HIGH WIND PENETRATION IN AN AGENT-BASED MODEL OF THE ELECTRICITY MARKET
THE CASE OF ITALY[1]

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In this paper, we build a realistic large-scale agent-based model of the Italian electricity market and run simulations to investigate how a significant increase in wind capacity can affect electricity prices at the national level when the wind resource is geographically concentrated, as in the case of Italy. The simulator implements both cost-based and oligopoly models in which electricity companies learn to bid strategically. We compare a scenario based on the 2010 wind supply and a scenario based on the maximum potential wind capacity as estimated in technical reports. Results confirm the beneficial effect of low-cost renewable energy in reducing average market prices, but simulated power flows in the grid suggest that congestion in the electricity network induced by high wind penetration creates market power opportunities that can offset the price reduction effects.

Keywords: Electricity Market, Wind Power, Agent-Based Modeling.

A number of environmental and security issues in recent years have pushed energy economists and policy makers to analyze the prospects of renewable energy sources. Government programs for the abatement of greenhouse gases (GHG) emissions caused by, among other things, combustion of fossil fuels, have been adopted

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to face growing worries about anthropogenic climate change. Foreign dependence of most countries from fossil fuels, which are nearing depletion and cause diplomatic clashes, call for the intensified exploitation of locally available energy sources. The high human and economic losses due to nuclear disasters (Three Miles Island, Chernobyl, Fukushima), the fear of nuclear proliferation, and the signs of diminished financial attractiveness of nuclear investments (Bradford, 2012) trigger the quest for alternative, cheap energy sources. Hydroelectricity, wind, solar radiation, biomass, tidal waves, and geothermal heat pumps are renewable as they are replenished over time through natural processes; they are locally available; and their GHG emissions and impact on climate change are negligible.

While the environmental benefits of renewables are not under discussion, the debate is open concerning their economic efficiency (see Joskow (2011) and references therein). Power plants using progressive renewable energy technologies, such as wind power and photovoltaics, are characterized by small efficient scale and low variable costs, but upfront costs are high. Market entry therefore needs to be subsidized. The ensuing burden on public budgets is more acceptable for tax-payers if, besides bringing environmental benefits, renewables push electricity prices down.

The impact on electricity prices of increasing power production from renewables has been examined in a number of papers with a focus on wind power, a highly dynamic renewable source in terms of growth rates of installed capacity.[2] Sensfuβ *et al.* (2008), Sáenz de Miera *et al.* (2008), Twomey and Neuhoff (2010), Green and Vasilakos (2010), Banal-Estañol and Rupérez-Micola (2011b) and Sioshansi (2011) are among the main references. Price reduction effects are commonly found, since greater availability of a power source with negligible marginal costs causes the displacement of high-cost, fossil-fueled power plants. However, faced with the prospects of lower prices, oligopolistic power generating companies (gencos henceforth) may look for market power opportunities. One such opportunity can be given by congestion in the transmission grid caused by increased wind outputs. This is likely to occur

2. Worldwide wind capacity has grown from 74 GW in 2006 to 197 GW in 2010 (World Wind Energy Association report 2010).

when wind production is geographically concentrated and there are significant transmission bottlenecks. High electricity demand and high wind production may jointly cause congestion, thereby magnifying local market power and partly or wholly offsetting price reduction effects.

Italy is an interesting test bed for hypotheses concerning the price effects of increasing wind penetration.[3] Thanks to relatively high wind speeds in its southern regions and islands, Italy has a strong potential for wind power production, and a rather fast growing wind power market thanks to incisive support policies. Wind production is concentrated in Italian regions where gencos possess relatively high market power. In particular, limited competition ensues when transmission lines between different zones of the electricity network are congested. This is far from being a rare event due to significant bottlenecks in the Southern Appennine and between Sicily and Calabria, that emerge because the grid was not designed to accommodate such levels of power generation. Because of such bottlenecks, forced outages of wind turbines have been ordered by the transmission system operator, in the face of threats for reliability and security of supply. This caused the loss of about 10.7% of wind energy in 2009, and 5.6% in 2010 (APER, 2011; Lo Schiavo *et al.*, 2011). Further reasons why wind power is a hot topic for Italy include the potential to stimulate development opportunities for regions whose per-capita incomes are below the national average, and concern that public resources in support to renewables may be appropriated by organized crime, which is particularly strong in those regions.

We are interested in verifying two research hypotheses. First, electricity prices decline as wind penetration increases. Second, growing wind power penetration causes an increase in congestion frequencies. These research questions are investigated by means of an agent-based model depicting an electricity market in which heterogeneous, boundedly rational, and capacity-constrained oligopolistic gencos serve a time-varying price-inelastic demand. Gencos engage in price competition in a uniform price (non discriminatory) auction. Their portfolios include both thermal power

3. Wind penetration is the fraction of electricity demand satisfied by means of wind power production.

plants and wind plants, but wind power is supplied unstrategically. Strategy learning on thermal capacity is modeled by means of genetic algorithms. The market-clearing price is set by the market operator using supply offers, taking into account transmission constraints between zones. A model along these lines is used by Guerci and Fontini (2011) for an assessment of the potential impact of nuclear power in Italy, and by Guerci and Sapio (2011) for a comparison between agent-based and optimizing models of the Italian electricity market. Previous applications of agent-based modeling to the electricity market include Bower and Bunn (2001), Bunn and Oliveira (2003), Sun and Tesfatsion (2007), Rastegar *et al.* (2009), while Weidlich and Veit (2008) and Guerci *et al.* (2010) provide critical surveys. To our knowledge, the impact of wind power on the Italian electricity market has never been studied before; most papers focus on Spain, Germany, and the UK.

In the simulations of the model, we set the parameters on wind power supply, electricity demand levels, and cost coefficients as equal to real-world data from the January 2010 Italian electricity market sessions, collected from various sources (REF-E, GME, GSE, Terna).[4] The simulated market outcomes in the scenario based on January 2010 data are then compared with a "wind potential scenario" in which we assess what would happen if, all else being given, the Italian wind power supply reached its potential, *i.e.* the maximum amount of wind power that could be produced, given the Italian orography and the geographical distribution of wind speeds, pressures, temperatures, and available land. Cost-based scenarios are also simulated for the sake of assessing the extent of markups charged by power generating companies.

Our findings show that electricity prices drop as wind supply reaches its potential, but prices remain well above marginal costs. Sharper drops are observed when demand is low than at times of peaking demand, thereby magnifying volatility. The sensitivity of electricity prices to wind power fluctuations, detected through regressions controlling for power demand, is larger in the wind potential scenario. Looking at the patterns of network congestion,

4. REF-E is a Milan-based research and consulting company specialized in energy and environmental economics. Gestore dei Mercati Energetici (GME) is the Italian electricity market operator. Gestore dei Servizi Energetici (GSE) is an Italian State-owned company in the field of renewables. Terna is the Italian electricity transmission system operator.

we find that high wind penetration comes at the cost of more frequent separation between the southern regions, rich in wind, and the 'windless' northern regions. The ensuing market power opportunities partly offset the price reduction effects of high wind penetration. This is a novel result in the literature.

The value added of agent-based modeling in the analysis of the effects of renewables on market outcomes lies in greater realism of the assumptions on behaviors and market structure than the commonly used alternatives (Cournot, Supply function equilibrium, auction-theoretic models). Beyond that, the gencos' environment is a large scale economic system with complex interactions between competing gencos and between possibly congested zones. In such circumstances, full optimization is impracticable, in the sense that a global optimum, if it exists, may not be found in a reasonable amount of time (Simon, 1978). This would force gencos to engage in search for satisficing solutions, which we model by means of genetic algorithms. Most previous works on the price effects of wind power relied on simple models depicting a small number of symmetric, profit-maximizing companies (e.g. duopolies) and ignored issues of grid congestion. Agent-based modeling allows to deal with a very detailed and realistic model of an electricity system—including the real-world structure of the Italian transmission grid and the true spatial distribution of power generating facilities—in an oligopolistic setting. This comes at the cost of giving up the assumption of perfect rationality, but for the reasons given above, bounded rationality provides a better approximation of individual behaviors even when economic agents are specialized in sophisticated activities, such as bidding in the electricity market.

The paper is structured as follows. Section 1 gives a brief overview of the electricity sector and of wind power production in general and in Italy. In Section 2, we summarize the existing literature on the impact of wind generation on electricity market outcomes. We then outline an agent-based model of the electricity market in Section 3, which also describes the implemented learning algorithm. Section 4 illustrates the simulated scenarios, whereas the results are in Section 5. Conclusions and suggestions for further research are provided in Section 6.

1. Basics of the electricity industry

This section offers basic information on the structure and functioning of the electricity industry. The interested reader can refer to the books by Stoft (2002), Kirschen and Strbac (2004), and Harris (2006) for thorough expositions of electricity economics.

Electricity is a property of certain subatomic particles (e.g. electrons, protons) which couples to electromagnetic fields and causes attractive and repulsive forces between them. Trading electricity amounts to trading the availability to supply electrical energy at given times. As such, electricity is not storable: one can only store the means to generate it—e.g. one can keep reserve capacity, or store water behind a dam. Electricity is produced by gencos through turbines activated by several alternative means, such as: combustion of fossil fuels (oil, coal, natural gas), biomass, or biofuels; the potential energy of water stored behind dams or in reservoirs (hydroelectricity); the kinetic energy of wind; geothermal energy; heating of fuels using sunlight (concentrated solar power); conversion of sunlight using the photoelectric effect (photovoltaics). Once generated, power is injected in sources (linked to the power plants) and withdrawn in sinks (loads), which, together with the transmission line system, constitute an interconnected transmission network or grid, through which electricity flows as an alternating current (AC) and is transported over long distances. Because AC repeatedly changes direction, it is impossible to link specific suppliers to specific users: all power is pooled in the network. This is due to Kirchhoff's law, stating that the sum of the currents entering any node (*i.e.*, any junction of wires) equals the sum of the currents leaving that node. Therefore, equality between demand and supply is a technical necessity. But, due to physical transmission constraints (some interconnecting branches may have small capacity values), there can be congestion in the transmission grid. From an economic viewpoint, this can be stated as if a supply and demand matching mechanism based on a purely economic merit order criterion cannot be implemented because of the implicit rationing determined by the Kirchoff's law. Hence an appropriate mechanism based on Kirchoff's law needs to be implemented in order to correctly account for the electrical power flows among the different areas of the grid.

Power from the grid is withdrawn by distributing companies and large industrial consumers. The former, in turn, supply small commercial users and households by means of low-voltage distribution networks and often are also integrated in the retail segment (e.g. billing and metering services). Final electricity consumers are in most countries allowed to choose among competing retailers, or stick to a regulated contract with a public utility. In the short run, final demand is price-inelastic (Considine, 1999; Halseth, 1999; Earle, 2000). The use of regulated tariffs is widely cited as shielding end users from hourly and daily price fluctuations, hence causing limited short-run sensitivity of electricity demand to prices. Demand responsiveness programs, involving real-time metering of electricity consumption and time-of-use pricing, are being experimented in many countries, with results that are so far below expectations (see Kim and Shcherbakova (2011) and references therein).

In countries where the electricity industry has been liberalized, wholesale trading of electricity takes place in organized markets and over-the-counter. Trading concerns the physical delivery of electricity as well as derivatives (forwards, futures, options) on various horizons. The day-ahead market draws much attention in research on electricity economics. Participation to that market involves the submission of production and consumption plans for the day after. Periodic (uniform or discriminatory) double auctions and bilateral continuous time trading are among the adopted trading setups. Further market sessions (adjustment market, market for reserves, real-time market) are held between the day-ahead session and delivery time. Such sessions allow buyers and sellers to adjust their forward and/or day-ahead positions in light of updated information on demand and plants availability, so that the transmission system operator can insure balancing between withdrawals from and injections into the grid.

1.1. The Italian wholesale electricity market

In Italy, day-ahead wholesale trading of electricity takes place in the Italian Power Exchange (Ipex), run by Gestore dei Mercati Energetici (GME), a State-owned company. The Ipex day-ahead market is a closed, uniform-price (non discriminatory), double auction. Each day, market participants can submit bids concerning each hour of the next day. Demand bids are submitted by large industrial consumers, by independent power providers (who serve final users) and by Acquirente Unico, a State-owned company that takes care of final customers who have not switched to competitive retailers. Supply bids are presented by gencos.

The market operator, GME, has the responsibility of clearing the day-ahead market, for each hour of the following day, based on supply and demand bids received from market participants. Market-clearing occurs through a constrained optimization algorithm with the objective to minimize the total expenditure for electricity. The constraints are given by minimum and maximum capacity constraints for each plant, and by transmission limits between zones. A zone is a subset of the transmission network that groups local unconstrained connections. Zones are defined and updated by the transmission system operator, or TSO (Terna in the case of Italy) based on the structure of the transmission power-flow constraints.[5] Choice variables for GME in such optimization problem are the dispatch quantities of electricity to be generated by each power plant, and electricity prices that remunerate electricity production. If transmission constraints are not binding, day-ahead supply offers are remunerated by the same price, the System Marginal Price (SMP). However, when lines are congested the optimal solution involves the calculation of zonal prices.[6] In all cases, electricity buyers pay a weighted average of zonal prices, called PUN (Prezzo Unico Nazionale, or single national price), with weights equal to zonal demand shares. At the optimum, GME calls into operation power plants in merit order, *i.e.* giving priority to offers for the lowest prices. In the merit order typically renewables come first, followed by coal-fired and gas-fired plants. By the same token, demand bids are ordered in decreasing price order. The day-ahead electricity demand curve, however, is typically very steep, consistent with low short-run demand elasticity to price.[7]

5. Zones in the Italian grid are: North, Central North, Central South, South, Sardinia, Sicily, plus some limited production poles, namely Brindisi, Foggia, Monfalcone, Priolo, and Rossano. In limited production poles, transmission capacity is lower than the installed power.
6. Holders of long-term contracts receive the contract price; subsidized plants receive regulated tariffs.

1.2. Wind power in general and in Italy

Italy's rich endowment of renewable energy sources—such as hydroelectricity (from the Alps), sunlight, wind (Southern Appennine, Sicily, Sardinia), geothermal energy (in Larderello, Tuscany)—puts it at the forefront of the battle against global warming. Recent years have witnessed the fast growth in wind power capacity in Italy—from 2123.4 MW in 2006 to 5797 MW in 2010. As a result, Italy in 2010 ranked 6^{th} in the world for installed wind capacity penetration, behind China, USA, Germany, Spain, and India, and 9^{th} in terms of wind capacity per land area (19.2 kW/sqkm), the first being Denmark with 86.6 kW/sqkm (source: World Wind Energy Association report 2010).

Wind turbines produce electricity by exploiting airflows. Because work done by a moving mass is proportional to the square of speed, power generated by a wind turbine goes like the cube of wind speed. The relationship between wind speed and power is tuned by the characteristics of the wind turbine, by air density, and by temperature. Minimum and maximum capacities of wind plants are also defined in terms of wind speed: they start operating when wind speed is about 4 m/s; above 25 m/s the turbine is automatically shut down, and a brake is applied to prevent mechanical damage (Bartolazzi, 2006).

Wind speeds are highly variable across space, altitude, and time. As to spatial heterogeneity, average wind speeds and nameplate capacities in Italian regions are given in Table 1. As it can be noticed, the top Italian regions for wind capacity and output fall into just four zones: Center-South, South, Sicily, and Sardinia.

7. We have computed the arc elasticity of national day-ahead electricity demand with respect to price in a neighborhood of the single national price (PUN) for all of the 744 hourly market sessions held in January 2010 (our period of interest in the subsequent analysis). We have chosen a pretty large neighborhood of the PUN, namely [0.5 PUN; 1.5 PUN], not to be too conservative, taking also into account that the real-world demand curves are discrete. The median arc price-elasticity of demand is 0.1080, the mean is 0.1051, and the 95% percentile is 0.1689.
That the price-elasticity of electricity demand in Italy is low may sound surprising in light of the wide program of real-time electricity consumption metering implemented by Enel, the former monopolist, as early as 2005. About 90% of final customers were equipped with smart meters by the end of 2009. This is a key step towards stimulating demand response, together with a time-of-use pricing scheme, that has been in place in Italy even before the creation of the day-ahead market in 2004 (Torriti *et al.*, 2010). However, until December 2011 the difference between the peak and off-peak retail prices was fixed by the energy regulator at 10%, hence it did not adequately reflect intra-day wholesale price fluctuations (Lo Schiavo *et al.*, 2011).

Such spatial concentration reflects differences in average wind speeds.[8]

Table 1. Wind power in Italy in 2010

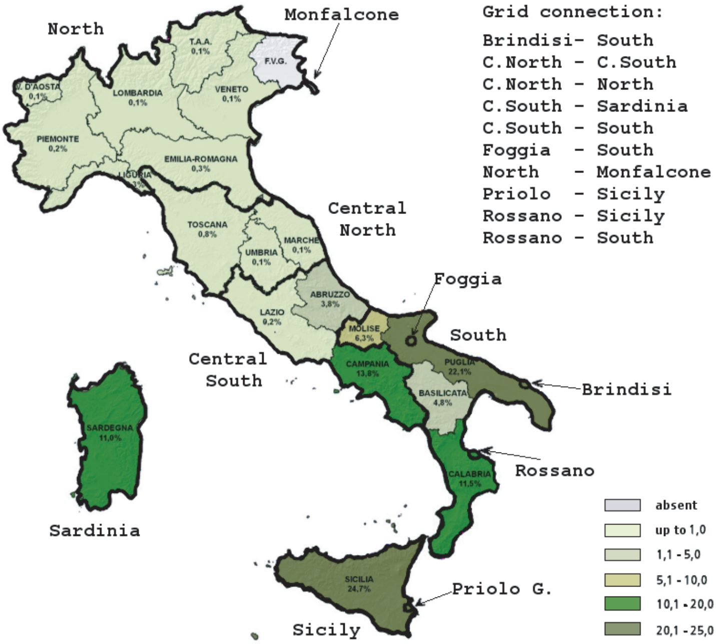
Regions	Zones	n. plants	Inst. capacity (MW)	Output (GWh)
Piedmont	North	7	14.4	21.4
Aosta Valley	North	1	0.0	0.0
Lombardy	North	1	0.0	—
Trentino Alto Adige	North	5	3.1	2.2
Veneto	North	5	1.4	1.7
Friuli Venezia Giulia	North	—	—	—
Liguria	North	15	19.0	34.8
Emilia Romagna	North	15	17.9	24.7
Tuscany	Central-North	17	45.4	76.1
Umbria	Central-North	1	1.5	2.3
Marche	Central-North	3	0.0	0.0
Lazio	Central-South	7	9.0	15.1
Abruzzo	Central-South	25	218.4	329.3
Molise	Central-South	23	367.2	532.3
Campania	Central-South	76	803.3	1333.2
Apulia	South	134	1287.6	2103.2
Basilicata	South	28	279.9	458.3
Calabria	South	31	671.5	952.3
Sicily	Sicily	62	1435.6	2203.0
Sardinia	Sardinia	31	638.9	1036.1

Source : GSE Rapporto Statistico 2010 - Impianti a fonti rinnovabili.

The map of Italy in Figure 1 shows wind penetration rates in Italian regions, in varying degrees of green, as well as the zonal market subdivision adopted by the transmission system operator (bold lines). The transmission lines connecting zones are listed in a grid connection table (top-right). The Italian transmission grid has the shape of a chain that connects the northern, almost windless zones, to the southern zones, rich in wind.

8. See the Italian Wind Atlas: http://atlanteeolico.rse-web.it/viewer.htm.

Figure 1. Map of Italy showing the regional distribution of installed wind capacity (in varying degrees of green) and the borders between zones in the transmission grid (thick black lines)*



*** Zonal connections are reported in the top right corner.**

High variability of wind speeds across time—that is, intermittency in the availability of the wind resource—implies that wind outputs are less controllable than outputs from fossil-fueled power plants, hence they cannot be set strategically in the short run. Large discrepancies can arise between wind supply and wind output if wind power must be offered in advance of delivery.[9] Gencos that cause such imbalances incur costs related to correcting their positions in the adjustment and real-time markets.

Although power plants using renewables are characterized by negligible marginal costs, high upfront costs—the cost of the turbine, foundation, electrical equipment, grid connection—tend to discourage their adoption. Various support schemes have there-

9. In a study on the Nordic countries, Holttinen (2005) mentions 30%-50% wind outputs were forecasted wrong over a time horizon of 7-38 hours ahead of delivery.

fore been enacted around the world. Support to renewables in Italy is channeled by means of feed-in tariffs[10] and green certificates.[11]

2. Literature review: the effects of wind power supply on electricity prices

A growing literature examines the price effects of high wind penetration in electricity markets under different assumptions on market structure. The main result of this literature is that, since wind plants have lower variable costs, fossil fueled power plants are displaced in the merit order, yielding a downward pressure on wholesale electricity prices.

Price reduction effects due to wind power are found by Saenz de Miera *et al.* (2008), who perform an empirical analysis focusing on the Spanish wholesale electricity prices. In their model, perfectly competitive gencos submit linear supply functions in order to maximize expected profits. Expected profits depend on a stable probability distribution of wind generation, and the opportunity costs of CO_2 allowances are internalized. The marginal cost of wind is assumed below that of fossil-fuel generation. A first exercise consists in comparing the market prices in three consecutive days with similar levels of electricity demand in order to isolate the impact of wind generation from the other factors affecting the market price. In a second exercise, the authors simulate the market solution in the absence of wind generation using data for 2005, 2006, and the first 5 months of 2007, and compute the difference between the prices simulated with and without wind generation. The findings indicate a reduction in wholesale electricity prices

10. Since 1992, energy generated through renewable sources is sold to the transmission system operator at a tariff set by the energy market regulator and revised annually. Legislative Decree 78/99 (Art. 12) obliges the transmission system operator to re-sell the subsidized power at prices determined through a merit order. Small plants (below 200 kW for wind plants) that started producing after December 2007 can choose to take advantage of an alternative feed-in tariff (*tariffa onnicomprensiva*). In this case, it is GME who withdraws renewable energy from producers and sells it on the market.

11. Legislative Decree 79/99 (art. 11) stipulates that producers and importers of energy from conventional power plants supply, from 2002 on, a minimal required amount of renewable energy. Such percentage was 3.8%, and has been increased by 0.75% every year, reaching 7.55% for 2012. Obliged parties can meet this requirement either by injecting electricity from renewables in their portfolios, or by purchasing green certificates for an equivalent amount. The green certificates market is managed by GME. Plants using renewables that started operations after April 1999 are assigned a number of green certificates that is proportional to their outputs.

due to wind power. Moreover, such price reduction is found to be greater than the increase in the costs for the consumers arising from feed-in tariffs.

More recent works assuming oligopolistic market structures have demonstrated that price-reduction effects of wind power penetration are exacerbated if thermal power plants are run by gencos with market power. Indeed, when wind is low, gencos with market power face a higher residual demand, therefore they find it optimal to withhold capacity, pushing up the wholesale electricity price. In a supply function equilibrium (SFE) model of the UK electricity market, Green and Vasilakos (2010) show that market power with high wind penetration magnifies price volatility: because strategic gencos view wind sales as a shift in their residual demand functions, increased wind penetration adds to the uncertainty in the residual demand faced by them.

Banal-Estañol and Rupérez-Micola (2011b) analyze an auction-theoretic model in which electricity demand, known with certainty, is served by two symmetric high-cost plants and a low-cost plant. Two cases are analyzed: the low-cost plant can generate intermittent energy (a wind plant) or dispatchable energy (a nuclear plant). In both cases, the model solution features multiple equilibria (with lower prices when high-cost plants are not pivotal, *i.e.* when their capacity is not essential for market-clearing) and mixed-strategy equilibria. The introduction of low-cost capacity—whether intermittent or dispatchable—depresses prices, but wind pushes price down more than nuclear when high-cost gencos are pivotal, and less so when they are not. Moreover, prices remain well above marginal cost even after substantial increases in wind capacity, and wind causes greater volatility. The reason why electricity prices stay above marginal costs is that wind intermittency makes it more difficult for gencos running high-cost plants to coordinate on low-price equilibria.[12] The main insight raised by the authors is that, in the presence of multiple equilibria, intermittency alters the process of equilibrium coordination.

12. The results are robust to several extensions of the analysis (larger strategy spaces, experience-weighted learning, high-cost capacity replacement through low-cost capacity, joint-ownership of low-cost and high-cost plants, risk aversion).

As a downside to price reduction effects, downward pressure on wholesale prices can discourage wind investments, since it amounts to a negative correlation between availability of wind power and electricity prices. Hence, wind plants receive, on average, lower prices than conventional plants—which can be dispatched at any time. Such a negative correlation can be mitigated if wind output is higher in months of high demand—but it is stronger when gencos running thermal power plants possess market power. Twomey and Neuhoff (2010) illustrate this effect in a model with a non-strategic wind generator and conventional Cournot gencos. According to their simulations, the average difference between energy prices of wind and thermal generation can be more than £20/MWh for some parameter settings. The results of the SFE oligopoly simulations of Green and Vasilakos (2010), based on the UK electricity market, confirm this. Sioshansi (2011) builds a Stackelberg oligopoly model wherein a wind generator acts as the leader, and fossil-fueled gencos—the followers—compete in SFE fashion. Using data concerning the ERCOT (Texas) market in 2005, a scenario including additional 10 GW of wind capacity shows that as more wind enters the market, the discrepancy between the average value of overall electricity sales and the average value of wind energy sales grows, depressing the profitability of wind generators.

The models that have been used in the wind power and electricity markets literature are open to critical observations concerning their general validity as well as their usefulness for the Italian case. One advantage of cost-based models is that, in assuming away strategic interaction and learning, they allow the modeler to give a rich description of the transmission grid. One may also argue that opportunities for market power exercise will vanish after a substantial increase in wind power penetration, thereby making marginal cost bidding a realistic behavioral assumption. Yet, in absence of grid investments that will relieve the existing transmission bottlenecks, market power in Italy should hardly disappear, given the spatial concentration of Italian wind. Modeling strategic interaction is therefore needed. Among models with strategic interaction, the Cournot model, as in Twomey and Neuhoff (2010), assumes quantity-setting gencos and a downward-sloping demand function, thereby violating the evidence of price-based competition and inelastic demand. SFE models (Green and Vasilakos, 2010) confine their analyses to symmetric oligopolies and company-wide supply functions. This is useful to avoid convergence problems of the kind highlighted by Baldick *et al.* (2004). Convergence problems are even more severe if, in order to consider transmission constraints, gencos are assumed to optimally set a supply function for each plant, with non-linear dependencies between marginal profits from different plants, and if plant-level marginal cost slopes are small (see Hobbs *et al.*, 2000). In such a case, even slight changes in parameters (e.g. in fuel prices) can push the model out of the convergence region, as mentioned by Sapio *et al.* (2009). Auction theory provides a more realistic framework for our analysis, as in Banal-Estañol and Rupérez-Micola (2011b). However, the authors' game-theoretical results crucially rely on mixed strategy equilibria and on equilibrium coordination between multiple equilibria. A mixed strategy equilibrium can be interpreted as the distribution of pure strategies in a large population of agents, or as plans of action that depend on exogenous, payoff-irrelevant factors (Rubinstein, 1991). Neither interpretation is appealing as a description of supply behaviors in electricity markets. Consider also that the practical application of mixed strategies is further hindered if their implementation is costly (Abreu and Rubinstein, 1988)—and when transmission constraints are involved, such computational costs can be high.

More generally, since the gencos' environment is a large scale system with complex interactions between competing gencos and between possibly congested zones, full optimization is likely impracticable, in the sense that a global optimum, if it exists, may not be found in a reasonable amount of time (Simon, 1978).[13] Following Simon (1972), this is even more true for a large-size combinatorial problem, such as competition in prices between gencos endowed with diversified portfolios. Temporal specificities in electricity market operations (Glachant and Finon, 2000) act as further constraints on computationally-intensive decision processes. Thus, gencos are very likely to rely on bounded rationality. Agent-based models are well suited to represent gencos that engage in search for 'satisficing' solutions (to use Simon's jargon) in

13. The definition of complexity that is relevant for our purposes was given by Simon (1962): a complex system is a system made up of a large number of parts that interact in non-simple ways.

an oligopolistic market with price competition and a highly detailed representation of the transmission grid. Search in agent-based models occurs through inductive strategy selection methods based on learning dynamics, that are shown to possess high predictive power with respect to agents' behaviors (Roth and Erev, 1995; Camerer and Ho, 1999).[14]

3. An agent-based model of the Italian day-ahead market

3.1. The model

Consider a day-ahead electricity market populated by G gencos and a large number of electricity consumers. Company g ($g = 1,\dots,G$) owns a portfolio of N_g thermal power plants and W_g wind plants. Thermal power plants can use either of F fuels, indexed by $f = 1,\dots,F$. Power plants inject power in a transmission network connecting Z zones indexed by $z = 1,\dots,Z$. Demand in each zone is price-inelastic.

Wind plants owned by genco g are placed in different zones, so that $\sum_{z=1}^{Z} W_g^z = W_g$. Wind plant j in zone z can produce at null marginal costs within the feasible production interval $[\underline{Q}_{g,j}^{w}, \overline{Q}_{g,j}^{w}]$. Wind power is offered at zero price and the offered volume is set equal to day-ahead forecasts. Sold quantities are denoted by $\hat{Q}_{g,j}^{w}$. The unitary remuneration consists of feed-in tariff TP.

Each thermal generation unit $i \in \mathcal{I}_g = \{1,\cdots,N_g\}$ is characterized by a feasible production interval defined by lower $\underline{Q}_{g,i}$ and upper $\overline{Q}_{g,i}$ production limits, so that dispatched power $\hat{Q}_{g,i}$ must satisfy $\underline{Q}_{g,i} \le \hat{Q}_{g,i} \le \overline{Q}_{g,i}$ [MWh]. The cost function of the i^{th} thermal power generating unit run by g and using fuel f is given by

$$TC_{g,i}\,(Q_{g,i}) = FP_f\,(a_{g,i} \cdot Q_{g,i} + b_{g,i}) \tag{1}$$

where FP_f [Euro/GJ] is the price of the fuel f and the term within round parentheses corresponds exactly to the amount of fuel in GJ required to generate an energy of $Q_{g,i}$ MWh. The dimensionless coefficient $a_{g,i}$ and the coefficient $b_{g,i}$ [GJ/MWh] refer to the technology-specific efficiency of the power plant and are assumed

14. To be fair, Banal-Estañol and Rupérez-Micola (2011b) perform simulations in which gencos select among equilibria through an Experience-Weighted Attraction mechanism.

time-invariant. In particular, $a_{g,i}$ specifies the relationship between the energy input and output, whereas $b_{g,i}$ denotes the real value of no-load costs that are born only if the plant is dispatched.[15]

The marginal cost $MC_{g,i}$ for g's thermal plant i is constant across the feasible production interval:

$$MC_{g,i}\ (Q_{g,i}) = FP_f \cdot a_{g,i} \tag{2}$$

Let $\mathcal{I}^r_g = \{1, \cdots, N^r_g\} \subset \mathcal{I}_g$ denote the set of all thermal power plants belonging to genco g in zone z using technology f, where $r = (z, f)$. Thus $\cup_r \mathcal{I}^r_g = \mathcal{I}_g$. For each hour of the following day, genco g sets for all plants in r the same markup level $m^r_g \in \mathcal{A}^r_g$.[16] Thus the action space of genco g is $\mathcal{A}_g = \times_r \mathcal{A}^r_g$, that is, the Cartesian product of the markup spaces $\mathcal{A}^r_g$ for the representative plant of g in r.[17]

Each genco g bids to the day-ahead market session of hour h a pair of price and quantity values for each generating unit $i \in \mathcal{I}_g$. A strategy for genco g is defined as

$$s_g(m^1_g, \ldots m^{R_g}_g) = \{(Q_{g,1}, P_{g,1}), \ldots, (Q_{g,N_g}, P_{g,N_g})\}$$

where R_g is the number of genco g 's representative plants. Each pair is defined by a limit price $P_{g,i} = m^r_g \cdot MC_{g,i}$ ([Euro/MWh]) with $i \in \mathcal{I}^r_g \subset \mathcal{I}_g$ and a quantity of power $Q_{g,i} = \overline{Q_{g,i}}$ [MWh], that is, gencos are assumed to bid the maximum capacity of their thermal power plants.

Upon receiving all generators' bids, the market operator clears the market by performing a total welfare maximization subject to equality constraints posed by zonal energy balance (Kirchhoff's law) and inequality constraints, *i.e.* the maximum and minimum

15. The cost structure of a thermal power-plant includes several terms which can be grouped in two distinct components, that is, fixed costs (such as debt and equity obligations associated with plant investments) and operating costs. The latter occur only if production takes place (*i.e.*, if fuel combustion takes place) and are commonly broken down into variable costs, no-load costs, startup and shutdown costs (see Kirschen and Strbac, 2004). In our model, only variable and no-load costs are considered and are both introduced in Equation (1). No-load costs in power engineering refer to quasi-fixed costs. They correspond to the hypothetical cost incurred by a generator if it could be kept running at nearly zero output.

16. This allows to reduce the size of the strategy space. See Müsgens and Neuhoff (2006) for a similar assumption.

17. For instance, the cardinality of the action space of a generation company owning 4 representative plants is $|\mathcal{A}_g| = |\times_r \mathcal{A}^r_g| \approx 10^4$.

capacity of each power plant and inter-zonal directional transmission limits (Kirschen and Strbac, 2004).[18] The dual of this welfare maximization, given perfectly inelastic demand, is the total production cost minimization. The optimal solution consists of a set of zonal prices ZP_z, for $z = 1,..., Z$, and dispatched quantities of electricity $\hat{Q}_{g,i}$ for $g = 1,..., G$ and $i = 1,..., N_g$.[19]

The profit per hour for genco g, Π_g, is obtained as the sum of the profits from representative thermal generating units and the profits from wind power generating units:

$$\Pi_g = \sum_{r=(z,f)} \left[ZP_z \sum_{i=1}^{N_g^r} \hat{Q}_{g,i} - \sum_{i=1}^{N_g^r} TC_{g,i}(\hat{Q}_{g,i}) \right] + TP \cdot \sum_{z=1}^{Z} \sum_{j=1}^{W_g^z} \hat{Q}_{g,j}^{w} \tag{3}$$

3.2. The learning algorithm

How do gencos decide their offers to the day-ahead market? The boundedly rational behavior of gencos is formalized here by assuming that gencos search for 'good enough' or 'satisficing' markup levels by means of a genetic algorithm. The genetic algorithm goes through T runs, indexed by $t = 1,..., T$. In run t, a population of P markup vectors evolves across K_t generations by means of selection, mutation, and crossover operators. Across runs, gencos compute the prices and profits associated to various points in the space of markups, treating the markups of their opponents as fixed. The conjectured markups of their opponents are updated after each run, allowing gencos more exploration.

The learning algorithm can be schematized as follows.

• *Initialization of the simulation*: at the beginning of run 1 each genco g draws uniformly a population of P–1 markup vectors, whose p-th element is ,

$$M_{g,p} = [m_{g,p}^{1},\dots,m_{g,p}^{r},\dots,m_{g,p}^{R_g}] \in \mathcal{A}_g$$

with $m_{g,p}^{r} \geq 1 \quad \forall r$ and p. Markup levels are drawn from the set $\{1.00, 1.04, 1.08, ..., 5.00\}$. Along with the P–1 randomly drawn

18. This optimization problem is known as DC optimal power flow (DCOPF).
19. Zonal prices are the shadow prices of the active power balance constraints in each zone in the minimization problem.

markup vectors, we include the markup vector $M_g = [1.00,...,1.00]$ (*i.e.* all plants bidding at marginal costs).

• *Initialization at each run t*: at the beginning of run t each genco g draws one markup vector M_g with probability

$$\pi_{M_{g,p},t} = \frac{e^{F_{M_{g,p}}/\lambda}}{\sum_{M_{g,p}} e^{F_{M_{g,p}}/\lambda}}$$

(a logit probabilistic choice model) from the population of P markup vectors. $F_{M_{g,p}}$ is the relative frequency of $M_{g,p}$ in the population of P markup vectors, and λ is a parameter that affects the probability of choosing a markup vector. As $\lambda \to 0$, the probability of choosing the markup vector with the highest frequency goes to 1. Only at run 1 we impose that the markup vector being chosen is $M_g = [1.00,...,1.00]$.

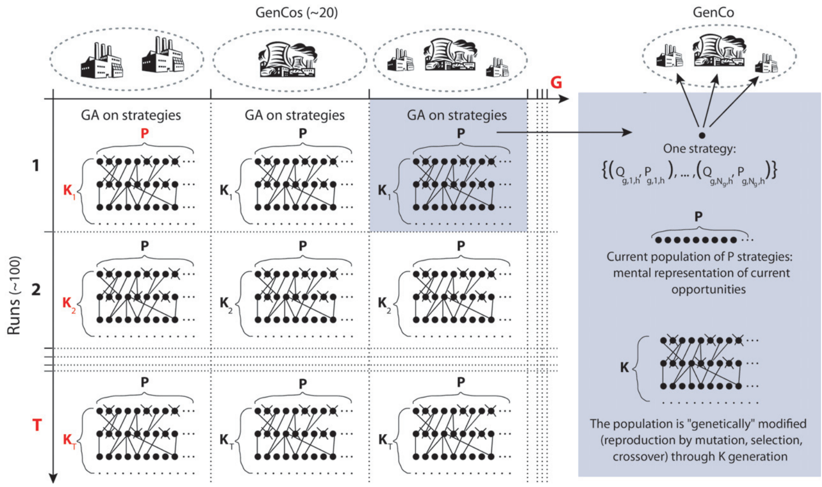
• *At each run t*: at generation $k \in \{1,..., K_t\}$ of run t, for each markup vector of the current population of size P genco g computes the zonal prices ZP_z, $z = 1,...,Z$, and its own profits Π_g under the conjecture that all other gencos play the markups selected at the beginning of run t. Given the current profits/fitnesses for each candidate strategy, a genetic procedure based on selection, mutation, and crossover establishes the next population to be used at $k + 1$ if $k + 1 \leq K_t$ or at run $t + 1$ otherwise.

The learning algorithm is depicted in Figure 2. The left part of the figure shows the evolution of the algorithm through T runs for all G gencos, whereas the right part zooms into the behavior of one genco in one generic run.

In the simulations, we adopt the following parameter settings: $P = 200, T = 50, K_1 = 3,..., K_{50} = 20$. Our simulation results are therefore based on the markups selected from the K_{50}th generation. Notice that the number of generations K_t changes across runs. The idea is to favor exploration in initial rounds (smaller K_t) and then to let agents exploit their experience (larger K_t).[20]

20. We assume that gencos learn independently to bid strategically on each hourly market, *i.e.*, no interrelationships are considered among such hourly auctions. The reason is that gencos bid simultaneously on all 24 hourly auctions scheduled for a day.

Figure 2. A schematic representation of the learning algorithm



Notice that search as described by the above learning algorithm need not end up on either a local or a global optimum, even if they exist. The idea here is that gencos set a stopping rule for their search that is independent of the optimality properties of the markups finally selected. The amount of search performed through the genetic algorithm can be thought of being viewed by a genco as satisfactory.

4. Simulation scenarios

By simulating the agent-based model described above, we aim to provide answers to two research questions. First, increasing wind penetration yields price reduction effects. Second, congestion frequencies increase with the rate of wind penetration. These research questions are investigated by building simulation scenarios that differ only for the amount of wind supply: a 'real' scenario, based on January 2010 wind data, and a 'wind potential' scenario, in which we set wind power production to its maximum potential, estimated for Italy in some technical reports. For the sake of comparison, further simulations are run in which all gencos bid their marginal costs. Detailed descriptions of each scenario are provided below.

4.1. Real strategic scenario

In the real scenario, plant-level and demand parameters are measured using January 2010 data from the Italian day-ahead electricity market.[21] We use data from a number of sources. A first source is a database covering most Italian thermal power plants, supplied to us by REF-E, including information on the capacity range (minimum and maximum capacity), technical coefficients of cost functions based on engineering estimates, and transmission constraints. In order to compute costs we also use REF-supplied data on fuel prices and CO_2 prices. We draw hourly data on zonal demands, imports, and the amount of power from renewable sources supplied into the Italian Power Exchange (Ipex) from the website of the market operator GME. Hereby we take into account day-ahead electricity demand after subtracting net imports. A database of Italian wind farms (featuring denomination, technical characteristics, and localization of each plant) is supplied by Terna, the transmission system operator. In the reference period, the available set of power plants consisted of 156 wind power plants and 223 thermal generating units (coal-fired, oil-fired, combined cycle, turbo-gas). Those power plants were independently or jointly owned by 19 different gencos.

We distinguish between core gencos, which behave as oligopolists, and fringe gencos that behave competitively. The competitive fringe includes seven price-taking companies (AA API, AEM, ATEL, Elettrogorizia, EnPlus, Italgen, Set) that own only one power-plant each, and a company, Sorgenia, which owns four generating units all located in the north zone where almost one third of all thermal units are installed. The remaining eleven companies (A2A, AceaElectrabel, EDIPOWER, EDISON, EGL, ENEL Produzione, ENIPOWER, EOn, ERG, IRENMERCATO, TIRRENO Power) behave as oligopolists.

One important issue in implementing our agent-based model concerns the measurement of wind supply. Ideally, one would like to have information on the technical characteristics of individual

21. Focusing on a recent year is an advantage in view of the increasing trend in the Italian wind capacity. In January, the Italian power consumption is at its highest on average, and in 2010 January was the second highest month in terms of wind production, the first being December—but power consumption falls during Christmas festivities (sources: GME and GSE Annual Reports).

wind turbines, as well as wind speeds, pressures, and temperatures at their exact locations. Such information is usually not available. In most papers, it is assumed that all gencos use wind turbines of a standard type—e.g. of given size and height—and wind outputs from such standard wind turbines are computed by plugging into the wind output-wind speed relationship weather data recorded at nearby weather stations. This approach neglects heterogeneity among wind farms and discrepancies in meteorological conditions between the wind farm location and the weather station location.

Our approach is to use the available data on wind power offers. Such offers are ostensibly determined by gencos based on their day-ahead forecasts of wind outputs. Because of intermittency, wind outputs typically deviate from their predicted values, hence blurring the information conveyed by wind offers. Yet, since imbalances imply monetary penalties, players in the wind industry spend resources to refine their forecasts, as testified by Niglio and Scorsoni (2008) in their description of wind forecasting methods employed by GSE. Our wind offers have the advantage of reflecting the individual choices of actual gencos based on weather conditions at the precise locations of wind plants.

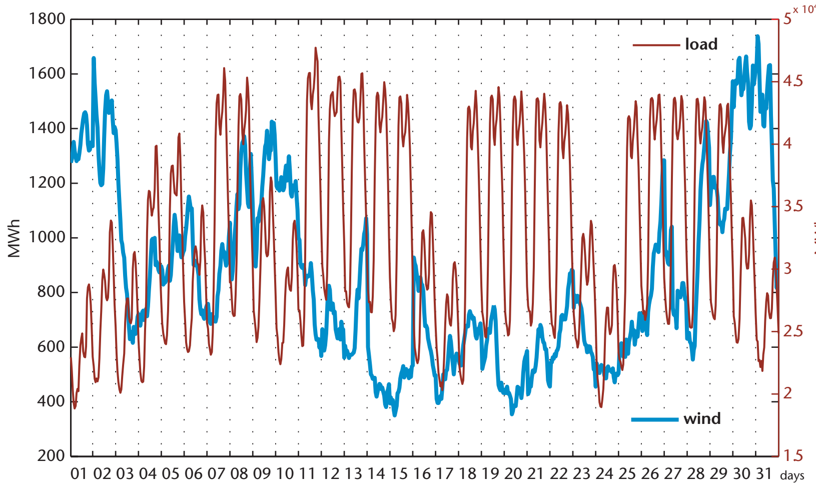
A simple statistical look at our data reveals a number of empirical facts. First, demand bids in the day-ahead market are inelastic in the relevant price range (see also footnote 7). Second, plant-level marginal cost functions are linear, with extremely low slopes. This justifies ex post the assumption of constant plant-level marginal costs of Equation (2). Third, gencos' portfolios are diversified across technologies/fuel types and include plants localized in different Italian regions. Fourth, about 75% of the sell offers consist of a single price-quantity point, even though up to 4 points can be submitted. Finally, intra-day patterns of wind offers are heterogeneous across gencos, due to different locations of the wind plants and different forecasting accuracies.[22]

The time profile of the Italian wind supply and electricity demand in January 2010 is represented in Figure 3, with hourly frequency. This plot shows that, while electricity demand follows quite regular intra-day and weekly patterns—only slightly blurred

22. Wind offer profiles for some gencos are flat across consecutive hours, despite wind intermittency.

by holidays in the first days of the year, wind supply is quite erratic, with fluctuations that suggest stronger winds at the beginning and at the end of January 2010.[23] Interestingly, these plots highlight the presence, in the same month, of market sessions in which the balance between wind supply and electricity demand was very different: low wind with high demand (the Jan 11-15 and Jan 18-22 weekdays), high wind with high demand (Jan 8, Jan 28), high wind with low demand (first and last weekend). This should allow to have a rather complete assessment of the potential effects of wind on electricity prices.

Figure 3. Time series of electricity demand and wind supply, Italy, January 2010



4.2. Wind potential strategic scenario

As a way to detect the price effects of high wind penetration, we build a scenario in which the wind outputs are scaled up, and all the other variables and parameters (the number of gencos, the composition of their thermal portfolios, zonal demands, fuel prices, plant efficiencies, thermal generation capacities, transmission constraints) are kept at the January 2010 level. In particular, we aim to scale up wind outputs until reaching a wind penetration rate similar to that considered by previous papers. Twomey and

23. No entry of new wind plants occurred during January 2010.

Neuhoff (2010) analyzed scenarios with wind covering 15% and 30% of the UK electricity demand. Other studies on the UK (Sinden, 2007; Oswald *et al.*, 2008) considered 20% and 16% scenarios, respectively.

It turns out that similar wind penetration rates can be attained if the January 2010 wind outputs are scaled up to the Italian wind potential, *i.e.* the maximum amount of on-shore wind energy that could in principle be produced, given the Italian orography and the geographical distribution of wind speeds, pressures, temperatures, and available land. Using data supplied by CESI, SPS Italia estimated the Italian wind potential to be about 60 TWh (31 GW), corresponding to about 20% of total electricity consumption in Italy.[24] A study performed by the University of Utrecht gave figures of 69 TWh (34.5 GW). For comparison, notice that wind power production covered about 2.6 % of demand as of January 2010; and that the 1999 Italian White Book targeted to install 12 GW of wind power capacity by 2020. See Ronchi *et al.* (2005) for further details. We therefore simulate our agent-based model as if the wind potential estimated by CESI-SPS was already available in January 2010.[25]

4.3. Cost-based scenarios

In addition to the above strategic scenarios we simulate cost-based scenarios—that is, we run the agent-based model as if all gencos bid their marginal costs. We perform this exercise with both wind supply at its January 2010 levels and at its potential. The outcomes of such cost-based scenarios will be compared with those of the corresponding strategic scenarios, in order to highlight the extent to which markups are eroded by the entry of additional wind power capacity. Notice also that some downward pressure on electricity prices should be expected even if gencos asked their

24. The CESI-SPS study focuses on only locations able to guarantee at least 1750 hour/year of wind power production, and assumes 25 MW of wind capacity per squared Km, and that only 2% of the available land would be occupied by wind farms.

25. Neither the CESI-SPS study, nor the present paper consider the potential for off-shore wind power production in Italy. According to RSE's Wind Atlas, annual average wind speeds of 7-8 m/s are recorded south-west of Sardinia and south of Sicily; 6-7 m/s south-west of Sicily, around Sardinia, and offshore Apulia. RSE (Ricerca sul Sistema Energetico) is a State-owned company performing research on the electricity industry.

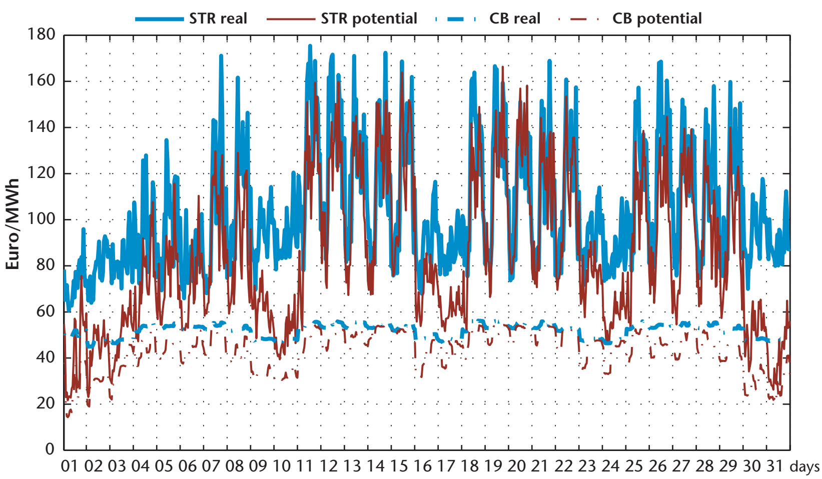
marginal costs, simply because expensive thermal plants are displaced in the merit order.

5. Results

After running the agent-based model, we obtain four simulated hourly-frequency time series of the single national price (PUN)—one for each scenario (real strategic, potential strategic, real cost-based, potential cost-based). In addition, our model yields, as outcomes, the quantity sold by each plant. Together with zonal demands and transmission limits, this allows to determine which lines are congested at each hour, and therefore what zonal configurations appear in the Italian transmission network.

The time dynamics of the single national price is compared across scenarios in Figure 4. The horizontal axis reports each hour of the days indicated. As the picture shows, the day-ahead electricity price fluctuates in a periodic fashion, following the daily and weekly cycles of economic activity. Prices are lower during nights and weekends, and during the first days of January due to holidays—but reach high peaks in the central hours of working days, when electricity demand is at its highest. Prices in strategic scenarios are much higher than cost-based simulation outcomes,

Figure 4. Time dynamics of Italian day-ahead electricity prices, January 2010: baseline cost-based, baseline strategic, wind potential cost-based, and wind potential cost-based scenarios



testifying to market power exercise. The impact of increased wind power capacity can be grasped by comparing the price series for the strategic real and wind potential scenarios. Electricity prices in the wind potential strategic scenario are nearly always below those obtained in the baseline strategic scenario. Such a price reduction effect is particularly strong during periods when demand is lower: weekends, nights, and holidays. A price reduction effect is observed even when gencos bid their marginal costs, as expected. Electricity prices are well above marginal costs even when wind capacity is at its potential. This result is consistent with findings by Banal-Estañol and Rupérez-Micola (2011b).

Wind power affects electricity prices not only across scenarios, but also over time. For each scenario, using hourly-frequency data, we estimate linear regressions of the simulated PUN on wind supply, the real-world national electricity demand, supply from hydropower and other non-wind renewables, and a dummy equal to 1 for all hourly sessions between Jan 1, 2010 and Jan 6, 2010 included and 0 otherwise. Such dummy accounts for exogenous shifts in demand caused by Christmas holidays, that in Italy last until January 6 included. All non-binary variables are in natural logarithms, hence regression coefficients can be interpreted as elasticities. Wind supply is at the January 2010 value in the real scenario, and at the potential value in the wind potential scenario. Estimates are obtained using ordinary least squares as well as a robust estimator, to control for heteroskedasticity and outliers.[26] Estimated coefficients and 95% confidence intervals are reported in Table 2. As indicated by the table, estimated coefficients for demand are positive and statistically significant, with larger magnitudes in strategic scenarios than in cost-based ones, and when wind is at its potential. Closer to our focus, the coefficient estimates for wind supply are all negative and statistically significant—showing that wind production can yield a downward pressure on electricity prices. More in detail, doubling wind supply yields nearly a 4% drop in electricity prices in the real, strategic scenario, a drop that becomes larger (36%) under the wind potential, strategic scenario.

26. Regressions have been performed in Matlab, using the 'regress' and 'robustfit' commands.

Table 2. Estimated coefficients from log-linear regressions of PUN on electricity demand, wind supply, supply from hydropower and other renewables, and holiday dummy: hourly frequency, various scenarios and estimation methods. 95% confidence intervals are reported in square brackets

Variables	Conf .Int.	Real, strat.		Pot., strat.		Real, cost-b.		Pot., cost-b	
		OLS	Robust	OLS	Robust	OLS	Robust	OLS	Robust
Constant	95%	-3.397 [-3.840 -2.954]	-3.552 [-4.016 -3.087]	-5.835 [-6.398 -5.271]	-5.968 [-6.542 -5.393]	2.381 [2.269 2.492]	2.210 [2.099 2.321]	0.822 [0.428 1.216]	1.138 [0.813 1.464]
Demand	95%	0.663 [0.533 0.793]	0.664 [0.527 0.801]	2.116 [1.958 2.275]	2.091 [1.930 2.253]	0.501 [0.468 0.534]	0.543 [0.510 0.576]	1.117 [1.007 1.228]	1.012 [0.921 1.104]
Wind supply	95%	-0.039 [-0.065 -0.013]	-0.037 [-0.064 -0.010]	-0.367 [-0.398 -0.335]	-0.361 [-0.393 -0.329]	-0.021 [-0.028 -0.015]	-0.017 [-0.023 -0.011]	-0.345 [-0.367 -0.324]	-0.299 [-0.317 -0.280]
Hydropower & other renewables	95%	0.151 [0.009 0.293]	0.165 [0.016 0.314]	-0.905 [-1.079 -0.732]	-0.870 [-1.046 -0.693]	-0.372 [-0.408 -0.337]	-0.404 [-0.439 -0.368]	-0.599 [-0.720 -0.478]	-0.559 [-0.659 -0.459]
Holidays	95%	-0.097 [-0.125 -0.069]	-0.102 [-0.132 -0.073]	0.024 [-0.010 0.059]	0.019 [-0.0157 0.054]	0.059 [0.052 0.066]	0.066 [0.059 0.073]	0.089 [0.065 0.113]	0.106 [0.087 0.126]

Elasticities of electricity prices to wind supply are around 2% in the real, cost-based scenario, and equal to -0.345 (OLS) or -0.299 (robust fit) in the potential, cost-based scenario. Regression results thus suggest that price reduction effects are much more seizable when wind reaches its potential. Moreover, comparing the coefficients of demand across scenarios suggests that increasing wind supply brings additional volatility to the market.

In Table 3 we report the congestion frequencies for each transmission line, *i.e.* the fraction of hours in which each line was congested. Congestion frequencies are computed for each scenario, and for different groups of days (workweek and weekend) and hours: off-peak (10 pm-6 am) and peak (7 am-9 pm). We observe that, although congestion becomes slightly more rare in the Rossano-Sicily line under the wind potential scenarios, congestion becomes more frequent precisely in lines that connect the zones hosting the bulk of wind capacity with each other or with the other zones: Central North-Central South, Central South-Sardinia, Central South-South, and Priolo-Sicily (except for peak hours in weekdays).[27] Notice that most wind capacity installed in Apulia and Campania is connected through the Central South-South line, which is affected by significant bottlenecks. The Central South-Sardinia line also connects zones with above average wind capacity, while the Central North-Central South line is likely congested because of exports of wind power from the Central South zone to the Central North zone. Congestion frequencies in other lines change only slightly. What we observe, thus, is that increasing wind penetration comes at the cost of increased congestion episodes that effectively separate the 'wind-intensive' southern regions from the 'windless' north, and that cause fragmentation even among southern zones. One may conjecture that such zonal separation creates more opportunities for market power exercise in the southern zones. If so, it might as well be that price reduction effects of wind penetration are partly offset by such stronger market power. The fact that increased wind power production yields more congestion may also be the reason why electricity prices lie above marginal costs even in the wind potential strategic scenario. Recall that Banal-Estañol and Rupérez-Micola (2011b) attributed this to equilibrium coordination attempts by agents. Our simulations provide a different explanation.

Table 3. Market splitting under strategic scenarios

Periods	Scenarios	BR S	CN CS	CN N	CS SA	CS S	FG S	MF N	PR SI	RS SI	RS S
Off-peak (10pm-6am)	**Real, workweek**	0.01	0.24	0.03	0.18	0.12	0.00	0.00	0.04	0.91	0.04
	Potential,workweek	0.00	0.47	0.06	0.52	0.19	0.00	0.00	0.21	0.82	0.01
	Real, weekend	0.01	0.21	0.05	0.07	0.07	0.00	0.00	0.01	0.93	0.04
	Potential, Weekend	0.00	0.62	0.04	0.52	0.20	0.00	0.00	0.47	0.66	0.00
Peak (7am-9pm)	**Real, workweek**	0.03	0.15	0.09	0.15	0.40	0.12	0.00	0.22	0.94	0.10
	Potential,workweek	0.00	0.25	0.11	0.58	0.54	0.04	0.00	0.15	0.79	0.04
	Real,weekend	0.01	0.12	0.06	0.07	0.19	0.01	0.00	0.06	0.92	0.06
	Potential, weekend	0.00	0.45	0.05	0.61	0.50	0.01	0.00	0.21	0.77	0.01

Legend: BR = Brindisi, CN = Central North, CS = Central South, MF = Monfalcone, N = North, PR = Priolo, RS = Rossano, SA = Sardinia, SI = Sicily, S = South.

27. The reader can refer to Fig.1 for a graphical representation of zones in the Italian grid.

6. Conclusion

In this paper, we have built an agent-based model with the purpose of assessing the impact of high wind power penetration on electricity prices in Italy. Our findings show that, as wind supply reaches its potential, electricity prices decrease, although they remain above marginal costs. Wind power fluctuations bring more volatility to the market, as testified by the fact that price falls more sharply when demand is low, thereby magnifying volatility. The elasticity of electricity prices to wind power fluctuations, detected by means of regression methods, is larger in the wind potential scenario. The patterns of network congestions show that high wind penetration implies more frequent separation between the southern regions, rich in wind, and the 'windless' northern regions. Our conjecture is that zonal separation induced by high wind penetration creates market power opportunities that, if exercised, offset the price reduction effects of wind.

The main policy implication of our results is that transmission investments in the southern zones would we worthwhile, since they would bring further electricity price reductions, to the benefit of consumers. Additional investments in the grid would of course put pressure on the public budget. Whether price reductions would be enough to compensate citizens for the additional tax burden is an interesting research question for the future. In particular, one could explore a further scenario relaxing the transmission constraints that separate the northern and the southern zones. This would confirm or falsify our conjecture that, in the case of Italy, price reduction effects of wind are partly offset by increased market power driven by congestion. Our policy implications are in any case in line with the idea that, since the existing power transmission grids had been conceived to support power generation by large centralized plants, large-scale use of renewable energy, fed into the grid by a myriad atomistic producers, will require the transition to smart grids able to 'communicate' with its users.

The foregoing analysis is by no means a complete assessment of costs and benefits from wind power. In performing comparisons between scenarios, a number of variables have been held constant, such as the efficiency and the vintages of power plants. Technological progress may cause obsolescence of the currently available projections on wind potential. Moreover, since intermittency of wind power production gives rise to large discrepancies between programmed and actually produced energy, supplemental energy reserves for balancing the system are required. Such reserve capacities will most likely be supplied by new thermal plants that will have low utilization rates. Generators will therefore be encouraged to install low-cost and low-efficiency plants with greater GHG emissions (Oswald *et al.*, 2008; Strbac *et al.*, 2007).

Future research will also have to take account of endogenous responses of gencos and energy users to the actual and expected impact of high wind power penetration. Following Twomey and Neuhoff (2010), one could build scenarios in which gencos engage in strategic forward trading. Further scenario analyses could be motivated by the likely increase in demand response induced by the diffusion of distributed generation facilities, relaxing the assumption of inelastic demand along the lines indicated by Banal-Estañol and Rupérez-Micola (2011a).

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