Financing renewables in the age of falling technology costs

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Abstract

Cost of renewable energies have dropped, approaching wholesale power price levels. As a result, the role of renewable energy policy design is shifting – from covering incremental costs towards facilitating risk-hedging. An analytical model of the financing structure of renewable investment projects is developed to assess this effect und used to compare different policy design choices: contracts for differences, sliding premia, fixed premia and a setting without dedicated remuneration mechanism. The expected benefit for electricity consumers from reduced risk and financing costs is approximated at the example of a 2030 scenario for Germany. Policies like sliding premia, previously evaluated as providing low-risk investment environments, provide for less risks hedging, when technology costs approach wholesale power prices. Contracts for differences provide in all scenarios the most effective hedge for investors against power prices uncertainty, enabling low-cost financing and reducing costs for consumers, while also hedging electricity consumers against high power prices.

Key words: Investments under uncertainty; Financing costs; Renewable energy policy; Contracts for difference

JEL classification: Q42, Q55, O38

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1 Introduction

For many years, substantial support for deployment of wind- and solar power technologies has been a key element of renewable energy policy. In combination with public support for R&D and production facilities, this resulted in steep cost reductions for technologies like wind and solar power.

As the falling costs of wind and solar power are approaching the costs of producing electricity with conventional technologies, investors require ever fewer, and eventually no more, support. For example, support levels for large-scale solar plants in Germany have fallen by almost 90 percent between 2007 and 2018 (IWR, 2018, Bundesnetzagentur, 2018). Does this imply that dedicated renewable energy policies can be abolished – or will they have to address other market failures? This paper focuses on market and policy risks for renewable energy investments and explores if and how this can be addressed with dedicated remuneration mechanisms.

Investors in power generation as well as electricity consumers are risk averse, and want to avoid the risk of low revenues for generation investment and respectively high costs of electricity consumption. Therefore, in most liberalized power markets, electricity is traded in forward contracts to hedge price risk. Such contracts are common for periods of 1-3 years both in Europe and liberalized markets in North America. Thus, they are the basis for hedging against annual price volatility linked to weather patterns and the commodity price cycles.

For traditional investments in thermal power plants, hedging beyond this time horizon was considered less important. Investments were pursued in the confidence that prices would always return to levels that warrant and therefore attract new investments, and would therefore also reward today's investment. Thermal power plants were also seen to offer a natural hedge against longer-term changes in commodity prices due to the high correlation of power price with fuel and moderate carbon prices (Roques et al. 2008). The remaining uncertainties with respect to future revenues and costs are then typically covered by equity of large energy companies, as the scale was in line with the capabilities of utility companies (Helms et al., 2015).

This situation does not easily translate to today's investments in wind- and solar power technologies. Large uncertainties persist about the cost developments of wind and solar power technologies, about availability and cost of storage and flexibility options, and about political choices on grid expansion and renewable energy deployment targets. This uncertainty about investment costs as well as additional uncertainty about carbon prices and fuel costs in the future, translates into long-term uncertainty on the value of wind- and solar power. Three-year contracts that hedge uncertainties of wind- or commodity cycles are no longer sufficient as they do not hedge against such long-term risks. Longer-term hedges or power purchasing contracts are required.

However, private longer-term contracts extending 15 to 20 years are likely to remain scarce: Offered to retail consumers, they would undermine retail competition and would entail large administrative efforts – for example in case of relocation of households. For most commercial and industrial consumers it would be difficult and costly to provide sufficient collateral to guarantee such contracts. After all, the value of a long-term contract can turn negative if expectations about power prices drop, and then can entail a large liability.

In the absence of contracts with final consumers (household or industry) it is also difficult for utilities to sign long-term contracts (Green 2003) with corresponding wind- and solar projects or to pursue the scale of desired investment in wind- and solar power capacity themselves. The scale of investment in wind- and solar generation to deliver the politically mandated decarbonisation targets is a multiple of the investment volumes previously observed in liberalized markets that were mainly driven by replacement needs – and at the same time balance sheets are significantly weaker. Furthermore, wind- and solar technologies do not require fuel input, and therefore are primarily capital intensive. This further increases the investment volumes, and makes the economics more sensitive to the cost of finance for the investment.

Renewable energy policy therefore needs to facilitate hedging of power price risks between producers and consumers. We develop a stylized model of investment and financing choices to assess the implications of renewable energy policies for financing structures and final electricity prices, depending on the wholesale electricity price development. In particular, we account for the market failure that no long-term hedging between energy producers and electricity consumers is available at large scale.

We contribute to the literature by analyzing analytically and numerically the implications of falling technology costs on financing conditions under various renewable energy policies.

Firstly, one-sided sliding premium systems[1] are option contracts guaranteed by the government. When the electricity price is lower than the strike price of the option contract, the option contract ensures that renewable energy operators are remunerated at the strike price (May, 2017). Therefore, sliding premia have traditionally been evaluated as contributing to enabling low-risk investments (Klobasa et al., 2013; Kitzing, 2014). They insure generators' revenues against low wholesale electricity prices, but do not insure consumers against potentially high wholesale prices.

Secondly, contracts for difference (CfDs), auctioned for example in the UK by a government backed entity, also provide a top-up payment facilitated by the regulator (Nera, 2013). However, when market values lie above the strike price, operators must pay back the difference between wholesale price and strike price (Pollitt and Anaya, 2015). In other words, the premium can become negative. In effect, a fixed price is guaranteed both for operators and consumers.

Thirdly, with fixed premia operators sell their output and receive a premium payment on top (Schmidt et al., 2013). However, this premium is fixed in auctions at the investment stage and does not adjust with the power price level. So while investors can use short-term hedges against power price volatility, at least in the long-term they are fully exposed to the wholesale electricity price risk (Kitzing, 2014).

Lastly, abolishing all remuneration mechanisms means that investments are undertaken on the expected and partially contracted power sales. When expected power prices are relatively high, e.g. due to higher prices for CO2, investors might be able to invest solely on the prospect of future revenues from power sales.

[1] In the remainder of the paper, we refer to one-sided sliding premia with their more common, abbreviated name „sliding premium", while we distinguish from two-sided sliding premia by referring to them as contracts for difference

The impact of power price and regulatory risk on financing and thus overall cost has been assessed with different approaches. Such risks are in principle common in commodity markets, and the literature on hedging pressure finds that asymmetric interest on hedging this risk results in a risk premium (Bessembinder 1992), which has been confirmed in studies on various commodity markets (Wang 2001). This results translate to the situation of renewable project investors – that are in principle interested to hedge power price risk, but due to the above mentioned institutional constraints fail to sign contracts with final consumers. In power markets additional complications result from the fact that power is not storable economically on the long-run at a sufficiently large scale and its value is heterogeneous as it differs with location and time of production (Finon, 2011, Roques, 2008).

Kitzing and Weber (2015) show, using a cash flow model, that the power price exposure under fixed premium schemes induces higher financing costs. NERA (2013) find a financing cost premium of a policy with full power price exposure of 0.8 – 1.7 percentage points, confirmed by May and Neuhoff (2017) who identify a financing cost premium of around 1.2 percentage points. However, when renewable energy investors are exposed to power prices, a significant share of the risk is usually transferred to off-takers of long-term contracts (Newbery, 2016). As outlined by Standard and Poor's (2017), as power prices usually cannot be hedged, such contracts are evaluated as liabilities on the balance sheets of the off-takers. This increases their leverage and negatively impacts their credit ratings, which increases the re-financing costs of their capital (May and Neuhoff, 2017). In total, power price exposure increases costs by around 30 percent (May and Neuhoff, 2017, Aurora Energy Research, 2018).

In addition to the impact on financing, a set of further aspects need to be considered when evaluating the effects of falling technology costs on the performance of renewable energy policies: Dedicated renewable energy policies are considered to be necessary to facilitate renewable energy targets which in turn are seen as a basis for the coordination of complementing measures (grid expansion, storage) and accelerate transition (replacing production from assets prior to decommissioning, e.g. competing on variable costs rather than full costs). Such technology specific targets, while in principle rather controversial, are often considered more viable in the case of renewables due to transparency on costs of different technologies emerging in global markets and the smaller scale of the technologies that allows competition within technology bands.

Renewable energy policies have already undergone two main developments in many countries. First, and most prominently, regulators often no longer set remuneration levels, but strike prices are found through competitive auctions. Second, a better market integration is supported. Initially, renewable energy remuneration mechanism were designed to facilitate market access of new technologies and to protect investors against dominant incumbents. With improvements of power market design and competition in markets, such protection became less important and priority dispatch requirements are gradually withdrawn. As a result, dedicated renewable energy remuneration mechanisms impact operational aspects considerably less – they can e.g. be designed so as to not distort operational incentives.

The remainder of this paper is structured as follows: In section 2, we describe the analytical financing model, followed by a numerical model of investments into solar energy. We quantify the annual differences in investment costs across policies in Germany in section 3 and the overall impact for consumers in section 4. The paper ends with a conclusion.

2 Analytical approach

We develop an analytical model of the financing structure of renewable investment projects, based on differences in the shares of debt and equity. We apply the financing model to different renewable policies in a competitive setting and discuss how the finance structure and costs differ between these policies.

2.1 Modeling the financing structure

Renewable power projects in Germany are usually financed on a project-finance basis (Steffen, 2017). The project developer can finance the capital costs with debt to the extent that they have certainty about revenue streams. We assume that long-term maintenance contracts cover the operational risk. Uncertain revenues however, e.g. from power market sales, cannot back debt. We assume that debt D can be raised at an interest rate r_d, which is typically relatively low. Potential explanations are adverse selection, the use of the interest rate as a screening device and resulting credit rationing (Stiglitz, 1981). Together equity and debt need to cover the investment cost $\mathrm{I} = \mathrm{E} + \mathrm{D}$. The remaining investment cost thus need to be covered by equity E that is assumed to expect a return of $r_e > r_d$. Power price risk exposure increase the share of equity and, thus, the financing costs, since creditors shy away from risk and only secure revenue streams can be used to obtain debt, while equity is required for financing costs covered by unsecure revenue streams.

To simplify the calculation, the annual payments to the creditor are structured to allow for a constant annual payment a_d D over the amortization period T. These payments have to suffice to cover interest and depreciation of the loan D:

$$\boldsymbol{D} = \sum_{t=1}^{T} \frac{a_d * \mathbf{D}}{(1+r_d)^t} = \sum_{t=1}^{\infty} \frac{a_d * \mathbf{D}}{(1+r_d)^t} - \frac{1}{(1+r_d)^T} \sum_{t=1}^{\infty} \frac{a_d * \mathbf{D}}{(1+r_d)^t} \qquad (1)$$

Using $\sum_{t=1}^{\infty} \frac{1}{(1+r_d)^t} = \frac{1}{r_d}$, this results in the annual debt serving factor a_d:

$$a_d = \frac{r_d(1+r_d)^T}{(1+r_d)^T - 1} \qquad (2)$$

The annual equity serving ratio a_e is defined analogously to the debt serving ratio. For simplicity we assume that equity investors expect the same payback period T as creditors.

$$a_e = \frac{r_e(1+r_e)^T}{(1+r_e)^T - 1} \qquad (3)$$

p	Realized net-market value, uniformly distributed between [0;2P]	**P**	Average net-market value
$\mathbf{R_{c,s,f}}$	Strike (reference) price for contract for difference, sliding premium, fixed premium	$\overline{\boldsymbol{C_{s,s,f}}}$	Average cost to consumer per MWh
I	Investment cost (per MW)	**Y**	Yield – in full load hours per year
D	Debt in financing structure (per MW)	**E**	Equity in financing structure (per MW)
$\mathbf{r_d}$	Interest rate on debt	$\mathbf{r_e}$	Return expectation on equity

a_d	Annual debt serving factor	a_e	Annual equity serving factor

2.2 Modelling of auctions for renewable policy instruments and electricity prices

We model different renewable policy regimes and assume that support is determined by the way of competitive auction, i.e. the lowest bid wins. In the case of contracts for differences and sliding premia this is the strike price, and in case of a fixed feed in premium it is the premium itself. As a higher share of debt leads to lower financing costs, and thus lower bids, there's a competitive pressure to maximize the debt-to-equity ratio, constrained by secure revenue to serve debt payments.

We assume that the investment volume in wind and solar power follows from policy choices on renewable targets (e.g. the EU 2030 strategy of minimum renewable targets reflected in national energy and climate plans). This determines the volume (MW) of wind and solar that is auctioned. For the modelling approach, we assume that the additional capacity of wind and solar connected to the system does not vary between the design choices of the remuneration mechanism, and, therefore, also the wholesale price does not differ between the mechanisms.

We consider the average market value – the price achieved when selling power to the wholesale market – as electricity price. In all scenarios, we assume the market value exceeds in all scenarios variable and annual fixed costs of operation, maintenance and insurance. To simplify our modelling, we consider throughout this paper the net-market value **p** – which is the market value minus variable and annual fixed costs.

We assume an average net-market value of **P**. To simplify the math, we assume **p** is uniformly distributed between zero and 2P. This reflects the large variance of expectations about the future net-market values of wind and solar power in the policy discourse.

2.3 Contracts for difference

With contracts for difference, we assume stable revenues, hence turbine investment costs C can be recovered from debt.[2] In a competitive equilibrium, the revenues from a contract for difference equal costs of interest and repayment. This means that the strike price S_c of contracts for difference, obtained for the annual energy yield Y, allows to recover investment cost I:

$$S_C = \frac{a_d \mathrm{I}}{Y} \tag{4}$$

The cost to consumer for the renewable energy equals the strike price of the contract for difference:

$$\overline{C_C} = S_C \tag{5}$$

2.4 Sliding premium

Sliding premium schemes hedge producers against low electricity producers, but do not hedge consumers against high prices. With levelized costs of electricity (LCOE) well-above wholesale electricity price levels, renewable energy operators always fall back on the option contract, stabilizing their revenues and taking out power price level exposure. This ensured low financing

[2] International experience suggests that 10-20% equity are common even in context of very secure revenue streams, to secure operational activities and liquidity. In our numerical model, we require a minimum equity share of 20 percent.

costs, enabling renewable energy investments at low costs to consumers (May and Neuhoff, 2017). Sliding premia are implemented by topping up technology-specific average market values of electricity to the project-specific strike prices (Gawel and Purkus, 2013): Operators sell their output and receive the premium payment of top, effectively shielding them from power price level fluctuations. However, when market values exceed strike prices, operators merely sell their electricity, benefitting from higher prices, and do not utilize the option contract, as the premium payment is set to zero. In a world of risk neutral producers and consumers, this asymmetric treatment of producers and electricity consumers has no effect, because all actors only consider the expected average revenue or cost. With more realistic risk-averse investors that charge risk premia for bearing risk and by consumers that are concerned about price spikes in their electricity bill, asymmetric hedging of producers and consumers can induce costs and reduce welfare.

With a one-sided sliding premium, only the guaranteed revenue up to the strike price S_s is considered secure enough to cover debt service:

$$D = \frac{YS_s}{a_d} \tag{6}$$

Revenue from power prices exceeding this strike price $[S_s, 2P]$ is uncertain and is, thus, used to remunerate equity investors (for $S_s \in [0,2P]$, cases outside this interval will be discussed later):

$$E = \frac{Y}{a_e}\int_{S_S}^{2P} \frac{(p-S_S)}{2P} dp = \frac{Y}{a_e}\int_{0}^{2P-S_S} \frac{p}{2P} dp = \frac{Y}{a_e}\frac{(2P-S_S)^2}{4P} = \frac{Y}{a_e}\left(P - S_S + \frac{{S_S}^2}{4P}\right) \tag{7}$$

In expectation debt and equity jointly need to cover investment costs (for $S_s \in [0,2P]$):

$$I = D + E = \frac{Y}{a_d}S_S + \frac{Y}{a_e}P - \frac{Y}{a_e}S_S + \frac{Y}{a_e}\frac{{S_S}^2}{4P} \tag{8}$$

In a competitive auction for sliding market premia, a market clearing strike price $S_S$will imply a remuneration that matches investment cost. Solving the quadratic equation for the equilibrium strike price gives:

$$S_S = 2P\left(1 - \frac{a_e}{a_d} + \sqrt{\left(1 - \frac{a_e}{a_d}\right)^2 + \frac{a_e}{Y}\frac{I}{P} - 1}\right), \tag{9}$$

The average cost $\overline{C_r}$ per MWh production to consumers is the weighted average outcome over possible market price:

$$\overline{C_s} = \int_0^{2P} \frac{1}{2P} max(S_S, p)dp = \frac{S_S^2 + \int_{S_S}^{2P} pdp}{2P} = \frac{S_S^2 + \frac{4P^2 - {S_S}^2}{2}}{2P} = P + \frac{{S_S}^2}{4P} \tag{10}$$

Substituting S_S from above:

$$\overline{C_s} = \frac{a_e}{Y}I + 2P\left(1 - \frac{a_e}{a_d}\right)\left(\left(1 - \frac{a_e}{a_d}\right) + \sqrt{\left(1 - \frac{a_e}{a_d}\right)^2 + \frac{a_e}{Y}\frac{I}{P} - 1}\right) \tag{11}$$

In the absence of an equity premium ($a_e = a_d$), or technology costs far exceeding potential electricity market prices ($\frac{a_d I}{2Y} > P$)the sliding premium is identical to the contracts for difference. With increasing equity premium ($a_e > a_d$) the average costs to consumers exceeds the costs in the reference case (contracts for difference). When the expected electricity market price P is equal to a pure equity financing ($P = \frac{a_e}{Y}\frac{I}{P}$), either by falling technology costs or rising market prices, the equilibrium strike price S_S falls to zero (assuming $a_e > a_d$)), and the cost to consumers corresponds to a pure equity financing structure $\overline{C_S} = \frac{a_e}{Y} I$

2.5 Fixed premium

A fixed premium guarantees a revenue S_f that can be used to secure debt. The revenue from power prices are uncertain, but can be used to raise equity:

$$I = D + E = \frac{Y}{a_d} S_f + \frac{Y}{a_e} P \quad (12)$$

In the market equilibrium the resulting premium is S_f:

$$S_f = \frac{a_d}{Y} I - \frac{a_d}{a_e} P \quad (13)$$

And the average price paid by consumers

$$\overline{C_f} = \frac{a_d}{Y} I + \frac{a_e - a_d}{a_e} P \quad (14)$$

As the second part of the sum is strictly positive (if $a_e > a_d$), the average price for consumers for the fixed premium is strictly larger than for the reference case (contracts for difference), as well as strictly larger than for the case of the sliding premium. On the other hand the strike price for the fixed premium is smaller than either for the sliding premium or the contract for difference.

2.6 No remuneration mechanism

Without a dedicated remuneration mechanism, all revenue is uncertain. In such a case, only equity can be used to finance the investment, based on expected electricity market revenues P.

$$I = E = \frac{Y}{a_e} P \quad (15)$$

Necessarily, investments will only take place if the electricity market price is high enough to finance the equity costs of investment. In equilibrium, the average price paid by consumers is defined by the annual equity-serving factor, the energy yield and the initial investment costs:

$$\overline{C_N} = \frac{a_e}{Y} I \quad (16)$$

3 Results

The analytical model provides the costs per megawatt hour (MWh) to consumers under the various remuneration mechanisms. Figure 1 visualizes two aspects per mechanisms: the strike price bid in competitive auctions and the resulting overall costs, derived from varying underlying financing costs. The x-axis depicts the market value of the renewable energy plant in Euro per MWh. Holding the technology costs constant, this is equivalent to varying the ratio between revenues from wholesale electricity sales and technology costs. With higher market values, a higher share of costs can potentially be recuperated through revenues from selling the electricity, inducing higher risks under some policies.

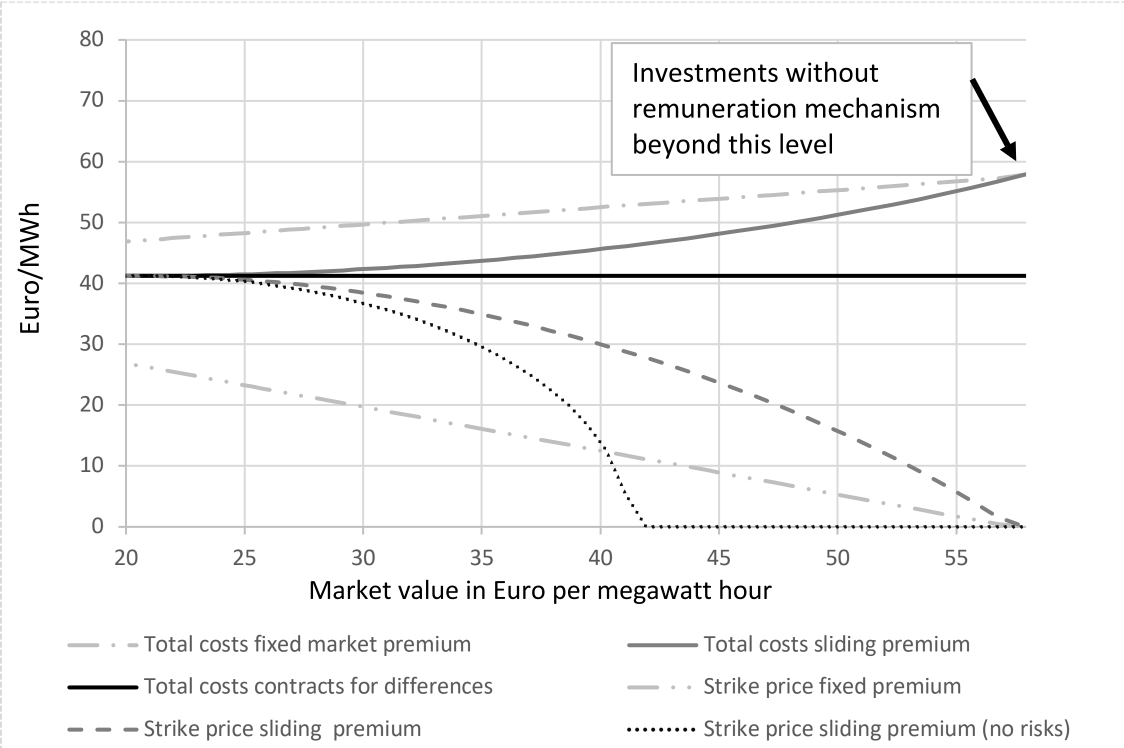

Figure 1 Evolution of strike prices and total costs to consumers of renewable energy with increasing wholesale price levels relative to technology costs.

Figure 1 illustrates that in a world with low wholesale prices relative to capital costs, sliding premia and contracts for differences produce the same outcomes. This is because the optionality of the sliding premium is never triggered. With a fixed premium the same effect can be observed as the level of wholesale prices further declines and therefore the share of revenue from fixed premium increases. As the expected wholesale price level increases, overall costs to consumers are significantly higher with a fixed premium.

With increasing wholesale price levels, contracts for difference and sliding premia increasingly lead to diverging deployment costs and, thus, costs to consumers. The strike price and cost for consumers under contracts for difference stay constant, as costs of the technology do not change with the wholesale price level. However, when sliding premia are in place, the strike price declines, as additional revenues are obtained in wholesale markets at times when wholesale prices exceed the strike price. Yet, the decline in the strike price only partially compensates for the increase in wholesale price level. Therefore, the average payment of consumers to renewable energy operators, wholesale price plus premium, is increasing. This is the case because the revenue recovered at times of wholesale prices exceeding the strike price is uncertain and can thus only serve equity-, but not debt-investors. Equity investors provide an increasing share of the capital. This increases financing costs and results in overall higher costs to consumers per MWh of electricity delivered. With increasing wholesale price levels, ultimately the incremental costs of an asymmetric sliding premium converges towards the incremental costs of a fixed premium.

At high market value compared to technology costs, sliding premia, fixed premia and the absence of remuneration mechanisms function similarly. Under the premia-based mechanisms, the bid strike prices converge to zero, providing no more secured revenues for the investors. The revenues depend solely on wholesale electricity prices. Thus, very high shares of equity need to be used for financing, increasing deployment costs.

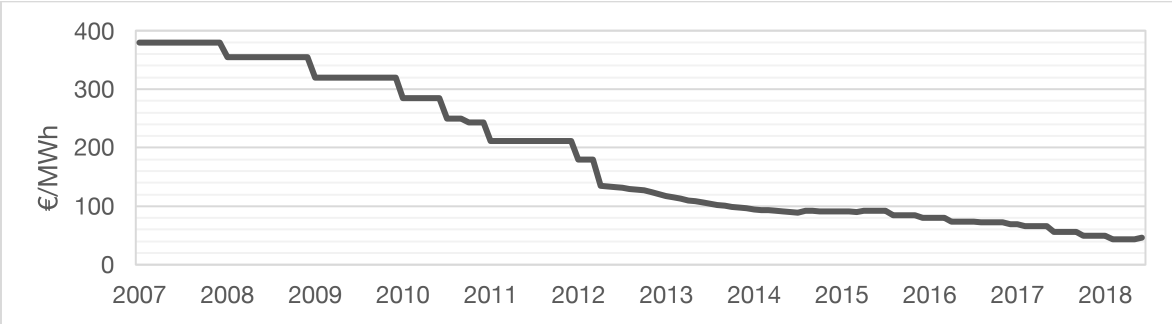

Figure 2: Remuneration levels of large-scale PV plants in Germany (Based on IWR, 2018 and Bundesnetzagentur, 2018)

Traditionally, levelized cost of electricity have been well above the market values of renewable energy.[3] Figure 7 depicts the approximate remuneration levels for large-scale solar power plants in Germany. Even though these do not match the costs one-to-one, they show the clear falling-cost trend. Remuneration levels dropped from almost 400 Euro/MWh in 2007 to around 46 Euro per MWh in 2018, i.e. a reduction by almost 90 percent.[4] Market values have not moved simultaneously: Even though they have fallen since 2007, they have not experienced decreases in the same order of magnitude (compare e.g. Hirth, 2013) and have not fallen strongly between 2012 and 2018 (50hertz et al., 2018).

Figure 3 explores how falling technology costs result in a differentiation between the remuneration mechanisms. With high technology costs (relative to wholesale price levels), contracts for difference and sliding market premium coincide in level and ensure low-cost financing, while a fixed market premium again results in an increase of overall costs per MWh. As technology costs decline, the sliding premium incurs ever higher wholesale price risk exposure. A larger share of cost reductions is covered through equity – reflecting the uncertainty of the wholesale revenues and increasing deployment costs.

[3] At least in the longer run – when looking at individual hours, market values of renewables frequently lie above strike prices.
[4] However, values for 2017 and 2018 stem from auctions, i.e. have two years for implementation, while previous values indicate remuneration levels at the date of implementation.

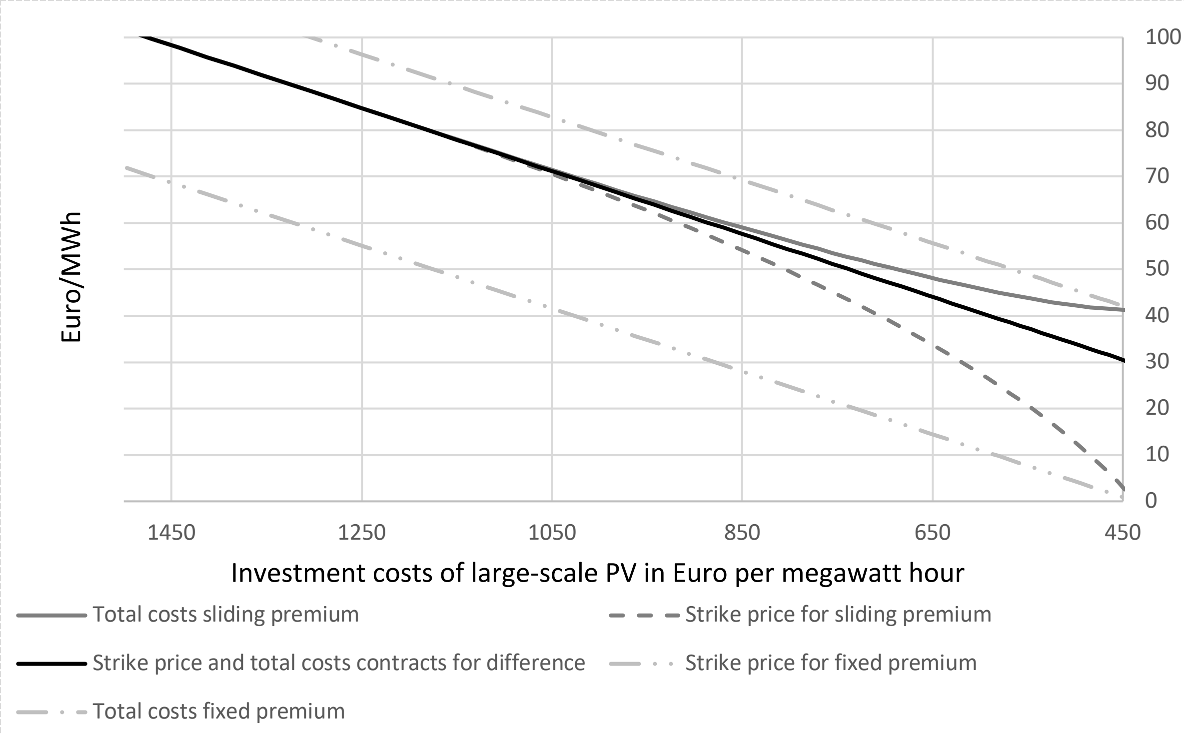

Figure 3 Evolution of strike prices and total costs to consumers of renewable energy with declining levelized costs of technology relative to wholesale price level.

Besides lowering the costs of renewable energies, other factors matter when designing renewable energy policies. Higher equity shares tend to benefit larger players, as only these can take on such risks onto their balance sheet. This market concentration effect would be counteracting the policy goals of greater actor diversity, and with it the participatory elements of the energy transitions which bring greater social acceptance, as well as greater competition in the renewable energy auctions.

Moreover, under a sliding premium, consumers are not symmetrically hedged against high power prices, unlike producers, who are hedged against low power prices. This may lead to issues of policy acceptance, if after long years in which renewable energy sources have been supported, newer projects are still protected against downside risks, while consumers are not protected against price spikes.

Finally, the increasing role of power market revenues can harm realization rates. Better or updated information on long-term developments of power prices between the time of the auction and the time of financial closure of a project may put in question the financial viability of the project. This may trigger a cancellation of the project. Dependent on the scale of required collateral for auction participation, market participants may deliberately take such a risk. Alternatively, less informed market participants may have a higher likelihood of winning the auction, and subsequently have to cancel the project with revelation of better information (winners' curse). Both effects will result in lower realization rates.

4 Numerical illustration

We can quantify the implications of increasing financing risks on the levelized costs of electricity and the overall cost differences between the remuneration mechanisms. We parameterize the analytical model using German data and expectations about technology cost developments for the period 2020 until 2030, proxied by cost parameters for 2025. We then estimate the overall demand for electricity from new renewable energy plants in 2030, yielding the overall differences in costs to final consumers around 2030.

4.1 Data

The analytical model includes parameters on financing parameters, technology costs, relative market values of renewable energies and power price levels. Moreover, to approximate the overall effects of identified differences in levelized costs of electricity, we make assumptions about the future demand for electricity from new renewable energy plants.

4.1.1 Financing assumptions

We assume that equity E can be raised at $r_e = 7\%$ and debt D at $r_d = 2\%$. Furthermore, we assume an identical amortization period of 20 years for both equity and debt. This is a conservative estimate (Diacore, 2016), to provide a lower bound for the estimated cost differences between renewable remuneration mechanism design options. The resulting annual equity serving factor a_e is 9.4 percent. We account for a minimum equity share of 20 percent to secure operational incentives and sufficient liquidity levels. Therefore, the adjusted debt-serving factor $\hat{a}_d$ is 6.78 percent.

4.1.2 Technology and electricity market assumptions

Parameterizing the analytical model requires assumptions on technology costs and power prices. Fraunhofer ISE (2018a) provide forecasts for technology costs and full load hours around 2025. For ground-mounted photovoltaics, the investment costs I_{PV} are 608 Euro per kW and the yield Y_{PV} is 1000 full load hours. For photovoltaics, we assume fixed O&M costs to be negligible. Rooftop solar provides a similar number of full load hours, but is more expensive at €1000 per kW. However, rooftop solar investments are not usually exposed to any of these remuneration mechanisms, benefitting from *de minimis* rules, rendering them eligible for feed-in tariffs and the general attractiveness of self-consumption, such that this set of remuneration mechanisms does not apply.

Onshore wind power costs about €1000 per kW and has around 2000 full load hours. Offshore wind power has higher investment costs of €3800 per kW, but exhibits considerably higher full load hours at 4100 hours. For both technologies we assume variable costs of 5 €/MWh (Fraunhofer ISE, 2018a) for maintenance and operation, which we for simplicity assume to be covered by certain wholesale market revenues.

For simplicity, we assume relative market values and power prices to remain constant after 2019, the last year, for which liquid futures exist. While relative market values are likely to further decline, this may well be offset by rising electricity price levels (for example due to coal and nuclear phase out or higher carbon prices). The power price level is, based on the Phelix Base-Future 2019, 43 Euro per MWh (EEX, 2018).[5] Photovoltaics in 2017 produced at an average relative market value of 96 percent of the base load power price (Fraunhofer ISE, 2018b

[5] as of June 28, 2018

and 50hertz et al., 2018), resulting in a price level P of 41.24 Euro per MWh. Onshore wind power's relative market value of 83 percent (Fraunhofer ISE, 2018b and 50hertz et al., 2018) yields an absolute market value of 35.9 Euro per MWh. Offshore wind power's average market value in 2017 was 91 percent, leading to an average value of 39.0 Euro per MWh.

4.1.3 Demand for electricity from new renewable energies

We estimate the amount of future investments based on what is required to increase the renewable energy share in electricity production from its 2017 level of 36.2 percent (BMWI, 2017) to 2030's goal of 65 percent (Coalition Agreement, 2018). To estimate the overall implications of cost differentials between remuneration mechanisms, we estimate the demand for electricity from new renewable energies, i.e. from plants built between 2018 and 2030. These new plants are potentially built under any of the remuneration mechanisms. Total payments to plant owners in 2030 differ with the varying levelized cost of electricity.

We assume a total demand of 776 TWh in 2030 based on the average of scenarios by Dena (2018). Thus, the German 65 percent renewable electricity target implies 505 TWh of electricity from renewable energies by 2030. The renewable-based generation of 2017, of around 210 TWh (Fraunhofer ISE, 2018b), therefore needs to increase by 295 TWh. In addition, older existing installations will retire. Deutsche WindGuard (2018) expect that this applies to around 16 GW of wind power capacity between 2020 and 2025 alone. We assume a lower bound of 8 GW of installations, formerly operating at 1000 full load hours, to retire by 2030. Thus, a total of 303 TWh of additional renewable energy generation is required.

We assume two-thirds of the new generation produced by wind power and one third from solar power. Of the total wind investment, we assume onshore wind power will represent three-quarters, mirroring the larger focus on onshore wind power than offshore wind power. We furthermore assume that ground-mounted PV makes up three-quarters of all PV deployment, with the remainder rooftop solar. However, as rooftop solar is financed against a combination of avoided retail tariffs and fixed feed-in tariffs, it is shielded wholesale power price developments, such thatwe do not account for it in the comparison.

4.2 Results

In the following, we present the results in terms of strike prices, levelized costs of electricity and overall annual costs of electricity from new renewable energy plants by 2030.

4.2.1 Solar power

Financing the investment costs of ground-mounted solar with secure revenue streams under contracts for difference yields levelized costs of electricity of around 41.2 Euro per MWh, as depicted in Figure 4. Investments taking place under sliding feed-in premia are riskier and thus require higher shares of equity, leading to increased levelized costs of electricity. While the strike price falls to 28.8 Euro per MWh, the overall costs increase to 46.1 Euro per MWh. Fixed premia increase the required expected total revenue to around 52.8 Euro per MWh, based on a strike price of only 11.7 Euro per MWh. In the absence of any remuneration mechanisms, required expected revenue are slightly higher yet at 53.6 Euro per MWh The difference in cost for consumers between fixed premium and the absence of support is low because technology costs of ground-mounted PV compared to its market value are so low that fixed premia provide little extra support and, consequently, also little revenue certainty.

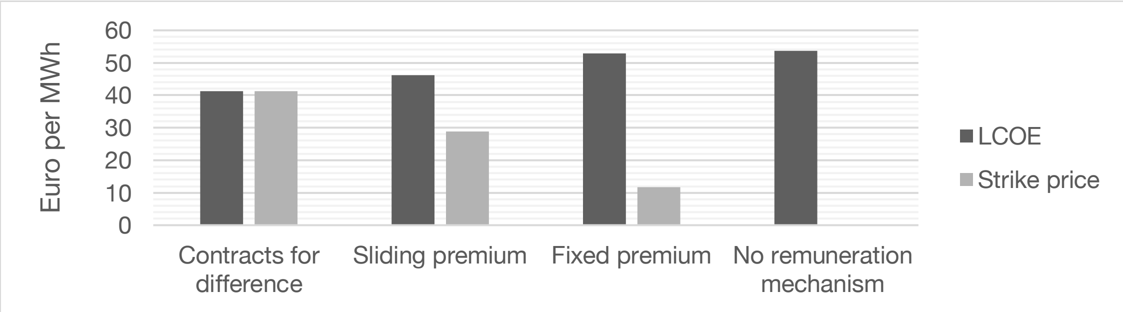

Figure 4: Levelized costs of electricity and strike prices of ground-mounted solar power

By 2030, the annual costs of the 75 TWh of new ground-mounted solar power differ by about 370 million Euro, as shown in Figure 5. Due to their higher costs per megawatt hour, fixed premia in total cost almost 900 million Euro more than contracts for difference. The absence of any remuneration mechanism is only barely more risky for investors, such that the overall cost premium is only 60 million Euro higher than under fixed premia, namely 935 million Euro.

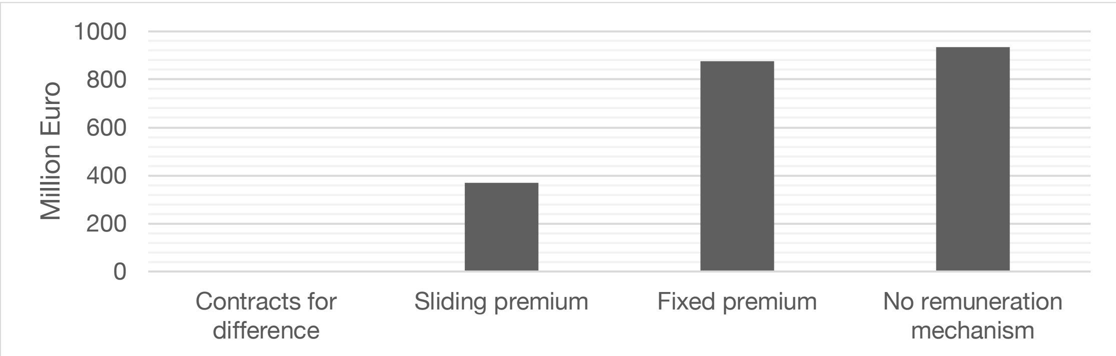

Figure 5: Overall annual cost differences of new solar power by 2030

4.2.2 Onshore wind power

Figure 6 shows the levelized costs of onshore wind power under the different remuneration mechanisms. Contracts for difference provide access to cheap capital for investors, rendering the strike price and the levelized costs of electricity rather low at 38.9 Euro per MWh. As the other mechanisms induce more revenue risks than contracts for difference, their costs lie higher. With sliding premia, investors bid lower strike prices at slightly more than 30 Euro per MWh, but levelized costs of electricity are seven percent higher at 41.7 Euro per MWh. Under fixed premia, strike prices are even lower at 16.7 Euro per MWh, but the LCOE is higher at 47.6 Euro per MWh, reflecting higher revenue risks. The absence of remuneration mechanisms yields rather similar outcomes at 49.1 Euro per MWh, indicating that under fixed premia, investors are exposed to a large part of the wholesale power price risk.

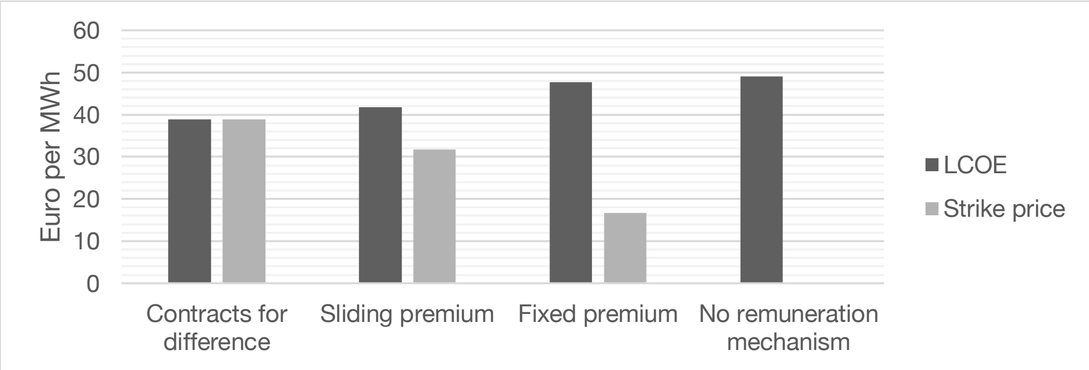

Figure 6: Levelized costs of electricity and strike prices of onshore wind power

Multiplying the levelized costs of electricity with the annual production of electricity from new onshore wind power plants by 2030, 151 TWh, returns the overall, annual costs in 2030. Figure 7 shows the resulting cost differences. Annual costs of onshore wind power under sliding premia lie almost 500 million Euro above the costs of contracts for difference. Fixed premia cost 1.3 billion Euro more than CfDs and the investments annually cost 1.5 billion Euro more if no remuneration mechanism is in place.

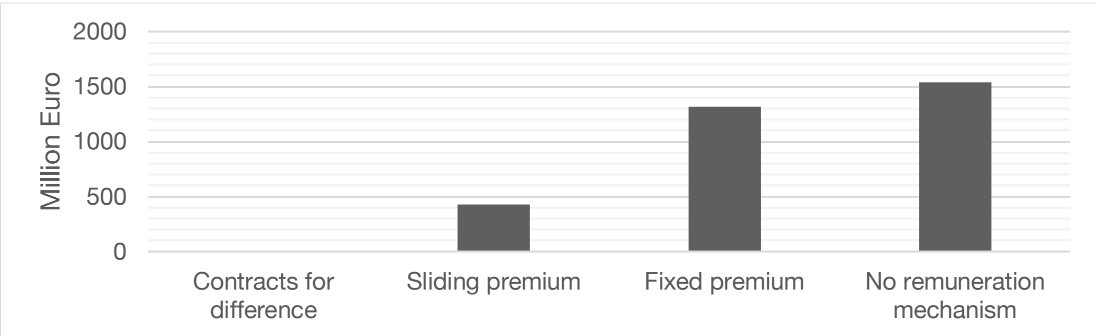

Figure 7: Overall annual cost differences of new onshore wind power by 2030

4.2.3 Offshore wind power

For offshore wind power, the annual costs by 2030 barely differ between contracts for differences and sliding feed-in premia in our calculation based on the used technology cost parametersThis is the case because even in the low-risk financing regime of contracts for difference, the costs are around 67.7 Euro per MWh (Figure 8) and thus considerably above the expected market value of offshore wind power 39.0 Euro per MWh. In such a scenario, a sliding premium still offers a similar insurance as contracts for difference, and therefore the required expected revenues are only slightly increased to 67.8 Euro per MWh. Only under fixed premia is there a cost increase to 77.3 Euro per MWh, based on a strike price of 43.7 Euro per MWh. The abolition of support policies would increase costs further to 88.2 Euro per MWh.

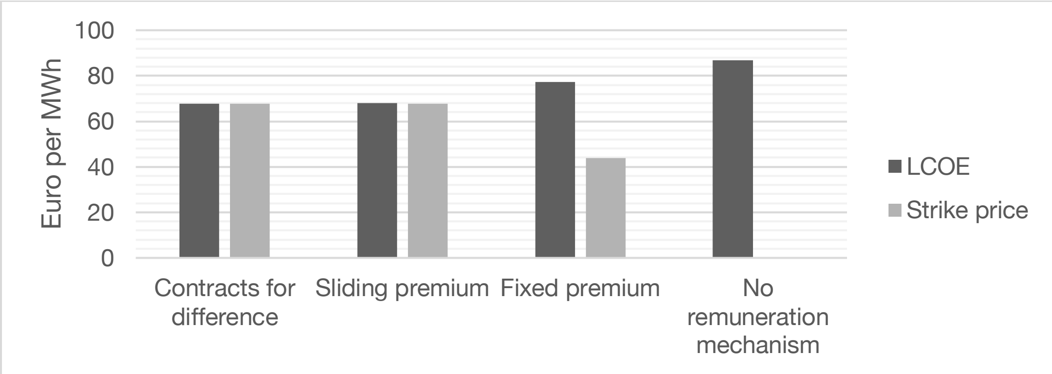

Figure 8: Levelized costs of electricity and strike prices of offshore wind power

Total annual costs of annually 50 TWh from new offshore wind power by 2030 under contracts for difference and under sliding premia are the same (Figure 9). Fixed premium are associated with an increase in annual costs by 477 million Euro, reflecting the higher risk exposure of investors. Without any remuneration mechanism, costs are even higher, totaling 950 million Euro annually more than contracts for difference or sliding premia.

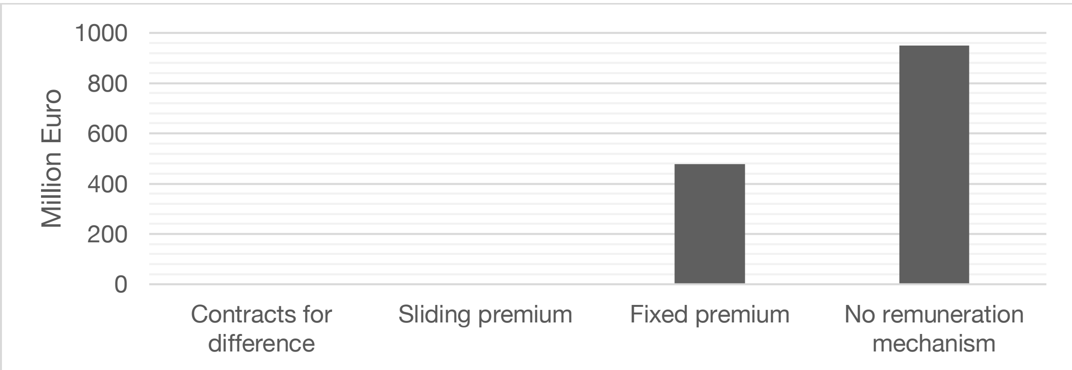

Figure 9: Overall annual cost differences of new offshore wind power by 2030

4.3 Overall cost differences

If investments into renewable energies are backed by contracts for difference rather than sliding premia, consumers can expect to save around 0.8 billion Euro per year by 2030, as shown in Figure 10. Fixed premia render the same investments 2.7 billion Euro more expensive than contracts for differences. Without support policies and if the investments were undertaken at all, which requires significantly higher power prices, the annual costs lie around 3.4 billion Euro higher than with secure remuneration schemes.

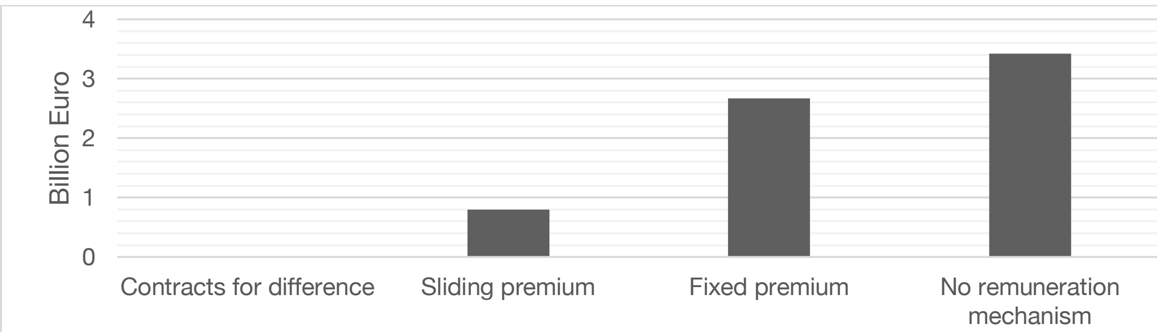

Figure 10: Differences in annual costs by 2030

4.4 Sensitivities

Decreasing all technology cost parameters by ten percent reduces all investment cost, annuities and thus on its own reduces the difference between remuneration mechanisms. However, also the power price risks under sliding premia plays a larger role. This effect dominates and therefore expected total cost to consumers increases to about 1.1 billion Euro compared to a scenario with contracts for difference (and decline correspondingly to 0.6 billion Euro with a 10% increase in technology costs)

Increased costs of equity from 7% to 9% – and thus a larger cost premium for equity compared to debt – have a weaker effect on the increased cost of sliding feed-in premia, but strongly affect fixed premia. The extra costs of sliding premia are 16 million Euro higher at 0.81 billion Euro. However, the extra costs of fixed premia increase more strongly to 3.2 billion Euro. In particular, also offshore wind power demonstrates a significant cost increase under fixed premia. Without support policies, costs lie somewhat higher by 3.6 billion Euro.

Equivalently, a lower equity premium does not strongly affect the differences between the policies. With equity costs of five percent, the additional costs of sliding premia fall by 13 percent to around 700 million Euro. The additional costs of a fixed premium also drop by eleven percent to 2.4 billion Euro. The extra costs of a scenario without any remuneration mechanism decline by four percent.

5 Conclusion

Recent years have seen rapid declines in renewable energy technology costs, with production costs rapidly approaching the marginal costs of thermal generation technologies and corresponding wholesale power market prices.

Through this cost decline, renewable energy policies are ever less required to provide additional funding to renewable energy projects. These can in principle fund a greater share of their revenues from electricity market revenues. In practice, the uncertainty about future power price developments is particularly difficult to manage for renewable project investors. In this paper, we explored the effect of falling technology costs on the ability of different renewable remuneration mechanisms to facilitate long-term hedging of market and regulatory risk, and thus allow for investments at low financing costs.

To do so, we model the financing structure of renewable energy investments analytically. Common one-sided sliding premia have historically been considered as low-risk for investors, as investors could and would always fall back on the option value. The analytical model shows that sliding premia, while historically a suitable hedging instrument, serve this function to a declining extent with falling technology costs. This is, because wholesale price levels are increasingly likely to exceed the strike price of sliding premia – and thus an increasing share of the revenue stream for project developers is linked to uncertain power prices. Financing costs increase, reducing the benefit of falling technology costs for consumers. Similarly, the risks of fixed premia also increase with lower technology costs, as unhedged electricity market revenue makes up a relatively larger share of investors' total revenues. In contrast, contracts for difference facilitate hedging at any technology cost level, facilitating lower-cost financing, and thus ensuring benefits of falling costs are fully passed to consumers.

In a numerical example based on 2030 target of 65% renewable electricity for Germany we find that compared to the sliding premium, contracts for difference are expected to save in the order of magnitude of 800 million euros annually by 2030. A fixed premium or abolishing remuneration mechanisms entirely, would, lead to an increase in total costs by 2.7 and 3.4 billion euros annually. This shows how the role of renewable energy policy shifts from a financial support to drive down technology cost, to a remuneration instrument that keeps financing costs low. It does so by facilitating long-term hedging and thus overcoming market failures constraining private long-term contracts.

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