Strategic investment decisions under the nuclear power debate in Belgium

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Abstract

In view of the current nuclear power debate in Belgium, we analyze how uncertainty about a nuclear phase-out, coupled with the implementation of renewable energy subsidies and nuclear taxes, affects investment capacity and productivity decisions by Belgian electricity suppliers. To achieve this goal, considering the market shares of the Belgian market, we build a Stackelberg two-step equilibrium model in which investment decisions are made in a first step under uncertainty regarding a nuclear phase-out, and productivity decisions are subsequently made in a second step for different investment possibilities found in the first step. Our analysis indicates that, regardless of subsidies, an increase in the probability of nuclear license extension results in lower levels of investment - primarily in renewable energy -. These lower investment levels in turn result in a lower total production and a higher electricity price in a subsequent period in the future. We also show that the implementation of renewable energy subsidies reduces the effect of an increase in probability of nuclear license extension on producer's decisions regarding expanded capacity and therefore, on total future profits in the market.

Keywords

electricity market, capacity investment decisions, stackelberg-based model, sequential two-step model, uncertainty nuclear production, renewable energy subsidies.

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C72, L94, L10, Q40, Q48

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1. Introduction

The Belgian electricity market is characterized by high dependence on nuclear energy and a dominant market position by one of the market players that operates all the nuclear plants in Belgium. Since 2003, the Belgian government seems committed to a nuclear phase-out. However, recently, the government extended the operational license permits of the three oldest nuclear power plant units from 2015 to 2025 because of a highly likely shortage of electricity supply. In view of this uncertainty regarding a nuclear phase-out and the EU's Renewable Energy Directive, ensuring security of supply and a stable investment climate has become an important challenge for decision makers. The goal of this study is to analyze how uncertainty about a nuclear phase-out, coupled with the implementation of renewable energy subsidies and nuclear taxes, affects the investment capacity and productivity decisions of electricity suppliers in Belgium.

In this context, a number of studies have already been conducted on the future of Belgian power generation and the optimal electricity mix (see Albrecht and Laleman (2014), Van Wortswinkel and Lodewijks (2012)). Van Wortswinkel and Lodewijks (2012) applied the Belgian TIMES model, which is a techno-economic, partial equilibrium model of the energy system, to the case of the Belgian region of Flanders, with the purpose of supporting the model user in their decision-making on cost-optimal energy. Through a model similar to the PRIMES[1] model, (Albrecht and Laleman, 2014) investigated policy trade-offs for the Belgian electricity system and concluded that (i) market participation by renewables is essential for an affordable and sustainable energy mix in the future, (ii) a higher share of renewables will result in higher overall system costs in future decades, and (iii) the feedstock costs of biomass will be the main driver in the overall costs of any energy mix involving a high share of renewable energy (RE) technologies.

Indeed, most of the economic literature about electricity market structure and production decisions is based on partial and general equilibrium models (Albrecht and Laleman (2014); Van Wortswinkel and Lodewijks, 2012), in which the main model assumption is that individual suppliers of the electricity market assume

[1] The PRIMES energy model simulates the European energy system through a multi-market equilibrium solution for energy supply and demand (Capros, 1998).

perfect competition; that is, they consider that no single firm can influence the market price. However, in reality, proper market models must deal with imperfectly competitive markets (see Ventosa et al., 2005 for a review), that is, suppliers can take a strategic position to influence the market price and, thereby, the total electricity generation capacity in the market. As explained above, the Belgian electricity market is characterized by a dominant firm which accounts for 60% of the installed capacity, including all nuclear plants. Even if there is no explicit proof of the market power by individual firms, we consider that to assume that individual firms can influence market price and that the dominant firm can act as market leader, as suggested by market shares, could be considered as an interesting case of study and a contribution to the existing literature of strategic behavior in electricity markets[2]. In order to take into account this fact within the modelling, we have developed a Stackelberg-based model in which there is one leader firm, who is the first to take decisions, and one follower, who chooses subsequently. Both leader and follower compete in quantities. Additionally, assuming that the European market is not fully integrated, as concluded in recent studies (cf. Böckers and Heimeshoff, 2014; Glachant and Ruester, 2014; de Menezes and Houllier, 2016), and reducing the complexity of the model, we have simulated the Belgian market as an autarky[3], and thereby, trade of electricity is not considered here. To the best of our knowledge, this equilibrium concept has not so far been introduced in the current models of electricity mix forecast for the Belgian case.

Moreover, as described in the first paragraph, we consider important characteristics of the Belgian electricity market context, such as policy uncertainty regarding nuclear phase-out. Indeed, the vast majority of the previous papers considers uncertainty on demand and prices as the main sources of uncertainty on electricity markets, while policy uncertainty is often neglected. Centeno et al. (2003) pointed out the difficulties in

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[2] We clarify that this scientific work does not suggest that players are undertaking illegal activities or that there is active coordination between players to set prices. There is extensive literature on tacit collusion and game theory illustrating how strategic behavior can arise in electricity markets without coordination. This paper should be seen as a contribution to this strain of literature, that is, tacit collusion can exist in European markets without legal consequences, as explained in (Petit, 2013).

[3] We acknowledge that this assumption is a simplification of the reality. However, taking into account that the European market is not fully integrated and that some elements, such as national emission targets will likely impact the electricity price convergence in EU countries, this work remains an interesting case of study at country level, from and economic and practical point of view.

accounting for uncertainty in large-scale problems. In this paper, we focus on the uncertainty about a nuclear phase-out and how this uncertainty influences new investments in clean technologies in the Belgian electricity market. In particular, production and additional investment capacity strategies in equilibrium are analyzed in a two-step sequential optimization model. Closed-loop dynamic models would be more suitable to represent the real decision process in the electricity market according to Wogrin et al. (2013). However, in this specific case, we use a two-step sequential optimization model, instead of a closed-loop dynamic game, in order to consider all the technologies and firms on the market, better reflect the decision flow that takes place in a real-life situation, and simplify the computational process. In our study, in a first step, firms decide about their investment capacity decisions under different probabilities of nuclear license extension, and, subsequently, in a second step, firms decide about their yearly production hours, in an environment with certainty about their current installed capacities, i.e., taking into account the results of the first step. We show that in the short term, higher production quantities and lower prices are reached in a certainty environment in which the extension of nuclear permits is guaranteed, as compared to the case of a definitive nuclear phase-out. However, in the long term, investments in renewables (and therefore production) increase when the probability of nuclear license extension decreases, reaching the maximum levels when definitive nuclear phase-out is anticipated. Finally, we analyze these previous results, with and without considering the implementation of renewable subsidies and nuclear taxes. We show that the presence of renewable energy subsidies plays a fundamental role in the overall entirety of electricity mix and strategic positioning of electricity producers.

The paper is organized as follows. Section 2 presents an overview of the Belgian electricity market context, including the specific nuclear policy framework, as well as power market characteristics and related literature. In Section 3, we describe the model, followed by an explanation of model parameters and assumptions in Section 4. Model results are presented in Section 5, and, finally, the paper is concluded and discussed in Section 6.

2. The Belgian context: Nuclear policy framework, power market characteristics and related literature

2.1. Legislative framework about nuclear phase out

Belgium currently has seven nuclear reactors, the first of which became operational in 1974. Engie Electrabel operates all seven nuclear units and owns three of the units outright, as well as 89.8% of another three (the remaining 10.2% are owned by EDF Luminus). Electrabel jointly owns the remaining unit with France's EDF.

On 31 January 2003, the Belgian Senate approved the Federal Act which prohibited the building of new nuclear power plants and limited the operating lives of existing ones to 40 years, effectively shutting down 30% of the country's nuclear capacity in 2015 (Belgian Federal Government, 2003; International Energy Agency, 2016; World Nuclear Association, 2016). In 2007, however, the Commission on Energy 2030, in its final report, advised keeping the nuclear option open and reconsidering the nuclear phase-out as it would be extremely expensive and greatly unsettling for the economy under post-Kyoto constraints and in the absence of Carbon Capture and Storage (D'haeseleer et al., 2007). This advice was repeated two years later in the government-commissioned report from GEMIX on the ideal energy mix for Belgium (Groep GEMIX, 2009). Moreover, the same Commission on Energy 2030 report defined four priorities to guarantee security of supply, the following two of which are the most relevant in the framework of this study. Firstly, the Commission identified diversity of supply of primary sources and technologies (type and origin) as a first and foremost rule. Secondly, they stated that a stable investment climate must be guaranteed for competitive market players to have timely and sufficient new electricity generation capacity and to retain a substantial refinery capacity (D'haeseleer et al., 2007), a recommendation that was reiterated in the GEMIX report (Groep GEMIX, 2009).

In 2009, based on the GEMIX report, the Belgian government decided to postpone the phase-out of the oldest reactors by 10 years, until 2025. However, new elections took place in 2010 before the postponement was passed by Parliament and the phase-out remained in place as originally planned, i.e. for 2015.

In December 2011, the government confirmed that it would close the nuclear power plants in accordance with the phase-out law of 2003. At the same time, wholesale prices were too low and policy uncertainty too high to trigger investments in other baseload capacity (International Energy Agency, 2016). This coincided with the unforeseen long outages at two units from mid-2012 onwards due to the detection of thousands of quasi-laminar flaws in the forged rings of the reactor vessels (FANC, 2015). As security of supply came under heavy pressure, the government, with the approval of the Nuclear Safety Authority, extended the long-term operation of the three oldest nuclear power plant units from 2015 to 2025, in combination with a number of other measures (International Energy Agency, 2016).

However, the extension of the operational license for these three nuclear plants has not solved the issue of security of supply. It has merely postponed it to 2022-25 when the remaining four plants will be shut down, as foreseen under the current policy. The International Energy Agency recommends that the government seriously consider what would be the optimal policy for securing affordable low-carbon electricity. It suggests that allowing the nuclear plants to run for as long as they are considered safe by the regulator would ease pressure on security of electricity supply. The extension of the nuclear license would also reduce the costs of electricity generation in the medium term and likely reduce the costs of the phase-out itself (International Energy Agency, 2016). This recommendation is in line with the recommendation formulated in the European Commission's Energy Road Map 2050 (European Commission, 2012) which states that nuclear energy will be required to provide a significant contribution to the energy transformation process in those Member States where it is pursued, as it remains a key source of low carbon electricity generation. In the meantime, the uncertainty about the nuclear phase-out still does not create a stable investment climate for competitive market players to diversify the primary power generation sources. In August 2017, the Federation of Enterprises in Belgium advocated more realism about the timing to close all nuclear plants

(Belga, 2017a). And in October 2017, Belga (Belga, 2017b) reported that the current draft of the Energy Pact, the energy consultation between the Federal government and the regions, does not make mention anywhere about the feasibility of the nuclear phase-out. The fact that the issue of the nuclear phase-out keeps reappearing in the news on a regular basis indicates the importance of our research topic.

In this context, we will analyze how investment capacity decisions by electricity suppliers in Belgium are influenced by an increase in the probability of extending the nuclear license, and how these results are affected by the implementation of environmental energy policies, such as nuclear tax or renewable subsidies. In what follows, we briefly describe the background of nuclear taxes and subsidies for renewables in Belgium.

2.1.1. Nuclear Taxes

Two types of nuclear tax exist in Belgium, i.e. the annual fee and the nuclear tax.

The annual fee is levied as the counterpart of the extension of the nuclear license and was established under the Federal Act of 31 January 2003, where it was decided that the operators of the three oldest nuclear plants should pay an annual fee. This fee is allocated to the 'Energy Transition Fund' and amounts to €20 million per year per reactor (Belgian Federal Government, 2003; JVH, 2016).

The nuclear tax is a repartition contribution levied by the Belgian Federal Government since 2008 for nuclear plant operators, targeting the four newest nuclear plants. The contribution is calculated based on the capacity of the installations and changes annually as a function of the profits generated by electricity production through nuclear fission. Contrary to the annual fee, this contribution is mainly aimed at funding the State's energy policy – it is allocated to the General State Budget - and at increasing competition on the electricity market. The repartition contribution amounted to €200 million in 2015 (Synatom, 2016).

2.1.2. Renewable Energy Subsidies

Tax and non-tax incentives in favor of renewables (RE) have been introduced both at the federal level and at the regional level. On the one hand, the Federal government has adopted different tax incentives, such as tax credit for research and development and green investment tax deduction. On the other hand, the three regions in the country have introduced a wide range of non-tax incentives, ranging from support systems for research and development, ecology and energy premiums, to a system of green certificates, allowing producers of RE sources to receive a complementary price for their sales of RE (CREG, 2010). The system works on the basis of green energy quotas, which transmission system operators are required to purchase. The price of the certificates is determined by the market, but a minimum price is guaranteed (Belgian Federal Government, 2002; Flemish Government, 2009).

Once our research question is justified, in the following section, we will describe the market power characteristics of the Belgian Electricity market, the related literature to market power and uncertainty in oligopolistic models, as well as the implication of both in the structure of the model, which is described in Section 3.

2.2 Market power characteristics

As is the case for most of the electricity industry in Europe, the Belgian electricity market is vertically unbundled. Transmission and distribution of electric power are regulated natural monopolies. Electricity generators and electricity suppliers operate in a liberalized market environment. Currently, the electricity market is an energy-only market (KU Leuven Energy Institute, 2015). The wholesale market consists of an Over The Counter (OTC) market and the spot market, which is made up of the Belpex Day-Ahead Market (DAM) and the Belpex Continuous Intraday Market (CIM) (Liebl, 2013). According to the KU Leuven Energy Institute (2015), in 2013, the total traded volume on the Belpex DAM amounted to 17.1 TWh, or 21% of the Elia[4] grid load, and a total of about 0.6 TWh was traded on the Belpex CIM, or 1.5% of the Elia grid load. Even though the majority of the traded electricity volume is settled through OTC contracts, the

[4] Elia is Belgium's high-voltage transmission system operator (30 kV to 380 kV), operating over 8000 km of lines and underground cables throughout Belgium.

DAM is of fundamental importance as a benchmark and reference point for other markets, such as OTC or forward markets (Grimm et al., 2008). Therefore, we model the capacity and production decisions of the electricity market through a two-step sequential game, as suggested by Murphy and Smeers (2005) and other authors, using Belpex DAM data.

Moreover, the Belgian electricity market is characterized by two specific features that have a substantial influence on the functioning of the market. These are presented in Table 1.

<< insert Table 1: Overview of Belgium's existing power generation structure (Elia, 2016a) >>

First of all, there is a high dependence on nuclear energy, with this technology being responsible for over 30% of the current total installed power generation capacity. The second biggest technology is the closed cycle gas turbine (CCGT), which accounts for almost 24% of the total installed capacity, followed by solar photovoltaic (PV) at 15%. Secondly, one player, i.e. Engie Electrabel, holds a dominant market position with more than 58% of this current capacity, including the nuclear reactors. None of the other market players hold a share of more than 5% of the total installed capacity. From this context, taking into account that strategic behavior can arise in electricity markets, we can assume a situation of imperfectly competitive oligopolistic market. In particular, market shares suggest a leader-follower approach in which the leader firm has a dominant position in the market. Moreover, we can also assume that remaining small firms act as one player (the follower).

Finally, the Belgian electricity grid is connected to the rest of Europe with the objective of reaching integration of EU electricity markets. However, as argued by Böckers and Heimeshoff (2014) and concluded in recent studies (de Menezes and Houllier, 2016; Glachant and Ruester, 2014), the "hypothesis of a fully integrated European power market cannot be supported". In addition, CREG (2017) states that, despite the progressive market coupling, there was no price convergence in the Central-Western European region in 2017 and that the trend of diverging prices continued well into 2018. Indeed, previous arguments do not mean that the Belgian electricity market is a real autarky, but it would probably also not be correct to simulate it as a fully integrated market, even with the available interconnection capacities. Finally, de

Menezes and Houllier (2016) and Glachant and Ruester (2014) argue that other elements, such as national emission targets, demand management, different market mechanisms and regulations, will likely impact the electricity price convergence. Thus, taking into account the above-mentioned reasons, we argue that simulating the Belgian market as autarky and applying a Stackelberg game is a justifiable simplification, knowing that the reality is more complex and that trade might attenuate our results.

An overview of related literature on oligopolistic markets and market power is then needed in order to develop the design of our model. This is described in the following section.

2.2.1 Literature related to oligopolistic market models and market power

Most of the papers dealing with decision-making in imperfectly competitive oligopolistic markets, the most common situation, have developed Nash-equilibrium models (see Ventosa et al., 2005 for a review). This is a concept of game theory in which players (in this case, electricity suppliers) choose their optimal decision strategies based on the strategies of all the other players. Thus, players are in Nash equilibrium when each firm's strategy is the best response to the strategies employed by the other players.

In particular, the formulation of our electricity market model as a Nash-equilibrium game is based on production (e.g. Leibowicz, 2015) and investment capacity decision models (e.g Filomena et al., 2014; Genc and Sen, 2008; Murphy and Smeers, 2005) from the existing literature. We can mainly distinguish between open-loop (e.g. Leibowicz, 2015), one-stage decision games, and closed-loop games (e.g Filomena et al., 2014), two-stage or multi-stage decision games. Leibowicz (2015) couples a regional integrated assessment model and a one-shot (open-loop) Nash-equilibrium model to investigate how climate policy and learning spillovers interact with market electricity structure to affect production decisisions, and more specifically, renewable technology adoption and producer profits. Filomena et al. (2014) analyze the problem of production decisions, technology selection and capacity investment for electricity generation in a competitive environment under uncertainty concerning marginal costs, by using a closed-loop game, in which investment decisions are made in a first step under uncertainty and productions decisions are made in a second step, when the marginal cost is fixed.

Another possible classification among Nash-equilibrium models depends basically on the type and scope of decisions, and market power of the different agents. On one hand, Nash-Cournot models are more easy to represent and are suitable for markets in which it is assumed that all players have market power, and then, take decisions simultaneously. Stackelberg-based models, on the other hand, consider that one agent (i.e., Mathematical Program with Equilibrium Constraints (MPEC) models, e.g. Ventosa et al., 2002; Gabriel and Leuthold, 2010) or several ones (i.e., Equilibrium Program with Equilibrium Constraints (EPEC) models, e.g. Murphy and Smeers, 2005) can act as leaders of the market and then take decisions in a first place. Remaining firms (followers) take decisions subsequently in a Cournot manner. Murphy and Smeers (2005) compare long-term investment in generation capacity under different electricity market structures, namely perfect competition and oligopolistic markets, with dynamic interactions (open-loop and closed-loop Nash equilibria). The closed-loop equilibrium is a two-stage decision game, where the first stage is solved by an EPEC model. Ventosa et al. (2002) analyze expansion planning under imperfectly competitive conditions, by using an MPEC approach, where the leader firm decides its optimal new capacity, subject to a set of market equilibrium constraints.

Finally, we can distinguish between static and dynamic models, which consider dynamic interactions between players. In fact, most of the papers that analyze strategic investment decisions in competitive markets advocate the use of dynamic multi-period models (e.g Genc and Sen, 2008, Murphy and Smeers, 2005). Genc and Sen (2008) focus on investment capacity decisions in the electricity market in Ontario, Canada, by using the concept of S-adapted open-loop Nash equilibrium, a multi-period dynamic game with an uncertain demand price function. However, in these papers, authors have to make strong modelling assumptions due to the complexity of finding analytical solutions. For example, they consider a reduced number of technologies and/or periods, and players are typically assumed to be symmetric in the market.

As a result, although their findings are sound from a theoretical perspective, they have limits in terms of its application to specific study cases.

In this paper, we simplify this theoretical literature by considering a two-step sequential game of production and investment capacity decisions, but which takes into account all the producers and technologies on the Belgian market. Due to the characteristics of the Belgian market, we assume that there is one leader firm (Electrabel) and one follower (remaining firms), and therefore, we build a Stackelberg-based model with MPEC structure in both decision steps. Moreover, in order to deal with our research question concerning decision-making under nuclear policy uncertainty, we assume that investment decisions in the first step are made under uncertainty. In the second step, however, production decisions are taken in a certainty environment. In this context, in the next sextion, we briefly review the existing literature of uncertainty in oligopolistic market models.

2.2.2. Literature related to uncertainty in oligopolistic market models

Indeed, the vast majority of oligopolistic market models considers uncertainty regarding economic parameters such as demand (e.g Genc and Sen, 2008; Murphy and Smeers, 2005), prices (e.g. Schröder, 2014), or marginal costs (e.g. Filomena et al., 2014) as the main sources of uncertainty on electricity markets. For example, Schröder (2014) pointed out the importance of considering long-term uncertainty, in this case, more specifically, uncertainty about fuel and carbon prices, on the analysis of investment decisions.

However, little attention is paid to instability of investments caused by policy uncertainty, in particular uncertainty about the future of nuclear power. Recent studies have analyzed the impact of the German nuclear phase-out on Europe's electricity generation and electricity prices. On the one hand, Bruninx et al. (2013) estimate that nuclear generation will be replaced by coal generation, leading to an increase in CO_2 emissions. They hence argue for an extension of some nuclear plants' licenses. On the other hand, Nestle (2012) calls into question the reasons of the German government's decision concerning nuclear plants' license extension and the expected increase on overall prices in a context of nuclear phase-out. However, in these papers, uncertainty about the nuclear phase-out policy is not explicitly considered.

The contribution of our paper consists of the analysis of how this uncertainty influences new investments in clean technologies in the Belgian market. Uncertainty is introduced in the first step of our model, when investment decisions are taken. In particular, investment capacity decisions are made under different probabilities of nuclear license extension scenarios. These investment outputs are subsequently introduced in the second step of the model. In what follows, we present and describe in detail the modelling approach.

3. The Model[5]

The model starts from the assumption that a finite number of firms *N* have a finite number of technologies H at their disposal and have to optimally decide about their additional investment capacity possibilities $E_i(k)$[6] and their annual number of production hours, $Ph_i(k)$, per firm i and per technology k, taking into account uncertainty about nuclear license extension in the future. As each type of decision is in reality taken under different conditions, in other words, investment decisions are long-term decisions taken under uncertainty, while production decisions are short-term decisions, which are taken in a certainty environment concerning the installed capacity, we construct a two-step sequential model. More specifically, in a first step, expansion capacities are decided under uncertainty about the extension of nuclear license permits, that is, for different probabilities of nuclear license extension. Subsequently, production hours are decided for different possible expansion capacities scenarios found in the first step of the modelling, in a certainty environment, that is, knowing if the nuclear license has been extended or not.

Moreover, as explained in the previous sections, due to the market shares of the electricity market in the study area, we will assume a Stackelberg-based model for each step, in which there is a leader firm (L) that

[5] We would like to thank the anonymous referee for the important suggestions concerning the improvement of the modelling approach.
[6] We acknowledge that a firm can invest in a new technology that is part of the Belgian portfolio of technologies (see Table 1), even if it does not currently have any installations of that technology.

decides its optimal decision, and a follower[7] (F) that makes its optimal decision, knowing the capacity (in the first step) and the production hours (in the second step) of the leader. A summary of the flow of decisions in the model is illustrated in Figure 1. A detailed description of the two-step sequential model is explained in the following sections.

<< insert Figure 1: Decision process of the model >>

3.1. First step: Expansion capacity decisions

3.1.1. Model description

In a first step, firms aim to decide about their expansion in installed capacities, $E_i(k)$, which maximize their expected individual profit $\hat{E}(\pi_i)$ (in €), where π_i is defined as a discrete random variable that takes the value π_i^1 with probability γ (given) if license permits for nuclear power plants are extended, and π_i^2 with probability *(1- γ)* if not.

Let I={L, F} denote the set of firms in the market, K={1..H} denote the set of available technologies and S={1,2}, the set of probability scenarios concerning the extension of nuclear license permits,

$$\hat{E}(\pi_i) = \gamma * \pi_i^1 + (1-\gamma) * \pi_i^2, \qquad \forall i \in I, \forall k \in K, \qquad (1)$$

with

$$\pi_i^s = \sum_k \pi_i^s(k), \qquad \forall i \in I, \forall k \in K, \ \forall s \in S. \qquad (2)$$

and $\pi_i^s(k)$, the individual profit per probability scenario per technology.

[7] In order to simplify our Stackelberg-based model and due to the specific characteristics of the study area, the remaining firms have been merged in one actor (F, the follower). We acknowledge that in a Stackelberg-based model, followers decide in a Nash-Cournot competition model (or a Nash-Cournot game) in which a finite number of non-cooperative firms maximize their profits, taking into account the decisions of the other firms, (see Genc and Sen, 2008; Leibowicz, 2015). A Nash equilibrium for this game exists and can be derived from the optimality conditions of the model for each individual player.

Firstly, $\pi_i^s(k)$ is described in Equation (3) as the difference between the individual total income $TI_i^s(k)$ and the individual total cost $TC_i^s(k)$ per firm *i*, technology *k*, and probability scenario *s*,

$$\pi_i^s(k) = TI_i^s(k) - TC_i^s(k), \qquad \forall i \in I, \forall k \in K,\ \forall s \in S. \qquad (3)$$

If we describe the previous equation in detail,

$$TI_i^s(k) = Q_i^s(k) * \left(p^s + \mathrm{subs(k)}\right), \qquad \forall i \in I, \forall k \in K,\ \forall s \in S, \qquad (4)$$

where $Q_i^s(k)$ is the quantity of electricity produced (in MWh) (Equation (5)), p^s is the electricity price (in €/MWh) (Equation (7)), and subs(k) are subsidies received per technology (in €/MWh). In particular, we assume subs(k) > 0 for renewable technologies and subs(k) = 0 for others.

Moreover, the individual amount of electricity produced per technology $Q_i^s(k)$ (in MWh), for each probability scenario *s*, is the product of the annual quantity of production hours $Ph_i(k)$ (in hours/year) and the final installed capacity, $FIC_i^s(k)$ (in MW), which is described in Equation (6) as the sum of the current installed capacity $I_i^s(k)$ (in MW), and the additional investment in capacity per firm and technology, $E_i(k)$ (in MW),

$$Q_i^s(k) = Ph_i(k) * FIC_i^s(k), \qquad (5)$$

$$FIC_i^s(k) = I_i^s(k) + E_i(k), \qquad \forall i \in I, \forall k \in K,\ \forall s \in S. \qquad (6)$$

Note that, in order to distinguish between the different probability scenarios *s*, we consider $I_i^1(nuclear) > 0$ and $I_i^2(nuclear) = 0$.

Next, the electricity price p^s (in €/MWh) depends linearly on demand (see Equation (7)), where coefficients *a* and *b* will be estimated later by linear regression (see Section 4.3),

$$p^s = \mathrm{a} - \mathrm{b} * \textstyle\sum_{i,k} Q_i^s(k), \qquad \forall i \in I, \forall k \in K,\ \forall s \in S. \qquad (7)$$

Finally, as described in Equation (8), the individual total cost, per technology and probability scenario, $TC_i^s(k)$ (in €), is made up of four components. The first component corresponds to the variable cost depending on the amount of electricity produced per technology, in particular, the sum of $VC(k)$, and feedstock/fuel costs, $FSC(k)$ (both in €/MWh). The variable cost $VC(k)$ includes variable operational and maintenance costs. It is a production-related cost which varies with electrical generation/consumption, and excludes personnel, fuel and CO_2 emission costs. The second component corresponds to fixed operational and maintenance costs (excluding personnel and refurbishment costs) per technology $FC(k)$ (in €/MW), which depend on the final installed capacity $FIC_i^s(k)$. The third component consists of the capital expenditure, or investment cost, which is defined as a quadratic cost function with respect to additional investment capacity, $E_i(k)$ (in MW) with $CC(k)$, the unitary marginal investment cost per technology (€/MW^2). Finally, the last component consists of the tax $t(k)$, in this case only applicable to nuclear energy and solely dependent on whether or not the technology is being used. The total cost $TC_i^s(k)$ (in €) can then be described as follows:

$$TC_i^s(k) = (\mathrm{VC(k)} + \mathrm{FSC(k)}) * Q_i^s(k) + \mathrm{FC(k)} * FIC_i^s(k) + \mathrm{CC(k)} * \frac{E_i^2(k)}{2} + \mathrm{t}(k),$$

$$\forall i \in I, \forall k \in K, \ \forall s \in S. \qquad (8)$$

3.1.2. Model resolution

As explained above, the first step of the game is a two-stage game in itself, in the sense that the leader firm is the first to choose its expansion capacity per technology, $E_L(k)$, and, subsequently, the follower decides on its expansion capacity per technology, $E_F(k)$, knowing the decision of the leader.

We firstly formulate the first-order optimality conditions, also known as the Karush-Kuhn-Tucker (KKT) conditions, of the follower problem in the first step. These are the derivatives of the follower firm's objective functions $\hat{E}(\pi_F)$ with respect to decision variable $E_F(k)$ and will be used as a constraint of the "leader" main optimization problem.

The first step KKT conditions are then:

$$\frac{\delta\,\hat{E}(\pi_F)}{\delta E_F(k)} = \gamma\,\frac{\delta\,\pi_F^1}{\delta E_F(k)} + (1-\gamma)\frac{\delta\,\pi_F^2}{\delta E_F(k)} = 0 \qquad \forall k \in K, \tag{9}$$

with,

$$\frac{\delta\,\pi_F^s}{\delta E_F(k)} = \frac{\delta Q_F^s(k)}{\delta E_F(k)} * \left(p^s + \text{subs(k)}\right) + \frac{\delta p^s}{\delta E_F(k)} * \sum_k Q_F^s(k) - \frac{\delta TC_F^s(k)}{\delta E_F(k)}, \tag{10}$$

$$\frac{\delta Q_F^s(k)}{\delta E_F(k)} = Ph_F(k), \tag{11}$$

$$\frac{\delta p^s}{\delta E_F(k)} = -\text{b} * Ph_F(k), \tag{12}$$

and,

$$\frac{\delta TC_F^s(k)}{\delta E_F(k)} = Ph_F(k) * [\text{VC}(k) + \text{FSC}(k)] + \text{FC}(k) + \text{CC}(k) * E_F(k),$$

$$\forall k \in K,\ \forall s \in S. \tag{13}$$

Next, the problem of the leader is solved by means of a non-linear, MPEC structure, executed in GAMS using the MPEC solver (GAMS Development Corporation, 2010),

We can formulate the “leader” problem as follows:

$$\max_{E_i(k)} \hat{E}(\pi_L)$$

$$\text{s.t } (1)-(8)\ and\ (9)-(13),$$

$$\sum_i E_i\,(k) \le E_{max}(k),$$

$$\forall i \in I,\ \forall k \in K,$$

where $E_{max}(k)$ (in MW) represents the parameter of the maximum amount of expansion capacity per technology.

3.2. Second step: Production hours decisions

3.2.1. Model description

In a second step, firms decide on the amount of production hours $Ph_i(k)$ that maximize their individual profit π_i (in €), by knowing their final installed capacities, $FIC_i(k)$. More specifically, decisions are taken in a certainty environment in which the decision-makers know their final installed capacities, which correspond to the current installed capacities ($I_i^s(k), s = 1, 2$) plus the given expansion capacities found in the first stage of the model, $E_i^*(k)$. As, in this step of the model, the uncertainty concerning the nuclear license extension has been revealed, two situations are possible, nuclear license extension is now guaranteed ($s = 1$) or nuclear phase-out has been implemented ($s = 2$).

Thus,

$$FIC_i^s(k) = I_i^s(k) + E_i^*(k), \qquad \forall i \in I, \ \forall k \in K, \forall s \in S \qquad (14)$$

For each possible scenario s, model parameters and model equations (2)-(8) on individual profit π_i, individual total income TCI_i, individual amount of electricity produced Q_i, final installed capacity FIC_i, price-demand function $p(Q_i)$, and individual total cost TC_i per technology k, in the second step are then identical to those in the first step of the model. As scenario s is fixed at this step, and the model is deterministic, in what follows, we ignore the notation related to the probability scenario s.

3.2.2. Model resolution

As in section 3.1.2, we first formulate the KKT conditions of the follower firm F, which will be used as a constrant of the main "leader" problem in the second step.

The second step KKT conditions for the follower are the derivatives of π_F with respect to the decision variable $Ph_F(k)$:

$$\frac{\delta \pi_F}{\delta Ph_F(k)} = \frac{\delta Q_F(k)}{\delta Ph_F(k)} * \left(p + \text{subs}(k)\right) + \frac{\delta p}{\delta Ph_F(k)} * \sum_k Q_F(k) - \frac{\delta TC_F(k)}{\delta Ph_F(k)}, \qquad (15)$$

$$\frac{\delta Q_F(k)}{\delta Ph_F(k)} = FIC_F(k), \tag{16}$$

$$\frac{\delta p}{\delta Ph_F(k)} = -\mathrm{b} * FIC_F(k), \tag{17}$$

and,

$$\frac{\delta TC_F(k)}{\delta Ph_F(k)} = FIC_F(k) * [\mathrm{VC}(k) + \mathrm{FSC}(k)], \qquad \forall k \in K. \tag{18}$$

As in 3.1.2, we can formulate the “leader” problem as follows:

$$\max_{Ph_i(k)} \pi_L$$

$$\text{s.t } (1) - (8) \; and \; (14) - (18)$$

$$Ph_i(k) \leq Ph_{max}(k),$$

$$\forall i \in I, \forall k \in K,$$

where $Ph_{max}(k)$ represent the parameter of the maximum number of operating hours per year and per technology.

4. Model Parameterization and assumptions

4.1. Technology assumptions

The starting point of the model is the current capacity of the different technologies installed in Belgium for the leader firm and the follower firm (see Table 2). These data were obtained from Elia (Elia, 2016a).

Table 2 provides an overview of the most relevant economic parameter values, as well as assumptions made on maximum values of decision variables.

<< insert Table 2: Economic parameter values (left-hand side) and maximum values assumed for decision variables (right-hand side), per firm i and technology k >>

Data regarding capital investment costs $CC(k)$[8] and fixed and variable operational costs, $FC(k)$ and $VC(k)$ respectively, were taken from the ETRI Report (Joint Research Centre, 2014). Feedstock costs $FSC(k)$ were taken from Laleman et al. (2012) for all technologies except anaerobic digestion. For the latter technology, feedstock costs were calculated based on assumptions from a 2016 report by the Flemish Energy Agency VEA (Vlaams Energieagentschap, 2017).

The maximum amount of production hours per technology $Ph_{max}(k)$ was taken from Albrecht and Laleman (2014), while the maximum possible expansion capacity for all firms per technology $E_{max}\ (k)$ was derived from a number of sources. First of all, the maximum capacity for offshore wind was taken from the Elia study on adequacy and flexibility in the Belgian electricity system (Elia, 2016b). Secondly, the maximum expansion capacity for onshore wind production for Belgium was calculated in the following way. The maximum wind production potential (European Wind Energy Association, 2005), being 5 TWh per year, was divided by the maximum amount of full load hours to determine the maximum capacity. The present installed capacity $\sum_i I_i^s(k)$ was then detracted from the maximum final capacity $\sum_i FIC_i^s(k)$, resulting in the maximum possible expansion capacity $E_{max}\ (k)$, which was finally split into equal parts in order to obtain the maximum possible expansion capacity per firm. Similar calculations were conducted for solar PV technology. In this case, however, we estimated the maximum annual production by first calculating the potential for building integrated photovoltaics for Belgium (International Energy Agency, 2001), followed by the calculation of the energy produced each month by taking into account monthly solar irradiance and number of days per month. As described in the nuclear exit framework (see section 2.1), there will no further expansion of nuclear energy. Moreover, due to the commitments made by Europe to reduce CO_2 emissions, we assume that there will be no expansion in the capacity of coal-fired power plants (Elia, 2016b). Equally, as Belgium has very limited potential to increase its hydro capacity, we assume that there will be no expansion in the capacity of this particular technology either (Albrecht and Laleman, 2014). Finally, we assume that municipal solid waste incinerators are built with the objective of getting rid of the last non-

[8] We assume that investment costs are amortized over 20 years.

recyclable fraction of municipal waste and not with the objective of producing additional power. We therefore assume that the expansion in capacity of this particular technology will also be zero.

4.2. Nuclear taxes and renewable energy subsidies

Section 2.1.1 explains the details of the nuclear tax calculation. However, to reduce model complexity, we opted to use a lump sum of €250 million instead of a more complex calculation. This amount is the sum of nuclear taxes for all Belgian plants in 2008.

In order to reduce the complexity of the model, subsidies for renewable energy (RE) were set at €93 per MWh produced for all RE technologies, except for municipal solid waste incineration. In Flanders, this is the minimum amount of support for all RE installations with a starting date of 1 January 2013 independent of the type of RE technology that is used. This amount of support was set in articles 7.1.6 and 7.1.7 of the Energy Decree (Flemish Government, 2009). For installations with a starting date before 1 January 2013 the system is much more complex (see VREG, n.d. for an overview). Municipal solid waste incinerators also receive subsidies in Flanders, as part of the waste is considered as a 'renewable' energy source. This fraction consists of food waste, badly sorted paper and cardboard, etc. As the waste is not considered to be 100% renewable, subsidies amount to €60 per MWh produced (Pauwels, 2016). As energy subsidies are regionalized (see section 2.1.2), a different system exists for the region of Wallonia and Brussels-capital (Elia, 2016c). However, to reduce model complexity we opted to use the Flemish approach for all power production.

4.3. Electricity demand-price function

The electricity price is endogenously determined by the model through a linear demand-price function (see Equation 7). This demand-price function is based on Belpex data regarding average electricity price on the day-ahead market (in €/MWh) (Belpex, 2016) from 2006 to 2014. We used day-ahead (spot) market data because, as previously mentioned in Section 2.2, according to Grimm et al. (2008), the DAM price is of fundamental importance as benchmark and reference point for other markets. For each year of data, we calculated the average hourly quantity of electricity produced (in MWh) as well as the average hourly electricity price (in €/MWh). We then conducted a linear regression using the statistical computing language R (R Development Core Team, 2008, version 3.1.2), where coefficients a and b of Equation (7) were determined:

$$a = 49.74,$$

$$b = -0.001679.$$

Finally, as Belpex DAM data is available on an hourly basis and the simulations in our decision model are made on a yearly basis, we had to make the transition from hours (derived from the Belpex data) to years (calculated in the model) in the demand-price function. Therefore, in the function, we divided the total quantity of electricity produced $\sum_{i,k} Q_i^s(k)$ by 8760, i.e., the amount of hours in one year. The adapted function we use in the model simulations then becomes

$$p^s = 49.74 - 0.001679 * \sum_{i,k} Q_i^s(k)/8760$$

Similarly, seasonal demand-price functions are estimated and used to compute seasonal simulations in Section 5.3. We used the same Belpex DAM data for hourly prices and split up every year according to the different seasons. As to hourly load, contrary to the yearly simulation, we used Elia data on grid load[9]. As these data are available for every quarter of an hour, we summed these numbers to hourly load and calculated the average hourly quantity of electricity produced for every season of each year. We used total load instead of hourly Belpex DAM quantities as these amounts represent the total Belgian electricity demand. Similar to the hourly price demand function, we conducted a linear regression. In this case, we divided the total quantity of electricity produced per season by 2190, i.e., the amount of hours in each season, i.e., 3 months.

The adapted seasonal functions are:

[9] Available at http://www.elia.be/en/grid-data/data-download

$$p^{Winter} = 206.848 - 0.003833 * \sum_{i,k} Q_i^{Winter}(k)/2190,$$

$$p^{Spring} = 93.509 - 0.001413 * \sum_{i,k} Q_i^{Spring}(k)/2190,$$

$$p^{Summer} = 87.742 - 0.001411 * \sum_{i,k} Q_i^{Summer}(k)/2190,$$

$$p^{Fall} = 174.498 - 0.003242 * \sum_{i,k} Q_i^{Fall}(k)/2190.$$

4.4. Investment cost function

We assume a quadratic investment cost function to capture increasing costs of additional investments, which will stimulate firms to expand their portfolio using multiple technologies, and to obtain more qualitative results (Genc and Sen, 2008; Genc and Zaccour, 2011). These increasing costs capture, for instance, the effect that the best locations to invest in technologies such as wind or solar PV are taken first at a lower cost. Increased levels of investment will require additional efforts to find more suitable places and make them available for the generation of power. In particular, the investment cost function per firm and per technology is assumed to be convex and increasing with respect to investment capacity expansion $E_i(k)$. It has the following functional form:

$$d(k) * E_i(k) + e(k) * \frac{E_i^2(k)}{2},$$

with $d(k)$ and $e(k)$ positive parameters.

Because we do not have sufficient data to regress investment expenses with respect to additional investment capacity, we attribute all investment expenses to the quadratic term[10]. Thus, we assume *d(k) = 0* and *e(k) = CC(k)*, where *CC(k)* is the marginal unit investment cost per technology and is taken from the ETRI Report

[10] Other papers, such as Genc and Thille (2011), argued that this type of convex investment cost function may stem from adjustment costs, which are due to costs of installing and/or removing equipment.

(Joint Research Centre, 2014). As final results could be affected by this important assumption, a discussion of these cost parameters is provided in the scenario analysis in Section 5.3.

5. Results

In this section, we analyze how an increase in the probability of extending the nuclear license, coupled with the implementation of renewable (RE) subsidies and nuclear taxes, influences investment capacity (first step) and productivity (second step) decisions by electricity suppliers. We first look, in section 5.1, at the effect of an increase in the probability of extending the nuclear license, or, equivalently, a decrease in the probability of nuclear phase-out, on additional installed capacities. We also study, for the case in which nuclear license extensions have been finally guaranteed, annual production, prices and profits of Belgian electricity suppliers obtained in the second step of the model, for different investment choices made in a first previous step of the modelling. Simulated results are shown for different predefined probabilities of nuclear license extension, in the absence and presence of taxes and RE subsidies respectively. The benchmark scenario calculates the Stackelberg equilibrium with nuclear tax and RE subsidies, assuming that nuclear license permits will be extended in the future ($\gamma = 1$). We also look at a high ($\gamma = 0.75$), medium ($\gamma = 0.5$), low ($\gamma = 0.25$), and nil ($\gamma = 0$) probability for extension, the latter corresponding to a probability scenario in which we assume that nuclear phase-out will be guaranteed in the future. Next, in section 5.2, we look at the effect of the implementation of RE subsidies and nuclear taxes on simulated results, by comparing results without and with RE subsidies and nuclear taxes. Finally, in section 5.3, in order to improve the result quality of our production decision model (second-step model), simulations are computed by considering short-term demand (seasonal demand) for the two possible cases at the beginning of the second modelling step, that is, when the nuclear phase-out has been implemented or when nuclear license extensions have been guaranteed. Table 3 provides an overview of the main results. More detailed results can be found in the annexes.

<< insert Table 3: Overview of results for the different model scenarios >>

5.1. Effect of probability of extending the nuclear license

To understand the effects of an increase in the probability of extending the nuclear license, we compare model results for different predefined probabilities γ of extending the nuclear license for the case of RE subsidies and nuclear taxes, which corresponds to the current situation in Belgium (see rows 3-7 in Table 3).

First of all, we look at additional investments (or expansion) in installed capacity depending on the level of probability γ (see column 3 of Table 3). These are the results of the first modelling step (see more results in annex 10). We can see that lower probabilities of license extension result in higher investments in capacity. This is because, when the probability of extension is low, players expect that more non-nuclear capacity will be needed to fulfill demand and then, more investments take place. More specifically, Figure 2 shows how the leader and follower expand capacities depending on the level of probability γ (see also Annex 4 for detailed numbers).

<< insert Figure 2: Expansion in capacity (in MW) in function of the level of probability of nuclear license extension γ for the leader and follower >>

Again, a lower probability of extension corresponds to a higher level of expansions for both players. We can observe that, even if the follower has higher levels of capacity expansion as compared to the leader in order to be able to compete - and this for each level of γ -, the expansion by the leader is more greatly influenced by an increase in probability. For example, when probability of nuclear license extension increases from 0 (nuclear phase-out) to 1 (nuclear extension), expansion capacity decreases by 1 655 MW for the leader and 568 MW for the follower. The reason is that, with decreasing probability of extension, the leader, who owns all the nuclear capacity, is more inclined to further expand in order to compensate losses for the non-use of this nuclear capacity.

Next, Figure 3 presents the portfolio of technologies that are used for the expansion, for the different extension probability levels (see also Annex 2 for results per player and Annex 3 for results per technology).

<< insert Figure 3: Installed capacity expansion (in MW) per technology and probability level γ >>

First of all, the figure shows that expansion takes place in RE technologies only. In particular, we can distinguish between two groups: those technologies that use biomass as feedstock (i.e., anaerobic digestion, biomass CHP cogeneration and biomass grate furnace steam turbines), and those that do not use any feedstock, namely intermittent, non-flexible renewables (i.e., offshore and onshore wind turbines and solar PV). Moreover, the figure indicates that the largest expansion takes place in two technologies, i.e. biomass grate furnace steam turbines and offshore wind, and this for different reasons. On the one hand, offshore wind is a cheap technology in terms of LCOE[11] costs (see LCOE calculations in Annex 7). On the other hand, we did not impose any expansion limits on biomass grate furnace and this technology has the lowest investment costs as compared to the other biomass-based technologies (see Table 2). While, with increasing probability of nuclear extension, the expansion in capacity decreases for all technologies, the ratio in which this decrease takes place is different for all technologies. Biomass-based technologies appear to be more influenced by a decrease in license extension probability than the others. For instance, the increase in expansion for anaerobic digestion from probability γ=1 to γ=0 is around 132% while it is only around 6% for solar PV. Onshore and offshore wind are the technologies least influenced by a decrease in probability of license extension, because players always invest in them up to the maximum capacity expansion limits.

Next, we analyze the results of the second step of the model, which depend on the investment choice made in the first step. Among the two possible scenarios at the beginning of the second step, that is, nuclear license extension or nuclear phase-out is guaranteed, we focus solely on the description of results for the nuclear license extension scenario in order to simplify the description of the results. A more complete analysis is performed in section 5.3 in which both scenarios are considered. We then perform simulations of annual

[11] For details on technology costs, please refer to the specific LCOE calculations in Annex 4. We define the LCOE per technology, as the total costs divided by the total production per technology (in euros/MW).When we compare these values to the ones from other sources (Albrecht and Laleman, 2014), we can see that they are in the same order of magnitude. Of course, due to the variable nature of the modeling, our LCOE values are lower as compared to the above-mentioned sources.

production, prices and profits by considering that nuclear installations can be still used, for different investment choices that in turn depend on the probability of nuclear license extension. As can be observed in column 5 of Table 3, total production decreases with decreasing investments, that is, with increasing probability of license extension in the first modelling stage. As the amount of producing hours is not influenced by a change in probability (see Annex 6), total production follows the same tendency as investments in capacity. For details regarding production per technology and probability level, we refer to Annex 8.

Moreover, as the total production decreases with decreasing investment outputs in the first stage (i.e. with increasing probabilities of nuclear license extension), prices[12] increases (see Table 3, column 6). More specifically, when assuming the total absence of nuclear power in the future ($\gamma = 0$) in the first stage, electricity prices found in the second stage will be around 8.5%[13] lower than in the baseline case, ($\gamma = 1$), in which the definite license extension is anticipated.

Finally, we can observe that total second-step profits are non-monotonic with respect to the probability of license extension (see Table 3, column 4) assumed in the first stage, and reach the highest value for investment scenarios where we have assumed that nuclear license extension or nuclear phase-out would be guaranteed in the future. Overall, total profits reach the maximum value for $\gamma = 1$, which corresponds to the scenario with the maximum simulated price. For profits per player, please refer to Annex 1.

5.2. Effect of renewable energy subsidies and nuclear tax

Next, we analyze the effect of the implementation of RE subsidies and nuclear taxes on the firms' decisions, by comparing results with RE subsidies (see rows 3 and 7 in Table 3) and results without RE subsidies (see rows 8 and 12 in Table 3). The detailed numbers for this comparison can be found in the annexes.

[12] We acknowledge that electricity price is assumed to be a linear (with negative slope) function with respect to demand, as explained in section 4.3.
[13] Prices obtained in the scenario where we anticipated the total absence ($\gamma = 0$) and presence ($\gamma = 1$), of nuclear power for the case of RE subsidies and nuclear taxes are 26.897 and 29.39 euro/MWh, respectively.

As expected, the numbers in Table 3 show that the implementation of RE subsidies promotes investment in RE capacity. The total installed capacity increases almost eight-fold for each probability of nuclear license extension. The model also simulates a shift in choice of technologies driven by RE subsidies. This can be seen in Figure 4. Without RE subsidies (left-hand side of the figure), the model favors onshore wind over offshore wind and solar PV. When subsidies are provided, biomass-based technologies enter the electricity mix. These results are mainly driven by the capacity limit for onshore (i.e., 947 MW in total) and offshore wind (i.e., 1 588 MW in total), and the quadratic investment cost function for all technologies. The RE subsidies stimulate both players to expand in RE technologies. They would do so preferably in the cheapest technology (see LCOE calculation in Annex 4) but, with increasing capacity, also the investment costs are simulated to increase (see section 4.4). The result is that the producers diversify their choice of technology when RE are provided.

<< insert Figure 4: Expanded installed capacity per technology in the absence (left-hand side) and presence (right-hand side) of RE subsidies and nuclear taxes >>

The above-mentioned results constitute a key element for decision-making in order to create a long-term stable investment strategy. Indeed, as stated in the existing literature, a very high share of intermittent (i.e., non-flexible) renewables (i.e., solar PV and wind) may reduce the security of the energy supply and grid stability and result in higher overall system costs (Albrecht and Laleman, 2014; Szarka et al., 2013). Biomass-based conversion systems, on the other hand, while having high feedstock costs, offer technical alternatives for flexible power generation to compensate for fluctuations and the resulting residual load (Szarka et al., 2013). In our specific case, we see that the presence of subsidies increases the overall production share of biomass-based systems from around 7% to around 30-40% of the total production, depending on the probability scenario.

Overall, simulated results follow the same patterns as in the previous section when the probability of nuclear license extension increases, but quantity levels are higher in the presence of RE subsidies and nuclear taxes. Thus, first-stage investment and second-stage total production outputs decrease, while second-stage prices increase with increasing probabilities of nuclear extension assumed in the first modelling stage. However, the presence of subsidies reduces the effect of the increase in probability on total expansion capacity and, then, on total production of the second step. In particular, total expansion capacity decreases by 37%, from $\gamma = 0$ to $\gamma = 1$ in the absence of subsidies, and only by 21%, from $\gamma = 0$ to $\gamma = 1$ in the presence of subsidies.

Finally, total profits are not greatly influenced by the different investment outputs of the first stage, and follow a different pattern in absence of RE subsidies and taxes as compared to the presence of RE subsidies and taxes. In the absence of subsidies and taxes, total profits slightly decrease (as does the total production) with decreasing investments, that is with increasing probability of license extension (see Table 3, column 4), in particular, decreasing of 0.8 % from $\gamma = 0$ to $\gamma = 1$. In presence of subsidies and taxes, on the contrary, profits only slightly increase, by 0.1 % from $\gamma = 0$ to $\gamma = 1$. Therefore, we can conclude that the implementation of subsidies and taxes slows down the effect of the increase in probability on new investment and then on total profits of the subsequent second-stage.

5.3. Scenario analysis of seasonal demands

As we explained in the previous section, second step decisions, i.e., annual production hours, are similar for the different investment outputs of the first stage, that is per probability scenario. This is logical seeing we assume that second step decisions are taken in a certainty environment regarding final installed capacity, that is, for a fixed probability of nuclear license extension and for the same annual demand function. Indeed, changes in production decisions depend mainly on seasonality in electricity demand throughout the year due to the strong dependence of the demand on weather conditions as well as on social and economic activities (Koopman et al., 2007). In order to better capture second step decisions[14], we performed additional simulations by considering different seasonal demands. Moreover, simulations are computed for the two possible cases at the beginning of the second modelling step, that is, where we assume, on the one hand, that the nuclear phase-out has been implemented (s = 2) and, on the other hand, that nuclear license

[14] We thank an anonymous referee for this important suggestion.

extensions have been guaranteed (s = 1), and for two different probabilities of nuclear license extension (that is for different investment possibilities), in presence of RE subsidies. Results are illustrated in Table 4.

<< insert Table 4: Results of the different seasonal demand scenarios in case of certainty about nuclear license extension or nuclear phase-out >>

Comparing simulated results per season, the simulation results are similar for the two possible scenarios, thus we first focus on results under certainty of nuclear license extension. It is clear that simulated production is the highest in winter, followed by spring, summer and fall. Detailed production hours per technology and firm, in case of certainty about nuclear license extension, are shown in Annex 9. Moreover, looking at price simulations, it is clear that the highest prices are obtained in winter, while the lowest values are found in summer. This is logical seeing, in Belgium, electricity supply in winter is higher as compared to summer. This is also reflected in the monthly average quotation of the BELPEX spotmarket, where historical data confirms that winter months consistently display higher wholesale electricity prices than summer months[15].

Next, focusing on simulated results per probability of nuclear license extension γ, the simulation shows that the main results in regard to total production and prices, as discussed in the previous section 5.1, are maintained. In particular, total production is higher and prices are lower when the first step assumed the total absence of nuclear power in the future ($\gamma = 0$) as compared to the case of definite nuclear license extension in the future ($\gamma = 1$).

Finally, if we compare simulated results in the case of certainty about nuclear license extension (columns 1-4) and in the case of certainty about nuclear phase-out (columns 5-8), we show that higher production quantities and lower prices are reached in a certainty environment in which the extension of nuclear permits

[15] This data is available at https://my.elexys.be/MarketInformation/SpotBelix.aspx.

is guaranteed, as compared to the case of a definitive nuclear phase-out, a statement that is in line with numerous reports on the Belgian power sector (D'haeseleer et al., 2007; Febeliec, 2017; Groep GEMIX, 2009; International Energy Agency, 2016). More specifically, winter prices in case of total absence of nuclear power could become around 16% higher as compared to the case of a definite nuclear license extension.

5.4. Scenario analysis of quadratic investment cost function

One important assumption of the model relates to the quadratic investment cost function (described in section 4.4). Because of the lack of data to estimate a quadratic cost function with respect to the additional investment capacity, we conducted a scenario analysis with different investment cost parameters in order to validate our choice which corresponds to the baseline case in Table 5. As can be seen in Table 5, we simulated four different scenarios, i.e. Baseline, Scenario 1a, Scenario 1b, Scenario 1c, in such a way that the marginal unitary cost per technology, *d(k)+e(k)*, is the same.

<< insert Table 5: Results of the different quadratic investment cost scenarios for each technology >>

More specifically, simulation results of the first modelling step regarding the optimal total additional investment capacity and expected profit are shown for the model probability scenario $\gamma = 1$, our benchmark case. We don't observe important changes in total expansion capacities per quadratic cost scenario. Simulated investments are less than 5% lower in the scenario 1c in comparison to the baseline scenario. However, expected total profits of the first modelling stage are significantly different for the different quadratic cost function scenarios. In particular, we found the maximum value in the baseline case to be €1 829 (in millions). Therefore, due to the small differences on investments per scenario, we used the values of the case for which we obtain the maximum profits for our analysis, i.e., the baseline case.

5.5. Scenario analysis of different market structures

Even if the market shares of different suppliers concerning installed electricity capacity (see Table 1) suggest a leader-follower approach, there is no explicit proof of this type of strategic behavior in the Belgian electricity market. A more common situation when assuming imperfect competition is the Nash-Cournot market structure, where all firms take decisions simultaneously. In order to show that the specific market structure is not the main driver of simulated results and in order to prove the robustness of our modelling approach, we performed additional simulation by supposing a nash-cournot[16] one stage equilibrium game and compared with previous results under the Stackelberg two-stage baseline model. As can be seen in Table 6, main tendencies are maintained with respect to an increase of the probability of license extension. In particular, lower levels of investment are obtained for higher probabilities of nuclear license extension in a first stage, which in turn also results in a lower total production and a higher electricity price in a subsequent stage, when assuming these different new installed capacity scenarios.

<< insert Table 6: Comparison of main results under different modelling approaches >>

6. Conclusion and Discussion

The Belgian power sector currently finds itself in a state of uncertainty regarding the nuclear phase-out. Until now, the government's official position has been that the remaining four nuclear reactors will be shut down in 2022-2025 without license extension. However, seeing that a permit extension was granted for the oldest reactors in 2015 and taking into account the shortage of electricity supply, opinions are divided about whether or not the current permits should be extended, creating an uncertain investment climate.

In this context, the goal of our study was to analyze how, for the Belgian electricity market, uncertainty about the nuclear phase-out, coupled with the implementation of renewable energy (RE) subsidies and

[16] In this case, the Nash-cournot equilibrium is solved by means of a non-linear, mixed complementary problem, executed in GAMS using the PATH solver (GAMS Development Corporation, 2010) and considering KKT conditions (equation (9) and (15)) for both players.

nuclear taxes, affects investment capacity and productivity decisions by electricity suppliers, when assuming strategic behavior by electricity suppliers.

In particular, as suggested by market shares concerning installed electricity capacity in Belgium, a Stackelberg-based equilibrium model was developed that allows to consider the hypothetical case that the nuclear monopolistic firm has a dominant position, acting as leader in the market. We assume then that the dominant firm takes decisions first, while a follower firm (remaining small firms) takes decisions subsequently. In addition, taking into account that the European market is not fully integrated and with the goal of reducing the complexity of the model, we also assumed the Belgian market as autarky in the modelling, and thereby, trade of electricity was not here considered. Moreover, suppliers' decisions are chosen through a two-step sequential model in which, in a first step, expansion capacities are decided under uncertainty about the extension of nuclear license permits, that is, under different probabilities of nuclear license extension. Subsequently, expansion capacities are injected in the second step of the model and the annual number of production hours are decided in a certainty environment regarding nuclear phase-out.

Our analysis indicates that, regardless of subsidies, an increase in the probability of nuclear license extension results in lower levels of investment - primarily in renewable energy. These lower investment levels, in turn, result in lower total production and a higher electricity price in a subsequent period in the future in which policy uncertainty has been already revealed. In absence of renewable energy subsidies and nuclear taxes, and when assuming higher probabilities of nuclear license extension, a lack of investments, leads to a slight decrease in total profit in a subsequent time period, due to the decrease in total production. However, we show that the implementation of renewable energy subsidies and nuclear taxes reduces the effect of the increase in probability, on total expansion capacity decisions, and then on total future profits.

Moreover, the results show that, in the framework of decarbonization of the energy sector, there should be continued support for renewable energy in the form of subsidies, as these help to secure supply and diversify the energy mix. Indeed, RE subsidies promote new investments in renewable technologies.

In particular, simulated results for the different policy scenarios show that, in total, 8.3-10.5 GW, respectively 1.4-2.3 GW, of new power stations would be needed in order to fulfill annual demand in presence, respectively, in absence of RE subsidies. When comparing the results obtained here with other studies[17], the Belgian Federal Planning Bureau (Gusbin and Devogelaer, 2017) estimated that, when considering the possible evolution of the Belgian energy system by 2050 and assuming that no new objectives or policies are implemented, around 1100 MW of capacity would be invested annually. Similar results are obtained here in absence of RE subsidies. Moreover, the Commission for Electricity and Gas Regulation, in their annual report for 2017 (CREG, 2017), stated that, from 2016 to 2017, the installed generation capacity increased only by 524 MW (half of what was estimated in Gusbin and Devogelaer (2017)), mainly delivered by an increase in installed capacity of offshore wind farms. This number corresponds to simulated investment capacity in offshore wind in our model, when assuming nuclear phase-out and the absence of RE subsidies. Other studies contradict our main results concerning the technologies in which capacity is expanded. For example, in a study on electricity scenarios for Belgium towards 2050 (Elia, 2017), Elia states that 3.6 GW of new-built fossil-based thermal generation capacity should be developed in Belgium at the moment of full nuclear phase-out at the latest, i.e., before the winter of 2025-2026. In contrast, in our model, investment in these thermal plants is not present in any policy scenario.

Finally, our study derives relevant policy implications regarding the debate on nuclear energy. While the Belgian government currently seems committed to a nuclear phase-out, as is the case in many other European countries (Golombek et al., 2015), the biggest political party since the 2014 Belgian parliament elections is questioning the phase-out, and most scientific reports recommend extending the nuclear license in order to reduce the current pressure on supply uncertainty, on the condition that the safety of the plants can be ensured (D'haeseleer et al., 2007; Febeliec, 2017; Groep GEMIX, 2009; International Energy Agency, 2016). Related to the safety issue but from the point of view of the individual user, Welsch and

[17] We acknowledge that our simulated numbers, as well as comparison with other studies, have to be taken with caution because of the different approaches used and the theoretical nature of our modelling.

Biermann (2014) used survey data for 139517 individuals in 21 European countries and found that preferences, in terms of subjective well-being, for solar & wind power over nuclear power have risen drastically after the Fukushima nuclear accident. In this study, we show that, in the long term (i.e., the first modelling stage) and in the presence of RE subsidies, if a definitive extension of nuclear permits was assumed, there would be around 27% less investment in additional RE capacity and around 8-14% less production, as compared to the case in which the total absence of nuclear production is anticipated. In contrast, in the short term (i.e., the second modelling stage), total seasonal production (and prices), could become up to 34% lower (and up to 14% higher) in case of total absence of nuclear power, as compared to the case of a definite nuclear license extension. At any rate, new installations will be necessary in the future in order to fulfill demand and future targets of the Renewable Energy Directive concerning renewable energy generation. Therefore, the main policy recommendation derived from our study is that, while extending the nuclear license could be seen as the short-term answer in order to reduce supply insecurity, a definite nuclear phase-out would be the long-term answer, not only to ensure supply security, but also to guarantee a stable investment climate in the future. Indeed, this long-term energy strategy without policy uncertainty regarding nuclear power should consider the future environmental benefits of RE technologies in order to move towards the decarbonization of the energy sector.

There are possible extensions of our paper. First of all, we could improve our two-step static model by using a multi-period dynamic model in order to analyze the effect of uncertainty about nuclear phase-out on the evolution of investment capacity decisions over time. Also, a more complex demand-price function could be considered in the modeling - for example a constant elasticity demand function. Moreover, we could also analyze the results for an endogenously determined probability as compared to a exogenously determined and fixed probability in the current model. Finally, we made the assumption that Belgian electricity supply equals Belgian demand. In reality, however, Belgium imports a net amount of electricity from abroad. In 2014, this net import amounted to 17 508 GWh from France, the Netherlands and Luxembourg (ENTSO-E, 2016). An alternative to increasing local generation capacity is to increase the transmission capacity from neighboring countries. In order to incorporate this aspect in our model, we could consider neighboring countries as additional players in the Belgian electricity market in a third decision step, which could strategically influence local suppliers' decisions.

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Tables

Table 1: Overview of Belgium's existing power generation structure (Elia, 2016a)

Technology	Installed capacity per technology (MW)	Suppliers	Installed capacity per supplier (MW)
Nuclear fission	5 926 (30.7%)	**Axpo trading**	119 (0.6%)
Coal	1 164 (6.0%)	**EDF Luminus**	820 (4.2%)
OCGT	464 (2.4%)	**Engie Electrabel**	11 339 (58.8%)
CCGT	4 588 (23.8%)	**Electrawinds Distributie**	38 (0.2%)
Biomass (furnace and anaerobic digestion)	620 (3.2%)	**Eneco Energy Trade**	270 (1.4%)
Hydropower	1 394 (7.2%)	**Enel Trade**	405 (2.1%)
Solar PV	2 953 (15.3%)	**GETEC Energie**	556 (2.9%)
Wind (onshore and offshore)	1 961 (10.2%)	**Lampiris**	243 (1.3%)
Waste incineration	230 (1.2%)	**RWE Supply & Trading**	305 (1.6%)
		T-Power	422 (2.2%)
		Uniper Global Commodities	556 (2.9%)
		Other[18]	4 227 (21.9 %)
		Total Leader	11 339 (58.8%)
		Total Follower	7 961 (41.2%)

[18] 'Other' in this case is actually the grouping together of different renewable energy technologies which are not exploited solely by one producer but operated by SME's and households. These technologies are onshore and offshore wind energy, solar PV and anaerobic digestion.

Table 2: Economic parameter values (left-hand side) and maximum values assumed for decision variables (right-hand side), per firm i and technology k

Technology k	$I_i^1(k)$ (in MW)[+]	$CC(k)$ (in 10^3 €/MW^2)[+++]	$FC(k)$ (in 10^3 €/MW)[+++]	$VC(k)$ (in €/MWh)[+++]	$FSC(k)$ (in €/MWh)[+++]	Maximum $Ph_{max}(k)$ (in hours/year)[*]	Maximum $E_{max}(k)$ (in MW)
Offshore wind	1249	3470	37.8	0	0	2716	1588[+]
Onshore wind	712	1400	128.4	0	0	2278	947[**]
Solar PV	2953	980	16.7	0	0	1007	5142[++]
OCGT advanced	464	550	16.5	11	65	964	n/a
CCGT	3823	850	21.3	2	50	7884	n/a
Pulverized supercritical coal plants	940	1600	40	3.6	30	7008	0[+]
Nuclear fission generation II	5926	0	0	8	8	7884	0[§]
Biomass grate furnace steam turbine	363	2890	63.3	3.5	75	5957	n/a
Anaerobic digestion	189	3880	159.1	3.1	65	5957	n/a
Biomass CHP cogeneration	68	3670	84.4	3.3	75	5957	n/a
CCGT conventional CHP	86	880	74.8	2.4	50	5957	n/a
CCGT advanced CHP	1308	1010	39.4	4	50	5957	n/a
Hydropower run-of-river	230	5500	82.5	5	0	2978	0[*]
Hydropower dam and	1249	2200	22	3	0	2978	0[*]

reservoir >100MW							
Municipal solid waste incinerator	712	6080	182.4	6.9	0	5957	0[§§]

*Albrecht and Laleman, 2014; **European Wind Energy Association, 2005; +Elia, 2016a; ++International Energy Agency, 2001; [+++] Joint Research Centre, 2014 ; § We assume zero expansion due to nuclear phase-out; §§ we assume that municipal solid waste incinerators are built with a main goal to get rid of waste and not to produce energy.

Table 3: Overview of results for the different model scenarios

Modelling step	**First model step**		**Second model step**		
	Probability of extending nuclear permits (γ)	**Total additional investment capacity $\sum_{i,k} E_i\ (k)$ (in MW)**	**Total profit $\sum_{i,k} \pi_i(k)$(in million €)**	**Total production $\sum_{i,k} Q_i(k)$ (in GWh)**	**Electricity price p (in €/MWh)**
RE subsidies and nuclear taxes	**γ=1**	8264	3654	105 041	29.39
	γ=0.75	8635	3643	107 158	28.98
	γ=0.5	9005	3626	109 275	28.57
	γ=0.25	9376	3601	111 392	28.16
	γ=0	10487	3650	117 934	26.89
No RE subsidies and no nuclear taxes	**γ=1**	1429	1291	73 298	35.54
	γ=0.75	1583	1293	73 643	35.47
	γ=0.5	1728	1296	73 966	35.41
	γ=0.25	1803	1296	74 132	35.38
	γ=0	2271	1301	74 691	35.27

Table 4: Results of the different seasonal demand scenarios in case of certainty about nuclear license extension (s=1) or nuclear phase-out (s=2) per model scenario.

Certainty about nuclear license extension (s=1)				**Certainty about nuclear phase out (s=2)**			
Model scenario		Total production (in GWh)	Electricity price (in €/MWh)	**Model scenario**		Total production (in GWh)	Electricity price (in €/MWh)
$\gamma = 1$	**Winter**	34 117	147.13	$\gamma = 1$	**Winter**	22 437	167.7
	Spring	27 800	75.58		**Spring**	22 109	79.25
	Summer	23 252	72.76		**Summer**	21 554	73.86
	Fall	21 388	142.83		**Fall**	14 714	152.71
	Annual	106 557	109.57 (average)		**Annual**	80 814	110.65 (average)
$\gamma = 0$	**Winter**	37 332	141.50	$\gamma = 0$	**Winter**	25 652	161.95
	Spring	37 021	69.63		**Spring**	25 342	77.16
	Summer	34 036	65.81		**Summer**	24 784	71.78
	Fall	26 397	135.42		**Fall**	25 805	136.29
	Annual	134 876	103.09 (average)		**Annual**	101 583	91.05 (average)

Table 5: Results of the different quadratic investment cost scenarios for each technology

Model scenarios		Quadratic cost scenarios	Total additional investment capacity $\sum_{i,k} E_i(k)$ (in MW)	Total expected profit $\sum_i \hat{E}(\pi_i)$ (in million €)
$\gamma = 1$	**Baseline**	**d(k)=0** **e(k)=CC(k)**	8264	1829
	Scenario 1a	**d(k)=CC(k)/3** **e(k)=2*CC(k)/3**	8071	1638
	Scenario 1b	**d(k)= CC(k)/2** **e(k)= CC(k)/2**	7884	1550
	Scenario 1c	**d(k)=2*CC(k)/3** **e(k)= CC(k)/3**	7890	1462

Table 6 : Comparison of main results under different modelling approaches

Stackelberg two-stage model				**Nash one-stage model**			
Model scenario	Expansion of the first stage (in MWh)		Electricity price of the second-stage (in €/MWh)	**Model scenario**	Expansion (in MWh)		Electricity price (in €/MWh)
$\boldsymbol{\gamma = 1}$	8264	**s=1**	29.39	$\boldsymbol{\gamma = 1}$	13518	**s=1**	26.41
		s=2	38.76			**s=2**	35.47
$\boldsymbol{\gamma = 0.5}$	9005	**s=1**	28.57	$\boldsymbol{\gamma = 1}$	14753	**s=1**	25.18
		s=2	37.62			**s=2**	34.24
$\boldsymbol{\gamma = 0}$	10487	**s=1**	26.89	$\boldsymbol{\gamma = 0}$	15988	**s=1**	23.95
		s=2	35.94			**s=2**	33

Figures

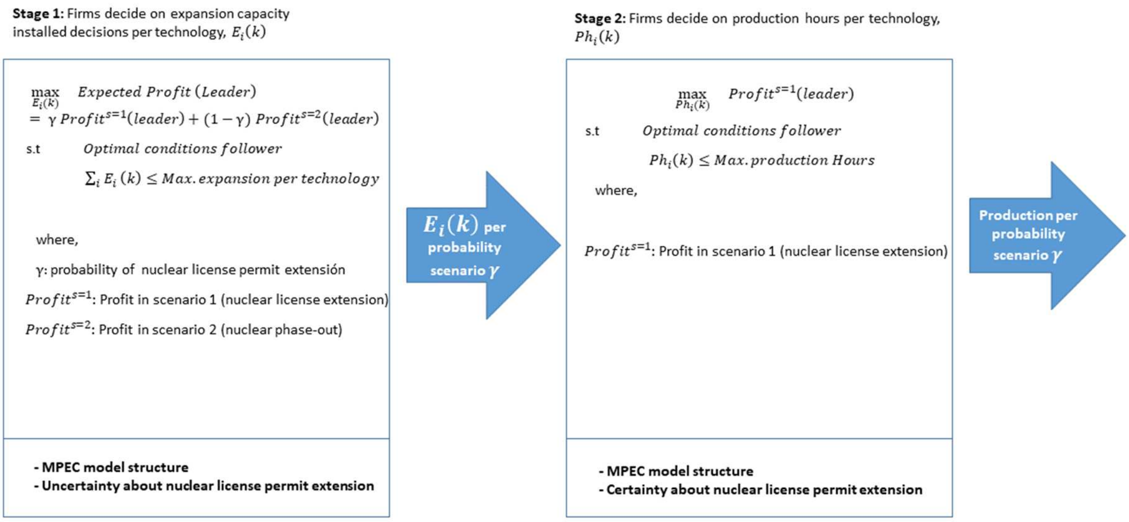

Figure 1: Decision process of the model, assuming certainty about nuclear license extension in the second step.

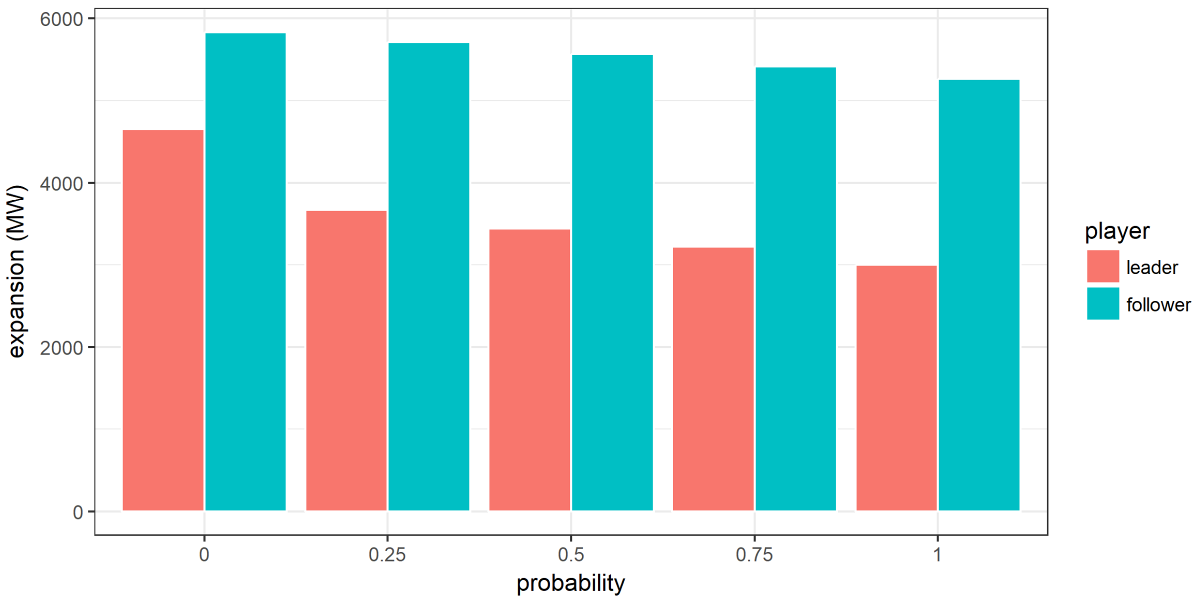

Figure 2: Expansion in capacity (in MW) in function of the level of probability of nuclear license extension γ for the leader and follower

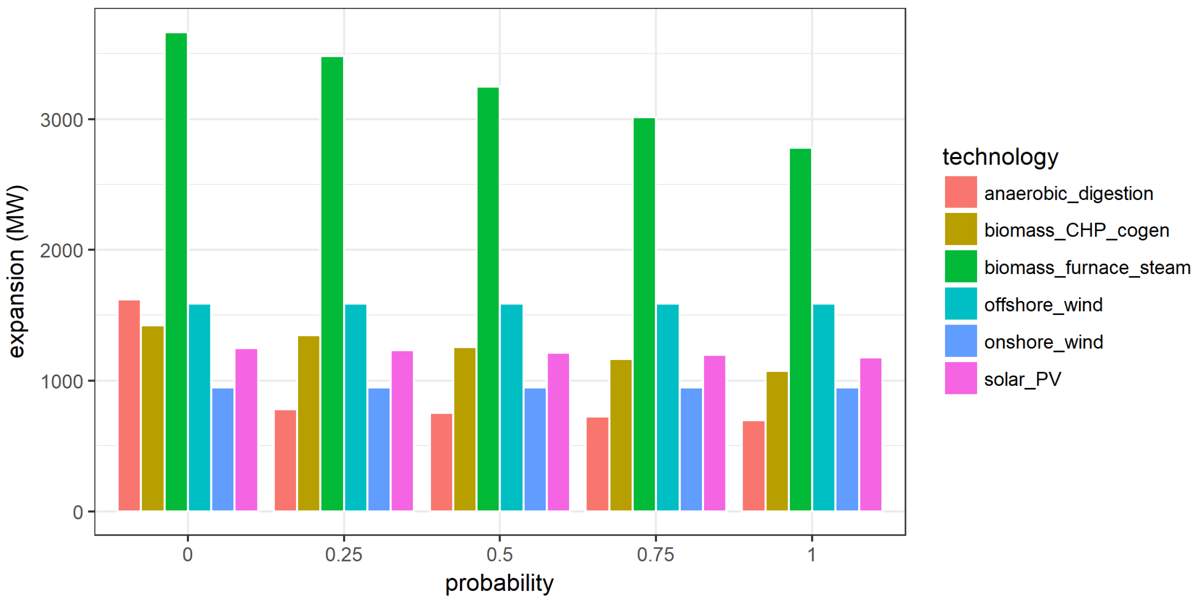

Figure 3: Installed capacity expansion (in MW) per technology and probability level γ

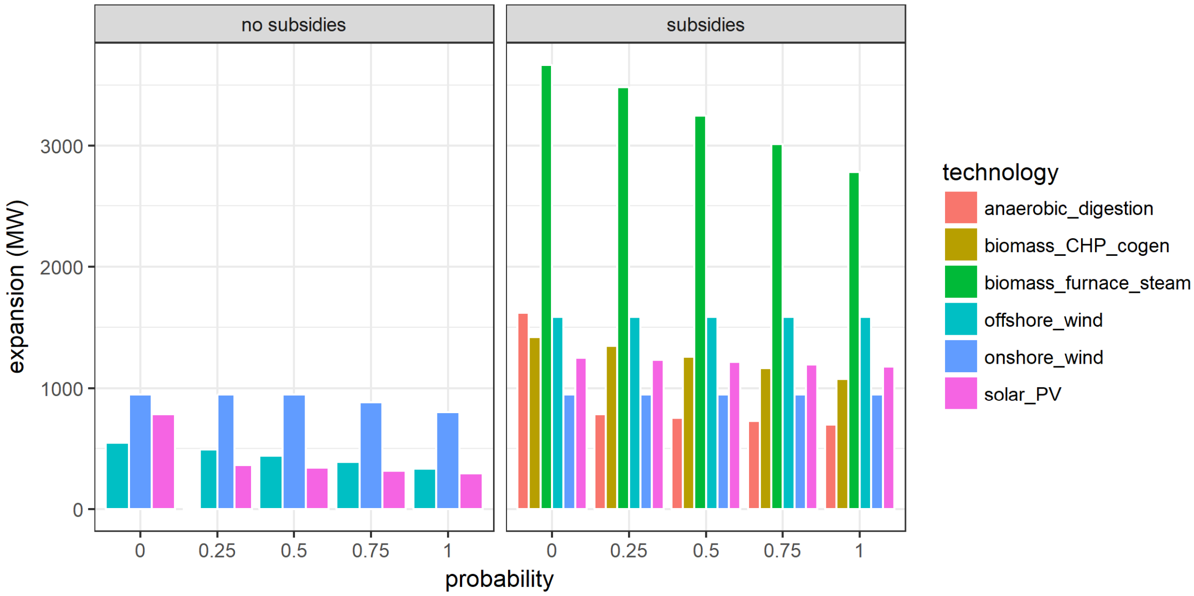

Figure 4: Expanded installed capacity per technology in absence (left-hand side) and in case (right-hand side) of RE subsidies and nuclear taxes

Annexes

Annex 1: Profit per player per scenario in the second model step

profit (million euro)	probability	Leader	Follower
RE subsidies and nuclear taxes	γ = 1	1701	1953
	γ = 0.75	1693	1950
	γ = 0.5	1680	1945
	γ = 0.25	1662	1939
	γ = 0	1756	1895
No RE subsidies and no nuclear taxes	γ = 1	996	294
	γ = 0.75	999	295
	γ = 0.5	1000	295
	γ = 0.25	1000	296
	γ = 0	1006	295

Annex 2: Expansion in capacity per technology and player in MW (first model step)

	probability	technology	expansion (MW) Leader	Follower
RE subsidies and nuclear taxes	γ = 1	onshore wind	473	473
		offshore wind	794	794
		solar PV	0	1177
		biomass grate furnace steam turbine	1252	1531
		anaerobic digestion	0	697
		Biomass CHP cogeneration	482	592
	γ = 0.75	onshore wind	473	473
		offshore wind	794	794
		solar PV	0	1196
		biomass grate furnace steam turbine	1410	1605
		anaerobic digestion	0	725
		Biomass CHP cogeneration	544	621
	γ = 0.5	onshore wind	473	473
		offshore wind	794	794
		solar PV	0	1214
		biomass grate furnace steam turbine	1569	1679
		anaerobic digestion	0	752
		Biomass CHP cogeneration	607	650
	γ = 0.25	onshore wind	473	473
		offshore wind	794	794
		solar PV	0	1233
		biomass grate furnace steam turbine	1727	1754
		anaerobic digestion	0	780

	probability	technology	expansion (MW) Leader	Follower
No RE subsidies and no nuclear taxes	γ = 1	onshore wind	332	466
		offshore wind	135	200
		solar PV	0	295
	γ = 0.75	onshore wind	404	473
		offshore wind	170	218
		solar PV	0	318
	γ = 0.5	onshore wind	473	473
		offshore wind	205	235
		solar PV	0	340
	γ = 0.25	onshore wind	473	473
		offshore wind	240	253
		solar PV	0	364
		CCGT conventional CHP	0	0
	γ = 0	onshore wind	473	473
		offshore wind	275	270
		solar PV	393	386

		Biomass CHP cogeneration	669	679
	γ = 0	onshore wind	473	473
		offshore wind	794	794
		solar PV	0	1247
		biomass grate furnace steam turbine	1853	1812
		anaerobic digestion	817	802
		Biomass CHP cogeneration	718	703

Annex 3: Total expansion per technology (first model step)

total expansion (MW)	probability	onshore wind	offshore wind	solar PV	biomass grate furnace steam turbine	anaerobic digestion	biomass CHP cogeneration
RE subsidies and nuclear taxes	$\gamma = 1$	947	1588	1177	2782	697	1073
	$\gamma = 0.75$	947	1588	1196	3015	725	1165
	$\gamma = 0.5$	947	1588	1214	3248	752	1257
	$\gamma = 0.25$	947	1588	1233	3481	780	1348
	$\gamma = 0$	947	1588	1247	3665	1619	1421
No RE subsidies and no nuclear taxes	$\gamma = 1$	799	336	295			
	$\gamma = 0.75$	877	388	318			
	$\gamma = 0.5$	947	440	340			
	$\gamma = 0.25$	947	493	364			
	$\gamma = 0$	947	545	779			

Annex 4: Total expansion per player (first model step)

total expansion (MW)	probability	Leader	Follower
RE subsidies and nuclear taxes	$\gamma = 1$	3000	5263
	$\gamma = 0.75$	3221	5413
	$\gamma = 0.5$	3442	5563
	$\gamma = 0.25$	3663	5713
	$\gamma = 0$	4655	5831
No RE subsidies and no nuclear taxes	$\gamma = 1$	467	962
	$\gamma = 0.75$	574	1009
	$\gamma = 0.5$	679	1049
	$\gamma = 0.25$	714	1089
	$\gamma = 0$	1141	1129

Annex 5: Final installed capacity per player and technology (first model step)

Final installed capacity (MW)	probability	technology	Leader	Follower	Final installed capacity (MW)	probability	technology	Leader	Follower
RE subsidies and nuclear taxes	γ = 1	onshore wind	485	1710	No RE subsidies and no nuclear taxes	γ = 1	onshore wind	344	1703
		offshore wind	1181	1119			offshore wind	522	526
		solar PV	0	4130			solar PV	0	3248
		OCGT advanced	48	416			OCGT advanced	48	416
		CCGT	2430	1393			CCGT	2430	1393
		pulverised supercritical coal plants	0	940			pulverised supercritical coal plants	0	940
		nuclear fission generation II	5926	0			nuclear fission generation II	5926	0
		biomass furnace steam	1615	1531			biomass grate furnace steam turbine	363	0
		anaerobic digestion	0	886			anaerobic digestion	0	189
		biomass CHP cogen	532	609			biomass CHP cogeneration	50	18
		hydropower run-of-river	12	74			hydropower run-of-river	12	74
		hydropower dam and reservoir >100MW	1164	144			hydropower dam and reservoir >100MW	1164	144
		municipal solid waste incinerator	72	158			municipal solid waste incinerator	72	158
		LVN/LF	224	0			LVN/LF	224	0
	γ = 0.75	onshore wind	485	1710		γ = 0.75	onshore wind	416	1710
		offshore wind	1181	1119			offshore wind	557	543
		solar PV	0	4148			solar PV	0	3270
		OCGT advanced	48	416			OCGT advanced	48	416
		CCGT	2430	1393			CCGT	2430	1393
		pulverised supercritical coal plants	0	940			pulverised supercritical coal plants	0	940
		nuclear fission generation II	5926	0			nuclear fission generation II	5926	0
		biomass furnace steam	1773	1605			biomass grate furnace steam turbine	363	0
		anaerobic digestion	0	913			anaerobic digestion	0	189
		biomass CHP cogen	594	639			biomass CHP cogeneration	50	18
		hydropower run-of-river	12	74			hydropower run-of-river	12	74
		hydropower dam and reservoir >100MW	1164	144			hydropower dam and reservoir >100MW	1164	144
		municipal solid waste incinerator	72	158			municipal solid waste incinerator	72	158

		LVN/LF	224	0
	γ = 0.5	onshore wind	485	1710
		offshore wind	1181	1119
		solar PV	0	4167
		OCGT advanced	48	416
		CCGT	2430	1393
		pulverised supercritical coal plants	0	940
		nuclear fission generation II	5926	0
		biomass furnace steam	1932	1679
		anaerobic digestion	0	941
		biomass CHP cogen	657	668
		hydropower run-of-river	12	74
		hydropower dam and reservoir >100MW	1164	144
		municipal solid waste incinerator	72	158
		LVN/LF	224	0
	γ = 0.25	onshore wind	485	1710
		offshore wind	1181	1119
		solar PV	0	4185
		OCGT advanced	48	416
		CCGT	2430	1393
		pulverised supercritical coal plants	0	940
		nuclear fission generation II	5926	0
		biomass furnace steam	2090	1754
		anaerobic digestion	0	969
		biomass CHP cogen	719	697
		hydropower run-of-river	12	74
		hydropower dam and reservoir >100MW	1164	144
		municipal solid waste incinerator	72	158
		LVN/LF	224	0
	γ = 0	onshore wind	485	1710
		offshore wind	1181	1119
		solar PV	0	4200
		OCGT advanced	48	416
		CCGT	2430	1393
		pulverised supercritical coal plants	0	940
		nuclear fission generation II	5926	0

		LVN/LF	224	0
	γ = 0.5	onshore wind	485	1710
		offshore wind	592	560
		solar PV	0	3293
		OCGT advanced	48	416
		CCGT	2430	1393
		pulverised supercritical coal plants	0	940
		nuclear fission generation II	5926	0
		biomass grate furnace steam turbine	363	0
		anaerobic digestion	0	189
		biomass CHP cogeneration	50	18
		hydropower run-of-river	12	74
		hydropower dam and reservoir >100MW	1164	144
		municipal solid waste incinerator	72	158
		LVN/LF	224	0
	γ = 0.25	onshore wind	485	1710
		offshore wind	627	578
		solar PV	0	3316
		OCGT advanced	48	416
		CCGT	2430	1393
		pulverised supercritical coal plants	0	940
		nuclear fission generation II	5926	0
		biomass grate furnace steam turbine	363	0
		anaerobic digestion	0	189
		biomass CHP cogeneration	50	18
		hydropower run-of-river	12	74
		hydropower dam and reservoir >100MW	1164	144
		municipal solid waste incinerator	72	158
		LVN/LF	224	0
	γ = 0	onshore wind	485	1710
		offshore wind	662	595
		solar PV	393	3339
		OCGT advanced	48	416
		CCGT	2430	1393
		pulverised supercritical coal plants	0	940
		nuclear fission generation II	5926	0

		biomass furnace steam	2216	1812			biomass grate furnace steam turbine	363	0
		anaerobic digestion	817	991			anaerobic digestion	0	189
		biomass CHP cogen	768	720			biomass CHP cogeneration	50	18
		hydropower run-of-river	12	74			hydropower run-of-river	12	74
		hydropower dam and reservoir >100MW	1164	144			hydropower dam and reservoir >100MW	1164	144
		municipal solid waste incinerator	72	158			municipal solid waste incinerator	72	158
		LVN/LF	224	0			LVN/LF	224	0

Annex 6: Quantity of producing hours per technology for all model scenarios in the second model step

technology	producing hours
onshore wind	2277.6
offshore wind	2715.6
solar PV	1007.4
pulverised supercritical coal plants	7008
nuclear fission generation II	7884
biomass grate furnace steam turbine	5956.8
anaerobic digestion	5956.8
biomass CHP cogeneration	5956.8
CCGT conventional CHP	5956.8
CCGT advanced CHP	5956.8
hydropower run-of-river	2978.4
hydropower dam and reservoir >100MW	2978.4
municipal solid waste incinerator	5956.8

Annex 7: Levelized Cost of Electricity (LCOE) per technology and per model scenario in the second model step

LCOE (euro.MWh^{-1})	**RE subsidies and nuclear taxes**					**No RE subsidies and no nuclear taxes**				
technology	**$\gamma = 1$**	**$\gamma = 0.75$**	**$\gamma = 0.5$**	**$\gamma = 0.25$**	**$\gamma = 0$**	**$\gamma = 1$**	**$\gamma = 0.75$**	**$\gamma = 0.5$**	**$\gamma = 0.25$**	**$\gamma = 0$**
onshore wind	3.97	3.97	3.97	3.97	3.97	3.29	3.63	3.97	3.97	3.97
offshore wind	19.87	19.87	19.87	19.87	19.87	4.15	4.58	5.06	5.59	6.14
solar PV	8.99	9.21	9.43	9.66	9.84	1.48	1.58	1.68	1.8	2.8
OCGT advanced	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
CCGT	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
pulverised supercritical coal plants	33.89	33.89	33.89	33.89	33.89	33.89	33.89	33.89	33.89	33.89
pulverised supercritical lignine plants	NA	NA	NA	NA	NA	NA	NA	NA	NA	76.67
nuclear fission generation II	21.35	21.35	21.35	21.35	21.35	16	16	16	16	16
biomass grate furnace steam turbine	94.11	95.42	96.77	98.15	99.26	79.03	79.03	79.03	79.03	79.03
anaerobic digestion	78.36	78.79	79.23	79.66	81.24	69.44	69.44	69.44	69.44	69.44
biomass CHP cogeneration	86.86	87.52	88.2	88.9	89.45	79.01	79.01	79.01	79.01	79.01
CCGT conventional CHP	52.4	52.4	52.4	NA	52.4	NA	52.4	52.4	163.89	NA
CCGT advanced CHP	54	54	54	NA	54	NA	54	54	54	NA
hydropower run-of-river	6.38	6.38	6.38	6.38	6.38	6.38	6.38	6.38	6.38	6.38
hydropower dam and reservoir >100MW	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37
hydropower dam and reservoir 10-100MW	5	5	5	5	5	5	5	5	5	5
hydropower dam and reservoir <10MW	5	5	5	5	5	5	5	5	5	5
municipal solid waste incinerator	8.43	8.43	8.43	8.43	8.43	8.43	8.43	8.43	8.43	8.43

Annex 8: Electricity production per technology and per model scenario in the second model step

production (GWh)	probability	onshore wind	offshore wind	solar PV	pulverised supercritical coal plants	nuclear fission generation II	biomass grate furnace steam turbine	anaerobic digestion	biomass CHP cogeneration	hydropower run-of-river	hydropower dam and reservoir >100MW	municipal solid waste incinerator
RE subsidies and nuclear taxes	**γ = 1**	5000	6246	4160	6588	46719	18735	5277	6798	256	3896	1367
	γ = 0.75	5000	6246	4179	6588	46719	20122	5441	7344	256	3896	1367
	γ = 0.5	5000	6246	4198	6588	46719	21509	5606	7890	256	3896	1367
	γ = 0.25	5000	6246	4216	6588	46719	22897	5771	8436	256	3896	1367
	γ = 0	5000	6246	4231	6588	46719	23995	10768	8868	256	3896	1367
no RE subsidies and no nuclear taxes	**γ = 1**	4663	2845	3272	6588	46719	2162	1125	404	256	3896	1367
	γ = 0.75	4842	2988	3295	6588	46719	2162	1125	404	256	3896	1367
	γ = 0.5	5000	3130	3318	6588	46719	2162	1125	404	256	3896	1367
	γ = 0.25	5000	3273	3341	6588	46719	2162	1125	404	256	3896	1367
	γ = 0	5000	3414	3759	6588	46719	2162	1125	404	256	3896	1367

Annex 9: Production hours per season (second model step) per model scenario for the case with certainty about nuclear license extension (s=1).

Season	Probability	technology	Leader	Follower	Season	Probability	technology	Leader	Follower
Winter	γ = 1	onshore wind	806.1	806.1	Spring	γ = 1	onshore wind	462.2	462.2
		offshore wind	738	738			offshore wind	542.9	542.9
		solar PV	143.6	143.6			solar PV	382.8	382.8
		OCGT advanced	240.9	240.9			OCGT advanced	0	0
		CCGT	1971	1971			CCGT	1576.8	1576.8
		pulverised supercritical coal plants	1752	1752			pulverised supercritical coal plants	1401.6	1401.6
		nuclear fission generation II	1971	1971			nuclear fission generation II	1576.8	1576.8
		biomass furnace steam	1489.2	1489.2			biomass furnace steam	1191.36	1191.36
		anaerobic digestion	1489.2	1489.2			anaerobic digestion	1191.36	1191.36
		biomass CHP cogen	1489.2	1489.2			biomass CHP cogen	1191.36	1191.36
		CCGT conventional CHP	1489.2	1489.2			CCGT conventional CHP	1191.36	1191.36
		CCGT advanced CHP	1489.2	1489.2			CCGT advanced CHP	1191.36	1191.36
		hydropower run-of-river	744.6	744.6			hydropower run-of-river	595.68	595.68
		hydropower dam and reservoir >100MW	744.6	744.6			hydropower dam and reservoir >100MW	595.68	595.68
		municipal solid waste incinerator	1489.2	1489.2			municipal solid waste incinerator	1191.36	1191.36
	γ = 0	onshore wind	806.1	806.1		γ = 0	onshore wind	462.2	462.2
		offshore wind	738	738			offshore wind	542.9	542.9
		solar PV	143.6	143.6			solar PV	382.8	382.8
		OCGT advanced	240.9	240.9			OCGT advanced	0	0
		CCGT	1971	1971			CCGT	1971	1971
		pulverised supercritical coal plants	1752	1752			pulverised supercritical coal plants	1752	1752
		nuclear fission generation II	1971	1971			nuclear fission generation II	1971	1971
		biomass furnace steam	1489.2	1489.2			biomass furnace steam	1489.2	1489.2
		anaerobic digestion	1489.2	1489.2			anaerobic digestion	1489.2	1489.2
		biomass CHP cogen	1489.2	1489.2			biomass CHP cogen	1489.2	1489.2
		CCGT conventional CHP	1489.2	1489.2			CCGT conventional CHP	1489.2	1489.2
		CCGT advanced CHP	1489.2	1489.2			CCGT advanced CHP	1489.2	1489.2

		hydropower run-of-river	744.6	744.6			hydropower run-of-river	744.6	744.6
		hydropower dam and reservoir >100MW	744.6	744.6			hydropower dam and reservoir >100MW	744.6	744.6
		municipal solid waste incinerator	1489.2	1489.2			municipal solid waste incinerator	1489.2	1489.2

Season	Probability	technology	Leader	Follower	Season	Probability	technology	Leader	Follower
Summer	γ = 1	onshore wind	318.5	318.5	Fall	γ = 1	onshore wind	690.7	690.7
		offshore wind	511.1	511.1			offshore wind	923.6	923.6
		solar PV	342.5	342.5			solar PV	138.5	138.5
		OCGT advanced	0	0			OCGT advanced	137.7	137.7
		CCGT	1314	1314			CCGT	1126.3	1126.3
		pulverised supercritical coal plants	1168	1168			pulverised supercritical coal plants	1001.1	1001.1
		nuclear fission generation II	1314	1314			nuclear fission generation II	1126.3	1126.3
		biomass furnace steam	992.8	992.8			biomass furnace steam	851	851
		anaerobic digestion	992.8	992.8			anaerobic digestion	851	851
		biomass CHP cogen	992.8	992.8			biomass CHP cogen	851	851
		CCGT conventional CHP	992.8	992.8			CCGT conventional CHP	851	851
		CCGT advanced CHP	992.8	992.8			CCGT advanced CHP	851	851
		hydropower run-of-river	496.4	496.4			hydropower run-of-river	425.5	425.5
		hydropower dam and reservoir >100MW	496.4	496.4			hydropower dam and reservoir >100MW	425.5	425.5
		municipal solid waste incinerator	992.8	992.8			municipal solid waste incinerator	851	851
	γ = 0	onshore wind	318.5	318.5		γ = 0	onshore wind	690.7	690.7
		offshore wind	511.1	511.1			offshore wind	923.6	923.6
		solar PV	342.5	342.5			solar PV	138.5	138.5
		OCGT advanced					OCGT advanced	160.6	160.6
		CCGT	972.16482	1971			CCGT	1314	1314
		pulverised supercritical coal plants	1752	1752			pulverised supercritical coal plants	1168	1168
		nuclear fission generation II	1971	1971			nuclear fission generation II	1314	1314
		biomass furnace steam	1489.2	1489.2			biomass furnace steam	992.8	992.8
		anaerobic digestion	1489.2	1489.2			anaerobic digestion	992.8	992.8
		biomass CHP cogen	1489.2	1489.2			biomass CHP cogen	992.8	992.8
		CCGT conventional CHP	1489.2	1489.2			CCGT conventional CHP	992.8	992.8

		CCGT advanced CHP	1489.2	1489.2			CCGT advanced CHP	992.8	992.8
		hydropower run-of-river	744.6	744.6			hydropower run-of-river	496.4	496.4
		hydropower dam and reservoir >100MW	744.6	744.6			hydropower dam and reservoir >100MW	496.4	496.4
		municipal solid waste incinerator	1489.2	1489.2			municipal solid waste incinerator	992.8	992.8

Annex 10: Production levels and prices for the first modeling stage

		Production (in GWh)		Price (in eur/MWh)	
		s=1	**s=2**	**s=1**	**s=2**
RE subsidies and nuclear taxes	**$\gamma = 1$**	104 520	57 801	29.5	38.5
	$\gamma = 0.75$	106 272	59 553	29.2	38.2
	$\gamma = 0.5$	108 025	61 306	28.8	37.9
	$\gamma = 0.25$	109 777	63 058	28.5	37.5
	$\gamma = 0$	113 597	66 878	27.7	36.8
No RE subsidies and no nuclear taxes	**$\gamma = 1$**	81 127	34 408	34.0	43.1
	$\gamma = 0.75$	81 300	34 581	34.0	43.0
	$\gamma = 0.5$	81 461	34 742	34.0	43.0
	$\gamma = 0.25$	81 544	34 825	33.9	43.0
	$\gamma = 0$	81 824	35 105	33.9	42.9