Designing Subsidy Contracts for Renewables: An Incentive-Risk Trade-off
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Abstract

Support mechanisms for variable renewable electricity (VRE) projects that expose firms to market electricity prices raise a trade-off for the regulator: they provide incentives for investors to develop more valuable projects, but they increase the risk borne by these investors and induce larger risk premiums. A variety of contracts, often referred to as sliding feed-in premiums, attempt to preserve the former while mitigating the latter. We assess whether and which specific contract designs succeed in doing so through a quantification of both risk premiums and incentives provided to firms, in the context of the French power system. This quantification is based on power system modeling, which allows us to account for CO2 emissions displaced by each VRE project and to simulate projects' revenues in alternative scenarios to measure the risk. Findings show that sliding feed-in premiums mitigate the risk premiums while providing good incentives as long as they insure against the yearly average of electricity prices, and not over a shorter period. We also find that if VRE subsidies are motivated by CO2 displacement, premiums that are proportional to market prices will provide better incentives than fixed premiums per unit of electricity produced.

Keywords: renewable electricity; wind power; solar power; feed-in tariff; feed-in premium; risk premium; incentives; power system model
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1 Introduction

Since the 1990s, particularly in the European Union, generation-based subsidies in favor of variable renewable electricity (VRE), such as wind and solar power, have been a key policy instrument to foster their development (e.g. Ragwitz, Steinhilber, 2013). These subsidies were, at first, primarily motivated by the positive externalities of the learning-by-doing induced by the growth of VRE, and the primary concern of policymakers was their effectiveness in stimulating this growth. To this end, a widely adopted instrument has been to offer to buy the electricity production of all VRE producers at a fixed price, well above electricity market prices. These support mechanisms, referred to as administratively set feed-in tariffs,[1] guaranteed to VRE power plants sufficient income to make such investments attractive for private firms, especially since this income would depend only on the amount of electricity produced.

Although effective in promoting the development of VRE, these support mechanisms were later deemed inefficient. The rapid decline in wind and solar costs in the early 2010s made existing feed-in tariffs so attractive to private investors that they became financially unsustainable in several countries (Pyrgou et al., 2016), prompting a new goal for policymakers to minimize the public cost associated with VRE support schemes. One solution to this problem, widely adopted in Europe, has been to award subsidy contracts through competitive auctions in which only the firms requiring the lowest subsidies are supported. Thus, VRE developers indirectly disclose their costs and the regulator can limit the subsidy awarded to the minimum amount necessary to ensure the desired growth of VRE (Cantillon, 2015).[2]

Another area where the initial feed-in tariff system was found ineffective is the inappropriate incentive provided to developers and operators of VRE plants, namely an incentive to produce as much electricity as possible at the lowest cost. One blatant manifestation of this failure is the increasingly frequent appearance of negative prices in wholesale electricity markets, during which wind and solar plant operators were incentivized to continue production as it would increase revenues received under feed-in tariff support schemes (Brandstatt et al., 2011). These distorted incentives have been shown to result in welfare losses (Andor, Voss, 2016). Beyond dispatch decisions, feed-in tariffs also distort investors' decisions at the development stage, including location and technological choices (May, 2017; Newbery, 2023): they encourage to seek the highest expected production at the lowest cost, while the expected timing of this electricity production should also be taken into account. Such incentives could be justified in the early days of VRE

[1]The designation "feed-in tariff" has often been used ambiguously to refer both to the guarantee of having one's electricity purchased at a fixed price, and to the fact that this fixed price is set administratively by the government and can benefit any VRE project. In this paper, the expression "feed-in tariff" refers only to the former.

[2]In the European Union, the adoption of competitive auctions to award VRE subsidies was made mandatory for large scale projects by the State Aid Guidelines adopted in 2014 (European Commission, 2014).

development, since at that time most of the social benefits of wind and solar projects came from learning-by-doing effects, and assuming that these effects are proportional to the amount of electricity produced.[3] But the collapse of VRE costs has changed the situation, and the social benefits of a VRE project's electricity output itself (beyond the learning-by-doing) now covers most of its cost. Therefore, the social value of this output is much better captured by the (time-varying) market value of electricity (Joskow, 2011) complemented with the various externalities associated (Borenstein, 2012).

In consideration of these issues, many governments have moved away from feed-in tariffs towards systems that expose VRE producers to price signals from electricity wholesale markets. In particular, the European Union has advocated for subsidies in the form of premiums to be paid to VRE producers in addition to the income derived from the sale of their production in these markets (European Commission, 2014). These mechanisms, unlike feed-in tariffs, recognize that while some of the social benefits of VRE projects come from positive externalities (which subsidies attempt to address), a significant portion of those benefits are directly related to the market value of their electricity production.

However, support mechanisms that expose VRE developers and operators to price variations in wholesale electricity markets raise the issue of risk-sharing: as revenues from VRE plants are subject to additional risk from these price variations, it makes these investments less attractive to risk-averse firms. In practice, the exposure of VRE power plants to this price risk has been found to significantly increase the cost of capital for financing VRE projects: May and Neuhoff (2021) find that policy instrument choices can change the overall financing cost by about 4.8%, while Newbery (2016) estimates that the U.K.'s move from a tradable renewable quotas system to a feed-in tariff system[4] resulted in a reduction in the cost of capital of about 3%. As a consequence, the level of subsidy required to make investing in VRE attractive is lower when risk exposure is limited (Kitzing, 2014; Kitzing, Weber, 2014). In a context where subsidy levels are set through auctions, the public cost of supporting these investments could be mitigated through the use of mechanisms that transfer risk from private firms to the (risk-neutral) regulator (Engel et al., 2001).

Therefore, the regulator faces a trade-off when deciding whether or not (and to what extent) VRE producers should be exposed to electricity prices: exposing them provides an incentive to develop projects that bring greater social benefits, but it also increases the public cost of support through the risk premiums reflected in their bids. This trade-off appears to have been identified

[3] Instead, some have argued that these effect are proportional to installed capacity (Andor, Voss, 2016), but in practice subsidizing capacity has been found to encourage developers to build projects with high nameplate capacity but low production (Boute, 2012).

[4] The instrument implemented in the UK, called "contract for differences" is technically different from feed-in tariff systems but similarly ensures a fixed revenue per energy produced.

and addressed by regulators: many have adopted various hybrid contracts that partially expose VRE generators to electricity price variations, while insuring them against some components of these variations. Many of these mechanisms, generally grouped under the label of sliding feed-in premiums, expose VRE producers to short-term price changes but insure them against changes in the general price level over the long term (Klobasa et al., 2013). These mechanisms follow the guideline provided by Cantillon (2015) that investors should be exposed to risk over which they have some control (to preserve incentives) but not to risk over which they have no control (to mitigate the risk premiums). Through their location and technological choices, investors have some control over how the output of their plants will correlate with typical short-term patterns in electricity prices. On the contrary, it seems reasonable to assume that they would have no way to compensate for or anticipate and adapt to exogenous shocks that could affect the general level of electricity prices in the long run, such as changes in fossil fuel prices or political decisions.

In this paper, we provide a quantitative evaluation of the performance of various contract designs in both mitigating risk premiums and providing appropriate incentives to VRE developers, in order to help arbitrate the incentive-risk tradeoff in the regulator's choice of subsidy contract design. We consider a theoretical framework where a regulator wishes to maximize the social benefits of a VRE project built under a budget constraint, and we compare the social benefits obtained under a first best situation with a situation where the construction of the VRE project is delegated to a firm through subsidies awarded through an auction and a specific contract design. On the one hand, a contract design providing appropriate incentives will induce the firm to choose a project with a higher social benefits to cost ratio, thus contributing to the regulator's objective. On the other hand, a contract design involving a high risk for the winning firm will induce the firm to require a larger risk premium in the auction which will oblige to scale down the VRE project in order to remain within the budget constraint, thus having a detrimental impact for the regulator's objective.

Quantitative estimates of these two impacts of the choice of contract design are provided through a case study in the context of the French power system by considering a sample of real wind and solar projects. This quantitative assessment builds on a work presented in a companion paper to this one, in which the social benefits from the VRE projects in the sample were assessed through power system modeling counterfactual simulations (Leblanc, 2023). We include in the social benefits of VRE projects the production costs avoided to the power system while meeting demand, the social costs of CO2 emissions displaced by the projects that are not already captured in the generation costs (i.e., through the EU-ETS), and a fixed externality per energy output accounting for the project's contribution to reaching VRE development policy targets (following Meus et al., 2021). In our simulations, the total positive externalities attributed to the VRE projects represent about 50% of the market value of their output. To assess the risk borne by investors, we build a set of scenarios whose impact on the revenues of VRE projects is simulated through power system modeling, and in which we vary the price of gas and the cost of CO_2 emissions,[5] the pace of development of VRE in the French power mix, and the weather conditions.

The results confirm that fully exposing firms to electricity price variations via a fixed feed-in premium contract induces significant risk premiums (around 2% under our set of assumptions). These risk premiums could be almost fully erased by using a feed-in tariff contract design instead, but at the cost of potentially significant welfare losses resulting from inappropriate choices on the part of VRE developers (up to 4% in the worst case). Which of these losses actually predominates varies according to the assumptions considered. However, the results also show that almost all of the sliding feed-in premiums variants considered reduce risk premiums to levels comparable to those induced by a feed-in tariff, while some sliding feed-in premium specifications (but not all) keep the welfare loss from distortions to a minimum. In particular, it appears preferable to base sliding feed-in premiums on a reference price that is a yearly average, rather than an average on a shorter period of time (e.g. a monthly average), in order to preserve the incentives conveyed by the seasonality of electricity prices. The findings also suggest that multiplicative feed-in premiums, where the subsidy is not fixed but proportional to the market price at time of production, are more favorable to projects that displace large amounts of CO_2 emissions. If a simple multiplicative feed-in premium exacerbates the risk and the resulting risk premium, it can be effectively mitigated by an insurance mechanism similar to those of sliding feed-in premiums. Finally, we find that one-sided sliding feed-in premiums, where firms are not required to repay negative premiums in the event of high market prices, increase risk premiums while performing exactly the same as standard (two-sided) sliding feed-in premiums in terms of distortions.

Related Literature Several studies have provided quantitative assessments of the distortions induced by various contract designs, and their implications for location or technology choices for wind and solar plants (e.g. Schmidt et al., 2013; Hartner et al., 2015; May, 2017; Meus et al., 2021). All adopt a macro perspective in which they simulate, for a country or region, the entire wind or solar farm that is the best response to a specific contract design, while relying on arguable assumptions regarding the investment and operating costs for each technology (e.g., assuming homogeneous land cost). In contrast, this paper adopts a microeconomic perspective in which a firm selects a single wind or solar project based on the contract design it faces, considering the existing power system as an exogenous input to the evaluation. Moreover, we remain agnostic on capital and operating costs and provide an upper bound on the welfare loss induced by the distortions associated with each contract design.

[5] These risk scenarios are built from the perspective of the year 2019, and may appear conservative in the lights of the more recent developments on European electricity markets following the COVID-19 crisis and the Ukrainian crisis.

Another thread of literature has focused on the risk that these contracts induce for investors, and has provided quantitative estimates of the impacts on the cost of capital (Newbery, 2016; May, Neuhoff, 2021) or on the attractiveness of VRE investments under these contract design (Kitzing, 2014; Kitzing, Weber, 2014; Bunn, Yusupov, 2015). We take a different approach where we estimate the risk premiums that risk-averse firms demand through their bids in the context of an auction. Finally, this paper looks at the detailed specifications of subsidy contracts, e.g. the reference time-period considered for sliding feed-in premiums, which have received little attention to date.[6] Moreover, because this paper considers risk mitigation and incentives concerns together, it sheds a new light on public policy choices for VRE subsidies.

The remainder of the paper is organized as follows: Section 2 provides a theoretical framework to capture both the distortions and risk induced by contract designs, and their welfare implications. Section 3 provides an overview of the contract designs evaluated and their motivations. Section 4 details our methodology for providing a quantitative assessment of distortions and risk premiums. Section 5 reports the simulation results and compares the performance of various contract designs. Section 6 concludes.

2 Theoretical framework

Next, we delineate the welfare loss resulting from both the risk premiums and the distortions induced by using a specific contract design to support VRE power plant projects. We consider a regulator willing to subsidize a VRE project within a budget constraint, which we normalize to 1. The choice is to be made among a set of potential VRE projects Ω. Each potential project $\omega \in \Omega$ induces a cost $C(\omega) \in \mathbb{R}_+^*$ to be built. Once built, the electricity it produces generates social benefits $V(\omega, X)$, which depend on which project ω is built, but also on a random realization X which is unknown ex ante and captures, e.g., the weather conditions determining the projects production, or the demand for power determining the value of the electricity produced. Furthermore, we assume that the projects can be scaled up and down in order to meet the budget constraint: for a scalar $\lambda \in \mathbb{R}_+^*$ we say that the project $\lambda \cdot \omega$ has a cost $C(\lambda \cdot \omega) = \lambda C(\omega)$ and generates social benefits $V(\lambda \cdot \omega, X) = \lambda V(\omega, X)$. The regulator's objective to maximize the expected social benefits over $\omega \in \Omega$ and $\lambda \in \mathbb{R}_+^*$ under a unit budget constraint is thus written as follows:

$$\max_{(\lambda,\omega)} \mathbb{E}_X[V(\lambda\omega, X)] \quad s.t. \quad C(\lambda\omega) \leq 1 \tag{1}$$

[6] One exception is Anatolitis and Klobasa (2019) who consider, for an identical strike price, the impact of a yearly reference price versus a monthly reference price in terms of revenues for wind power plants.

In the first best solution, where we assume the regulator can directly choose the project, i.e. $\lambda\omega$ and cover for its cost $C(\lambda\omega)$, the optimal solution (ω^*, λ^*) consist in scaling the project up to the budget constraint $\lambda^* = \frac{1}{C(\omega^*)}$, and selecting a project with a maximum expected value to cost ratio: $\omega^* \in \operatorname{Arg\,max}_{\omega\in\Omega} \frac{\mathbb{E}_X[V(\omega,X)]}{C(\omega)}$.

We compare this first best benchmark to a practical implementation where the choice, building and operation of the VRE project is delegated to a private firm through subsidies awarded through an auction. We consider that several candidate firms participate in the auction, each submitting a bid δ and the firm placing the lowest bid is awarded a subsidy depending on this bid. After being selected, the winning firm chooses and declares its project ω,[7] and then benefit from payments $R(\omega, X; \delta)$ where R denote the contract design (known before the auction) which takes a parameter δ, the winning bid.[8] For simplification we assume the payment $R(\omega, X; \delta)$ constitutes the whole revenues of the firm and is entirely paid by the regulator,[9] with for any project $\omega \in \Omega$ and any realization of X, $R(\omega, X; \delta)$ strictly positive, continuous and (weakly) increasing with the firm's bid δ, and with $\lim_{\delta\to+\infty} R(\omega, X; \delta) = +\infty$ and $\lim_{\delta\to-\infty} R(\omega, X; \delta) = 0$.

After getting knowledge of the winning firm's project, the regulator adjust the project's scale by λ_R in order for the expected payment made to firm to meet the unit budget constraint: $\lambda_R = \frac{1}{\mathbb{E}_X[R(\omega,X;\delta)]}$. This feature of the model is intended to account for an overall long-term budget constraint for VRE grants, with many VRE candidate projects being subsidized and the budget constraint being exhausted in proportion to the expected subsidy paid to all selected projects. The study of a single selected project and a unitary budget constraint should be viewed as a way to study a marginal expansion of the overall VRE subsidy budget.

We consider that the firms competing in the auction are symmetric in the set of projects from which they choose Ω, in their cost to build each project $C(\omega)$ and in their utility function $U(\cdot)$. This utility function is assumed continuous, strictly increasing and concave on $\mathbb{R}_+^*$. For a contract design R, a bid δ and a selected project $\omega \in \Omega$ we denote the expected profit of a firm conditional on winning $\pi_R(\omega, \delta) = \mathbb{E}_X[U(R(\lambda \cdot \omega, X; \delta))] - U(C(\lambda \cdot \omega))$. Anticipating that the scaling factor

[7] In practice, the firms are generally asked to declare their project before the auction is held and can marginally adjust it afterwards. This does not affect our model, the only constraint being that regulator must know the project after the auction is held and be able to adjust the scale factor accordingly.

[8] The payment depends indirectly on the chosen project ω and the realization of X (typically through the quantity of electricity produced and electricity market prices). We write the payment as a direct function of ω only to avoid cluttering up the notations.

[9] In practice many contract designs imply that part of the firm's revenues comes from selling their electricity production on wholesale electricity markets instead of being bought by the government. We abstract from such consideration and model these revenues as a direct payment by the regulator instead, considering it does not have an impact on firms' incentive and risk exposure, and that electricity being bought by the regulator or by the consumer is neutral in terms of welfare.

will be adjusted to meet the budget constraint, this ex post profit is rewritten:

$$\pi_R(\omega,\delta) = \mathbb{E}_X\left[U\left(\frac{R(\omega,X;\delta)}{\mathbb{E}_X[R(\omega,X;\delta)]}\right)\right] - U\left(\frac{C(\omega)}{\mathbb{E}_X[R(\omega,X;\delta)]}\right) \tag{2}$$

For a given winning bid δ, the firm will choose to build a project belonging to the set $\Omega_R(\delta) = \operatorname{Arg\,max}_{\omega\in\Omega}\pi_R(\omega,\delta)$. Thus we denote $\pi_R(\delta) \equiv \max_{\omega\in\Omega}\pi_R(\omega,\delta)$ the firm's expected payoff conditional on winning with bid δ. All firms being symmetric, Bertrand competition leads to an auction outcome characterized by an equilibrium bid $\delta_R = \min\{\delta \in \mathbb{R}_+ \mid \pi_R(\delta) \geq 0\}$. From the continuity of U over $\mathbb{R}_+^*$ and the continuity of $R(\omega,X;\delta)$ in δ for any project $\omega \in \Omega$ and any realization of X, we get that $\pi_R(\omega,\delta)$ is continuous in δ. Moreover from the concavity of U we get that $\mathbb{E}_X\left[U\left(\frac{R(\omega,X;\delta)}{\mathbb{E}_X[R(\omega,X;\delta)]}\right)\right] < U(1)$, thus the payoff $\pi_R(\omega,\delta)$ is negative for any bid such that $C(\omega) > \mathbb{E}_X[R(\omega,X;\delta)]$, which we know exists since $R(\omega,X;\delta)$ is continuous and $\lim_{\delta\to-\infty} R(\omega,X;\delta) = 0$. Therefore, we only need to assume that Ω is such that at least one project ω is profitable with a winning bid sufficiently high to ensure that the equilibrium bid δ_R exists and satisfies the zero-profit condition $\pi_R(\delta_R) = 0$.

Assuming the latter and relying on the assumption that U is strictly increasing and admits an inverse function, we can derive the following equation which indirectly captures the risk premium:

$$\frac{C(\omega_R)}{\mathbb{E}_X[R(\omega_R,X;\delta_R)]} = U^{-1}\left(\mathbb{E}_X\left[U\left(\frac{R(\omega_R,X;\delta_R)}{\mathbb{E}_X[R(\omega_R,X;\delta_R)]}\right)\right]\right) \tag{3}$$

Note that the right hand term in (3) is equal to 1 if the firms are risk neutral (if U is linear) but inferior to 1 if the firms are risk-averse (if U is concave). We further refer to the excess expected payment as compared to the project's cost as the risk premium, which we denote $\mu_{R,\delta}(\omega)$, defined by $C(\omega_R) = (1-\mu_{R,\delta}(\omega))\mathbb{E}_X[R(\omega_R,X;\delta_R)]$. From (3) we obtain the direct expression of this risk premium, reported in (4).

$$\mu_{R,\delta}(\omega) \equiv 1 - U^{-1}\left(\mathbb{E}_X\left[U\left(\frac{R(\omega,X;\delta)}{\mathbb{E}_X[R(\omega,X;\delta)]}\right)\right]\right) \tag{4}$$

Whereas the scaling factor in the first best situation was $\lambda^* = \frac{1}{C(\omega^*)}$, in the auction outcome we obtain from (3) that the scaling factor is $\lambda_R = (1-\mu_{R,\delta}(\omega))\frac{1}{C(\omega_R)}$: the risk premium required by the firm impose that a smaller project is built in order to meet the budget constraint.

Next, we compare the social benefits obtained in the first best situation, which we denote $W^* \equiv \mathbb{E}_X[V(\lambda^*\cdot\omega^*,X)]$, with the social benefits from the project built with the same budget constraint through the subsidy mechanism using a contract design R, $W_R \equiv \mathbb{E}_X[V(\lambda_R\cdot\omega_R,X)]$.

From the above expressions of the scaling factors we first note that:

$$\frac{W_R}{W^*} = (1 - \mu_{R,\delta_R}(\omega_R)) \frac{\mathbb{E}_X[V(\omega_R, X)]/C(\omega_R)}{\mathbb{E}_X[V(\omega^*, X)]/C(\omega^*)} \tag{5}$$

We directly observe two sources of welfare loss as compared to the first best situation: the risk premium required by risk-averse firms induce a welfare loss $\mu_{R,\delta}(\omega)$, and the distortion inducing a sub-optimal project choice which cause a welfare loss $\left(1 - \frac{\mathbb{E}_X[V(\omega_R,X)]/C(\omega_R)}{\mathbb{E}_X[V(\omega^*,X)]/C(\omega^*)}\right)$.

Next, we characterize these welfare loss as depicted in (5) while assuming that we observe the selected project ω_R, the bid δ_R and the social benefits $V(\omega, X)$ and payments $R(\omega, X; \delta)$ associated with each project $\omega \in \Omega$.[10] On the contrary, we consider that we do not know the costs of the projects $C(\omega)$, and therefore that we cannot infer the first best project ω^*. With the available information we can directly derive the risk premium $\mu_{R,\delta_R}(\omega_R)$, but not the term capturing the welfare loss resulting from a sub-optimal choice of project. However we can rely on an observable measure of the distortion induced by the contract design R between two projects to infer an upper bound on this latter component of the welfare loss.

To describe the distortions resulting from each contract design, let us introduce $\chi_{R,\delta}(\omega, \omega')$ the distortion-induced advantage for project ω relative to project ω' under a contract design R with a bid δ:

$$\chi_{R,\delta}(\omega, \omega') \equiv \frac{\mathbb{E}_X[R(\omega, X; \delta)]/\mathbb{E}_X[V(\omega, X)] - \mathbb{E}_X[R(\omega', X; \delta)]/\mathbb{E}_X[V(\omega', X)]}{\mathbb{E}_X[R(\omega, X; \delta)]/\mathbb{E}_X[V(\omega, X)]} \tag{6}$$

If $\chi_{R,\delta}(\omega, \omega') > 0$ (resp. < 0), the contract design R with bid δ induce a distortion in favor of ω relative to ω' (resp. in favor of ω' relative to ω). In addition, let us denote $\overline{\chi}_{R,\delta}(\omega)$ the maximum distortion-induced advantage for project ω over Ω: $\overline{\chi}_{R,\delta}(\omega) \equiv \max_{\omega' \in \Omega} \chi_{R,\delta}(\omega, \omega')$. In the following proposition, we use this measure to place an upper bound on the welfare loss due to a sub-optimal choice of project when firms are risk neutral.

Proposition 1. [11] *If firms are risk neutral, for a contract design R and an equilibrium bid δ_R, the welfare loss induced by the sub-optimal project choice ω_R in comparison to the first best project ω^* admits as upper bound the maximum distortion-induced advantage of ω_R:*

$$1 - \frac{\mathbb{E}_X[V(\omega_R, X)]/C(\omega_R)}{\mathbb{E}_X[V(\omega^*, X)]/C(\omega^*)} \leq \overline{\chi}_{R,\delta_R}(\omega_R) \tag{7}$$

Proof The projects built by the firm ω_R induce a larger expected payment to cost ratio than

[10] In the remainder of the paper we will consider as ω_R all projects within a sample of actual projects $\hat{\Omega}$, for which we estimate social benefits and revenues conditional on an assumed bid δ_R.

[11] Proposition 1 derives from the notion of providing marginal rewards *within* ϵ proposed by Hatfield et al. (2018), in which a contract is said to provide marginal rewards within ϵ if, for all pairs of projects, $|\chi_{R,\delta}(\omega, \omega')| < \epsilon$.

any other project, and in particular than the first best project: $\frac{\mathbb{E}_X[R(\omega_R,X;\delta_R)]}{C(\omega_R)} \geq \frac{\mathbb{E}_X[R(\omega^*,X;\delta_R)]}{C(\omega^*)}$. Multiplying this inequality by $\mathbb{E}_X[V(\omega_R,X)]\cdot C(\omega^*)/(\mathbb{E}_X[V(\omega^*,X)]\cdot\mathbb{E}_X[R(\omega_R,X;\delta_R)])$, we obtain that $\frac{\mathbb{E}_X[V(\omega_R,X)]/C(\omega_R)}{\mathbb{E}_X[V(\omega^*,X)]/C(\omega^*)} \geq 1-\chi_{R,\delta}(\omega^*,\omega_R)$. Therefore $1-\frac{\mathbb{E}_X[V(\omega_R,X)]/C(\omega_R)}{\mathbb{E}_X[V(\omega^*,X)]/C(\omega^*)} \leq \chi_{R,\delta}(\omega^*,\omega_R) \leq \overline{\chi}_{R,\delta}(\omega_R)$. **Q.E.D.**

With the additional assumption that risk aversion does not affect the choice of project by the firm, i.e. that $\Omega_R(\delta_R)$ is the same regardless of firms' risk aversion, the result from Proposition 1 can be extended to the case when firms are risk averse.[12] This assumption evacuates the possibility that risk-averse firms might be reluctant to choose projects putting a high risk on the resulting payment. The effect of this reluctance on the welfare W_R could be two-folds: firms valuing risky projects less than the expected revenue associated creates an additional distortion possibly inducing a welfare loss. On the other hand, the firm choosing less risky projects reduces its risk premium which allows for a larger scaling of the project within the budget constraint. In both cases we conjecture these are second order effects and choose to neglect them. In the remainder of the paper, we consider the inequality in (8) and provide a quantitative evaluation of the right-hand side through simulations.

$$\frac{W_R}{W^*} = (1-\mu_{R,\delta_R}(\omega_R))\frac{\mathbb{E}_X[V(\omega_R,X)]/C(\omega_R)}{\mathbb{E}_X[V(\omega^*,X)]/C(\omega^*)} \geq (1-\mu_{R,\delta_R}(\omega_R))(1-\overline{\chi}_{R,\delta_R}(\omega_R)) \tag{8}$$

3 Subsidy Contracts

As highlighted in section 2, the distortion-induced maximum welfare loss depends on the extent in which the expected payment received for a VRE project deviates from the social benefits of that project. The appropriateness of the incentives provided by a contract design is assessed against some measure of the social benefits of VRE projects. These social benefits include the avoided cost to the system of generating the necessary electricity by other means, which is fairly well approximated by the market value of the electricity produced (Leblanc, 2023). In addition, these social benefits include some positive externalities attributed to the addition of VRE electricity to the power system, which constitute a justification for subsidizing it. However, which externalities to consider as justification for VRE subsidies and how to measure them is a matter of debate in the literature.

One is the emissions of pollutants (including GHG) by alternative sources of electricity that are avoided thanks to additional VRE production: where the social costs of these emissions is not (fully) internalized by other policy instruments, VRE subsidies can be regarded as a second

[12]This additional assumption could be justified if we assume that differences in risk premiums depending on the selected project are negligible: assuming that $\forall(\omega,\omega')\in\Omega^2, \mu_R(\omega,\delta)=\mu_R(\omega',\delta)$, Proposition 1 is extended to any of the utility functions considered above.

best option to address this market failure (Abrell et al., 2019; Cullen, 2013). Considering this externality, a subsidy mechanism providing marginal rewards, without distortions, would be one that grants a subsidy equivalent to the social cost of the (expected) emissions avoided thanks to the VRE project. In the companion paper to this one, we have found this externality to be approximately proportional to the market value of the project's output (Leblanc, 2023). A second major justification for VRE subsidies is the learning-by-doing positive externality associated with their development. Then the precise source of this externality should determine the shape of the subsidies aimed at internalizing it: some have advocated in favor of subsidies based on capacity rather than production considering the learning-by-doing does not result from electricity generation per se (Andor, Voss, 2016; Newbery, 2018). However, subsidizing capacity creates an incentive for firms to maximize nameplate capacity at the lowest cost, resulting in the construction of low output projects (Boute, 2012) whose benefits in terms of learning-by-doing are arguable. We may argue on the contrary that learning-by-doing externalities result from building the most (socially) valuable projects, and thus are proportional to the other components of the social benefits from VRE projects. A third justification for VRE subsidies, proposed by Meus et al. (2021), is to note that, from the government's perspective, the additional renewable energy injected into the power system contributes to the achievement of eventual policy targets for the share of renewable energy in the energy mix. This applies in particular to all EU member states, which have such targets set at the European level. From a cost-effectiveness perspective, a constraint set on a minimum amount of renewable energy to be achieved implies a positive externality that is directly proportional to the amount of energy produced by a VRE project.

Therefore, a contract design that limits distortions (and thus the welfare loss associated) to a minimum is one in which the firm's revenue depends on the expected market value of its project's output and on the positive externalities associated, where these externalities may be proportional to the installed capacity, to the amount of energy produced or to the market value of the latter, depending on the assumptions made. However, limiting these distortions may come at the price of a greater risk for the firm. Next, we review several existing (generation-based) contract designs, and comment on the distortions and risk-exposure induced by each design. As in the previous framework, for each contract the payment received by a firm will depend on their bid δ, and (indirectly) on the RES-E project built ω and a random component accounting in particular for weather and electricity market conditions X. However, we focus on designs in which ω and X will determine the firms' revenue through two components only: the amount of electricity produced in each time period $\boldsymbol{q} = (q_t)_{t\in T}$ and the electricity prices in these same time-periods $\boldsymbol{p} = (p_t)_{t\in T}$. Thus, to avoid cluttering up the notations, we denote $R(\boldsymbol{q}, \boldsymbol{p}; \delta)$ the total revenue of the subsidized project over its lifetime for each contract design R. We also omit discounting for the same reason.

3.1 Feed-in tariffs and feed-in premiums: two polar cases

Feed-in tariff contracts guarantee to the firm that its power output is entirely purchased by the regulator at a fixed price δ, so that the revenue of the firm does not depend on electricity prices:

$$R_{FiT}(\boldsymbol{q}, \boldsymbol{p}; \delta) = \sum_{t \in T} \delta \cdot q_t$$

Contracts for differences, even though slightly different in their practical implementation, result in the same revenue for the firm.[13] Since the firms' revenue does not depend on electricity prices, the risk borne by the firm is limited to weather-related variations in its plant output, which is likely to result in limited risk premiums. However, a consequence from insulating the firm against price variations is that its profit maximizing choice of project will be in favor of projects maximizing the output to cost ratio ($\Omega^{FiT}(\delta) = \text{Arg}\max_{\omega \in \Omega} \sum_{t \in T} q_t - C(\omega)$), while ignoring the market value of its output.[14] Besides, another undesirable property of FiT contract design is that, during the operating phase, firms have an incentive to produce as much as possible regardless of the electricity price, thus even when electricity prices are negative.

Another form of simple contract, which could be considered as the polar case of feed-in tariff contracts, is the (fixed) feed-in premium contract. Under such contract, the firm's revenue is the sum of the revenues from selling electricity at its market price, and a fixed premium δ for each unit of energy produced:

$$R_{FiP}(\boldsymbol{q}, \boldsymbol{p}; \delta) = \sum_{t \in T} (p_t + \delta) \cdot q_t$$

Feed-in premiums fully expose the firm's revenue to variations in electricity prices, in the sense that any change in price $\boldsymbol{p}$ will cause a change in the firm's revenue.[15] The firm is thus exposed to an additional risk related to electricity prices which should increase the risk premiums. But this exposure to market prices also induces the firm to account for the market value of a project's output, thus limiting the distortion-induced welfare loss. However, since a fixed premium is granted for each unit of energy produced, this contract design still amplifies the value of projects whose total production is large (as compared to a firm that would only sell its production on electricity markets). This feature can be viewed as a remaining distortion induced by the contract, except if we consider that the premium δ internalizes a fixed positive externality per energy output, e.g. the contribution to the achievement of a target renewable energy share in the mix.

[13] The main difference is that a firm holding a Contract-for-Difference is still in charge of selling its production on the market but is then compensated for the difference between market prices and the fixed price stated in the contract.

[14] In other words, such mechanisms will induce firms to choose projects with the lowest LCOE (Levelized Cost of Electricity), even though this measure was deemed as inadequate for variable sources of electricity (Joskow, 2011).

[15] An exception would be price variations that only affect time-periods in which the production q_t is null.

As previously discussed, we may assume on the contrary that the positive externality to be internalized is proportional to the market value rather than to the amount of energy (e.g. as an approximation of the CO_2 emissions displaced). In such a case, a variant of this contract design, further referred to as multiplicative feed-in premiums, may appear more appropriate. In this contract design, δ denotes a percentage of the market price granted as a subsidy to the firm.[16]

$$R_{mFiP}(\boldsymbol{q}, \boldsymbol{p}; \delta) = \sum_{t \in T} (1 + \delta) \cdot p_t \cdot q_t$$

In contrast to feed-in tariffs or standard feed-in premiums, this contract does not create an incentive for the firm to overvalue projects with a greater production: it simply amplifies the market value of each project's output relative to its costs. Note that, ignoring discounting, a multiplicative feed-in premium contract with a premium δ is equivalent in terms of incentives to an investment subsidy where firms are reimbursed for a share $\frac{\delta}{1+\delta}$ of their costs, such as that advocated by Meus et al. (2021): $\Omega^{mFiP}(\delta) = \operatorname{Arg\,max}_{\omega \in \Omega} (1 + \delta) \sum_{t \in T} p_t q_t - C(\omega) = \operatorname{Arg\,max}_{\omega \in \Omega} \sum_{t \in T} p_t q_t - (1 - \frac{\delta}{1+\delta}) C(\omega)$. A drawback of multiplicative feed-in premiums, which may explain that they have not been implemented in practice, is that they further amplify the risk associated with electricity price variations. Thus it is expected that the associated risk premium would be increased as compared to standard feed-in premiums (which are themselves regarded as risky contracts).

Finally, it should be noted that standard feed-in premiums do not fully overcome the undesirable property of feed-in tariffs in the operational phase, namely that firms have an incentive to produce even when prices are negative. Indeed, with an additive premium δ firms are better off producing as long as the electricity price $p_t > -\delta$.[17] In contrast, multiplicative feed-in premiums do not suffer from this disadvantage since the marginal revenue from production becomes negative (or zero) as soon as prices do so.

3.2 Sliding feed-in premiums: a great variety of intermediary designs

Sliding feed-in premiums are similar to fixed feed-in premiums in that they expose the firm to the variability of electricity prices, but they differ in that they provide insurance against changes in the average price over contractually defined time slices (e.g., years, months, days). As with feed-in premiums, the firm is free to sell its output on the market, and receives a subsidy in addition. The latter is determined as the difference between a strike price δ defined ex ante and the observed

[16] Note that in both cases, the contract provides marginal rewards to the firm only if δ is exactly equal to the positive externality. Considering that in practice δ is set through the firms' bids in the tender procedure, there is no reason to believe this would be the case.

[17] In practice, recent subsidy contracts usually include specific clauses for negative wholesale market prices, so that companies have no incentive to produce during these periods.

average price $\bar{p}_S$ over each time slice $S \in \mathcal{S}$, and is paid for each unit of electricity generated during this period. Therefore, the revenue of the firm is expressed as below.

$$R_{sFiP}(\boldsymbol{q}, \boldsymbol{p}; \delta) = \sum_{S \in \mathcal{S}} \sum_{t \in S} (p_t + [\delta - \bar{p}_S]) \cdot q_t$$

Firms facing such contracts are therefore insured against variations in the average prices $\bar{p}_S$ but exposed to price variations within each in time slice S. The strength of these contracts is that they pass on to the firm the incentives conveyed by short-term price variations that can impact the firm's investment choice, such as seasonal or daily patterns or weather-related variations. Conversely, companies are not exposed to longer-term variations that are generally determined by factors that are difficult to predict and are not relevant to investment choices, such as fuel prices.

Beyond the general expression above, this class of contracts actually covers a great variability of implementation observed in practice. One dimension in which implementation may differ is the time slice division $\mathcal{S}$ over which the average price is computed (e.g. yearly, monthly, daily). A shorter period of time is expected to imply a lower risk for the firm, but it also removes some of the incentives: for instance, a yearly sliding Feed-in Premium will favor technologies producing the most in the season when prices are higher, while a monthly sliding Feed-in Premium will not.[18] Another aspect in which contract designs may differ within this class is the weights used to compute the average price $\bar{p}_S$. The most common practice observed in the EU is to use as weights the total production of the considered technology in the country. Such contracts thus do not exactly insure against the average price, but against the average market value of solar/wind power over each time-span. Alternative practices have also been observed or could be considered, such as using a load-weighted average price or a simple unweighted average.[19]

The above expression of the firm's revenue describes the case of symmetric sliding feed-in premium contracts, in which, if the average price over a period is above the strike-price δ, firms are required to pay back the difference to the regulator . In some cases (e.g. for most VRE subsidy mechanisms in Germany), firms are not required to pay such a negative premium. These contracts, generally called one-sided sliding feed-in premium, induce a greater variation in the firm's revenue and thus may be considered riskier.

As with previous designs, sliding feed-in premium contracts also occasionally induce adverse incentives in the operation phase of the power plant. As can be noted from the expression of the firm's revenue, under such contracts it is beneficial to produce in a given time period t as long as $\bar{p}_S - p_t < \delta$. Therefore there is no guarantee that the firm will prefer to produce if and only if

[18] See Huntington et al. (2017) for an illustration of the implications of the time-span choice.

[19] The "reference plant mechanism" advocated by Huntington et al. (2017) may also be interpreted as a sliding feed-in premium contract where the weights used to compute average prices are based on the production of a theoretical "reference plant".

the price p_t is positive: it may occur that firms have an incentive to produce even though prices are negative and, more surprisingly, that firms have no incentive to produce even though prices remain positive.[20] As before, a multiplicative variation of the contract design is not subject to such issues: if the firm is paid a premium expressed as a share of the market value of its output, it is beneficial to produce if and only if prices are positive. Even though we have no knowledge of any government using such a scheme, it could be defined with the revenue expression below.

$$R_{msFiP}(\boldsymbol{q}, \boldsymbol{p}; \delta) = \sum_{S \in \mathcal{S}} \sum_{t \in S} \left(\frac{\delta}{\bar{p}_S} \right) \cdot p_t \cdot q_t$$

Similarly, as with a standard sliding feed-in premium, the firm would receive a larger premium if the average price over each period is lower than the strike price, which would provide some insurance against long term price variations. However, the incentives conveyed by the short-term price variations would still be passed on the firms, and further amplified by the premium. In contrast with the multiplicative feed-in premium presented above, the implications of such contracts in terms of risk borne by the firm are unclear. These are left as an empirical question dealt with in the following.

4 Quantitative Assessment Strategy

Next we compare the various contract designs discussed in section 3 through a quantitative assessment of their welfare implications, decomposed into a risk premium and distortions-induced welfare loss as in (8). This assessment is based on a case study on a sample of wind and solar projects in France, building upon the work presented in Leblanc (2023). In the following, we first provide some further context for the case study on which we rely, before detailing the methodology employed to assess both the distortions and the risk premiums induced by each contract design.

4.1 A case study on wind and solar projects in France

In 2019, our reference year, the French power system is dominated by nuclear power (70.6% of energy production), hydro power (11.2%) and natural gas (7.2%). Even though representing a small share of the total energy production, natural gas is still very often the marginal technology and constitutes the price-setting technology in most time-periods. The share of VRE in the mix has reached 6.3% for wind power and 2.2% for solar power in 2019, and is rapidly growing. However, since this share still remains limited at that time, the market value of these technologies still is

[20] The latter may occur if large variations are observed during a time-period S, namely if the price briefly drops much below the average (but not necessarily below zero).

only moderately affected by the cannibalization effect.[21] On the demand side, the widespread use of electric heating induces a strong seasonality in electricity prices, with higher prices in the winter. This seasonality increases the market value of wind power (whose production is greater in the winter) and compensates, in the comparison between wind and solar, the effect of prices being higher during the day than at night, which benefits solar power. Thus, the average market value of solar energy and wind energy are of the same order of magnitude in France (Leblanc, 2023).

In this context, we consider a sample of potential wind and solar projects $\hat{\Omega}$ that the firm could choose to build. This sample, which is the same as the one considered in Leblanc (2023),[22] is made of 93 projects (43 wind projects and 50 solar projects) spread in mainland France and which differ in capacity and in several technological characteristics (hub height and turbine model for wind projects, panel orientation and presence of trackers for solar projects). These projects are based on actual projects that were built or under consideration in France, in order to reflect likely options that could reasonably be considered by investors.[23] Doing so ensures that our empirical equivalent of Ω does not amplify nor downplay the upper bound we estimate on the welfare loss: these projects having been actually considered by investors ensures that they could possibly constitute the most profitable option within a set of projects (i.e. belong to $\Omega^R(\delta)$), while considering a random set of such projects allows to capture some variability within this class. In particular, we attempt to capture the variability in projects' characteristics that could be explained by heterogeneity in costs, but would be missed if selecting projects focusing only on the amount of electricity produced (or its market value). For instance, in many solar projects, the panels are set back-to-back facing east and west, which should appear as a sub-optimal option compared to southward facing panels when considering only the energy output and its market value (Hartner et al., 2015), but can be explained by the land saved by this panel layout and the cost savings associated. Basing our quantitative approach on a sample of actual projects allows us to capture this heterogeneity, which is ignored when a homogeneous cost per capacity is assumed for each technology. However, a limitation to this argument must be acknowledged in the fact that the wind and solar projects in the sample were all actually considered by investors within a time period in which a single contract design was used by the regulator in France: we cannot rule out the possibility that a different contract design could have induced firms to consider very different projects, which would not be represented in this sample.

[21]The cannibalization effect refers to the deflating effect that additional VRE capacity has on electricity market prices, which is particularly strong in periods when the resource (wind, solar) is widely available, which particularly hurts the market value of these technologies.

[22]Offshore wind projects that were considered in Leblanc (2023) have been removed from the sample, since these projects typically do not participate in the same auctions for VRE subsidies as onshore wind projects.

[23]These projects were identified through the published lists of projects awarded a subsidy contracts in each auction round, and selected when the necessary information could be found in publicly available documents (such as mandatory impact assessment studies).

Based on projects' characteristics, their electricity output is simulated at an hourly time-step using historic weather data from 2016-2019 and a model developed by Staffel and Pfenninger (2016). These electricity production time-series are then used to derive the costs avoided for the power system thanks to this output, and the revenues it generates under the various subsidy contracts. We do so using a numerical model of the power dispatch in France and neighboring countries. This model, EOLES-Dispatch, simulates the cost-minimizing dispatch that meets an exogenous hourly demand for electricity considering an exogenous set of installed capacity in each generation technology. Its outputs include the total cost of meeting demand for electricity and the marginal cost of the system in each hour, which are simulated considering several inputs including scenarios regarding the capacity installed in each technology or the costs of fuels. The marginal cost of the system in each hour is interpreted as the electricity market price, and used as such to compute the firm's revenues under contract designs making these revenues depend on the market price. Market prices being considered equal to the marginal cost of the system implicitly rely on the assumption of perfect competition on electricity wholesale markets. But beyond this arguable assumption, EOLES-Dispatch marginal costs are found to reproduce quite well the observed electricity market prices in our reference year both in terms of mean (39.37 EUR/MWh in simulations, 39.45 EUR/MWh for actual prices) and standard deviation (13.52 EUR/MWh in simulations, 14.02 EUR/MWh for actual prices). Furthermore, it is confirmed in Leblanc (2023) that the model, and the marginal costs it simulates, perform well at reproducing the value of wind and solar projects' outputs evaluated through observed market prices. More details about the EOLES-Dispatch model are provided in Leblanc (2023).

4.2 Distortion assessment

First we estimate the distortions induced by each contract design on our sample of projects. We use the measure of the maximum distortion-induced advantage for project ω, $\overline{\chi}_{R,\delta}(\omega)$ introduced in section 2, for which we propose an empirical equivalent for each project $\omega \in \hat{\Omega}$ (with $\hat{\Omega}$ the sample of wind and solar projects described in the previous section). We consider both the social benefits $V(\omega, X)$ and the revenue $R(\omega, X; \delta_R)$ over one year, and consider as expected value the average of the four years available in our data (2016-2019).

The social benefits of the projects are based on those presented in Leblanc (2023), which are assessed through counterfactual simulations of the power dispatch, with and without the project's output being available to meet electricity demand. We further consider two benchmarks for the social benefits of each project. In the first one, we take the costs avoided for the power system to meet electricity demand in a baseline scenario matching the context of the year 2019 in installed generation capacity, fuel prices and cost of CO2 emissions (based on the average observed price for the EU-ETS emission allowances, i.e. 24.9 EUR/tCO2). In a second benchmark, the cost of CO2 emissions is instead set at 70 EUR/tCO2 in line with the shadow cost of CO2 in France in 2019 according to Quinet (2019).[24] Thus the values of wind and solar projects in the second benchmark are augmented in proportion to the amount of CO2 emissions they allow to displace, considering the gap between the shadow cost of CO2 and the actual cost enforced through the EU-ETS.[25] Regardless of the benchmark considered for the social benefits of projects, the simulated marginal costs used for computing the revenues $R(\omega, X; \delta)$ are drawn from the simulations where the cost of CO2 emissions is set at the 2019 average observed price, and after having included the project ω to the power system.

The parameters δ_R for each contract R are adjusted such that all contract designs are equivalent in terms of average revenue per energy output over the sample of projects. Thus switching the contract design may affect the revenue per energy output of individual projects but not the sample average. All these δ_R parameters are based on the average bids of the large-scale wind and solar projects selected in auctions held in 2019 in France. These auctions were for subsidy contracts in the form of sliding feed-in premiums based on a monthly average price weighted by the total production of the relevant technology (solar total production for solar projects, and wind total production for wind projects). For solar projects, we consider the only 2019 auction for ground-mounted solar power with a capacity superior to 5 MWc, that was held on June 3rd, 2019 and in which the average selected bid was 59.5 EUR/MWh. For wind projects, we consider the two auctions for large-scale onshore wind projects that were held on April 1st and August 1st, 2019, in which the (global) average bid was 64.75 EUR/MWh.[26] Taking these average bids as parameter δ_R for the contract design in use in France at the moment, we derive the equivalent parameters for all other contract designs, with the constraint that the average revenue per energy produced is kept constant over the sample of projects. The resulting parameters are reported in Table 1 for a selection of contract designs (see Table 4 in Appendix for an exhaustive report on all contract designs).

A difference remains between the social benefits of projects and the revenues generated through the subsidy schemes. We interpret this difference as the manifestation of an additional value attributed to VRE projects by the government, possibly reflecting the contribution of these projects to the achievement of renewable energy policy goals. Following the discussion in section 3, these are to be regarded as a fixed positive externality per unit of energy produced. We denote this externality δ^* and derive it by assuming that the social benefits of projects $\hat{V}(\omega)$, including this

[24]These two benchmarks are extensively detailed in Leblanc (2023).

[25]Note that since the cost of CO2 emissions is modified in the inputs of the model EOLES-Dispatch, it is the whole dispatch that is adjusted in response to this increased cost of CO2 emissions (not only the value of the VRE projects). This avoids technical difficulties that are discussed in Leblanc (2023).

[26]The official reports of the wind and solar auctions are available on the website of the French Energy Regulatory Commission.

Table 1: Calibration of bids δ_R and renewable energy externalities δ^* (short) [EUR/MWh]

			Solar projects ($n = 50$)				Wind projects ($n = 43$)			
Contract Design				Revenue (per output)				Revenue (per output)		
	Period	*Weighting*	δ_R	*mean*	*min*	*max*	δ_R	*mean*	*min*	*max*
Feed-in tariff			59.49	*59.49*	59.49	59.49	65.01	*65.01*	65.01	65.01
Feed-in premium			18.32	*59.49*	58.70	61.16	22.40	*65.01*	64.22	65.76
sl. FiP	Year	Load	64.02	*59.49*	58.64	61.29	68.04	*65.01*	64.43	65.79
—	—	Technology	59.65	*59.49*	58.60	61.36	64.86	*65.01*	64.51	65.79
—	—	Unweighted	61.94	*59.49*	58.63	61.29	65.96	*65.01*	64.44	65.78
—	Month	Load	60.07	*59.49*	59.19	60.30	67.66	*65.01*	64.45	66.14
sl. FiP	**Month**	**Technology**	**59.50**	*59.49*	59.18	60.30	**64.75**	*65.01*	64.55	66.06
—	—	Unweighted	59.10	*59.49*	59.19	60.31	66.65	*65.01*	64.46	66.12
				Value (per output)				Value (per output)		
Social Benefits			δ^*	*mean*	*min*	*max*	δ^*	*mean*	*min*	*max*
Baseline (24.9 EUR/tCO2)			18.31	*59.49*	58.69	61.18	22.39	*65.01*	64.36	65.76
Full SCP (70 EUR/tCO2)			2.21	*59.49*	58.37	61.81	5.57	*65.01*	64.00	66.18

Notes: "sl. FiP": Sliding feed-in premiums, "m. sl. FiP": Multiplicative sliding feed-in premiums, "1s. sl. FiP": One-sided sliding feed-in premium. All values expressed in EUR/MWh, except for the multiplicative feed-in premium parameter δ_R which is a percentage of the electricity market price. Full table reported in Appendix 6.

positive externality, must match the effective payment on average over the sample of projects.[27] We derive this externality considering both benchmarks regarding the remaining part of the social benefits of VRE projects (i.e. costs avoided in meeting the power demand): with the cost of carbon simply matching the observed cost of EU-ETS allowances (24.9 EUR/t) on the one hand, and with the full shadow cost of CO_2 (70 EUR/t) internalized in the dispatch on the other hand. In the second case, we assume the subsidies to VRE are partly justified by the CO2 emissions the project avoids and the non-internalized part of the social benefits associated. Only the remaining excess revenue paid to projects is attributed to their contribution to the achievement of renewable energy policy goals (and thus to a fixed externality per energy output δ^*). Finally, this additional externality δ^* is included in $\mathbb{E}_X[V(\omega, X)]$.

These simulations of $\mathbb{E}_X[V(\omega, X)]$ and $\mathbb{E}_X[R(\omega, X; \delta_R)]$ are first used to directly derive $\overline{\chi}_{R,\delta_R}(\omega)$ for each project, which provides an upper-bound on the distortion-induced welfare loss, as in (8). To complement this upper-bound, we provide some insight into the expected welfare loss by making some additional assumptions about the costs of the projects $C(\omega)$ (whereas they were left completely unspecified in previous approaches). We assume that the costs of each project follow a distribution $C(\omega) \sim F_\omega$ such that the ratio $\mathbb{E}_X[V(\omega, X)]/C(\omega)$ follows a normal distribution $\mathcal{N}(1, \sigma)$, identical for all projects. Next we simulate the ω^* and ω_R for each contract design

[27]Therefore, when the avoided costs are simulated with the baseline scenario (with a cost of CO2 emissions limited to the cost of EU-ETS allowances, i.e. 24.9 EUR/t), the fixed externality per energy output δ^* is very close to the fixed feed-in premium parameter since the social benefits from the project is very close to the market value of its output. A slight difference remains however, due to the difference between projects' benefits estimated through counterfactual simulations or directly with the marginal system costs. This divergence is discussed in detail in Leblanc (2023).

R and the average effective distortion-induced welfare loss, i.e. $\frac{\mathbb{E}_X[V(\omega_R,X)]/C(\omega_R)}{\mathbb{E}_X[V(\omega^*,X)]/C(\omega^*)}$.

4.3 Risk premiums estimation

Next we estimate the risk premiums $\mu_{R,\delta_R}(\omega)$ as expressed in (4). To do so additional assumptions are needed about the firm's utility function $U(\cdot)$ and the risk faced by the firm through the contract design R, represented by the random variable X. We assume that the firms have a constant relative risk aversion (CRRA) denoted γ, and that their utility function is $U(x) = \frac{1}{1-\gamma}x^{1-\gamma}$ for any $\gamma \neq 1$, and $U(x) = ln(x)$ for $\gamma = 1$.

For all the contract designs considered, the impact of X on the firm's revenue goes through the quantities of electricity produced $\boldsymbol{q}$ and the prices of electricity $\boldsymbol{p}$ in each time period. The former is determined by both the chosen project ω and the weather conditions contained in X, while the latter is determined by a variety of factors contained in X such as for instance electricity demand, available means of production or the costs of fuels and CO2 emissions (and marginally by the project chosen ω). As before, the quantity produced by each project is obtained from simulations based on historic weather data over the period 2016-2019, while we consider for market prices the marginal cost simulated with EOLES-Dispatch considering the conditions over that same period. We use the variations among these four years to capture the risk related to weather conditions, power demand and some other factors (e.g. availability of hydro and nuclear power). To this end, we consider one year of revenue for the firm that we assume will result from a random draw (with equal probability) among the 4 years in our sample (2016-2019).

	(baseline)	Low	Median	High
Probability		*10%*	*80%*	*10 %*
Natural Gas Price [USD/mmbtu]	*6.62*	4.5	8.5	15.0
EU ETS Allowances [EUR/tonCO2]	*24.9*	20	40	100

Table 2: Scenarios on fuel prices and CO2 emissions cost

To reflect the risk induced by uncertainty on fuel prices and CO2 emissions costs (i.e. EU-ETS allowances price), we consider a set of scenarios for each of which we simulate the resulting electricity prices using EOLES-Dispatch. We consider one very likely central scenario and two alternative scenarios, each occurring with probability 10%. The values considered are reported in Table 2. For natural gas price, the median value roughly matches World Bank's commodities price forecast for Europe in 2025 released at the beginning of the energy crisis in October 2021.[28] The price in the low scenario roughly matches the 2016 average price (4.56 USD/mmbtu), which was

[28] See https://thedocs.worldbank.org/en/doc/ff5bad98f52ffa2457136bbef5703ddb-0350012021/related/CMO-October-2021-forecasts.pdf

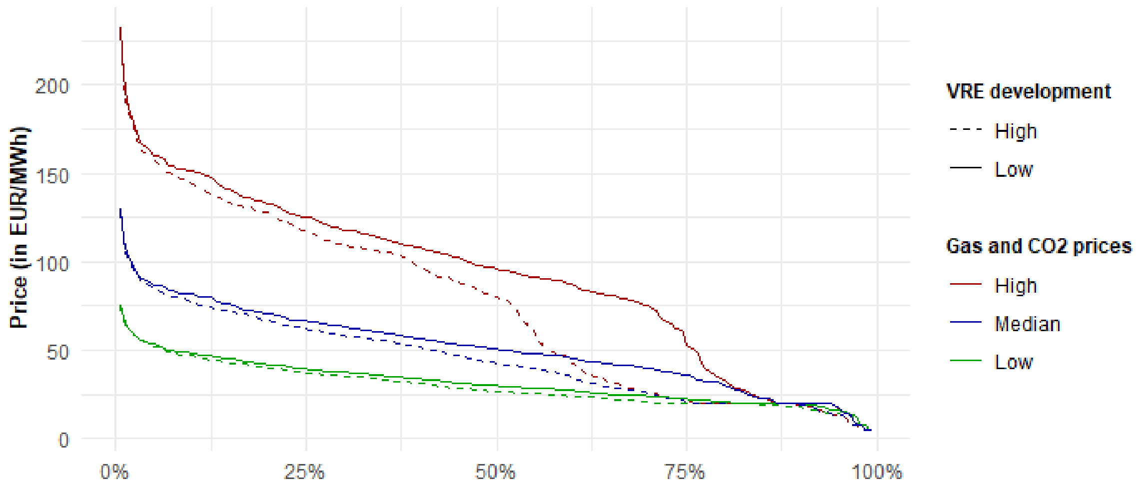

Figure 1: Price duration curves depending on risk scenarios (2016-2019)

the lowest yearly average since the early 2000s. The price in the high scenario is slightly below the average price observed on the whole 2021 year (16.12 USD/mmbtu) and much lower than those observed in 2022 (40.34 USD/mmbtu).[29] The projection of EU CO2 emissions allowance prices is rather difficult considering the mechanism has been through several phases with dramatically different dynamics, mostly driven by institutional decisions. Therefore, the values considered in the scenarios are rather arbitrary, even though they remain in the range of commonly discussed values for the value of CO_2 emissions. These assumptions, both on fuel prices and on the cost of CO2 emissions, may seem very conservative in light of recent events in the electricity markets. However, we must keep in mind that since we are only considering a single year of revenue for the VRE project to be built, what we are trying to capture is rather the range of possibilities for the representative year of the project's life, not the full range of possibilities over a specific year.

	(baseline)	VRE-	VRE+
Probability		*50%*	*50%*
Solar PV	*9.158*	13.7	20.1
Onshore Wind	*14.551*	20.6	24.1
Offshore Wind	*0.000*	0.02	2.4

Table 3: Scenarios on VRE capacities installed in France [GW]

Finally, we assume a risk associated with uncertainty about the evolution of the electricity

[29] Natural gas price in Europe (TTF) according to World Commodity Price Data (February 2023). See https://thedocs.worldbank.org/en/doc/5d903e848db1d1b83e0ec8f744e55570-0350012021/related/CMO-Historical-Data-Monthly.xlsx

mix, and in particular the pace of development of VRE capacity. Due to the cannibalization effect, the pace at which wind and solar power capacities are installed have a significant influence on the revenues expected by wind and solar plants. In particular, while we may expect shocks on fuel or CO2 costs to globally affect the average price of electricity, in contrast a larger VRE capacity will specifically affect electricity prices in times at which wind and solar power plants produce the most, when the weather is favorable. Therefore, we anticipate in particular that a sliding feed-in premium insuring against variations in the average electricity prices might not be as efficient in insuring against this specific cannibalization risk. To account for this risk, we run the simulations with the capacity installed in the beginning of the year 2023 for all technologies, except for VRE capacities for which we consider two scenarios with equal probability: one where the development objectives for wind and solar set by the French government in 2019 have been reached, and one where the solar and wind capacity installed match the one actually installed in the beginning of 2023.[30] Doing so, we capture the uncertainty associated with the evolution of the power system as planned by the government. The corresponding capacities are reported in Table 3.

Combining the scenarios regarding fuel and CO2 emissions costs and regarding the development of VRE, we simulate the electric dispatch for 2016-2019 with the EOLES-Dispatch model to obtain 24 sets of simulated prices. The latter are depicted in the price duration curves in Figure 1, which show the proportion of time for which price exceeded a certain value (in each scenario). Finally, we use these prices to compute, for each project and each subsidy contract, the 24 revenue levels possible over one year with a probability associated with each, and then compute the expected utility and expected revenue allowing us to derive the risk premium.

5 Results

In this section, we use these simulations to infer the welfare loss that the different contract designs can induce. As discussed above, the results will depend on what is considered the benchmark for the social value of VRE projects. First, we consider as a baseline the benchmark in which the social benefits of VRE projects are composed of the avoided generation costs (including the effective cost of CO2 emissions imposed by the EU ETS, 24.9 EUR/t), and a fixed positive externality per energy output δ^* accounting for the project's contribution to renewable energy policy targets. We then consider the alternative benchmark, in which the projects' ability to displace CO_2 emissions constitutes most of the positive externality included in their social value.

[30] These objectives were set through the Multiannual Energy Plan (PPE) in 2019. See https://www.ecologie.gouv.fr/programmations-pluriannuelles-lenergie-ppe. Generation capacity actually installed per technology is reported on the ENTSO-E Transparency platform for 2023.

5.1 Sliding feed-in premiums: a good compromise between tariffs and fixed premiums

Without making any assumptions about project costs, the simulations suggest that some sliding feed-in premium contracts outperform both feed-in tariff and fixed feed-in premium contracts, although this is not necessarily true for all sliding feed-in premium designs. We first discuss these results, which are based on no assumptions about project costs. We then report simulations based on additional assumptions about project costs which suggest that the expected welfare loss due to distortions is likely to be rather small, even for the most distortive contracts.

5.1.1 Maximum Welfare Loss and Risk premiums

Assuming that a given project $\omega \in \Omega$ is realized, the associated maximum welfare loss, represented in the inequality (5), is computed based on a point estimate of the risk premium $\mu_{R,\delta_R}(\omega)$ and an estimated upper bound on the distortion induced welfare loss $\overline{\chi}_{R,\delta_R}(\omega)$. These results are shown in Figure 2 and reported in detail in Tables 5 and 6 in Appendix. As expected, a fixed feed-in premium provides (almost) marginal reward: the premium compensates for the positive externality, and the revenue from selling the output on the wholesale market match is almost exactly equal to the avoided generation costs for the power system thanks to the VRE project.[31] Thus, the distortions induced by (fixed) feed-in premiums are almost null for all projects: even in the worst combination of project costs, a sub-optimal project choice by the firm could only cause a maximum welfare loss of about 0.2% (in both the wind projects sample and the solar projects sample). However, feed-in premiums pose a significant risk to the firm, whose revenues are largely subject to fluctuations in electricity market prices, and thus lead to large risk premiums: 1.67% on average for solar projects and 1.63% for wind projects (assuming a relative risk aversion equal to 1). In contrast, feed-in tariffs expose the firm to much less risk (limited to the variation of the project's total production depending on weather conditions) and thus induce risk premiums that are about ten times smaller for wind projects (0.11%) and negligible for solar projects (0.02%). On the other hand, because feed-in tariffs value each unit of energy the same, even though its value to the power system varies, they induce large distortions. The maximum welfare loss due to these distortions (associated with the worst pair of selected/optimal projects, and the worst cost of projects that could still make this sub-optimal choice possible) is about 4.1% in the case of solar projects and 2.1% in the case of wind projects. If instead we fix the selected project ω_R and only the worst case conditional on this ω_R, this worst case is on average 2.77% for solar projects and 1.13% for wind projects (see the means reported in Tables 5 and 6). Note that these results

[31] There remains a slight discrepancy between the market value of the output and the avoided generation costs, because the latter is based on counterfactual simulations of EOLES-Dispatch while the former is based on ex-post marginal costs simulated by the model. This point is discussed in detail in Leblanc (2023).

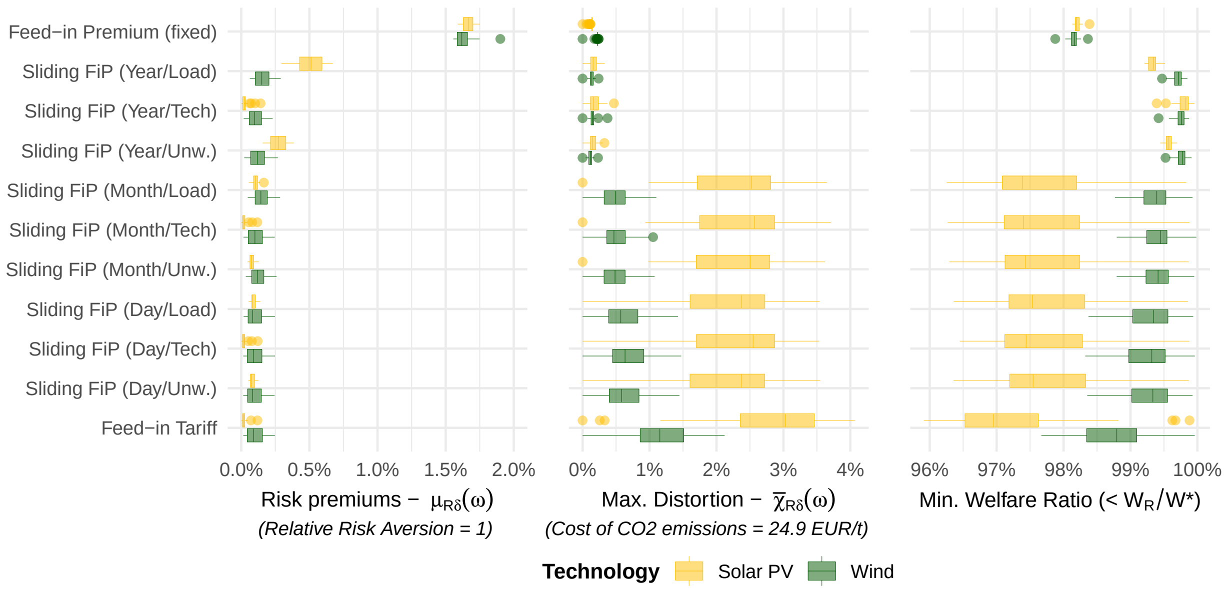

Figure 2: Sliding feed-in premiums: distortions and risk premiums

are heavily influenced by the extreme project in our distribution, the most undervalued project, which (in the worst case, with the worst combination of projects' costs) could be the optimal one. The simulations presented in the next section allow us to address this issue.

In summary, we cannot arbitrate between feed-in tariff and feed-in premium subsidy mechanisms without some additional assumptions about the distribution of project costs, and this arbitration would be sensitive to assumptions about the relative risk aversion. However, some sliding feed-in premiums contracts appear to be clearly preferable to both feed-in premiums and feed-in tariffs, regardless of these assumptions. As shown in Figure 2, sliding feed-in premiums in which the reference price is a yearly average ensure that the distortions are very limited (with a maximum welfare loss of 0.5% in the worst case) while achieving very significant reductions in risk premiums compared to fixed feed-in premiums. In particular, when the reference price is a yearly average weighted by the national production of the same technology (solar or wind), the risk premiums are comparable to those simulated for a feed-in tariff contract (0.11% on average for wind projects, 0.03% for solar projects). Sliding feed-in premiums with a simple unweighted average or a load-weighted average as reference price result in slightly smaller distortions (a reduction of the total range by about 0.1%), but induce an increase in the risk premium, especially for solar projects (+0.24% if unweighted and +0.47% if load-weighted, on average). Given that the reduction in the total range of distortions, i.e. in the worst case welfare loss, is of the same order of magnitude as the average increase in risk premiums, a sliding feed-in premium contract with a yearly average weighted by the total technology production should probably be preferred. This is confirmed in the next section when relying on additional assumptions about project costs.

Sliding feed-in premiums that compensate firms based on an average price over a shorter period, such as a monthly or daily average, induce much larger distortions with very limited benefits for risk premiums compared to yearly sliding feed-in premiums. In particular, when considering contracts with a technology-weighted reference price, the risk premiums are the same as for a yearly average (within 0.01%) but the maximum welfare loss from distortions is multiplied by 3-4 for wind projects and by almost 10 for solar projects. This reflects the fact that by insuring firms against variations in monthly average prices, the subsidy contract insulates them from the incentives conveyed by the seasonality of prices (e.g., that electricity is more valuable in the winter than in the summer). It should be noted, however, that the way in which the risk is constructed in our simulations may underestimate the benefits in terms of risk exposure that sliding feed-in premiums based on intra-year (monthly or daily) average prices can bring. Indeed, the price shocks used to simulate risk premiums are all based on full-year simulations: we do not represent, for example, a fuel price shock that would affect only part of the year, and that could be less well compensated by a yearly sliding feed-in premium.[32]

A variation of the sliding feed-in premium design that has been implemented in some countries (e.g., Germany) are one-sided sliding feed-in premium contracts, where firms receive a subsidy if the reference price is lower than the strike price δ^R, but are not required to pay back a negative premium if the reference price is higher. A consequence of this feature is that the firms' revenues still depend in part on the average price of electricity if there is a positive probability that it will at some point be higher than the strike price. This leads to greater variability in the firm's revenue which translates into larger risk premiums, as confirmed by the simulation results reported in Tables 5 and 6 in Appendix. While one-sided sliding feed-in premiums induce exactly the same distortions as their two-sided counterparts, they slightly but consistently increase the average risk premium required by the firm (by $0.05 - 0.50\%$ points depending on the specification). These results suggest that regulators should prefer two-sided sliding feed-in premiums to mitigate the risk borne by firms.[33]

5.1.2 Expected welfare loss depending on costs distribution

To avoid making assumptions regarding project costs, the welfare loss resulting from distortions were previously assessed through an upper bound which, as previously mentioned, heavily depends

[32] Nevertheless, a full-year average fuel price shock, or a shock to installed VRE capacity, will not necessarily affect prices uniformly throughout the year. Thus, some risk mitigation benefits of a monthly or daily sliding feed-in premium could appear, but the results show that they are limited.

[33] Moreover, the latter also avoids that firms receive windfall profits in the case of high market prices, as recently experienced in Europe.

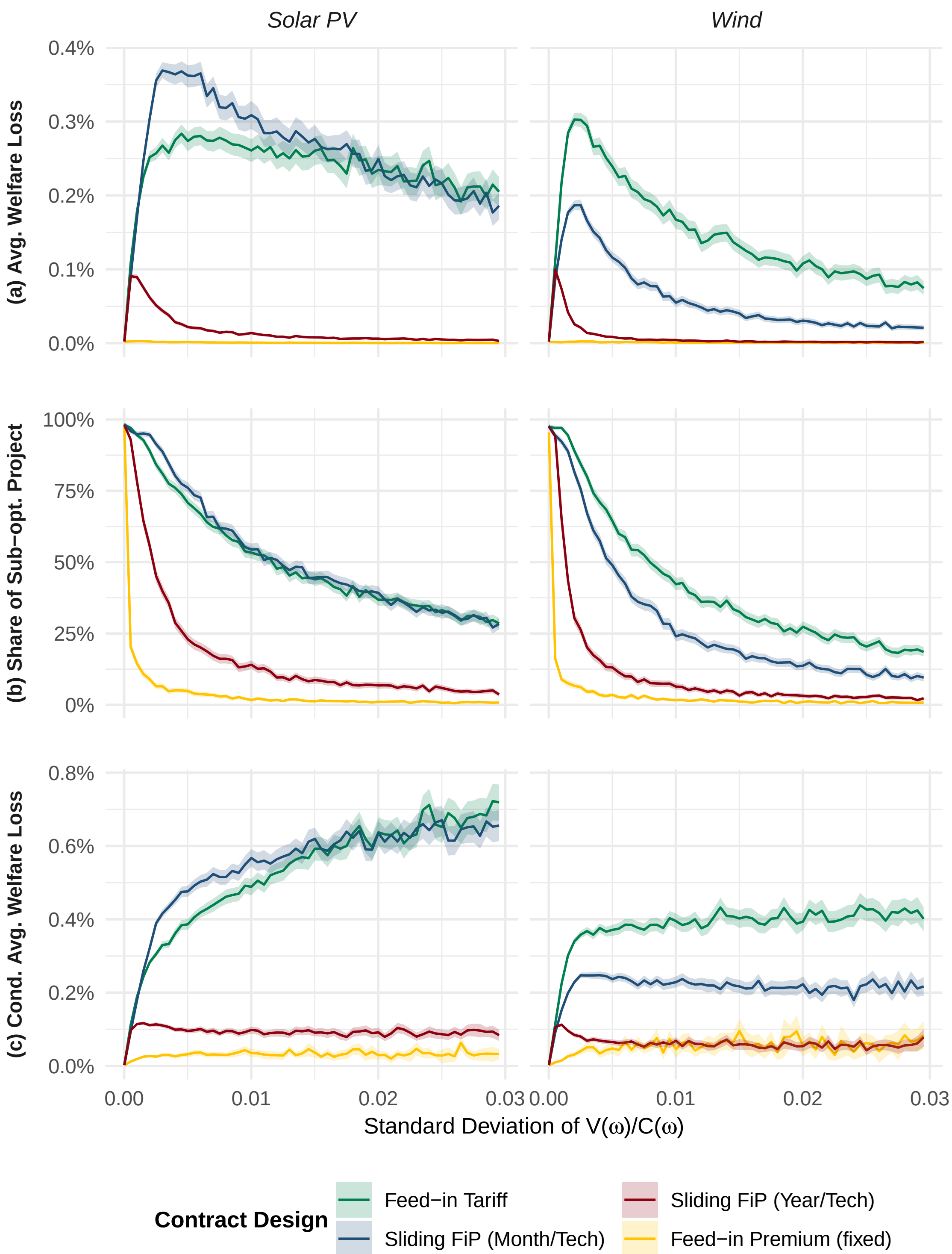

Figure 3: Welfare loss due to distortion when assuming normally distributed $V(\omega)/C(\omega)$

on the extreme projects in our sample (those whose value is most distorted by the contract design). In the following, we assume a normal distribution of project costs, as described at the end of section 4.2, and rely on simulations to compute the resulting expected welfare loss induced by distortions. The simulation results are presented in Figures 3 and 4 for 2000 draws and where the shaded areas depict the 95% confidence interval.

One key parameter in determining the expected welfare loss is the standard deviation in the value to cost ratio of projects, which impacts the outcome in two ways. As is depicted on panel (c) in Figure 3, the higher this standard deviation is, the greater will be the average welfare loss conditional on a sub-optimal project being selected. However, the greater the standard deviation, the less likely it is that such sub-optimal choice will occur, as is depicted on panel (b). These conflicting effects explain that the overall expected welfare loss, depicted on panel (a), increases up to a maximum as the standard deviation goes up to a certain level, before decreasing when the standard deviation increases further.

What appears from results presented on Figure 3 is that the average welfare loss induced by distortion remain limited, remaining under 0.4% of the first best project's value for the most unfavorable dispersion of projects' costs and the most distortive contracts. This welfare loss is much smaller than the risk premium induced by fixed feed-in premium contracts, and comparable in magnitude with the risk premium induced by other contracts considered here. Besides, these simulations provide confirmation that sliding feed-in premium contracts can perform well at limiting the welfare loss from distortions, but not when the reference price is computed on a period shorter than one year. This appears to be especially true for solar projects, in which case monthly sliding feed-in premium contracts appear to perform as bad as feed-in tariff contracts (and even slightly worse within some range of dispersion of the value to cost ratio). In the case of wind projects, monthly sliding feed-in premium contracts do perform a bit better than feed-in tariff contracts. Still, in both cases, switching to a yearly sliding feed-in premium contract reduces the distortions to almost zero (except if the standard deviation of value to cost ratio is small), while having little impact on the risk premium as mentioned above.

A design features on which conclusions previously remained unclear is the weighting that should be adopted for the reference price in sliding feed-in premium: an average price weighted by the national production of the technology to which the plant belong (solar or wind) yields lower risk premiums but slightly increase the distortions as compared to load-weighted or unweighted average for reference price. Based on these additional assumptions on cost distribution we may assess the magnitude of the latter, as presented in Figure 4. Results confirm that unweighted and load-weighted averages are comparable and induce smaller distortions than contracts with a technology-weighted average price for reference. However, the magnitude of this gap never exceeds 0.045% for solar projects and 0.075% for wind projects. Comparing this (maximum)

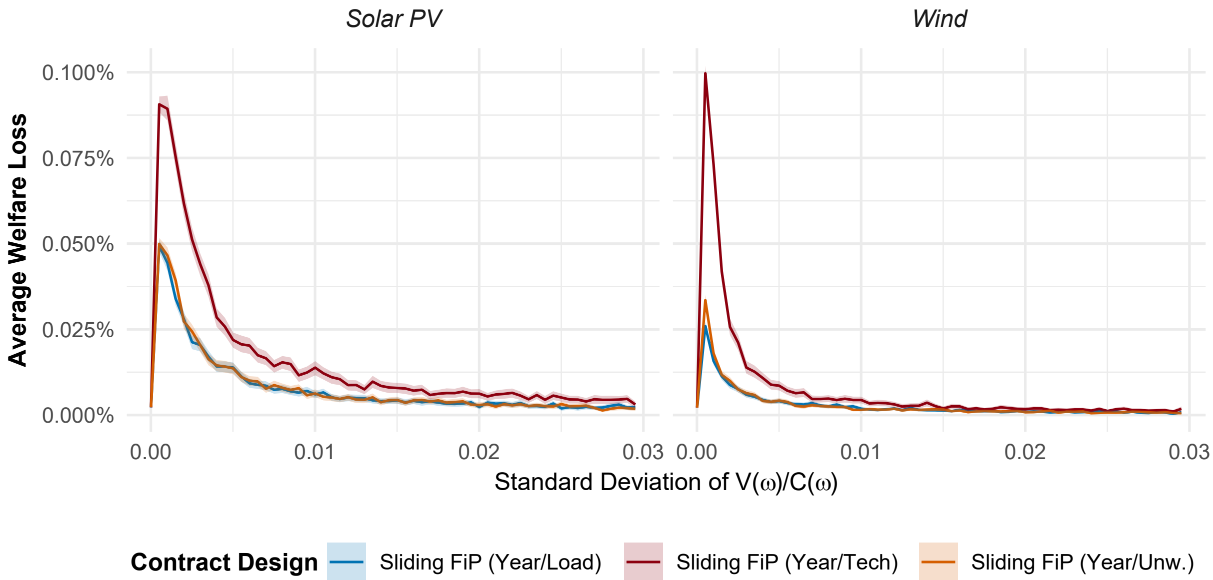

Figure 4: Weighting used by sliding feed-in premium and expected welfare loss

welfare loss avoided with the risk premium reductions obtained from using technology-weighted reference prices suggest that the latter should be used.

5.2 Multiplicative premiums better value CO2 emissions displacement

Next we consider the second benchmark which assumes VRE subsidies are partly motivated by the discrepancy between the cost of EU-ETS allowances (24.9 EUR/t on average in 2019) and the shadow cost of CO2 emissions commonly accepted in France (70 EUR/t in 2019). As is depicted on Figure 5, when adopting this perspective the variation in projects' social benefits is not as well captured by their market value and fixed premium. This is explained by the additional variability in projects' social benefits associated with their varying performance in displacing CO2 emissions. As found in Leblanc (2023), this performance in displacing CO2 emissions is roughly proportional to the market value of their output, and not to the amount of electricity produced. A corollary of this result is that multiplicative feed-in premium, where the premium paid is in proportion to market prices, better capture this variability, and thus induce smaller distortions. Whereas the maximum distortion-induced welfare loss with a standard (additive) feed-in premiums is 1.05% for wind projects and 1.60% for solar projects, it is only 0.51% and 0.45% respectively with multiplicative feed-in premiums. However, as expected, multiplicative feed-in premiums induce much larger risk premiums, about twice as large as those induced by standard feed-in premiums (3.37% for solar projects and 3.42% for wind projects on average). This is a consequence from

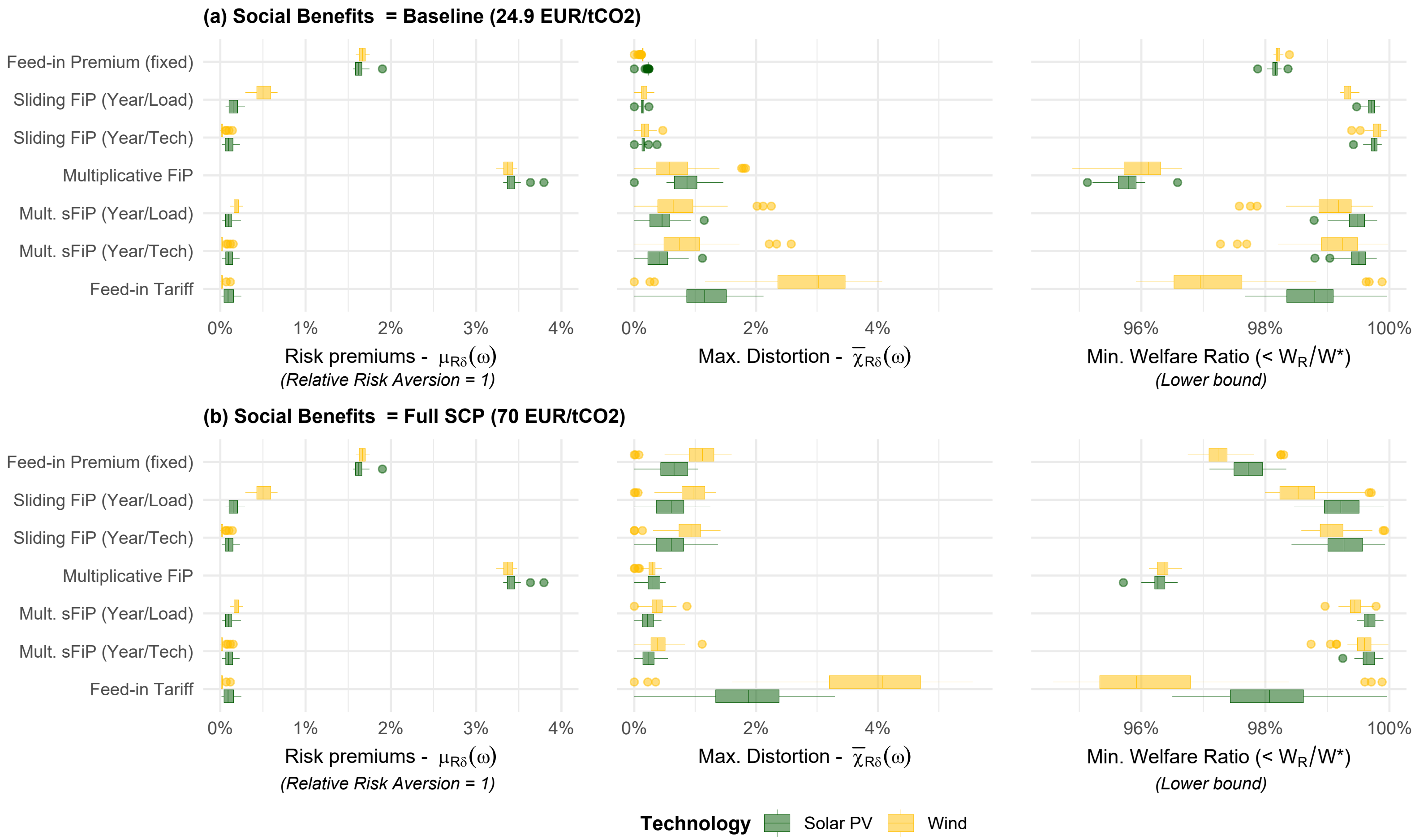

Figure 5: Comparing additive and multiplicative feed-in premiums

multiplicative premium amplifying the risks associated with the variability of electricity market prices.

However, findings also show that, similarly to standard sliding feed-in premiums, their multiplicative counterparts are effective in drastically reducing the risk premiums while preserving appropriate incentives for VRE developers. For wind projects in particular, all three versions of yearly multiplicative sliding feed-in premiums brings the risk premiums down to about 0.1% on average (same as with a feed-in tariff) while the maximum distortion-induced welfare loss is the same as with (fixed) multiplicative feed-in premium (about 0.5%). In the case of solar projects, multiplicative sliding feed-in premiums brings the risk premiums down to levels comparable to feed-in tariffs (0.02%) only if the reference price is weighted by the national solar production, and the distortions they induce are moderately smaller than their additive counterpart (by $0.3-0.4\%$ in total range).

Thus, if VRE subsidies are (at least partly) motivated by the displacement of CO2 emissions by VRE projects, our results suggest that multiplicative sliding feed-in premiums would perform better at inducing firms to choose the most valuable projects while inducing no increase in risk premiums as compared to standard additive sliding feed-in premiums. Moreover, as we mentioned in section 3, multiplicative sliding feed-in premiums induce no distortions in dispatch decisions, in contrast to other contracts, since the firm gets a positive payoff from producing if and only if electricity market prices are positive.

6 Conclusions

To shed light on which contract designs should be preferred to support VRE projects, we use a case study of a sample of wind and solar projects in France to quantitatively assess the performance of various designs with respect to the incentives passed on to firms on the one hand, and the risk premiums they induce on the other hand. Our results advocate for a popular class of contracts, sliding feed-in premiums, which expose firms to price signals conveyed by short-term changes in electricity market prices while protecting them from shocks to the average market price level, related to, for example, changes in fuel costs or changes in the power mix. The results also suggest that these contracts should adopt an annual average as a reference price (rather than monthly as is currently the case in France and other countries) in order to provide better incentives to VRE developers, in particular to incentivize them to take into account seasonal trends in electricity prices. Our results show that this improvement in the incentives transmitted to firms would induce welfare gains without significantly increasing the risk premiums demanded by firms. Besides, we find that multiplicative premiums, in which subsidies paid to VRE producers are in proportion to market prices, provide better incentives when we assume that the main motivation for VRE subsidies is the CO2 emissions displaced by wind and solar power. If VRE subsidies were to play the role of a second best instrument to mitigate the emissions of the power sector (in replacement for a carbon tax), multiplicative premiums would thus be a better option. Still, most support schemes in the EU are in the form of additive premiums indexed on the amount of energy produced. Other arguments in favor of such mechanisms are that the multiplicative equivalent of sliding feed-in premiums is found as effective as their additive counterpart in reducing the risk premiums, and that they also provide better incentives in terms of dispatch (ensuring that VRE producers are willing to produce if and only if prices are positive).

Even though our quantitative assessment directly applies only to the specific case of the present French power system, we may conjecture that some of these conclusions may apply to other (similar) contexts. Furthermore, the methodology implemented here could be replicated in any context to confirm it. However, conclusions may differ in very different power systems. In particular, it seems likely that the present results will not apply to power systems in the longer term future, which are expected to integrate a much larger share of renewables. Increased variability in electricity prices and the strengthening of the cannibalization effect that undermines the market value of renewables may raise specific issues, possibly requiring different policy instruments to address them. The most appropriate instruments to support VRE development in this future context remains to be identified.

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Appendix – Detailed simulation results

Table 4: Calibration of bids δ_R and renewable energy externalities δ^* (full) [EUR/MWh]

			Solar projects ($n = 50$)				Wind projects ($n = 43$)			
Contract Design				Revenue (per output)				Revenue (per output)		
	Period	*Weighting*	δ_R	*mean*	*min*	*max*	δ_R	*mean*	*min*	*max*
Feed-in tariff			59.49	*59.49*	59.49	59.49	65.01	*65.01*	65.01	65.01
Feed-in premium			18.32	*59.49*	58.70	61.16	22.40	*65.01*	64.22	65.76
sl. FiP	Year	Load	64.02	*59.49*	58.64	61.29	68.04	*65.01*	64.43	65.79
—	—	Technology	59.65	*59.49*	58.60	61.36	64.86	*65.01*	64.51	65.79
—	—	Unweighted	61.94	*59.49*	58.63	61.29	65.96	*65.01*	64.44	65.78
—	Month	Load	60.07	*59.49*	59.19	60.30	67.66	*65.01*	64.45	66.14
sl. FiP	**Month**	**Technology**	**59.50**	*59.49*	59.18	60.30	**64.75**	*65.01*	64.55	66.06
—	—	Unweighted	59.10	*59.49*	59.19	60.31	66.65	*65.01*	64.46	66.12
—	Day	Load	59.73	*59.49*	59.19	60.40	65.98	*65.01*	64.85	65.46
—	—	Technology	59.49	*59.49*	59.16	60.24	64.95	*65.01*	64.88	65.50
—	—	Unweighted	59.16	*59.49*	59.19	60.40	65.38	*65.01*	64.85	65.45
Multiplicative feed-in premium			44%	*59.49*	58.35	61.90	1.53	*65.01*	63.80	66.15
m. sl. FiP	Year	Load	66.10	*59.49*	58.25	62.12	69.71	*65.01*	64.07	66.22
—	—	Technology	59.73	*59.49*	58.19	62.26	64.76	*65.01*	64.20	66.22
—	—	Unweighted	63.11	*59.49*	58.24	62.13	66.53	*65.01*	64.09	66.22
—	Month	Load	60.33	*59.49*	59.04	60.70	69.21	*65.01*	64.12	66.74
—	—	Technology	59.50	*59.49*	59.02	60.72	64.59	*65.01*	64.30	66.66
—	—	Unweighted	58.88	*59.49*	59.05	60.72	67.62	*65.01*	64.14	66.73
—	Day	Load	60.14	*59.49*	59.04	60.83	66.60	*65.01*	64.75	65.76
—	—	Technology	59.49	*59.49*	58.99	60.64	64.89	*65.01*	64.78	65.85
—	—	Unweighted	59.27	*59.49*	59.05	60.83	65.64	*65.01*	64.75	65.74
1s. sl. FiP	Year	Load	64.02	*59.49*	58.64	61.29	68.04	*65.01*	64.43	65.79
—	—	Technology	59.65	*59.49*	58.60	61.36	64.86	*65.01*	64.51	65.79
—	—	Unweighted	61.94	*59.49*	58.63	61.29	65.96	*65.01*	64.44	65.78
—	Month	Load	59.76	*59.49*	59.18	60.34	67.66	*65.01*	64.45	66.14
—	—	Technology	59.17	*59.49*	59.16	60.32	64.75	*65.01*	64.55	66.06
—	—	Unweighted	58.82	*59.49*	59.18	60.35	66.65	*65.01*	64.46	66.12
—	Day	Load	59.15	*59.49*	59.18	60.45	65.81	*65.01*	64.83	65.50
—	—	Technology	58.84	*59.49*	59.15	60.33	64.77	*65.01*	64.86	65.54
—	—	Unweighted	58.61	*59.49*	59.18	60.45	65.22	*65.01*	64.84	65.48
				Value (per output)				Value (per output)		
Social Benefits			δ^*	*mean*	*min*	*max*	δ^*	*mean*	*min*	*max*
Baseline (24.9 EUR/tCO2)			18.31	*59.49*	58.69	61.18	22.39	*65.01*	64.36	65.76
Full SCP (70 EUR/tCO2)			2.21	*59.49*	58.37	61.81	5.57	*65.01*	64.00	66.18

Notes: "sl. FiP": Sliding feed-in premiums, "m. sl. FiP": Multiplicative sliding feed-in premiums, "1s. sl. FiP": One-sided sliding feed-in premium. All values expressed in EUR/MWh, except for the multiplicative feed-in premium parameter δ_R which is a percentage of the electricity market price.

Table 5: Detailed simulation results for all contract designs – Solar projects ($n = 50$)

			Max. Distortion loss *(24.9 EUR/tCO2)*			Max. Distortion loss *(70 EUR/tCO2)*			Risk premium *(RRA = 1)*		
Contract Design					$\overline{\chi}_{R,\delta}(\omega)$			$\overline{\chi}_{R,\delta}(\omega)$			$\mu_{R,\delta}(\omega)$
	Period	*Weighting*	Mean	Median	Max	Mean	Median	Max	Mean	Median	s.d.
Feed-in tariff			2.77	3.03	4.07	3.76	4.08	5.56	0.02	0.02	0.02
Feed-in premium			0.13	0.14	0.15	1.06	1.12	1.60	1.67	1.67	0.04
sl. FiP	Year	Load	0.16	0.16	0.33	0.91	0.98	1.34	0.50	0.51	0.10
—	—	Technology	0.18	0.16	0.47	0.86	0.93	1.42	0.03	0.02	0.03
—	—	Unweighted	0.15	0.15	0.33	0.90	0.98	1.34	0.27	0.27	0.07
—	Month	Load	2.30	2.52	3.65	3.29	3.62	5.13	0.11	0.10	0.02
—	—	Technology	2.36	2.57	3.71	3.34	3.66	5.17	0.02	0.02	0.02
—	—	Unweighted	2.29	2.50	3.62	3.28	3.60	5.11	0.08	0.07	0.02
—	Day	Load	2.20	2.37	3.54	3.19	3.49	5.04	0.09	0.08	0.02
—	—	Technology	2.31	2.55	3.53	3.30	3.61	5.03	0.02	0.02	0.02
—	—	Unweighted	2.20	2.37	3.55	3.19	3.49	5.05	0.08	0.07	0.02
Multiplicative feed-in premium			0.67	0.57	1.83	0.28	0.30	0.45	3.37	3.36	0.07
m. sl. FiP	Year	Load	0.75	0.64	2.25	0.37	0.37	0.86	0.19	0.18	0.04
—	—	Technology	0.86	0.74	2.58	0.39	0.38	1.11	0.03	0.02	0.03
—	—	Unweighted	0.77	0.65	2.29	0.36	0.36	0.88	0.14	0.13	0.03
—	Month	Load	2.17	2.32	4.18	3.16	3.49	5.04	0.09	0.09	0.02
—	—	Technology	2.21	2.35	4.23	3.20	3.50	5.05	0.02	0.02	0.02
—	—	Unweighted	2.23	2.38	4.26	3.22	3.55	5.15	0.09	0.08	0.02
—	Day	Load	1.97	2.10	3.89	2.96	3.21	4.83	0.09	0.09	0.02
—	—	Technology	2.13	2.32	3.87	3.12	3.49	4.83	0.02	0.02	0.02
—	—	Unweighted	2.00	2.14	3.96	3.00	3.25	4.90	0.10	0.09	0.02
1s. sl. FiP	Year	Load	0.16	0.16	0.33	0.91	0.98	1.34	0.55	0.55	0.02
—	—	Technology	0.18	0.16	0.47	0.86	0.93	1.42	0.24	0.23	0.04
—	—	Unweighted	0.15	0.15	0.33	0.90	0.98	1.34	0.48	0.47	0.02
—	Month	Load	2.16	2.39	3.43	3.15	3.47	4.91	0.47	0.46	0.03
—	—	Technology	2.15	2.36	3.39	3.14	3.43	4.85	0.36	0.35	0.05
—	—	Unweighted	2.15	2.38	3.41	3.14	3.46	4.90	0.48	0.47	0.03
—	Day	Load	1.97	2.14	3.17	2.96	3.26	4.67	0.57	0.57	0.03
—	—	Technology	2.00	2.22	3.07	2.99	3.26	4.57	0.51	0.50	0.04
—	—	Unweighted	1.97	2.13	3.18	2.96	3.26	4.68	0.58	0.58	0.03

Notes: All values expressed in percentage points. The minimum value for the maximum distortion loss $\overline{\chi}_{R,\delta}(\omega)$ is zero by construction, when taking as realized project ω the one that is least favored by the contract design. "sl. FiP": Sliding feed-in premiums, "m. sl. FiP": Multiplicative sliding feed-in premiums, "1s. sl. FiP": One-sided sliding feed-in premium.

Table 6: Detailed simulation results for all contract designs – Wind projects ($n = 43$)

Contract Design			Max. Distortion loss *(24.9 EUR/tCO2)* $\overline{\chi}_{R,\delta}(\omega)$			Max. Distortion loss *(70 EUR/tCO2)* $\overline{\chi}_{R,\delta}(\omega)$			Risk premium *(RRA = 1)* $\mu_{R,\delta}(\omega)$		
	Period	*Weighting*	Mean	Median	Max	Mean	Median	Max	Mean	Median	s.d.
Feed-in tariff			1.13	1.15	2.12	1.77	1.88	3.29	0.11	0.09	0.07
Feed-in premium			0.22	0.23	0.24	0.64	0.65	1.05	1.63	1.62	0.06
sl. FiP	Year	Load	0.14	0.14	0.24	0.59	0.61	1.25	0.17	0.15	0.07
—	—	Technology	0.15	0.15	0.37	0.60	0.61	1.37	0.11	0.10	0.06
—	—	Unweighted	0.11	0.12	0.23	0.60	0.61	1.27	0.13	0.12	0.07
—	Month	Load	0.50	0.49	1.10	0.83	0.83	1.52	0.15	0.14	0.07
—	—	Technology	0.50	0.47	1.05	0.84	0.81	1.68	0.11	0.10	0.07
—	—	Unweighted	0.49	0.48	1.08	0.82	0.81	1.52	0.13	0.12	0.07
—	Day	Load	0.60	0.57	1.43	1.12	1.09	2.49	0.11	0.08	0.07
—	—	Technology	0.65	0.63	1.47	1.17	1.23	2.53	0.11	0.09	0.07
—	—	Unweighted	0.61	0.58	1.45	1.13	1.11	2.51	0.10	0.08	0.07
Multiplicative feed-in premium			0.87	0.87	1.46	0.31	0.29	0.51	3.42	3.40	0.09
m. sl. FiP	Year	Load	0.45	0.46	1.15	0.22	0.21	0.45	0.11	0.10	0.06
—	—	Technology	0.42	0.42	1.12	0.24	0.23	0.55	0.11	0.10	0.06
—	—	Unweighted	0.41	0.41	1.11	0.24	0.24	0.47	0.12	0.11	0.07
—	Month	Load	0.72	0.59	2.19	0.62	0.53	1.50	0.10	0.09	0.06
—	—	Technology	0.70	0.57	2.06	0.68	0.64	1.46	0.11	0.11	0.07
—	—	Unweighted	0.72	0.59	2.18	0.62	0.54	1.50	0.10	0.08	0.06
—	Day	Load	0.46	0.46	1.12	0.98	0.94	2.18	0.10	0.08	0.06
—	—	Technology	0.57	0.53	1.23	1.09	1.08	2.29	0.11	0.09	0.07
—	—	Unweighted	0.49	0.48	1.19	1.02	0.98	2.25	0.10	0.08	0.06
1s. sl. FiP	Year	Load	0.14	0.14	0.24	0.59	0.61	1.25	0.47	0.47	0.05
—	—	Technology	0.15	0.15	0.37	0.60	0.61	1.37	0.38	0.38	0.05
—	—	Unweighted	0.11	0.12	0.23	0.60	0.61	1.27	0.45	0.44	0.06
—	Month	Load	0.49	0.49	1.10	0.83	0.82	1.51	0.51	0.50	0.05
—	—	Technology	0.50	0.47	1.05	0.84	0.81	1.68	0.53	0.52	0.05
—	—	Unweighted	0.49	0.48	1.08	0.82	0.81	1.52	0.52	0.51	0.05
—	Day	Load	0.57	0.54	1.35	1.09	1.06	2.42	0.60	0.59	0.05
—	—	Technology	0.62	0.60	1.40	1.14	1.19	2.46	0.62	0.61	0.05
—	—	Unweighted	0.58	0.55	1.38	1.10	1.08	2.44	0.61	0.60	0.05

Notes: All values expressed in percentage points. The minimum value for the maximum distortion loss $\overline{\chi}_{R,\delta}(\omega)$ is zero by construction, when taking as realized project ω the one that is least favored by the contract design. "sl. FiP": Sliding feed-in premiums, "m. sl. FiP": Multiplicative sliding feed-in premiums, "1s. sl. FiP": One-sided sliding feed-in premium.