Optimal Price Design in the Wholesale Electricity Market

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ABSTRACT

In this paper, we construct an optimal price design mechanism to determine the equilibrium in the day-ahead electricity market, specifically aimed at solving the uncomfortable conflict between conventional thermal sources (CTS) and renewable energy sources (RES). We find that the actual hourly market design is inadequate to achieve an efficient solution in the presence of a large and increasing share of RES. It is not conducive to catalyzing the correct price signal for future investments and does not take into account welfare considerations. Our proposal for a new market design is based on three main pillars. We state pro-competitive incentives to CTS participation in the market. We take into full account the opportunity cost of RES for society and propose correct price signals on the demand side through an optimal Ramsey pricing scheme. We show an empirical application to the Italian electricity market, using empirical measures of LCOE for RES and empirical estimation of heterogeneous buyers' behavior. The results show improvement in efficiency and welfare in the Italian electricity market with respect to the existing zonal market prices for suppliers and uniform price for buyers.

Keywords: Renewables, Optimal Ramsey prices, New Electricity Market Design

http://dx.doi.org/10.5547/01956574.37.SI2.sbig

1. INTRODUCTION

One of the main pillars of the electricity market liberalization at the end of the 1980s has been the creation of organized electricity markets. The three main components are a day-ahead market (DAM) to determine quantity and price for the next day, an adjustment market (AM) to perform intraday operations and an ancillary service market (ASM) to ensure adequate dispatching resources, which are needed to build the reserve margins for the Transmission System Operator (TSO) security management of the transmission network.

These markets were designed when conventional thermal sources (CTS) were predominant in the market and renewable energy sources (RES) were only a small fraction of the total supply. The actual configuration of the electricity markets is profoundly different from the ideal framework envisioned in those times. There is a growing conflict in the market among CTS and RES that goes beyond the desirable degree of competition and risks to endanger the entire market structure (Henriot and Glachant 2013). Transmission line congestion results in the creation of rents, and price signals

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for future investments may be distorted. Therefore, we deem it necessary to rethink the entire market design to provide a proposal for comprehensive reform.

The main aim of this paper is to define an optimal design to determine zonal prices in an organized electricity market. We think that the market design must take into consideration the promotion of competition among all suppliers. This means promoting pro-competitive incentives to all generators to bid the marginal cost (MC) for every hour, which is the short-term variable cost, knowing that the cumulated difference (integral) between the short-term MC and the equilibrium System Marginal Price (SMP) in the long run will recover the fixed costs of the investments (Cardell et al. 1997, Hogan 2014). Specifically, we deem it necessary to take into full account the opportunity cost of RES for society when submitting bids to the market. In addition, the market design must recognize the existence of externalities associated with the transmission security management. This calls for designing correct price signals on the demand side through an optimal Ramsey (1927) pricing scheme.

According to the uncontroversial theoretical principle of efficient market equilibrium, the regulation of the electricity market entails that each generator submits a bid to supply a certain quantity at a desired price and that each buyer submits a bid to purchase a certain quantity at a desired price. The time span is generally short: the typical electricity market is organized by the hour, e.g., Nordpool in the Scandinavian countries, EEX in Germany, Powernext in France, IPEX in Italy, OMEL in Spain, and PJM in the US, while some other markets are organized by the half-hour, as in Australia, New Zealand, and the UK (Green, 2005).

Each bid is attributed a merit order; supply bids are cumulated according to an increasing price order to construct a market supply function, and demand bids are cumulated according to a decreasing price order to construct a demand supply function. The efficient price is determined by the intersection of supply and demand every hour, yielding the SMP. It is evident that this outcome is efficient insofar as the following four ideal conditions are satisfied.[1] The supply side is constituted by a large number of perfectly competitive units. The aggregate marginal cost function is non-decreasing, yielding a non-negative sloped supply function. There is no impediment to free trading, and there are no externalities in the market. Unfortunately, none of the four above-mentioned conditions are fully satisfied in the world's electricity markets.

In practice, regulators have tried to improve efficiency, introducing various peculiar features in the electricity markets. In the UK, a 2013 reform (Energy Act 2013) introduced a Capacity Market (CM), which will help ensure security of electricity supply at the least cost to the consumer and Contracts for Difference (CfD), which will provide long-term revenue stabilization for new low carbon initiatives. In Italy, CFD were envisioned by regulations since their creation in 2004, while CM was effectively introduced with regulatory reform in 2014 and will start operations in 2016. In the EU, there is a coordinated effort under EU regulations to achieve a common model of market coupling among various national markets (Glachant 2010). In the market reform debate, geographical differences in the demand structure have not been adequately considered.

In this paper, we propose a new and comprehensive set of rules for determining the efficient equilibrium price in the market, accounting simultaneously for the existence of supply market power, line congestion, RES abundance and heterogeneity of buyers' behavior (Cardell et al. 1997). As an empirical example, we elaborate upon the elementary bid data of the Italian IPEX market

1. There is an extensive literature on the departure from ideal conditions in the electricity markets. For recent analysis of market power and congestion in the Italian market, see Bigerna et al. (2016). For a theoretical justification of the violation of the positive supply slope condition, see Holmberg and Willems (2015).

from the period 2010–2014 (as published by the Italian market operator, GME), to simulate counterfactual market outcomes in the DAM.

The remainder of the paper is organized as follows. Section 2 presents the theoretical framework for the optimal market design. Section 3 shows the empirical methodology and describes the dataset that was used. Section 4 discusses the empirical results, and Section 5 presents policy implications and concludes the paper.

2. OPTIMAL MARKET DESIGN

In a perfect theoretical market, the SMP provides an efficient solution insofar as there are only price taking agents (buyers and sellers) and there are no externalities. In reality, electricity markets contain several departures from the ideal model of perfect competition. We analyze four main causes of inefficiencies embedded in the specific functioning of the electricity market and discuss the appropriate solutions (Garber et al. 1994, Glachant 2010).

The first cause is the existence of market power exercised by the large oligopolistic generators. The resulting equilibrium price can be different from the competitive solution because oligopolists may adopt a markup strategy for setting the price. This is a relevant issue especially when the exercise of market power is intertwined with transmission line congestion (Bigerna et al. 2016). We assume that it can be properly measured and can be contrasted with adequate pro-competitive regulatory actions (Garber et al. 1994, Bigerna et al. 2015b). For this reason, we do not dwell further on this issue and instead focus mainly on the other three causes of inefficiencies, which are related to the externalities arising from the abundance of RES supply and from line congestion.

The second cause is constituted by the positive externality related to network security management, which has some characteristics of a public good (Tangerås 2012). In fact, the network management must take care of network security, which is an indivisible good. As a virtual thought experiment, consider a bolt of lightning that unexpectedly strikes a transmission line, causing it to trip and creating congestion between two adjacent zones. The resulting increase in the electricity load of the hit area yields a higher zonal price. This raises the issue of who should pay for this increased congestion cost. A pure zonal pricing mechanism would put the burden uniquely on the shoulders of the consumers in the hit area. If these consumers had the opportunity to make a decision in advance, however, they would probably have rescheduled their behavior optimally. Notice that if weather conditions are systematically different among different areas, i.e., lightning occurs more often in one area than in another, the consequences are certainly socially unfair.

The third cause is constituted by the positive externality of the existence of RES. In other words, the large amount of RES creates a positive externality because RES provides relief from pollution and therefore provides a public good, which is clean air (deLlano-Paz et al. 2015). The localization of RES in a country is largely a consequence of the incentive schemes designed by the regulator. There is a normative issue here as well. If the incentive is equal (as is the case for most countries) in all areas of the country, this yields a profitability advantage to the south for solar technology or to windy coastal and hilly areas for wind technology. In other words, a citizen who invests the same amount of resources garners benefits in a region where RES are relatively more productive with respect to another area. This occurs because the combination of the same investment and different electricity generation output yields a higher profit because the incentive is proportional to the amount of electricity generation obtained (Henriot and Glachant 2013).

The fourth cause is the negative externality arising from the uneven and specific patterns of the localization of RES in a country, which can be different from the distribution of the demand load in the country. There are two consequences, one in the short term related to the transmission line congestion (and network security), and the other in the long term related to the need for new line investment. In other words, congestion results from the peculiar localization of RES supply, such as solar where there is sunshine and wind where there is wind, which is not necessary coherent with the localization of the bulk of industrial and residential load. This can possibly result in market splitting and zonal price differentials (AEEG, 2014).

In other words, like weather conditions, RES availability is not under consumers' control. If the south is more endowed with sunshine, it could create congestion in the transmission lines from south to north, or alternatively, a need for additional investment in new lines. This raises an immediate question: why is the cost of investment in new lines to evacuate RES supply borne by the TSO socialized among all consumers when the congestion created by RES is charged differently among various areas (consumers) across the country? It is somewhat surprising that these normative issues are so infrequently considered in the electricity market debate.

We turn now our attention to the operational determination of the equilibrium market price. Under the current regulatory design, RES have dispatch priority and are therefore recorded as offer bids with zero prices in the merit order on the supply side. For this reason, the large amount of RES injection in the market tends to push the equilibrium price in the electricity market down to zero. In addition, the fraction of non-programmable RES requires an adequate backup of CTS for security reasons. This raises the price in the ASM.

In the long run, if RES supply is completely satisfying the demand, the price level is set equal to zero, which clearly conveys the wrong signal for investments in new capacity, both in CTS and RES. In fact, a zero price is trivially wrong to spur investments in CTS. In addition, a zero price determined by RES abundance is also inadequate to spur new RES investments because the feed-in-premium is typically set by the regulator as a premium over a normally positive market price. The rationale behind the recent UE suggestion to adopt the feed-in-premium is precisely the idea that RES investors should share part of the market price risk. This contradicts the essence of the "premium," however, because the only compatible subsidy for RES when the market price is zero would be a fully administered guaranteed tariff.

In reality, RES are characterized by a non-zero cost for society and we feel that it is possible to measure it. It is well known that from a technological viewpoint, the short-term cost of RES is mainly constituted by the fixed cost of investment, while the marginal cost is nearly zero for RES such as hydro, wind and solar power (biomass power is different because there is the cost of the biomass as a fuel to consider). The short-term cost of RES from a regulatory viewpoint, however, is certainly different from zero. The RES subsidy system prevailing worldwide, whether it is based on green certificates, feed-in-tariffs or feed-in-premium, imposes a short-term cost on all electricity consumers that is akin to the concept of opportunity cost to support emissions reduction policies. In other words, there is a well-defined short-term cost for the final consumer, which is the burden imposed on the electric bill every month to finance the RES subsidy policy.

In Italy, this mechanism is known as the "A3 component" of the electric bill, which is charged to all consumers by the Energy Authority according to a very simple and primitive administrative system. The Energy Authority multiplies the unitary incentive granted by law to a specific RES producer by the KWh produced and records it in an individual account. The Energy Authority computes and records the total sum accrued to all RES producers in a national fund as a liability. This sum is divided by the total KWh consumed in the country and the unitary charge is levied on each customer's electric bill. Disregarding some exceptions and exemptions that are specific to Italian regulations, this mechanism ensures that support for the environmental policy is designed according to the "polluter pays" principle. The total sum collected from consumers is funneled to the national fund as an asset. The Energy Authority is responsible for balancing the national fund and revising these computations every quarter.

This scheme shows that RES do have a definite opportunity cost for society. We deem that the correct way to measure this opportunity cost is to consider the Levelized Cost of Energy (LCOE) of RES. Obviously, the LCOE for the society depends crucially on the localization chosen, besides other financial and institutional factors. The LCOE measures the effective cost of generating electricity at a specific site as a function of the solar irradiation, wind conditions, land crop productivity, factor costs, operational costs, capital costs and administrative costs (for a more detailed analysis, see Bigerna et al. 2015a).

The problem of the current market design is that RES enjoy the privilege of dispatching priority in the wholesale market (e.g., zero price bid in the DAM) but are then financed compulsorily in the retail market. The regulatory question is therefore quite simple: are there alternative ways to ensure the correct formation of the price signal in the DAM, and at the same time, ensure adequate and equitable support to RES?

This is a sensitive issue. The recent history of DAM operation coupled with the fixed incentive to RES in the form of a feed-in-premium is quite discomforting. In fact, a constant unitary subsidy per KWh to RES to be added to the wholesale electricity market price is subject, by definition, to market price volatility. It can happen that the sum of the market price and subsidy is too generous for RES simply because the market price is above normal due to a shortage of generation capacity, line congestion or market power. Notice that only in the first case (shortage of generation capacity) does the above-normal RES profitability give the correct signal for future investment to develop new RES generation, although at an inefficient cost for the society. In the following two cases (congestion and market power), high RES profitability only hides an inefficient rent. On the contrary, it can also happen that the sum of market price and subsidy is too low to repay RES investment simply because the market price is below normal. Again, inefficiencies can arise, e.g., in the case of an excess of CTS generation capacity, because too-low RES profitability hurts the achievement of environmental goals.

We now turn our attention to the demand side of the DAM. In this market, there are heterogeneous behaviors because consumers' behavior may change in various zones due to price differentials, and this change may have consequences on overall consumer welfare. Despite this obvious consideration, there is no recognition of welfare issues in the current market design. On the one hand, there is a solution that shelters consumers from congestion costs. For instance, in Italy's hourly DAM, there is a Unique Systems Marginal Price (USMP) charged to all buyers that is computed as the weighted average of zonal SMP prices when line congestion determines market splitting. The USMP was devised as an instrument of equity to force all Italian consumers to equally share the consequences of the pre-liberalization period, when the former national monopolist developed large hydro plants in the north (close to the mountains) and large thermal plants in the south (close to the ports and the refineries). Thus, the argument in favor of the USMP is that it is fair to consumers. The argument against the USMP is that it provides an implicit incentive for NIMBY behavior against new line development.[2]

On the other hand, there is the solution of zonal or nodal prices, which charge different prices to different consumers. In principle, nodal prices are more efficient than zonal prices (Hogan 1998, Neuhoff et al. 2013), but this is true only on a partial equilibrium basis. In fact, the advocates

2. Feng and Fuller (2005) report that the USMP has adverse effects on investments in the new generation in Italy.

of zonal prices take into account the efficiency of the competition among different suppliers at each node, which is efficient only with respect to the supply. In summary, zonal SMP prices as determined by the current market design are not an efficient solution for the system as a whole. They would be so only if perfect competitive conditions would yield equality between private costs and total costs (i.e., an absence of social costs and externalities).

We propose a New Electricity Market Design (NEMD) to tackle all of the above problems and achieve an optimal pricing scheme in the electricity market. Our proposal is simply based on the principle of optimizing overall welfare, enacting six basic rules:

Rule 1. The DAM equilibrium price is set as the SMP maximizing overall welfare.
Rule 2. Congestion is resolved with market splitting and supply zonal prices.
Rule 3. All bids must reflect at least their true opportunity cost.
Rule 4. There is no dispatch priority in the DAM.
Rule 5. The ASM equilibrium is set on the pay-as-bid principle, including all available RES.
Rule 6. Ramsey pricing resolves all market inefficiencies.

Under Rule 1, pro-competitive regulation is required to curtail completely, or as much as possible, the exercise of market power on the supply side. There is the issue of the relationship between market power and transmission line congestion, as discussed in Bigerna et al. (2016). Under Rule 2, there is an explicit price assigned to the existing inefficiencies, such as line congestions. This means that rules 1 and 2 work together, inducing the regulator to promote efficient investment in generation and transmission.

Under Rule 3, bidding the marginal cost is in the interest of CTS. Bids below are obviously potentially loss-making, if accepted at the margin. Bids above the marginal cost are not competitive (indicating some market power exercise) and risk rejection in the merit order. Given that the marginal cost curve of CTS is rising, or at least non-decreasing, such bidding of the CTS is efficient. As far as RES are concerned, they have zero short-run marginal cost; however, each RES has an opportunity cost, which can be accurately estimated by the LCOE and reflects its long-run marginal cost for the society. The LCOE depends on age, technology and other factors, which can be easily computed within the initial licensing or commissioning process. The regulatory body supervising RES incentives can easily estimate the virtual LCOE of each licensed unit and publish it. This LCOE is the reference level for setting the bid, according to the NEMD.

This scheme is valid insofar as there are competitive market conditions, inducing both CTS and RES to provide sincere bidding. In this respect, our proposal is pro-competitive because both RES and CTS bids should reflect their respective marginal cost for the system. In general, pro-competitive regulation should treat equally both RES and CTS, discouraging bids above the LCOE, which could hint at potential non-competitive behavior. Bids below LCOE are risky for the supplier of a non-programmable RES in the presence of balancing costs.

Under Rule 4, the merit order in the supply side is strictly determined according to the price bid. This means that RES and CTS are intermingled in the merit order only based on their price bid. As a result, some RES may be rejected in the DAM. This raises a conflict with the general environmental policy to use all available RES. Under Rule 5, this conflict is resolved in the NEMD as follows. The TSO considers the rejected RES as potential “must run” units in the ASM, which is regulated on a pay-as-bid basis.[3]

3. There is an obvious difference between must run and priority dispatch. The former is related to network security management, while the latter is related to the environmental benefit. In both cases, there is a regulatory intervention that is superimposed on the market outcome, but the social cost associated may be different.

Notice that the justification of this action is that RES supply is beneficial for the system regardless and must therefore be accommodated in the group of dispatched units, even if it has been rejected in the DAM merit order. The TSO accepts the RES on a pay-as-bid basis at a price, which is set equal to the LCOE and reduces the injection schedule of the corresponding CTS in the ASM. In this way, the TSO can rebalance the injection program, recovering spinning reserves and using up and down regulation of CTS. At the same, time this scheme allows for maximum RES supply.

According to our proposed NEMD, the existing inefficiencies in the electricity market, such as market power and line congestion, must be managed in a better way than they are under existing regulations. To maximize efficiency and therefore welfare, the total cost must be allocated optimally to the demand side. According to Rule 6, the extra cost over the efficient solution should be charged to the different groups of consumers on the demand side on the basis of an optimal Ramsey pricing scheme. This scheme is straightforward to implement (Bigerna and Bollino 2015b). The elasticity of demand for the different zones of the country is estimated and updated periodically by the Energy Authority. For each zone, the virtual efficient SMP for the entire country is computed. This virtual solution yields the efficient equilibrium price in the absence of line congestion and any other potential inefficiencies. In particular, notice that non-competitive behavior is ruled out by Rule 3. Thus, in the case that such behavior still exists in the market, the pro-competitive measures should be able to identify and measure it. The difference between this virtual efficient SMP and the actual USMP represents the mark up to be computed according to the Ramsey pricing schemes.

The set of rules of the NEMD can lead to two possible outcomes, both of which are relevant to appraise the efficiency of this proposal to regulate the functioning of an electricity market.

Outcome 1. All RES are accepted in merit order. In this case, it is irrelevant whether the marginal unit determining the SMP is a RES or a CTS unit. This is the ideal situation if there is no line congestion. All of the potential of RES is used. There are no negative externalities to account for and the SMP reflects the efficient solution for the entire system. If there are line congestions in the above case, the efficient solution is resolved according to Rules 2 and 6.

Outcome 2. Some RES are rejected in the merit order. Again, it is irrelevant whether the marginal unit determining the SMP is a RES or a CTS unit; however, the rejection of some RES means that some accepted CTS are displacing some RES. In this case, the merit order of bids is different from the actual market implementation. A different transmission line congestion pattern with different costs may occur. Thus, the difference between the actual market and the NEMD outcome accounts for this difference.[4] This outcome must be appraised with a cost benefit analysis for the entire society. On the one hand, partial RES rejection deprives society from fully exploiting the environmental benefit. On the other hand, the fact that some RES units cost more than CTS units means that the marginal cost of this environmental benefit is higher than the equilibrium price. This means that there is a need not to avoid wasting the RES supply but to preserve efficiency.

Note that under actual rules, RES units enjoy priority of dispatching so that RES bids are recorded at zero prices, guaranteeing that all RES are automatically accepted in the merit order. This means that some CST units are rejected. The SMP is determined by the marginal CTS unit, which could be lower than the SMP determined in the proposed NEMD. Recall, however, that for all RES, the final consumer pays the sum of the SMP plus the public incentive or the feed-in-

4. We point out that Ramsey pricing allows us to set charges independently from the zonal location of generating units. On the contrary, local prices deviates from the SMP based on demand elasticity and demand is not affected by the changing market regime (actual vs. NEMD).

premium. This last consideration highlights that the comparison between our proposal and the actual regulation must include the public incentive. The question is whether the final consumer pays more or less under our proposal.

We argue that there are two advantages of the proposed NEMD scheme. First, if the supply of a specific RES unit conflicts with the network security management, then that RES unit bid is rejected under Rules 2 and 5, exactly as it is the actual case. Second, there is a superior benefit for the system with respect to the case of priority dispatching with subsidies. The justification is given by the fact that up regulation is more costly than down regulation. According to the Energy Authority (AEEG, 2014), in 2013, the average upward price was 130 EUR/MWh and the average downward price was 25 EUR/MWh. Typically, it happens that with dispatch priority, all RES are always accepted in the DAM, possibly distorting the SMP downward. Subsequently, for network security, some CTS units are called to increase their generation plan in the ASM at the upward bid. Indeed, recent empirical analysis of the Italian market shows that CTS may obtain higher prices in the ASM as a remuneration of their flexibility, which is required to manage the abundant injection of RES (Gianfreda et al, 2015). Alternatively, in the proposed NEMD some CTS units are called to reduce their generation plan at the downward bid. Regulation imposes that the upward bid must be higher than the downward bid. Consequently, for a given quantity to be adjusted in the ASM there is a potential lower cost for the system.

Let us clarify this with a numerical example, which assumes plausible values. i.e close to historical values, for the LCOE of RES, for the marginal costs of CTS, for the up and down bid prices in the AMS and for the average RES unit subsidy. There are two RES units, each with a capacity of 500 MW with two different values of LCOE, 35 and 65 EUR/MWh. There are three CTS units, each with a capacity of 500 MW with different costs, 55, 60 and 65 EUR/MWh, respectively. In the ASM, the up and down bid prices are 130 and 25 EUR/MWh, respectively. The RES subsidy is set at the average value of 50 EUR/MWh. The total load is 1500 MWh. We show the computation of the hypothetical market equilibrium in Figure 1, where Case 1 below refers to the actual market rules, while case 2 refers to the new proposed NEMD.[5]

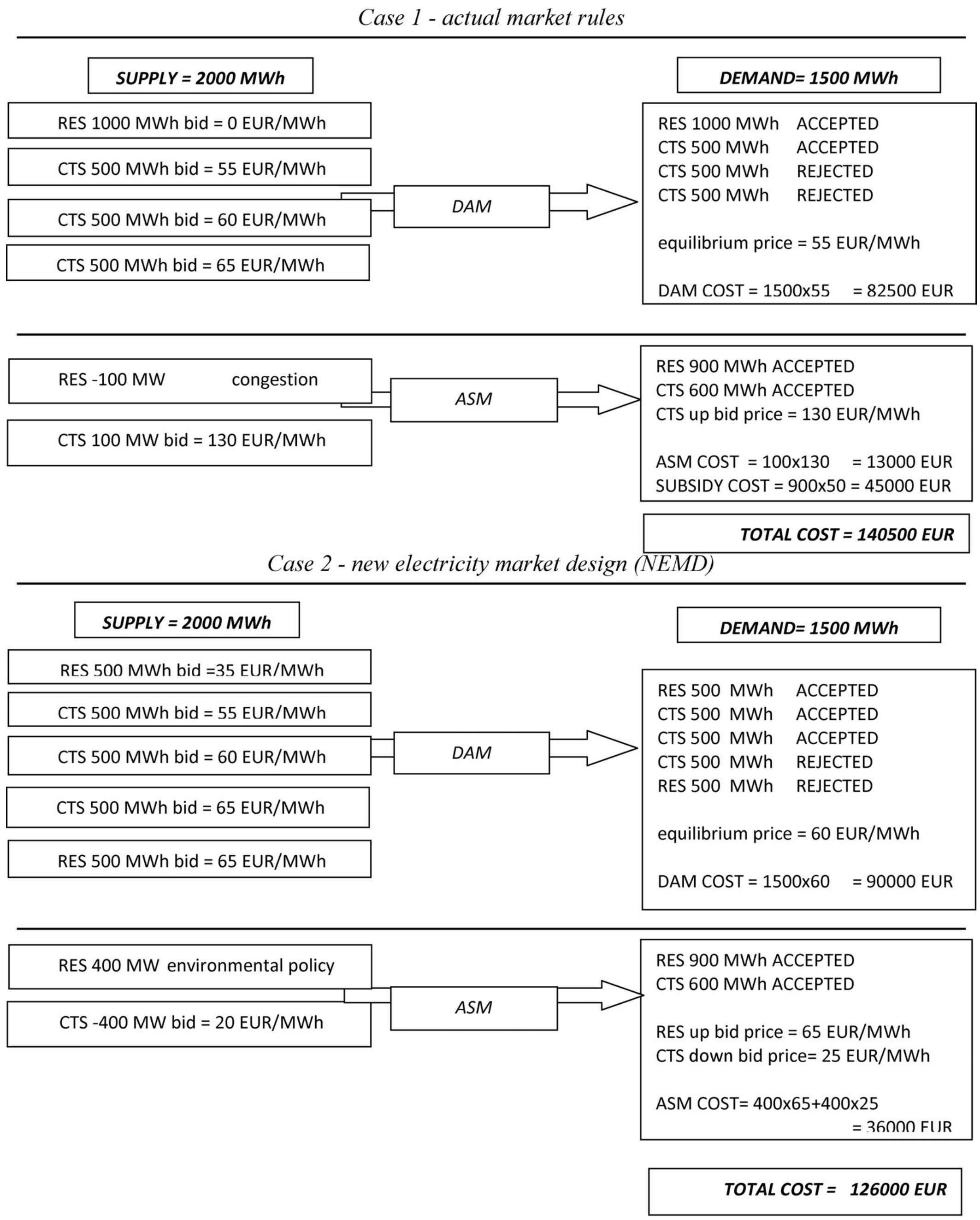
Case 1: there are 1000 MWh of RES bid at zero price; 500 MWh of CTS accepted at a SMP = 55 EUR/MWh; and 1000 MWh of CTS rejected. In the ASM, network security renders it necessary to curtail 100 MWh of RES and accept 100 MWh of CST at a pay-as-bid-price equal to 130 EUR/MWh. Actual RES production is subsidized at 50 EUR/MWh. The total cost for the consumer is 1500x55 + 100*130 + 900*50 = 140,500 EUR.

Case 2: there are 500 MWh of RES bid at LCOE = 35 EUR/MWh; 1000 MWh of CTS accepted at 60 EUR/MWh; and 500 MWh RES rejected at LCOE = 65 EUR/MWh. In the ASM, it necessary to accept 400 MWh of RES at 65 EUR/MWh and consequently, there are 400 MWh of CST reduced at a pay-as-bid price equal to 25 EUR/MWh. Notice that RES are not subsidized. The total cost for the consumer is 1500x60 + 400x65 + 400*25 = 126,000 EUR.

In this way, the new NEMD yields a lower total cost, which is the sum of two additional costs and three additional benefits for the system with respect to the actual solution. The first additional cost is the cost of the rejected RES, which are now paid by the LCOE (under Rule 3) above the SMP. From the societal viewpoint, this cost is needed to obtain the environmental benefit associated with the displacement of the CTS and the consequent reduction in emissions. The second additional cost is that of reducing the CTS in the ASM. From the viewpoint of the society, this is

5. Obviously, this is a hypothetical numerical example, which shows that the new NEMD can be potentially superior to the actual market design. The empirical simulation is provided in the next section.

Figure 1: Simulation of the New Electricity Market Design



bid = bid price of the supplier in the DAM and in the ASM.
equilibrium price = SMP determined in the DAM.
Total Cost = sum of the costs of the DAM, ASM and subsidization mechanisms.

the additional penalty to pay in order to obtain the environmental benefit. In other words, there is an additional social cost that the society should bear to achieve the environmental benefit, which must be added to private cost of supplying CTS to the system; that cost, in turn, is determined by the merit order in the DAM. The benefits are represented by the subsidy savings, the lower CTS cost in the ASM and more efficient pricing for RES with different levels of LCOE.

3. EMPIRICAL METHODOLOGY AND DATA

We use the individual bids in IPEX for the period from 2010 to 2014, made publicly available by the Italian market operator. The data set is constituted by an average of 1.5 million elementary observations per month. There is relevant information for each unit, such as identity, technical characteristics and the status of the bidder on the demand or supply side of the market, the merit order of the bid, the quantity and the price bid to the market, the status of acceptance or rejection, and the awarded price to the all accepted bids. In addition, for each hourly market, there are zonal SMP on the supply side and USMP on the demand side. We construct the cumulated demand and supply curve for each zonal market, determined in the period, to replicate the market equilibrium quantity and price outcomes.

Using the computed demand curve for each hour, we assume that the demand behavior in the DAM expressed by all buyers obeys a cost minimization process. Buyers in the DAM are both traders and distributors who resell electricity to their customers (residential and industrial users, services and public administrations) and large industrial firms (such as cement, steel and chemical firms).

According to this assumption, we parameterize a system of hourly demand functions of buyers, signifying that buyers react to price signals with well-defined demand elasticity. We extend the parametric estimation of Bollino (1987) and Bigerna and Bollino (2015b), explicitly considering the heterogeneity of behavior based on buyers' different geographical zones.

In this set up, electricity demanded in each hour is a different good because it has a different hourly price so that the buyer must solve a simultaneous cost minimization problem for the 24 hours in each day. We assume that the policy maker has knowledge of individual demand functions and is willing to charge buyers belonging to the same zone optimal prices, taking into account efficiency objectives. This is tantamount to using the knowledge of demand elasticity of each group of consumers to compute the optimal Ramsey price scheme. Let us define the (absolute value of the) elasticity in hour h for the group of buyers in zone j as $|\varepsilon_{hj}|$.

We show that the policy-maker behaves in the following way. The policy maker considers the first best solution as the virtual efficient market solution, where there are no inefficiencies. In this case, the virtual efficient price should be equal to the marginal cost of supplying the equilibrium market quantity in each hour h. Let us define this virtual efficient price for each hour h as p^*_h. The market operator determines the actual market equilibrium according to the proposal discussed above. This equilibrium solution yields a market price that includes both market inefficiencies, such as line congestions, and social externalities, such as the cost of dispatching all of the RES units. Let us define it for each hour h and each zone j as p_{hj}. In general, this price yields the total market revenue, which is higher than the total market cost based on the efficient price. This is because there is transmission line congestion and extra RES payments, which must be considered in the market outcome.

The policy maker determines the optimal Ramsey price in each hour, computing the optimal charge x_{hj} to be levied in each hour h to each group of buyers in zone j, which must be added to the price to satisfy the constraint that total market revenues equal total market costs:

$$p_{hj}{}^{*} = p^{*}{}_{h} + x_{hj} \tag{1}$$

where the constraint is expressed as:

$$R = \Sigma p_{jh} e_{jh} = \Sigma p_{jh}{}^{*} e_{jh} \tag{2}$$

The operational computation for each hour h and all zones j according to the classic Ramsey (1927) formula is as follows:

$$[(p^{*}{}_{hj} - p^{*}{}_{h})/p^{*}{}_{h}]/[(p^{*}{}_{hi} - p^{*}{}_{h})/p^{*}{}_{h}] = (1/|\varepsilon_{hj}|)/(1/|\varepsilon_{hi}|) \tag{3}$$

which can be directly expressed in terms of the optimal charges, as follows:

$$[x_{hj}/p^{*}{}_{h}]/[x_{hi}/p^{*}{}_{h}] = (1/|\varepsilon_{hj}|)/(1/|\varepsilon_{hi}|) \tag{4}$$

Eqs. (1)–(4) show the usual constrained result that charges over the efficient price are inversely proportional to the demand elasticity, where $p^{*}{}_{hj}$ and $p^{*}{}_{hi}$ are optimal prices, p_{hj} and p_{hi} are actual zonal prices, e_{hj} and e_{hi} are quantities, ε_{hj} and ε_{hi} are estimated own price elasticities[6] for each hour h and zones i and j. Our welfare maximizing solution is efficient, but it does not take into consideration the distributive equity issue (Diamond 1975). In other words, charges are higher for the group of buyers that exhibits lower demand elasticity, irrespective of the group's socio-economic conditions. Moreover, if we assume that the estimated preferences of each zone j can be attributed to a representative consumer who expresses a well-defined utility function U_j, then our solution can be derived from a social welfare function maximization problem. The social welfare function is: $W = W(U_1, U_2, \ldots, U_J)$, with the minimal assumption that $\partial W/\partial Uj > 0$, under the constraint that the optimal market revenue R is the same as the market equilibrium outcome.

We empirically estimated zonal demand elasticity values from the individual bid data discussed above, using the aggregate demand quantity and price vectors for six geographical zones. The aggregate demand in these zones represents the heterogeneous behavior of different buyers. Notice that in the Italian DAM, imports from foreign border areas constitute approximately 14% of the country's total electricity consumption and buyers who contract electricity purchases from foreign zones may have different behavior from the other national buyers. For this reason, the six zones are chosen to represent the behavior of three domestic areas and three foreign border areas: North, Center-South, the Islands, France, Switzerland (with Austria and Slovenia) and Greece. The North is the heavily industrialized area of Italy. The Center-South is characterized by lower per capita income, a higher share of public administration and small and medium enterprises. The Islands are the lowest-income and least-industrialized areas of Italy. We report some aggregate statistics of the Italian electricity market in Table 1. Notice that the average price increased from 2010 to 2012 and declined in 2013–2014. In the past, the Italian electricity price showed a pattern similar to the international gas price pattern, given the dominance of gas-fired units in Italy. This pattern held until 2012, with the decline in 2013–2014 being due to specific characteristics of the Italian electric market, namely the increasing share of RES, especially photovoltaic energy, during the daily hours. This feature is clearly shown by the reversal of the peak/off-peak price averages. In fact, while as expected, average peak hour quantities are always higher than all day averages,

6. Further details on the estimation methodology of price elasticities are given in Bigerna and Bollino (2014, 2015a).

Table 1: Italian Equilibrium Market Prices and Quantities,* 2010–2013-EUR/MWh and MWh

	All hours							
Year	2010				2011			
	Price			Quantity	Price			Quantity
	Min	Average	Max		Min	Average	Max	
	10.0	66.5	174.6	26438	10.0	71.1	164.8	25958
Year	2012				2013			
	Price			Quantity	Price			Quantity
	Min	Average	Max		Min	Average	Max	
	12.1	75.5	324.2	34089	0.00	63.0	151.9	33243
Year	2014							
	Price			Quantity				
	Min	Average	Max					
	2.2	52.1	149.4	32454				
	Peak hours							
Year	2010				2011			
	Price			Quantity	Price			Quantity
	Min	Average	Max		Min	Average	Max	
	71.5	84.2	174.6	41104	75.9	86.5	142.9	40263
Year	2012				2013			
	Price			Quantity	Price			Quantity
	Min	Average	Max		Min	Average	Max	
	12.1	71.3	207.1	37997	0.00	56.9	99.3	37305
Year	2014							
	Price			Quantity				
	Min	Average	Max					
	2.2	47.5	89.2	35779				

* Equilibrium market price minimum, average and maximum values and average market quantity in the year; “All hours” refers to all 24 hours of the day; “Peak hours” refers to 11:00–15:00 business day hours only.

we find that average peak hour prices are above all hours prices until 2011, but below it after that. Minimum prices are near zero in 2013 and 2014, while maximum prices do not occur during peak hours after 2011.

These patterns are mainly determined by the increase in the share of RES in the total consumption of electricity, from 22.4% in 2010 to 24.0% in 2011, 27.1% in 2012 to 34.0% in 2013 and 36% in 2014 (Table 2). Notice that these shares include hydropower generation, which has always been relevant in the Italian electric system. If we only consider the RES share of wind, solar power and biomass power, the rate of change has been even more dramatic in the same period: from 5.9% in 2010 to 16.3% in 2014. We report the cost of subsidies for RES in the last two columns of Table 2. The total cost is estimated as the “A3 component” charged by the energy authority on the electric bill of final consumers. We compute the unit cost per MWh borne by final consumption as simply the total cost divided by total consumption, showing that this has increased

Table 2: RES Production and Shares of Total Electricity Consumption in Italy, 2010–2014

	Wind	Biomass	PV#	TOT RES	TOT Cons	Tot Cost*	Unit cost**
Years	Electricity Production TWh					Bil EUR	EUR/MWh
2010	9.1	9.4	2.1	77	344	3.6	10.5
2011	9.8	10.8	10.8	83	346	7.4	21.4
2012	13.4	12.5	18.9	92	340	9.7	28.5
2013	14.9	17.1	21.6	112	330	11.8	35.8
2014	15.0	14.0	23.2	116	321	13.4	41.7
	Share of total consumption						
2010	2.6	2.7	0.6	22.4			
2011	2.8	3.1	3.1	24.0			
2012	3.9	3.7	5.6	27.0			
2013	4.5	5.2	6.6	34.0			
2014	4.7	4.4	7.2	36.1			

Photovoltaic
* "A3 component" annual cost, billion EUR, GSE estimates
** Total Cost divided by Total Cons, EUR/MWh
Source: GSE Annual report, various years

from approximately 10 EUR/MWh in 2010 to 35.8 EUR/MWh in 2013 and 41.7 EUR/MWh in 2014.

4. RESULTS AND DISCUSSION

We apply the proposed NEMD scheme to the Italian data to compute the efficient and optimal prices for every hour. To save space, we report only annual averages.

To compute the optimal Ramsey prices, we require elasticity estimates. For this purpose, we updated the estimation of own price elasticities for six categories of heterogeneous buyers, differentiated by the geographical zone of operation in the DAM (taken from Bigerna and Bollino 2015b) for the period from 2010 to 2014, confirming that there are significant differences across zones and time of the year within the range $-.04$ to $-.10$ (Table 3). Elasticity values are generally higher during the morning and late evening hours. In addition, zone elasticity estimation shows that price elasticities are relatively higher for zones 5 and 6. These differences justify the adoption of the Ramsey optimal pricing schemes.

We use the estimated values for the LCOE of the main RES considered, namely hydropower, wind power, biomass power and solar power (Bigerna et al. 2015a), which are computed while taking into account the cost of investment, interests, operating and maintenance costs and locational productivity at the macro-regional level. On average in 2013, the current estimated LCOE in EUR/MWh is 31 for hydropower, 69 for wind power, 96 for biomass power and 115 for photovoltaic power.

We simulate the counterfactual market outcome according to our proposed NEMD via the following steps. First, we impute to all RES[7] bids originally at zero-price the relative LCOE and compute the counterfactual virtual efficient SMP for every hour. This is the unconstrained solution

7. In the DAM, RES bids at zero price are coded as originating from the Government Agency, named GSE, which is in charge of administering the Energy Authority computation of the RES subsidy mechanism.

Table 3: Average Estimated Own Price Elasticities by Zone (*), 2010–2014

Hours	E1	E2	E3	E4	E5	E6
1	−0.065	−0.075	−0.050	−0.075	−0.075	−0.070
2	−0.065	−0.070	−0.050	−0.070	−0.070	−0.075
3	−0.050	−0.070	−0.045	−0.065	−0.065	−0.070
4	−0.040	−0.065	−0.040	−0.055	−0.060	−0.065
5	−0.045	−0.055	−0.040	−0.050	−0.055	−0.055
6	−0.055	−0.070	−0.045	−0.065	−0.065	−0.070
7	−0.080	−0.075	−0.055	−0.070	−0.075	−0.080
8	−0.085	−0.080	−0.070	−0.080	−0.085	−0.095
9	−0.070	−0.090	−0.065	−0.085	−0.085	−0.095
10	−0.050	−0.055	−0.045	−0.050	−0.045	−0.055
11	−0.055	−0.055	−0.050	−0.050	−0.050	−0.055
12	−0.055	−0.055	−0.050	−0.050	−0.050	−0.055
13	−0.050	−0.055	−0.040	−0.050	−0.045	−0.055
14	−0.050	−0.050	−0.040	−0.050	−0.045	−0.045
15	−0.050	−0.050	−0.045	−0.045	−0.045	−0.050
16	−0.040	−0.045	−0.045	−0.045	−0.045	−0.050
17	−0.050	−0.045	−0.045	−0.045	−0.045	−0.050
18	−0.060	−0.045	−0.045	−0.050	−0.045	−0.055
19	−0.055	−0.055	−0.050	−0.055	−0.050	−0.055
20	−0.050	−0.050	−0.045	−0.055	−0.050	−0.055
21	−0.045	−0.045	−0.040	−0.050	−0.045	−0.050
22	−0.090	−0.080	−0.070	−0.085	−0.085	−0.100
23	−0.085	−0.085	−0.060	−0.080	−0.085	−0.095
24	−0.085	−0.075	−0.060	−0.080	−0.080	−0.085

(*) Zones are 1 = North; 2 = Center and South; 3 = Islands; 4 = France; 5 = Switzerland, etc.; 6 = Greece.

of the DAM, yielding the hourly virtual efficient SMP. Second, we simulate the ASM adjustment, computing the cost of accepting the quantity of RES (which were previously rejected in the DAM) on a pay-as-bid basis at their LCOE and the cost of rejecting the same amount of CTS based on the (average) historical downward bid. Third, we compute the simulated total cost in every hour and we compute the difference with respect to the total cost in the case of the virtual efficient SMP (as computed in step 1). Fourth, we use this latter difference as the constraint to compute the optimal Ramsey prices for the heterogeneous buyers (according to Eqs. (1)–4) above) in every hour. Finally, we compare the total cost between the historical scheme and the proposed NEMD.

Specifically, we report on the comparison among the historical prices and costs for Italian consumers, the simulated prices and costs according to the proposed NEMD in Table 4, and the optimal Ramsey prices for the six zones in Table 5.

We have averaged market outcomes by the hour so that the first two columns of Table 4 report the equilibrium market quantity and the uniform system marginal price (USMP) paid by all buyers. The USMP is computed by the GME as the weighted average of zonal prices arising from transmission line congestion. We estimate the effective cost of the MWh for the consumer as the sum of the USMP and the unit cost of RES subsidy, as it is computed by the Energy Authority in col. 3 of Table 4. Obviously, the market price is determined hourly, while the RES subsidy is computed and updated every quarter and levied on the consumer's final bill based on the monthly electricity consumption. This means that the historical price for the consumer of col. 3 is estimated hourly, considering a uniform spread of the RES cost throughout the day. The historical total cost in mil EUR for consumers is reported in col. 4. The annual total cost in 2013 is estimated to be approximately 29 billion EUR.

Table 4: Historical and Simulated Optimal Prices and Costs for Consumers, 2013 Averages

Hours	Quantity MWh 1	USMP EUR/ MWh 2	Hist. price cons. EUR/ MWh 3	Hist. Cost Cons. mil EUR 4	Eff. SMP EUR/ MWh 5	Eff. Cost Cons. mil EUR 6	ASM Cost Cons. mil EUR 7	Simul. Cost Cons. mil EUR 8	Diff. mil EUR 9
1	27386	59.7	95.5	2615	64.7	1772	137	1909	−707
2	26817	52.7	88.6	2375	57.7	1549	142	1691	−684
3	25123	47.9	83.7	2103	57.9	1455	138	1592	−511
4	24767	45.1	80.9	2004	55.1	1365	137	1502	−502
5	24784	44.8	80.6	1997	59.7	1482	136	1618	−379
6	25500	49.3	85.1	2170	64.2	1639	135	1775	−395
7	27891	57.2	92.9	2593	72.1	2013	159	2172	−421
8	32038	65.0	100.8	3231	85.0	2725	251	2976	−255
9	36132	72.7	108.6	3922	92.7	3352	455	3807	−116
10	37838	71	106.8	4041	91.0	3443	734	4177	136
11	38122	64.7	100.5	3831	84.7	3229	975	4204	373
12	38157	60.9	96.8	3692	80.9	3090	1116	4206	514
13	36785	53.6	89.4	3289	78.6	2891	1170	4061	772
14	36045	51.1	86.9	3133	76.1	2744	1147	3891	758
15	36286	54.0	89.8	3260	79.0	2868	1035	3903	643
16	36434	58.2	94.1	3428	73.3	2670	858	3528	100
17	36768	64.1	99.9	3673	79.1	2908	657	3566	−107
18	37347	73.3	109.1	4074	83.3	3111	415	3526	−548
19	37738	79.7	115.6	4361	84.8	3199	242	3441	−920
20	37976	87.2	123.0	4671	87.2	3311	138	3450	−1221
21	36893	86.7	122.5	4519	86.7	3198	112	3309	−1209
22	35063	78.8	114.6	4019	78.8	2763	105	2868	−1150
23	32124	69.9	105.7	3396	69.9	2245	105	2350	−1045
24	29349	63.7	99.5	2921	63.7	1870	105	1975	−946
p.m.									
Year tot.				*28951*		*22225*	*3871*	*26096*	*−2855*
% diff.									*9.86*

Note:
Quantity = Average MWh. UMSP = national average price. Hist. price cons = UMSP plus the unit RES charge.
Hist. Cost cons. = total cost for consumers of DAM plus RES charges. Eff SMP = Virtual Efficient SMP without congestions. Eff. Cost Cons. = Cost for consumers of Eff. SMP solution. ASM Cost Cons. = Cost for consumers of ASM extra costs of RES acceptance and CTS downward reduction. Simul. Cost Cons. = Sum of Eff Cost Cons plus ASM Cost Cons. Diff. = difference between col. 8 and col 4.

The virtual efficient SMP is shown in col. 5. This price represents the optimal solution in the market. It is used as the p^*_h in eq. (1) to estimate the optimal Ramsey scheme, shown in Table 5, taking into account the extra cost due to the transmission line congestion. Notice that the ratio of the optimal Ramsey prices to the average USMP is an average of 16% lower for zone 3 (Islands) and 6–9% higher for the foreign Eastern zones 5 and 6 (Switzerland, Austria, Slovenia and Greece).

In addition, the virtual efficient SMP is used to estimate the efficient cost in the DAM in col. 6 of Table 4. Subsequently, we compute the additional cost in the ASM due to the acceptance of all of the RES (previously rejected) and to the downward injection program reduction for the CTS units (previously accepted) in col. 7. Finally, we add all of the simulated costs for the consumer in col. 8 and show the difference with respect to the historical cost of col. 4.

Notice that the difference is negative during the off-peak and night hours and positive in the peak hours during the day. This is expected because during the daily hours, there is a maximum injection of photovoltaic power, which is the most costly RES.

Table 5: Optimal Ramsey Price Scheme Coefficients, 2010–2014 Averages

Hours	Coef1	Coef2	Coef3	Coef4	Coef5	Coef6
1	1.00	1.02	0.95	1.01	1.05	1.03
2	1.00	1.02	0.96	1.00	1.04	1.04
3	0.99	1.03	0.95	1.00	1.04	1.04
4	0.99	1.03	0.95	1.00	1.04	1.04
5	1.00	1.03	0.94	1.00	1.04	1.04
6	1.00	1.03	0.95	1.00	1.03	1.04
7	1.00	1.03	0.95	1.00	1.03	1.04
8	1.02	1.04	0.88	1.02	1.04	1.06
9	1.03	1.08	0.78	1.04	1.06	1.12
10	1.04	1.10	0.77	1.05	1.06	1.16
11	1.03	1.11	0.78	1.03	1.06	1.18
12	1.03	1.11	0.79	1.03	1.05	1.17
13	1.06	1.07	0.76	1.07	1.08	1.11
14	1.05	1.07	0.79	1.05	1.06	1.10
15	1.03	1.09	0.80	1.04	1.06	1.13
16	1.02	1.08	0.81	1.03	1.05	1.14
17	1.04	1.08	0.80	1.04	1.06	1.11
18	1.05	1.07	0.79	1.06	1.08	1.10
19	1.06	1.07	0.77	1.07	1.09	1.09
20	1.08	1.06	0.74	1.09	1.11	1.08
21	1.08	1.07	0.72	1.09	1.11	1.09
22	1.07	1.07	0.74	1.08	1.10	1.09
23	1.04	1.04	0.82	1.04	1.06	1.07
24	1.03	1.03	0.86	1.03	1.06	1.05
Ave	*1.03*	*1.06*	*0.84*	*1.04*	*1.06*	*1.09*
Stdv	*0.03*	*0.03*	*0.08*	*0.03*	*0.03*	*0.05*
Min	*0.99*	*1.02*	*0.72*	*1.00*	*1.02*	*1.03*
Max	*1.08*	*1.11*	*0.96*	*1.09*	*1.11*	*1.18*

Note:
Coef = ratio optimal price / zonal price. Zones are 1 = North; 2 = Center-South; 3 = Islands; 4 = France virtual zone; 5 = Switz., Austria, Slovenia virtual zones; 6 = Greece virtual zone. Ave = hourly averages; Stdv = standard deviation; Min, Max = minimum and maximum hourly values.

The most important finding is that the total cost is 9.86% lower under the proposed NEMD with respect to the actual market design.

5. CONCLUSION AND POLICY IMPLICATIONS

We have proposed an optimal design to determine zonal prices in an organized electricity market, changing the electricity market rules in Italy to take into account four important market imperfections: line congestion, the existence of supply market power, zero price for RES and the heterogeneity of buyers' behavior. We propose a new market design centered on the concept that the true long-term opportunity cost of RES for the society should be used to determine the equilibrium market price. We deem that if appropriately computed, the LCOE can represent such a long-term opportunity cost for each RES.

To take market externalities such as line congestion and network security management into account, we propose using a Ramsey optimal price scheme. To this end, we estimated a complete demand system with different zonal behavior in the Italian electricity market and recovered estimations of zonal elasticities.

We simulated our proposed scheme for the Italian market in 2013 and obtained overall savings for the consumer in the order of 10%. This is the most important empirical result, which shows that it is possible to improve the efficiency and welfare of the electricity market. Further research could include the electricity markets of other countries to empirically assess the extent of the benefits accrued to final consumers.

The most important policy implication is that an efficient solution is viable in the energy-only market, disposing of the distorting RES subsidy system. In addition, our results show that there is not necessarily any need to resort to additional market complications, such as the creation of a capacity market.

Finally, our proposal avoids the distorted signal of zero price of RES. We restore the possibility of providing an adequate market signal to guide profitability for both the conventional fossil-fueled generation and new RES development in the long run.

ACKNOWLEDGMENTS

We would like to thank Giovanni Battista Aruta and Stefano Alaimo of GME for helpful suggestions to access market data. We also thank Maria Chiara D'Errico for her valuable research assistance for data computation. All errors are ours.

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