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Microeconomic analysis of subsidy mechanisms for power generation from wind and solar sources

Clément Leblanc

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École des Ponts
ParisTech

THÈSE DE DOCTORAT de l'École des Ponts ParisTech



Analyse micro-économique des mécanismes de subvention à la production d'électricité éolienne et solaire

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Résumé en français

Le développement des énergies renouvelables, et en particulier le développement de l'électricité solaire et éolienne, constitue l'un des leviers les plus prometteurs pour réduire notre dépendance aux énergies fossiles et lutter contre le dérèglement climatique. Pour cette raison, de nombreux États et gouvernements mettent en place des politiques publiques visant à favoriser le développement de ces énergies. Les subventions à la production d'électricité solaire et éolienne constituent l'un des principaux instruments de politiques publiques mobilisés pour cela, et sont particulièrement utilisées en Europe.

Après avoir expérimenté divers mécanismes, la plupart des pays européens octroient désormais ces subventions via des systèmes d'appels d'offres auxquels les porteurs de projets éoliens et solaires à l'échelle industrielle candidatent pour obtenir un contrat de subvention. Ces contrats de subvention peuvent prendre différentes formes, que cette thèse vise à analyser et évaluer dans le but de dresser des recommandations de politiques publiques. Ces différentes formes incluent notamment des systèmes de tarifs d'achat, qui garantissent aux producteurs que leur électricité est achetée à un tarif fixe avantageux, et des systèmes de primes de marché dans lesquels le producteur vend librement son électricité et perçoit en plus une prime pour chaque unité d'électricité produite. Il existe par ailleurs de nombreuses variantes de systèmes de complément de rémunération, où les montants versés obéissent à des calculs plus complexes.

Cette thèse pose plusieurs questions concernant le design de ces contrats de subventions et leurs implications : celle des incitations qui sont données aux porteurs de projets éoliens et solaires en termes de conception des projets de centrale (localisation,

choix technologiques), celle du risque auxquels sont exposés les investisseurs et des conséquences que cela peut avoir sur le coût public des subventions aux renouvelables, et celle d'éventuelles failles qui pourraient exister dans ces contrats et qui pourraient amener les développeurs à adopter des comportements stratégiques non anticipés par le régulateur.

Un enjeu central de la conception de ces contrats est le niveau d'exposition des producteurs d'énergie renouvelable aux prix de marché de l'électricité : dans le cas d'un tarif d'achat cette exposition est nulle, tandis que le système de prime de marché rétablit cette exposition puisqu'une partie du revenu des producteurs provient de la vente de leur électricité sur ces marchés. L'argument en faveur de cette seconde catégorie de contrats réside dans le fait qu'il est souhaitable que les producteurs et développeurs de projets d'énergie renouvelable tiennent compte des incitations induites par les prix de marché. Cela comprend notamment une incitation à couper sa production lorsque l'électricité est excédentaire dans le système électrique (ce qui se traduit par des prix négatifs, de plus en plus courants), mais également une incitation à concevoir des projets qui soient susceptibles de produire aux moments où l'électricité se fait la plus rare, c'est-à-dire au moment où les prix sont les plus élevés. Cela incite en particulier à choisir des projets qui soient moins sujets au phénomène de cannibalisation, c'est-à-dire au phénomène qui veut que lorsque la part d'une technologie donnée (par exemple l'éolien) dans le mix électrique croît, la valeur relative de l'électricité produite par cette technologie décroît, car l'électricité devient abondante dans les moments qui correspondent aux pics de production de cette technologie (par exemple lorsqu'il y a beaucoup de vent). Les projets moins sujet à ce phénomène, et donc susceptibles de capter des prix plus élevés lorsqu'ils produisent de l'électricité, peuvent être par exemple des centrales éoliennes avec des mâts plus hauts et des pâles plus grandes ce qui leur permet de produire même avec des vitesses de vent plus faibles (et donc pas seulement lorsque l'électricité éolienne est déjà abondante), ou bien des centrales solaires dont les panneaux sont orientés de manière à ne pas forcément avoir leur pic de production à midi en été (lorsque l'électricité solaire est déjà abondante). Si les développeurs de projets éoliens et solaires ne sont pas exposés aux prix de marché et seulement rémunérés en fonction de la quantité produite, comme

c'est le cas avec les tarifs d'achats fixes, alors ils ne tiendront pas compte de ces incitations portées par les variations de prix et chercheront simplement à maximiser la quantité d'électricité produite pour un montant donné investi. Dans cette thèse, il est mis en évidence (Chap. 2) que cette hétérogénéité en termes de valeur pour le système électrique entre projets solaires ou entre projets éoliens, bien que faible, n'est pas tout à fait négligeable : considérant un échantillon de projets solaires et éoliens réalisés ou proposés par des développeurs en France, la valeur moyenne de la production de chaque projet sur le marché de gros de l'électricité présente un coefficient de variation supérieur à 1% au sein de chaque catégorie (solaire et éolien). De plus, on peut s'attendre à ce que cette variabilité augmente avec l'augmentation de la part de ces énergies dans le mix électrique.

Si l'exposition aux prix de marché, par exemple via des systèmes de primes, a le mérite d'inciter les développeurs à prendre en compte cette variation dans leurs arbitrages, elle a en revanche le défaut d'augmenter le risque supporté par les investisseurs. Or ce risque supplémentaire rend moins attractif l'investissement dans des projets renouvelables, et doit donc être compensé par une prime de risque. Dans le cas où les subventions sont attribuées via des appels d'offres, ces primes de risques se reflètent dans les enchères émises par les développeurs, qui demanderont des niveaux de subvention plus élevés. Ainsi, un contrat de subvention qui fait porter un risque important aux investisseurs est susceptible d'augmenter le coût public des subventions aux énergies renouvelables. Les résultats de cette thèse suggèrent de plus que les primes de risque engendrées par les systèmes de primes de marché sont d'un ordre de grandeur plus grand que les gains de bien-être liés aux meilleures incitations fournies aux développeurs (Chap. 3). Cependant, il apparaît également que certaines formes de contrats permettent à la fois d'inciter les firmes à prendre en compte les incitations portées par les prix tout en limitant les risques et donc les primes de risques. Avec ces contrats, dits compléments de rémunération ou *sliding feed-in premium*, la production renouvelable est vendue sur les marchés et donc développeurs et investisseurs sont incités à prendre en compte les schémas typiques de variations de prix dans leurs arbitrages (saisonnalité des prix, corrélation avec la météo). Cependant ils perçoivent des subventions sous la forme d'une prime calculée en fonction du niveau général des

prix de l'électricité qui est destinée à compenser une éventuelle baisse ou hausse des prix (liée par exemple aux prix des combustibles fossiles) par une variation inverse de la prime. Ainsi, les investisseurs ne sont pas exposés aux variations du niveau général des prix de l'électricité, principalement lié à des éléments qu'ils ne peuvent pas anticiper précisément et donc auxquels ils peuvent difficilement s'adapter (comme l'évolution du prix des combustibles fossiles, ou l'évolution du mix électrique sur le long terme). Les résultats de cette thèse confirment que de tels contrats peuvent constituer une bonne solution au dilemme risque-incitations, mais soulignent l'importance de certaines spécifications de ces contrats qui sont souvent négligées. En particulier, il est mis en évidence que le calcul du niveau général des prix sur une base mensuelle, actuellement pratiqué en France, a pour conséquence que les incitations fournies aux développeurs sont presque aussi mauvaises que celles qui seraient fournies par un simple tarif d'achat.

Ces résultats peuvent porter à penser que la priorité doit être donnée à la réduction des risques pour les investisseurs afin de réduire le coût public du soutien aux renouvelables. Cependant la conception de contrats transférant les risques depuis les investisseurs privés vers l'Etat doit se faire en prêtant garde à ne pas ouvrir la voie à des comportements stratégiques qui s'avéreraient nuisibles aux objectifs poursuivis par les gouvernements. Les travaux de cette thèse ont permis de mettre en évidence un écueil qui consisterait à vouloir assurer les investisseurs et développeurs de projets renouvelables contre la variabilité de leur production liée aux conditions météorologiques (Chap. 1). De tels dispositifs ont par exemple été utilisés en France dans le cadre des premiers appels d'offres pour des centrales éoliennes en mer. Cette thèse propose une analyse de ce dispositif, étendue à une classe assez large de dispositifs visant à assurer vis-à-vis de ce risque, et montre qu'un tel dispositif incite les entreprises à manipuler les informations transmises au gouvernement dans le cadre de l'appel d'offre (ou bien à adopter des comportements dommageables *a posteriori*). Les simulations réalisées montrent que les gains potentiels dans le meilleur des cas (si aucune entreprise n'adoptait de comportement stratégique de ce type) sont d'un ordre de grandeur inférieur aux pertes en cas de comportement stratégique de la part de certaines entreprises.

Cette thèse fournit un certain nombre de recommandations concernant la conception des contrats de subvention aux énergies éolienne et solaire, dont la part dans le mix électrique dans les années à venir est amenée à croître fortement. Les résultats sur lesquels s'appuient ces recommandations sont essentiellement basés sur l'état actuel du système électrique français, cependant la part croissante d'énergies renouvelables intermittentes dans le mix est potentiellement amenée à modifier ces résultats notamment du fait de la cannibalisation croissante de l'électricité éolienne et solaire. Les outils développés dans le cadre de cette thèse, notamment un modèle numérique du système électrique français EOLES-Dispatch, permettent de fournir des éléments de prospective qui confirment notamment l'importance croissante de fournir de bonnes incitations aux développeurs, des incitations à concevoir des projets dont la production a la plus grande valeur possible pour le mix électrique.

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General Introduction

The use of fossil fuels for electricity generation has been and continues to be a major contributor to climate change. Reducing and eventually phasing out the use of fossil fuels by transitioning to low-carbon power generation options is critical to mitigating the effects of climate change. The IPCC's 2022 report on climate change mitigation identifies wind and solar power as two of the globally most promising climate change mitigation solutions, each with an estimated potential to reduce greenhouse gas emissions by about 4 GtCO₂eq per year by 2030 (IPCC, 2022). The transition to renewable sources of electricity, especially wind and solar power, has therefore become a priority for many countries seeking to decarbonize their power systems. Although the cost-competitiveness of these technologies has improved in recent years,¹ this transition still requires massive investments, particularly in building new generation capacity.

Subsidies for renewable electricity have become a popular policy instrument to encourage such investments. The total amount granted worldwide in 2017 was estimated at around USD 128 billion, with the largest share of these subsidies (USD 78.4 billion) being located in the European Union (EU) (Taylor et al., 2020). This concentration of subsidies in the EU can be explained by a specific combination of ambitious renewable energy targets and a commitment to promoting competition in all sectors, including electricity. This commitment to organizing the electricity sector as a competitive market implies that the development of wind and solar power is to be realized by private firms while meeting public policy objectives, creating a coop-

1. According to the IRENA, between 2010 and 2021, the global average levelized cost of electricity (LCOE) fell from 102 to 33 USD/MWh for onshore wind power, from 188 to 75 USD/MWh for offshore wind power and from 417 to 48 USD/MWh for solar PV, while the LCOE for fossil fuel-fired power generation ranges from 54 to 167 USD/MWh (IRENA, 2022).

eration problem between governments and private firms operating in the electricity sector. Subsidies help solve this cooperation problem by inducing private firms to contribute to these ambitious policy targets.

This dissertation examines the design of the subsidy mechanisms put in place for this purpose, and whether their design is likely to induce efficient development of solar and wind power, i.e., development that maximizes the benefits derived from these technologies. Therefore, we will begin by briefly examining some of the specific features of these power generation technologies, specific features that strongly influence their economic value. The most important of these, which has many implications, is that both solar and wind power are variable renewable energy (VRE) sources of electricity: their energy production does not depend on the operator's decision, as it is the case with dispatchable technologies (e.g. gas-fired or coal-fired power plants), but on the random availability of a (renewable) resource, wind or sunlight.² When assessing the economic value (or cost-competitiveness) of these technologies, one factor is the cost of building new capacity, and another one is the amount of energy that we expect this new capacity to produce over a given period of time. The latter is measured by the capacity factor, i.e. the amount of energy produced per capacity on average over a given period of time, and is highly dependent on the resource available to the specific wind or solar power plant considered. For utility-scale power plants in 2021, the global average capacity factor was about 17% for solar PV and 39% for both onshore wind and offshore wind (IRENA, 2022), but comparing different regions shows a great heterogeneity: for example, the average capacity factor of onshore wind power is 43% in Spain but only 28% in Germany, and for offshore wind the average capacity factor reaches 48% in the United Kingdom and 50% in Denmark. Even at a smaller geographic scale, within a country or region, the expected capacity factor of a particular wind or solar project varies from project to project. This capacity factor is determined by both the technology choices and the location of the project, as the latter determines the wind or solar resource that will be available over the lifetime of the plant (with some uncertainty related to actual weather conditions).

2. The only decision the VRE operator can make is to curtail production despite the availability of the resource, such as when there is excess electricity in the grid.

Another implication of the variable nature of wind and solar power is that the timing of electricity generation is also dependent on the availability of a natural resource, not just the total amount of electricity generated. Because electricity cannot be easily stored, and because the supply of electricity to the grid must match the demand for electricity at any given moment, the timing of production is important: a VRE plant that is likely to produce when demand for electricity is high and supply is scarce will be most valuable to the system than one that produces when demand is low and supply is abundant. For instance, solar power which produces most in the summer during the day is valued higher in regions which experience large power consumption at that moment due to air conditioning, and wind power which tends to produce more in the winter and at night is valued relatively higher in regions who rely on electricity for heating buildings. Furthermore, electricity is a good whose transportation is also constrained by the existing network infrastructures. Thus its value also depends on where it is fed to the grid considering the demand that can be served by this output. To account for the heterogeneous value of renewable generation based on its location and timing, one approach suggested by Joskow (2011) is to factor into its valuation the prices observed in the wholesale electricity market at the time and place where the renewable technologies are generating, based on the idea that wholesale market prices correctly capture the economic value of electricity in each time period. Even though this valuation at wholesale market prices provides a good first order approximation of the value of VRE power production, it may neglect a number of externalities that characterize these technologies, such as their impact on greenhouse gas emissions or air pollutants, or on balancing, congestion and network costs (Borenstein, 2012). These externalities, which are further discussed below, are part of what motivates public intervention in electricity markets (such as VRE subsidies).

Moreover, wind and solar power are also characterized by high risks for investors, mainly due to the high upfront investment costs compared to negligible operation and maintenance costs. Thus, once a VRE power plant is built, there is no way to reduce the cost of the project if it turns out to be less profitable (unlike, for example, thermal plants, where fuel and operating costs make up a large part of the overall cost and decrease if production is reduced). Thus, investment in a VRE project is rewarded

only after almost all costs have been sunk, and is rewarded by revenues that depend on a number of factors, some of which are beyond the developer's control. Of these risks to the revenue generated by a VRE project, this dissertation addresses two sources: 1. the fact that electricity production depends on actual weather conditions, which are, at the time of plant construction, unknown beyond a (possibly biased) estimate of their distribution, and 2. the price at which this electricity will be sold, when this price is not known in advance. Other important sources of risk that are not discussed here affect VRE developers (and are relevant to the design of subsidy mechanisms), such as uncertainty about construction costs when a developer commits to building a project (Kreiss et al., 2017), or counterparty risk when the authority granting the subsidy is not fully reliable (Ryan, 2023).

While accounting for these specific characteristics of VRE technologies, this dissertation considers the subsidy mechanisms actually used by various governments to support wind and solar power and examine their performance in efficiently contributing to the (presumed) goals that governments pursue by subsidizing these energy sources. To this end, it relies on formal modeling of the behavior of rational, profit-maximizing firms in the face of these subsidy mechanisms. These approaches draw theoretically on contract and auction theory, and empirically on bottom-up simulations of renewable electricity generation and power system dispatch.

In what follows, we first provide a brief overview of the policy instruments that have been used to promote VRE deployment since the late 20th century, before discussing in more detail what policymakers should consider when designing such instruments. Then, we provide a brief summary of the contributions of this dissertation to this topic.

0.1 A short history of renewable electricity support

Aside from support for research and development (R&D), support for the deployment of VRE generation capacity first emerged in the 1980s in Europe and as early as the late 1970s in the United States, with programs that granted tax rebates to partially cover the investment costs of wind and solar power installations (IEA, 2023).

These early programs were followed in the 1990s by a wider variety of support mechanisms adopted in many European countries. A first classification of these support mechanisms was proposed by Faber et al. (2001) and is reproduced here in Table 1.³ This classification distinguishes between direct strategies, which provide direct support for VRE deployment through targeted instruments, and indirect strategies, which create favorable conditions for VRE deployment by addressing related issues (e.g. imposing a carbon tax on fossil fuel-fired power generation). Among the direct mechanisms, they distinguish between price-driven strategies on the one hand, which set a price or subsidy amount for VRE deployment (e.g., an administratively set tariff at which all VRE electricity is purchased) and let the market determine the amount of VRE capacity to be installed, and quantity-driven strategies on the other hand, in which the amount of VRE to be deployed is set by the regulator (e.g., the capacity to be subsidized through tenders). They also distinguish between regulatory strategies and voluntary strategies, the latter referring, for example, to green tariffs voluntarily offered by electricity providers to their customers, and between investment focused and generation based strategies, depending on which triggers the support received.

Among the direct regulatory mechanisms, on which this dissertation will focus, the three main systems implemented were quota systems based on tradable green certificates, administratively set feed-in tariffs, and tendering procedures for new capacity (Faber et al., 2001, Haas et al., 2011). All three induce generation-based additional revenue for renewable energy producers: administratively set feed-in tariffs guarantee that their production will be purchased at a preferential fixed price set in advance by the government (or regulator); competitive bidding sets a similar fixed price through an auction in which the least-cost projects are selected up to a predetermined quantity set by the regulator; while quota systems require electricity providers to purchase a certain number of "green certificates" in proportion to the amount of electricity they supply to their customers – green certificates that renewable energy producers emit

3. This table is an exact replica of Haas et al.'s (2011) table, although the meaning they attach to some of the terms may differ slightly from how they are used in this dissertation. In particular, "feed-in tariffs" and "fixed premium system" here refer to systems in which the subsidy is set administratively by the government, whereas these terms are used throughout the rest of this dissertation to refer to the contract design, even though these contracts are typically awarded through tendering procedures.

	Direct		Indirect
	Price-driven	Quantity-driven	
Regulatory Investment focused	Investment incentives, Tax credits, Low interest/soft loans	Tendering system for investment grant	Environmental taxes, Simplification of authorisation procedures, Connexion charges, balancing costs
Generation based	(Fixed) Feed-in tariffs, Fixed premium system	Tendering system for long term contracts, Tradable green certificate system	
Voluntary Investment focused	Shareholder programs, Contribution programs		Voluntary agreements
Generation based	Green tariffs		

Table 1 – Fundamental types of promotion strategies (source: Haas, 2011)

and sell in proportion to the amount of renewable electricity they produce. By the late 2000s, administratively set feed-in tariffs such as those introduced in Germany in 2000 with the EEG (Erneuerbare-Energien-Gesetz) law, were deemed as the most effective (Couture, Gagnon, 2010), with the European Commission stating that "well adapted feed in tariff regimes are generally the most efficient and effective support schemes for promoting renewable electricity".⁴ In comparison, quota systems were found to expose investors to high risk, as the market price of green certificates was difficult for investors to predict (Mitchell et al., 2006; Butler, Neuhoff, 2008). Moreover, by inducing direct competition between technologies these systems leave little chance for less mature technologies to develop (Meyer, 2003), which may lead to undesirable lock-ins in the long-run (Frondel, 2010). On the other hand, the bidding mechanism experimented with in the United Kingdom in the 1990s through the NFFO (Non-Fossil Fuel Obligation) has proved largely ineffective, since less than a third of the projects selected during the bidding process were actually carried out by the firms that had proposed them (Meyer, 2003). This phenomenon can be largely explained by the lack of penalties for developers in case of non-realization, which led them to consider the won contracts as options to be exercised in case of a sudden decrease in the cost of VRE (Cantillon, 2015; Kreiss et al., 2017; Matthäus, 2020).

4. See ec.europa.eu/energy/climate_actions/doc/2008_res_working_document_en.pdf.

When supporting VRE through administratively set feed-in tariffs, the level of subsidy provided has had an impact on the efficiency of the support scheme: those that set payment levels as close as possible to the actual costs of wind and solar power have been found to lead to more substantial deployment of VRE (Couture, Gagnon, 2010). This issue became critical in the early 2010s when the cost of solar PV modules suddenly collapsed, causing the levelized cost of electricity (LCOE)⁵ of solar PV to nearly divide by 2 between 2010 and 2012, and to divide by 2 again between 2012 and 2015 (IRENA, 2022). As this rapid cost reduction was not followed by a corresponding reduction in the subsidy levels set by governments, the existing feed-in tariffs became extremely attractive to private investors, leading to massive recourse that made these schemes financially unsustainable in several countries (Pyrgou et al., 2016). This phenomenon showed the need for a more appropriate way to adjust the level of payments to the real costs of VRE, which vary over time. In this perspective, the tendering procedure abandoned in the early 2000s became the object of renewed interest, as it offered a solution to adjust support to the evolution of VRE costs by having firms compete in an auction and reveal the minimum subsidy needed for VRE deployment (Cantillon, 2015). This prompted the European Commission to issue new guidelines in 2014, calling on EU member states to award VRE subsidies through tender procedures in which the least-cost projects are selected through auctions (European Commission, 2014). In line with these guidelines, most governments in the EU have abandoned administratively set feed-in tariffs for utility-scale solar PV and wind power plants and have instead begun to regularly hold auctions to award subsidy contracts for a pre-determined amount of capacity. These systems would give the government some control over the total VRE capacity to be subsidized while ensuring that payment levels decrease as VRE costs decrease.

During the same period, the prevailing contract design, i.e., the rule that determines payments made to subsidized VRE plants (as opposed to the selection process discussed above), which most governments used, fixed feed-in tariffs, also came under scrutiny. While the fixed revenue received per unit of energy produced under this

5. The LCOE is a widely used metric in the electricity industry to compare generation technologies or power plants. It is the sum of the discounted costs over the life of a plant divided by the sum of the electricity generated by that plant (which is also discounted).

scheme induces little risk for investors, which contributes to the efficiency of the support mechanism, it also completely insulates VRE producers from the price signals conveyed by electricity market prices. This feature had a downside that was eventually recognized due to the increasingly frequent occurrence of negative prices in wholesale electricity markets: wind and solar plant operators were incentivized to continue production during these periods (even though they could interrupt it at little or no cost) because doing so would increase the revenue received under the feed-in tariff support schemes. Other technologies would have to cease production instead of VRE (and at a cost), resulting in these negative prices (Brandstatt et al., 2011). Feed-in tariffs thus imply distorted incentives for the operation of renewable energy power plants and undermine the efficiency of power dispatch, but the lack of exposure to market prices also means that developers had no incentive to make technology or siting choices that would have allowed them to obtain higher market prices (Schmidt et al., 2013). For example, exposure to market prices should motivate investors to place a higher value on higher swept area wind turbines (Hirth, Müller, 2016; May, 2017) and solar panel orientation diversification (Hartner et al., 2015), as these typically favor production profiles that better match periods of high electricity market prices. In light of these issues, a 2018 directive issued by the European Union called on member states to offer subsidy contracts for VRE "in a market-based and market-responsive way" and further specified that subsidies "shall be granted in the form of a market premium, which could be, inter alia, sliding or fixed" (European Parliament, 2018).

Although it closes the door to administratively fixed feed-in tariffs for utility-scale projects,⁶ the Directive still opens the way to a variety of contracts that could be adopted in practice by Member States. In practice, the support mechanisms used by different governments (within and outside the EU) are indeed very diverse. Some of the features in which these mechanisms may differ are summarized in Table 2. The way in which subsidy contracts are awarded to VRE projects, i.e. the diversity of auction designs, has been studied extensively in the literature, in particular through the work carried out by the AURES (Auctions for Renewable Energy Support) project (see e.g. Anatolitis et al., 2022). In contrast, the diversity of contract design has received less

6. Small-scale installations and demonstration projects are exempted from these restrictions.

Table 2 – Non-exhaustive inventory of the diversity in tender-based VRE subsidies

Auction Design
<ul style="list-style-type: none"> • Degree of specificity <ul style="list-style-type: none"> — Technology-neutral – <i>Different technologies (wind, solar) can compete in the same auction</i> — Technology-specific – <i>Separate auctions are organized for each technology, but any project of this technology can compete</i> — Project-specific – <i>An auction is organized for a specific project with many characteristics, typically location and total capacity, being predefined. Typically used for offshore wind projects.</i> • Qualification conditions (<i>financial deposit, building permit...</i>) • Pricing rule <ul style="list-style-type: none"> — Pay-as-bid – <i>Each selected project is subsidized according to its own bid</i> — Uniform price – <i>All selected projects are subsidized according to the bid of the last project accepted (or first project rejected)</i> • Auction format <ul style="list-style-type: none"> — Static / Sealed Bid auction – <i>Candidates place a single bid, that is not revealed to other bidders before the auction is resolved</i> — Dynamic / Descending Clock auction – <i>Bidders learn the bids of other bidders during the auction process, and can subsequently undercut them</i> — Hybrid Formats – <i>Auction processes divided into phases combining static and dynamic formats</i> • Reserve price / Floor price – <i>Maximum / Minimum bid accepted in the auction, which may or may not be made explicit to bidders (but still implies the elimination of all bids placed above/below this price)</i> • Non-price award criteria – <i>Evaluation criteria other than the amount of subsidy required that may be considered in the ranking of bids, such as the project's environmental impact or impact on local employment</i> • Discrimination in favor of specific actors (<i>e.g., citizen energy cooperatives</i>)

Contract Design

- Type of contract
 - Feed-in Tariff (FiT) – *All the electricity produced is bought at a predetermined price (typically the bid placed in the auction)*
 - Fixed Feed-in Premium (fFiP) – *The VRE producer sells its production on electricity markets, and receives a fixed premium (typically the bid placed in the auction) for each unit of electricity produced*
 - Sliding Feed-in Premium (sFiP) – *The VRE producer sells its production on electricity markets and receives a compensation for the difference between a reference price observed on the wholesale market and a predetermined strike price (typically the bid placed in the auction)*
 - Reference price definition [*Applicable to sFiP*]
 - Averaging period – *Is the reference price considered the average price over one year, one month, one day or the price observed each hour?*
 - Weighting applied – *Is the reference price a weighted average? if it is, is it by the total load, by the total production of a technology category (solar, wind)...*
 - Two-sided or one-sided [*Applicable to sFiP*] – *Whether or not negative subsidies are to be paid back by the VRE producer when the reference price exceeds the strike price (yes for two-sided sFiP, no for one-sided sFiP)*
 - Time-varying tariff (*Tariff at which electricity is bought/Amount of the premium received varying in time, e.g. with a winter/summer rate, day/night rate...*)
 - Negative Price Clause – *Clause that prevents VRE from being incentivized to produce electricity when wholesale electricity market prices are negative, e.g., by temporarily suspending subsidy payments*
 - Cap/floor on total payment or on payment per given period, non-linear payment rules or other sophisticated payment rules – *Adjustment in the determination of subsidy payments aimed at minimizing variability in the perceived subsidy*
 - Contract Term – *Typically 15 to 25 years, sometimes expressed in amount of energy produced (subsidy ends after X TWh has been produced by the plant)*
 - Subsidy Adjustment for Inflation / Indexation on a Stable Currency (*e.g., subsidy denominated in USD*)
 - Penalties for Delays / Non-realization of the project
 - Preferential conditions, reduced cost for the connection to the power grid
-
-

attention in the literature, even though it may have significant implications for the efficiency of support mechanisms.

This dissertation aims to fill this gap and examine these diverse contract design features which are often hidden under generic labels typically limited to "feed-in tariff", "feed-in premium" or "sliding feed-in premium". It is worth noting that this diversity of contract designs has been a recurring caveat in the empirical literature comparing the performance of the different schemes adopted in different countries through the observed bids (Winkler et al., 2018; Jansen et al., 2020). Indeed, the price observed from the bidding process in one country is typically not directly comparable to the price observed in another country, as the same price does not induce the same payment.⁷

Nevertheless, in the late 2010s in Europe, tender results have shown a decrease in the subsidies required by VRE developers, with some projects appearing to be profitable with "zero subsidies" (Jansen et al., 2020). However, the continuation of this historical trend is not guaranteed for several reasons. First, wind and solar sites are a finite resource, and their cost per energy output may begin to rise again as the windiest and sunniest locations are exhausted. Second, the growing share of VRE in the mix tends to reduce the revenues that wind and solar power can earn in the electricity market alone: as the share of wind and solar power in the mix grows, electricity will become cheap during periods when the wind is blowing or when the sun is high, hurting the revenues of wind and solar producers. This phenomenon, known as the cannibalization effect (Hirth, 2013; Prol et al, 2020), may become much more pronounced in the coming years as the share of wind and solar in the mix reaches a critical point (and massive storage is not yet available). Indeed, taking this effect into account, it appears that subsidies will still be needed in the near and medium term to make renewables profitable (Alonzo et al., 2022).

Moreover, as noted by Jansen et al. (2020), the observation of zero-subsidy bids

7. For example, the sliding feed-in premium mechanisms in France and Germany may appear comparable at first glance, but the contracts implemented are two-sided in France and one-sided in Germany. This means that when the reference market price observed on the wholesale market is high, above the strike price, VRE producers have to pay back a negative subsidy in France but not in Germany. Thus, a similar strike price observed in both countries does not induce the same expected payment to VRE producers. Moreover, different prices observed in the two wholesale markets would also imply different levels of subsidy for the same strike price.

should not necessarily call for the discontinuation of the VRE support mechanism, as these support schemes also mitigate the risk on future revenues (even in the absence of expected net subsidies). This risk mitigation is key to reducing the cost of capital, which accounts for a large part of the cost of VRE (due to its large upfront costs and delayed revenues). The recent Covid-19 and Ukraine crises have drawn attention to the unpredictable shocks that energy markets can experience and the magnitude of the risks associated with any investment in power generation capacity over the medium to long term. In this context, the use of mechanisms similar to those used to subsidize VRE has even been suggested as a tool to manage this risk for investments in most power generation capacity, beyond VRE alone (Fabra, 2022).

0.2 What makes a good subsidy contract?

In a context where the subsidy mechanisms used by governments have demonstrated the potential diversity of these instruments, this dissertation examines some of these mechanisms from an economic perspective in order to provide public policy recommendations regarding their design. Doing so, we focus on three main issues. First, we consider the ability of these mechanisms to induce investment with the greatest possible contribution to welfare. In other words, we seek to determine whether the incentives provided to VRE project developers are consistent with the objectives of a welfare-maximizing regulator. Second, we account for the constraints on the availability of public funds that may lead regulators to want to limit the public cost of VRE subsidies. From this perspective, mechanisms that limit the risk borne by investors would be desirable because they would limit the risk premiums required, and make investment in VRE more attractive at constant subsidies. Third, we consider the possible existence of loopholes in the design of support schemes that may lead to harmful strategic behavior on the part of subsidized firms.

Aligning Private Interests with Government Objectives

One of the elements that has motivated the evolution of the subsidy mechanisms implemented since the 1990s is that changes in the design of subsidy contracts can

induce changes in the incentives passed on to VRE developers. Fixed feed-in tariffs, by offering the developer a fixed revenue per unit of energy produced, induce these developers to select projects with the lowest LCOE, i.e., projects that minimize the cost per unit of energy produced. Yet, as pointed out by Joskow (2011), LCOE is a biased measure of a renewable project's contribution to welfare because it ignores the timing of its production. This was the main motivation for the shift from fixed feed-in tariffs to premium schemes: exposure to electricity market prices was considered a better option to induce VRE developers to take into account the economic value of the electricity they produce (or should stop producing if prices are negative) and the economic value of the projects they conceive (by favoring the expected production profile likely to capture higher prices). The implicit assumption here is that the wholesale market price of electricity is a good measure of the welfare contribution of a VRE power plant's output. However, such an implicit assumption should raise the question of the rationale for subsidies at all, and why not just let VRE producers sell their output into these wholesale markets.

Such public intervention is typically motivated by externalities, here components of economic value that are not reflected in the market value of electricity. In the case of VRE, these numerous externalities have been reviewed by Borenstein (2012). Learning-by-doing and CO₂ emission reduction are among the most commonly cited to justify production subsidies for wind and solar. Although the first best policy instrument to address the negative externality associated with CO₂ emissions would be a carbon tax, subsidies for VRE production have often been described as a second best instrument, considered more feasible due to better social acceptance.⁸ With this perspective, it has been argued that subsidies for VRE should be proportional to the amount of CO₂ emissions it displaces, which may vary, in particular, depending on the technology or location of the VRE project (Cullen, 2013; Callaway et al., 2018; Abrell et al., 2019). While this consideration has generally been discussed for differentiating subsidies across technologies or across energy systems, in this dissertation we

8. It is noteworthy, however, that past VRE subsidies in Europe may have been largely ineffective in mitigating CO₂ emissions due to their combination with the EU Emissions Trading Scheme (ETS) and the resulting so-called waterbed effect (Eichner, Rüdiger, 2019): additional VRE production, if replacing fossil fuel power generation, would free up some emission quotas that would be used by another industry subject to the ETS.

extend this consideration to comparing specific individual projects and the amount of emissions they displace (Chapters 2 and 3).

The other commonly cited externality, learning-by-doing, refers to the future cost reductions resulting from the deployment of new VRE capacity, which would justify subsidizing this development today because it will induce future welfare benefits associated with these cost reductions, welfare benefits that will not be compensated if the sale of VRE output in electricity markets is the only source of revenue. The evolution of the costs of wind and solar technologies suggests that this externality is massive, justifying the large subsidies that were provided when these technologies were less mature (Newbery, 2018). The justification of these subsidies by the learning-by-doing externality raises a debate about the form these subsidies should have taken, with some pointing out that subsidies should be allocated in proportion to what triggers this learning-by-doing, namely additional capacity rather than production (Andor, Voss, 2016). However, the capacity-based subsidy system that these considerations require may induce adverse investment decisions that focus on nameplate capacity rather than potential production, which has been termed the steel-in-the-ground effect (Boute, 2012; Meus et al. 2021).

Other externalities associated with VRE, not discussed in this dissertation, may also require some form of public intervention, either benefiting or disadvantaging VRE. One negative externality is that these technologies negatively affect the cost of ancillary services due to the difficulty of predicting VRE generation, even in the short term (Tageras, Wolak, 2019). Another potential negative externality is that the geographic concentration of VRE power plants in sun- or wind-rich regions sometimes leads to grid congestion (see, e.g., Fell et al., 2021 or Gonzales et al., 2022), so that the output of a VRE plant that is highly valued in a national wholesale market might not be delivered to consumers in practice.⁹ In contrast, some have argued that the distributed nature of VRE, with small power plants scattered across the territory, can reduce network cost by bringing electricity production closer to consumption. Yet,

9. This phenomenon actually implies an externality only in the absence of locational marginal pricing (LMP), which allows the price of electricity to vary from one location to another to account for congestion. This is the case in Germany, for example, where the regulator is trying to address the concentration of wind power in the north of the country by differentiating subsidies depending on the location of the project (Hitaj, Löschel, 2019).

this positive externality has been found to be very small if not negligible, with a very limited impact on network needs in practice (Astier et al., 2023).

In order to justify subsidies for VRE (and to examine their design), an approach different from the one based on the identification of externalities would be to consider, from a cost-effectiveness perspective, simply as a constraint the renewable energy development objectives decided at the policy level. Thus, the value of VRE production would consist, on the one hand, of its market value (and possibly externalities), but completed with an additional value corresponding to its contribution to the government's objectives for wind and solar development. Since some governments have set targets for total VRE production, as is the case in the EU, each unit of VRE produced should thus be assigned a fixed positive "externality" reflecting this contribution (Meus et al., 2021).¹⁰

Limiting Public Costs by Limiting Risks

Seeking to design subsidy schemes that encourage VRE developers to behave in a certain way may, however, increase the risk to which they are exposed. This trade-off is illustrated, for example, by the financial guarantees required in tenders and the penalties for not implementing projects: these provide a better incentive not to bid too low in auctions for projects to be effectively profitable, but at the same time they introduce risk and may discourage project developers, who can no longer simply abandon the project in case of difficulties after a subsidy contract has been awarded (Kreiss et al., 2017). As mentioned above, this dissertation does not address these risks that materialize during project development, but rather focuses on two risks that affect project revenues during the operational phase of VRE plants: the risk regarding the amount of electricity produced by the plant, which depends on the weather conditions during operation, and the risk regarding the price at which this electricity can be sold, which (depending on the subsidy mechanisms used) may depend on the conditions in electricity markets.

The risk associated with the amount of electricity produced by a VRE plant,

10. As noted by Meus et al. (2021), a fixed feed-in premium scheme happens to fit perfectly with this fixed positive externality per energy produced.

or generation risk, remains fairly limited and, with a few exceptions (including the mechanism discussed in Chapter 1), is generally left to the project owner: even under a feed-in tariff contract, which will be more or less considered the risk-minimizing benchmark contract throughout this dissertation, the revenue generated by a VRE project is directly proportional to the amount of energy produced (so that project developers have an incentive to design productive VRE plants). This risk remains limited in particular because the quantity produced in one year will be compensated from year to year, the weather conditions observed in one year not being correlated (or weakly) to those of the following years. A risk that is persistent throughout the operation of the projects, but still limited, is that of having misjudged the site's resource.¹¹

In contrast, electricity market prices in the future are hard to predict and could easily be higher or lower than expected over the whole lifetime of a VRE project. Thus, exposing VRE producers to electricity market prices, as may be necessary to provide better incentives to VRE developers, creates a greater risk to project revenues. Some components of market price fluctuations follow regular patterns that developers should expect (e.g., higher prices in the evening, in winter, lower prices in windy or sunny weather), but some other determinants of these market prices are largely unpredictable. One is the price of fossil fuels, especially natural gas, which is a major determinant of electricity prices in many countries and is subject to factors that are difficult to predict in the mean term (as the Ukraine crisis demonstrated). Similarly, the cost of CO₂ emissions has a direct impact on marginal generators (often gas or coal-fired) and thus on the market price of electricity. However, the cost of CO₂ emissions is mainly subject to political decisions, such as the carbon budgets allocated under the EU ETS, which are also difficult to predict for investors in VRE projects. The evolution of electricity market prices is also strongly dependent on the evolution of the power system, and in particular on the total installed capacity of each technology. For example, a rapid increase in installed VRE capacity in a country will lead to a more pronounced decline in market prices (which will moreover affect the VRE power plants

11. This risk concerns mainly wind power plants, and the techniques of resource assessment have improved significantly in recent years (Jourdier, 2017).

themselves more strongly due to the cannibalization effect). However, the ability to predict the evolution of the power mix is limited: although governments typically publish development plans that provide insight into future capacity to be installed and retired, the realization of these plans is not guaranteed, and actual developments may differ significantly from the announced scenarios.

Contract theory would recommend that VRE support mechanisms should expose developers to risks over which they have some control in order to induce them to mitigate those risks, while insulating them from risks over which they have no control, such as those mentioned above (Cantillon, 2015). One reason for this is that this greater risk borne by investors comes at a cost: by making these risky investments less attractive, it induces firms to demand an additional expected profit to compensate for these risks, known as a risk premium. In a context where subsidy contracts are awarded through auctions, this risk premium will be reflected in higher bids from developers. In the broader context of procurement auctions, these risk premiums should induce auctioneers to transfer as much risk as possible from bidders to the buyer through contract design, as this is likely to induce lower bids (Engel et al., 2001).¹² Indeed, VRE support mechanisms that limit investor risk have been found to lower the cost of capital (Newbery, 2016; May, Neuhoff, 2021) and thus require smaller subsidies (Kitzing, 2014, Kitzing, Weber, 2014).

This recommendation to limit the risk borne by investors is somewhat at odds with the recommendation to expose developers to market prices. This dissertation provides a quantitative comparison of the stakes on these two dimensions, and shows that some (more sophisticated) contract designs, such as sliding feed-in premiums, manage to reconcile them (Chapter 3). We also find that the risk premiums induced by full exposure to market prices appear to be larger than the potential welfare loss induced by insulating developers from price signals.

12. The contract design proposed and discussed by Engel et al. (2001) for highway concessions is such that the contract duration is adjusted to compensate for lower than expected traffic on the highway (and thus lower toll revenues). Interestingly, a similar mechanism is implemented in some EU countries (e.g., Germany, Denmark) for wind power, by adjusting the duration of the subsidy contract depending on the amount of electricity produced.

Avoiding Manipulable Designs

While regulators try to anticipate the strategy that firms will adopt in the face of a given regulation, the anticipated strategy may be overly simplistic or naive compared to what firms actually choose to do. As a result, the regulation that is ultimately adopted may have unanticipated side effects or perverse incentives due to loopholes in its design that were not identified or properly addressed.

An example of this in the electricity industry would be the way some U.S. states regulate monopoly utilities, by periodically reviewing their costs over a specified period of time to update the retail price at which they can sell electricity to consumers. In this way, the regulator expects to be able to set the price at a level that is just sufficient to cover the monopolist's costs. Abito (2019) shows that in the face of such regulation, utilities tend to operate their generation fleet inefficiently during the period in which their costs are being monitored, in order to increase the legally set price that will apply for the next few years. Similarly, in liberalized electricity markets, some regulators have attempted to prevent large electricity producers from exercising market power by imposing restrictive rules on the price bids that can be submitted to the wholesale market, ignoring that the firms can instead drive up prices by strategically making some of their generating units unavailable (Wolak, Patrick, 2002).

The issue of strategic agents taking advantage of a manipulable design also arises in the context of public procurement auctions, which include the VRE auctions discussed here. Mechanisms that combine an auction with subsequent contracting may indeed allow bidders to engage in strategic behavior that gives them a comparative advantage. This is all the more likely the more complex the design of the mechanism. A typical example of such behavior is skewed bidding, a strategy that has been observed in various domains such as timber auctions (Athey, Levin, 2001), online advertising auctions (Agarwal et al, 2009), or infrastructure procurement (Luo, Takahashi, 2019).¹³ Other strategies may arise from features designed to insure bidders against a risk associated with the contract being auctioned, in order to lower

13. Such strategies arise in auctions where bids are made on multiple items and are ranked by a weighted average: if bidders anticipate an error in the weights used to rank bids, they will be tempted to inflate their bids on items whose weight is underestimated and to deflate their bids on items whose weight is overestimated.

bids, as discussed above. An example of such a case was identified by Ryan (2020) in auctions for the construction and operation of coal-fired power plants in India: the auctioneer offered bidders the possibility of being insured by the contract against coal price fluctuations at the cost of a penalty in the bid ranking. He shows that firms that were well-connected to the government and knew that they could renegotiate their contract *ex post* in the event of a coal price spike opted out of the insurance offered in the auction, thereby gaining a comparative advantage over other bidders. In this dissertation, we describe and analyze another case where a feature of an offshore wind subsidy contract designed to insure against weather variability (and the resulting production variability) actually opened the door to strategic behavior by bidders (Chapter 1). More generally, it appears that if governments should attempt to insure VRE developers against price variability, they should not do so for production variability (especially based on self-reported expected production).

0.3 Contributions

This thesis is divided into three chapters, each of which provides different insights into the design of VRE production subsidy contracts.

In the first chapter, we consider the subsidy mechanism that has been used in France for the first offshore wind tendering procedure in 2011 and 2013. We further generalize our results to auctions for procurement contracts involving exogenous production risk and whose payment rule depends not only on actual production but also on self-reported expected production. We first establish a conflict between insurance provision and strategy-proofness. We then analyze equilibrium bidding behavior under several paradigms regarding bidders' ability to misreport their expected production: Payment rules that are manipulable could produce rents for strategic bidders which may overwhelm the benefits from reduced risk premiums thanks to insurance provision. We illustrate our results through simulations calibrated on the offshore wind power auctions held in France and estimate that public spending could have increased by 3% given that strategic bidders would benefit from overestimating their expected production by more than 10%. Such potential losses are 15 times greater

than the potential benefits from reduced risk premiums under truthful reporting. We also introduce variants of the French rule with punishments intended to discourage misreporting, and find limited room for improving linear contracts. Various extensions of our baseline model are discussed.

In the second chapter, we are interested in measuring and comparing the social benefits associated with specific VRE projects, in order to better understand the incentives that should be passed on to VRE developers. We define the social benefits of a variable renewable energy (VRE) power plant project as its contribution to meeting electricity demand, i.e., the costs and externalities that are avoided by other means of electricity generation in the power system. These depend on various characteristics (e.g., location and technical characteristics) that determine how much and when each project would produce electricity. While the market value of a project's output is generally considered a good measure of these social benefits, we detail why it is incomplete. A case study of a sample of solar and wind projects in France allows us to quantify the errors in project comparisons resulting from an incomplete consideration of two determinants of social benefits: CO₂ emissions avoided, and the increasing share of VRE in the mix that decreases the value of VRE's output. Using a power dispatch model to accurately assess the value of each project through counterfactual simulations, we find that, while these errors are not negligible, a simple correction applied to the market value of the projects corrects them for the most part.

In the third chapter, we study the trade-off for the regulator raised by support mechanisms for variable renewable electricity (VRE) projects that expose firms to market electricity prices: these mechanisms 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.

Chapter 1

Pitfalls of insuring production risk ¹

Abstract

We consider auctions for procurement contracts involving exogenous production risk and whose payment rule depends not only on actual production but also on self-reported expected production. We first establish a conflict between insurance provision and strategy-proofness. We then analyze equilibrium bidding behavior under several paradigms regarding bidders' ability to misreport their expected production: Payment rules that are manipulable could produce rents for strategic bidders which may overwhelm the benefits from reduced risk premiums thanks to insurance provision. We illustrate our results through simulations calibrated on a few offshore wind power auctions in France and estimate that public spending could have increased by 3% given that strategic bidders would benefit from overestimating their expected production by more than 10%. Such potential losses are 15 times greater than the potential benefits from reduced risk premiums under truthful reporting. We also introduce variants of the French rule with punishments intended to discourage misreporting, and find limited room for improving linear contracts. Various extensions of our baseline model are discussed.

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1.1 Introduction

The transition towards low-carbon economies has led many countries to support renewable energy sources of electricity (RES-E) on a large scale, especially wind and solar power. This support often involves subsidy contracts awarded to RES-E projects through auctions.² These can be regarded as standard procurement contracts through which public authorities buy green electricity, and which involve various risks for the producer. In general, when producers are more risk averse than the public decision-maker, designing Public–Private Partnerships such that producers bear a smaller share of these risks reduces risk premiums (Engel, Fischer and Galetovic (2013)), and thus in our case may help to develop RES-E at a lower cost (Cantillon, 2015). As an example, Engel, Fischer and Galetovic (2001) plead for least-present-value-of-revenue auctions where the franchise terms adjust to demand realizations: according to their estimates for a highway franchising project in a developing country, such contracts could reduce public spending by more than 20% compared to the widespread fixed term contracts where contractors bid on tolls.

RES-E are often subsidized through Feed-in-Tariffs (FiT) where producers receive a fixed subsidy for each MWh produced. Producers' revenue is thus proportional to the quantity produced, even though wind and solar electricity generation does not involve variable costs. Henceforth, FiT contracts make producers' revenues highly dependent on the quantity produced, which is in turn highly dependent on weather conditions. As argued by Cantillon (2014), economic theory calls for reducing producers' exposure to risks over which they have no control, such as the weather, while risks over which they have some control call for contractual arrangements that tradeoff the benefits of risk sharing with incentive provision. Incentivizing producers to make ex ante efforts to upgrade production (e.g. through turbine model selection) is the main rationale for using FiT contracts instead of capacity (or investment) subsidies: the latter fully eliminate both risk exposure and incentives to maximize production.³ Nevertheless,

2. In 2019, an estimated 115 GW (resp. 60 GW) of solar PV (resp. wind power) capacity was installed worldwide. RES-E subsidies were awarded through auctions in 48 countries according to REN21's 2020 global status report.

3. Huenteler et al. (2018) analyze the performance of wind farms and argue that the huge gap between US and China is driven by factors that are related to efforts made by the producers.

once the RES-E capacity is built and connected to the electricity network, producers have no control over the quantity produced which they then view as an exogenous risk. For wind farm projects, this risk is not negligible since the standard deviation of the yearly production could represent at least 10% of the mean production (Newbery, 2012) but also and mainly because until recently wind power forecasting suffered from an important over-prediction bias.⁴ Some countries – including Brazil, France and Germany – have departed from (standard) linear FiT and adopted contract designs (henceforth referred to as “payment rules”) where wind farm revenue is made less sensitive to production variations within an interval around the reported reference production. For instance, the payment rule for early offshore wind auctions in France was designed in a way that makes producers’ yearly revenues almost insensitive to the annual quantity produced within $\pm 10\%$ around a *reference production* reported by the producers themselves. We presume that the rationale for such a risk sharing agreement was to lower the risk premiums producers include in their bids, and thus to reduce public spending.

However, such designs open the door to strategic behavior, in particular when letting producers freely self-report their reference production.⁵ We formalize and analyze this pitfall through a model where a set of firms compete for a procurement contract in which the buyer’s total payment is a function of the contractor’s per-unit price bid, of its actual production (whose realization is determined after the auction) and of the reference production as reported in the contractor’s bid. We call *linear contracts* the rules where the total payment is equal to the per-unit price bid times the actual production. The winning firm is selected on the sole criterion of its per-unit price bid, regardless of the reported reference production. We then consider two kinds of firms: those that are constrained to report their expected production truthfully and those that are entirely free – at no cost – to make any possible report. The former (resp. latter) firms are called truthful (resp. strategic).

We introduce the class of so-called *production-insuring payment rules* which we

4. See Lee and Fields (2020) for a survey.

5. E.g., in offshore wind farm auctions in France, the reference production was based on the firm’s own data and calculation and there was thus no guarantee that this self-reported parameter would correspond to the expected production.

define as the rules such that the buyer's expected cost is the same as in the linear contract while the expected utility of any risk averse contractor is greater for any symmetric production distribution and any given per-unit price, and provided that the reference production matches the expected production. However, the buyer's expected cost depends on the chosen payment rule insofar as the per-unit price results from a competitive auction. Under truthful reporting, a production-insuring payment rule incurs (by definition) lower risk premiums compared to the linear contract. These will be reflected in lower equilibrium price bids placed by the firms, and consequently in a lower expected cost for the buyer.

Production-insuring payment rules seem to be a salient choice for risk neutral buyers facing risk averse firms as they certainly represent an improvement over the linear contract when all firms are truthful. Our research question is then to analyze the performance of such rules if we depart from the assumption that all bidders are necessarily truthful.

As a preliminary, we analyze the incentives of strategic firms to misreport their expected production. We formalize a fundamental conflict between insurance provision and strategy-proofness: for any given production-insuring payment rule and any given symmetric single-peaked distribution, risk neutral firms strictly benefit from stating a reference production greater than their actual expected production. We also impose additional structure to analyze the incentives to manipulate the payment rule under risk aversion and to derive some comparative statics. We show in particular that risk aversion reduces the incentive to overstate the reference production.

Such deceptive behavior gives a comparative advantage to strategic firms. Furthermore, a strategic firm overstating its reference production in its bid causes disappointment for the buyer when it wins the auction: the effective per-unit price, i.e. the average ex post subsidy paid per quantity produced, will be greater than the submitted price bid. With a production-insuring payment rule, the effective per-unit price and the submitted price bid only match when the winning firm reports its actual expected production as its reference production. Intuitively, the larger the misreporting, the larger the discrepancy between the effective subsidy and the bid.

We then analyze the auction game when firms differ only regarding their ability to

misreport their reference production. We consider that all firms have the same production distribution, the same costs and the same payoff function (capturing possible risk aversion). We first derive the equilibria under complete information, depending on whether and how many firms are truthful or strategic. Second, we derive the (mixed strategy) equilibrium when each firm is, independently of the others, either truthful or strategic with some given probability. In all cases, we establish that the presence of strategic firms produces a lower equilibrium price compared to the case where all firms are truthful, but the buyer's expected cost does not necessarily decrease, quite the contrary.

Production-insuring payment rules not being strategy-proof leads to two kinds of pitfalls to which the linear contract is immune: a) Instead of evening out the firms' revenue (as would be the case under truthful reporting), a production-insuring payment rule could have exactly the opposite effect, as illustrated in Section 1.2, and those risks are borne ultimately by the buyer through an increased risk premium. b) Heterogeneity regarding the ability to misreport the reference production leads to non-competitive rents. Informally, these rents increase with the degree of heterogeneity: the highest buyer's expected cost is reached when a single strategic firm captures all the benefits from strategic misreporting. In the specific case where firms are risk neutral the comparison is unambiguous: for any symmetric single-peaked production distribution, the linear contract (strictly) outperforms any production-insuring payment rule provided that there is a positive probability of having a single strategic firm.

We then use our RES-E application to illustrate those effects quantitatively. We consider the production-insuring payment rule which was used in early offshore wind auctions in France and calibrate the production risk distribution based on wind production simulations. For any realistic degree of risk aversion, we find that the potential benefits from insurance provision are much lower in magnitude than the potential losses due to misreporting. Furthermore we show that the largest pitfall of production-insuring payment rules does not result from misreporting per se (since risk premiums are actually quite small) but rather from the non-competitive rents resulting from the possible heterogeneity in the way bidders (mis)report their reference production.

According to our simulations with a coefficient of risk aversion equal to 1, the non-competitive rents accruing to a single strategic firm exceed 3% of the buyer's expected cost while the risk premiums barely exceed 0.3%.

On the whole, this first step of our analysis can be viewed as a strong warning against production-insuring rules: if the buyer is poorly informed about the distribution of production risk such that it can not screen the reference production, then departing from linear contracts to reduce risk premium seems quite a risky bet.

Last, we depart from our baseline model in two directions. First, we depart from production-insuring payment rules and adopt the perspective of a sophisticated buyer who anticipates firms' strategic behavior and can partially adapt its payment rule to the production risk. While only imposing that the payment rule should be homogeneous of degree 1, we establish that it is impossible to eliminate the risk premium with strategic bidders: for any given symmetric single-peaked production distribution and any form of risk aversion, we cannot design a payment rule such that strategic firms would be fully insured against production risk. Then, inspired by the payment rules that have been used in some countries to subsidize wind farms, we analyze, using numeric simulations, a class of payment rules that introduces on top of insurance provision some punishments consisting of payment cuts in case actual production is too far removed from the reported expected production. Heftier punishments reduce the incentives to misreport production, and then a fine-tuning of these punishments could allow strategy-proofness to be restored and eliminate non-competitive rents. However, such payment rules could exacerbate the risk associated with the lowest levels of actual production, producing effects on risk premiums and on the cost for the buyer that are not clear-cut.

Second, we discuss the relevance of our results beyond our limited framework and question more generally the benefits of departing from the linear contract: we start with a discussion on the (non)optimality of the linear contract when firms are risk neutral in the presence of both moral hazard and adverse selection, we then depart from the multiplicative payment rules we considered where the remuneration is proportional to the price bid; we consider moral hazard meaning that the winning firm can make some efforts ex post to upgrade its production distribution; we extend

our analysis to environments where production involves variable costs on top of the initial investment cost; we briefly sketch how non-competitive rents would be modified if the asymmetry between firms comes not only from the heterogeneity in terms of truthful/strategic behavior but also in terms of cost and production distribution; last we discuss the case where misreporting is costly.

Links with the literature

Like Eso and White (2004), we consider an auction setup where bids incorporate risk premiums because the value of the good for sale, or equivalently the profit from the contract to be awarded, suffers from an exogenous risk. However, the connection goes no further because Eso and White (2004) do not consider contingent auctions but rather analyze –and compare– standard auction formats and how informational rents interact with risk aversion.

Contingent auctions This paper contributes to the theoretical literature on contingent auctions as surveyed by Skrzypacz (2013). Hansen’s (1985) seminal contribution shows that royalty auctions leave lower informational rents to the winning bidder compared to cash-only auctions. More generally, DeMarzo et al. (2005) introduce the concept of “steepness”, arguing that having “steeper” securities reduces informational rents. Intuitively, the ranking of securities with respect to the concept of “steepness” is related to risk sharing. In this vein, Abhishek et al. (2015) consider a model with risk averse bidders and argue that steeper securities are beneficial not only because they reduce informational rents but also because they provide more insurance and thus reduce risk-premiums.

The empirical literature on auctions and procurement is also taking a growing interest in auctions involving contingent contracts. Bhattacharya et al. (2018) consider auctions for oil tract contracts and analyze the trade-off between the benefits for having higher royalties (reducing both risk premiums and informational rents as argued above) and the losses resulting from inadequate incentives to drill (or not) the tracts in an efficient manner. They estimate that the optimal royalty rate is around 26% which is more than 50% higher than the one currently used in oil lease auctions. The analog of this issue in procurement is the analysis of the performance of Fixed Price (FP)

contracts – where the contractor bears all the cost overruns – versus unit-price (UP) contracts that specify a percentage of the observable costs that accrue to the buyer. In procurement for transport infrastructure projects, Bolotnyy and Vasserman (2019) estimate that switching to a FP contract would more than double public spending compared to a UP scaling auction where producers are partially insured against cost overruns. For similar infrastructure projects, Luo and Takahashi (2019) show that UP contracts are chosen by project managers more often than FP contracts when the projects are more complex and thus more risky *ex ante* in terms of cost overruns, suggesting that they are regarded as an appropriate risk management instrument.

In our setup, linear contracts correspond to cash-only auctions or FP contracts in the sense that bidders perceive it as being the most risky. On the contrary, production-insuring payment rules correspond to risk sharing agreements as with royalty contracts (to share the stochastic benefits) or with UP contracts (to share the stochastic costs). The trade-off we analyze here is different from what has been previously covered by this strand in the literature, as we leave aside moral hazard to focus on an asymmetric information problem resulting in an opportunity to game the auction rule thanks to the insurance-provision feature of the contract. This leads us to another strand of the auction literature to which our work is related.

Bid manipulation/Gaming in auctions This paper contributes to the literature involving flaws in the bid evaluation process, either because some bidders have opportunities to “game” the auction rules or because the principal is corrupted and could deliberately misevaluate some bids in exchange for a bribe.

Various contributions have investigated the benefits of individual manipulations, where bidders do not bid according to the “spirit” of the auction rules. We stress that such manipulations are often legal but may not be available to all bidders either due to a lack of sophistication/rationality or to a lack of information. These issues arise in complex environments, in particular when bids are multi-dimensional.⁶ Yokoo et al. (2004) consider multi-object combinatorial auctions where bidders can benefit from

6. The standard auction formats (that prevail in auction textbooks, e.g. Krishna (2002)) are immune to individual gaming strategies, but not to collective manipulations which are referred to as collusion and have received considerable interest (see for instance Correia-da-Silva (2017) for a survey).

using multiple identities to bid in the auction.⁷ In scaling auctions, the score of a bid is computed based on ex ante estimates of the various underlying quantities. If bidders receive, ex ante, information about actual quantities, then they will benefit from skewing their bids (Athey and Levin, 2001).⁸ In a related manner, Agarwal et al. (2009) discuss such incentives and mention other manipulations in sponsored search auctions for online advertising. In the electricity sector, gaming can involve the manipulation of information about production capacity – as in our case study on tenders for new renewable capacity. On another mechanism, Ito and Reguant (2016) and Fabra and Llobet (2023) point out that the sequential design of the electricity spot market also incentivizes such manipulation, as underestimating production in the forward (day-ahead) market and compensating in the real-time market typically allows to capture some rents. Last, and even more closely related to the mechanism discussed in this chapter, Ryan (2020) considers procurement auctions for coal-fired power plants with a hedging instrument against the future price of hard coal. Bids are evaluated through a score combining a price bid and an index of how much the firm wishes to be hedged against coal price variations. Ryan (2020) shows that some firms prefer not to use the hedging instrument in order to increase their score, having in mind their ability to renegotiate their contract in case of spikes in the price of coal. The main insight from this literature is that heterogeneity between bidders’ abilities or opportunities in gaming opens the door to welfare inefficiencies by selecting – instead of the firms with the lowest cost – the best “manipulators” and/or to non-competitive rents accruing to those manipulators. In this perspective, our strategic bidders are the analog of the firms who benefit the most from ex post renegotiation in Ryan (2020) and of the firms who benefit the most from skewing their bids in Luo and Takahashi (2019).

7. Such false-name bidding activity is sometimes referred to as shill bidding, a term that is also used for manipulation by the seller that consists of bidding (possibly fraudulently) in the auction (Lamy, 2013) in order to increase the selling price.

8. In Athey and Levin’s (2001) bi-dimensional timber scaling auctions model, the optimal strategy of a risk neutral bidder consists of bidding zero on the species whose percentage has been underestimated by the seller and paying the Forest Service only for the overestimated species. Such extreme unbalanced bids are not observed in practice, partly due to risk aversion (Athey and Levin, 2001). Bajari et al. (2014) mention another explanation: the risk that a bid could be rejected when its skewness is too visible. Luo and Takahashi (2019) consider multidimensional UP contracts and argue that bidders form their bid portfolios to balance their risks.

In contrast to the literature on bid manipulations which take as exogenous which bidder(s) can “game” the auction rules, the literature on corruption in auctions typically endogenizes the set of bidders which are able to manipulate the bid evaluation process. Celentani and Ganuza (2002) is thus a kind of exception in the literature on corruption by considering a model where the dishonest principal that organizes the procurement is randomly matched to one of the firms who will later benefit from the opportunity to deliver a good at a lower quality than specified in its bid. This model is thus highly related to our bidding paradigm where there is a single strategic firm. On the contrary, in Compte et al. (2005), firms compete ex ante through bribes to be the favored bidder at the auction stage, while in Burguet and Che (2004) firms simultaneously submit a bid and a bribe.

The remainder of the paper is organized as follows. Section 1.2 introduces the payment rule used by the French government and some of its caveats. Section 1.3 presents our auction model with production risk. The manipulability of production-insuring contracts is analyzed in Section 1.4. Section 1.5 develops the equilibrium analysis of the auction game under several paradigms regarding how bidders (mis)report their expected production. We come back to our empirical application in Section 1.6: various estimates regarding the buyer’s expected cost under French rules compared to the linear FiT are reported. The (possible) benefits from designs that do not fall into the class of production-insuring payment rules are investigated in Section 1.7. Section 1.8 discusses the relevance and robustness of our insights beyond our simple model through several extensions. Section 1.9 concludes. Details of our simulations and the proofs of our results are presented in the Appendix A.

1.2 French offshore wind auctions

In 2011 and 2013, the French government auctioned up to 4 GW of capacity through six offshore wind farm projects.⁹ For each retained project, the feed-in-tariff

9. The auction and contract rules are provided (in French) by the French Energy Regulatory Commission for both auction rounds from 2011 and 2013: www.cre.fr/Documents/Appels-d-offres/Appel-d-offres-portant-sur-des-installations-eoliennes-de-production-d-electricite-en-mer-en-France-metropolitaine and www.cre.fr/Documents/Appels-d-offres/Appel-d-offres-portant-sur-des-installations-eoliennes-de-production-d-electricite-en-mer-en-France-metropolitaine2.

(FiT) contract specifies the yearly amount paid by the government to the winning firm as a function of its actual yearly production (in MWh). The French payment rule differs from standard FiT linear contracts where the payment is strictly proportional to total production: the yearly remuneration depends not only on the auction-determined price (per MWh) and the amount of electricity produced during the year, but also on how the latter compares to the *reference production* reported by the firms in their bids.

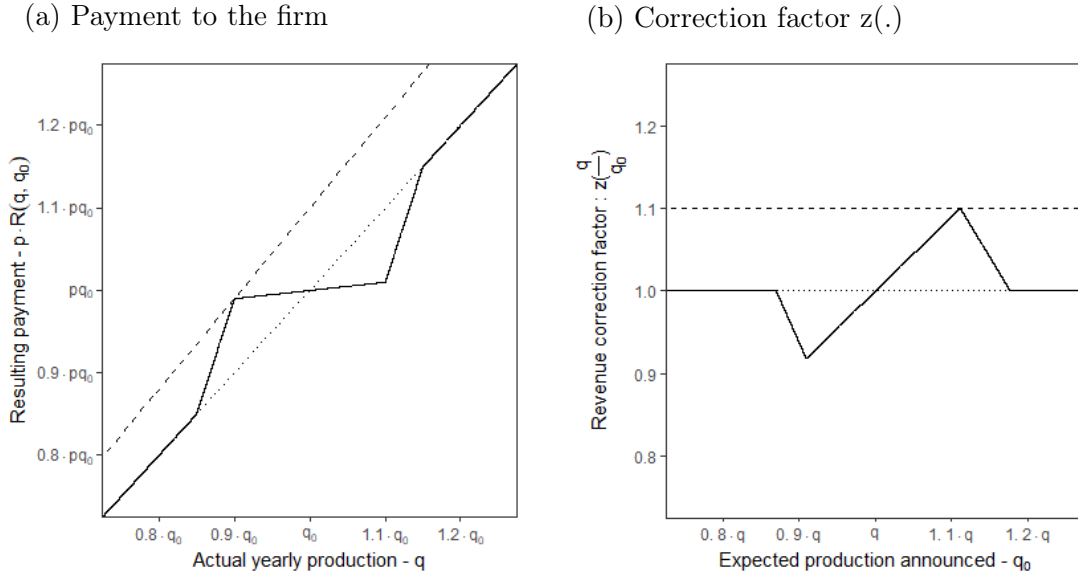
Formally, let p denote the price bid of the winning firm, q_0 the reported reference production and q_t the actual production in year t . According to the French payment rule, the firm's revenue for each year t can be expressed as $p \cdot R(q_t, q_0) = p \cdot q_t \cdot z(\frac{q_t}{q_0})$ where the function $z : \mathbb{R}_+ \rightarrow \mathbb{R}_+$ with $z(1) = 1$ is referred to as the correction factor. For a given price bid p , the solid (resp. dotted) line in Figure 1.1a depicts the yearly subsidy according to the French payment rule (resp. the linear contract) as a function of the actual production and on how it compares to q_0 .

To hedge firms against variation of q_t , it is desirable to set the correction factor $z(\cdot)$ such that the payment is higher (resp. lower) than it would have been under the linear payment rule for the same per-unit price when the actual production stands below (resp. above) the reference production, i.e. $z(\frac{q_t}{q_0}) \geq 1$ (resp. ≤ 1) if $q_t < q_0$ (resp. $q_t > q_0$). The French payment rule is such that indeed $z(\frac{q_t}{q_0}) > 1$ in the range $[0.85 \cdot q_0, q_0]$ and symmetrically $z(\frac{q_t}{q_0}) < 1$ in the range $[q_0, 1.15 \cdot q_0]$.¹⁰ The solid line in Figure 1.1b depicts the correction factor $z(\frac{q}{q_0})$ as a function of q_0 the reference production. For a given price p , firms wish to generate higher correction factors. If firms already knew ex ante their actual production q , then they would maximize their revenue by overestimating production by about 11%. Thanks to this strategic misreporting, the subsidy would increase by 10% compared to truthful reporting. This shift corresponds to the difference between the slopes of the dashed and the dotted lines depicted in Figure 1.1a. We expect firms overestimating incentives to extend to environments with production risk, at least when the risk is small.

When the production is risky and if $q_{max} > 0$ denotes the upper bound of the

10. More specifically, the French rule is defined such that the function $\epsilon \rightarrow (1 + \epsilon) \cdot [z(1 + \epsilon) - 1]$ is an odd function which is null outside the $[-0.15, 0.15]$ range and strictly negative for $\epsilon \in]0, 0.15[$.

Figure 1.1 – Payment rule in French offshore wind auctions



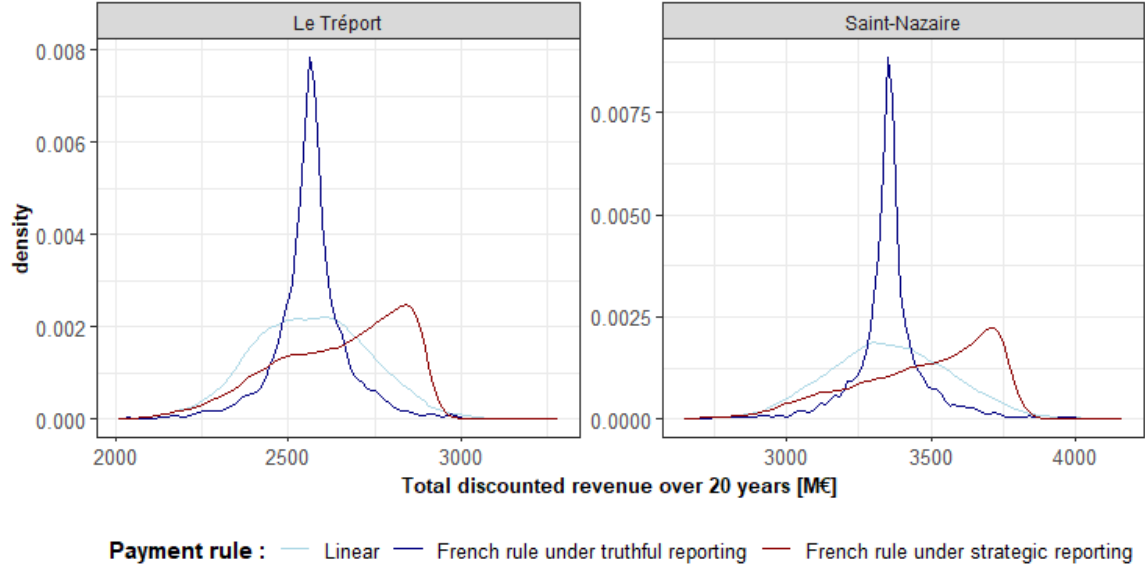
distribution f , then a firm reporting q_{max} for the reference production is guaranteed that any production outcome will generate a correction factor that is greater than 1. If q_t is symmetrically distributed, note on the contrary that the expected value of the correction factor under truthful reporting is equal to one. This illustrates that strategic risk neutral firms, which should report a reference production q_0 that maximizes $\mathbb{E}[z(\frac{q_t}{q_0})]$, should misreport their expected production. More generally, we expect that their optimal misreport consists of overestimating the expected production: it would more often generate a favorable correction factor $z(\frac{q_t}{q_0}) > 1$ (and less often a correction factor below 1). By optimizing their report q_0 , firms benefit from the *effective feed-in-tariff* $p \cdot \mathbb{E}[q_t z(\frac{q_t}{q_0})] / \mathbb{E}[q_t]$ which is thus necessarily greater than $p \cdot \mathbb{E}[q_t z(\frac{q_t}{\mathbb{E}[q_t]})] / \mathbb{E}[q_t]$ the per-unit subsidy under truthful reporting (the latter being equal to p if q_t is symmetrically distributed¹¹). The *effective feed-in-tariff* is bounded above by $p \cdot \max_{x \geq 0} z(x)$, a bound that is achieved when future production is perfectly known ex ante and firms optimize their report q_0 .

To obtain a first-order approximation of the magnitude of the incentives to misreport expected production and of its consequences on revenues, Appendix A provides a methodology to model the yearly production distribution of a wind farm project,

¹¹. If q_t is symmetrically distributed, then we have $\mathbb{E}[\frac{q_t}{\mathbb{E}[q_t]} [z(\frac{q_t}{\mathbb{E}[q_t]}) - 1]] = 0$ since the function $\epsilon \rightarrow (1 + \epsilon)z(1 + \epsilon)$ is odd.

and this from an ex ante perspective.

Figure 1.2 – Firm’s revenue distribution depending on the payment rule and the strategy regarding the reference production



For three different scenarios and for a given price bid (equal to that awarded to the winning bidder in the corresponding project), Figure 1.2 depicts the PDF of the discounted revenue raised over 20 years for two offshore wind farm projects in Le Tréport and Saint-Nazaire. The scenarios correspond to the linear FiT and the French payment rule, first when all firms are truthful and then when all firms are strategic, i.e. formally when $q_0 = \mathbb{E}[q_t]$ and when $q_0 = q_0^* \in \text{Arg max}_{q \in \mathbb{R}_+} \mathbb{E}[R(q_t, q)]$ respectively.¹² When firms report their expected production truthfully, we observe (as expected) that the revenue distribution is less spread out under the French rule than under the linear FiT. However, firms could benefit from a significant upward shift in their revenue distribution by strategically overestimating their expected production: for the five wind farms used in our simulations, we estimate that risk neutral firms’ optimal report consists of overestimating their expected production by 11.9 to 12.5% which would increase their expected revenue by 3.2 to 3.6% (for any given price). But by doing so, they also increase the standard deviation of their revenue distribution by

12. Here, in order to simplify, we consider that the optimal reported reference production is that which would maximize the expected revenue, or equivalently the expected payoff of a risk neutral firm. More generally, the optimal (mis)report would depend on firms’ risk aversion and also possibly on the price bid p , as explained later.

72 to 85% compared to truthful reporting, which ends up being 10 to 13% greater than the standard deviation under the linear FiT. In overall terms, the French payment rule that was presumably insuring firms against production risk could have exactly the opposite effect.

To pursue the comparison with the linear FiT, we should also take into account the fact that the price bid should not be the same under both contracts. Assuming that the contracts are awarded through competitive auctions and that all bidders are strategic, the benefits from overstating production would be competed away in the auction. Suppose that p is the equilibrium price under the linear FiT once firms are risk neutral. Then let p^S denote the price bid that yields the same expected subsidy under the French rule with strategic reporting (formally, $p^S = p\mathbb{E}[q_t]/\mathbb{E}[R(q_t, q_0^*)]$). After this price rescaling, we find that the variance of $p^S \cdot R(q_t, q_0^*)$ is greater than the variance of $p \cdot q_t$ by 6.6 to 9.3% in the five wind farm projects included in our simulations. In other words, the alleged benefit from the French rule – insurance provision – can be largely offset by strategic reporting and is likely to fail to achieve its original objective of reducing firms’ risk premiums. An in-depth analysis of risk premiums and of the expected equilibrium subsidy in this application is developed in Section 1.6.

1.3 The model

We develop a theory of auctions for production contracts when the quantity produced ex post is determined by exogenous conditions and when the payment rule has an insurance provision clause. Namely, we consider the following setup:

Production risk: A buyer wishes to contract with a firm to develop a risky project where the quantity produced ex post q is an exogenous random variable.¹³ In particular, efforts made by the contractor have no influence on the distribution of q . We assume that the random variable q is distributed on \mathbb{R}_+ according to the PDF f with the expected value $\mathbb{E}_f[q] \equiv \bar{q} > 0$. Let F denote the corresponding (atomless) CDF. Throughout our theoretical analysis we often consider distributions

13. The variable q could also correspond to a measure for quality, or more generally to any kind of uni-dimensional verifiable measure characterizing the contractor’s output.

that are symmetric and single-peaked and we let \mathcal{F}_{sp} denote the corresponding set of distributions.¹⁴

The auction rule: The buyer selects the contractor through a first-price auction among $N \geq 2$ firms: each bidder submits a pair $(p, q_0) \in \mathbb{R}_+^2$ where p corresponds to a (per quantity) price bid and q_0 to the so-called *reference production*. The buyer selects the offer involving the lowest price bid p . When necessary for our equilibrium analysis, a tie-breaking rule will be specified. In particular, when two firms submit the same lowest price bid and if, when winning, one would make zero profit while the other's expected payoff would be strictly positive, then we always assume that the tie is broken in favor of the latter.

As clarified below, the buyer expects contractors to report the expected production \bar{q} for q_0 . If a firm reports a reference production $q_0 \neq \bar{q}$, then we will say that the firm misreports its expected production.

The class of contracts: The contract between the buyer and the winning firm specifies a remuneration rule as a function of the latter's bid (p, q_0) and of the actual production q . The remuneration rule takes the multiplicative form $p \cdot R(q, q_0)$ where the function $R : \mathbb{R}_+^2 \mapsto \mathbb{R}_+$ is called the *payment rule*.¹⁵ Among these contracts, we call linear contracts those for which $R(q, q_0) = q$ for any q_0 . In addition, we always assume that the payment rule satisfies the following technical restrictions: i) The function $q \mapsto R(q, q_0)$ is continuously non-decreasing¹⁶ with $R(0, q_0) = 0$ for any $q_0 \in \mathbb{R}_+$; ii) The function $q \mapsto R(q, q)$ is strictly increasing with $\lim_{q \rightarrow +\infty} R(q, q) = +\infty$; iii) The function $q_0 \mapsto R(q, q_0)$ is differentiable for any $q \in \mathbb{R}_+$; iv) Without loss of generality, we also make the normalization $R(q_0, q_0) = q_0$.¹⁷

We further say that a payment rule is *homogeneous of degree 1* if $R(\lambda \cdot q, \lambda \cdot q_0) =$

14. Formally, this means that $f(\bar{q} + x) = f(\bar{q} - x)$ for any $x \in [0, \bar{q}]$, $f(q) = 0$ for $q > 2\bar{q}$ and that f is non-decreasing on $[0, \bar{q}]$.

15. Our analysis of firms' incentives to misreport their expected production holds for any given price p and our specific multiplicative form is imposed without loss of generality. On the contrary, it plays a role in Section 1.5 to derive the quantitative impact of strategic behavior on the buyer's expected cost. See Section 1.8 for a discussion.

16. The non-decreasing property guarantees that the contractor does not wish to reduce production ex post. The continuity assumption is not mandatory for most of our results but allows us to avoid technicalities related to intermediate properties holding almost everywhere instead of everywhere.

17. Since the function $q \mapsto R(q, q)$ is a bijection on \mathbb{R}_+ , then we can always renormalize the variable q such that $R(q, q) = q$. Nevertheless, renormalizing the variable q in this way could be at the cost of losing the property $f \in \mathcal{F}_{sp}$. From this perspective, the assumption that $f \in \mathcal{F}_{sp}$ is not innocuous.

$\lambda \cdot R(q, q_0)$ for any $\lambda, q, q_0 \geq 0$.

Firms' payoff: We assume that firms value their revenue according to an increasing differentiable concave utility function U with $\lim_{x \rightarrow +\infty} U(x) = +\infty$. Firms are risk neutral if U is linear and are risk averse (resp. strictly risk averse) if U is concave (resp. strictly concave). For some results, we consider CRRA utility functions, i.e. utility functions U such that $U'(x) = x^{-\gamma}$, where $\gamma \geq 0$ corresponds to the relative risk aversion coefficient. The firm's expected payoff conditional on winning the auction with the bid (p, q_0) is denoted by $\Pi(p, q_0) \equiv \mathbb{E}_f[U(p \cdot R(q, q_0))]$. If a firm loses the auction and thus does not sign any contract, its expected payoff is given by $U(C)$ where C corresponds to the fixed cost that is needed to develop the project. The cost C is sunk after signing the contract such that losing the auction can be viewed as offering the equivalent cash revenue C .¹⁸

Truthful/Strategic behavior: Each firm is either truthful, meaning it reports \bar{q} for q_0 , or strategic, meaning it reports a quantity q_0 belonging to the set $Q_0^*(p) \equiv \text{Arg max}_{q_0 \in \mathbb{R}_+} \Pi(p, q_0)$ given its price bid p .¹⁹ In other words, for a given price bid p , strategic firms face the menu of contracts $\{p \cdot R(q, q_0)\}_{q_0 \in \mathbb{R}_+}$ among which they pick the contract they prefer. We let $\Pi^S(p)$ (resp. $\Pi^T(p)$) denote the expected payoff of a strategic (resp. truthful) firm winning the auction at the price bid p , i.e., $\Pi^S(p) = \max_{q_0 \in \mathbb{R}_+} \Pi(p, q_0)$ (resp. $\Pi^T(p) = \Pi(p, \bar{q})$). Then, for a given distribution f , a given utility function U and a given contract price $p > 0$, we say that a payment rule is *strategy-proof* (resp. *manipulable*) if firms do not benefit (resp. do strictly benefit) from misreporting their expected production, i.e., formally, if $\Pi^S(p) = \Pi^T(p)$ (resp. $\Pi^S(p) > \Pi^T(p)$). The linear contract is always strategy-proof since the contractor's payoff does not depend on q_0 . If a firm reports $q_0 > \bar{q}$ (resp. $q_0 < \bar{q}$), then we say from now on it overstates (resp. understates) its reference production (compared to its expected production).

In the specific case of CRRA utility functions (which includes the case of risk

18. An alternative specification would consist of letting the winning bidder's payoff be $\mathbb{E}_f[U(p \cdot R(q, q_0) - C)]$ and the losing bidder's payoff be $U(0)$. Such a specification would be equivalent to ours, thanks to a re-normalization of U that would not modify the concavity property. However, our specification is more convenient when dealing with CRRA utility functions.

19. We assume implicitly that the payment rule is such that this set is not empty for any price p . This set is guaranteed to be non-empty if we specify the payment rule such that $R(q, q_0) = q$ for $q \geq 2q_0$, an extra assumption that we could add while remaining consistent with our analysis.

neutral firms), then the ratio $\Pi^S(p)/\Pi^T(p)$ does not depend on p and we thus obtain that if a payment rule is manipulable (resp. strategy-proof) for a given price bid $p > 0$, then it is manipulable (resp. strategy-proof) for any price bid in \mathbb{R}_+ . Thus for a given distribution f and a given CRRA utility function, we say that a payment rule is manipulable/strategy-proof without specifying any price bid.

We are interested in payment rules that provide insurance against production variability compared to the linear contract. From a positive perspective, the latter appears as a natural benchmark since it is both commonly used and strategy-proof. The theoretical status of the linear contract as an optimal contract when firms are risk neutral is discussed later in Section 1.8.

Definition 1. *A payment rule $R(q, q_0)$ is production-insuring if for any $f \in \mathcal{F}_{sp}$, any risk averse firm and any contract price $p > 0$,*

$$\mathbb{E}_f[U(p \cdot R(q, \bar{q}))] \geq \mathbb{E}_f[U(p \cdot q)] \quad (1.1)$$

and where the inequality is strict (resp. stands as an equality) if the firm is strictly risk averse (resp. risk neutral).

In words, the production-insuring payment rules correspond to the payment rules that make risk averse truthful firms better off without increasing the expected payment made to the firm and this in a robust way insofar as it should hold for any distribution $f \in \mathcal{F}_{sp}$.

Our model considers that all firms have the same investment cost C , the same utility function U and the same production distribution f . Thus it leaves out the usual adverse selection issues which would generate some trade-off between maximizing allocative efficiency and minimizing firms' informational rents. Moreover it also leaves out moral hazard.²⁰ We do not attempt to derive an optimal procurement as Laffont and Tirole (1986) and McAfee and McMillan (1987) did in models with risk neutral firms competing for a contract, but rather adopt a "positive" perspective: Our objective is to delineate a pitfall associated with production-insuring payment rules,

20. Both asymmetry between firms and moral hazard are briefly discussed in Section 1.8.

motivated by the fact it has been used and it is quite tempting to use when the environment involves exogenous production risk. It can indeed be viewed as the natural class of rules that a naive buyer might adopt, assuming bidders would report their true reference production (as one could naively expect). Under such an assumption, the risk premium or equivalently the buyer's expected cost would indeed be reduced compared to the linear contract (as detailed in Section 1.5).

To evaluate the performance of a payment rule, the criterion we consider is to maximize the expected payoff of a risk neutral buyer. In our setup where all firms have the same production distribution, this criterion reduces to the buyer's expected cost (henceforth the BEC), i.e., $p \cdot \mathbb{E}_f[R(q, q_0)]$ where (p, q_0) corresponds to the winning bid), which depends on the payment rule $R(., .)$ but also on whether firms are truthful or strategic.

1.4 Strategic misreporting in production-insuring payment rules

We analyze firms' incentives to misreport their expected production when the payment rule is production-insuring. Intuitively, the magnitude of misreporting can be viewed as a proxy of the flaws resulting from the presence of strategic bidders as will be developed in our equilibrium analysis in Section 1.5.

Let us first characterize the payment rules that are production-insuring. For any payment rule and any pair $q, q_0 > 0$, we can express the term $R(q, q_0)$ as $q \cdot z_{q_0}(\frac{q}{q_0})$ where the function $z_{q_0} : \mathbb{R}_+ \rightarrow \mathbb{R}_+$ can be viewed as a correction factor with $z_{q_0}(1) = 1$. Definition 1 implies that $\mathbb{E}_f[z_{q_0}(\frac{q}{q_0})] = 1$ for any $f \in \mathcal{F}_{sp}$. Lemma 1 (whose tedious proof is relegated to the SA) establishes in addition that a production-insuring payment rule would never deflate (resp. inflate) payments compared to the linear contract for production occurrences that are lower (resp. higher) than the reference production q_0 : the correction factor is greater (resp. less) than one when production is lower (resp. higher) than q_0 . Furthermore, the fact that these correction factors should compensate in expectation for any symmetric risk imposes a one-to-one relationship between $z_{q_0}(1 + \epsilon)$ and $z_{q_0}(1 - \epsilon)$.

Lemma 1. *A payment rule is production-insuring if and only if we have for any $q_0 > 0$ and $\epsilon \in]0, 1]$, $z_{q_0}(1 + \epsilon) \leq 1$, $z_{q_0}(1 - \epsilon) \geq 1$, $(1 + \epsilon) \cdot z_{q_0}(1 + \epsilon) + (1 - \epsilon) \cdot z_{q_0}(1 - \epsilon) = 2$ and $\int_0^\epsilon z_{q_0}(1 + t)dt < \epsilon$.*

We then obtain the fact that the payment rule used by the French government is production-insuring (see in particular Footnote 10). As a corollary of Lemma 1, we also obtain that if there is no risk relating to production, then overestimating (resp. underestimating) future production can never be detrimental (resp. beneficial) to the contractor under a production-insuring payment rule. Furthermore, the contractor would also strictly gain from slightly overestimating production since the correction factor $z_{q_0}(\cdot)$ is strictly greater than 1 for some values in the left neighborhood of 1. Next we generalize this insight for any $f \in \mathcal{F}_{sp}$ and when the contractor is risk neutral.

Proposition 2. *For any $f \in \mathcal{F}_{sp}$, any production-insuring payment rule is manipulable if the contractor is risk neutral. Furthermore, the contractor weakly increases (resp. decreases) its expected payoff by overestimating (underestimating) its expected production.*

Proposition 2 formalizes a fundamental conflict between insurance provision and strategy-proofness. We stress that the incentive to overestimate the expected production holds for any distribution in \mathcal{F}_{sp} . Nevertheless, this result holds only when the contractor is risk neutral. Risk aversion modifies the (mis)reporting incentives: in particular, underestimating production could be a way to hedge against the worst production outcomes. To get more intuition about this novel channel, think of the French payment rule where $R(q, q_0) = q$ if $q \leq 0.85 \cdot q_0$. If production of below $0.85 \cdot q_0$ may occur with positive probability, then, under truthful reporting, the worst production outcomes would not benefit from a correction factor greater than one. On the contrary, underestimating the reference production could be a way to increase the contractor's revenue for those worst outcomes. From an empirical perspective, this channel does not play a significant role under the French rule in our simulations. Nevertheless it prevents us from deriving the analog of Proposition 2 under risk aversion.

To obtain further insights into the way risk averse contractors wish to misreport

their expected production, and in particular about the factors that drive the magnitude of overestimation, we impose more structure on our model. We consider a specific class of payment rules where the remuneration to the contractor is totally flat within a range around the reference production q_0 , and matches the linear contract outside this range. We assume that the insurance range is large enough to fully insure the contractor under truthful reporting and that the PDF f is continuous on \mathbb{R}_+ and such that $x \mapsto \frac{1-F(x)}{f(x)}$ is decreasing on the interior of its support. Under such assumptions, we obtain the following results (whose tedious proofs are relegated to the SA): any optimal report of a risk averse (strategic) contractor is above the true expected production and below the optimal report of a risk neutral contractor (the latter does not depend on the contract price p and is then denoted q_0^{RN}). Formally, for any $q_0^* \in Q_0^*(p)$, we have $\bar{q} \leq q_0^* \leq q_0^{RN}$.

With the additional restriction that U is a CRRA utility function, we obtain that the set of optimal reports $Q_0^*(p)$ is a singleton which does not depend on p and derive the following comparative statics on the corresponding optimal report $q_0^* > \bar{q}$:

1. The lower is the coefficient of relative risk aversion γ , the higher is q_0^* .
2. Considering two production distributions F_1 and F_2 , where F_1 is less risky than F_2 in the sense that $\frac{f_1(q)}{(1-F_1(q))} \leq \frac{f_2(q)}{(1-F_2(q))}$ for any $q \leq \bar{q}$, then the optimal report q_0^* is higher when the contractor faces the least risky distribution F_1 than when they face the most risky distribution F_2 .
3. If the insurance range is larger for payment rule R_1 than for R_2 (which implies that $R_1(q, q_0) \geq R_2(q, q_0)$ if $q \leq q_0$), then a strategic contractor with $\gamma \geq 1$ reports a higher reference production q_0^* when facing R_1 than when facing R_2 .

1.5 Auction prices and the buyer's expected cost

Through our equilibrium analysis, we characterize the bid pairs (p, q_0) submitted by firms and the resulting BEC depending on whether firms are truthful or strategic, and the number in each category. We assume throughout Sections 1.5 to 1.7 that the cost C , risk distribution F and utility function U are the same for all firms and are common knowledge. We first consider a complete information setup where strategic

firms know whether their opponents are truthful or strategic. We first consider the case when all firms are truthful, then the case when several firms are strategic, and last when a single firm is strategic. Finally, we turn to an incomplete information setup where each firm is strategic (independently of the others) with a given probability α which is assumed to be common knowledge.

Firms' beliefs regarding whether their opponents are truthful or strategic do matter for strategic firms (and the specifications below are consistent with rational expectations), but they do not matter for truthful firms: in equilibrium, truthful firms bid the price that leads to zero surplus and this independently of their beliefs regarding their opponents.²¹ Therefore, our analysis fits both the case where truthful firms are unaware of the possibility of misreporting their expected production (in which case it would be natural to assume that they believe that their opponents are also truthful) and the case where truthful firms are not able to misreport their expected production but are fully aware that some of their opponents could do so.

We stress that the results derived hereafter (unless specified otherwise) are not limited to production-insuring payment rules but hold for any payment rule R that fails to be strategy-proof.

Complete information

If all firms are truthful or if at least two firms are strategic, then the winning firm had to compete in the auction with at least one fully identical firm. In such cases, Bertrand competition leads to zero surplus for the firms and the equilibrium price is characterized by their indifference to winning or losing the auction (see formal details in the SA). Nevertheless, the BEC depends on the payment rule and the presence of strategic bidders, as both result in different levels of insurance provision, and therefore different risk premiums.

Case 1: all firms are truthful

If all firms are truthful, the equilibrium price, denoted p^T , is the unique solution

21. We ignore equilibria based on weakly dominated strategies where truthful firms submit a bid that would generate a negative surplus when winning because they expect to be outbid for sure by a strategic firm. Standard refinements (like trembling-hand perfect equilibrium, see Fudenberg and Tirole (1991)) allow those non-relevant equilibria to be eliminated.

of:

$$\Pi^T(p^T) \equiv \Pi(p^T, \bar{q}) = U(C) \quad (1.2)$$

and the BEC is equal to $p^T \cdot \mathbb{E}_f[R(q, \bar{q})]$, which reduces to $p^T \cdot \bar{q}$ if R is production-insuring and if $f \in \mathcal{F}_{sp}$. Let p^L denote the equilibrium price for the linear contract, then the corresponding BEC is equal to $p^L \cdot \bar{q}$ if $f \in \mathcal{F}_{sp}$.

When firms are risk neutral, we obtain from (1.2) that the BEC is equal to the contractor's cost C for any payment rule. On the contrary, the BEC depends on the payment rule under risk aversion.

Proposition 3. *Suppose all firms are truthful and $f \in \mathcal{F}_{sp}$. The equilibrium price and the buyer's expected cost are smaller under a production-insuring payment rule than under the linear contract. They are strictly smaller if firms are strictly risk averse, and equal if firms are risk neutral.*

Since U is concave, we obtain from (1.2) and Jensen's inequality that $p^T \cdot \mathbb{E}_f[R(q, \bar{q})] \geq C$ for any payment rule R , or equivalently that: the BEC is necessarily greater than the firm's cost. If the payment rule fully insures the contractor so that the transfer is unchanged for any production outcome in the support of f , then the equilibrium price and the BEC are the same as in the risk neutral case: $p^T = \frac{C}{\bar{q}}$, and the cost for the buyer is C . On the contrary, if firms are strictly risk averse and the payment rule does not fully insure, a strict difference emerges between the BEC and C which corresponds to a risk premium. This is true in particular for the linear contract, for which we have $p^L \cdot \bar{q} > C$.²² As formalized in Proposition 3, production-insuring payment rules reduce this risk premium compared to the linear contract.

Case 2: several firms are strategic

Consider now the case where at least two firms are strategic. The strategic firms' equilibrium price bid, denoted by p^S , is the unique solution of:

^{22.} Here we use the strict version of the Jensen inequality which guarantees that $U(p^L \cdot \bar{q}) > \mathbb{E}_f[U(p^L \cdot q)]$ for any strictly concave function U , while from (1.2) the latter term is equal to $U(C)$.

$$\Pi^S(p^S) \equiv \max_{q_0 \in \mathbb{R}_+} \Pi(p^S, q_0) = U(C) \quad (1.3)$$

while truthful firms (if any) submit price bids that are greater than p^S and thus irrelevant for the equilibrium outcome.²³ Strategic firms report a reference production $q^S \in Q_0^*(p^S) \equiv \text{Arg max}_{q_0 \in \mathbb{R}_+} \mathbb{E}_f[U(p^S \cdot R(q, q_0))]$. If the latter set is not a singleton, multiple equilibria exist and they are equivalent in terms of firms' payoff but possibly produce different BEC, depending on the reference production (within $Q_0^*(p^S)$) submitted by the winning firm.

When firms are risk neutral, we obtain from (1.3) that the BEC is equal to C for any payment rule due to the absence of both risk premiums and positive surplus (the latter being competed away in the presence of several strategic firms). However, in such a case, the equilibrium price differs from that when all firms are truthful: we have $p^S = \frac{C}{\max_{q_0 \in \mathbb{R}_+} \mathbb{E}_f[R(q, q_0)]} \leq p^T$ (with a strict inequality if the payment rule is manipulable at price p^T). Proposition 4 generalizes this inequality to environments with risk averse firms.

Proposition 4. *Suppose several firms are strategic. The equilibrium price is lower than the equilibrium price when all firms are truthful (p^T), and the inequality is strict for payment rules that are manipulable at price p^T . If the payment rule provides full insurance against production risk to a truthful firm, is homogeneous of degree 1 and if firms are strictly risk averse, then the buyer's expected cost is strictly greater with several strategic firms than with only truthful firms.*

The second part of Proposition 4 points out a particular case where the BEC is greater than in the environment where all firms are truthful because the ex post revenue becomes risky and then risk premiums (absent under truthful bidding) emerge. This illustrates the fact that when the winning firm is strategic, a lower equilibrium price does not necessarily imply a lower cost for the buyer: the BEC is equal to the product of the equilibrium price with the term $\mathbb{E}_f[R(q, q^S)]$. There are thus two effects at work with respect to the BEC when we move from case 1 to case 2, i.e.,

23. In equilibrium, a truthful firm would necessarily make a negative surplus by outbidding a strategic firm whose bid satisfies the zero surplus condition: formally, this comes from $\Pi^T(p) < \Pi^S(p^S) = U(C)$ for any $p < p^S$.

from competition between truthful firms to competition between strategic firms: on the one hand the equilibrium price decreases as firms' benefits from misreporting are competed away; on the other hand, the term $\mathbb{E}_f[R(q, q_0)]$ varies due to misreporting. Furthermore, given our equilibrium analysis in Section 1.4, we expect that $\mathbb{E}_f[R(q, q^S)] > \mathbb{E}_f[R(q, \bar{q})]$ and thus that these two effects will be conflicting²⁴: formally, for any $f \in \mathcal{F}_{sp}$ and risk neutral firms, it will be the case for any production-insuring payment rule such that in equilibrium strategic firms overestimate their expected production, insofar as Proposition 2 shows that $\mathbb{E}_f[R(q, q_0)] \geq \mathbb{E}_f[R(q, \bar{q})] = \bar{q}$ for any $q_0 \geq \bar{q}$. Moreover, the further insights presented at the end of Section 1.4 reinforce our conjecture in favor of overestimation even in the risk averse case. On the whole, the zero surplus condition imposes that these two effects perfectly cancel each other out regarding the contractor's expected payoff, but they are not necessarily neutral regarding the BEC. We conjecture that strategic behavior will typically expose firms to higher risk and thus increase risk premiums, as will be confirmed by our simulations. Nevertheless, Example 1 in the SA exhibits a production-insuring payment rule where the equilibrium BEC with several strategic firms may be lower than when all firms are truthful.²⁵

In a nutshell, when all firms are truthful any production-insuring payment rule outperforms the linear contract (Proposition 3). The presence of several strategic bidders lowers the equilibrium price even more, but through a deceptive effect which does not necessarily imply a lower BEC than under a linear contract. The last case considered below departs from perfect Bertrand competition and the single strategic firm benefits from a positive surplus. This novel channel acts in favor of strategy-proof payment rules.

Case 3: a single firm is strategic

In this third case under complete information, we consider that there is a single

24. On the contrary, under the less plausible hypothesis that $\mathbb{E}_f[R(q, q^S)] < \mathbb{E}_f[R(q, \bar{q})]$, then the BEC is unambiguously lower in case 2 than in case 1: under such circumstances, switching from case 1 to case 2 would be Pareto improving. When R is production-insuring and $f \in \mathcal{F}_{sp}$, note from Proposition 2 that $\mathbb{E}_f[R(q, q^S)] < \mathbb{E}_f[R(q, \bar{q})]$ holds only if $q^S < \bar{q}$, and the latter inequality is never satisfied if firms are risk neutral.

25. In this example, the insurance provided by the payment rule is almost vanishing under truthful reporting while the payment rule is flat further away from the expected production \bar{q} and provides insurance when firms are optimally misreporting their expected production.

strategic firm. The equilibrium then takes the following form:²⁶ truthful firms bid (p^T, \bar{q}) exactly as in the equilibrium where all firms are truthful, while the strategic firm (knowing ties are broken in its favor) bids (p^T, q^{S-T}) where $q^{S-T} \in Q_0^*(p^T)$. The latter firm wins the auction and the BEC is then equal to $p^T \cdot \mathbb{E}_f[R(q, q^{S-T})]$. The difference $\Pi^S(p^T) - \Pi^T(p^T) \geq 0$ represents the surplus reaped by the strategic firm from misreporting its expected production. This surplus is strictly positive if the payment rule is manipulable at price p^T .

Proposition 5. *Suppose only one firm is strategic. The equilibrium price is the same as the equilibrium price when all firms are truthful (p^T). If firms are risk neutral, then the buyer's expected cost is equal to the sum of C and the non-competitive rent $p^T \cdot (\mathbb{E}_f[R(q, q^{S-T})] - \mathbb{E}_f[R(q, \bar{q})])$, the latter being null under the linear contract and strictly positive under a payment rule that is manipulable.*

If U is a CRRA utility function and if the payment rule is manipulable, then the buyer's expected cost is strictly higher than when several firms are strategic.

When comparing the BEC in case 3 and case 2, both the effect on the equilibrium price and the variation of $\mathbb{E}_f[R(q, q_0)]$ could be at work. However, when $q^S = q^{S-T} \neq \bar{q}$ which happens to be the case when the utility function is CRRA and R is manipulable, then only the price effect matters. Then, since $p^S < p^T$, the BEC is strictly greater when a single firm is strategic than when several firms are strategic.

When comparing case 3 with case 1, only the second effect matters. In addition, given Proposition 2 and as argued in case 2, we again expect that $\mathbb{E}_f[R(q, q^{S-T})] \geq \mathbb{E}_f[R(q, \bar{q})]$: formally, if R is production-insuring and $f \in \mathcal{F}_{sp}$, then the BEC increases when switching from the case where all firms are truthful to the case where a single firm is strategic provided that $q^{S-T} \geq \bar{q}$. Yet this overestimation hypothesis is supported by our analysis in Section 1.4. Thus the BEC presumably increases by a larger magnitude when only one firm (instead of several firms) become strategic.

In both case 2 and case 3 (but also in our incomplete information paradigm below), the equilibrium price is (weakly) lower than p^T . We then obtain the fact

26. In order to avoid the well-known problem of the non-existence of an equilibrium in some discontinuous strategic games (Simon and Zame, 1990), we assume in this case that ties are broken in favor of the strategic firm.

that the percentage increase of the BEC compared to case 1 is bounded above by $[\sup_{q, q_0} \{z_{q_0}(q/q_0)\} - 1]$. In the French rule, the latter bound is equal to $1/9$ meaning that the BEC increase due to misreporting cannot exceed 12%.

Regarding the comparison between a production-insuring payment rule and the linear contract (for any $f \in \mathcal{F}_{sp}$), the ranking is ambiguous in general when there is a single strategic firm. However, if firms are risk neutral then the linear contract strictly outperforms any production-insuring rule when a single firm is strategic. We next consider an incomplete information setup where firms ignore whether their competitors are truthful or strategic.

Incomplete information

Consider now $N \geq 2$ firms each being strategic (resp. truthful) with probability α (resp. $1 - \alpha$) independently of the other firms. Each firm knows its own status and the parameter $\alpha \in]0, 1[$ but ignores other firms' status.

Proposition 6. *Equilibrium under incomplete information*

Suppose each firm is strategic (resp. truthful) with probability α (resp. $1 - \alpha$) independently of each other, where $\alpha \in]0, 1[$ is common knowledge. If the payment rule is manipulable at p^T , then in equilibrium, all firms adopt the following strategy:

- *If the firm is truthful, it bids (p^T, \bar{q}) .*
- *If the firm is strategic, it adopts a mixed strategy, consisting of bidding (p, q_0) with $q_0 \in Q_0^*(p)$ and the price bid p being distributed according to the CDF $G(p) = \max\{1 - \frac{1-\alpha}{\alpha} \left(\sqrt[N-1]{\frac{\Pi^S(p^T) - U(C)}{\Pi^S(p) - U(C)}} - 1 \right), 0\}$. The upper (resp. lower) bound of the distribution G is equal to p^T (strictly greater than p^S).*

If for any price bid p in the support of G the set $Q_0^*(p)$ is a singleton, then the equilibrium is unique. On the contrary, if there are multiple optimal misreports, then any selection forms an equilibrium and the BEC would depend on the selection denoted next by $q_0^*(p)$ for any given price in the support of G .

In equilibrium, the expected surplus of a truthful (resp. strategic) firm is null (resp. is equal to $(1 - \alpha)^{N-1}[\Pi^S(p^T) - \Pi^T(p^T)] > 0$). Intuitively, such positive surplus should translate into higher costs for the buyer. Note that in this incomplete information

setup, the BEC is an expectation not only over the production distribution F but also over the probability for each firm to be strategic and over strategic firms' mixed strategy G . Thus the BEC differs from that under complete information through two effects: first, the probability of being in each state (none, several or a single strategic firm), second the bids submitted by each strategic firm which, independently of the realized state, do take into account the probability of facing competition from another strategic firm. To obtain further insights, we consider in the next proposition that firms are either risk neutral or risk averse with a CRRA utility function. In such cases, the set $Q_0^*(p)$ does not depend on p and is denoted Q_0^* .

Proposition 7. *Suppose that U is a CRRA utility function and consider a payment rule R that is manipulable. Under incomplete information, for all $\alpha \in]0, 1[$:*

- *If $\mathbb{E}_f[R(q, q_0^*)] \geq \mathbb{E}_f[R(q, \bar{q})]$ for any $q_0^* \in Q_0^*$, then the buyer's expected cost is strictly lower than the highest buyer's expected cost when there is a single strategic firm under complete information, and it is strictly higher than the lowest buyer's expected cost under complete information.²⁷*
- *If firms are risk neutral, then the buyer's expected cost is equal to the sum of C and the non-competitive rent*

$$N \cdot \alpha(1 - \alpha)^{N-1} \cdot p^T \left(\mathbb{E}_f[R(q, q^{S-T})] - \mathbb{E}_f[R(q, \bar{q})] \right) > 0. \quad (1.4)$$

When firms are risk neutral, the expected non-competitive rents in (1.4) vanish in the two polar limit cases where α is equal to 0 or 1, which are actually covered by Propositions 3 and 4. Moreover for any intermediary value of α , the uncertainty about each firm being strategic or not moderates the expected extra cost for the buyer compared to the case of complete information with a single strategic firm case, where the extra cost is equal to $p^T(\mathbb{E}_f[R(q, q^{S-T})] - \mathbb{E}_f[R(q, \bar{q})])$. The maximum expected extra cost (over α) is reached for $\alpha = \frac{1}{N}$, that is when the probability of having exactly one strategic firm is the highest. We thus obtain that the increase in the BEC cannot be higher than half of the extra cost when there is a single strategic firm under

²⁷ Formally, the highest BEC when there is a single strategic firm is equal to $p^T \cdot \max_{q_0 \in Q_0^*} \mathbb{E}_f[R(q, q_0^*)]$. The lowest BEC under complete information can be reached either with zero or several strategic firms.

complete information (this bound is reached for $N = 2$).²⁸

When firms are risk averse, additional assumptions are needed to draw conclusions about the BEC. The condition $\mathbb{E}_f[R(q, q_0^*)] \geq \mathbb{E}_f[R(q, \bar{q})]$ for any $q_0^* \in Q_0^*$ is a very mild condition stating that the equilibrium with truthful firms outperforms any equilibrium with a single strategic firm under complete information. Such conditions, which were previously discussed for production-insuring payment rules, guarantees that the BEC under incomplete information lies somewhere in between the worst case and the best case under complete information.

We conclude that the rents captured by the firms are smaller with such “miscoordinated heterogeneity”, but could still have a sizable effect of the same order of magnitude. In our simulations we consider the complete information case with a single strategic firm to evaluate a worst case scenario, while bearing in mind that the increase in the BEC would be mitigated under incomplete information.

Comments: Our equilibrium analysis is analogous to the analysis of first price auctions with two (possibly risk averse) symmetric bidders having binary valuations developed by Maskin and Riley (1985): being strategic (resp. truthful) in our procurement setup corresponds to having a high (resp. low) valuation in Maskin and Riley’s (1985) auction setup.²⁹ There are nevertheless two differences: First we consider any number of bidders. Second, the ex post revenue of a strategic bidder, which is equal to $p \cdot R(q, q_0^*(p))$, where $q_0^*(p) \in Q_0^*(p)$, may no longer be linear in the price bid p insofar as the optimal report $q_0^*(p)$ could now depend on p . The latter difference matters when it comes to the analysis of other auction formats and to establishing a revenue ranking. If the set $Q_0^*(p)$ does not depend on the price bid p (let us use the shortcut notation Q_0^*), then the equilibrium analysis is straightforward in the second price auction (or equivalently the English auction): truthful (resp. strategic) firms bid (p^T, \bar{q}) (resp. (p^S, q_0) with $q_0 \in Q_0^*$). Then exactly as in Maskin and Riley (1985) when valuations are drawn independently, we can check the revenue equivalence between first-price and second-price auctions if firms are risk neutral, and that the first-price

28. Conversely, in this worst case, the increase in the BEC cannot go lower than 36% of the extra cost when there is a single strategic firm (since $(1 - 1/N)^{N-1} > \exp(-1) > 0.36$, which results from a standard logarithm inequality).

29. Doni and Menicucci (2012) extend the analysis to two asymmetric bidders when bidders are assumed to be risk neutral.

auction outperforms the second-price auction if firms are risk averse.³⁰ Note that the equivalence between first- and second-price auctions holds only under the complete information paradigm.

1.6 Performance analysis of the French rule

The French government used a production-insuring payment rule in the auctions for six offshore wind farm sites. These contracts were awarded separately through first-price sealed bid auctions: The firm asking for the lowest subsidy per MWh was declared the winning bidder.³¹ It was then subsidized according to both this price and its reference production, the latter being the yearly production derived from the firm’s self-reported average capacity factor.³² From a practical perspective, unrealistic capacity factors would lead to disqualification. Nevertheless, France did not adopt explicit ranges for eligible capacity factors as other countries do. Our analysis leaves out the disqualification risk associated with misreporting. Such disqualification risk does not seem particularly relevant in our case since the optimal overestimation never exceeds 13%, which is of the same order of magnitude as the prediction bias observed in practice for wind farms (Lee and Fields, 2020).

A first slight difference with our theoretical framework is that we now explicitly consider multi-year contracts: the length is 20 years, during which the production-insuring payment rule $R(.,.)$ defined in Section 1.2 applies separately to each year, based on the expected yearly production q_0 reported freely by firms in their bid. A second difference is that we consider both a (fixed) investment cost IC occurring before production (which corresponds to C in our model), and (fixed) operating costs OC occurring each year. The values we use for our analysis are reported in Appendix

30. On the contrary, if $Q_0^*(p)$ does depend on the price bid p , then the analysis under incomplete information is less straightforward: in particular, neither the bid pair (p^S, q^S) nor the pair (p^S, q^{S-T}) is a weakly dominant strategy for a strategic firm. The optimal reference production of a given strategic firm depends on its expectation on the price bid fixed by the auction rule in the case where it wins.

31. These auctions were actually *scoring* auctions: in addition to the per-unit subsidy bid p , other criteria such as local environmental impact or carbon footprint were taken into account to determine the winning bid. We leave out such “multidimensional bidding” aspects given that they do not interfere with the production-insuring payment rule.

32. The capacity factor is the power output divided by the maximum power capacity of the installation (the latter being a technical feature that is verifiable).

A. For a given bid (p, q_0) , firms' expected payoff difference between winning and losing the auction can then be expressed as:

$$\mathbb{E} \left[U \left(\sum_{t=1}^{20} \frac{[p \cdot R(q_t, q_0) - OC]}{(1+r)^t} \right) \right] - U(IC), \quad (1.5)$$

where the expectation is made w.r.t. the vector of yearly production (q_1, \dots, q_{20}) and where r denotes firms' annual discount rate which is set equal to 5.7%.³³ Let $FC = IC + \sum_{t=1}^{20} \frac{OC}{(1+r)^t}$ denote firms' net present cost. Firms' risk aversion is captured through CRRA utility functions where we take γ between 0 and 15. For a given price bid p , a strategic firm reports an expected production $q_0^*(p)$ that maximizes the expression in (1.5). As a robustness check, we have also considered, in more general terms, the utility function $U(x) = \frac{(x-IC+w)^{1-\gamma}}{1-\gamma}$ where w should be interpreted as the firm's initial wealth. The results reported below correspond thus to $w = IC$. In the SA, we report results when the initial wealth is equal to the total net present cost of the firm, i.e., when $w = FC$.

When the payment rule is homogeneous of degree 1, as are the French rule and also the payment rules considered in Section 1.7, CRRA utility functions generate useful properties that are detailed in the SA. We show in particular that the equilibrium BEC (under our various bidding paradigms) is strictly proportional to firms' net present cost and does not change if we multiply actual production by a constant. These fundamental properties are established in Lemma 10 in the SA. In this section, it implies that the ratio between the equilibrium expected subsidy paid by the buyer and firms' net present cost FC remains unchanged if we multiply the investment and operation costs by the same constant.³⁴

As detailed in Appendix A, we calibrate the distribution of the vector of yearly production (q_1, \dots, q_{20}) based on historic production simulated by models developed

33. Our choice is based on an estimation of the cost of capital for onshore wind projects in France made by Angelopoulos et al. (2016) which accounts for taxation and for compensation for other kinds of risks. Note that our analysis leaves out many kinds of risks, including cost overruns or delays that are not entirely under the control of the firms (e.g. connection to the grid). Those risks could generate much larger risk premiums but they are orthogonal to the design of the payment rule.

34. These ratios would change if we modified the investment cost while fixing the operating costs, or analogously if we changed firms' interest rates. However, in the same way as having an initial wealth different to IC has little impact on our results, it would not change our insights.

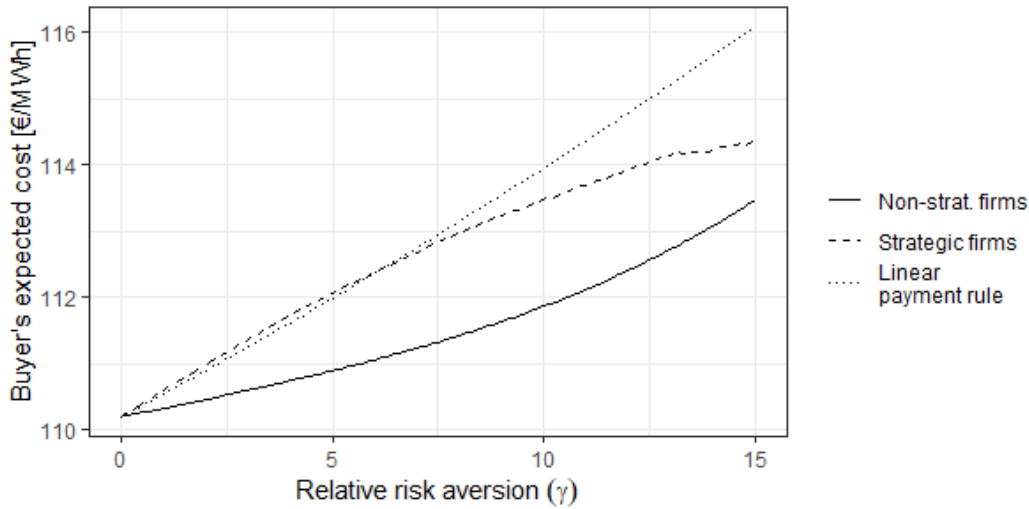
by Staffell and Pfenninger (2016) and whose outputs are easily accessible through the site `www.renewables.ninja`. The calibration procedure considers a wide range of possible yearly production based on recombination of quarterly production values randomly drawn from historical data. On top of this meteorological risk, we also consider that the capacity factor of each site's wind resource suffers from a *misevaluation risk* through a multiplicative normally-distributed shock (with a standard deviation taken as $\sigma = 6.3\%$).

We evaluate performance in comparison to the linear contract. Let $BEC(p, q_0) := p \cdot \sum_{t=1}^{20} \frac{\mathbb{E}[R(q_t, q_0)]}{(1+r)^t}$ denote the buyer's expected cost as a function of the winning firm's bid (p, q_0) . We compute equilibrium bids under the three complete information cases analyzed in Section 1.5: when all firms are truthful, when several firms are strategic, and last when a single firm is strategic. Note first that for each bidding paradigm, firms submit only bids (p, q_0) that lead to positive surplus, i.e., such that the expression in (1.5) is positive. This implies (by applying Jensen's inequality) that $BEC(p, q_0) \geq FC$. As shown in Section 1.5, if firms are risk neutral this inequality stands as an equality, except when there is a single strategic firm. Higher values for the equilibrium BEC are driven either by a risk premium (resulting from firms' risk aversion) or by a positive noncompetitive rent captured by a (single) strategic winning bidder. Since the linear FiT is strategy-proof, Bertrand competition prevails and firms make zero surplus.

Hereafter, all ranges presented correspond to the smallest and the largest result obtained among the five sites retained.³⁵ First, the risk premiums under a linear contract are notably small: for $\gamma = 1$ they are between 0.29 – 0.36%, and fluctuate in the range 0.89 – 1.1% for $\gamma = 3$. When all firms are truthful, the risk premium is reduced by a bit more than half under the French rule. However, these (limited) gains are entirely lost when all firms are strategic and this for any reasonable level of risk aversion, as depicted in Figure 1.3 which depicts the BEC divided by the expected quantity produced: only for unrealistic degrees of risk aversion ($\gamma > 6$) do we find that the French payment rule outperforms the linear contract under strategic reporting.

35. Detailed results are given in the SA. We have removed one site from our analysis because the recombination procedure is inadequate for this specific site.

Figure 1.3 – Buyer’s expected cost per quantity produced with homogeneous firms as a function of γ the relative risk aversion coefficient (Courseulles site)



As shown in section 1.5, heterogeneity among firms regarding misreporting produces noncompetitive rents that inflate the BEC. Our simulations support the idea that such rents are of a larger order of magnitude than the risk premium reduction that the buyer could save in the most favorable case where all firms are truthful: with a single strategic firm, we find a BEC 3.3 – 3.6% greater than under the linear FiT when firms are risk neutral, and 2.6 – 2.9% greater when firm’s risk aversion is up to $\gamma = 3$. Note that those figures are much lower than $\frac{1}{9} \approx 11.11\%$ the theoretical upper bound mentioned in Section 1.5. Nevertheless, for any intermediate risk aversion level, the increase in BEC when a single firm is strategic is always more than four times greater than the cost reduction thanks to insurance provision when all firms are truthful. For $\gamma = 1$, this increase is more than 15 times greater than the potential cost reduction in the most favorable case where all firms are truthful.

On the whole, we conclude that the premiums associated with production risk were quite negligible which limits the benefits that the French payment rule could have brought thanks to insurance provision. Furthermore, those potential benefits relied crucially on the hypothetical assumption that all firms report their expected production truthfully, an assumption which conflicts with their incentives. Finally, the French rule opens the door to two kinds of pitfall: 1) Strategic firms increase the variability of their revenue by overestimating their production which nips in the

but the presumed benefits from a production-insuring rule if all firms are strategic; 2) Heterogeneity among firms regarding truthful/strategic behavior could produce noncompetitive rents. If all firms are strategic, we see from Figure 1.3 that the French rule and the linear FiT perform almost equally well for any realistic level of risk aversion. On the contrary, the second pitfall could increase the BEC by about 3%.

Last, we stress that our specification with a misevaluation risk (which tends to shrink over time thanks to improvements in capacity factor predictions, see Lee and Fields' (2020)) exacerbates the potential benefits from insurance provision but also reduces the incentives from overestimating production (as formalized at the end of Section 1.4) and thus the associated surplus captured by strategic firms. Keeping this in mind reinforces the conclusion above.

1.7 Beyond production-insuring payment rules

Our analysis so far provides strong arguments against the use of production-insuring payment rules: they are (typically) manipulable which then leads to non-competitive rents in the auction once firms are heterogeneous regarding their ability to misreport the reference production. However, our analysis does not claim that we should stick to the linear payment rule. We now adopt the perspective of a sophisticated buyer who anticipates that firms may strategically report the reference production q_0 . We explore whether there are any payment rules $R(q, q_0)$, not necessarily production-insuring in the sense of Definition 1, that could bring a lower BEC in a manner that is robust to strategic behavior, i.e. for any of our bidding paradigms.

With this in mind, we first formalize the fact that no payment rule $R(q, q_0)$ that is homogeneous of degree 1 can fully eliminate risk premiums for strategic firms. The restriction to payment rules that are homogeneous of degree 1 excludes payment rules tailored to a specific distribution f , which would be inappropriate in the presence of asymmetric information regarding f .³⁶ In other words, we formalize the fact that

36. Without the homogeneous of degree 1 restriction, an obvious strategy-proof payment rule for any $f \in \mathcal{F}_{sp}$ such that 0 does not belong to its support is that where $R(q, q_0) = \bar{q}$ if $q_0 = \bar{q}$ and $R(q, q_0) = q$ otherwise. To implement such a payment rule, the contract designer needs to know \bar{q}

it is impossible to fully insure strategic firms against production risk if the contract designer does not know the production distribution up to a homothetic transformation.

Proposition 8. *Consider a payment rule that is homogeneous of degree 1 and a contract price $p > 0$. If the contractor optimally (mis)reports its reference production, then it is not fully insured against production risk. Formally, $q_0 \in Q_0^*(p)$ necessarily implies that the variance of $p \cdot R(q, q_0)$ is strictly positive, which means that the contractor's revenue is risky.*

This results from the fact that if reporting q_0 ensures that the contractor is fully insured, the latter would strictly benefit from reporting a reference production slightly higher than q_0 : the potential loss from moving some of the lowest production outcomes (provided this mass is small enough) outside the range where it is perfectly insured would be overcompensated by the benefits from raising the correction factor for production outcomes remaining in this range.

Even though there is no hope of fully insuring strategic contractors, we attempt to find a better performing class of contracts, possibly by discouraging misreporting through “punishments” (defined hereafter). Inspired by rules adopted in some countries for RES-E auctions,³⁷ we consider the following class of homogeneous of degree 1 payment rules $R_{(w,\eta)}$ parameterized by the pair of coefficients $(w, \eta) \in [0, 1]^2$ and defined in the following way:

- $R_{(w,\eta)}(q, q_0) = q_0$, if $q \in [q_0(1 - w), q_0(1 + w)]$,
- $R_{(w,\eta)}(q, q_0) = (1 - \eta) \cdot q + \eta \cdot q_0(1 + w)$, if $q > q_0(1 + w)$,
- $R_{(w,\eta)}(q, q_0) = \max\{\frac{1}{1-\eta} \cdot q + (1 - \frac{1}{1-\eta}) \cdot q_0(1 - w), 0\}$, if $q < q_0(1 - w)$.³⁸

Figure 1.4 depicts such payment rules for $w = 0.15$ and various values for η . The parameters w and η capture respectively the width of a range around q_0 where firms are fully insured and the strength of the punishment when actual production lies outside this range. If $\eta = 0$, then the payment rule matches the linear payment rule outside the insured range and the payment rule $R_{(w,\eta)}$ is production-insuring for

exactly.

37. In Brazil, e.g., features comparable to the “punishment” we study hereafter are implemented: the contractor must pay $1.06 \cdot p$ (where p is the per-unit price) for each quantity that it fails to deliver, while overproduction is sold on the spot market (and thus typically at a lower price than p).

38. If $\eta = 1$, then we adopt the convention that $R_{(w,\eta)}(q, q_0) = 0$ if $q < q_0(1 - w)$.

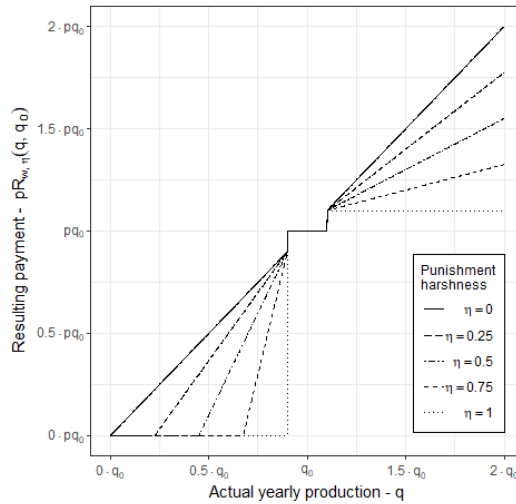


Figure 1.4 – Simplified production-insuring payment rule with punishments

any $w > 0$. On the contrary, when $\eta > 0$ then payment to the firm decreases more rapidly (resp. increases more slowly) when production falls below (resp. goes above) the insured range. Then the expected value of the correction factor under truthful reporting may be strictly lower than one: the payment rule $R_{(w,\eta)}$ thus fails to be production-insuring when $\eta > 0$.³⁹ We thus circumvent the impossibility result in Proposition 2 and for any $f \in \mathcal{F}$, there may exist some $R_{(w,\eta)}$ differing from the linear contract but which are still strategy-proof. Intuitively, the risk of production outcomes falling outside the insured range, which would be “punished” by a correction factor below 1, deters firms from misreporting their expected production.

The main question we ask is whether fixing the parameters (w, η) appropriately may lower public spending in a way that is robust to some firms being strategic. We study this class of payment rules through simulations of the complete information equilibria presented in Section 1.5. Throughout this section, we consider a single year contract as in our theoretical framework, a CRRA utility function with $\gamma = 1$ and two production distributions: first, a normal distribution where the standard deviation is equal to 20% of the mean (Figure 1.5) and, second, a uniform distribution on the

39. If $\eta > 0$, then $\mathbb{E}_f[R(q, \bar{q})] < \bar{q}$ for any distribution $f \in \mathcal{F}_{sp}$ whose support is not a subset of $[q_0(1-w), q_0(1+w)]$.

interval $[0.5\bar{q}, 1.5\bar{q}]$ (Figure 1.6).⁴⁰ In Figures 1.5 and 1.6, the three panels (a), (b), and (c) depict the ratio between the BEC and the producer's cost, respectively in the equilibrium when all firms are truthful, when several firms are strategic, and last when only one firm is strategic. Next those three ratios are referred to as the performance ratios. We stress that all these performance ratios depend neither on the production cost C nor on the mean of the production distribution \bar{q} (that were thus left unspecified). Panel (d) depicts the ratio between the reference production reported by a strategic firm q_0^* and the true expected production \bar{q} . If the payment rule is strategy-proof, then both strategic and truthful firms submit the bid pair (p^T, \bar{q}) and the performance ratios are identical in the various paradigms. In Figures 1.5 and 1.6 we report our results for the parameters (w, η) varying over the square $[0, 0.5]^2$, i.e., for values such that the performance ratios lie strictly above one since the BEC always includes a risk premium.⁴¹ When there is a single strategic firm – panel (c) – the BEC also includes the positive surplus captured by the winner: note that the scale in the legend of panel (c) differs significantly from those for panels (a) and (b).

With truthful firms, the impact of both parameters on the performance ratio (or equivalently on the risk premium) is quite intuitive: the larger the insurance range and the lower the extent to which firms are punished, the lower is the risk premium, as shown in panel (a) in both Figures 1.5 and 1.6. The results are less straightforward in the presence of strategic firms.

Panel (d) in Figures 1.5 and 1.6 show that, overall, the larger the insurance range w the more strategic firms overestimate their expected production. This is consistent with the comparative statics regarding w that we derived in Section 1.4 (for $\eta = 0$). On the other hand, harsher punishments η lead firms to understate their expected production in an attempt to avoid outcomes falling below the lower bound of the insurance range. A surprising result is the discontinuity of the function mapping the payment rule parameters (w, η) into the optimal q_0^* that appears only for the uniform

40. Then the standard deviation is equal to $\sqrt{\frac{1}{12}} \approx 29\%$ of the mean. The distributions thus differ mainly in the sharpness of the peak.

41. The payment rule $R_{(w,\eta)}$ provides full insurance only for the uniform distribution and in the limit case where $w = 0.5$ such that production outcomes remain in the flat part under truthful reporting. The performance ratio is equal to one only in this limit case.

Figure 1.5 – Auction outcome depending on payment rule for a normally distributed production

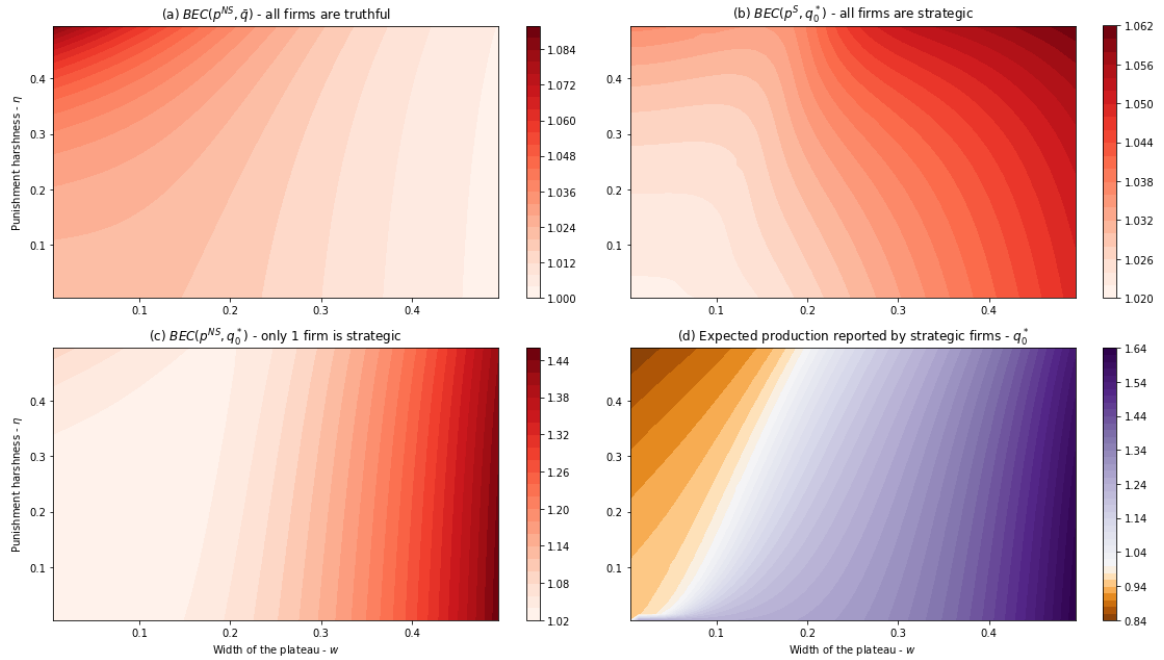
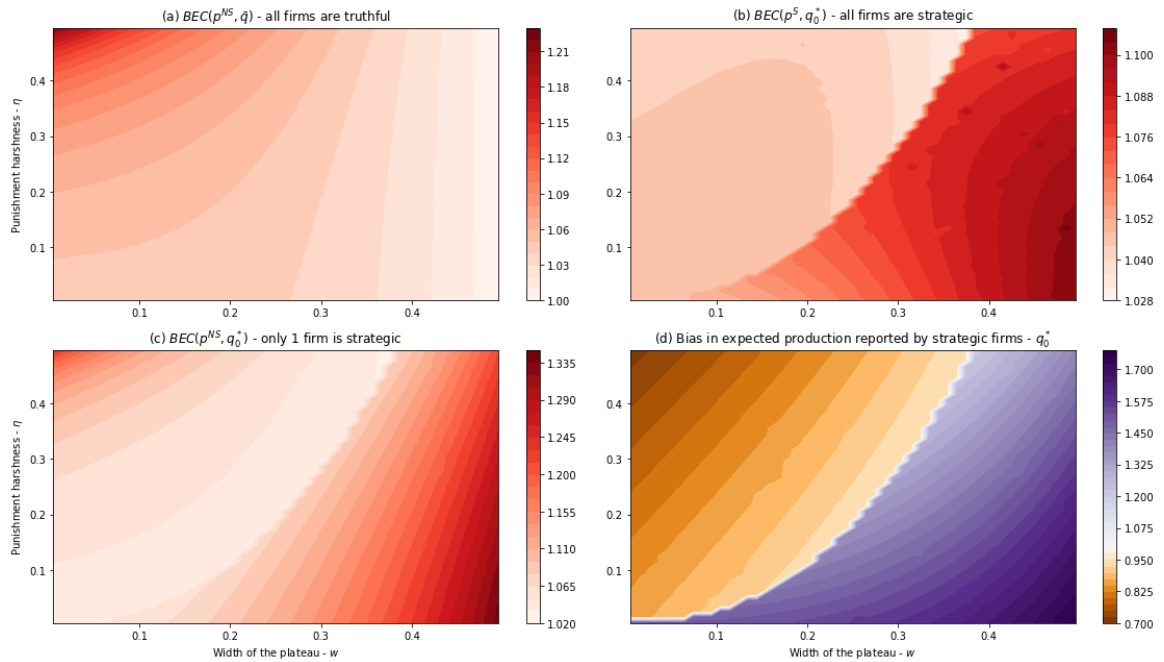


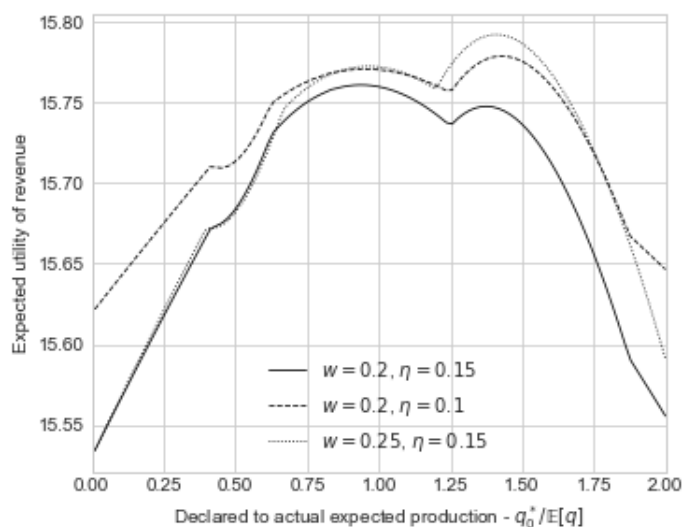
Figure 1.6 – Auction outcome depending on payment rule for a uniformly distributed production



distribution. This discontinuity results from the existence of two local maximums, each moving in different directions with w and η . See Figure 1.7 for an illustration: the local maximum on the left (with the lowest q_0) consists of reporting a reference production slightly underestimated compared to expected production to insure oneself against low production outcomes. This cautious strategy is the *global* maximum for small w and large η . The local maximum on the right consists of overestimating expected production to maximize the expected compensation the contractor obtains for “lower than expected” production outcome. This risky strategy corresponds to the *global* maximum for large w and small η . Switching from one side to another of the (w, η) discontinuity line, which corresponds roughly to the “white convex curve” in Figure 1.6d, generates a discontinuity in the risk premium as can be seen in Figure 1.6b.

A consequence of this discontinuity is that under the uniform distribution, optimal reporting is always either a strict overestimation or a strict underestimation when $(w, \eta) \neq (0, 0)$. Consequently, any payment rule $R_{(w, \eta)}$ differing from the linear contract is manipulable. On the contrary, such discontinuity does not exist under the normal distribution and we observe a (w, η) curve (close to the line $\eta = 0.2 \cdot w$) for which the payment rule is strategy-proof.

Figure 1.7 – Producer’s expected payoff as a function of $\frac{q_0}{\bar{q}}$ under the uniform distribution



Under the normal distribution and when there is at least one strategic firm, we see

from Figures 1.5b and 1.5c that a higher w or a higher η are in all cases associated with a higher BEC: the linear contract ($w, \eta = 0$) minimizes the BEC. The extra cost generated by using another payment rule $R_{(w,\eta)}$ is typically much larger when there is a single strategic firm: this reflects the fact that the surplus captured by the strategic firm is of a larger order of magnitude than the risk premium. But even in the absence of such surplus, i.e. for strategy-proof payment rules, departing from the linear contract increases the BEC: the intuition is that for any given $w > 0$, the punishment $\eta > 0$ needed to guarantee strategy-proofness is so large that it exacerbates the risk more than it is mitigated by the insurance range.

The picture is different and more subtle for the uniform distribution. The performance depends crucially on which side of the line of discontinuity the subject lies. On the right-hand side, for which strategic firms overestimate production, the impact of parameters w and η is similar to the case with the normal distribution. However, if we wish to minimize the BEC, we would rather focus on the range of parameters on the left-hand side of the discontinuity line where the BEC is much lower. Over this range and when there is at least one strategic firm, the BEC does not increase but rather decreases with w and η . The BEC-minimizing contract within the square $[0, 0.5]^2$ corresponds to the intersection of the discontinuity line with the line $\eta = 0.5$ where w is approximately equal to 0.375. For such a contract, compared to the linear contract, the BEC is lowered by 1.31% when several firms are strategic, by 1.37% when a single firm is strategic and by 1.16% when all firms are truthful. However, adopting such a payment rule might be risky: The contract designer would most likely not have sufficient information to precisely determine the optimal payment rule, and a slight mistake may result in producers switching to the risky strategy (i.e., moving to the right side of the discontinuity line), which would dramatically increase the BEC. For instance, when several firms are strategic, if firms' relative risk aversion coefficient γ is equal to 0.9, then the contract that was optimal with $\gamma = 1$ would instead underperform the linear contract by 2.56%.

In conclusion, payment rules with punishments may bring a better outcome than a standard linear payment rule in some cases. However, adopting such payment rules would remain risky as imprecise information about the production distribution

or firms' preferences may lead the designer to choose an inadequate payment rule resulting in larger losses than the potential gains. From a robust mechanism design perspective (Bergemann and Morris, 2012), the linear contract seems a safe choice.

1.8 Discussion and extensions

Our baseline model leaves out aspects that are important in most procurement contracts. In particular, it assumes that the production distribution is independent of any effort provided by the firm, that the firms have fixed costs alone, that firms are perfectly symmetric in all dimensions (except for strategic behavior) and finally that the manipulation being studied is cost-free. Hereafter we comment on how our results would be affected by a modification of our model to account for moral hazard, for observable variable costs, for asymmetry between firms and last for costs incurred by strategic reporting of q_0 . First of all, let us delineate the theoretical status of the linear contract by clarifying what would be the socially optimal contract when firms are risk neutral.

Optimal contracts under risk neutrality

Let us consider an environment with possibly asymmetric risk neutral firms. Each firm $i = 1, \dots, N$ is characterized by the cost function $C_i : \mathcal{F}_{sp} \mapsto \mathbb{R}_+ \cup \{+\infty\}$. After signing the contract with the buyer, the contractor chooses the production distribution which maximizes its expected payoff. The buyer is assumed to value production linearly and let $\bar{p} > 0$ denote the buyer's value per quantity produced. The (expected) social welfare when contractor i chooses distribution f is then equal to $\bar{p} \cdot \mathbb{E}_f[q] - C_i(f)$. Let (i^*, f^*) denote the corresponding welfare optimal allocation.⁴²

If the payment rule takes the form $p \cdot q + b$ where firms bid on the fixed cash payment b in a second price auction, then bidding $b_i = -\max_{f \in \mathcal{F}_{sp}} \{p \cdot \mathbb{E}_f[q] - C_i(f)\}$ is a (weakly) dominant strategy for each firm i . When the buyer sets $p = \bar{p}$ the equilibrium allocation is socially optimal: the winning bidder is firm i^* and it chooses production

42. To simplify the discussion, we consider here that the set $\text{Arg max}_{(i,f)} \{\bar{p} \cdot \mathbb{E}_f[q] - C_i(f)\}$ is a singleton.

distribution f^* , since the payment rule makes its payoff congruent with the social welfare. This design provides *marginal rewards* to the contractor which is the key ingredient to guarantee social optimality.⁴³ This efficient contract design corresponds to the so-called “cash auctions” in the contingent auction literature. Departure from this design (e.g., to share risk) is known to generate social inefficiencies either in terms of moral hazard (Laffont and Tirole (1986) and McAfee and McMillan (1987)) or in terms of adverse selection (Che and Kim, 2010).

The linear contract where firms bid on the unit price p (without cash payment b) is prone to such inefficiencies. In the second price auction bidding $\min\{p \geq 0 \mid \max_{f \in \mathcal{F}_{sp}} \{p \cdot \mathbb{E}_f[q] - C_i(f)\} \geq 0\}$ is a (weakly) dominant strategy for each firm i , and the equilibrium allocation (i^{eq}, f^{eq}) belongs to $\text{Arg max}_{(i,f)} \{p^{eq} \cdot \mathbb{E}_f[q] - C_i(f)\}$ where p^{eq} denotes the equilibrium price. If $p^{eq} < \bar{p}$,⁴⁴ then the contractor has lower incentives to upgrade its production: informally, if the most efficient firm i^* wins the auction, then the equilibrium expected production will be lower than that under the optimal distribution f^* . Furthermore, there is no guarantee that i^* wins the auction: a firm with lower fixed costs but which is less efficient in upgrading production could outbid the most efficient firm i^* . However, assuming the equilibrium price p^{eq} is not far from \bar{p} , the linear contract would still be “approximately efficient” in terms of social welfare.^{45, 46}

Beyond multiplicative payment rules

Our analysis can be adapted straightforwardly to the class of additive payment rules where the remuneration takes the form $A \cdot R(q, q_0) + b$ with $A > 0$ and where b corresponds to the auction price while the winning bidder is determined by the

43. In a related manner, Rogerson (1992) shows that providing marginal rewards guarantees social optimality in a setup which includes ex ante private investments from the competing bidders. Hatfield, Kojima, and Kominers (2018) establishes a converse result and provides approximate versions.

44. If $p^{eq} > \bar{p}$, then the buyer should prefer not to contract with the winning firm.

45. From the equilibrium conditions, we have $p^{eq} \cdot \mathbb{E}_{f^{eq}}[q] - C_{i^{eq}}(f^{eq}) \geq p^{eq} \cdot \mathbb{E}_{f^*}[q] - C_{i^*}(f^*)$, which implies that the equilibrium social welfare $\bar{p} \cdot \mathbb{E}_{f^{eq}}[q] - C_{i^{eq}}(f^{eq})$ is greater than $\bar{p} \cdot \mathbb{E}_{f^*}[q] - C_{i^*}(f^*) - (\bar{p} - p^{eq}) \cdot [\mathbb{E}_{f^*}[q] - \mathbb{E}_{f^{eq}}[q]]$, i.e. the optimal social welfare minus the term $(\bar{p} - p^{eq}) \cdot [\mathbb{E}_{f^*}[q] - \mathbb{E}_{f^{eq}}[q]]$.

46. In a related manner, Hatfield et al. (2018) shows that a mechanism providing approximately marginal rewards is approximately efficient (for any type realization). On the contrary, our approximate efficiency claim relies on the assumption that bidders’ equilibrium payoffs are close to marginal rewards, which corresponds in our case to p being close to \bar{p} .

offer with the lowest (possibly negative) bid. Our definition of production-insuring rules (that suits the multiplicative framework) also suits the additive setup if the corresponding linear benchmark now becomes the remuneration rule $A \cdot q + b$. In particular, Proposition 3 extends to this setup: production-insuring payment rules still constitute an improvement over the linear benchmark when firms are truthful. Furthermore, the same qualitative pitfalls hold when some firms are strategic: e.g. when firms are risk neutral and when there is a single strategic firm, the strategic firm captures the non-competitive rents $A \cdot (\max_{q_0} \mathbb{E}_f[R(q, q_0)] - \mathbb{E}_f[R(q, \bar{q})]) \geq 0$, an expression which differs from the one we have derived if $A \neq p^T$.⁴⁷ More generally, Definition 1 suits any remuneration rule taking the form $A(b) \cdot R(q, q_0) + B(b)$, with $A(b) > 0$, because it implies that $\mathbb{E}_f[U(A(b) \cdot R(q, q_0) + B(b))] \geq \mathbb{E}_f[U(A(b) \cdot q + B(b))]$ for any concave function U and any bid b . The sole difference from our analysis is qualitative: the exact expression of the BEC depends on how functions $A(\cdot)$ and $B(\cdot)$ are specified.

Moral hazard

Instead of inviting bidders to report their idiosyncratic reference production, another approach for the buyer would consist of setting the reference production, bearing in mind that the contractor will make ex post efforts to match its expected production to the reference production. As formalized below, our results in Section 1.4 could be reinterpreted from this moral hazard perspective: insurance provision would reduce the contractor's incentives to upgrade its expected production compared to the linear contract and then prevent to implement the socially optimal level of effort.⁴⁸

Suppose that after signing the contract with the price $p > 0$ and the payment rule $R(q, q_0)$, the contractor chooses its expected production \bar{q} , which generates the cost $C(\bar{q})$. Let us assume that the contractor is risk neutral, the cost function $C : \mathbb{R}_+ \mapsto \mathbb{R}_+$

47. From this narrow perspective, lowering A would reduce the buyer's expected cost. However, this is an artefact of our baseline model which leaves out moral hazard and adverse selection, both pleading in favor of setting $A = \bar{p}$, the buyer's value per quantity produced, as argued above.

48. See Shavell (1979) for a seminal contribution on an insured agent's effort reduction in a model where the random variable is binary. Note also that Tirole (1997) criticized the contract proposed by Engel et al. (2001) on the grounds that hedging highway franchises against demand risk would kill the incentives to upgrade quality and then reduce demand.

is increasing and strictly convex and that the distribution $F_{\bar{q}}$ belongs to \mathcal{F}_{sp} . Hence the level of effort \bar{q} generates the private payoff $p \cdot \mathbb{E}_{f_{\bar{q}}}[R(q, q_0)] - C(\bar{q})$ for the contractor. Under the linear contract, the optimal level of effort for the contractor is equal to $[C']^{-1}(p)$.

For a given price p , if the buyer designs a production-insuring⁴⁹ payment rule $R(\cdot, q_0)$ where q_0 is set to the contractor's optimal level of effort under the linear contract, then the contractor's optimal level of effort can not be larger q_0 . As a corollary, we obtain that for any price $p < \bar{p}$, where \bar{p} is the buyer's value per unit, it is impossible to ensure that the contractor provides the socially optimal level of effort $\bar{q}^* := [C']^{-1}(\bar{p})$ while offering a payment rule that is production-insuring for this same level of effort. Formally, if $p < \bar{p}$ and if the buyer sets the reference production \bar{q}^* , then the contractor would strictly benefit from shirking, i.e. providing an effort strictly lower than \bar{q}^* . The formal proof is detailed in the SA. In other words, the reduced incentives to make efforts when $p < \bar{p}$ under the linear contract are reinforced under a production-insuring payment rule.⁵⁰

Similarly to the results in Section 1.5, we expect at the auction stage that the equilibrium price would be lower under a production-insuring payment rule than under the linear rule but that this effect is deceptive, the extra cost from socially suboptimal efforts being borne ultimately by the buyer.

Variable costs

In line with our case study of RES-E generation, we assume in our baseline model that there is no variable cost incurred by production. Other applications may however require an extension of this model. E.g., in procurement for infrastructure projects (studied by Bolotnyy and Vasserman (2019) and Luo and Takahashi (2019)), the analog of the production risk corresponds to the quantity of inputs needed for the project and those quantities (which are random variables from the perspective of the

49. Here, the properties of a production-insuring payment rule as stated in Definition 1 will apply conditionally on the contractor providing a level of effort \bar{q} matching the q_0 set by the buyer, rather than conditionally on the contractor reporting its true \bar{q} as q_0 .

50. We also show under additional technical restrictions that the contractor has an incentive to reduce its effort even if $p = \bar{p}$.

auction stage) do not solely shape the payment rule but also involve (physical) costs for the supplier. With a fixed cost to build the production capacity and then no variable costs associated with production, our renewable energy application is a kind of exception.

Suppose that actual production q leads to the variable cost $\tilde{C}(q)$ in addition to the fixed cost C . Our analysis can be adapted straightforwardly to this framework if we assume that these variable costs are observable ex post, or equivalently if the function $\tilde{C}(\cdot)$ is known by the contractor: according to our notation, it would consist of replacing the payment rule $p \cdot R(q, q_0)$ by the function $p \cdot R(q, q_0) + \tilde{C}(q)$. In this more general setup, the analog of the linear FiT (resp. a production-insuring rule) consists first of reimbursing the observable variable costs $\tilde{C}(q)$ and then adding to this the linear transfer $p \cdot q$ (resp. a term $p \cdot R(q, q_0)$ where q_0 is the reported reference production and with $R(q, q_0) \geq q$ if and only if $q \leq q_0$). In particular, if the cost function \tilde{C} is linear, then the analog of the linear FiT remains a linear payment rule. From this point of view, departing from the commonly used unit price contracts to hedge against ex post risk would raise the same kind of issues.

Asymmetry between firms

In our baseline model, all firms have the same production distribution F , the same investment cost C and the same utility function U . Let us now discuss how our results from Section 1.5 change in the presence of asymmetries. Consider for simplicity two firms indexed by $i = 1, 2$ and characterized by the primitives C_i, f_i and U_i . We assume below complete information, meaning that all primitives (C_i, f_i and $U_i, i = 1, 2$) are common knowledge. Let us denote p_i^L the zero surplus bid of firm i under the linear contract. Without loss of generality, let us assume that firm 1 is dominant under a linear contract, i.e. $p_1^L < p_2^L$. Similarly, let us denote p_i^T (resp. p_i^S) the zero surplus bid of a truthful (resp. strategic) firm i under a given production-insuring contract and say that firm i is dominant under the truthful/strategic paradigm if it has the lowest zero surplus bid in the corresponding paradigm. Next we always make the implicit assumption that the production-insuring contract of interest is manipulable and that strategic firms overstate their reference production: for any given price p

and any given winning firm, the BEC is higher if the winning firm is a strategic.

In equilibrium with a linear contract both firms bid p_2^L , the BEC is equal to $p_2^L \cdot \mathbb{E}_{f_1}[q]$ and the dominant firm wins and captures the surplus $(p_2^L - p_1^L) \cdot \mathbb{E}_{f_1}[q]$.⁵¹ One noteworthy twist when switching to a production-insuring payment rule is that the winning firm might not be the same as under the linear contract: which firm is dominant depends not only on the contract but also on the truthful/strategic paradigm considered (in particular because bidder i 's benefits from misreporting depend on the spread of its production distribution spread and its risk aversion). Given that the winning bidder's identity might change and given potential discrepancies between firms' expected production, let us now consider as our performance criterion the buyer's expected cost divided by the expected production, further referred to as the per-unit BEC.

If the two firms are homogeneous regarding truthful/strategic behavior and it is common knowledge, then we reach conclusions similar to those in Section 1.5. Given Propositions 3 and 4, we have $p_i^S < p_i^T \leq p_i^L$ with the last inequality being strict if firm i is strictly risk averse. We obtain thus that the equilibrium price bid when both firms are truthful (resp. strategic), which is equal to $\max\{p_1^T, p_2^T\}$ (resp. $\max\{p_1^S, p_2^S\}$), is lower than the equilibrium price bid under the linear contract. When firms are truthful, the price bid and the per-unit BEC match and we conclude then that the production-insuring contract outperforms the linear contract. When firms are strategic the equilibrium price bid is lower than under the linear contract, but as before we cannot conclude on how the equilibrium per-unit BEC will be affected.

When a single firm is strategic, the picture is quite different in the presence of asymmetry. As developed below and as in Burguet and Perry (2007), the impact of the bid manipulation on buyer's cost depends crucially on whether it is the strategic firm or the truthful firm which is dominant. Next we compare the equilibrium per-unit BEC when a single firm is strategic with the case when both firms are truthful.⁵²

If the strategic firm (say firm 1) is dominant under the truthful paradigm (i.e.

51. As before (see Footnote 26), we assume that ties are broken in favor of the firm that makes a strictly positive surplus.

52. In the special case where firms are risk neutral, then this corresponds to the comparison between the production-insuring contract and the linear contract.

$p_1^T < p_2^T$) then it still wins at price p_2^T and also benefits from misreporting q_0 . The surplus due to strategic reporting and due to its dominant position ‘are added to one another’. Hence the per-unit BEC increases when a single firm becomes strategic.

If the truthful firm (say firm 2) is dominant under the truthful paradigm (i.e. $p_2^T < p_1^T$), then we distinguish three different cases. Contrary to the model developed in Section 1.5, here the equilibrium depends on whether the truthful firm is aware or not that its competitor is strategic.

In one case the truthful firm is strongly dominant such that $p_2^T < p_1^S$, and aware that its competitor (firm 1) is strategic. Firm 2 then still wins the auction but gives up part of its surplus by bidding p_1^S , i.e. lower than its bid when both firms are truthful. In sharp contrast with the previous case, the presence of a strategic firm is here unambiguously beneficial to the buyer. In a second case, we assume that firm 2 does not know that firm 1 is strategic. Then firm 1 wins the auction by bidding slightly below p_1^T , while firm 2 presumes it can win the auction by bidding p_1^T . In this case, the presence of a single strategic firm is unambiguously detrimental. In a third case, the truthful firm is dominant under the truthful paradigm ($p_2^T < p_1^T$) but only slightly insofar as $p_2^T > p_1^S$ and we assume furthermore that firm 2 knows that firm 1 is strategic. Then the strategic firm is able to win the auction by bidding (slightly below) p_2^T . In this case there are two conflicting effects at work: On the one hand, the equilibrium price bid is lowered by the presence of a strategic firm which increases the competitive pressure on the price bid. Second, the deceptive effect associated with misreporting is at work. The overall effect is ambiguous.

The main insight we obtain is that bid manipulations can have a pro-competitive effect when bidders are asymmetric. However, this insight holds only when the strategic firm faces a dominant truthful firm such that manipulations reduce bidders’ surplus.⁵³

53. In an incomplete information model for the first price auction with favoritism, Burguet and Perry (2007) show surprisingly that the manipulation is beneficial to the buyer when the dishonest supplier is a strong bidder.

Costly manipulation

Our model can be viewed as one where the cost of falsification is binary, either zero for strategic bidders or infinity for truthful bidders. In practice, inflating q_0 involves some costs (because you need either to produce a fake justification for it, or to corrupt the agent in charge of the technical evaluation of the project). Following Maggi and Rodriguez-Clare (1995), let us briefly consider a simple model where the falsification cost is a smooth increasing function of the magnitude of the difference between the reported reference production and the (true) expected production \bar{q} . Under risk neutrality, then it is straightforward given Proposition 2 that the optimal report with such falsification costs would lie somewhere between \bar{q} and q_0^* the optimal report without falsification costs. From this perspective, our results are a kind of upper bound to the increased BEC resulting from misreporting. Nevertheless, from a welfare perspective, falsification is also a wasteful activity.

1.9 Conclusion

We study procurement auctions with ex post risk. In such environments, it is tempting for the buyer to design risk sharing contracts. We have shown that a hedging instrument used in France to subsidize offshore wind farms suffered from large pitfalls: the cure is likely to produce a worse net result in terms of buyer's cost. In addition, reducing risk premiums seems a second order issue in this specific application, in contrast to environments where risks are cumulative.⁵⁴ Both our theoretical analysis and our numerical investigations support the insight that departing from linear contracts (that are non-manipulable) is a risky bet. However, the class of payment rules we have analyzed rely on two important restrictions. On the one hand, bidders are free to report any reference production. On the other hand, the hedging instrument is static: it does not use the fact that in some applications (including RES-

54. In Engel et al. (2001), risk concerns demand for a highway and is related to future GDP growth. In Ryan's (2020) auctions for fossil power plants, risk concerns future coal prices. Spurred by the European Commission, many European countries have shifted their subsidy design for RES-E in the direction of Feed-in-Premium (FiP) where producers are free to sell their production on the market and then receive a premium per MWh as a revenue complement. In FiP contracts, risk concerns future electricity prices.

E), the outcome can be modeled as a vector of independent draws from a common distribution.

These restrictions have been relaxed by some countries who used innovative RES-E subsidy designs. In Brazil, the analog of the reference production is certified by a third party based on wind measurements, while in Germany it is determined according to administrative rules independently of the specific characteristics of the project.⁵⁵ It may be thought that this would resolve the pitfalls we have identified when firms self-report their reference production. Nevertheless, if the reference production is mis-estimated (in relative terms) across the competing projects (due to asymmetric information or if the third party can be corrupted by some bidders), then it would lead to the same kinds of inefficiencies. In Brazil, the payment rule is not additive across years but involves an instrument that smooths the revenue across years: e.g., if the outcome is low in the first year, then the producer is not penalized on a short term basis but could compensate this shortage by a high production outcome in a subsequent year. More generally, as argued in Thomas and Worrall (1990) with a repeated principal-agent setup with i.i.d. shocks, efficient risk sharing relies on dynamic contracts and repeated interactions allow asymmetric information to be reduced.⁵⁶ Dynamic contracts are a promising avenue for future research. Nevertheless, we emphasize that many procurement applications do not fit into a repeated screening setup.

55. See the report D4.1-BRA (2016) of the AURES project and Bichler et al. (2020) for details.

56. See Malin and Martimort (2016) and Krasikov and Lamba (2021) for more recent contributions on optimal dynamic contracts with risk aversion and cash constraints, respectively.

Chapter 2

Comparing the social benefits of variable renewable energy projects ¹

Abstract

We define the social benefits of a variable renewable energy (VRE) power plant project as its contribution to meeting electricity demand, i.e., the costs and externalities that are avoided by other means of electricity generation in the power system. These depend on various characteristics (e.g., location and technical characteristics) that determine how much and when each project would produce electricity. While the market value of a project's output is generally considered a good measure of these social benefits, we detail why it is incomplete. A case study of a sample of solar and wind projects in France allows us to quantify the errors in project comparisons resulting from an incomplete consideration of two determinants of social benefits: CO₂ emissions avoided, and the increasing share of VRE in the mix that decreases the value of VRE's output. Using a power dispatch model to accurately assess the value of each project through counterfactual simulations, we find that, while these errors are not negligible, a simple correction applied to the market value of the projects corrects them for the most part.

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2.1 Introduction

Many governments have pushed, through dedicated public policies, for the deployment of variable renewable energy (VRE), such as wind and solar power, with the motivation that the social benefits from VRE exceed its private benefits, and in particular because it helps reduce greenhouse gas (GHG) emissions from electricity production. To guide such public intervention towards efficient policies, a proper assessment of the various market and non-market components of the social value of VRE is necessary, though not an easy task (Borenstein, 2012). The literature has provided quantitative assessments for many of the non-market components of the social costs and benefits associated with wind and solar energy, including the social benefits associated with reducing greenhouse gas emissions (Cullen, 2013) and the emissions of other pollutants (Kaffine et al., 2013), the extra costs induced by intermittency (Gowrisankaran et al., 2016), the impact on grid congestion (Savelli et al., 2022) or on ancillary services (Tangeras, Wolak, 2019).

One of the motivations in determining precisely the social value of the power generated by VRE has been to suggest policy instruments to support its development that are in line with this social value, as is done in Chapter 3. For instance, the difference between wind and solar power in terms of GHG emission reduction per energy produced (Abrell, Kosch, Rausch, 2019) has been used to motivate a differentiation of direct subsidies to these technologies reflecting this gap (Abrell, Rausch, Streitberger, 2019). But beyond broad technology categories, the design of these subsidies also determines the differentiated support benefiting individual wind and solar farms (Meus et al., 2021). Still, most studies on the social value of VRE have considered wind power or solar power as homogeneous generation technologies and provided estimations of the average benefits associated with each technology, while little attention has yet been devoted to the heterogeneity within each technology. Variability in the social value of individual VRE power plants' output may arise from differences in geographic location or technical characteristics which determine the amount of electricity produced and when it is produced. Some have documented the varying value of solar and wind power depending on the regional context, but the effects captured relate

primarily to the type of thermal generation that is present in the region and to which the VRE power is substituted (Kaffine et al., 2013; Lamp, Samano, 2023), or to the varying economic damages induced by local air pollution (Sexton et al., 2018). Their geographic location may also affect the production profile of wind and solar farms (through local wind or solar irradiation patterns) and thus the social value of their output. This was considered in the literature, e.g. by Odeh and Watts (2019), but only through a macro perspective to determine the optimal geographic distribution of the fleet at the scale of an entire power system. Similarly, the detailed technical characteristics of projects have implications for the social benefits from their power output, which were primarily examined through the optimization of an entire power system rather than through the evaluation of individual projects. The technical characteristics studied in the literature include the hub height and the swept area in wind farms (May, 2017; Hirth, Müller, 2016) and the orientation of the panels in solar farms (Hartner et al., 2015). Meus et al. (2021) jointly examine the geographic and technological heterogeneity among onshore wind projects with a similar perspective of approaching the optimal set of projects through policy instruments. Rather, in this article we abstract from such a generation fleet optimization perspective, and instead assess the heterogeneity in social value among a given set of VRE power plant projects. In doing so, we focus only on gross social benefits, as this is the relevant metric for a government attempting to incentivize the most valuable projects (e.g., through subsidies). Thus, we do not rely on any assumption about the costs of VRE projects, which ensures that the discussions in this article hold even in the presence of unobserved cost heterogeneity.²

A starting point for measuring the social benefits of a wind or a solar farm is the market value of their output, as first suggested by Joskow (2011). The main argument in favor of this measure is that if wholesale electricity markets are complete and competitive, prices should reflect the marginal social costs of electricity at all

2. Such unobserved cost heterogeneity could result from a large variety of causes such as variability in the cost of land, in particular the use of cheap polluted land, cost reductions from placing solar panels in certain configurations, lower grid connection cost due to the proximity of existing infrastructures, constraints imposed by the terrain or the access to the location, etc. This heterogeneity is often overlooked in the literature, in which an homogeneous cost per capacity installed is often assumed.

time, and thus the market value should match the value that VRE projects have for society (Hirth, 2013). In this article, we argue that the comparison of VRE projects on the sole basis of an evaluation based on electricity wholesale market prices suffers from at least three shortcomings.

First, we note that this approach, hereafter referred to as price-based valuation, fails to account for the portion of the social cost of meeting electricity demand that is not paid by agents operating in wholesale electricity markets. This portion of the social cost, hereafter referred to as external costs, includes the damages induced by GHG emissions when these are not properly internalized through policy instruments³ (e.g., through a carbon tax on electricity producers equal to the value of mitigating CO₂ emissions).⁴ Thus, the damages from GHG emissions are not (or only partially) reflected in market clearing prices, and this gap is typically filled by additional estimates of these emissions. However, most of the methods used do not capture the variation from one VRE project to another, which is what we try to explore in this article. Among them, econometric studies can determine the amount of pollution displaced on average by a VRE technology in a given electricity market (Gutiérrez-Martin et al., 2013 ; Novan, 2015 ; Thomson et al, 2017), but these estimates do not allow to assess the potential difference between different projects belonging to the same technology (depending on the specific timing of their production). Econometric methods have also been used to estimate average marginal emissions by time of day or season (Callaway et al., 2017), but while these estimates can capture the effect of seasonal or daily patterns on the GHGs displaced by a given project, they cannot capture effects related to how well a project's output is correlated with system marginal costs beyond these patterns (e.g., through weather conditions). We overcome these problems by evaluating the CO₂ emissions avoided through power system modeling.

A second shortcoming of price-based valuation methods is that they are, in practice, limited to contexts in which market prices have been observed. Thus the social

3. These external costs may also include other costs not discussed in this article, such as transmission and grid congestion costs, balancing costs, or other pollution damages, as long as these are not properly internalized through policy instruments or market design features.

4. Note that in the following, instead of considering a value representing the social cost of carbon per se, we consider a shadow carbon price (SCP) estimated by Quinet et al. (2019) based on a cost-effectiveness approach.

value of a VRE project is evaluated in the context of power systems as they were in the past, whereas cost-benefit analysis is typically concerned with projects to be built in the future. It would not be a major concern if past prices conveyed all the relevant and available information about the market value of the electricity that will be produced over the project's lifetime, i.e., starting a few years later and lasting 20 to 30 years. But the valuation of VRE projects will be affected by the rapid energy transition underway and its effect on marginal costs, which appears through changes in electricity prices. Specifically, an increase in the share of wind and solar in the mix has been found to have a general downward effect on market prices, known as the merit order effect, and also decreases the relative value of the output of these technologies as it creates and reinforces a negative correlation between their output and market prices, which is known as the cannibalization effect (Hirth, 2013; Prol et al, 2020). These effects can modify the comparison of individual VRE projects with each other since certain technical choices can mitigate the cannibalization effect, such as choosing wind turbines with a smoother generation profile (May, 2017; Hirth, Müller, 2016), diversifying the orientation of solar panels (Hartner et al., 2015) or diversifying the geographic location of projects (Roques, Hiroux, Sagan, 2010; Mills, Wisser, 2015). The flexibility offered by power system modeling allows these foreseeable effects to be taken into account when assessing the social value of wind and solar projects.

The last shortcoming we examine is the bias induced by using market prices for assessing the value of a power plant's output, even when assuming they perfectly reflect the marginal cost of the power system. After clarifying that such estimation is an approximation that relies on the assumption that each individual project is a marginal addition to the system, we show that the gap between this approximation and the true value is likely to depend on several characteristics of the projects: typically larger projects, projects who produce more often at peak load, and projects whose production is more erratic⁵ may exhibit a larger gap between the true value of their output and the one estimated through marginal costs. Furthermore, applying this to external costs, e.g. using marginal emission factors to assess CO₂ savings, might lead

5. This effect is a consequence of the fact that the erratic production of solar and wind power induces dynamic costs, such as the start-up costs of the dispatchable power plants that must make up for a sudden drop in their output (Jha, Leslie, 2020; Bushnell, Novan, 2021).

to errors of a larger magnitude (Elenes et al., 2022).

In this article, we first delineate the biases that price-based valuation introduces when comparing different VRE projects in terms of their gross social benefits. We then provide quantitative insights into their magnitude through a case study of a sample of real wind and solar projects that came under consideration by investors in France, for which we collect location and technical characteristics and use them to simulate their electricity production. To estimate the gross social benefits associated with these projects, we develop a model of the power dispatch in France and neighboring countries and use it to run counterfactual simulations of the integration of each project into the electricity generation mix. This model simulates the dispatch that meets demand for electricity at an hourly time step at minimum cost over a year, while explicitly representing trade with neighboring countries, various dynamic constraints related to hydropower or start-up and ramping costs of thermal power plants, and other key determinants of the hourly marginal cost of the system. As a result, we obtain valuations from the simulations that are consistent with the price-based valuation of VRE projects at constant perimeter, and then use the model to assess the consequences for these valuations of accounting for the external costs associated with CO₂ emissions on the one hand, and of accounting for a foreseeable increase in the share of VRE in the mix on the other. The CO₂ emissions avoided thanks to each VRE project are accounted for in the social benefits considering the gap which existed in France in 2019 between the generally accepted shadow carbon price (SCP) of 70 EUR/tCO₂ and the average price of CO₂ emission allowances (24.9 EUR/MWh) in the EU emissions trading scheme (EU-ETS) to which electricity producers are subjected.⁶ The corresponding addition to the social benefits of VRE projects is found to represent about 35% of their price-based value on average. Next, to characterize the effect of anticipating the foreseeable increase in the installed capacity of VRE in the mix (i.e. anticipating the increased cannibalization effect), we consider an expansion of VRE matching the percentage increase in wind and solar capacity that was observed

6. The price of EU-ETS allowances have sharply increased since then, reaching about 90 EUR/tCO₂ in the beginning of 2023. However the reference shadow carbon price proposed by Quinet (2019) also increases in time and reaches about 150 EUR/tCO₂ in 2023 (after correcting for inflation).

over the last 3-year period for which data is available, that is 2018-2021.⁷ For France, this corresponds to an increase by 25% of wind capacity (+3.7 GW) and an increase by 52% of solar capacity (+4.8 GW). It results in a decrease by -3.5 EUR/MWh of the value of wind projects on average, and a decrease by -5.4 EUR/MWh for the value of solar projects. Beyond these average effects, our key finding is that for both the effect of accounting for CO₂ external costs and the effect of an increase in VRE capacity, the heterogeneity regarding how individual VRE projects' value is affected could be captured in large part through a linear function of their price-based value, as such a function captures more than 90% of the variation in the value of projects. Interestingly we find that the additional social benefits from CO₂ emissions avoided is proportional to a project's output market value, not to the quantity of energy produced. Even though these results are specific to our case study, i.e. to the French power system, we expect that similar relations could be identified in other contexts as well, and could provide a simple way of accounting for CO₂ avoided and of anticipating future increases in installed VRE capacity when assessing the social benefits from VRE projects.

The remainder of the paper is organized as follows. Section 2 discusses the potential biases induced by price-based valuation methods. Section 3 details the protocol employed to provide quantitative insights about the magnitude of these biases, including the numerical model of the power system. Section 4 presents the results. Section 5 concludes.

2.2 A theoretical framework for the valuation of VRE projects

In this article, we focus on the social benefits associated with VRE projects, understood as those resulting from the injection of their electricity production on the grid, while leaving out the social costs associated with building, operating and dismantling

7. To properly account for the full life of wind and solar projects, a much larger addition of VRE to the mix would need to be considered. However, considering such a longer-term horizon would require much more complex assumptions about the evolution of the power system as a whole, including thermal and storage capacity and electricity demand, which we do not wish to address.

these projects.⁸ Therefore, the variations in the value of projects discussed hereafter result entirely from heterogeneity in their electricity production profile, and in their contribution to the power system's ability to meet electricity demand. It is further assumed that the demand for electricity is exogenous, inelastic and necessarily covered, therefore the social benefits associated with a VRE project are the social costs avoided while still meeting the demand thanks to this additional power injected on the grid.

Consider a discrete time period $\llbracket 1, T \rrbracket$ where T is the lifetime of the project. The residual load, i.e. the total demand for electricity net of the fatal electricity production,⁹ is denoted $\mathbf{l} = \{l_t\}_{t \in \llbracket 1, T \rrbracket} \in \mathbb{R}_+^T$ where l_t is the residual load in period t . The VRE project's output is denoted $\mathbf{q} = \{q_t\}_{t \in \llbracket 1, T \rrbracket} \in \mathbb{R}_+^T$ where q_t is the project's production in period t . The electric system is characterized by a cost function $C : \mathbb{R}_+^T \mapsto \mathbb{R}^+$, where $C(\mathbf{l})$ denotes the social cost of meeting the residual demand \mathbf{l} over the whole period. These social costs are further divided into costs paid for by electricity suppliers $S(\mathbf{l})$, further referred to as the supply cost, and external costs $E(\mathbf{l})$, in which we include the system costs that are not paid for by electricity producers (e.g. transportation or congestion costs) and non-internalized external damages induced by electricity production (e.g. pollution).¹⁰ The social benefits associated with a VRE project considering the ex ante residual load \mathbf{l} is denoted $V_l(\mathbf{q}) = C(\mathbf{l}) - C(\mathbf{l} - \mathbf{q}) = [S(\mathbf{l}) - S(\mathbf{l} - \mathbf{q})] + [E(\mathbf{l}) - E(\mathbf{l} - \mathbf{q})]$.

But even knowing the production of a VRE project \mathbf{q} , the social benefits associated are difficult to estimate directly if the true total cost function $C(\cdot)$ is not known, which is generally the case, and if there is no easily available proxy for it. To circumvent this issue, the price-based valuation approach rely on marginal costs to approximate the decrease in total social costs induced by the additional VRE production: $C(\mathbf{l}) - C(\mathbf{l} - \mathbf{q}) \approx \sum_{t=0}^T \frac{\partial C}{\partial l_t}(\mathbf{l}) \cdot q_t$, where the partial derivatives can be interpreted as the marginal

8. Thus we do not exclude heterogeneity among projects with respect to these costs at any point in the article, even within each VRE technology.

9. Fatal electricity production is electricity produced at no cost and that cannot be shifted in time, such as wind, solar or run-of-river hydroelectric generation.

10. In practice the following empirical implementation focuses on CO₂ emissions in a context (in France) where they are not fully internalized by existing policy instruments, namely the EU-ETS whose allowance price have been persistently lower than the generally accepted shadow carbon price. However similar approaches could apply to other external costs.

social costs of the system in each time period, further denoted $c_t^m(\mathbf{l}) = \frac{\partial C}{\partial l_t}(\mathbf{l})$.¹¹ Even though the true value of these marginal social costs are not known either, prices observed on wholesale electricity markets p_t are often considered to be a suitable proxy for it ($p_t \approx c_t^m(\mathbf{l})$), relying on the assumption that these markets are complete and competitive. Thus the social benefits from VRE projects can be approximated through the total market value of their production $\hat{V}^p = \sum_{t=0}^T p_t q_t$. In the following we will discuss the limits of the two underlying assumptions to this approach, namely:

1. That market prices p_t reflect the marginal social costs $c_t^m(\mathbf{l})$ that are relevant for the valuation of the projects considered, and
2. That the change in total cost resulting from the additional production \mathbf{q} is well approximated through these marginal costs, with $C(\mathbf{l}) - C(\mathbf{l} - \mathbf{q}) \approx \sum_{t=0}^T c_t^m(\mathbf{l}) q_t$.

2.2.1 Are market prices a good proxy for the marginal social costs?

The assumption that market prices p_t reflect the marginal social cost $c_t^m(\mathbf{l})$ rely on the double hypothesis that electricity markets are competitive and complete. The competitiveness, meaning that electricity producers operating on the market cannot exercise any market power, ensures that the behavior of the latter truly reflects their marginal costs. In such conditions, the market clearing price should theoretically match the overall marginal cost to meet demand for electricity. This is arguable in practice since empirical evidence has been provided that some firms exercise their market power to distort prices away from their marginal costs (Ito, Reguant, 2016).¹²

The second condition for market prices p_t to reflect the marginal social costs $c_t^m(\mathbf{l})$ is for the market to be complete, meaning that the costs paid for by electricity producers $S(\mathbf{l})$ match the entire social costs of providing their electricity production to the consumers $C(\mathbf{l})$. In contrast, external costs that are not paid for by electricity producers $E(\mathbf{l})$, when they exist, will not be reflected in the market clearing price

11. This intuitive approximation implicitly results from a first order Taylor expansion of $C(\cdot)$ around \mathbf{l} .

12. Ito and Reguant (2016) provide econometric evidence that electricity producers operating on the Iberian market have taken advantage of the sequential electricity markets, on which electricity is traded at different time horizons, to benefit from a systematic price premium.

p_t . But even acknowledging that markets are not complete, prices may still be a good proxy for the private marginal costs of electricity producers (or marginal supply cost) $p_t \approx s_t^m(\mathbf{l}) = \frac{\partial S}{\partial l_t}(\mathbf{l})$, and could be used in an approximation of $S(\mathbf{l}) - S(\mathbf{l} - \mathbf{q}) \approx \sum_{t=0}^T p_t q_t$. The total social benefits of the project can then be approached by completing this approximation of the supply cost value with an estimation of the additional value associated with external costs $E(\mathbf{l}) - E(\mathbf{l} - \mathbf{q})$. While some have used power system modeling to directly estimate this difference in external costs (e.g. Savelli et al., 2022, for estimating congestion costs induced by wind power in the UK), when it comes to pollution displaced by VRE most studies rely on a marginal approximation similar to the one applied to private costs. Rather than directly estimating $E(\mathbf{l}) - E(\mathbf{l} - \mathbf{q})$, it is indeed convenient to estimate marginal emission factors $e_t^m(\mathbf{l})$, as is done by Deetjen and Azevedo (2019), that are then used to approach $E(\mathbf{l}) - E(\mathbf{l} - \mathbf{q}) \approx \sum_{t=0}^T \hat{e}_t^m(\mathbf{l}) \cdot q_t$. The shortcomings of such marginal approximation for both private supply costs and external costs are discussed in section 2.2.3.

2.2.2 The pitfall of measuring future value using past prices

In addition to the concern that market prices might not match the underlying marginal social costs, another practical issue for project valuation is that the available price data might not be relevant for the evaluation of future VRE projects. Since price data have necessarily been observed in the past, it reflects the power system as it existed in previous years, not the future system that VRE projects under consideration today would serve. Using this price data, one implicitly assumes that prices (and marginal costs) will remain the same (e.g. with respect to daily and seasonal patterns or their correlation with VRE production), or at least that there is no foreseeable change in these patterns and correlations. But the ongoing energy transition, and particularly the rapid increase in the share of VRE in the mix, will impact electricity prices and the value of VRE electricity output in a way that is somehow predictable through the merit order and cannibalization effects. Even if the prices used for the valuation were a good proxy of past $c^m(\mathbf{l})$, these past marginal costs are a biased estimate of the future marginal costs due to foreseeable changes in the distribution

of the residual load \mathbf{l} (resulting from the increased installed capacities of VRE), and in the cost function C (resulting from planned commissioning and decommissioning of dispatchable capacities). Most likely the merit order effect and cannibalization effect should lower the marginal costs when VRE projects produce, thus an *ex-ante* valuation based on past prices would overestimate the *ex-post* value of these projects. When relying directly on observed prices, anticipating these foreseeable changes is not possible. In contrast, the use of power system modeling allows for such anticipation since planned changes in generation capacity for each technology can be explicitly specified in such a model and factored into the evaluation of VRE projects.

2.2.3 The approximation of using marginal costs

Price-based valuation methods also rely on the assumption that the project's output is a marginal addition to the system, and thus that its value can be assessed through the marginal cost of the system as expressed in (2.1). I further detail the underlying approximations and argue that it might not be neutral when comparing various VRE projects.

$$V_i(\mathbf{q}) = C(\mathbf{l}) - C(\mathbf{l} - \mathbf{q}) \approx \sum_{t=0}^T q_t \cdot c_t^m(\mathbf{l}) \quad (2.1)$$

Note that the marginal system cost $c_t^m(\mathbf{l}) = \frac{\partial C}{\partial l_t}(\mathbf{l})$ depends on the whole load \mathbf{l} and not only on the load in time period t , l_t . This accounts for the dynamic nature of some costs and constraints of the power system, such as the management of hydro resources and other storage technologies, or the start-up and ramping costs of thermal power plants. In contrast to the approximation (2.1), an exact expression of the projects value $V_i(\mathbf{q})$ in terms of marginal costs can be derived without loss of generality as a line integral along a curve going from $\mathbf{l} - \mathbf{q}$ to \mathbf{l} as in (2.2), where $\mathbf{l}_{i>t} = \{l_i\}_{i>t}$ and $(\mathbf{l} - \mathbf{q})_{i<t} = \{l_i - q_i\}_{i>t}$. The decomposition in (2.2), where $\mathbf{l}_{-t} = \mathbf{l} \setminus \{l_t\}$, further exhibits two error terms omitted in the approximation (2.1), and thus allows

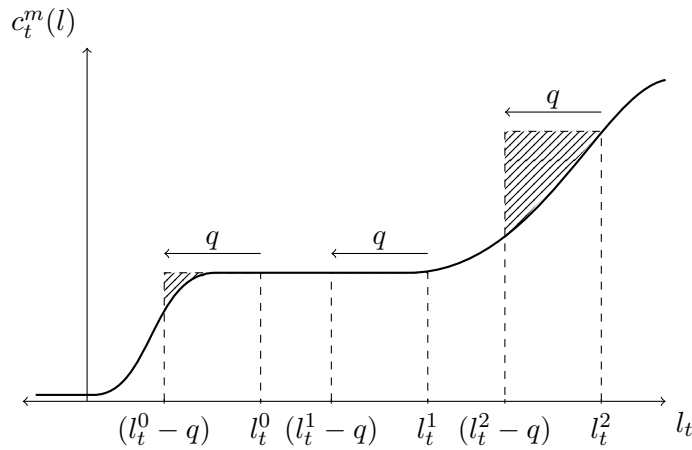


Figure 2.1 – Within time-period approximation of using marginal costs

to determine under which conditions they could be neglected.

$$\begin{aligned}
 V_t(\mathbf{q}) = C(\mathbf{l}) - C(\mathbf{l} - \mathbf{q}) &= \sum_{t=1}^T \int_{l_t - q_t}^{l_t} c_t^m((\mathbf{l} - \mathbf{q})_{i < t}, x, \mathbf{l}_{i > t}) dx \\
 &= \sum_{t=1}^T \left[q_t c_t^m(\mathbf{l}) + \int_{l_t - q_t}^{l_t} [c_t^m(x, \mathbf{l}_{-t}) - c_t^m(\mathbf{l})] dx \right. \\
 &\quad \left. + \int_{l_t - q_t}^{l_t} [c_t^m((\mathbf{l} - \mathbf{q})_{i < t}, x, \mathbf{l}_{i > t}) - c_t^m(x, \mathbf{l}_{-t})] dx \right] \quad (2.2)
 \end{aligned}$$

A sufficient condition for the second term in (2.2) to be null would be that in each time period t , the marginal cost does not vary when the residual load in that same time-period varies between l_t and $l_t - q_t$. Let us refer to it as the "within time-period approximation" term. Note that the magnitude of this error term depends on the size of the project, since it should most likely be larger for a larger q_t , but also on the slope of $c_t^m(\cdot, \mathbf{l}_{-t})$ in the interval $[l_t - q_t, l_t]$. Therefore, the approximation will depart further away from the true value for larger projects but also for projects who produce mostly when the marginal cost function is steeper (e.g. during peak load time periods), as illustrated on Figure 2.1 in which the error is represented by hatched areas.

On the other hand, the third term in (2.2), which we may call the "across time-period approximation" term, is null if changes in the residual load do not impact the system's cost "in other time periods", that is if $c_t^m(\mathbf{l})$ actually depends only on l_t (for any residual load in other time periods comprised between $(\mathbf{l} - \mathbf{q})_{-t}$ and \mathbf{l}_{-t}).

Neglecting this error term means neglecting the impacts of the additional VRE production \mathbf{q} on costs across time periods, e.g. through start-up or ramping costs. These impacts may differ across projects, in particular depending on how stable or erratic through time is the output of the project. To get a better intuition of these effects, a numerical example illustrating both the within and across time-period approximation is provided in Appendix B.

In a complete electricity market where the private supply cost $S(\mathbf{l})$ matches the total social cost $C(\mathbf{l})$, the biases induced by the non-marginality of projects and in particular the within time-period approximation error are contained by the merit-order principle which ensures that $s^m(\mathbf{l})$ is generally (weakly) increasing: the various generation technologies available are ranked according to their individual marginal cost and called in that order as \mathbf{l} increases, which imposes that a shift in the residual load will result in a minimal shift in the marginal cost. However, this is not true of external costs: since these are not accounted for in the dispatch choices, the marginal external cost function $e_t^m(\mathbf{l})$ is not necessarily increasing and may exhibit large and erratic variations in response to small shifts in the residual load. The very erratic marginal emissions factors derived by Deetjen and Azevedo (2019) for three interconnections in the U.S. make this appear as a major concern, which is confirmed by results presented in section 2.4.2 of the present article.

2.3 Numerical implementation strategy

Next, let us assess the magnitude of the biases previously discussed. For that purpose, we compare the price-based valuation method with a method that relies on power system modeling. The use of such numerical model provides a direct proxy for the total supply cost $S(\mathbf{l})$ and an estimation of CO₂ emissions that allows to quantify the associated externality $E^{CO_2}(\mathbf{l})$. Thus we can circumvent the approximation based on marginal costs and the use of market prices as a proxy for the latter, and we can modify the baseline power system as needed. This method is implemented on a sample of wind and solar projects in France while using a numerical model of the French and neighboring countries' electric dispatch. In this manner, we determine how

accounting for avoided CO₂ emissions and anticipating for a higher share of VRE in the mix may affect the estimates of the social benefits from VRE projects as compared to a price-based valuation, and in particular how it may affect the comparison of individual projects to each other. In the following, some background information on the electricity sector in France is first provided before describing the sample of wind and solar projects on which the methodology is applied, and the numerical power dispatch model that is employed.

2.3.1 Context: the French electricity sector

Electricity production in France amounted to 537 TWh in 2019 and is largely dominated by nuclear power, which provided more than 70% of this total production. The remaining electricity production is provided by hydro power (11%), gas-fired power plants (7%) and VRE, mostly onshore wind power (6%) and solar power (2%). Wind and solar power are expected to grow rapidly in the coming years: wind capacity already increased from 16.5 GW in 2019 to 18.8 GW in 2021, and solar from 9.4 GW to 13.1 GW. Wind and solar capacity objectives are set by the French government for 2028 at about 40 GW each (including about 6 GW of offshore wind).¹³

	Capacity [GW]		Production [TWh]	
<i>Nuclear</i>	63.1	46.6%	379.5	70.6%
<i>Natural Gas</i>	12.2	9.0%	38.6	7.2%
<i>Coal</i>	3.0	2.2%	1.6	0.3%
<i>Oil</i>	3.4	2.5%	2.3	0.4%
<i>Hydro</i>	25.6	18.9%	60.0	11.2%
<i>Wind</i>	16.5	12.2%	34.1	6.3%
<i>Solar</i>	9.4	7.0%	11.6	2.2%
<i>Bioenergy</i>	2.1	1.6%	9.9	1.8%

Source: RTE - Bilan électrique 2019

Table 2.1 – France’s Electricity Mix in 2019

The total electricity consumption in France in 2019 was 474 TWh, with a peak consumption at 88.5 GW.¹⁴ The electricity consumption is highly sensitive to cold

¹³ French Multi annual Energy Plan (2019), ecologie.gouv.fr/sites/default/files/PPE-Executive%20summary.pdf

¹⁴ RTE, "Bilan électrique 2019", assets.rte-france.com/prod/public/2020-06/bilan-electrique-2019_1_0.pdf

temperature due to electric heating being widespread in France, but not to high temperature as air conditioning remains limited. Then it presents a strong seasonality with a generally greater consumption in winter than in summer, which translates into higher prices. The market value of both wind and solar are thus subject to contradictory effects from seasonal and daily patterns. Wind power production being generally greater in the winter and at night, its market value is inflated by the winter-summer price differential but deflated by the daily consumption patterns (consumption being greater during the day). Conversely solar power production being greater in the summer and during the day, its market value is inflated by the daily consumption pattern but deflated by the winter-summer price differential.

Load following is generally provided by reservoir hydro power and gas power plants, with the latter setting the wholesale market price for most of the year (while the option value of reservoir hydro production is itself set by gas power plants). However, the uniquely high share of nuclear power in the mix forces the nuclear power fleet to adapt its production to power demand, in the short term by occasionally lowering its production in times of low consumption and great availability of VRE, and in the long term by adapting its maintenance planning to the seasonal patterns of consumption.

2.3.2 Sample of wind and solar projects

The sample of VRE projects considered is made of 100 potential power plants (50 solar farms, 50 wind farms) based on projects that were actually built or under consideration in France.¹⁵ Thus we ensure that the sample is made of economically viable projects that can realistically be considered by investors, while eliminating unlikely options. Basic technical characteristics are collected for each project, including geographic coordinates, capacity, orientation of solar panels (azimuth and tilt), whether they are mounted on trackers, wind turbine model installed and hub height. Based on these characteristics, the hourly production of each project is simulated using historical weather data and the models developed by Staffell and Pfenninger (2016). These hourly production time-series are then used as input to the electric dispatch model

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

described hereafter, which is run with the additional VRE production available corresponding to the project's simulated output each hour, and compared to a baseline. The difference in total dispatch cost and total carbon emission between the baseline and this simulation is attributed to the project. These simulations are run with weather data, power demand and other time-variable inputs from years 2016-2019, and the results are compared with a valuation based on the day-ahead market prices for these same years.

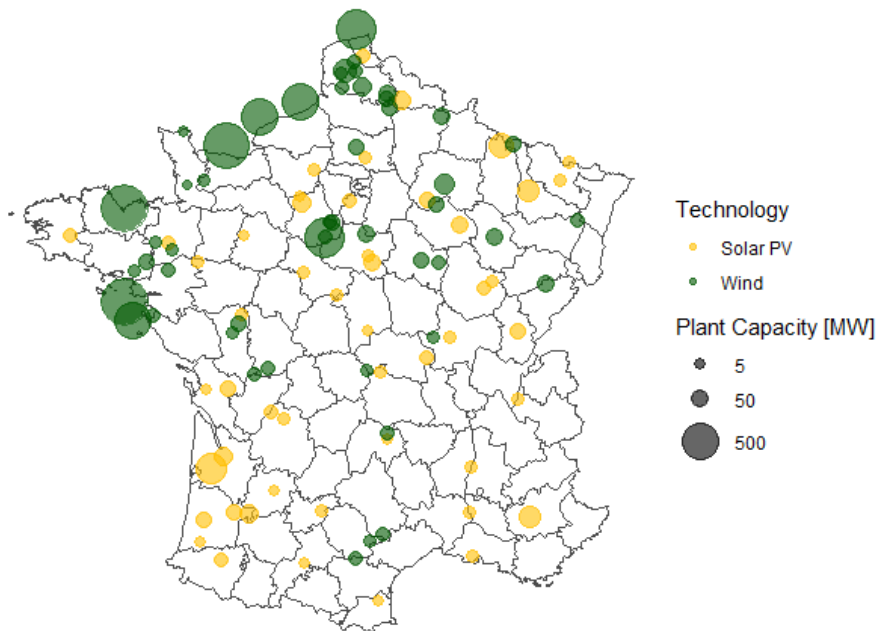


Figure 2.2 – Geographic location of projects included in the sample

2.3.3 The numerical power dispatch model

The numerical model used is a bottom-up power dispatch model adapted from the EOLES model (Shirizadeh et al., 2021), hereafter referred to as EOLES-Dispatch. It is an optimization model that minimizes the total operating cost of satisfying an exogenous (and perfectly inelastic) demand with the available generation fleet, where the latter is also an exogenous input to the model. It represents 4 VRE technologies (onshore and offshore wind, solar, and run-of-river hydro), 9 thermal technologies (1 nuclear, 3 coal-fired, 4 gas-fired, and 1 oil-fired), and a reservoir hydro/pumped hydro storage (PHS) technology. The optimal dispatch is solved at an hourly time step for

a full year with perfect foresight. It takes about 30 minutes to run on a personal computer.

The EOLES-Dispatch model is designed with to provide a realistic simulation of the short-run marginal cost of generating electricity in each hour, which is used as a proxy for electricity wholesale market prices, based on an exogenous set of capacities describing the electricity system, so that it is possible to simulate how this short-run marginal cost may be affected by a change in installed generation capacity (in particular, an increase in VRE capacity). By fulfilling this first objective, it is also expected that the model can be used to estimate the short-run economic value of a small change in the power system, such as the addition of a specific wind or solar project. In this perspective, the model is developed to faithfully represent not only the average marginal costs of the power system, but also the dynamics and variation patterns of these marginal costs. Therefore, particular attention is paid to the representation of some dynamic constraints on power dispatch that can influence hourly marginal costs and project valuation.

First, lake hydro and pumped hydro storage (PHS) are modeled as a dispatchable storage technology: this technology generates electricity at no cost, but within the limits of the available (potential) energy stock. The marginal cost of hydro generation is thus the option value of using up this stock which prevents generation at another time. This modeling provides a more realistic representation of this technology than, for example, representing it as an exogenous fatal production, although its flexibility may be exaggerated because the model optimizes dispatch with perfect foresight.¹⁶ Because hydro provides some flexibility to the power system by generating at times when the marginal costs are the highest, we expect it to mitigate these sharpest spikes in marginal costs and, more generally, to have a smoothing effect on hourly marginal costs (and thus on the value of fatal electricity production, such as VRE). Some constraints specific to hydropower that somewhat limit this flexibility are also taken into account: seasonal variations in energy and capacity availability are provided as input data to the model and constrain the dispatch optimization, and, similarly,

16. In practice, the value that an operator would place on hydro generation is the opportunity cost of not generating at a later time, but with uncertainty about what that opportunity cost will be.

interseasonal storage is exogenously constrained to avoid consumption patterns that would conflict with alternative water uses (agriculture, tourism...).

The model also attempts to carefully represent the dynamic constraints of thermal technologies, namely the start-up costs and the inefficiency of power plants operating at part load. Thus, a representation of the capacity that is in operation and available for generation, the capacity of the started power plants, is introduced in the model. To avoid the introduction of explicit generation units and to keep the model fully linear (which ensures a limited computational time), we rely on a continuous endogenous variable representing, for each technology, the capacity in operation and available for generation (following e.g. Palmintier, 2014; Zhang et al., 2016).¹⁷ This variable acts as an upper bound on the actual output of the technology, and its increase involves start-up costs. Conversely, available capacity is factored into the operating cost of the technology in such a way that a low ratio of output to available capacity (i.e., a low capacity factor) increases the operating cost per unit, which accounts for part-load inefficiency.

Among thermal generation, nuclear power is a major driver of marginal costs in France due to its very large share in the electricity mix. A challenge for its modeling is to account for maintenance planning, which is subject to constraints that apply to time horizons longer than one year (Lynch et al., 2022).¹⁸ To ensure a realistic dispatch, the model accounts for this maintenance planning through a weekly availability constraint that is exogenously set based on historical observations.

Finally, to account for the effect of trade on the marginal prices in France, the optimal dispatch of all directly neighboring countries is simulated simultaneously. This endogenous modeling of neighboring power systems allows to properly account for France's imports and exports (and to simulate the evolution of installed capacity in neighboring countries as well). These direct neighbors are represented as seven sepa-

17. The model remains linear in the sense that no dummy variable representing the status of individual units is introduced into the model: the variable "capacity in operation" variable is a continuous variable between 0 and the total installed capacity for the technology (excluding capacity under maintenance).

18. Letting the maintenance planning be endogenously determined by the model would lead to a very large share of the fleet being under maintenance in the summer, when demand is at its lowest, whereas such planning is not feasible in practice.

rate areas, namely Belgium, Germany, Switzerland, Italy, Spain, and Great-Britain.¹⁹ Imports and exports of these countries from countries not included in the model (neighbors of France's neighbors, e.g., Austria, Portugal, Ireland) are accounted for by using exogenous prices, based on historical observations at which they can export or import.

The total wind and solar power output of the entire power system is derived from the average hourly capacity factors provided by the simulation model developed by Staffel and Pfenninger (2016). Monthly fuel prices are taken from the World Bank's commodity price data.²⁰ The remaining time-varying data are obtained from the ENTSO-E transparency platform, including electricity demand, hydro production and nuclear availability. Installed capacity and cost parameters are also obtained from ENTSO-E, but are adjusted to make the model outputs consistent with historical observations for 2019. The hourly marginal costs obtained for 2019 match the observed day-ahead market price in terms of mean (the average simulated price is 39.37 EUR/MWh while the actual average price was 39.45 EUR/MWh) and standard deviation (13.52 EUR/MWh for simulated prices and 14.02 EUR/MWh for observed prices). An hour-by-hour comparison of simulated and observed prices shows a mean absolute error (MAE) of 5.04 EUR/MWh.

A detailed description of the model and some comparisons of its outputs with historically observed wholesale prices can be found in Appendix D.

2.4 Results

In what follows, we first confirm that the relative value of the VRE projects evaluated through simulations is consistent with the price-based value by comparing them on an identical scope. We then characterize the impact of accounting for CO₂ emissions and associated external costs on the relative value of these projects, before looking at the effect of increasing the share of VRE in the electricity mix.

19. Luxembourg's demand and capacity are counted as part of Germany.

20. World Bank, "World Bank Commodity Price Data (The Pink Sheet)", worldbank.org/en/research/commodity-markets.

2.4.1 Price-based and optimal-dispatch-based value

As discussed in section 2.2.1, since both measures neglect external costs, the *price-based value* of projects $\hat{V}^p(\mathbf{q}) = \sum_t p_t q_t$ should be consistent with the *supply cost value* that we simulate $\hat{V}^{SC}(\mathbf{q}) = \hat{S}(\mathbf{l}) - \hat{S}(\mathbf{l} - \mathbf{q})$, where $\hat{S}(\cdot)$ is the cost to meet the demand for electricity derived from simulations of EOLES-Dispatch parameterized as the 2019 power system. Differences between the price-based value and the supply cost value can still arise from three sources: from a bias in EOLES-Dispatch's representation of power system costs $\hat{S} \neq S$ (e.g. due to mistakes in parameters defining the marginal costs of some generation technologies), from a misrepresentation of the hourly marginal cost of the system by day-ahead market prices $p_t \neq s_t^m(\mathbf{l})$ (e.g. because some producers exercise market power), and from the errors induced by the assumption that projects are a marginal addition to the system (see section 2.2.3). Luckily, we can directly observe the simulated marginal supply cost $\hat{s}_t^m(\mathbf{l}) = \frac{\partial \hat{S}}{\partial l_t}(\mathbf{l})$, and use it to assess the magnitude of the latter effect by comparing the supply cost value of each project $\hat{V}^{SC}(\mathbf{q})$ with a marginal valuation based on the same simulation $\sum_t \hat{s}_t^m(\mathbf{l}) q_t$. The gap between these two measures, that is attributed to the error terms omitted in the marginal approximation (2.1), is inferior to 0.6% of the supply cost

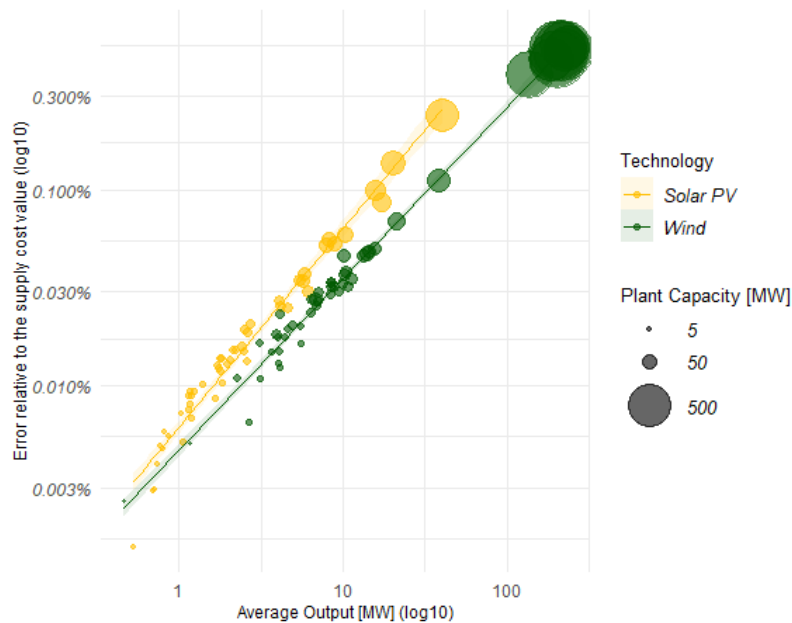


Figure 2.3 – Error from the marginal approximation $\sum_t \hat{s}_t^m(\mathbf{l}) q_t - \hat{V}^{SC}(\mathbf{q})$

	Wind			Solar		
	Price-based Value – $\hat{v}^p(\mathbf{q})$	Supply cost Value – $\hat{v}^{SC}(\mathbf{q})$	Diff.	Price-based Value – $\hat{v}^p(\mathbf{q})$	Supply cost Value – $\hat{v}^{SC}(\mathbf{q})$	Diff.
Mean	41.23	42.66	+1.43	41.13	41.18	+0.05
Std. Dev.	0.44	0.30	0.17	0.58	0.59	0.14
Minimum	40.57	41.97	+1.10	40.15	40.38	-0.19
Maximum	42.27	43.37	+1.75	42.71	42.88	+0.38
Correlation	96.2%			97.2%		

Table 2.2 – Projects valuation ignoring external costs – Descriptive Statistics [EUR/MWh]

value $\hat{V}^{SC}(\mathbf{q})$ in all cases. Figure 2.3 shows that the magnitude of the error is mostly driven by the average output of projects, i.e. the nameplate capacity adjusted for the average capacity factor. It is slightly larger for solar projects (at equivalent average output), which can be explained by the greater variability of solar power. Considering the limited magnitude of this source of discrepancy between $\hat{V}^{SC}(\mathbf{q})$ and $\hat{V}^p(\mathbf{q})$, the differences should primarily be explained either by inaccuracies of the model or by the misrepresentation of the marginal cost of the system by day-ahead market prices. I further conservatively assume that the former dominates, even though the latter cannot be ruled out.

Table 2.2 reports descriptive statistics for our sample of VRE projects depicting their price-based values and supply cost values expressed per unit of energy produced: $\hat{v}^p(\mathbf{q}) = \hat{V}^p(\mathbf{q}) / \sum_t q_t$ and $\hat{v}^{SC}(\mathbf{q}) = \hat{V}^{SC}(\mathbf{q}) / \sum_t q_t$.²¹ The supply cost value of projects appears to suffer from a systematic overestimation bias relative to the price-based value, which is attributable to a slight overestimation of marginal system costs by the model over the period 2016-2019: the average day-ahead market price p_t was 42.84 EUR/MWh, while the average hourly marginal cost simulated by the model $\hat{s}_t^m(\mathbf{l})$ is 43.63 EUR/MWh. For both wind and solar the average price-based value $\hat{v}^p(\mathbf{q})$ is slightly lower than the average day-ahead market price p_t , and consistently the average supply cost value $\hat{v}^{SC}(\mathbf{q})$ for both solar and wind is slightly lower than the average simulated hourly marginal cost $\hat{s}_t^m(\mathbf{l})$. The systematic overestimation is small for solar projects (+0.05 EUR/MWh) but much stronger for wind projects (+1.43 EUR/MWh), larger than the full range of variation among wind projects. An explanation for that difference is that EOLES-Dispatch tends to overestimate prices

21. Similarly in the remainder of the article, lower case notations indicate an expression per unit of energy produced.

in the winter and underestimate them in the summer, which inflates the relative value of wind power. Considering this bias, we refrain from using these simulations for comparisons across technologies. However, within each technology the relative values of VRE projects according to price-based valuation or simulated are consistent, as shown in Figure 2.4 and suggested by the high correlation of the two measures (97.2% for solar projects and 96.2% for wind projects). It suggests that valuation measures based on EOLES-Dispatch simulations are suitable for comparing VRE projects within each technology category (wind and solar).

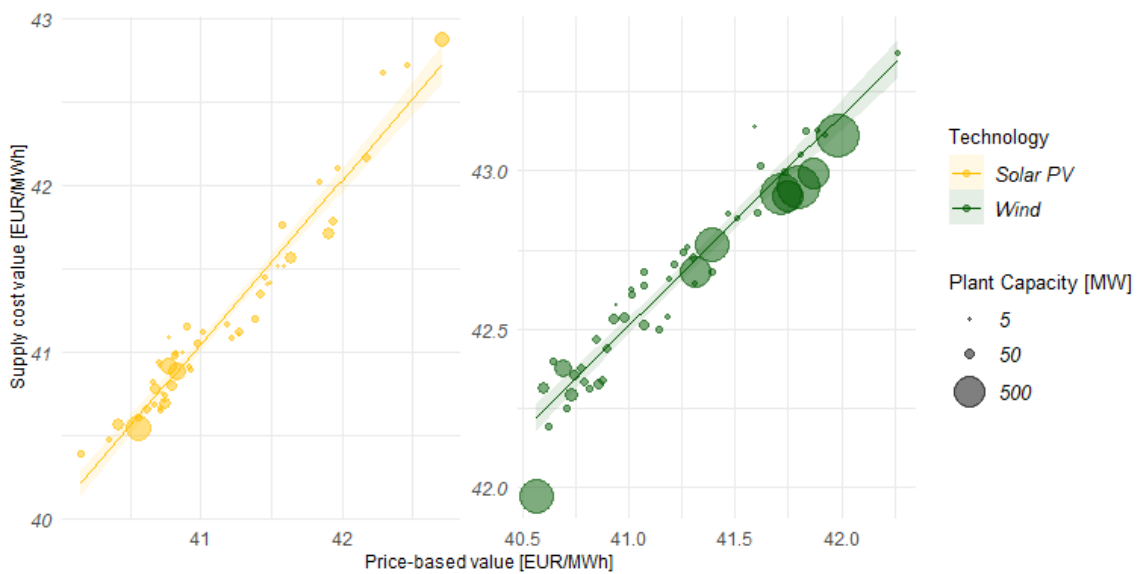


Figure 2.4 – Consistency of price-based and supply cost valuation

2.4.2 Accounting for CO₂ emissions

Both the price-based value and the supply cost value ignore the part of the social benefits of VRE projects associated with external costs, and in particular external costs associated with the CO₂ emissions that would be avoided if the wind or solar farms were built. Denoting $E^{CO_2}(\mathbf{l})$ the external costs due to CO₂ emissions induced by power generation to meet the demand \mathbf{l} , VRE projects should be granted an additional value corresponding to $\Delta E^{CO_2}(\mathbf{q}) = E^{CO_2}(\mathbf{l}) - E^{CO_2}(\mathbf{l} - \mathbf{q})$. Next the estimates of the social value of projects accounting for (the simulation of) this externality are denoted $\hat{V}^{EXT}(\mathbf{q}) = \hat{V}^{SC}(\mathbf{q}) + \Delta \hat{E}^{CO_2}(\mathbf{q})$.

	Wind			Solar		
	<i>Avoided</i> <i>CO₂</i> [kgCO ₂ /MWh]	Externality* $\Delta\hat{e}^{CO_2}(\mathbf{q})$ [EUR/MWh]	Social Value* $\hat{v}^{EXT}(\mathbf{q})$ [EUR/MWh]	<i>Avoided</i> <i>CO₂</i> [kgCO ₂ /MWh]	Externality* $\Delta\hat{e}^{CO_2}(\mathbf{q})$ [EUR/MWh]	Social Value* $\hat{v}^{EXT}(\mathbf{q})$ [EUR/MWh]
Mean	337.6	15.22	57.89	321.2	14.49	55.67
Std. Dev.	27.4	1.24	1.32	56.6	2.55	2.78
Minimum	295.3	13.32	55.57	176.8	7.97	49.06
Maximum	478.5	21.58	64.15	473.4	21.35	62.87

*The externality associated with CO₂ emissions is considered equal to 45.1 EUR/tCO₂.

Table 2.3 – Simulated CO₂ emissions avoided by the sample projects

According to EOLES-Dispatch simulations, the solar projects in the sample would reduce emissions by 337 kgCO₂/MWh on average, and the wind projects would reduce them by 321 kgCO₂/MWh on average,²² with very large variations among projects (see Table 2.3). In France, part of the damage caused by CO₂ emissions from electricity production is internalized through the E.U. emissions trading scheme (EU-ETS) to which they are subjected. However, the EU-ETS allowance price was 24.9 EUR/tCO₂ on average in 2019, while the reference value commonly accepted as shadow carbon price in this same year in France was 70 EUR/tCO₂,²³ which leaves a social cost of 45.1 EUR/tCO₂ that is not internalized and that we consider as an external cost associated with electricity production. Thus, we estimate that the social value of the wind (resp. solar) projects should be increased on average by $\Delta\hat{e}^{CO_2}(\mathbf{q}) = 15.22$ EUR/MWh (resp. $\Delta\hat{e}^{CO_2}(\mathbf{q}) = 14.49$ EUR/MWh), i.e. about 35% of their respective average supply cost value $v^{SC}(\mathbf{q})$ (see Table 2.2).

While the amount of CO₂ emissions avoided is comparable on average for wind power and solar power, it varies considerably from project to project. This seems to mostly result from the very large shifts in CO₂ emissions induced by small shifts in residual demand: since the numerical model minimizes the total cost to cover demand while ignoring externalities, small shifts in demand may cause the model to switch from one dispatch solution to another that is close in terms of generation cost

22. For comparison, the emission factor of gas-fired power plants is 429 kgCO₂e/MWh according the French TSO. The French TSO has also estimated for 2019 that the total wind and solar capacity installed in France has avoided the emission of 22 MtCO₂ (both in France and abroad via electricity exports), which represents about 480 kgCO₂/MWh (see assets.rte-france.com/prod/public/2021-12/Bilan-previsionnel-2019-rapport.pdf). The discrepancy with the results presented here is explained by the fact that the latter estimates the amount avoided by a marginal increase in either technology, not the average effect of the whole installed fleet.

23. Quinet (2019) provides the reference estimate of the shadow carbon price adopted in France.

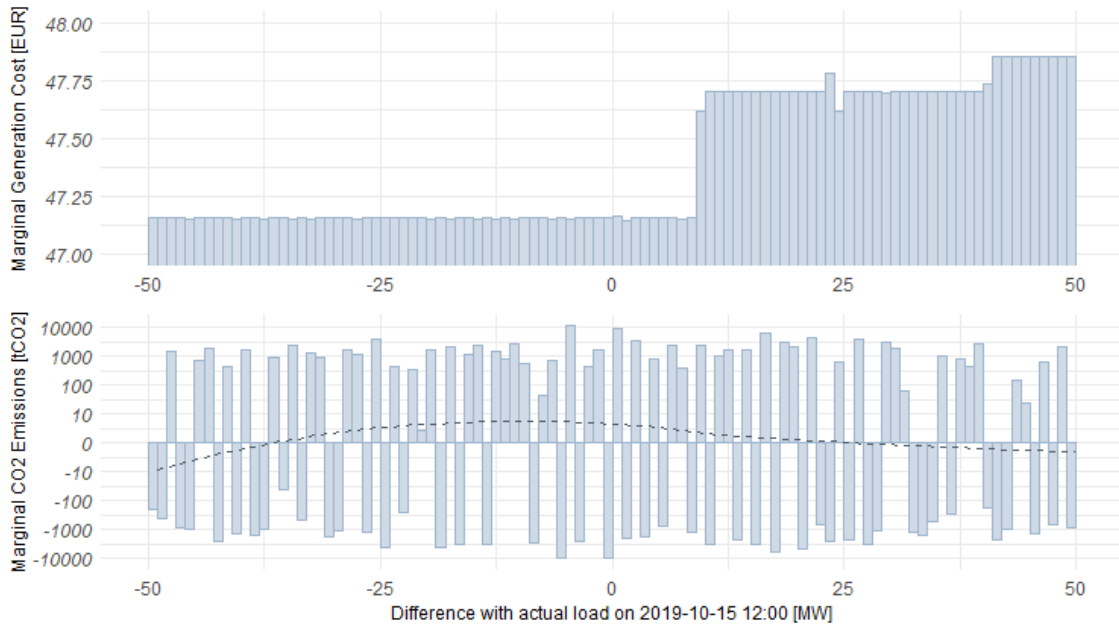


Figure 2.5 – Illustrative simulation of the marginal cost and emission curve

but might be dramatically different in terms of emissions. This is illustrated by the marginal emission curve on Figure 2.5, which presents a simulation of the variations in marginal costs and marginal emissions in response to small demand variations in France in one randomly chosen specific hour. While the marginal cost remains very steady and slightly increasing over the ± 50 MW interval tested around the actual load,²⁴ the marginal CO₂ emissions exhibit dramatic changes induced by each 1 MW variation of demand. The large variations in CO₂ savings associated with each project most likely results for a large part from this (mostly random) effect, rather than being associated with characteristics of the power plant projects.²⁵ As a consequence the price-based value of the VRE projects $\hat{v}^p(\mathbf{q})$ is poorly correlated with the estimate of their social value that account for this externality $\hat{v}^{EXT}(\mathbf{q})$ (48.9% for solar power and 29.0% for wind power). This can be attributed to the inability of power dispatch modeling to provide robust estimates of the externality associated with CO₂ emissions.

Considering this instability of the previously discussed results and to get more

24. This range corresponds in order of magnitude to the impact that a solar or wind power plant would have on the residual load.

25. Additional simulations have shown that the amount of CO₂ emissions displaced by a VRE project (per energy output) is highly sensitive to the specified capacity, further supporting this hypothesis.

robust insights about the ability of VRE projects to displace CO₂ emissions, another approach is next considered. Rather than adding the external benefits $\Delta\hat{E}^{CO_2}(\mathbf{q})$ to their supply cost value $V^{SC}(\mathbf{q})$, the value of VRE projects is considered in the context of an hypothetical dispatch where the SCP is fully internalized. This implies that the SCP is incorporated into the supply cost of electricity $S(\mathbf{l})$, but also that the dispatch of the generation capacities is optimized while accounting for the SCP and thus different from the one obtained in previous simulations. The associated estimates of VRE projects is $\hat{V}^{INT}(\mathbf{q}) = \hat{S}^{CO_2+}(\mathbf{l}) - \hat{S}^{CO_2+}(\mathbf{l} - \mathbf{q})$, where \hat{S}^{CO_2+} is the total cost function of the power system simulated by EOLES-Dispatch when the cost of carbon is set at 70 EUR/tCO₂. Over the period 2016-2019, raising the cost of CO₂ emissions for power producers from 24.9 EUR/tCO₂ to 70 EUR/tCO₂ induces an increase in the simulated marginal cost of the system, going from 43.63 EUR/MWh to 61.17 EUR/MWh on average. The value of the VRE projects increases accordingly, with their value per energy produced $\hat{v}^{INT}(\mathbf{q})$ slightly below the average marginal cost, as for $\hat{v}^{SC}(\mathbf{q})$ (see Table 2.4). The average increase in the value of projects is of the same order of magnitude as the previously estimated externality $\Delta\hat{e}^{CO_2}(\mathbf{q})$, even though slightly higher for both wind and solar.²⁶ But the additional value $\hat{v}^{INT}(\mathbf{q}) - \hat{v}^{SC}(\mathbf{q})$ is much less variable among projects, with a standard deviation about 0.48 EUR/MWh for wind projects and 0.81 EUR/MWh for solar projects (about 3 times smaller than the standard deviation of $\Delta\hat{e}^{CO_2}(\mathbf{q})$, reported in Table 2.3). Furthermore, while the price based value $\hat{v}^p(\mathbf{q})$ is poorly correlated with $\hat{v}^{EXT}(\mathbf{q})$, the former is highly correlated with the value of projects when the SCP is fully internalized in the dispatch decisions $\hat{v}^{INT}(\mathbf{q})$ and seems to constitute a good proxy for it (as suggested by Figure 2.6).

To get more precise insights on how well can the price-based value approximate the actual social value of VRE projects, we estimate linear regressions in which the former predicts the latter in the form $\hat{v}(\mathbf{q}) = \beta_0 + \beta_1\hat{v}^p(\mathbf{q})$. The results are presented in table 2.5. A first observation is that, as suggested before, the price-based value is consistent with (and thus is a good predictor of) the simulated supply cost value.

26. This may suggest that rather than exhausting the CO₂ emissions pool, CO₂ pricing instead enhance the ability of VRE projects to displace emissions. A paired t-test confirms that the difference is significant at $p < .001$.

2.4. Results

	Wind			Solar		
	$\hat{v}^{SC}(\mathbf{q})$ (baseline)	$\hat{v}^{INT}(\mathbf{q})$ (SCP intern.)	Diff.	$\hat{v}^{SC}(\mathbf{q})$ (baseline)	$\hat{v}^{INT}(\mathbf{q})$ (SCP intern.)	Diff.
Mean	42.67	59.50	+16.83	41.18	57.27	+16.09
Std. Dev.	0.30	0.48	0.19	0.59	0.81	0.23
Minimum	41.97	58.43	+16.46	40.39	56.16	+15.77
Maximum	43.37	60.61	+17.24	42.88	59.59	+16.74
Correlation with $\hat{v}^P(\mathbf{q})$	96.2%	97.4%		97.2%	96.3%	

CO₂ emissions cost in dispatch simulation is 24.9 EUR/tCO₂ for baseline, 70 EUR/tCO₂ for SCP intern.

Table 2.4 – Impact of internalizing SCP on the simulated value VRE projects [EUR/MWh]

For solar projects, $\hat{v}^P(\mathbf{q})$ is an almost perfect and direct predictor of $\hat{v}^{SC}(\mathbf{q})$ since 95% of the variation is predicted with $\hat{\beta}_0$ non significant and $\hat{\beta}_1$ close to (and not significantly different from) 1. The price-based value is also a good predictor of wind projects' value ($R^2 = 93\%$) but with a systematic bias exaggerating the variation among projects, that is corrected in the regression estimates with $\hat{\beta}_1 < 1$ and $\hat{\beta}_0 > 0$ (both difference are significant at $p < .001$). In contrast, when attempting to predict $\hat{v}^{EXT}(\mathbf{q})$ the price-based value of projects is a very poor predictor, with R^2 as low as 24% for solar projects and 8% for wind projects. Considering this result, one may question whether the most socially valuable projects should be identified based on their market value rather than simply based on the quantity of energy they produce. However this conclusion must be moderated considering the low robustness of the

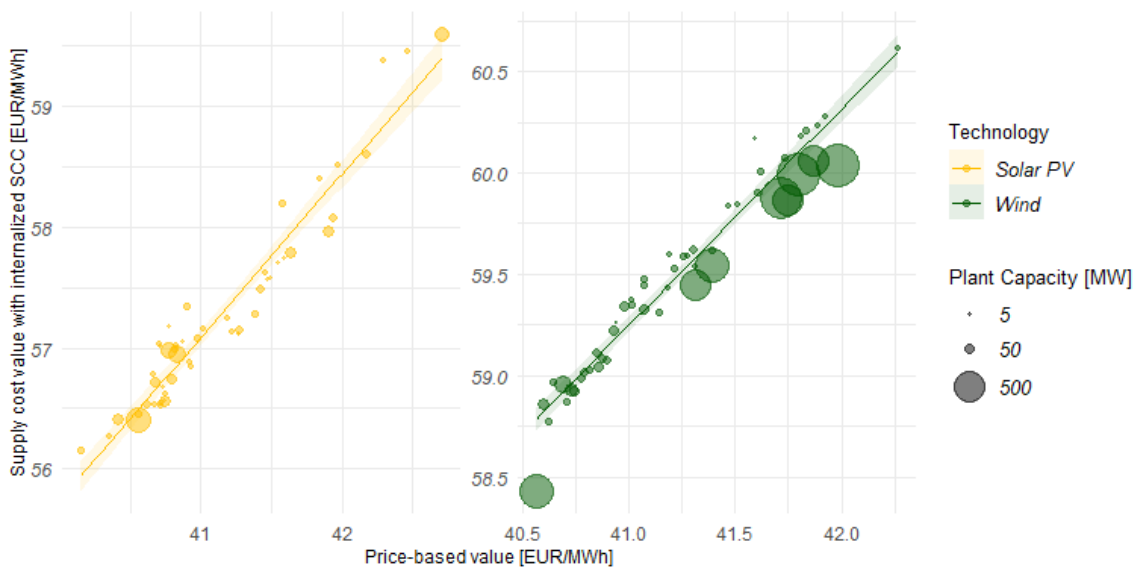


Figure 2.6 – Valuation after internalizing SCP in the power dispatch

	$Y = \hat{v}^{SC}(\mathbf{q})$		$Y = \hat{v}^{EXT}(\mathbf{q})$		$Y = \hat{v}^{INT}(\mathbf{q})$	
	Solar	Wind	Solar	Wind	Solar	Wind
β_0	0.68 (1.40)	15.21*** (1.12)	-41.13 (24.90)	21.88 (17.16)	1.60 (2.24)	15.46*** (1.47)
β_1	0.98*** (0.03)	0.67*** (0.03)	2.35*** (0.61)	0.87* (0.42)	1.35*** (0.05)	1.07*** (0.04)
R^2	0.95	0.93	0.24	0.08	0.93	0.95
Adj. R^2	0.94	0.92	0.22	0.06	0.93	0.95
Num. obs.	50	50	50	50	50	50

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$

Table 2.5 – Value of VRE projects predicted by observed prices valuation [EUR/MWh]

simulated $\hat{v}^{EXT}(\mathbf{q})$. Last, when attempting to predict $\hat{v}^{INT}(\mathbf{q})$, the price-based value of projects is once again a good predictor, with a R^2 equal to 93% (resp. 95%) for solar projects (resp. wind projects). Since the value of projects is increased by the increased cost of CO₂ emissions (for the electricity producers), then the coefficients are different from those of the model predicting $\hat{v}^{SC}(\mathbf{q})$. For both wind and solar the intercept β_0 remains unchanged and it is β_1 that significantly increases, suggesting that the additional value granted to VRE projects following the increased cost of CO₂ emissions is not proportional to the amount of energy produced, but rather to its market value.

2.4.3 Projects value in a future mix

As discussed in section 2.2.2, differences in the electric system between the time a wind or solar project is considered and the time it actually begins generating may have a significant impact on the social benefits of these projects. In particular, the increase in the share of VRE in the mix is expected to lower their value through the merit order and cannibalization effect. Next, we assess the magnitude and characterize this effect by simulating the impact that a three-year growth of wind and solar capacity in Europe would have on the value of projects in our sample. The observed growth in solar, onshore wind, and offshore wind capacity over the latest available 3-year period (2018-2021) for the seven countries represented in EOLES-Dispatch is applied to the baseline power system. For France, this represents a 25.3% growth (+3.7 GW)

in onshore wind capacity and a 52.2% growth (+4.8 GW) in solar capacity.²⁷ The corresponding value attributed to projects is $\hat{V}^{VRE+}(\mathbf{q}) = \hat{C}(\mathbf{l}^{VRE+}) - \hat{C}(\mathbf{l}^{VRE+} - \mathbf{q})$, where \mathbf{l}^{VRE+} denotes the residual load after the VRE capacities were increased. A new set of EOLES-Dispatch simulations is run with a modified baseline power system to estimate these values.

	Wind			Solar		
	$\hat{v}^{SC}(\mathbf{q})$	$\hat{v}^{VRE+}(\mathbf{q})$	<i>Diff.</i>	$\hat{v}^{SC}(\mathbf{q})$	$\hat{v}^{VRE+}(\mathbf{q})$	<i>Diff.</i>
Mean	42.67	39.16	-3.51	41.18	35.80	-5.38
Std. Dev.	0.30	0.39	0.11	0.59	0.69	0.12
Minimum	41.97	38.33	-3.75	40.39	34.93	-5.52
Maximum	43.37	39.98	-3.27	42.88	37.82	-4.90
<i>Correlation with $\hat{v}^p(\mathbf{q})$</i>	<i>96.2%</i>	<i>98.0%</i>		<i>97.2%</i>	<i>95.7%</i>	

Table 2.6 – Impact on projects’ value of increasing the share of VRE in the mix [EUR/MWh]

A first striking result is that the increase in VRE capacity observed in Europe over 3 years leads to a sharp decrease in the value attributed to wind and solar projects. As indicated in Table 2.6, the specified increase in installed VRE capacity induces a decrease by 3.51 EUR/MWh of the value of wind projects and by 5.38 EUR/MWh of the value of solar projects on average. This effect is also found to be quite homogeneous among projects, with a standard deviation of the decrease experienced by each project about 0.1 EUR/MWh for each technology and a narrow span between the most and the least affected project.

As a result, and as is illustrated in Figure 2.7, the increase in renewable capacity does not significantly affect how projects compare to each other. Even after increasing the installed capacity of wind and solar in the mix, the simulated value attributed to projects $\hat{v}^{VRE+}(\mathbf{q})$ is still highly correlated with their price-based value $\hat{v}^p(\mathbf{q})$, and thus the latter can be used to predict the former rather precisely (see Table 2.7). Again we estimate a linear regression predicting simulated values using price-based values, and find indeed that the variance of simulated values obtained after increasing the share of VRE $\hat{v}^{VRE+}(\mathbf{q})$ is as well explained by $\hat{v}^p(\mathbf{q})$ than the baseline simulated value, with $R^2 > 90\%$. This suggest that the variation in value induced by the increased share of VRE in the mix is well captured by modifications of the coefficients β_0 and

27. Based on IRENA (2022), detailed figures for the other countries are reported in Appendix B.

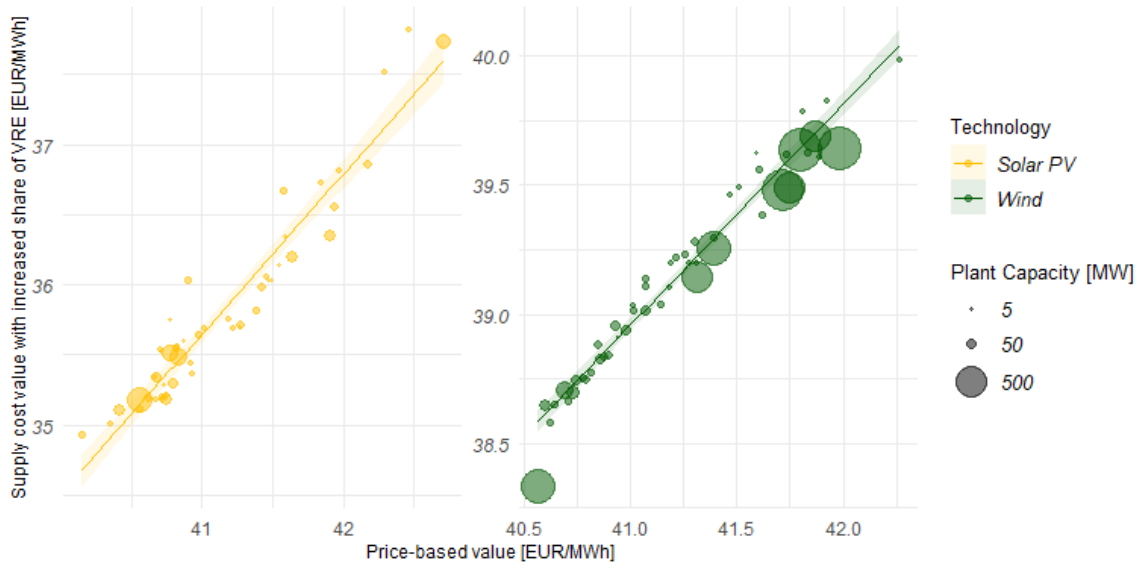


Figure 2.7 – Valuation with an increased share of VRE compared to based on historic prices

β_1 , namely a decrease in β_0 by -11.89 for solar and -11.52 for wind and an increase in β_1 by $+0.16$ for solar and $+0.19$ for wind projects. The increased share of VRE in the mix seem thus to have an effect on the value of wind and solar projects that is in a large part proportional to the amount of energy produced (effect captured by β_0), even though it also slightly increases discrepancies among projects in the average unit value of their electricity production (which is captured by the increase in β_1).

	$Y = \hat{v}^{SC}(\mathbf{q})$		$Y = \hat{v}^{VRE+}(\mathbf{q})$	
	Solar	Wind	Solar	Wind
β_0	0.68 (1.40)	15.21*** (1.12)	-11.21*** (2.04)	3.69*** (1.04)
β_1	0.98*** (0.03)	0.67*** (0.03)	1.14*** (0.05)	0.86*** (0.03)
R^2	0.95	0.93	0.92	0.96
Adj. R^2	0.94	0.92	0.92	0.96
Num. obs.	50	50	50	50

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$

Table 2.7 – Future value of VRE projects predicted with price-based valuation [EUR/MWh]

2.5 Conclusion and policy implications

There is a non-negligible heterogeneity among VRE electricity sources in terms of social benefits, not only between different technologies but also between power plants belonging to the same technology.²⁸ Even though this heterogeneity can be partly captured through the market value of each project's output, such an approach misses the heterogeneity associated with external costs, neither does it allow for anticipating the rapid evolution of the electric systems these projects are meant to serve. However, these limitations can be overcome through the use of power system modeling. By doing so to account for the avoided CO₂ emissions and for a short-term increase in VRE capacity in the electric mix in the valuation of a sample of wind and solar projects in France, we find that the effect on projects' value can still be well approximated through the market value of projects' output after applying a linear correction that we estimate.

The results of our case study on France suggest that the discrepancies between projects in average market value per unit are amplified when including the entire social benefits from avoided CO₂ emissions. The same is true when anticipating a short-term increase in the capacity of VRE installed in the power system. These effects should be accounted for in the design of public policy in favor of VRE, so that investors' incentives are in line with the social benefits of projects. In particular, if the avoided CO₂ emissions are a motivation for VRE subsidies, these subsidies should be, as are the social benefits from avoided CO₂, proportional to the market value of the project's output. In contrast, in most European countries subsidies in favor of VRE (such as Feed-in Tariffs and Feed-in Premiums) are proportional to the amount of energy produced, not to its market value. The adequacy of the different subsidy mechanisms with respect to the social benefits of the projects is discussed in detail in Chapter 3.

Even though the linear corrections we estimate are specific to the French electric system, such approach could be replicated in other contexts and provide an easy mean

²⁸. In the specific case of France, we even find that variations in the average market value of their electricity output are larger within technologies among projects, than when comparing solar power and wind power on average.

of roughly estimating the social benefits from CO₂ emissions avoided by VRE projects, and how these projects value will be affected by changes to come in the electric system. Furthermore, the approach based on power system modeling proposed here could be extended to the estimation of other non-markets components of the social value of VRE projects, e.g. the benefits from avoided emissions of local air pollutant or the costs resulting from grid congestion, even though these may require a different numerical model of the power system detailing these specific aspects.

Chapter 3

Designing subsidy contracts for renewables: an incentive-risk trade-off¹

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.

1. I am very grateful to Laurent Lamy for his thoughtful and helpful comments on this work. I also thank team members of the French Energy Regulation Commission (CRE) and the participants of the 71st Congress of the French Economic Association (AFSE, 2023) for their comments. All errors are my own.

3.1 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,² 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).³

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

2. 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.

3. 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).

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 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.⁴ 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

4. 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).

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 system⁵ 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 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.

5. 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.

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 (Chapter 2). 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 CO₂ emissions,⁶ the pace of development of

6. 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.

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 CO₂ 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.

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.⁷ 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 3.2 provides a theoretical framework to capture both the distortions and risk induced by contract designs, and their welfare implications. Section 3.3 provides an overview of the contract designs evaluated and their motivations. Section 3.4 details our methodology for providing a quantitative assessment of distortions and risk premiums. Section 3.5 reports the simulation results and compares the performance of various contract designs. Section 3.6 concludes.

3.2 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.

7. 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.

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:

$$\max_{(\lambda, \omega)} \mathbb{E}_X[V(\lambda \omega, X)] \quad s.t. \quad C(\lambda \omega) \leq 1 \quad (3.1)$$

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: $\omega^* \in \text{Arg max}_{\omega \in \Omega} \frac{\mathbb{E}_X[V(\omega, X)]}{C(\omega)}$.

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 ,⁸ 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.⁹ For simplification we assume the payment $R(\omega, X; \delta)$ constitutes the whole revenues of the firm and is entirely paid by the regulator,¹⁰ with for any

8. 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.

9. 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.

10. 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

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 $\lim_{\delta \rightarrow +\infty} R(\omega, X; \delta) = +\infty$ and $\lim_{\delta \rightarrow -\infty} R(\omega, X; \delta) = 0$.

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

$$\pi_R(\omega, \delta) = \mathbb{E}_X \left[U \left(\frac{R(\omega, X; \delta)}{\mathbb{E}_X[R(\omega, X; \delta)]} \right) \right] - U \left(\frac{C(\omega)}{\mathbb{E}_X[R(\omega, X; \delta)]} \right) \quad (3.2)$$

For a given winning bid δ , the firm will choose to build a project belonging to the set $\Omega_R(\delta) = \text{Arg max}_{\omega \in \Omega} \pi_R(\omega, \delta)$. 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

electricity being bought by the regulator or by the consumer is neutral in terms of welfare.

$\lim_{\delta \rightarrow -\infty} R(\omega, X; \delta) = 0$. 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:

$$\frac{C(\omega_R)}{\mathbb{E}_X[R(\omega_R, X; \delta_R)]} = U^{-1} \left(\mathbb{E}_X \left[U \left(\frac{R(\omega_R, X; \delta_R)}{\mathbb{E}_X[R(\omega_R, X; \delta_R)]} \right) \right] \right) \quad (3.3)$$

Note that the right hand term in (3.3) 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 (3.3) we obtain the direct expression of this risk premium, reported in (3.4).

$$\mu_{R,\delta}(\omega) \equiv 1 - U^{-1} \left(\mathbb{E}_X \left[U \left(\frac{R(\omega, X; \delta)}{\mathbb{E}_X[R(\omega, X; \delta)]} \right) \right] \right) \quad (3.4)$$

Whereas the scaling factor in the first best situation was $\lambda^* = \frac{1}{C(\omega^*)}$, in the auction outcome we obtain from (3.3) 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:

$$\frac{W_R}{W^*} = (1 - \mu_{R,\delta_R}(\omega_R)) \frac{\mathbb{E}_X[V(\omega_R, X)]/C(\omega_R)}{\mathbb{E}_X[V(\omega^*, X)]/C(\omega^*)} \quad (3.5)$$

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 (3.5) 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 $\omega \in \Omega$.¹¹ 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 :

$$\chi_{R, \delta}(\omega, \omega') \equiv \frac{\mathbb{E}_X[R(\omega, X; \delta)]/\mathbb{E}_X[V(\omega, X)] - \mathbb{E}_X[R(\omega', X; \delta)]/\mathbb{E}_X[V(\omega', X)]}{\mathbb{E}_X[R(\omega, X; \delta)]/\mathbb{E}_X[V(\omega, X)]} \quad (3.6)$$

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 $\bar{\chi}_{R, \delta}(\omega)$ the maximum distortion-induced advantage for project ω over Ω : $\bar{\chi}_{R, \delta}(\omega) \equiv \max_{\omega' \in \Omega} \chi_{R, \delta}(\omega, \omega')$. 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 9. ¹² *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 :*

$$1 - \frac{\mathbb{E}_X[V(\omega_R, X)]/C(\omega_R)}{\mathbb{E}_X[V(\omega^*, X)]/C(\omega^*)} \leq \bar{\chi}_{R, \delta_R}(\omega_R) \quad (3.7)$$

Proof The projects built by the firm ω_R induce a larger expected payment to cost ratio than any other project, and in particular than the first best project:

11. 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 .

12. Proposition 9 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, $|\chi_{R, \delta}(\omega, \omega')| < \epsilon$.

$\frac{\mathbb{E}_X[R(\omega_R, X; \delta_R)]}{C(\omega_R)} \geq \frac{\mathbb{E}_X[R(\omega^*, X; \delta_R)]}{C(\omega^*)}$. 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 $1 - \frac{\mathbb{E}_X[V(\omega_R, X)]/C(\omega_R)}{\mathbb{E}_X[V(\omega^*, X)]/C(\omega^*)} \leq \chi_{R,\delta}(\omega^*, \omega_R) \leq \bar{\chi}_{R,\delta}(\omega_R)$. **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 9 can be extended to the case when firms are risk averse.¹³ 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 (3.8) and provide a quantitative evaluation of the right-hand side through simulations.

$$\frac{W_R}{W^*} = (1 - \mu_{R,\delta_R}(\omega_R)) \frac{\mathbb{E}_X[V(\omega_R, X)]/C(\omega_R)}{\mathbb{E}_X[V(\omega^*, X)]/C(\omega^*)} \geq (1 - \mu_{R,\delta_R}(\omega_R))(1 - \bar{\chi}_{R,\delta_R}(\omega_R)) \quad (3.8)$$

3.3 Subsidy Contracts

As highlighted in section 3.2, 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 (Chapter 2). In addition, these social benefits include some positive externalities attributed to the addition of VRE electricity to the power

13. 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 9 is extended to any of the utility functions considered above.

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 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 (Chapter 2). 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 $\mathbf{q} = (q_t)_{t \in T}$ and the electricity prices in these same time-periods $\mathbf{p} = (p_t)_{t \in T}$. Thus, to avoid cluttering up the notations, we denote $R(\mathbf{q}, \mathbf{p}; \delta)$ the total revenue of the subsidized project over its lifetime for each contract design R . We also omit discounting for the same reason.

3.3.1 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:

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

Contracts for differences, even though slightly different in their practical implementation, result in the same revenue for the firm.¹⁴ 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

14. 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.

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.¹⁵ 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:

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

Feed-in premiums fully expose the firm's revenue to variations in electricity prices, in the sense that any change in price \mathbf{p} will cause a change in the firm's revenue.¹⁶ 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.

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 CO2 emissions displaced). In such a case, a variant of this contract design, further referred to as multiplicative feed-in premiums,

15. 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).

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

may appear more appropriate. In this contract design, δ denotes a percentage of the market price granted as a subsidy to the firm.¹⁷

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

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): $\Omega^{mFiP}(\delta) = \text{Arg max}_{\omega \in \Omega} (1 + \delta) \sum_{t \in T} p_t q_t - C(\omega) = \text{Arg max}_{\omega \in \Omega} \sum_{t \in T} p_t q_t - (1 - \frac{\delta}{1+\delta})C(\omega)$. 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 $p_t > -\delta$.¹⁸ 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.

17. 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.

18. 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.

3.3.2 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 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.

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

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.¹⁹ 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.

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

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.²⁰

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 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.²¹ 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.

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

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,

20. 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".

21. 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).

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.

3.4 Quantitative Assessment Strategy

Next we compare the various contract designs discussed in section 3.3 through a quantitative assessment of their welfare implications, decomposed into a risk premium and distortions-induced welfare loss as in (3.8). This assessment is based on a case study on a sample of wind and solar projects in France, building upon the work presented in Chapter 2. 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.

3.4.1 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 only moderately affected by the cannibalization effect.²² 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

22. 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.

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 (Chapter 2).

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 Chapter 2,²³ 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.²⁴ 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

23. Offshore wind projects that were considered in Chapter 2 have been removed from the sample, since these projects typically do not participate in the same auctions for VRE subsidies as onshore wind projects.

24. 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).

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.

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 Chapter 2 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 Chapter 2 and in Appendix D.

3.4.2 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 , $\bar{\chi}_{R,\delta}(\omega)$ introduced in section 3.2, 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 Chapter 2, 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).²⁵ 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.²⁶ 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

²⁵ These two benchmarks are extensively detailed in Chapter 2.

²⁶ 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 Chapter 2.

Table 3.1 – Calibration of bids δ_R and renewable energy externalities δ^* (short) [EUR/MWh]

Contract Design			Solar projects ($n = 50$)				Wind projects ($n = 43$)			
			δ_R	Revenue (per output)			δ_R	Revenue (per output)		
<i>Period</i>	<i>Weighting</i>		<i>mean</i>	<i>min</i>	<i>max</i>	<i>mean</i>	<i>min</i>	<i>max</i>		
Feed-in tariff			59.49	59.49	59.49	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
Social Benefits			δ^*	Value (per output)			δ^*	Value (per output)		
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 C.

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.²⁷ 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 3.1 for a selection of contract designs (see Table C.1 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 3.3, these are to be regarded as a

²⁷. The official reports of the wind and solar auctions are available on the website of the French Energy Regulatory Commission.

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 positive externality, must match the effective payment on average over the sample of projects.²⁸ 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 CO₂ (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 $\bar{\chi}_{R, \delta_R}(\omega)$ for each project, which provides an upper-bound on the distortion-induced welfare loss, as in (3.8). 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 R and the average effective distortion-induced welfare loss, i.e. $\frac{\mathbb{E}_X[V(\omega_R, X)]/C(\omega_R)}{\mathbb{E}_X[V(\omega^*, X)]/C(\omega^*)}$.

3.4.3 Risk premiums estimation

Next we estimate the risk premiums $\mu_{R, \delta_R}(\omega)$ as expressed in (3.4). 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

28. 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 Chapter 2.

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 \mathbf{q} and the prices of electricity \mathbf{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).

	<i>(baseline)</i>	Low	Median	High
<i>Probability</i>		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 3.2 – 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 3.2. 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 2021.²⁹ The price in

29. See <https://thedocs.worldbank.org/en/doc/ff5bad98f52ffa2457136bbef5703ddb-0350012021/related/CMO-October-2021-forecasts.pdf>

the low scenario roughly matches the 2016 average price (4.56 USD/mmbtu), which was 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).³⁰ 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 CO₂ 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.

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

Table 3.3 – Scenarios on VRE capacities installed in France [GW]

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

³⁰. 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>

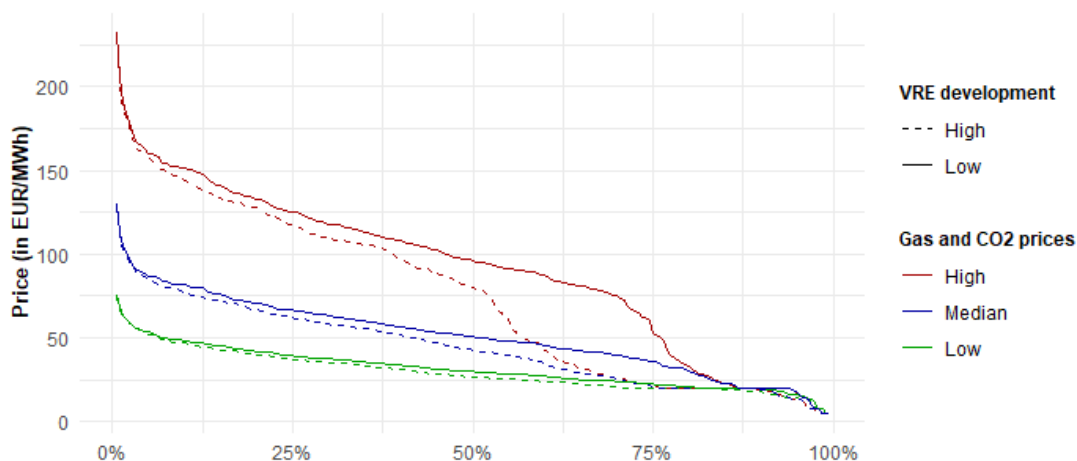


Figure 3.1 – Price duration curves depending on risk scenarios (2016-2019)

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 2023.³¹ 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 3.3.

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 3.1, 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.

31. 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.

3.5 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 CO₂ emissions constitutes most of the positive externality included in their social value.

3.5.1 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.

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 (3.5), 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 $\bar{\chi}_{R,\delta_R}(\omega)$. These results are shown in Figure 3.2 and reported in detail in Tables C.2 and C.3 in Appendix C. 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.³² 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 C.2 and C.3). Note that these results 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 3.2, sliding feed-in premiums in which the reference

32. 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 Chapter 2.

3.5. Results

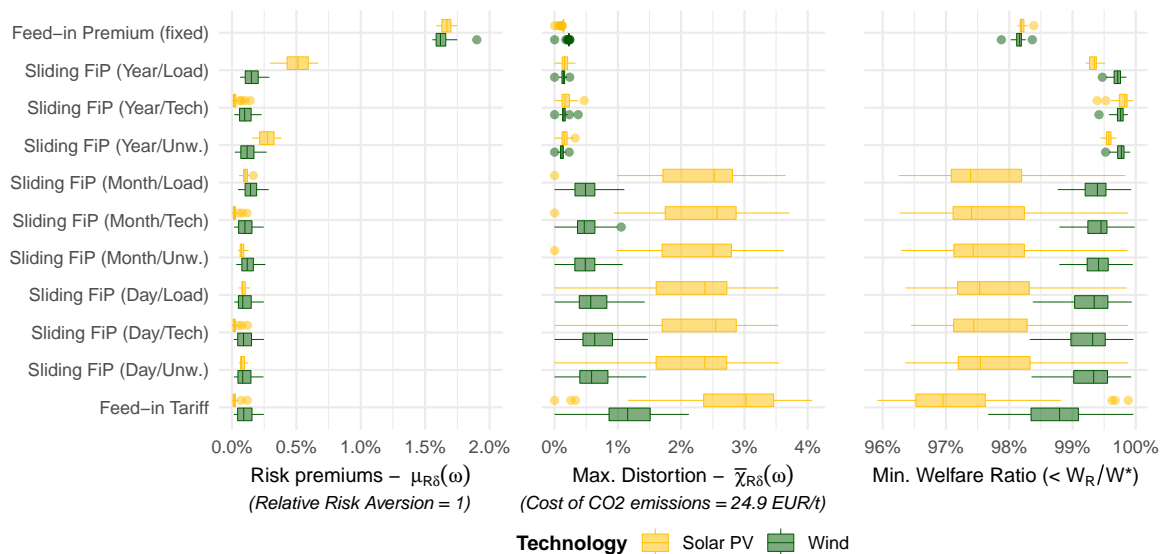


Figure 3.2 – Sliding feed-in premiums: distortions and risk premiums

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.³³

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 C.2 and C.3 in Appendix C. 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.³⁴

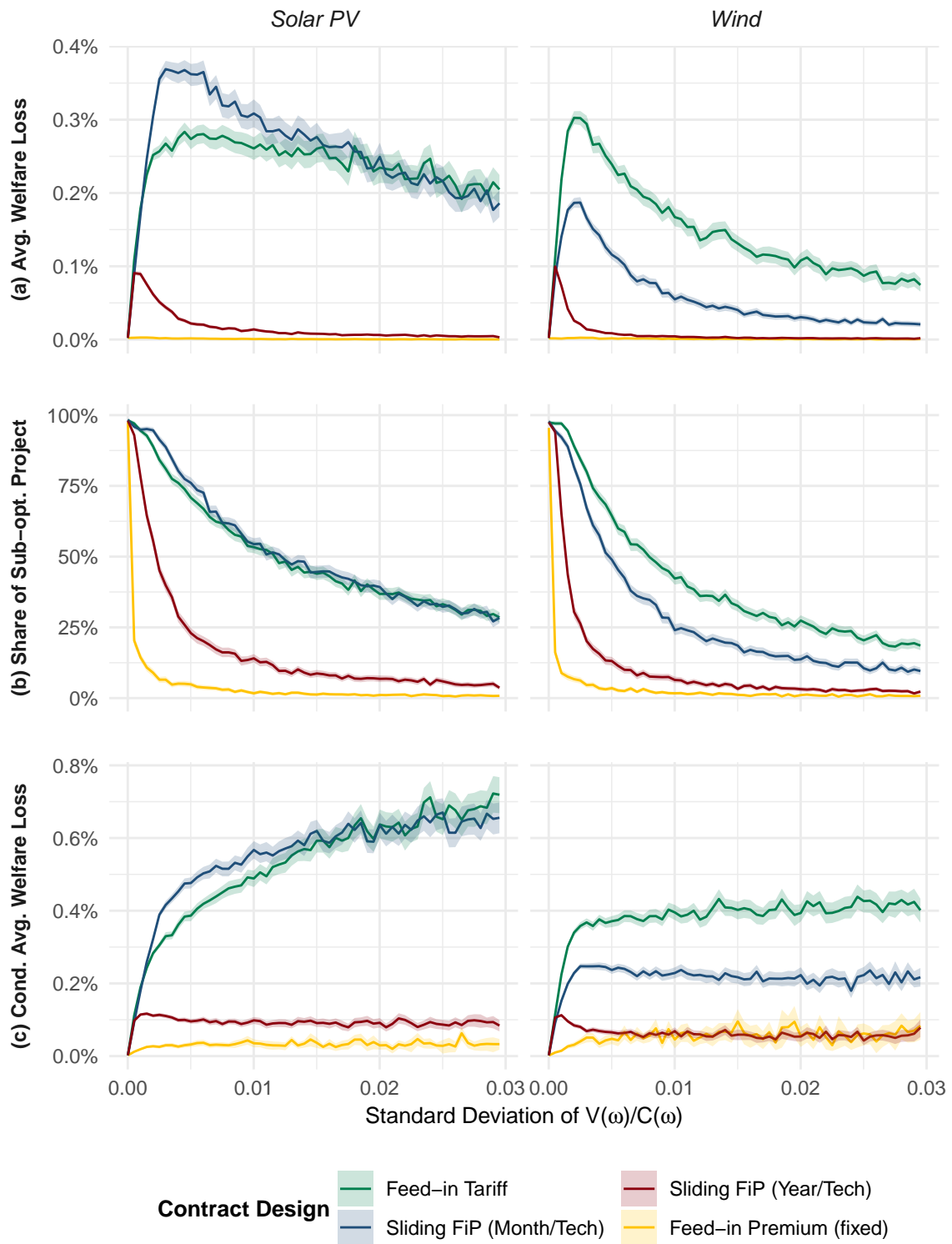


Figure 3.3 – Welfare loss due to distortion when assuming normally distributed $V(\omega)/C(\omega)$

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 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 3.4.2, and rely on simulations to compute the resulting expected welfare loss induced by distortions. The simulation results are presented in Figures 3.3 and 3.4 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 3.3, 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 3.3 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

33. 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.

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

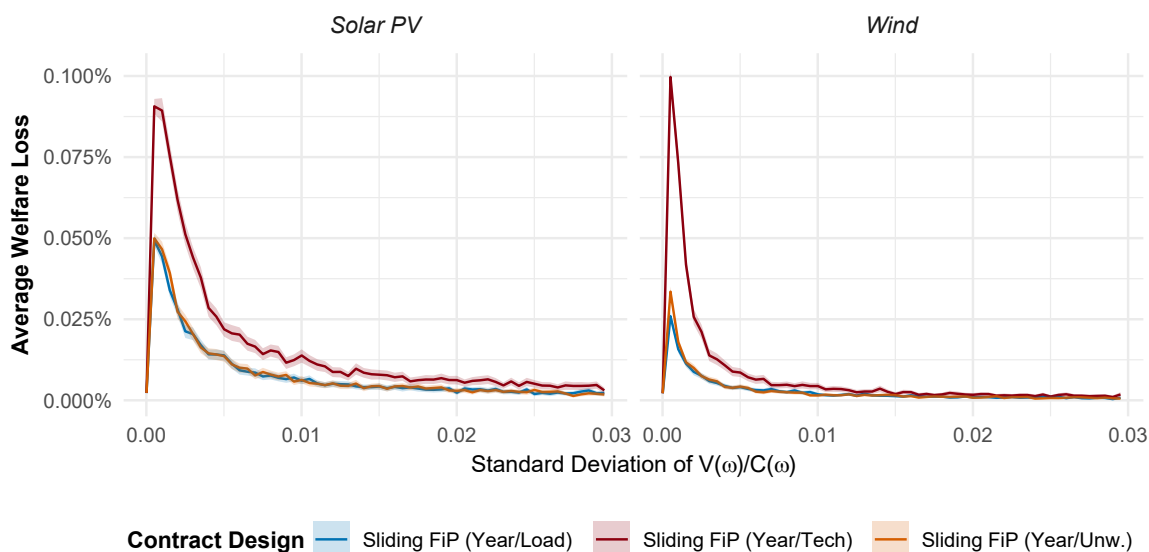


Figure 3.4 – Weighting used by sliding feed-in premium and expected welfare loss

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

3.5.2 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 3.5, 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. We have found in Chapter 2 that 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 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

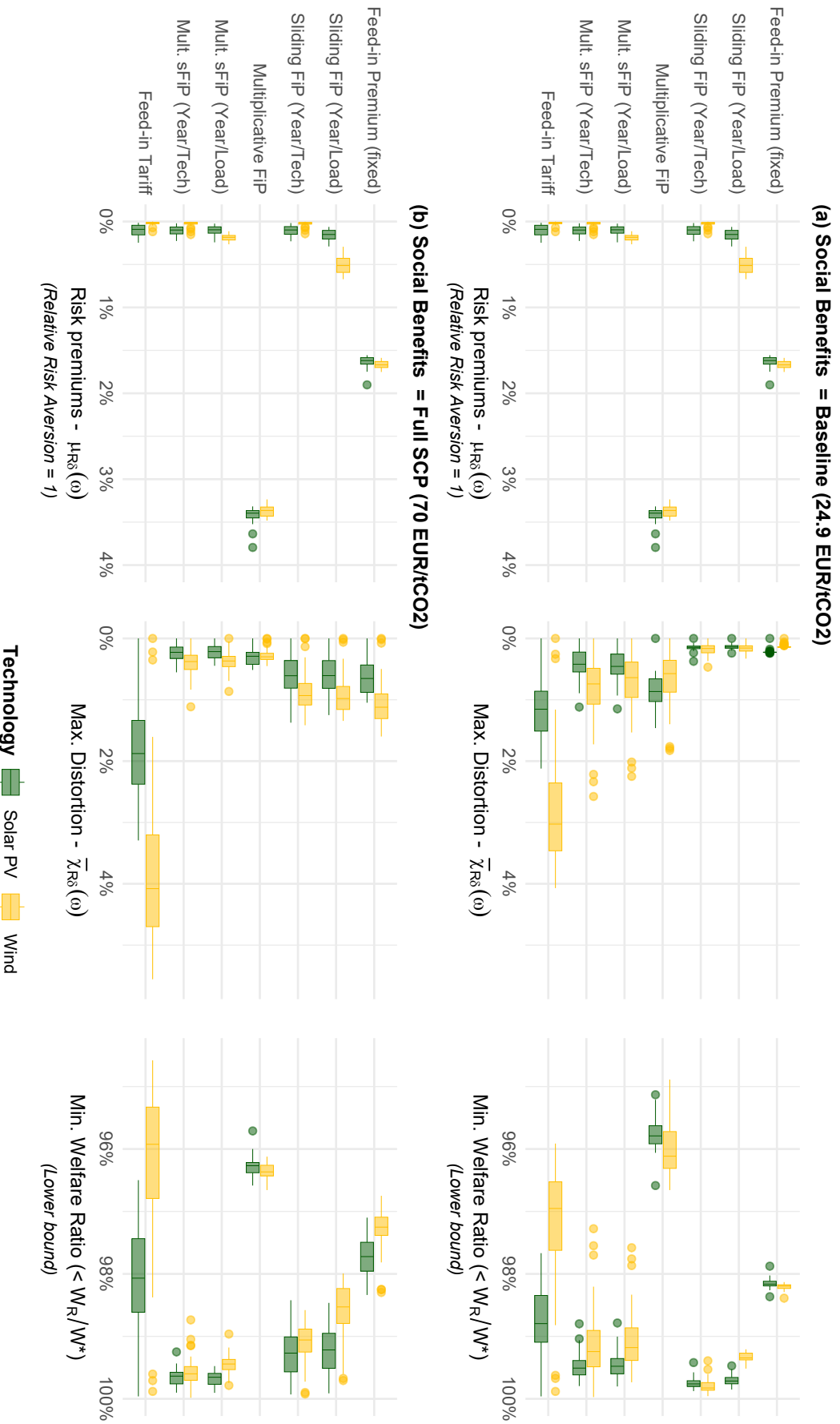


Figure 3.5 – Comparing additive and multiplicative feed-in premiums

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 3.3, 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.

3.6 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.

General Conclusion

The desire of some governments, particularly in Europe, to liberalize the electricity sector while retaining some political control over power generation is leading these governments to contract with private firms operating in the industry. The development of renewable sources of electricity, where governments set targets while private firms make the investments, is a typical example of such a situation. In the European Union (as well as in other European countries), this coordination problem has been addressed over the past decade by awarding subsidy contracts to private firms selected through auctions. Although this general idea has spread across Europe since the early 2010s, the design of these subsidy contracts has evolved and still shows some diversity. This dissertation explores this diversity and provides an analysis to identify pitfalls and best practices, focusing specifically on the incentives provided to the developers in their project selection, on the risk borne by the investors and how it may increase the public cost of support, and on the strategic behaviors that may arise in the face of contract designs that attempt to address these issues.

Contributions and Policy Implications

Limiting the risk borne by investors reduces the cost of capital, which is key to limiting the cost of VRE due to the high upfront capital costs and almost negligible operating costs that characterize these technologies. Designing subsidy mechanisms that transfer as much risk as possible from the firms to the regulator, assuming the regulator is risk neutral, may therefore seem like a good idea to limit the cost of public support. However, contract designs that attempt to achieve this risk transfer may have undesirable effects, which have been examined in this dissertation. As

shown in Chapter 1, a first adverse effect arises when the regulator attempts to insure VRE developers and investors against the risk associated with their production being dependent on weather conditions. Apart from the fact that these risks and the corresponding risk premiums are found to be low, the contract designs that provide such insurance are likely to induce some form of strategic behavior that will ultimately be detrimental to the government's objectives. This is consistent with the more general idea that firms should be exposed to risks over which they have some control, and that failure to do so may induce moral hazard or adverse selection. Beyond the case study presented in Chapter 1 of a mechanism used in France in the early 2010s, other mechanisms still in place today provide some form of insurance against production risk (e.g., in Brazil, in Germany, in Denmark)³⁵ and could induce such undesirable effects. Although the French contract design studied in Chapter 1 has been abandoned, a recently adopted disposition in France states that, in some cases, VRE support schemes "may provide for an annual modulation of the feed-in tariff for the electricity produced, in order to compensate for all or part of the losses of producibility due to less favorable than average siting conditions in the project area."³⁶ As this provision has not yet been translated into concrete measures, it is not possible to say that it will fall into a comparable pitfall. However, its implementation should be carried out with attention to the strategic behaviors it could induce.

Another risk for VRE producers is the market price of electricity, on which their revenues may depend. This price risk combines elements that VRE developers can hardly anticipate and cannot adapt to (e.g., the evolution of global fuel prices) with elements to which they have the ability to respond (e.g., recurring daily and seasonal patterns in electricity prices). The work presented in Chapter 2 has emphasized that the heterogeneity in the economic value of VRE projects comes not only from the amount of electricity produced, but also from the timing of its production. This implies that a full insurance against electricity market price risk, as provided by feed-in tariff contracts, may imply distorted incentives for VRE developers not to consider the timing of their electricity production when considering different siting and/or

35. See AURES (2016), Liñeiro, Müsgens (2023), and AURES II (2019).

36. Loi n°2023-175 du 10 mars 2023 relative à l'accélération de la production d'énergies renouvelables, Article 17.

technology options.

However, the welfare gains from providing better incentives to developers by exposing them to market prices must be weighed against the increase in public support costs that this increased risk to investors induces through the risk premiums. Confronting these two issues through a quantitative exercise is one of the contributions of this dissertation, presented in Chapter 3. In the case of the current French power system under study, it appears that the increase in risk, and thus in support costs, that would result from subsidizing VRE through fixed feed-in premium contracts (instead of, for example, feed-in tariff contracts) would exceed in magnitude the welfare gains from the better incentives provided to developers. Sliding feed-in premium contracts also appear to be a promising option, with results supporting the intuition that they succeed in passing through the incentives carried by short-term patterns in market prices while insuring against long-term shocks that are beyond the control and expectations of VRE developers. However, some specifications of these contracts, usually hidden under the general label of "sliding feed-in premium", are crucial. For example, sliding feed-in premiums with a reference price defined on a monthly basis (as currently implemented in France) are likely to induce distortions of the same order of magnitude as those induced by a feed-in tariff. Another example is the choice of a one-sided sliding feed-in premium contract (as in Germany, for example) rather than two-sided, which would induce an increase in risk premiums without any identified benefit in terms of incentives. The results of Chapter 3 suggest that the best option for our French case study would be a two-sided sliding feed-in premium contract with as reference price a yearly average weighted by the total national production of the considered technology (solar or wind) in each hour. On the other hand, it is not clear that the current sliding feed-in premium scheme is better suited than a simple feed-in tariff.

However, these recommendations regarding the design of subsidy contracts should be considered valid in the context of the power system in which they were tested, i.e. the French power system as it existed in the late 2010s. Moving to a different context, such as a power system dominated by hydro or coal generation (for example),³⁷ may

37. Because hydropower is a very flexible source of electricity, countries with large hydro resources

lead to different results. The results that are presented for France are not necessarily true for any other European country.³⁸ Moving in time to a future VRE-dominated power system could also lead to very different results.

Subsidizing VRE within future power systems

The ongoing energy transition, and in particular the increasing share of VRE in the mix, will significantly reshape the context in which future VRE projects will be implemented. In particular, we can expect a radical change in the shape and pattern of electricity prices in wholesale markets,³⁹ reflecting a change in the economic value of new wind and solar projects. The cannibalization effect that reduces the relative value of VRE electricity production is likely to increase, and VRE project's whose production timing is not as correlated with the rest of the fleet are likely to appear much more valuable. Next, the work presented in Chapter 2 is extended to gain some insight into these effects of the coming energy transition. The simulation of the value of the sample of wind and solar projects using the numerical model EOLES-Dispatch (presented in Chapter 2) is reproduced, but in the context of a power system projected to the year 2030. The scenario built to represent this future power system is based, for the most part, on various energy planning documents published by the governments of the countries that are modeled in EOLES-Dispatch,⁴⁰ and is (partly) described in Table 4.

The switch from the baseline power system to the proposed scenario for 2030 induces a small increase in the average marginal cost (from 43.63 EUR/MWh to 52.06 EUR/MWh) and a very large increase in the standard deviation of these marginal costs

typically have less daily or seasonal variation in electricity prices, limiting the importance of exposing developers to price signals. In a power system with large coal-fired generation capacity, low prices typically imply that the marginal generation unit is a coal-fired power plant, which emits much more CO₂. Thus, accounting for displaced CO₂ emissions may actually downplay the importance of projects that produce when prices are high.

38. In particular, the poor performance of monthly sliding feed-in premiums is likely to be specific to the French electricity system, which is characterized by strong seasonal price patterns due to the massive use of electric heating and the very large share of rather inflexible nuclear power generation.

39. See, e.g., Ekholm, Virasjoki (2020) for a simulation of market prices in a 100% VRE power system.

40. In particular, the development of wind and solar power in France is based on a linear extrapolation of the objectives set for 2028 in the Multiannual Energy Plan (PPE) published by the French government in 2019. See <https://www.ecologie.gouv.fr/programmations-pluriannuelles-lenergie-ppe>.

	Baseline (2019)		Projection (2030)
Capacity in France			
<i>Nuclear</i> [GW]	63.1	-9%	57.7
<i>Natural Gas</i> [GW]	6.8	0%	6.8
<i>Coal</i> [GW]	4.0	-100%	0.0
<i>Hydro</i> [GW]	22.0	+30%	28.6
<i>Wind</i> [GW]	14.1	+218%	44.9
<i>Solar</i> [GW]	9.1	+420%	47.3
Fuel and CO₂ costs			
<i>Natural Gas</i> [EUR/mmbtu]	5.91	+12%	6.61
<i>CO₂ allowance</i> [EUR/t]	24.9	+402%	100
Simulated marginal costs			
<i>Average (Unw.)</i> [EUR/MWh]	43.63	+19%	52.06
<i>Std Dev.</i> [EUR/MWh]	15.89	+160%	41.30

Table 4 – Scenario for the French power mix in 2030

(from 15.89 EUR/MWh to 41.30 EUR/MWh). This reflects the fact that for much of the time VRE-generated electricity is abundant (at zero marginal cost), but there are periods when it is not available and the marginal cost of electricity becomes very high (driven up by the increased cost of fossil fuels and CO₂ emission allowances).

As reported in Table 5, the effect on the value of the sample of projects presented in Chapter 2 is dramatic, especially in terms of how projects compare to each other. Solar power projects are much more affected than wind power projects, and see the average value of their production collapse from 41.18 to 25.80 EUR/MWh (while it slightly increases for wind projects). And most interesting for the topic of this dissertation, the standard deviation of the project values is multiplied by more than 4 for solar projects and by almost 3 for wind projects. In the light of this increased discrepancy among project values, the conclusions regarding the incentives provided to VRE developers might be reconsidered and given a greater importance in the incentive-risk trade-off discussed in Chapter 3. On the other hand, the fact that the share of VRE in the mix has a major impact not only on the average price but also on the volatility of electricity prices raises the question of whether subsidy schemes that manage to mitigate risk in the current electricity mix, such as yearly sliding feed-in premiums, will continue to do so in the face of this emerging volatility risk.

It should be emphasized here that any projection scenario to 2030 is highly arguable, and the present exercise, based on one specific scenario, is presented only as

	Wind			Solar		
	Baseline (2019)	Projected (2030)	<i>Diff.</i>	Baseline (2019)	Projected (2030)	<i>Diff.</i>
Mean	42.66	45.68	<i>+3.01</i>	41.18	25.80	<i>-15.38</i>
Std. Dev.	0.30	1.37	<i>1.18</i>	0.59	1.71	<i>1.28</i>
Minimum	41.97	43.03	<i>+0.62</i>	40.38	24.31	<i>-16.41</i>
Maximum	43.37	48.78	<i>+5.67</i>	42.88	32.16	<i>-10.56</i>
Correlation	67.5%			81.9%		

Table 5 – Simulated value of VRE projects in present and future power mix [EUR/MWh]

a hint of what the impact might be. In particular, the scenario considered here does not include a large increase in storage capacity, nor an adaptation of electricity demand in response to evolving market conditions. Either of these elements, if properly accounted for, could mitigate the impacts presented here. Nevertheless, these simulation results suggest that some of the general conclusions reached in this dissertation might not hold in the mean-term future. In particular, the relative importance of providing appropriate incentives to VRE developers versus protecting investors from price risk may be reshuffled. Moreover, contract designs that perform well in containing distortions or limiting risk premiums in the context of the 2019 French may not perform as well in a future mix where wholesale prices are much more volatile and the cannibalization effect is much stronger. These questions should be answered by a thorough prospective evaluation of these contract designs, which is left to future research.

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Appendix A

Appendix to Chapter 1

A.1 Modelling production risk and costs

Our simulations of producers' equilibrium bidding behaviour and then of the corresponding expected public spending are based on a production distribution built from historic simulated data and this for each of the six offshore wind farm sites that were actually auctioned under the production-insuring payment rule we have presented in Section 2. The characteristics of those projects (name, location, size in MW) are listed in Table A.1.

Hourly electricity productions of these farms are simulated for 19 years (from 2000 to 2018) using the model developed by Staffell and Pfenninger (2016) and this thanks to the website <https://www.renewables.ninja/> to which the location and the characteristics of the turbines have been given as inputs. The production is simulated considering the full capacity of each farm.¹ In most cases, data needed to simulate production with the turbine type actually implemented by the winning bidder (most often the Adwen AD 8-180 turbine) was not available. For the six projects, we consider instead the Vestas V164 8000 turbine which seems the most closely related kind of turbine for such projects.

Historic hourly production obtained from the simulator is then aggregated at the quarterly level. Then we bootstrap our 19 years of aggregated quarterly data to generate the distribution of yearly production: quarters are randomly drawn and summed to generate yearly production points. This resampling approach to generate more than our 19 original years of production is relevant if there is no significant autocorrelation between quarterly aggregate production.²

At the bidding stage, firms do not have a perfect knowledge on their average capacity factor which does not depend solely on their technological choice (e.g., the size and the height of the turbine) but also on the local meteorological conditions which are estimated from measurement mats. In the past, such estimations has suffered from important bias: Lee and Fields' (2020) survey report an over-prediction of the

1. Staffell and Pfenninger's (2016) model is for an isolated turbine. Therefore, the production of each farm (which consists of many turbines) is likely to be slightly overestimated due wake effects.

2. The Saint-Brieuc site suffers from significant autocorrelation between quarterly aggregate production. Therefore we do not further consider results related to this site which differ importantly from the other sites.

median of the capacity factor distribution around 4%. The methodologies have been improved with the aim to reduce bias, but they still involve economically relevant errors: e.g. Jourdir and Drobinski (2017) show that the commonly used statistical model based on Weibull distributions lead to a mean absolute error around 4 or 5% of the average electricity production. In order to account for such noise in the estimation of the capacity factor, the distribution of the vector of yearly-production (q_1, \dots, q_{20}) is build in the following way: each yearly-production q_t is the product of a yearly-dependent production drawn independently across years according to the bootstrapped distribution defined above with $1 + \epsilon$ where ϵ is a non-year-dependant noise distributed according to a centered normal distribution with the variance σ^2 . We assume that $\sigma = 6.3\%$, which matches a mean absolute error of 5%. The noise ϵ for the capacity factor estimation is the main driver for the risk premiums relative to net present value of the subsidy contracts: contrary to weather risk, this additional risk is not averaged out over the 20 years of production.

Table A.1 – Characteristics on the wind farm projects (source : European Commission (2019) and French Energy Regulatory Commission (2011, 2013))

Site	Location (lat.,long.)	Capacity [MW]	CAPEX [M€]	OPEX/year [M€]	FiT awarded [€/MWh]
Le Tréport	(50.1, 1.1)	496	2000	105	131
Ile d'Yeu	(46.9, -2.5)	496	1860	110	137
Fécamp	(49.9, 0.2)	497	1850	75	135.2
Courceulles	(49.5, -0.5)	448	1600	69	138.7
Saint-Brieuc	(48.8, -2.5)	496	2200	63	155
Saint-Nazaire	(47.2, -2.6)	496	1800	78	143.6

We consider throughout the paper that producers are fully homogeneous, meaning:

- Producers do not receive any private information on future production distribution which does not depend on the winning bidder's identity. The revenue distribution derived from any given contract is thus the same across all producers.
- Producers have the same costs made of two components: a fixed cost IC (reflecting the initial investment at the date $t = 0$) and a yearly operational cost OC (reflecting operation and maintenance for each year $t = 1, \dots, 20$). Our assumptions for the cost for the various projects come from a reported of

the European Commission.³ are reported in Table A.1.

3. https://ec.europa.eu/competition/state_aid/cases1/201933/265141_2088479_221_2.pdf

A.2 Proofs of main theoretical results

Throughout the appendix we use the notation $\delta := \sup\{t \geq 0 \mid f(\bar{q}(1-t)) = 0\}$. For $f \in \mathcal{F}_{sp}$, note that the support of f corresponds then to the interval $[\bar{q}(1-\delta), \bar{q}(1+\delta)]$ and that $\delta \in]0, 1]$.

Proof of Proposition 2

Let us first show that if $q_0 \geq \bar{q}$, then $\mathbb{E}_f[R(q, q_0)] \geq \mathbb{E}_f[R(q, \bar{q})] = \bar{q}$ for any $f \in \mathcal{F}_{sp}$ (where the last equality comes from the assumption that $R(\cdot, \cdot)$ is production-insuring) or equivalently $\mathbb{E}_f[q \cdot z_{q_0}(\frac{q}{q_0})] \geq \bar{q}$. Take $q_0 \geq \bar{q}$ and let $\alpha := 1 - F(q_0) \leq \frac{1}{2}$.

Consider first the case where $\alpha = 0$, that is when q_0 is higher than any realization of q . Then $\mathbb{E}_f[R(q, q_0)] = \int_0^{q_0} q \cdot z_{q_0}(\frac{q}{q_0}) dF(q) \geq \int_0^{q_0} q dF(q) = \bar{q}$, since from Lemma 1 we have $\forall q \leq q_0, z_{q_0}(\frac{q}{q_0}) \geq 1$.

Consider now the complementary case where $\alpha > 0$. Let $G_{q_0} : \mathbb{R}_+ \rightarrow \mathbb{R}_+$ denote the function defined by:

$$\begin{aligned} \text{for } q \geq q_0, \quad G_{q_0}(q) &= \frac{1 + F(q) - 2F(q_0)}{2\alpha} \\ \text{for } q \leq q_0, \quad G_{q_0}(q) &= 1 - G_{q_0}(2q_0 - q). \end{aligned}$$

As a CDF, the function F is non-decreasing and then G_{q_0} is also non-decreasing. Since $f \in \mathcal{F}_{sp}$, we have $\forall q \geq 2\bar{q}, F(q) = 1$. Therefore $\forall q \geq 2q_0$ (which implies $q \geq 2\bar{q}$), $G_{q_0}(q) = 1$, and consequently $G_{q_0}(0) = 0$. Now let g_{q_0} denote the derivative of G_{q_0} , for $q \geq q_0, g_{q_0}(q) = \frac{f(q)}{2\alpha}$ and for $q \leq q_0, g_{q_0}(q) = g_{q_0}(q_0 + (q_0 - q))$. Then G_{q_0} is the CDF and g_{q_0} the PDF of a symmetric distribution with expected value q_0 . We can then conclude that $\mathbb{E}_{g_{q_0}}[q \cdot z_{q_0}(\frac{q}{q_0})] = \mathbb{E}_{g_{q_0}}[q] = q_0$.

Let us define the function $H_{q_0} : \mathbb{R}_+ \rightarrow \mathbb{R}_+$ by $H_{q_0}(q) := F(q) - 2\alpha \cdot G_{q_0}(q)$, in such a way that $f(q) = H'_{q_0}(q) + 2\alpha \cdot g_{q_0}(q)$. Then we may write :

$$\begin{aligned}
\mathbb{E}_f[qz_{q_0}(\frac{q}{q_0})] &= \int_0^{2\bar{q}} qz_{q_0}(\frac{q}{q_0})dF(q) = \int_0^{2q_0} qz_{q_0}(\frac{q}{q_0})dF(q) \\
&= \int_0^{2q_0} qz_{q_0}(\frac{q}{q_0})H'_{q_0}(q)dq + 2\alpha \cdot \mathbb{E}_{g_{q_0}}[qz_{q_0}(\frac{q}{q_0})] \\
&= \int_0^{2q_0} qz_{q_0}(\frac{q}{q_0})H'_{q_0}(q)dq + 2\alpha \cdot q_0
\end{aligned}$$

For $q \geq q_0$, $2\alpha g_{q_0}(q) = f(q)$ and therefore $H'_{q_0}(q) = 0$. Moreover, $\forall q \leq q_0$, $z(\frac{q}{q_0}) \geq 1$. We obtain therefore :

$$\begin{aligned}
\mathbb{E}_f[q \cdot z_{q_0}(\frac{q}{q_0})] - 2\alpha \cdot q_0 &= \int_0^{q_0} q \cdot z_{q_0}(\frac{q}{q_0})H'_{q_0}(q)dq \\
&\geq \int_0^{q_0} q \cdot H'_{q_0}(q)dq = \int_0^{q_0} qdF(q) - 2\alpha \int_0^{q_0} qdG_{q_0}(q) \\
&= \bar{q} - \int_{q_0}^{2\bar{q}} qdF(q) - 2\alpha \int_0^{q_0} qdG_{q_0}(q) \\
&= \bar{q} - 2\alpha \underbrace{\left(\int_{q_0}^{2\bar{q}} qdG_{q_0}(q) + \int_0^{q_0} qdG_{q_0}(q) \right)}_{=\mathbb{E}_{g_{q_0}}[q]=q_0} = \bar{q} - 2\alpha \cdot q_0.
\end{aligned}$$

Finally, $\mathbb{E}_f[R(q, q_0)] \geq \bar{q} = \mathbb{E}_f[R(q, \bar{q})]$ (for any $q_0 \geq \bar{q}$). By symmetry, we can show that $\mathbb{E}_f[R(q, q_0)] \leq \bar{q}$ for any $q_0 \leq \bar{q}$.

To prove that the payment rule is manipulable, then for any given $f \in \mathcal{F}_{sp}$, let us build $q_0 > \bar{q}$ such that $\mathbb{E}_f[R(q, q_0)] > \bar{q}$. If $f \in \mathcal{F}_{sp}$, there are two possibilities: 1) f is a uniform distribution, 2) there exists a point $q' > \bar{q}$ such that $f(q' - t) > f(q' + t) > 0$ for any $t \in]0, q' - \bar{q}]$.

Consider first the case where f is a uniform distribution on its support $[(1-\delta)\bar{q}, (1+\delta)\bar{q}]$. Let $q' \equiv (1+\delta)\bar{q}$. For any realization q in the support of f , we have $z_{q'}(\frac{q}{q'}) \geq 1$. Furthermore, from Lemma 1, there is a subset of the interval $[\bar{q}, q']$ which has positive measure and on which $z_{q'}(\frac{q}{q'}) > 1$. Finally, we obtain that $\mathbb{E}_f[q \cdot z_{q'}(\frac{q}{q'})] > \mathbb{E}_f[q]$.

Consider now the case where there exists a point $q' > \bar{q}$ such that $f(q' - t) > f(q' + t) > 0$ for any $t \in]0, q' - \bar{q}]$. Since the latter interval is non-null, we know that for such q' , $F(q') < 1$. To show that $\mathbb{E}_f[R(q, q')] > \bar{q} = \mathbb{E}_f[R(q, \bar{q})]$ using the same arguments as above, it is sufficient to show that $\int_0^{q'} qz_{q'}(\frac{q}{q'})H'_{q'}(q)dq > \int_0^{q'} qH'_{q'}(q)dq$.

For $q \in [\bar{q}, q']$, we have $H'_{q'}(q) = f(q) - 2\alpha_{q'}(q) = f(q) - f(2q' - q)$. Since f is non-increasing for $q > \bar{q}$ and $f(q' - t) > f(q' + t) > 0$ for any $t \in (0, q' - \bar{q}]$, then $\bar{q} < q < q' < 2q' - q$ implies $f(q) > f(2q' - q)$ and therefore $H'(q) > 0$ for any $q \in [\bar{q}, q']$. Moreover we know from Lemma 1 that there is a subset of $[\bar{q}, q']$ with positive measure in which $z_{q'}(\frac{q}{q'}) > 1$. We then obtain $\int_{\bar{q}}^{q'} q z_{q'}(\frac{q}{q'}) H'_{q'}(q) dq > \int_{\bar{q}}^{q'} q H'_{q'}(q) dq$ which further implies $\int_0^{q'} q z_{q'}(\frac{q}{q'}) H'_{q'}(q) dq > \int_0^{q'} q H'_{q'}(q) dq$ (since $z_{q'}(q) \geq 1$ and $H'_{q'}(q) = 2F(q') - 1 \geq 0$ for $q \leq q'$ given that $q' \geq \bar{q}$). **Q.E.D.**

Proof of Proposition 3

As shown in the SA, we have that p^L and p^T are characterized by the zero surplus conditions: $\mathbb{E}_f[U(p^L \cdot q)] = \mathbb{E}_f[U(p^T \cdot R(q, \bar{q}))] = U(C)$ and the function $p \mapsto \mathbb{E}_f[U(p \cdot R(q, \bar{q}))]$ is continuously increasing. Applying Definition 1, we have $\mathbb{E}_f[U(p^L \cdot R(q, \bar{q}))] \geq \mathbb{E}_f[U(p^L \cdot q)]$, the inequality being strict if firms are strictly risk averse and standing as an equality if firms are risk neutral. We then obtain the fact that $p^T \leq p^L$. Since $\mathbb{E}_f[R(q, \bar{q})] = \bar{q}$ for any production-insuring payment rule when $f \in \mathcal{F}_{sp}$, we then obtain the fact that $\mathbb{E}_f[p^T \cdot R(q, \bar{q})] \leq \mathbb{E}_f[p^L \cdot \bar{q}]$. The previous inequalities are strict if firms are strictly risk averse, and stands as equalities if firms are risk neutral.

Q.E.D.

Proof of Proposition 4

As shown in the SA, we have that p^S is characterized by the zero surplus condition: $\max_{q_0 \geq 0} \mathbb{E}_f[U(p^S \cdot R(q, q_0))] = U(C)$ and the function $p \mapsto \max_{q_0 \geq 0} \mathbb{E}_f[U(p \cdot R(q, q_0))]$ is continuously increasing.

In order to show that $p^S \leq p^T$, we proceed by contradiction. Suppose that on the contrary that $p^S > p^T$. Then we have $\Pi^S(p^S) = \max_{q_0 \geq 0} \mathbb{E}_f[U(p^S \cdot R(q, q_0))] \geq \mathbb{E}_f[U(p^S \cdot R(q, \bar{q}))] > \mathbb{E}_f[U(p^T \cdot R(q, \bar{q}))] = \Pi^T(p^T)$. From (1.2) (resp. (1.3)), the last (resp. first) term is equal to $U(C)$ and we have thus raised a contradiction.

If the payment rule is manipulable at price p^T , then we have $\max_{q_0 \geq 0} \mathbb{E}_f[U(p^T \cdot R(q, q_0))] > \mathbb{E}_f[U(p^T \cdot R(q, \bar{q}))]$. Given (1.2), then the last term is equal to $U(C)$. If $p^S = p^T$ and given (1.3), then $\max_{q_0 \geq 0} \mathbb{E}_f[U(p^T \cdot R(q, q_0))] = U(C)$ and we have thus raised a contradiction. We have thus shown that if the payment rule is manipulable

at price p^T , then $p^S < p^T$. Note that Proposition 2 establishes that if firms are risk neutral and if $f \in \mathcal{F}_{sp}$, all production-insuring payment rule are manipulable.

If the payment rule R^{full} provides full insurance against production risk to truthful bidders and is homogeneous of degree 1, then we obtain from Proposition 8 that a strategic bidder will not be fully insured against production risk: $\text{Var}_f[R^{full}(q, q^S)] > \text{Var}_f[R^{full}(q, \bar{q})] = 0$ if $q^S \in \text{Arg max}_{q_0 \in \mathbb{R}_+} \mathbb{E}_f[U(p^S R(q, q_0))]$. From the zero surplus conditions (1.2) and (1.3), we have $\Pi^S(p^S) = \Pi^T(p^T)$. Since the payoff of the truthful firm is deterministic (under R^{full}), we have $\Pi^T(p^T) = U(p^T \bar{q})$.

$\mathbb{E}_f[U(p^S R(q, q_0^S))] = U(p^T \bar{q})$ since the payoff of the truthful bidder is certain thanks to full insurance by the payment rule.

If bidders are strictly risk averse then U is strictly concave, given $R^{full}(q, q^S)$ is not deterministic, we have that $U(\mathbb{E}_f[p^S R(q, q^S)]) > \mathbb{E}_f[U(p^S R(q, q^S))] = \Pi^S(p^S)$. Combined the previous equalities, we have then $U(\mathbb{E}_f[p^S R(q, q^S)]) > U(p^T \bar{q})$ which further implies that $p^S \cdot \mathbb{E}_f[R(q, q^S)] > p^T \cdot \bar{q}$, or equivalently that the BEC in the equilibrium with strategic firms is greater than the BEC in the equilibrium with truthful firms. **Q.E.D.**

Proof of Proposition 5

If U is a CRRA utility function (which includes the case where firms are risk neutral), then the set $Q_0^*(p)$ does not depend on p (as shown in the SA). Furthermore, we assume that the payment rule is manipulable and thus that $\bar{q} \notin Q_0^*(p)$, $\Pi^S(p^T) > \Pi^T(p^T) = U(C)$ and $p^S < p^T$. The proposition makes also the implicit assumption that strategic firms use the same optimal (mis)report $q_0^* = q^S = q^{S-T}$ both when several firms are strategic and when a single firm is strategic. Then we obtain for any manipulable payment rule that $p^T \cdot \mathbb{E}_f[R(q, q_0^*)] > p^S \cdot \mathbb{E}_f[R(q, q_0^*)]$, i.e. that the BEC when there is a single strategic firm is strictly greater than when there are several strategic firms. Furthermore, if U is linear, then $\Pi^S(p^T) > \Pi^T(p^T) = U(C)$ is equivalent to $p^T \mathbb{E}_f[R(q, q_0^*)] > p^T \mathbb{E}_f[R(q, \bar{q})] = C$. If the payment rule is linear, then we have under risk neutrality that $\Pi^S(p^T) = \Pi^T(p^T) = U(C)$ which is equivalent to $p^T \mathbb{E}_f[R(q, q_0^*)] = p^T \mathbb{E}_f[R(q, \bar{q})] = C$. **Q.E.D.**

Proof of Proposition 6

The equilibrium analysis is analogous to Maskin and Riley (1985): having a low (high) valuation corresponds here to being a truthful (strategic) firm. Note that the assumption that $\Pi^S(p^T) > \Pi^T(p^T)$ guarantees that strategic firms make positive surplus and the equilibrium involves a mixed strategy. On the contrary, if $\Pi^S(p^T) = \Pi^T(p^T)$, then all firms would submit the price bid p^T . As in Maskin and Riley (1985), we have in equilibrium that truthful bidders make no surplus ($\Pi^T(p^T) = U(C)$) and bid thus (p^T, \bar{q}) and that all firms when strategic adopts the same bidding strategy which involves no atoms but rather a mixed strategy where the upper bound of the price bid distribution, denoted by p_{max} , is equal to p^T (if $p_{max} < p^T$, then strategic bidders submitting a price bid around p_{max} would have a strictly profitable deviation by bidding just below p^T). Let $G(\cdot)$ denote the CDF of the price bid of a strategic firm. In equilibrium, any price bid p made as part of a mixed strategy must generate the same expected payoff, and in particular the same expected payoff as bidding p^T (under the assumption that ties are broken in favor strategic firms). This translates into the distribution G satisfying:

$$[1 - \alpha + \alpha(1 - G(p))]^{N-1} \cdot [\Pi^S(p) - U(C)] = (1 - \alpha)^{N-1} \cdot [\Pi^S(p^T) - U(C)]. \quad (\text{A.1})$$

We then obtain $G(p) = 1 - \frac{1-\alpha}{\alpha} \left(\sqrt[N-1]{\frac{\Pi^S(p^T) - U(C)}{\Pi^S(p) - U(C)}} - 1 \right)$ for any p in the support of G . Let p_{min} denote the lower bound of the support of G . p_{min} is characterized as the unique solution of $\Pi^S(p_{min}) = (1 - \alpha)^{N-1} \cdot [\Pi^S(p^T) - U(C)] + U(C)$. For any $\alpha \in (0, 1)$, we have $\Pi^S(p_{min}) - U(C) = (1 - \alpha)^{N-1} \cdot [\Pi^S(p^T) - U(C)] > 0 = [\Pi^S(p^S) - U(C)]$, and then that $\Pi^S(p_{min}) > \Pi^S(p^S)$ which further implies that $p_{min} > p^S$. **Q.E.D.**

Proof of Proposition 7

The BEC can be written as

$$(1 - \alpha)^N \cdot p^T \cdot \mathbb{E}_f[R(q, \bar{q})] + \int_{p_{min}}^{p_{max}} p \cdot \mathbb{E}_f[R(q, q_0^*(p))] dK(p) \quad (\text{A.2})$$

where $q_0^*(p) \in Q_0^*(p) \equiv \text{Arg max}_{q \geq 0} \Pi(p, q)$ and $K(p) := 1 - (1 - \alpha + \alpha(1 - G(p)))^N$

denotes the CDF of the price bid of the winning bidder. If U is a CRRA utility function, then $Q_0^*(p)$ does not depend on p (as detailed in the SA). Furthermore, if firms are risk neutral, $\mathbb{E}_f[R(q, q_0^*(p))]$ does not depend on the selection for $q_0^*(p)$ and is equal in particular to $\mathbb{E}_f[R(q, q^{S-T})]$. If firms are risk neutral, we have $C = p^T \cdot \mathbb{E}_f[R(q, \bar{q})]$ and we then obtain from A.2 the fact that the BEC is equal to the cost C plus the term $N\alpha \cdot (1 - \alpha)^{N-1} [p^T \cdot \mathbb{E}_f[R(q, q^{S-T})] - C] = N\alpha \cdot (1 - \alpha)^{N-1} p^T \cdot (\mathbb{E}_f[R(q, q^{S-T})] - \mathbb{E}_f[R(q, \bar{q})])$.

Consider now the case where U is a CRRA utility function and assume that $\mathbb{E}_f[R(q, q_0)] \geq \mathbb{E}_f[R(q, \bar{q})]$ for any $q_0 \in Q_0^*$.

From (A.2) and given that $p_{max} = p^T$, the BEC is strictly smaller than

$$(1 - \alpha)^N \cdot p^T \cdot \mathbb{E}_f[R(q, \bar{q})] + (1 - (1 - \alpha)^N) \cdot p^T \max_{q_0 \in Q_0^*} \mathbb{E}_f[R(q, q_0)] \leq p^T \max_{q_0 \in Q_0^*} \mathbb{E}_f[R(q, q_0)]$$

and where the latter term corresponds to the BEC in an equilibrium under complete information and with a single strategic firm choosing the reference production that maximize the BEC among the (optimal) reports in the set Q_0^* .

From (A.2) and given that $p_{min} > p^S$, the BEC is strictly greater than

$$(1 - \alpha)^N \cdot p^T \cdot \mathbb{E}_f[R(q, \bar{q})] + (1 - (1 - \alpha)^N) \cdot p^S \min_{q_0 \in Q_0^*} \mathbb{E}_f[R(q, q_0)].$$

The BEC is thus strictly greater than the minimum of the BEC with truthful firms ($p^T \cdot \mathbb{E}_f[R(q, \bar{q})]$) and the lowest possible BEC with several strategic firms under complete information (which is reached when the strategic firms choose the reference production that minimize the BEC among the (optimal) reports in the set Q_0^*). **Q.E.D.**

Proof of Proposition 8

In this proof, we do not assume that f is symmetric. We introduce then the notation $q_{min} := \inf\{q \in \mathbb{R}_+ | f(q) > 0\}$ and $q_{max} := \sup\{q \in \mathbb{R}_+ | f(q) > 0\}$. Since f is atomless, then we have $q_{max} > q_{min}$.

Suppose the existence of a payment rule that is homogeneous of degree 1 and such that for $p > 0$ and $q_0^* \in Q_0^*(p)$, the contractor is fully insured against production risk, meaning $\text{Var}_f[R(q, q_0^*)] = 0$ and let us establish a contradiction.

Note first that the payment rule being homogeneous of degree 1 implies that the function $z_{q_0}(\cdot)$ does not depend on q_0 . Below we use then the shortcut notation $z(\cdot)$.

Let $x_{min}^* := \frac{q_{min}}{q_0^*}$ and $x_{max}^* := \frac{q_{max}}{q_0^*}$. Since $q \rightarrow R(q, q_0^*)$ is continuous and nondecreasing, the contractor being fully insured against production risk when reporting q_0^* implies that there exists a constant $k \geq 0$ such that $R(q, q_0^*) = k$ for any realization $q \in [q_{min}, q_{max}]$, and thus that $z(x) = \frac{k}{q_0^*} \frac{1}{x}$, $\forall x \in]x_{min}^*, x_{max}^*[$. Note that $\Pi(p, q_0) > 0$ if q_0 belong to the support of f . We have then $\Pi(p, q_0^*) > 0$ and then $k > 0$.

If the firm reports a reference production $q_0 \geq q_0^*$, then we have that $x_{min}^* q_0 \geq q_{min}$ and the payment rule $q \mapsto R(q, q_0)$ is flat in the interval $]q_0 x_{min}^*, q_0 x_{max}^*[$ where it is equal to $k \cdot \frac{q_0}{q_0^*}$. For $q_0 \in [q_0^*, \frac{q_{max}}{q_{min}} q_0^*]$, the contractor's expected payoff is then given by:

$$\begin{aligned} \Pi(p, q_0) &= \int_{q_{min}}^{q_{max}} U \left(pqz\left(\frac{q}{q_0}\right) \right) dF(q) \\ &= \int_{q_{min}}^{x_{min}^* q_0} U \left(pqz\left(\frac{q}{q_0}\right) \right) dF(q) + \int_{x_{min}^* q_0}^{q_{max}} U \left(pk \frac{q_0}{q_0^*} \right) dF(q) \\ &= \int_{q_0^*}^{q_0} U \left(px_{min}^* q' \cdot z\left(x_{min}^* \frac{q'}{q_0}\right) \right) f(x_{min}^* q') x_{min}^* dq' + U \left(pk \frac{q_0}{q_0^*} \right) [1 - F(x_{min}^* q_0)] \end{aligned} \tag{A.3}$$

Since the function $q \mapsto R(q, q_0)$ is assumed to be continuous and non-decreasing, it is differentiable almost everywhere. As $z(x) = R(x \cdot q_0, q_0)/x \cdot q_0$ (for any $q_0 > 0$), the function z is also differentiable almost everywhere in \mathbb{R}_+ and let $z'(x)$ denote the corresponding derivative when it exists and let us adopt the convention $z'(x) = 0$ otherwise. Recall also that U is assumed to be differentiable and that F is an atomless CDF and is thus semi-differentiable. Let us adopt below the convention that f correspond to its right-derivative.

From (A.3), we then obtain the fact that the function $q_0 \mapsto \Pi(p, q_0)$ is semi-differentiable on the interval $[q_0^*, \frac{q_{max}}{q_{min}} q_0^*]$ and we have then the following expression for the right derivative:

$$\begin{aligned}
& U(px_{min}^*q_0 \cdot z(x_{min}^*))x_{min}^*f(x_{min}^*q_0) \\
& - \int_{q_0^*}^{q_0} p[x_{min}^*\frac{q'}{q_0}]^2 \cdot z'(x_{min}^*\frac{q'}{q_0})U'(px_{min}^*q' \cdot z(x_{min}^*\frac{q'}{q_0}))f(x_{min}^*q')x_{min}^*dq' \quad (A.4) \\
& + \frac{pk}{q_0^*}U'(pk\frac{q_0}{q_0^*})[1 - F(x_{min}^*q_0)] - U(pk\frac{q_0}{q_0^*})x_{min}^*f(x_{min}^*q_0)
\end{aligned}$$

At the limit $q_0 = q_0^*$, (A.4) simplifies (the integral vanishes and $F(x_{min}^*q_0^*) = 0$) and the right derivative of $q_0 \mapsto \Pi(p, q_0)$ is then equal to

$$\frac{pk}{q_0^*}U'(pk) + [U(px_{min}^*q_0^*z(x_{min}^*)) - U(pk)]x_{min}^*f(x_{min}^*q_0^*) = \frac{pk}{q_0^*}U'(pk) > 0$$

since by continuity of $q \mapsto R(q, q_0^*)$ at $q = q_{min} = x_{min}^*q_0^*$, we have $x_{min}^*q_0^*z(x_{min}^*) = k$. Therefore, starting from the reference production q_0^* , the contractor would strictly increase its expected payoff by increasing slightly its reference production, which stands in contradiction with $q_0^* \in Q_0^*(p)$. **Q.E.D.**

A.3 Supplementary appendix

A.3.1 Additional proofs of theoretical results

Proof of Lemma 1

"Only if" part For a given $q_0 > 0$ and a given $\epsilon \in]0, 1]$, let $f_{q_0, \epsilon}^*$ denote the uniform distribution on the interval $[q_0(1 - \epsilon), q_0(1 + \epsilon)]$. We have that $f_{q_0, \epsilon}^* \in \mathcal{F}_{sp}$ and that $\bar{q} = q_0$.

Applying Definition 1 to the contract price $p = 1$ and when U is linear, we have that :

$$\begin{aligned} q_0 &= \mathbb{E}_{f_{q_0, \epsilon}^*}[q] = \mathbb{E}_{f_{q_0, \epsilon}^*}\left[q \cdot z_{q_0}\left(\frac{q}{q_0}\right)\right] \\ &= \int_{q_0(1-\epsilon)}^{q_0(1+\epsilon)} q \cdot z_{q_0}\left(\frac{q}{q_0}\right) \cdot \frac{dq}{2q_0\epsilon} = \frac{q_0}{2\epsilon} \int_{-\epsilon}^{\epsilon} (1+t) \cdot z_{q_0}(1+t) dt. \end{aligned}$$

We then obtain the fact that $\int_0^\epsilon [(1+t) \cdot z_{q_0}(1+t) + (1-t) \cdot z_{q_0}(1-t)] dt = 2\epsilon$ for any $\epsilon \in [0, 1[$. The left-hand side of this latter equation has a derivative (w.r.t. ϵ) almost everywhere in the interval $[0, 1]$ and which is equal to $(1+\epsilon) \cdot z_{q_0}(1+\epsilon) + (1-\epsilon) \cdot z_{q_0}(1-\epsilon)$, and which should thus be equal to the derivative of the right-hand side. Since the function $z_{q_0}(\cdot)$ is continuous (because the function $q \rightarrow R(q, q_0)$ is assumed to be continuous), we obtain that

$$(1 + \epsilon) \cdot z_{q_0}(1 + \epsilon) + (1 - \epsilon) \cdot z_{q_0}(1 - \epsilon) = 2 \quad (\text{A.5})$$

for any $\epsilon \in [0, 1]$.

In order to show that $z_{q_0}(1 + \epsilon) \leq 1$ for any $\epsilon \in [0, 1]$, let us proceed by contradiction. Suppose on the contrary that $z_{q_0}(1 + \epsilon) > 1$ for some $\epsilon \in [0, 1]$ and let then $\underline{\delta} := \inf\{\epsilon \in [0, 1] \mid z_{q_0}(1 + \epsilon) > 1\}$. Since $z_{q_0}(\cdot)$ is continuous, we have then $\underline{\delta} < 1$ and we can also define $\bar{\delta} \in (\underline{\delta}, 1]$ such that $z_{q_0}(1 + \epsilon) > 1$ for any $\epsilon \in]\underline{\delta}, \bar{\delta}[$. Since $z_{q_0}(\cdot)$ is continuous, we also have $z_{q_0}(1 + \underline{\delta}) = 1$.

Consider then $f_{q_0, \bar{\delta}}^*$ the uniform distribution on $[q_0(1 - \bar{\delta}), q_0(1 + \bar{\delta})]$. Consider a continuous function U such that $U(x) = x$ for $x \leq q_0(1 + \underline{\delta})$ and $U'(q) \in]0, 1[$ being

strictly decreasing for $q > q_0(1 + \underline{\delta})$.⁴ Note that U is then increasing and concave.

Given that the function $q \mapsto q \cdot z_{q_0}(\frac{q}{q_0})$ is non-decreasing and that $z_{q_0}(1 + \underline{\delta}) = 1$ (which implies $z_{q_0}(1 - \underline{\delta}) = 1$ given (A.5)), we have that $q \cdot z_{q_0}(\frac{q}{q_0}) \in [q_0(1 - \underline{\delta}), q_0(1 + \underline{\delta})]$ for any $q \in [q_0(1 - \underline{\delta}), q_0(1 + \underline{\delta})]$. Therefore using that $U(x) = x$ for $x \in [q_0(1 - \underline{\delta}), q_0(1 + \underline{\delta})]$, the symmetry of $f_{q_0, \bar{\delta}}^*$ around q_0 , and making the change of variable $\epsilon = \frac{q}{q_0} - 1$ in (A.5) we obtain:

$$\begin{aligned}
 \int_{q_0(1-\underline{\delta})}^{q_0(1+\underline{\delta})} U(q \cdot z_{q_0}(\frac{q}{q_0})) dF_{q_0, \bar{\delta}}^*(q) &= \int_{q_0(1-\underline{\delta})}^{q_0(1+\underline{\delta})} q \cdot z_{q_0}(\frac{q}{q_0}) dF_{q_0, \bar{\delta}}^*(q) \\
 &= \int_{-\underline{\delta}}^{\underline{\delta}} q_0(1 + \epsilon) \cdot z_{q_0}(1 + \epsilon) dF_{q_0, \bar{\delta}}^*(q_0(1 + \epsilon)) \\
 &= q_0 \int_0^{\underline{\delta}} [(1 + \epsilon) \cdot z_{q_0}(1 + \epsilon) + (1 - \epsilon) \cdot z_{q_0}(1 - \epsilon)] dF_{q_0, \bar{\delta}}^*(q_0(1 + \epsilon)) \\
 &= 2q_0 \cdot [F_{q_0, \bar{\delta}}^*(q_0(1 + \underline{\delta})) - \frac{1}{2}] = q_0 \cdot [F_{q_0, \bar{\delta}}^*(q_0(1 + \underline{\delta})) - F_{q_0, \bar{\delta}}^*(q_0(1 - \underline{\delta}))] \\
 &= \int_{q_0(1-\underline{\delta})}^{q_0(1+\underline{\delta})} q_0 dF_{q_0, \bar{\delta}}^*(q) = \int_{q_0(1-\underline{\delta})}^{q_0(1+\underline{\delta})} q dF_{q_0, \bar{\delta}}^*(q) = \int_{q_0(1-\underline{\delta})}^{q_0(1+\underline{\delta})} U(q) dF_{q_0, \bar{\delta}}^*(q)
 \end{aligned}$$

Note that the first and the last equalities use the assumption that U is linear on $[0, q_0 \cdot (1 + \underline{\delta})]$.

We obtain thus that the difference $\mathbb{E}_{f_{q_0, \bar{\delta}}^*}[U(q)] - \mathbb{E}_{f_{q_0, \bar{\delta}}^*}[U(q \cdot z_{q_0}(\frac{q}{q_0}))]$ resumes to

$$\int_{q_0(1-\bar{\delta})}^{q_0(1-\underline{\delta})} [U(q) - U(q \cdot z_{q_0}(\frac{q}{q_0}))] \frac{dq}{2\bar{\delta}} + \int_{q_0(1+\underline{\delta})}^{q_0(1+\bar{\delta})} [U(q) - U(q \cdot z_{q_0}(\frac{q}{q_0}))] \frac{dq}{2\bar{\delta}}$$

Thanks to the change of variable $\epsilon = 1 - \frac{q}{q_0}$ and $\epsilon = \frac{q}{q_0} - 1$ in the first and second integrals, respectively, we obtain:

$$\mathbb{E}_{f_{q_0, \bar{\delta}}^*}[U(q)] - \mathbb{E}_{f_{q_0, \bar{\delta}}^*}[U(q \cdot z_{q_0}(\frac{q}{q_0}))] = \frac{q_0}{2\bar{\delta}} \int_{\underline{\delta}}^{\bar{\delta}} [U(q_0(1 - \epsilon)) - U(q_0(1 - \epsilon)z_{q_0}(1 - \epsilon))] d\epsilon$$

4. How to build a function U satisfying such properties (which will guarantee then its existence) is left to the reader.

$$+ \frac{q_0}{2\bar{\delta}} \int_{\underline{\delta}}^{\bar{\delta}} [U(q_0(1+\epsilon)) - U(q_0(1+\epsilon)z_{q_0}(1+\epsilon))] d\epsilon. \quad (\text{A.6})$$

Let us show below that in the first (resp. second) integral the function U is applied to values where it is linear (resp. strictly concave).

For $\epsilon \in [\underline{\delta}, \bar{\delta}]$, we have $z_{q_0}(1+\epsilon) \geq 1$. From (A.5), we obtain for any $\epsilon \in [\underline{\delta}, \bar{\delta}]$ that $z_{q_0}(1-\epsilon) \leq 1$, which further implies that $q_0(1-\epsilon)z_{q_0}(1-\epsilon) \leq q_0(1-\epsilon) \leq q_0 \leq q_0(1+\underline{\delta})$. In the first integral, the function U is thus applied only for values below $q_0(1+\underline{\delta})$ where the function U is defined such that $U(x) = x$ for $x \leq q_0(1+\underline{\delta})$. We have thus that $\forall \epsilon \in [\underline{\delta}, \bar{\delta}]$:

$$U(q_0(1-\epsilon)) - U(q_0(1-\epsilon)z_{q_0}(1-\epsilon)) = q_0 \cdot [(1-\epsilon) - (1-\epsilon)z_{q_0}(1-\epsilon)]. \quad (\text{A.7})$$

Since the function $\epsilon \mapsto q_0(1+\epsilon)z_{q_0}(1+\epsilon)$ is non-decreasing and $z_{q_0}(1+\underline{\delta}) = 1$ (from the way we have defined $\underline{\delta}$), then for $\epsilon \in [\underline{\delta}, \bar{\delta}]$, we have that $q_0(1+\epsilon)z_{q_0}(1+\epsilon) \geq q_0(1+\underline{\delta})z_{q_0}(1+\underline{\delta}) = q_0(1+\underline{\delta})$. Besides, we note that $q_0(1+\epsilon) \geq q_0(1+\underline{\delta})$. In the second integral, the function U is thus applied only for values above $q_0(1+\underline{\delta})$ where the function U is concave and with $U'(x) < 1$ (for $x \geq q_0(1+\underline{\delta})$). We have thus that $\forall \epsilon \in (\underline{\delta}, \bar{\delta}]$:

$$\begin{aligned} U(q_0(1+\epsilon)) - U(q_0(1+\epsilon)z_{q_0}(1+\epsilon)) &\geq [q_0(1+\epsilon) - q_0(1+\epsilon)z_{q_0}(1+\epsilon)] \cdot U'(q_0(1+\epsilon)) \\ &> q_0(1+\epsilon) - q_0(1+\epsilon)z_{q_0}(1+\epsilon) \end{aligned} \quad (\text{A.8})$$

Finally, plugging (A.7) and (A.8) into (A.3.1) and using A.5, we obtain:

$$\begin{aligned} \mathbb{E}_{f_{q_0, \bar{\delta}}^*} [U(q)] - \mathbb{E}_{f_{q_0, \bar{\delta}}^*} [U(q \cdot z_{q_0}(\frac{q}{q_0}))] &> \\ \frac{q_0^2}{2\bar{\delta}} \int_{\underline{\delta}}^{\bar{\delta}} \underbrace{[2 - (1-\epsilon)z_{q_0}(1-\epsilon) - (1+\epsilon)z_{q_0}(1+\epsilon)]}_{=0} d\epsilon &= 0 \end{aligned}$$

We have thus shown that $\mathbb{E}_{f_{q_0, \bar{\delta}}^*}[U(q)] > \mathbb{E}_{f_{q_0, \bar{\delta}}^*}[U(q \cdot z_{q_0}(\frac{q}{q_0}))]$, which stands in contradiction with the production-insuring assumption. On the whole we have shown that $z_{q_0}(1 + \epsilon) \leq 1$ for any $\epsilon \in [0, 1]$. From (A.5), we then obtain $z_{q_0}(1 - \epsilon) \leq 1$ for any $\epsilon \in [0, 1]$.

The remaining part of Lemma 1 to be shown is that z_{q_0} can not be equal (uniformly) to one in the neighborhood of one or equivalently (given that we have shown that $z_{q_0}(1 + t) \leq 1$ for $t \in [0, 1]$ and that z_{q_0} is continuous) that for all $\epsilon \in]0, 1]$ we verify $\int_0^\epsilon z_{q_0}(1 + t)dt < \epsilon$. Suppose that $z_{q_0}(t) = 1$ for any $t \in [-\epsilon, \epsilon]$ (with $\epsilon > 0$) and let us establish a contradiction. Consider a strictly concave payoff function U , the contract price $p = 1$ and the uniform distribution $f_{q_0, \epsilon}^*$. Since z_{q_0} is uniformly equal to 1 on the support of $f_{q_0, \epsilon}^*$, then we obtain that $\mathbb{E}_{f_{q_0, \bar{\epsilon}}^*}[U(q)] = \mathbb{E}_{f_{q_0, \bar{\epsilon}}^*}[U(q \cdot z_{q_0}(\frac{q}{q_0}))]$ which stands in contradiction with the production-insuring property.

"If" part

Consider first the case where U is linear. If Eq. (A.5) holds for any $q_0 > 0$ and $\epsilon \in [0, 1]$, then for any contract price p and any symmetric distribution f with expected value \bar{q} (such that the support of f is a subset of $[0, 2\bar{q}]$), using the change of variable $q = \bar{q}(1 + \epsilon)$, we obtain below that Eq. (1.1) stands as an equality (note that it is the first and the last equality that uses that U is linear):

$$\begin{aligned} \mathbb{E}_f[U(pqz_{\bar{q}}(\frac{q}{\bar{q}}))] &= U\left(\mathbb{E}_f[pqz_{\bar{q}}(\frac{q}{\bar{q}})]\right) = U\left(p\bar{q}\int_{-1}^1(1+\epsilon)z_{\bar{q}}(1+\epsilon)f(\bar{q}(1+\epsilon))d\epsilon\right) \\ &= U\left(p\bar{q}\int_0^1[(1+\epsilon)z_{\bar{q}}(1+\epsilon) + (1-\epsilon)z_{\bar{q}}(1-\epsilon)]f(\bar{q}(1+\epsilon))d\epsilon\right) \\ &= U\left(p\bar{q}\underbrace{\int_0^1 2f(\bar{q}(1+\epsilon))d\epsilon}_{=1}\right) = U(p\mathbb{E}_f[q]) = \mathbb{E}_f[U(pq)]. \end{aligned}$$

Let us now consider the case where U is strictly concave. Consider the function $\varphi : \lambda \rightarrow U(p\bar{q}\lambda) + U(p\bar{q}(2 - \lambda))$. If U is strictly concave, then $U'(p\bar{q}\lambda) < U'(p\bar{q}(2 - \lambda))$ as long as $\lambda > 1$. We have thus that $\varphi'(\lambda) = p\bar{q}[U'(p\bar{q}\lambda) - U'(p\bar{q}(2 - \lambda))] < 0$ for $\lambda > 1$.

Moreover, since f is symmetric and given (A.5), we have both following equations

for any function U :

$$\begin{aligned}\mathbb{E}_f[U(p \cdot q)] &= \int_0^1 \overbrace{[U(p \cdot \bar{q}(1 + \epsilon)) + U(p \cdot \bar{q}(1 - \epsilon))]}^{=\varphi(1+\epsilon)} dF(\bar{q}(1 + \epsilon)) \\ \mathbb{E}_f[U(p \cdot q \cdot z_{\bar{q}}(\frac{q}{\bar{q}}))] &= \int_0^1 \overbrace{[U(p \cdot \bar{q}(1 + \epsilon)z_{\bar{q}}(1 + \epsilon)) + U(p \cdot \bar{q}(1 - \epsilon)z_{\bar{q}}(1 - \epsilon))]}^{=\varphi((1+\epsilon)z_{q_0}(1+\epsilon))} dF(\bar{q}(1 + \epsilon))\end{aligned}$$

In addition to (A.5), we also assume that $z_{q_0}(1 + \epsilon) \leq 1$ for any $\epsilon \in [0, 1]$ and that for any $\epsilon' \in]0, 1[$, there exists a subset S of $[0, \epsilon']$ with positive measure such that $z_{q_0}(1 + t) < 1$ for any $t \in S$. Moreover, since $q \mapsto q \cdot z_{q_0}(\frac{q}{q_0})$ is non decreasing, we have $(1 + \epsilon) \cdot z_{q_0}(1 + \epsilon) \geq 1$ for $\epsilon \in [0, 1]$. For any $\epsilon \in [0, 1]$, we have thus $1 \leq (1 + \epsilon)z_{q_0}(1 + \epsilon) \leq 1 + \epsilon \leq 2$.

The function φ is strictly decreasing on $[1, 2]$ and thus on the interval $[(1 + \epsilon)z_{q_0}(1 + \epsilon), 1 + \epsilon]$ for any $\epsilon \in [0, 1]$. Finally we have for any $\epsilon \in [0, 1]$,

$$\varphi((1 + \epsilon)z_{q_0}(1 + \epsilon)) \geq \varphi(1 + \epsilon). \quad (\text{A.9})$$

Furthermore, for any $\epsilon' > 0$, there exists a subset S of $[0, \epsilon']$ with positive measure such that the inequality (A.9) is strict for any $\epsilon \in S$.

Since $f \in \mathcal{F}_{sp}$, then there exists $\epsilon' > 0$ such that the function $\epsilon \rightarrow f(\bar{q}(1 + \epsilon))$ is strictly positive on $[0, \epsilon']$. Therefore, if we integrate the inequality (A.9) which is strict on a positive measure of $[0, \epsilon]$, we obtain the strict inequality:

$$\int_0^1 \varphi((1 + \epsilon)z_{q_0}(1 + \epsilon))dF(\bar{q}(1 + \epsilon)) > \int_0^1 \varphi(1 + \epsilon)dF(\bar{q}(1 + \epsilon))$$

or equivalently $\mathbb{E}_f[U(p \cdot q \cdot z_{\bar{q}}(\frac{q}{\bar{q}}))] > \mathbb{E}_f[U(p \cdot q)]$.

Last, in the remaining case where U is concave, it is straightforward according to the arguments above (it is sufficient to integrate the weak inequality (A.9)) that the inequality (1.1) holds. On the whole, we have established that any payment rule associated with the correction factors $\{z_{q_0}(\cdot)\}_{q_0 > 0}$ is production-insuring.

Comment: when U is concave, note that the inequality (1.1) holds for any symmetric distribution f (even if it is not single-peaked).

Q.E.D.

A.3.2 Section 1.4 – Results for a specific class of payment rules

As a complement to the general results on optimal reporting derived in the case where the contractor is risk neutral, we further study a much more restricted setup to provide some insights about how a risk averse contractor reports its expected production depending on various parameters. The setup considered is as follows:

- The payment rule denoted R_w is parameterized by $w \in]0, 1[$ and is such that $R_w(q, q_0) = q_0$ if $q \in [(1 - w)q_0, (1 + w)q_0]$ and $R_w(q, q_0) = q$ otherwise. In other words, the contractor is perfectly insured and its remuneration depends only on reported expected production q_0 as long as its actual production is no more than $w\%$ away from q_0 . Beyond this interval, the remuneration is the same as under the linear contract.
- The production risk is distributed according to $F \in \mathcal{F}_{sp}$ which admits a continuous PDF f and whose support is $[(1 - \delta)\bar{q}, (1 + \delta)\bar{q}]$ with $\delta \leq w$. A direct consequence of this last restriction is that a truthful contractor would be fully insured: the whole support of its production distribution is included in the area where the payment does not depend on q .

To derive the optimal reporting of q_0 , we consider the contractor's payoff in four separate cases regarding the chosen q_0 which cover all possible reported q_0 (given the assumption $\delta \leq w$):

1. q_0 is such that actual production never falls in the insured range;
2. q_0 is such that actual production always falls in the insured range;
3. q_0 is such that actual production sometimes falls in the insured range, sometimes above;
4. q_0 is such that actual production sometimes falls in the insured range, sometimes below;

Case 1 Actual production never falls in the insured range if q_0 is chosen such that either $(1 + \delta)\bar{q} < (1 - w)q_0$ or $(1 - \delta)\bar{q} > (1 + w)q_0$, i.e., for any q_0 outside the interval $[\frac{1-\delta}{1+w}\bar{q}, \frac{1+\delta}{1-w}\bar{q}]$. For such q_0 , the contractor's expected payoff is $\mathbb{E}_f[U(pR(q, q_0))] = \mathbb{E}_f[U(pq)] \leq U(p\mathbb{E}_f[q]) = U(p\bar{q})$. The last inequality results from the concavity of U and implies that the case 1 never brings a better payoff to the

contractor than truthful reporting.

Case 2 Actual production always fall in the insured range if q_0 is chosen such that $(1-w)q_0 \leq (1-\delta)\bar{q}$ and $(1+w)q_0 \geq (1+\delta)\bar{q}$, i.e., for $q_0 \in [\frac{1+\delta}{1+w}\bar{q}, \frac{1-\delta}{1-w}\bar{q}]$. In this interval, the firm's payoff is $\mathbb{E}_f[U(pR(q, q_0))] = U(pq_0)$, which is then maximized for the highest value of q_0 within this interval: $q_0 = \frac{1-\delta}{1-w}\bar{q} \geq \bar{q}$.

Case 3 This case corresponds to reported expected productions such that the upper bound of the insurance range is within the support of F : $(1-\delta)\bar{q} \leq (1+w)q_0 < (1+\delta)\bar{q}$, or equivalently $q_0 \in [\frac{1-\delta}{1+w}\bar{q}, \frac{1+\delta}{1+w}\bar{q}]$. The contractor's expected payoff can then be expressed as

$$\Pi(p, q_0) = \mathbb{E}_f[U(pR(q, q_0))] = F((1+w)q_0) \cdot U(p \cdot q_0) + \int_{(1+w)q_0}^{(1+\delta)\bar{q}} U(p \cdot q) dF(q).$$

Let us define the distribution F^* from the (atomless) CDF F , by replacing the smooth part on the interval $[(1-\delta)\bar{q}, (1+w)q_0]$ by an atom at q_0 . Formally, $F^*(q) = 0$ for $q < q_0$, $F^*(q) = F((1+w)q_0)$ for $q \in [q_0, (1+w)q_0]$ and $F^*(q) = F(q)$ for $q \geq (1+w)q_0$. Equipped with this definition we have $\Pi(p, q_0) = \mathbb{E}_{f^*}[U(p \cdot q)] \leq U(p \cdot \mathbb{E}_{f^*}[q])$ where the latter inequality comes from the concavity of U . Therefore if we show that $U(p \cdot \mathbb{E}_{f^*}[q]) \leq U(p\bar{q})$ we would have shown that no q_0 in this interval brings a better expected payoff to the contractor than truthfully reporting \bar{q} .

We then want to show for any $q_0 \in [\frac{1-\delta}{1+w}\bar{q}, \frac{1+\delta}{1-w}\bar{q}]$ that $\mathbb{E}_{f^*}[q] \leq \bar{q}$, or equivalently that:

$$\int_{(1-\delta)\bar{q}}^{(1+w)q_0} q dF(q) \geq F((1+w)q_0) \cdot q_0. \quad (\text{A.10})$$

First note that for $q_0 \leq (1-\delta)\bar{q}$, $\int_{(1-\delta)\bar{q}}^{(1+w)q_0} q dF(q) \geq \int_{(1-\delta)\bar{q}}^{(1+w)q_0} q_0 dF(q) = F((1+w)q_0) \cdot q_0$.

Now, supposing $q_0 \geq (1-\delta)\bar{q}$ we can decompose the left-hand side in (A.10) as follows:

$$\int_{(1-\delta)\bar{q}}^{(1+w)q_0} q dF(q) = \int_{(1-\delta)\bar{q}}^{q_0} q dF(q) + \int_{q_0}^{2q_0-(1-\delta)\bar{q}} q dF(q) + \int_{2q_0-(1-\delta)\bar{q}}^{(1+w)q_0} q dF(q) \quad (\text{A.11})$$

$$= \int_0^{q_0-(1-\delta)\bar{q}} [(q_0 - \epsilon) \cdot f(q_0 - \epsilon) + (q_0 + \epsilon) \cdot f(q_0 + \epsilon)] d\epsilon + \int_{2q_0-(1-\delta)\bar{q}}^{(1+w)q_0} q dF(q). \quad (\text{A.12})$$

Where the two first parts of the integral are merged through a change of variable, resp. $\epsilon = q_0 - q$ and $\epsilon = q - q_0$. To characterize this first term in (A.12), consider $\epsilon \in [0, q_0 -$

$(1-\delta)\bar{q}]$ and note that from the symmetry of f around \bar{q} we have $f(q_0 - \epsilon) = f(2\bar{q} - q_0 + \epsilon)$. Moreover, knowing $q_0 < \frac{1+\delta}{1+w}\bar{q} < \bar{q}$ we obtain that $q_0 - \epsilon < q_0 + \epsilon < 2\bar{q} - q_0 + \epsilon$ and therefore since F is single-peaked we know that $f(q_0 - \epsilon) = f(2\bar{q} - q_0 + \epsilon) \leq f(q_0 + \epsilon)$.

Thus we obtain:

$$\begin{aligned} (q_0 - \epsilon) \cdot f(q_0 - \epsilon) + (q_0 + \epsilon) \cdot f(q_0 + \epsilon) &= q_0(f(q_0 - \epsilon) + f(q_0 + \epsilon)) + \epsilon((f(q_0 + \epsilon) - f(q_0 - \epsilon))) \\ &\geq q_0(f(q_0 - \epsilon) + f(q_0 + \epsilon)). \end{aligned}$$

Then, plugging this inequality into (A.12) we obtain:

$$\begin{aligned} \int_{(1-\delta)\bar{q}}^{(1+w)q_0} q dF(q) &\geq q_0 \underbrace{\int_0^{q_0 - (1-\delta)\bar{q}} (f(q_0 - \epsilon) + f(q_0 + \epsilon)) d\epsilon}_{= \int_{(1-\delta)\bar{q}}^{2q_0 - (1-\delta)\bar{q}} f(q) dq} + \underbrace{\int_{2q_0 - (1-\delta)\bar{q}}^{(1+w)q_0} q dF(q)}_{\geq q_0 \int_{2q_0 - (1-\delta)\bar{q}}^{(1+w)q_0} f(q) dq} \\ &\geq q_0 \int_{(1-\delta)\bar{q}}^{(1+w)q_0} f(q) dq = F((1+w)q_0) \cdot q_0 \end{aligned}$$

We have then establish the inequality (A.10), which implies (as detailed above) that no $q_0 \in [\frac{1-\delta}{1+w}\bar{q}, \frac{1+\delta}{1-w}\bar{q}]$ brings a better payoff to the contractor than reporting truthfully \bar{q} .

Case 4 This case corresponds to reported expected productions such that the lower bound of the insurance range is within the support of F : $(1-\delta)\bar{q} < (1-w)q_0 \leq (1+\delta)\bar{q}$, or equivalently $q_0 \in]\frac{1-\delta}{1-w}\bar{q}, \frac{1+\delta}{1-w}\bar{q}]$. We have already shown through the three previous cases that $q_0 = \frac{1-\delta}{1-w}\bar{q}$ brings a better payoff than any other $q_0 \notin [\frac{1-\delta}{1-w}\bar{q}, \frac{1+\delta}{1-w}\bar{q}]$, therefore the (globally) optimal report of expected production necessarily lies within the present interval.

The contractor's expected payoff on this interval and its derivative are expressed as:

$$\Pi(p, q_0) = \int_{(1-\delta)\bar{q}}^{(1-w)q_0} U(p \cdot q) dF(q) + (1 - F((1-w)q_0)) \cdot U(p \cdot q_0)$$

And its derivative with respect to q_0 is:

$$\frac{\partial \Pi(p, q_0)}{\partial q_0} = (1-w) [U((1-w)pq_0) - U(pq_0)] f((1-w)q_0) + (1 - F((1-w)q_0)) p U'(pq_0) \quad (\text{A.13})$$

$$= p \cdot U'(pq_0) f((1-w)q_0) \left[\frac{1 - F((1-w)q_0)}{f((1-w)q_0)} - \frac{1-w}{p} \cdot \frac{U(pq_0) - U(p(1-w)q_0)}{U'(pq_0)} \right] \quad (\text{A.14})$$

Note that since $U'(pq_0) f((1-w)q_0) > 0$, $\frac{\partial \Pi(p, q_0)}{\partial q_0}$ has the same sign as the term in brackets in (A.14), that we further denote $M(q_0)$. Then, any interior optimum within this interval q_0^* must satisfy the FOC:

$$M(q_0^*) \equiv \frac{1 - F((1-w)q_0^*)}{f((1-w)q_0^*)} - \frac{(1-w)}{p} \cdot \frac{U(pq_0^*) - U(p(1-w)q_0^*)}{U'(pq_0^*)} = 0 \quad (\text{A.15})$$

Note that we know from the previous cases that if $\delta < w$, then reporting the lower bound of the interval $\frac{(1-\delta)}{1-w} \bar{q}$ brings a strictly better payoff to the contractor than the upper bound (the latter raising the same payoff as a linear contract, i.e., $\mathbb{E}_f[U(pq)]$). The latter is therefore ruled out as a global optimum.

Finally, if $\delta < w$, any optimal reporting $q_0^* \in Q_0^*(p)$ satisfies either $q_0^* = \frac{1-\delta}{1-w} \bar{q}$ or the first order condition (A.15). The set $Q_0^*(p)$ can be further characterized when assuming:

- The distribution F is such that the function $q \mapsto \frac{1-F(q)}{f(q)}$ is continuously decreasing.⁵
- The PDF f is continuous on \mathbb{R}_+ , or to put it otherwise the distribution F is vanishing at the bounds of its support: $\lim_{q \rightarrow (1-\delta)\bar{q}} f(q) = 0$.

Let us first consider the case of a risk neutral contractor. In such a case, we use the notation $M^{RN}(q_0)$ for the function $M(q_0) = \frac{\partial \Pi(p, q_0)}{\partial q_0}$. If U is linear, then

5. This assumption is stronger than most often needed, in order to cover any potential value taken by w : we actually only need the function $M(q_0)$ defined in Eq. (A.15) to be continuously decreasing in q_0 on the interval $] \frac{1-\delta}{1-w} \bar{q}, \frac{1+\delta}{1-w} \bar{q} [$.

$U(pq_0) - U(p(1-w)q_0) = wpq_0U'(pq_0)$ and we have consequently:

$$M^{RN}(q_0) = \frac{1 - F((1-w)q_0)}{f((1-w)q_0)} - (1-w)wq_0.$$

From the first assumption above, $M^{RN}(q_0)$ is decreasing in q_0 for any $w \in]0, 1[$, and therefore $M^{RN}(q_0^*) = 0$ admits at most one solution. Moreover, since F is symmetric and single peaked we have that $f(\bar{q}) \geq \frac{1}{2\delta\bar{q}}$. Therefore:

$$M^{RN}\left(\frac{1}{1-w}\bar{q}\right) = \frac{1 - F(\bar{q})}{f(\bar{q})} - w\bar{q} \leq \bar{q}(\delta - w) < 0.$$

Then there is a unique global optimal which necessarily belongs to the interval $] \frac{1-\delta}{1-w}\bar{q}, \frac{1}{1-w}\bar{q} [$. This optimum denoted next q_0^{RN} is characterized as the solution of $M^{RN}(q_0^{RN}) = 0$ and thus does not depend on p .

In the general case, for any risk averse contractor with the concave utility function U , we have $U(pq_0) - U(p(1-w)q_0) \geq wpq_0U'(pq_0)$ and therefore that $M(q_0) \leq M^{RN}(q_0)$ for any q_0 . If $q_0 > q_0^{RN}$, then $M(q_0) \leq M^{RN}(q_0) < 0$ which implies that $q_0^* \notin Q_0^*(p)$. Overall, for any concave utility function U , any optimum $q_0^* \in Q_0^*(p)$ is below the optimum with a risk neutral contractor: $q_0^* < q_0^{RN}$. In other words, any risk averse strategic contractor always overestimate its production less than a risk neutral strategic contractor.

In addition, note that the second assumption above (the continuity of f) implies that $\lim_{q_0 \rightarrow \frac{1-\delta}{1-w}\bar{q}} \frac{1 - F((1-w)q_0)}{f((1-w)q_0)} = +\infty$ which further implies that:

$$\lim_{q_0 \rightarrow \frac{1-\delta}{1-w}\bar{q}} M(q_0) = +\infty$$

and therefore that the derivative of the contractor's payoff is positive (and infinite) at the lower bound $\frac{1-\delta}{1-w}\bar{q}$. The potential corner solution $q_0^* = \frac{1-\delta}{1-w}\bar{q}$ is then ruled out and any global optimum necessarily satisfies $M(q_0^*) = 0$.

Last, we assume the contractor's utility function is a CRRA utility function. The

first order condition (A.15) simplifies to:

$$M_F(q_0^*; w, \gamma) \equiv \frac{1 - F((1-w)q_0^*)}{f((1-w)q_0^*)} - (1-w)q_0^* \cdot K(w, \gamma) = 0 \quad (\text{A.16})$$

where $K(w, \gamma) = \frac{1-(1-w)^{1-\gamma}}{1-\gamma}$. Note that $\forall \gamma \neq 1$, $K(0, \gamma) = 0$ and $\frac{\partial K(w, \gamma)}{\partial w} = \frac{1}{(1-w)^\gamma} > 0$, therefore $\forall (w, \gamma) \quad K(w, \gamma) \geq 0$. Moreover $\frac{1-F(q)}{f(q)}$ is strictly decreasing on $] (1-\delta)\bar{q}, \bar{q}[$, then $M_F(\cdot; w, \gamma)$ is strictly decreasing as well. Then Eq. (A.16) admits a single solution on this interval. Overall, we obtain that $Q_0^*(p)$ is a singleton and does not depend on p . Let q_0^* denote the global optimum.

We now are able to derive the following comparative statics on q_0^* from (A.16):

1. $K(w, \gamma)$ is increasing in γ and then $M_F(q_0; w, \gamma)$ is decreasing in γ for every q_0 . Therefore, the optimal report q_0^* decreases with γ : the more risk averse firms are, the less they overestimate their production.
2. Consider two distributions F_1 and F_2 (on the same support), with F_1 less risky than F_2 in the sense that $\forall q \leq \bar{q}$, $\frac{f_1(q)}{1-F_1(q)} < \frac{f_2(q)}{1-F_2(q)}$. Then $M_{F_1}(q_0; w, \gamma) > M_{F_2}(q_0; w, \gamma)$ for any $q_0 \in] \frac{1-\delta}{1-w}\bar{q}, \frac{1}{1-w}\bar{q}[$ (the interval where the optima are to be found), and consequently the solution to $M_{F_1}(q_0; w, \gamma) = 0$ is larger than the solution to $M_{F_2}(q_0; w, \gamma) = 0$: if production is less risky, then firms overestimate more their expected production.
3. Assuming $\gamma \geq 1$, $K(w, \gamma)$ is non-increasing in w , and therefore $(1-w)q_0 \cdot K(w, \gamma)$ is strictly decreasing in w . In addition, since $\frac{1-F(q)}{f(q)}$ is decreasing on $] (1-\delta)\bar{q}, \bar{q}[$, we also have $\frac{1-F((1-w)q_0)}{f((1-w)q_0)}$ decreasing in w for $q_0 \in] \frac{1-\delta}{1-w}\bar{q}, \frac{1}{1-w}\bar{q}[$. Then $M_F(q_0; w, \gamma)$ is strictly decreasing in w on the interval containing q_0^* , and therefore the greater is w the greater is the solution to (A.15): the larger the insurance range is, the more firms overestimate their production if $\gamma \geq 1$.

A.3.3 Section 1.5 – The zero surplus condition when firms are homogeneous

To simplify the arguments, below we consider implicitly symmetric equilibria and that ties are resolved randomly with equal probabilities.⁶ Nevertheless, we do not exclude equilibria in mixed strategies.

Let $S_p \subseteq R_+$ denote the support of the price bid of a firm characterizing a (possibly mixed) equilibrium, i.e., the set such that in equilibrium firms are indifferent between any bid $p \in S_p$. Let \bar{p} denote the upper bound of S_p , with $\bar{p} > 0$. Suppose that there exists an equilibrium where firms' expected payoff π^* , raised by any bid $p \in S_p$, is strictly greater than $U(C)$. Let $P(b)$ denote the probability to win with the price bid p .

Assume the firm's payoff (conditional on winning) is continuous in p . Then the equilibrium strategy could not have any atom: slightly undercutting such an atom would incur a discrete positive change in the probability of winning but a negligible change in the firm's payoff conditional on winning (and such that it remains strictly superior to $U(C)$), and therefore lead to a strict increase in the firm's expected payoff. In the absence of any atom in the equilibrium strategy, $p \mapsto P(p)$ is continuous and we cannot have $P(\bar{p}) = 0$, because otherwise the expected payoff raised by some equilibrium bid in the neighborhood of \bar{p} would be strictly lower than π^* (it would converge to zero as p tends to \bar{p}) which would raise a contradiction. So we must have $P(\bar{p}) > 0$, which is possible only if opponents bid \bar{p} with a strictly positive probability. Thus we have an atom at \bar{p} which raises a contradiction as argued above.

On the whole, we have shown that bidders' expected payoff cannot be strictly superior to and then should be equal to $U(C)$ (the payoff when losing the auction) in equilibrium with homogeneous bidders. Furthermore, we show below that there is a single price bid that is consistent with zero surplus, both under the "all truthful" and the "all strategic" paradigms. In other words, the set S_p is a singleton.

All truthful paradigm On the one hand, the function U is (strictly) increasing and concave and so we have $U'(x) > 0$ for any x . On the other hand $q \mapsto R(q, \bar{q})$ is

6. The zero surplus condition extends to asymmetric ones. In particular, there exists asymmetric equilibria where two firms bid competitively while other firms submit non-competitive offers.

continuously non-decreasing with $R(\bar{q}, \bar{q}) = \bar{q} > 0$ so that $R(q, \bar{q}) > 0$ on a positive measure of the support of f . Therefore the function $p \mapsto \mathbb{E}_f[U(p \cdot R(q, \bar{q}))]$ is strictly increasing. Furthermore, the function $p \mapsto \mathbb{E}_f[U(p \cdot R(q, \bar{q}))]$ is continuous and is equal to $U(0)$ for $p = 0$ and goes to infinity when p goes to infinity. The zero surplus condition $\mathbb{E}_f[U(p \cdot R(q, \bar{q}))] = U(C)$ has thus a solution which is unique.

All strategic paradigm Let us show below that the function $H : \mathbb{R}_+ \mapsto \mathbb{R}_+$ defined by $H(p) := \max_{q_0 \geq 0} \mathbb{E}_f[U(p \cdot R(q, q_0))]$ is strictly increasing on \mathbb{R}_+ . This function is well-defined since we have assumed that the sets $\mathcal{Q}_0^*(p)$ are non-empty for any $p > 0$. As in the previous case with truthful bidders, the function $q \mapsto R(q, \bar{q})$ is strictly positive on a positive measure of the support of f . This property hold then for the function $q \mapsto R(q, q_0^*(p))$ where $q_0^*(p) \in \mathcal{Q}_0^*(p)$ (because if $R(q, q_0^*(p)) = 0$ almost everywhere on the support of f , then the firm would raise its expected payoff by reporting \bar{q} instead of $q_0^*(p)$ which would raise a contradiction). Take $p' > p > 0$. We have then $\mathbb{E}_f[U(p' \cdot R(q, q_0^*(p)))] > \mathbb{E}_f[U(p \cdot R(q, q_0^*(p)))]$. Then from the optimality of $q_0^*(p')$ when the price bid is p' , we have $\mathbb{E}_f[U(p' \cdot R(q, q_0^*(p')))] \geq \mathbb{E}_f[U(p' \cdot R(q, q_0^*(p)))]$. We have thus shown that H is (strictly) increasing on \mathbb{R}_+ .

Furthermore, H is continuous (since it is a maximum of continuous functions) and is equal to $U(0)$ for $p = 0$ and goes to infinity when p goes to infinity.⁷ The zero surplus condition $H(p) = U(C)$ has thus a solution which is unique.

A.3.4 Properties with CRRA utility functions

For a given payment rule $R(., .)$ and a given utility function U , let us use the notation $Q_f^*(p) := \text{Arg max}_{q_0 \geq 0} \mathbb{E}_f[U(p \cdot R(q, q_0))]$. For a set $S \subseteq \mathbb{R}$ and $\lambda \in \mathbb{R}$, we let $\lambda \times S := \{x \in \mathbb{R} | \exists s \in S \text{ such that } \lambda \cdot s = x\}$.

For a given production distribution f (with the corresponding CDF F) and $\lambda > 0$, we let denote $f_\lambda(.)$ the PDF (with the corresponding CDF F_λ) such that $f_\lambda(q) = \lambda \cdot f(\lambda \cdot q)$ (or equivalently $F_\lambda(q) = F(\lambda \cdot q)$) for any $q \in \mathbb{R}_+$. The distribution f_λ corresponds to a homothetic transformation of the distribution f . The mean of f_λ is then equal to $\frac{\bar{q}}{\lambda}$.

⁷. We have that $\mathbb{E}_f[U(p \cdot R(q, \bar{q}))]$ goes to infinity when p goes to infinity, while the optimality of $q_0^*(p)$ implies that $H(p) \geq \mathbb{E}_f[U(p \cdot R(q, \bar{q}))]$ for any p .

Let BEC_f^T , BEC_f^S and BEC_f^{S-T} denote the BEC in the paradigms where all firms are truthful, all firms are strategic and a single firm is strategic while the other firms are truthful, respectively. We have that $BEC_f^T = p^T \cdot \mathbb{E}_f[R(q, \bar{q})]$. When all firms are strategic (resp. one firm is strategic while the others are truthful), the BEC in equilibrium depends implicitly on how the optimal report is selected in the set $Q_f^*(p^S)$ (resp. $Q_f^*(p^T)$). Next we let $q^S(f) \in Q_f^*(p^S)$ (resp. $q^{N-S}(f) \in Q_f^*(p^T)$) the corresponding selection such that $BEC_f^S = p^S \cdot \mathbb{E}_f[R(q, q^S)]$ (resp. $BEC_f^{S-T} = p^T \cdot \mathbb{E}_f[R(q, q^{S-T})]$).

Lemma 10. *Suppose that the utility function U is a CRRA utility function and consider a production distribution f on \mathbb{R}_+ .*

1. *Then the set $Q_f^*(p)$ does not depend on p for any $p > 0$ and there is thus a selection rule such that neither $q^S(f)$, $q^{S-T}(f)$, $\frac{p^T}{C}$, $\frac{p^S}{C}$ nor the performance ratios $\frac{BEC_f^k}{C}$, $k = T, S, S - T$, depend on C .*
2. *If the payment rule R is homogeneous of degree 1, then $Q_{f_\lambda}^*(p) = \frac{1}{\lambda} \times Q_f^*(p)$ for any $p, \lambda > 0$ and there is thus a selection rule such that neither $\lambda \cdot q^S(f_\lambda)$, $q^{S-T}(f_\lambda)$, $\frac{p^T}{\lambda}$, $\frac{p^S}{\lambda}$ nor the performance ratios $\frac{BEC_f^k}{C}$, $k = T, S, S - T$, depend on λ .*

Lemma 10 involves various ratios between the BEC and the producer's cost. Lemma 10 says that those (performance) ratios depend neither on C nor on λ under various bidding paradigms: This non-dependence holds when all firms are truthful, when all firms are strategic and also if a single firm is strategic while its competitors are truthful. In particular, in the two first cases where firms are homogeneous, it means that risk premiums does not depend on C and λ . In the third case, the ratio capture both a risk premium and a non-competitive rent.

Proof of Lemma 10

If U is a CRRA utility function, then $U(p \cdot R(q, q_0)) = p^{1-\gamma} \cdot U(R(q, q_0))$. For any $p > 0$, we have then $Q_f^*(p) = Q_f^*(1)$.

Let us now consider the ratios between the cost for the buyer and the cost for the firm under our various bidding paradigms. With a CRRA utility function, (1.2) and (1.3) can be rewritten respectively as

$$\left(\frac{p^T}{C}\right)^{1-\gamma} \cdot \mathbb{E}_f[U(R(q, \bar{q}))] = 1$$

and

$$\left(\frac{p^S}{C}\right)^{1-\gamma} \cdot \mathbb{E}_f[U(R(q, q^S(f)))] = 1$$

with $q^S(f) \in Q_f^*(p^S) = Q_f^*(1)$ where the set $Q_f^*(1)$ does not depend on C . Next we pick a selection rule such that $q^S(f)$ does not depend on C .

We obtain that the ratios $\frac{p^T}{C}$ and $\frac{p^S}{C}$ do not depend on C and finally that the ratios $\frac{BEC_f^k}{C}$, $k = T, S, S - T$ do not depend on C . We have show part 1.

Consider now that R is homogeneous of degree 1. We have then $\mathbb{E}_{f_\lambda}[U(p \cdot R(q, q_0))] = \int_0^\infty U(p \cdot R(q, q_0)) f_\lambda(q) dq = \int_0^\infty U(p \cdot R(q, q_0)) f(\lambda q) d(\lambda q) = \int_0^\infty U(p \cdot R(\frac{q}{\lambda}, q_0)) f(q) dq = \mathbb{E}_f[U(p \cdot R(\frac{q}{\lambda}, \lambda \cdot \frac{q_0}{\lambda})] = \frac{1}{\lambda^{1-\gamma}} \cdot \mathbb{E}_f[U(p \cdot R(q, \lambda q_0))]$ where the last equality uses the homogeneity of degree 1 assumption and that U is a CRRA utility function. Since $\mathbb{E}_{f_\lambda}[U(p \cdot R(q, q_0))] = \frac{1}{\lambda^{1-\gamma}} \cdot \mathbb{E}_f[U(p \cdot R(q, \lambda \cdot q_0))]$, we then obtain $Q_f^*(p) = \lambda \times Q_{f_\lambda}^*(p)$.

Let us show that the equilibrium prices p^T and p^S are linear in λ . Below we explicit in our notation the dependence in λ and in particular use the notation \bar{q}_λ (for the mean of f_λ) and p_λ^T and p_λ^S (for the equilibrium prices for f_λ). According to our notation, we have thus $\bar{q}_\lambda = \frac{\bar{q}}{\lambda}$, $p^T = p_1^T$ and $p^S = p_1^S$. Since $Q_f^*(p) = \lambda \times Q_{f_\lambda}^*(p)$ (for any $\lambda > 0$), for any given $p > 0$ and given f , we can pick a selection $q_\lambda^*(p)$ in the sets $Q_{f_\lambda}^*(p)$ such that $q_\lambda^*(p) = \frac{q^*(p)}{\lambda}$. Next we have $q^S(f_\lambda) = q_\lambda^*(p_\lambda^S)$ and $q^S(f) = q_\lambda^*(p_\lambda^S)$.

If we apply (1.2) for both f and f_λ , we obtain that for any λ :

$$\mathbb{E}_f[U(p^T \cdot R(q, \bar{q})] = U(C) = \mathbb{E}_{f_\lambda}[U(p_\lambda^T \cdot R(q, \bar{q}_\lambda))] = \mathbb{E}_f[U(p_\lambda^T \cdot R(\frac{q}{\lambda}, \frac{\bar{q}}{\lambda})] = \mathbb{E}_f[U(\frac{p_\lambda^T}{\lambda} \cdot R(q, \bar{q})].$$

The equality $\mathbb{E}_f[U(p^T \cdot R(q, \bar{q})] = \mathbb{E}_f[U(\frac{p_\lambda^T}{\lambda} \cdot R(q, \bar{q})]$ implies then that $p_\lambda^T = \lambda \cdot p^T$.

Similarly, if we apply (1.3) for both f and f_λ , we obtain that for any λ :

$$U(C) = \mathbb{E}_{f_\lambda}[U(p_\lambda^S \cdot R(q, q_{0,\lambda}^*(p_\lambda^S)))] = \mathbb{E}_f[U(p_\lambda^S \cdot R(\frac{q}{\lambda}, \frac{q_0^*(p_\lambda^S)}{\lambda})] = \mathbb{E}_f[U(\frac{p_\lambda^S}{\lambda} \cdot R(q, q_0^*(p_\lambda^S)))]$$

and

$$U(C) = \mathbb{E}_f[U(p^S \cdot R(q, q_0^*(p^S)))] = \mathbb{E}_f[U(p^S \cdot R(q, q_0^*(p_\lambda^S)))]$$

where the last equality comes from the fact that $q_0^*(p^S) = q_0^*(p_\lambda^S)$ because the optimal report $q_0^*(p)$ does not depend on p . Finally, this implies that $p_\lambda^S = \lambda \cdot p^S$.

We conclude the proof by noting that the buyer's expected cost can be written expressed in the following way in the three bidding paradigms:

- $p_\lambda^T \cdot \mathbb{E}_{f_\lambda}[R(q, \bar{q}_\lambda)] = p_\lambda^T \cdot \mathbb{E}_f[R(\frac{q}{\lambda}, \frac{\bar{q}}{\lambda})] = p^T \cdot \mathbb{E}_f[R(q, \bar{q})]$ if all firms are truthful,
- $p_\lambda^S \cdot \mathbb{E}_{f_\lambda}[R(q, q_{0,\lambda}^*(p_\lambda^S))] = p_\lambda^S \cdot \mathbb{E}_f[R(\frac{q}{\lambda}, \frac{q_0^*(p_\lambda^S)}{\lambda})] = p^S \cdot \mathbb{E}_f[R(q, q_0^*(p_\lambda^S))] = p^S \cdot \mathbb{E}_f[R(q, q_0^*(p^S))]$ (the last equality results from the fact that $q_0^*(p)$ is independent of p), if all firms are strategic,
- $p_\lambda^T \cdot \mathbb{E}_{f_\lambda}[R(q, q_{0,\lambda}^*(p_\lambda^T))] = p_\lambda^T \cdot \mathbb{E}_f[R(\frac{q}{\lambda}, \frac{q_0^*(p_\lambda^T)}{\lambda})] = p^T \cdot \mathbb{E}_f[R(q, q_0^*(p_\lambda^T))] = p^T \cdot \mathbb{E}_f[R(q, q_0^*(p^T))]$ (the last equality results from the fact that $q_0^*(p)$ is independent of p), if a single firm is strategic while the other firms are truthful.

Q.E.D.

Remark: Under the multi-year contracts used in France and in presence of operating costs, we could extend Lemma 10.

Formally, let us denote the producer's total (discounted) cost over the life time of the plant by $TC := IC + \sum_{t=1}^{20} \frac{OC}{(1+r)^t}$. Let us generalize the definition of BEC_f^k , for the bidding paradigm $k = NS, S, S - T$, to our multi-period setup. BEC_f^k corresponds then to the expected (discounted) total subsidy paid by the buyer to the contractor in the paradigm k . We have e.g. that $BEC_f^T = \sum_{t=1}^{20} \frac{p^T \cdot \mathbb{E}_{f_\lambda}[R(q, \bar{q})]}{(1+r)^t}$.

Lemma 10 extends to this framework in the following way:

If the utility function U is a CRRA utility function, then the set of optimal reports $q_0^*(p)$ remains the same if we simultaneous multiply the price bid p and the operation cost OC by the same constant.

Then the ratios $\frac{BEC_f^k}{TC}$, for $k = S, NS, S - T$ remain the same if we multiply both the investment cost and the operation costs by the same constant.⁸ Note that if the investment and operation costs are multiplied by different constants, then there would

8. If this constant is equal to $\alpha > 0$, then there exists an equilibrium (in the three paradigms we consider) where the corresponding equilibrium price is multiplied by α and the optimal report remains unchanged.

be a wealth effect that would complicate the analysis.

Last, if we also assume that the payment rule $R(.,.)$ is homogeneous of degree 1, then the ratios $\frac{BEC_f^k}{TC}$, for $k = S, NS, S - T$ remain the same after a homothetic transformation of the distribution f , i.e., does not depend on λ .

A.3.5 Section 1.5 – Example 1

Let us build a production-insuring rule $R(.,.)$ and a distribution f such that the cost to the buyer under truthful reporting is greater than under strategic reporting.

Take $\epsilon \in (0, 1)$. For each $q_0 > 0$, let us define the function $R(., q_0) : \mathbb{R}_+ \rightarrow \mathbb{R}_+$ recursively in the following way: for $q \in [\frac{5}{6}q_0, \frac{7}{6}q_0]$, we let $R(q, q_0) := q_0 + (1 - \epsilon) \cdot (q - q_0)$ so that payment is almost equivalent to the linear contract for ϵ small, but with a slightly smaller slope; for $q \in [(\frac{1}{2} + \epsilon)q_0, \frac{5}{6}q_0[$ we let $R(q, q_0) := R(\frac{5}{6}q_0, q_0)$, for $q \in [\frac{7}{6}q_0, (\frac{3}{2} - \epsilon)q_0]$ we let $R(q, q_0) := R(\frac{7}{6}q_0, q_0)$ so that payment is flat in these two intervals; for $q \in [0, \frac{1}{2}q_0[$ and for $q \geq \frac{3}{2}q_0$ we let $R(q, q_0) := q$, then the payment is equivalent to the linear contract on these intervals; finally we define $R(.,.)$ in $[\frac{1}{2}q_0, (\frac{1}{2} + \epsilon)q_0[$ and in $[(\frac{3}{2} - \epsilon)q_0, \frac{3}{2}q_0[$ so that payment is continuous in q : on the first segment $R(q, q_0) := q(\frac{1}{3\epsilon} + \frac{1}{6}) + q_0(\frac{5}{12} - \frac{1}{6\epsilon})$, and on the second segment $R(q, q_0) := q(\frac{1}{3\epsilon} + \frac{1}{6}) + q_0(\frac{5}{4} - \frac{1}{2\epsilon})$.

For the distribution f , take the uniform distribution on $[1 - \delta, 1 + \delta]$ where $\delta < \frac{1}{6}$. Under truthful reporting, we have that the equilibrium price p^T is characterized by $\int_{1-\delta}^{1+\delta} U(p^T \cdot (1 - \epsilon)q) = U(C)$. Under strategic reporting, we have that the firm overestimates its production by reporting $q^* > \bar{q}$ in order to benefit from the payment being largely inflated in lower flat areas.

Through simulations with $\delta = 1/6$, a CRRA utility function with $\gamma = 1$ and $\epsilon = 0.01$, we find the optimal reporting of q_0 being 1.6605. For such reporting, the lower bound of the distribution (relative to the average realization \bar{q}), $1 - \delta$, is slightly below $1/2$ (0.044), while the upper bound is slightly below $5/6$ (0.77). Then most of the support of the distribution stands on the flat part of the payment rule, which results in a smaller risk premium. With the firm's cost being 1, the buyer's expected cost drops from 1.0045 when firms are truthful to 1.0009 when firms are strategic.

A.3.6 Model with moral hazard

We know from Proposition 2 that $q_0 < \bar{q}$ implies that $\mathbb{E}_{f_{\bar{q}}}[R(q, q_0)] \leq \bar{q}$ if $R(\cdot, \cdot)$ is production-insuring. For any $p > 0$, if the buyer sets a reference production $q_0 \geq [C']^{-1}(p)$ (or equivalently $p \leq C'(q_0)$ since C is convex), i.e. the optimal level of effort for the contractor under the linear contract, then for any $\bar{q} > q_0$, we have

$$p \cdot (\mathbb{E}_{f_{\bar{q}}}[R(q, q_0)] - q_0) \leq p(\bar{q} - q_0) \leq C'(q_0)(\bar{q} - q_0) < C(\bar{q}) - C(q_0) \quad (\text{A.17})$$

where the last inequality comes from the strict convexity of C .

For any price p and any reference production q_0 , let $\Pi(p, q_0, \bar{q}) \equiv \mathbb{E}_{f_{\bar{q}}}[p \cdot R(q, q_0)] - C(\bar{q})$ denote the contractor's expected payoff as a function of its effort \bar{q} . Note that $\Pi(p, q_0, q_0) = pq_0 - C(q_0)$ (given the definition of a production-insuring payment rule). From (A.17), we obtain then that

$$\Pi(p, q_0, \bar{q}) < \Pi(p, q_0, q_0) \quad (\text{A.18})$$

if $\bar{q} > q_0 \geq [C']^{-1}(p)$. We have thus shown that the contractor's optimal level of effort can not be larger than q_0 , when the latter is set greater or equal to the optimal level of effort under the linear contract.

Remark: Under additional restrictions (presented below), we show that $\frac{\partial \Pi(p, q_0, \bar{q})}{\partial \bar{q}} \Big|_{\bar{q}=q_0} < 0$ guaranteeing that the contractor's optimal level of effort is actually strictly smaller than under the linear contract.

Since C is convex, then for any price $p < \bar{p}$, the optimal level of effort under the linear contract $[C']^{-1}(p)$ is lower than the socially optimal level of effort $\bar{q}^* = [C']^{-1}(\bar{p})$. Finally we obtain that for any $p < \bar{p}$, if the production of reference is set strictly above $[C']^{-1}(p)$, then the contractor will provide a lower level of effort. In particular the level of effort $[C']^{-1}(\bar{p})$ can not be implemented this way if $p < \bar{p}$.

Strict incentives to shirk with production-insuring payment rules:

Under additional restrictions (presented below), this impossibility result is extended to the case where $p = \bar{p}$.

Consider a production-insuring payment rule $R(\cdot, q_0)$ where q_0 is set by the buyer. Once q_0 is fixed, we can assume without loss of generality that $R(\cdot, \cdot)$ is homogeneous of degree 1, which implies that for any $\lambda > 0$, $\frac{d\mathbb{E}_{f_{\bar{q}}}[R(\lambda q, \lambda q_0)]}{d\lambda} = \mathbb{E}_{f_{\bar{q}}}[R(q, q_0)]$, or equivalently

$$\mathbb{E}_{f_{\bar{q}}} \left[q \cdot \frac{\partial R}{\partial q}(\lambda q, \lambda q_0) \right] + q_0 \cdot \mathbb{E}_{f_{\bar{q}}} \left[\frac{\partial R}{\partial q_0}(\lambda q, \lambda q_0) \right] = \mathbb{E}_{f_{\bar{q}}}[R(q, q_0)]. \quad (\text{A.19})$$

From the homogenous of degree 1 property, we can also write $R(q, q_0) = q \cdot z\left(\frac{q}{q_0}\right)$. Below we assume implicitly that all the derivatives we use are well-defined. Let us assume a change in \bar{q} is associated with a homothetic transformation of the distribution: $F_{\bar{q}}(q) = F_1\left(\frac{q}{\bar{q}}\right)$ for any $q \in \mathbb{R}_+$ which implies that $\bar{q}f_{\bar{q}}(q) = f_1\left(\frac{q}{\bar{q}}\right)$. After the change of variable $\epsilon = \frac{q}{\bar{q}}$, we have then

$$\mathbb{E}_{f_{\bar{q}}} \left[\frac{\partial R}{\partial q_0}(q, \bar{q}) \right] = - \int_0^2 \epsilon^2 \cdot z'(\epsilon) f_1(\epsilon) d\epsilon.$$

Note that the latter expression does not depend on \bar{q} . Proposition 2 implies here that $\mathbb{E}_{f_{\bar{q}}} \left[\frac{\partial R}{\partial q_0}(q, \bar{q}) \right] \geq 0$. In our case, it corresponds thus to

$$- \int_0^2 \epsilon^2 \cdot z'(\epsilon) f_1(\epsilon) d\epsilon \geq 0 \quad (\text{A.20})$$

Let us assume that the inequality is strict.

From the structure regarding the distributions $F_{\bar{q}}$, we have then: $\mathbb{E}_{f_{\bar{q}}}[R(q, q_0)] = \int R(q, q_0) f_{\bar{q}}(q) dq = \int R(q \cdot \bar{q}, q_0) f_{\bar{q}}(q \cdot \bar{q}) d[q \cdot \bar{q}] = \int R(q \cdot \bar{q}, q_0) f_1(q) dq = \mathbb{E}_{f_1}[R(\bar{q} \cdot q, q_0)]$. This further implies that $\frac{d\mathbb{E}_{f_{\bar{q}}}[R(q, q_0)]}{d\bar{q}} = \frac{d\mathbb{E}_{f_1}[R(\bar{q} \cdot q, q_0)]}{d\bar{q}} = \mathbb{E}_{f_1}\left[q \cdot \frac{\partial R}{\partial q}(\bar{q} \cdot q, q_0)\right]$, which when multiplied by \bar{q} gives $\bar{q} \frac{d\mathbb{E}_{f_{\bar{q}}}[R(q, q_0)]}{d\bar{q}} = \mathbb{E}_{f_1}[\bar{q} \cdot q \cdot \frac{\partial R}{\partial q}(\bar{q} \cdot q, q_0)] = \mathbb{E}_{f_{\bar{q}}}\left[q \cdot \frac{\partial R}{\partial q}(q, q_0)\right]$. Applying $\lambda = 1$ in (A.19) and replacing the first term thanks to the previous equality, we get the general result in (A.21).

$$\bar{q} \cdot \frac{d\mathbb{E}_{f_{\bar{q}}}[R(q, q_0)]}{d\bar{q}} + q_0 \cdot \mathbb{E}_{f_{\bar{q}}} \left[\frac{\partial R}{\partial q_0}(q, q_0) \right] = \mathbb{E}_{f_{\bar{q}}}[R(q, q_0)] \quad (\text{A.21})$$

We then can derive that for any q_0 set by the buyer, for a level of effort $\bar{q} = q_0$ we get from (A.21) that:

$$\frac{d\mathbb{E}_{f_{\bar{q}}}[R(q, q_0)]}{d\bar{q}}\Big|_{\bar{q}=q_0} = 1 - \mathbb{E}_{f_{\bar{q}}}\left[\frac{\partial R}{\partial q_0}(q, \bar{q})\right] < 1 \quad (\text{A.22})$$

where the strict inequality comes from the strict version of (A.20). Therefore for any price p , we get the following inequality on the derivative of its payoff $\Pi(p, q_0, \bar{q}) \equiv \mathbb{E}_{f_{\bar{q}}}[pR(q, q_0)] - C(\bar{q})$ at the reference production q_0 :

$$\frac{d\Pi(p, q_0, \bar{q})}{d\bar{q}}\Big|_{\bar{q}=q_0} = p \frac{d\mathbb{E}_{f_{\bar{q}}}[R(q, q_0)]}{d\bar{q}} - C'(q_0) < p - C'(q_0). \quad (\text{A.23})$$

For all $q_0 \geq [C']^{-1}(p)$, which includes $q_0 = \bar{q}^*$ as long as $p \leq \bar{p}$, we know that the last term in (A.23) is negative and thus we have shown that the contractor has a strict incentive to shirk. This precludes in particular the buyer from setting a payment rule that both is production insuring and incentivize to provide the socially optimal level of effort, unless the buyer accepts to pay a price p higher than its value \bar{p} .

A.3.7 Detailed results on the performance of the French rule

For 5 wind farm sites and 5 level of relative risk aversion (including risk neutrality), Table 2 reports the performance ratio

$$\frac{p \cdot \sum_{t=1}^{20} \frac{\mathbb{E}[R(q_t, q_0)]}{(1+r)^t}}{IC + \sum_{t=1}^{20} \frac{OC}{(1+r)^t}} \quad (\text{A.24})$$

for different equilibrium values for the bid pair (p, q_0) of the winning bidder: first we consider the equilibrium under the linear FiT, second we consider the equilibrium under the French payment rule according to our three bidding paradigms of interest. The performance ratio is necessary above (or equal to) one: otherwise the winning bidder would have preferred to lose the auction which would raise a contradiction with the pair (p, q_0) being an equilibrium bid. Under the linear FiT or if bidders are homogeneous (either all truthful or all strategic), then our performance ratio minus one corresponds to the risk premium that the buyer have to concede to firms to insure them against production risk (and which vanishes if $\gamma = 0$).

Table 3 does the same exercise when the equilibrium bid pairs (p, q_0) in (A.24)

are computed with the utility function $U(x) = \frac{[x-IC+w]^{1-\gamma}}{1-\gamma}$ with the initial wealth w being equal to the total net present cost $IC + \sum_{t=1}^{20} \frac{OC}{(1+r)^t}$ (instead of taking implicitly $w = IC$ in Table 2). Given Table 1, the initial wealth used for the computations in Table 3 are then about twice larger than in our main specification: this makes firms less risk averse in absolute terms and thus reduce the risk premium. This is consistent with what we obtain in the columns 3 to 5. E.g., under the linear FiT and for $\gamma = 1$, the risk premiums are about 50% larger in Table 2 than in Table 3. However, if a bidder is less risk averse (as it is the case with a larger initial wealth), then he/she is more prone to bias his/her report (i.e., here to overestimate even more the expected production): due the corresponding effect on the noncompetitive rents, the performance ratio may be worse in Table 3 than in the corresponding estimates in Table 2 for some specification (it is actually the case for large values of γ , e.g. for $\gamma = 10$ in Fécamp). Overall, due to these two opposite effects in the case with a single strategic producer, we obtain that the performance ratios are very close in column 6 of Table 2 and 3.

Table A.2 – Performance ratio with $U(x) = \frac{x^{1-\gamma}}{1-\gamma}$.

Site	γ	Linear FiT	French Payment Rule		
			All truthful	All strategic	A single strategic bidder
Courseulles	0	1.000	1.000	1.000	1.035
	1	1.003	1.001	1.004	1.036
	3	1.009	1.003	1.010	1.038
	5	1.016	1.006	1.016	1.038
	10	1.033	1.014	1.028	1.038
Fécamp	0	1.000	1.000	1.000	1.036
	1	1.003	1.001	1.003	1.037
	3	1.009	1.003	1.010	1.038
	5	1.015	1.006	1.016	1.039
	10	1.032	1.013	1.028	1.039
Le Tréport	0	1.000	1.000	1.000	1.033
	1	1.003	1.001	1.004	1.034
	3	1.010	1.004	1.011	1.036
	5	1.017	1.008	1.018	1.038
	10	1.037	1.019	1.033	1.040
Saint-Nazaire	0	1.000	1.000	1.000	1.036
	1	1.003	1.001	1.004	1.037
	3	1.009	1.003	1.010	1.038
	5	1.016	1.006	1.016	1.039
	10	1.033	1.014	1.028	1.039
Noirmoutier	0	1.000	1.000	1.000	1.035
	1	1.004	1.001	1.004	1.036
	3	1.011	1.004	1.012	1.038
	5	1.019	1.007	1.019	1.039
	10	1.039	1.019	1.032	1.038

Table A.3 – Performance ratio with $U(x) = \frac{[x-IC+w]^{1-\gamma}}{1-\gamma}$ with the initial wealth w being equal to the total net present cost of the project

Site	γ	Linear FiT	French Payment Rule		
			All truthful	All strategic	A single strategic bidder
Courseulles	0	1.00000	1.00000	1.00000	1.03501
	1	1.00202	1.00072	1.00237	1.03571
	3	1.00612	1.00218	1.00693	1.03688
	5	1.01030	1.00372	1.01117	1.03770
	10	1.02115	1.00807	1.02032	1.03844
Fécamp	0	1.00000	1.00000	1.00000	1.03560
	1	1.00197	1.00069	1.00227	1.03627
	3	1.00598	1.00209	1.00664	1.03737
	5	1.01006	1.00356	1.01080	1.03822
	10	1.02065	1.00771	1.02002	1.03906
Le Tréport	0	1.00000	1.00000	1.00000	1.03251
	1	1.00207	1.00085	1.00231	1.03335
	3	1.00625	1.00259	1.00677	1.03483
	5	1.01052	1.00439	1.01099	1.03602
	10	1.02163	1.00943	1.02082	1.03819
Saint-Nazaire	0	1.00000	1.00000	1.00000	1.03563
	1	1.00226	1.00082	1.00266	1.03643
	3	1.00686	1.00250	1.00777	1.03773
	5	1.01159	1.00426	1.01248	1.03860
	10	1.02390	1.00930	1.02262	1.03920
Noirmoutier	0	1.00000	1.00000	1.00000	1.03456
	1	1.00212	1.00079	1.00244	1.03533
	3	1.00641	1.00238	1.00706	1.03658
	5	1.01077	1.00404	1.01146	1.03758
	10	1.02203	1.00864	1.02086	1.03846

Appendix B

Appendix to Chapter 2

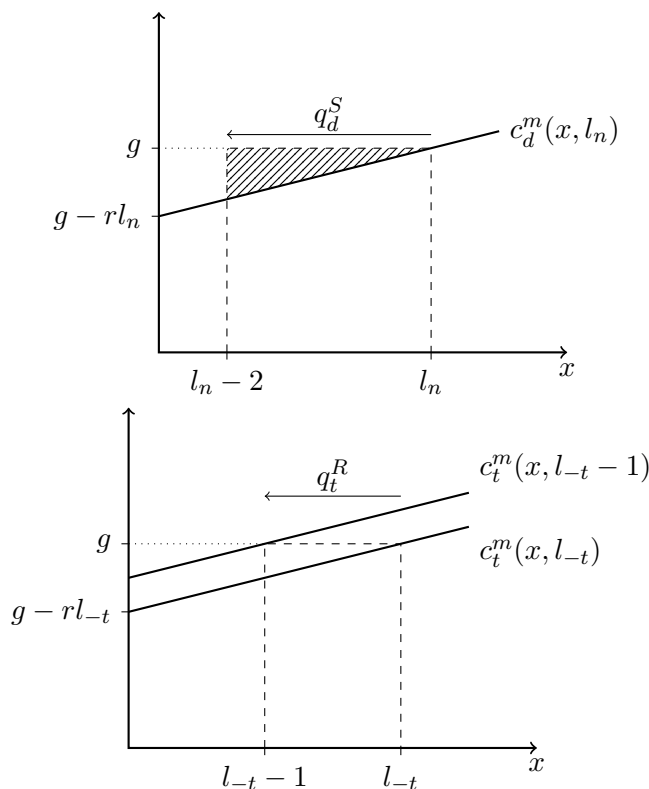
B.1 Illustrative case for section 2.2.3

To get a better intuition of the approximations induced by the marginal approach, consider a simple case where time is divided in cycles of days and nights, denoted d and n , with a total load to cover l that is constant through time: $l_d = l_n > 2$. In the following we consider the value over one day-night cycle.

Say we depart from a situation where the load is covered by a thermal power plant whose cost to produce $x = \{x_d, x_n\}$ is

$$C(x) = \sum_{t \in \{d, n\}} \left[g \cdot x_t + \frac{r}{4} (x_t - x_{-t})^2 \right]$$

where g is a parameter denoting the generation cost per unit, and r is the ramping cost parameter with this ramping cost depending on the variation of the output between night and day. The resulting marginal cost is thus $c_t^m(x, l_{-t}) = \frac{\partial C}{\partial l_t}(x, l_{-t}) = g + r(x - l_{-t})$, and in particular in the baseline scenario where $l_d = l_n$, $c_d^m(l) = c_n^m(l) = g$.



Now consider two VRE projects that could be added to that system: A. a run-of-river hydro power plant q^R that constantly produces $q_d^R = q_n^R = 1$, and B. a solar

power plant q^S that produces $q_d^S = 2$ during the day but nothing at night ($q_n^S = 0$). Based on the marginal approximation of their value, both projects have the same value $V(q | l) \approx \sum_{t \in \{d,n\}} q_t \cdot c_t^m(l) = 2g$. However, computing their exact value $V(q | l) = C(l) - C(l - q)$ shows that the approximation is true for q^R but wrong for q^S , which is actually worth $V(q^S | l) = 2(g - r)$. Detailing where the approximation went wrong, a first component of the error is that within time period approximation term, the second term in (2.2), is not null since the marginal cost $c_t^m(x, l_{-t})$ is not constant but increasing with a slope r due to the ramping cost. This explains the gap of value $2r$ for the solar project, but should also cause an error r in the evaluation of the hydro run-of-river projects. However the latter is cancelled out by an undervaluation error $-r$ resulting from the across time-period approximation, the third term in (2.2). The fact that the residual load is equally diminished in $-t$ shifts the marginal cost function in t towards left, and compensates for the within time-period approximation error.

B.2 Detailed VRE capacity increase (section 2.4.3)

The increase in VRE capacity installed in France and in neighboring country is based on the percentage increase reported by IRENA (2022) for the last 3-years period available, i.e. the percentage increase between 2018 and 2021. It is applied as such to the baseline VRE capacities in EOLES-Dispatch, which differ from the capacity reported by IRENA (2022) as they are adjusted to match the electricity production reported by ENTSO-E in 2019.

Solar				
	<i>Increase</i>	Baseline Capacity	Add. Capacity	VRE+ Capacity
France	+52.2%	9.16	+4.78	13.94
Belgium	+64.6%	3.18	+2.05	5.23
Germany	+29.5%	37.91	+11.17	49.08
Switzerland	+58.7%	0.31	+0.19	0.50
Italy	+12.8%	17.09	+2.20	19.29
Spain	+125.7%	9.52	+11.97	21.49
Great-Britain	+4.7%	11.87	+0.56	12.43
Onshore Wind				
	<i>Increase</i>	Baseline Capacity	Add. Capacity	VRE+ Capacity
France	+25.3%	14.55	+3.69	18.24
Belgium	+20.9%	1.80	+0.38	2.18
Germany	+7.0%	55.97	+3.95	59.92
Switzerland	+16.0%	0.05	+0.00	0.05
Italy	+10.2%	11.15	+1.14	12.29
Spain	+17.5%	21.55	+3.76	25.31
Great-Britain	+6.5%	10.47	+0.68	11.15
Offshore Wind				
	<i>Increase</i>	Baseline Capacity	Add. Capacity	VRE+ Capacity
France	<i>n.a.</i>	0		0
Belgium	+90.7%	1.55	+1.40	2.95
Germany	+21.2%	9.63	+2.04	11.67
Switzerland	<i>n.a.</i>	0		0
Italy	<i>n.a.</i>	0		0
Spain	<i>n.a.</i>	0		0
Great-Britain	+54.6%	6.09	+3.32	9.41

Table B.1 – Increase in VRE capacity considered for simulations in section 2.4.3 [GW]

Appendix C

Appendix to Chapter 3

C.1 Detailed simulation results

Table C.1 – Calibration of bids δ_R and renewable energy externalities δ^* (full) [EUR/MWh]

Contract Design			Solar projects ($n = 50$)				Wind projects ($n = 43$)			
			δ_R	Revenue (per output)			δ_R	Revenue (per output)		
<i>Period</i>	<i>Weighting</i>		<i>mean</i>	<i>min</i>	<i>max</i>	<i>mean</i>	<i>min</i>	<i>max</i>		
Feed-in tariff			59.49	59.49	59.49	59.49	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
Social Benefits			δ^*	Value (per output)			δ^*	Value (per output)		
Baseline (24.9 EUR/tCO ₂)			18.31	59.49	58.69	61.18	22.39	65.01	64.36	65.76
Full SCP (70 EUR/tCO ₂)			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 C.2 – Detailed simulation results for all contract designs – Solar projects ($n = 50$)

Contract Design			Max. Distortion loss (24.9 EUR/tCO ₂)			Max. Distortion loss (70 EUR/tCO ₂)			Risk premium (RRA = 1)		
			$\bar{\chi}_{R,\delta}(\omega)$			$\bar{\chi}_{R,\delta}(\omega)$			$\mu_{R,\delta}(\omega)$		
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 $\bar{\chi}_{R,\delta}(\omega)$ 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 C.3 – Detailed simulation results for all contract designs – Wind projects ($n = 43$)

Contract Design			Max. Distortion loss (24.9 EUR/tCO ₂)			Max. Distortion loss (70 EUR/tCO ₂)			Risk premium (RRA = 1)		
			Mean	Median	$\bar{\chi}_{R,\delta}(\omega)$ Max	Mean	Median	$\bar{\chi}_{R,\delta}(\omega)$ Max	Mean	Median	$\mu_{R,\delta}(\omega)$ s.d.
			1.13	1.15	2.12	1.77	1.88	3.29	0.11	0.09	0.07
			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
			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 $\bar{\chi}_{R,\delta}(\omega)$ 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.

Appendix D

EOLES-Dispatch Model

EOLES-Dispatch is a numerical simulation model of electricity dispatch focused on the French power system, and whose main purpose is to simulate the evolution of electricity market prices given marginal or short to medium term evolutions of the electricity mix and other associated cost factors (such as fossil fuel prices or CO₂ emissions). It is derived from the EOLES model developed by Shirizadeh et al. (2022), but focuses on the optimization of the electricity dispatch, leaving aside the optimization of investments in generation capacity. Thus, instead of leaving the latter as an optimization variable of the model, the existing fleet of generation capacities is set as an exogenous input of the model. The simplification that comes from having capacity as an exogenous input allows for a more detailed modeling of the dispatch problem, which is described in detail below. Similar to the EOLES model, EOLES-Dispatch is a linear optimization model that minimizes the total dispatch cost of the power system over a year while satisfying power demand at an hourly time step.

These refinements are primarily aimed at providing a more realistic simulation of hourly marginal costs, which is used as a proxy for wholesale market prices. One improvement is that EOLES-Dispatch models power exchanges between the French power system and neighboring countries. Thus, the model is replicated and solved simultaneously for France and for all electric systems that have a direct interconnection with France, namely Belgium, Germany (including Luxembourg), Switzerland, Italy, Spain, and Great Britain. Another direction in which improvements have been made

is the modeling of the dynamic costs of power generation, in particular for thermal generation, as these play a major role in explaining the variations in wholesale market prices.

A central output of the model is the hourly marginal cost in each modeled country, that is the marginal increase in total cost when marginally increasing the demand for power in that hour in that country. This marginal cost is intended to be interpreted as a simulation of the market price of electricity. This interpretation calls for a number of comments on the biases it potentially implies:

- It completely ignore any inefficiency or market power of generators (or buyers). Actually, the structure of the power industry (atomistic or oligopolistic) or the design of the wholesale market are fully ignored here, and it is implicitly perfect competition that is assumed. However, the cost parameters that determines marginal costs (e.g. the efficiency of gas-fired power plants) have been adjusted for the model to better reproduce the prices historically observed on the market prices. Doing so, the mark-ups resulting from market power may have been embedded in the technical cost parameters of the model. One specific matter in which this assumption may have its importance with what is the main purpose of the model relates to the dynamic costs: it has been shown that non-competitive mark-ups typically vary in response to variations in the residual load (Reguant, 2014; Bushnell, Novan, 2021). Similarly to the previous comment, these specific mark-ups may have been embedded in the technical parameters defining the dynamic costs.
- It assumes that the power dispatch is optimized with perfect foresight on the whole time period simulated (one year), whereas many power dispatch models assume a shorter time horizon to account for uncertainty. However such approach could also result in neglecting future time periods, unless some sophisticated iteration process is applied (e.g. the approach proposed by Terila, 2020). Moreover many features of the model limit such long-term optimization decisions, in particular considering hydro management is constrained to be done month by month.
- It considers that capital costs of installed capacity are entirely sunk and irrele-

vant for electricity spot prices. In other words, the last capacity called during the year do not charge for its capacity cost, assuming for instance this is settled for through another mechanism such as a capacity market or forward or cap-contracts (see Wolak, 2021).

The following first details and comments on the structure of the model, before documenting its performance in reproducing electricity wholesale market prices.

D.1 Model Description

D.1.1 Objective and Adequacy

The objective of the model is to minimize, over the entire set of endogenous variables¹, the total cost of electric dispatch over a time period T and a set of electric systems (or areas) A :

$$\min \sum_{a \in A} \sum_{t \in T} hCost_{a,t} \quad (\text{D.1})$$

The dispatch cost in each time period t includes the cost of generation from thermal and storage technologies (detailed in section D.1.2), the cost of importing electricity from areas not modeled (see section D.1.3), and the value of lost load applicable to each unit of demand not met by supply (as imposed by the adequacy constraint (D.2) described below).

The difference between supply and demand, the lost load, is denoted by $LL_{a,t}$ and incurs a specific cost, which is entered as $hCost_{a,t}$ and corresponds to the value of the lost load (VOLL). The VOLL is set to 15,000 EUR/MWh and as a consequence, since the cost of generation is much cheaper, the model will almost always prefer to meet the electricity demand if possible. Note also that final demand is assumed to be strictly inelastic, since it is defined as an exogenous input.

1. In the following, endogenous variables are all identified with capital letters and are all constrained to be positive.

$$\sum_{tec} GENE_{tec,a,t} + \sum_{a' \in \bar{A}} IM_{a,a',t} + LL_{a,t} = demand_{a,t} + \sum_{a' \in \bar{A}} EX_{a,a',t} + \sum_{sto} STORAGE_{sto,a,t} \quad (D.2)$$

The Lagrange multiplier associated with this adequacy constraint in period t and market a can be interpreted as the marginal cost associated with a marginal increase in electricity demand in that market and period. This Lagrange multiplier is further used as a proxy for the electricity price in market a at time t . This value should in fact correspond to the price formed in a wholesale electricity market, subject to several assumptions:

- Perfect competition – All producers (or at least the marginal producer) bid their exact marginal cost to produce an additional unit of electricity. This hypothesis could be criticized given the oligopolistic nature of the electricity generation market, and more importantly, the fact that this oligopolistic nature is reinforced when considering certain narrow price ranges where most producers are either excluded (due to higher marginal costs) or not involved in market clearing (they produce anyway because they have lower marginal costs). As a result, actual prices should theoretically exceed the Lagrange multiplier due to the mark-ups applied by individual bidders in the market.
- Omission of capacity costs – Since the generation fleet is considered exogenous, i.e. already built and free, capacity costs are not included in the Lagrange multiplier. This aspect is actually more in line with the French and most European wholesale electricity markets, in the sense that these costs should be covered by capacity markets specifically designed for this purpose. On the contrary, in an "energy-only" market (i.e. in the absence of capacity markets), bids submitted by the last capacity called during the year should cover both the operating and investment costs of building the last peaking capacity. Such a situation is actually fairly represented by the baseline EOLES model, which includes both investment and operation in the cost minimization objective, resulting in the Lagrange multiplier accounting for the additional capacity to be built to meet the last units of electricity demand.

It should be noted, however, that some technical parameters of the model, such as the thermal efficiency of gas-fired power plants, have been adjusted so that the model best reflects observed wholesale market prices. Thus, it is possible that market power and other factors that raise market prices in practice have been incorporated into these "technical" parameters.

D.1.2 Generation

Various generation technologies are available to the model to meet electricity demand. The generation capacity for each technology tec in each area a (i.e., in each electric system) is exogenous, constant, and denoted $capa_{tec,a}$. The amount of electricity generated by them in each time period $t \in T$ is denoted $GENE_{tec,a,t}$ and is subject to optimization.² These technologies are divided into three categories (or subsets) that are modeled differently: variable (vre), thermal (thr), and storage (sto) technologies.

Variable Generation Technologies

Variable generation technologies include all technologies whose production is considered costless, but is constrained by a time-varying availability. This availability is determined by the time series denoted by $cf_{vre,a,t}$, which is an exogenous input to the model. Specifically, this includes all variable renewable electricity (VRE) sources. 4 technologies are considered, each characterized by specific time series of availability (or capacity factors): Onshore wind, offshore wind, solar PV, and run-of-river hydro. Thus, electricity generation from these technologies is subject to a constraint (D.3) that is specific to each technology, time period, and region.

$$GENE_{vre,a,t} \leq capa_{vre,a} * cf_{vre,a,t} \tag{D.3}$$

Note that the constraint (D.3) is specified as an inequality rather than a strict equality, meaning that generation from VRE sources is constrained if it lowers the total dispatch

2. In the following, endogenous variables of the model are denoted with capital letters only, in contrast to exogenous parameters and data.

cost. This assumption largely prevents negative prices from appearing in the output of the model. In the short run, the realism of this hypothesis may be questioned, as solar and wind power are partially subsidized by feed-in tariff contracts, which do not provide an incentive to curtail generation. Conversely, removing the possibility of such curtailment would lead to negative prices when wind and solar availability is high and demand is low, as is currently the case. However, these are expected to disappear in the medium to long term as subsidy contracts are adjusted.

The variable generation category also includes generation technologies whose dispatch is assumed to depend on factors other than electricity markets, referred to as non-market dependent (*nmd*) technologies. This category includes generators that may be technically dispatchable, but for which the sale of electricity in the regular market is not the primary activity or source of revenue, and therefore do not optimize their operations in response to electricity market signals. Examples include waste-to-energy or combined heat and power (CHP) from biomass. Generation from these technologies is exogenously set based on aggregate historical observations of hourly generation in each area.

Thermal Generation Technologies

Unlike the original EOLES model, EOLES-Dispatch aims to simulate the dispatch of the current or near-term power system and therefore models a portfolio of thermal generation technologies, including fossil and nuclear. These technologies are dispatchable, costly to operate, and subject to a more complex set of constraints than variable renewable technologies.

General Constraints on Thermal Generation – To keep the model as a linear optimization problem, individual power plants are not explicitly represented in the model. Instead, the installed capacities for each technology are grouped into pools whose total capacity is denoted by $capa_{thr,a}$. However, the dynamics of the electric system associated with start-up costs or inefficiencies of thermal plants at part load are accounted for by a modeling approach following Palmintier (2014) and Zhang et al., (2016). It is based on the definition of a time-varying variable for each technology, in addition to the amount of electricity generated $GENE_{thr,a,t}$, which is

the capacity *available for generation*, or in other words, the capacity of power plants of each technology that are turned on in each time period, denoted by $ON_{thr,a,t}$. Note that this variable is endogenous in the model, and thus subject to cost minimization, and that it is a continuous variable that abstracts from the discrete nature of the decision to turn plants on and off.

The available capacity represents an upper limit on power generation, including reserve requirements (see section D.1.4). This constraint, expressed in (D.4), means that to increase production by the technology beyond the available capacity requires an increase in the latter, with start-up costs proportional to $\Delta ON_{thr,a,t}^+ = \max\{ON_{thr,a,t} - ON_{thr,a,t-1}, 0\}$. Conversely, the available capacity $ON_{thr,a,t}$ also sets a lower bound on effective generation (excluding reserve requirements), expressed by (D.5), which is the minimum capacity factor at which plants of the technology can operate. This is captured by the minimum stable generation parameter $minSG_{thr}$.³ Thus, a significant reduction in the amount of electricity generated by the technology will sometimes require a reduction in available capacity (to "turn off" power plants). Although this has no direct cost, there is an opportunity cost associated with it, as it may be necessary to restart that capacity at a later time, when the start-up costs could have been avoided. This opportunity cost can cause the shadow cost to fall below the marginal technology's generation cost if there is a sudden drop in electricity demand, and even (theoretically) cause negative shadow costs.⁴

$$GENE_{thr,a,t} + RSV_{thr,a,t} \leq ON_{thr,a,t} \quad (D.4)$$

$$minSG_{thr} \cdot ON_{thr,a,t} \leq GENE_{thr,a,t} \quad (D.5)$$

In addition, the available capacity cannot exceed the installed capacity $capa_{thr,a}$

3. This minimum stable generation is typically between 30 and 50% of available capacity for fossil, depending on the technology. For nuclear, the assumed minimum stable generation is 70% of available capacity, based on a weighted average that takes into account that part of the fleet is operating in load-following mode while the rest of the fleet is operating at full capacity.

4. This possibility remains largely theoretical, since it would generally be possible to curtail renewable electricity production at no cost, and thus the shadow cost should be at least zero. However, in the unlikely event that no remaining renewable generation can be displaced, negative prices could occur.

adjusted by the maximum availability factor $maxAF_{thr}$, which accounts for unplanned outages⁵, as specified in (D.6). The model also accounts for a minimum amount of time that power plants should stay off (or on) after being turned off (or on), denoted $\underline{\delta}_{thr}$ (or $\bar{\delta}_{thr}$). This is accounted for by a limit on the capacity that can be started (resp. turned off), as specified in (D.7) (resp. (D.8)). Finally, the average percentage of installed capacity that is turned on over the year must take into account planned outages (i.e. maintenance periods). Thus, (D.9) sets an upper bound on this fraction at yAF_{thr} , the yearly availability factor, which accounts for the annual rate of planned outages. The modeling approach is such that maintenance can be planned very flexibly, which is probably unrealistic. However, it is unclear whether the effect on the model results is significant. This annual availability factor is also used to account for political constraints, which is mainly a roundabout way of accounting for the fact that coal-fired power plants are only operated during emergency periods as part of French environmental policy.

$$ON_{thr,a,t} \leq capa_{thr,a} \cdot maxAF_{thr} \quad (D.6)$$

$$\Delta ON_{thr,a,t}^+ \leq capa_{thr,a} - ON_{thr,a,t} - \sum_{t-\underline{\delta}_{thr} < j < t} \Delta ON_{thr,a,t}^- \quad (D.7)$$

$$\Delta ON_{thr,a,t}^- \leq ON_{thr,a,t} - \sum_{t-\bar{\delta}_{thr} < j < t} \Delta ON_{thr,a,t}^+ \quad (D.8)$$

$$\sum_{t \in \mathcal{T}} ON_{thr,a,t} \leq \sum_{t \in \mathcal{T}} capa_{thr,a} \cdot yAF_{thr} \quad (D.9)$$

Nuclear Planning – As nuclear power represents about 70% of the French electricity mix, the availability of nuclear capacity is a major determinant of electricity prices. However, the modeling of plant availability by (D.9) and (D.6) allows too much flexibility compared to the real constraints applicable to the planning of nuclear plant maintenance. Indeed, the "maintenance planning" resulting from this optimization constraint will lead to a maximum concentration of nuclear generation in the winter

5. Due to the deterministic nature of the model, unplanned outages could not be modeled as a random phenomenon and are therefore modeled as a small fraction of the fleet being constantly unavailable.

months, much more than seems feasible when looking at historical data (see Figure D.1). In fact, this planning results from an optimization over several years (Lynch et al., 2022), and thus cannot be adequately modeled by constraints set to a single year.

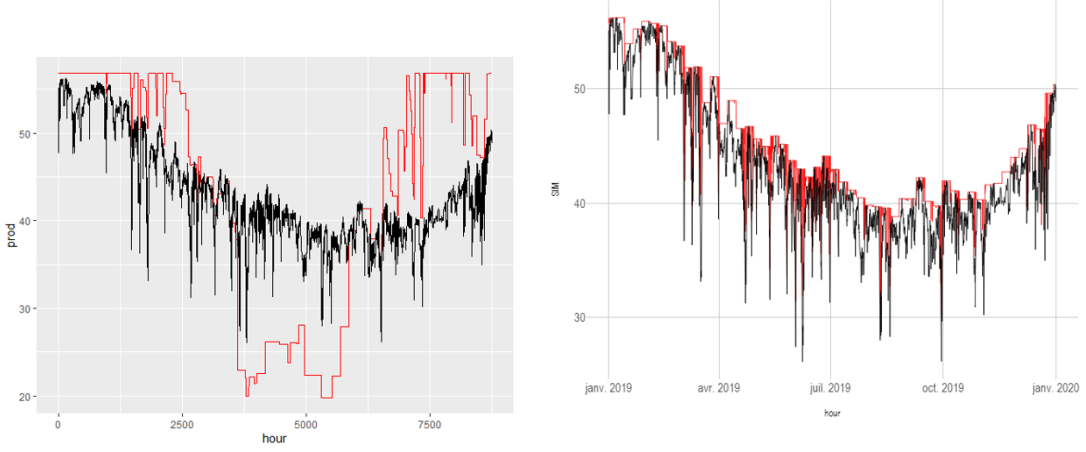


Figure D.1 – Optimal dispatch of nuclear power plants: Left – without additional constraints ; right – under the additional specific constraint (D.10)

Therefore, nuclear maintenance planning is introduced as an exogenous input to the model through a weekly time series of the fraction of the nuclear fleet that is not under maintenance $nucAF_{week}$. Therefore, the nuclear capacity available for generation is subject to the additional constraint (D.10).

$$ON_{nuclear,a,t} \leq capa_{nuclear,a} \cdot nucAF_{week(t)} \quad (D.10)$$

Costs of Thermal Generation – Thermal generation costs are the major component of the objective function minimized by the model, and as such largely determine the shadow costs associated with electricity demand, which is used as a proxy for the market price.

These costs include operating costs, start-up costs, and ramping costs. The former, running costs, are static costs incurred in period t and determined by the electricity generation in period t . In contrast, startup and ramping costs are dynamic costs determined by the evolution between $t - 1$ and t . Startup costs are proportional to the increase in capacity available for generation $\Delta ON_{thr,a,t}^+$, while ramping costs are proportional to a positive increase in generation $\Delta GENE_{thr,a,t}^+$. These different costs

have in common that they depend on the technical characteristics of the considered technology, the price of the fuel consumed by the technology, and the cost associated with carbon emissions (i.e., the price of EU ETS allowances). Thus, fuel and carbon prices are key parameters of the model that affect the generation costs of all thermal technologies. The carbon price is assumed to be homogeneous across time and regions, consistent with the fact that EU ETS allowances can be transferred free of charge from one region to another⁶ and from one time period to another (allowances are not costly to store). However, these two statements cannot be extended to fuels, which may incur transportation and storage costs. To account for this, fuel prices in the model are adjusted by a monthly time series to account for fuel price volatility and by a region-specific factor to account for systematic fuel price differences between countries.

Running Costs – When a technology pool is running at full capacity (when all of its available capacity is actually generating, i.e., when $GENE_{thr,a,t} = ON_{thr,a,t}$), its running costs per unit assumed in the model can be written as follows. In (D.11), eff_{thr} denotes the efficiency of the technology thr , $fuelPrice_{thr,a,month}$ is the price in EUR/GJ of the fuel used by thr , adjusted to area a and month m , $co_2factor_{thr}$ is the emission factor associated with this fuel in tCO₂/GJ, and co_2price is the cost associated with these emissions in EUR/tCO₂.

$$unitRC_{thr,a,t}(100\%) = \frac{1}{eff_{thr}} \cdot 3.6 \cdot (fuelPrice_{thr,a,m} + co_2factor_{thr} \cdot co_2price) \quad (D.11)$$

In reality, the efficiency of a thermal power plant depends on the capacity factor at which it is operating: it is generally considered to be optimally efficient when it is operating at full capacity, but less efficient when it is operating at part load. This part-load inefficiency is expected to have an impact on prices when the system faces short-term variations in the residual demand to be met by the thermal power plant, as these short-term variations may imply that some thermal power must temporarily run at part-load.

The model allows to take this effect into account since the capacity factor is ex-

6. except for Switzerland, whose electricity generation is already largely free of GHG emissions, and for the United Kingdom, which recently left the EU ETS as it exited the EU.

plicit: where $ON_{thr,a,t}$ denotes the capacity that is turned on, $GENE_{thr,a,t}/ON_{thr,a,t}$ can be considered as the (average) capacity factor of the thermal plant fleet in technology thr .

To account for this effect, the total operating cost is divided into a first component that is a factor of the amount of energy produced $GENE_{thr,a,t}$ and a second component that is a factor of the capacity available for production $ON_{thr,a,t}$, so that the unit operating cost depends on the capacity factor $GENE_{thr,a,t}/ON_{thr,a,t}$.

$$\begin{aligned}
 runningCost_{thr,a,m}(GENE_{thr,a,t}, ON_{thr,a,t}) &= \alpha \cdot GENE_{thr,a,t} + \beta \cdot ON_{thr,a,t} \\
 unitRC_{thr,a,t} \left(\frac{GENE_{thr,a,t}}{ON_{thr,a,t}} \right) &= \frac{RunningCost_{thr,a,t}}{GENE_{thr,a,t}} = \alpha + \frac{1}{\frac{GENE_{thr,a,t}}{ON_{thr,a,t}}} \cdot \beta
 \end{aligned}$$

To run the model, the parameters α and β are taken from the assumed efficiency at full capacity (with $unitRC_{thr,a,t}(100\%) = \alpha + \beta$) and the assumed efficiency at half capacity (with $unitRC_{thr,a,t}(50\%) = \alpha + 2\beta$).⁷

Startup and Ramping Costs – The thermal generation costs that the model minimizes also include dynamic costs, namely startup costs, which are proportional to the positive variation in the capacity available for generation compared to the previous period $\Delta ON_{thr,a,t}^+ = \min(0, ON_{a,t,thr} - ON_{a,t-1,thr})$, and ramping costs, which are proportional to the positive variation in generation compared to the previous period $\min(0, GENE_{a,t,thr} - GENE_{a,t-1,thr})$. As for the operating costs, these costs (expressed per unit of variation) are detailed according to the following equations, which allow to take into account variations in fuel and CO_2 prices.

$$\begin{aligned}
 suCost_{thr,a,t} &= suFuelCons_{thr}(fuelPrice_{thr,a,m} + co2factor_{thr} \cdot co2price) \\
 &\quad + suFixedCost_{thr}
 \end{aligned} \tag{D.12}$$

$$\begin{aligned}
 rampCost_{thr,a,t} &= rampFuelCons_{thr}(fuelPrice_{thr,a,m} + co2factor_{thr} \cdot co2price)
 \end{aligned} \tag{D.13}$$

7. In the list of model parameters and equations at the end of this appendix, α and β correspond to $genCost_{thr}(p_{fuel(thr),month(t)})$ and $onCost_{thr}(p_{fuel(thr),month(t)})$ respectively.

CO₂ emissions – As can be seen in (D.11-D.13), the way thermal generation costs are expressed in the model allows for a fairly straightforward estimation of the *CO₂* emissions from that thermal generation. These are also provided as an output of the model and represent the amount of *CO₂* emissions resulting from the operation of the electric system (thus excluding the emissions resulting from the construction of generating capacity). However, as discussed in Chapter 2, these emissions are not very robust and appear to be very sensitive to slight changes in the parameters of the model.

Hydroelectricity and Storage

A final set of power generation capacity is represented in the model in a third category, which includes all technologies whose production is linked to the depletion of a stock. This includes lake hydro – which is dispatchable and typically involves a dam and a water reservoir, as opposed to run-of-river hydro installations – and other electricity storage technologies such as batteries. Lake hydro and pumped hydro storage (PHS) are grouped together as a single technology that receives some natural inflow (as do standard lake hydro facilities) and can also increase its stock by consuming power from the system (up to the installed PHS capacity).

These technologies are characterized, like thermal generation technologies, by a capacity to generate electricity $capa_{sto}$. Unlike thermal technologies, they are also characterized by a capacity to consume electricity to store it, denoted $capaIn_{sto,a}$, and a maximum stock of energy stored by the technology at any time $stockMax_{sto,a}$. Note that the first two characteristics are a measure of power (expressed in GW) while the last is a measure of energy (expressed in TWh). Furthermore, in each time period, these technologies are characterized by the amount of electricity generated at this moment $GENE_{sto,a,t}$, but also by an amount of energy that is available in stock $STORED_{sto,a,t}$ and an amount of electricity that is consumed to add to the stock $STORAGE_{sto,a,h}$. These three variables are constrained by the aforementioned parameters according to the inequalities below.

$$STORED_{sto,a,t} \leq stockMax_{sto,a} \quad (D.14)$$

$$STORAGE_{sto,a,t} \leq capaIn_{sto,a} \quad (D.15)$$

$$GENE_{sto,a,t} + RSV_{sto,a,t} \leq capa_{sto,a} \quad (D.16)$$

In addition, these storage technologies are subject to the following dynamic relationship between their consumption, generation and stock of energy. Any energy that is consumed to be stored by the technology in period t is added to the energy stock in period $t + 1$, and vice versa for energy that is generated, while both are adjusted to account for the efficiency of the technology when storing in η_{sto}^{in} and when storing out η_{sto}^{out} , respectively. To limit border effects, (D.17) uses the convention that the last simulated hour is followed by the first simulated hour.

$$STORED_{sto,a,t+1} = STORED_{sto,a,t} + \eta_{sto}^{in} STORAGE_{sto,a,t} - \frac{1}{\eta_{sto}^{out}} GENE_{sto,a,t} \quad (D.17)$$

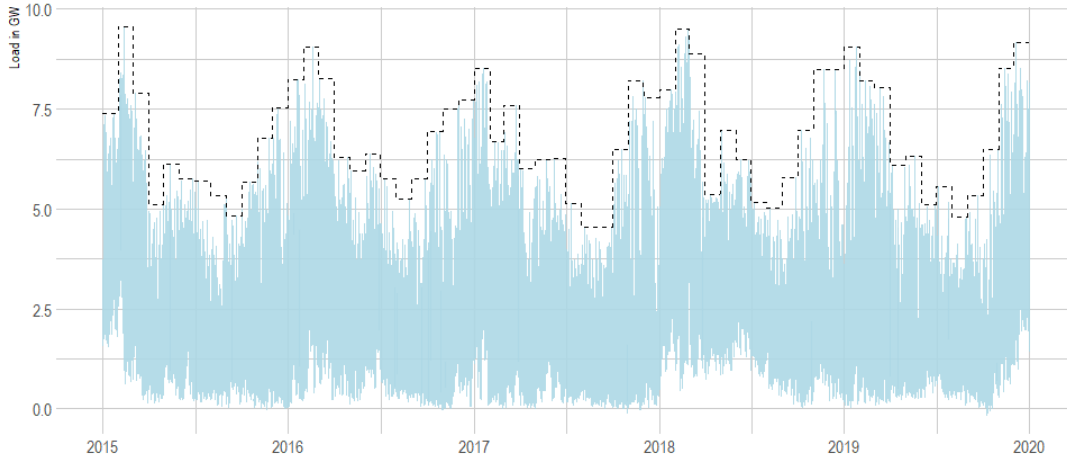
Specific features of hydroelectricity – Hydroelectricity differs from other storage technologies in that: 1. It typically benefits from a natural inflow of water (i.e. potential energy) that is not the result of electricity consumption in a previous period, 2. Its operation is subject to numerous non-power-related constraints, particularly those resulting from alternative uses of water (e.g., for agriculture and tourism).

The first issue is addressed by modifying (D.17) to account for this natural inflow. As a proxy for this water inflow expressed in potential energy, the model's natural inflow is based on historically observed electricity generation aggregated to the monthly level (denoted $lakeInflow_{a,m}$) and evenly distributed over each hour of the month in question ($card(month(t))$ denotes the number of hours in the month corresponding to the hour t). Since the proxy used is based on the effective power output, i.e. less the efficiency loss η_{lake}^{out} , this natural inflow is augmented by $1/\eta_{lake}^{out}$. Note that pure PHS plants are modeled as lake hydro capacity with zero natural inflows.

$$\begin{aligned}
STORED_{lake,a,t+1} = & STORED_{lake,a,t} + \eta_{lake}^{in} STORAGE_{lake,a,t} \\
& - \frac{1}{\eta_{lake}^{out}} \left(GENE_{lake,a,t} + \frac{lakeInflow_{a,m}}{card(month(t))} \right)
\end{aligned} \tag{D.18}$$

To account for seasonal constraints on hydro generation and consumption capacity, we adjust (D.15) and (D.16) by a monthly factor based on historical maximum hourly consumption and hourly generation observed in each month. This follows the intuition that these maximum capacities seem to follow some seasonal patterns, as shown in Figure D.2.

Figure D.2 – Hydroelectric power generation in France (2015-2019)



Note: Historic observation of hydroelectric hourly generation is represented by the solid light blue line, while the dashed black line denotes the monthly maximum that is set as a constraint in the model.

Finally, the model accounts for non-energetic related constraints on storage levels (i.e., lake levels) through an additional constraint that ensures that the use of hydropower for interseasonal storage is limited to what has been observed in the past. To do so, it is imposed by constraint (D.19) that the total power generation from the natural inflow of water over each month is equal to the historically observed one.

$$\sum_{t \in m} [GENE_{lake,a,t} - \eta_{lake}^{in} \eta_{lake}^{out} STORAGE_{lake,a,t}] = lakeInflow_{a,m} \tag{D.19}$$

Storage Technology Costs – For each of the storage technologies, there is a

simple static variable cost proportional to the total amount of electricity generated by these technologies. This is in addition to the option value implicit in the constraint that generation using these technologies consumes a resource that could have been used in another period.

D.1.3 Trade

The final means available in the model to satisfy electricity demand is electricity trade between neighboring areas. Among the modeled electricity markets – i.e., France and all its direct neighbors – electricity trade is modeled as a transfer of electricity from one country to its neighbor, bounded by an exogenous transfer capacity and incurring a transport loss. Imports and exports are then included in country-specific adequacy constraints (D.2) as a way to satisfy each country’s demand. Thus, trade between two areas a and a' is subject to the equilibrium constraint (D.20) and the capacity constraint (D.21) below, where $IM_{a,a',t}$ denotes the amount imported into country a from country a' , $EX_{a,a',t}$ denotes the amount exported from country a to country a' , $trLoss$ denotes the transmission loss factor and $icCapa_{a,a'}$ denotes the interconnection capacity from a' towards a .

$$IM_{a,a',t} = (1 - trLoss) \cdot EX_{a',a,t} \quad (D.20)$$

$$IM_{a,a',t} \leq icCapa_{a,a'} \quad (D.21)$$

The model also allows trading with electricity markets whose dispatch is not simulated. Thus, electricity prices on these markets are an exogenous input to the model (based on historical data). This applies to countries that are not direct neighbors of the French power market, but that are interconnected with direct neighbors of the French power market. As before, the constraint (D.21) also applies to these trades, meaning they are limited by an exogenous transmission capacity parameter. However, unlike trade between modeled countries, this trade has a direct impact on the total cost of dispatch. Importing from an "exogenous" country will incur a cost equal to the historically observed price in the hour under consideration, while exporting to such a

country will reduce the total cost ("generate revenue" for the exporting country) by the same amount. Imports and exports from non-modeled countries then appear in the cost minimization objective. A drawback of this modeling approach is that electricity prices in these countries are invariant and unresponsive to what happens in the electricity market of the modeled countries. However, the impact on electricity prices in France should be limited since none of these countries is directly interconnected with the French power grid.

D.1.4 Reserve requirements

Following Shirizadeh and Quirion, an additional constraint imposes that some generation capacities belonging to specific technologies should be available for generation but not actually generating. This amount of capacity stands as a proxy for reserve requirements, which are used to face uncertainties in particular regarding power demand and VRE production. The required amount is proportional to the hourly demand and to the installed solar and wind capacity, according to (D.22).

$$\sum_{tec \in frr} RSV_{tec,a,t} = demand_{a,t} \cdot loadUnc \cdot (1 + loadVar) + \sum_{tec \in vre} capa_{tec,a} \cdot vreRR_{tec} \quad (D.22)$$

$loadUnc$ denotes the uncertainty on power demand due to forecast errors, $loadVar$ is the load variation factor and $vreRR_{tec}$ is the additional reserve requirement for VRE technologies due to forecast errors.⁸ The set of technologies suitable for meeting these reserve requirements, denoted frr , includes all storage technologies and some thermal technologies (namely nuclear and open-cycle gas-fired power plants), provided that these capacities are "on" but not generating (see section D.1.2).

D.2 Performance of the model

To evaluate the performance of the model, we compare the prices simulated based on the characteristics of the electricity system in 2019 with those observed during that

8. Specifications are kept identical to Shirizadeh et al. (2021).

period. This comparison is not entirely satisfactory as a test of the model’s validity, since the 2019 data was used to adjust some of the model’s parameters. Therefore, as a complement, the same comparison is repeated for the years 2015-2018, after adjusting for the wind and solar capacity installed in each country (but leaving the thermal capacity untouched, which could be a source of error) and for changes in fossil fuel and CO₂ emissions costs.

	2019		2018		2017		2016		2015	
	Sim.	Act.	Sim.	Act.	Sim.	Act.	Sim.	Act.	Sim.	Act.
Median	38.74	38.65	51.28	49.94	39.06	40.11	31.39	32.45	40.03	39.00
Mean	39.37	39.45	48.96	50.20	41.48	44.96	32.51	36.75	39.63	38.46
Std. Dev.	13.51	14.02	18.15	18.45	13.73	20.23	11.02	24.44	16.23	12.99
Skewness	0.53	0.28	-0.02	0.80	1.25	1.59	0.57	14.12	0.26	0.20
Kurtosis	5.57	4.39	6.75	9.42	11.36	8.10	3.52	435.8	3.44	3.64
Median Error	+0.000		+0.000		-1.051		-1.604		+0.117	
Mean Error	-0.076		-1.240		-3.480		-4.244		+1.010	
RMSE	7.175		11.176		11.915		18.640		9.685	
MAE	5.040		7.760		7.007		6.695		7.304	
R^2 [%]	73.81		63.30		65.31		41.82		44.37	
Corr. [%]	86.48		81.59		84.23		72.27		80.38	

Table D.1 – Simulated and actual prices and prediction errors [EUR/MWh]

Table D.1 provides some descriptive statistics of the prices simulated by the model, the prices that were actually observed, and the difference between the two, i.e. the prediction error. For the year 2019, the model is able to reproduce the moments of the historic prices, and the prediction errors are rather small with a mean average error (MAE) of 5 EUR/MWh. When computing the R^2 by taking the model’s simulation as the prediction and the actual price as observation, it suggests that the model predicts about 74% of the price variation. However the model’s prediction are less accurate for previous years, which can be attributed to two causes: 1. the parameterization of the model was adjusted by comparing outputs with observations from 2019, and its external validity (validity on other years of data) is not as good ; 2. Some inaccuracies in the parameterization of the model appear since all parameters were not adjusted to match previous years and were left at their 2019 value (e.g. thermal generation capacities).

The year 2016 is found to have a very high RMSE (but a rather small MAE): this can be explained by few very big prediction errors. Detailed results show that these large mistakes are mostly concentrated on a few hours in November 2016 when mar-

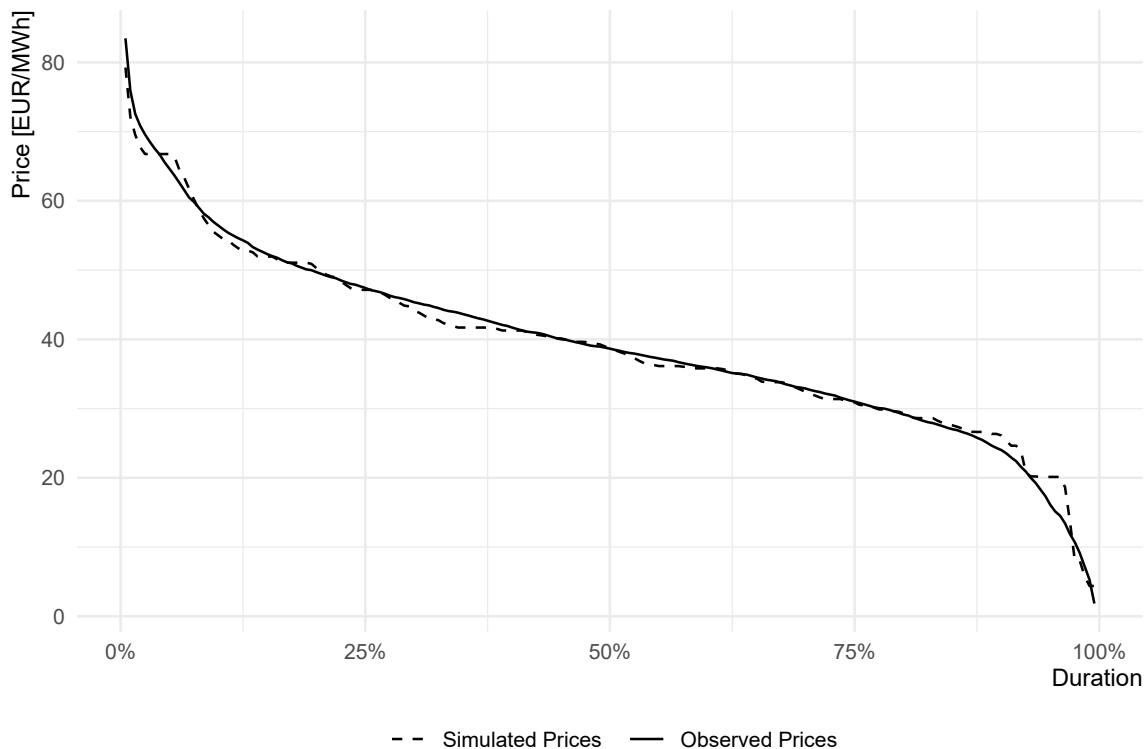


Figure D.3 – Observed and simulated price duration curve in France in 2019

ket prices skyrocketed at up to 875 EUR/MWh, whereas the model only predicts 110 EUR/MWh. During this period, historic generation data shows that power supply relied significantly (up to 3 GW) on oil-fired generation capacity, which almost never happens. This could explain high marginal costs and thus very high prices (exacerbated by market power). In contrast, the model's simulation was able to satisfy the demand for power without oil-fired capacities thanks to a gas-fired production higher than observed. Moreover the model does not account for market power, which might be particularly pregnant in periods of high scarcity.

The errors may be partially explained by intra-year variation of EU ETS carbon allowances' prices, which is only accounted for through a yearly average value. This should be particularly striking for 2018, when the price went from 8 EUR/t in January to about 20 EUR/t in December.

Figure D.3 shows the price duration curve for 2019, that is, the time (as a percentage of the year) during which the electricity price was higher than a certain level. The comparison of the simulation outputs with historical observations suggests that

the model is able to reproduce a price distribution similar to the distribution of actual prices. However, some small flat steps appear on the curve representing the simulation outputs, steps that correspond to the marginal costs of some specific technologies specified in the model. For example, a relatively large step is visible at 20 EUR/MWh, which corresponds to a large number of hours in which nuclear power plants were marginal.

In addition to the global distribution of prices, we want to ensure that the model correctly reproduces daily, weekly, and seasonal patterns. These patterns are depicted in Figure D.4, which shows the average price in 2019 per hour of the day, per quarter, and comparing weekdays and weekends. During weekdays, the daily patterns seem to be well reproduced by the model. During the winter, the model seems to slightly overestimate market prices during morning and evening peaks, as well as prices during the night. During the summer, it seems to underestimate market prices during the middle of the day, when prices are pushed down by lower consumption and solar production. This latter bias may explain why the simulation results presented in Chapter 2 tend to show a downward bias for the value of solar projects as compared to wind projects. Weekend price patterns appear to be less well reproduced by the model, possibly because these average prices are computed over a smaller number of hours. Looking closely at some sample time series of simulated prices compared to their observed counterparts, such as those shown in Figure D.5, even though simulations are occasionally wrong compared to actual realization, they do not seem to exhibit any systematic bias, such as smoother or sharper price changes.

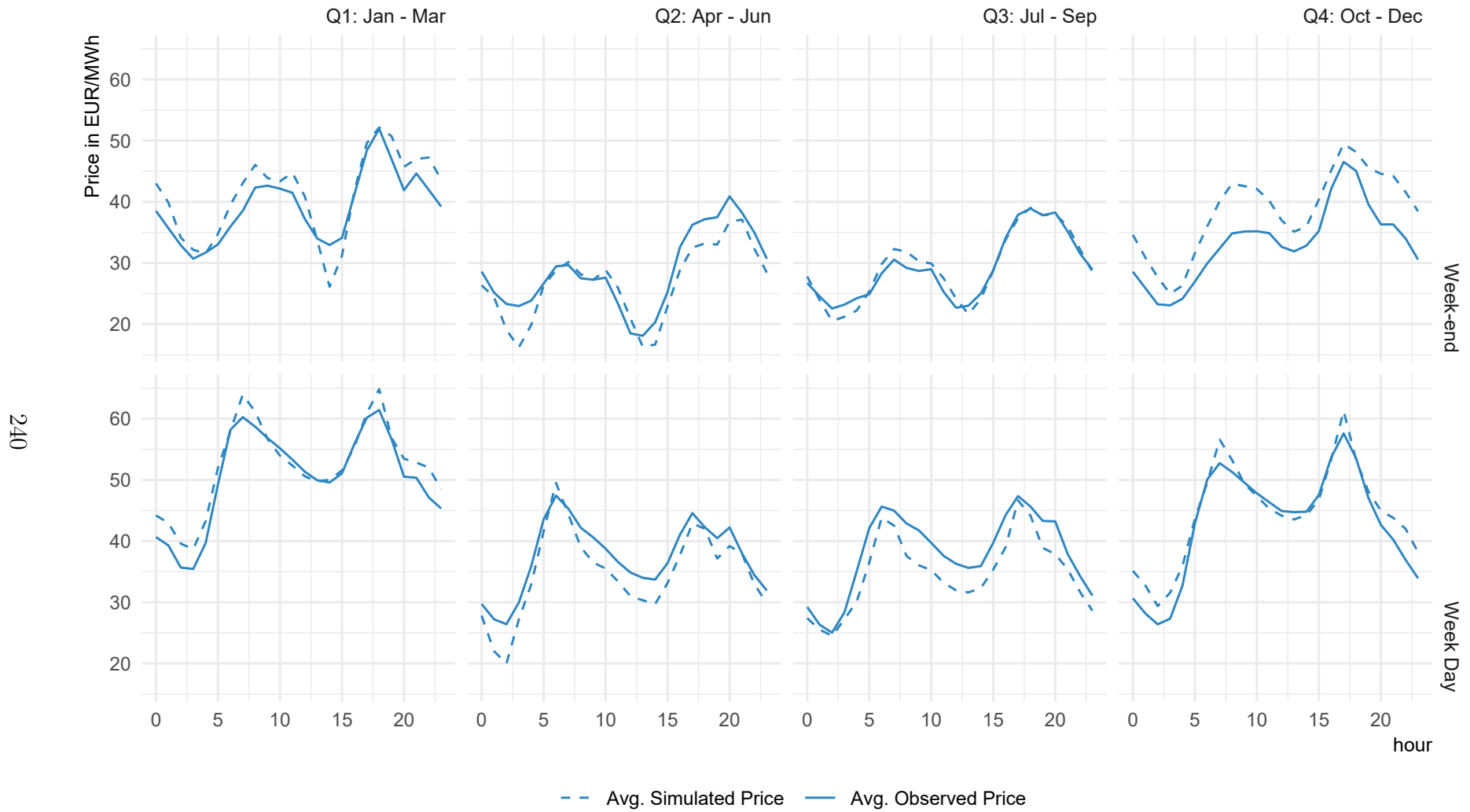


Figure D.4 – Observed and simulated price patterns by time of day, season and day of the week in France in 2019

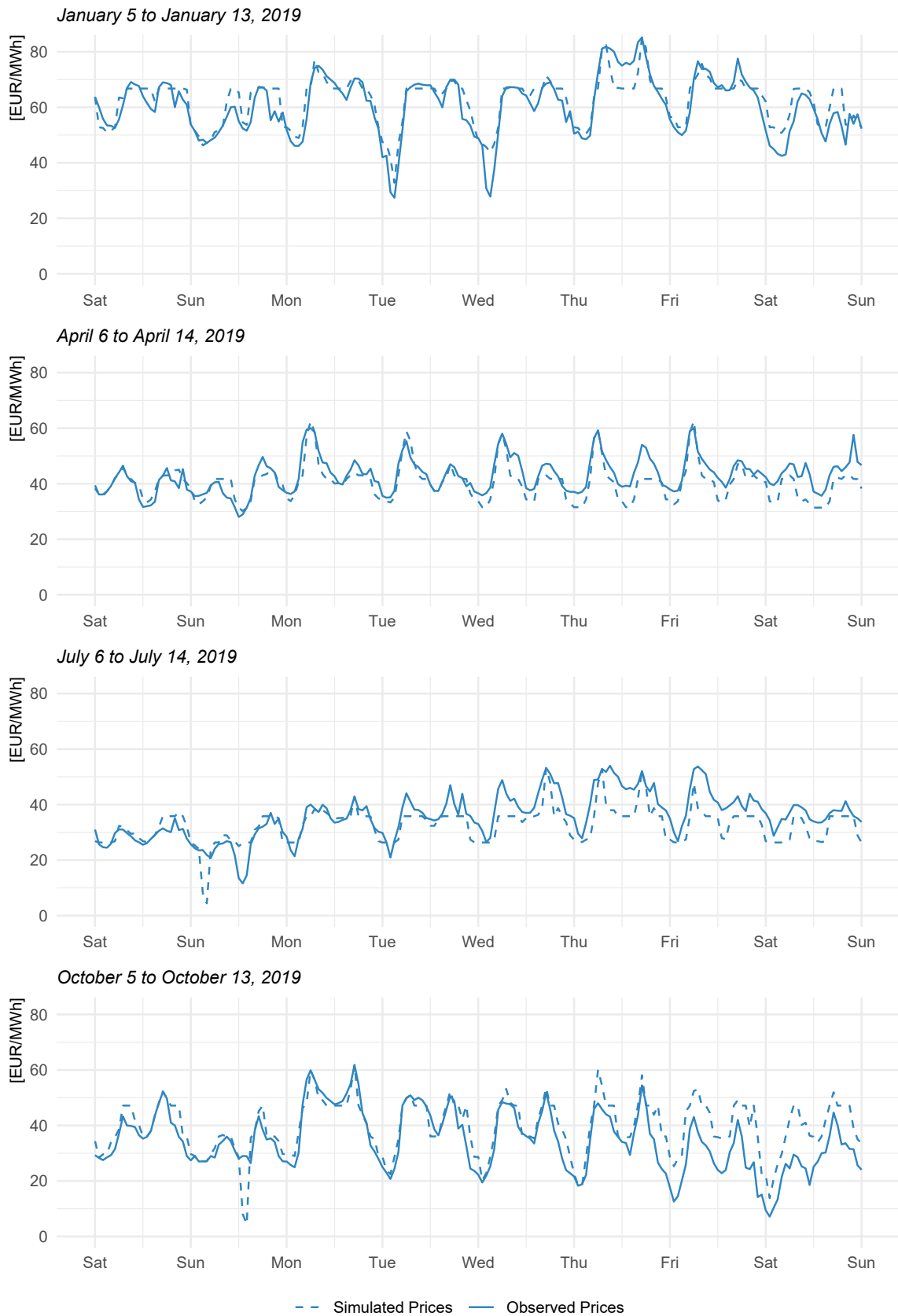


Figure D.5 – Samples of observed and simulated prices in 2019

D.3 List of model parameters and equations

Indices

$t \in T$	Time-period (1 hour)
$week(t) \in WEEK(T)$	Partition of T in weeks
$month(t) \in MONTH(T)$	Partition of T in months
$a \in A$	Areas, representing independent markets (typically one country)
$aEX \in AEX$	Neighboring areas whose dispatch is not modelled but represented as exogenous traders
$tec \in TEC$	Power generation technologies
$vre \in VRE \subset TEC$	Variable renewable technologies (offshore and onshore wind, solar, run-of-river hydro)
$thr \in THR \subset TEC$	Thermal technologies (nuclear, gas-fired, coal-fired and oil-fired technologies)
$sto \in STO \subset TEC$	Storage technologies (reservoir hydro power)

Endogenous variables

$GENE_{a,t,tec}$	Power generated at time t in area a by technology tec
$ON_{a,t,thr}$	Capacity available for generation at time t in area a for thermal technology thr
$\Delta ON_{a,t,thr}^+$	Start-up: Increase in available capacity between $t - 1$ and t in area a for technology thr (strictly positive)
$\Delta ON_{a,t,thr}^-$	Turn-off: Decrease in available capacity between $t - 1$ and t in area a for technology thr (strictly positive)
$RSV_{a,t,tec}$	Reserve requirement covered by technology tec in area a at time t
$IM_{a,a',t}$	Imports from area a' to area a at time t

$EX_{a,a',t}$	Exports to area a' from area a at time t
$LL_{a,t}$	Lost load (unmet demand) at time t in area a
$STORAGE_{sto,a,t}$	Power consumed for storage at time t in area a by technology sto
$STORED_{sto,a,t}$	Amount of energy in stock at time t in area a for technology sto

Exogenous time-varying inputs

$demand_{a,t}$	Demand for electricity at time t in area a
$cf_{vre,a,t}$	Capacity factor of variable technology vre at time t in area a
$nucAF_{week(t)}$	Share of nuclear capacity available in week $week(t)$
$lakeInflow_{a,month(t)}$	Natural energy inflow in hydro power reservoirs in month $month(t)$ in area a
$pfuel(thr),month(t)$	Fuel price for technology thr in month $month(t)$

Exogenous parameters

$capa_{tec,a}$	Installed capacity in area a for technology tec
$capaIn_{sto,a}$	Maximum power consumed for storage by technology sto in area a
$stockMax_{sto,a}$	Maximum energy stored by technology sto in area a
$icCapa_{a,a'}$	Interconnection capacity between area a and area a'
$genCost_{thr}(pfuel(thr),month(t))$	Generation cost of technology thr as a function of fuel price
$onCost_{thr}(pfuel(thr),month(t))$	Availability cost of technology thr as a function of fuel price

D.3. List of model parameters and equations

$suCost_{thr}(p_{fuel(thr),month(t)})$	Start-up cost of technology thr as a function of fuel price
$rampCost_{thr}(p_{fuel(thr),month(t)})$	Ramping cost of technology thr as a function of fuel price
$minSG_{thr}$	Minimum capacity factor for thermal technology thr
$maxAF_{thr}$	Maximum availability factor at any time for thermal technology thr
yAF_{thr}	Maximum yearly availability factor for thermal technology thr
$\underline{\delta}_{thr}$	Minimum time off for thermal technology thr
$\bar{\delta}_{thr}$	Minimum time on for thermal technology thr
η_{sto}^{in}	Storage efficiency at consumption for technology sto
η_{sto}^{out}	Storage efficiency at generation for technology sto
$trLoss$	Transportation loss applicable trade accross areas
$loadUnc$	Parameter of reserve requirement accounting for load uncertainty
$loadVar$	Parameter of reserve requirement accounting for load variability
$vreRR_{vre}$	Reserve requirement accounting for uncertainty on the output of technology vre
$voll$	Value of lost load (cost of not serving demand)

Objective

$$\min \sum_{a \in A} \sum_{t \in T} hCost_{a,t} \quad (D.23)$$

with

$$\begin{aligned} hCost_{a,t} = & \sum_{thr \in THR} [genCost_{thr}(p_{fuel}(thr), month(t)) * GENE_{a,t,thr} \\ & + onCost_{thr}(p_{fuel}(thr), month(t)) * ON_{a,t,thr} \\ & + suCost_{thr}(p_{fuel}(thr), month(t)) * \Delta ON_{a,t,thr}^+ \\ & + rampCost_{thr}(p_{fuel}(thr), month(t)) \\ & \quad * \min(0, GENE_{a,t,thr} - GENE_{a,t-1,thr})] \\ & + \sum_{sto \in STO} [stoCost_{sto} * GENE_{a,t,sto}] \\ & + \sum_{aEX \in AEX} [exoPrice_{aEX} * (IM_{a,aEX,t} - EX_{a,aEX,t}) / (1 - trLoss)] \\ & + [voll * LL_{a,t}] \end{aligned}$$

Constraints
Adequacy

$$\forall a \in A, t \in T,$$

$$\begin{aligned} \sum_{tec} GENE_{tec,a,t} + \sum_{a' \in AUAEX} IM_{a,a',t} + LL_{a,t} = \\ demand_{a,t} + \sum_{a' \in AUAEX} EX_{a,a',t} + \sum_{sto} STORAGE_{sto,a,t} \end{aligned} \quad (D.24)$$

VRE generation

$$\forall a \in A, t \in T, vre \in VRE,$$

$$GENE_{vre,a,t} \leq capa_{vre,a} * cf_{vre,a,t} \quad (D.25)$$

D.3. List of model parameters and equations

Thermal generation

$$\forall a \in A, t \in T, thr \in THR,$$

$$GENE_{thr,a,t} + RSV_{thr,a,t} \leq ON_{thr,a,t} minSG_{thr} \cdot ON_{thr,a,t} \leq GENE_{thr,a,t} \quad (D.26)$$

Thermal start-ups and turn-offs

$$\forall a \in A, t \in T, thr \in THR,$$

$$ON_{thr,a,t} \leq capa_{thr,a} \cdot maxAF_{thr} \quad (D.27)$$

$$\Delta ON_{thr,a,t}^+ \leq capa_{thr,a} - ON_{thr,a,t} - \sum_{t-\tilde{\delta}_{thr} < j < t} \Delta ON_{thr,a,t}^- \quad (D.28)$$

$$\Delta ON_{thr,a,t}^- \leq ON_{thr,a,t} - \sum_{t-\bar{\delta}_{thr} < j < t} \Delta ON_{thr,a,t}^+ \quad (D.29)$$

$$\forall a \in A, thr \in THR,$$

$$\sum_{t \in T} ON_{thr,a,t} \leq \sum_{t \in T} capa_{thr,a} \cdot yAF_{thr} \quad (D.30)$$

Nuclear availability

$$\forall a \in A, t \in T,$$

$$ON_{nuclear,a,t} \leq capa_{nuclear,a} \cdot nucAF_{week(t)} \quad (D.31)$$

Storage

$$\forall a \in A, t \in T, sto \in STO,$$

$$0 \leq STORED_{sto,a,t} \leq stockMax_{sto,a} \quad (D.32)$$

$$STORAGE_{sto,a,t} \leq capaIn_{sto,a} \quad (D.33)$$

$$GENE_{sto,a,t} + RSV_{sto,a,t} \leq capa_{sto,a} \quad (D.34)$$

$$STORED_{sto,a,t+1} = STORED_{sto,a,t} + \eta_{sto}^{in} STORAGE_{sto,a,t} - \frac{1}{\eta_{sto}^{out}} GENE_{sto,a,t} \quad (D.35)$$

Hydroelectricity

$$\forall a \in A, t \in T,$$

$$\begin{aligned} STORED_{lake,a,t+1} = & STORED_{lake,a,t} + \eta_{lake}^{in} STORAGE_{lake,a,t} \\ & - \frac{1}{\eta_{lake}^{out}} \left(GENE_{lake,a,t} + \frac{lakeInflow_{a,month(t)}}{card(month(t))} \right) \end{aligned} \quad (D.36)$$

$$\forall a \in A, month(t) \in month(T),$$

$$\sum_{t \in m} [GENE_{lake,a,t} - \eta_{lake}^{in} \eta_{lake}^{out} STORAGE_{lake,a,t}] = lakeInflow_{a,m} \quad (D.37)$$

Trade

$$\forall a \in A, a' \in A \cup AEX, t \in T,$$

$$IM_{a,a',t} = (1 - trLoss) \cdot EX_{a',a,t} IM_{a,a',t} \leq icCapa_{a,a'} \quad (D.38)$$

Reserve requirement

$$\forall a \in A, t \in T,$$

$$\begin{aligned} \sum_{tec \in frr} RSV_{tec,a,t} = \\ demand_{a,t} \cdot loadUnc \cdot (1 + loadVar) + \sum_{vre \in VRE} capa_{tec,a} \cdot vreRR_{vre} \end{aligned} \quad (D.39)$$

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Titre: Analyse micro-économique des mécanismes de subvention à la production d'électricité éolienne et solaire

Mots clés: Électricité renouvelable, Subventions, Incitations, Risque, Comportements Stratégiques

Résumé: Le déploiement des énergies renouvelables intermittentes est soutenu par les pouvoirs publics de nombreux pays, particulièrement en Europe, via des mécanismes de subvention à la production, souvent sous la forme de contrats de subventions accordés par appels d'offres. Ces mécanismes, et en particulier le design des contrats qui déterminent la subvention versée, varient dans le temps et suivant les juridictions : ils peuvent aller d'un tarif d'achat fixe à un système de primes de marché en passant par des systèmes plus complexes de compléments de rémunération. Ce choix a des conséquences sur les incitations transmises aux développeurs de centrales renouvelables, des conséquences sur le risque supporté par les investisseurs, et peut parfois ouvrir la voie à des comportements stratégiques nuisibles aux objectifs poursuivis par les pouvoirs publics. Cette thèse s'emploie à analyser ces conséquences à travers la modélisation microéconomique du comportement des firmes subventionnées pour développer des centrales solaires et éoliennes, en mobilisant des outils de théorie des contrats et de théorie des enchères. Des éléments de quantification sont apportés par la modélisation technico-économique du système électrique et de la production d'électricité éolienne et solaire en France.

Les choix de localisation des centrales ou les choix techniques (ex. : modèles des turbines éoliennes installées, orientation des panneaux solaires) dépendent notamment de la manière dont le revenu des firmes dépend (ou non) des prix des marchés de l'électricité. Si c'est le cas, comme avec un système de primes de marché mais pas avec des tarifs d'achat fixes, les firmes sont incitées à accorder une plus grande valeur aux projets susceptibles de produire au moment où l'électricité est la plus chère. Bien que significatif, le rôle de ces incitations est à mettre en regard des risques accrus que génère l'exposition aux prix de marché pour les firmes. Ces dernières exigeraient des primes de risques plus élevées en compensation au travers des appels d'offres. Des simulations présentées dans cette thèse montrent qu'en France, aujourd'hui, cette augmentation des primes de risques suite à l'adoption de primes de marché serait d'un ordre de grandeur supérieur aux gains de bien-être résultant des meilleures incitations fournies aux développeurs. Cependant, certains systèmes de complément de rémunération permettent de limiter le risque pour les firmes tout en améliorant les incitations qui leur sont fournies, à condition que ces systèmes soient bien conçus (ce qui n'est pas toujours le cas des systèmes en place en Europe aujourd'hui). La part croissante des énergies renouvelables intermittentes dans le mix électrique pourrait cependant modifier ces conclusions à plus long terme.

Bien que la limitation des risques pour les investisseurs apparaisse comme un enjeu majeur du design des contrats de subventions, cette thèse met également en évidence un écueil qui consisterait à vouloir assurer les investisseurs vis-à-vis du risque lié à la production de leurs projets (qui dépend notamment des conditions météorologiques) : il est montré que des contrats visant à assurer vis-à-vis de ce risque sont susceptibles d'induire des comportements stratégiques de la part des développeurs, qui entraîneraient des surcoûts et/ou inefficacités dans le développement des renouvelables. Ce constat s'applique en particulier au mécanisme utilisé par la France pour l'éolien en mer au début des années 2010.

Title: Microeconomic analysis of subsidy mechanisms for power generation from wind and solar sources

Keywords: Renewable electricity, Subsidies, Incentives, Risk, Strategic Behavior

Abstract: The deployment of intermittent renewable energy is supported by public authorities in many countries, particularly in Europe, through production support mechanisms. Increasingly, these take the form of subsidy contracts that are awarded through competitive bidding to projects that bid the lowest amount of subsidy in an auction. These mechanisms vary over time and across jurisdictions, particularly with respect to the design of the contract that determines the subsidy paid, which can range from a fixed feed-in tariff to a system of pure feed-in premiums to more complex systems of sliding feed-in premiums. The design of these contracts has consequences on the incentives transmitted to the developers of renewable power plants, consequences on the risk borne by investors, and can sometimes open the way to strategic behavior detrimental to the objectives pursued by the public authorities. This thesis attempts to analyze these different dimensions through a microeconomic modeling of the behavior of firms subsidized to develop solar and wind power plants, using tools from contract theory and auction theory. Elements of quantification are introduced through bottom-up modeling of the electricity system and the production of wind and solar power in France.

In particular, the location of power plants or technical choices (e.g., the types of wind turbines to be installed, the orientation of solar panels) depend on how exposed (or not) firms are to price signals from electricity markets. These price signals induce firms to place a higher value on projects that are likely to produce when electricity is most expensive, provided that their revenues depend on market electricity prices. This is the case with feed-in premium systems, but not with fixed feed-in tariffs. Although significant, the role of these incentives must be weighed against the increased risk to firms created by exposure to market electricity prices, which is likely to be reflected in higher risk premiums that will be factored into the bids submitted in the auction that determines the level of subsidy. Simulations of the electricity system presented in this paper show that in France in the late 2010s, the increase in risk premiums that would result from a pure feed-in premium subsidy scheme is an order of magnitude higher than the welfare gains that would result from better incentives for developers. However, some systems of sliding feed-in premiums can keep the risk for investors low while improving the incentives for developers, as long as these systems are well designed (which is not true of all systems in place in Europe today). However, the growing share of intermittent renewables in the electricity mix may change these conclusions in the longer term.

Although risk limitation for investors is found to be an important issue in the design of subsidy contracts, this paper also highlights the pitfalls of trying to insure investors against the production risk of their projects (which depends, inter alia, on weather conditions): it is shown that contract designs aimed at insuring against this risk are very likely to induce strategic behavior on the part of developers that would lead to additional costs and/or inefficiencies in the development of renewable energy. This observation applies in particular to the mechanism used by France for offshore wind in the early 2010s.