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Renewable Energy Sources

Sam AFLAKI
Serguei NETESSINE
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Sam Aflaki*

Serguei Netessine**

* PhD Candidate in Decision Sciences at INSEAD, Boulevard de Constance 77305 Fontainebleau, France. Email: sam.aflaki@insead.edu

** Professor of Technology and Operations Management, The INSEAD Chaired Professor of Technology and Operations Management, Research Director of the INSEAD-Wharton Alliance at INSEAD, Boulevard de Constance 77305 Fontainebleau, France.
Email: Serguei.netessine@insead.edu

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Sam Aflaki

INSEAD, Decision Sciences Area. sam.aflaki@insead.edu

Serguei Netessine

INSEAD, Technology and Operations Management Area. serguei.netessine@insead.edu

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In this paper we analyze incentives for investment in renewable electricity generating capacity. In particular, we model the tradeoff between investing in a renewable technology (such as wind) and a non-renewable technology (such as natural gas). The renewable technology has higher investment cost and is intermittent—that is, the supply of electricity from this technology is uncertain. The non-renewable technology is reliable and has a lower investment cost, but generation of electricity from this technology entails fuel expenditures as well as emission (carbon) costs. Motivated by existing electricity markets, we model several interrelated contexts, including: (a) vertically integrated electricity supplier, (b) market competition and (c) partial market competition with long-term fixed-price contracts for renewable electricity. Within these contexts we examine the impact of carbon taxes on the total cost and the share of wind capacity in the total capacity portfolio. We find that intermittency is the critical aspect of renewable technologies which drives the effectiveness of carbon pricing mechanisms. Our results suggest that, due to intermittency of supply and the need for backup generating capacity, increasing the price of carbon emissions may have an unexpected adverse effect on investment in renewables. In addition, we show that market liberalization can have a negative effect on investment in renewable capacity, total cost and total emissions of the system. Fixed price contracts with renewable generators can mitigate these detrimental effects, but they may also lead to excess renewable capacity and insufficient non-renewable capacity in view of their complementary role as backup generators. We conclude that actions towards reducing the intermittency of the renewable energy sources (e.g., through capacity pooling or unit-specific buffering) may be more effective in promoting investment in renewable generation capacity than reliance on carbon taxes alone.

Key words: Electricity Generation, Renewables, Intermittency, Capacity Investment, Incentives

1. Introduction

Renewable (or “green”) sources of energy, such as wind and solar power, will play a key role in the future energy landscape. By providing emission-free and sustainable energy, these sources

are considered to be important alternatives to fossil fuels. Worldwide capacity installations for renewables have been increasing at an accelerating rate. For instance, wind capacity installations have increased ten-fold in the last decade with the highest level of installations in the USA (25 GW), followed by Germany (24 GW), then Spain (17 GW), China (12 GW) and India (9 GW). An important feature of renewable technologies such as wind and solar power is intermittency—i.e., the supply of electricity from these sources is uncertain. For instance, wind does not blow at all times when there is demand and electricity generation from solar panels is highly volatile, depending on weather conditions, air pollution and other determinants of solar radiation intensity. Although some of this variability in supply is natural and can be planned for (e.g., the lack of generation from solar panels at night), there is still significant uncertainty associated with outputs of renewable technologies. In addition to intermittency, high investment costs in renewable energy sources handicap capacity investment.

A variety of strategies have been adopted to incentivize investment in renewables. These include renewable portfolio standards (RPS), minimum prices for energy from renewable energy injected into the grid (so-called Renewable Feed-in Tariffs) and multi-year subsidies and investment credits in some jurisdictions as direct incentives for new renewable capacity.¹ Added to these direct incentives for renewable investment, there are also indirect incentives based on increasing the price of fossil-fuel electricity generation (e.g., gas-fired, coal, etc.) by penalizing the environmental damage of these technologies. The most significant of these is carbon pricing.² An important objective of this paper is to understand the relationship between supply intermittency and the effectiveness of carbon pricing strategies.

Besides the introduction of renewables, electricity markets have gone through a second important change in the last two decades: market liberalization. Historically, electric utilities have been

¹ See Bushnell (2010) for a critical review of various incentives for renewable energy investments.

² The most common proposals for implementation of pricing of carbon emissions from fossil-fuel electricity plants are through cap and trade and through carbon tax systems. For a discussion of various forms of carbon pricing in the context of technology planning, see Drake et al. (2010).

vertically integrated, meaning that such functions as generation, transmission, retailing and distribution were performed within a single utility company. The typical reason was operational constraints associated with balancing generation, transmission and distribution. Such balancing would also contribute to the economics of electricity generation by reducing retailing costs (Michaels 2007). “Vertical unbundling” of generators and retailers in the electricity industry was the first step towards the liberalization of electricity markets. The idea of such restructuring was to create competition among generators to reduce retail prices as well as to keep the incumbent utilities from exercising market power inherent in their historically dominant position. Movement towards market liberalization has made electricity a commodity that can be traded in wholesale electricity markets. These markets are typically organized through a national or regional pool, with a so-called Independent System Operator responsible for assuring stability and control of the interconnecting transmission network. The pool (or spot) price for these markets are determined by a complex set of bidding and dispatching rules which vary significantly across different countries and regions. The common characteristic of all these markets, however, is significant volatility of spot prices. The reason is that, with some minor exceptions, electricity cannot be economically stored so that instantaneous balancing of supply and demand is required. Accomplishing this in a decentralized fashion through competitive power markets implies that a pool price reflecting the marginal cost of the last unit dispatched will vary considerably over time, driven by economic and technical uncertainties in supply and demand, as well as by uncertain exogenous variables such as weather conditions.

Motivated by the two developments described above, in this paper we study the effect of market liberalization on the investment in renewable electricity generation capacity. In particular, we portray an important role of intermittency of supply for renewables in their competitiveness in a liberalized market. We propose a stylized economic model which is motivated by the key features of electricity markets. In our model there can be two electricity generators (e.g., wind and gas) who make capacity investment decisions given the pricing mechanism established by the electricity

retailer. Shortfalls in supply are procured from the backup generators. Our model captures uncertainty in both supply and demand of electricity. We use this model to answer the following broad questions: How does intermittency affect capacity investment in renewables? Is the comparative disadvantage of renewables due to intermittency simply a cost issue? How will taxing emissions from fossil-fuel generation change the share of green technologies in the generation portfolio and total emissions?

Within this framework, we study how carbon taxing would affect investment in renewable and non-renewable electricity generation capacities. We find that increasing carbon price has two counteracting effects on investments in renewables. First, it improves cost competitiveness of renewables relative to thermal technologies due to lower GHG emissions for the former. On the other hand, renewables need backup generation, which typically comes from fossil fuel based generators. So increasing carbon price also leads to an increase in the cost of reserves to cover intermittency. How these counter-forces affect the technology share of renewables in the overall generation portfolio depends on the emission intensity of backup generation technologies as well as on the carbon price. It is often the case that older vintage generation technologies which are more emission intensive are used as backup. In this case increasing carbon price may decrease the proportion of the renewable generation within the overall generation portfolio. This effect takes place both in the vertically integrated and liberalized settings. However, in the liberalized market the negative effect of intermittency is further accentuated because of the marginal cost pricing that is typically employed in these markets, namely, the price of electricity is equal to the marginal cost of the last dispatched unit. This finding offers a very different support to the suggestion that the movement towards market liberalization may lead to under-investment in new renewable electric generation capacity (Joskow 2006).

To mitigate disincentives to invest in renewables in the liberalized market, public policy experts suggest long-term fixed-price contracts with generators to protect investment in new generating capacity from the risk of highly volatile spot prices (Joskow 2006; Borenstein 2002). For instance, long-term contracts between wind developers and electricity suppliers and some large customers

are used in the U.S. and Europe to promote investment in renewable capacity. Such fixed-price contracts with renewable generators are typically benchmarked on feed-in-tariffs, often with regulatory guarantees, that specify long-term prices based on generation costs rather than based on spot prices. We therefore consider an extension of our basic model where the price of the non-green electricity is determined in the spot market, but the retailer sets a fixed price for green electricity *ex ante*. We find that fixed-price contracts are effective in stimulating investment in renewables and renewable capacity may even exceed the vertically integrated level. However, over-reliance on carbon-intensive backup generation and an increase in total emissions (relative to the vertically integrated case) can result.

To summarize, the contributions of this paper are threefold. First, we study the effect of supply intermittency of renewables in electricity markets on the capacity investment decision. Second, we demonstrate how incentives arising from the vertical unbundling in the organizational structure of electricity supply affect capacity investments, total cost and emissions as well as the share of the renewable technology in the capacity portfolio. Third, we show the counter-intuitive result that increasing the price of carbon can have an adverse effect on investments in renewables because of the interdependence of wind capacity and backup capacity, with the latter typically being more carbon intensive. Our analysis leads to new insights about the relative merits of different structures of the electricity market as well as the impact of carbon pricing with respect to promoting renewable energy sources. Throughout, we use numerical analysis based on real-world data to support our analytical results.

The rest of the paper is structured as follows. In section 2 we review the related literature and position our paper. Section 3 lays out the foundations of our model. In section 4, we study a vertically integrated electricity supplier and examine the effect of intermittency of green technology on the capacity decisions. In section 5 we analyze market competition. Section 6 considers fixed price contracts for green electricity and Section 7 concludes the paper.

2. Literature Review

Our paper draws from and contributes to two distinct streams of literature. The first stream belongs to the operations management literature and is concerned with (incentives for) capacity investment, technology choice and unreliability in supply chains. The second stream is closer to the economics tradition and studies optimal strategies with respect to generation and pricing of electricity.

2.1. Capacity Investment, Technology Choice and Unreliable Supply Chains

The literature on capacity investment and technology choice in operations management considers the tradeoffs that firms face when investing in technologies with different characteristics. For a comprehensive review of capacity investment literature in the operations management tradition see Van Mieghem (2003). A large body of literature considers production flexibility in the presence of demand uncertainty (Chod and Rudi 2005; Röller and Tombak 1993; Goyal and Netessine 2007). This literature is relevant because in our model there is also flexibility in supplying electricity using different capacity types (wind, gas) although there is only a single demand stream. A few recent papers have considered incentives for capacity investment across supply chain participants (see e.g. Plambeck and Taylor 2005). These papers do not consider intermittency in supply.

The issues of supply uncertainty/intermittency are considered in the literature on unreliable supply chains (see the references in Tomlin 2006), random yield and disruption management (reviewed in Yano and Lee 1995). For instance, Parlar and Perry (1995) considers an EOQ model with a single supplier and a single retailer where the ordered amount may sometimes be unavailable. They analyze optimal inventory policies in such situations. Closer to our setting, Tomlin and Wang (2005) consider a dual sourcing problem in which the retailer can meet demand by ordering either from a cheap but unreliable supplier, or from a more expensive but reliable supplier. These papers focus on unreliability and capacity investment but typically do so in the vertically integrated (monopolistic) setting.

Our paper is also related to a fairly recent stream of literature that studies the incentives for capacity investments in a vertically unbundled setting. In particular we consider fixed price

contracts, where a retailer³ announces a fixed price for (renewable) electricity and the generator/supplier chooses capacity based on the announced price. Lariviere and Porteus (2001) consider simple price-only contracts in the context of the newsvendor problem. Taylor and Plambeck (2007) consider non-binding price contracts (i.e. “promises”) and characterize conditions under which price-only contracts are preferred over price-quantity contracts. Van Mieghem (1999) and Plambeck and Taylor (2005) analyze price contracts in an outsourcing relationship. Cachon (2003) surveys the stream of papers on supply chain contracting. This stream of literature typically does not consider intermittency/unreliability, perhaps with the exception of Deo and Corbett (2009) where a very different setting is studied with a single capacity type.

Our paper emerges from the interfaces of the above mentioned literatures by addressing supply intermittency as well as incentive issues associated with vertical unbundling in the context of integrating the renewable energy sources into electricity markets.

2.2. Economics of Electricity Generation

Capacity choice and peak-load pricing in electricity markets received significant attention from economists in 70s and 80s (see Crew et al. 1995, for a review). Given the characteristics of the electricity markets at that time, these studies focused on monopolistic settings. For instance, Crew and Kleindorfer (1976) model joint determination of capacity and prices when a variety of technologies with different cost structures are available and demand is uncertain. Chao (1983) extends this analysis by considering uncertain supply in a monopolistic setting.

Vertical unbundling of the electricity supply chain and the introduction of competition in generation have drawn fresh attention to this field. Liberalized electricity markets have been the subject of a fast-growing stream of research (for a detailed review see Ventosa et al. 2005). Models of liberalized markets can be separated into short-term pricing and dispatching models and longer-term investment models. The short-term models focus on the strategic aspects of electricity supply when

³We use the term “retailer” to denote the economic entity having the ultimate responsibility for interactions with the end buyer or customer in the electricity supply chain. Depending on the context, this could be a “supplier”, an independent broker or wholesale power intermediary, a distribution company, or (in the case of vertically integrated) the division of an industrial company responsible for installing its own self-generation.

firms have already made their investment decisions (see e.g. Borenstein et al. 2000; Green and Newbery 1992). Longer-term investment incentives are examined in papers such as Von der Fehr and Harbord (1997) and Castro-Rodriguez et al. (2009) which consider capacity investment decisions, often in the context of Cournot competition. The main finding of these papers, consistent with the broad Cournot literature, is that decentralization (vertical unbundling) leads to under-investment in capacity, which further leads to higher electricity prices.

Research on renewable energy sources has examined both the theory of efficient integration of renewables into grid operations as well as the cost competitiveness of renewables empirically.⁴ A key finding of this literature (e.g. Owen 2004) is that renewables can be competitive/efficient when the pricing of traditional sources of energy (e.g. fossil fuel based) reflects environmental externalities. The issue of intermittency along with its cost and reliability implications for electricity generation has been addressed primarily in empirical studies that are often region-specific. (e.g. Neuhoff et al. 2007; Kennedy 2005; Butler and Neuhoff 2008). A few exceptions that address the issue of intermittency are Ambec and Crampes (2010) and Garcia and Alzate (2010). Similar to our model, both of these papers consider the optimal investment in two types of technologies: an intermittent renewable technology and a reliable fossil fuel technology with different cost structures. They too characterize and compare the optimal capacity investments under vertical integration and competition. However, unlike our paper, these papers do not consider demand uncertainty. Neither do they address incentive issues arising from fixed price contracting between the electricity retailer and the generator.

Finally, our research is related to the literature on the interface of operations management and energy markets. Examples within this stream include Elmaghraby (2005); Secomandi (2010) and Islegen and Reichelstein (2010). A related paper is Drake et al. (2010) which considers capacity investment under carbon pricing, but does not study either the impact of alternative sourcing arrangements or problems of intermittency, which are the primary focus of this paper.

⁴ For an overview on characteristics of renewable technologies and related grid integration problems, see (Twidell and Weir 2006). For a recent review of both the theoretical and empirical work on incentives and market efficiency in respect to renewable, see Bushnell (2010). For a related review of the interaction of regulatory practices in promoting efficient investments in renewables, see Boehringer and Rosendahl (2010).

3. The Model Setup

This section introduces our basic model and assumptions. We consider an electricity retailer, indexed by R , that is responsible to meet the random market demand. Demand is represented by a random variable \tilde{D} with positive support, distribution function $F(\cdot)$ and density $f(\cdot)$. Two types of electricity generation technologies are available. For expositional purposes, we refer to these technology types as Wind and Gas although they could potentially represent other technology types (e.g., photovoltaic and coal, correspondingly). The (renewable) wind technology is denoted by index W , while the (non-renewable) gas technology is denoted by G .

The key decision for the firm for each technology is its investment in capacity which will determine both limits on electricity production in the long term as well as the carbon intensity of electricity production from the resulting generation portfolio. We denote by k_i the decision with respect to capacity investment for each technology type $i \in \{W, G\}$. We denote by $\alpha_i > 0$ the investment and maintenance costs of each unit of capacity, while representing the unit fuel cost by u_i . We assume that each unit of electricity generation using gas capacity entails one unit of GHG emissions and we let a represent the price of “unit emission allowance”. Hence, the total unit variable cost for gas technology is $U_G = u_G + a$. We assume that $u_W = 0$; that is, the fuel and operational cost of the wind generator are negligible. Moreover, we assume that wind technology is emission-free, so that the total unit cost is $U_W = u_W = 0$. This cost structure is consistent with existing technologies for which investment costs for the green technologies are significantly higher than efficient fossil fuel technologies such as combined heat and power (CHP) gas turbines, while the variable generation costs (including emission costs) are significantly lower (Tarjanne and Kivistö 2008). The data that we use for numerical experiments reflects the same relationship.

We further assume that the wind technology is intermittent—i.e., the production from the available capacity is uncertain so that with capacity k_W only an actual production amount of $\tilde{v}_W k_W$ is obtainable. The random variable $\tilde{v}_W \in [0, 1]$ represents the uncertain wind capacity availability factor, which for tractability reasons we assume has a two-point distribution $\tilde{v} = [1, q; 0, 1 - q]$, i.e., the capacity is available with probability q and it is unavailable with probability $1 - q$. This

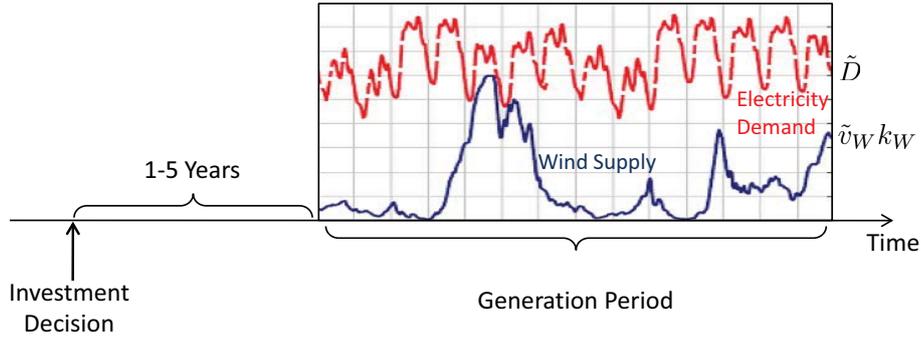


Figure 1 Decision time-line.

assumption captures presence/absence of wind (for wind capacity) or sun (for solar panels) but is not an entirely accurate approximation of reality because both wind and sun can have continuously varying strengths. However, this assumption serves the purpose of capturing intermittency in its simplest form while allowing for tractable solutions. A similar assumption is made by Tomlin and Wang (2005) and Ambec and Crampes (2010). Assuming that supply follows a continuous distribution does not alter our insights. To present the problem formulation in a unified way, we will represent the gas capacity’s availability factor using $\tilde{v}_G = 1$ with a slight abuse of notation.

We present the time-line of events in Figure 1. The decision about capacities is made before realization of demand and of the wind capacity availability factor $\tilde{v}_W \in [0, 1]$. There is typically a 1-5 years gap between the time of the investment decision and the actual operation in the market. The demand and supply are then realized in real time over a longer operational period. Our model captures these temporal variations by considering single-shot random variables in supply and demand so that the expectation operator over the random variables acts as an expectation over a representative period (e.g., a typical month) during the operational time period, with units of demand and cost all normalized to correspond to the length of the chosen representative period.⁵

Because the variable cost of wind is negligible (0 in our model), it is always dispatched to the grid first. When the total demand exceeds the amount of production by wind technology—i.e.,

⁵ This “representative period” model is standard in both the operations and economics literature. Needless to say, it is important that the definitions of demand, capacity and variable costs be consistent with the length of the representative period chosen; see (see Crew et al. 1995, for a review).

$\tilde{D} > \tilde{v}K_W$, the firm uses the gas capacity to generate the extra needed amount of electricity up to the available capacity. In case demand further exceeds the production from both technologies—that is, $\tilde{v}k_W + k_G < \tilde{D}$, the firm meets the extra demand from an external “backup” source with an infinite capacity and a unit fuel and operational cost of c . We can think of the backup as the set of generation units with backstop technology when the combined capacity of focal units of wind and gas turbines is exceeded. The normal generation mix of backup will typically be at the upper end of the dispatch order, thus with higher operating costs than wind or efficient gas units. The backup technology also entails GHG emissions, with emission intensity of e per unit of generation so that the total unit generation cost from the backup technology is $C = c + ae$. Backup generation is not only at the upper end of the dispatch merit order in operating cost; it is also more emission intensive than gas (or wind). The reason is that often times the older vintage coal or gas generation units are used as a backup when there is not enough supply. Another reason is that thermal generation units that are typically used as a backup are run less efficiently when they are not used in a steady base load. Hence, in practice, it is usually the case that $e > 1$. Although this assumption is not needed for our theoretical results, most of our numerical experiments are based on a realistic figure for e which is estimated to be between 2.0-2.5. Furthermore, we assume that the total generation cost from the backup technology (which may include transmission costs from the nearby region) is higher than both wind and gas technologies, so that whenever installed capacity is available, the backup technology is not used. The following assumption represents this notion technically.

ASSUMPTION 1. $C > \max\{U_G + \alpha_G, \frac{\alpha_W}{q}\}$.

The resulting short-run supply function for our three technology world is depicted in Figure 2. This is the standard merit-order dispatch function that is the basis for both ISO pool dispatch operations and efficiency analysis in the economics literature on electricity generation (see e.g. Hogan 1995).

4. The Vertically Integrated Retailer

For almost a century the electricity sector resembled a natural monopoly. All four primary elements of electricity supply—i.e., generation, transmission, distribution and retailing—were organized as a

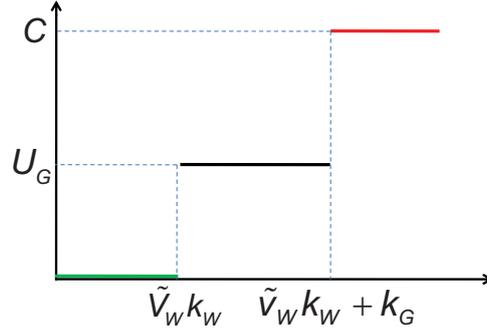


Figure 2 The Supply function.

vertically integrated firm which would be either state-owned or privately-owned with price and entry regulations identical to natural monopolies. In this section we consider such a vertically integrated firm which owns the generation capacity and is responsible to meet the demand. Within this framework, we first consider the case in which only one of the technologies is available for electricity generation. Besides its theoretical importance to understand the comparative advantage of two technology types independent of each other, this section helps us better understand the key factors underlying capacity choice for each technology, which we then use to analyze the case in which the two types of technologies are available.

4.1. Single Technology

The optimization problem of the vertically integrated firm when only one technology $i \in \{W, G\}$ is available can be formulated as

$$\min_{k_i} \bar{\Pi}_i(k_i) = \mathbb{E}_{\tilde{D}} \{U_i \min(\tilde{D}, \tilde{v}_i k_i) + C(\tilde{D} - k_i)^+\} + \alpha_i k_i. \quad (1)$$

Thus, the firm chooses capacity k_i to minimize expected operating costs (the first term in (1)) plus expected backup generation costs (the second term in (1)) plus total investment cost (the third term in (1)). Note that the emission cost is included in the operating and backup costs.

We define the critical ratio $A_i = \frac{\alpha_i}{\mathbb{E}\{v_i\}(C-U_i)}$ so that $A_W = \frac{\alpha_W}{qC}$ and $A_G = \frac{\alpha_G}{C-U_G}$. Intuitively, this is the ratio of the “overage cost”—i.e., the unit cost of over-investing in capacity, divided by the summation of the overage cost and the “underage cost”—i.e., the cost of under-investing in a unit of capacity. In other words, one extra unit of capacity bears one unit of investment

cost α_i , while if capacity is not developed and demand exceeds the capacity, the expected unit cost for such under-investment is equal to $\mathbb{E}\{v_i\}(C - U_i)$. Note that Assumption 1 implies that $A_i < 1$. Let $\bar{F}(\cdot) = 1 - F(\cdot)$ represent the survival function for the random variable \tilde{D} . Recall that the distribution function F has increasing⁶ failure rate (IFR) if the fraction $\phi(x) = f(x)/\bar{F}(x)$ is increasing. Decreasing failure rate (DFR) is defined analogously. We next state the solution of the vertically integrated problem with one technology type.

PROPOSITION 1. *Suppose that demand distribution has IFR. Then:*

- (a) *The unique optimal vertically integrated capacity in the single technology setting k_i^{FB} for technology $i \in \{W, G\}$ solves $\bar{F}(k_i) = A_i$.*
- (b) *$k_G^{FB} \geq k_W^{FB}$ if and only if $A_G \leq A_W$.*
- (c) *k_W^{FB} is increasing in a . k_G^{FB} is increasing in a if and only if $e > 1$.*

The solution is essentially equivalent to the well-known newsvendor solution in the operations literature (Cachon and Terwiesch 2006): the probability of meeting the demand with the backup capacity (a.k.a rationing demand in the context of newsvendor problem) is equal to the ratio of overage over overage plus underage costs. We can see that, as A_i increases, the optimal capacity for technology i decreases. So we can think of A_i in cost terms: the higher it is, the less attractive is the focal technology. As a consequence, Part (b) of Proposition 1 states that the technology which has lower critical ratio will have higher capacity than the other technology.

We wish to note that this view of technology investment decision based on the critical ratio is different from the simple average total cost view. The total average unit generating cost of the wind technology is equal to α_W/q , while it is equal to $\alpha_G + U_G$ for the gas technology. The comparison between these two total unit costs is not necessarily equivalent to the comparison of A_i . As is evident from Figure 3, given the parameters presented below the figure, the total generating cost of the gas technology is always higher than that of wind technology. However, we can see that for $a \geq 13$, the critical ratio of the gas technology falls below that of wind technology implying

⁶ We use the terms “increasing” and “decreasing” in their weak sense, unless otherwise stated.

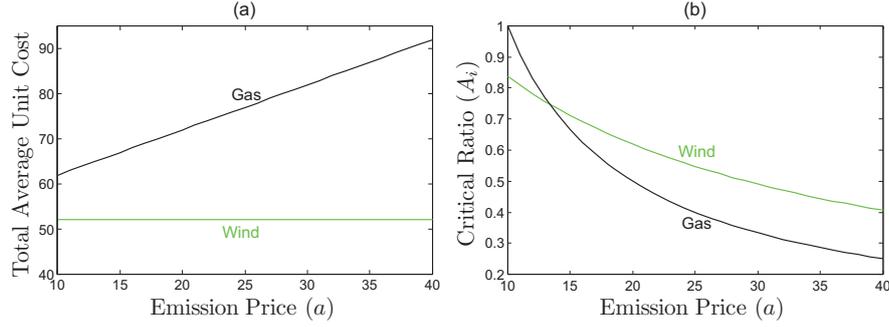


Figure 3 (a) Total generating cost and (b) critical ratio of the two technologies as a function of the price of emission allowance a . $\alpha_W = 12$, $q = 0.25$, $\alpha_G = 13$, $u_G = 40$, $e = 2.2$.

that for $a > 13$, the gas capacity exceeds the wind capacity, even considering the fact that it has higher generating cost. Looking at the critical ratio rather than the average total cost has the advantage of taking into account the effect of intermittency. The total cost of the wind technology is independent of the price of carbon emission a , or how emission intensive the backup technology is—which is reflected in parameter e —while its critical ratio depends on it. Also, the total costs of both technologies are not affected by the magnitude of c (backup cost), which is not the case for the critical ratios.

We finally emphasize that Part (c) of Proposition 1 states that the amount of wind capacity is always increasing in the price of carbon allowance a . This is not always the case for natural gas technology. Indeed, in accordance to what one would expect, gas-based capacity decreases in the carbon price when the backup technology is less emission intensive or when its price is independent of the carbon price. When $e > 1$ —that is, when the backup technology is more emission intensive than the gas technology, as is usually the case in practice, then gas capacity is also increasing in the carbon price.

4.2. Two Technologies

When both technologies are available, the firm's objective is to minimize the expected production and capacity costs, subject to meeting all the demand while dispatching the wind technology first:

$$\min_{k_W, k_G} \bar{\Pi}(k_W, k_G) = \mathbb{E}_{\tilde{D}} \mathbb{E}_{\tilde{v}_W} \left\{ U_W \min(k_W, \tilde{D}) + U_G \min(k_G, \tilde{D} - \tilde{v}_W)^+ + C(\tilde{D} - \tilde{v}_W - k_G)^+ \right\}$$

$$- \alpha_W k_W - \alpha_G k_G. \quad (2)$$

Proposition 2 characterizes the solution to the vertically integrated problem formulated in (2).

PROPOSITION 2. (a) *The optimal capacities for each technology, k_W^{FB} and k_G^{FB} are unique, and jointly solve the following first-order conditions:*

$$\begin{aligned} q\bar{F}(k_W + k_G) + (1 - q)\bar{F}(k_G) &= A_G \\ (1 - \frac{U_G}{C})\bar{F}(k_W + k_G) + \frac{U_G}{C}\bar{F}(k_W) &= A_W. \end{aligned} \quad (3)$$

Furthermore, under Assumption 1, the two types of technologies are strategic substitutes;

- (b) *if $A_W \leq (\geq) A_G$ and $q \geq (\leq) 1 - \frac{U_G}{C}$, then $k_W^{FB} \geq (\leq) k_G^{FB}$.*
- (c) *The optimal capacity k_W^{FB} (k_G^{FB}) is increasing (decreasing) in q and u_G .*
- (d) *The optimal capacity for each technology k_i^{FB} , $i \in \{W, G\}$ is decreasing in its own unit investment cost α_i and increasing in the other technology's unit investment cost, α_{-i} .*

The first observation we make is that the set of equations (3) that characterizes the optimal solution with two technologies resembles the solution to the single technology case. Essentially, the left-hand sides of both equations are convex combinations of the probability of rationing demand when both capacities are available and when only one of the capacities is available. In particular, when $A_W \rightarrow 1$ it is straightforward to verify that $k_W^{VI} = 0$ and when $A_G \rightarrow 1$, $k_G^{VI} = 0$, which reduces (3) to the solution in the single technology case $\bar{F}(k_i) = A_i$.

In Part (b) of Proposition 2, we can see that, similar to the single technology case, the critical ratio A_i plays an important role in determining the economic attractiveness of the technology. When $A_W < A_G$ and q is high ($q \geq 1 - \frac{U_G}{C}$), the optimal wind capacity is higher than the optimal gas capacity. Parts (c) and (d) further state relatively intuitive comparative statics results. Keeping all else constant, as wind technology becomes more reliable (i.e. q increases), the firm invests more in this technology. Also, when the variable cost of gas generation increases, the firm has more incentives to invest in the wind generation. An increase in the unit investment cost of each technology i leads to a decrease in its capacity at the optimum, and because the two capacity

types are substitutes, this leads to an increase in the other capacity type. The following proposition provides less intuitive comparative statics results with respect to the cost of backup generation as well as with respect to carbon price.

PROPOSITION 3. (a) *The optimal capacity for gas-based generation k_G^{FB} is increasing in the unit backup price c . If the distribution function of the electricity demand has IFR, then the optimal capacity for wind is decreasing in c ; otherwise it is increasing in c . The total optimal capacity $k_W^{FB} + k_G^{FB}$ is increasing in c .*

(b) *If $e \leq 1$ – that is, backup emission intensity is higher than gas, then k_W^{FB}/k_G^{FB} is strictly increasing in the unit price of carbon allowance a . This does not necessarily hold for $e > 1$.*

Interestingly, monotonicity of the optimal capacities in the cost of backup generation does not depend on the marginal production and capacity costs of wind and gas. Rather, it depends on the structure of the demand distribution and in particular on its failure rate. Proposition 3 states that, regardless of the relative magnitude of production costs for wind and gas, increased backup cost always leads to higher gas capacity while under the assumption of increasing failure rate, it leads to a decrease in the wind capacity. This is a direct consequence of wind intermittency along with the fact that wind is the primary technology in the dispatch order. In fact, if $q = 1$ —that is, the wind technology is not intermittent, the amount of wind capacity does not change as c increases, while gas capacity is increasing in c (see the proof of Proposition 3). An increase in c leads to higher cost of underage for wind. There is, however, a second effect: since an increase in c leads to more gas capacity, the probability of having “low” underage (when demand does not exceed wind plus gas capacity) increases. Which effect dominates depends on the failure rate of demand distribution: when the failure rate is increasing, the probability of having demand in the region between wind and wind+gas capacity increases, and therefore the probability of “low” underage increases fast while the probability of “high” underage decreases. As a result, the optimal wind capacity decreases.

Another counter-intuitive and perhaps surprising result is related to part (b). It is quite expected that, as the emission price increases, the share of the wind technology increases. However, it turns

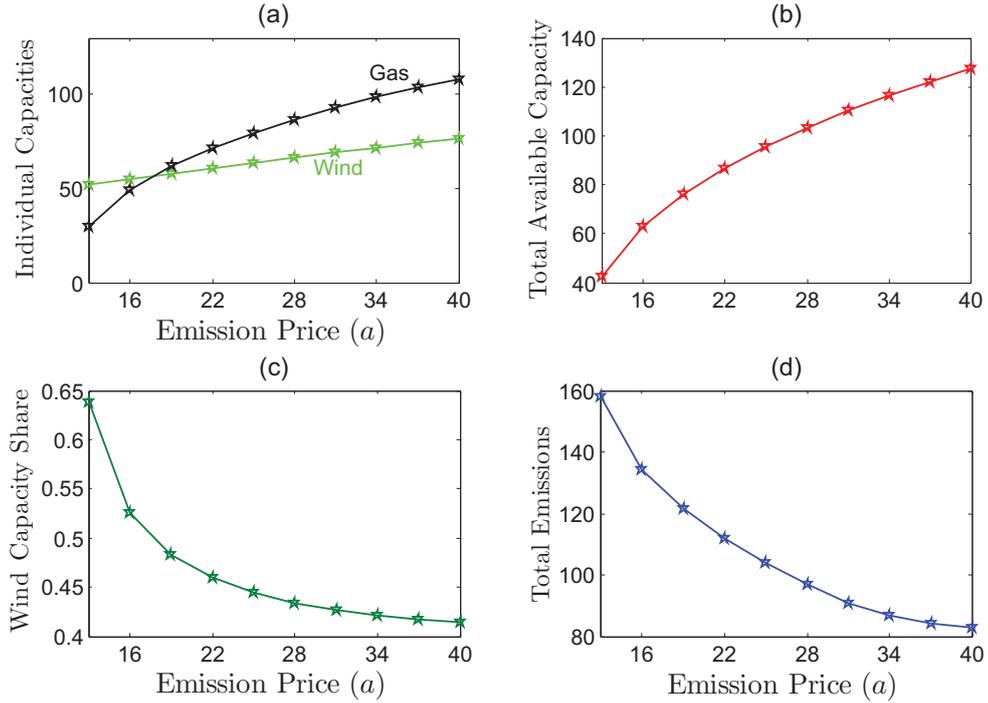


Figure 4 (a) Individual capacities, (b) total available capacity ($qk_W^{VI} + k_G^{VI}$), (c) share of wind capacity ($\frac{k_W^{VI}}{k_G^{VI} + k_W^{VI}}$) and (d) total emissions as functions of the price of emission allowance in the vertically integrated case.

$\tilde{D} \sim \text{LogN}(100, 50)$, $\alpha_W = 12$, $q = 0.25$, $\alpha_G = 13$, $u_G = 40$, $c = 40$, $e = 2.2$.

out that this is the case only when $e < 1$. One would reasonably expect that, when the carbon price a increases, it leads to a similar comparative statics effect as with a single technology when $e > 1$: if the backup technology is more carbon intensive than the gas technology, an increase in the carbon price a leads to higher capacity investment in both technologies but perhaps wind capacity would grow much faster since this technology has lower emissions. Moreover, in the case of two technologies the substitution effect comes into play as well and one would expect that the investment in wind would further increase (due to substitution from gas to wind) as gas technology becomes more expensive. However, this is not what happens as Figure 4 illustrates. The numbers that are used in this figure and the numerical experiments throughout this paper are consistent with the recent findings in the report of Poyry Energy Consulting (one of the Europe’s leading energy consultancy companies). We observe that, as the carbon price increases from zero, investment in gas capacity increases significantly while the wind capacity barely changes. The intuition behind this observation is that, when $e > 1$, the cost of intermittency for wind increases as a increases

because the backup technology becomes more expensive. Hence wind technology becomes *less* attractive relative to gas. Moreover, when $e > 1$, an increase in the price of carbon allowance a also leads to an increase in the optimal gas capacity. Because the two capacities are substitutes, this has an adverse effect on the optimal wind capacity and hence the corresponding decrease in the share of the renewable technology. Of course, higher carbon price leads to less total emissions as we can see in Figure 4(d) but this decrease in total emissions comes from substitution of the emission-intensive backup with gas, rather than from an increase in the wind capacity installation as one could reasonably expect. Thus, we see already in the vertically integrated scenario that higher carbon prices may be ineffective in stimulating investment in renewable energy sources.

5. Market Competition

In this section we consider a liberalized market in which the two firms are competing through their capacity decisions. We model this situation as a non-cooperative game, such that each firm's capacity decision affects the other firm's profit through the market price. Bellow, we elaborate on the market price mechanism and then we present our capacity game. We further explore how moving from a vertically integrated institution to a game setting changes the decisions for each capacity type.

5.1. Marginal Cost Pricing

In a competitive electricity market, power generators typically submit their supply offers to the market (grid or pool) administrator while retailers (representing their end-use electricity customers) submit their demand bids. The Independent System Operator (the ISO) then sorts the supply offers from the lowest to the highest and then schedules dispatch based on the merit order subject to the transmission and other physical constraints. The efficient dispatch algorithms that are used in this process along with the bidding rules imply that the spot price of electricity under typical conditions and in a perfectly competitive market is determined by the marginal cost of the last dispatched unit of energy (Joskow 2006). Hence, the realization of the random demand and supply determine the realization of the spot price. Modeling details of the dynamic competitive bidding

process is outside of the scope of this paper since we focus on the long-term capacity decisions rather than on the market micro-structure. Instead, we present a stylized model of such process, a model that captures the essential features of the outcome of such bidding. In our model, if the total demand is less than the available wind capacity, the electricity price is equal to the marginal cost of wind electricity generation, in our case 0. On the other hand, when realized demand is more than the available wind capacity but less than the total wind and gas capacity, then the spot price is equal to the marginal cost of gas electricity generation, U_G . In case demand exceeds the total available capacity, the price jumps to C . Each generator earns positive margin only when the realized demand exceeds its own capacity in the dispatch order. The expected margin is used to cover the investment cost of each technology. Given this background, the spot price in our competition model can be formalized as:

$$\tilde{p}_s = \begin{cases} 0 & \tilde{D} \leq \tilde{v}_W k_W \\ U_G & \tilde{v}_W k_W < \tilde{D} \leq \tilde{v}_W k_W + k_G \\ C & \tilde{v}_W k_W + k_G < \tilde{D} \end{cases} \quad (4)$$

Two assumptions should be noted in this price model. First, as an approximation to the findings of empirical studies of electricity markets that demand is fairly inelastic in the short run, we assume that the electricity demand is perfectly inelastic, so it is not affected by the price level. Second, we assume that it is only the demand of the single retailer in our model \tilde{D} that determines the price. In practice, there may be extra demand D_0 in the market that is served by other retailers, which will affect the spot price. Our assumption can be justified in a situation where only one retailer serves the whole market's demand, or when there is not considerable variability in D_0 . Indeed, D_0 can be considered as a constant demand that is met by base-load technologies such as nuclear or coal, while \tilde{D} is the shoulder demand in addition to the base load that is met by a single retailer. We focus on the case of a single retailer and note that explicit modeling of other retailers is outside of the scope of our paper.

5.2. The Capacity Game

Under market competition, the wind generator chooses capacity to maximize its own profit:

$$\max_{k_W} \mathbb{E}_{\tilde{D}} \mathbb{E}_{\tilde{v}_W} \{ \tilde{p}_s \min(\tilde{D}, \tilde{v}_W k_W) \} - \alpha_W k_W, \quad (5)$$

while the analogous gas generator's problem is:

$$\max_{k_G} \mathbb{E}_{\tilde{D}} \mathbb{E}_{\tilde{v}_W} \{ \tilde{p}_s \min(\tilde{D} - \tilde{v}k_W, k_G)^+ \} - \alpha_G k_G. \quad (6)$$

Proposition 4 characterizes the Nash equilibrium of the capacity game.

PROPOSITION 4. *Assume that \tilde{D} has an IFR distribution.*

(a) *The Nash equilibrium capacity levels (k_W^{NE}, k_G^{NE}) exist, are unique and they are found from the following set of simultaneous equations:*

$$\begin{aligned} q\bar{F}(k_W + k_G)(1 - k_G\phi(k_W + k_G)) + (1 - q)\bar{F}(k_G)(1 - k_G\phi(k_G)) &= A_G \\ (1 - \frac{U_G}{C})\bar{F}(k_W + k_G)(1 - k_W\phi(k_W + k_G)) + \frac{U_G}{C}\bar{F}(k_W)(1 - k_W\phi(k_W)) &= A_W. \end{aligned} \quad (7)$$

(b) $k_W^{NE} \geq (\leq) k_G^{NE}$ if $A_W \leq (\geq) A_G$ and $q \geq (\leq) 1 - \frac{U_G}{C}$.

(c) *The total installed capacity under competition is less than under the vertically integrated case.*

Existence and uniqueness of the pure strategy Nash equilibrium is guaranteed if the demand distribution has increasing failure rate. A comparison between the system of equations (7) that characterizes the solution to the capacity game and the system of equations (3) which characterizes the solution to the vertically integrated case reveals that they follow the same structure, except that the hazard rate of the demand distribution has entered into the picture for the case of competition. Similar to the vertically integrated case, part (b) of Proposition 1 confirms the importance of the critical ratio in the technology merit. Hence, under competition, investment will be higher for a technology that has the lower critical ratio, not for the technology that has the lower average total cost.

Part (c) of Proposition 1 states that the total installed capacity under the vertically integrated case is higher than under competition. As a consequence, due to Assumption 1 which states that the backup option is more expensive, we can conclude that the total cost of the system is higher under competition.

The intuitive reason for observing these effect is hidden in the market pricing mechanism. Recall that both wind and gas suppliers get paid the highest price only when they run out of capacity.

For instance, if demand never exceeds wind capacity then the wind supplier always receives zero payment (its marginal cost). This pricing mechanism creates direct incentives for both suppliers to build lower capacity thus increasing the chance that demand exceeds it. This result is consistent with several recent studies in electricity markets showing that under competition new capacity investments can fall and the total cost of the system can increase. For instance, Michaels (2004) reviews a large body of research on economics of vertical unbundling and concludes (in the context of the U.S.) that “it remains unclear why restructuring acquired a critical mass of support as quickly as it did in most states. Many may have been blinded to its potential costs by an understandable dissatisfaction with regulation”⁷. While our model does not capture all elements of market competition for electricity, the findings of our stylized model on inefficient (under-) investment under competition and marginal-cost pool operations seems to be rather robust in practice and in more detailed models of electricity markets.

Which technology is hurt more by moving towards competition? Due to complex interaction between capacities and the impact of capacities on the spot price, it is difficult to obtain the answer to this question analytically. However, we can address this question numerically using real-world data; see Figure 5. Comparing Figures 5(a) and (c), it appears that the wind technology’s portfolio share is lower (higher) under competition when it has a lower (higher) critical ratio. So, interestingly, when wind is more attractive (has higher capacity) under the vertically integrated case, it is hurt more under competition. The intuition is that the incentive of each generator for under-investment in the competition setting depends on their unit total cost, as well as market price. Higher carbon price increases the unit cost of gas electricity hence creating a disincentive

⁷ Of course, market liberalization and regulation go hand in hand and inappropriate or rigid regulation, together with market liberalization, can lead to trouble. The most famous example of this was the California electricity crisis in 2001. The electricity market in California opened in April 2000. By June 2000 the spot price for electricity increased twice as high as any month before since the market opened, while regulated retail prices remained fixed. By March 2001 the electricity spot price was so high relative to allowed end prices that the state’s largest utility declared bankruptcy and the state of California was forced to take over guarantees for power purchases for the three major distribution companies in the State, spending 1 billion dollars each month during the Spring of 2001 to meet the state’s electricity demand. Beyond regulatory problems of end user prices below market values, other factors contributed to the California crisis, including: the format of the wholesale auctions in California, the way generating capacity was priced, and local sources of market power among transmission-constrained generators (Borenstein 2002).

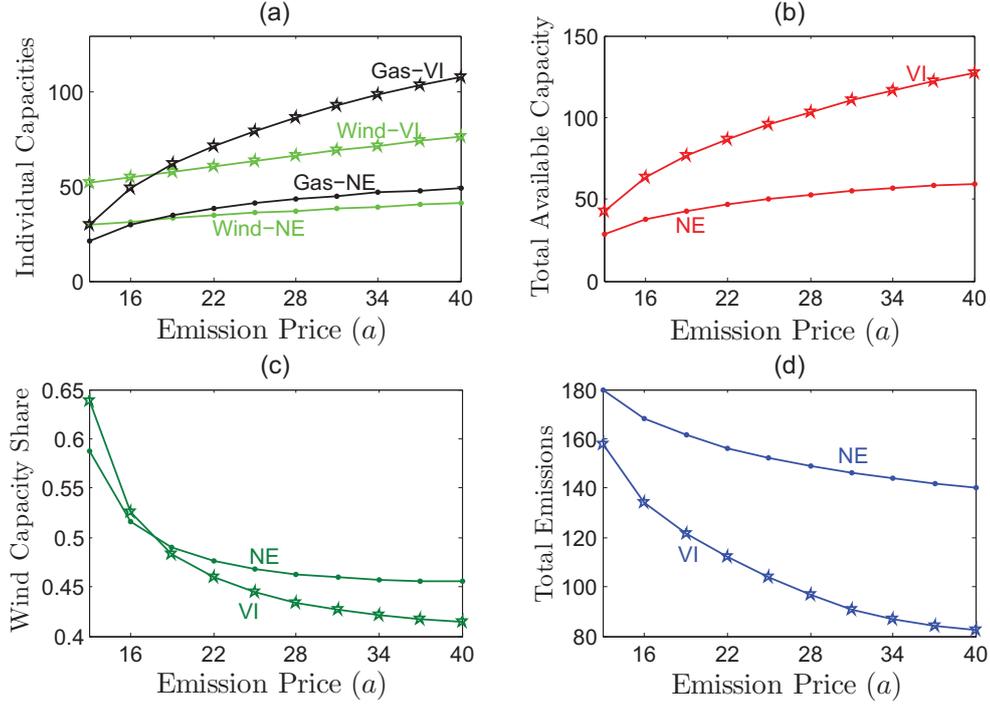


Figure 5 (a) Individual capacities, (b) total available capacity ($qk_W^{NE} + k_G^{NE}$), (c) share of wind capacity ($\frac{k_W^{NE}}{k_G^{NE} + k_W^{NE}}$) and (d) total emissions as functions of the price of emission allowance under competition.

$$\tilde{D} \sim \text{LogN}(100, 50), \alpha_W = 12, q = 0.25, \alpha_G = 13, u_G = 40, c = 40, e = 2.2.$$

for the gas generator to invest under competition. On the other hand, we can see in (4) that the spot price of electricity is decreasing in the availability of wind capacity. Namely, the price is lowest when wind is available and it is higher when wind is unavailable which gives a significant competitive disadvantage to VI. So competition creates a clear disincentive to invest for wind generator in the market through the intermittency problem. As a result we observe in Figure 5(c) that for current market prices for carbon (below 16) where the difference between total unit cost of wind and gas is relatively small the share of wind capacity is lower under competition than under vertically integrated case (the spot price disadvantage of wind dominates). This disadvantage fades as carbon prices become higher and the difference between unit prices of the two technologies becomes so high (see Figure 3(a)) that the cost disadvantage of gas becomes overwhelming and the proportion of wind capacity exceeds the corresponding proportion under vertical integration.

Finally, we note in Figures 5(b) and (d) that, the increase in total capacity and decrease in total emissions as a result of higher carbon price happens in a faster rate under vertically integrated

case than competition. In other words, increasing carbon price is less effective to reduce carbon emissions under competition. This is mainly due to under-investment incentives resulting from vertical unbundling and their effect on the spot price. The higher the carbon price, the more generators would benefit from under-investment under competition. This is because the backup technology is more carbon intensive and its total cost increases in carbon price with a high rate. Hence generators would benefit more from the fact that their capacity is exceeded when carbon price is high, and they have a stronger incentive to under-invest in this case.

This section demonstrated the adverse effect of market competition on capacity investment in electricity generation technologies. A common solution that is proposed in related studies is the long-term capacity contracts to ensure sufficient capacity investments, which is the subject of our discussion in the next section.

6. Fixed Price Contracts

In this section, we consider a partially liberalized market in which the retailer signs a long-term fixed price (FP) contract with the electricity generator. We denote all solutions in this case with the superscript ‘FP’. As a result of high volatility in the spot prices, bilateral forward contracts between retailers and generators play a significant role in almost all electricity markets today⁸. The time horizon of the forward contracts can range from 1 day to 15-20 years. The short-term forward contracts are typically signed a day ahead and include arrangements over committed capacity as well as agreed price. In the U.S., long-term forward contracts are being considered as an important way forward to promote investment in renewable generation capacity and “spur the growth of renewable generation” (Wislon et al. 2005). In various states such as Massachusetts, Rhode Island, New Jersey and Delaware, the legal instruments to sign long-term power purchase agreements with fixed prices are already in place with contracting horizons of 10-25 years. Germany and Spain,

⁸ Such bilateral arrangements can essentially take two different forms Borenstein (2002). In an electricity pool, or market-based bilateral contracts, all generators sell to a pool, which is run by an independent system operator, and all retailers buy from the pool. In this case, the system operator manages the physical feasibility of electricity flow in the network. An alternative to this arrangement is the case in which buyers and sellers make their own arrangements in terms of electricity purchase, and they let the system operator know about their arrangements. The system operator steps in only in the case when some physical infeasibility may occur – that is, some part of the transmission grid is overloaded. In this case the operator sets grid usage charges to balance the network.

the two countries with highest installed capacity for renewable energy in Europe, have used long-term fixed price contracts to promote renewable energy investments. As earlier, we start with one technology benchmark to understand the basic effects of fixed price contracts, and then move to the case of two technologies, where fixed price forward contracts are signed to promote investment in renewable capacity.

6.1. Benchmarks Case: One Technology

Given the announced fixed price p_i , the generator's problem is to choose k_i , $i \in \{W, G\}$ to maximize its expected profit:

$$\max_{k_i} \Pi_i(k_i, p_i) = \mathbb{E}_{\tilde{v}_i} \mathbb{E}_{\tilde{D}} \{(p_i - U_i) \min(\tilde{D}, \tilde{v}_i k_i)\} - \alpha_i k_i. \quad (8)$$

The retailer seeks to minimize the total cost of the system by choosing p_i , given that the supplier solves (8).

$$\begin{aligned} \min_{p_i} \Pi_R(k_i) &= \mathbb{E}_{\tilde{v}_i} \mathbb{E}_{\tilde{D}} \{p_i \min(\tilde{D}, \tilde{v}_i k_i) + C(\tilde{D} - \tilde{v}_i k_i)^+\} \\ \text{s.t. } k_i &= \arg \max_{k_i} \Pi_i(k_i, p_i). \end{aligned} \quad (9)$$

Let $\varepsilon_i = \frac{k_i^{FB} - k_i^{FP}}{k_i^{FB}}$ represent the inefficiency arising from contracting.

PROPOSITION 5. *Suppose the distribution of demand has IFR.*

- (a) *There exist unique prices $(p_i^*, i \in \{W, G\})$ and capacities k_i^{FP} , $i \in \{G, B\}$, that solve Problem (9). These are characterized as follows:*

$$p_i^* = U_i + \frac{A_i}{\bar{F}(k_i^{FP})}, \quad (10)$$

where k_i^{FP} solves:

$$L(k, A_i) = A_i \phi(k) \left(\frac{\int_0^k x f(x) dx}{\bar{F}(k)} + k \right) + A_i - \bar{F}(k) = 0. \quad (11)$$

- (b) $k_G^{FP} \geq k_W^{FP}$ if and only if $A_G \leq A_W$.
(c) k_W^{FP} is increasing in a . k_G^{FP} is increasing in a if and only if $e > 1$.

(d) If the demand distribution is IFR, then regardless of the technology type, firms always underinvest under fixed price contract setting at the optimal solution (10)-(11). Moreover, $\varepsilon_W \geq \varepsilon_G$ if and only if $A_W \geq A_G$.

Proposition 5 states that the optimal fixed price for the long-term contract between the generator and the retailer is determined as the total unit variable cost of generating electricity with technology i plus a markup which is a function of technology's critical ratio. This markup is not necessarily increasing in the critical ratio A_i because the optimal capacity k_i^{FP} is decreasing in A_i , so the nominator and the denominator of the markup fraction $\frac{A_i}{F(k_i^{FP})}$ move in the same direction.

Similar to the vertically integrated and competition settings, the driver of technology advantage here is the critical ratio A_i , because the backup cost is reflected in the contract price which determines capacity decisions by the generators. As a result, all of the comparative static results associated with A_i apply. In particular, Part (c) of Proposition 5 states that the optimal wind capacity is always increasing in the carbon price. The gas capacity is increasing in the carbon price only when it incurs less carbon emissions than the backup technology, which, as we argued before, is typically the case. In the next section, we will see that this result may not hold when there is simultaneous investment in two technologies because of the substitution effect. Finally, Proposition 5 states that the vertical separation of the retailer and the generator in a fixed price contract setting leads to an inefficiency as a result of under investment in capacity, $\varepsilon_i \geq 0$. Further, this inefficiency is higher for the technology that has higher critical ratio (and thus lower capacity investment) because this technology can be more efficiency substituted for the backup generation. In the next section, we will see that, due to comparative advantage of one technology, this is not the case when both technologies are present.

6.2. Partial Market Competition with Long-Term Fixed Price Contracts for the Wind Generator

In this section, we consider the case in which the retailer enters into a long-term fixed price contract with the wind generator, but the price for the gas generator is still determined through the spot market mechanism similar to the one described in the previous Section. Based on the proposed

price, the wind generator decides on the level of wind capacity to install. This decision, in turn, affects the spot price by shifting the demand curve and therefore influencing the gas generator's decision on the level of capacity to install. Hence, the level of installed capacity for gas technology will indirectly be affected by the fixed price that is set by the retailer for the wind technology and in this sense the two suppliers compete in the market. The retailer's objective is to choose the price for wind electricity, such that its total cost is minimized:

$$\min_{p_W} \mathbb{E}_{\tilde{v}_i} \mathbb{E}_{\tilde{D}} \left\{ p_W \min(\tilde{D}, \tilde{v}k_W) + \tilde{p}_s \min(\tilde{D} - \tilde{v}k_W, k_G)^+ \right\}. \quad (12)$$

The wind generator decides on the amount of capacity to install, based on the announced price for wind electricity by the retailer;

$$\max_{k_W} \Pi_W(k_W) = \mathbb{E}_{\tilde{v}_i} \mathbb{E}_{\tilde{D}} \left\{ p_W \min(\tilde{D}, \tilde{v}k_W) \right\} - \alpha_W k_W, \quad (13)$$

while the gas generator's problem is formulated as:

$$\max_{k_G} \Pi_G(k_G) = \mathbb{E}_{\tilde{v}_i} \mathbb{E}_{\tilde{D}} \left\{ (\tilde{p}_s - U_G) \min(\tilde{D} - \tilde{v}k_W, k_G)^+ \right\} - \alpha_G k_G. \quad (14)$$

Because of the complex relationship between the contracted capacity and gas generator's problem, we are not able to establish the concavity of the retailer's objective function analytically. However, the following proposition provides necessary conditions for the interior capacity solutions.

PROPOSITION 6. *The interior optimal capacities for wind and gas under fixed price contract for the wind generator, k_W^{FP} and k_G^{FP} , solve the following first-order conditions:*

$$\begin{aligned} q\bar{F}(k_W + k_G)(1 - k_G\phi(k_W + k_G)) + (1 - q)\bar{F}(k_G)(1 - k_G\phi(k_G)) &= A_G \\ (1 - \frac{U_G}{C})\bar{F}(k_W + k_G)(1 + k_G f(k_W + k_G)) + \frac{U_G}{C}\bar{F}(k_W) &= A_W \left(1 + \phi(k_W) \left(k_W + \frac{\int_0^{k_W} x f(x) dx}{\bar{F}(k_W)} \right) \right). \end{aligned} \quad (15)$$

Figure 6 illustrates the solution of the fixed price case in addition to the vertically integrated and the market competition settings. Although we have shown in the previous section that fixed-price contracts decrease investment for individual technologies, in this case the result is different because of interacting capacities since wind capacity has the advantage over the gas capacity:

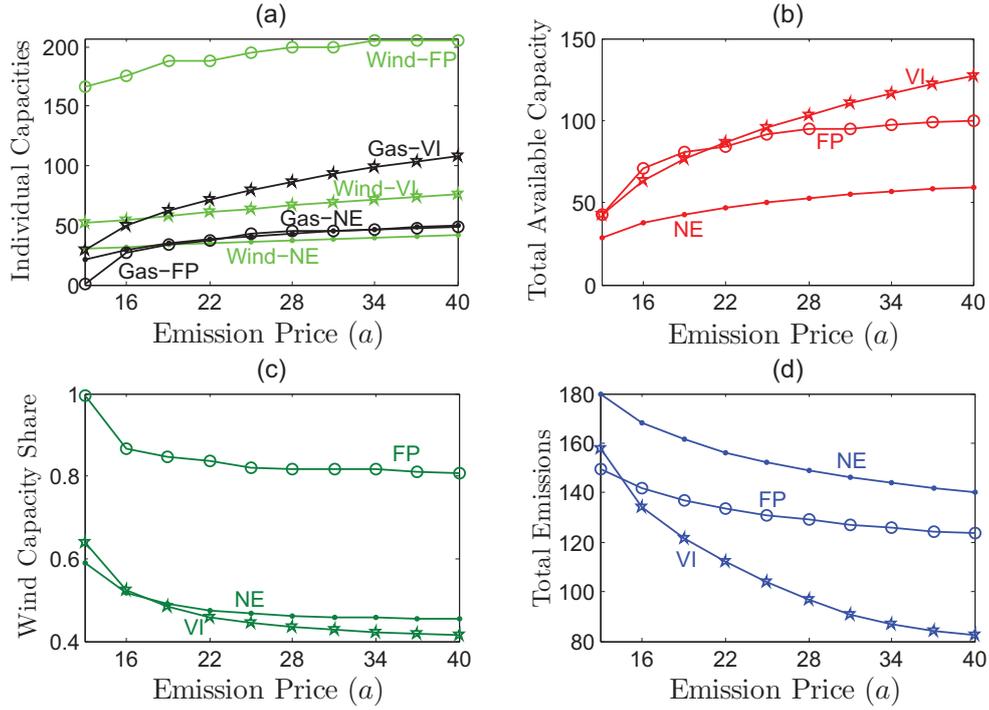


Figure 6 (a) Individual capacities, (b) total available capacity ($qk_W^{FP} + k_G^{FP}$), (c) share of wind capacity ($\frac{k_W^{FP}}{k_G^{FP} + k_W^{FP}}$) and (d) total emissions as functions of the price of emission allowance under partially liberalized market. $\tilde{D} \sim \text{LogN}(100, 50)$, $\alpha_W = 12$, $q = 0.25$, $\alpha_G = 13$, $u_G = 40$, $c = 40$, $e = 2.2$.

no uncertainty in prices. Thus, in agreement with what one would expect, fixed price contracts increase the installed wind capacity and decrease the gas capacity relative to the case of market competition. We can also see that incentives to invest in wind are so high that the investment level increases far above the vertically integrated case. Somewhat surprisingly, the investment in gas capacity is not dramatically different from the market competition case. As a result, we observe that the total installed capacity increases significantly relative to competition, where most of the generation capacity now comes from the renewables. When the carbon price is not very high and therefore backup generation cost (and intermittency price) are low, the installed wind capacity is so high that the average total installed capacity $qk_W + k_G$ under fixed price contract is higher than the total capacity for the vertically integrated case.

While overall increase in the wind capacity under the fixed price contract is good news, there is no free lunch: the increase in wind and total capacity is such that the total emissions in this case can be higher than in the vertically integrated case for high enough carbon prices (which can be

expected in the near future). The reason is that the (small) portion of installed gas capacity in this case is too low to provide sufficient backup for the (large) intermittent wind capacity and therefore the retailer has to often go for the emission-intensive backup option. Thus, fixed price contracts work quite well when the carbon price is low but when it is high the under-investment in backup generation technology (gas) can become extremely expensive. Of course, this happens only when the proportion of renewable electricity generation capacity is quite high.

7. Conclusions

In this paper we study the effect of two recent developments in the electricity markets: the introduction of renewables and market liberalization. We analyze how intermittency of renewables links these two changes in the electricity industry. In particular, we demonstrate how the cost structure and the intermittency issue of renewables affect capacity investments for both renewable and non-renewable technologies as well as the effectiveness of renewable-promoting policies such as carbon pricing. As we show, despite the fact that renewables become more cost competitive on average as the carbon price increases, higher carbon prices might decrease the share of renewable capacity in the overall generation portfolio in both the vertically integrated and the (partially) liberalized market. Thus, although a higher price of carbon emissions does lead to lower total emissions, this might not be a good policy to promote investment in renewables. Moreover, we show that market liberalization may not promote efficient investment in generation capacity. Total emissions from the generation portfolio also increase in a liberalized market, and for a reasonable range of carbon prices, liberalization leads to a lower share of renewables compared to the vertically integrated case. The root cause of this effect is the interaction between intermittency problem and the market pricing mechanism. We further show that the long-term electricity contracts, which offer fixed feed-in tariffs to the owners of renewable generation capacity, indeed ameliorate some disadvantages of the liberalized markets. Namely, they lead to a significant increase in renewable capacity investment while not strongly affecting the non-renewable capacities. As a result, long-term contracts with renewable generators increase the total installed capacity (possibly even above the vertically

integrated level) and reduce emissions relative to the market competition case. We conclude that long-term fixed price contracts are a good tool to compensate for the disadvantages of market liberalization, both from a total cost and greenness points of view. However, these contracts also may lead to dramatic over-investment in renewables and under-investment in gas generation (relative to the vertically integrated case) for high enough levels of carbon prices. This further leads to over-reliance on the backup (coal-fired) generators which is detrimental to the environment and it can also potentially lead to the issues of balancing the grid if there is need for significant backup generation.

Overall our analysis points out to intermittency of renewable energy sources as a problematic feature that handicaps investment decisions in these technologies. Although increasing carbon taxes is meant to improve the attractiveness of renewables, we show that it is not necessarily an effective policy. A more effective approach to increase capacity investment in renewables would be to reduce intermittency by, for example, pooling multiple generation units (possibly with different technologies) whose supply is not perfectly correlated. For instance, this may only be possible for large enough generators who have resources to invest in multiple wind farms in different geographical regions. Thus, although there are no economies of scale in wind electricity generation, there are clearly statistical economies of scale due to lower intermittency.

In our analysis we suppressed modeling of multiple generating firms, each possibly with multiple technologies, which can easily happen in practice. Such extension would require modeling a complex bidding process of many firms with many technologies, which is analytically challenging. We also focused on two technology types only, while other electricity generation technologies can possess drastically different characteristics. For instance, nuclear and large-scale coal generators have essentially no flexibility in adjusting output and no intermittency at the same time. Future research may consider these and other extensions of the long-time capacity investment problems.

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Appendix: Proofs.

Proof of Proposition 1. (a) Define

$$\bar{\Pi}(k; \alpha, q, u) = \mathbb{E}_{\tilde{D}} \left\{ q \left(u \min(\tilde{D}, k) + C(\tilde{D} - k)^+ \right) + (1 - q)C\tilde{D} \right\} + \alpha k. \quad (16)$$

It is straightforward to verify that $\bar{\Pi}_W(k_W) = \bar{\Pi}(k_W; \alpha_W, q, 0)$ and $\bar{\Pi}_G(k_G) = \bar{\Pi}(k_G; \alpha_G, 1, U_G)$. So, for solving Problem (1), it is sufficient to characterize the solution to $\min_k \Pi(k; \alpha, q, u)$. (16) can be equivalently written as:

$$\bar{\Pi}(k; \alpha, q, u) = q \left(u \left(\int_0^k x f(x) dx + \int_k^\infty k f(x) dx \right) + c \int_k^\infty (x - k) f(x) dx \right) + (1 - q) c \mathbb{E}\{\tilde{D}\} + \alpha k. \quad (17)$$

We write the first order condition (FOC) to obtain

$$\frac{\partial}{\partial k} \bar{\Pi}(k; \alpha, q, u) = -q(c - u)(\bar{F}(k)) + \alpha = 0, \quad (18)$$

or equivalently $\bar{F}(k) = \frac{\alpha}{q(c-u)} = A(\alpha, q, u)$. The rest follows from the definition of A_W and A_G . We note that for $c > u$ $\frac{\partial^2}{\partial k^2} \bar{\Pi}(k; \alpha, q, u) = q(c - u)f(k) > 0$, hence the FOC is sufficient.

(b) The result follows immediately from part (a) of Proposition 1, considering that $A_i > 0$ and $\bar{F}(k)$ is decreasing.

(c) The result follows immediately from part (a) of Proposition 1 by verifying that A_W is always decreasing in a , while A_G is decreasing in a if and only if $e > 1$.

Proof of Proposition 2. (a) We rewrite (2) as:

$$\begin{aligned} \bar{\Pi}(k_W, k_G) = & q \left(\int_{k_W}^{k_W+k_G} U_G(x - k_W) f(x) dx + \int_{k_W+k_G}^\infty (U_G k_G + c(x - k_W - k_G)) f(x) dx \right) \\ & + (1 - q) \left(\int_0^{k_G} U_G x f(x) dx + \int_{k_G}^\infty (U_G k_G + C(d - k_G)) f(x) dx + \alpha_W k_W + \alpha_G k_G \right). \end{aligned} \quad (19)$$

First we verify that $\bar{\Pi}(k_W, k_G)$ is jointly convex. Calculating the Hessian matrix we have:

$$H = \begin{pmatrix} \frac{\partial^2 \Pi}{\partial k_W^2} & \frac{\partial^2 \Pi}{\partial k_W \partial k_G} \\ \frac{\partial^2 \Pi}{\partial k_W \partial k_G} & \frac{\partial^2 \Pi}{\partial k_G^2} \end{pmatrix}, \quad (20)$$

where,

$$\begin{aligned} \frac{\partial^2 \Pi}{\partial k_W^2} &= q \left(U_G f(k_W) + (C - U_G) f(k_W + k_G) \right) > 0 \\ \frac{\partial^2 \Pi}{\partial k_G^2} &= (C - U_G) \left(q f(k_W + k_G) + (1 - q) f(k_G) \right) > 0 \\ \frac{\partial^2 \Pi}{\partial k_W \partial k_G} &= q(C - U_G) f(k_W + k_G) > 0, \end{aligned}$$

and $|H| = Cq\left((qU_G f(k_W) + (1-q)Cf(k_G))f(k_W + k_G) + U_G(1-q)f(k_W)f(k_G)\right) > 0$. So H is a positive definite matrix, implying that $\bar{\Pi}(k_W, k_G)$ is jointly convex in its arguments and hence, the FOCs are sufficient. Writing the FOCs with respect to k_W and k_G we obtain:

$$-q\left(U_G \int_{k_W}^{k_W+k_G} f(x)dx + C \int_{k_W+k_G}^{\infty} f(x)dx\right) + \alpha_W = 0 \quad (21)$$

$$-(C - U_G)\left(q \int_{k_W+k_G}^{\infty} f(x)dx + (1-q) \int_{k_G}^{\infty} f(x)dx\right) + \alpha_G = 0, \quad (22)$$

which after some simplification and substitution yield the system of equations identified in Proposition 2.

(b) The result is obtained by verifying that $\Pi(k_W, k_G)$ is supermodular in its arguments (see Vives 2001, Thm 2.3). Indeed,

$$\frac{\partial^2 \Pi}{\partial k_W \partial k_G} = q(C - U_G)f(k_W + k_G) > 0. \quad (23)$$

(c) If $A_W \leq A_G$ and $q \geq 1 - \frac{U_G}{C}$ then we have:

$$\begin{aligned} & q\bar{F}(k_W^{FB} + k_G^{FB}) + (1-q)\bar{F}(k_W^{FB}) \\ & \leq \left(1 - \frac{U_G}{C}\right)\bar{F}(k_W^{FB} + k_G^{FB}) + \frac{U_G}{C}\bar{F}(k_W^{FB}) \quad (\text{because } q \geq 1 - \frac{U_G}{C} \text{ and } \bar{F}(k_W^{FB} + k_G^{FB}) \leq F(k_W^{FB})) \\ & \leq q\bar{F}(k_W^{FB} + k_G) + (1-q)\bar{F}(k_G^{FB}) \quad (\text{because } A_W \leq A_G) \\ & \Rightarrow \bar{F}(k_W^{FB}) \leq \bar{F}(k_G^{FB}) \Rightarrow k_W^{NE} \geq k_G^{NE} . \end{aligned}$$

The converse case is obtained analogously.

(d) and (e): These results are similarly obtained by using monotone comparative statics (see e.g. Vives 2001, Thm 2.3), by verifying that $\Pi(k_W, k_G; q, u_G, \alpha_W, \alpha_G)$ has increasing (decreasing) differences in the following parameters:

$$\begin{aligned} \frac{\partial^2}{\partial k_W \partial q} \Pi(k_W, k_G; q, U_G, \alpha_W, \alpha_G) &= - \int_{k_W}^{k_W+k_G} U_G f(x)dx - \int_{k_W+k_G}^{\infty} C f(x)dx \leq 0 \\ \frac{\partial^2}{\partial k_W \partial u_G} \Pi(k_W, k_G; q, U_G, \alpha_W, \alpha_G) &= -q \int_{k_W}^{k_W+k_G} f(x)dx \leq 0 \\ \frac{\partial^2}{\partial k_W \partial \alpha_W} \Pi(k_W, k_G; q, U_G, \alpha_W, \alpha_G) &= 1 > 0 \end{aligned}$$

$$\begin{aligned}
 \frac{\partial^2}{\partial k_W \partial \alpha_G} \Pi(k_W, k_G; q, U_G, \alpha_W, \alpha_G) &= 0 \\
 \frac{\partial^2}{\partial k_G \partial q} \Pi(k_W, k_G; q, U_G, \alpha_W, \alpha_G) &= (C - U_2) \left(\int_{k_G}^{\infty} f(x) dx - \int_{k_W+k_G}^{\infty} f(x) dx \right) \geq 0 \\
 \frac{\partial^2}{\partial k_G \partial u_G} \Pi(k_W, k_G; q, U_G, \alpha_W, \alpha_G) &= q \int_{k_W+k_G}^{\infty} f(x) dx + (1-q) \int_{k_G}^{\infty} f(x) dx \geq 0 \\
 \frac{\partial^2}{\partial k_G \partial \alpha_W} \Pi(k_W, k_G; q, U_G, \alpha_W, \alpha_G) &= 0 \\
 \frac{\partial^2}{\partial k_G \partial \alpha_G} \Pi(k_W, k_G; q, U_G, \alpha_W, \alpha_G) &= 1 \geq 0.
 \end{aligned}$$

Proof of Proposition 3. (a) Based on the general rule for implicit derivatives we have:

$$\begin{pmatrix} \frac{\partial k_W^{FB}}{\partial c} \\ \frac{\partial k_G^{FB}}{\partial c} \end{pmatrix} = H^{-1} \cdot \begin{pmatrix} \frac{\partial^2 \Pi}{\partial k_W \partial c} \\ \frac{\partial^2 \Pi}{\partial k_G \partial c} \end{pmatrix}, \quad (24)$$

where H^{-1} is the inverse of the Hessian matrix defined in the proof of Proposition 2. We calculate the partial derivatives to obtain:

$$\begin{aligned}
 \frac{\partial^2 \Pi}{\partial k_W \partial c} &= -q \int_{k_W+k_G}^M f(d) dd \\
 \frac{\partial^2 \Pi}{\partial k_G \partial c} &= - \left(q \int_{k_W+k_G}^M f(d) dd + (1-q) \int_{k_G}^M f(d) dd \right)
 \end{aligned}$$

Substituting these values in (24), and applying the Cramer's rule, we obtain:

$$\begin{pmatrix} \frac{\partial k_W^{FB}}{\partial c} \\ \frac{\partial k_G^{FB}}{\partial c} \end{pmatrix} = \frac{1}{|H|} \begin{pmatrix} (C - U_G)q(1-q) \left(-f(k_W + k_G) \bar{F}(k_G) + \bar{F}(k_W + k_G) f(k_G) \right) \\ q \left(q \bar{F}(k_W + k_G) U_G f(k_W) + (1-q) \bar{F}(k_G) (u_G f(k_W) + (C - U_G) f(k_W + k_G)) \right) \end{pmatrix}, \quad (25)$$

where $|H| > 0$ is the determinant of the Hessian matrix. We observe in (25) that if F has IFR, we have $\frac{f(k_G)}{\bar{F}(k_G)} \leq \frac{f(k_W+k_G)}{\bar{F}(k_W+k_G)}$, implying that $\frac{\partial k_W^{FB}}{\partial c} \leq 0$; besides $\frac{\partial k_G^{FB}}{\partial c} \geq 0$. Furthermore,

$$\frac{\partial k_W^{FB}}{\partial c} + \frac{\partial k_G^{FB}}{\partial c} = \frac{q}{|H|} \left((qu_G f(k_W) + (1-q)C f(k_G)) \bar{F}(k_W + k_G) + (1-q) \bar{F}(k_G) u_G f(k_W) \right) \geq 0. \quad (26)$$

(b) We show that if $e \leq 1$, k_W^{FB} is increasing, while k_G^{FB} is decreasing in a . Similar to the proof of Proposition 2, the desired result is obtained using monotone comparative statics by calculating the cross partial derivatives of $\bar{\Pi}(k_W, k_G; a)$ with respect to (k_W, a) and (k_G, a) and using the fact that capacities are substitutes.

$$\frac{\partial^2}{\partial k_W \partial a} = -q \left(\int_{k_W+k_G}^{\infty} f(x) dx + e \int_{k_W+k_G}^{\infty} f(x) dx \right) \leq 0, \quad (27)$$

$$\frac{\partial^2}{\partial k_G \partial a} = (1 - e) \left(q \int_{k_W + k_G}^{\infty} f(x) dx + (1 - q) \int_{k_G}^{\infty} f(x) dx \right) \geq 0, \quad (28)$$

because $e \leq 0$. The second part of the proposition is proved by the existence of the counter example provided in the text.

Proof of Proposition 4. We rewrite the Wind generator's profit in (5) as:

$$\Pi_W(k_W, k_G) = q \left(U_G k_W \int_{k_W}^{k_W + k_G} f(x) dx + C k_W \int_{k_W + k_G}^{\infty} f(x) dx \right) - \alpha_W k_W, \quad (29)$$

and the gas generator's problem in (6) as:

$$\Pi_G(k_W, k_G) = q k_G (C - U_G) \int_{k_W + k_G}^{\infty} f(x) dx + (1 - q) k_G (C - U_G) \int_{k_G}^{\infty} f(x) dx - \alpha_G k_G. \quad (30)$$

Taking the derivatives of $\Pi_W(k_W, k_G)$ with respect to k_W and $\Pi_G(k_W, k_G)$ with respect to k_G , we obtain that the NE of the capacity game solves the following system of equations:

$$\begin{aligned} q U_G \int_{k_W}^{k_W + k_G} f(x) dx + q C \int_{k_W + k_G}^{\infty} f(x) dx - q k_W (C - U_G) f(k_W + k_G) - q U_G k_W f(k_W) - \alpha_W &= 0 \\ (C - U_G) \left(q \int_{k_W + k_G}^{\infty} f(x) dx + (1 - q) \int_{k_G}^{\infty} f(x) dx - q k_G f(k_W + k_G) - k_G (1 - q) f(k_G) \right) - \alpha_G &= 0. \end{aligned}$$

Replacing $f(\cdot) = \phi(\cdot) \bar{F}(\cdot)$, after some simplification we obtain that the NE of the capacity game solves the system of equations specified in Proposition 4. We note that if the demand distribution is IFR—that is, $\phi(x)$ is increasing, the left hand side of both of the FOC equations above are strictly decreasing in both arguments; hence $\Pi_W(k_W, k_G)$ is strictly concave in k_W and $\Pi_G(k_W, k_G)$ is strictly concave in k_G implying that the FOCs are sufficient and the NE is unique.

The proof for the second part of Proposition 4 is analogous to that of Proposition 2.

Recall that the optimal capacities for the first-best case solve the system of equations in Proposition 2. Suppose that the total capacity under competition is higher than the first best case—that is $k_W^{NE} + k_G^{NE} > k_W^{FB} + k_G^{FB}$. Then we should have either $k_G^{FB} < k_G^{NE}$ or $k_W^{FB} < k_W^{NE}$ or both. In the first case, $k_G^{FB} < k_G^{NE}$, we have:

$$\begin{aligned} A_G &= q \bar{F}(k_W^{NE} + k_G^{NE}) (1 - k_G^{NE} \phi(k_W^{NE} + k_G^{NE})) + (1 - q) \bar{F}(k_G^{NE}) (1 - k_G^{NE} \phi(k_G^{NE})) \\ &< q \bar{F}(k_W^{NE} + k_G^{NE}) + (1 - q) \bar{F}(k_G^{NE}) \end{aligned}$$

$$< q\bar{F}(k_W^{NE} + k_G^{NE}) + (1 - q)\bar{F}(k_G^{NE}) = A_G,$$

which is a contradiction. The other two cases also lead to a contradiction in a similar fashion. So we conclude that $k_W^{NE} + k_G^{NE} > k_W^{FB} + k_G^{FB}$ can never hold.

Proof of Proposition 5. (a) The objective function in (8) for the wind technology is written as

$$\Pi_W(k_W, p_W) = p_W q \left(\int_0^{k_W} x f(x) dx + \int_{k_W}^{\infty} k_W f(x) dx \right) - k_W \alpha_W, \quad (31)$$

while for gas technology it is written as

$$\Pi_G(k_G, p_G) = (p_G - U_G) \left(\int_0^{k_G} x f(x) dx + \int_{k_G}^{\infty} k_G f(x) dx \right) - k_G \alpha_G. \quad (32)$$

The rest of the proof is done for wind technology. The case for gas technology is analogous. Writing the FOC for Problem (32) with respect to k_W , we obtain:

$$\frac{\partial \Pi_W(k_W, p_W)}{\partial k_W} = p_W q \left(\int_{k_W}^{\infty} f(x) dx \right) - \alpha_W = p_W q (\bar{F}(k_W)) - \alpha_W = 0. \quad (33)$$

We note that $\frac{\partial^2}{\partial k_W^2} \Pi_W(k_W, p_W) = -p_W q f(k_W) < 0$, so the FOC is sufficient. The retailer's problem (9) is then written as

$$\begin{aligned} \min_{p_W} \quad & q \left(p_W \int_0^{k_W} x f(x) dx + c \int_{k_W}^{\infty} (x - k_W) f(x) dx \right) \\ \text{s.t.} \quad & k_W \text{ solves (33)}. \end{aligned} \quad (34)$$

Because there is a one-to-one relationship between k^* and p^* in (33), Problem (34) can be transformed, so that the decision variable is k_W . For this, we solve (33) for p_W to obtain:

$$p_W = \frac{\alpha_W}{q(\bar{F}(k_W))}. \quad (35)$$

Substituting this to (34), we find that the retailer's problem turns to:

$$\min_{k_W} \quad q \left(\frac{\alpha_W}{q(\bar{F}(k_W))} \int_0^{k_W} x f(x) dx + c \int_{k_W}^{\infty} (x - k_W) f(x) dx \right). \quad (36)$$

Writing the FOC for Problem (36), after some simplification we find that that k^* solves $L_W(k, A_W) = 0$.

It is straightforward to verify that if the demand distribution is IFR—that is, $\frac{f(k)}{F(k)}$ is increasing in k , $L(k, A_i)$ is increasing in k , because $\int_0^k xf(x)dx$ and $F(k)$ are strictly increasing in k . This is equivalent to the objective function in (34) being strictly convex in k , so the FOC is sufficient and the solution to Problem (34) is unique.

(b) The result follows by verifying that $L(k, A_i)$ is increasing in k and A_i .

(c) By Proposition 1, k_i^{FB} solves $A_i - \bar{F}(k) = 0$ and by part (a), k_i^* solves $L(k, A_i) = l(A_i, k) + A_i - \bar{F}(k) = 0$, where $l(A_i, k) > 0$ is the first term in $L(k, A_i)$ defined in (11). The first part of the result follows by considering that $A_i - \bar{F}(k)$ and $L(k, A_i)$ are increasing and $L(k, A_i) \geq A_i - \bar{F}(k)$. Because $l(A_i, k)$ is increasing in A_i , we conclude that $k_i^{FB} - k_i^*$ is increasing in A_i . This, along with the fact that k_i^{FB} is decreasing in A_i implies that ε_i is increasing in A_i .

Europe Campus
Boulevard de Constance
77305 Fontainebleau Cedex, France
Tel: +33 (0)1 60 72 40 00
Fax: +33 (0)1 60 74 55 00/01

Asia Campus
1 Ayer Rajah Avenue, Singapore 138676
Tel: +65 67 99 53 88
Fax: +65 67 99 53 99

Abu Dhabi Campus
Muroor Road - Street No 4
P.O. Box 48049
Abu Dhabi, United Arab Emirates
Tel: +971 2 651 5200
Fax: +971 2 443 9461

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