The impact of the introduction (or phasing out) of nuclear power on electricity prices in a power exchange-based liberalized market.

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1. Introduction

Worldwide, there seems to be a twofold attitude towards nuclear power (NP) production. On one hand, the increasing cost of hydrocarbons, the security of supply concerns and environmental pressures related to global warming are encouraging new investment in NP plants for electricity production in several countries, such as Russia, Finland, India, China and the United Kingdom (UK).[1] On the other hand, increasing safety concerns, exacerbated by the accident at the Fukushima Daiichi Nuclear Power Plant in Japan, have delayed or halted NP development plans in those countries that were planning to extend the operating licences of existing NP plants or build new ones, such as Germany and Switzerland, or reintroduce NP plants where they were previously phased out, such as Italy. Regardless of the different trends that can be observed in several countries, from an economic point of view the issue of compatibility of NP with liberalized markets remains an open point to be analysed. In particular, an intriguing and challenging research question refers to the evaluation of the impact that the introduction of NP may have in a liberalized electricity market in which electricity is traded in a centralized power exchange.[2] Indeed, increasing the share of NP production in the production mix should lower the price of electricity, taking into account the NP's marginal cost component. The rationale for this is that the wholesale electricity price is determined by the supply cost of the marginal technology, namely, the technology that is providing the last watt-hour in a given period of time. An increase in the base load determined by NP production would displace the supply curves of some more expensive hydrocarbon-fired turbine (HT) plants, thus lowering the marginal cost. The common counterargument to

[1] At the end of 2011, there were 63 plants already under construction and 143 planned in 28 countries. Source [9].

[2] In the literature, it is common to distinguish between a 'power exchange' and a 'power pool', on the basis of whether
[2] In the literature, it is common to distinguish between a 'power exchange' and a 'power pool', on the basis of whether there is a single price or a nodal one [13] or whether the participation to the market is voluntary or compulsory, respectively [2]. In what follows, we will refer to a power exchange in a broad sense, namely, a centralized market for exchanging electricity at a wholesale level with a single equilibrium price. Moreover, we will assume that all plants, including NPs, will participate in the exchange, regardless of whether such participation is compulsory or not.

this is that, if the amortisation and fixed-cost component of NP production are to be restored through some specific component of the electricity tariff, the end price for consumers may increase. However, both arguments should be contextualised in the specific market structures and physical settings of a given real power system. The proper way to evaluate the possible impact of NP introduction in a liberalized market is to assess hour by hour which plant is likely to be displaced, i.e., become ultra-marginal by the supply of NP. This can be done by trying to replicate, in the most realistic way, the specific market setting where the NP plant is assumed to be introduced, taking into account both its actual and perspective characteristics (grid constraints, physical location of all other plants, load shape and size, etc.). This is the aim of our work. In order to evaluate the impact of the possible introduction of NP production in a liberalized pool-based market, we analyse the behaviour of a real market through an agent based simulation,[3] which is able to provide a rich understanding of the dynamics of player interaction, as well as viable forecasts of future dynamics. We frame the study in the context of the liberalized Italian market for several reasons. First of all, it is one of the most liquid power exchanges in Europe [1]. Transmission constraints play an important role in the Italian market, which is split into price zones. This, coupled with the observation that the structure of the power supply is largely dominated by gas-fired power plants, ease the identification in each zone and hour of the power plant that is most likely to be displaced by the introduction of NP. Moreover, the Italian ISO makes available (with a time lag) a large set of data regarding the effective hourly market bids submitted, as well as the characteristics of all active plants for a sufficiently long time series. This allows disaggregating the analysis at an extremely detailed level. Finally, there is presently no NP production in Italy. There were plans to introduce it, but those plans were halted by a referendum following the accident at the Fukushima Daiichi Nuclear Power Plant. Regardless of the effective future introduction of NP in Italy, the information available on the proposed NP plan, its actual absence in the market and the level of disaggregation of the available data allow us to realistically simulate, to a large degree, the impact of NP introduction for different possible scenarios of NP ownership. Indeed, when assessing the possible consequences of some market interactions, it is insufficient to evaluate the market structure. It is also important to take into account the behaviour of those who participate in the market. It is commonly assumed that NP plants cannot be used strategically, reducing the market supply in order to set the price. As mentioned before, the introduction of a large base load shifts the supply curve to the right,

[3] The agent-based literature on electricity markets is quite vast. For an extensive survey on the topic see [7], [8].

crowding out other plants that have higher marginal costs and reducing the equilibrium price. Let us call this the "base-load effect". The introduction of such a large baseload generator, however, increases the possibility of rent-seeking by its owner, if it can operate strategically on the equilibrium price of the market, i.e., the system marginal price (smp) withholding some capacity from the market. Consider Figure 1.

[Figure 1 about here]

Figure 1: Power exchange market equilibrium (a) with physical withholding (b) and economical withholding (c) of capacity.

In (a), we have reported five hypothetical supply bids made by plants fired under different technologies (labelled as 1 to 5 in the figure), and ordered on the basis of these bids. Let the bids correspond to the marginal cost of production for each technology. Given the load (in red), the second highest expensive is the marginal supply (the technology whose marginal cost determines the equilibrium price). The most expensive in such a market configuration is not dispatched. The lowest supply bid is the NP plant. The dashed area in (a) is the NP plant's rent (difference between the equilibrium price – system marginal price – and the production cost for a given amount of energy produced). Assume that the owner of the NP plant owns another non-NP plant, e.g., the supply curve (labelled 3) described by the dotted line in Figure 1 (a). Such an owner can be tempted to behave strategically, withholding the capacity of the non-NP plant; even if it would lose the marginal rent of the non-NP plant (dotted in Figure 1 (a)), it would gain the increase on the marginal rent of the NP plant due to the increase in the equilibrium system marginal price (vertically dashed area in Figure 1 (b)). This may lead to a net positive gain, as depicted in Figure 1 (b). Notice that it is not necessary to physically withhold capacity at the power exchange. There can be an economic withholding, namely, bidding at a price higher than the marginal cost in order to induce the market maker to alter the cost merit order, as described in Figure 1 (c).[4] The possibility of operating strategically

[4] In principle there are two types of withholding, physical withholding (in which a serviceable power plant is deliberately rendered unavailable) and economic withholding (in which high bids are submitted in an expectation that the plant will not be called upon to run). We assume a market in which all economic withholding is permitted. Situations of physical withholding are not modelled, but the importance of such tactics is arguably moot in a context where economic withholding is unconstrained. The real Italian market allows economic withholding and forbids physical withholding (whenever the plants' unavailability is not due to cases of force majeur and is aimed at influencing the price).

with HT power plants owning NP plants can be termed "strategic interaction effect". Studying the extent that the latter can impact on the base-load effect is the aim of this paper.

In order to perform our task, we simulate the actual effective behaviour of the Italian power market. We create an agent-based interaction model that replicates the wholesale day-ahead Italian market and calibrate it over a sufficiently long time series. Then, we describe the structure of the power system at the time the NP plants may become active, according to a plausible scenario for technologies and grid structure. We repeat the simulation under the foreseen scenario to calculate the future hourly electrical prices for some representative days of the year, with and without NP plants. For the former case, we will investigate if and how the structure of competition across agents will be altered by the introduction of such a large baseload generator, if it is assigned to a single market operator.

The paper is structured as follows: In Section 2, we describe the actual structure of the day-ahead market that we investigate in our analysis. In Section 3, the agent-based simulation methodology is introduced, explained and discussed. In Section 4, we briefly describe the structure of the prospective scenario for the year 2025, first without NP plants and then introducing the proposed NP plants into the scenario. The simulation of the electrical prices in 2025 is presented in Section 5. Conclusions and references follow in Section 6. The Appendix describes in greater detail the characteristics and assumptions adopted for the 2025 scenario.

2. The power exchange market model

2.1. The day-ahead market

The model we adopt here replicates the features of an actual centralized wholesale power exchange market, namely, the Italian wholesale day-ahead market (DAM) of the Italian Power Exchange (IPEX). Bids in the pool consist of[5] $\widehat{Q}_i$ and $\widehat{P}_i$, the quantity that will be produced and the minimum price that will be accepted for that quantity for each hour of the subsequent day. We assume that each unit of power generation have a lower $\underline{Q_i}$ and upper $\overline{Q_i}$ production limits that define a feasible production interval for its hourly real-power production level: $\underline{Q_i} \leq \widehat{Q}_i \leq \overline{Q_i}$ (MW). Generator cost curves for hydrocarbon-fired thermal (HT) power plants, are usually not smooth. One commonly used approximation is to represent generator total

5 The bidding format of supply functions allows a maximum of four couples of prices and quantities offered. However, a simple statistical analysis performed on historical data shows that almost 75% of the offers are composed of a single point bid.

variable costs, i.e., costs of operation, as quadratic functions [12]. The cost function of the ith thermal power generator is:

$$TC_i = (FP_l + ETS \cdot x_l) \cdot (a_i Q_i^2 + b_i Q_i + c_i) \quad (1)$$

where both FP_l and x_l (Euro/GJ) are fuel-specific parameters: the price of the fuel l (GJ) used by the ith generator and the conversion value to determine the amount of CO2 generated by the combustion of a unit of fuel l. ETS is the price of carbon permits in the European Emission Trading System. Coefficients a_i (GJ/MW^{2}h), b_i (GJ/MWh) and c_i (GJ/h) are assumed to be constants, but vary across power plants with different technologies and efficiency levels. They represent technology-specific efficiency parameters that specify the relationship between the energy input and output. The constant term $(FP_l + ETS \cdot x_l) \cdot c_i$ corresponds to the no-load cost, the quasi-fixed costs that generators bear if they continue to run at almost zero output. However, these costs vanish if energy is not supplied.

We assume, as is common in the literature for HT power plants [13], that plants' amortisation is being repaid by marginal rent that is assigned to producer g, once the energy price is set by the system. The marginal costs MC_i (w.r.t. Q_i) for the ith thermal generator can be easily derived from the cost function TC_i:

$$MC_i = (FP_l + ETS \cdot x_l) \cdot (2a_i Q_i + b_i) \quad (2)$$

Demand is assumed to be rigid. After receiving all generator bids, the market operator, (Gestore del Mercato Elettrico in the case of IPEX), clears the market by performing a total welfare maximisation, subject to the equality constraints posed by the zonal energy balance (Kirchhoff's laws) and inequality constraints, i.e., the maximum and minimum capacity of each power plant and inter-zonal transmission limits. This is generally denoted as the DC optimal power flow (DCOPF). The welfare maximisation, given inelastic demands, corresponds to the total production cost minimisation problem providing the locational marginal price (LMP). The LMP is the shadow price of the active power balance equations constraint (Kirchhoff's law) in each zone [10]. In the model we adopt (which mimics the Italian market), an LMP is set for each zone, namely a subset of the transmission network that groups local

unconstrained connections.[6] Producers receive their zonal LMP, while consumers in the wholesale market, i.e., retailers (load-serving entities) pay the weighted average of the zonal prices (called national single price in the case of Italy).[7]

In our work, we take into account real demand, including that traded on forward markets, which is effectively dispatched. Supply from imports, hydropower (including pumped-storage facilities) and other renewables is modelled as must-run production at zero-price. Bilateral contracts are modelled on the supply side as quantities at zero-price. The system marginal price is given in each zone by the LMP of the marginal thermal technology. For HT plants, the profit per hour R_i for the ith generator belonging to zone k is obtained as follows:

$$R_i = ZP_k \cdot Q_i^* - TC_i \cdot Q_i^* \qquad (3)$$

where Q_i^* is the equilibrium quantity generated by each power plant. It is the quantity that solves the ISO's cost minimisation problem, given the constraints and the quantity offered by each plant. ZP_k is the set of LMP prices calculated by the ISO for each zone $k \in \{1,2, \dots, K\}$.

3. The agent-based simulation methodology

The constructed model replicates the rules of the power exchange. Demand is assumed to be price-inelastic and equals the historical load profile for the observation period. The supply side of the market is composed of generation companies (GenCos) submitting bids for each of their power plants and gaining an overall profit, which corresponds to the sum of the profits displayed in Equation 3 for each plant they own. Agents/GenCos simultaneously submit 24 bids, one for each hourly session of the wholesale market. Each hourly market is assumed to be independent. Plants are grouped by five major technologies: coal-fired (CF), oil-fired (OF), combined cycle (CC), combined heat and power (CHP) and turbo-gas (TG). Each gth GenCo, g = (1, 2, ..., G), owns $M_{z,f}^g$ thermal power plants in zone z with technology f. We collect the $M_{z,f}^g$ power plants of GenCo g in zone z and of technology f in a representative generating unit r = (z, f), and we assume that GenCo g adopts a common strategy for them. By doing so, we reduce the size of the strategy space. Let us denote N_r^g as the number of representative generating

6 This is without loss of generality: when the transmission constraints are not binding, i.e., there are no relevant transmission constraints, the smp of each zone coincide.

7 Zones are defined and updated by the TSO (Terna, in the case of Italy) based on the evolution and the structure of the transmission power-flow constraints. The transmission network model considered in this paper reproduces exactly the zonal market structure and the relative maximum transmission capacities between neighbouring zones of the Italian grid model, as defined by Terna S.p.A. for the reference period.

units of GenCo g in all zones and for all technologies. For every r and every hour h, each GenCo g bids to the DAM $M_{z,f}^{g}$ pairs of values $\left(\hat{P}_{r,1}^{g}, \hat{Q}_{r,1}^{g}\right)$, … , $\left(\hat{P}_{r,M_{z,f}^{g}}^{g}, \hat{Q}_{r,M_{z,f}^{g}}^{g}\right)$. $\hat{P}_{r,i}^{g} = a_{r}^{g} \cdot MC_{r,i}^{g}$ ([Euro/MWh]) corresponds to a limit price, where $a_{r}^{g} \in A_{r}^{g}$ denotes the common mark-up value adopted for all power plants belonging to the representative power unit r and $MC_{r,i}^{g}$ is the marginal cost of the ith power plant belonging to the rth representative power plant owned by GenCo g. GenCos are assumed to bid the maximum capacity for each power plant $\hat{Q}_{r,i}^{g} = \bar{Q}_{r,i}^{g}$ [MW]. Let A^{g} denote the action space of GenCo g. It equals the Cartesian product of the action space of each representative unit it owns: $A^{g} = \times_{r} A_{r}^{g}$, where A_{r}^{g} denotes the action space of the representative generating unit. Actions are mark-up levels. In the computational experiments, we assume A_{r}^{g} = {1.00, 1.04, 1.08, …, 5.00}, corresponding to a mark-up increase value of 4% and a maximum mark-up value of 500%, with respect to the marginal cost, for a total of 100 actions. The strategy space is huge. In order to make the problem computationally tractable, a learning procedure based on a standard genetic evolutionary process has been employed. Each GenCo repeatedly interacts with the other companies at the end of each run t ∈ 1, …, T; that is, they all submit bids to the market according to their current beliefs of the opponents' strategies. At the beginning of run t, GenCos need to study the current market situation in order to identify a better reply to the opponents, to be played at the end of run t. In order to explore its strategy space in search of a better strategy, the gth GenCo needs to repeatedly solve the market for different private strategies, and keep fixed the strategies of its opponents at run $t-1$. This procedure is adopted in order to enable each GenCo to learn foregone profits by exploring the profitability of fictive actions. A standard genetic algorithm is adopted to keep a large population of candidate strategies and, at the same time, to improve their fitness/performance in the market. We define a population of size Po of strategies, which will evolve throughout the K_t generations belonging to run t. The number of generations per run varies with the run t. The idea is to favour exploration in initial rounds (small values for K_t) and then to exploit the gained experience (large values for K_t), expressed in the final population of candidates by the relative frequency of occurrences of each candidate solution F_{m_g}. Then, at the end of each run, each GenCo bids to the market by selecting one strategy belonging to its current population of candidates. The selection is done according to a probabilistic choice model in order to favour the most represented strategy in the population, i.e., the one that has best responded to the evolutionary pressure by ensuring the highest fitness. The logit is considered as the functional form of the probabilistic choice model. The

algorithm can be seen as an "approximate" best reply at each run because of three aspects: a) at each run, the population of candidate solutions represents only a subset of all actions; b) even if the number of generations progressively increases, it is limited and does not guarantee convergence to the optimal action for the current population; and c) a probabilistic choice model has been adopted to select the action being played by each GenCo at the end of each run.

For all simulations in the initial population of candidate actions, we have included the no mark-up case, that is, the bid at marginal cost. Furthermore, we have imposed that the first action being played by all agents at run $t = 0$ is the marginal cost for each power plant. Figure 2 describes in brief the agent-based iterative procedure (Figure 2 a), and the genetic evolutionary process (Figure 2 b). In particular, part (a) of Figure 2 describes the market clearing rules of the model in each zone, and the iterative procedure applied to reach the equilibrium. The left-hand side of Figure 2 b illustrates the game played in each round (except round 0) by all GenCos (labelled as action 3 in Figure 2 a), whereas the right-hand side zooms into the behaviour of one GenCo at one generic run.

[Figure 2 a about here]

Figure 2 (a): The agent-based iterative procedure.

[Figure 2 b about here]

Figure 2 (b): The genetic evolutionary process.

It is worth noting that the reward functions proposed in our model do not allow the emergence of tacit collusion. Some scholars [5], [6] have addressed such an issue in the context of auction markets. They have shown that a reasonable condition for the emergence of tacit collusion is the presence of an inter-temporal mechanism in the learning algorithm. Agents have to learn to increase not only their actual profit but also the stream of future profits in order to select game outcomes corresponding to collusive behaviours. In our learning model, on the contrary, agents play in each round a one-shot game and do not take into account the sum of future profits.

The model's parameters have been calibrated in such a way that during the final run all the GenCos select their optimal action given the final population of strategies. After calibrating the model, 10 computational experiments were run on a sufficiently long time series in order to

measure the performance level of the simulator. In particular, the average results of the simulations were compared with the observed time series of the hourly prices that were effectively realised in the Italian market for an entire week, for three different weeks of the year 2011, corresponding to different yearly load profiles (high-, mid- and low-demand periods). The correlation coefficient between the 504 observations and the simulations equals 0.78, showing a satisfactory performance level of the model.

4. The simulated future scenarios

We start by simulating a scenario for the market described above by the time in which it is possible to assume that the NP plant will be on line. Indeed, we frame our analysis in the context of a real market, trying to replicate its features with our simulator. We have, therefore, taken into account the time-to-market of NP production in such a market, foreseeing its structure by the time it is will be possible to have NP plants on line. We chose year 2025 as the reference year for the evaluation of the possible impact of NP production in the (Italian) power exchange on the basis of our evaluation of the long delays in prior large Italian investment projects and the long time-to-market of other new NP projects (such as Olkiluoto in Finland).

4.1. The forecasted scenario without NP Plants[8]

The 2025 scenario depicts the future structure of electrical supply and demand. It relies on the forecast created by a leading Italian research company specializing in energy markets (REF-E S.r.l.) and has been discussed and validated with market operators and institutional entities. It takes into account: *i*) the existing plans to dismiss power plants, renovate power plants or invest in new power plants, as have been disclosed by existing operators; *ii*) a plausible evolution of the market share of the operators; *iii*) the planned investment in the grid by the Transmission System Operator (TSO); *iv*) the introduction of new power capacity due to renewable sources considering the EU targets; *v*) the introduction of the best flexible thermal technology that is actually being developed, which is also needed for system balancing; and *vi*) the forecasted evolution of energy vector costs and energy demands.

We stress, however, that the 2025 scenario is created only to provide a plausible benchmark

8 The scenario has been developed by REF-E S.r.l., a leading consultancy company in Italy and discussed with operators and public bodies. It is described in greater detail in the Appendix. For further details, please contact REF-E S.r.l. at the following email address: info@ref-e.com.

case to contrast with the introduction of NP plants, under both the independent and strategic cases, at a time in when it is meaningful to assume that NP can be introduced into the market. For this reason, even if we have made great efforts to describe and incorporate a realistic description of the market in 2025 into our simulator, we do not undertake a sensitivity analysis to the set of all relevant prices, but rather focus on the main research question, namely, evaluating the impact of the introduction of NP into a power exchange under different possible ownership structures.

4.2. The introduction of NP plants.

NP production can assume very different configurations based on market size, technology, ownership, et cetera. In our work, aiming at replicating most accurately the structure and behaviour of real markets, we tailor the future NP plants to those that were proposed for the Italian case. In particular, we assume, cohering with the information available at the time of the proposed NP reintroduction in Italy, that NP capacity will be derived from four 1650 MWe reactors (based on EPR technology). As for the physical location, we assume that they could be uniformly distributed across the major zones, the north, centre-north, centre-south and south, for the following reasons: a) such a distribution would minimise the impact on the transmission network and reduce transmission losses; this would cohere with the TSO Strategic Plan aimed at eliminating zonal congestion by 2015; b) a uniform distribution may reduce the opposition of local communities, which may be exacerbated by the concentration of NP plants in particular regions; and c) it roughly corresponds to the distribution of former NP sites, which indicates the proper physical locations for NP plants.

We assume, moreover, that the increased capacity based on NP installation will reduce the need for investments in new capacity in the NP scenarios, given that NP power is a must-run base load. This implies that the new capacity that is expected to come in line is lowered to 7.4 GW under the two NP scenarios, and the additional 6.6 GW are replaced by NP capacity (see the Appendix for details).

A crucial element to simulate market behaviour refers to the ownership of NP plants. The benchmark case, namely, the case in which the introduction of NP plants does not alter agents' market behaviour, is simulated assuming that NP plants are independently owned, i.e., owned by agents different from those who possess other power plants. We shall call it the NP-IND(ependent) Scenario. Such a case will be compared with the opposite, namely, the scenario

in which the NP plants are attributed to the agent who has the largest market share, which we shall term NP-STR(ategic) Scenario.

4.3. The simulation of PUN in 2025 with and without NP plants

We assume that market rules will remain unchanged. Therefore, we first repeat the simulation exercise described in Section 3 for 2025 without NP plants (NO-NP Scenario). We simulate the price for four days, a working day and an off-peak day both in a high- and a low-load period. We stress that the simulation exercise should not be seen as a tool that forecasts the hourly Italian electrical prices exactly, but rather provides a reference measurement to compare the role played by NP plants under the same circumstances. The price is simulated for 24 hours of a mid-week day (Wednesday) and a week-end day (Saturday) of a peak and off-peak load week (the 28th and 39th week of 2025). On these days in the simulations, there are 40 active agents in the market. After running the NO-NP scenario, the simulation of prices in year 2025 for the representative days chosen is repeated introducing the NP plants. The methodology described in Section 3 is updated, assuming that four EPR reactors will be active in the NP scenario. The following equation describes the cost function of an NP plant:

$$TC_{NP}(Q_{NP}) = dQ_{NP} \tag{5}$$

where d is the (constant) NP marginal cost that depends, inter-alia, on the technology adopted, the uranium cost, the enrichment process costs and the operation and maintenance (O&M) expenses, including waste cycle management. QNP is the energy supplied to the market by the NP plant. The marginal cost of NP has been set[9] at 10 Euros/MWh. The cost function in Equation 5 allows us to calculate the operating profit of the NP plants. The nuclear power plants' profits are:

$$R_{NP} = (ZP_k - d)Q_{NP} \tag{6}$$

We focus on the NP plants' operating costs rather than full profits, because we do not intend to evaluate ex ante the optimality of the decision to invest in NP, but rather to measure ex post

[9] For NP costs, see [4]; [11]; [14], [15] and the discussion in [3]. Notice, however, that for the purpose of our simulations, the exact estimation of the cost is not relevant, because NP is simulated as a must-run technology that generates the base load for the electric production. It is sufficient, therefore, that the assumed marginal cost is lower than the cost for the other fossil-fuelled power plants.

the impact of such a decision on energy prices. In other words, we assume that, if NP plants are going to be built, this is because some economic agents will have decided to do so, namely, will have envisaged the possibility to gain some long-run profits, which are not modelled here.

For the NP-IND scenario, a single agent that owns the NP plants is added to the other 28 agents that represent HT power plants, replacing the 12 NC producers that are supposed to be active under the NO-NP scenario. The NP producer always bids at the NP marginal cost, i.e., its bid is (d, $4Q_{NP}$). This implies that its bids are always accepted and that it constitutes the base load of energy production, which is consistent with the observed behaviour of other markets with active NP plants. In the NP-STR Scenario, the four NP plants are owned by the largest market operator. Economic capacity withholding by such an operator is allowed through strategic bidding, namely bidding at a high price on the other technologies and inducing the market maker to refuse the offer, thus pushing the price up by withholding capacity from the market. We modify the profit function of the largest operator (LO) including NP rent, as follows:

$$R_{LO} = \sum_r R_r + R_{NP} \qquad (7)$$

In all scenarios, all other agents can operate strategically with the bids on the HT technologies.

5. The wholesale electrical price by 2025

We report the simulation results for the chosen days in 2025 in Figures 2 and 3. The figures display the hourly prices in the three scenarios (left axis) and the market demand (right axis), for the Wednesday (left panel) and Saturday (right panel) in July (Figure 3) and October (Figure 4). Table 1 describes the summary statistics for the chosen days, distinguishing between peak and off-peak hours.

[Figure 3 about here]

Figure 3: Simulated prices for the NO-NP (blue circle-marked line), NP-IND (black diamond-marked line) and NP-STR (red circle-marked line) scenarios - left axis; market demand (dashed line) - right axis; Wednesday, the 4th (left panel) and Saturday, the 9th (right panel) of July 2025.

[Figure 4 about here]

Figure 4: Simulated prices for the NO-NP (blue circle-marked line), NP-IND (black diamond-marked line) and NP-STR (red circle-marked line) scenarios - left axis; market demand (dashed line) - right axis; Wednesday, 01 (left panel) and Saturday, 04 (right panel) of October 2025

		July (09 and 12)			October (01 and 04)		
		NONP	NP-IND	NP-STR	NONP	NP-IND	NP-STR
Mean price	all hours	77.16	73.39	74.40	105.05	75.18	78.51
St. Dev.		7.63	10.17	11.24	30.43	16.98	20.62
Mean price	peak hours	84.15	83.60	86.72	136.96	95.74	105.18
St. Dev.		0.35	0.05	1.08	26.45	21.02	23.17
Mean price	off peak hours	74.57	69.60	69.83	93.19	67.54	68.61
St. Dev.		7.40	9.39	9.73	22.35	4.56	5.03

Table 1. Simulated prices for the NO-NP, NP-IND and NP-STR Scenarios and summary statistics

The plotted time series show quite different behaviours between the two weeks. The weeks in July show a rather stable pattern for the hourly demand, completely flat for the peak hours. This is coupled with an almost uniform shape for the peak hours in the NO-NP time series, which becomes slightly more volatile during the off-peak hours. The October demand is higher and more volatile across all hours. The NO-NP time series is higher on average and more volatile as well, both in peak and off-peak hours. The introduction of NP reduces the average prices. This can be observed by comparing the NO-NP time series with the NP-IND series. When prices are low, as in July, the reduction is extremely small: 0.6% in peak hours and 6.6% in off-peak hours. The reduction is much higher when prices are high, as is the case of the October simulations: 30% in peak hours and 27.5% in off-peak hours. In October, the introduction of NP also reduces the volatility, in particular of the off-peak prices. On the contrary, there is a slight increase of volatility in July. However, its impact on prices is quite negligible. In summary, the impact of NP on electricity prices seems to corresponds to what is expected, namely, the higher the price the more NP reduces them and stabilizes the market. However, such a result crucially depends on the ownership structure of the NP plants. In the simulation, we have considered two extreme cases: one in which there is an independent and non-strategic ownership, and another in which there is an ownership fully concentrated in the hands of the largest operator. In the latter case, the possibility for the owner of the NP plant to

operate strategically, using the HT power plant, generates positive strategic externalities that may increase prices. This can be observed by comparing the prices and the volatility for the NP-IND and the NP-STR scenarios. In situations with high prices, as was the case for the October simulations, the relative increase in the NP-STR series compared to the NP-IND series was not high enough to overtake the reduction in prices, due to the introduction of a large nuclear base load. As a result, prices are reduced compared to the NO-NP Scenario, yet less than in the NP-IND Scenario: 23% during peak hours and 26% off-peak. However, when prices are low, as in the July simulation, the base load effect due to NP production is highly reduced or more than compensated for by the increase in prices, due to the strategic externality effect: Peak hours prices in the NP-STR scenario are, on average, 3% higher than they are in the NO-NP scenario, while there is hardly any change for off-peak hours.

6. Conclusions

This paper examines the possible impact on electricity prices by introducing NP plants into a liberalized system based on trades at a power exchange. In order to do this, a realistic agent-based model was created that replicates a true market, namely, the Italian day-ahead one, along with its structural supply and transmission conditions. Given that the NP introduction takes time, the analysis is placed in the future, assuming a plausible market scenario based on conjectures discussed and validated with real market operators. In such a scenario, prices are simulated with and without NP. It is shown that NP power production will reduce and stabilize prices. The effect is high in situations with high prices, but quite negligible when prices are lower. Such an intuitive result, however, depends crucially on the ownership structure of the NP plants. Indeed, the simulations show that the strategic interaction effect induced by the possible joint ownership of NP and non-NP plants partially compensates for the reduction in prices due to the base-load effect. However, its net impact crucially depends on the level of electricity prices without NP and the magnitude of the base-load effect. When prices are high, the magnitude of the base-load effect is also high; thus, there is a net positive impact on prices due to the reintroduction of NP: electricity prices are reduced. However, when electricity prices are not high, the order of magnitude of the base-load effect is low as well. This implies that the strategic interaction effect may more than compensate for the reduction in prices, due to the reintroduction of NP.

Several caveats must be mentioned when interpreting the results of our simulation. The result depends, first of all, on the assumptions adopted in the agent-based interaction through which

we simulate the market behaviour of the players. Indeed, no collusion among agents is allowed in the model, while, in reality, there may be some uncompetitive behaviour, both at present and in the future. This problem could be reinforced by the structure of bids that agents in our model are allowed to place. Indeed, only simple bids are assumed in the model, while in reality, 25% of bids are complex, such as multiple prices and quantities; complex bids may favour a (implicit) collusive behaviour (for instance through hockey-stick bidding strategies). However, they are not considered in the simulation. One further source of discrepancy stems from the specific modelling assumptions related to the historical characteristics of the market scenarios learned by the adaptive agents. In our model, each hourly auction is independent from the other hourly auctions. Even if this resembles the structure of the market, it is very possible that, in reality, agents do not treat those hourly auctions as independent. Moreover, the misalignment between the expected demand and supply and the real one is another potential source of mismatch among bidding strategies in the current model. A detailed study on the optimal assumptions on past expectations that would determine the best fit goes beyond the aim of this paper; however, it is certainly an intriguing research issue that will be addressed in future works.

We do not aim at evaluating the likelihood or the economic viability of NP reintroduction in a given market, for instance in Italy. For the latter, a clear estimate of NP investment costs would be needed, as well as an assessment of other aspects, such as risks, externalities, social consensus, and other similar factors. Such an analysis is beyond the scope of our work. Our aim was simply to try to measure, in a realistic context, the impact of a possible introduction of NP on electrical prices (which are just one of the components of the tariff paid by end-consumers) taking into account both the agents' behaviour and market structures. We have shown that the ownership structure is an important point that must be taken into account when evaluating NP reintroduction, as well as the level of the demand. Both affect the relative importance of the price reduction due to NP production.

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Appendix. The 2025 scenario for the Italian market

The 2025 scenario begins by evaluating the Italian economic growth, which is expected to return to its (low) long run level. This determines the recovery of the electrical demand growth after the present economic crisis. However, the composition of demand will be changed by the reduction of residential demand, due to improved energy efficiency, and the increase in the service sector demand, coupled with the increase in private transportation and heating needs. By 2025, the electrical demand is expected to be equal to 421.1 TWh. The future hourly composition of the market thermal load, i.e., the net demand for self-production, renewables, imports and pumped-storage hydroelectric, will be different from the current situation. On one hand, there is expected to be a rise in production from renewables, fostered by European and national programs for the development of sustainable energy. As a result, it is expected that 30% of electricity consumption needs will be filled by renewables in the year 2025, of which 40% will be hydroelectric, 17% wind power and 23% PV. On the other hand, there will probably be a reduction in imports, due to a reduction in base load electrical production in Germany and Switzerland, following their NP phase-out, which will be replaced by some other more expensive forms of energy. Moreover, the reduction in residential demand is coupled with an enhanced domestic efficiency due to improved two-sided real-

time metering that increases off-peak demand. As a result, the hourly profile of the market thermal load is expected to assume a more uniform shape compared to that of 2010, with reduced differences between night-time and peak hours. The hourly profile for the market thermal load for the simulation period is displayed in Figures 2 and 3 (right axis). The structure of supply is expected to evolve also. On one hand, older power plants are expected to go off-line on the basis of their age or repowered according to plans brought to the market by operators. This, however, will not significantly change the actual power supply structure until 2020, given that the Italian power plants are quite new on average. After 2000, 60% were entered into production, and 35% were entered after 2005. A new large ultra-super critical coal-fired plant (about 2 GW at Porto Tolle) is expected to be operating by 2021, together with other CC units. After 2020, the estimated need for newly installed capacity rises in order to maintain the adequacy of supply. The reserve margin is expected to fall far below the targeted level of adequacy (23%), because of the dismissal of old plants and the increasing relevance of renewables. This implies that there will be an increasing need for new, flexible capacity in order to balance the system. The price signals on the day-ahead market and the ancillary service market would induce new investment in the best flexible technology, which, at present, we expect to be the full-flexible combined cycle gas turbines with a top efficiency factor of 61%. The long-run scenario does not consider the introduction of any new Capacity Remuneration Mechanism aimed at addressing explicitly the need of adequate capacity. Thus, the system will gradually become inadequate to cover the overall demand, and boom-and-bust investment cycles will occur. Such a dynamic is related to strong overcapacity and low margins for market participants during the boom phase, and capacity shortages and elevated margins during the bust cycles. For our simulation, this implies that, by the year 2025, there will be newly installed fully-flexible combined cycle gas turbines (we will identify these as "new CCGT", using the acronym NC) that will have a capacity equalling 14 GW. A caveat must be placed about the ownership of NC and the market share of operators. Indeed, it is expected that actual market share will not change very much, on the basis of the divested investment plans of existing operators, until 2020. In that year, the actual largest operator is expected to maintain its market share, measured in terms of installed capacity. By 2025, however, when new investments in NC will have been introduced into the market, such a new capacity will almost equalize the actual market share of the by-then largest operator. Clearly, attributing such a new capacity to a single owner implies abruptly changing the market structure of Italian electrical production from a market characterized by a leader and several smaller

followers to an almost pure duopoly. As a result, the other operators' market shares will be dramatically reduced by 2025, which is highly implausible. The new capacity will have to be planned, financed and constructed by companies. Already active in the Italian market, it is likely that active operators will exploit, at least partially, their pre-emption advantages when investing in the new NC. In order to provide a plausible description of market evolution, we assume, therefore, that the flow of investment to new capacity will be partially distributed across active operators and partially attributed to potential entrants. More precisely, it will be uniformly distributed[10] across the 28 existing GenCos in 2020. There will also be 12 newcomers that will provide an additional 6600 MW of capacity to the market. These new plants will be displaced by the NP investments under the NP scenario, as explained below.

New transmission and interconnection lines are expected to be completed according to the TSO Strategic Plan, which sets up the needed investment to eliminate zonal congestion. Accordingly, zonal prices will become uniform across zones by 2015.

Energy prices are expected to continue to covariate with Brent Blend oil price.[11] The latter is expected to reduce slowly from a $110/bbl spike and converge with the long-run limit set at $77/bbl. As a consequence, oil prices in 2025 will equal $89/bbl. The dollar/euro exchange rate is expected to oscillate around $1.42 by year 2025, and the price differential across energy vectors is assumed to replicate the actual one. The NG price is linked to oil prices through a standard indexing formula. Finally, the ETS cost is assumed to reach €28/tonCO2.

[10] The uniform distribution is chosen so as not to exogenously alter the market share of existing operators. It corresponds to the application of the probabilistic principle of "insufficient reason", which claims that an equal probabilistic treatment is appropriate for similar cases, when there is no information supporting different conjectures.

[11] Brent Blend is a mix of crude oil from the North Sea that is commonly used in Europe as a price benchmark for crude oil.

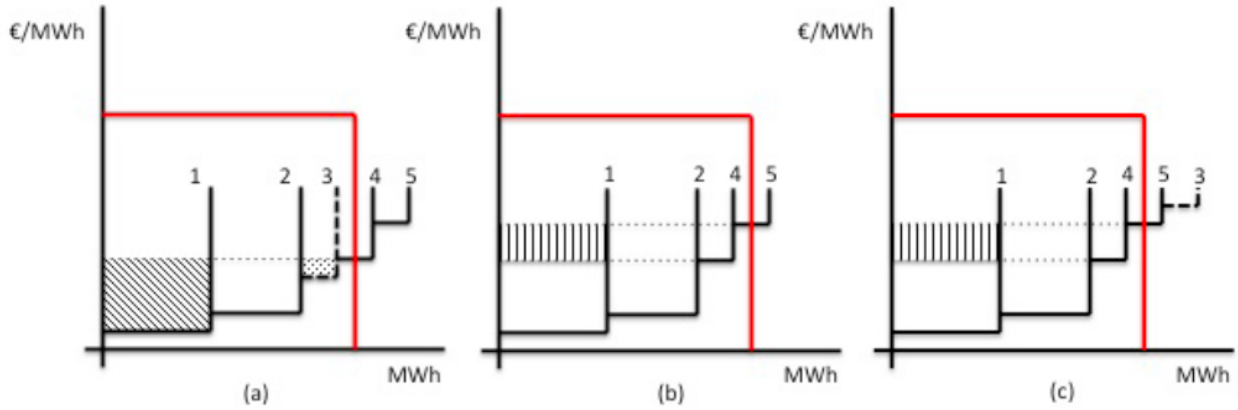

Figure 1: Power exchange market equilibrium (a) with physical withholding (b) and economical withholding (c) of capacity.

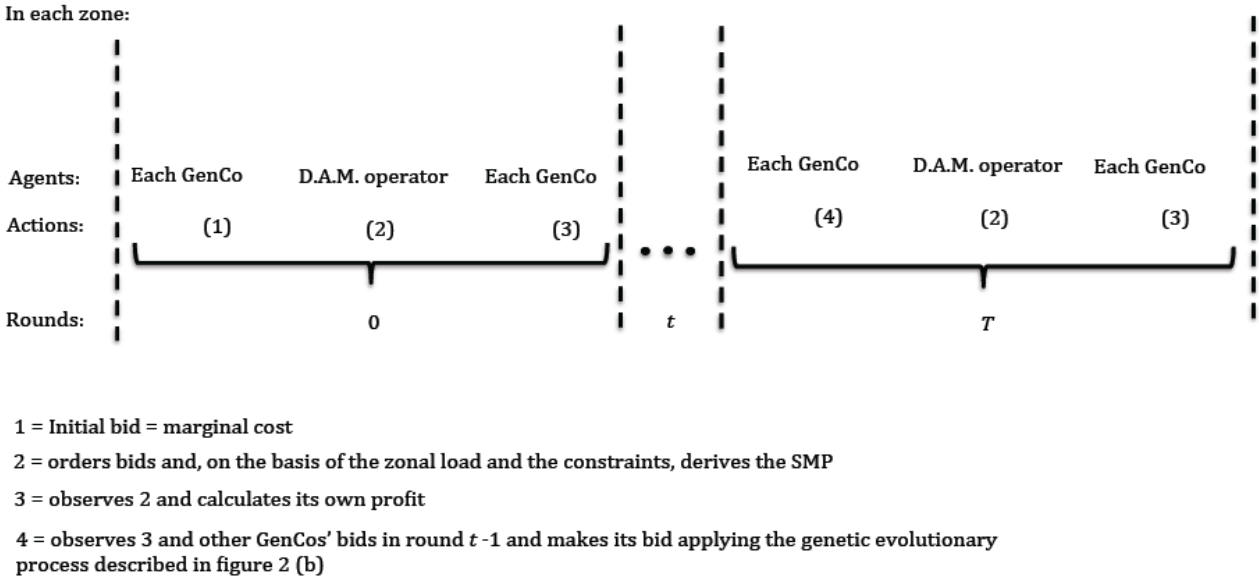

Figure 2 (a): The agent-based iterative procedure.

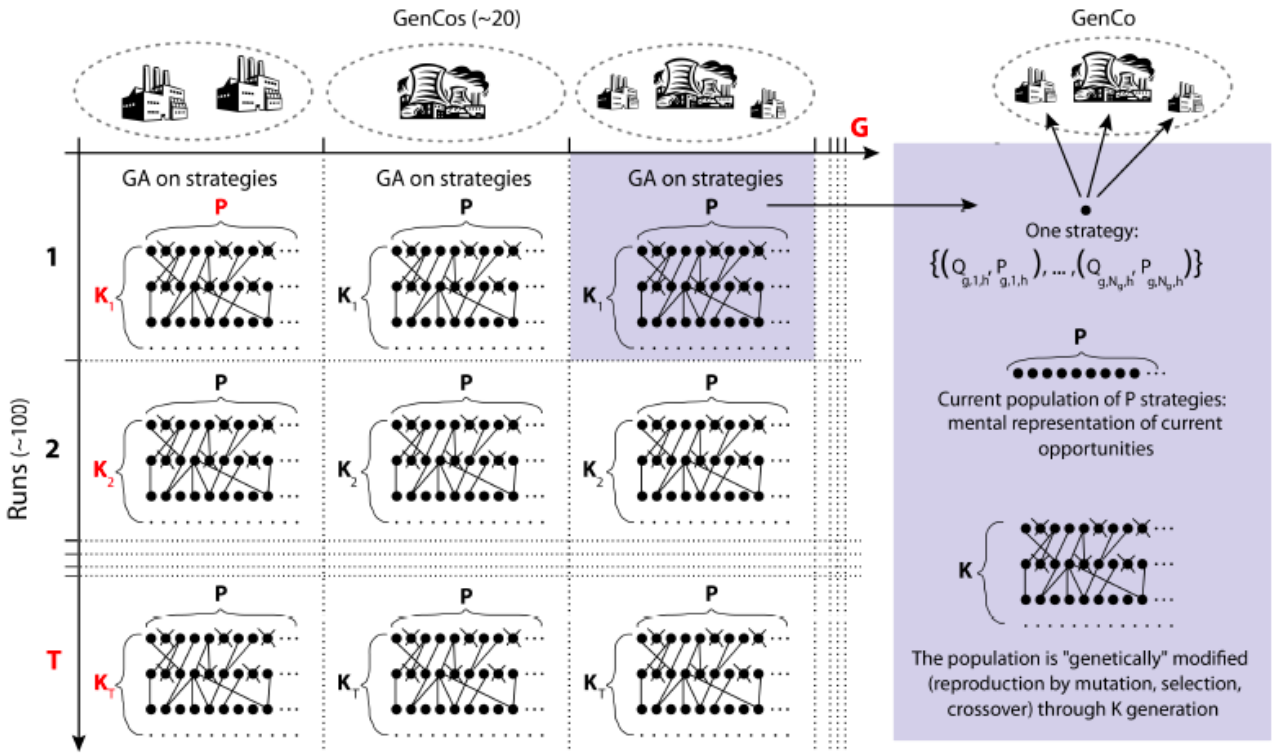

Figure 2 (b): The genetic evolutionary process.

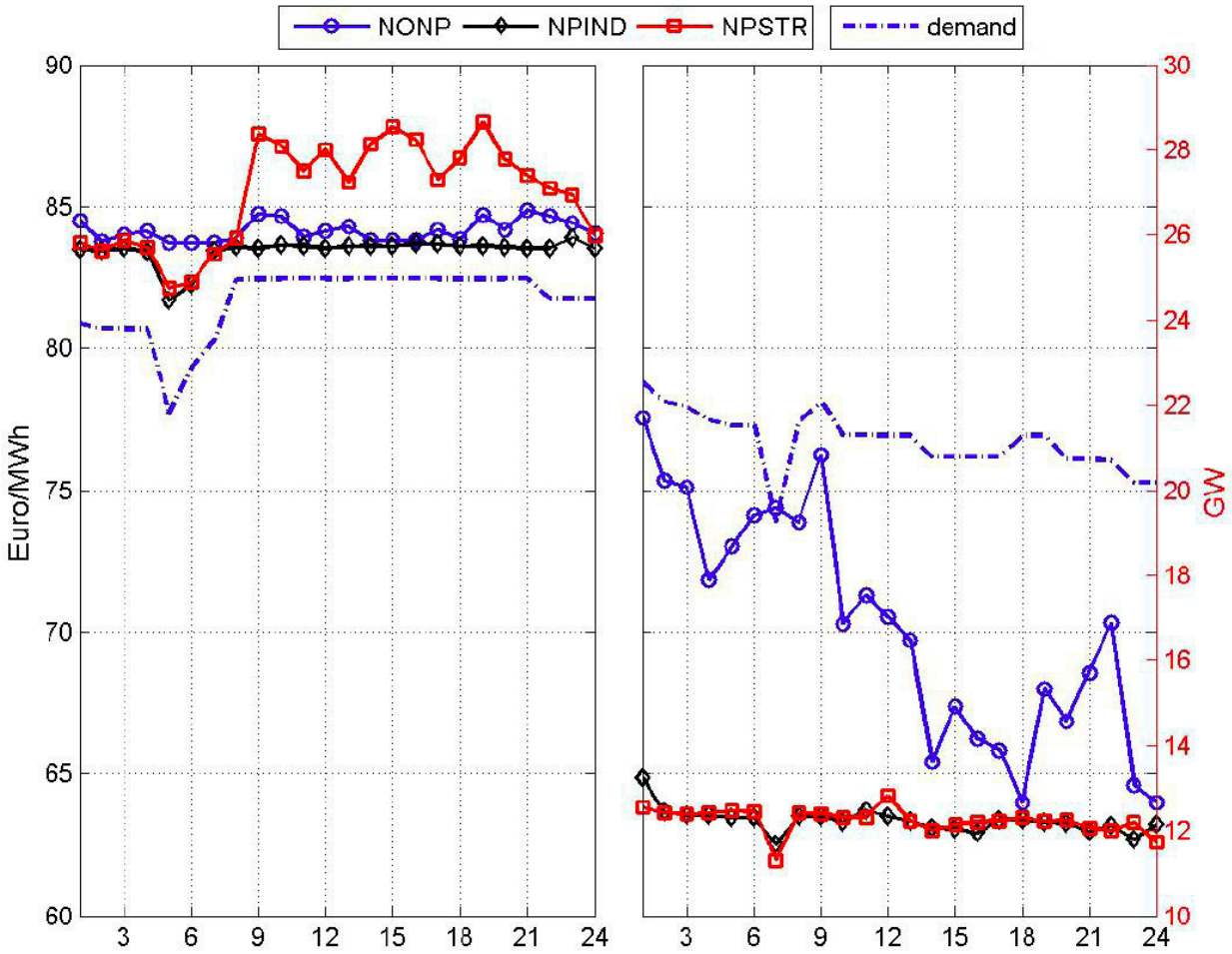

Figure 3: Simulated prices for the NO-NP (blue circle-marked line), NP-IND (black diamond-marked line) and NP-STR (red circle-marked line) scenarios - left axis; market demand (dashed line) - right axis; Wednesday, the 4th (left panel) and Saturday, the 9th (right panel) of July 2025.

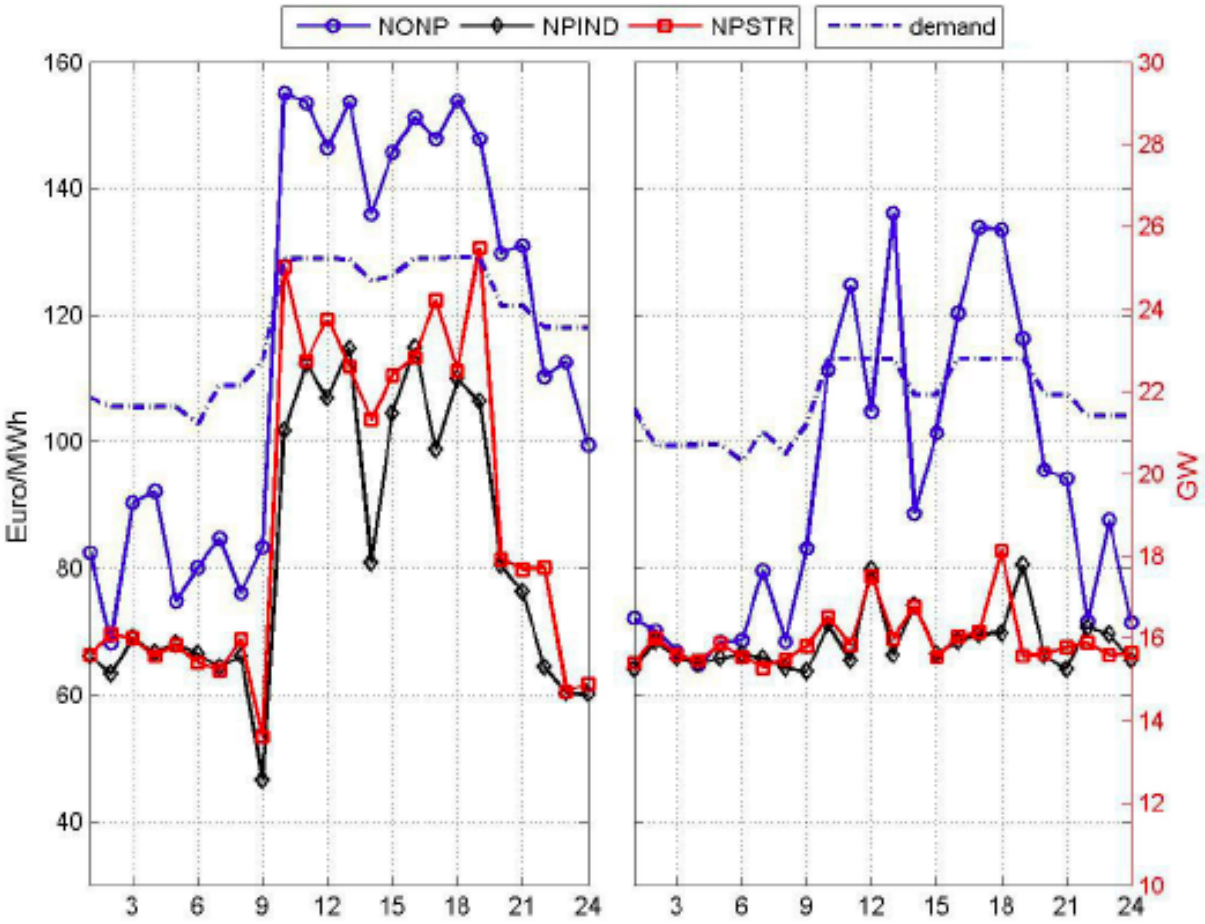

Figure 4: Simulated prices for the NO-NP (blue circle-marked line), NP-IND (black diamond-marked line) and NP-STR (red circle-marked line) scenarios - left axis; market demand (dashed line) - right axis; Wednesday, 01 (left panel) and Saturday, 04 (right panel) of October 2025