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The effects of meshed offshore grids on offshore wind investment – a real options analysis

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Abstract

Offshore wind farms in future meshed offshore grids could be subject to different regulatory regimes. Feed-in tariffs would absorb market risk from wind farm operators, whereas price premium mechanisms leave operators exposed to market price signals. In this case, it plays a decisive role which price applies to a node in an offshore grid.

The offshore node will either be integrated into any of the neighbouring markets, with access to the respective maximum price, or be subject to separate nodal pricing. We investigate the different regulatory regimes for connections to one to four countries based on a stochastic model capturing uncertainties in prices and line failures.

The stochastic analysis shows that in case the wind park is granted access to the respective maximum price, there is a significant option value connected to the operational flexibility of accessing several markets: The wind farm's IRR can increase by up to 33% in the analysed (fictive) cases when connected to four neighbouring countries. Contrarily, in case of nodal pricing, the wind farm will have to cope with IRRs that are up to 15% lower when connected to more than one country. These effects can either hamper adequate investment or lead to windfall profits, if the level of support were not adjusted according to the choice of regulatory regime. This should therefore be considered when designing the regulatory regime and level of support in the offshore grid in order to maintain an effective and efficient development of offshore wind in Europe.

1. Introduction

Offshore wind power is one of the cornerstones for achieving a higher share of renewable energy sources (RES) in a number of coastal European countries. Despite a comparatively high number of full-load hours in comparison to fluctuating onshore technologies, offshore wind is still a rather expensive option due to its remoteness. The connection of offshore wind farms (OWF) to the shore is a main cost component which can amount to about 25% of total project costs [1]. This holds especially for far-offshore projects where HVDC cable systems and respective converters are required. Substantial savings potentials can be realised if several neighbouring OWF are connected via a single interconnector. This has already been done in Germany and regulatory implementation suggestions under the British OFTO regime are currently under discussion [2].

Until now, the connection of OWF is mainly pursued from a national approach. An exception is the Kriegers Flak project where Denmark, Germany and possibly Sweden at a later stage collaborate on a common offshore node. OWFs in close proximity are to be erected at the offshore border triangle of these countries. Joining the connections to national shores would allow for electricity trade and could thus become a first case of an integrated infrastructure serving offshore wind as well as international electricity exchange. Similar projects are also under discussion for the Irish Sea and for the North Sea [3]. There, it is demonstrated that a common connection of OWFs as well as further connections between them can lead to large cost savings and extra benefits from electricity transmission of up to 21 bill. Euro for the North Sea region. Research in this field is increasing: beside the aforementioned sources, [4] suggest a methodology for an optimal topology of an offshore network. From a legal point of view, [5] and [6] analyse offshore electricity grids and their potential implementation. They distinguish several cases, among them one where an OWF is in addition to its 'home' country also connected to one other, or where it forms part of a meshed offshore grid.

All of these analyses deal with offshore grids from a macroscopic perspective. The successful implementation will however in reality likely depend on good regulatory set-ups for single projects –

both for OWF and for transmission. Despite that, the amount of studies dealing with the effect of offshore grids on an OWF is limited: [7] shows that participation in national balancing markets constitutes a main part of an OWF's economy and that changing this situation to several markets impacts the business case. Depending on the support scheme and resulting economic incentives, the OWF or the transmission system operator (TSO) may act strategically with regard to several power markets [8].
The effect of multiple connections under different regulatory regimes on the OWF's business case has to our knowledge not yet been scientifically analysed. This understanding is however of utmost importance when designing the regulatory regime in order to ensure adequate investment incentives for OWFs and transmission capacity. An offshore grid will only reap the expected benefits if OWFs are built as planned; if, by contrast, the connection to an offshore grid leaves the OWF at a higher risk, the result may be contrary to the intention. We approach this research gap of multiple connections with a real-options approach: under different support scheme constellations, additional cables are connected to the OWF which may find itself in a neutral offshore price area. In the case of price premiums and exposition to market price fluctuations, prices are different than under a single national affiliation. To recognise the possibility of additional connections being established during the project's lifetime before taking an investment decision is a significant parameter in the investment analysis of an OWF in an offshore grid that can only be dealt with in a real-options analysis.

Figure 1 illustrates the different fictive connection cases we distinguish in this paper: the benchmark case is a 600 MW OWF connected to country A by a cable with the same capacity. This connection can be complemented by additional 600 MW interconnectors to the neighbouring markets B, C and D. We further distinguish two policy regimes for all countries: In the first case, the OWF can sell its power at the highest market price of the countries it is connected to. We will refer to this case as the 'primary access' case in the following. Alternatively, the OWF receives the price that applies to the offshore hub under nodal pricing. The latter case could apply especially for internationally coordinated support schemes in the future to ensure neutrality between the neighbouring countries (see e.g. [9], and sources therein).

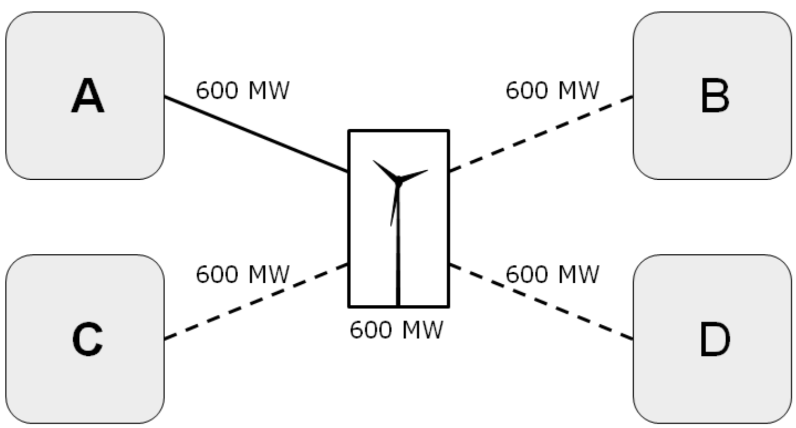

Figure 1: Overview of connection options

The remainder of the paper is structured as follows: first we address the applied method, including a detailed description of the model developed and an explanation of the considerations for the different analysed cases. Next, we address the quantitative assumptions that are common to all cases, before turning to the quantitative results. The subsequent discussion and conclusion sections conclude the paper providing qualitative analyses and first considerations on policy options.

2. Method

2.1 A stochastic model for the value of a wind park under price uncertainty

We use a well-established and often used approach (based on [10]) to develop a stochastic model of the spot electricity price in four countries. We let the electricity price be a stochastic process following a Brownian motion. The stochastic behaviour of prices, including drift and volatility, are exogenously given to the model. It has often been shown that most commodities in general and electricity prices specifically show characteristics of mean reversion and seasonal patterns [11]. Considering the nature of our analysis (being a comparative one), mean reversion will indeed affect the comparative attractiveness of the different analysed scenarios, especially because the cases are sensitive to small price differences between the countries. Seasonal patterns however are not expected to modify the comparative attractiveness of the cases significantly, as they would apply similarly to all countries. Therefore, we chose not to include seasonal patterns in the model at this stage.

The price processes are modelled as plain mean reverting Wiener processes. The stochastic change of price in each time step dx is expressed with the mean reverting stochastic process:

$$dx = \kappa * (x^* - x)\, dt + \sigma\, dW_t \tag{1}$$

Where:

- W_t is a Wiener process with independent increments at $W_t - W_s \sim N(0; t-s),\ for\ 0 \leq s < t$
- κ is the mean reversion factor of the market (exogenously given)
- σ is the standard deviation of the market (exogenously given)
- x^* is the 'normal' level of the price x_t, to which it tends to revert, i.e. the long-run marginal cost of production in an electricity system.

The processes are Markovian, meaning that the distribution of future prices is only dependent on the present price and not the past history of prices, i.e. it follows fundamental signals. In this framework, the price x_t in each time step can be calculated from the previous price plus the expected change dx from a stochastic process:

$$x_t = x_{t-1} + dx \tag{2}$$

For the simulation, we use the related first-order autoregressive process in discrete time (see [10], p. 76):

$$x_t = \overline{x_t} * (1 - e^{-\kappa}) + (e^{-\kappa} - 1) * x_{t-1} + \varepsilon_t + x_{t-1} \tag{3}$$

Where:

- $\overline{x_t}$ is the 'normal' level of x_t, to which it tends to revert. $\overline{x_t}$ includes a drift in the process and is therewith also dependent on t
- ε_t is a normally distributed random variable with mean of zero and variance of

$$\sigma_\varepsilon^2 = \frac{\sigma^2}{2*\kappa} * (1 - e^{-2\kappa}) \tag{4}$$

Having the stochastic price processes for all four countries in place, we then model the hourly expected future cashflows of the wind park mainly dependent on revenues from sales into the different spot market based on the restrictions given by the different cases we investigate.

We then aggregate the future cashflows over the analysis period, i.e. the lifetime of the wind project, and add a traditional discounted cashflow calculation to determine the project value, here expressed as the internal rate of return in each scenario and each realisation of the stochastic price process [12].

$$NPV = \sum_{t=0}^{T} \frac{CF_t}{(1 + IRR)^t} = 0 \tag{5}$$

Where:

- IRR is the internal rate of return in each realisation of the price processes in each scenario
- NPV is the net present value of the wind park
- CF_t is net cashflow in period t (net of positive and negative cashflows)
- t is the time period of the Cashflow
- T is Number of periods, i.e. the lifetime of the wind park

Finally, we run an N=1000 Monte Carlo simulation of different realisations of the price processes in order to determine the mean and standard deviation of the net present value of the project for the different cases.

2.2 A model for stochastic line failures

We add the option of stochastic line failures to the model. We model the probability of occurrence of a line failure with a Poisson distribution $P(\lambda)$, which reflects the nature of the failures much better than e.g. a normal distribution. This modelling approach is comparable to modelling of jump processes in commodity prices (see e.g. [13]). The probability of duration of the line failure is modelled as a normal distribution $N(0; d)$. We also add an exponential recovery process for the available capacity y_t when ramping up after the line failure, approaching exponentially to the maximum available capacity $\hat{y}$, the nominal capacity of the interconnection capacity between the wind park and the respective country.

$$y_t = \hat{y} - \hat{y} * i_{(t,\varepsilon)} - \left(\hat{y} * j_{(t,\theta)} + (e^{-\kappa} - 1) * y_{t-1} + y_{t-1}\right) \tag{6}$$

Where:

- y_t is the value of available interconnection capacity, being restricted to $0 \leq y_t \leq \hat{y}$
- $\hat{y}$ is the nominal capacity, i.e. the maximum available interconnection capacity between the wind park and the respective country. It also serves here as the jump size in the Poisson process, meaning that the failure is expected to always affect 100% of the capacity
- κ is the recovery rate of the exponential process towards the maximum available capacity $\hat{y}$
- $i_{(t,\varepsilon)}$ is the variable that activates the line failure, with
  $$i_{(t,\varepsilon)} = \begin{cases} 1, & \varepsilon_t > 0 \\ 0, & \varepsilon_t = 0 \end{cases}$$
- ε_t is a Poisson distributed random variable with mean of λ , $\varepsilon_t \sim Pois(\lambda)$
- λ is reflecting the expected number of line failures per year
- $j_{(t,\theta)}$ is the variable that activates the recovery process after an outage, with
  $$j_{(t,\theta)} = \begin{cases} 1, & t = t_p + \theta_t \\ 0, & t \neq t_p + \theta_t \end{cases}$$
- t_p is the maximum value of t, in which a line failure last occurred, with $t_p = t \;\; at\, \varepsilon_t > 0$
- θ_t is a normally distributed random variable with mean of zero and standard deviation of d, $\theta_t \sim N(0; d)$
- d is reflecting the expected number of hours the outage lasts

2.3 Cases

We use the model to analyse several different cases, which are interesting in the light of a wind park investment with the option to be connected to several different countries under various regulatory frameworks. We compare the results of the different scenarios, especially in terms of value for the investors in relation to the base case. Any additional value related to the operational flexibility of being connected to other countries is investigated as the option value of the additional interconnection.

A main difference between the regarded cases is the support scheme: under *feed-in tariffs (FIT)*, a guaranteed fixed remuneration per MWh is paid for a fixed number of years (or generation hours). Selling the generation on power markets and correction of forecast errors is administered by an agent, typically the TSO, leaving the operator of the OWF with only limited market risk. Under *feed-in premiums (FIP)*, this task is left to the operator of the OWF: the operator receives a fixed premium per MWh generated, but needs to sell the generated electricity on power markets.

Since there are no existing offshore nodes without demand, and a pricing scheme for future offshore nodes has not been decided upon yet, we investigate several different cases. Under a FIT scheme, an OWF is indifferent to the pricing rules; under a FIP scheme, the underlying spot market price that can be obtained plays a decisive role. The most straightforward option is the price in the offshore node is always identical to that of its home country. However, in this case, additional risk evolves only from balancing issues and not from the spot market income [7] which is in the focus here. With regard to spot pricing, we regard two cases and differentiate according to the pricing rule: we assume that an OWF has either *primary access* to all markets or that *nodal pricing* applies for the offshore hub. In the case of primary access, it always incurs the highest spot market price. This reduces the necessary support but in return, reduces the congestion rent income of the TSO. The other option is that the TSO can always incur the maximum amount of congestion rents possible and that the price signal to generation in the offshore node is optimal. This leads to the effect that congestion rent income is high, whereas the OWF receives only the second- or third-highest price – corresponding to the country to which the interconnector is uncongested [8].

Besides the support scheme and the pricing rule, a number of other factors are crucial for the economics of an OWF. The most substantial of them are the connections of the OWF to neighbouring countries. In the benchmark case we assume only one connection to one market. If, at a later stage, this situation is altered by additional connections to other markets, the profitability of the OWF can be significantly impacted – positively or negatively. In this regard, the number of connections, their capacities as well as the timing of the additional connections are crucial elements.

In addition to the connections, two other parameters are worth investigating: risk of failure of any of the transmission lines might impact the business case of the OWF significantly, depending on the regulatory set-up. Especially relevant for the stochastic analysis and therewith the option value is the strength of price correlation between the investigated markets.

These considerations lead us to the following cases that we investigate during the remainder of the study:

1. One country – benchmark case
    a. Feed-in tariff
    b. Price premium
2. Primary market access and price premium in all markets
    a. Two countries
    b. Three countries
    c. Four countries
3. Offshore hub price and price premium in the offshore market
    a. Two countries
    b. Three countries
    c. Four countries
4. Special cases
    a. Line failures
    b. High spot market correlations

3. Assumptions

We assume a fictive case with four archetypical markets and a typically sized offshore wind farm of 600 MW. We assume the addition of 600 MW interconnectors to the other countries as main distinction criterion between the cases. This has a crucial effect on results: the capacity of the wind farm is such that typically, all its power can be sold into one market. Other capacity combinations, especially combined with different electricity price characteristics in the neighbouring countries, would most likely have a considerable impact on the results. However, the authors prefer to present the results of the described simple set-up because a more complicated structure of the cases would partially conceal differences between policy choices

The electricity price processes for all four countries (see section 2.1) share the same fictive parameters, though they are not correlated between each other (except for one case with a focus on a correlation of 0.9 between market A with B, C, D). More specifically, the starting mean value is 50 Euro/MWh with a drift of +1 Euro/MWh towards the end of each year. The volatility before and after mean reversion are set at 1.5 and 2.228, respectively, while the mean reversion coefficient κ is set at 0.01.

Regarding the stochastic line failures (see section 2.2), we assume that on average 3 annual interruptions occur with an average duration of 50 hours. Due to the Poisson distribution characteristics, the frequency and duration of line failures typically exhibit single shorter interruption, representing planned maintenance, and rare interruptions of longer duration, representing planned maintenance (see Figure 2). The average failure duration of 150 hours per year corresponds to 1.7% outages per year, which is regarded to lie in a realistic range [14][15]. The spike mean reversion parameter, reflecting the return speed to nominal capacity, is set at 0.05.

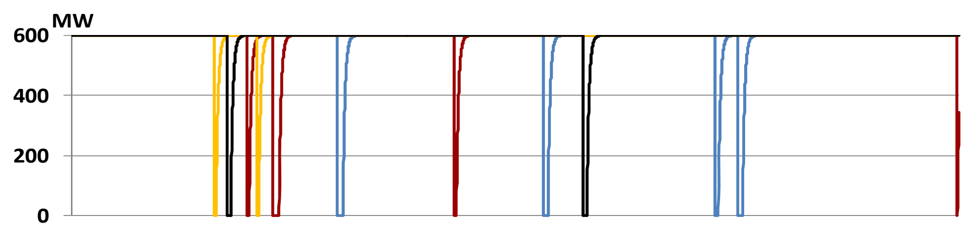

Figure 2: Exemplary outage results for the 4 interconnectors over a full year

The wind time series is based on measured wind data at the FINO1 platform in the Southwestern part of the German sector of the North Sea for the year 2006. It has been processed into an hourly production pattern accordingly to [16] and approximately adjusted for wake effects. The 600 MW OWF is assumed to have a lifetime of 25 years, about 4475 full load hours, investment cost of 2,450 mill. Euro/MW and operational expenditure of 0.07 mill. Euro/MW/year. Apart from the rather high value for full load hours derived from wind time series, these numbers are in line with [17] and estimated to be realistic for the nearest years to come.

4. Quantitative results

4.1 One country – base case

In the base case where the wind park is only connected to one country, the wind park is, depending on the regulatory framework and renewable support mechanism, exposed to the market of the one country and the volatility of its prices.

In case the wind park receives a guaranteed price in form of a feed-in tariff, the wind park is not exposed to the volatility of that market and all Monte Carlo simulations result in the same IRR for the wind park (see Figure 3, left). In case of a fixed price premium paid out in addition to the market price, the wind park is exposed to the underlying volatility and the Monte Carlo simulations yield a normally distributed outcome of the IRR (right). The expected mean IRR corresponds in our fictive case to the IRR in based on a Feed-in tariff. The standard deviation is 0.4%-points. This result forms the basis of comparison for our further analyses.

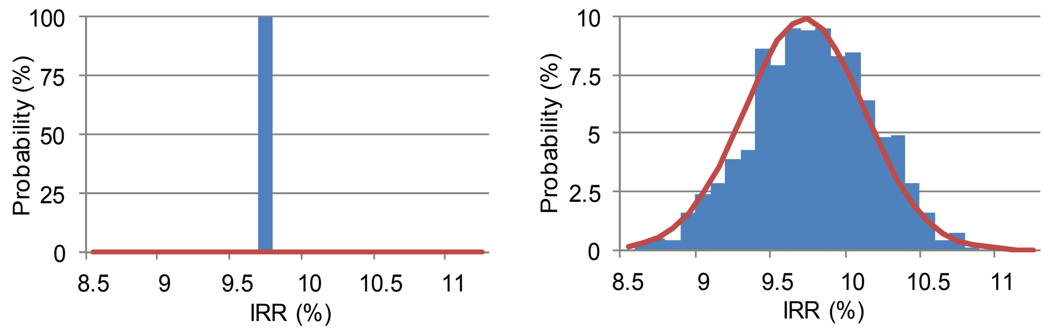

Figure 3: IRR for feed-in tariff support (left) and price premium support (right)

4.2 Primary market access

In cases with primary access, the option to be connected to different countries increases the value of the wind park significantly. The wind park can choose into which market it sells the electricity and can therewith achieve a higher average price from choosing the highest price at any point in time – the more countries are connected, the higher the value of the wind park (see
Figure 4).

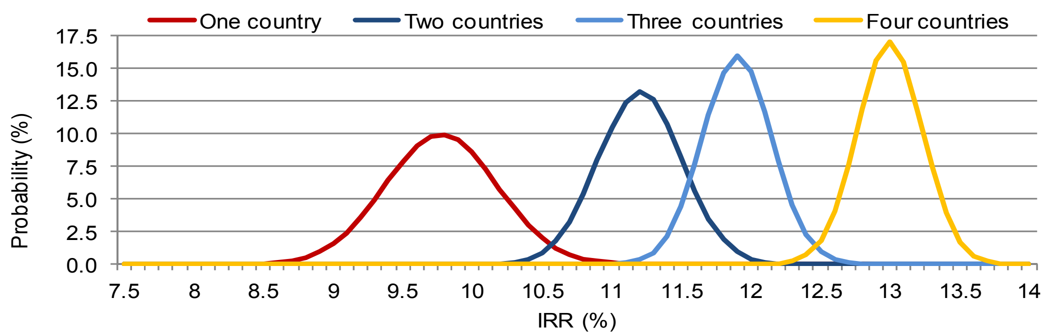

Figure 4: IRR probability distributions under primary market access

Next to this rather obvious result of a higher expected IRR, it is interesting to see how much the standard deviation, which we use as indication for riskiness of the investment, decreases when adding more countries. This is due to the fact that the wind park is less exposed to the volatility of market prices in one country as it has the option to switch sales to any other country whenever a low price period occurs.
The value of the operational flexibility in this regulatory regime results in an up to 33% higher IRR in the four-country case (up from 9.8% to 13.0%) with a constant feed-in premium. In future valuations of wind parks and offshore hubs, not only the option of higher expected IRR when connecting to more countries should be taken into account, but also the risk reducing effect of diversification into several markets, stemming from the fact that revenues of the wind park are less exposed to low price periods in a single country. This effect is increased when taking line failures into account, whereas it is decreased when considering correlation between the market prices of adjacent markets. In our example, the IRR decreased by 0.6%-points when considering a two-variate correlation of all countries with country A.

4.3 Offshore price hub

In case the regulations are chosen in such way that the offshore hub forms its own price area, the wind park will not be able to choose a market of one of the adjacent countries and therewith the market price to sell at. In almost all realistic cases, there will be at least one connection from the wind park to a country which is not congested, and the offshore hub price will thus equal the price of that market. This will typically not be the highest available price. Therefore, the wind park will be valued at a lower level than in the case of primary access.

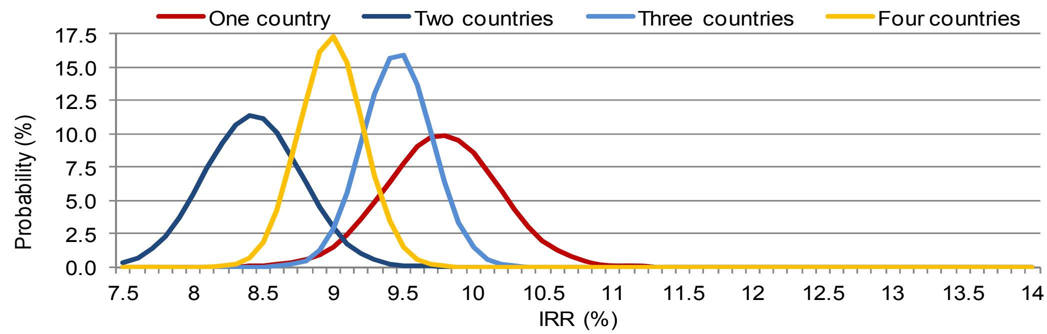

Figure 5: IRR probability distributions under nodal pricing at the offshore hub

The model results reveal an interesting characteristic of how this regulatory framework impacts the wind park under the assumption of identical interconnector capacities. When two countries are connected to the offshore price hub, the hub will always form a price that corresponds to the lower of the two prices; therefore the impact is very significant with a decrease of ca. 15% (from 9.8% to 8.4%). In a case of three countries, the offshore price hub will form a price that corresponds to the medium of all three prices. Some of the impact of the two-country case is mitigated. In a four country case, however a price will form that corresponds to the second lowest of the four market prices. The resulting IRR probability distributions are illustrated in Figure 5. Of course, the differences of the cases are much less pronounced if there is significant price correlation between the markets of the countries especially when including periods of equal prices.

4.4 Line failures

We analyse stochastic line failures as described above in the case of connection to one country and for comparison in the four country case, assuming primary access to the highest-price market.

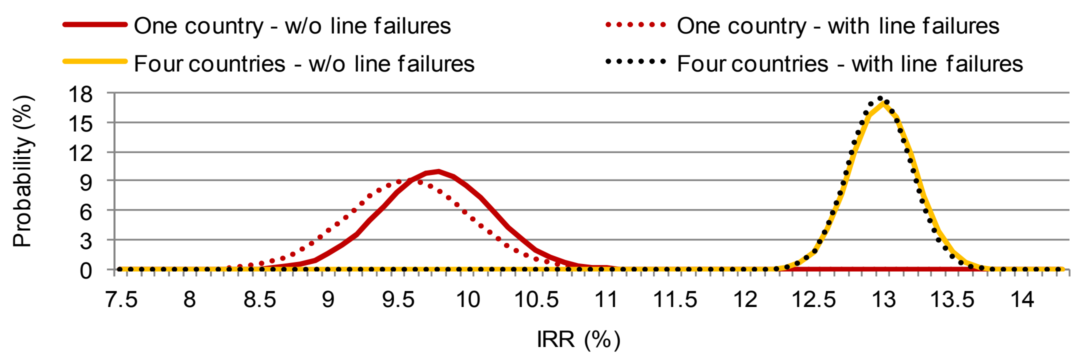

Figure 6: IRR probability distribution changes considering line failures

The impact on the wind park value – in case of no compensation through the TSO – is significant in the one-country case. Almost the complete negative effect of line outages is mitigated in case the wind park is connected to four countries as the probability that all four lines have failures at the same time is very low. Moreover, the consequences of a line failure to the highest-price market are reduced because of access to several alternative markets.

This result can be of significant impact for the future valuation of wind parks in offshore hubs. Of course, the compensation framework needs to taken into account here. In case the wind park operators are fully compensated for line outages, there will be no measurable impact on the wind park value. In that case, this analysis can be used for risk analysis of the TSO's income from the interconnection operations, as the compensation payments will significantly affect the TSO's financials in that case.

4.5 Comparison of all cases

An overall comparison of all cases is illustrated in Figure 7. The standard deviation and the mean IRR values are shown in a scatter plot. In comparison to the benchmark case with only one country connection (red), all primary access cases provide better IRR and risk characteristics with every additional interconnector. The image is different for nodal pricing in the offshore hub, where the case with 3 countries provides the highest IRR after the one-country case. The cases with line failures (dark blue) are connected by lines with their respective benchmark cases. It is clearly visible that the effect is much more pronounced for the one-country case than for the four-country case. Yet more distinctive is the change when assuming a high price correlation between markets: the IRR decreases while the standard deviation increases remarkably. This illustrates that option values between several cases are highly dependent on the underlying assumptions.

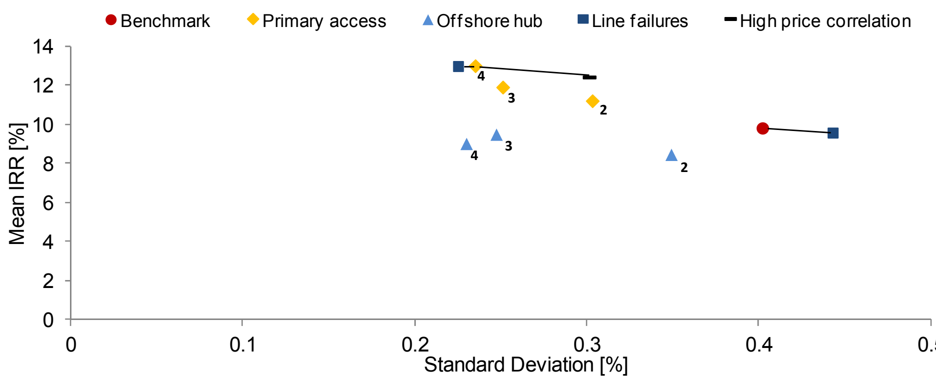

Figure 7: Comparison of all cases

4.1 Congestion rents

Until now, the focus of our analysis has been on the economic effects on the OWF. Let us now turn towards the other main party involved, the TSO. This is addressed by congestion rents (see Figure 8). As could be expected, they increase with the number of connections and are higher under nodal pricing than under primary access. The latter effect is least pronounced for the three-country case: here, the primary access and nodal pricing cases differ only by approx. 41 mill. Euro on average. The reason is that comparatively good case for the OWF under nodal pricing, which is at the expense of congestion rent income.

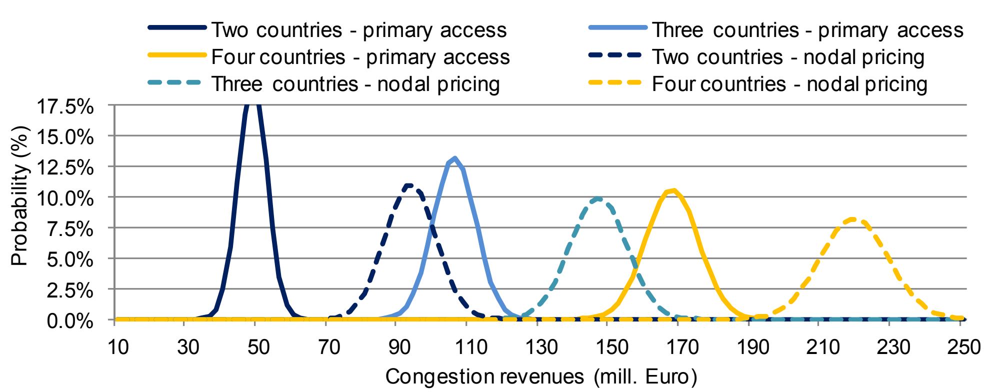

Figure 8: Congestion revenues under different regulatory regimes

5. Discussion

This study presents an analysis on the economic effects of different regulatory regimes on offshore wind farms. It quantifies the impact of different regulatory regimes on the OWF and shows that a connection to several markets affects the return and risk structures if they are not absorbed by other mechanisms, e.g. a TSO provision. The cases are fictitious, but carry the notions of the main points the authors wish to highlight. We have limited our analysis to spot markets. In reality, balancing markets and their prices might be a very decisive factor in choosing on which market to sell. The cases and countries investigated do not represent a realistic market environment. Before drawing conclusions on real cases, the model should be calibrated to real market characteristics, especially the level and volatility of the markets are decisive. This, however, could first be applied for a real-world case where the interconnector capacities and market price characteristics are known and where the offshore node's generation is handled differently than national onshore generation. In addition, the authors expect that sensitivity analysis on interconnector capacities to different markets would lead to remarkably different quantitative results than presented here. A main simplification taken is that we look at real option values *for the whole lifetime* of the project. This supports transparency, but would probably not apply in real-world cases: additional interconnectors are first decided upon after the offshore wind farm comes into operation. So, for more realistic cases, a sensitivity analysis on additional interconnectors only *after a certain number of years* would provide valuable insights.

6. Conclusions

We have shown that the regulatory framework, especially market access rules, has a significant impact on the valuation of a wind park in an offshore hub. Our analysis shows that the connection of different markets into an offshore hub can have a positive effect of up to 33% increase of IRR as well as a negative impact of up to 15% decrease of IRR on the wind park business case, depending how the regulatory framework is designed. If wind park operators are not compensated for lost revenue in case of line failures, the connection to several countries diminishes the risk of line failures.

Our results can be used when considering how to design a cross-border offshore hub, such as envisaged in the Kriegers Flak area, to make an informed decision. In order to balance incentives for investment and socio-economic efficiency, the support level, i.e. in our case the fixed price premium, could be adjusted according to changes in wind park value and riskiness.

The presented results emphasise that the incorporation into an offshore grid is not neutral for the OWF. This leads to the question of how to compensate for possible losses or gains under the suggested regulatory mechanisms. Our results show this may need to be handled on a interconnector-by-interconnector basis: while the connection to a third country is beneficial for the OWF under nodal pricing, the connection to a fourth country is negative. Thus, different stakeholders like TSOs and OWFs may take different positions towards new cables at different stages of an offshore grid erection process – which may hamper the construction of new lines that are beneficial from a holistic viewpoint.

For further research, we envisage to overcome some of our model limitations by further developing and implementing the presented methodology. The focus of analysis could also be turned from offshore wind farms to a balanced picture between OWF and TSOs: solutions that are advantageous for the OWF could be detrimental for the TSO, and vice versa. Thus, a stronger focus on revenue and risk characteristics of interconnectors from a TSO perspective needs to be envisaged.

7. Acknowledgements

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