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Market design for electrical systems where renewables are a growing presence

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1. Introduction

The central aim of the electric sector liberalization reforms carried out in numerous countries from the late 1980s onwards was to foster and encourage competition in segments of the electric sector production chain (generation and commercialization) that were considered potentially competitive. In European countries, for example, competition in the generation segment was generally introduced by setting up a day-ahead market, where power prices and each generator's output level are determined at auction. This market design has proven suited to systems where prices are formed primarily by fossil-fuelled power plants. However, it does not function reliably in systems where renewables are dominant.

In that light, this article intends to demonstrate the following hypothesis: depending on the cost structure of the electric power generation matrix, price formation in a competitive spot market may not be functional and efficient, but give out misleading economic signals, which can undermine generators' financial equilibrium and impair the expansion of installed capacity.

This problem is particularly evident when analyzing systems where the power mix is dominated by generating facilities with high fixed costs and low or inexistent

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marginal costs, as is the case with most renewables plants. In such systems, spot prices tend to hold stationary at excessively low levels for long periods of time, making it impossible to remunerate investments in generation.

As a result, electric power systems involving an power mix of hydroelectric, wind and other renewable sources, and even nuclear power – and which do not have major interconnections with systems dominated by fossil fuel-fired generating plants – have difficulty in establishing or maintaining a fully functional spot market. A competitive power market can exist in such systems, but only if contract mechanisms different from, or complementary to, the spot market are set up, to offset generators' fixed costs and emit reliable economic signals to guide expansion of the system's installed capacity.

Brazil's electric sector is a typical case of a system where no spot market was formatted for commercialization of power. That decision was taken in view of the characteristics of the electricity generation matrix, which is based primarily on hydro resources.

With the growth of generation from renewable sources, Europe generally – and the Iberian market in particular – began to encounter problems resulting from the transition to a generation matrix based on very low marginal costs: power spot market prices are no longer able to emit appropriate, efficient economic signals. The shifting makeup of the electricity matrix in some European systems tends to create distortions in the market, reducing average power prices on the spot market and jeopardizing remuneration of fixed costs and capital invested in thermal ventures. This problem can now be seen clearly in the Iberian electric power market, especially in Spain, as will be discussed below.

The overall aim of this study is to examine the consequences of substantially increasing the amount of generation based on sources with little or no marginal cost on the functioning of liberalized power markets. The specific aim is to examine the impact of renewables' taking an increased share of the Iberian power market, particularly in Spain.

Methodologically, the study uses basic concepts of the microeconomic theory of traditional competitive markets and of markets comprising predominantly generators with sunk fixed costs and very low marginal costs. It offers an analysis of the Brazilian electric sector, where the system is dominated by generation with nil marginal cost. It then presents the fundamental microeconomic features of markets where generation is largely thermal. Lastly, it presents a case study of the Iberian power market, assessing the impact of increased participation by renewables.

2. Electric sector liberalization and competition in generation

The electric power industry is framed basically by the need for investments involving large amounts of capital and long maturities. The investments are by nature of such an order that substantial gains of scale can be made, while purchases of certain assets constitute “sunk costs“. However, these characteristics figure with differing intensity in different segments of the electric power production chain.

Gains of scale are especially important in the transmission and distribution segments. In these two segments, marginal costs are very small: if the installed capacity exists, then a new customer can be served at very low marginal cost. More importantly, in the absence of regulation, economies of scale enable an installed firm with investments partly amortized to stave off competitors by the simple expedient of setting a price that makes it impossible for any new entrant to gain return on investment. In the distribution and long-distance transmission segment the efficient scale is reached by a single firm in any given location. Because of those characteristics, these segments are classic examples of natural monopolies. By contrast, the generation and commercialization segments, which are not subject to economies of scale of the same magnitude, are considered potentially competitive.

The liberalizing reforms of the electric sector which began in the 1980s fostered competition in these two latter segments by guaranteeing free access to the transmission grid for any player interested in commercializing power, and by setting up power markets. Fostering competition where possible, the liberalizing reforms sought to encourage economic efficiency through the market, focusing economic regulation on tariffs in the other segments which were characteristically natural monopolies.

In European countries, competition in power generation and commercialization was fostered largely by setting up power spot markets, with an hourly price set at auction. This type of market has a dual purpose:

i. it enables optimal system functioning to be determined every day, to meet consumer demand for power from generation firms' supply at lowest possible cost; and

ii. spot market prices serve as economic signalers for investment in expanding the generating capacity and restricting operation of the less cost-effective plants.

However, it is not possible or workable to introduce a competitive spot market for just any electricity system and expect it to operate efficiently and at the same time issue the right economic signals. The cost structure of the predominant generation type may make it unfeasible to set up a functional spot market. This is the case with systems dominated by generators with low or negligible marginal costs (nuclear, hydro and renewable sources such as wind, biomass and solar power), which do not conform to an power commercialization model centered on a spot market. For these types of system, the spot market may fulfill the function of defining optimal system functioning on a day-to-day basis, but the prices formed by such a market will not emit efficient economic signals. This can be understood with the help of some basic tenets of microeconomic theory applied to the cost structure of firms participating in the power market, as set out in the next section.

3. Microeconomics: basic concepts of competitive markets

The working of a competitive market can be understood by way of theories of how individual firms' output, and short- and long-term market prices, are determined under perfect competition.

The key concepts that deserve mention in order to help understand the foundations of power markets are:

i. Fixed cost: this is cost that does not depend on output level. It includes the cost of the capital applied, lease of installations, overheads and so on. Average fixed cost or unit fixed cost is the fixed cost divided by the number of units produced, i.e., the fraction of the fixed cost associated with each unit produced.

ii. Variable cost: is the cost that relates to, and depends on, production volume. In the case of thermoelectric generation, the main variable cost is fuel. For wind or hydroelectric facilities, variable cost is zero or very close to zero. Average variable cost is the fraction of total variable cost associated with each unit produced.

iii. Marginal cost: is the variable cost associated with manufacturing one additional unit of product. In the case of a power plant, the marginal cost is the cost of producing one more MWh, which in turn is generally the variable unit cost of the energy resource used in the production process.

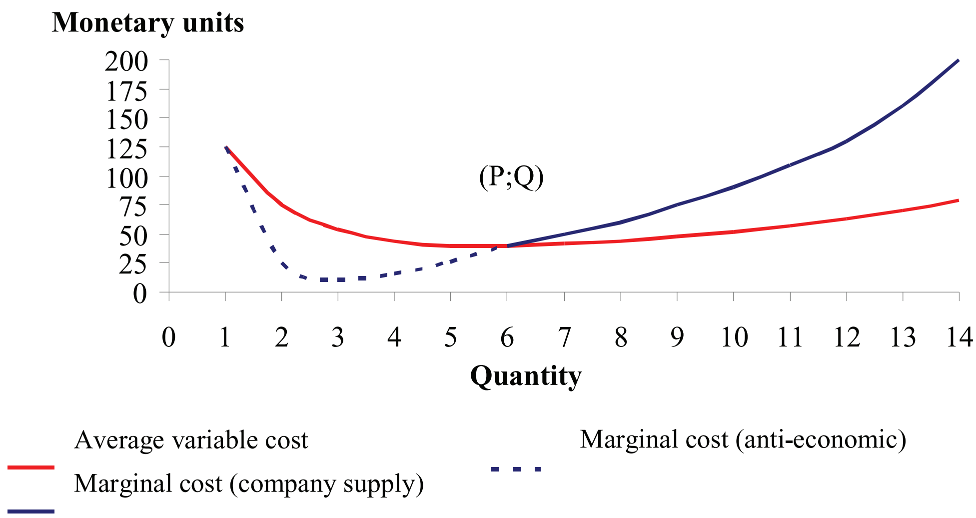
Perfectly competitive markets are those involving a large number of producers and buyers of a homogeneous product and where there are no barriers to producers' entering (new entrants have free access to the market) or exiting the market (no sunk costs to constrain capital mobility). In such a situation, producers are unable to exert market power, but rather are forced to sell their products at the going price, with no influence over that price. The producers are price takers, restricted to choosing between selling at the market price or not selling.

In market structures with perfect competition, prices tend to the level of the industry's marginal cost. Each producer will increase production whenever revenue from an additional unit sold (marginal revenue) equals or exceeds the directly-incurred cost of producing it (marginal cost). On this kind of market, products differ only in price (given that the product is homogeneous) and, accordingly, free competition leads all players to agree to sell even at the borderline price permitted by economic rationality: the price where marginal revenue equals marginal cost, i.e., where the revenue from one additional unit sold equals the variable cost of producing it. Accepting a cost lower than marginal cost would lead to unjustifiable losses; it would be better not to produce than to sell at such a price.

Graph 1 represents such a situation. The firm's short-term supply on a perfectly competitive market is the portion of the marginal cost curve above the average variable cost curve[5] and it is represented by the continuous blue line.

5 Supply by a firm in perfect competition will be determined by its marginal production cost, with one exception: the firm will not offer its product if the price is less than average variable cost. The logic behind that behavior can be seen in an example from the electricity sector. Many thermoelectric plants have significant start-up costs, because they have to burn fuel in order to heat a boiler, only then to be able to generate electric power from steam. For such generators, the variable average cost of producing their first MWh is high because of start-up costs, even though the cost of producing any subsequent MWh (marginal cost) is low. Such thermoelectric plants have no motivation to begin production until revenue can cover start-up costs, i.e., until price is higher than variable average cost.

Graph 1 – Supply by a firm under perfect competition

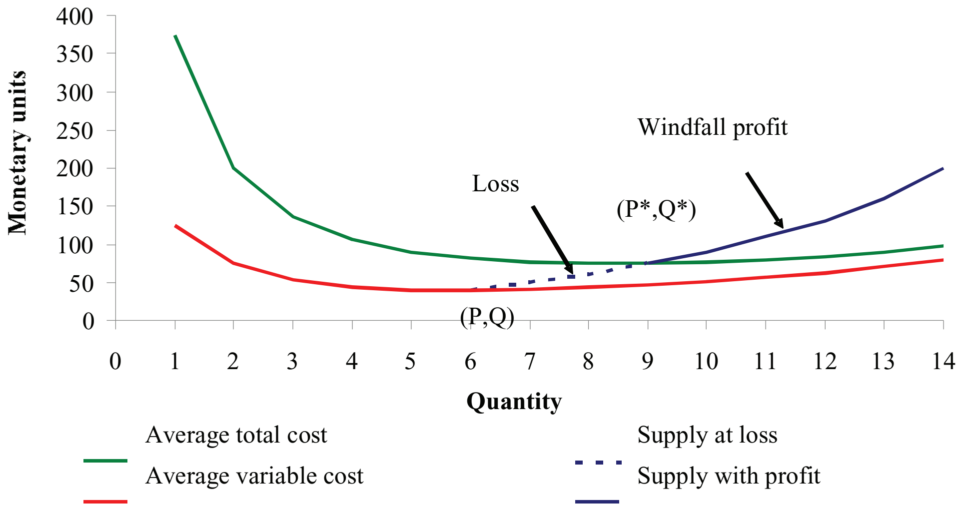


Source: Prepared by the authors based on Varian (1999).

Graph 2 shows the break-even position. It shows the price level which at least equals the firm's unit production cost. This graph is similar to Graph 1, but also includes the average total cost curve, which corresponds to the total cost per unit produced, including both fixed and variable costs.

From Graph 2 the firm can be seen to reach break-even, where revenues cover costs, only from point (P*, Q*) onwards, i.e., from the moment the marginal cost curve intersects the total unit cost curve. Between points (P, Q) and (P*, Q*) – the dotted portion of the supply curve – the firm manages to recover all variable costs, but only part of its fixed costs, and is thus operating at a loss. For the firm, it is preferable to be in that situation than to halt production, which would entail the firm's bearing the fixed costs in full. By continuing to produce, it minimizes its losses, covering variable costs and part of its fixed costs.

Graph 2 – Supply by a firm under perfect competition



Source: Prepared by the authors based on Varian (1999).

In the short term, firms can operate over the output range where only variable costs are completely covered, i.e., they can produce at a loss. That situation cannot be sustained in the long run, however. Many firms cannot hold out for long when they are unable to remunerate their fixed costs, and they end up exiting the market. Firms' exiting the market reduces supply, causing prices to rise to a level equal to or greater than average cost.

In a competitive market, revenues tend in the long run to be equal to total costs. Prices tend to equal total average costs and also marginal costs: the long-term breakeven price will be the point (P*,Q*) in Graph 2. The classic explanation is that agents take decisions in such a way as to anticipate the natural market trend: any prospect of economic gain or loss attracts or repels investors until the predicted gain or loss is neutralized.

However – and this is an important issue that applies to the electric sector – in markets where there are barriers to firms' entering or exiting the market, the convergence between price and costs is imperfect. In power markets, the entry barriers are eliminated by free access to transmission networks at non-discriminatory prices. However, by the very nature of investments in electricity generation, the barriers to firms' exiting the market cannot be eliminated. Exit barriers exist when capital is invested in specific fixed assets which can only be used to produce a specific type of good or service. In such situations, the capital invested is a sunk cost, which cannot be recovered on ceasing production.

In classic competitive markets involving the production and sale of farm commodities, there are no exit barriers. Land and most of the farm equipment used in producing soya or corn, for instance, can be used in producing other goods. A producer dissatisfied with the prospects for corn prices, for example, can leave that market and turn to producing soya for the next harvest, without that entailing any loss of invested capital. In the electric sector, however, that possibility does not exist: a power plant does not have alternative uses. A producer dissatisfied with power prices can even sell the plant, but that does not mean any reduction in supply: the purchaser will go on producing electricity. Supply will be reduced only if power plants are shut down, in which case there will be heavy (even total) losses of invested capital. These exit barriers lead producers to keep on producing for long periods even when market prices entail steady losses. Naturally, there always comes a point when some can no longer bear the losses, such as when cash flows are insufficient for them to honor debts. Only then are plants closed down, and supply diminishes.

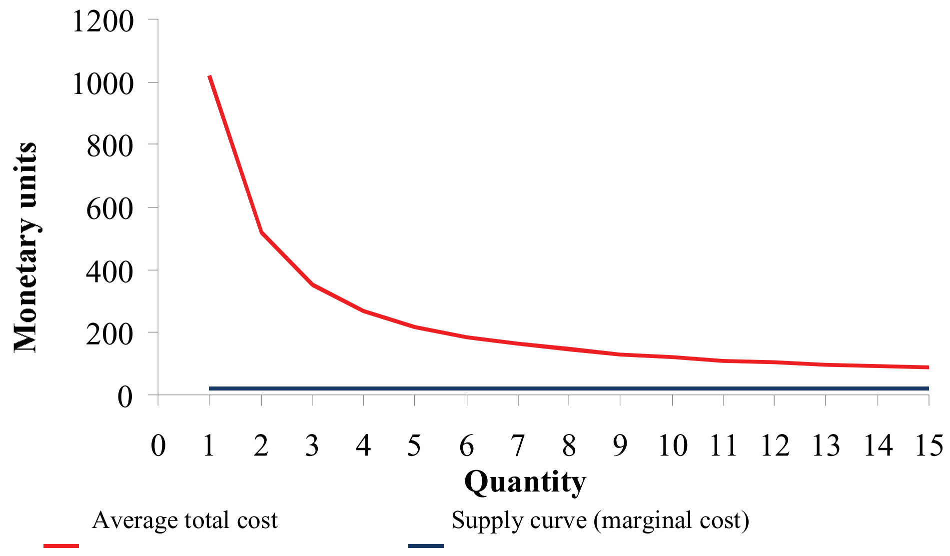
4. Markets with firms with very low marginal costs

Power markets where each plant's generation and the market price are determined on a day-ahead spot market endeavor to practice the microeconomic theory of competitive markets. However, as they depend on the power plants' cost structure, the competitive market may not function properly in every system.

Industries whose cost structure is strongly based on fixed costs and involves sunk costs do not normally even form competitive markets. There is a strong tendency to concentration, so that after a time the main players manage to obtain market power. One case of particular interest is production facilities which, in addition to being capital-intensive, have extremely low variable costs. This is the case with hydroelectric plants, nuclear plants, wind farms and other generators from renewable sources. This is due to the fact that, compared to the cost of capital, the respective fuels are highly economical (nuclear plants) or even free (most renewables).

However, there are other examples of industries with similar cost structures, such as fixed and mobile telephony and information reproduction on digital media. Graph 3 illustrates the supply curve of a firm of this type, where total average cost consists essentially in fixed costs, while average variable cost is always very close to zero.

Graph 3 – Supply by firms with low marginal costs



Source: Prepared by the authors

Firms with this kind of cost structure will offer their products whatever the market price (the supply curve is a straight line parallel to the X axis). Unlike Graphs 1 and 2, which show increasing marginal cost, here marginal cost is constant. The result is that the firm will produce to the limit of its production capacity whenever price at least equals marginal cost. In practice, however, as marginal cost is tiny, production will be kept to a maximum, unless price really falls to zero. In a situation where many – if not all – firms have such a cost structure, the market will be flooded with products.

It is important to note that at no point does the supply curve intersect the total average cost curve (representing the sum of fixed and variable costs). That means that, under conditions of pure competition, where producers do not have market power, firms will always operate at a loss. Firms will always endeavor to produce at full capacity so as to minimize their losses: better to sell all their product at the market price and cover – albeit a small – part of their fixed costs than to halt production and have to bear the whole fixed cost. If all their competitors also try to maximize output and are willing to do so at any price, the result will be high levels of supply, which will bring the market price down to very low levels.

In this connection, note that, on markets where firms have high fixed costs and very low marginal costs, price never covers all costs. Firms never reach break-even: price is always a point on the marginal cost curve, but that curve never intersects with the total average cost curve.

If, on such markets, break-even is not reached in the short term, neither is it to be expected that an equilibrium situation will occur in the long term. If some firms cannot withstand the losses and exit the market, the price will continue equal to marginal cost all the same, i.e., it will continue close to zero, because the remaining firms will continue to maximize production. The situation only changes when so many firms abandon the market that total installed capacity in the industry is no longer sufficient to meet demand. In that case, prices will rise momentarily above marginal costs. If demand has little price elasticity, as in the electric power market, then prices will rise to indefinitely high levels. That fact will not be sufficient to attract new investors, however, because who will be willing to invest in a market where price tends to hold stationary at a level where everyone loses money whenever there is enough supply to meet demand?

A market with a homogeneous product, with a cost structure centered on fixed costs, which include substantial sunk costs, is only economically sustainable in three circumstances:

i. If firms can exert market power to fend off potential competitors and influence prices;
ii. If the market is regulated in such a way as to enable firms to attain economic and financial equilibrium; and
iii. If firms have other sources of revenue besides from selling their products on the market.

These three cases will now be examined in greater detail.

The first situation in which markets with highly capital-intensive cost structures and low marginal costs achieve a certain equilibrium is when a pattern of competition is established that affords firms (or at least the larger ones) some degree of market power. These are oligopolized markets. When unrestrained competition pushes prices downwards, firms with greater foresight and financial capacity buy out competitors in difficulties and, in the process, grow to a size where they gain market power and can thus influence prices.

When the fixed costs are predominantly investments in specific assets or in other sunk costs, then firms already established on the market occupy a particularly comfortable position. The simple fact that they hold partly amortized assets serves as a deterrent – i.e., an entry barrier – to new competitors. New entrants run the risk of being forced out of the market and suffering heavy losses in any price war. Markets with cost structures based on fixed costs with sunk-cost characteristics and which also offer considerable economies of scale display the tendency towards concentration even more intensely: these are the classic examples of natural monopolies, as in power transmission and distribution.

The second case where industries with cost structures centered on fixed costs function appropriately is in regulated markets. Regulation does not need to be restricted to natural monopolies nor to eliminate all competition. It is enough for competition to be framed so that it can be kept healthy.

This is the case, for instance, with mobile telephony. It is a service entailing fixed costs that represent a high proportion of total costs and for that reason would never be economically sustainable under full competition. However, it is not a case of a natural monopoly, because the economies of scale are much smaller than with fixed telephony. Regulation normally permits only limited competition, erecting regulatory barriers to prevent too many firms from entering. This is done, for instance, by limiting the number of licenses for mobile operators. In this case, regulation is designed to strike a balance between allowing the business to be financially feasible, which it could not be under full competition, and consumer interests, which are served if appropriate services are offered at reasonable cost.

Lastly, the third case: industries with cost structures where sunk fixed costs and low or negligible marginal costs predominate can be viable in a competitive environment if there are alternative sources of revenue besides the sale of their products on the market. The best example of a competitive market where firms survive with revenues from sources besides product sales is the Internet website "market" (Shapiro & Varian, 1999). Setting up a website essentially involves the fixed costs of equipment, wages, administration, operation and maintenance. However, the marginal cost (i.e., the cost of producing an additional web page) is tiny, a small fraction of a cent. Moreover, the fixed costs are sunk costs, because once the expenditure has been incurred it cannot be recovered. Accordingly, once the investment has been made, there is no reason not to produce web pages whatever the price.

There may be direct costs to producing content for a web page (for example, payment to a freelance writer to draft text and a freelance designer to format it), but the essence of the business is that it costs little or nothing to reproduce that same page.

As a result there is no way websites without proprietary content can charge for access. Any price charged for access to the site will be greater than the marginal cost and accordingly, other participants in the market will be willing to sell their product for an even lower price. Marginal cost on that market amounts to so little that there is no point even thinking of charging for access to a site.

This, naturally, is not to say that it is impossible to make money on the Internet website "market". The most common strategy is to look for alternative sources of revenue to selling access to web pages. It is possible, for instance, to attract large numbers of users and so earn from publicity, by renting space to advertisers interested in reaching the website's public.

The Brazilian electric power market, where all consumers have to back their consumption with financial power contracts, is one example of this type of setup. In Brazil, generation firms' revenues derive mainly from these financial contracts and not from the sale of power actually generated. A thermal generator, for example, which will be idle most of the time in a system like Brazil's where hydro-power is strongly dominant, earns revenue with its financial contracts, and these revenues are not connected with either the power actually generated or the power spot price (which is all too frequently very low).

5. Competition on power markets

A power market has to be designed and formatted in direct relation to the cost structure of the generation matrix of the country or region it serves.

Electric power markets only function properly (remunerating generators appropriately and signaling the need to expand installed capacity) if market mechanisms are designed in view of the cost structure of the firms operating on the market.

European power spot markets can be taken as an example for purposes of analysis.

On all European power exchanges there is a day-ahead auction where generators make price bids to meet forecast demand on an hourly basis. The successful bids for each time interval are those with the lowest prices that together meet forecast consumption. On most markets of this type, the highest accepted supply price determines the power price for the period (a mechanism known as the uniform price auction or UPA[6]).

This spot market design approximates to the competitive market of classic microeconomics and has functioned successfully for several years on various European markets. However, European electricity markets have one strong trait in common: substantial participation by fossil fuel-based generation, so that price is often formed by supply from a thermal plant with substantial marginal costs.[7]

It should be remembered that the argument set out above endeavored to show that there is no way such a competitive market design can function properly in a system where generator firms have very low or negligible marginal costs.

One hypothetical example may help reinforce and clarify the issue.

Let us assume an electric system where all generators have negligible marginal costs, for example, a system where all installed capacity is geothermal.

A geothermal generator uses steam produced from the heat of volcanic rocks to drive turbines and produce power. It is renewable energy, because the heat extracted in the process is a negligible portion of the heat in the Earth's interior. In addition, it is controllable generation, unlike other renewables, such as wind power, for instance.

6 The alternative is called pay-as-bid auction (PABA). At such auctions, each generator is paid exactly its market bid. This auction design is less used.

7 There is one important exception. Nord Pool originally comprised generators with very low variable costs, and to this day that type of generation still accounts for a high market share. Nord Pool differs slightly from the European market model in that, from the outset, it was a voluntary market whose participants were firms which already held long-term power contracts. Accordingly, at the outset Nord Pool transactions did not determine physical dispatch. When Nord Pool was first set up, Norway's generation matrix was almost totally hydroelectric, while Sweden's was split between hydroelectric and nuclear plants. With an industry centered on generators with that kind of cost structure, it is no surprise that Nord Pool ushered in a period of several years of low energy prices. The generator firms, nearly all State owned, suffered successive years of poor financial performance. Naturally, as spot market prices were low, for a long time there was no price signal of the need for investment in generation. Nor was it necessary, because demand was growing at only 1% per year, starting from a baseline situation of comfortable energy supply (See Von Der Fehr, N. et. all. *The Nordic Market: Signs of Stress?* Cambridge Working Papers in Economics, 2005). With time, Nord Pool attracted more countries and the share of fossil fuel-based thermal generation in the generation market mix increased. Of course, this raised market prices. Today, in normal years, Nord Pool prices are low in Spring and Summer, when water inflows to hydroelectric facilities are greater, but significantly higher in Autumn and Winter, when thermo-electric plants have to be brought online more intensely.

However, what makes it important as an example here is that it is a form of thermoelectric generation that does not use fossil fuels. Its variable and marginal costs are accordingly extremely small. The great majority of the costs of a geothermal facility relate to recovering what was invested in building the plant (equipment and drilling). There are also fixed administration, operation and maintenance costs. The variable costs are restricted to maintenance costs, which depend on the number of equipment use hours.

If the power from this hypothetical system were commercialized on a European-style day-ahead market, with producers having no market power, the power price would be equal to the marginal cost of the thermal generator with the highest variable cost. In this system, all generators' marginal costs are tiny and, therefore, the power price will always be very close to zero. It is obvious that generators will not be able to remunerate the capital invested and that there will be no new investments. Strictly speaking, it will not even be possible to pay the fixed administration, operation and maintenance costs. All the producers will soon be on the brink of bankruptcy and it will not be long before some shut down their operations.[8]

A model of commercialization centered on a European-style power spot market makes no sense in an electric system where generation entails very low variable and marginal costs. In fact, the main reason for the existence of a day-ahead market – to ensure that generation is performed by the plants with lowest variable costs – does not even arise in a system where no plant has substantial variable costs.

With rising and increasingly volatile oil prices, dependence on massive energy imports, and greenhouse gas emission reduction targets, European countries are encouraging and providing incentives for change in the generation mix, with a view to boosting renewables share in the electricity matrix and curbing fossil fuel-based generation. This points to a tendency for generation with low marginal costs to expand and, in such a system, as highlighted earlier, spot prices may give out inappropriate signals.

The next section offers a brief analysis of the specific case of Brazil. There, hydro generation is strongly predominant in the system and thermal generation plays a

8 A point will evidently come when generation capacity is no longer sufficient to meet demand. Prices will rise only when such a situation of insufficient supply occurs. Given the inelastic nature of electric power demand, the tendency is for prices to rise considerably. In fact, they will hold at the price that causes demand to diminish to a level that can be met by the firms in operation. If, by chance, any of the plants that shut down begin to operate again, once again permitting demand to be met in full, spot market prices will drop back to very low levels.

complementary role, and the need is for rapid expansion of installed capacity. The Brazilian electric system underwent liberalizing reforms in the 1990s, but did not go as far as to adopt a true spot market; instead of a day-ahead market, it set up a market in compulsory financial contracts.

6. The Brazilian case: fixed cost-based generation

Brazil's generating matrix comprises mainly hydroelectric plants, making it a good example of a system where very low fixed and marginal costs predominate. Table 1 shows the distribution of installed capacity in the national interconnected system (Sistema Interligado Nacional, SIN[9]).

Table 1
Composition of Brazil's generation matrix, 2009

Source	MWV	% of total
Hydroelectirc*	82,189	83.2
Thermoelectric	13,945	14.1
Nuclear	2,007	2.0
Wind	358	0,4
Others	197	0,2
Total	**98,727**	**100.0**

* Includes all the installed capacity of Itaipu

Source: National System Operator (ONS)

Despite quite considerable thermoelectric installed capacity, electricity is actually produced predominantly from hydroelectric sources, as can be seen in Table 2.

9 The SIN represents nearly the whole Brazilian electric power market, excluding the isolated system located in the North (Amazon) region.

Table 2
Hydroelectric generation in the SIN as a percentage of total generation, 2000-2009

Year	% of total
2000	94.11
2001	89.65
2002	90.97
2003	92.14
2004	88.63
2005	92.45
2006	91.81
2007	92.78
2008	88.61
2009	93.27

Source: National System Operator (ONS).

In addition to hydro generators, the Brazilian system also includes other generators whose cost structures are determined by fixed costs. Nuclear plants accounted for 3.5% of generation in 2009, and most of their output is contracted on a take-or-pay basis; they produce electricity whenever the plant is available, regardless of the economic signals. Also, a portion of coal-fired thermal generation is contracted as take-or-pay, the same occurring with cogeneration facilities and (as yet incipient) wind generation. The authors estimate that, in a hydrologically generous year like 2009, about 98% of the power produced in the National Interconnected System was generated using technologies with no appreciable variable costs.

In such a system, there is no way that a commercialization model centered on a spot market, where agents' daily price bids determine both dispatch and an a spot price, can become functional. The literature on the Brazilian model normally points out that the option to maintain centralized dispatch rather than set up a mechanism along the lines of the European day-ahead market, taken in the 1990s during the market liberalization process, was justified by the need to ensure that hydro resources located in various hydrographic basins would be managed optimally to a long-term horizon (Araújo, 2009). It was often argued that, in a system like Brazil's, a day-ahead auction would not be able for form optimal system dispatch.

This point of view is doubtless correct[10]. However, it does not put an end to the issue, because from the strictly economic standpoint a pure spot market is unable to emit the right economic signals, either for system expansion or for antiquated plants to exit the system.

If there was a European-style day-ahead market in Brazil, spot prices would be derisory most of the time, i.e., whenever hydrological conditions permitted, electric power would be supplied only by generator firms with very low marginal costs.

However, as the Brazilian system is not exclusively hydroelectric, complementary fossil-fuelled thermal generation can be brought on-line in periods of intense drought. In such situations, very high spot prices would be inevitable for long periods. Nonetheless, alternating long periods of very low prices and short periods of very high prices would not constitute a robust, appropriate economic signal of the need to expand system installed capacity. Price uncertainty would be too strong, making return on investment uncertain and, on the basis of investment decisions, hampering efforts to attract investment finance loans.

Nor would the economic signal to decommission obsolete facilities be appropriate: a period of a few years of very low prices would be an economic signal for a good number of thermal plants to close down. However, it too would be an incorrect signal, because those plants are essential to the system in very dry years.

Graph 4 is designed to illustrate this erratic price behavior. It shows the clearance price (Preço de Liquidação das Diferenças, PLD) of the Southeast-Mid-West (SE-CO) submarket (Brazil's main market) over several years.[11] The PLD is not determined by

10 Two examples will serve to illustrate why a hydro plant owner's commercial interest may not correspond to optimal system operation. The first example occurs in a very dry year when the owner of a reservoir at the headwaters of a river will tend to hoard water, expecting prices to soar, and then to generate at full capacity. However, optimal operation of a set of generating plants in cascade occurs when the headwater reservoir is emptied before the others. When the cascade is operated in that fashion, the greater flow volume from the upstream reservoir enables the cascade to generate more energy without the other reservoirs having to reduce their levels of operation, making it possible to maintain a greater total head in the set of facilities. If the same energy were to be produced with the output from the last plant in the cascade alone, its reservoir would empty rapidly, losing head, and thus power. The second example is when energy prices rise to very high levels in the course of a severe drought. On such occasions, a plant whose reservoir still holds sufficient water will tend to maximize production. From an overall system standpoint, however, that may entail undesirable risk of a severe supply deficit in the short term. In that case, the "system optimum" would recommend maintaining a strategic reserve of water. The entrepreneur will see no reason to save water, however, particularly if prices have already reached the regulatory ceiling.

11 Prices corrected by inflation in Brazil to January 2011 values and converted to euros at the exchange rate for that month. Note, however, that the exchange rate used in the conversion – 2.28 reals per euro – is not

market mechanisms, but established on the basis of the marginal cost of operation calculated by computer models for optimizing dispatch at minimum cost. In any case, it will serve to illustrate the problem.

Graph 4
Weekly average PLD in the SE-CO subsystem, Jan 2005 - Jan 2011

Prepared by GESEL/IE/UFRJ on the basis of CCEE data.

The frequency distribution of average weekly prices between January 2005 and January 2011 is shown in Table 3. The high frequency of very low weekly average prices can be seen clearly. In around 54% of weeks average prices were less than € 30 and in 41.7% of weeks, below € 20.

representative of the foreign exchange conversion rate during the period in question. If the conversion was performed at the rate current each week, the values in euros would be smaller.

Table 3
Average weekly PLD in the SE-CO subsystem: Jan 2005 - Jan 2011

Prince range* (€/MWh)	Weeks	%Total
<10	57	17.9%
10 to 20	76	23.8%
20 to 30	39	12.2%
30 to 40	33	10.3%
40 to 50	32	10.0%
50 to 70	52	16.3%
>70	30	9.4%
Total	319	100.0%

Prepared by Gesel - IE - UFRJ from CCEE data (www.ccee.org.br).

The commercial model in place in Brazil, which emerged from the reforms carried out from 2003-2004 onwards, was designed specifically to prevent excessive spot price volatility from contaminating generator revenues.

That commercial model centers on financial contracts that rest on the following key principle:

All consumption must be anchored in a bilateral financial contract, not involving physical dispatch of power, with a generator or a trader. Consumers or traders are not permitted to purchase power directly on the market.

In addition to the bilateral financial contracts, there is also a clearance mechanism, a balancing market, called the short-term market (Mercado de Curto Prazo). This, it must be clear, is not a competitive spot market, where generators make bids to determine prices and quantities sold, but an automatic mechanism for periodically adjusting the power purchased or sold in financial contracts to the power actually measured. The differences between what is stipulated by contract and what actually takes place are valued by the PLD, i.e., at the "price" calculated by the minimum-cost computer models that guide dispatch.

The financial contracts with the generators were designed according to the cost structure of each generator type and the uncertainties specific to each business type, as in the following examples.

i) Contracts with hydroelectric plants. Generation by hydroelectric plants is limited by the water available. As dispatch decisions are made centrally in Brazil, the

National System Operator (ONS) can decide to hold available water in reserve at a given hydroelectric facility, and the generator has no say in that decision: the Operator gives the orders and the generator obeys.

Given that magnitude of uncertainty, two commercial mechanisms were established which jointly enable generator firms to predict their cash flow reliably. The first is that each generator can sell in the long term only the guaranteed physical power (garantia física), which always corresponds to a fraction of the installed capacity and of the average generation expected of a hydroelectric plant, the values of which are determined by official methodologies.

The second is the Power Reallocation Mechanism (Mecanismo de Realocação de Energia, MRE). This is an automatic, compulsory hedge that distributes the power generated by a group of hydroelectric plants among them, so that any surplus or deficit in power from a given hydroelectric plant in relation to the overall guaranteed physical power of the plants in the group is shared equally among all of them. By this mechanism, a plant that, for lack of water or because of some decision by the System Operator, generates much less than its guaranteed physical power, receives power sufficient to cover its deficit from the other hydroelectric plants. In this way, the whole group of hydroelectric plants functions like a condominium, sharing the hydrological risk.

This contract arrangement enables hydroelectric plants' revenues to have characteristics close to fixed income: regardless of the volume of power generated, revenue remains basically constant. The risk is limited to the group of hydro generators' producing less than the overall guaranteed physical power of the hydroelectric facilities in the group, in which case they would all be subject, in the same proportion, to (in theory small) adjustments on the spot market.

ii) Contracts with thermoelectric plants. Actual generation by a (non-nuclear) thermal plant is highly volatile in a system like Brazil's. In periods of normal or favorable hydrology, many thermal generators tend to remain idle for years on end. In years of water scarcity, however, even thermal plants with high variable costs may be operated continuously for long periods. In order to make the business feasible for new thermal generators in view of these uncertainties, contracts with new thermal generators are designed to eliminate the risks associated with frequency of dispatch and fuel price volatility.

The contract mechanism is quite simple: each thermal plant receives a fixed monthly income and transfers to the consumer any variable costs incurred by occasional dispatch. This continues to be advantageous to the consumers, because in the event the thermoelectric plants are operated intensely, they pay the cost of the fuels used rather than the power price on the spot market, which would be extremely high in a situation of critical hydrology. Thus the thermal generators' risk is limited to the penalties levied in the event they fail to generate their declared power when called on; and the costs to the consumer are restricted to the fixed payment to the generator and the expenditure on fuels.

On the other hand, power trading by way of financial contracts introduces competition among generators, which enter into dispute to supply the free and captive markets. As the contracts always span relatively long timeframes (the minimum unit is one month and some for new hydropower ventures run up to thirty years) and as they do not stipulate day-to-day supply of physical power, they tend to reflect long-term fixed costs of generation rather than short-term variable costs.

7. Microeconomics of European power markets

In Europe there are a variety of regional power markets organized along similar lines and involving commercial transactions at several levels:

i. Private bilateral "over-the-counter" contracts (OTCs);
ii. Day-ahead spot market;
iii. Intraday markets;
iv. Real-time markets; and
v. Balancing market.

The day-ahead spot market is the most important of these markets structurally, in that the prices and conditions of longer-term bilateral contracts tend to be tied to spot market expectations[12].

The microeconomic logic underlying the design of power spot markets in Europe is that the most efficient generators receive extra revenue, in excess of their

12 Today, about 30% of electric power consumed in the European Union is traded directly via energy spot markets, according to Meeus (2010).

marginal cost. They receive the difference between the market price (determined by the marginal cost of the least efficient generator dispatched) and their own marginal costs. With this extra revenue, they manage to cover their fixed costs and remunerate invested capital. This extra revenue is also an economic signal to undertake new investments: more efficient plants post surplus profits, above normal levels of return on invested capital in the industry. The surplus profits constitute a stimulus to construction of new, efficient plants. That is why uniform price auction (UPA) prices are considered to reflect efficiency and are capable of covering both long- and short-term marginal costs for the economically more efficient generators.[13] However, this model meets with three distinct problems, which tend to be circumvented by regulatory intervention.

The first problem has to do with the economic signal for investment, represented by the possibility of surplus earnings by new, efficient generators. This economic signal does not function properly for investments in highly capital-intensive plants – nuclear or hydroelectric plants, for example. Projects of this latter type are very unlikely to be viable without long-term contracts to assure them a high – and reliable – level of fixed revenue. Nonetheless, as the benchmark price is the spot price, there is no motivation for consumers and traders voluntarily to take on the risk that long-term contract costs may not be matched by market prices.

Spot market prices are a function of fossil fuel-fired generators' marginal costs, and correlate strongly with fuel prices. Accordingly, prices on the power spot market tend to rise and fall with fuel prices – whereas the same situation does not occur with the fixed costs of capital-intensive plants. If there is no regulation to favor long-term contracts for generators that have costs unrelated to spot prices, then the tendency is for new projects of this type not to get off the drawing board. It is unlikely that a firm will pursue a highly capital-intensive project, even when the average cost of power is competitive in the current price scenario, because it may perform disappointingly if thermal generation fuel prices – and consequently, spot prices – fall markedly in the future (Crampton & Stoft, 2006).

The lack of clear economic signaling for highly capital-intensive investments in generation leads regulatory agents to set up mechanisms to favor of fixed revenues

13 Marques *et. al.* (2008) is one example.

for what are considered strategic investments. In Finland, for example, building of new nuclear reactors, which forms part of the country's energy policy, has been made possible through long-term power purchase agreements (PPAs) signed with a consortium of distributors.

In Portugal and Spain, contracts for renewable power ventures under the "special regime" arrangements (Regimens Especiales) ensure non-market revenues. It should be noted, however, that the motivation to produce notoriously expensive renewable power relates to greenhouse gas emission reduction goals and concerns over respect for energy autonomy. It was thus not intended to provide an economic signal that the market would be unable to furnish.

The second distortion that may be produced by a market design centered on a daily spot market has to do with peak demand price behavior. In such situations, load is met by the generators with highest variable costs. The inelastic nature of short-term electricity demand affords these generators, which are last in order of dispatch, the power to demand prices much higher than their marginal costs. As very high prices are considered difficult to justify socially, regulators will often set a cap on the spot price. That cap, in turn, casts doubt on the business model of the peak generators, which are dispatched only occasionally. In some situations, these generators need to have revenues in excess of their variable costs so as to remunerate investment and cover other fixed costs. A ceiling on spot prices may therefore pose a problem. The regulatory workaround for this problem is to establish capacity payments, i.e. a fixed payment for peak generators which is sufficient to ensure them business feasibility and, at the same time, guarantee system reliability in situations of peak demand.

The third problem of the European power market model, which is centered on a spot market, is the difficulty of dealing appropriately with increasing penetration by renewables in the electricity generation matrix. One consequence of increased generation from renewable sources, which has resulted mainly from efforts to cut CO_2 emissions, is a reduction in participation by fossil fuel-fired generators in the matrix in favor of growth by renewables, nearly all of them with fixed cost-based cost structures and with very low or negligible marginal costs.

Renewables' increased share in the electricity matrix and priority dispatch from such sources heighten spot price volatility and reduce average market prices. However, a spot market with excessively low, volatile prices becomes dysfunctional, losing the ability to afford generators economic sustainability or to furnish economic signals to orient and support the need to expand generation. This issue will be addressed in the sections below, through an analysis of the systems in Portugal and Spain.

8. Growth in renewbles in Portugal and Spain

Increasing penetration by renewables in the electricity matrix is a phenomenon that is occurring throughout Europe for reasons examined above. The advance by these sources in the matrix in Portugal and Spain is particularly interesting because it occurs in an integrated, but relatively isolated, market. Recent trends and the outlook indicate that the generation matrix on the Iberian market will tend towards a cost structure strongly centered on fixed costs, where marginal generators will often have very low variable costs.

The two Iberian countries form a power market, the MIBEL, operating under rules that follow the pattern of Europe’s other power markets. Interconnections between Portugal and Spain are of sufficient magnitude to cause power prices in the two countries to converge most of the time. Meanwhile, the interconnection with the rest of the European continent via France is relatively small-scale, and will continue modest even when upgrades currently planned come into operation. This suggests that integration between the Iberian Peninsula and other European markets is a relatively distant prospect.

Renewable power sources have grown considerably in Portugal and Spain, and CO_2 emission reduction targets for 2020 should lead these two countries to encourage significant new increases in renewables’ participation in electricity generation. There are ambitious projections for growth in installed capacity in wind and solar power in Spain. Portugal, meanwhile, has plans to increase both its wind and hydro generation, while also adding in substantial pumping capacity sufficient to regularize, in part, wind power.

Table 4 shows the makeup of the Iberian electricity matrix in 2009, in percentages of total installed capacity in each country, separating low and high marginal cost technologies.

Table 4
Composition of the Iberian electricity generation matrix, 2009
(% of Total)

Type of technology	Spain	Portugal
Low marginal costs		
Hydroelectric*	20.1	19.5
Nuclear	8.0	-
Wind	20.0	20.8
Solar	3.7	0.5
Other renewables	1.1	0.0
High marginal costs		
Gas	25.0	17.9
Coal	12.0	10.5
Fuel/Gas	3.0	11.1
Thermal (RE)	7.2	9.6

*Includes special regime

Sources: REE, El Sistema Electrico Español 2009
REN, Caracterização da Rede Nacional de Transporte 2009.

In 2009, low marginal cost technologies accounted for 52.3% of the generation matrix in Spain, and 50.8% in Portugal. However, as Spain uses nuclear generation, designed for continuous generation with a high capacity factor, sources with low marginal costs accounted for a larger portion of actual power output in Spain in 2009, as can be seen from Table 5.

Table 5
Iberian Market: power output by technology, 2009
(% of total output)

Type of technology	Spain	Portugal
Low marginal costs		
Hydroelectric*	11.1	18.9
Nuclear	19.0	-
Wind	13.8	16.3
Solar	2.6	0.3
Other renewables	1.6	-
High marginal costs		
Gas	29.0	24.9
Coal	12.0	26.0
Fuel/Gas	1.0	0.7
Thermal (RE)	10.4	13.0

*Includes special regime

Sources: REE, El Sistema Electrico Español 2009
REN, Caracterização da Rede Nacional de Transporte 2009.

In Spain, about 48% of all power produced originated from generating plants with low marginal costs, as against 35.5% in Portugal. The natural consequence of this predominance of low marginal cost generation in Spain was a tendency for prices to be lower, leading to frequent electric power exports from Spain to Portugal.

Any additional growth in renewables' share will have major impact on the Iberian power market, particularly as regards its ability to form prices able to emit appropriate economic signals. The most immediate consequences are:

i. Increased price volatility; and
ii. Lower average market price.

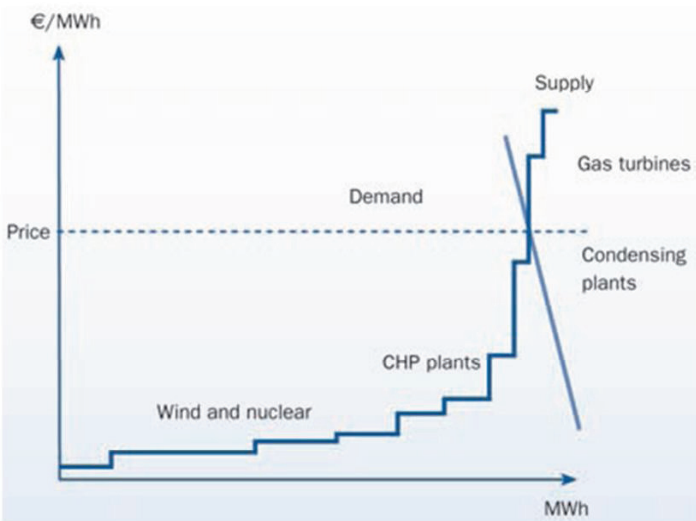
The greater price volatility results from growth in wind generation. Wind farms operate with low capacity factors most of the time, but generation increases significantly in favorable weather conditions and this tends to occur precisely in periods when water is abundant. As a result, generation from other sources decreases, momentarily depressing prices.

The reduction in average market prices resulting from increased power supply from renewable sources is a trend that parallels the reduction in thermal generators' operating levels. However, it is as well to explain in more detail how the phenomenon comes about.

9. Renewables reduce market prices

In a competitive power market with various different generation sources, the market supply curve is the "merit order curve". This curve is formed by the supply from each of the generators: available power and price bid at auction (in a competitive market the price bid by each plant tends to be equal to its marginal cost). In Graph 5, generators' supply is ordered from the least to the most expensive, so that generators with cost structures hinging on fixed costs are grouped in the left hand portion of the curve, while those where variable costs are more significant in their cost structures are concentrated in the right hand portion of the curve. In the power market, the demand curve is quite inelastic and commonly represented by a slanting straight line. In a real-life auction setting, demand is given by consumption forecast for each hour of the day, and describes an almost vertical straight line. The power price is given by the intersection of the supply and demand curves.

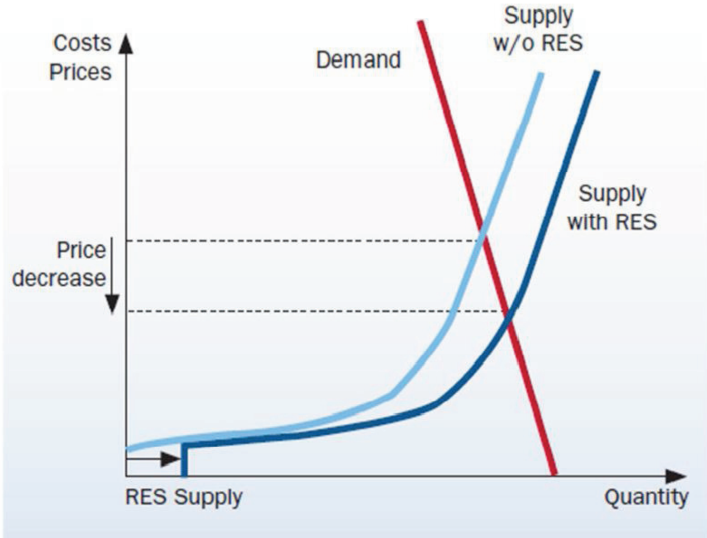
Graph5
Electricity market supply and demand curves



Source: EWEA, Economics of Wind, 2010.

An increase in generation from renewable sources or from other generators with high fixed costs and very low marginal costs leads to a displacement of the market supply curve to the right, as illustrated in Graph 6 (supply with renewables). This shift produces a price reduction, as shown in the graph.

Graph 6
Order of merit and the effect of increased participation by Renewable Power Sources in total generation



Source: EWEA - Economics of Wind, 2010.

This tendency for renewables' increasing participation in the power matrix to depress prices may, at first sight, seem a bonus to consumers. Closer analysis reveals a more complex picture, however.

Certainly, in a competitive market, increased participation by firms with low marginal costs leads to lower prices. The problem arises when this results in a systematic predominance of plants with low marginal costs. In such a situation, lower prices may not correspond to a reduction in production costs, and the economic signaling function of market prices would be seriously impaired.

One first way of looking at the problem of a disconnect between prices and production costs is in the very business model of the new renewable power generators. In Portugal and Spain the new renewables do not depend on the market. They have dispatch priority and enjoy complementary revenue in the form of a premium – the Special Regime contracts – established by regulation in order to guarantee them business sustainability. Accordingly, while renewables bring down market prices, this does not affect their competitiveness directly, because they have other sources of revenue.

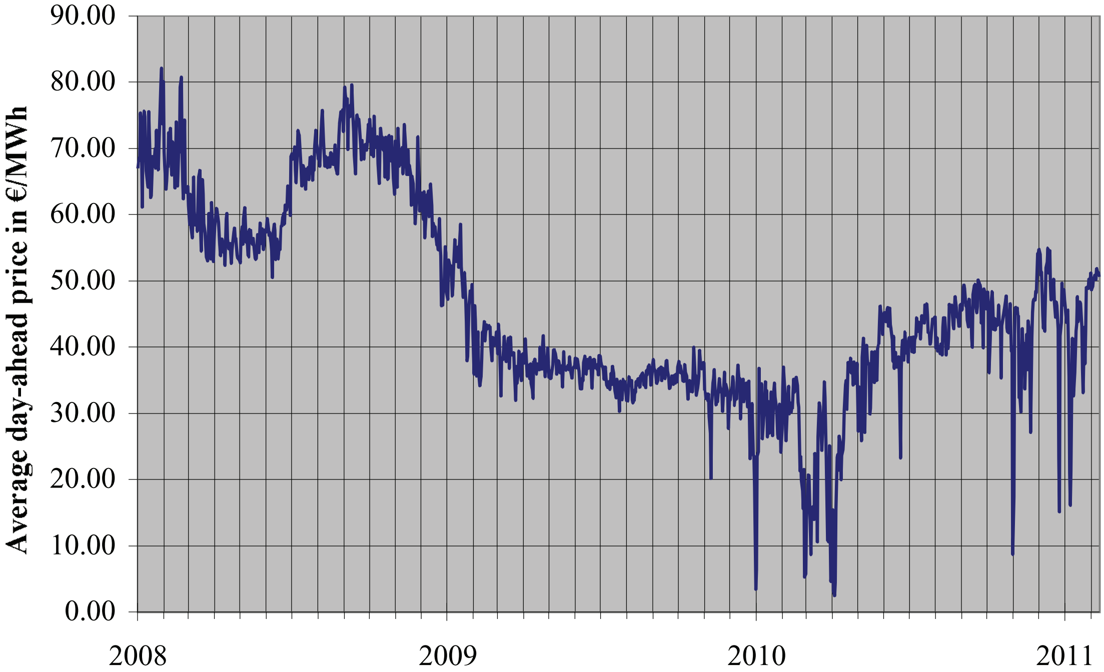
The problem of the disconnect between prices and costs can be seen even more clearly in the adverse effect that increased participation by renewables has on the business sustainability of traditional thermal generators. By and large, the traditional thermal generators, particularly in Spain, belong to the Ordinary Regime (Regimen Ordinario) and depend on the market, the day-ahead auctions, in order to ensure business profitability. Increasing participation by renewables in the electricity matrix means that these thermal plants are dispatched less and less frequently, which reduces their revenues.

10. Power price behavior in 2010

An analysis of power prices on the Iberian market in 2010 will illustrate the central argument of this article. In 2010, because of a specific set of circumstances, renewable power sources' share in power generation expanded substantially in Portugal and Spain. In the first place, the economic crisis caused power consumption to slacken from late 2008 onwards. Secondly, installed capacity in renewables continued to grow in response to existing incentives. Lastly, 2010 was notable for higher than average wind and hydro capability. Simultaneously then, power demand grew less than expected, while supply by renewables expanded considerably.

Increased participation by power plants with very low or negligible marginal costs altered price dynamics, heightening volatility, and for a time severing the correlation between power prices fuel prices. These two phenomena can be seen clearly from the graphs below. Graph 7, showing average day-ahead spot prices in Spain from 2008 onwards, reflects a clear increase in price volatility in 2010.

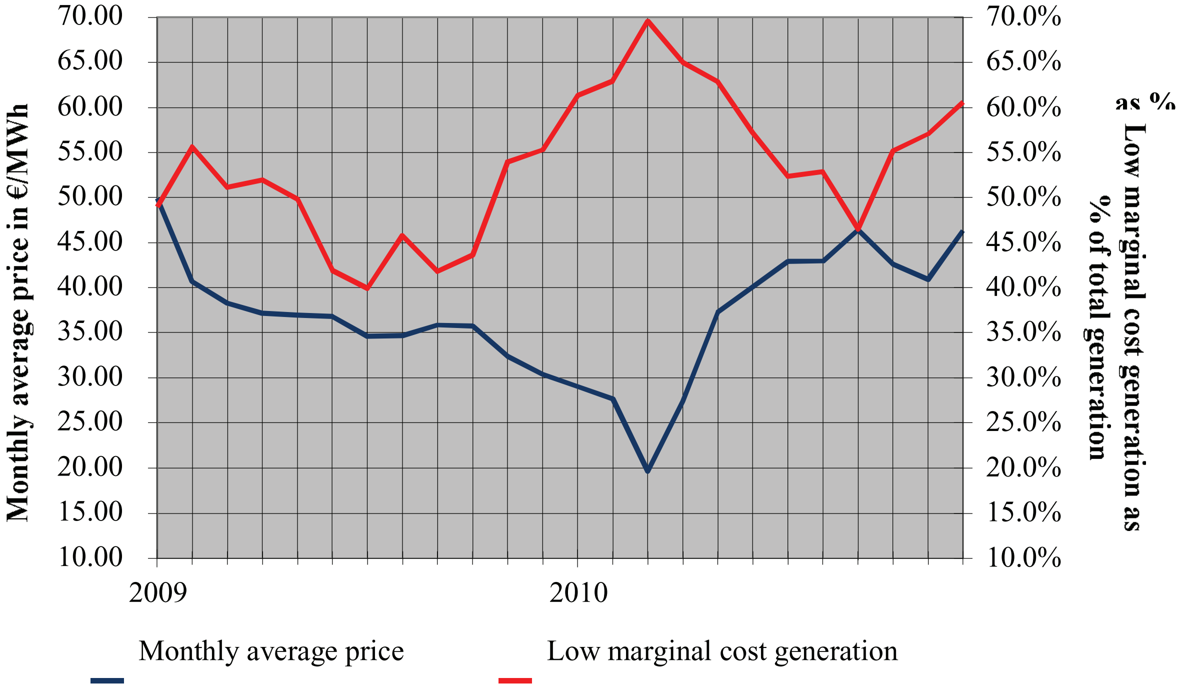
Graph 7
Average day-ahead spot prices in Spain, 2008-2011



Source: OMEL, 2011.

Graph 8 shows the behavior of monthly average power prices in Spain and participation by low marginal cost generation in total generation in 2009 and 2010. The classification "low marginal cost generation" includes hydro-power, nuclear power, and non-thermal power production under the Special Regimes. It can be seen from the graph that, in February and April 2010, when renewables' share of total generation stood above 65%, spot market prices fell significantly.

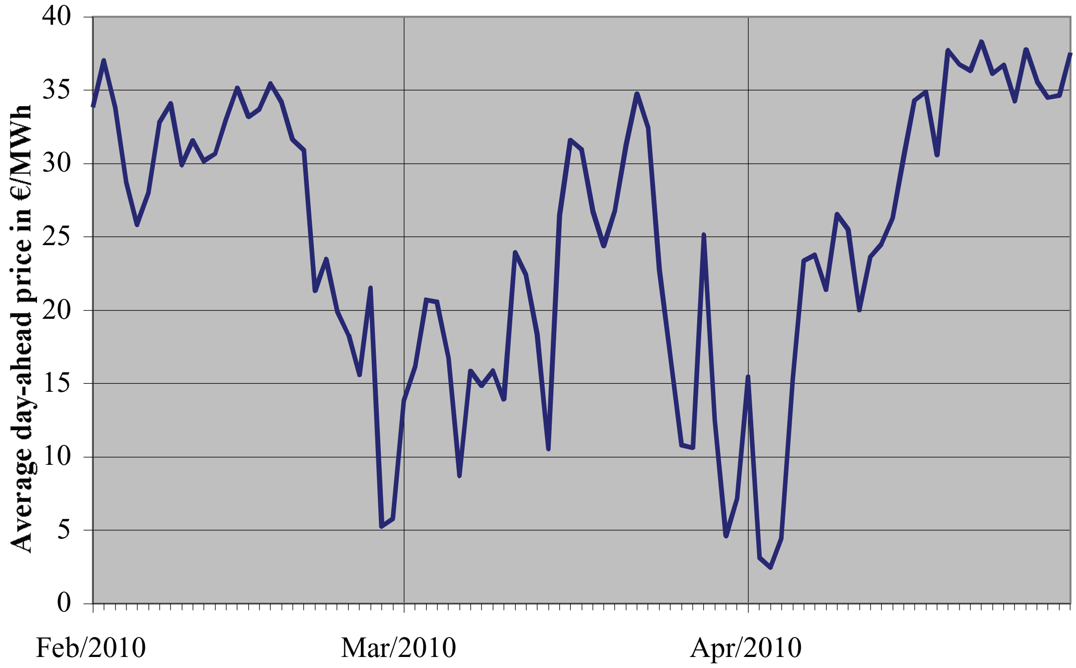
Graph 8
Participation by low marginal cost generation in total generation, and monthly average prices in Spain, 2009-2010



Sources: REE and OMEL.

Spot prices did not decline homogeneously over these months, as can be seen from Graph 9, which shows average day-ahead prices for February to April 2010 only. The most marked price fluctuations occurred because the balance between power demand and low marginal-cost generation supply was not homogeneous over these periods. On days when renewables' share of total generation was smaller, average day-ahead prices were above € 30/MWh, while at other times extremely low prices, of less than € 15/MWh, can be seen.

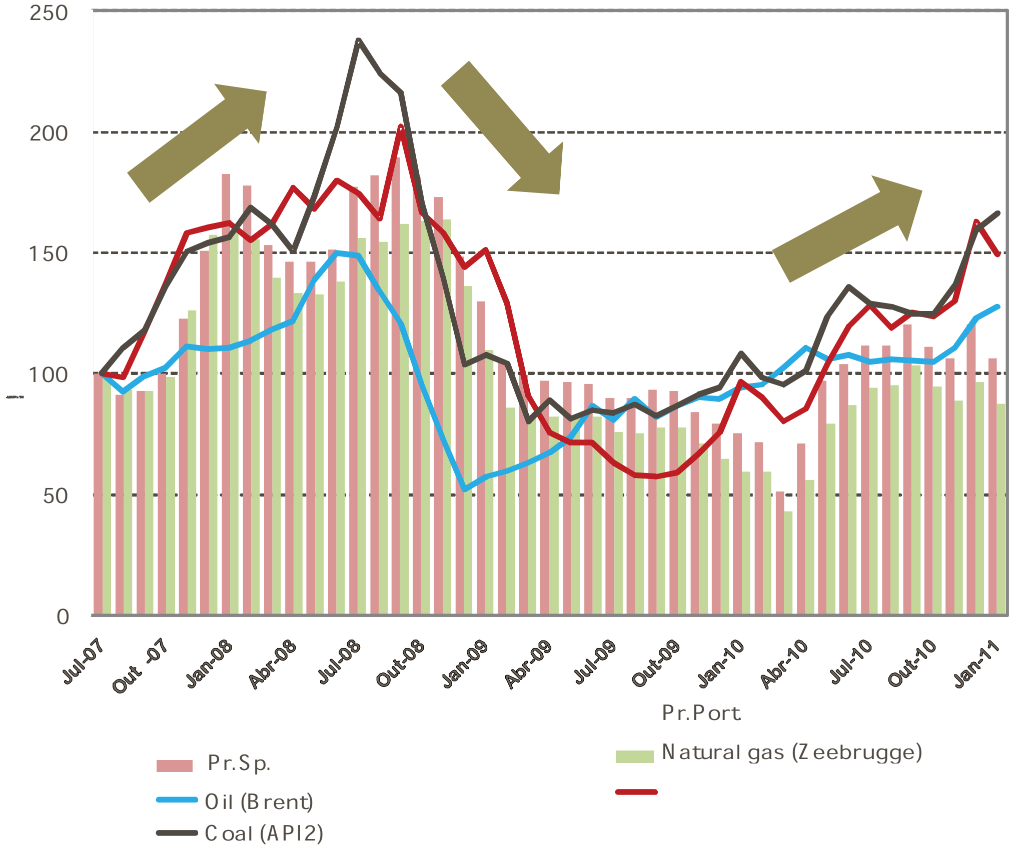
Graph 9
Daily average spot prices in Spain, February - April, 2010.



Source: OMEL

Graph 10 shows monthly power prices on the Iberian market and, at the same time, monthly prices of the main energy resources (oil, gas, and coal). Most of the time, power prices correlate strongly with the main fuels prices, as is to be expected in a system where price is nearly always formed by a fossil fuel-fired generator. However, this correlation ceases from February to April, 2010, as power prices reach their lowest levels at a time when the main fuel prices area tending upwards. This momentary loss of correlation between power and fuel prices can be attributed to increased participation by low marginal-cost generation in the Iberian generation mix, as confirmed by the data in Graph 8.

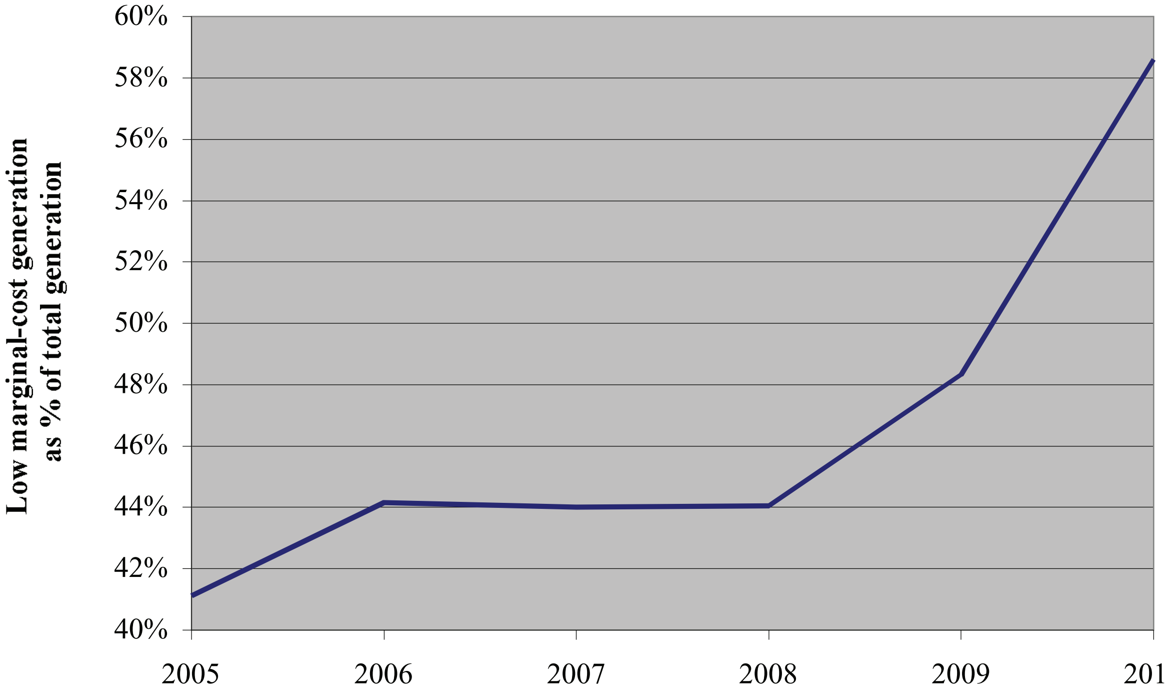
Graph 10
Monthly spot prices and main fuel prices – July 2007 to January 2011.



Source: Teixeira, 2011.

Although price behavior in early 2010 may be regarded as atypical (resulting from the increased hydro-flows and historical peak in wind generation that occurred in the period), it is a phenomenon that should be considered representative of a long-term trend towards increasing participation by low marginal-cost generation on the Iberian market. Graph 11 shows the share of low marginal-cost generation (nuclear, hydro and production under Special Regime arrangements, excluding thermoelectric plants) in total power production in Spain year by year. Low marginal-cost production advanced substantially in the period, from 41% in 2005 to nearly 59% in 2010. As the electricity sector will play an important role in meeting CO_2 emission reduction targets for 2020, it is to be expected that the share of low marginal-cost generation will increase still further by the close of the decade. This has important implications for the dynamics of power price formation.

Graph 11
Share of low marginal-cost generation in total generation in Spain, 2005 - 2010



Source: Prepared by the authors based on REE data.

11. Deficiencies in economic signaling by spot prices as renewables' share in the matrix increases

In a market able to give the right economic signals, plants that fail to achieve break-even must shut down sooner or later. However, unreliable economic signals are given out when renewables' share in generation increases steadily. In such a case, the reduction in market price is merely an expression of the key characteristic of competitive markets dominated by firms with very low marginal costs and considerable sunk costs. As shown above in the section on microeconomics concepts applied to competitive markets with firms with very low marginal costs, such firms are willing to offer their products at practically any price, which leads to a trend towards very low prices, which are always lower than average production costs.

In a market dominated by firms with high variable costs, price signals may actually bring an inefficient firm to close down. However, that is not what happens here, because the apparent inefficiency of some thermal generators is fruit of a change in the dynamics of price formation caused by a substantial increase in generation from plants with very low marginal costs.

The shutdown of thermal generators which the market price signals pointed to as “inefficient” firms would result in impaired system reliability. This is because the increased participation by renewable sources, particularly non-controllable sources, like wind, demands the presence of generators com rapid start-up capability and flexibility, which can be deployed to modulate generation to offset the fluctuations and uncertainties of natural energy sources. If the system lacks sufficient numbers of generating firms with these characteristics, it will not be able to guarantee a stable, reliable power supply.

Renewables’ increased participation in the Iberian market thus jeopardizes the very business model of the traditional thermal plants, whose outlook is for less, and less certain, generation. This tendency undermines both the equilibrium and financial feasibility of existing generating plants and also the attractiveness of new thermal plant projects. In this regard, the problem is not limited to the feasibility of the generators already installed, because growth in load will ultimately make it necessary to build new thermal generators in order to maintain secure supply at times of declining availability of natural energy sources. Diminishing market prices with no relation to fuel prices certainly do not signal correctly the need for generation under Ordinary Regime (Regimen Ordinario) arrangements to be expanded.

Sensitive to this problem, in 2007 the Spanish government introduced “capacity payments” for thermal generators, managed by the system operator[14]. Capacity payments provide peak thermal generators with a source of fixed revenue under contracts of up to one year. In Spain, new thermal generators are offered a fixed revenue for up to ten years, making it feasible to remunerate at least a part of fixed costs. This mechanism constitutes a non-market economic signal to prevent the closure of existing thermal generators and to enable new thermal generation projects to be built, even with the prospect of only occasional dispatch.

It is to be expected that increased participation by generation from renewable sources will bring the Iberian market system to increase still further the proportion of fixed cost-based generation. The result will probably be, as already seems to be happening, a

14 Portugal is preparing to introduce a similar payment mechanism in 2011.

growing need for regulatory interventions to ensure reliable economic signaling and progressively reduce the structural importance of the existing power market.

Conclusions

A system where power trading is centered in a day-ahead market will never, on its own, give rise to an electricity system based on plants with high fixed costs and very low marginal costs. Such a system is incapable of giving out clear economic signals for projects whose costs do not correlate with fuel prices, as is the case with all capital-intensive plants. However, European Union energy policies designed to reduce CO_2 emissions and secure greater energy autonomy have led to the adoption of non-market incentives for expanding the participation of generation from renewable sources in the electricity matrix.

These energy policies are leading to a reshaping of the industry's cost structure, as is particularly clear in the Iberian power market. This article has sought to demonstrate that the transition to an electricity matrix where sunk fixed costs predominate and where price is often determined by a generating plant with very low or negligible marginal costs destroys the foundations underpinning the day-ahead power market.

Short-term wholesale power markets only operate functionally in systems where thermal generators with substantial marginal costs predominate. In electric systems where generators with high fixed costs and low or negligible marginal costs predominate, a market along the lines of the European power markets will not be able to foster economic efficiency.

When subject to short-term competition, as in a day-ahead market, fixed cost-based systems are notable for:

i. Very low market prices dissociated from production costs;
ii. Inability to guarantee existing firms financial viability;
iii. Unreliable economic signaling for investment and for closure of inefficient generators; and
iv. Frequent regulatory intervention to correct distortions in economic signaling by market prices.

The advance of renewable sources in Europe, and particularly on the Iberian market, is increasing the share of fixed cost-based generation, with serious implications for the functionality of the day-ahead market. The most noteworthy are:

i. Pressure on regulatory agencies to introduce mechanisms which provide non-market signaling, so as to guarantee remuneration of generators' fixed costs;
ii. A lack of market-based signaling for investments in generation of whatever type; and
iii. Economic signaling for power imports and exports which is increasingly divorced from power costs.

The declining structural importance of day-ahead markets does not mean abandoning the idea that competition in power generation is advisable. The commercial model adopted in Brazil – a country with predominantly hydroelectric, and consequently fixed cost-based, generation facilities – may offer alternatives in terms of new forms and mechanisms for establishing competition in generation in systems with such characteristics.

In the Brazilian electric system, liberalization – which began in the 1990s and was reformulated in 2003-2004 – took place without the creation of a day-ahead market. In the model that was introduced, payment to generators is largely unconnected with actual power generation. Generation expansion planning to a continuous 30-year horizon is performed by a public enterprise, EPE. Competition among public and, particularly, private entrepreneurial groups occurs through auctions of long-term financial power contracts (up to 30 years for hydroelectric plants).

The Brazilian Electric Sector model established in 2003 and 2004 fosters competition in generation in a fixed cost-centered system. However, this model cannot be transposed to Europe, where fossil fuel-based generation systems will continue to be an important presence for many years to come. In addition, the Brazilian model features characteristics and problems specific to large-scale hydro-generation.

However, with very low marginal-cost generators accounting for an ever growing share of the market, particularly the Iberian market, the economic signaling power of day-ahead prices is tending to deteriorate steadily. This will make the need to encounter innovative market designs for power trading increasingly present and pressing.

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