Centre for
Climate Change
Economics and Policy

An ESRC Research Centre

Grantham Research Institute on
Climate Change and
the Environment

Renewables, allowances markets, and capacity expansion in energy-only markets

Paolo Falbo, Cristian Pelizzari and Luca Taschini

July 2016

Centre for Climate Change Economics and Policy
Working Paper No. 276

Grantham Research Institute on Climate Change and the Environment
Working Paper No. 246

E·S·R·C ECONOMIC & SOCIAL RESEARCH COUNCIL

The Grantham Foundation for the Protection of the Environment

University of Leeds

LSE The London School of Economics and Political Science

The Centre for Climate Change Economics and Policy (CCCEP) was established by the University of Leeds and the London School of Economics and Political Science in 2008 to advance public and private action on climate change through innovative, rigorous research. The Centre is funded by the UK Economic and Social Research Council. Its second phase started in 2013 and there are five integrated research themes:

1. Understanding green growth and climate-compatible development
2. Advancing climate finance and investment
3. Evaluating the performance of climate policies
4. Managing climate risks and uncertainties and strengthening climate services
5. Enabling rapid transitions in mitigation and adaptation

More information about the Centre for Climate Change Economics and Policy can be found at: http://www.cccep.ac.uk.

The Grantham Research Institute on Climate Change and the Environment was established by the London School of Economics and Political Science in 2008 to bring together international expertise on economics, finance, geography, the environment, international development and political economy to create a world-leading centre for policy-relevant research and training. The Institute is funded by the Grantham Foundation for the Protection of the Environment and the Global Green Growth Institute. It has nine research programmes:

1. Adaptation and development
2. Carbon trading and finance
3. Ecosystems, resources and the natural environment
4. Energy, technology and trade
5. Future generations and social justice
6. Growth and the economy
7. International environmental negotiations
8. Modelling and decision making
9. Private sector adaptation, risk and insurance

More information about the Grantham Research Institute on Climate Change and the Environment can be found at: http://www.lse.ac.uk/grantham.

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

Paolo Falbo, Cristian Pelizzari
Università degli Studi di Brescia - Dipartimento di Economia e Management
Contrada Santa Chiara, 50 - 25122 Brescia BS - Italy
E-mail: {paolo.falbo, cristian.pelizzari}@unibs.it

Luca Taschini
The London School of Economics and Political Science
Grantham Research Institute on Climate Change and the Environment
Houghton St., WC2A 2AE, London - UK
l.taschini1@lse.ac.uk

Abstract

We investigate the combined effect of an Emission Trading System (ETS) and renewable energy sources on electricity generation investment in energy-only markets. We propose a simple representation of the capacity expansion decision between fossil fuel and renewable production, where electricity demand is uncertain. Increasing renewable capacity creates a tradeoff for large electricity producers: 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 demand is met by cheaper renewable production. A numerical application of the model shows that producers prefer withholding investments in renewable energy sources, calling into question the long-term efficacy of an ETS in achieving decarbonisation goals.

JEL: L51, L94.

Keywords: Emission Trading Systems, Emission Allowances, Renewable Energy Sources, Pass-Through.

[0]Part of Taschini's research was supported by the ESRC Centre for Climate Change Economics and Policy, which is funded by the UK Economic and Social Research Council. Useful comments on earlier drafts were provided by participants at the EAERE, ECOMFIN, the Commodity Markets Conference, and the Energy Finance annual conferences and seminar participants at the CIRANO. The authors would like to thank Luciano Campi, Anna Creti, Carolyn Fischer, Beat Hintermann, Jennifer Mills, Juan-Pablo Montero, María Eugenia Sanin for their useful comments. The usual disclaimers apply.

1 Introduction

The past five years have witnessed a systematic decrease in electricity producers' operational profitability and a consequent decline in electricity investments in market-based systems, (*Financial Times*, 2015; *The Economist*, 2015). Overcapacity of fossil fuel electricity generation[1] and a larger share of renewable electricity generation[2] are among the main causes (Koch et al., 2014). Particularly in Europe, renewables[3] have not just put pressure on margins; they have also transformed the established business model of utilities (*The Economist*, 2013). Electricity from renewables has favourable access to the grid, squeezing the earnings of producers that generate electricity from fossil fuels. However, this 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. Here we explore some of the implications of this changing business model on the capacity expansion decision for electricity producers that can supply electricity generated from both fossil fuel and renewable sources.

Central to the capacity expansion problem is the tradeoff 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 capacity investment in renewable generation. The market structure and the regulatory framework are crucial for determining the extent to which electricity producers withhold capacity investments. In recent contributions, Murphy and Smeers (2005), Zöttl (2011), Murphy and Smeers (2012), and Grimm and Zoettl (2013) investigate investment incentives when markets are not competitive. These authors show that withholding investments can in fact increase producers' profits, ultimately hampering adequate capacity expansion.

In this paper, we contribute to this literature by investigating how regulatory constrains affect long-term capacity investment decisions. Specifically, we illustrate the pending tradeoffs in electricity markets in the presence of renewable obligations and emission restrictions. This line of analysis adds to the growing literature that stresses the need to account for the full effects of co-existing emission constraints and renewable energy policies due to the sometimes conflicting incentives of the stakeholders involved.[4] Acknowledging these effects is critically important for the design of

[1] We will write fossil fuel generation as a shorthand. Conventional generation and polluting generation will be used as synonyms.

[2] We will write renewable generation as a shorthand. Non-conventional generation and green generation will be used as synonyms.

[3] Renewables will be used as a shorthand for renewable energy sources throughout the paper.

[4] Previous analyses have highlighted the potential detrimental impacts of overlapping renewable energy policies

long-term energy markets, as conflicting incentives can often lead to sub-optimal outcomes, or even outcomes contradictory to the stated goals of the policy instrument. For example, Acemoglu et al. (2015) investigates the incentives of fossil fuel energy producers to expand their energy portfolios to include renewables. They demonstrate in an oligopolist setup that renewable capacity expansion 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 oligopolistic setup, but focus, instead, on the capacity expansion decision, in order to examine the interplay between the efforts of the regulatory authority, the incentives of electricity producers, and the prices of electricity and emission allowances.[5]

Our formulation is probably the simplest allowing one to examine the question of capacity expansion in energy-only markets subject to electricity and environmental constraints. Specifically, we propose a simple representation of the investment decision between fossil fuel and renewable generation, where electricity demand is uncertain. We derive analytical dependencies between equilibrium prices and the capacity expansion decision. The model allows for a probabilistic representation of the decision problem and illustrates the fundamental tradeoff associated with increased renewable generation: a higher potential for profits from selling renewable generation at the marginal cost of electricity generated from fossil fuels is tempered by a lower likelihood of obtaining those profits. On the one hand, a higher share of renewable plants creates the opportunity for higher profit margins when demand is high, as the share of electricity generated from renewables is priced at the higher marginal cost of fossil fuel plants. On the other hand, it also leads to a greater loss when demand is low and completely satisfied by renewable generation; in this case, fossil fuel plants remain unused and renewable production is priced at the (virtually zero) marginal cost.

Using our model, we explore the combined effect of increasing renewables penetration and more stringent emission constraints. We numerically solve the optimal capacity expansion problem for three market scenarios, formulated to represent different stylised stages of an Emission Trading System (ETS), where the cap is progressively tightened up. The more electricity demand is satisfied with renewables, the greater the incentive to withhold capacity investment or, depending on the level of pass-through of costs into electricity prices, to even dismantle renewable plants. The intuition for this result is instructive. As renewables penetration increases and the emissions cap becomes tighter, producers become less incentivised to expand renewable capacity. In this numerical application, we observe that there is an incentive to maintain fossil fuel generation. In fact, the only market scenario where renewable capacity increases is when the starting level of installed renewable capacity is limited and the cap is rather generous. These results provide insights into the observed decline of new investments in renewables in Europe,[6] where the flagship ETS is entering its fourth

(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.

[5]We will write allowances as a shorthand for emission allowances throughout the paper.

[6]New investments in renewables in Europe peaked in 2011 at $120 billion and have fallen since; new investments

(more stringent) Phase and the existing share of renewable capacity is relatively large. As such, our analysis also contributes to the discussion on the current reform of energy and environmental policies.

Moreover, the model allows us to dissect the mechanism by which producers prefer to expand or dismantle renewable capacity. Producers can pursue two distinct pathways of profit generation, which have radically different determinants. In what we define as normal solutions (to the capacity expansion decision), we observe that operational profits, which are obtained from the sale of renewable generation at a price equal to the marginal cost of fossil fuel generation, are the dominant component of expected profits. Under such solutions, producers generally increase their renewable capacity. By contrast, in degenerate solutions producers derive larger profits by exceeding the emissions cap and by adjusting the electricity price to include the cost of non-compliant fossil fuel generation (i.e. generation that exceeds the emissions cap and is fined accordingly).

A sensitivity analysis demonstrates how the market structure and the characteristics of a cap-and-trade programme can influence which of the two pathways is the most favourable for electricity producers. Remarkably, the two classical design features of an ETS, i.e. a progressively declining emissions cap and a progressively increasing penalty for non-compliance, drive producers towards degenerate solutions, which are characterized by a significant fossil fuel capacity. The larger the level of pass-through of costs into electricity prices, the stronger this effect. Thus, depending on the market structure, we observe that electricity producers will tend to make counter-intuitive decisions that work against the decarbonisation goals of an ETS. These results highlight the need for a critical appraisal of the existing tradeoffs within electricity markets, in the context of the current renewable energy policy reforms.

The remainder of the paper is set out as follows. In Section 2, we develop an analytical model of the capacity expansion decision of electricity producers that can supply electricity both from fossil fuel and renewable plants. In Section 3, we solve the electricity producer's capacity expansion problem and describe how the expansion of renewable capacity impacts on producer's profits. In Section 4, we explicitly explore the combined effects of increased renewables penetration and more stringent environmental regulations by numerically solving the optimal capacity expansion problem for three market scenarios. Section 5 concludes.

in 2014 were less than half that maximum at $57.5 billion (see Frankfurt School-UNEP Collaborating Centre for Climate & Sustainable Energy Finance and Bloomberg New Energy Finance, 2015).

2 Model

2.1 General setting

The focus of the present paper is on the long-term impact of an ETS on the capacity expansion of green technologies to the detriment of polluting ones. As such, we consider an electricity sector endowed with conventional and non-conventional technologies and abstract from short-term effects, such as fuel switching (i.e. the generation mix of conventional plants). We describe a model in a single period $[0, T]$. To represent the decision process, we split the initial time into two separate instants, 0 and 0^+. The generation capacity available at time $t = 0$ is Q_c and Q_{nc} for conventional and non-conventional technologies, respectively. At time $t = 0$, the generating companies decide on the optimal expansion of their capacity, and, in particular, the desired level of expansion for conventional, Q_c^*, and non-conventional, Q_{nc}^*, capacity. Negative capacity expansion corresponds to dismantling of plants. We neglect implementation time, so the new capacities for both technologies are assumed as immediately available and operational. The capacity expansion decision is risky, since electricity demand for the entire period, D, is assumed to be uncertain and distributed as a normal random variable with mean μ and standard deviation σ.[7] Assuming a log-normal distribution for D would be formally more appropriate, since log-normal distributions do not take negative values. Nonetheless, normality is a reasonable assumption as long as μ is significantly larger than σ, as indeed it is the case in this analysis. Demand is also assumed to be price inelastic.[8] In the Appendix, we generalise the model for the case where a random amount of non-conventional electricity, Q_{nc}^h, is generated by households and small businesses.

Electricity demand is assumed to be revealed at time $t = 0^+$, i.e. after the new plant expansion has been decided upon and implemented. Electricity demand remains constant throughout $[0^+, T]$. Electricity is generated to satisfy demand following a merit order based on marginal costs.

Two spot markets are relevant in this model: the market of electricity and the market of allowances. The first is where energy is asked and offered, and p is the price of 1 MWh of electricity. The second is a market-based tool designed to control a major environmental variable, i.e. greenhouse gas emissions. The price of an allowance is p_a. One allowance allows a producer to emit 1 e of carbon dioxide equivalent (CO_2e). Electricity producers face two distinct generation costs: direct production costs and (in the case of conventional generation) the costs associated with allowances purchase and surrendering. Let $c_{v,nc}$ and $c_{v,c}$ represent the costs of generating 1 MWh of electricity using non-conventional and conventional plants, respectively. The regulatory authority determines the number of allowances that are available, C. Allowances may be allocated free of charge, or

[7] 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 $f(x) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{1}{2}\left(\frac{\mu - x}{\sigma}\right)^2}$.

[8] The validity of our model does not change even if electricity demand is slightly price elastic; we assume total independence of demand from price, in order to simplify the analytical treatment.

distributed via auctions. Thus, if a conventional plant emits m tonnes of CO_2e from the generation of 1 MWh of electricity, the (unit) regulatory cost is $c_a = mp_a$. Furthermore, $H = C/m\ MWh$ corresponds to the total conventional generation covered by allowances. In other words, conventional plants can produce $H\ MWh$ of electricity, covered by C allowances, and still be compliant with the emissions cap.

Since the aim of the paper is to study the long-term impact of an ETS on the energy mix, we consider the case where the $[0, T]$ period covers the entire lifetime of new investments. Also, we assume that the total amount of allowances needed by non-electricity sectors in $[0, T]$ just equals the amount of allowances allocated to them in $[0, T]$. Thus, we can abstract from allowances banking/borrowing and trading, and we can express the allowances demand as $m \times \min(H; Q_c + Q_c^*)$. In effect, this says that the non-compliance event (where emissions exceed the cap) is solely determined by the capacity decision of the electricity sector. Unsurprisingly, the economic value of allowances is linked to the level of electricity demand. Because eventually allowances may not be sufficient to cover the high emission levels implied by the required generation, producers will have to pay a penalty (f) for every uncovered tonne of CO_2e (Carmona et al., 2010; Chesney and Taschini, 2012). Hence, at time $t = 0$ the cost of allowances c_a is determined by the probability that during the period $[0^+, T]$ conventional plants will be required to produce more electricity than can be covered by available allowances.

2.2 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 (see Figure 1). In practice, non-conventional plants (such as wind, solar, and nuclear) 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 energy supply, electricity is priced at the marginal cost of non-conventional plants. Generators 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 many types of energy sources with different marginal costs. 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 unique class, it does not lend itself to the modelling of short-term fuel switching effects of allowances markets. Nevertheless, given our interest on the long-term effects of such markets (i.e. the capacity expansion decision), the model can be simplified by contrasting the class of non-conventional technologies to the class of conventional technologies.

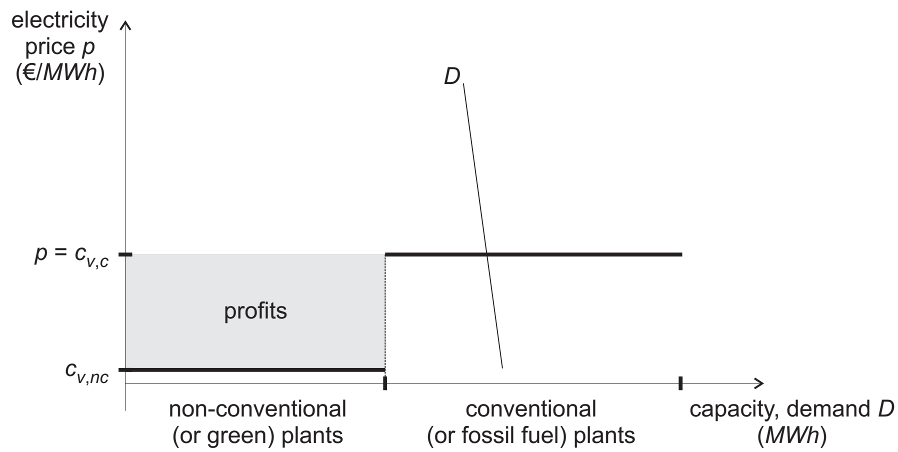


Figure 1: The classical merit order curve ranks electricity generation based on ascending marginal costs. The curve is a step-function with two values: the near-zero cost of non-conventional generation and the higher cost of conventional generation. Electricity from non-conventional plants is used first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

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. However, when producers supply electricity both from conventional and non-conventional plants and demand is uncertain, the viability of increasing the capacity of non-conventional plants is not straightforward. The more non-conventional capacity is created and maintained, the higher is the risk of costly idleness, which could quickly outweigh the potential rewards from selling non-conventional production at higher conventional generation prices. Depending on the installed non-conventional and conventional capacities, investments in extra non-conventional capacity may be a bad decision (Murphy and Smeers, 2012).

2.3 Allowances markets, merit order, and pass-through

The previous section shows that there are incentives for producers to keep a share of conventional capacity, so that green generation yields profits during periods of high demand. This holds, and is even reinforced, in the presence of an allowances market and, in particular, when electricity producers can pass-through the costs of allowances to the consumers. Morthorst (2001), Böhringer and Rosendhal (2011), and, more recently, Böhringer and Behrens (2015) investigate how emission constraints change the electricity market outcome of support schemes for non-conventional production. We complement and expand this stream of work by deriving analytical dependencies between the capacity expansion decision and the prices of electricity and allowances.

The price of electricity in an energy-only market includes all marginal costs, such as fossil fuel for conventional plants. In the presence of an ETS, conventional plants need to buy m allowances for every MWh of generation (recall that m is the number of tonnes of CO_2e emitted from the generation of 1 MWh of electricity). Therefore regulatory costs must be included within the direct costs. The impact of the allowances cost on the electricity price is modelled here by a pass-through coefficient $\beta \in [0,1]$, which describes the ability of electricity producers to transfer a fraction of the cost of allowances (on to consumers). When demand 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 price of the allowance to emit 1 tonne of CO_2e. The pass-through coefficient 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), and Hintermann (2016) find empirical evidence of allowances cost pass-through in numerous European electricity markets. Although this literature does not provide an unambiguous figure for the level of pass-through, it shows that there is potential for high levels of allowances cost pass-through.[9] We investigate the influence of pass-through on the capacity expansion decision in Section 4.2.

When demand is particularly high, conventional generation may be required to exceed H (i.e. the generation threshold that can be covered by existing allowances). This means that producers must pay a penalty (f) for every uncovered MWh produced beyond H (see Figure 2). In this case and depending on the pass-through coefficient β, electricity is priced at the marginal cost of uncovered conventional plants:

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

This means that non-conventional generation can now be sold at even higher prices, since $p_a \leq f$ under normal conditions. In the Appendix, we show that, when the useful life of the new investment is equal to $\tau \in (0, T)$, and correspondingly that at $t = 0^+$ only the demand up to τ is revealed, the two areas of profits illustrated in Figure 2 are still obtainable.

From Figures 1 and 2, we can see that the opportunities for a large electricity producer running both conventional and non-conventional plants to accrue profits are determined by:

1. the amount generated by renewables when demand is high enough to require contribution from polluting plants, but not enough to cause polluting generation to exceed H;
2. the amount generated by both non-conventional and conventional plants when demand is so high as to require (polluting) generation to exceed H and $\beta > 0$ (the fraction $1 - \beta$ of the allowances cost is not passed-through to consumers).

[9] All these studies do not reject the null hypothesis of complete pass-through.

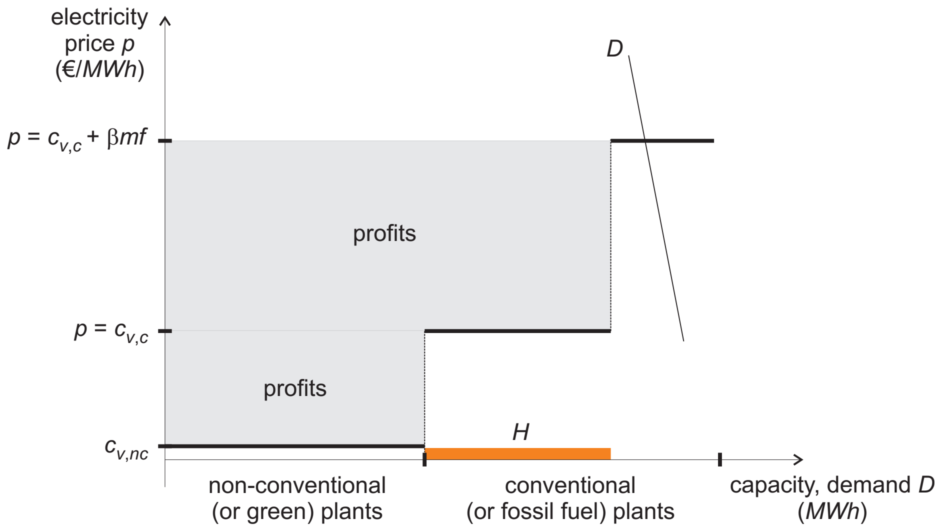


Figure 2: The possible impact of including the allowances cost into electricity prices (the so-called pass-through of costs to consumers). Large profits can be expected if the level of demand requires polluting plants to exceed the covered generation H, which raises the price of electricity above the marginal cost of conventional generation.

Figures 1 and 2 also show that demand high enough to require the contribution of polluting plants is a necessary condition to trigger both profit opportunities. Clearly this fact conflicts with the objective of establishing an electricity sector that is largely based on renewables (as such a system would fully satisfy demand most of the times, shrinking significantly those profit opportunities). Such a conflict casts serious doubts on the effectiveness of cap-and-trade programmes, together with energy-only markets, to reach the intended target of a substantial emission reduction through a technology shift from conventional to non-conventional generation.

2.4 Market structure

The liberalisation of electricity markets observed in many parts of the world has, to some degree, increased competition among electricity producers. However, it is worth distinguishing between short-term decisions (e.g. electricity generation) and long-term decisions (e.g. energy portfolio). In energy-only markets, uniform auctions have created a compelling economic incentive for each electricity producer to behave, with respect to daily generation decisions in particular, in a competitive fashion. This result holds true even in those regions where market concentration is still significantly high. As it is expected under perfect competition, the generation decision is solved by means of the merit order, with each generator offering her generation at marginal cost.

With respect to long-term decisions, several factors are raising serious doubts about the level of competitiveness in the electricity sector. First, electricity markets are still significantly concentrated, with large electricity players dominating their domestic markets. Therefore both cooperative oligopoly and monopoly seem natural descriptions of the market under investigation. For example, using a closed loop Cournot game, Murphy and Smeers (2012) demonstrate that electricity producers have incentives to withhold investments. Fabra and Toro (2005) and Tellidou and Bakirtzis (2007) find evidence of the development of tacit collusion among generators even under competitive conditions. Second, industry associations actively work to identify solutions to common problems (e.g. the funding gap and the ensuing debate around capacity markets). So, in the absence of regulations to promote long-term competition as well, a monopoly or a cooperative oligopoly is a reasonable framework to adopt for our analysis.

Moreover, to assess the different impacts of the allowances market, we consider different values of the pass-through coefficient β as part of the sensitivity analysis.

2.5 Relevant events

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

$$
\begin{aligned}
A_1 &= \{\omega \in \Omega : D \leq Q_{nc} + Q^*_{nc}\},\\
A_2 &= \{\omega \in \Omega : Q_{nc} + Q^*_{nc} < D < Q_{nc} + Q^*_{nc} + H\},\\
A_3 &= \{\omega \in \Omega : D > Q_{nc} + Q^*_{nc} + H\}.
\end{aligned}
$$

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

Let us consider the possible values of electricity and allowances prices during period $[0^+, T]$, i.e. after that electricity demand is known. In event A_1, electricity demand is entirely satisfied by non-conventional capacity, $D \leq Q_{nc} + Q^*_{nc}$. Therefore the allowances demand is zero. As we will see later on, the price of allowances p_a^T is proportional to the probability of the system exceeding the emissions cap. Therefore, conditional on event A_1, p_a^T must be zero. In this case, the electricity price p^T is driven by the marginal cost of green technologies. So we have

$$p^T|A_1 = c_{v,nc} \quad \text{and} \quad p_a^T|A_1 = 0.$$

In event A_2, electricity demand exceeds non-conventional capacity. However, in this case, all emissions are covered by the existing allowances: $Q_{nc} + Q^*_{nc} < D < Q_{nc} + Q^*_{nc} + H$. Therefore the conditional price of allowances is zero and that of electricity coincides with the marginal cost:

$$p^T|A_2 = c_{v,c} \quad \text{and} \quad p_a^T|A_2 = 0.$$

In event A_3, electricity demand is so high that it exceeds both non-conventional and covered conventional capacities: $D > Q_{nc} + Q_{nc}^* + H$. Hence, producers must pay a penalty for each uncovered tonne of CO_2e and the conditional price of allowances reaches f due to arbitrage. In this case, p^T and p_a^T are

$$p^T|A_3 = c_{v,c} + \beta c_a = c_{v,c} + \beta m f \quad \text{and} \quad p_a^T|A_3 = f.$$

These three events are summarised in Table 1.

Table 1: Electricity and allowances prices in the three events identified by the combination of realised electricity demand and the emissions cap $C = mH$.

Event	Electricity demand	Use of conventional capacity	Allowances price, p_a^T	Electricity price, p^T
A_1	Low	None	0	$c_{v,nc}$
A_2	Medium	$< H$	0	$c_{v,c}$
A_3	High	$> H$	f	$c_{v,c} + \beta m f$

2.6 Expected electricity and allowances prices

At time $t = 0$, the expected electricity price is calculated as

$$\mathbb{E}(p^T) = p^T|A_1 \times \mathbb{P}(A_1) + p^T|A_2 \times \mathbb{P}(A_2) + p^T|A_3 \times \mathbb{P}(A_3),$$

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

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

Similarly, at time $t = 0$ the allowances price is determined by the probability of conventional plants needing to produce more electricity than is covered by allowances:

$$\mathbb{E}(p_a^T) = f \times \mathbb{P}(A_3).$$

Only in event A_3 are available allowances below the amount needed to cover emissions; in this case, producers must pay a penalty for each uncovered unit of pollution emitted during the period. Given that demand is assumed to be normally distributed, the expected price of allowances can be expressed as

$$\begin{aligned}\mathbb{E}(p_a^T) &= f \times \mathbb{E}(1_{(H,\infty)}\,(D - Q_{nc} - Q^*_{nc})) \\ &= f\left(1 - \frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+Q^*_{nc}+H} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx\right),\end{aligned} \tag{1}$$

where f is the fixed penalty charged by the regulatory authority for each uncovered unit of pollution, and $1_{(H,\infty)}$ is the indicator function that is equal to one when electricity demand is not satisfied by non-conventional generation.

By arbitrage arguments and assuming risk-neutral electricity producers and a null interest rate, it is possible to show that the time $t = 0$ price of allowances, p_a, is the expected allowances price, $\mathbb{E}(p_a^T)$.

2.7 Gross and net profits of the electricity producer

In this section, we analyse the profits that accrue to the electricity producers. We begin by analysing the gross profits accruing to the electricity sector (i.e. total revenues less direct costs incurred to generate and sell electricity), in order to develop an economic intuition for the results of the model. Gross profits can be linked more directly to the variables discussed so far, and can be represented as areas 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 shaded areas in Figure 3 illustrate the (conditional) gross profits associated with the three events discussed in Section 2.5 (A_1, A_2, and A_3). We assume that the price of non-conventional production is zero given its virtually zero variable costs (i.e. $c_{v,nc} = 0$).

Figure 3 highlights some aspects relevant to our discussion. First, apart from event A_1, where gross profits are zero, the size of gross profits depends directly on the decision variables Q^*_{nc} and Q^*_c. Second, gross profits do not increase proportionally with demand. Rather, they increase by steps, as soon as demand exceeds the thresholds defining the three events. Nevertheless, in case of events A_2 and A_3, we observe a negative component (area 2 and area 5, respectively) changing proportionally with demand. Given the accounting definition of gross profits, the initial cost of

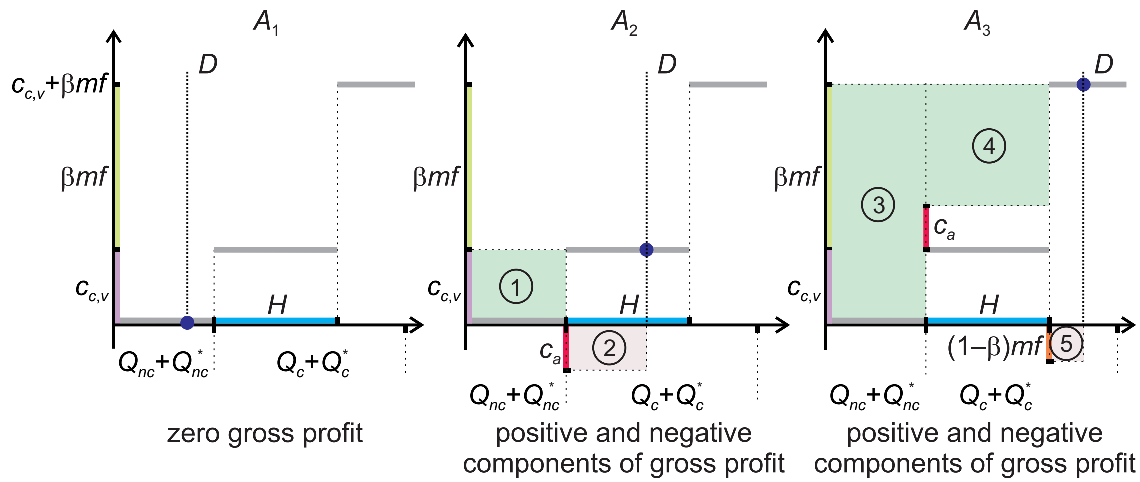


Figure 3: Gross profits depending on events A_i, $i = 1, 2, 3$.

allowances (i.e. $c_a \times \min(H; Q_c + Q_c^*)$) must be in part included in the calculation of these profits. More precisely, the calculation must account for the cost of allowances used to cover the generation required by demand ($c_a(D - (Q_{nc} + Q_{nc}^*))$). In event A_2, the remainder part of this cost should be treated as a sunk cost, that is a component of fixed costs. Because the summation of the two parts is constant, the initial cost of allowances does not generally depend on demand, as we will see in the final expression of net profits. In case of event A_3, the negative component of gross profits includes a penalty paid for the excess generation (beyond H). Indeed, such a penalty can not be recovered through the sales when $\beta < 1$. This negative component depends on electricity demand. Third, the largest value that profits can take is linked to event A_3, where both electricity and allowances prices reach their maximum theoretical values.

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

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

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 for non-conventional ones. We motivate this choice with the fact that for non-conventional plants the best locations are used first, with the consequence that the investments required to obtain 1 MWh should increase more than linearly as the total capacity in place gets larger.[10]

As discussed previously, an additional component of costs relates to allowances and is equal to

$$c_a \min \left(H; Q_c + Q_c^*\right)$$

overall for the electricity sector; it is the smaller of the two costs - of buying all the allowances (recall that $c_a H = p_a m H = p_a C$) and of covering all the conventional capacity in place (i.e. $c_a \left(Q_c + Q_c^*\right)$). Both fixed costs (i.e. FC) and the allowances cost are incurred at time $t = 0$. Neither depend on the demand level that is revealed at time $t = 0^+$.

Given these costs, we examine the profits of 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, $D \leq Q_{nc} + Q_{nc}^*$. Gross profits are zero, because the price of electricity is equal to the variable cost of generation, which is virtually zero (left diagram of Figure 3). Thus, non-conventional production generates negative conditional aggregate profits G, since such a production is sold at a price equal to its variable costs, while fixed costs and the cost of allowances are not zero:

$$G|A_1 = -FC - c_a \min(H; Q_c + Q_c^*). \tag{2}$$

In event A_2, electricity demand requires the contribution of conventional capacity (in addition to non-conventional capacity), $Q_{nc}+Q_{nc}^* < D < Q_{nc}+Q_{nc}^*+H$, but all emissions from conventional generators are covered by allowances. Thus, gross profits can be separated into two components. Non-conventional generation is sold at a price equal to the cost of conventional generation (generating positive gross profits), while conventional generation is sold at cost and therefore generates zero profits. In this case, the conditional aggregate profits G are equal to

$$G|A_2 = -FC - c_a \min(H; Q_c + Q_c^*) + (c_{v,c} - c_{v,nc}) \left(Q_{nc} + Q_{nc}^*\right). \tag{3}$$

In event A_3, electricity demand exceeds the sum of non-conventional capacity and covered conventional capacity: $D > Q_{nc} + Q_{nc}^* + H$. This means that conventional plants must generate electricity in excess of the threshold H. The marginal cost of electricity must therefore include both the cost of conventional generation ($c_{v,c}$) and a penalty per unit of emission eventually reduced by the pass-through coefficient ($\beta m f$). Depending on the levels of the pass-through coefficient, generators can sell both non-conventional and covered conventional generations at a price well above their unit direct costs (areas 3 and 4, right diagram of Figure 3). Finally, the uncovered conventional generation, $D - Q_{nc} - Q_{nc}^* - H$, costs $mf + c_{v,c}$ (electricity producers pay a penalty),

[10] The constant returns assumption for conventional plants follows from the fact that conventional technologies are easily scalable and thus 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.

but it is sold at $\beta mf + c_{v,c}$. If $\beta = 1$, the uncovered conventional generation would be sold at cost and therefore it would generate zero profits. If $\beta < 1$, the uncovered conventional generation generates negative profits. In this case, the conditional aggregate profits G are equal to

$$\begin{aligned} G|A_3 = {} & -FC + (\beta mf - c_a) \min(H; Q_c + Q_c^*) \\ & + (\beta - 1)\, mf\, (D - Q_{nc} - Q_{nc}^* - H) \\ & + (\beta mf + c_{v,c} - c_{v,nc})\,(Q_{nc} + Q_{nc}^*)\,. \end{aligned} \tag{4}$$

Depending on the levels of the pass-through coefficient, it is not always preferable to expand non-conventional capacity. We discuss this further in Section 4.

We do not consider the case of $D = Q_{nc} + Q_{nc}^* + H$, i.e. the case where demand perfectly matches electricity generation. This is an unlikely event – the probability of this event is zero when D is assumed to be a continuous random variable. Also, the price of allowances would not be uniquely defined. In this case, it could take any value between 0 and the fixed penalty f.

The events determining the gross profits of Figure 3 are discussed in Table 2 as a function of the demand revealed in the relevant period.

Table 2: Description of the three gross profit events.

Event	Electricity price, p^T	Gross profits
A_1	$c_{v,nc}$	The low-cost non-conventional production generates null gross profits, since it is sold at a price equal to its variable costs (i.e. zero).
A_2	$c_{v,c}$	Area 1: non-conventional production is sold at the cost of conventional production, i.e. high profits. Area 2: conventional production generates negative profits, since it is sold at a price equal to its variable costs, so the initial cost of allowances cannot be recovered.
A_3	$c_{v,c} + \beta mf$	Area 3: non-conventional production is sold at the cost of uncovered conventional production, i.e. very high profits. Area 4: conventional, covered production also generates positive profits, since it is sold at a price equal to the marginal cost of uncovered production, which includes a penalty payment. Conventional, uncovered production is sold at null profits. Area 5: conventional, uncovered production generates negative profits, since it is sold at a price lower than its marginal cost in the case of a pass-through coefficient $\beta < 1$.

2.8 Profit decomposition

For each of the three profit events, we can separate profits net of fixed costs into two components: an operational component and an allowance component. The operational component arises from selling 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.

In event A_1, there is no operational component or allowance component of profits. In event A_2, the operational component is positive and the allowance component is negative:

$$G|A_2 + FC = \underbrace{(c_{v,c} - c_{v,nc})\,(Q_{nc} + Q_{nc}^*)}_{\text{operational component}} + \underbrace{(-c_a \min(H; Q_c + Q_c^*))}_{\text{allowance component}}. \tag{5}$$

The allowance component is negative in this case, because, as demand is revealed and the market learns about the sufficiency of allowances to cover the generation for the period $[0^+, T]$, p_a (and so c_a) falls to zero.

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. However, only very small values of β generate a negative allowance component.

$$\begin{aligned} G|A_3 + FC &= (\beta mf - c_a)\min(H; Q_c + Q_c^*) + (\beta mf + c_{v,c} - c_{v,nc})\,(Q_{nc} + Q_{nc}^*) \\ &\quad - (1-\beta)\,mf\,(D - Q_{nc} - Q_{nc}^* - H) \\ &= \underbrace{(c_{v,c} - c_{v,nc})\,(Q_{nc} + Q_{nc}^*)}_{\text{operational component}} - \underbrace{(1-\beta)\,mf\,(D - Q_{nc} - Q_{nc}^* - H)}_{\text{allowance component}} \\ &\quad + \underbrace{\beta mf\,(Q_{nc} + Q_{nc}^* + \min(H; Q_c + Q_c^*)) - c_a \min(H; Q_c + Q_c^*)}_{\text{allowance component}}. \end{aligned} \tag{6}$$

The influence of the level of β is examined in Section 4.2.

Such a decomposition helps us separate out two components of the electricity price increase: the first one is the amount paid by consumers for the investment and operation activities in the electricity sector and the second one represents the profits that will arise solely from the introduction of a regulatory instrument, such as an ETS.

3 Capacity expansion problem

In Section 2, we outlined the model and the profit events based on electricity demand. However, the capacity expansion decision must be solved at time $t = 0$, i.e. when demand D is unknown. We consider the case where the monopolist maximises her expected profit under the capacity expansion constraints previously discussed. The electricity producer's expected profit is

$$\begin{aligned}\mathbb{E}(G) = &-FC - c_a \min(H; Q_c + Q_c^*) + (c_{v,c} - c_{v,nc})\,(Q_{nc} + Q_{nc}^*)\,\mathbb{P}(A_2) \\ &+ (\beta m f \min(H; Q_c + Q_c^*) + (\beta m f + c_{v,c} - c_{v,nc})(Q_{nc} + Q_{nc}^*) + (1-\beta)\,m f\,(Q_{nc} + Q_{nc}^* + H))\mathbb{P}(A_3) \\ &+ \int_{A_3} (\beta - 1)\,m f D(\omega) d\mathbb{P}(\omega),\end{aligned}$$

and the electricity producer's capacity expansion problem can be stated as[11]

$$\begin{array}{rl} & \max_{Q_{nc}^*, Q_c^*} \mathbb{E}(G) \\ \text{s.t.} & Q_{nc}^* > -Q_{nc} \\ & Q_c^* > H - Q_c \end{array} . \tag{7}$$

The first constraint states that dismantling of renewables is allowed up to Q_{nc}. The second constraint prevents the case where the cap is slack, i.e. the probability of event A_3 is zero. Indeed, for reasons previously discussed, there is no incentive for the producer to reduce total polluting capacity below H.

We report the analytic solution of this problem in the Appendix. For evaluation purposes, it must be in part calculated numerically. In the next section, we analyse the model through an application to three market scenarios.

As Figure 4 shows, net profits can be represented by a piece-wise linear function of demand D: the graph of this function is made of two segments at constant levels $G|A_1$ and $G|A_2$, respectively, plus a third segment with negative slope equal to $(\beta-1)mf$ (recall that $\beta \in [0,1]$ and refer to Eq. (4) for the expression of $G|A_3$ depending on D). In the left panel of the same figure, we consider both the distribution of demand D and the graph of the net profit function, as it appears to the electricity producer before her decision. The three shaded areas (1, 2, and 3) represent the probabilities corresponding to the three events (A_1, A_2, and A_3).

In short, Figure 4 gives the intuition of the (optimal) tradeoff that the electricity producer must solve, in the case of a positive expansion of non-conventional capacity (from Q_{nc} to $Q_{nc} + Q_{nc}^*$). Such a decision leads to several economic consequences, of opposite sign:

- Area 1 (region of 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 area. This effect clearly decreases the expectation of net profits.

- Area 2 (region of profits with only the operational component) shrinks under more common

[11] The 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.

initial settings; however, net profits within that area ($G|A_2$) can increase thanks to the additional non-conventional generation being sold at the price of conventional generation. The sign of this effect is not clear.

- Area 3 (region of profits with a very high allowance component) shrinks with certainty; however, profits within this area increase sharply (for large values of β) 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) the conditional profit $G|A_3$ can eventually be lower than $G|A_2$. Again, the sign of this effect is not clear.

In summary, expansion of non-conventional capacity has the following qualitative consequences: whereas the probability of demand being satisfied by non-conventional plants (event A_1) increases (along with worsening negative profits), the probability of event A_2 or A_3 decreases. Nonetheless, the potential profits within areas 2 or 3 increase (at a decreasing rate, in area 3). Thus, it is not immediately clear what the final result of a positive expansion of non-conventional capacity might be.

Figure 4 shows that increasing non-conventional capacity has a combined effect. On the one hand, when demand is high and electricity is priced at the marginal cost of conventional plants, producers can enjoy higher profits from the higher share of non-conventional capacity (shaded areas 2 and 3, right diagram of Figure 4). On the other hand, during periods of low demand, electricity is priced at the marginal cost of non-conventional capacity, so the higher share of non-conventional capacity results in a higher loss (shaded area 1, right diagram of Figure 4).

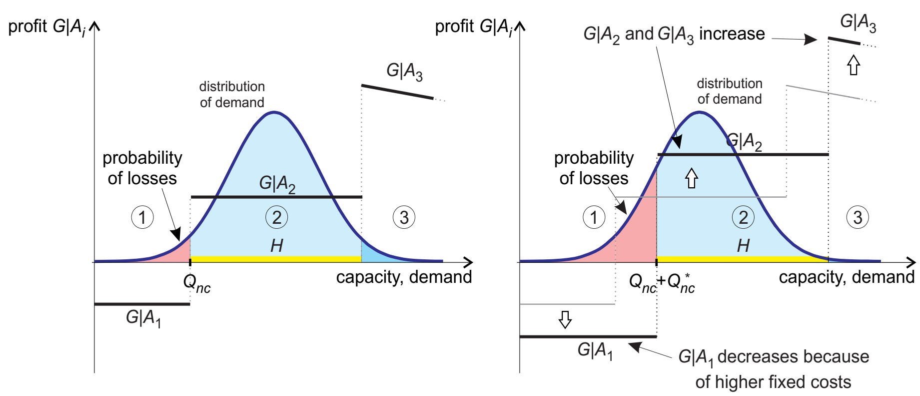


Figure 4: Expansion decision (of green technology), probability density function of D, and probabilities of events A_i, $i = 1, 2, 3$. The covered generation H is equal to the length of area 2.

In reality, the opportunity of pursuing the strategy of increasing the probability of event A_3 (in the sight of the highest level of profits) depends on the initial setting of a national energy portfolio. For example, Germany has a high share of renewables in its current energy portfolio.[12] This means that (relative to other countries) there is a higher chance that demand would be completely satisfied by non-conventional capacity, so electricity would be priced at the marginal cost of non-conventional plants (i.e. virtually zero). In this case, generators could have low or even no incentive to keep a substantial share of conventional plants. This case looks similar to the second market scenario, which is discussed in Section 4.1.

In the next section, we present an application where the capacity expansion problem is solved numerically in the context of an ETS with increasing stringency.

4 Numerical Application

To explore the capacity expansion decision in the context of the current energy policy reforms, we present three market scenarios that describe different stylised stages of an ETS, where the cap is progressively tightened up and renewables penetration is increasing. The section concludes with a sensitivity analysis of two key model parameters: the amount of conventional generation that can be covered by the issued allowances and the pass-through coefficient. In the following, to ease the discussion, we will refer to electricity prices instead of expected electricity prices, unless otherwise stated.

4.1 Capacity expansion decisions under three market scenarios of an ETS

We apply the model to three market scenarios: the first corresponds to the early stage of an ETS, where the emissions cap is relatively generous and the share of renewable capacity is low; the second corresponds to the maturity stage of an ETS, where the emissions cap is tighter and the share of renewable capacity is larger; and the last market scenario corresponds to the case where the emissions cap is significantly tighter and renewables cover a relatively large amount of electricity demand.

The installed conventional generation is 330 MWh in all the market scenarios, whereas the installed non-conventional generation is assumed to increase in line with the existing policies that support renewables penetration in most electricity markets. Finally, the amount of covered emissions decreases in line with standard decarbonisation targets.

Electricity demand is normally distributed with mean $\mu = 200$ and standard deviation $\sigma = 30$ (in MWh). We then solve Problem (7) and provide a discussion of the solutions for the three

[12] In 2013, during a period of low demand and high supply of wind and solar energy, Germany's wholesale electricity price fell to minus 100 €/MWh (*The Economist*, 2013).

Table 3: Initial settings under three stylised market scenarios of an ETS.

Capacity (MWh)	Scenario: Early stage	Maturity stage	System rejection
Installed conventional capacity Q_c	330	330	330
Installed non-conventional capacity Q_{nc}	20	100	210
Amount of covered conventional capacity H	120	100	20

market scenarios described in Table 3. In particular, we consider how decisions about the expansion of non-conventional capacity are affected by different initial levels of installed non-conventional generation, and by the amount of available allowances, e.g. the cap.

Figure 5 summarises the characteristics of the three market scenarios: the green line represents the initial non-conventional generation, the red line represents the installed conventional generation, and the blue line represents the amount of allowances, in MWh, issued at the start of an ETS.

Early stage The first case describes an electricity sector at the beginning of an ETS, when most demand is satisfied by conventional plants and renewable generation represents a secondary component of the overall generation capacity. There is a relatively small amount of installed non-conventional generation, and electricity demand is almost completely satisfied by conventional plants. By observing the probability density function of demand D (left panel, Figure 5), one can note that the probability of paying the fixed penalty f for each MWh of electricity above the level indicated by the end of the blue line is very high (over 90%); this is because the expected demand of 200 MWh is well above the level of allowances, i.e. covered conventional generation.

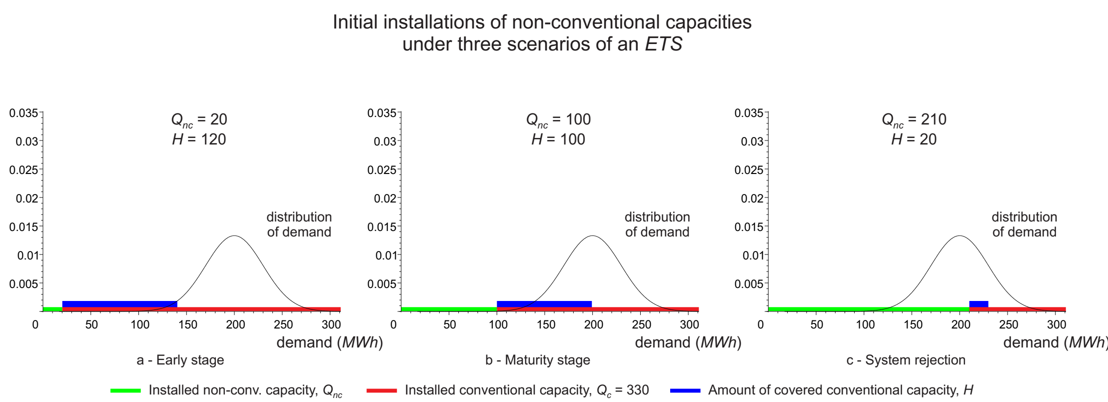


Figure 5: Capacities and allowances before expansion decisions under the three market scenarios.

Maturity stage The middle diagram in Figure 5 describes a maturity stage. At this point, there is a significant amount of non-conventional generation, but conventional plants are almost always necessary to satisfy electricity demand at any one time. The regulatory authority issues allowances that allow for a 50% probability of demand to be higher than the level indicated by the end of the blue line.

System rejection We label the last stage of an ETS as system rejection (the choice of this name will become clear later). At this stage, non-conventional capacity fully covers demand in 75% of cases. The regulatory authority allocates a small number of allowances to induce the electricity sector to do the "last step" (i.e. to achieve a full decarbonisation and eliminate the last 25% probability of conventional generation), and to almost completely cover electricity demand by non-conventional generation (right panel, Figure 5).

The expected profit functions under the three market scenarios are shown in Figure 6 with respect to the decision variables, Q_c^* and Q_{nc}^*. To evaluate numerically the optima of the expected profit function with respect to Q_c^* and Q_{nc}^*, we assign the following values to the various parameters of $\mathbb{E}(G)$: $m = 1.1$ (es/MWh), $f = 100$ (€/e), $\alpha = 0.01$, $c_{v,c} = 60$ (€/MWh), $c_{v,nc} = 0$ (€/MWh), $c_{f,c} = 1.5$ (€/MWh), $c_{f,nc} = 6$ (€/MWh), and (for the present section) full pass-through, i.e. $\beta = 1$.

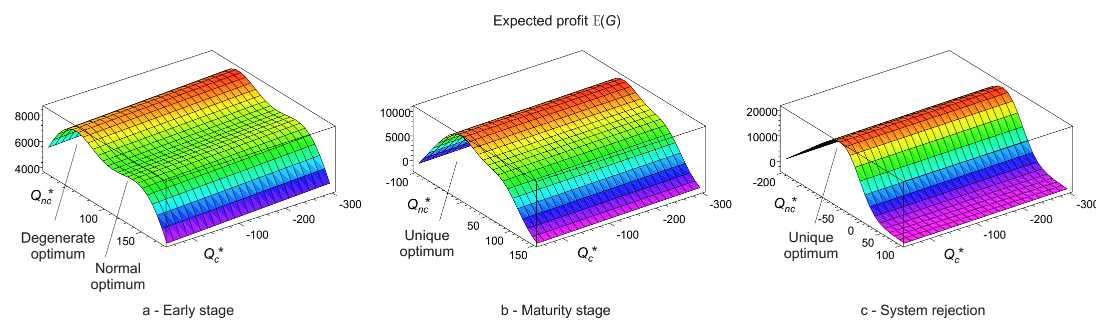


Figure 6: Expected profit $\mathbb{E}(G)$ for various expansion decisions of the conventional capacity Q_c^* and the non-conventional capacity Q_{nc}^*. Panel a refers to the early stage, Panel b to the maturity stage, and Panel c to the system rejection.

4.1.1 Solution

Early stage Panel *a* of Figure 6 represents the expected profit in the early stage of an ETS. We observe two optima: a "degenerate" optimum and a "normal" optimum. We refer to the first optimum as degenerate, because electricity producers seek to be non-compliant and thus generate *unreasonably* higher electricity and allowances prices. Non-compliance corresponds to event

A_3 and implies an allowances price equal to its theoretical maximum f and the highest possible electricity price that, for $\beta = 1$, also includes the allowances cost. The second optimum is dubbed as normal, because it does not yield the artificially high electricity and allowances prices of the degenerate optimum. Instead, this solution corresponds to event A_2, where profits are maximised by selling non-conventional generation at the marginal cost of conventional production. We thus formally distinguish between normal and degenerate optima depending on the solution of inequality $\mathbb{E}(G|A_3) > \mathbb{E}(G|A_2)$: the type is degenerate if the inequality is satisfied; otherwise, the type is normal. Although profits are lower under the normal optimum than under the degenerate optimum, the normal solution favours increasing non-conventional capacity, in order to stay within the emissions cap set by an ETS. Thus, the normal solution is preferable from both an economic and an environmental standpoint. We explore this further in Section 4.2.

The degenerate and normal optimal installations of non-conventional capacity are shown in the upper panel of Figure 7. The degenerate optimum corresponds to a new installed non-conventional generation of around 58 MWh. Given that in this market scenario there is already 20 MWh of installed non-conventional generation, the final generation amounts to around 78 MWh. Comparing this value to an expected demand of 200 MWh, it is evident that non-conventional generation will not be enough to completely satisfy demand in virtually any situation. Indeed, under these settings, renewable generation will satisfy demand with a negligible probability and the likelihood of exceeding the emissions cap is 53%.

The normal optimum corresponds to a total non-conventional generation of about 155 MWh (i.e. $Q_{nc} = 20$ MWh and $Q^*_{nc} = 135$ MWh). Again, comparing this to an expected demand of 200 MWh, there is a 7% chance of completely satisfying demand with renewable generation and only a 0.6% probability of missing the emissions cap. Although a positive technology switch towards non-conventional generation is observed, it is not a complete switch.[13] Conventional generation is still required to meet demand in the vast majority of cases.

Maturity stage Panel b of Figure 6 shows the expected profit in the maturity stage, which contains a unique optimum. In this market scenario, the initial non-conventional capacity is equal to 100 MWh (50% of the expected demand), which means that the potential increase in renewable capacity can be substantial (see lower left panel, Figure 7). Despite this, the unique optimum corresponds to an expansion of non-conventional capacity of -10 MWh, i.e. non-conventional capacity is dismantled.

At this stage of an ETS, the optimal solution corresponds to a decrease in non-conventional capacity instead of an expansion. Electricity producers are incentivised to maintain a conventional capacity such that demand is seldom fully satisfied by non-conventional generation. Such an ETS

[13] Note that the normal optimum is characterised by a level of non-conventional capacity and a number of allowances which together almost completely cover demand: $Q_{nc} + Q^*_{nc} + H \simeq 20 + 135 + 120 = 275$ corresponds to the $99th$ percentile of the demand distribution.

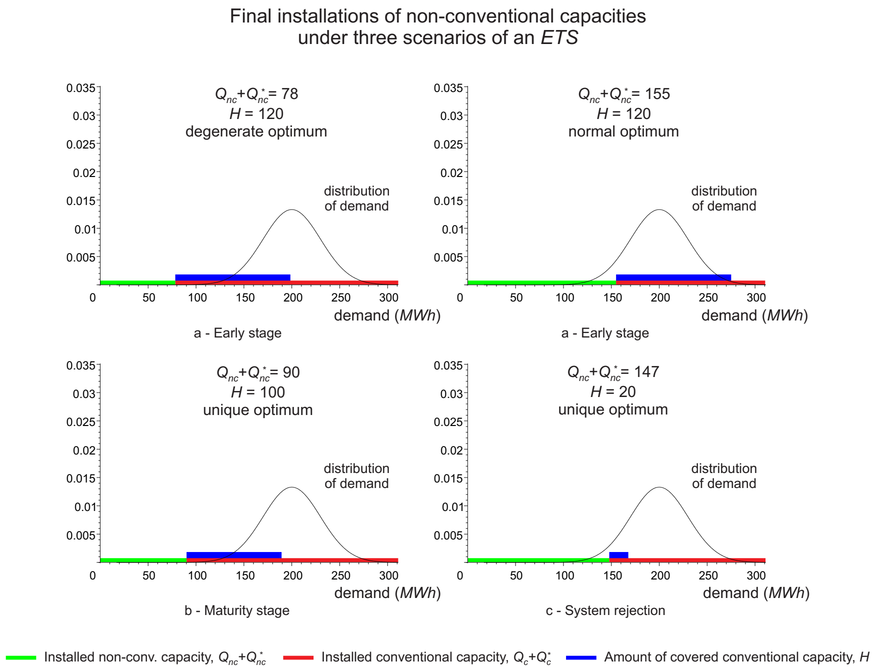


Figure 7: Optimal solutions $(Q_{nc}+Q_{nc}^{*})$ of the capacity expansion decisions under the three market scenarios. In the early stage, we obtain both a degenerate and a normal optimum.

is *mature*: it is not able to cause a positive technology switch even though the volume of allocated allowances (100 MWh) is lower than the allocation in the early stage. Given that the probability of exceeding the emissions cap remains high (the probability increases to 63% from 50% in the early stage), this solution can be considered of degenerate type.

System rejection Panel c of Figure 6 shows the expected profit in the system rejection of an ETS, which, again, contains a unique optimum. The unique optimum is obtained when the non-conventional capacity expansion decision is equal to -63 MWh (i.e. dismantling of 63 MWh of capacity). As in the maturity stage, this profit-optimising solution to dismantle non-conventional capacity is a consequence of the incentive to maintain non-conventional capacity at levels which do not fully satisfy demand. In the system rejection, the already-installed non-conventional generation is equal to 210 MWh, greater than the expected demand of 200 MWh (lower right panel, Figure 7). Electricity producers thus *reject* the constraints of an ETS in favour of maintaining the higher prices associated with conventional generation. It is clear that the optimal solution is again of degenerate type: the likelihood of being non-compliant increases from an initial 16% to 86%, following the decision to dismantle non-conventional capacity.

The Appendix provides a description of the allowances price and of the expected electricity price in each of the three stages of an ETS.

4.2 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 existing allowances[14] and β, the pass-through coefficient. For this purpose, Problem (7) is solved (using only the decision variable Q^*_{nc}) under different values of the two parameters.

Table 4 lists the other parameters used in the sensitivity analysis. We assume that conventional capacity remains constant, i.e. $Q^*_c = 0$, and we consider 3 values for the standard deviation of electricity demand: $\sigma = 10, 20, 30$.

Table 4: Parameters used in the sensitivity analysis.

Parameter	Value	Parameter	Value
σ (MWh)	10, 20, 30	μ (MWh)	200
m (es/MWh)	1.1	f (€/e)	100
Q_c (MWh)	330	Q_{nc} (MWh)	160
Q^*_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

Panels a of Figures 8 and 9 illustrate the expected profit $\mathbb{E}(G)$ varying with respect to the installation of non-conventional capacity Q^*_{nc} and the parameters H and β, respectively, and for $\sigma = 30$. Panels b of Figures 8 and 9 illustrate the sets of stationary points of $\mathbb{E}(G)$ for $\sigma = 10, 20, 30$. The stationary points for $\sigma = 30$ correspond to the ridges (maxima) and the valley floors (minima) of the three dimensional diagrams in panels a. Note that, for some combinations of values of H, β, and Q^*_{nc}, there are two (local) maxima: a normal and a degenerate solution. Below we present the numerical results of the sensitivity analysis and offer an economic interpretation.

We first study the effect of varying H and β by considering five value combinations for the pair (H, σ) in Table 5 and five value combinations for the pair (β, σ) in Table 6, respectively. Before discussing the results reported in the tables, we introduce the *green ratio*, defined as $(Q_{nc} + Q^*_{nc})/\mu$, which represents the share of the expected demand covered by non-conventional generation, as determined in the optimal solution. In the long run, a full decarbonisation requires large green ratios, at least equal to 1. The initial green ratio (before the optimisation) is $160/200 = 0.8$. This corresponds to the system rejection described in the previous section.

[14]Recall that $H = \frac{C}{m}$, where C is the number of allowances and m is the amount of CO_2e (in es) emitted from the generation of 1 MWh of electricity.

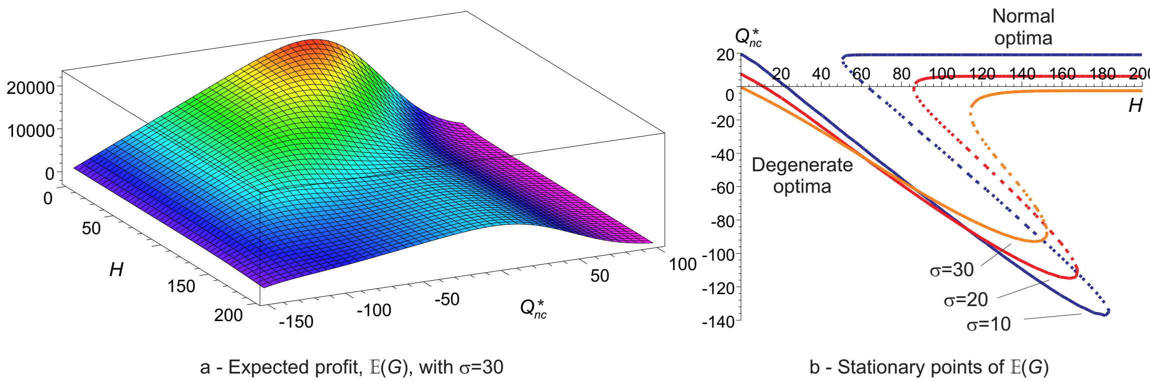


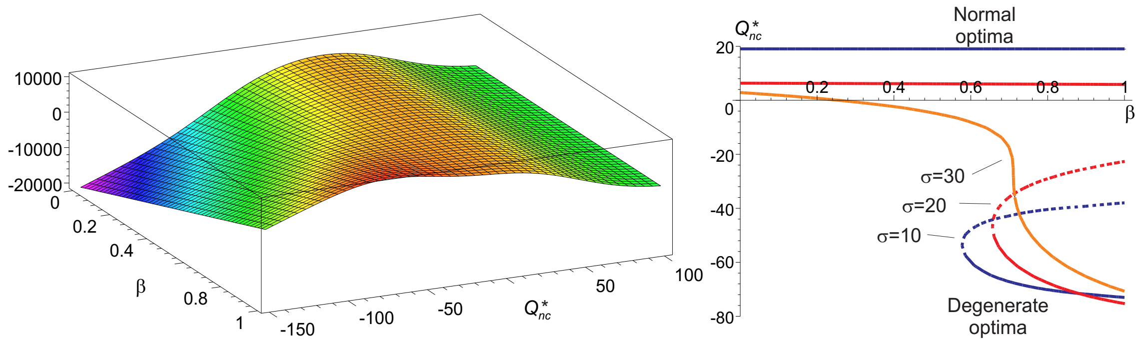
Figure 8: An ETS at work. Panel a shows the expected profit $\mathbb{E}(G)$ with respect to H and Q^*_{nc}. Electricity demand D is a normal random variable with mean $\mu = 200$ and standard deviation $\sigma = 30$. Panel b shows the sets of stationary points of $\mathbb{E}(G)$ letting the standard deviation of D assume the values 10, 20, and 30. The solid lines represent stationary points associated with maxima. The dotted lines represent stationary points of no interest, since they correspond to minima of $\mathbb{E}(G)$. Here β is fixed to 1, i.e. we allow producers to pass-through all the regulatory compliance costs to consumers.

Each table reports key elements of the capacity expansion problem solutions: the optimal non-conventional capacity expansion, the expected profit, the allowance component, the green ratio, the expected electricity price, the allowances price, and the type of optimum. With regard to this last element, the tables show the normal/degenerate classification. Not surprisingly, the highest levels of expected profit correspond to the case where optima are degenerate. Moreover, non-conventional capacity is significantly expanded only when the optimum is normal.

Analysis of H

In Table 5, we consider two values of H, namely 20 and 100, and two values of σ, namely 10 and 30. β is kept constant at 1.

We make the following observations. First, low values of H (cases A and B) result in a very high expected profit. Non-conventional capacity is marginally increased or even decreased (+2.56 MWh in case A and -12.77 MWh in case B). Consequently, the green ratio is virtually unchanged (0.81 in case A and 0.74 in case B) and is relatively high. Despite this, the likelihood of non-compliance (expressed as $\frac{p_a}{f}$) remains relatively high (86% and 96%, respectively). These solutions are degenerate optima: electricity and allowances prices are close to their theoretical maxima, and approximately 68% and 67% of profits are derived from the allowance component in case A and B, respectively. Second, when H takes high values (cases C, D, and E), the solution depends on the level of σ. When σ is high (30 in case E), there is a unique degenerate solution. When σ



a - Expected profit $\mathbb{E}(G)$ with σ=30

b - Stationary points of $\mathbb{E}(G)$

Figure 9: An ETS at work. Panel a shows the expected profit $\mathbb{E}(G)$ with respect to β and Q^*_{nc}. Electricity demand D is a normal random variable with mean $\mu = 200$ and standard deviation $\sigma = 30$. Panel b shows the sets of stationary points of $\mathbb{E}(G)$, letting the standard deviation of D assume the values 10, 20, and 30. The solid lines represent stationary points associated with maxima. The dotted lines represent stationary points of no interest, since they correspond to minima of $\mathbb{E}(G)$. Here H is fixed to 100.

is low (10 in cases C and D), we observe two solutions, normal and degenerate, with the latter dominating the former in terms of expected profit. Not surprisingly, in both the degenerate cases D and E the green ratio halves (to about 44%), whereas electricity and allowances prices, as well as allowance components of profits, are very high. Electricity producers prefer to increase the likelihood of non-compliance, ultimately reducing the green ratio. Under the normal solution (case C), the green ratio significantly increases (approximately 0.90). The likelihood of non-compliance is virtually zero; consequently, the allowances price and the allowance component of profits are both zero. Also, the electricity price is 59 €$/MWh$ (about 63% less than the corresponding value in case D). In short, case C is the preferable solution from both an economic and an environmental point of view, but cannot match the expected profit of the degenerate solutions.

We now consider the impact of σ in the cases of degenerate optima. Moving from $\sigma = 10$ to $\sigma = 30$ does not change the green ratio significantly. The impact of σ is more pronounced when considering the expected profit, and electricity and allowances prices. More precise demand forecasts (i.e. low σ in cases A and D) correspond to an expected profit 20% higher than in comparable market scenarios where σ is higher (cases B and E, respectively). Moreover, higher levels of σ correspond to lower electricity and allowances prices.

To summarise, by inspecting Table 5 (and, similarly, Table 6 later) we observe that the degenerate solution occurs when $\mathbb{E}(G|A_3) > \mathbb{E}(G|A_2)$. Whenever the key parameters take values such that this inequality is strengthened, an ETS delivers an undesired outcome. In particular, with respect to parameter H, degenerate solutions prevail when the cap is sufficiently tight, e.g. low H.

Table 5: Sensitivity analysis of H. Optimal installations of the non-conventional capacity Q^*_{nc} with respect to 5 combinations of values of H, the total conventional generation covered by allowances, and σ, the standard deviation of electricity demand.

Parameters and variables	Cases[a] A	B	C	D	E
σ (MWh)	10	30	10	10	30
β	1	1	1	1	1
H (MWh)	20	20	100	100	100
Q^*_{nc} (MWh)	2.56	−12.77	19.20	−73.50	−70.73
$\mathbb{E}(G)$ (€)	25174	20863	8659	12774	10527
Allowance component of $\mathbb{E}(G)$[b]	0.68	0.67	0	0.68	0.60
Green ratio[c]	0.81	0.74	0.90	0.43	0.45
$\mathbb{E}(p^T)$ (€/MWh)	165.53	152.54	58.87	160.26	130.36
p_a (€/e)	95.94	86.27	0	91.15	63.97
$\mathbb{E}(G\|A_3) > \mathbb{E}(G\|A_2)$[d]	Yes	Yes	No	Yes	Yes
Point of optimum of $\mathbb{E}(G)$	Unique	Unique	Double[e]	Double[e]	Unique
Type of optimum	Degenerate	Degenerate	Normal	Degenerate	Degenerate

[a] The 5 couples of values (Q^*_{nc}, H) corresponding to cases A-E belong to the sets of stationary points drawn in panel b of Figure 8 for $\sigma = 10$ and $\sigma = 30$.
[b] The allowance component, as a percentage of the expected profit, is based on Eq. (5) and Eq. (6). In particular, it is the sum of the allowance component of Eq. (5) multiplied by the probability of event A_2 and the allowance component of Eq. (6) multiplied by the probability of event A_3. Finally, the sum is divided by the amount of the expected profit.
[c] The green ratio is defined as $(Q_{nc} + Q^*_{nc})/\mu$, i.e. the share of the expected demand covered by non-conventional generation, as determined in the optimal solution.
[d] $\mathbb{E}(G|A_3)$ and $\mathbb{E}(G|A_2)$ are the expected profits conditional on events A_3 and A_2, respectively.
[e] 'Double' indicates that the (local) optima with $H = 100$ and $\sigma = 10$ are two.

Conversely, normal solutions prevail when the cap is sufficiently loose, e.g. high H. Conventional wisdom would suggest that an ETS with a strict cap sustains the expansion of renewable capacity. On the contrary, in scenarios where the share of renewable capacity already covers a considerable portion of electricity demand (e.g. system rejection), this is not the case. Dismantling of renewable capacity is even preferable when β is high. This effect is even stronger for increasing values of the fixed penalty f (see Eq. (4)).

Analysis of β

In Table 6, we consider two values of β, namely 0.5 and 0.9 (representing low and approximately full pass-through), and two values of σ, namely 10 and 30. Here H is fixed to 100 MWh.

Unlike the previous analysis, we now obtain three normal optima (cases A, B, and C). Cases A and B are characterised by the same relatively low value of the pass-through coefficient, $\beta = 0.5$. They are of particular interest, because they are normal and unique optima. Conversely, the

Table 6: Sensitivity analysis of β. Optimal installations of the non-conventional capacity Q^*_{nc} with respect to 5 combinations of values of β, the pass-through coefficient, and σ, the standard deviation of electricity demand.

Parameters and variables	Cases[a] A	B	C	D	E
σ (MWh)	10	30	10	10	30
β	0.5	0.5	0.9	0.9	0.9
H (MWh)	100	100	100	100	100
Q^*_{nc} (MWh)	19.20	-3.85	19.20	-71.92	-63.40
$\mathbb{E}(G)$ (€)	8659	7094	8659	10778	9088
Allowance component of $\mathbb{E}(G)$[b]	0	0.01	0	0.61	0.49
Green ratio[c]	0.90	0.78	0.90	0.44	0.48
$\mathbb{E}(p^T)$ $(€/MWh)$	58.87	57.37	58.87	147.45	113.95
p_a (€/e)	0	3.06	0	88.34	54.51
$\mathbb{E}(G\|A_3) > \mathbb{E}(G\|A_2)$[d]	No	No	No	Yes	Yes
Point of optimum of $\mathbb{E}(G)$	Unique	Unique	Double[e]	Double[e]	Unique
Type of optimum	Normal	Normal	Normal	Degenerate	Degenerate

[a] The 5 couples of values (Q^*_{nc}, β) corresponding to cases A-E belong to the sets of stationary points drawn in panel b of Figure 9 for $\sigma = 10$ and $\sigma = 30$.
[b] The allowance component, as a percentage of the expected profit, is based on Eq. (5) and Eq. (6). In particular, it is the sum of the allowance component of Eq. (5) multiplied by the probability of event A_2 and the allowance component of Eq. (6) multiplied by the probability of event A_3. Finally, the sum is divided by the amount of the expected profit.
[c] The green ratio is defined as $(Q_{nc} + Q^*_{nc})/\mu$, i.e. the share of the expected demand covered by non-conventional generation, as determined in the optimal solution.
[d] $\mathbb{E}(G|A_3)$ and $\mathbb{E}(G|A_2)$ are the expected profits conditional on events A_3 and A_2, respectively.
[e] 'Double' indicates that the (local) optima with $\beta = 0.9$ and $\sigma = 10$ are two.

normal solution of case C is accompanied by the degenerate (and more profitable) solution of case D. Thus, for low values of β, the expected profit is predominantly determined by the operational component (the allowance component is 1% at most) and electricity prices are relatively low (around 58 $€/MWh$). Non-conventional capacity is either expanded or maintained: the green ratio moves to 0.90 in case A and stays around 0.78 in case B. When the pass-through coefficient is high (cases C, D, and E), the model outputs are similar to those in the market scenarios with high H (cases C, D, and E in Table 5). Again, a large green ratio is preferable from both an economic and an environmental point of view. Nevertheless, dismantling of non-conventional generation (case D) dominates the case where non-conventional generation is increased (case C). As in the discussion of H, under degenerate solutions, green ratios are low, the likelihood of non-compliance is high, and, consequently, allowances and electricity prices are high too, ultimately generating high profits. Again, low values of σ are observed to have a positive impact on the expected profit of electricity producers.

To summarise, normal solutions prevail when the pass-through is sufficiently small, e.g. low β. A low β reduces the allowance component of profits, mitigating the preference for being non-compliant. Investing in non-conventional capacity is preferable when it is not possible to recoup most of non-compliance costs. Conversely, degenerate solutions prevail for large values of the pass-through, e.g. large β. In contrast to conventional wisdom, although non-compliance can be costly, this does not discourage producers from keeping a significant share of conventional generation.

5 Conclusions

This paper addresses the set of tradeoffs that define the capacity expansion decision of a monopolist in energy-only markets. We specifically investigate the factors that determine the producer's optimal expansion of renewable (non-conventional, or green) capacity in the context of a cap-and-trade programme (ETS) covering fossil fuel (conventional, or polluting) generation. Understanding the expected outcomes and the tradeoffs associated with a producer's decision to expand capacity under the constraints of renewable obligations and emission restrictions is critical for ensuring effective environmental legislations and energy market reforms.

In this paper, we present a model of the long-term capacity expansion problem involving the choice between fossil fuel and renewable generation where demand is uncertain, and derive analytical dependencies between the expansion decision and market prices. The novelty of the model stems from both its relative simplicity and its ability to separate out the constituent factors of the expected profits that ultimately determine the capacity expansion decision. The model highlights the fundamental tradeoffs faced by electricity producers considering capacity investments, given the marginal costs of two reference technologies (fossil fuels and renewables) and the impact of non-compliance costs on profits. Although an increased renewable capacity means that a larger share of renewable production can be priced at the higher marginal cost of fossil fuel plants, the likelihood that producers can enjoy such a higher price is reduced, because a larger share of demand is met by the cheaper renewable production.

In order to investigate the relationship between the key feature of an ETS (i.e. stringency of the cap) and the optimal renewable capacity expansion, we develop three market scenarios representing stylised stages of an ETS. In energy-only markets, we find that the optimal expansion of renewable capacity often works against the decarbonisation goals of an ETS. A technological shift towards increased renewable generation is only induced in the early stage of an ETS. The later stages, when the cap is tighter, lead to dismantling of renewables, in order to maintain fossil fuel generation at the margin; this ultimately yields higher profits. In no market scenario are producers incentivised to meet 100% of electricity demand with renewables alone.

Thus, on its own, an ETS will not result in a fully decarbonised electricity sector - at least in the context of energy-only markets - even with an incomplete allowances cost pass-through.

In particular, although an ETS can initially incentivise an expansion of environmentally friendly technologies, it is always favourable for producers to retain a portion of fossil fuel plants due to the merit order.

A sensitivity analysis demonstrates how the market structure and the stringency of an ETS cap can result in two distinct paths of profit generation, thus determining whether renewable capacity is expanded or dismantled. In some cases, termed normal solution (to the capacity expansion decision), the producers obtain profits through the sale of renewable generation at the marginal cost of fossil fuel generation. In these market scenarios, producers generally increase their renewable capacity and, at the very least, respect the bounds of an ETS (i.e. do not exceed the emissions cap). In other cases, termed degenerate solution, the producers reject the constraints of an ETS altogether and derive profits from the sale of renewable and fossil fuel generation at the marginal cost of uncovered fossil fuel generation (i.e. generation that exceeds the emissions cap and is fined accordingly). Importantly, conditions in line with the goals of an ETS (i.e. tighter emissions cap along with higher penalty) drive producers towards degenerate solutions and the maintenance of significant fossil fuel capacity. These findings call into question the long-term efficacy of an ETS in achieving decarbonisation goals when implemented alongside energy-only markets, and highlight the need for a critical appraisal of the dependence between prices and the capacity expansion problem.

References

Acemoglu, D., A. Kakhbod, and A. Ozdaglar (2015). Competition in electricity markets with renewable energy sources. Working paper, Massachusetts Institute of Technology.

Böhringer, C. and M. Behrens (2015). Interactions of emission caps and renewable electricity support schemes. *Journal of Regulatory Economics 48*(1), 74–96.

Böhringer, C., H. Koschel, and U. Moslener (2008). Efficiency losses from overlapping regulation of EU carbon emissions. *Journal of Regulatory Economics 33*(3), 299–317.

Böhringer, C., A. Löschel, U. Moslener, and T. F. Rutherford (2009). EU climate policy up to 2020: An economic impact assessment. *Energy Economics 31, Supplement 2*, S295–S305. International, U.S. and E.U. Climate Change Control Scenarios: Results from EMF 22.

Böhringer, C. and K. E. Rosendhal (2011). Greening electricity more than necessary: On the cost implications of overlapping regulation in EU climate policy. *Schmollers Jahrbuch 131*(3), 469–492.

Bunn, D. W. and C. Fezzi (2007). Interaction of European carbon trading and energy prices. Technical report, Fondazione ENI Enrico Mattei. FEEM Nota di Lavoro 63.2007.

Carmona, R., M. Fehr, J. Hinz, and A. Porchet (2010). Market design for emission trading schemes. *SIAM Review 52*(3), 403–452.

Chesney, M. and L. Taschini (2012). The endogenous price dynamics of emission allowances and an application to CO_2 option pricing. *Applied Mathematical Finance 19*(5), 447–475.

Fabra, N. and M. Reguant (2014). Pass-through of emissions costs in electricity markets. *American Economic Review 104*(9), 2872–2899.

Fabra, N. and J. Toro (2005). Price wars and collusion in the Spanish electricity market. *International Journal of Industrial Organization 23*(3-4), 155–181.

Fischer, C. and L. Preonas (2010). Combining policies for renewable energy: Is the whole less than the sum of its parts? *International Review of Environmental and Resource Economics 4*(1), 51–92.

Frankfurt School-UNEP Collaborating Centre for Climate & Sustainable Energy Finance and Bloomberg New Energy Finance (2015). Global trends in renewable energy investment 2015. Technical report, United Nations Environment Programme.

Grimm, V. and G. Zoettl (2013). Investment incentives and electricity spot market competition. *Journal of Economics & Management Strategy 22*(4), 832–851.

Hintermann, B. (2016). Pass-through of CO2 emission costs to hourly electricity prices in Germany. *Journal of the Association of Environmental and Resource Economists forthcoming.*

Koch, N., S. Fuss, G. Grosjean, and O. Edenhofer (2014). Causes of the EU ETS price drop: Recession, CDM, renewable policies or a bit of everything?−New evidence. *Energy Policy 73*, 676–685.

Morthorst, P. E. (2001). Interactions of a tradable green certificate market with a tradable permits market. *Energy Policy 29*(5), 345–353.

Murphy, F. and Y. Smeers (2012). Withholding investments in energy only markets: Can contracts make a difference? *Journal of Regulatory Economics 42*(2), 159–179.

Murphy, F. H. and Y. Smeers (2005). Generation capacity expansion in imperfectly competitive restructured electricity markets. *Operations Research 53*(4), 646–661.

Sijm, J., K. Neuhoff, and Y. Chen (2006). CO_2 cost pass-through and windfall profits in the power sector. *Climate Policy 6*(1), 49–72.

Tellidou, A. C. and A. G. Bakirtzis (2007). Agent-based analysis of capacity withholding and tacit collusion in electricity markets. *IEEE Transactions on Power Systems 22*(4), 1735–1742.

Financial Times (2015, August). Renewable Energy Sector Runs the Risk of Overpowering Market. August 3rd, 2015.

The Economist (2013, October). European Utilities: How to Lose Half a Trillion Euros. October 12th, 2013.

The Economist (2015, November). Special Report on Climate Change: Hot and Bothered. November 28th, 2015.

Zachmann, G. and C. von Hirschhausen (2008). First evidence of asymmetric cost pass-through of EU emissions allowances: Examining wholesale electricity prices in Germany. *Economics Letters 99*(3), 465–469.

Zöttl, G. (2011). On optimal scarcity prices. *International Journal of Industrial Organization 29*(5), 589–605.

Appendix

Electricity producer's expected profit

The electricity producer's expected profit is

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

where $\Omega = A_1 \cup A_2 \cup A_3$.
Let D be normally distributed with mean μ and standard deviation σ and recall that fixed costs are defined as

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

Let us now consider Eq. (2), Eq. (3), and Eq. (4), which report the expressions of G in events A_1, A_2, and A_3, respectively. Substituting those expressions, we obtain

$$\begin{aligned} \mathbb{E}(G|A_1) &= \int_{A_1} G(\omega) d\mathbb{P}(\omega) \\ &= \int_{A_1} -FC - c_a \min(H; Q_c + Q_c^*) d\mathbb{P}(\omega) \\ &= \left(-FC - c_a \min(H; Q_c + Q_c^*)\right) \int_{A_1} d\mathbb{P}(\omega) \\ &= \left(-FC - c_a \min(H; Q_c + Q_c^*)\right) \mathbb{P}(A_1), \end{aligned}$$

$$\begin{aligned} \mathbb{E}(G|A_2) &= \int_{A_2} G(\omega) d\mathbb{P}(\omega) \\ &= \int_{A_2} -FC - c_a \min(H; Q_c + Q_c^*) + \left(c_{v,c} - c_{v,nc}\right)\left(Q_{nc} + Q_{nc}^*\right) d\mathbb{P}(\omega) \\ &= \left(-FC - c_a \min(H; Q_c + Q_c^*) + \left(c_{v,c} - c_{v,nc}\right)\left(Q_{nc} + Q_{nc}^*\right)\right) \int_{A_2} d\mathbb{P}(\omega) \\ &= \left(-FC - c_a \min(H; Q_c + Q_c^*) + \left(c_{v,c} - c_{v,nc}\right)\left(Q_{nc} + Q_{nc}^*\right)\right) \mathbb{P}(A_2), \end{aligned}$$

and

$$
\begin{aligned}
\mathbb{E}(G|A_3) &= \int_{A_3} G(\omega) d\mathbb{P}(\omega) \\
&= \int_{A_2} -FC + (\beta mf - c_a)\min(H; Q_c + Q_c^*) d\mathbb{P}(\omega) \\
&+ \int_{A_2} (\beta - 1)\, mf\, (D(\omega) - Q_{nc} - Q_{nc}^* - H)\, d\mathbb{P}(\omega) \\
&+ \int_{A_2} (\beta mf + c_{v,c} - c_{v,nc})\,(Q_{nc} + Q_{nc}^*)\, d\mathbb{P}(\omega) \\
&= (-FC + (\beta mf - c_a)\min(H; Q_c + Q_c^*) + (\beta mf + c_{v,c} - c_{v,nc})\,(Q_{nc} + Q_{nc}^*))\,\mathbb{P}(A_3) \\
&+ \int_{A_2} (\beta - 1)\, mf\, (D(\omega) - Q_{nc} - Q_{nc}^* - H)\, d\mathbb{P}(\omega) \\
&= (-FC + (\beta mf - c_a)\min(H; Q_c + Q_c^*) + (\beta mf + c_{v,c} - c_{v,nc})\,(Q_{nc} + Q_{nc}^*))\,\mathbb{P}(A_3) \\
&+ (1 - \beta)\, mf(Q_{nc} + Q_{nc}^* + H)\mathbb{P}(A_3) \\
&+ \int_{A_3} (\beta - 1)\, mf D(\omega) d\mathbb{P}(\omega).
\end{aligned}
$$

Therefore

$$
\begin{aligned}
\mathbb{E}(G) = &- \Big(c_{f,c}\,(Q_c + Q_c^*) + c_{f,nc}\,(Q_{nc} + Q_{nc}^*) + \alpha\,(Q_{nc} + Q_{nc}^*)^2\Big) - c_a \min(H; Q_c + Q_c^*) \\
&+ (c_{v,c} - c_{v,nc})\,(Q_{nc} + Q_{nc}^*)\,\mathbb{P}(A_2) \\
&+ (\beta mf \min(H; Q_c + Q_c^*) + (\beta mf + c_{v,c} - c_{v,nc})(Q_{nc} + Q_{nc}^*) + (1 - \beta)\, mf\, (Q_{nc} + Q_{nc}^* + H))\mathbb{P}(A_3) \\
&+ \int_{A_3} (\beta - 1)\, mf D(\omega) d\mathbb{P}(\omega).
\end{aligned}
$$

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.

$$
- \Big(c_{f,c}\,(Q_c + Q_c^*) + c_{f,nc}\,(Q_{nc} + Q_{nc}^*) + \alpha\,(Q_{nc} + Q_{nc}^*)^2\Big) - c_a \min(H; Q_c + Q_c^*),
$$

is included also in the expressions of G in events A_2 and A_3, therefore it appears with probability 1 in the expression of the expected profit. Substituting the density function of the normally distributed demand D, we can re-write the expected profit as

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

We observe from Eq. (1) that $c_a = mp_a = mf\left(1-\frac{1}{\sigma\sqrt{2\pi}}\int_{-\infty}^{Q_{nc}+Q_{nc}^*+H}e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}dx\right)$, therefore the expected profit becomes

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

which can be further simplified into

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

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 behaviour of $\mathbb{E}(G)$ as Q_c^* and Q_{nc}^* tend to the extremes of their domains (see the constraints of Problem (7)). Recalling that $c_{v,c} - c_{v,nc} > 0$ and $\beta \in [0, 1]$, we obtain

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

since R tends to 0 as Q_{nc}^* tends to $+\infty$, and

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

which is a negative number. Besides, we have

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

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

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

which is a real number.

The analytic expression of the derivative of $\mathbb{E}(G)$ with respect to Q_{nc}^* is

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

which can be further simplified to

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

We now consider the derivative of $\mathbb{E}(G)$ with respect to Q_c^*. Neglecting the case $Q_c + Q_c^* = H$, where $\frac{\partial}{\partial Q_c^*} \min(H; Q_c + Q_c^*)$ does not exist and which occurs with probability 0, we focus our attention on the two cases $H < Q_c + Q_c^*$ and $H > Q_c + Q_c^*$:

1. if $H < Q_c + Q_c^*$, then
$$\frac{\partial \mathbb{E}(G)}{\partial Q_c^*} = -c_{f,c},$$
since $\frac{\partial}{\partial Q_c^*} \min(H; Q_c + Q_c^*) = \frac{\partial}{\partial Q_c^*} H = 0$;

2. if $H > Q_c + Q_c^*$, then

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

since $\frac{\partial}{\partial Q_c^*} \min(H; Q_c + Q_c^*) = \frac{\partial}{\partial Q_c^*}(Q_c + Q_c^*) = 1$.

In Section 4, we present some numerical applications, and comment on the corresponding solutions of the capacity expansion problem.

Electricity demand net of non-conventional auto-generation

Currently, a significant amount of non-conventional electricity is generated and consumed by small businesses and households. Investments in small renewable plants (e.g. photovoltaic, micro-wind generation, etc.) can be quite attractive: generous incentives reduce the capital costs, plants have virtually zero variable costs, and unused electricity can be sold.

We do not explicitly model non-conventional capacity investments of small businesses and households. Rather, we assume that such a generation is self-consumed and uncertain. Therefore the impact of this generation can be captured by an appropriate change of the variable representing (net) electricity demand. This allows us to preserve the tractability of the model.

Let Q_{nc}^h represent the aggregate, uncertain, and self-consumed generation of non-conventional electricity. We assume it is distributed as a normal random variable with mean μ_h and standard deviation σ_h. We can express net electricity demand as

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

where D and Q_{nc}^h are jointly normally distributed and ρ is the linear correlation coefficient between D and Q_{nc}^h. This coefficient can be assumed as loosely positive, since investments are in general positively correlated with economic growth (which is indeed well approximated by the levels of D).

We consider four different levels for the mean μ_h and set $\sigma_h = 10$, $\rho = \frac{1}{6}$, and $D \sim \mathcal{N}\left(200, 30^2\right)$. Therefore net electricity demand D_n has normal distribution $\mathcal{N}\left(200 - \mu_h, 30^2 + 10^2 - 2 \times \frac{1}{6} \times 30 \times 10\right)$, i.e. $\mathcal{N}\left(200 - \mu_h, 30^2\right)$. Finally, the remaining settings about Q_c, Q_{nc} and H are the same as those in Table 3. Table 7 summarises the impact of Q_{nc}^h on the optimal capacity expansion in the three stylised stages of an ETS. We capture the impact of Q_{nc}^h reporting the optimal expansion of non-conventional capacity Q_{nc}^*.

Unsurprisingly, the electricity producer offsets a lower net electricity demand (due to a larger expected non-conventional self-consumed generation) by reducing its non-conventional capacity.

Table 7: Optimal expansion of non-conventional capacity for varying μ_h of Q_{nc}^h

	Q_{nc}^*			
Scenario	$\mu_h = 0$	$\mu_h = 10$	$\mu_h = 20$	$\mu_h = 50$
Early stage - degenerate[a]	58	51.9	48	-
Early stage - normal[a]	135	125.5	117.3	92.9
Maturity stage	-10	-17.1	-23.1	-33.3
System rejection	-63	-71.4	-80	-105.1

[a] The early stage is characterized by two (local) optima, which were labelled as normal and degenerate (see Section 4.1.1).

Allowance value at time $\tau \in (0, T)$

Let us consider the case where at time $t = 0^+$ electricity demand up to an intermediate time $\tau \in (0, T)$ is revealed. Under normal circumstances, i.e. emissions in $[0, \tau]$ have not exceeded the cap, p_a^τ is in the interval $(0, f)$ and the upper rectangle of profits in Figure 2 has an area equal to

$$0 < \beta m p_a^\tau (Q_{nc} + Q_{nc}^* + H) < \beta m f (Q_{nc} + Q_{nc}^* + H).$$

Therefore the profits are proportional to p_a^τ and they are not vanishing. Thus, as long as the allowance price is positive, our analysis and our results hold for any intermediate time $\tau \in (0, T)$.

Allowances and expected electricity prices under three market scenarios of an ETS

Figure 10 represents the allowances price as a function of non-conventional capacity expansion. In each market scenario, the degenerate optima (including the unique optima of the maturity stage and the system rejection) yields an allowances price that is significantly positive. This is because, in the 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, the allowances price increases from the early stage to the system rejection, as the sum of non-conventional and covered conventional generation falls, thereby increasing the probability that further purchases of allowances will be necessary (thus driving up the price). For example, the price of allowances generated by the early stage degenerate optimum, with a total covered generation of around 198 MWh[15] compared to an expected demand of 200 MWh, is 52 €/e. But the allowances price generated by the unique optimum in the system rejection is a whopping 90 €/e, because total covered capacity dropped to 167 MWh due to dismantling of non-conventional capacity.

The exception to this rule of significantly positive allowances prices is the early stage normal optimum. In the normal optimum, the price of allowances is very close to 2 €/e. This is not

[15] 20 MWh installed non-conventional, 58 MWh new non-conventional, and 120 MWh covered conventional capacity.

surprising, as total covered generation is equal to around 275 MWh (20 MWh installed non-conventional, 135 MWh new non-conventional, and 120 MWh covered conventional capacity), which greatly exceeds the expected demand of 200 MWh. Notice that an allowances price of nearly 2 €/e is rather close to the European Union ETS allowances (EUA) price observed during 2007, i.e. the end of the first period of life of the European Union ETS.

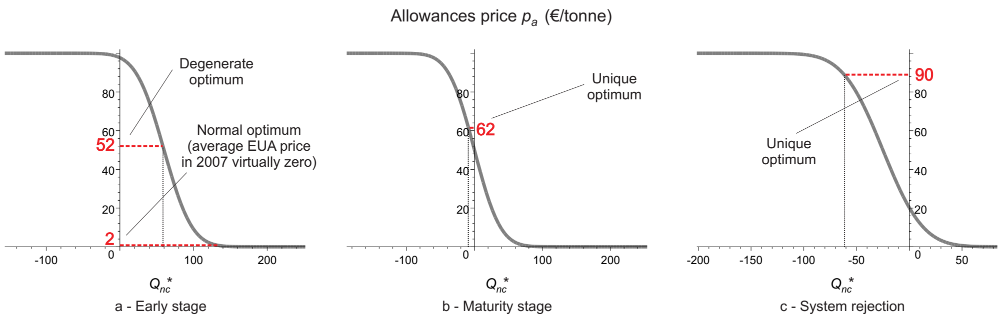


Figure 10: Allowances price p_a (in €/e) for various expansion decisions of the non-conventional capacity Q^*_{nc}. Panel a refers to the early stage, panel b to the maturity stage, and panel c to the system rejection.

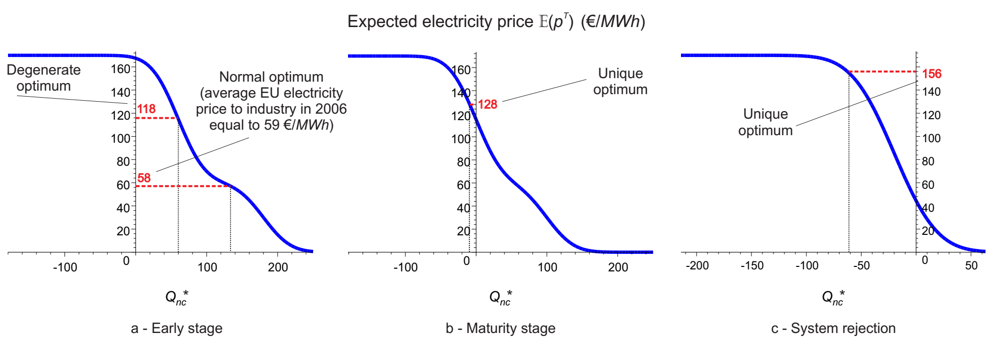


Figure 11: Expected electricity price $\mathbb{E}(p^T)$ (in €$/MWh$) for various expansion decisions of the non-conventional capacity Q^*_{nc}. Panel a refers to the early stage, panel b to the maturity stage, and panel c to the system rejection.

Figure 11 represents the electricity price as a function of non-conventional capacity expansion. The price increases as we pass from the early stage to the system rejection. Divestment (or withholding of non-conventional investment) drives the price up. As previously observed, this result is due to the increasing allowances price (combined with an assumed complete allowances cost pass-through, $\beta = 1$). The only exception to this finding occurs in the context of the early stage normal optimum. Here, green and covered conventional capacity (about 275 MWh) cover demand almost in full, leaving a near-zero probability of non-compliance; consequently, the allowances price is virtually zero and electricity prices are lower.