Renewables, Allowances Markets, and Capacity Expansion in Energy-Only Markets

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ABSTRACT

We investigate the combined effect of an Emissions Trading System (ETS) and renewable energy sources on investments in electricity capacity in energy-only markets. We study the long-term capacity expansion decision in fossil fuel and renewable technologies when electricity demand is uncertain. We model a relevant tradeoff: a higher share of renewable production can be priced at the higher marginal cost of fossil fuel production, yet the likelihood of achieving higher profits is reduced because more electricity demand is met by cheaper renewable production. We illustrate our theoretical results comparing the optimal solutions under a business-as-usual scenario and under an ETS scenario. This illustration shows under which limiting market settings a monopolist prefers to withhold investments in renewable energy sources, highlighting the potential distortionary effect introduced via an ETS. Our conclusions remain unaltered under varying key modelling assumptions.

Keywords: Emissions Trading System, Energy-mix, Pass-through, Electricity markets, Electricity sector

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1. INTRODUCTION

The past five years have witnessed a systematic decrease in the electricity sector operational profitability and a consequent decline in capacity investments in market-based systems (*Financial Times*, 2015; *The Economist*, 2015). Overcapacity of fossil fuel electricity generation and a larger share of renewable electricity generation[1] are among the main causes (Koch et al., 2014). Particularly in Europe, renewables[2] have not just put pressure on margins; they have also transformed the established business model of utilities (*The Economist*, 2013). Electricity from renewables has favorable access to the grid, squeezing the earnings of polluting generation. However, this

1. We will write fossil fuel generation as a shorthand throughout the paper. Besides, conventional generation and polluting generation will be used as synonyms. Also, we will write renewable generation as a shorthand throughout the paper. And non-conventional generation and green generation will be used as synonyms.

2. Renewables will be used as a shorthand for renewable energy sources throughout the paper.

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preferential grid access is not solely the result of policies favouring renewables. It is also logical in electricity markets that operate based on the merit order: since the marginal cost of renewables is virtually zero, grids would take their electricity first anyway. In this paper, we explore some of the implications of this changing business model on the long-term capacity expansion decision of the electricity sector when polluting emissions from fossil fuel generation are regulated by an Emissions Trading System (ETS).

The long-term capacity expansion decision in the electricity sector (the so-called energy-mix decision) is key to the goal of a low-carbon economy. Electricity and heat generated by fuel combustion are responsible for approximately 42% of CO_2 emissions worldwide (International Energy Agency, 2017). Consequently, electricity sectors in many countries have been brought under ETS regulations. This is the case in Europe (EU ETS, European Union Emissions Trading System), the U.S. (Californian cap-and-trade program), South Korea (KETS, Korea Emissions Trading Scheme), and China (pilot ETS in the Province of Guangdong). In particular, the EU ETS is a cornerstone of the European policy to reduce CO_2 (80% by 2050, see European Commission, 2011) and, ultimately, to combat climate change. Research studying the energy-mix decision in the presence of an ETS is slowly emerging and has primarily focused on the short-term effects, e.g. the fuel switching effect (see Kirat and Ahamada, 2011, and references therein). We contribute to this literature by investigating the impact of emission caps on long-term capacity expansion decisions in energy-only markets. The policy implications of our work directly speak to the debate about the role of capacity markets and equivalent administrative interventions.

Central to this problem is the tradeoff on profits associated with increased renewable generation. Investments in renewables drive fossil fuel plants out of the market, resulting in costly idle capacity. This is the so-called merit order effect. Yet, investments in renewables generate higher rents because green generation can be sold at the marginal cost of fossil fuel plants. Which of the two effects dominates depends on which generation is at the margin. This means that electricity producers might have an incentive to withhold investments in renewable capacity. The market structure and the regulatory framework are crucial for determining the extent to which the electricity sector withholds capacity investments. In recent contributions, Murphy and Smeers (2005), Zöttl (2011), Murphy and Smeers (2012), and Grimm and Zoettl (2013) investigate capacity investment incentives when markets are not competitive. These authors show that withholding capacity investments can in fact increase profits, ultimately hampering adequate capacity installation. These papers develop their analysis either abstracting from the presence of emission regulations, or treating emission regulations in the form of an ETS as given. In particular, the price of allowances associated with an ETS is either omitted or treated as a given parameter.[3] However, in the energy-mix decision, which is long-term, the price of allowances heavily depends on the energy-mix itself. Consequently, such a price should be treated (as we do here) as an endogenous variable and should be part of the long-term capacity expansion decision.

In this paper, we contribute to this literature by investigating how an ETS affects the profits resulting from long-term capacity expansion decisions. This line of analysis adds to the growing literature that stresses the need to account for the full effects of coexisting emission constraints and renewable energy source policies due to the sometimes conflicting incentives of the stakeholders involved.[4] Acknowledging these effects is critically important for the design of long-term electricity

3. We will write allowances as a shorthand for emission allowances associated with an ETS throughout the paper.

4. Previous analyses have highlighted the potential detrimental impacts of overlapping renewable energy source policies (reviewed by Fischer and Preonas, 2010), including overall declines in cost-efficiency (Böhringer et al., 2008, 2009) and increases in the consumer electricity price (Böhringer and Behrens, 2015). We add to this literature too.

markets since conflicting incentives can often lead to suboptimal outcomes, or even outcomes in contrast to the compelling goals of the environmental policy. For example, Acemoglu et al. (2017) investigates the incentives of fossil fuel energy producers to increase the share of renewables in their energy portfolios. They demonstrate, in an oligopolistic setup, that the installation of renewable capacity can actually decrease net welfare as a result of reductions in energy production when the supply of renewables is high. We also assume a cooperative oligopoly in capacity investments and adopt an equivalent monopolist set up to examine the interplay between incentives to the electricity sector and prices of electricity and allowances.

The monopolist set up allows us to transparently investigate the potential distortion of market prices in energy-only markets via an ETS.[5] We do not undertake a full-fledged welfare analysis. Rather, we focus our attention on key socio-economic variables, such as the percentages of renewable generation and fossil fuel generation, the level of electricity prices, and the level of profits accruing to the electricity sector, and compare the solutions under a Business-As-Usual (BAU) scenario and under an ETS scenario.

Our theoretical results show that the monopolist has an incentive to drive the allowances price to the level of the penalty for non-compliance.[6] This occurs when allowances to cover emissions associated with fossil fuel generation are insufficient. Thus, the decarbonizing potential of an ETS is weakened. We illustrate this result with a quantitative example and present under which limiting market setting renewable capacity is increased. These results provide insights into the observed decline of new investments in renewables in Europe,[7] where the flagship ETS is entering its fourth (more stringent) Phase and the existing share of renewable capacity is already significant. As such, our analysis also contributes to the current discussion on the reform of energy and environmental policies.

The remainder of the paper is set out as follows. In Section 2, we develop an analytical model of the long-term capacity expansion decision of a monopolist that can supply electricity both from fossil fuel and renewables plants. In Section 3, we solve the long-term capacity expansion problem of the monopolist and describe how the installation of renewable capacity impacts on profits. In Section 4, we illustrate the combined effects of increased renewables penetration and more stringent emission regulations by numerically solving the long-term capacity expansion problem under two scenarios and for three distinct market settings. Section 5 discusses the implications of relaxing the key model assumptions of monopoly and perfectly inelastic electricity demand, as well as relaxing various modelling choices (adjustments of capacity expansion; inter-temporal allowance banking; and regulatory adjustments). Section 6 concludes. The Appendix reports several details of the solution to the long-term capacity expansion problem, with a particular focus on a sensitivity analysis with respect to two key model parameters.

5. In energy-only markets, electricity producers are paid for the amount of electricity produced, but they are not compensated for keeping capacity available.

6. The results in Hintermann (2017) are compatible with our theory. In Hintermann (2017), the monopolist under-abates emissions in order to drive up the allowances price. The logic in our model and in that of Hintermann is the same: driving up the allowances price increases the costs of marginal plants, but it also increases infra-marginal profits. Previous arguments along similar lines are discussed in Misiolek and Elder (1989) and, more recently, in Hintermann (2011). The assertion that regulated electricity firms benefit from a higher allowances price has been empirically verified (e.g. see Oberndorfer, 2009; Hirth and Ueckerdt, 2013).

7. New investments in renewables in Europe peaked in 2011 at $120 billion and have fallen ever since; new capacity investments in 2015 and 2016 were less than half that maximum at $59.8 billion (see Frankfurt School-UNEP Collaborating Centre for Climate & Sustainable Energy Finance and Bloomberg New Energy Finance, 2017).

2. MODEL

2.1 Market Structure

We consider an electricity sector endowed with polluting and green technologies. We also assume that plants are owned by few large electricity producers, so that the electricity sector can be seen as an oligopoly. Around the world, electricity markets remain highly concentrated, with few major national producers controlling a substantial share of the domestic capacity. For example, according to EIA,[8] the first 108 U.S. electricity producers (over a total of 4,138) accounted for 60% of the national nominal capacity in 2017. In addition, in the nine largest European national markets,[9] approximately 3,208 electricity producers covered 95% of net domestic demand in 2016, but only 30 of them had a domestic market share larger than 5%.[10] Yet, cross-border electricity transmissions are increasing, contributing to the development of a more competitive electricity market.

In order to simplify our analytic treatment and concentrate on the price distortion of an ETS, we assume that electricity production is sold through the standard system of uniform auction. This price fixing mechanism and the presence of a share of smaller competitive electricity producers can exert a significant pressure on major producers to make them bid at the marginal cost (as if they were acting under perfect competition). Notice that assuming collusion on the electricity market by producers that, consequently, would charge a constant markup on top of their marginal costs would leave our main conclusions unaffected. Indeed, such a markup would not eliminate the economic incentive to profit from exceeding the emissions cap. This will be discussed in more detail later. Moreover, we assume that electricity producers cooperatively act to decide the energy-mix. By adopting a cooperative oligopoly (or, equivalently, a monopolist set up), we obtain a tractable model of the aggregated energy-mix decision. This allows us to obtain an analytic solution of the problem and to transparently describe the distortion mechanism that an ETS can spawn. Besides, the adoption of a cooperative oligopoly is not an outlandish assumption given the anecdotal evidence of market concentration.[11]

In the following, we will interchangeably use the terms monopolist and electricity sector.

2.2 Model Settings

The focus of the present paper is on the long-term impact of an ETS on the installation of green technology capacity. As such, we abstract from short-term effects of an ETS, e.g. fuel switching, and consider a one-period model. The implications of a two-period extension of our model are qualitatively discussed in Section 5.

Given period $[0,T]$, we distinguish the time of decision $t=0$, the time when key information is revealed (and uncertainty is resolved) $t=0^+$, and the generation period $[0^+,T]$, where no news are announced and no decisions take place. The capacity available at time $t=0$ is Q_c and Q_{nc}, for conventional and non-conventional technologies respectively (capacity will be expressed as the total MWh that can be potentially generated during period $[0^+,T]$). At time $t=0$, the electricity sector decides on the long-term expansion of its capacity, and, in particular, the desired level of installation for

8. See https://www.eia.gov/electricity/data/eia860/.

9. Austria, Belgium, Denmark, France, Germany (with data for 2012), Italy, Netherlands, Spain, UK.

10. See Eurostat at https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Electricity_market_indicators#Electricity_markets_-_generation_and_installed_capacity.

11. In Europe, RWE takeover of EON electricity generation assets increased concentration on generation.

conventional, ΔQ_c, and non-conventional, ΔQ_{nc}, capacity. Negative levels of installation mean that the respective technology is disconnected/dismantled and will no longer generate electricity. For simplicity, we assume that disconnecting a plant from the grid or dismantling a plant can be done at insignificant cost. We neglect implementation time, so the new capacities for both technologies are assumed to be immediately available and operational, and assume that no additional capacity is added during period $[0^+,T]$. The long-term capacity expansion decision is risky since electricity demand during period $[0^+,T]$ (hereafter D) is uncertain at time $t=0$. D is assumed to be revealed at time $t=0^+$. In particular, D is normally distributed with expected value μ and standard deviation σ.[12] In order to simplify the analytical treatment, we also assume that D is price inelastic during period $[0^+,T]$. Our results largely remain unaltered when considering an elastic electricity demand. We present this case later in Section 5 and discuss its implications.

Two spot markets are relevant in this model: the electricity market and the allowances market. In the first market, electricity is asked and offered, and p is the resulting equilibrium price of one *MWh* of electricity. This price is set at time $t=0$ and depends on the uncertain level of D at that time. p remains constant during period $[0^+,T]$. In line with the literature and the common practice in electricity markets, electricity is traded through a uniform auction system. Under this setting, as it is well known, every agent has an incentive to offer all its capacity at the marginal cost, "as if" agents were perfect competitors (i.e. independently of the real level of competition in the market). In the second market, which is a feature of an ETS, allowances can be traded. One allowance entitles a producer to emit one tonne of carbon dioxide (CO_2), the main greenhouse gas, or the equivalent amount of two other powerful greenhouse gases, nitrous oxide (N_2O) and perfluorocarbons (PFCs). In the following, we will not distinguish among these greenhouse gases, and we will label them as CO_2e. The price of an allowance is p_a and it is paid upfront at time $t=0$ when allowances are auctioned off (and D is uncertain).

The electricity sector faces two distinct generation costs: direct production costs and the cost of allowances (environmental cost). Let $c_{v,nc}$ and $c_{v,c}$ represent the costs of generating one *MWh* of electricity using non-conventional and conventional plants, respectively. The regulatory authority determines the number of allowances, C. Thus, if a conventional plant emits m tonnes of CO_2e to generate one *MWh* of electricity, the (unit) cost of allowances is $c_a=mp_a$ per each *MWh*. Furthermore, $H=C/m$ *MWh* corresponds to the total conventional generation covered by allowances. In other words, conventional plants can produce a maximum of H *MWh* of electricity—covered by C allowances—to remain compliant with the emissions cap. In case of non-compliance, producers must pay the penalty f for each tonne of CO_2e beyond C. We define an ETS as being effective if the total emissions of CO_2e from fossil fuel generation do not exceed C. At time $t=0$, the demand of allowances by the electricity sector is $m \times \min(H; Q_c + \Delta Q_c)$. By arbitrage arguments (e.g. see Carmona et al., 2010; Chesney and Taschini, 2012), c_a, which is the cost of allowances at time $t=0$, is determined by the probability that, during period $[0^+,T]$, conventional plants will be required to produce more electricity than can be covered by allowances.

Finally, since the aim of the paper is to study the long-term impact of an ETS on the energy-mix decision, we consider the case where period $[0,T]$ covers the entire lifetime of new capacity

12. The uncertainty of the model is handled with the triple $(\Omega, \mathcal{A}, \mathbb{P})$, where Ω is the event space, $\mathcal{A}$ is the σ-algebra of subsets of Ω, whereas $\mathbb{P}$ is the probability corresponding to the normal distribution of D. Besides, D has density function on the set of real numbers given by $f(x) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{1}{2}\left(\frac{\mu - x}{\sigma}\right)^2}$. Even though a non-negative distribution (e.g. lognormal) would be more appropriate for D, normality is still a reasonable assumption as long as μ is significantly larger than σ, as, indeed, it is the case in this analysis.

investments. Also, we assume that (i) the ETS ends at T and (ii) the amount of allowances needed by non-electricity sectors just equals the amount of allowances allocated to them. Thus, we abstract from (i) banking and borrowing of allowances and (ii) trading between the electricity and non-electricity sectors. We consider the effect of banking in Section 5.

2.3 Energy-Only Markets and the Merit Order Curve

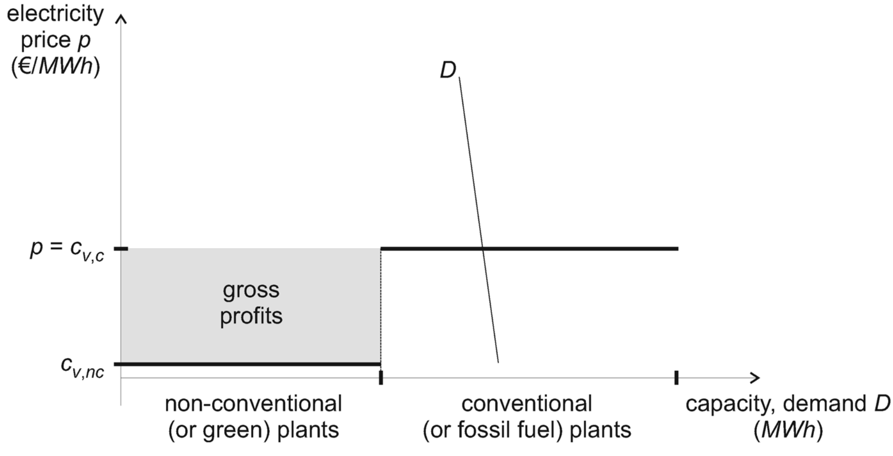
In an energy-only market, prices are determined by the interaction between demand and supply, and supply is determined by the merit order. The merit order is a ranking of electricity generation, based on ascending marginal costs. In practice, non-conventional plants (such as wind, solar, and nuclear plants) have extremely low marginal costs, so electricity from these plants is usually cheaper than that generated by conventional plants using coal or natural gas as fuel. This means that, when demand is low and fully satisfied by non-conventional technologies, electricity is priced at the marginal cost of non-conventional plants. Electricity producers will turn on conventional plants only if the supply of non-conventional plants does not fully satisfy demand. In this case, electricity is priced at the marginal cost of conventional production.

Hence, the merit order is a step-function composed of different marginal costs, each cost depending on one among many types of energy sources. Our analysis uses a simplified two-step merit order curve consisting of only two types of energy sources, non-conventional and conventional (see Figure 1). Since this approach groups all polluting technologies in a single class, it is not cater for the modelling of short-term fuel switching effects of allowances markets. Nevertheless, given our interest on the long-term impact of an ETS to drive the decarbonization process of an economy, the aggregate capacity of green technologies versus that of conventional technologies are the fundamental variables to be modelled here.

Figure 1 clearly shows the peak-load pricing effect: when electricity demand is high, non-conventional production is priced at the higher marginal cost of conventional plants.

Profit opportunities change introducing an ETS. Morthorst (2001), Böhringer and Rosendhal (2011), and, more recently, Böhringer and Behrens (2015) investigate how emission constraints

Figure 1: The classic merit order curve ranks electricity generation based on ascending marginal costs. The curve is a step-function with two values: the near-zero cost of non-conventional generation and the higher cost of conventional generation. Electricity from non-conventional plants is used first to meet demand, followed by electricity from conventional plants.



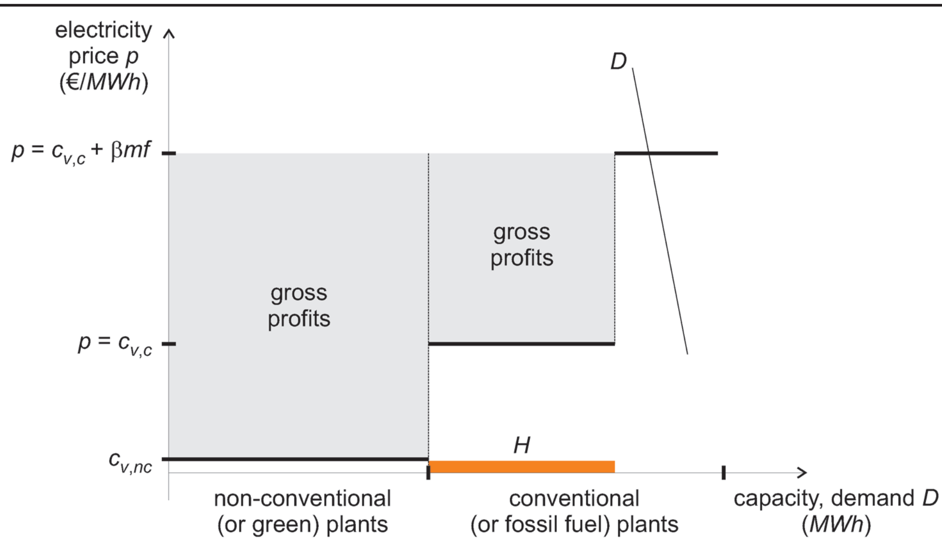
change the electricity market outcome of support schemes for non-conventional production. We complement this stream of works by deriving analytical dependencies between the long-term capacity expansion decision and prices of electricity and allowances. In the presence of an ETS, producers need to buy m allowances for every MWh of conventional generation (recall that m is the number of tonnes of CO_2e emitted from the generation of one MWh of electricity). Therefore, the cost of allowances must be included into the direct costs. The impact of the cost of allowances on electricity prices is modelled here by a pass-through coefficient $\beta \in [0,1]$, which describes the ability of the electricity sector to transfer a fraction of the cost of allowances to consumers.

If D is large enough to require the contribution of conventional plants, the price of electricity will be equal to

$$p = c_{v,c} + \beta m p_a,$$

where p_a is the market price of the allowance to emit one tonne of CO_2e. At time $t=0$, p_a is calculated as a risk-neutral expectation of its final price. We provide the expression of such a price in Eq. (2). The value of p_a during period $[0^+,T]$ is, however, much simpler than that of p_a at time $t=0$. Since D is assumed to be perfectly known at time $t=0^+$, by simple arbitrage arguments, it is immediate to see that the market price of allowances becomes either 0 or $f>0$ and remains constant during period $[0^+,T]$. Indeed, as soon as D is known, it is immediate to check if the generation required from polluting plants exceeds H (i.e. the generation threshold that can be covered by existing allowances). In case of an excess of emissions, producers must pay the penalty mf for every MWh of uncovered conventional generation (i.e. generation beyond H, see Figure 2), whereas allowances become worthless in the opposite case. The pass-through coefficient β has been the subject of some recent studies. Using different econometric techniques, Sijm et al. (2006), Bunn and Fezzi (2007), Zachmann and von Hirschhausen (2008), Fabra and Reguant (2014), Wild et al. (2015), and Hintermann (2016) find empirical evidence of pass-through of allowance costs in numerous electricity markets. This

Figure 2: The possible impact of including the cost of allowances into electricity prices (the so-called pass-through of allowance costs) with $t>0$. Large gross profits can be expected if the level of demand requires polluting plants to exceed the covered generation H, which fixes electricity prices at $p=c_{v,c}+\beta mf$.



literature shows that there is potential for high levels of pass-through of allowance costs.[13] However, it does not provide unambiguous figures. In the Appendix, we present a sensitivity analysis, where we investigate the influence of different levels of pass-through of allowance costs on the long-term capacity expansion decision.

If, at time $t=0$, D is expected to be particularly high, so that conventional generation will exceed H, we can assume that p_a, i.e. the risk-neutral expectation in Eq. (2), is equal to f. Depending on the pass-through coefficient β, the electricity market is cleared at the marginal cost of uncovered conventional plants:

$$p = c_{v,c} + \beta m f.$$

As Figure 2 shows, this price generates large profit opportunities for both technologies.

Comparing the size of profits in the two figures, it is evident that the monopolist has an incentive to drive up the allowances price and, consequently, to increase its infra-marginal profits.

2.4 Relevant Events

In this framework, uncertainty is represented by the unknown value of D at time $t=0$. The event space Ω can be split into three events:

$$A_1 = \{\omega \in \Omega : D \le Q_{nc} + \Delta Q_{nc}\},$$

$$A_2 = \{\omega \in \Omega : Q_{nc} + \Delta Q_{nc} < D < Q_{nc} + \Delta Q_{nc} + H\},$$

$$A_3 = \{\omega \in \Omega : D > Q_{nc} + \Delta Q_{nc} + H\}.$$

Recall that H corresponds to the maximum conventional generation that can be covered by allowances.

Let us consider the possible values of electricity and allowance prices during period $[0^+,T]$, i.e. when electricity demand is known. In event A_1, electricity demand is entirely satisfied by non-conventional capacity, $D \le Q_{nc}+\Delta Q_{nc}$, so the allowances demand falls to zero and p_a must be zero. In this case, the electricity price p is only driven by the marginal cost of green technologies. Therefore,[14]

$$p(A_1) = c_{v,nc} \quad \text{and} \quad p_a(A_1) = 0.$$

In event A_2, electricity demand exceeds non-conventional capacity. However, in this case, all emissions are covered by allowances: $Q_{nc} + \Delta Q_{nc} < D < Q_{nc} + \Delta Q_{nc} + H$. Therefore, the conditional price of allowances is zero and the electricity price coincides with the marginal cost of polluting technologies:[15]

$$p(A_2) = c_{v,c} \quad \text{and} \quad p_a(A_2) = 0.$$

In event A_3, the electricity demand is so high that D exceeds both non-conventional and covered conventional capacities: $D > Q_{nc} + \Delta Q_{nc} + H$. Technically, total emissions of CO_2e from fossil fuel

13. All these studies do not reject the null hypothesis of complete pass-through.
14. With a small abuse of notation, we write $p(A_1)$ to mean $p(\omega)$ for all $\omega \in A_1$. The same simplification applies to $p_a(A_1)$.
15. See footnote 14, with A_2 in place of A_1.

generation exceed C, and the ETS is environmentally ineffective. Hence, producers must pay the penalty for each uncovered tonne of CO_2e and the conditional price of allowances reaches f. Therefore,[16]

$$p(A_3) = c_{v,c} + \beta mf \quad \text{and} \quad p_a(A_3) = f.$$

Table 1 synthesizes the values of some variables depending on a combination of technical conditions and chance. The technical conditions depend on H and the energy-mix decision. The chance, events A_1, A_2, and A_3, consists of realized levels of electricity demand.

Table 1: Electricity and allowance prices for $t \in [0^+,T]$, as identified by a combination of technical conditions and realized levels of electricity demand. The technical conditions depend on H and the energy-mix decision, i.e. $Q_{nc}+\Delta Q_{nc}$ and $Q_c+\Delta Q_c$.

Technical condition	Event	Allowances price, p_a	Cost of allowances, c_a	Electricity price, p
$Q_{nc}+\Delta Q_{nc}>0$	A_1	0	0	$c_{v,nc}$
$Q_c+\Delta Q_c>0$	A_2	0	0	$c_{v,c}$
$Q_c+\Delta Q_c>H$	A_3	f	mf	$c_{v,c}+\beta mf$

We assume throughout the paper that the technical conditions are satisfied. In particular, they will be included into the constraints of the optimization problem developed here.

2.5 Electricity and Allowance Prices

At time $t=0$, the electricity price p is calculated as an expectation. We denote it as p_0:

$$p_0 = p(A_1)\mathbb{P}(A_1) + p(A_2)\mathbb{P}(A_2) + p(A_3)\mathbb{P}(A_3),$$

where $p(A_i)$, $i=1,2,3$, is the price of electricity during period $[0^+,T]$ for the three events A_1, A_2, and A_3. Recalling that D is normally distributed with expected value μ and standard deviation σ, the expression of the electricity price at time $t=0$ can be analytically written as

$$\begin{aligned} p_0 &= \underbrace{c_{v,nc}}_{p(A_1)}\underbrace{\left(\frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx\right)}_{\mathbb{P}(A_1)} \\ &+ \underbrace{c_{v,c}}_{p(A_2)}\underbrace{\left(\frac{1}{\sigma\sqrt{2\pi}}\int_{Q_{nc}+\Delta Q_{nc}}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx\right)}_{\mathbb{P}(A_2)} \\ &+ \underbrace{\left(c_{v,c}+\beta mf\right)}_{p(A_3)}\underbrace{\left(1-\frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx\right)}_{\mathbb{P}(A_3)}. \end{aligned} \tag{1}$$

16. See footnote 14, with A_3 in place of A_1.

Recall that allowances have a positive price only in event A_3 (non-compliance event). By arbitrage arguments (e.g. see Carmona et al., 2008) and assuming a risk-neutral electricity sector, a null interest rate, and a normally distributed electricity demand, it is possible to show that the price of allowances at time $t=0$, which we denote as $p_{a,0}$, is equal to the product between the penalty for non-compliance f and the probability of event A_3:

$$p_{a,0} = f\left(\mathbb{E}(1_{(H,\infty)}(D - Q_{nc} - \Delta Q_{nc}))\right) = f\left(1 - \frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx\right), \tag{2}$$

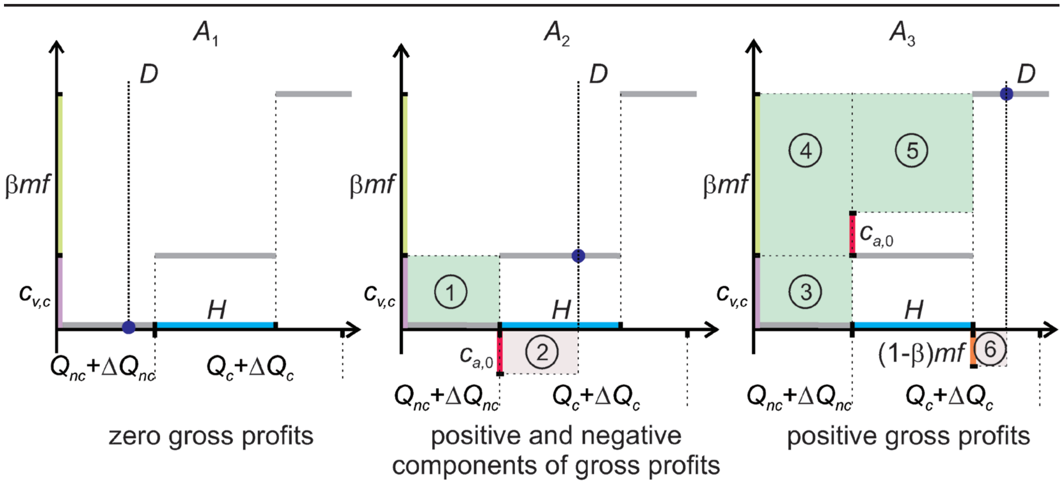
where $1_{(H,\infty)}(D - Q_{nc} - \Delta Q_{nc})$ is the indicator function that is equal to one if electricity demand is satisfied by uncovered conventional generation.

2.6 Gross and Net Profits of the Electricity Sector

In this section, we analyse the profits accruing to the electricity sector. To develop an economic intuition for the results of the model, we analyse the gross profits accruing to the electricity sector (i.e. total revenues less direct costs incurred to generate and sell electricity). Gross profits can be more directly linked to the variables discussed so far, and can be represented as areas of regions under the merit order curves presented in the previous sections (see Figures 1 and 2). Later on, we turn to the analysis of net profits, including fixed costs.

The areas of the shaded regions in Figure 3 illustrate the (conditional) gross profits associated with the three events A_1, A_2, and A_3 discussed in Section 2.4. In this figure, variable costs of green technologies are set equal to zero ($c_{v,nc}=0$). This figure highlights some aspects relevant to our discussion. First, apart from event A_1, where gross profits are zero, the size of gross profits directly depends on the decision variables ΔQ_{nc} and ΔQ_c. Second, gross profits do not proportionally increase with electricity demand. Rather, they increase by steps, as soon as D exceeds the thresholds defining the three events. Nevertheless, in case of events A_2 and A_3, we observe a negative component (areas of regions 2 and 6, respectively), proportionally changing with electricity demand. More

Figure 3: Gross profits, in € per MWh, depending on events A_1, $i=1,2,3$, of the sample space Ω (capacity, "Q" and "ΔQ," and electricity demand, D, are given in MWh). In particular, $c_{a,0}=mp_{a,0}$ and $p_{a,0}$ is defined in Eq. (2).



precisely, the area of region 2 accounts for the initial cost of allowances used to cover the generation required by D. As such, these are direct generation costs. Unused allowances, on the contrary, can be treated as sunk costs. Because the summation of the two cost components is constant, the initial cost of allowances does not generally depend on electricity demand, as it will be made clear in the expression of expected profits accrued to the electricity sector (see Eq. (8)). Third, in case of event A_3, a significant share of gross positive profits from non-conventional and conventional generation is represented by the areas of regions 4 and 5. This sizeable amount makes event A_3 highly desirable. Concurrently, when event A_3 is realized, there is a negligible negative component too, area of region 6. This corresponds to the penalty paid for the excess generation (beyond H). Both the area of region 5 is sizeably positive and that of region 6 is negligibly negative for empirically relevant values of β. As it will be clear in Section 3, the crux of the energy-mix decision is to increase the likelihood of event A_3.

We now turn to net profits, which are obtained by subtracting fixed costs from gross profits. Fixed costs contain different components, mainly labour, maintenance, and investment, and they can be linked to the size of plants. We define fixed costs as

$$FC = FC(c_{f,c}, c_{f,nc}) = c_{f,c}\left(Q_c + \Delta Q_c\right) + c_{f,nc}\left(Q_{nc} + \Delta Q_{nc}\right) + \alpha\left(Q_{nc} + \Delta Q_{nc}\right)^2,$$

where $c_{f,nc}$ and $c_{f,c}$ are the unit investment costs (per *MWh*) of non-conventional and conventional plants, respectively. Notice that we consider a linear function of costs for conventional plants and a quadratic function of non-conventional costs. We motivate this choice with the fact that, for non-conventional plants, the best locations are used first, with the consequence that the capacity investments required to obtain one *MWh* should increase more than linearly as the total capacity in place gets larger.[17]

Given these costs and assuming the technical conditions of Table 1, we examine the net profits in the electricity sector under the three events A_1, A_2, and A_3. In event A_1, electricity demand is entirely satisfied by non-conventional capacity, $D \leq Q_{nc} + \Delta Q_{nc}$. Gross profits are zero because the price of electricity is equal to the variable cost of generation, which is zero by assumption (left panel of Figure 3). In this case, the conditional net profits G are negative because of fixed costs and the cost of allowances:[18]

$$G(A_1) = -FC - c_{a,0}H. \tag{3}$$

In event A_2, electricity demand requires the contribution of conventional capacity (in addition to non-conventional capacity), $Q_{nc} + \Delta Q_{nc} < D < Q_{nc} + \Delta Q_{nc} + H$, but all emissions from conventional generation are covered by allowances. In this case, non-conventional generation is sold at a price equal to the cost of conventional generation. The conditional net profits G are equal to[19]

$$G(A_2) = -FC - c_{a,0}H + \left(c_{v,c} - c_{v,nc}\right)\left(Q_{nc} + \Delta Q_{nc}\right). \tag{4}$$

17. The constant returns assumption for conventional plants follows from the fact that conventional technologies are easily scalable and, consequently, do not generate a scarcity rent. The decreasing returns assumption for non-conventional plants follows from the fact that the best production sites are used first and that further non-conventional development implies investing in less and less productive sites.

18. With a small abuse of notation, we write $G(A_1)$ to mean $G(\omega)$ for all $\omega \in A_1$.

19. See footnote 18, with A_2 in place of A_1.

In event A_3, $D > Q_{nc} + \Delta Q_{nc} + H$. Conventional plants generate electricity in excess of the threshold H. Therefore, the marginal cost of electricity must include both the cost of conventional generation ($c_{v,c}$) and the penalty per unit (MWh) of emission eventually reduced by the pass-through coefficient (βmf). The conditional net profits G are equal to[20]

$$\begin{aligned} G(A_3) &= -FC + \left(\beta mf - c_{a,0}\right)H \\ &\quad + \left(\beta - 1\right)mf\left(D - Q_{nc} - \Delta Q_{nc} - H\right) \\ &\quad + \left(\beta mf + c_{v,c} - c_{v,nc}\right)\left(Q_{nc} + \Delta Q_{nc}\right). \end{aligned} \tag{5}$$

Depending on the levels of the pass-through coefficient, it is not always preferable to expand non-conventional capacity. We discuss this later in footnote 21.

Two observations are in order. First, the application of a constant markup on top of marginal costs leaves our conclusions unaltered. Such a markup can only change the height of the shaded regions in Figure 3, leaving the energy-mix decision problem—namely, the control of the horizontal dimension of the shaded regions—practically unaffected. Second, we do not consider the case of $D = Q_{nc} + \Delta Q_{nc} + H$, i.e. the case where D exactly exhausts allowances. This is an unlikely event—the probability of this event is zero if D is assumed to be an absolutely continuous random variable. Also, the price of allowances would not be uniquely defined in such a case: indeed, it could take any value between 0 and f.

2.7 Operational and Allowance Components of Profits

For each of the three events, we can separate gross profits into two components: an *operational component* and an *allowance component*. The operational component is determined by the sale of non-conventional electricity at the marginal cost of conventional generation. The allowance component comes from including into the price of electricity the cost of allowances needed to cover emissions from conventional generation.

Assuming the technical conditions of Table 1 and conditioning on the corresponding event, we have the following results. In event A_1, there is neither operational component nor allowance component. In event A_2, the operational component is positive and the allowance component is negative:

$$\begin{aligned} G(A_2) + FC + \underbrace{c_{a,0}(H - D + Q_{nc} + \Delta Q_{nc})}_{\text{sunk cost for unused allowances}} \\ = \underbrace{\left(c_{v,c} - c_{v,nc}\right)\left(Q_{nc} + \Delta Q_{nc}\right)}_{\text{operational component}} - \underbrace{c_{a,0}(D - Q_{nc} - \Delta Q_{nc})}_{\text{allowance component}}. \end{aligned} \tag{6}$$

The allowance component is negative because the conventional generation "consumes" allowances that costed $c_{a,0}$ per MWh. It corresponds to the area of region 2 in the central panel of Figure 3. Unused allowances, on the contrary, are treated as sunk costs. In event A_3, the operational component is positive and the allowance component, depending on the levels of the pass-through coefficient β, can be positive or negative:

20. See footnote 18, with A_3 instead of A_1.

$$
\begin{aligned}
G(A_3)+FC &= \left(\beta mf - c_{a,0}\right)H + \left(\beta mf + c_{v,c} - c_{v,nc}\right)\left(Q_{nc}+\Delta Q_{nc}\right) \\
&\quad -\left(1-\beta\right)mf\left(D - Q_{nc} - \Delta Q_{nc} - H\right) \\
&= \underbrace{\left(c_{v,c} - c_{v,nc}\right)\left(Q_{nc}+\Delta Q_{nc}\right)}_{\text{operational component}} - \underbrace{\left(1-\beta\right)mf\left(D - Q_{nc} - \Delta Q_{nc} - H\right)}_{\text{allowance component}} \\
&\quad + \underbrace{\beta mf\left(Q_{nc}+\Delta Q_{nc}+H\right) - c_{a,0}H}_{\text{allowance component}}.
\end{aligned} \tag{7}
$$

Notice that only small values of β generate a negative allowance component.[21] In the Appendix, we present a sensitivity analysis, where we examine the influence of the level of β on the long-term capacity expansion decision.

3. LONG-TERM CAPACITY EXPANSION PROBLEM

The long-term capacity expansion problem is solved at time $t=0$, i.e. when D is unknown. We consider the case where the monopolist maximizes expected profits under the capacity expansion constraints previously discussed. Combining Eq. (3), (4), and (5) along with the corresponding probabilities (see Eq. (1)), expected profits are

$$
\mathbb{E}(G) = G(A_1)\mathbb{P}(A_1) + G(A_2)\mathbb{P}(A_2) + G(A_3)\mathbb{P}(A_3), \tag{8}
$$

and, considering H (i.e. the conventional generation covered by allowances) and S (a minimum level of conventional capacity to guarantee the security of supply), the long-term capacity expansion problem of the monopolist can be stated as[22]

$$
\begin{aligned}
&\max_{\Delta Q_{nc},\Delta Q_c} \ \mathbb{E}(G) \\
\text{s.t.}\quad & \Delta Q_{nc} > -Q_{nc} \\
& \Delta Q_c > H - Q_c \\
& \Delta Q_c \geq S - Q_c
\end{aligned} \ . \tag{9}
$$

The first constraint guarantees that the installed renewable capacity is positive. The second constraint avoids the case where the emissions cap is slack, i.e. the probability of event A_3 is zero. In-

21. We can identify the threshold value of β associated with a null allowance component for $G(A_3)$ in Eq. (7). Such a null component is equivalent to the areas of regions 4, 5, and 6 in Figure 3 summing up to 0. Let us call this value $\overline{\beta}$. Adopting values of β lower than $\overline{\beta}$ causes the area of region 6 to prevail with respect to the areas of regions 4 and 5, therefore making the allowance component negative. Since the allowance component depends on the random variable D, we perform the calculation of $\overline{\beta}$ on the expected allowance component of event A_3, i.e. the expression of the allowance component in Eq. (7) multiplied by the probability of event A_3. After some rearrangement, $\overline{\beta}$ is such that

$$
\left(-\left(1-\overline{\beta}\right)mf\left(D-Q_{nc}-\Delta Q_{nc}-H\right)+\overline{\beta}mf\left(Q_{nc}+\Delta Q_{nc}+H\right)-c_{a,0}H\right)\times\mathbb{P}(A_3)=0.
$$

Given the market settings of Section 4.1 and the capacity investment decisions under the ETS scenario of Section 4.2 (see, in particular, Table 4), the values of $\overline{\beta}$ are 0.04, 0.40, 0.42, and 0.28, for the low RES (first two values), average RES, and high RES market settings, respectively.

22. The long-term capacity expansion problem can be easily extended in various ways (e.g. presence of budget constraints, risk constraints, etc.). We leave this for future research.

deed, if the installed conventional capacity ($Q_c+\Delta Q_c$) happened to be lower than H, event A_3 would never occur. However, as discussed above, it is in the interest of the monopolist that event A_3 occurs. The third constraint guarantees that $Q_c+\Delta Q_c$ is not lower than the security of supply conventional capacity S. When (i) it is optimal for the monopolist to reduce conventional capacity (which is, indeed, what we show in the Appendix) and (ii) H progressively decreases (as it is expected in a low-carbon economy), then $S>H$ and the third constraint is more stringent than the second one.

We report the analytical solution to this problem in the Appendix. For evaluation purposes, it must be partially numerically calculated. In the next section, we analyse the problem through a quantitative application to three distinct market settings under two scenarios.

Figure 4 shows the three levels of conditional profits (see Eq. (3), (4), and (5)), as well as the corresponding probabilities (see Eq. (1)). The latter are the areas of the three shaded portions of the distribution of D. Also, Figure 4 illustrates the tradeoff faced by the monopolist when expanding non-conventional capacity from Q_{nc} (left panel) to $Q_{nc}+\Delta Q_{nc}>Q_{nc}$ (right panel): a higher share of non-conventional production can be priced at the higher marginal cost of conventional production; yet the likelihood of achieving higher profits is reduced because more electricity demand is met by cheaper non-conventional production. There is empirical evidence about such a tradeoff: Germany has a high share of renewables in its current energy portfolio. In Germany, many electricity producers complain that (relative to other countries) there is a higher chance that demand is completely satisfied by non-conventional capacity (corresponding to A_1), so electricity is priced at the marginal cost of non-conventional plants (actually, the price of electricity has occasionally become even negative).[23] This indicates that German electricity producers have an incentive to keep the expansion of renewables below some optimal threshold.

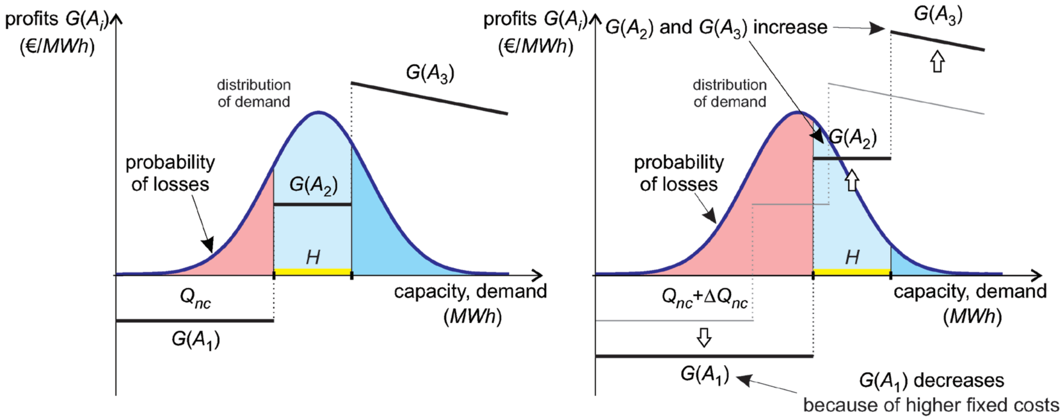
The decision to expand non-conventional capacity leads to several economic consequences, of opposite signs:

- probability of event A_1 (losses) expands, as there is a higher likelihood that non-conventional generation can fully meet electricity demand. At the same time, the increased fixed costs resulting from the additional non-conventional generation cause higher losses within this region. Letting $\Delta Q_{nc}>0$ clearly decreases the expectation of these conditional profits;
- probability of event A_2 (profits with only the operational component) shrinks especially if the share of non-conventional capacity is substantial; however, profits within this region ($G(A_2)$) can increase thanks to the additional non-conventional generation being sold at the price of conventional generation. Therefore, the impact of $\Delta Q_{nc}>0$ is not clear;
- probability of event A_3 (profits with a very high allowance component) shrinks with certainty; however, profits within this region ($G(A_3)$) sharply increase (especially for values of β close to one) due to: (a) additional non-conventional capacity being sold at a higher unit profit and (b) covered conventional generation also being sold at a profit. However, under particular circumstances (i.e. β very small and, at the same time, D sufficiently high) conditional profits $G(A_3)$ can significantly reduce. Again, the impact of $\Delta Q_{nc}>0$ is not clear.

In summary, an increase of non-conventional capacity does not have an obvious overall impact on expected profits. Much of this impact depends on the tradeoff between the increase of $G(A_2)$ and $G(A_3)$ and the reduction of $\mathbb{P}(A_2)$ and $\mathbb{P}(A_3)$.

23. Over the last few years, European wholesale electricity markets have shown a manifold increase of occurrences of negative prices (*The Economist*, 2017). For instance, in 2013, during a period of low demand and high supply of wind and solar energy, the German wholesale electricity prices fell to –100 €/MWh (*The Economist*, 2013).

Figure 4: Impact of a positive expansion of green technologies. Increasing the green capacity from Q_{nc} (left panel) to $Q_{nc}+\Delta Q_{nc}$ (right panel) impacts both the levels of profits and the corresponding probabilities. In this example, the probability of the intermediate level of profits ($G(A_2)$) is reduced, that of the high level of profits ($G(A_3)$) becomes very small, while the probability of losses ($G(A_1)$) greatly increases.



4. NUMERICAL ILLUSTRATION

We present an application of the long-term capacity expansion Problem (9) that is numerically solved first in the absence of emission regulations (BAU scenario) and then in the presence of emission regulations (ETS scenario). The BAU scenario is the benchmark. The benchmark solution is obtained by setting the penalty for non-compliance f equal to zero. A null penalty dramatically simplifies the expression of expected profits (Eq. (8)): the price of allowances is zero for $t \in [0,T]$ under all states of nature; consequently, the allowance components in Eq. (6) and (7) vanish and the profits in events A_2 and A_3 become indistinguishable. Notice also that, since the penalty is zero, the level of H becomes irrelevant. The benchmark solution and the ETS solution are compared considering three distinct market settings with various degrees of cap stringency and renewables penetration. This allows us to test the impact of changes in the market setting on the long-term capacity expansion decision. Below we discuss first the market settings and then the solutions under the BAU scenario and the ETS scenario.

4.1 Market Settings

In all market settings, we set S, the minimum level of conventional capacity, equal to the expected value of electricity demand, i.e. 200 *MWh*. This way, electricity demand can be satisfied, on average, in all settings.

The first market setting (left panel of Figure 5) corresponds to the case where the initial share of renewable capacity is the lowest ($Q_{nc}=20$ *MWh*) and the emissions cap is relatively generous ($H=120$ *MWh*). We label this market setting as *low RES*. The second market setting, labelled as *average RES* (middle panel of Figure 5), corresponds to the case where the initial share of renewable capacity is larger ($Q_{nc}=100$ *MWh*) and the emissions cap is tighter ($H=100$ *MWh*) than that of the first setting. Notice that $S>H$ in all three market settings and the security of supply constraint becomes binding. The sum of initial non-conventional capacity and allowances exactly meet the expected value of electricity demand, 200 *MWh*. Hence, at time $t=0$, emissions from conventional plants can exceed the cap with a probability of 50% (see the dashed segment with respect to the distribution of D in the middle panel of Figure 5). The last market setting, labelled as *high RES*, corresponds to the case where renewables cover a relatively large amount of electricity demand ($Q_{nc}=210$ MWh) and the emissions cap is significantly tighter ($H=20$ MWh). In this last market setting, the initial non-conventional capacity plus the amount of allowances cover electricity demand with a probability of 84% (right panel of Figure 5). The model parameters common to the three distinct market settings are reported in Table 2, whereas the initial capacities of these settings are reported in Table 3 and illustrated in Figure 5.

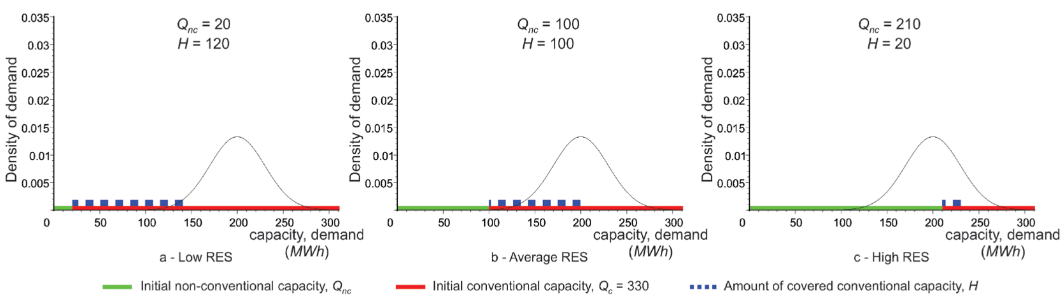
Table 2: Model parameters common to the three distinct market settings.

Model parameter	Value	Model parameter	Value
Security of supply conventional capacity, S (MWh)	200	$c_{v,c}$ (€/MWh)	60
Expected value of electricity demand, μ (MWh)	200	$c_{v,nc}$ (€/MWh)	0
Standard deviation of electricity demand, σ (MWh)	30	$c_{f,c}$ (€/MWh)	1.5
m (tonnes/MWh)	1.1	$c_{f,nc}$ (€/MWh)	6
f (€/tonne)	100	β	1
α	0.01		

Table 3: Initial capacities in the three distinct market settings.

	Market setting		
Capacity	Low RES	Average RES	High RES
Initial conventional capacity, Q_c (MWh)	330	330	330
Initial non-conventional capacity, Q_{nc} (MWh)	20	100	210
Covered conventional capacity, H (MWh)	120	100	20

Figure 5: Capacities before installation decisions in the three distinct market settings of the ETS scenario. Capacities are only read on the horizontal axis, whereas the vertical axis shows the density of electricity demand.



4.2 Capacity Investment Decisions under the BAU and ETS Scenarios

In order to assess the environmental outcome corresponding to each market setting, we define the *green ratio*:

$$\text{green ratio} = \frac{Q_{nc} + \Delta Q_{nc}^{*}}{\mu}.$$

The ratio quantifies the share of the expected value of electricity demand covered by renewable generation. Notice that a green ratio equal to one corresponds to just a 50% probability that renewables will cover electricity demand since μ is the 50th percentile of the distribution of D.

Table 4 reports the solutions to Problem (9) and the corresponding green ratios under the BAU and ETS scenarios and for all market settings. Table 5 focuses on the economic variables, reporting the electricity price (Eq. (1)), the price of allowances (Eq. (2)), expected profits (Eq. (8)), and the percentage of expected profits corresponding to the allowance component of solutions. In particular, the latter corresponds to the sum of the allowance component of Eq. (6) multiplied by the probability of event A_2 and the allowance component of Eq. (7) multiplied by the probability of event A_3. Finally, this sum is divided by the amount of expected profits.

Table 4: Physical analysis of solutions: expansion of conventional and non-conventional capacities, green ratios, under the BAU and ETS scenarios and for the three distinct market settings.

	Market setting			
BAU scenario	Low RES		Average RES	High RES
Type of solution	Optimal Normal		Optimal Normal	Optimal Normal
ΔQ_c^* (MWh)	–130		–130	–130
ΔQ_{nc}^* (MWh)	137.5		57.5	–52.5
Green ratio	0.7875		0.7875	0.7875
ETS scenario	Low RES	Low RES	Average RES	High RES
Type of solution	Suboptimal Normal	Optimal Degenerate	Optimal Degenerate	Optimal Degenerate
ΔQ_c^* (MWh)	–130	–130	–130	–130
ΔQ_{nc}^* (MWh)	133.5	57	–10.5	–63
Green ratio	0.7675	0.3850	0.4475	0.7350

Table 5: Economic analysis of solutions: electricity prices, allowance prices, expected profits, allowance components of profits, under the BAU and ETS scenarios and for the three distinct market settings.

	Market setting			
BAU scenario	Low RES		Average RES	High RES
Type of solution	Optimal Normal		Optimal Normal	Optimal Normal
p_0 (€/MWh)	55.30		55.30	55.30
$p_{a,0}$ (€/tonne)	0		0	0
$\mathbb{E}(G)$ (€)	7217.10		7217.10	7217.10
Allowance component of $\mathbb{E}(G)$ (%)	0		0	0
ETS scenario	Low RES	Low RES	Average RES	High RES
Type of solution	Suboptimal Normal	Optimal Degenerate	Optimal Degenerate	Optimal Degenerate
p_0 (€/MWh)	57.15	119.38	130.04	152.76
$p_{a,0}$ (€/tonne)	0.71	53.98	63.68	86.43
$\mathbb{E}(G)$ (€)	7316.13	8370.96	10721.88	21057.37
Allowance component of $\mathbb{E}(G)$ (%)	0.02	0.55	0.58	0.67

We distinguish between optimal or suboptimal solutions and between normal or degenerate solutions. The first distinction is of mathematical nature: a suboptimal solution is local, whereas an optimal solution is global. In some cases, the problem admits a suboptimal solution that turns out to be of economic interest. The second distinction refers to the outcome of an ETS missing its target, namely emissions below the cap. Unexpected high levels of a normally distributed electricity demand (triggering event A_3) have always a positive probability. However, a solution aiming at exceeding the emissions cap also when electricity demand takes average values will be labeled as degenerate. This is the case where the electricity sector benefits the most from a high allowances price due to deliberate non-compliance. Conversely, a normal solution seeks to maximize the probability of event A_2 (where profits accrue from selling non-conventional generation at the marginal cost of conventional production), resulting in negligible probabilities of event A_3. Similarly to what happens under the BAU scenario, a normal solution neglects the influence of allowances and turns out to be preferable from an environmental standpoint. It corresponds to the highest green ratio. At the same time, it does not yield high electricity prices.

Let us discuss the solutions under the BAU scenario first. Actually, we can talk about a unique solution. A quick inspection of Table 4 reveals that the only apparent difference across the three distinct market settings is about ΔQ^*_{nc}. However, the final installed renewable capacity ($Q_{nc}+\Delta Q^*_{nc}=157.5$ MWh) is constant in all market settings. As for conventional capacity, we analytically show in the Appendix (under the BAU and ETS scenarios) that it has a negative impact on expected profits. Indeed, the optimal solution in all market settings ($\Delta Q^*_c=-130$ MWh) consists in reducing it up to the security of supply conventional capacity. Consequently, the green ratio remains constant too. The optimal solution under the BAU scenario is normal since, by construction, there is no ETS. Turning to the economic perspective, the electricity price is equal to 55.30 €/MWh. Absent an allowances market, this corresponds to the lowest price in all market settings. Similarly, expected profits for the electricity sector take the lowest value (7271.10 €); they do not include any allowance component.

In contrast to the BAU scenario, Table 4 shows that the solutions under the ETS scenario are affected by the different market settings. The table reports the physical features of four solutions, three optimal and one suboptimal. However, a common feature of these solutions is that $\Delta Q^*_c=-130$ MWh, the same value as under the BAU scenario.

The (mathematically) suboptimal solution occurs in the low RES market setting and it is similar to the optimal and normal solution under the BAU scenario. In this market setting, the resulting non-conventional capacity and the green ratio are close to those of the BAU scenario. This solution is normal since the probability of event A_3 is approximately zero. Recall from Eq. (2) that allowance prices are linked to the probability of event A_3 by $\mathbb{P}(A_3)=p_{a,0}/f=p_{a,0}/100=0.71\%$. Correspondingly, $p_{a,0}=0.71$ €/tonne; $p_0=57.15$ €/MWh is also low. Expected profits and the allowance component are slightly higher than under the BAU scenario.

The three optimal solutions under the ETS scenario are all degenerate. The installed renewable capacity, $Q_{nc}+\Delta Q^*_{nc}$, varies in response to the different levels of H in the three distinct market settings. In particular, the smaller H the higher the installed renewable capacity, as one would expect under a progressively more stringent ETS. That said, we notice that the installation of renewables, ΔQ^*_{nc}, is systematically lower than that under the BAU scenario. The difference between green capacities is particularly relevant in the low RES and average RES market settings: 80.5 and 68 MWh, respectively. In particular, in the average RES market setting, we observe a negative expansion (disconnection/dismantling) equal to –10.5 MWh under the ETS scenario and a positive expansion of 57.5 MWh under the BAU scenario. Similarly, the green ratio under ETS is systematically lower than that under BAU. This is counterintuitive: sustained investments in renewables and higher shares of green generation might be expected outcomes of an ETS. On the contrary, the three optimal solutions are degenerate since emissions exceed the cap with substantial probabilities ($\mathbb{P}(A_3)=54\%$, 64%, and 86.5%, respectively in the low RES, average RES, and high RES market settings). Such probabilities are represented by the areas of the shaded regions in Figure 6.

The economic consequences of such solutions are dramatically clear: allowance prices significantly increase, driving electricity prices to exceptionally high levels; expected profits also increase (e.g. almost 300% with respect to the high RES market setting under the BAU scenario), mainly due to the allowance component.

Figure 6: Installed renewable capacities, $Q_{nc}+\Delta Q^*_{nc}$, of the long-term capacity expansion problem in the three distinct market settings of the ETS scenario. Capacities are only read on the horizontal axis, whereas the vertical axis shows the density of electricity demand. In the low RES market setting, both an optimal and degenerate solution and a suboptimal and normal solution are obtained.

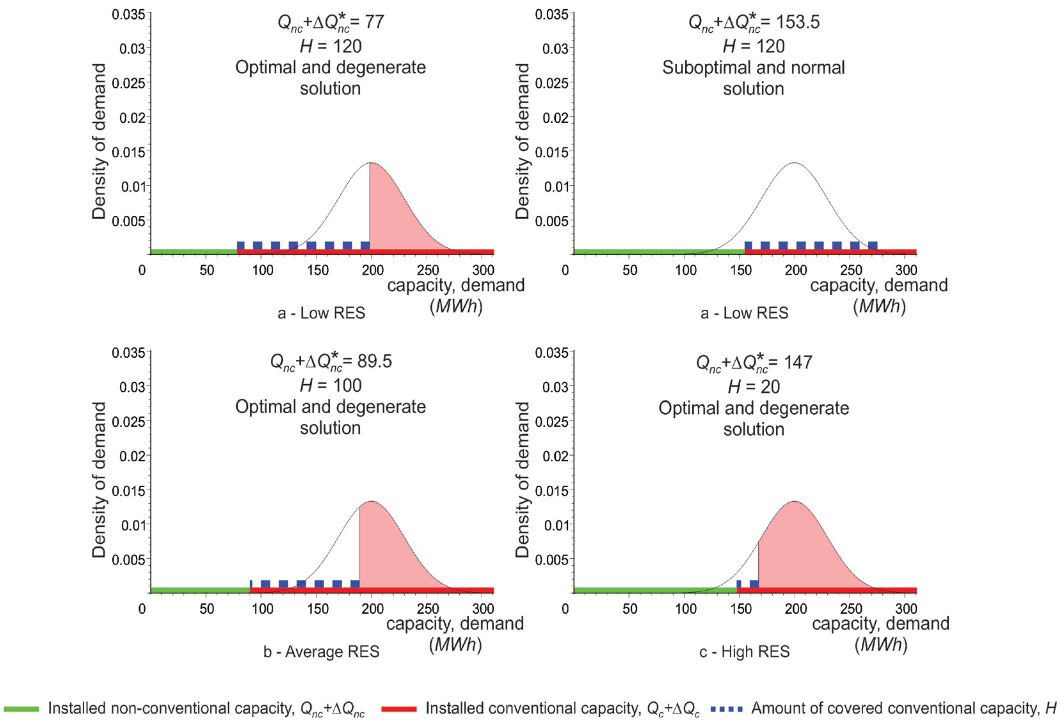
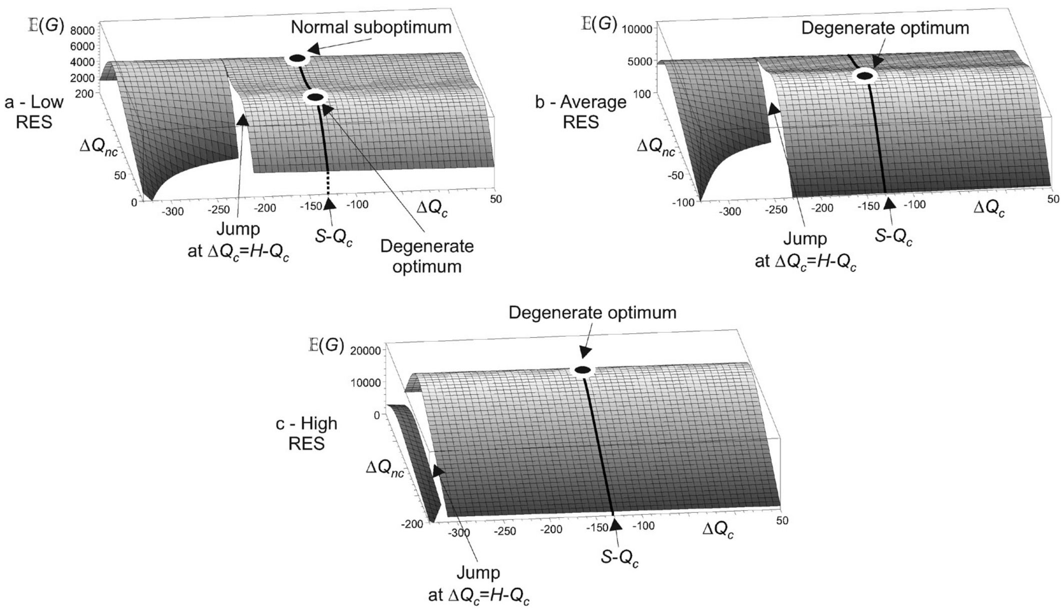


Figure 7 illustrates $\mathbb{E}(G)$ (under the ETS scenario and for all market settings) as a function of the decision variables ΔQ_{nc} and ΔQ_c, under the constraints $Q_{nc}+\Delta Q_{nc}>0$ and $Q_c+\Delta Q_c>0$. The graphical relationship between $\mathbb{E}(G)$ and ΔQ_{nc} is self-evident. Conversely, the dependence of $\mathbb{E}(G)$ and ΔQ_c is not that neat. Yet, as shown in the Appendix, the partial derivative $\partial\mathbb{E}(G)/\partial\Delta Q_c$ is negative over all the domain.

Notice that the conventional capacity investment strategy of the monopolist is simple. It has an incentive to reduce the installed conventional capacity $Q_c+\Delta Q_c$ to $H+\varepsilon$, with $\varepsilon\to 0^+$ (i.e. just enough to make event A_3 possible). Yet, the supply constraint prevents the monopolist from adopting such an extreme solution. This is clearly observable in the figure, where the optimum occurs at $\Delta Q_c=S-Q_c$. However, the corresponding expected profits are lower than what would be attainable at $\Delta Q_c=H-Q_c$. Finally, observe that, for $\Delta Q_c<H-Q_c$, expected profits drop because A_3 becomes impossible. The incentive to disconnect/dismantle conventional capacity illustrated here is related to the so-called "missing money problem." Among others, capacity compensation schemes (e.g. reliability options, capacity markets) and the application of penalties to producers for electricity demand left unsatisfied are alternative ways to address the security of supply.

The mathematical details of $\mathbb{E}(G)$, in particular its partial derivatives with respect to both ΔQ_{nc} and ΔQ_c, are obtained and discussed in the Appendix, both under the constraints of Problem (9) and considering only the constraints $Q_{nc}+\Delta Q_{nc}>0$ and $Q_c+\Delta Q_c>0$. In the Appendix, we also discuss allowance and electricity prices under the ETS scenario as functions of ΔQ_{nc}.

Figure 7: Expected profits, $\mathbb{E}(G)$, as a function of ΔQ_c (installation decision of conventional capacity) and ΔQ_{nc} (installation decision of non-conventional capacity), subject to the constraints $Q_c+\Delta Q_c>0$ and $Q_{nc}+\Delta Q_{nc}>0$. The three panels refer to the market settings adopted in the ETS scenario.



To summarize, although one would expect that an ETS will sustain investments in renewables in the long-term, our analysis shows that this is not the case when the electricity sector cooperatively acts. Green capacity investments and green ratios are higher under BAU than under ETS, highlighting the distortionary effect of an ETS. A tighter emissions cap does not drive greater green capacity investments since the opportunity of exceeding the cap remains unaffected. The effect of regulatory adjustments is discussed in Section 5.

5. SENSITIVITY TO KEY ASSUMPTIONS

Our benchmark set up corresponds to a one-period model, where the long-term capacity expansion decision is taken under uncertainty over the future electricity demand. Immediately after the decision is taken, demand is realized and electricity is dispatched. By focusing the analysis on a single period, the benchmark model abstracts from the possibility of capacity adjustments, banking of allowances, and regulatory adjustments. In this section, we qualitatively discuss the sensitivity of our results to these key modelling choices and to two model assumptions: perfectly inelastic electricity demand and use of a monopolistic framework.

Two- and Multi-Period Frameworks A proper analysis of a multi-period decision framework requires dynamic programming techniques and it is beyond the scope of this work. Yet, it is possible to explore the likely impact of introducing an intermediate time $\tau \in (0,T)$, where adjustment of capacity can occur by building on the main lessons learned from real options theory. For ease of exposition, let us suppose that the residual period $T-\tau$ is sufficiently long to cover the entire lifetime of new capacity investments. Also, since the partial derivative of $\mathbb{E}(G)$ with respect to ΔQ_c is negative and independent of D, we concentrate the analysis on ΔQ_{nc}.

As time passes, information accumulates. Thus, at time $t=\tau$, more information about D is available. Under the real options approach, this introduces for the monopolist an opportunity to optimally delay part of (or the entire) capacity expansion.

To see this, let us call $\Delta Q^*_{nc,0}$ the decision at time $t=0$ and $\Delta Q^*_{nc,\tau}$ the decision at time $t=\tau$ and let us compare the result $\Delta Q^*_{nc,0}+\Delta Q^*_{nc,\tau}$ and the optimal expansion decided in a one-period framework (ΔQ^*_{nc}). A qualitative description of this comparison can be obtained examining panels b of Figures 11 and 12, where the darker curves correspond to the optimal solutions with a less uncertain D (i.e. smaller value of $\sigma=10$). According to the real options theory, these solutions can be seen as if they were obtained under a two-period framework. By the same token, the lighter curves correspond to the optimal solutions in the one-period framework ($\sigma=30$, i.e. more uncertain D). We can observe that, when, in the one-period framework, the optimal solution seeks event A_3, then we have $\Delta Q^*_{nc,0}+\Delta Q^*_{nc,\tau}<\Delta Q^*_{nc}$, i.e. the disconnection/dismantling in the two-period framework will be even more pronounced then that in the one-period framework. Vice versa, when, in the one-period framework, the optimal solution is normal, then the conclusion is reversed: $\Delta Q^*_{nc,0}+\Delta Q^*_{nc,\tau}>\Delta Q^*_{nc}$.

In summary, we can expect that our results could be extended to the two-period framework. Also, this line of reasoning could extend the discussion from a two-period framework to a multi-period framework.

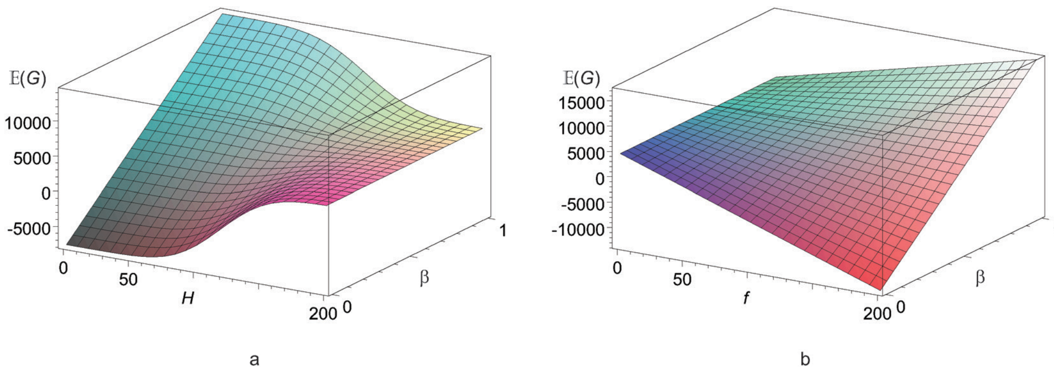
Banking of Allowances Most of existing ETS allow for some form of banking of unused allowances between phases for future compliance. Borrowing future allowances for present compliance is uncommon. To account for banking, we extend our benchmark model introducing the intermediate time $T_1=(0,T)$ such that, if $[0,T_1]$ emissions exceed the $[0,T_1]$ cap, the penalty for non-compliance f is paid.

The possibility to bank allowances has no consequences for our results. As shown in Carmona and Hinz (2011) and Grüll and Taschini (2011) with banking, the allowances price at time $t=0$ can be decomposed into two parts: the expected value of non-compliance in $[0,T_1]$ and the expected value of non-compliance in $(T_1,T]$, namely the banking value. As shown in the previous cited papers, this sum is larger than the allowances price evaluated in a single-phase framework. Therefore, the introduction of an intermediate time does not reduce (possibly increases) the chances for the monopolist to be in non-compliance.

Regulatory Adjustments To explore the likely impact of regulatory adjustments, possibly occurring after the capacity investment decision of the monopolist, we comment Figure 8, which shows expected profits, $\mathbb{E}(G)$, as a function of H and f, respectively, for different levels of the pass-through coefficient β. The figure is obtained under the average RES market setting (see Tables 2, 3, and 4). First of all, we can see that the dependence of $\mathbb{E}(G)$ from both f and H depends on the level of β. In particular, when β is sufficiently large, expected profits for the monopolist increase (linearly) with f and decrease (not linearly) with H.

Therefore, we can argue that, in the case the regulatory authority would adjust one or both the parameters to reduce the profit opportunities for the monopolist, it should reduce f and/or increase H. Notice, in particular, that, for low values of f and high values of H, $\mathbb{E}(G)$ flattens out to a level which is independent of β. Such a level corresponds to $\mathbb{E}(G)$ under the BAU scenario (i.e. where the price of allowances falls to zero). Intermediate adjustments do not cancel the incentive

Figure 8: Expected profits, $\mathbb{E}(G)$, as a function of H (panel a) and f (panel b), for different levels of the pass-through coefficient β.



to distort prices by the monopolist. Therefore, either the regulatory authority selects f and H corresponding to the BAU scenario, or the monopolist will always seek degenerate solutions. Unfortunately, such an adjustment corresponds to ruling out an ETS.

Inelastic Electricity Demand Our benchmark model assumes a perfectly inelastic electricity demand D. In particular, D is normally distributed with constant mean μ and constant standard deviation σ. However, one may contend that consumers will respond to the prospects of high electricity prices and D may not be perfectly elastic. Without imposing any specific relationship between D and electricity prices, we can reasonably assume that higher electricity prices reduce demand or, equivalently, decrease μ. By varying μ, we can explore the effect of an elastic electricity demand and argue that it is inconsequential.

To build intuition, let us consider the case where consumers can react to the increase of electricity prices by investing in (non-conventional) auto-generation. We capture the impact of this reaction by introducing the random variable D_n representing the resulting net electricity demand. This change of variables has no consequences for our analytical results.

Let D_h represent the uncertain self-satisfied electricity demand (self-consumption). We assume that it is normally distributed with expected value μ_h and standard deviation σ_h. We express the resulting net electricity demand as

$$\begin{aligned} D_n = D - D_h &\sim \mathcal{N}\left(\mu, \sigma^2\right) - \mathcal{N}\left(\mu_h, \sigma_h^2\right) \\ &\sim \mathcal{N}\left(\mu - \mu_h, \sigma^2 + \sigma_h^2 - 2\rho\sigma\sigma_h\right), \end{aligned}$$

where D and D_h are jointly normally distributed and ρ is the linear correlation coefficient, which can be assumed positive.

To illustrate the effect of a more elastic D, we let μ_h vary and set $\sigma_h = 10$, $\rho = \frac{1}{6}$, and $D \sim \mathcal{N}\left(200, 30^2\right)$. Substituting, we obtain $D_n \sim \mathcal{N}\left(200 - \mu_h, 30^2\right)$. The remaining settings of Q_c, Q_{nc}, and H are the same as those in Table 3. Table 6 summarises the impact of an increasing demand elasticity on ΔQ_{nc}^* in the three distinct market settings of the ETS scenario.

Therefore, we can infer that an increasing demand elasticity (higher values of μ_h) pushes the monopolist to more aggressively reduce investments in non-conventional capacity. Although unreported, the green ratios remain unaffected.

Table 6: Optimal/suboptimal installation of non-conventional capacity for some values of μ_h, the expected value of D_h.

		ΔQ^*_{nc} (MWh)			
Market setting[a]	Type of solution	$\mu_h=0$	$\mu_h=10$	$\mu_h=20$	$\mu_h=50$
Low RES	Degenerate	57	52	48	—
Low RES	Normal	133.5	125.5	117.5	93
Average RES	Degenerate	–10.5	–17	–23	–33.5
High RES	Degenerate	–63	–71.5	–80	–105

[a] The low RES market setting is characterized by two solutions, which are labelled as normal and degenerate (see Section 4.2). The degenerate solutions of all market settings are optimal, whereas the normal solutions obtained for the low RES market setting are suboptimal, except for the optimal and normal solution corresponding to $\mu_h=50$.

Fully Competitive Market Let us hypothesize that the energy-mix decision is adopted competitively and independently of the decisions of the other producers. As it can be easily argued, in a competitive framework, each producer exclusively expands renewables and the resulting energy-mix would include only green technologies; conventional plants would be completely replaced. This outcome is highly implausible (and problematic) for different reasons. First, since electricity demand would be met only by non-conventional plants, allowance prices, electricity prices, and expected profits would drop to zero for all producers. This calls into question the economic sustainability of the electricity sector itself. Second, with an energy-mix dominated by intermittent renewables, the security of supply would be at risk. Third, we have been observing a significant slowdown of investments in non-conventional plants in the recent years, which can be explained (at least partially) as a non-competitive stance of the electricity sector to prevent the adverse outcomes described above.

6. CONCLUSIONS

This paper addresses the tradeoff that defines the long-term capacity expansion decision of a monopolist in energy-only markets. We specifically investigate the factors that determine the optimal/suboptimal energy-mix decision of the monopolist in the context of an Emissions Trading System (ETS). Understanding the expected outcomes and the tradeoff associated with such a decision is critical for ensuring effective environmental legislation and electricity market reforms.

In this paper, we present a model under uncertain electricity demand and derive analytical dependencies between the expansion decision and market prices. We show that increasing the share of renewables (1) provides the highest profitability and (2) reduces the chances that an ETS is compliant, which is the most desired outcome for the monopolist. In particular, we find that, under both a BAU scenario (absence of emission regulations) and an ETS scenario, the monopolist has an incentive to maintain the renewable capacity at the levels that do not fully satisfy electricity demand. However, under the ETS scenario, the monopolist has an opportunity to create larger infra-marginal profits by even more markedly reducing renewable capacity. This opportunity consists in setting up an energy-mix such that the emissions exceed the cap in a systematic fashion, i.e. even under average values of electricity demand.

The distortion described in this paper is twofold: first, emissions exceed the cap with high probability; second, prices of electricity and allowances are inflated. The monopolist leverages on the first seeking for the second. As we have shown, under such a market structure, the regulatory authority is completely defenseless. Other policies, for example a carbon tax, could lessen (or even completely eliminate) this distortion, possibly at the cost of lower economic efficiency.

Perhaps surprisingly, an unintentional consequence of an ETS is an alleviation of the "missing money problem." Even in the absence of a security of supply constraint, the monopolist will not reduce the conventional capacity below the emissions cap since, otherwise, the distortion of allowances and electricity prices would not be possible.

The results of this analysis do not necessarily extend to other sectors included into an ETS. What makes the electricity sector subject to the problem discussed here are two key hypotheses: (1) the cooperative oligopoly feature of the electricity sector (which we, equivalently, model as a monopoly) and (2) the uniform auction system adopted in energy-only markets. Related to (1), under perfect competition, renewables will likely reach 100% of the energy-mix. In this case, a virtually zero electricity price will prevail in energy-only markets making electricity generation unprofitable. Therefore, if some degree of concentration is desirable in electricity markets, then the concerns raised in this paper about the energy-mix distortion via an ETS should be an important issue in the energy and environmental policy debate.

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APPENDIX

A.1 Expected Profits Accrued to the Electricity Sector

Expected profits accrued to the electricity sector can be expressed as

$$\mathbb{E}(G) = G(A_1)\mathbb{P}(A_1) + G(A_2)\mathbb{P}(A_2) + G(A_3)\mathbb{P}(A_3),$$

with $\Omega = A_1 \cup A_2 \cup A_3$, $A_1 \cap A_2 = \varnothing$, $A_1 \cap A_3 = \varnothing$, and $A_2 \cap A_3 = \varnothing$. With a small abuse of notation, we write $G(A_1)$, $G(A_2)$, and $G(A_3)$ to mean $G(\omega)$ for all $\omega \in A_1$, for all $\omega \in A_2$, and for all $\omega \in A_3$, respectively.

Let D be normally distributed with expected value μ and standard deviation σ and recall that fixed costs are defined as

$$\begin{aligned} FC &= FC(c_{f,c}, c_{f,nc}) \\ &= c_{f,c}\left(Q_c + \Delta Q_c\right) + c_{f,nc}\left(Q_{nc} + \Delta Q_{nc}\right) + \alpha\left(Q_{nc} + \Delta Q_{nc}\right)^2. \end{aligned}$$

Let us now consider Eq. (3), (4), and (5), which report the expressions of G in events A_1, A_2, and A_3, respectively. Substituting those expressions, we obtain

$$\begin{aligned} G(A_1)\mathbb{P}(A_1) &= \int_{A_1} G(\omega)d\mathbb{P}(\omega) \\ &= \int_{A_1} -FC - c_{a,0}Hd\mathbb{P}(\omega) \\ &= \left(-FC - c_{a,0}H\right)\int_{A_1} d\mathbb{P}(\omega) \\ &= \left(-FC - c_{a,0}H\right)\mathbb{P}(A_1), \end{aligned}$$

$$\begin{aligned} G(A_2)\mathbb{P}(A_2) &= \int_{A_2} G(\omega)d\mathbb{P}(\omega) \\ &= \int_{A_2} -FC - c_{a,0}H + \left(c_{v,c} - c_{v,nc}\right)\left(Q_{nc} + \Delta Q_{nc}\right)d\mathbb{P}(\omega) \\ &= \left(-FC - c_{a,0}H + \left(c_{v,c} - c_{v,nc}\right)\left(Q_{nc} + \Delta Q_{nc}\right)\right)\int_{A_2} d\mathbb{P}(\omega) \\ &= \left(-FC - c_{a,0}H + \left(c_{v,c} - c_{v,nc}\right)\left(Q_{nc} + \Delta Q_{nc}\right)\right)\mathbb{P}(A_2), \end{aligned}$$

and

$$
\begin{aligned}
G(A_3)\mathbb{P}(A_3) &= \int_{A_3} G(\omega)d\mathbb{P}(\omega) \\
&= \int_{A_3} -FC + \left(\beta mf - c_{a,0}\right)Hd\mathbb{P}(\omega) \\
&+ \int_{A_3} \left(\beta - 1\right)mf\left(D(\omega) - Q_{nc} - \Delta Q_{nc} - H\right)d\mathbb{P}(\omega) \\
&+ \int_{A_3} \left(\beta mf + c_{v,c} - c_{v,nc}\right)\left(Q_{nc} + \Delta Q_{nc}\right)d\mathbb{P}(\omega) \\
&= \left(-FC + \left(\beta mf - c_{a,0}\right)H + \left(\beta mf + c_{v,c} - c_{v,nc}\right)\left(Q_{nc} + \Delta Q_{nc}\right)\right)\mathbb{P}(A_3) \\
&+ \int_{A_3} \left(\beta - 1\right)mf\left(D(\omega) - Q_{nc} - \Delta Q_{nc} - H\right)d\mathbb{P}(\omega) \\
&= \left(-FC + \left(\beta mf - c_{a,0}\right)H + \left(\beta mf + c_{v,c} - c_{v,nc}\right)\left(Q_{nc} + \Delta Q_{nc}\right)\right)\mathbb{P}(A_3) \\
&+ \left(1 - \beta\right)mf(Q_{nc} + \Delta Q_{nc} + H)\mathbb{P}(A_3) \\
&+ \int_{A_3} \left(\beta - 1\right)mfD(\omega)d\mathbb{P}(\omega).
\end{aligned}
$$

Therefore,

$$
\begin{aligned}
\mathbb{E}(G) = &-(c_{f,c}\left(Q_c + \Delta Q_c\right) + c_{f,nc}\left(Q_{nc} + \Delta Q_{nc}\right) + \alpha\left(Q_{nc} + \Delta Q_{nc}\right)^2) - c_{a,0}H \\
&+ (c_{v,c} - c_{v,nc})\left(Q_{nc} + \Delta Q_{nc}\right)\mathbb{P}(A_2) \\
&+ (\beta mfH + (\beta mf + c_{v,c} - c_{v,nc})(Q_{nc} + \Delta Q_{nc}) + \left(1 - \beta\right)mf\left(Q_{nc} + \Delta Q_{nc} + H\right))\mathbb{P}(A_3) \\
&+ \int_{A_3} \left(\beta - 1\right)mfD(\omega)d\mathbb{P}(\omega).
\end{aligned}
$$

The integrals over the events A_1, A_2, and A_3 are calculated factoring out the corresponding expressions of G, except for one element of $G(A_3)$, which depends on D. We note that the expression of G in event A_1, i.e.

$$
-(c_{f,c}\left(Q_c + \Delta Q_c\right) + c_{f,nc}\left(Q_{nc} + \Delta Q_{nc}\right) + \alpha\left(Q_{nc} + \Delta Q_{nc}\right)^2) - c_{a,0}H,
$$

is also included into the expressions of G in events A_2 and A_3, therefore it appears with probability one in the expression of expected profits. Substituting the density function of the normally distributed D, we can re-write $\mathbb{E}(G)$ as

$$
\begin{aligned}
\mathbb{E}(G) = &-(c_{f,c}\left(Q_c + \Delta Q_c\right) + c_{f,nc}\left(Q_{nc} + \Delta Q_{nc}\right) + \alpha\left(Q_{nc} + \Delta Q_{nc}\right)^2) - c_{a,0}H \\
&+ \frac{(c_{v,c} - c_{v,nc})\left(Q_{nc} + \Delta Q_{nc}\right)}{\sigma\sqrt{2\pi}} \int_{Q_{nc}+\Delta Q_{nc}}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx \\
&+ (\beta mfH + (\beta mf + c_{v,c} - c_{v,nc})(Q_{nc} + \Delta Q_{nc}) + \left(1 - \beta\right)mf\left(Q_{nc} + \Delta Q_{nc} + H\right)) \\
&\times \left(1 - \frac{1}{\sigma\sqrt{2\pi}} \int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx\right) \\
&+ \frac{\left(\beta - 1\right)mf}{\sigma\sqrt{2\pi}} \int_{Q_{nc}+\Delta Q_{nc}+H}^{+\infty} xe^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx.
\end{aligned}
$$

We observe from Eq. (2) that $c_{a,0} = mp_{a,0} = mf\left(1 - \frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx\right)$, therefore expected profits become

$$\begin{aligned}
\mathbb{E}(G) = &-(c_{f,c}\left(Q_c + \Delta Q_c\right) + c_{f,nc}\left(Q_{nc} + \Delta Q_{nc}\right) + \alpha\left(Q_{nc} + \Delta Q_{nc}\right)^2) \\
&-mf\left(1 - \frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx\right)H \\
&+\frac{(c_{v,c} - c_{v,nc})(Q_{nc} + \Delta Q_{nc})}{\sigma\sqrt{2\pi}}\int_{Q_{nc}+\Delta Q_{nc}}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx \\
&+(\beta mfH + (\beta mf + c_{v,c} - c_{v,nc})(Q_{nc} + \Delta Q_{nc}) + \left(1-\beta\right)mf\left(Q_{nc} + \Delta Q_{nc} + H\right)) \\
&\times\left(1 - \frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx\right) \\
&+\frac{\left(\beta-1\right)mf}{\sigma\sqrt{2\pi}}\int_{Q_{nc}+\Delta Q_{nc}+H}^{+\infty} xe^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx,
\end{aligned}$$

which can be further simplified into

$$\begin{aligned}
\mathbb{E}(G) = &-(c_{f,c}\left(Q_c + \Delta Q_c\right) + c_{f,nc}\left(Q_{nc} + \Delta Q_{nc}\right) + \alpha\left(Q_{nc} + \Delta Q_{nc}\right)^2) \\
&+\frac{(c_{v,c} - c_{v,nc})(Q_{nc} + \Delta Q_{nc})}{\sigma\sqrt{2\pi}}\int_{Q_{nc}+\Delta Q_{nc}}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx \\
&+(mf + c_{v,c} - c_{v,nc})(Q_{nc} + \Delta Q_{nc}) \\
&\times\left(1 - \frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx\right) \\
&+\frac{\left(\beta-1\right)mf}{\sigma\sqrt{2\pi}}\int_{Q_{nc}+\Delta Q_{nc}+H}^{+\infty} xe^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx.
\end{aligned}$$

The previous expression of $\mathbb{E}(G)$ can be written as the sum of (negative) fixed costs, $-FC$, and the remainder:

$$\mathbb{E}(G) = -FC + R.$$

At this point, it is interesting to analyse the limit behavior of $\mathbb{E}(G)$ as ΔQ_c and ΔQ_{nc} tend to the extremes of their domains, as set by the constraints of Problem (9). Recalling that $c_{v,c} - c_{v,nc} > 0$ and $\beta \in [0,1]$, we obtain

$$\lim_{\Delta Q_{nc}\to+\infty} \mathbb{E}(G) = \lim_{\Delta Q_{nc}\to+\infty} -FC + \lim_{\Delta Q_{nc}\to+\infty} R = [-\infty + 0] = -\infty,$$

since R tends to 0 as ΔQ_{nc} tends to $+\infty$, and

$$\lim_{\Delta Q_{nc}\to -Q_{nc}^{+}} \mathbb{E}(G) = -c_{f,c}\left(Q_c+\Delta Q_c\right)+\frac{\left(\beta-1\right)mf}{\sigma\sqrt{2\pi}}\int_H^{+\infty} xe^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx,$$

which is a negative number. In addition, we have

$$\lim_{\Delta Q_c\to+\infty}\mathbb{E}(G)=\lim_{\Delta Q_c\to+\infty}-FC+\lim_{\Delta Q_c\to+\infty}R=[-\infty+h]=-\infty,$$

since R tends to $h\in\mathbb{R}$ as ΔQ_c tends to $+\infty$, and

$$\begin{aligned}\lim_{\Delta Q_c\to(H-Q_c)^{+}}\mathbb{E}(G)&=-c_{f,c}H-c_{f,nc}\left(Q_{nc}+\Delta Q_{nc}\right)-\alpha(Q_{nc}+\Delta Q_{nc})^2\\
&+\frac{(c_{v,c}-c_{v,nc})\left(Q_{nc}+\Delta Q_{nc}\right)}{\sigma\sqrt{2\pi}}\int_{Q_{nc}+\Delta Q_{nc}}^{Q_{nc}+\Delta Q_{nc}+H}e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx\\
&+(mf+c_{v,c}-c_{v,nc})(Q_{nc}+\Delta Q_{nc})\\
&\times\left(1-\frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H}e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx\right)\\
&+\frac{\left(\beta-1\right)mf}{\sigma\sqrt{2\pi}}\int_{Q_{nc}+\Delta Q_{nc}+H}^{+\infty}xe^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx,\end{aligned}$$

which is a real number.

The analytical expression of $\frac{\partial\mathbb{E}(G)}{\partial\Delta Q_{nc}}$, the partial derivative of $\mathbb{E}(G)$ with respect to ΔQ_{nc}, is

$$\begin{aligned}\frac{\partial\mathbb{E}(G)}{\partial\Delta Q_{nc}}&=-c_{f,nc}-2\alpha\left(Q_{nc}+\Delta Q_{nc}\right)\\
&+\frac{c_{v,c}-c_{v,nc}}{\sigma\sqrt{2\pi}}\int_{Q_{nc}+\Delta Q_{nc}}^{Q_{nc}+\Delta Q_{nc}+H}e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx\\
&+\frac{(c_{v,c}-c_{v,nc})\left(Q_{nc}+\Delta Q_{nc}\right)}{\sigma\sqrt{2\pi}}\left(e^{-\frac{1}{2}\left(\frac{Q_{nc}+\Delta Q_{nc}+H-\mu}{\sigma}\right)^2}-e^{-\frac{1}{2}\left(\frac{Q_{nc}+\Delta Q_{nc}-\mu}{\sigma}\right)^2}\right)\\
&+(mf+c_{v,c}-c_{v,nc})\left(1-\frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H}e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx\right)\\
&+(mf+c_{v,c}-c_{v,nc})(Q_{nc}+\Delta Q_{nc})\left(-\frac{1}{\sigma\sqrt{2\pi}}e^{-\frac{1}{2}\left(\frac{Q_{nc}+\Delta Q_{nc}+H-\mu}{\sigma}\right)^2}\right)\\
&-\frac{\left(\beta-1\right)mf(Q_{nc}+\Delta Q_{nc}+H)}{\sigma\sqrt{2\pi}}e^{-\frac{1}{2}\left(\frac{Q_{nc}+\Delta Q_{nc}+H-\mu}{\sigma}\right)^2},\end{aligned}$$

which can be further simplified to

$$\frac{\partial \mathbb{E}(G)}{\partial \Delta Q_{nc}} = -c_{f,nc} - 2\alpha\left(Q_{nc} + \Delta Q_{nc}\right)$$

$$+\frac{c_{v,c} - c_{v,nc}}{\sigma\sqrt{2\pi}} \int_{Q_{nc}+\Delta Q_{nc}}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx$$

$$+\frac{(c_{v,c} - c_{v,nc})\left(Q_{nc} + \Delta Q_{nc}\right)}{\sigma\sqrt{2\pi}}\left(-e^{-\frac{1}{2}\left(\frac{Q_{nc}+\Delta Q_{nc}-\mu}{\sigma}\right)^2}\right)$$

$$+(mf + c_{v,c} - c_{v,nc})\left(1 - \frac{1}{\sigma\sqrt{2\pi}} \int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx\right)$$

$$+((\beta - 1)mfH + \beta mf(Q_{nc} + \Delta Q_{nc}))$$

$$\times\left(-\frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{1}{2}\left(\frac{Q_{nc}+\Delta Q_{nc}+H-\mu}{\sigma}\right)^2}\right).$$

The analytical expression of $\frac{\partial \mathbb{E}(G)}{\partial \Delta Q_c}$, the partial derivative of $\mathbb{E}(G)$ with respect to ΔQ_c, is easily calculated since the expression of $\mathbb{E}(G)$ linearly depends on ΔQ_c. Indeed, we have

$$\frac{\partial \mathbb{E}(G)}{\partial \Delta Q_c} = -c_{f,c}.$$

In Section 4, we numerically solve the long-term capacity expansion problem under two scenarios and for three distinct market settings, and comment on the solutions.

A.1.1 A more general framework for expected profits

Recall the technical conditions listed in Table 1 and assume that the constraints $Q_{nc} + \Delta Q_{nc} > 0$ and $Q_c + \Delta Q_c > 0$ hold, but, now, $Q_c + \Delta Q_c$ can be less than or equal to H. An interesting analysis of expected profits can be performed if we consider such a more general framework. In particular, the expression of $\mathbb{E}(G)$ is modified accordingly. We first re-write the expressions of Eq. (3), (4), and (5) in the present framework. They are essentially the same as the original ones, except for the cost of allowances paid at time $t=0$, becoming $c_{a,0}\min(H; Q_c + \Delta Q_c)$ instead of $c_{a,0}H$, and for an indicator function introduced to account for conventional capacity built in excess with respect to H. We have

$$G(A_1) = -FC - c_{a,0}\min(H; Q_c + \Delta Q_c), \tag{10}$$

$$G(A_2) = -FC - c_{a,0}\min(H; Q_c + \Delta Q_c) + (c_{v,c} - c_{v,nc})(Q_{nc} + \Delta Q_{nc}), \tag{11}$$

and

$$\begin{aligned}G(A_3) = &-FC - c_{a,0}\min(H;Q_c+\Delta Q_c)\\&+(c_{v,c}-c_{v,nc})(Q_{nc}+\Delta Q_{nc})\\&+\beta mf\min(H;Q_c+\Delta Q_c)1_{(H,\infty)}(Q_c+\Delta Q_c)\\&+(\beta-1)mf(D-Q_{nc}-\Delta Q_{nc}-H)1_{(H,\infty)}(Q_c+\Delta Q_c)\\&+\beta mf(Q_{nc}+\Delta Q_{nc})1_{(H,\infty)}(Q_c+\Delta Q_c).\end{aligned} \tag{12}$$

The new expression of $G(A_3)$ includes the indicator function $1_{(H,\infty)}(Q_c+\Delta Q_c)$, which is equal to one if conventional capacity exceeds H. The indicator function multiplies mf. Indeed, a pass-through of allowance costs in event A_3 (mf) is viable if conventional capacity is built in excess with respect to H. The new expression of expected profits becomes

$$\begin{aligned}\mathbb{E}(G) = &-(c_{f,c}\left(Q_c+\Delta Q_c\right)+c_{f,nc}\left(Q_{nc}+\Delta Q_{nc}\right)+\alpha\left(Q_{nc}+\Delta Q_{nc}\right)^2)\\&-mf\left(1-\frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H}e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx\right)\min(H;Q_c+\Delta Q_c)\\&+\frac{(c_{v,c}-c_{v,nc})(Q_{nc}+\Delta Q_{nc})}{\sigma\sqrt{2\pi}}\int_{Q_{nc}+\Delta Q_{nc}}^{Q_{nc}+\Delta Q_{nc}+H}e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx\\&+\left(Q_{nc}+\Delta Q_{nc}+H\right)\left(1-\beta\right)mf1_{(H,\infty)}(Q_c+\Delta Q_c)\times\left(1-\frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H}e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx\right)\\&+(\min(H;Q_c+\Delta Q_c)\beta mf1_{(H,\infty)}(Q_c+\Delta Q_c)+(\beta mf1_{(H,\infty)}(Q_c+\Delta Q_c)+c_{v,c}-c_{v,nc})(Q_{nc}+\Delta Q_{nc}))\\&\times\left(1-\frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H}e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx\right)\\&+\frac{\left(\beta-1\right)mf1_{(H,\infty)}(Q_c+\Delta Q_c)}{\sigma\sqrt{2\pi}}\int_{Q_{nc}+\Delta Q_{nc}+H}^{+\infty}xe^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx.\end{aligned} \tag{13}$$

Figure 7 compares expected profits in the electricity sector (under the ETS scenario and for all market settings) as a function of the decision variables ΔQ_{nc} and ΔQ_c in the present more general framework (where only the constraints $Q_{nc}+\Delta Q_{nc}>0$ and $Q_c+\Delta Q_c>0$ hold). Figure 7 shows both the optimal and degenerate solutions and the suboptimal and normal solutions. For ease of understanding, Figure 7 considers decreasing values of ΔQ_c towards the right. We can see that the graphs are composed of two parts, with a jump at the junction points. These points share the same value of ΔQ_c, i.e. $H-Q_c$. We analytically characterize such points in the following, while here we comment that the monopolist has an incentive to reduce the installed fossil fuel capacity down to $H+\varepsilon$, with $\varepsilon\to 0^+$ (i.e. just enough to trigger event A_3).

The partial derivative of $\mathbb{E}(G)$ with respect to ΔQ_c in such a more general framework has two expressions:

1. if $\Delta Q_c > H - Q_c$, then

$$\frac{\partial \mathbb{E}(G)}{\partial \Delta Q_c} = -c_{f,c},$$

since $\frac{\partial}{\partial \Delta Q_c}\min(H; Q_c + \Delta Q_c) = \frac{\partial}{\partial \Delta Q_c} H = 0$ and $1_{(H,\infty)}(Q_c + \Delta Q_c) = 1$;

2. if $\Delta Q_c < H - Q_c$, then

$$\frac{\partial \mathbb{E}(G)}{\partial \Delta Q_c} = -c_{f,c} - mf\left(1 - \frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx\right),$$

since $\frac{\partial}{\partial \Delta Q_c}\min(H; Q_c + \Delta Q_c) = \frac{\partial}{\partial \Delta Q_c}(Q_c + \Delta Q_c) = 1$ and $1_{(H,\infty)}(Q_c + \Delta Q_c) = 0$.

The partial derivative of $\mathbb{E}(G)$ with respect to ΔQ_c exists almost everywhere since it does not exist at $\Delta Q_c = H - Q_c$, for $\frac{\partial}{\partial \Delta Q_c}\min(H; Q_c + \Delta Q_c)$ does not exist at $\Delta Q_c = H - Q_c$. Passing from $Q_c + \Delta Q_c < H$ to $Q_c + \Delta Q_c > H$, or, equivalently, passing from $\Delta Q_c < H - Q_c$ to $\Delta Q_c > H - Q_c$, triggers event A_3, and so the highest level of profits ($G(A_3)$). In particular, the two limits $\lim_{\Delta Q_c \to (H-Q_c)^-}\mathbb{E}(G)$ and $\lim_{\Delta Q_c \to (H-Q_c)^+}\mathbb{E}(G)$ exist and are finite:

$$\lim_{\Delta Q_c \to (H-Q_c)^-} \mathbb{E}(G) = -(c_{f,c}H + c_{f,nc}\left(Q_{nc} + \Delta Q_{nc}\right) + \alpha\left(Q_{nc} + \Delta Q_{nc}\right)^2)$$
$$-mf\left(1 - \frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx\right)H$$
$$+\frac{(c_{v,c} - c_{v,nc})(Q_{nc} + \Delta Q_{nc})}{\sigma\sqrt{2\pi}}\int_{Q_{nc}+\Delta Q_{nc}}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx$$
$$+(c_{v,c} - c_{v,nc})(Q_{nc} + \Delta Q_{nc})\left(1 - \frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx\right)$$

and

$$\lim_{\Delta Q_c \to (H-Q_c)^+} \mathbb{E}(G) = -(c_{f,c}H + c_{f,nc}\left(Q_{nc} + \Delta Q_{nc}\right) + \alpha\left(Q_{nc} + \Delta Q_{nc}\right)^2)$$
$$-mf\left(1 - \frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx\right)H$$
$$+\frac{(c_{v,c} - c_{v,nc})(Q_{nc} + \Delta Q_{nc})}{\sigma\sqrt{2\pi}}\int_{Q_{nc}+\Delta Q_{nc}}^{Q_{nc}+\Delta Q_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} dx$$

$$+\left(1-\beta\right)mf\left(Q_{nc}+\Delta Q_{nc}+H\right)\left(1-\frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H}e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^{2}}dx\right)$$

$$+(\beta mfH+(\beta mf+c_{v,c}-c_{v,nc})(Q_{nc}+\Delta Q_{nc}))\left(1-\frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H}e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^{2}}dx\right)$$

$$+\frac{\left(\beta-1\right)mf}{\sigma\sqrt{2\pi}}\int_{Q_{nc}+\Delta Q_{nc}+H}^{+\infty}xe^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^{2}}dx.$$

Therefore, $\mathbb{E}(G)$ shows a jump at $\Delta Q_c = H - Q_c$. Analytically, such a jump occurs because of the expressions $1_{(H,\infty)}(Q_c + \Delta Q_c)$ and $\min(H; Q_c + \Delta Q_c)$ appearing in Eq. (13), in particular $1_{(H,\infty)}(Q_c + \Delta Q_c) = 0$ if $\Delta Q_c < H - Q_c$. We calculate such a jump in the following:

$$\text{Jump} = \lim_{\Delta Q_c \to \left(H-Q_c\right)^+}\mathbb{E}(G) - \lim_{\Delta Q_c \to \left(H-Q_c\right)^-}\mathbb{E}(G)$$

$$=\left(1-\beta\right)mf\left(Q_{nc}+\Delta Q_{nc}+H\right)\left(1-\frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H}e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^{2}}dx\right)$$

$$+\beta mf(Q_{nc}+\Delta Q_{nc}+H)\left(1-\frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+\Delta Q_{nc}+H}e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^{2}}dx\right)$$

$$+\frac{\left(\beta-1\right)mf}{\sigma\sqrt{2\pi}}\int_{Q_{nc}+\Delta Q_{nc}+H}^{+\infty}xe^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^{2}}dx.$$

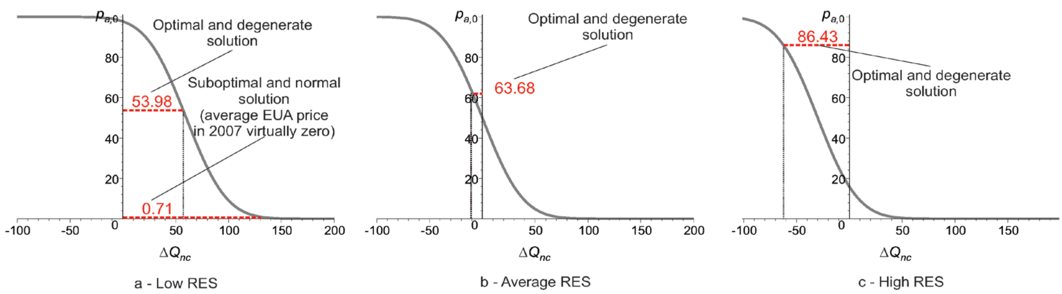
We can see that the jump is equal to the difference between the allowance component of profits in event A_3 (Eq. (7)) and the allowance component of profits in event A_2 (Eq. (6)), multiplied by the probability of event A_3.

A.2 Allowance and Electricity Prices under the ETS Scenario

Figure 9 represents allowance prices under the ETS scenario as a function of ΔQ_{nc}. In each market setting, the optimal and degenerate solutions yield allowance prices that are significantly positive. This is because, in the optimal and degenerate solutions, event A_3 is pursued and there is a high probability that electricity demand will exceed non-conventional and covered conventional generation. Moreover, allowance prices corresponding to the optimal and degenerate solutions increase from the low RES market setting to the high RES market setting since the sum of non-conventional and covered conventional generation falls, thereby increasing the probability that further purchases of allowances will be necessary (therefore driving up the price). For example, the price of allowances corresponding to the low RES market setting optimal and degenerate solution is 53.98 €/tonne, with a total covered generation of around 197 *MWh*[24] with respect to an expected value of electricity demand of 200 *MWh*. But the allowances price corresponding to the optimal and degener-

24. 20 *MWh* initial non-conventional capacity, 57 *MWh* new non-conventional capacity, and 120 *MWh* covered conventional capacity.

Figure 9: Allowance prices, $p_{a,0}$ (€/tonne), for various installation decisions of the non-conventional capacity, ΔQ_{nc} (MWh), under the ETS scenario. The highlighted prices correspond to the solutions of Problem (9).

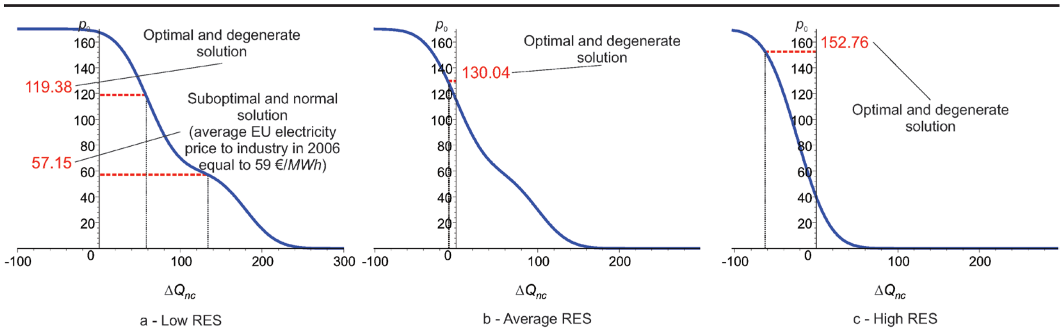


ate solution in the high RES market setting is a whopping 86.43 €/tonne since total covered capacity dropped to 167 MWh due to disconnection/dismantling of non-conventional capacity.

The exception to this rule of significantly positive allowance prices is the low RES market setting suboptimal and normal solution. In the suboptimal and normal solution, the price of allowances is very close to one €/tonne. This is not surprising since total covered generation is equal to around 273.5 MWh (20 MWh initial non-conventional capacity, 133.5 MWh new non-conventional capacity, and 120 MWh covered conventional capacity), which greatly exceeds the expected value of electricity demand. We notice that an allowances price of nearly one €/tonne is rather close to the EU ETS allowances (EUA) price observed in 2007, i.e. at the end of the first period of life of the EU ETS.

Figure 10 represents electricity prices under the ETS scenario as a function of ΔQ_{nc}. Prices corresponding to the optimal and degenerate solutions increase as we pass from the low RES to the high RES market setting. Disconnection/dismantling of non-conventional capacity drives prices up. As previously observed, this result is due to increasing allowance prices (combined with an assumed complete pass-through, i.e. $\beta = 1$). The only exception to this finding occurs with the low RES market setting suboptimal and normal solution. Here, green and covered conventional capacities (about 273.5 MWh) meet electricity demand almost in full, leaving a near-zero probability of non-compliance and causing virtually null allowance prices and low electricity prices.

Figure 10: Electricity prices, p_0 (€/MWh), for various installation decisions of the non-conventional capacity, ΔQ_{nc} (MWh), under the ETS scenario. The highlighted prices correspond to the solutions of Problem (9).



A.3 Sensitivity Analysis

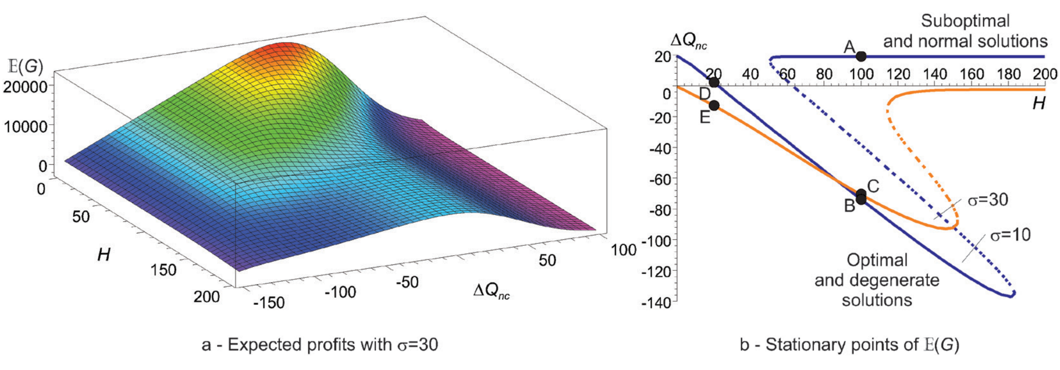
In this section, we provide a sensitivity analysis of two key model parameters, H, the amount of conventional generation that can be covered by allowances,[25] and β, the pass-through coefficient. For this purpose, Problem (9) is solved (in the decision variable ΔQ_{nc} only) under different values of the two parameters.

Table 7 lists the rest of the model parameters used in the sensitivity analysis. We assume that conventional capacity remains constant, i.e. $\Delta Q_c = 0$ *MWh*, and we consider two values for the standard deviation of electricity demand: 10 and 30 *MWh*.

Table 7: Parameters used in the sensitivity analysis.

Model parameter	Value	Model parameter	Value
σ (*MWh*)	10, 30	μ (*MWh*)	200
m (tonnes/*MWh*)	1.1	f (€/tonne)	100
Q_c (*MWh*)	330	Q_{nc} (*MWh*)	160
ΔQ_c (*MWh*)	0	α	0.01
$c_{v,c}$ (€/*MWh*)	60	$c_{f,c}$ (€/*MWh*)	1.5
$c_{v,nc}$ (€/*MWh*)	0	$c_{f,nc}$ (€/*MWh*)	6

Figure 11: Panel a shows expected profits, $\mathbb{E}(G)$, with respect to H and ΔQ_{nc}. Electricity demand is a normal random variable with expected value $\mu = 200$ *MWh* and standard deviation $\sigma = 30$ *MWh*. Panel b shows the sets of stationary points of $\mathbb{E}(G)$, letting the standard deviation of D assume the values 10 and 30 *MWh*. The solid lines represent stationary points associated with optimal/suboptimal solutions. The dotted lines represent stationary points of no interest since they correspond to minima of $\mathbb{E}(G)$. Here β is fixed to one, i.e. we have a complete pass-through. Panel b highlights the five solutions A-E described in Table 8.



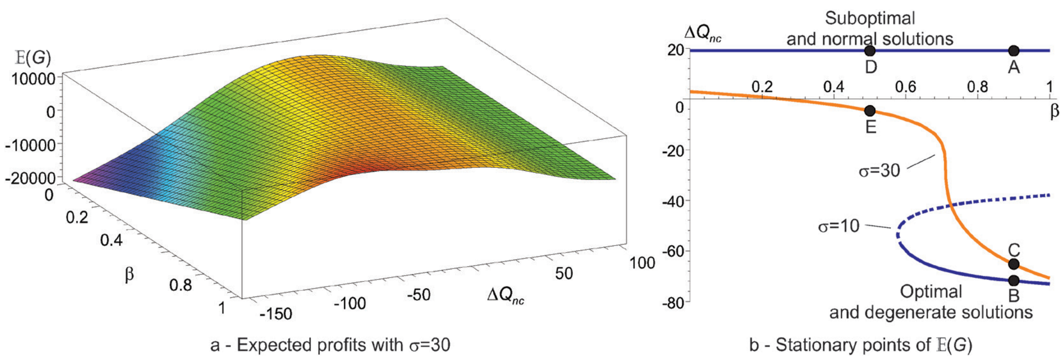
a - Expected profits with σ=30

b - Stationary points of E(G)

Panels a of Figures 11 and 12 illustrate expected profits $\mathbb{E}(G)$ varying with respect to the installation of non-conventional capacity ΔQ_{nc} and the parameters H and β, respectively, and for $\sigma = 30$ *MWh*. Panels b of Figures 11 and 12 illustrate the sets of stationary points of $\mathbb{E}(G)$ for σ equal to 10 and 30 *MWh*. The stationary points for $\sigma = 30$ *MWh* correspond to the ridges (maxima) and the valley floors (minima) of the three-dimensional graphs in panels a. Note that, for some combinations of values of H, β, and , there are two solutions: a normal solution and a degenerate solution.

25. Recall that $H = \frac{C}{m}$ *MWh*, where C is the number of allowances and m is the amount of CO_2e (in tonnes) emitted to generate one *MWh* of electricity.

Figure 12: Panel a shows expected profits, $\mathbb{E}(G)$, with respect to β and ΔQ_{nc}. Electricity demand is a normal random variable with expected value $\mu = 200$ MWh and standard deviation $\sigma = 30$ MWh. Panel b shows the sets of stationary points of $\mathbb{E}(G)$, letting the standard deviation of D assume the values 10 and 30 MWh. The solid lines represent stationary points associated with optimal/suboptimal solutions. The dotted lines represent stationary points of no interest since they correspond to minima of $\mathbb{E}(G)$. Here H is fixed to 100 MWh. Panel b highlights the five solutions A-E described in Table 9.



Below we present the numerical results of the sensitivity analysis and offer an economic interpretation. In particular, we study the effect of varying H and β by considering five combinations of values for the pair (H,σ) in Table 8 and five combinations of values for the pair (β,σ) in Table 9, respectively. In particular, the tables report the percentage of expected profits corresponding to the allowance component of solutions. The percentage is calculated as the sum of the allowance component of Eq. (6) multiplied by the probability of event A_2 and the allowance component of Eq. (7) multiplied by the probability of event A_3. Finally, the sum is divided by the amount of expected profits. The two tables also show the green ratio of solutions. Notice that the initial green ratio (before the optimization) is equal to $\frac{160}{200} = 0.8$.

A.3.1 Analysis of H

In Table 8, we consider two values of H, namely 20 and 100 MWh, and two values of σ, namely 10 and 30 MWh. β is kept constant at one. First, let H vary, fixing σ equal to 10 MWh (solutions A, B, and D) and 30 MWh (solutions C and E). Solution A is suboptimal and normal and we postpone its discussion for the moment. Matching solutions B to D and C to E, we see that a lower value of H (more stringent emissions cap) causes a neat increase of green capacity and the green ratio. Of course, this environmental improvement comes at a cost. Electricity and allowance prices increase, as well as expected profits and the corresponding allowance component. As discussed earlier (see Section 4.2), the suboptimal and normal solution A yields a greater green capacity investment and a larger green ratio, at a (neatly) lower cost.

Second, we fix H and investigate the effect of a more volatile electricity demand on the capacity investment decision. Moving from $\sigma = 10$ MWh to $\sigma = 30$ MWh does not have a clear impact on the green ratio, nor on investments in renewables. The impact of σ is more pronounced when considering expected profits, and electricity and allowance prices. More precise electricity demand forecasts (i.e. low σ in solutions B and D) correspond to expected profits 20% higher than in comparable market settings, where σ is higher (solutions C and E, respectively). Moreover, higher levels of σ correspond to lower electricity and allowance prices (since allowances have a financial digital option nature).

Table 8: Sensitivity analysis of *H*. Optimal/suboptimal installations of non-conventional capacity (ΔQ^*_{nc}) with respect to five combinations of values of *H*, the total conventional generation covered by allowances, and σ, the standard deviation of electricity demand.

	Solutions[a]				
Problem settings	A	B	C	D	E
H (MWh)	100	100	100	20	20
σ (MWh)	10	10	30	10	30
β	1	1	1	1	1
Type of solution	Suboptimal[b] Normal	Optimal[b] Degenerate	Optimal Degenerate	Optimal Degenerate	Optimal Degenerate
ΔQ^*_{nc} (MWh)	19.20	–73.50	–70.73	2.56	–12.77
Green ratio	0.90	0.43	0.45	0.81	0.74
$\mathbb{E}(G)$ (€)	8659	12774	10527	25174	20863
Allowance component of $\mathbb{E}(G)$ (%)	0	0.68	0.60	0.68	0.67
p_0 (€/MWh)	58.87	160.26	130.36	165.53	152.54
$p_{a,0}$ (€/tonne)	0	91.15	63.97	95.94	86.27

[a] The five solutions A-E are drawn in panel b of Figure 11.
[b] The solutions with $H=100$ MWh and $\sigma=10$ MWh are two, one is optimal and the other is suboptimal.

A.3.2 Analysis of β

The interest to analyse the impact of the pass-through coefficient (that is applied here only with respect to the cost of allowances) is due to some empirical research that has questioned whether that coefficient is actually equal to one. The reported estimates tend to show that possible values are in the range 0.9–0.95 (Fabra and Reguant, 2014), which cannot be significantly distinguished from one at the usual level of confidence.

From an economic theory point of view, there are no obvious reasons for β to be less than one. A possible explanation could be that the electricity sector decides to reduce its markups to minimize the negative impact of a very high allowances price on electricity demand and, in this way, to keep up with profits. Moreover, as long as the difference $\beta mf - c_{a,0}$ remains positive, (part of the) conventional plants produce profits (area of region 5 in Figure 3). So, for the electricity sector, reducing β to some extent corresponds to giving up part of the profits, not to recovering a variable cost.

In Table 9, we consider two values of β, namely 0.5 and 0.9 (representing low and approximately complete pass-through), and two values of σ, namely 10 and 30 MWh. Here H is fixed to 100 MWh.

Unlike the previous analysis, we now obtain two optimal and normal solutions (D and E). They are characterized by $\beta = 0.5$. Thus, for a low β, expected profits are predominantly determined by the operational component (the allowance component is 1% at most) and electricity prices are relatively low (around 58 €/MWh). When β is high, optimal solutions B and C are degenerate and, correspondingly, the likelihood of non-compliance, as well as allowance and electricity prices, are high, ultimately generating high profits. Solution A is a suboptimal (and normal) solution dominated by solution B. Again, low values of σ are observed to have a positive impact on expected profits of the electricity sector.

Table 9: Sensitivity analysis of β. Optimal/suboptimal installations of non-conventional capacity (ΔQ^*_{nc}) with respect to five combinations of values of β, the pass-through coefficient, and σ, the standard deviation of electricity demand.

	Solutions[a]				
Problem settings	A	B	C	D	E
H (MWh)	100	100	100	100	100
σ (MWh)	10	10	30	10	30
β	0.9	0.9	0.9	0.5	0.5
Type of solution	Suboptimal[b] Normal	Optimal[b] Degenerate	Optimal Degenerate	Optimal Normal	Optimal Normal
ΔQ^*_{nc} (MWh)	19.20	–71.92	–63.40	19.20	–3.85
Green ratio	0.90	0.44	0.48	0.90	0.78
$\mathbb{E}(G)$ (€)	8659	10778	9088	8659	7094
Allowance component of $\mathbb{E}(G)$ (%)	0	0.61	0.49	0	0.01
p_0 (€/MWh)	58.87	147.45	113.95	58.87	57.37
$p_{a,0}$ (€/tonne)	0	88.34	54.51	0	3.06

[a] The five solutions A-E are drawn in panel b of Figure 12.
[b] The solutions with $\beta=0.9$ and $\sigma=10$ MWh are two, one is optimal and the other is suboptimal.

The relevance of this sensitivity analysis is that it highlights again the distorting impact (on energy-mix) of the profit opportunity introduced by ETS for the electricity sector. Indeed, if β takes a sufficiently low value, it "kills" such a profit opportunity and, consequently, the electricity sector reverts to an optimal and normal energy-mix decision.