the bid price when assuming the same project characteristics and auction design. In the basic simulation case, the bid price would increase to an investment-based support of 976.3 €/kW or to a corresponding discount on the initial investment of 18.7% when changing the level of competition to medium and the ambition to win to low. We conclude that the effect of a regular schedule would most probably be that the general support level increases. This effect is likely to lead to a higher realisation rate and induce bids which better reflect the real costs of the projects. In light of the very low bids in the auction already conducted and the remaining large project pipeline, this may be desirable for future auctions in Spain. However, we also conclude that the effect of a regular schedule on the resulting support level is less strong than e.g. a change of the WACC of 0.5%.

4 Case 3 – Offshore Wind Power in Denmark

The concession for constructing of and receiving support for the offshore wind farm Anholt located in the Kattegat was auctioned in Denmark in 2010. It was the third support auction for offshore wind farms in Denmark. The auction resulted in a support level of approximately 14.1 ct/kWh with only one bidder participating (Kitzing & Wendring, 2015). The result of the Anholt auction was the highest result seen in the five auctions for offshore windfarms held in Denmark so far. For comparison, the auction of the windfarm Rødsand 2, which took place two years before, resulted in a support level of 8.5 ct/kWh.Five years later, the subsequent auction of the windfarm Horns Rev 3 resulted in a support level of 10.3 ct/kWh. The high support level in the Anholt case led to an additional third-party evaluation of the bid price authorised by the Danish Ministry for Climate and Energy and conducted by Ernst & Young (Ernst & Young, 2010). The evaluation named three main reasons for the comparatively high bid price in the Anholt auction (Energistyrelsen, 2010):

- The project location is both further away from the coast and in deeper water (compared to the offshore wind farm Rødsand 2), which leads to increased costs for installation and maintenance.
- In 2010, there was a general increase in demand for offshore turbines, foundations and construction vessels on the European market, which both increased the supply uncertainty and the overall capital investment costs.
- The auction design increased the bid price and reduced the number of interested bidders by including high penalties for delay and non-compliance combined with a very tight construction schedule.

In the following, the auction is implemented in the DCF model and a non-strategic bid price is simulated. Afterwards, the aforementioned three factors CAPEX, OPEX and penalties are further investigated.

4.1 Auction scheme

Only the main features of the auction are described here. Please refer to Kitzing & Wendring (2015) for further details regarding the auction design.

The auction for the Anholt offshore windfarm was first announced in April 2009 and the final bid was placed in April 2010. The auction followed a pure public auction approach without prequalification and without negotiations between the contracting authorities and the bidders.

The auction was organised as single-item auction for the total installed capacity of 400 MW. The remuneration type is a sliding premium paid for 20 TWh of production. Bids were awarded on basis of a price-only criterion.

Penalties applied for both delay and non-compliance. There were two types of delay penalty: Reduction of support level and one-off payment. The penalty level of support reduction depended on the actual delay of grid connection of the first turbine counting from 31 December 2012.The following reductions of support level applied:

- Delay of 1-3 months: 1 øre/kWh (approx. 0.13 ct/kWh)
- Delay of 4-8 months: 3 øre/kWh (approx. 0.26 ct/kWh)

- Delay of 9-12 months: 3 øre/kWh (approx. 0.39 ct/kWh)

The one-off penalty level depended on the full connection to grid: In case the contracted capacity of 400 MW was not connected to the grid by 31 December 2013 (approximately three years and eight months after the placement of the bid), the following penalties applied, depending on the time at which the delay was announced:

- 100 million DKK (approx. 13.4 million €) if delay announced within 5 month after contracting
- 200 million DKK (approx. 26.8 million €) if delay announced within 12 month after contracting
- 400 million DKK (approx. 53.7 million €) otherwise

In case of non-compliance, the concessionaire would have to pay 400 million DKK as well. Additionally, there was a stand-by requirement established, which obliged the bidder offering the second best offer to be on stand-by for six months and to overtake the project in case the winner opted out.

4.2 Observed bid prices

There was only one bid offered in the auction. The bid was at 14.1 ct/kWh, which was the highest observed price in all offshore wind auctions conducted in Denmark so far.

4.3 Implementation in the DCF model

4.3.1 Project characteristics

Table 11 shows the project characteristics as implemented in the DCF model.

Table 11: Project characteristics for the Anholt offshore wind auction simulation

Technology	Offshore wind
Location	DK
Operating Time [years]	25
Lead Time [years]	3
Delay Probability [%]	40
Length of Delay [years]	1
Non-compliance probability [%]	5
Depreciation time [years]	13

Offshore windfarms in Denmark may be depreciated using a declining balance method with a maximum annual depreciation of 15% of the remaining book value. The DCF model only includes linear depreciation. Therefore, we approximate declining balance depreciation by decreasing the linear depreciation time to 13 years. This reflects the higher depreciation rates in the beginning of the project life time. A lead time of 3 years will not induce any penalties. A delay of at least 1 year beyond the lead time will induce a penalty for delay.

In the basic simulation it is assumed that the probability for delay is 40% due to the strict schedule in the auction design and the assumed uncertainty in supply and availability of construction vessels (as mentioned in the beginning of the section). The probability for total non-compliance is set to 5%.

The capacity factor of the Anholt offshore wind farm can be found on Energy Numbers (2016). Here, the latest capacity factor calculated over the last 12 month of production was 46.2% while the capacity factor over the overall lifetime of the turbines was 47.8%.

All base prices (before adding inflation) have to be expressed in real 2010 values, which was the evaluation year of the project. Current price estimations are therefore deflated using the average inflation rate for Denmark between 2010 and 2015 of 1.5% per year (tradingeconomics, 2016a).

For power price estimations, old forecasts for the market area DK-West from energinet.dk are used (Energinet.dk, 2013). It is assumed that the starting price is the same as in 2013. Deflating the price to real 2010 values leads to a starting price of 273.5 DKK/MWh (corresponding to 36.6 €/MWh) in 2010 and 457.1 DKK/MWh (corresponding to 61.4 €/MWh) in 2035. The market value factor for wind power in the market area DK-West was 0.94 in the years 2008 – 2010 (energinet.dk, 2016). For the assumptions, a market value factor range between 0.9 and 0.98 is assumed.

The total CAPEX of the Anholt offshore wind farm are estimated to be 10 billion DKK (4Coffshore, 2016). This corresponds to 25000 DKK/kW (approx. 3356 €/kW). The grid connection to land is established by the Danish TSO. Therefore, the wind farm operator only has to pay for the cabling within the windfarm and until the offshore substation. The cost for the cable connection to land were estimated to be 1.3 billion DKK (Energinet.dk, 2011), corresponding to approx. 436 €/kW. If these costs are deducted from the aforementioned assumption, the actual CAPEX which had to be paid by the investor reduces to 2920 €/kW.

The OPEX for offshore wind turbines are estimated to be 97.9 €/kW per year in nominal 2014 values (Smart et al., 2016). This corresponds to an OPEX level of 89.1 €/kW per year in real 2010 values assuming an inflation rate of 1.9%.

The balancing expenditures seen by wind power generators are estimated to be between 2-3 €/MWh on average (EWEA, 2015a). Relating this to the average power price in the market area DK-West in 2014 and 2015 of 26.8 €/MWh (nordpoolspot, 2016), this corresponds to a share between 7% - 11% of the revenues from power market. For the simulated offshore wind farm we use the lower limit of 7%.

Table 12 sums up the assumptions under the different scenarios as implemented in the model.

Table 12: Assumed project characteristics for the Anholt offshore wind auction simulation

Assumption	Low	Medium	High	Source
Capacity Factor	44.0%	46.2%	48.0%	Energy Numbers (2016)
Achieved Price [€/MWh]	55.3	57.7	60.2	Energinet.dk (2013)
CAPEX [€/kW]	2820	2920	3020	4Coffshore (2016); Energinet.dk (2011)
OPEX [€/kW*a]	86.1	89.1	92.1	Smart et al. (2016)
Balancing Expenditures		7%		EWEA (2015)
Corporate Tax Rate		22.00%		KPMG (2015)
Inflation Rate		1.90%		Energinet.dk (2015)
WACC		7.00%		Noothout, Jager, Rooijen, & Angelopoulos (2016)

4.3.2 Support characteristics

Table 13 shows the support characteristics as implemented in the DCF model.

Table 13: Support characteristics for the Anholt offshore wind auction simulation

Remuneration type	Sliding premium
Duration of support [years]	13
Prequalification Cost/Sunk Cost [€/kW]	0
Penalty for delay	Reduced support level of 0.39 ct./kWh and one-off payment of 134.2 €/kW
Penalty for non-compliance	One-off payment of 134.2 €/kW

The support for the Anholt offshore windfarm is paid for 20 TWh of production. Assuming an overall capacity factor between 44% and 48% and given the total installed capacity of 400 MW, this corresponds to a support period of 12 – 13 years. The sunk costs are estimated to be very low, since there was no pre-qualification round applying and the cost for preliminary investigations were reimbursed by the TSO (Energistyrelsen, 2009). It is assumed that the one-off payment penalties occur in year 4 after contracting.

4.3.3 Market conditions and market position

The states chosen for the different market conditions and the market position of the simulated investment appraisal are shown in Table 14.

Table 14: States for market conditions and market position for the Anholt offshore wind auction simulation

Condition	Chosen State	Main reason
Level of Competition	Low	Many concurrent investment alternatives, unattractive auction scheme
Sunk Cost	Low	Costs reimbursed
Secondary Benefits	Medium	Possible further extension of market share
Market Position	Strong	High experienced company in the offshore business
Ambition to Win	Low	Many investment alternatives

DONG Energy A/S was the only bidder in the auction. The company was and is still the biggest operator of offshore wind power in Europe (EWEA, 2015b). Taking this into account, a highly developed supply chain can be assumed and thus a strong market position. The ambition to win in exactly the Anholt wind farm auction is assumed to be low, since there were many investment alternatives taking place at the same time (especially in the UK).

4.4 Comparison of the results and sensitivity analysis

Figure 11 shows the simulation result with the aforementioned assumptions. The bid prices range from 13.46 ct/kWh to 16.08 ct/kWh. The non-strategic bid price that the model proposes based on the chosen market conditions (see previous section) is 14.77 ct/kWh.
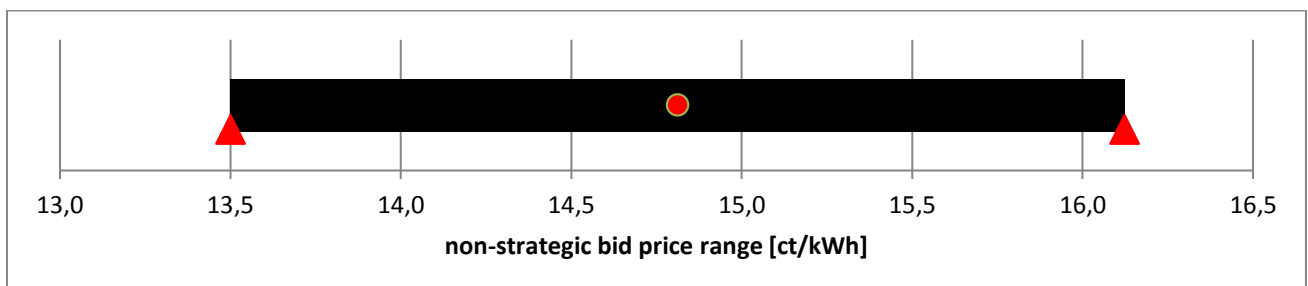

Figure 11: Non-strategic bid price range for Anholt offshore wind auction simulation

The simulation result is slightly higher than the observed bid price of 14.1 ct/kWh. The range indicates that a lower bid price would have been possible with a more aggressive bidding behaviour. On the other hand, the observed bid price still reflects the assumed costs and could have been even higher with less optimistic assumptions.

The resulting bid price range is similar to the estimation in the third party evaluation conducted by Ernst & Young which indicates a bid price range of 13.3 – 15.9 ct/kWh as economically fair (Ernst & Young, 2010).

4.4.1 Influence of the market conditions

The placement factor resulting from the assumed market conditions is 0.5. When changing the state of the level of competition to medium, the placement factor would change to 0.25 and the resulting bid price would be 14.11

ct/kWh, which is very close to the observed bid price. Setting the condition "Ambition to Win" to medium would have the same effect on the result.

It could be assumed that the level of competition was estimated to be medium if the bidder did not know whether other competitors were to participate in the auction as well. A medium ambition to win could be assumed if e.g. additional benefits connected to the specific site were present or if there was an incentive to e.g. strengthen or uphold the market position in the Danish offshore wind sector.

4.4.2 Influence of CAPEX and OPEX

As mentioned above, one reason for the increase in support level for the Anholt offshore wind farm compared to the former project Rødsand II mentioned in the bid price evaluation was the increased OPEX and CAPEX cost. According to EEA (2009) the CAPEX for offshore wind farms increases with the distance to shore and the water depth. The study points out that for a distance to shore of 10-20 km the CAPEX increase by 2.2% while for a distance to shore of 20-30 km the CAPEX increase by 4.3% compared to a reference of a distance of 0-10 km. Measured from the centre of the wind farm area, the Anholt windfarm is located 22.6 km from coast while the wind farm Rødsand II is located only 9 km from coast(4Coffshore, 2016). Increasing the water depth has an even stronger effect on CAPEX. It has been estimated that an increase in water depth of 10m will lead to an increase in CAPEX of 7% (EEA, 2009). Compared to Rødsand II, the Anholt windfarm is placed at a site with 10m greater water depth on average (4Coffshore, 2016)

Figure 12 shows the changes in the bid price range for increased and decreased CAPEX or OPEX assumptions. A change in the CAPEX assumption of 5% leads to a shift of the bid price range of 0.58 ct/kWh while a change of 10% leads to a shift of 1.15 ct/kWh. For the OPEX, a change of 5% leads only to a shift of 0.17 ct/kWh and a change of 10% leads to a shift of 0.33 ct/kWh. This shows that the simulated bid price is much more sensitive to CAPEX assumptions than to OPEX assumptions. Reducing OPEX by one third would reduce the bid price by 1.2 ct/kWh to 13.57 ct/kWh. This would have the same effect as lowering the WACC by 0.9% pts to 6.1%.Based on the assumed dependency of the CAPEX mentioned above, a 10% higher CAPEX could be assumed for Anholt compared to Rødsand II. When also assuming 10% higher OPEX, this could explain a bid price that is about 1.5 ct/kWh above the level of the Rødsand II auction. However, the actual bid price was 5.6 ct/kWh higher. Thus, we conclude that other parameters increased the price further. Among those factors, we assume to be the higher market price assumptions at the time the bid for Rødsand II was placed as well as the introduction of penalties (in the auction of Rødsand II no penalties were applied). Of course, also strategic considerations could have played a role.

The average electricity price on the day-ahead market was about 20% higher in 2008 (when the bid for Rødsand II was placed) than in 2010 (nordpoolspot, 2016). Increasing the market price assumptions by 20%, leads to a simulated bid price of 14.45 ct/kWh. Thus, the effect of higher market price assumptions is rather low. The effect of the penalties is further quantified in the next section.
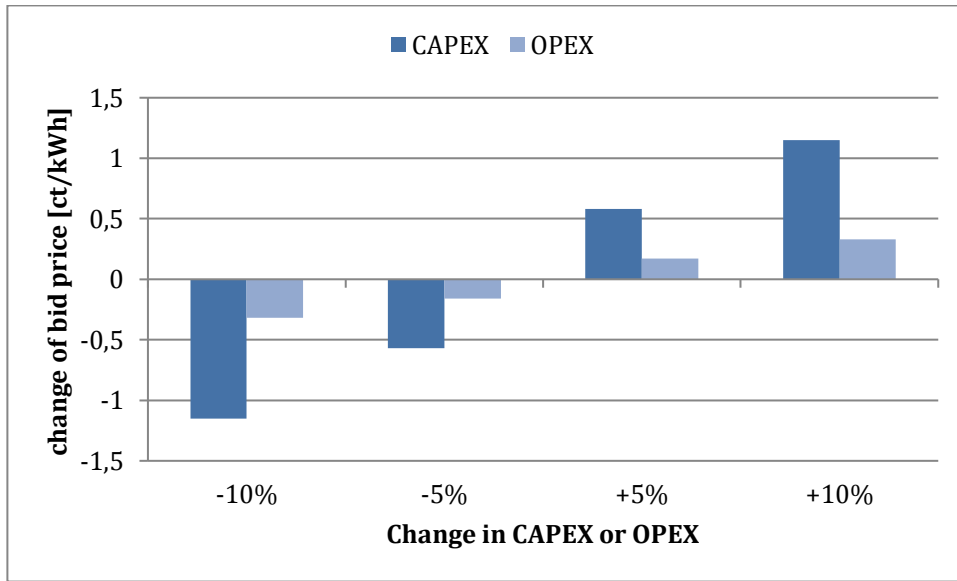
Figure 12: Change of the non-strategic bid price range with different CAPEX and OPEX assumptions for the Anholt offshore wind auction simulation

4.4.3 Influence of the penalties

Figure 13 shows the results of simulating the investment project in the Anholt wind farm auction with different assumptions of the probability of the delay case. The bars show the increase in the resulting bid price due to the delayed cash flows (comparing the bid price to a delay probability of 0% and without penalties for delay) and due to the two penalties for delay. Here, the bid price is compared to the case with the same delay probability but without the respective penalty. It can be seen that around 45% of the influence of an assumed delay of one year on the bid price stem from the penalty level for delay while around 55% stem from the delayed cash flows and the resulting lower NPV of the project income. The influence of the two types of penalties is equally strong.
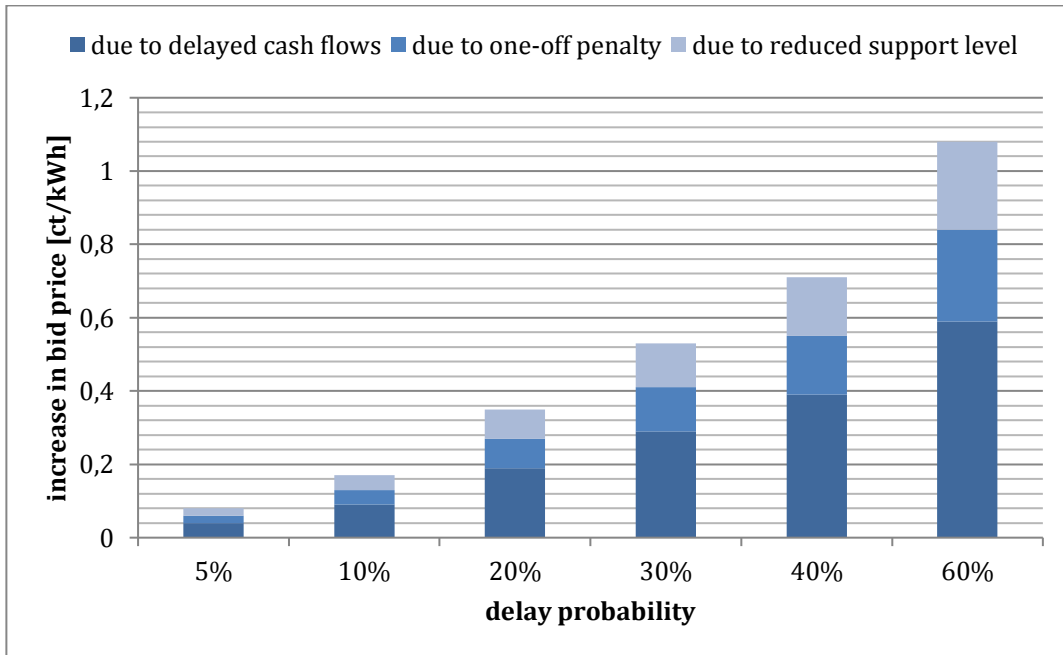
Figure 13: Increase of bid price in the Anholt offshore wind auction simulation assuming different delay probabilities and penalties

In case of the assumed delay probability of 40%, the effect of the penalties on the bid price is simulated to be 0.32 ct/kWh. This corresponds to an increase of the CAPEX assumptions of 2.8%.

Reducing the level of penalties by 50% (i.e. to a one-off payment of 67.1 €/kW for delay and non-compliance and a reduced support level of 0.2 ct/kWh in case of delay) would decrease the bid price by 0.17 ct/kWh to 14.60 ct/kWh.

The results of the conducted bid price simulation for the Anholt wind farm are very close to the real outcome and the third party evaluation. From this fact we conclude that the reasons for the higher bid price must stem from a combination of several cost factors including high CAPEX and OPEX due to the location of the project and the timing of its implementation and an overall supply uncertainty that led to a high probability of project delay inducing delayed cash flows and the risk of incurring high penalties. The effects of lack of competition and other potentially strategic considerations cannot be investigated comprehensively using a DCF model such as the one applied here with single-investor scope. For such a more comprehensive analysis, we refer to the upcoming agent-based model using game theoretic approaches that is currently being developed within the AURES project.

5 Conclusion

5.1 Limitations of this analysis

The conducted analysis can quantify impacts of different aspects of auction designs on the resulting bid prices such as the penalty level, the remuneration type or the project characteristics as WACC, OPEX or CAPEX. However, the model cannot cover the full range of design aspects of RES auctions. Aspects that are not covered by the DCF model applied here are for example the pricing rule, the prequalification design and the impact of repeated auction rounds. Especially the last mentioned aspects include a higher degree of strategic considerations that cannot be expressed by the single project representation of the DCF model. A crude representation of certain strategic factors are in this model expressed by the placement factor. However, the value of this factor is a rough approach and provides an indication rather than describing strategic behaviour thoroughly.

Furthermore, the cash flows are simplified. For example, they do not include loss carry forward or overall balance sheet calculations. In this light, all results obtained in this analysis should be regarded as qualitative implications rather than exact quantitative results.

5.2 Summary of the findings

Overall, the results confirm that expected project cash flows can form the basis of observed bid prices in past auctions. The observed bid prices both for the German solar PV auction and for the Anholt offshore windfarm auction seem to be strongly oriented on project costs and can be well reflected with the DCF model. Furthermore, it could be seen that uncertainties and variation in project costs have a large influence on bid prices and should not be disregarded in the auction design. Especially the influence of WACC and the operating time can be reflected quite well in the DCF model. The influence of the operating time assumptions is higher for projects with a low discount rate, as it can be assumed for solar PV projects and in countries with good financing conditions.

With the DCF model, the penalty design can be directly projected on project costs. However, the expectation value approach does not cover all aspects of this. As pointed out in Kreiss, Ehrhart, & Haufe (2016) it could play a role if the penalties are designed as a financial deposit at contracting time, which is retained or repaid later, or as a payment first becoming due when the penalty case applies. In this, it is important to compare the level of penalty to the overall assets of the investor. In our DCF approach, the only difference between a later or earlier payment of the penalty (with the option of being refunded) is seen as the time value of money. Under this assumption we conclude that the timing of penalty payment should not have a strong effect on the bid price. However, Kreiss, Ehrhart, & Haufe (2016) show that the demand for an early bid bond may affect companies also in other, more severe ways, especially when liquidity is an issue.

The example of the German auctions for solar PV showed a general decreasing trend of bid prices over several rounds. This implies some kind of a learning curve for participating investors especially when taking into account that the auction rounds were conducted all four months. We conclude that it is not very likely that the bid prices

decrease during this short period is due to a significant change in the overall cost level for PV modules or other project related costs. Possible learning effects cannot be reflected in the DCF model. For this, an agent based simulation with the possibility to include learning behaviour is necessary. However, our simulation here did help to quantify the change in project parameters WACC and CAPEX which are needed to result in the observed bid price reductions. When taking the third and fourth auction round into account, the decrease in bid prices could be explained by moderate decrease in the CAPEX or in the return expectation of the invested equity. Referring to the first and the second round, however, the observed decrease in the bid prices can hardly be reflected by changes in those cost parameters and a strategic learning effect seems to be more likely here.

The very low bid prices observed in the Spanish auction are difficult to explain on a cash flow basis. It is possible that pipeline projects do benefit from lower discount rates than what we assumed as generally realistic for Spain. But even very low WACC levels can only partially explain the actual auction result. Therefore, we conclude that systematic underbidding is likely as the bid prices do not seem to reflect the real project costs for onshore wind power in Spain. The effect of a one-shot auction with missing regular schedule combined with many projects in pipeline seems to be very strong so that strategic considerations have dominated over bid price formation based on real project costs.

In the case of the Anholt offshore wind farm, the impact of a high probability of delay (and the related delayed cash flows) was shown to be stronger than the penalty level itself. This means that auction design could with benefit focus on decreasing the delay probability while rather high penalty levels may be acceptable to ensure high realisation rates without affecting the resulting support level much. Through good auction design, policy makers can strive to reduce the probability of delay e.g. by adequate timing of processes and lenient grace periods – keeping in mind that this again will be affecting other success criteria such as realisation rate etc. Nonetheless, some aspects of delay probability are difficult to be influenced by policy makers in a single country. In this regard, special attention should be paid on the timing of a specific auction in the overall European context. A period with many parallel auctions for the same technology conducted in neighbouring countries could lead to a general scarcity on the supply market and increase the probability for delays, which can be strongly reflected in bid prices (even without defining additional penalties).

5.3 Proposals for game theoretic investigations of the past cases

We conclude that the DCF approach applied here is a good first step in quantitatively investigating certain auction designs, including penalties and risk effects. In that, it can be a very useful tool for example in regards to impact assessments of auction designs. It, however, lacks important aspects related to auctions, such as capturing strategic bidding behaviour and learning effects from consecutive auction rounds. For this, a game theoretic approach is required.

The DCF approach used in this paper uses an expectation value approach for modelling the effect of penalties on the bid prices. However, this neglects the fact that a penalty may induce different risks for different investors. The different risk levels mainly result from the different relation of the penalty to the overall asset of the investor. The

possibility of declaring bankruptcy and thus not paying the penalties should be taken into account especially for small investors with low assets (Kreiss, Ehrhart & Haufe, 2016)). It would be interesting to quantify how the level of penalty influences the strategic aspect of the bid price calculation for a small and large investor respectively.

The analysis also showed that the bid-price ranges can be large depending on the uncertainties in the project characteristics. The exact placement of the bid price is modelled very roughly with the placement factor. A quantification of the placement factor depending on the market condition states would be helpful also in order to extend the cash flow model. Of course, an agent-based model would optimise each bidder's placement in the auction based on individually modelled preferences and also regarding the auction outcome and related learning effects. Thus, we expect the agent-based full auction model to be able to produce the quantified factors as model outcomes. We will then be able to compare these with our assumptions here and may update them if necessary.

A multi-bidder perspective will also help to better evaluate the factors market position and ambition to win, since the own cost parameters could be set in relation to the assumed cost parameters of other participants. Moreover, a simulation of a learning curve in auctions with multiple rounds could further help to understand the behaviour in those auctions, such as the German solar PV auction.

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The general objective of the project is to promote an effective use and efficient implementation of auctions for RES to improve the performance of electricity from renewable energy sources in Europe.

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